2018 Distributed System Implementation Plan

Orange and Rockland Utilities, Inc.
Case No. 14-M-0101 and Case No. 16-M-0411
July 31, 2018

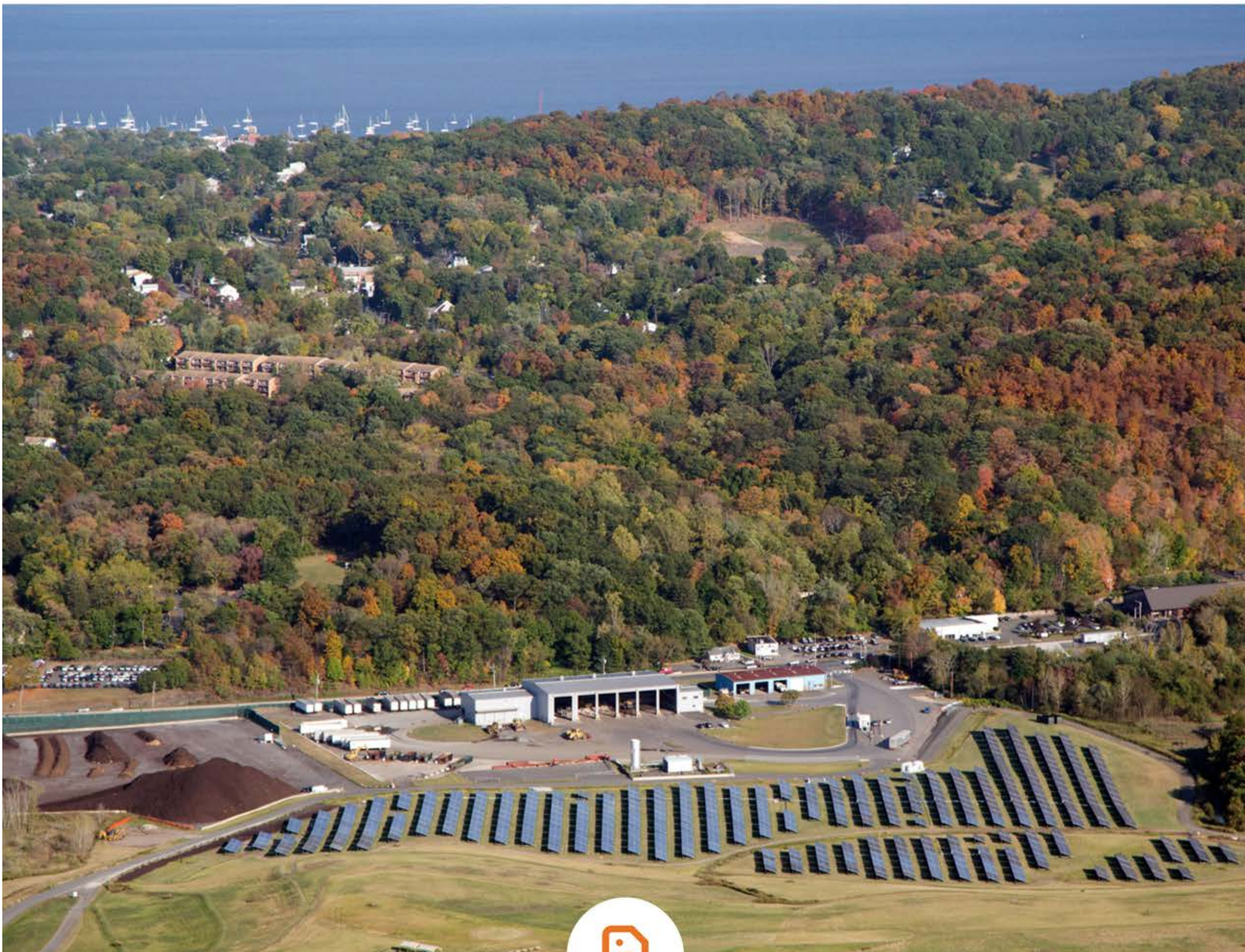


Table of Contents

2018 Distributed System Implementation Plan

Executive Summary

Introduction

The electric industry in general, and in New York State in particular, is undergoing a fundamental transformation. The power grid originally based on one-way electric flow is evolving into a more complex, smart, two-way electric grid with the goal of a cleaner and more resilient energy system. Various forces are driving this transition, including technological advances, state and federal policy decisions, and more favorable economics for distributed energy resources ("DER").[1] At the same time, the manner in which customers interact with electric utilities is changing. Customers expect more personalized services, easier access to their energy usage information, and more control over when and how they use their energy.

Orange and Rockland Utilities, Inc. ("O&R" or "Company") embraces this transformative period in the industry and is responding to these changing customer desires, advances in technology, and federal and state regulatory policy goals, including the State's Reforming the Energy Vision ("REV")[2] initiative. The Company is entering into partnerships with DER providers and operators, changing how it communicates and engages with its customers, and making innovative strategic investments that will allow it to continue to deliver electricity safely and reliably while advancing New York State's vision to develop a cleaner, more resilient, and affordable energy system.

The Company welcomes the opportunity to showcase its accomplishments and to provide a roadmap to DER providers, third-parties, customers, and the New York Public Service Commission ("Commission") of its path to become a Distributed System Platform ("DSP")[3] provider. This filing is the first biennial update of the Company's Initial Distributed System Implementation Plan ("IDSIP"),[4] filed in June 2016.

Furthering the State's vision shapes many of the Company's processes and drives the implementation of upgrades and tools. These efforts—whether completed, ongoing, or planned—are highlighted in this DSIP update submitted in accordance with the Commission's *Order Adopting Regulatory Policy Framework and Implementation Plan* ("Track One Order")[5] in its REV proceeding, and the Department of Public Service ("DPS") Staff's *Whitepaper on Guidance for 2018 DSIP Updates*[6] ("Staff DSIP Update Whitepaper").

O&R's IDSIP served as a source of public information regarding the Company's first steps and plans for developing its DSP, as well as the incorporation of clean technologies such as solar and energy efficiency ("EE") into the Company's planning, operations, and market activities. Following the submission

---

[1] For the purpose of this document, DER refers to energy storage, energy efficiency, demand response, and other distributed generation solutions.
[2] Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision* ("REV Proceeding"), Order Instituting Proceeding (issued April 25, 2014)("REV Order").
[3] Throughout this document, "DSP" refers to the utilities' role of developing and implementing the distributed system platform.
[4] Case 16-M-0411, *In the Matter of Distributed System Implementation Plans* ("DSIP Proceeding"), Orange and Rockland Utilities Initial Distributed System Implementation Plan, (filed June, 30 2016)("IDSIP").
[5] REV Proceeding, *Order Adopting Regulatory Policy Framework And Implementation Plan*, (issued February 26, 2015)("Track One Order").
[6] Department of Public Service Staff Whitepaper, Guidance for 2018 DSIP Updates (dated April 26, 2018)("Staff DSIP Update Whitepaper").

of its IDSIP, the Company filed along with the Joint Utilities of New York ("JU")[7] a Supplemental Distributed System Implementation Plan ("SDSIP") on November 1, 2016.[8] The SDSIP outlined the tools, processes, and protocols to address issues that required further discussion, collaboration, and stakeholder engagement in order to develop coordinated deployment approaches.

To facilitate strong partnerships with DER developers and operators, customers, and other stakeholders, this DSIP update highlights the processes and tools currently being used by the Company, as well as those under development. Ongoing communication and third-party awareness and understanding of the Company's planned transition to the DSP is critical to the success of REV. This DSIP update covers the five-year period ending July 31, 2023, and includes highlights of achievements in the areas of:

- Non-Wires Alternative ("NWA") identification and procurement;
- Integrated planning and forecasting;
- DER integration;
- Energy storage planning and implementation;
- Transparency of customer and system data;
- Plans to modernize O&R's grid operations; and
- Stakeholder engagement.

This DSIP update represents a collective Company effort, with critical input from the Utility of the Future ("UotF") organization, Engineering, Electric Operations, and Customer Operations. Chapter 1 provides a Long-Term Vision collaboratively developed by the JU to provide an overview of the roadmap for continued efforts to implement the DSP, and eventually enable the transaction of distribution-level DER product and services. Chapter 2 provides an overview of the advancements O&R is making in developing and adapting its processes, procedures, and technologies to facilitate the integration of DERs and addresses the specific questions outlined in the Staff DSIP Update Whitepaper. Chapter 3 includes the Company's DSIP Governance and links to its Marginal Cost of Service Study ("MCOS") and Benefit Cost Analysis ("BCA") Handbook. Appendices include a discussion of Tools and Information Sources, Load and DER Forecast, the BCA Handbook, and a list of Acronyms.

In addition, this DSIP update has benefited from a collaborative process with the JU, DPS Staff, and stakeholders. The JU work collaboratively to progress the DSPs as consistently as possible across the while recognizing the inherent differences of each of the utility's systems. To facilitate the review of each utility's 2018 DSIP update, the JU are presenting its plans in alignment with a standard table of contents and employing common language and figures. Where appropriate, the language and figures may be adapted to reflect the progress and plans of a specific utility.

Topical Sections

This DSIP update includes topical sections which highlight the Company's efforts to evolve the DSP across a number of functional areas.

---

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

[8] DSIP Proceeding, Joint Utilities Supplemental Distributed System Implementation Plan (filed November 1, 2016)("JU Supplemental DSIP").

Integrated Planning is fundamental to the safe, reliable, and cost-effective management of the Company's electric delivery system. O&R is dedicated to maintaining a planning process that is progressive and pragmatic in order to maintain a reliable, safe, and efficient electric delivery system. This includes the continued refinement of integrated planning processes in order to incorporate greater amounts of DERs and new technologies.

Since the IDSIP filing in 2016, the Company has made significant changes to further incorporate DERs into its planning processes. These changes include enhancements to the planning process that have increased the Company's ability to identify capital projects for potential deferral or replacement with NWAs. The Company: (1) implemented new NWA suitability criteria; (2) committed to develop and evaluate a portfolio of potential NWA solutions for each NWA; and (3) committed to conduct a detailed BCA for each of its NWA projects.

In addition, the Company is working on: (1) expanding its planning horizon, for 2018 planning and beyond, to include a ten-year outlook in addition to the traditional five-year outlook; (2) modifying the planning process to include top-down and bottom-up methodologies for projecting peak loads; and (3) developing a software toolkit to enable O&R to develop more granular portfolios of DERs for analyzing the feasibility and cost-effectiveness of NWAs.

In the future, O&R plans to work with industry experts, developers, and the JU to develop a methodology to enable probabilistic planning to facilitate further DER penetration.

Advanced Forecasting is an integral part of the Company's planning process. As part of its current load forecasting and risk assessment processes, each year the Company forecasts overall system load and the projected summer peak loads for each transmission facility, individual substation, station transformer bank, and distribution circuit. The Company also projects the peak loads for each transmission line, substation, and station transformer bank as part of its five-year forecast. In recent years, the Company expanded the list of DERs it considers in its forecast from EE and demand response ("DR") to include solar photovoltaics ("PVs") (starting with the 2016 forecast) and electric vehicles ("EVs") (starting with the 2017 forecast).

Recognizing its importance to DER developers, the Company is exploring methods to improve its forecasting process to account for the growth of load modifiers such as PVs, EVs, Distributed Generation ("DG"), and other Demand Side Management ("DSM") measures, such as EE programs and voluntary or Company-administered load reduction programs, at a more granular level.

Starting in 2019, the Company's DER forecasts will become even more granular. In addition to considering DER impacts at a system level, the forecasts for each substation, bank, and circuit will reflect the impact of DERs on that particular element of the system. This newly developed forecasting methodology will add granular detail for the electric delivery system within specific geographic/operating regions to provide improved study and solution development for projected system needs.

As DERs proliferate in O&R's service territory, managing these resources as part of **Grid Operations** will become even more important. The requirements, opportunities, impacts, and challenges generated by DERs will expand. Establishing the appropriate level of visibility and monitoring and control ("M&C") will be critical to realizing the most value to customers and the system from DERs while maintaining a safe and reliable grid. In 2016, O&R completed a scoping study which determined that the Company could expect significant operational efficiencies through grid optimization by implementing an Advanced Distribution Management System ("ADMS") and upgrading its current Distribution Supervisory Control and Data Acquisition ("DSCADA") System.

O&R is working to upgrade its communications infrastructure, Distribution Automation ("DA"), and Substation Automation in preparation for the DSCADA upgrade and ADMS installation, which are scheduled to begin in 2019. These initial technology investments will provide the necessary interfaces to further engage customers, increase the volume and granularity of data, and enable greater DER penetration.

The ADMS is the foundational platform that O&R will use to integrate other near real-time systems and data sources, such as the Energy Management System ("EMS"), Geospatial Information System ("GIS"), a DSCADA system, DA devices, substation automation equipment, Advanced Metering Infrastructure ("AMI"), DG, communications infrastructure, and the Outage Management System ("OMS"). These will enhance electric distribution system situational awareness, M&C, and improve reliability, resiliency, and efficiency. The Company will initiate additional upgrades in 2020 to implement Fault Location, Isolation, and Service Restoration ("FLISR"), Voltage Var Optimization ("VVO") and the installation of a Distributed Energy Resource Management System ("DERMS"), as well as other applications. These upgrades will enhance O&R's ability to monitor and control the grid of the future and transition to the DSP.

Energy Storage is growing in importance to the industry and to O&R. **Energy Storage Integration** is a priority for the Company and has the potential to transform the electric system by performing a variety of services across the distribution and bulk power systems, including facilitating customer-sided demand reduction. Since its IDSIP, O&R has enhanced its energy storage capabilities and has a variety of energy storage projects underway. These projects will demonstrate the value that energy storage can provide to the distribution system as well as its benefits to customers and potential uses in the wholesale market.

The Monsey and Pomona NWA projects focus on leveraging storage to provide load relief, deferring the need for traditional infrastructure upgrades. In addition, through the Innovative Storage Business Model ("ISBM") demonstration project, the Company is working with partners to enable storage assets to participate in multiple markets, thereby providing benefits and incentives to multiple stakeholders.

In June 2018, DPS Staff and the New York State Energy Research and Development Authority ("NYSERDA") released the New York State Energy Storage Roadmap ("Roadmap").[9] The Roadmap lays out a path to achieving the Governor's goal of reaching 1,500 MW of energy storage by 2025 "in a manner that reflects the principles underpinning REV."[10] O&R looks forward to its ongoing involvement in the execution of the Roadmap through its participation in the collaborative and stakeholder processes and the Company's ongoing ISBM demonstration project and NWA efforts.

In 2019, in conjunction with the Consolidated Edison Company of New York, Inc. ("CECONY"), O&R will launch its Smart Home Rate ("SHR") demonstration project which will evaluate new rate designs and test energy storage assets in residential markets. This project will provide O&R with the experience and data needed to implement behind-the-meter ("BTM") storage on a large scale and assist New York State in meeting its energy storage target.

---

[9] Case 18-E-0130, *In the Matter of Energy Storage Deployment Program* ("Energy Storage Proceeding"), New York State Energy Storage Roadmap and Department of Public Service/New York State Energy Research and Development Authority Staff Recommendations ("Roadmap")(filed June 21, 2018).
[10] *Id.,* p. 17.

The Company supports **EV Integration**, another focus of REV,[11] and the development of a robust EV market. O&R has begun multiple initiatives to enhance its tools and capabilities to support the growth of the EV market. Since 2016, the Company has: (1) partnered with a leading auto manufacturer to promote a rebate to its customers on an all-EV; (2) developed online tools to facilitate informed EV decision making; (3) participated in EV industry forums; (4) incorporated EV load into its bottom-up forecast methodology; and (5) participated with the JU in the development of the EV Readiness Framework.

In the future, the Company plans to own, operate, and deploy charging infrastructure in its service territory. This program will provide a means for Electric Vehicle Supply Equipment ("EVSE") deployment until significant EV adoption enables a sustainable business model for third-party EVSE providers. The program will help fulfill the charging infrastructure needs of the EV market while providing the Company an opportunity to explore the operation of EVSE as DERs. In addition, the Company will continue its EV education and outreach efforts and has proposed new rate designs including expanded Time-of-Use ("TOU") rates and the Plug-in Electric Vehicle ("PEV") Quick Charging Station Program.

The **Integration of EE** into the Company's overall plans for DERs is critical and will build upon O&R's long history of implementing EE programs. EE programs can assist in reducing demands on the grid and deferring expensive distribution system upgrades. The Company's EE offerings continue to expand to engage customers. Since the IDSIP, O&R has continued the implementation of multiple EE programs for both residential and commercial and industrial ("C&I") customers which contribute to MWh reductions. The Company currently implements three EE programs: Residential Efficient Products Program, Small Business Direct Install Program, and C&I Electric Rebate Program. Since 2009, these programs have reduced energy use by 149,000 MWh and 119,000 Dth and peak demand by 32 MW. Over 26,000 customers have participated in these programs, received over $25 million in rebates, and realized $26 million in bill savings. These savings are equivalent to reducing carbon emissions by 103,000 tons and taking over 22,000 cars off the road.

In its 2018 electric base rate case,[12] the Company proposed four new EE programs for residential customers and five new EE programs targeting C&I customers. The expansion of the electric programs supports the goals of the Commission's Clean Energy Standard ("CES") Order[13] and builds on the Company's current Energy Efficiency Transition Implementation Plans ("ETIP") portfolio, which consists of the three electric EE programs discussed above.

In 2016, the Company launched its online Customer Engagement Marketplace Platform ("CEMP") to help customers buy EE products and services and to better understand their energy use. Through the CEMP, the Company has begun to integrate EE and DR initiatives to provide a more streamlined customer experience. By purchasing products from the Company's Residential Efficient Products Program through the CEMP, customers are able to apply for instant rebates at checkout, instead of filling out a rebate

---

[11] Case 18-E-0138, *Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure (*"EVSE Proceeding"), Order Instituting Proceeding (issued April 24, 2018)("EVSE Order").
[12] 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* (filed January 26, 2018)("O&R Electric Rate Case").
[13] Cases 15-E-0302 *et al., Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard* ("CES Proceeding"), Order Adopting a Clean Energy Standard (issued August 1, 2016)("CES Order").

application and waiting four to six weeks for a rebate check. In 2019, O&R will transition the ETIP into the System Energy Efficiency Plan ("SEEP") pursuant to the Commission's direction.[14]

The availability of **Distribution System Data** enables the integration and optimization of DERs on the grid by facilitating market participation and DER deployment via signals that publicize where DER products and services can provide the greatest value to customers and the grid, aiding in the development of DER business cases, and guiding investment decisions of third-parties and customers. Since 2016, O&R has made significant progress in collecting system data and information for use by third-parties, developed visualization tools to make the data more accessible, and made this information available to stakeholders and developers via a variety of methods.

Through the Company's hosting capacity maps, the JU website,[15] and O&R's online data portal, the Company makes a wealth of relevant system data available to stakeholders, which they can include as inputs to their technical and business decisions. In addition to hosting capacity information, the Company's hosting capacity maps also include information on Locational System Relief Value ("LSRV") areas,[16] NWA areas and both historical and forecasted 8760 load data. Moreover, the Company website provides access to other relevant system data such as NWA opportunities, interconnection queue information, and Value of Distributed Energy Resources ("Value of DER")[17] tranche status.

O&R has joined the JU in conducting stakeholder engagement sessions focused on the availability of system data and its uses. These sessions provided valuable information to stakeholders regarding the location and common uses of this data. The JU also collected feedback from the stakeholders on the system data catalog, types of data, and ease of access. The Company, with the JU, will use those comments to continue to improve the system data available, as well as identify potential new business use cases.

As O&R collects more granular system data, the Company will continue to work closely with the JU to establish consistency in the distribution of system data to third-parties. The increase in both the granularity of and ease of access to information is essential to the furtherance of market participation and the development of informed DER business cases.

Customer Data is also critical to the success of market development under REV. Providing customers and developers with more granular and timely usage and cost data improves energy literacy and empowers customers to make more informed energy choices. Customer data can also help DER developers and third-parties tailor their products and services to customer needs, as well as inform business decisions. Since 2016, the Company has increased the types and amount of customer data available and has improved access to data through investment in the O&R Digital Customer Experience ("DCX"). DCX was designed to serve the changing needs of increasingly digitally connected customers and offers customer-facing platforms such as the Company's oru.com website, mobile website, My Account portal, and mobile application.

[14]Case 15-M-0252, *In the Matter of Utility Energy Efficiency Programs* ("Utility Energy Efficiency Proceeding"), Order Authorizing Utility-Administered Energy Efficiency Portfolio Budgets and Targets for 2019-2020 (issued March 15, 2018)("Utility-Administered EE Order").
[15] http://jointutilitiesofny.org/home/
[16] Case 15-E-0751 et al., *In the Matter of the Value of Distributed Energy Resources, et al*., ("Value of DER Proceeding"), Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters (issued March 9, 2017) ("Value of DER Order"), p. 16.
[17] *Id*., p. 16.

Customer data is currently securely available via Green Button Connect ("GBC"), Electronic Data Interchange ("EDI"), and in the very near future the Utility Energy Registry ("UER"). Ongoing investments in AMI, GBC, EDI, and the UER are resulting in more data being available to third-parties in a useable format to help support market development.

As the Company continues to make more customer data available, it shares the Commission's interest and long-standing policy of protecting the confidentiality of customer information. The Company continues to collaborate with the JU and stakeholders to strike the right balance between advancing state policy objectives and maintaining customer privacy and data security.

Cybersecurity remains a priority for O&R, particularly in light of the expanded access granted to customer and system data. The prevention of security breaches is an essential responsibility of O&R. Through coordination with the Commission, the JU, and stakeholders, the Company will address the exchange of both system and customer data, while maintaining customer protections and system security. The JU Cyber and Privacy Framework[18] focuses on people, processes, and technology to maintain data security. The framework requires the implementation of an industry-approved risk management methodology and alignment of control implementations with the control families in the National Institute of Standards and Technology ("NIST") Special Publication (SP) 800-53 rev. 4. The JU periodically assess the need for updates to the framework. The current version, as filed in the SDSIP, remains relevant with no updates required.

O&R continues to be in the forefront of making the **DER Interconnection** process as streamlined and transparent as possible. Since its IDSIP, O&R has made improvements to its Interconnection Online Application Portal ("IOAP") and DER energization process thereby significantly reducing the interconnection application process for most projects from months to weeks. In addition, O&R participates in innovative interconnection projects such as DOE ENERGISE—one of only 13 projects awarded nationally aimed at improving the electric grid's ability to accommodate power generated from renewable energy sources.

The Company is working to improve the IOAP as Phase II will automate the Standardized Interconnection Requirements ("SIR") defined screens. Phase III of the IOAP will begin in 2019 and will focus on the integration of the interconnection process with the distribution planning process. At the end of Phase III, all IOAP application and portal processes will be fully automated thereby reducing the overall time to interconnect.

As the interconnection process evolves, O&R will test DER management solutions as an alternative to traditional system connection upgrade costs. The Optimal Export Demonstration Project will test the application of system protection and M&C technologies to reduce the cost of upgrades required for interconnections.

The Company will continue to be actively involved in the Interconnection Policy Working Group ("IPWG"), the Interconnection Technical Working Group ("ITWG"), and the Electric Power Research Institute ("EPRI"). Through these groups, the Company will continue to seek opportunities to further streamline the interconnection process, gain insights on best practices in the industry, and implement changes based on lessons learned.

Beyond DER interconnection, **Advanced Metering Infrastructure** will deliver operational benefits and drive improvements in the convenience, speed, and quality of the services that the Company provides

[18] DSIP Proceeding, JU Supplemental DSIP, pp. 148-160

to all of its customers. AMI provides a foundation of information and communications capabilities that will enable the Company's customers to become informed and engaged energy consumers. Operating in concert with an advanced web portal, AMI will provide customers with the information and controls necessary to help them manage their energy usage, control costs, and improve the environment.

O&R was the first utility in New York to receive Commission approval to move forward with a Smart Meter AMI program. This enabled O&R's deployment of electric smart meters across Rockland County and installation of an AMI communications infrastructure to handle the new data from the meters and support a number of Grid Modernization initiatives such as DA and VVO.

In late 2017, the Company received Commission approval to implement the AMI program throughout the remainder of its service territory. Since July 2017, O&R has deployed over 112,600 smart meters and is on track to complete the deployment of 363,000 smart meters in New York by December 2020. In addition to the smart meters, the Company is set to begin the communications equipment upgrade in Orange County in August 2018 and in Sullivan County in the first quarter of 2019.

A primary focus of the AMI implementation has been communicating the benefits of AMI to customers. The Company has engaged customers through numerous focus groups, surveys, customer education events, home shows, and municipal events. Through these events, the Company has informed customers about the tools available to help them understand and manage their energy usage.

Hosting Capacity analysis and visualization is an essential tool for DER developers, as it enables them to focus on the parts of the distribution system best able to accommodate DERs. O&R is a leader in hosting capacity analysis and was the first utility in the nation to integrate EPRI's Distribution Resource Integration and Value Estimation ("DRIVE") tool into an automated process—one that is being replicated by utilities and vendors across the country. The Company's efforts to provide hosting capacity and interconnection information to stakeholders have followed the four-stage approach defined by EPRI and adopted by the JU. This methodology is reflected in the IDSIP and SDSIP filings. EPRI defines the stages as:

Stage 1 – Distribution Indicators;
Stage 2 – Hosting Capacity Evaluations;
Stage 3 – Advanced Hosting Capacity Evaluations; and
Stage 4 – Fully Integrated DER Value Assessments

O&R began laying the foundation for this method when it updated its mapping and power flow simulation systems, which included releasing and updating its Stage 1 red zone distribution indicator maps. Soon after that, the Company completed its Stage 2 hosting capacity analysis for all radial distribution circuits at and above 12 kV, using the DRIVE tool. Integrating the DRIVE tool into O&R's automated process has allowed the Company to go beyond the goal of updating hosting capacity maps annually to updating the results of its hosting capacity analysis on a monthly basis.

Ongoing improvements will provide additional tools and visibility for DER developers as they consider locations for DERs. Looking forward, O&R is on track for the release of Stage 3.0 by October 1, 2019, which will provide sub-feeder level hosting capacity and incorporate existing installed DERs into the modeling. The evolution to a more granular hosting capacity analysis will provide better visibility into sub-feeder segments, allowing developers to identify specific locations with higher levels of hosting capacity and potentially lower interconnection costs. Future releases will include enhancements such as substation-level hosting capacity analysis and additional information such as forecasted hosting capacity evaluations.

Like hosting capacity, the identification of **Beneficial Locations for DERs and NWAs** is important to DER developers' ability to locate resources in optimal locations. O&R identifies and makes information available to stakeholders about the locations in its service territory where DERs may provide benefits to its electric system. Opportunities may exist for DERs to provide value to the grid where a particular DER technology and/or application (or a portfolio of DERs) may defer specific distribution-system upgrades and do so with the same degree of reliability and functionality afforded by traditional distribution investments. O&R's planning process not only reviews and identifies traditional infrastructure projects, but it also screens and reviews these major capital investment projects to determine their suitability as NWAs.

Improvements to the Company's planning process and the development of more granular load modifier forecasts will help O&R better identify beneficial locations for DERs well in advance of system needs. In addition, the Company has developed methodologies, in support of the Value of DER Proceeding for calculating LSRV and Demand Reduction Values ("DRV") to support the relief of locational system constraints by compensating DERs according to the value they provide to the system through the Value Stack tariff.[19] The Company is continuing to enhance these methodologies by undertaking efforts to develop a more granular MCOS study. O&R will continue to work with industry experts, developers, and the JU to improve its ability to identify beneficial locations for DERs.

As the Company improves its ability to identify beneficial locations for DERs, **Procuring NWAs** will become more important. The use of NWAs to defer expensive infrastructure upgrades, realize environmental benefits, and maintain system reliability and resiliency is an opportunity for the Company to provide benefits to its customers while meeting the REV goal of integrating more DERs. Since the SDSIP filing, the Company has focused on improving processes to identify and procure NWAs to meet system needs. In addition, the Company has implemented a new request for proposals ("RFP") platform to facilitate NWA procurements, conducted RFP webinars to inform vendors of activities related to the Company's NWA RFPs, and implemented new RFP evaluation criteria. O&R has also updated its BCA methodology to facilitate comparisons of NWAs with traditional solutions.

O&R is in the process of developing a software toolkit and improving its data collection to enable the Company to assess the potential for a broad range of DER technologies within its service territory. These improvements will also help the Company determine whether to proceed with an RFP for an NWA. All of these improvements will make the Company's processes to integrate NWAs more efficient.

Conclusion

In the two years since O&R's IDSIP and the JU SDSIP filings, O&R has made significant progress in implementing a myriad of new processes and methodologies necessary to implement the DSP. The Company is a leader in analyzing the ability of the system's capacity to host DERs and regularly makes that information, along with a variety of other system and customer data, available to stakeholders. In addition, O&R has enhanced its planning processes allowing it to identify NWA opportunities up to five years earlier than in previous processes. The Company also leads the in the deployment of AMI and has begun the steps to integrate energy storage assets onto its system. Lastly, the Company has made great strides in upgrading its electric delivery system and has developed the processes needed to identify and procure NWAs and currently has seven NWA opportunities identified, three of which are in the procurement process.

[19] Value of DER Proceeding, Value of DER Order, pp. 111-119.

O&R's implementation of the REV initiatives and its transition to a DSP provider is impacting people, processes, technologies, and organizations, all of which require rigorous and ongoing change management. The **Governance** of this transition is critical to O&R's success in implementing these efforts. O&R's UotF organization has governance and oversight for the various initiatives that the Company is undertaking to implement the DSP and coordinates the Company's efforts across many departments and with those of the JU. These changes are discussed in detail in subsequent sections and are focused on the following services:

- DER Integration Services**;**
- Information Sharing Services; and
- Market Services**.**

As O&R continues to progress in its evolution toward becoming the DSP provider, there is much more to accomplish, and the Company remains committed to the achievement of New York State's energy goals and the goals of REV. In the coming years, the Company will continue to leverage DERs as grid assets and integrate these assets into its planning, forecasting, and operations processes; will enhance its ability to provide hosting capacity and other system and customer data to developers and other third-parties to facilitate the development of market-based solutions; and will continue to develop processes and integrate technologies aimed at the development of the DSP. These achievements and future efforts are described in detail in the remainder of this document.

2018 Distributed System Implementation Plan

Chapter 1 - Progressing the Distributed System Plan

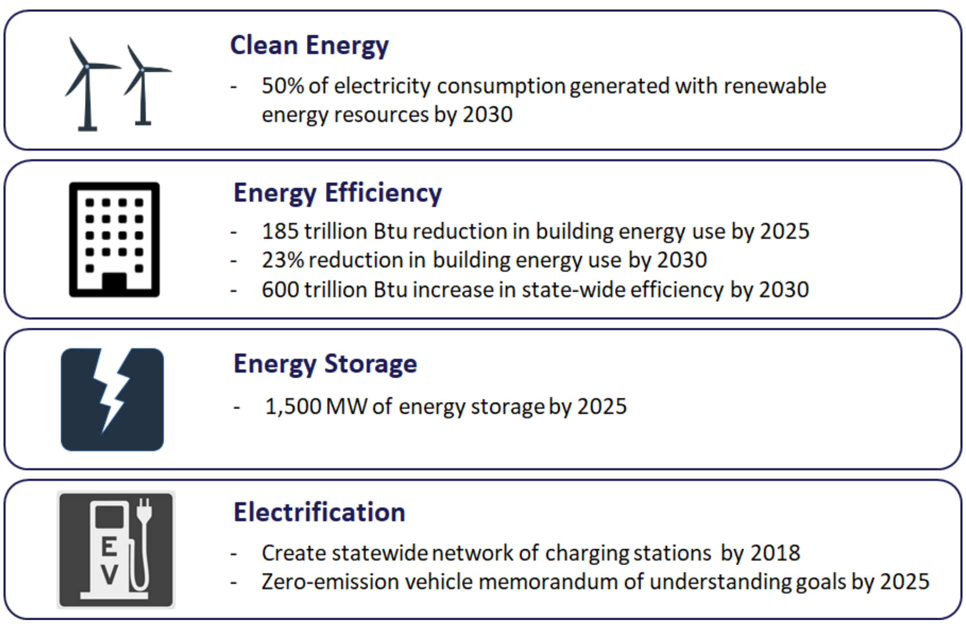
Introduction

Over the next decade, New York's electricity system will become significantly cleaner and more efficient, flexible, reliable, and resilient. The transformation of the electricity system will play a central role in the decarbonization of the 's economy. DERs—end-use EE, DR, energy storage, and DG[20]—are expected to be a key part of this transformation. To facilitate adoption and grid integration of these resources, O&R is developing a DSP that will offer tools, services, and information useful to DER providers, producing new sources of value for customers and market participants.

O&R has made substantial progress in laying a foundation for its DSP as described in detail in this DSIP update and summarized in the DSP Progress and Implementation Roadmap section. Building upon this early progress requires a vision of how DSP functions and capabilities will evolve in the foreseeable future. O&R continues to evaluate and strategize its own transformation to become the DSP provider, drawing on lessons learned from DER providers and other stakeholders.

The implementation of DSPs is occurring within the broader context of New York's energy policy goals and vision of a sustainable, low-carbon future. The Commission's quantitative clean energy targets for this vision[21] seek to significantly expand deployment of renewable energy, energy storage, and EE. In addition, the has established goals for zero-emission vehicles ("ZEVs") and is actively promoting EV adoption and development of EV-charging infrastructure.[22] The DSPs will play a central role in fulfilling the Commission's vision.

Figure 1: Key New York State Energy Policy Goals



Meeting the targets outlined in Figure 1 above will require a transformation of the 's energy sector from independent energy end-users that are heavily reliant on fossil fuels to an increasingly integrated energy system in which clean electricity serves a growing share of building and transportation energy

[20] REV Proceeding, Track One Order, p. 3.
[21] CES Proceeding, CES Order.
[22] EVSE Proceeding, EVSE Order.

demand. A flexible, smarter electric grid will be at the center of this more integrated energy system. O&R's contribution to the modernization of the electric grid, as envisioned and articulated in the DSIPs, is a critical step toward meeting policy goals.

The State's quantitative energy policy targets are complemented by more qualitative REV goals: affordability, clean energy innovation, greenhouse gas ("GHG") emission reductions, choice empowerment, infrastructure improvement, job development, natural resource protection, energy system resiliency, cleaner transportation, and EE.[23] The Company's NWA process incorporates the value of GHG emission reductions and infrastructure improvements, which is one example of its support for these goals.

In addition, the REV proceeding laid out a vision for a distributed electricity marketplace that will enable customers to participate in supplying local energy resources and managing their electricity needs.[24]

Meeting the REV goals will require a transformation of New York's electricity system, progressing to a system that is information-rich, facilitates customer engagement and choice, seamlessly integrates DERs, and encourages clean energy resources and EE. The transition to this future electricity system is being enabled by improvements in energy, information, communications, and grid control technologies.

O&R is committed to the 's clean energy goals in both the deployment and interconnection of DERs and in its evolution to the DSP provider, as described later in this section. One example of this is the Company's interconnection of utility-scale and other solar projects connected to O&R's distribution system. To date, O&R has interconnected 8.3 MWs of utility-scale solar and 56.8 MWs of distributed solar to its system. As the table below illustrates, the Company's interconnection queue suggests this trend will continue. The capacity of these installed and in-queue resources comprises approximately 17% of the Company's peak load in its New York service territory area. While this combination of utility-scale and distributed solar further the Company's and the 's commitments to clean energy, their integration and optimization will require sustained effort so that the Company maintains its high standards of reliability.

Table 1: Installed and in Queue Solar Capacity in New York State

Solar Type	Installed Capacity	Capacity in Queue
Utility-Scale	8.3 MW	~ 130MW
Rooftop/DG	56.8 MW	~ 4.5 MW

The REV proceeding created a vision for a distributed electricity marketplace that will enable customers to participate in supplying local energy resources and managing their electricity needs. Progressing to a utility model that is information-rich, facilitates customer engagement and choice, seamlessly integrates DERs, and encourages clean energy resources and EE is fundamental to accomplishing the State's vision. O&R is enabling the transition to this future electricity system by making improvements in energy, information, communications, and grid control technologies.

[23] New York State, REV4NY website: https://rev.ny.gov/

[24] REV Proceeding, REV Order, p. 4.

Long-Term Vision for the DSP

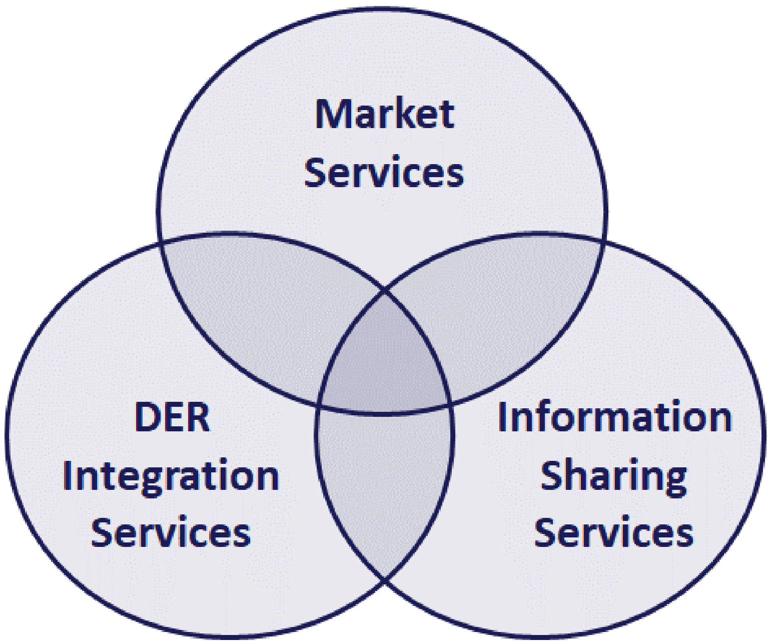
The DSP Vision

Defining DSPs

The REV Track One Order defines DSPs as an intelligent network platform that will provide safe, reliable, and efficient electric services by integrating diverse resources to meet customers' and society's evolving needs. The DSP fosters broad market activity that monetizes system and social values by enabling active customer and third-party engagement that is aligned with the wholesale market and bulk power system.[25]

Taken further, DSPs are the set of people, processes, and systems that allow utilities to provide three core interrelated services: DER integration, information sharing, and market services.

Figure 2: Three Core DSP Services



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

DSP Function and Value

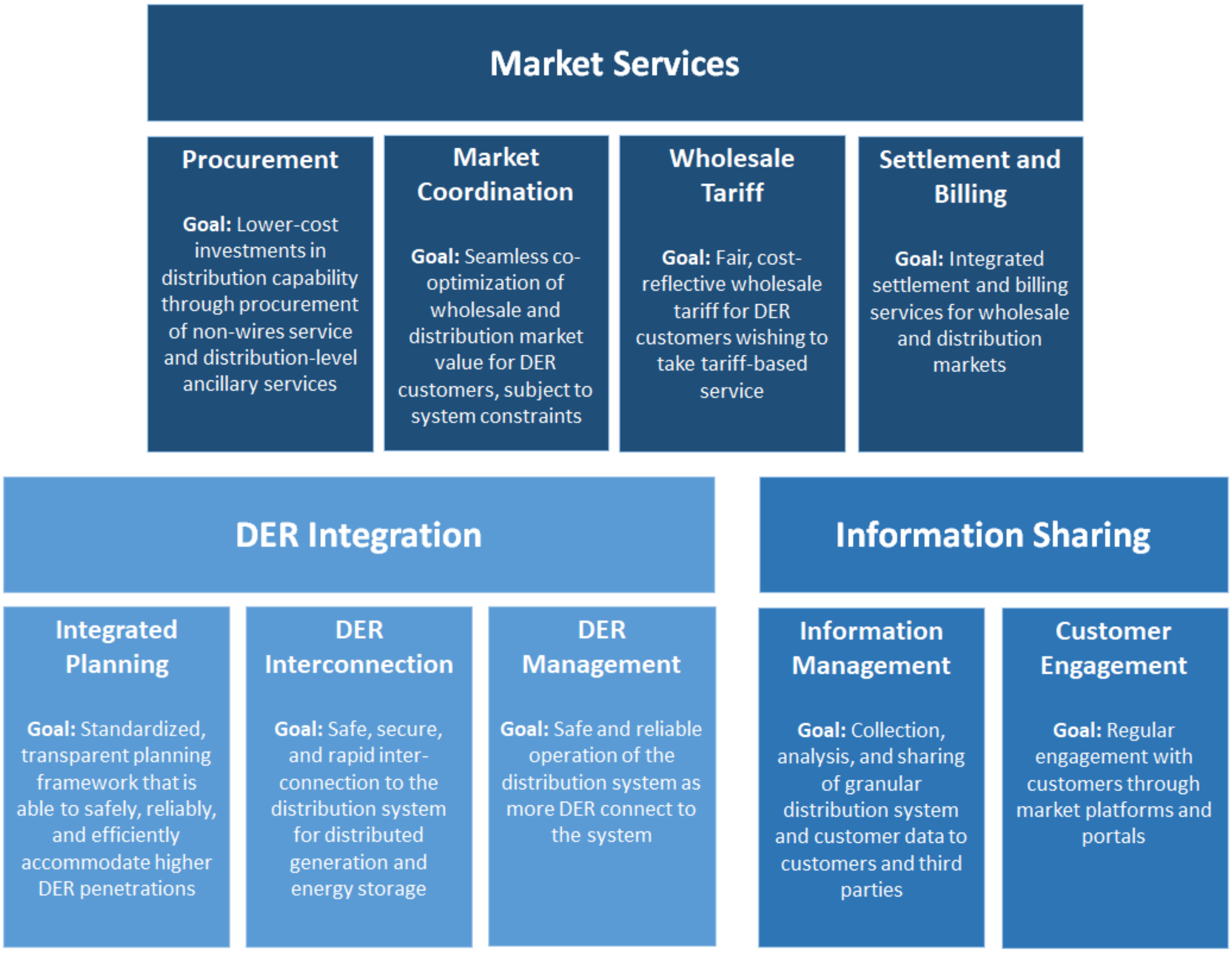
As DSP providers, utilities are developing the capabilities, processes, and systems that will enable key DSP functions: integrated planning, DER interconnection, and DER management (*DER integration*

---

[25] REV Proceeding, Track One Order, p. 31.

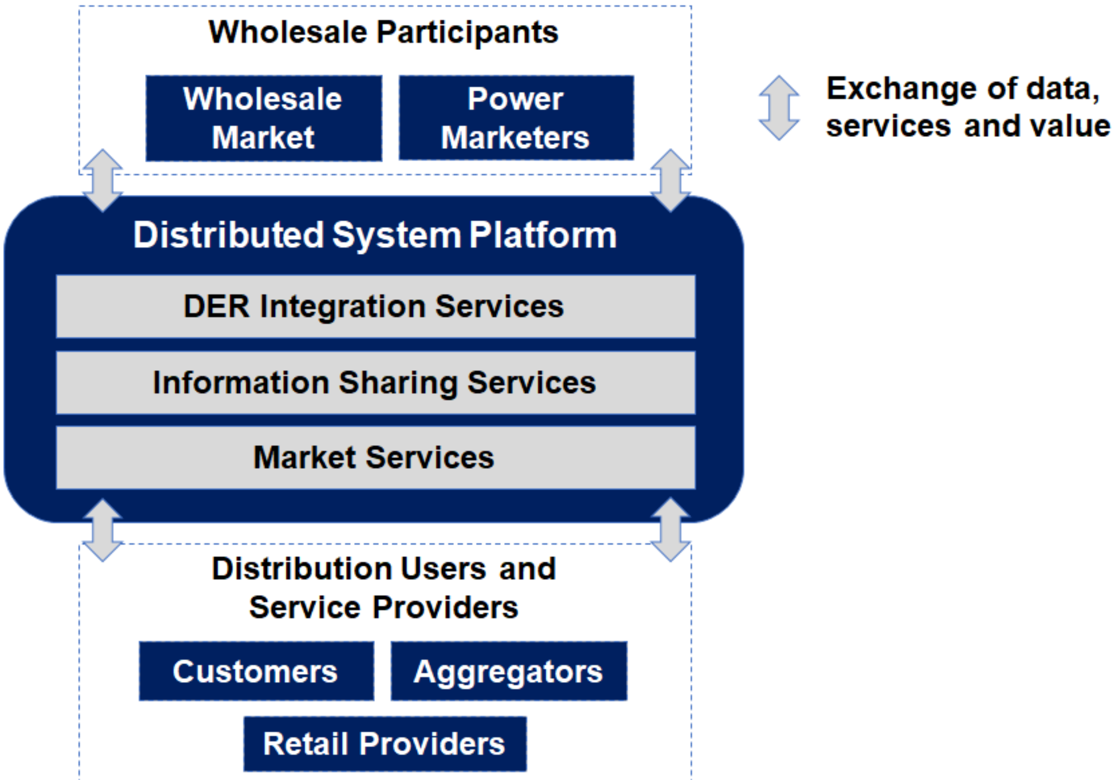
services); information management and customer engagement (*information sharing services*); and procurement, market coordination, wholesale tariff, and settlement and billing (*market services*). The following figure describes long-term goals for each DSP function.

Figure 3: Long-Term Goals for DSP Functions within Each Core DSP Service Area



As they evolve, DSPs will increasingly bring together suppliers and buyers of electricity services, becoming more populated with information and transactions over time. DSPs will become a natural marketplace for third-party aggregators and technology vendors to gather data and offer their services.

Figure 4: Illustration of the DSP as an Energy Marketplace



DSPs will open up new sources of value for electricity customers and market participants by expanding customer choice, enhancing DER integration, and maximizing the distribution and wholesale Value of DER.

Table 2: DSP Value to Customers and Market Participants in the Longer Term

Customers
• Ability to identify products and services that lower costs, emissions, and improve reliability • Products and services that can be tailored and bundled to meet customer preferences • Ability to shop among different service providers • Granular information on usage, cost, reliability, and emissions
Market Participants
• Streamlined interconnection; detailed information on hosting capacity, interconnection costs, and locational value • Co-optimization of wholesale and distribution market value • Procurement for non-wires and other distribution services • Billing and settlement services for wholesale and distribution markets • Access to granular customer information with customer consent

O&R and the JU anticipate that the DSP vision will continue to advance as key drivers and markets evolve.

DSP Evolution

DSP functions and capabilities will progress through different phases, as described in the JU 2016 SDSIPs.[26] A phased approach aligns the pace of investment with the speed of DER adoption, recognizing that some capabilities are not required until DER penetration reaches significantly higher levels. Additionally, a phased approach provides an opportunity to learn from demonstration projects in New York and experiences in other states and countries.

The JU have established a framework for understanding and navigating the different phases of DSP functionality and capability, encapsulated in three DSP "models." DSP 1.0 refers to the first, and current, phase of DSP development. DSP 2.0 refers to a second phase with enhanced integration, information, and market services. DSP 2.x refers to a longer-term phase of DSP development, characterized by the emergence of transactional distribution markets.

This content focuses on DSP 1.0 and 2.0 and the transition between them, describing three key aspects of DSP evolution: (1) function and capability, (2) customer value, and (3) enabling investments and conditions.

DSP 1.0

In DSP 1.0, utilities create foundations for the platform, which enables:

- More streamlined interconnection and enhanced distribution system measurement, monitoring, and control capabilities;
- Safe operation of the grid with increasingly higher levels of DERs;
- More accessible, granular information on customer use and closer engagement with customers and aggregators through information portals;
- Regular NWAs procurement[27] and incorporation of wholesale value through the Value of DER tariff.[28]

In this phase, DSPs provide retail settlement and billing services to customers based on Value of DER, and wholesale settlement and billing services to aggregators for NWA procurement. DER aggregators and their customers can also access wholesale settlement and billing services through the NYISO.

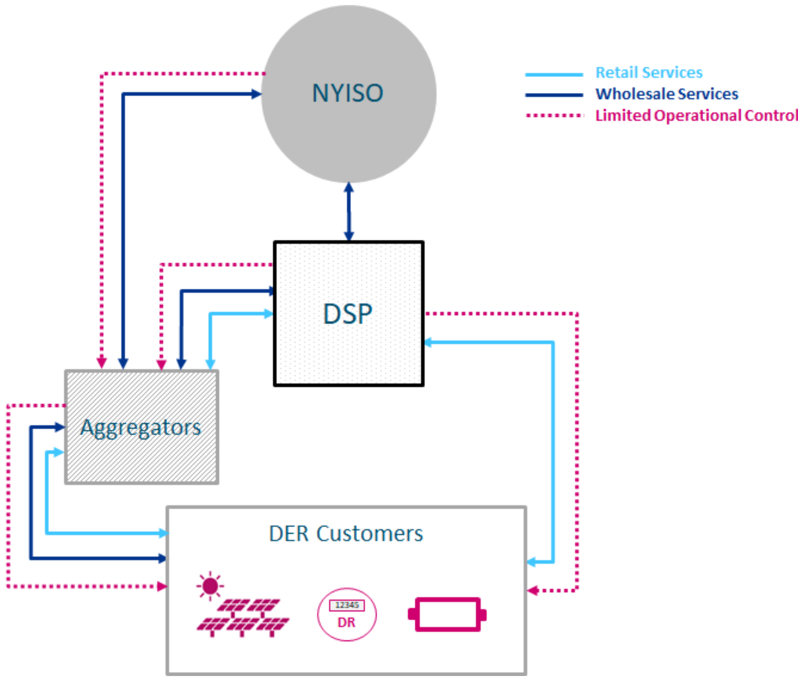
---

[26] DSIP Proceeding, JU Supplemental DSIP. http://jointutilitiesofny.org/wp-content/uploads/2016/10/3A80BFC9-CBD4-4DFD-AE62-831271013816.pdf.

[27] DSIP Proceeding, Joint Utilities' Supplemental Information on the Non-Wires Alternatives Identification and Sourcing Process and Notification Practices (filed May 8, 2017) ("NWA Filing"), Appendix 5.

[28] *E.g.,* Value of DER Proceeding, Order on Phase One Value of Distributed Energy Resources Implementation Proposals, Cost Mitigation Issues, and Related Matters (issued September 14, 2017) ("Value of DER Phase One Order").

Figure 5: DSP 1.0 Wholesale and Retail Services



DSP 1.0 promotes increased DER integration up to the limitations of today's distribution grid. Utilities have sufficient visibility and operational control over DERs to maintain safe and reliable grid operations. Operational coordination with the New York Independent System Operator ("NYISO") is based on pre-determined rules for joint participation in NWA procurement and the NYISO markets.

O&R has made substantial progress in developing the systems, processes, and capabilities that enable DSP 1.0. Continued progress in DSP 1.0 will be facilitated by investments in:

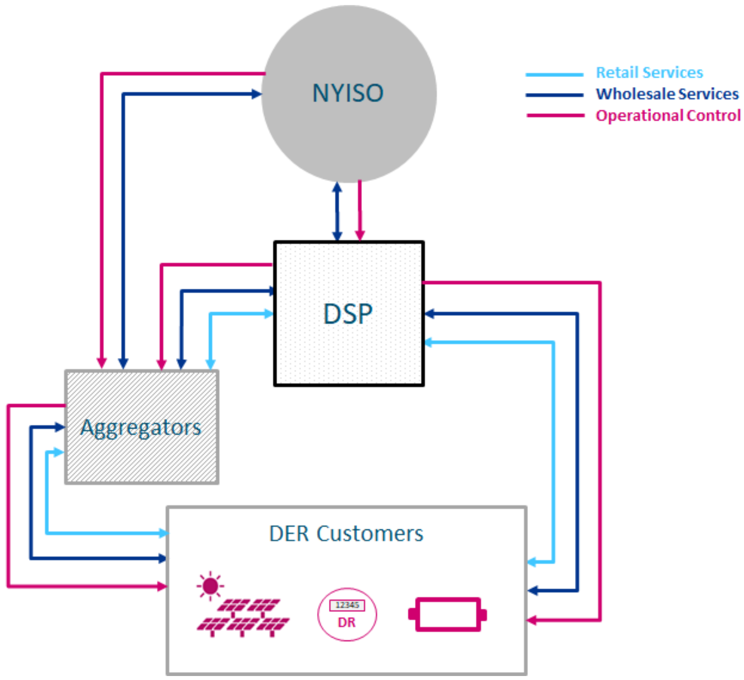
- ***DER integration capabilities***: integrated planning; operational communications; measurement, monitoring, and control capabilities; DA; and distribution management systems;
- ***Information sharing capabilities***: data management and analysis software; customer and aggregator interfaces;
- ***Market services capabilities***: NWA planning and procurement; NYISO coordination: Value of DER tariff improvements.

DSP 2.0

DSP 2.0 builds on the functions and capabilities of DSP 1.0, adding significantly greater visibility and operational control over DERs. Greater visibility and operational control allow for the creation of integrated markets for wholesale and distribution services.

In DSP 2.0, DSPs offer wholesale scheduling and dispatch services, allowing customers and aggregators to maximize the value of their resources across NYISO wholesale markets and distribution markets. As shown below, aggregators can still access wholesale markets directly through the NYISO. The NYISO also has enhanced capabilities to monitor and control DERs.

Figure 6: DSP 2.0 Wholesale and Retail Services and Operational Control



Via DSP market platforms, DSP 2.0 provides an additional "wholesale services" route for DER customers to deliver their services to markets—illustrated by the solid blue line connecting DER Customers and the DSP in the previous figure. These market platforms will be described in greater detail in the DSP Market Design and Integration Report.

Several functions and capabilities in DSP 2.0 do not yet exist and require innovations in software, systems, and process. For instance, DSP 2.0 is characterized by much larger volumes of information flow, which require new approaches and tools for data management and analysis. The protocols, processes, and software enabling near real-time DER control also require innovation and development.

DSP 1.0 and 2.0 are distinguished by key high-level differences in platform function and capability rather than checklists of essential features. Thus, the transition from DSP 1.0 to 2.0 will evolve and develop over multiple years, with variation among utilities. Timelines for individual utilities will depend on grid topology, funding, and need.

With further market and technology development, DSP 2.0 could eventually evolve into DSP 2.x, where DER penetration is substantially larger than it is today, loads are highly price sensitive, and decentralized transactions are feasible on a larger scale.

The remaining chapters of this filing focus on building the functions and capabilities necessary to continue progress in DSP 1.0 and lay the groundwork for DSP 2.0.

DSP Progress and Implementation Roadmap

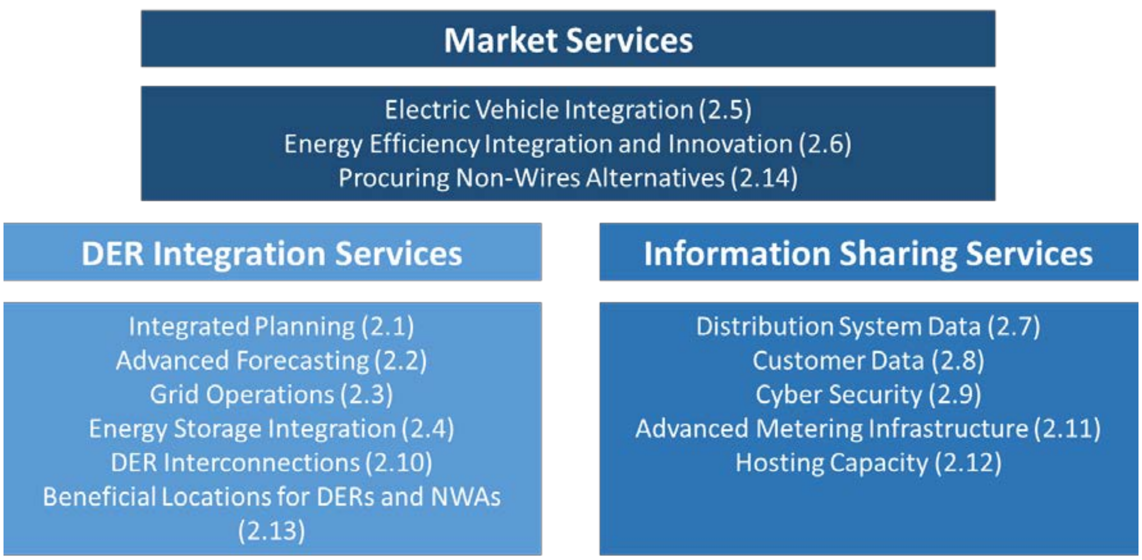
O&R's has continued efforts to modernize and strengthen its electric distribution system and provide customers with the information and opportunities to make better business and usage decisions. The Company's long-standing programs focused on integrated system planning, technology enhancements, EE, and customer engagement all support REV. Such programs have been integral to its efforts to plan, build, and manage its electric distribution system. In addition, the Company has been engaged in integrating DERs for many years, with significant experience conducting EE programs, interconnecting DG, and soliciting DER solutions for targeted load relief, among other initiatives.

Since filing its IDSIP, O&R, along with the JU, has focused its DSP implementation efforts on three aspects of the platform: DER Integration Services, Information Sharing Services, and Market Services. The progress achieved in these areas benefits customers and market participants by:

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

The figure below illustrates O&R's approach to implementing these initiatives; it does not reflect where each initiative may ultimately reside in a mature DSP.

Figure 7: Topical Sections Aligned with Each Core DSP Service Area



DER Integration

DER Integration encompasses the planning, operation, and infrastructure initiatives associated with implementing the DSP. This includes, but is not limited to, distribution system infrastructure upgrades, the evolution of planning methodologies, and operational changes, which will result in the reduction of barriers to DER adoption. The goal of this aspect of the platform is to maintain safety and reliability in a higher DER penetration environment, allowing for more DERs to come onto the grid faster, cheaper, and with higher levels of visibility allowing for greater provision of grid services and more access to value streams. Recognizing that the safe and reliable operation of the grid as the DSP evolves is critical to achieving the shared goals of REV, O&R continues to enhance processes that facilitate the integration of DERs into planning and grid operations. O&R has implemented several DER integration initiatives, including:

- Expanding its planning horizon to include a ten-year outlook, in addition to the traditional five-year plan (Planning);
- Implementing new NWA criteria (Planning);
- Modifying the planning process to include top-down and bottom-up methodologies (Planning);
- Incorporating DERs into forecasting in a more robust and granular fashion (Forecasting);
- Developing more granular load modifier forecasts to help better identify beneficial locations for DERs (Forecasting & Beneficial Locations);
- Establishing the appropriate level of visibility, monitoring, and control (Grid Ops);
- Investing in grid modernization (Grid Ops);
- Enhancing its energy storage capabilities and conducting energy storage demonstration projects to prove the value that energy storage can provide the distribution system (Energy Storage);
- Enhancing its online interconnection application portal (Interconnection); and
- Developing methodologies for identifying grid values through price signals to support the relief of locational system constraints (Beneficial Locations).

O&R envisions collectively accomplishing the following in the next two years:

- Developing IOAP 3.0 to facilitate increased automation in the DER interconnection process;
- Facilitating ongoing demonstration and deployment of foundational technologies to enable active network management and facilitate system analysis and DER coordination, optimization, and control;
- Advancing M&C standards for a broader set of asset types and sizes via direct control and third-party aggregation;
- Expanding smart inverter integration, including advanced functions; and
- Establishing DER forecasting as a standard part of the utility planning process.

The Company's DER Integration accomplishments, current initiatives, and future plans are further described in the corresponding sections in Chapter 2 of this DSIP update.

Information Sharing

Sharing information that is useful to customers and developers is central to achieving REV goals and is a fundamental function of the DSP. Information sharing is also central to the Company's ongoing commitment to enhance the customer experience and provide market opportunities. As the Commission described, "data sharing between the Utilities and third-parties is essential and must become part of the Utilities' normal business practices."[29] In addition, the Commission set the expectation that the utilities will increase "the types and amounts of data to be shared," and expand "customers' ability to readily share their data with others."[30] Expanded information sharing, including more granular customer data

[29] DSIP Proceeding, Order on Distributed System Implementation Plan Filings (issued March 9, 2017) ("DSIP Order"), p. 8.
[30] *Id.*, p. 9.

and system data, will facilitate DER market development and deployment by signaling where DERs can provide the greatest value to customers and the grid. This will aid in the development of new DER offerings and in building business cases to support the investment decisions of third-parties and customers.

O&R continues to support efforts to increase the amount of customer data and system data available to customers and third-parties and has made significant progress in this area. O&R's key achievements to facilitate access to useful information, while protecting sensitive data, include:

- Enhancing its system data portal (System Data);
- Establishing a central location on the JU website for utility links to individual NWA RFP opportunities (System Data);
- Supporting the launch of REV Connect to communicate DER opportunities for all utilities (System Data);
- Implementing Green Button Connect (Customer Data);
- Working with the JU to produce a statewide anonymity standard (Customer Data);
- Supporting the launch of NYSERDA's Utility Energy Registry[31] making aggregated customer data available to the public (Customer Data);
- Providing access to circuit-level hosting capacity data (Hosting Capacity); and
- Deploying AMI.

To advance its information sharing capabilities, O&R continues to implement current initiatives and is evaluating additional actions and initiatives to pursue over the next five years, including:

- Refinement and expansion of system data use cases to meet stakeholder needs and support market participation (System Data);
- Continued collaboration with the JU and stakeholders to advance state policy objectives while maintaining customer privacy and data security (Customer Data);
- Addressing the exchange of both system and customer data, while preserving customer protections and system security using the JU Cyber and Privacy Framework (Cybersecurity);
- Beginning the communications equipment upgrade in Orange County mid-2018 and early 2019 in Sullivan County (AMI);
- Completing the implementation of the Company's AMI Program throughout the remainder of its service territory (AMI); and
- Releasing Stage 3.0 hosting capacity map updates that provide sub-feeder level hosting capacity and incorporating existing installed DERs into the Company's modeling, providing developers with the ability to identify specific locations with higher levels of hosting capacity and potentially lower interconnection costs (Hosting Capacity).

The Company's key Information Sharing Services accomplishments, current initiatives, and future plans are further described in the corresponding sections in Chapter 2 of this DSIP update.

Market Services

While the DSP must perform multiple functions, a key focus of the Track One and Track Two Orders was evolving the New York market at the distribution level to allow DERs to bring value to the

[31] Cases 17-M-0315, *et al., In the Matter of the Utility Energy Registry* ("Utility Energy Registry Proceeding"), Order Adopting Utility Energy Registry (issued April 20, 2018)("Utility Energy Registry Order").

system and be compensated through enhanced market mechanisms. This evolution has also been a major focus for the JU in the past two years.

O&R has made progress on several key Market Services initiatives, including:

- Implementing EE programs (EE);
- Identifying and documenting EV readiness requirements in the EV Readiness Framework developed with the JU (EV);
- Identifying, developing, and implementing NWAs (Procuring NWAs); and
- Applying Phase One Value of DER Value Stack (Procuring NWAs).

The Company is also evaluating and planning additional initiatives to increase its Market Services capabilities, such as:

- Developing new EE programs for residential and C&I customers in support of the Commission's CES goals[32] (EE);
- Evolving the Company's ETIP into the SEEP pursuant to the Commission's EE goals[33] (EE);
- Continuing to participate in the Clean Energy Advisory Council and JU working groups (EE);
- Proposing to own, operate, and deploy charging infrastructure in its service territory, providing a means for EVSE deployment until significant EV adoption enables a sustainable business model for third-party EVSE providers (EV);
- Exploring the operation of EVSE as DERs (EV);
- Proposing the continuation of its EV education and outreach efforts including the development of new proposed rate designs such as expanded TOU rates and the PEV Quick Charging Station Program (EV);
- Continuing participation in the EVSE and Infrastructure proceeding; and
- Leveraging lessons learned from current and future NWA projects to identify and implement additional improvements to the Company's NWA procurement process (Procuring NWAs).

The Company's key Market Services accomplishments, current initiatives, and future plans are described in the corresponding sections in Chapter 2 of this DSIP update.

In summary, O&R continues to evolve by making innovative, strategic, and in some cases foundational process and system investments to transition to the DSP provider. At the same time, the Company continues to prioritize its core goals of enhancing public and employee safety, enhancing the customer experience, and improving operational excellence. The Company also continues to establish new programs, processes, and demonstration projects at a pace aligned with the needs of its customers and system. The Company is working with customers and third-parties to test innovative concepts and technologies before solutions are fully implemented, so as not to deviate from the high standards of safe and reliable service that the Company provides to its customers. This approach allows the Company to manage costs on behalf of its customers.

[32] CES Proceeding, CES Order.
[33] Utility Energy Efficiency Proceeding, Utility-Administered EE Order.

Innovation (Official "Demo projects" and Other Initiatives)

The Company is implementing Demonstration Projects that it will use to understand its customer's needs, learn valuable lessons, and support its progress toward becoming the DSP provider. These Demonstration Projects and other initiatives support the REV Track One Order where the Commission directed the JU to develop and file demonstration projects consistent with the guidelines adopted by the Order.[34]

The following figure shows the various principles the REV Demonstration projects strive to implement.

Figure 8: REV Demonstration Project

As the Commission noted, these projects are intended to demonstrate new business models (*i.e.*, new revenue stream opportunities for third-parties and the electric utilities). In that regard, the projects will inform decision makers about the development of DSP functionalities, measure customer response to programs and prices associated with REV markets and determine the most effective implementation of DERs. Further, as demonstrations, these projects are intended to test new technology and approaches to assess value, explore options, and stimulate innovation before committing to full-scale implementation. Therefore, demonstration projects should also be designed to deliver observable results and actionable information within a reasonable timeframe. The Company will regularly assess these Demonstration Projects over the course of their project life cycle.

O&R currently has four demonstration projects and one pilot program underway, which are testing a variety of concepts and capabilities required for the Company's transformation to the DSP provider, as described below.

[34] REV Proceeding, Track One Order, pp. 115 - 117.

Customer Engagement Marketplace Platform Demonstration Project

The Customer Engagement Marketplace Platform ("CEMP") Demonstration Project was designed to build partnerships with a network of third-party product and service providers to increase customer awareness and understanding of energy consumption, motivate customers to participate in Company programs, improve the distribution and adoption of EE and DER products and services, and develop new revenue streams for the Company and its partners. O&R also worked with Suez Water New York, Inc. to develop and co-rebate water saving products for its customers.

The Company's CEMP project is comprised of two components—the My ORU Store and the My ORU Advisor. The My ORU Store is an online environment where customers can purchase DER products and services. To drive awareness and interest, customers receive weekly emails about new product and service offerings, special offers, and messaging on how to reduce energy consumption and save money.

The My ORU Advisor is an interactive, behavior-based portal that provides tips and energy usage insights. This portal also includes a virtual home tour explaining how energy is typically consumed within each room and by each appliance in a typical home. Customers are encouraged to explore energy tips, view and analyze their energy consumption data, share information, and interact with others to earn points and rewards for taking energy savings actions. Customers are provided with home energy reports on a monthly basis. These reports provide customers with individual monthly electric usage information and an individual energy comparison rating that is based on how the customer's energy usage compares to a similar home as well as an EE home.

Thus far, experience with the various components of the CEMP has proven to be successful. Product purchases fluctuate on a monthly basis but overall, they remain strong. Customers have responded positively to promotional advertisements and periodic messaging, as demonstrated by the combination of repeat visitors and the increasing number of new user visits to the site. The Company believes the My ORU Store (link) and its expanding product line, coupled with third-party service provider offerings and the ability of customers to apply instant EE rebates will continue to attract the interest of customers.

Innovative Storage Business Model Demonstration Project

The Innovative Storage Business Model ("ISBM") Demonstration Project was developed to identify and realize the unique attributes of energy storage to enable its wide-scale deployment. O&R is partnering with Tesla to test the hypothesis that batteries can provide a range of services across multiple applications (*e.g.*, deferred transmission and distribution ("T&D") costs, wholesale revenue, and reduced demand charges) by maximizing storage use and developing a new business model that allows for sharing of costs and benefits across multiple stakeholders (*e.g.*, grid benefits for utilities and reduced demand charges for customers). Furthermore, the project will develop and test methods for mitigating storage implementation barriers in order to support the acceleration of widespread storage deployment in New York.

This project has three overlapping phases. Phase 1 is focused on customer acquisition for BTM systems and site selection for front-of-the-meter ("FTM") systems. This phase is currently in progress and is expected to run through Q2 2019. Phase 2 will focus on demonstrating the operational control and dispatch capability for the aggregated storage assets to meet system needs. Phase 2 will last for approximately 8–10 months and is expected to be complete in Q1 2020. Phase 3 will demonstrate the ability to bid aggregated energy storage assets into NYISO wholesale markets. This phase will last between 24–26 months and is expected to begin in early 2020.

Table 3: ISBM Demonstration Project Phases

ISBM Demonstration Project Phases			
Phase	1	2	3
Timing	10-12 months	8-10 months	24-26 months
Objective	Customer Adoption/ Site Selection	Operational Control and Dispatch	Wholesale Market Participation

As part of its efforts to integrate energy storage assets into the wholesale market, the Company has been actively engaged with NYISO. Work with NYISO has included meetings with its staff to review potential energy storage use cases, market products, participation models, and the M&C of local energy storage assets. This collaboration will continue throughout the demonstration period.

Optimal Export Demonstration Project

The Company's Optimal Export Demonstration Project is designed to provide practical experience in the optimization of DER exported to the Company's distribution system through the use of advanced control and inverter functionality. Based upon traditional planning and interconnection criteria, there is typically a limit to the amount of DERs that can be interconnected to the grid without requiring significant system upgrades to mitigate potential detrimental impacts on the distribution system. The Company's Optimal Export Demonstration Project will test whether advanced inverter functionality and third-party M&C hardware and software technology can maximize the proposed DER project's ability to export without negatively impacting reliability, power quality, and distribution system performance.

Through this project, the Company will validate the use of these new technologies on its distribution system and will also gain insight into the value proposition and developer willingness to employ such technologies as an alternative to traditional interconnection arrangements. While interconnection screening processes have evolved to better accommodate the unique attributes of individual DER projects, active management of DER resources, through the deployment of new technologies, is expected to allow for higher penetrations of DERs on the Company's system.

O&R received its Staff Assessment letter on July 19, 2018 and is targeting to start the project Q4 2018. This Demonstration Project will include three overlapping phases. Phase 1 will be focused on analysis and customer engagement; phase 2 will involve the delivery, installation, and commissioning of the solution at a range of candidate sites; and in phase 3, the Company will evaluate the operating performance at implemented locations to confirm the technology is maximizing DER output without negatively impacting the Company's electric delivery system.

Smart Home Rate Demonstration Project

Through the Smart Home Rate ("SHR") Demonstration Project, O&R and CECONY ("the Companies") will conduct a research study, testing two different, dynamic rate designs side by side, both enabled by price-responsive home automation technology. The focus of the SHR demonstration project is to combine customers' enthusiasm for proactive energy management and technology with rate designs that result in energy management through programmed response and to test and learn from the resulting actions and reactions of those customers. Some of the innovative features of these rates include: reflecting the day-ahead hourly prices for energy, moving from flat volumetric (kWh) to Time of Use

(“TOU”) demand-based (kW) charges to recover delivery costs, and incorporating event-based critical peak charges to recover forward T&D and generation capacity costs.

Two rates are proposed, each rate with a different structural approach to reflect both generation and T&D capacity costs: Rate A proposes a daily demand charge with peak event demand charges, while Rate B will combine a monthly demand subscription charge with peak event overage penalties. The demonstration will also assess the impacts of battery storage as an enabling technology specifically for customers with existing photovoltaic systems. The Companies have selected partners that will provide the home automation technologies to participating customers and collect and analyze empirical data to test the project results and gauge market opportunities. O&R believes that testing customer responsiveness to these two rate designs will provide useful information on how consumers react to more sophisticated rates and aid in developing future rate designs. The SHR Implementation Plan will be submitted in August 2018 and will include a detailed schedule, budget, projected milestones, and detailed test scenarios.

Innovative Pricing Pilot

O&R and CECONY submitted their AMI customer engagement plan on July 26, 2016,[35] which included a pricing pilot intended to identify how innovative pricing structures can enhance customer benefits from AMI deployment. This pilot targets mass market (Service Class-1) and small commercial (Service Class-2) customers with AMI in Westchester County, Staten Island, and Brooklyn. The pilot timeline is primarily driven by the timing of the CECONY AMI rollout, with the pilot going live in Staten Island and Westchester County approximately one year before the pilot is active in Brooklyn. In addition, the opt-in customer group will begin the pilot approximately six months prior to the opt-out group. The pilot will run for a time period of time sufficient to capture load impacts over two summer peak periods.

The pricing pilot design includes three main components: (1) pricing of delivery service, (2) enabling technologies, and (3) education and outreach. The goal is to gauge customer acceptance and response to new prices, as well as estimate system impacts derived from changes in customer behavior. In addition, the pilot will collect data to help estimate customer benefits and inform future mass-market rate design. The pilot will test both opt-in and opt-out approaches to recruit customers.

The new delivery prices are based on demand, with one demand rate based on conventional methods for assessing demand charges and the other rate based on a subscription service that allows customers to choose different levels of demand. The Company is continuing to investigate enabling technologies that may benefit customers on demand-based rates, such as smart thermostats, in-home displays, and app-based services.

Conclusion

Through its Demonstration Projects and pilot programs, O&R is testing many of the capabilities to evolve the DSP, with a focus on the use and application of innovative technologies, as well as ways to connect with and engage its customers. The Company is actively testing the use of battery storage on its system through the Innovative Storage Model and SHR Demonstration Projects and is testing the use of smart inverters through its Optimal Export Demonstration Project. To better connect and engage consumers, the Company is testing methods for raising awareness of its EE and DER offerings through its

[35] Cases 15-E-0050 *et al*., ConEdison and Orange and Rockland AMI Customer Engagement Plan (filed July 29, 2016).

CEMP Demonstration Project and is testing innovative rate designs through its SHR Demonstration Project and Innovative Pricing pilot program.

O&R has learned, and expects to continue to learn, many valuable lessons from its demonstration projects. As it does, the Company will continue to use these lessons to improve the design of future Demonstration Projects, implement the tested technologies or methods, and augment the processes and capabilities required to function as the DSP.

Orange & Rockland

Grid Modernization and the DSP Technology Platform

As O&R moves toward becoming the DSP provider, Grid Modernization investments, some of which may be considered foundational and/or DSP-enabling, that improve the reliability, resiliency, efficiency, and automation of the T&D system are critical. Such investments can include the sensors, data, and communications networks that enable enhanced visibility and understanding of the behavior of the network; technologies and equipment that facilitate greater customer engagement regarding energy usage and alternatives; and the underlying systems, data management, and analytics that facilitate situational awareness, asset management, contingency and risk analysis, outage management, and restoration. These necessary core investments underpin the required focus on grid reliability and resiliency. They provide the basis for increased operational flexibility, can enable efforts toward achieving state policy goals, including the integration of various types of DERs, and are beneficial for any resource mix.

Further definition and clarification are provided for terms included in the Grid Modernization definition (as defined by the JU):

- Foundational: Enabling grid capabilities that provide and/or support applications that increase reliability, resiliency, safety, and enhanced situational awareness and operational flexibility through advanced technology and equipment including robust sensing and measurement, information management, data management and analytics and communications networking capabilities. Foundational investments are “no regrets actions” that can support both current applications and future applications, such as integration and utilization of DERs, in a modular fashion;
- Reliability: The ability of the electric system to receive and deliver the aggregate electric power and energy requirements of electricity consumers at all times, taking into account scheduled and unscheduled outages of system components, while maintaining the ability to withstand sudden disturbances or unanticipated loss of system components within accepted and defined risk tolerances and goals;
- Resiliency: Preparation for, and adaption to changing conditions and the ability to withstand or rapidly recover from system disruptions. Disruptions can be caused by deliberate attacks, accidents, or naturally occurring threats or incidents;
- Safety: Operation of the distribution grid in a manner that provides for public and workforce welfare, operational risk management, and appropriate fail-safe modes; and
- Operational Flexibility: The ability to operate physically connected generation, T&D facilities in a manner which accommodates dynamic grid conditions and changing demand, type of generation and resource availability. This also includes the efficiency of utility operations.

Investments that promote these functions and attributes provide beneficial outcomes which may be distinctly separate or complementary to (or foundational to) investments made for the express purpose of DER integration.

Investments that enable these attributes may be foundational, enabling multiple benefits or they may directly enable the integration and optimization of DERs.

In its 2018 electric base rate case,[36] O&R outlined its plans to make foundational investments that will provide operational flexibility and reliable operations, as well as enable the functionality envisioned

[36] O&R Electric Rate Case.

for advanced grid modernization and future market enablement. These initiatives support the Company's continued DSP evolution and are grouped in the following areas:

- ADMS and DERMS;
- Data Analytics;
- Communications Infrastructure;
- Distribution Automation;
- Planning and Forecasting; and
- Hosting Capacity and Interconnection.

These Grid Modernization initiatives are also described in more detail in the corresponding sections in Chapter 2 of this DSIP update.

2018 Distributed System Implementation Plan

Chapter 2 - DSIP Update Topical Sections

Integrated Planning

Introduction/Context and Background

Background

O&R's electric delivery system planning process is designed to maintain and enhance the safety and reliability of the T&D system while maintaining system performance within defined and acceptable design and operating risk tolerances. The Company's planning process evaluates the electric delivery system over a specified future forecast period and identifies system needs and solutions. The Company develops forecasts and performs contingency analyses as required to support operating reviews of its assets and apply its design standards and risk-assessment methodology to the results to identify current and future operating risks and potential corrective solutions.

O&R is expanding its distribution planning horizon to ten years to accommodate early identification of NWA opportunities

O&R uses its electric system planning design standards to assess operating risk, identify system needs, and prioritize electrical infrastructure projects. The Company's design standards are designed intended to balance the costs of infrastructure investment against the benefits of mitigating the risk of significant outage events. The planning process provides an approach by which future risk mitigation investments are identified and prioritized. The planning process and associated design standards provide a gauge to ensure appropriate progress is being made to achieve the desired future state of the system.

As a standard practice, the Company investigates if major capital infrastructure investments can be substantially deferred, reprioritized, or even eliminated by alternative and less costly traditional infrastructure investments, as well as targeted non-traditional measures and alternative solutions, such as DG, energy storage, DR, EE, or a combination of these.

Progress Since the IDSIP Filing

Since its IDSIP filing, the Company has made changes to its planning process to better integrate DERs on its system. O&R changed its planning process to include a ten-year outlook in addition to its current five-year outlook, which is expected to facilitate identification of potential NWA opportunities and consideration of potential NWA solutions. The Company made three additional changes to its process for screening projects for potential deferral or replacement with a NWA project. First, the Company updated its NWA suitability criteria to a Company-specific version of the NWA suitability criteria matrix[37] that was developed by the JU to provide a common framework for identifying projects that are most suitable for NWA consideration. Second, the Company committed to develop and evaluate portfolios of potential NWA solutions.[38] Third, the Company committed to conduct detailed BCA for each of its NWA projects in accordance with the BCA handbook that was developed and communicated as part of its IDSIP, and to file an updated BCA Handbook with each subsequent DSIP filing.

In addition to these process changes, the Company has identified potential locations for which it will solicit NWA solutions and has made information about these opportunities available to stakeholders through its website, its hosting capacity maps, and the NYSERDA REV Connect website.

---

[37] DSIP Proceeding, NWA Filing, Appendix 5.
[38] *Id*., pp. 10 - 11.

O&R uses its NWA suitability criteria to make an initial assessment about the viability of a NWA to replace a traditional infrastructure project. This assessment helps the Company determine if a proposed traditional project is a potential candidate from both a technical and timing perspective to be deferred or replaced through the implementation of a NWA, which could include DG, DR, EE, DSM, or a portfolio thereof. The implementation of the NWA suitability criteria allows the Company to better identify potential NWAs that are better positioned for success, which promotes an efficient allocation of time and resources for both developers and utilities.

The Company is working toward a future in which it will prepare hypothetical portfolios of NWA solutions to determine whether it can obtain sufficient capacity to satisfy the project need. Considering portfolios of NWA solutions expands the Company's options for meeting the system need and the likelihood of obtaining sufficient capacity to meet the project need. O&R is currently working to establish the processes, tools, and data—including historical market information—required to develop these hypothetical portfolios of NWA solutions.

If the Company determines that it can secure sufficient capacity, it will conduct a BCA and other economic evaluations to determine the cost-effectiveness of portfolio scenarios, as well as associated potential customer rate and bill impacts. O&R worked with the JU to develop a BCA methodology to comply with the Commission's *Order Establishing the Benefit-Cost Analysis Framework* ("BCA Order")[39] The Company then combined the JU methodology with Company-specific data to develop O&R's BCA Handbook. The BCA Handbook, filed in conjunction with the Company's IDSIP in June 2016, is being incorporated into the integrated planning process and the review and assessment of actual RFP bids and portfolio solutions. The BCA Handbook illustrates the Company's support for the evaluation and deployment of NWAs, where appropriate, and serves as an integrated part of the Company's updated electric delivery system planning process.

Looking forward, O&R anticipates continued refinement and improvement to its BCA model and process. As the Company continues to develop its BCA process, it is working with stakeholders including DPS Staff, the JU, and external experts to further refine the assumptions and values included in the BCA Handbook and include new benefits as they are identified such as the value of optionality as recently directed in the New York State Energy Storage Roadmap.[40]

Additional details on these accomplishments can be found in the Additional Details section of this Integrated Planning section.

Implementation Plan, Schedule, and Investments

Current Progress

O&R is in the process of making additional refinements to its planning processes to support the growth of DERs and support the Company's commitment to implementing NWAs while still adhering to basic planning principles. The first of these potential refinements is designed to facilitate consideration of potential alternative solutions and NWA opportunities. Starting with its 2018 planning process, the Company is employing its new ten-year planning horizon that it had previously built into its planning process. O&R expects this new ten-year planning horizon will facilitate consideration of NWA opportunities and other alternative solutions by allowing O&R to identify potential NWA opportunities

[39] REV Proceeding, Order Establishing the Benefit-Cost Analysis Framework (issued January 21, 2016)("BCA Order").
[40] Energy Storage Roadmap Proceeding, Roadmap.

further in advance of the need, providing more time for developers to develop and propose solutions, and the Company additional time to evaluate and implement potential solutions. For future load-growth based system expansion projects, the Company will potentially be able to implement solutions far enough in advance to mitigate associated operating risk prior to critical need timeframes, while preserving adequate timing for potential traditional infrastructure solution commitment dates.

The Company is also in the process of modifying its planning process to account for the growth of DERs and other load modifiers. Due to the increased penetration of DERs and other load modifiers, the Company is implementing new methods and approaches that provide more granular and location-based information about how load and load modifiers will evolve and impact local system reliability and system investment requirements. This information will assist O&R in developing DSP capabilities and integrating DERs on its system. Details on this process enhancement can be found in the Advanced Forecasting section of this DSIP update. The Company expects that both the more granular understanding of load modifiers and the implementation of the ten-year planning horizon will also benefit the Company's process for identifying grid values through price signals, which are discussed in greater detail in the Beneficial Locations section of this DSIP update.

O&R is enhancing distribution planning through the inclusion of scenario and probabilistic planning methods to provide a greater window of opportunity for NWAs

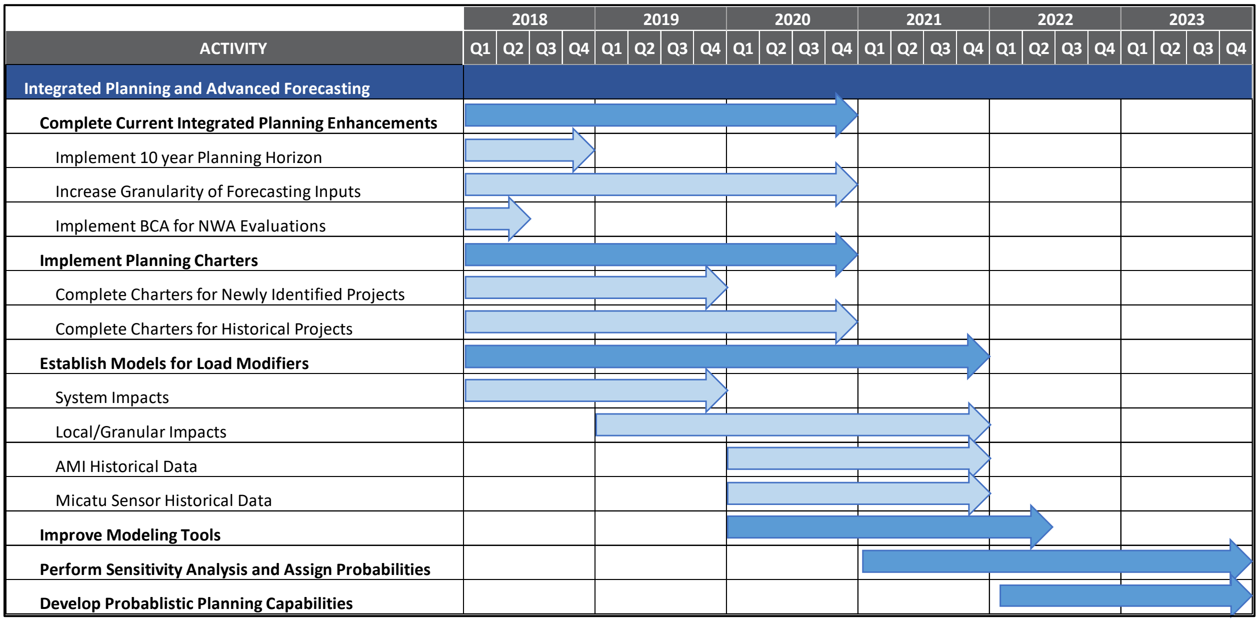
Additionally, to provide completeness for a review of all potential project alternatives throughout the lifecycle of a project while it is still within the planning process, the Company is amending its documentation processes to develop a Planning Charter for all projects. Each Planning Charter will provide documentation of all alternatives, both traditional and non-traditional for a particular need. The alternatives will be thoroughly reviewed, evaluated, and cost-benefit assessed with documented results to reflect decisions and analysis along a project timeline.

Lastly, the Company is exploring the possibility of developing a software "toolkit" that will be designed to facilitate analysis for some of the key steps in the Company's planning and review process, such as local area peak load forecasting, NWA screening, developing potential portfolios for NWAs, and evaluation of NWA bidders. This toolkit could potentially enable O&R teams to create and analyze granular portfolios of DERs for the purposes of analyzing the feasibility and cost-effectiveness of NWAs. It could also potentially be used to generate technical, economic, achievable, and naturally occurring DER potential outputs for EE, DR, DG, and energy storage.

Future Implementation and Planning

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

Figure 9: Integrated Planning 5-Year Implementation Plan



Over the course of the next five years, the Company expects to both complete in-flight process improvements, such as implementation of the new ten-year planning horizon, and the suite of tools supporting planning and NWA procurement, as well as identify, develop, and complete additional process improvements designed to develop the capabilities required to support probabilistic planning. The Company's current capital plan can be found on the JU website (link).

O&R recognizes the importance of probabilistic planning and the need to develop the underlying capabilities to support it, including advanced forecasting capabilities described in the subsequent section of this document. The Company is working toward a future in which it plans to determine sensitivities for load modifier growth levels that will advise scenarios to be used in the Company's planning processes, ultimately enabling scenario and probabilistic planning. Such planning will lead to defining a range of dates within which a system constraint might be violated, rather than a single date. The Company will then select a "base case" date for the criteria violation from the range of dates produced in the Company's probabilistic planning studies based on a determination of highest probability. With the inputs from probabilistic planning, the Company can then have a more defined window of opportunity for the identification of potential NWA projects that might alleviate the constraints and allow for a committable date range in which a traditional solution might be required.

The key next steps for O&R will be to work with industry experts, developers, and the JU to solidify a methodology for enabling probabilistic planning, building the required capabilities, and collecting and analyzing the resulting data with its new tools and capabilities. Once this has occurred, the Company will be in a position to leverage the full set of new capabilities to perform probabilistic planning. While these steps will add complexity to the planning process, they will allow the Company to better understand and plan for the complex impacts and interactions of numerous load modifiers on the system.

Risks and Mitigation

O&R plans to invest in reliability driven projects designed to reduce risk while applying REV like solutions in a targeted approach. Opportunities for innovative solutions to mitigate enterprise-level risk while providing safety and reliability are sought and customer-driven solutions preferred. The planning process provides guidance to aid in prioritizing electrical infrastructure projects for the electric delivery system, which balances costs of the investment versus the benefit of mitigating the risk such as a significant outage event, as measured by both customers impacted and the anticipated duration of the event.

The development of probabilistic planning capabilities will require collaboration and coordination with other utilities and industry to fully flesh out the process requirements and identify the necessary steps and their associated timing. The full set of requirements, and resulting new capabilities, necessary to perform probabilistic planning are not yet known to the Company, posing a risk to the timely implementation of probabilistic planning. In addition, forecasting process changes, described in the subsequent section, will be key components of the probabilistic planning process and necessary for the Company to successfully implement probabilistic planning. Lastly, probabilistic planning requires a new way of thinking about the planning process and will require training on the process changes and change management to promote adoption of the new methodologies.

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

Stakeholder Interface

The development of long-term load forecasts is one of the central functions of distribution 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 update. 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.

In addition, O&R and National Grid have "Planning Days" in which they conduct planning process benchmarking and discuss emerging topics such as 8760 forecast methodologies. The companies' most recent Planning Day was in June of 2018 during which they discussed planning criteria and how they are used to identify systems that do not meet the criteria and those that are in danger of failing to meet the criteria in the future. The discussion helped keep each utility updated on the various methods used in each company's planning process, share ideas, and create greater transparency between the companies with respect to utility planning and operations.

Additional Detail

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

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

Integrated Planning Process Overview

The Company's electric delivery system planning process is designed to maintain and enhance the safety and reliability of the T&D system while maintaining system performance within defined and acceptable design and operating risk tolerances. The planning process evaluates the electric delivery system over a specified future forecast period and identifies system needs and solutions.

Historically, the Company performs a forecast and contingency analysis for the upcoming summer period annually. This annual process includes a two-year forecast for its distribution circuits and a five-year forecast for its substation banks/transmission feeders. The Company then conducts operating reviews of its assets through that forecast period and applies its design standards and risk-assessment methodology to the results to identify current and future operating risks and potential corrective solutions. The Company also investigates if major capital infrastructure investments can be substantially deferred, reprioritized, or even eliminated by alternative and less costly traditional infrastructure investments, as well as targeted non-traditional measures and alternative solutions, such as DG, DR, EE, or a combination thereof. As part of its approach to employing traditional solutions, O&R considers the use of new technologies and/or DA/smart grid asset deployment for improved asset utilization, as well as the timing of traditional solution implementation to defer major upgrades or new builds.

As further described in this section below, the Company is exploring ways to better facilitate consideration of alternatives as part of its planning and capital budgeting process. The Company also reassesses previously identified needs and project solutions that have not yet been initiated to confirm the need and timing of the solution. As part of this reassessment, the Company reviews available data such as updated load forecasts, load modifier forecasts (which include DERs), asset condition, system reliability, and the system's load serving capability under normal and specific contingency conditions.

As part of its current peak demand forecasting and risk assessment processes, each year the Company forecasts peak loads for the overall system and each transmission facility, individual substation and station transformer bank, and distribution circuit. The Company produces a ten-year look ahead for each transmission line, substation, and station transformer bank. Substations are grouped into specific load regions based on geographic proximity and available switching capabilities among adjacent stations and circuits. Mathematical regression models consider and incorporate historical peak loads for each region, along with other relevant variables, to forecast weather-normalized loads for the summer peak and a future forecast period for each region.

The Company considers the impact of load modifiers, which include PV, EVs, energy storage, DG, and other DSM measures, such as EE programs and voluntary or Company-administered load reduction programs. The Company then uses the forecasted loads to perform operating reviews on each of its major assets. These reviews cover transmission lines and banks down through their distribution circuits, for both normal and contingency operating conditions. The results of the contingency analysis are then evaluated against the Company's design standards to assess if the electric facilities are, or will be, operating outside of acceptable design and/or risk tolerances. If any of the assets do not operate within their respective design standards either currently, or at some point during the future forecast period, the Company identifies a need, determines a solution, and develops a schedule to implement the solution consistent with its priority, as part of its capital budget development process. This process includes evaluating traditional solutions, identifying areas for NWAs and grid values.

The Company utilizes electric system planning design standards to provide guidance in assessing operating risk, identifying system needs, and prioritizing electrical infrastructure projects. The design standards balance the costs of infrastructure investment against the benefits of mitigating the risk of significant outage events as described by the magnitude of the outage and duration of the event. The electric design standards provide criteria to evaluate whether electric facilities are, or will be, operating outside of acceptable tolerances for equipment loading, operating parameters, and customer outage exposure. For the Company, acceptability is measured by meeting Company criteria for both the amount of load or number of customers impacted and the reliability impact based on anticipated customer hours of outage duration. These standards are foundational to the capital planning process and key for both short-term and long-term planning, as they provide a process by which future risk mitigation investments are identified and prioritized.

Integrated Planning Process Changes

O&R is in the process of making a number of changes to its integrated planning processes. These changes will extend the time horizon over which it plans and will also provide the opportunity to both perform more detailed analyses of load modifiers and begin the incorporation of additional load modifier forecasts into its planning processes. These changes enable O&R to perform its planning in a more thorough and informed way that takes more nuanced load modifier impacts into account.

The first of these refinements is designed to facilitate consideration of potential alternative solutions and NWA opportunities. Commencing with the 2018 planning process, the Company is now expanding its planning horizon to include a ten-year outlook in addition to the traditional five-year outlook. The expanded ten-year planning horizon will facilitate consideration of NWA opportunities and other alternative investments by providing the Company additional time to identify and analyze potential solutions. For future load-growth based system expansion projects, the Company will also potentially be able to implement solutions far enough in advance to mitigate associated operating risk prior to critical need timeframes, while preserving adequate timing for potential traditional infrastructure solution commitment dates.

Another refinement the Company is exploring is modifications to its planning process to account for the growth of DERs and other load modifiers. Traditionally, the Company's load forecasts with respect to load modifiers have relied on top-down, deterministic methods to provide projections for peak load levels across the electric delivery system. However, because of the increased penetration of DERs and other load modifiers, the Company is implementing new methods and approaches that provide more granular and location-based information about how load and load modifiers will evolve and impact local system reliability and system investment requirements. Such information will also assist the Company in developing DSP capabilities and integrating DERs on its system.

Historically, the Company has evaluated the impact of DERs at a system level. The Company incorporated DERs into its system forecasts by applying load modifiers that were determined at the overall system level and subtracted from gross load. Over time, the Company expanded the list of load modifiers it considered from EE and DR to include DG/CHP, PV, EV, and Battery (beginning with the 2016 forecast).

The Company's 2019 DER forecasts will become more granular. In addition to considering DER impacts at a system level, the forecasts for each substation, bank, and circuit will reflect the impact of DERs on that particular element of the system. This newly developed forecasting methodology will add granular detail for the electric delivery system within specific geographic/operating regions to provide improved study and solution development for projected system needs. The Company establishes this initial methodology with the expectations that data sources and assumptions will continue to evolve and, as such, will enhance and refine its processes for projecting load growth and for modifying the net load to account for all load modifiers appropriately.

Once a set of projects has been selected, the Company utilizes 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.

In the first step, Electrical Engineering prioritizes projects based on multiple drivers that have several possible components that contribute a weighted value. The key drivers include load, existing condition toward satisfying design standards, equipment condition, relationship to sequential project needs, reliability, customer needs, and construction window availability. Other drivers, such as operating conditions, safety, age and obsolescence, system losses, and voltage improvements, are also considered. The total weight awarded a project establishes its priority relative to other projects for the entire forecasted planning period. These results are used in the development of the Company's five-year budget.

In the second step, the overall capital budget for a one-year future-looking forecast period is reviewed and prioritized. The Company then analyzes its corporate portfolio using its strategic alignment optimization methodology and process. During this optimization process, capital projects seeking funds for the upcoming budget year are ranked after they are reviewed using a series of corporate key drivers. Projects are ranked relative to each other based on their attributes with consideration toward the following objectives (in no particular order).

- Improve Public and Employee Safety;
- Reduce Cost to Customers;
- Provide Reliable Service;
- Improve Customer Experience;
- Enhance External Relationships;
- Reduce and Manage Risk;
- Strengthen and Develop Employees;
- Strengthen Company Processes; and
- Sustain Environmental Excellence.

The initial portfolio prioritization is selected by a team comprised of subject matter experts, department managers, and directors from relevant areas of the Company. The overall capital portfolio is reviewed, necessary adjustments are made, and a final portfolio is approved by the O&R Capital Governance Committee.

Since its IDSIP filing, the Company has changed its process for screening projects for potential deferral or replacement with an NWA. Previously, the Company employed a three-step process. First, the Company used a technical screening process similar to the current NWA suitability matrix as discussed later in this document. Second, when the Company determined that an NWA was a viable technical option, it determined a present value for deferring the project. The present value was determined by dividing the present value savings (in terms of revenue requirement) by the load reduction required to defer the traditional project. The result was a value in dollars per kW. The Company used a hurdle rate of $150/kW, which was based on the Commission's previously adopted value for system-wide EE programs, as the standard to determine whether it will perform more detailed studies. Third, for projects that overcame the hurdle rate, the Company performed studies that reviewed the type and number of customers affected and the load profiles attendant for the circuits in the geographic area of the project. These studies also included an analysis of whether enough capacity reductions could be achieved and, if so, a cost-benefit analysis of the alternative as compared to the traditional investment.

Today, the Company continues to use a three-step process but with different criteria. First, the Company uses a Company-specific version of the NWA suitability criteria matrix developed by the JU as part of the ongoing REV/DSP implementation process. The JU developed the NWA suitability criteria matrix to have a common framework to identify projects that are most suitable for NWA consideration. The Company's specific NWA suitability criteria matrix is provided below. The new suitability criteria address different project type, timeline, and cost criteria to identify traditional projects that can be deferred by a NWA project, rather than using a $/kW hurdle rate. Project timeline (in months) and Cost suitability (in $) vary among the JU. Second, the Company committed to develop and evaluate a portfolio of potential NWA solutions. The Company also identifies the date by which the NWA project will need to be in service to defer the traditional investment. The date gives prospective bidders an idea of when their NWA projects will need to be in service to meet the need. Third, the Company committed to conduct detailed BCA for each of its NWA projects in accordance with the BCA handbooks that were developed and communicated as part of the IDSIP filing and to file an updated BCA Handbook with each subsequent DSIP filing.

Table 4: NWA Suitability Criteria

Criteria	Potential Elements Addressed	
Project Type Suitability	Project types include Load Relief or Load Relief in combination with Reliability. Other categories have minimal suitability and will be periodically reviewed for potential modifications due to state policy or technological changes.	
Timeline Suitability	Large Project (Projects that are on a major circuit or substation and above)	▪ 30 to 60 months
	Small Project (Projects that are feeder level and below)	▪ 18 to 24 months
Cost Suitability	Large Project (Projects that are on a major circuit or substation and above)	▪ No cost floor
	Small Project (Projects that are feeder level and below)	▪ Greater than or equal to $450k

The Company uses the criteria in the NWA suitability matrix to make an initial assessment of whether an NWA should be considered as an alternative to a traditional infrastructure project. This screening process determines if a proposed traditional project is a potential candidate from a technical and timing perspective to be cost-effectively deferred or replaced by implementing an NWA, which could include DG, energy storage, DR, DSM, including EE, or a portfolio thereof.

The NWA suitability criteria matrix provides greater clarity, certainty, and long-term visibility to the market. It promotes an efficient allocation of time and resources for both developers and utilities. The NWA suitability matrix focuses on three criteria: project type, timeline, and cost. These criteria identify projects that are best suited for competitive procurement of an NWA, giving developers the greatest opportunity to compete and providing the greatest opportunity for the success of the process.

The nature and characteristics of electric delivery system needs are a primary influence on whether a given project is viable and suitable for NWA consideration. As part of the project evaluation concerning the suitability criteria matrix, the Company considers numerous factors when determining whether a proposed solution, or portfolio of solutions, has the characteristics that will effectively satisfy the system need. These factors include the lead time with respect to the system need date, the economics of the project, and any additional positive reliability impacts of the traditional project beyond the identified planning need. Based on an assessment of these three criteria, load relief or capacity projects, as well as some types of reliability projects, are expected to be the best candidates for NWAs in the near term.

Load Relief or capacity projects are projects where additional T&D capacity will be needed at some forecasted future period to meet O&R's planning design standards resulting from projected increases in load, typically during hours of peak demand. These projects are best suited for replacement or deferral by an NWA for several reasons. First, the grid services provided by installed DERs are more likely to align with traditional load relief and reliability solutions. Second, these types of projects will be required to be identified far enough in advance to provide sufficient lead time for an NWA solicitation. Finally, the scale of investment for the project can influence the likelihood of an NWA being cost-effective.[41]

Typically, projects that are driven by new customer demand—typically driven by new or expanding customer load—involve high-risk circumstances such as those needed to address system conditions that already are failing design standards, address regulatory compliance requirements (such as those imposed by the North American Electric Reliability Corporation ("NERC"), Federal Energy Regulatory Commission ("FERC"), or NYISO), address safety or operational issues, or are required to replace aging or obsolete equipment are not good candidates for replacement or deferral by an NWA.

The timeline suitability criterion addresses whether there is sufficient time to conduct an NWA solicitation and successfully implement the chosen solution before the required trigger date to commit significant funds and resources toward meeting the required traditional T&D project in-service date. Timelines vary depending on factors such as project size, complexity, and customer demographics. Similarly, the traditional utility project required in-service date greatly influences whether there is sufficient time to conduct and implement an NWA solicitation.

The cost-suitability criterion sets a threshold above which NWA solutions are more likely to be cost-competitive with traditional solutions. O&R established a cost floor for small projects at $450K based on historical averages of previously completed capital projects. For large projects, no cost floor is assigned.

O&R is working toward a future in which potential NWA projects that pass the NWA suitability criteria evaluation have hypothetical portfolios of NWA solutions developed to determine whether the Company can obtain enough capacity to satisfy the project need. To assist in the development of these hypothetical portfolios, the Company is developing a software 'toolkit' as previously described.

The JU have collaboratively developed a BCA methodology to comply with the Commission's Order Establishing the Benefit-Cost Analysis Framework.[42] That methodology and the associated templates have been combined with Company-specific data to develop O&R's BCA Handbook. The BCA Handbook, filed in conjunction with the Company's IDSIP, is being incorporated into the integrated planning process, the forecasting and modeling tools described above, and the review and assessment of actual RFP bids and portfolio solutions. The BCA Handbook illustrates the Company's support for the evaluation and deployment of NWAs, where appropriate. It also serves as an integrated part of the Company's updated electric delivery system planning process, from forecasting to implementation of DERs as potential solutions and potential deferrals for traditional solutions, in a manner that best serves the Company's customers, manages risk, and maintains the safety and reliability of the grid.

[41]DSIP Proceeding, NWA Filing.
[42]REV Proceeding, BCA Order.

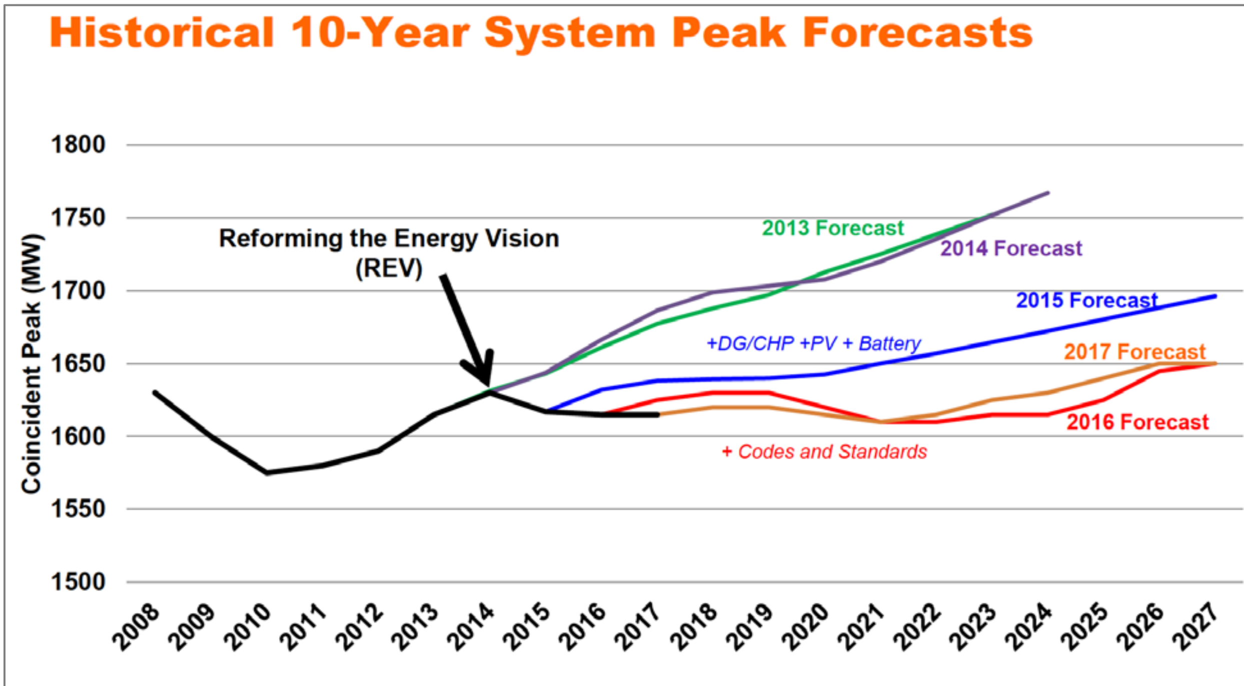
2) How the utility's means and methods enable probabilistic planning which effectively anticipates the inter-related effects of DG, energy storage, EVs, beneficial electrification, and EE.

O&R recognizes the importance of probabilistic planning and the need to develop the underlying capabilities to support it. The Company is currently in the early stages of both understanding the requirements and developing the required capabilities. The Company has just begun to establish a process for determining load modifier growth and collecting this data over time. The collection of load modifier data will subsequently allow O&R to identify growth trends, model growth rates, understand key modeling assumptions, and eventually develop growth and sensitivity projections for load modifier penetration within its service territory. Each load modifier is unique and must be studied, analyzed, and modeled individually before modifier interactions can be studied, understood, and incorporated into the Company's load forecast. As part of this process, the Company is working to understand load modifier penetration levels in terms of both natural adoption and through use in NWAs, which will be driven in part by the business case for each as part of NWA portfolio evaluations.

O&R is working toward a future in which it plans to determine sensitivities for load modifier growth levels that will advise scenarios to be used in the Company's planning processes, ultimately enabling scenario and probabilistic planning. This will lead to defining a range of dates within which a system constraint might be violated, rather than a single date. The Company will then select a "base case" date for the criteria violation from the range of dates produced in the Company's probabilistic planning studies based on a determination of highest probability. With the inputs from probabilistic planning, the Company can then have a more defined window of opportunity for the identification of potential NWA projects that might alleviate the constraints and allow for a committable date range in which a traditional solution might be required.

O&R has already begun to understand and model some load modifiers like PV, EV, DG/CHP, and battery storage, while others are new and the Company is just developing an approach for analyzing and understanding them. It will take time to collect the data required to understand and forecast the load modifiers, and in some cases, it will require greater penetrations of particular load modifiers to provide enough data for analysis. However, the Company is well positioned to understand and incorporate load modifiers as increasing penetration levels impact the system and will be prepared to adjust its plans/forecasts as required. The following figure shows the inclusion of load modifiers in the Company's forecasts starting in 2015 and the inclusion of the impacts of codes and standards starting in the 2016 forecast.

Figure 10: O&R System Peak Forecasts



	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast
5-Year CAGR	0.9%	0.9%	0.9%	0.3%	-0.06%	0.0%
10-Year CAGR	1.0%	0.8%	0.8%	0.4%	0.2%	0.2%

Although O&R is just beginning to develop the capabilities required to support probabilistic planning, one area in which it is already engaging in a form of probabilistic planning is in its use of a temperature variable (“TV”) in its system peak forecasting process. O&R has a longstanding practice, as part of its risk-based methodologies, of forecasting loads on a weather-normalized (“WN”) basis using a TV; the result of which is the weather-adjusted peak (“WAP”). Each year, O&R creates a peak demand forecast incorporating projected impacts from new business, DSM programs, and other load modifiers (EE, EV, DG/Combined Heat and Power (“CHP”), PV, and Battery Storage), which is then adjusted based on the Company’s calculated TV.

The TV is used in calculating and forecasting future system peak demands by taking into account summer weather conditions (heat and humidity) over a weighted three-day period. There is a 1-in-3 probability that the actual load will meet or exceed design capacity based on the projected peak loads at the Company’s design TV of 85 degrees. Through the use of TV, the Company’s planning processes currently take into account a probabilistic assessment of the upcoming summer peak temperatures. Through the analysis and modeling of the load modifiers described earlier in this section, the Company expects to perform sensitivity analysis for load modifiers that will facilitate a more probabilistic planning approach as an enhancement to its planning processes, as it has already done with TV.

The key next steps for O&R will be to work with industry experts, developers, and the JU to solidify a methodology for enabling probabilistic planning, build the required capabilities, and collect and analyze the resulting data with its new tools and capabilities. Once this has occurred, the Company will be in a position to leverage the full set of new capabilities to perform probabilistic planning. These steps will complicate the planning process to a significant degree; however, they will allow the Company to better understand and plan for the extremely complex impacts and interactions of numerous load modifiers on the system. Through all of these efforts, the Company seeks to maintain its excellent forecasting accuracy in the face of new challenges.

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

As part of its process to collect and utilize timely data for its planning processes, the Company's Energy Control Center pulls hourly load demand values from the Load Profile Data System ("LPDS") and its data historian application known as eDNA. The LPDS collects load data for transformer banks, transmission lines, and the overall system in intervals ranging from 15 to 60 minutes and stores them in the LPDS Customer Inquiry module. The eDNA system maintains records of near real-time system data for transformer banks and circuit feeders. The Company uses hourly load values for forecasting purposes that are primarily a combination of data extracted from eDNA and the LPDS. In addition, the Company tracks and manages data on DG connected to its electric system through the NRG mapping system and PowerClerk.

O&R collects near real-time telemetry data from its substations including circuit feeder amps, voltage, and megawatt values for each transformer bank. The Company currently records amp readings for 94% of its circuit feeders via its Supervisory Control and Data Acquisition ("SCADA") network and uses this data as an input to its annual load forecasting process. The Company currently has years of feeder amperage data stored within eDNA, which can be accessed internally via desktop or web client software.

As enhancements to its current capabilities, O&R has extensive plans to increase the collection of granular system data through SCADA as part of the Company's Distribution Automation and Technology Expansion program. This will be accomplished through the deployment of additional and improved substation-level metering data and the complete deployment of AMI. O&R is also in the process of installing and commissioning intelligent distribution equipment (*e.g.,* reclosers, motor-operated air break switches ("MOABs"), and smart capacitors) in the field that will report back data (*e.g.*, voltage, amps, Watts, volt-ampere reactives) through the DSCADA system. O&R has also been systematically installing sensors throughout its service territory to provide additional data points for operational, planning, and forecasting purposes.

Once data is collected, O&R works to identify and address potential data quality issues. As part of this process, the Company checks actual transformer bank load data for metering discrepancies or other factors that may have impacted the accuracy of the hourly or peak demand readings. O&R also compares transformer bank load data against historic load levels. If large or unusual discrepancies are found, a second-level review may be conducted using peak-load values from the transformer bank's supplying substation, including the loads of the substation's individual transformers. Another potential indicator of a data quality issue is metering data indicating significantly unbalanced transformer loads, which could potentially be caused by a faulty remote terminal unit ("RTU"), defective transducer, or some other source. Suspicious data or potential metering problems are reported to the Company's System Operations group and to the corresponding Protective System & Testing Department for verification and correction of identified problems. Data values impacted by metering irregularities may show up as outliers and should be excluded from the weather adjustment analysis. Identifying and addressing these metering irregularities is important to developing accurate weather adjusted values.

In addition to checking for data errors, the Company also makes adjustments to the data to account for the impact of DR and EE programs. For example, transformer bank peak demands are evaluated and revised as appropriate to account for the impact of DR programs emanating from the

NYISO. The Company's Energy Services Department provides information about load reductions achieved as a result of programs called on during the summer period.

O&R takes numerous actions to promote the availability of high-quality data for its forecasting processes, including the use of current data collected in appropriate intervals, reviewing that data for quality issues, and taking action to address observed issues. O&R's investments in its SCADA and DSCADA systems provide it with excellent operating system data on its assets, providing high-quality, granular data for its forecasting processes. In addition, the Company's investment in AMI will provide it with a wealth of additional granular data that can be leveraged in the future as inputs to its forecasting and planning processes.

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

As described in the response to question #2 above, the Company's plans to develop additional capabilities required to perform sensitivity analyses that will supplement and enhance its probabilistic planning initiatives.

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.

As described in the response to question #1 above, O&R's current planning process accounts for changes to forecasts and trends to adjust its plans accordingly. The Company already considers the impact of load modifiers, which include PV, EVs, DG, and other DSM measures, such as EE programs and voluntary or Company-administered load reduction programs. The Company then uses the forecasted loads to perform operating reviews on each of its major assets. These reviews include all of the Company's transmission lines, transformer banks, and distribution circuits, for both normal and contingency operating conditions.

The Company also reassesses previously identified needs and project solutions that have not yet been initiated to confirm the need and timing of the solution. As part of this reassessment, the Company reviews available data such as updated load forecasts, load modifier forecasts, asset condition, system reliability, and the system's load serving capability under normal and specific contingency conditions.

As described in the response to question #2 above, O&R will continue to advance its forecasting and data collection and analysis capabilities to better understand and model load modifier impacts and sensitivities to maintain its high level of forecasting accuracy.

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's current integrated planning process takes aging infrastructure into account as described in the response to question #1 above. After performing its forecasting and contingency analysis for the upcoming summer period, the Company conducts operating reviews of its assets through that forecast period and applies its design standards and risk-assessment methodology to the results to identify current and future operating risks and potential corrective solutions, including those from aging infrastructure. Once a set of projects has been selected, the Company utilizes a two-step process for prioritizing major 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.

In addition, as described in the response to question #1 above, O&R's planning process currently takes EVs into account as one of many load modifiers, and as a result, the Company's electric system is currently ready for EVs. The O&R electric system can easily accommodate EV charging because the vast majority occurs at relatively low power and over long durations, such as while EVs are parked at home or work. Even as the number of EVs grows, the ability to shape load through pricing and other charging management strategies will help minimize impacts to the O&R electric system. As an example of infrastructure required to support EVs in other areas of the United States with higher levels of EV penetration, less than 1% of the 277,000 EVs on California roads required a service line or distribution upgrade solely to support the EV at a residential location.[43] Additionally, the Company is actively working to improve its understanding of, and ability to model, EVs and other load modifiers as described in the response to question #2 above to stay ahead of demand changes from EVs that may impact its electric system.

The Company's work in this area will also allow it to prepare for the impacts of beneficial electrification, which is expected to be largely driven by the increased adoption of EVs. With the rise of EV, beneficial electrification has the ability to transform the current transportation market, enhance the Company's ability to manage the grid and integrate renewable resources, improve environmental outcomes, and provide its consumers with new products and services. Through the modeling and forecasting of the impacts of load modifiers like EVs, the Company will be able to anticipate the impacts of beneficial electrification on both system and peak loads and consider these impacts as inputs to its planning process. The Company will then identify system constraints that may be violated as a result of these changes and address them as described in the response to question #1 above.

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

As described in the response to question #1 above, O&R's planning processes currently take EE into account as one of many load modifiers. Additionally, the Company is actively working to improve its understanding of, and ability to model EE and other load modifiers as described in the response to question #2 above.

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 responses above, the Company will continue to refine its planning and forecasting processes and develop new capabilities required to support probabilistic planning. In support of this effort, the Company plans to work with industry experts, developers, other stakeholders, other utilities, and the JU to identify best practices and lessons learned. Additional information on utility coordination and stakeholder involvement can be found in the Stakeholder Interface section above.

[43] Edison Electric Institute, *Electric Vehicle Trends & Key Issues* (March 2018). http://www.eei.org/issuesandpolicy/electrictransportation/Documents/EV_Trends_and_Key_Issues_March2018.pdf

Advanced Forecasting

Introduction/Context and Background

Forecasting is an integral part of the Company's planning process as described in the preceding section. O&R has worked internally, with CECONY, and with the JU to explore new opportunities to develop long-term forecasting capabilities that can precisely reflect the impacts of DERs on system needs. The Company forecasts summer peak loads for the system and each transmission facility, individual substation, and station transformer bank, and distribution circuit on an annual basis. The Electric Forecasting Services group develops the System Peak Forecast, based on summer month peak load data. The Peak Demand forecast is then used as an input to the overall forecasting process. The table below provides an overview of the forecasts discussed in this section.

Table 5: Type of Forecast

Forecast Type	Forecast Level	Description
Peak Demand	System	Top-down methodology is used to produce forecasts annually for two-year, five-year, and ten-year forecast periods, incorporating impacts of DG/CHP, PV, Battery, EV, and DSM programs
	Substation Bank	Produced annually for two-year, five-year and ten-year forecast periods
	Circuit	Produced annually for a two-year forecast period
8760	Substation	Developed for stakeholder use, providing projected loads for every hour of the year over a three-year forecast period

The O&R system peak demand forecast is produced by adding incremental MW demand growth for residential and commercial sectors, as well as non-sector-specific technology-driven load growth (such as EVs) to its most recent summer WAP. Sector forecasts are generally developed using a top-down methodology, which takes a holistic view of macroeconomic conditions that influence electric demand. Bottom-up methodologies are also used when there is sufficient data available about projects in queue 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 Company is also working to integrate additional sources of data into forecasts such as system monitoring information, meteorological data, and customer demographics.

As part of its forecasting methodology, the Company considers the impact of load modifiers, which include DERs such as PV, EVs, and energy storage, and other demand-side management ("DSM") measures, such as EE programs and voluntary or Company-administered load reduction programs. The Company also projects the peak loads for each transmission line, substation, and station transformer bank as part of its ten-year forecast. Substations are grouped into specific load regions and mathematical regression models are used to consider and incorporate historical peak loads for each region, along with other relevant variables, to forecast weather-normalized loads for the summer peak and a future forecast period for each region.

Although O&R has begun to understand and model some load modifiers such as those listed above, there are additional load modifiers for which the Company is just beginning to develop an approach to recognize and analyze them. It will take time to collect the data required to fully appreciate and forecast the load modifiers, and in some cases, it will require greater penetrations of particular load modifiers to provide enough data for analysis. However, the Company is well-positioned to recognize and incorporate load modifiers as increasing penetration levels impact the system and is able to adjust its plans/forecasts as required.

The Company has also developed 8760 load forecasts by substation area and made them available to stakeholders via its hosting capacity and system data portal. The 8760 forecasts were developed in response to stakeholder interest and Commission guidance based on actual hourly loads from the previous year. The 8760 forecasts are further described in the Additional Details sections below.

For additional detail on DER forecasts, including methodologies and the latest forecasts, please see Appendix A.

Implementation Plan, Schedule, and Investments

Current Progress

The Company is currently exploring modifications to its forecasting processes to account for the growth of DERs and other load modifiers. As a result of the increased penetration of DERs and other load modifiers, the Company is implementing new methods and approaches that provide more granular and location-based information about how load and load modifiers will evolve and impact local system reliability and system investment requirements. Such information will also assist the Company in developing DSP capabilities and integrating DERs on its system.

The granularity of O&R's load forecasts for substations, substation transformer banks, and distribution circuits is evolving to provide more localized information to potential DER providers

O&R has historically evaluated the impact of DERs at a system level. The Company incorporated DERs into its system forecasts by applying load modifiers that were determined at the overall system level and subtracted from gross load. Over time, the Company expanded the list of load modifiers it considered from EE and DR to include DG/CHP, PV, EV, and Battery (beginning with the 2016 forecast).

The Company's 2018 DER forecasts will be more granular. In addition to considering DER impacts at a system level, the forecasts for each substation, bank, and circuit will reflect the impact of DERs on that particular element of the system. This newly developed forecasting methodology will add granular detail for the electric delivery system within specific geographic/operating regions to provide improved study and solution development for projected system needs. The Company establishes this initial methodology with the expectation that data sources and assumptions will continue to evolve, and as such, will enhance and refine its processes for projecting load growth and for modifying the net load to account for all load modifiers appropriately.

Future Implementation and Planning

As stated in the preceding Integrated Planning section, O&R will continue its efforts to understand and develop the required capabilities to support integrated forecasting and probabilistic planning. The Company is currently in the early stages of both understanding the requirements and developing the necessary capabilities. The Company has just begun to establish a process for determining load modifier growth and collecting this data over time. Additionally, the Company must identify and incorporate new load modifiers, like TOU rates, into its forecasts as they emerge and begin to impact its electric system.

The collection of load modifier data will subsequently allow O&R to identify growth trends, model growth rates, understand key modeling assumptions, and eventually develop growth projections and sensitivities for load modifier penetration within its service territory. O&R is working toward a future in which it plans to determine sensitivities for load modifier growth levels that will advise scenarios to be used in the Company's planning processes; ultimately enabling scenario and probabilistic planning.

The Company is implementing more granular and location-based forecasting methods as a means of better understanding how load and load modifiers will evolve and impact local system requirements

As noted in the Integrated Planning section, the Company plans to work with industry experts, developers, and the JU to identify the forecasting requirements necessary to support probabilistic planning. While these steps will add significant complexity to the forecasting process, they will allow the Company to better understand and plan for the complex impacts and interactions of numerous load modifiers on the system. Through all of these efforts, the Company seeks to maintain its excellent forecasting accuracy in the face of new challenges.

Risks and Mitigation

As discussed in the preceding Integrated Planning section, O&R plans to invest in reliability driven projects designed to reduce risk while applying REV like solutions in a targeted approach. The Company's forecasting processes play an integral role in this process by providing key inputs used to make investment decisions through the planning process.

One of the risks to the Company's plans to advance its forecasting capabilities relates to its ability to collect the granular data required to support its efforts. O&R is in the process of installing and/or planning to install intelligent distribution equipment (*e.g.,* AMI, reclosers, MOABs, and smart capacitors) on its electric system. The ability of this equipment to provide the required data as expected is a key risk to the Company's plans in this area. In addition, the Company will also be required to develop new forecasting tools and capabilities to better model and forecast load modifiers.

Stakeholder Interface

O&R continues to collaborate with the JU on the evolution of long-term load forecasting including enhancing forecasting tools and methodologies for forecasting DERs, increasing the granularity of forecast data, and improving coordination with NYISO. In support of these efforts, the JU hosted stakeholder engagement sessions on March 27, 2017, and July 14, 2017, focused on long-term load forecasting and DER forecasting. In these sessions, the JU solicited stakeholder feedback on several topics of interest to stakeholders, including forecasting use cases and the role of 8760 forecasts in addressing those use cases; incorporation of additional external inputs to utility forecasts, such as public policy and developer forecasts; and the evolution of forecasting to incorporate more probabilistic methods and scenario analysis.

The JU extended their outreach to utilities across the country and in the European Union—including Westnetz in Germany, Eandis in Belgium, and Alliander in the Netherlands—to exchange best practices in long-term load forecasting and DER forecasting, including approaches, impacts on investment planning, geospatial and temporal granularity, and inputs. These discussions allowed the JU to benchmark their forecasting practices with other utilities dealing with similar or advanced DER penetrations and to identify forecasting processes worth investigating within each respective company's distribution planning design. In addition, the JU coordination with NYISO has been mutually beneficial in ensuring effective communication on integrated T&D planning processes, forecasting planning inputs and assumptions, and data resources. For instance, the JU coordinated with NYISO in the fall of 2017 on approaches to capture DER impacts in long-term forecasts in the context of system planning.

Internal collaboration, as well as coordination with NYISO on long-term forecasting of load and DERs, will continue to be focus areas for the JU. Future discussions will extend coordination on information sharing and on forecasting aspects, such as load modifiers and customer-owned generation, to ensure DER impacts are accurately reflected in the forecasts at the bulk system level and distribution level.

Additional Detail

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

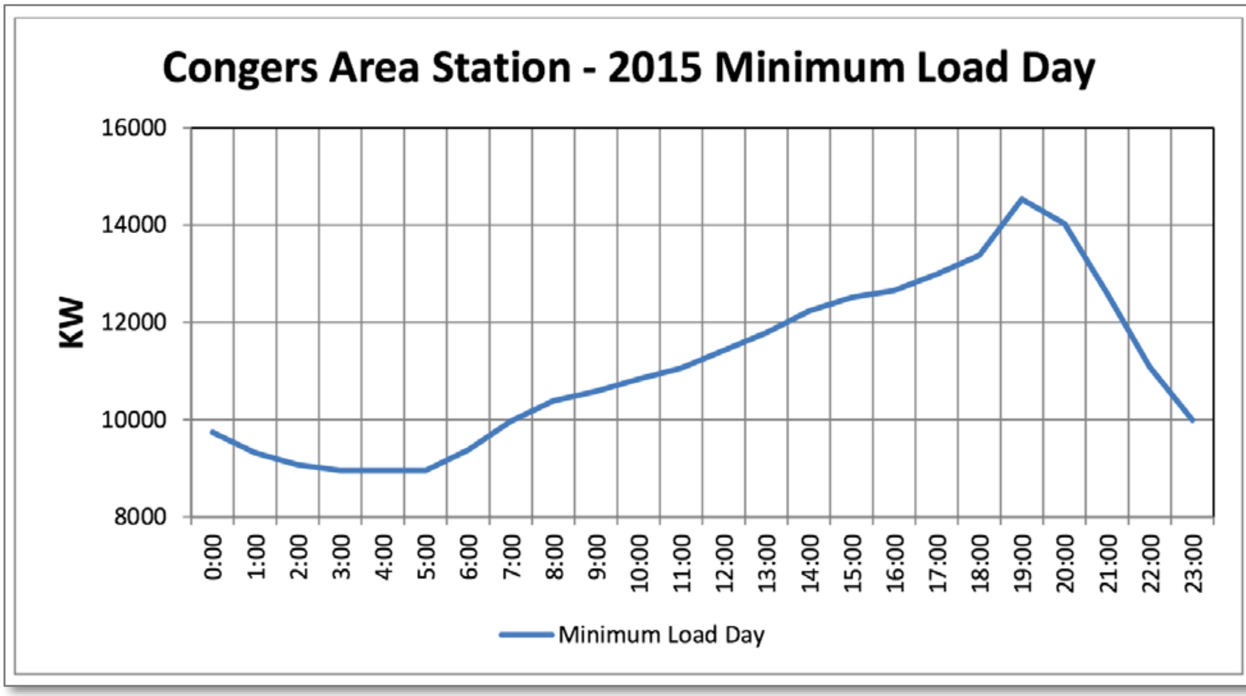
1) Identify where and how DER developers and other stakeholders can readily access, navigate, view, sort, filter, and download up-to-date load and supply forecasts.

DER developers and other stakeholders can view, sort, filter, and download up-to-date load forecasts through the Company's hosting capacity site (link). First-time users can sign up for an account to gain access and returning users can simply use their existing login credentials to access the hosting capacity site. Once logged in, users can access substation-level 8760 historical and forecast data as well as minimum 24-hour load duration curves, as shown in the following two figures. The addition of 8760 forecasts represents a substantial addition to the forecast data available to developers and other stakeholders. At the time of the IDSIP, the Company provided historical 8760 data and the peak and minimum load curves. Details on the 8760 forecast and methodology can be found in the response to question #10 below. Users can access links to this information by clicking on the circuit of interest on the hosting capacity map.

Figure 11: 8760 Forecast Data

3		Blooming Grove Area Station
4	1/1/2019	6524.79
5	1/1/2019 1:00	6114.54
6	1/1/2019 2:00	5996.32
7	1/1/2019 3:00	5945.87
8	1/1/2019 4:00	6159.56
9	1/1/2019 5:00	6711.35
10	1/1/2019 6:00	7563.35
11	1/1/2019 7:00	7848.51
12	1/1/2019 8:00	7678.84
13	1/1/2019 9:00	7624.79
14	1/1/2019 10:00	7574.84
15	1/1/2019 11:00	7608.44
16	1/1/2019 12:00	7657.57
17	1/1/2019 13:00	7750.68

Figure 12: Area Station – 2015 Minimum Load Day Curve – 24 Hour



O&R is not currently providing DER supply forecasts to stakeholders, but it may consider doing so in the future contingent on data capture and analysis capabilities and through the identification of appropriate use cases. Internally, the Company must be able to better understand and model load modifier growth rates and impacts. The Company must also be able to deconstruct the load curve by separating native load from the load modifiers, which will better provide for the means to study the individual impacts and potential interactions. O&R will work to do this first at the system level and then move to the more granular levels of load areas and substations.

In support of the Company's efforts to continually improve its forecasting capabilities, it will need better data from developers on their development plans and schedules, so this information can be incorporated into the Company's forecasts. It will also be important for O&R to work with developers and other stakeholders to understand how they will be using the data shared with them by the Company. O&R will then develop use cases for this data and work to provide information to stakeholders that meets their needs.

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

Following the submission of the SDSIP, the JU continued to collaborate on the evolution of long-term load forecasting, including enhancing forecasting tools and refining methodologies for forecasting DER, increasing the granularity of forecast data, and coordinating with NYISO. As part of this collaboration, the JU hosted two stakeholder engagement sessions in March and July 2017. In these sessions, the JU provided overviews of the role of forecasting in planning and presented case studies on current forecasting approaches, tools, and data sources. The case studies also presented the various load modifiers that are incorporated to develop accurate forecasts. For example, to support greater accuracy, O&R added organic or naturally-occurring EE as a load modifier. In addition to the other load modifiers being considered, as mentioned above in this section, this provides a more complete assessment of the factors that appropriately adjust the forecasts.

The JU also solicited stakeholder feedback and participated in discussions on several forecasting topics of interest to stakeholders, including forecasting use cases and the role of 8760 forecasts in addressing those use cases; incorporation of additional external inputs to utility forecasts such as public policy and developer forecasts; and the evolution of forecasting to incorporate more probabilistic methods and scenario analysis.

In response to stakeholder interest and Commission guidance, substation-level 8760 hourly load forecasts were developed and published consistent with methodologies discussed with the JU and as described in the response to question #10 below. The development of 8760 forecasts included internal discussions among the companies on topics like data resources, treatment of interconnection queue data, and policy issues. As noted above, the forecasts are available in the Company's hosting capacity platform within the system data portal.

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

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

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

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

For supply forecasts, from the Company's perspective with regard to system impacts, O&R has historically evaluated the impact of DERs at a system level in its forecasts, but it is in the process of making its DER forecasts more granular. The Company incorporated DERs into its system forecasts by applying load modifiers that were determined at the overall system level and subtracted from gross load. Over time, the Company expanded the list of DERs it considered from EE and DR to include DG/CHP, PV, EV, and Battery (starting in the 2016 forecast) and EVs (beginning with the 2017 forecast).

Because of the increased penetration of DERs and other load modifiers, the Company is in the process of determining and implementing new methods and approaches that seek to provide more granular and location-based information about how load and load modifiers will evolve and impact local system reliability and system investment requirements. Such information will also assist the Company in developing DSP capabilities and integrating DERs on its system. Starting with the 2018 forecast, in addition to considering DER impacts at a system level, the forecasts for each substation, bank, and circuit will reflect the impact of DERs on that particular element of the system.

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

O&R has a long-standing practice of incorporating EE and DR as load modifiers that reduce the total forecasted system load. The Company has evolved its forecasting methodologies and expanded them to specifically include PV, CHP, EVs, and battery storage. The Company also added organic or naturally-occurring EE as a load modifier in the fall 2017 forecasts to further refine the forecasting process. The

Company will look for opportunities to refine existing load modifiers and potentially add new modifiers as DER technologies proliferate, such as growth in geothermal heat pumps and other electrification efforts.

As described in the response to question #1 above, O&R is not currently providing DER supply forecasts to stakeholders but may consider doing so at a later date.

A detailed description of the DER forecasts and development methodologies is included in Appendix A.

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

The Company has explored opportunities to advance forecasting capabilities to better reflect the impacts of DERs on system needs, including developing forecast methodologies related to:

- Dispatch DERs (five-minute intervals);
- Committing DERs (hourly to day ahead or two days ahead);
- Scheduling work on the system (weekly); and
- Schedule DER maintenance (monthly).

For example, to build a forecast for dispatching DERs, the Company will use the probabilistic output from multiple weather services models to create a blend of weather temperatures and other variables with their corresponding probability of occurrence. To do this, the Company will need a short-term, local, and a refined weather forecast that uses data from a high-frequency S-band dual pol radar, as well as short-term solar radiance and wind forecast models, NASA solar flare models, and multiple satellite images. The Company will incorporate feedback from DER resources set points to produce and forecast the next five minutes set points.

The Company also plans to use actual customer hourly load data from AMI to help determine customer contribution to peaks. As described above and below, the Company is adding and refining load modifiers to better capture exogenous factors influencing peak load. However, as noted previously in this document, the Company is in the early stages of understanding the forecasting capabilities required to support probabilistic planning and developing the necessary capabilities. The Company has just begun to establish a process for determining load modifier growth and collecting this data over time. The collection of load modifier data will subsequently allow O&R to identify growth trends, model growth rates, understand key modeling assumptions, and eventually develop growth and sensitivity projections for load modifier penetration within its service territory.

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

As fully described in the preceding Integrated Planning section and as described in the response to question #6 above, the Company continues to develop the forecasting capabilities required to analyze and understand interactions among load modifiers. However, O&R is in the early stages of developing the processes and methodologies that will be modified and enhanced as it begins to better understand load modifier trends individually, and that it can subsequently use to understand load modifier interactions.

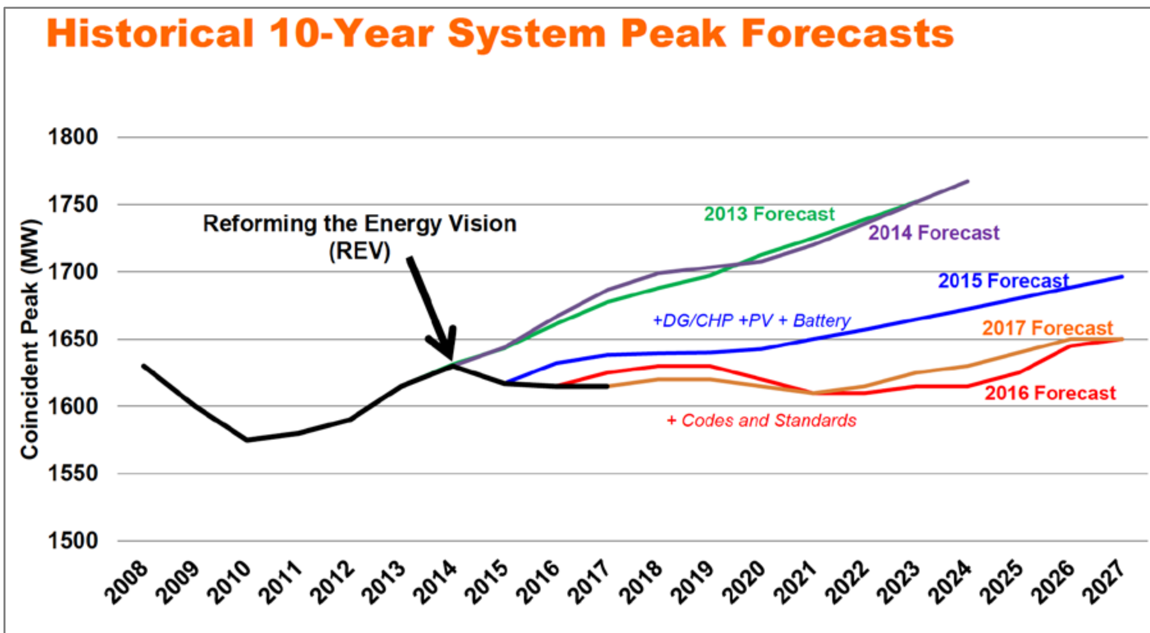
8) Describe in detail the forecasts produced for utility use and explain how those forecasts fulfill the evolving utility requirements for load and supply forecasts.

The development of long-term load forecasts is one of the primary deliverables of electric delivery system planning process and a key input to the Company's strategic and long-range planning. System and local area peak demand forecasts guide infrastructure investment decisions, directing capital to the areas of greatest need and operating risk, and setting the stage for identification of potential NWA and location-specific pricing. Additionally, peak demand forecasts are provided to bulk level system planners as an input to their planning process. Energy forecasts are used to determine the revenue forecast and set rates.

The forecasting of DERs becomes increasingly important as DER penetration grows, requiring more granular load forecasts. As peak demand forecasts incorporate more robust and granular DER forecasts, it will become increasingly more complex and challenging to maintain forecast 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.

Toward that end, O&R is in the process of developing methodologies and enhancing its forecasting process to account for the individual growth trends and effects of load modifiers at more granular levels of its system, including the addition of organic or naturally-occurring EE as a load modifier, which provides a more complete assessment of the factors that improve the accuracy of the forecasts. O&R has begun a new process of developing a more granular approach toward forecasting at the substation level. It involves using a more advanced program to develop its forecast to capture the different kinds of DERs at the circuit level. As shown in the following figure, the addition of DER load modifiers has significantly reduced the ten-year forecasts in line with the increased adoption of these technologies, as driven by naturally occurring customer adoption and REV policies.

Figure 13: Historical 10-Year System Peak Forecasts



	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast
5-Year CAGR	0.9%	0.9%	0.9%	0.3%	-0.06%	0.0%
10-Year CAGR	1.0%	0.8%	0.8%	0.4%	0.2%	0.2%

At this time, resources capable of exporting energy to the grid, such as DG/CHP, PV, EV, and Battery, are treated as load modifiers in the forecasts. Separating on-site consumption from exported energy (*i.e.*, supply) will 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.

The Company uses a range of data inputs to produce its forecasts, including but not limited to meter data, queued projects, technology-specific growth forecasts, and macroeconomic trends. To support more advanced forecasting methodologies, the Company plans to leverage the more granular and accurate meter data available through AMI. Actual customer hourly load data from AMI coincident with system or substation peaks will help in the determination of customer contribution to these peaks. This information can then be extrapolated to the queue of customers connecting to O&R's system to determine short- and long-term (one-year) growth. With AMI data, the Company can also calculate a customer's load with DR and DER reductions to also determine, by customer type, the reductions at the time of the peak.

In addition, O&R has taken steps toward developing forecasts that include more granular data on DERs. The Company's approach revolves around expanding the forecast to develop its native load growth and also include the growth for each DER technology to obtain an amalgamated growth rate. Although the process is at its initial stages, the utility is working toward making improvements as it begins to execute the process and gain familiarity the data.

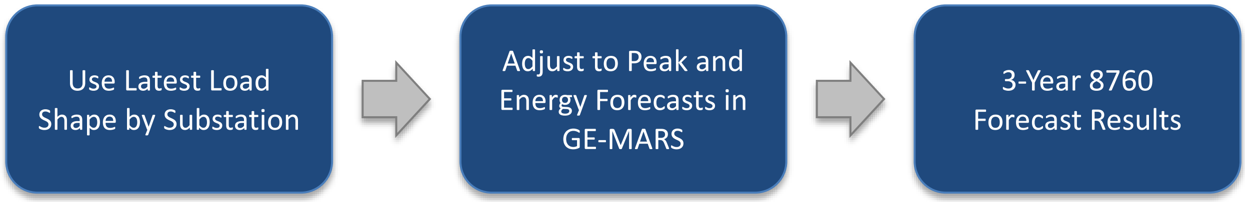
In support of its more granular forecasts, the Company has extensive plans to increase the collection of granular system data through SCADA as part of its DA and technology expansion deployment. This will be accomplished through the deployment of additional and improved substation-level metering data and through the complete deployment of AMI. O&R is in the process of installing and commissioning intelligent distribution equipment (*e.g.,* AMI, reclosers, MOABs, and smart capacitors) in the field that will report back data (*e.g.*, voltage, amps, Watts, volt-ampere reactives) through the DSCADA system. O&R has also been systematically installing sensors throughout its service territory to provide additional data points for planning and forecasting purposes. In addition, the Company is interested in evaluating the benefit of acquiring more meteorological data, such as high-frequency S-band dual pol radar to enable more granular DER forecasting and dispatch.

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

The peak demand forecast utilizes regression analysis to determine the individual substation weather-adjusted peaks. The job growth and load modifiers use a combination of bottom-up (jobs in queue) and top-down (econometric and/or industry trends) methods. A combination of queue data and historical trends is used to allocate top-down forecasts to each substation.

The three-year 8,760 substation forecast utilizes the GE-MARS program to modify the actual hourly loads from the previous year based on monthly energy distribution of the prior year, forecasted peak demand, and energy send-out. The most recent actual hourly loads are used to capture the DER impacts embedded in the service area to develop the load shapes for the individual substations. The load shapes are adjusted to the individual substation peak demand and energy send-out forecasts including the projected DER impacts, such that the forecast includes the impact of load modifiers. The basic process is shown below.

Figure 14: 8760 Forecast Methodology Overview



The 8,760 Hour Forecasts are for informational purposes. These forecasts have 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. O&R does not warrant the accuracy of these informational forecasts.

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

O&R has a process whereby the previous year's electric demand forecasts, as quantified by the previously described electric delivery system planning process, are compared to the actual and observed system-level loads for accuracy. Historically, this comparison has resulted in a difference of less than 5 MW (i.e., less than 1%) for each of the past five years. O&R's top-down forecasting process has thus proven to be very accurate, with only minor disparities attributed to varying new business loads and/or slight changes in transmission losses.

O&R's bottom-up forecasting methodology provides an individual forecast for each substation bank and distribution circuit, which allows the Company to verify the demand accuracy at granular levels of the system, and also potentially identify more granular impacts of DERs. WAP demands for individual transformer bank data are determined and summed to obtain the coincidental substation peak demand load. Transmission system losses are then added to the coincident substation WAP to obtain the bottom up system load. The historic substation-level peak demand forecasts are also fairly accurate, estimated at +/- 5%, but typically have slightly higher average error rates due to many variables that impact demand forecasting such as load, temperature, population, and DERs. Bank-level forecast accuracy is verified through calculations from actual distribution circuit phase readings as compared to actual bank loading measurements. O&R's 2018 top-down and bottom-up forecasting approaches aligned within 5%, and the Company's access to verifiable SCADA operating data allows for more accurate forecasting at granular levels of the system. This data will continue to improve as the Company implements AMI and expands the deployment of advanced sensors and metering packages on its system through its DA program and for implementation at larger DG interconnections.

O&R has also commenced work in 2018 to develop a supplemental substation bank forecasting process, which is expected to improve forecast accuracy. It is also anticipated that this work will help provide a better understanding of DER impacts at more granular system levels, as modifier penetration levels increase throughout the electric delivery system

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.

The Company's hosting capacity platform includes 8760 hourly forecasts at the station load area level, as well as observed peak values at the substation level for the prior year. The 8760 forecasts were requested by stakeholders to provide an indication of the duration of peak and off-peak periods, which is useful for evaluating energy storage opportunities, for example. Details on the 8760 forecast can be found in the response to question #10 above.

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 substation-level and system-level forecast accuracy and refine methodologies as appropriate. The Company updates its ratings and performance assumptions each year based on observed performance and operational experience.

For example, the Company will collect detailed outage information from DERs and use the information to develop DER metrics that analyze outage frequency, duration, causes, and many other factors related to DER outages. The Company will also issue an annual public report showing aggregate metrics for each. Each DER reporting DER Outage Data ("DOD") will be provided a confidential copy of the same metrics for its facilities.

While DOD is not intended to provide determinative performance measures, it will be used to probabilistically quantify certain performance aspects by building transition rate tables for each distribution feeder. In addition to collecting simple DER equipment availability, DOD will collect detailed information about individual outage events that, when analyzed at the substation level, will provide data that may be used to improve reliability. Specific equipment outages will be linked to disturbance reports in the substations, enabling better association of DER outages with load and distribution outages. Additionally, outages by one DER owner will now be tracked to outages of other DER owners so that any relationship between multiple outages can be established. As described in the preceding Integrated Planning section, the Company plans to perform sensitivity analyses as part of its future capabilities required to support probabilistic forecasting and planning. The process of integrating DERs in the forecast is in its initial stages but the collection of load modifier data over time will allow O&R to eventually develop growth projections and sensitivities for load modifier penetration within its service territory. The Company plans to determine sensitivities for load modifier growth levels that will advise scenarios to be used in the Company's planning processes; ultimately enabling scenario and probabilistic planning.

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. The Company believes the current practice of using actual performance data and data from trusted academic sources results in a more accurate forecast and prevents potential market manipulation. Additionally, at this time, DER developers appear to have reservations about providing forecasted installation data, as it can be considered trade secret.

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

O&R continues to collaborate with the JU to share best practices and align forecasting approaches. The JU hosted discussions with utilities across the country and in the European Union to exchange best practices on long-term load and DER forecasting, including frequency of updates, impacts on investment planning, geospatial and temporal granularity, and inputs and methods. These discussions allowed the JU to benchmark their forecasting practices with utilities facing similar issues and to identify lessons learned.

As an example of collaboration with other utilities, O&R and National grid have "Planning Days," as described in the previous Integrated Planning section of this DSIP update. These Planning Days are used to conduct planning process benchmarking and discuss emerging topics such as the 8760 forecast methodology. The sessions are designed to provide a forum in which the utilities can share ideas, discuss important planning topics, and create greater transparency between the companies' utility planning and operations.

The Company will continue to coordinate with the JU and NYISO on the forecasting of load and DERs, as well as track developments in other states to identify lessons learned and best practices. Work with the JU and NYISO has helped to advance the inclusion of load modifiers in the Company's forecasts and has helped with the development of the Company's 8760 forecast. Future discussions will continue information sharing on forecasting aspects such as load modifiers, customer-owned generation, and other forecasting issues to ensure DER impacts are accurately reflected in the forecasts at the bulk system level and distribution level.

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 to improve forecast accuracy by better capturing the impacts of DERs on load, particularly through the addition and refinement of load modifiers. O&R includes all reliable information it has in its forecasts, so it doesn't have out-of-model impacts from factors it is aware of and cannot account for out-of-model impacts caused by factors about which it is not aware. O&R's current forecast accuracy levels show that the Company is able to develop accurate forecasts at the current level of DER penetration. However, the Company will both continue monitoring its performance and adjust as required while at the same time building additional capabilities required to adjust to increasing complexity brought on by elevated levels of DER penetration. O&R also recognizes that some degree of statistical error is inherent in the process and cannot be completely eliminated.

Grid Operations

Introduction/Context and Background

O&R's vision for the grid is to have control devices and instrument measurements all feeding data back to a centrally located server containing logic to orchestrate model-based programs for control of a wide-area, open network of overhead circuits

Grid operations aims to find an appropriate operating balance among reliability, availability, and the optimal dispatch of localized DERs, efficiency, and cost. In order to enable these optimal scenarios, the grid must first be modernized to capture all the necessary data points and have extensive and targeted command and control of actionable devices through robust communications. As outlined in this section, O&R is continuing the initiatives, investments, and activities necessary to improve the reliability, resiliency, efficiency, and automation of the electric delivery system, while facilitating the continued evolution and progression of critical systems, equipment, sensors, and M&C capabilities to further integrate and advance DERs and expand DSP provider capabilities.

These efforts center on modernizing and strengthening the electric delivery system and infrastructure, enhancing M&C capabilities, and making the necessary changes to processes and organizational structures. Foundational investments in information technology ("IT"), advanced systems, and technologies are being made along with similar investments in communications infrastructure. New programs and demonstration projects are being established to enable DER integration and future market development.

Grid modernization investments are being made to build adaptability; increase grid-edge monitoring; improve the reliability, flexibility, and efficiency of the electric delivery system; and automate the electric delivery system. Such investments include:

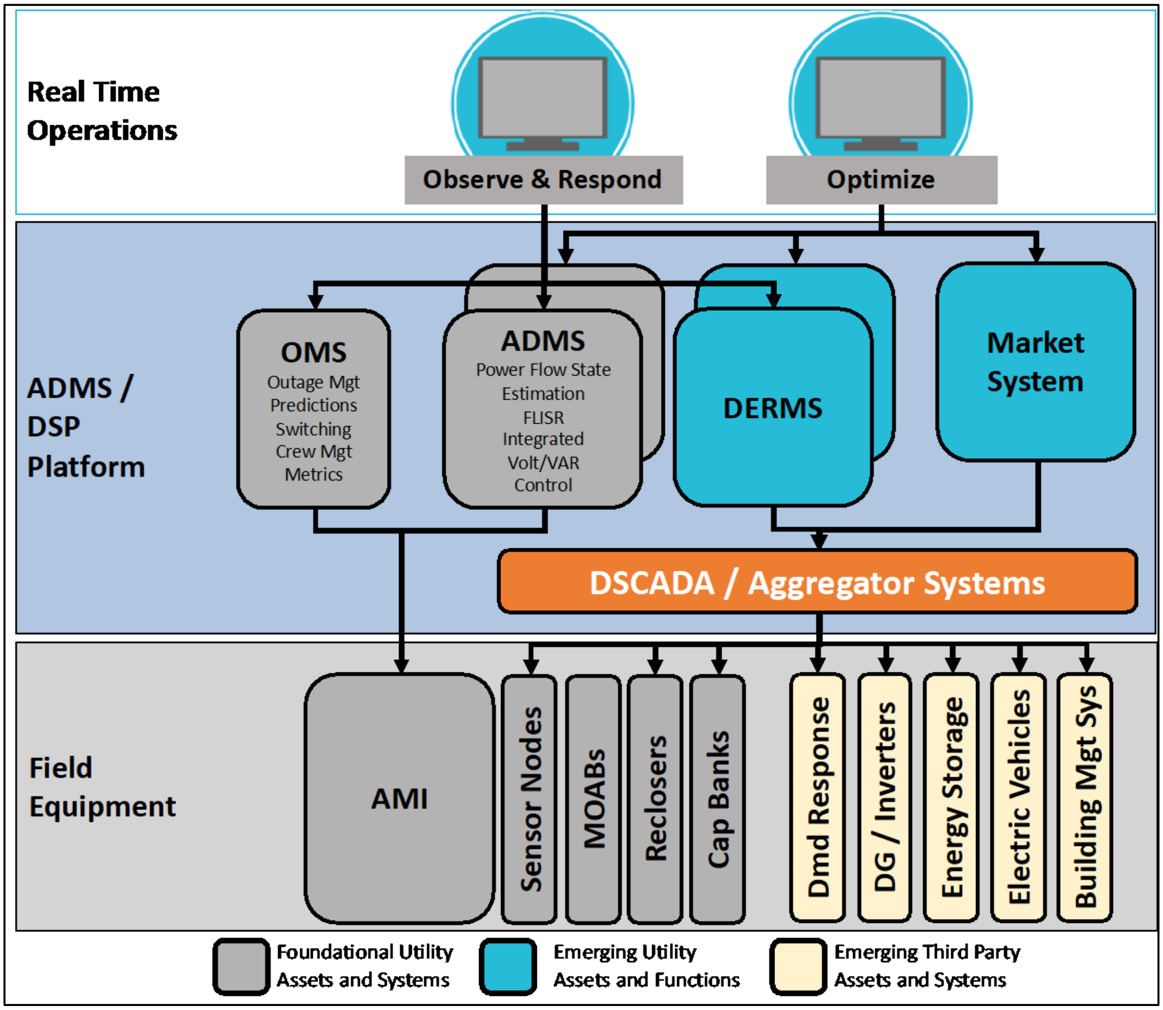
- The sensors, data, and communications networks that enable enhanced visibility and understanding of the behavior of the distribution system;
- The underlying systems, data management, and analytics that facilitate situational awareness, asset management, contingency and risk analysis, outage management and restoration; and,
- The technologies and equipment that promote greater customer engagement regarding energy usage and alternatives

As the penetration of DER increases across the Company's service territory, the requirements, opportunities, impacts, and challenges generated by DERs continue to expand. There will be an increased and ongoing need for situational awareness and control which will require systems and applications to acquire data and produce actionable information in a near real-time environment. Establishing the appropriate level of visibility, monitoring, and control is critical to realizing optimization of the grid and gaining the highest value from interconnected DERs.

Further, near real-time monitoring of DERs will be essential for the Company to understand DER performance and capabilities on the system, both to make same-day operational decisions and for near-term forecasts and scenario planning. As the amount of information gathered grows, the need for a system that will aggregate, analyze, validate, and display the data to the operator will become a necessity. Information will have to move among systems on a common information model as it becomes increasingly integrated with data sources, historical measurements, and advanced applications.

The following figure illustrates various management systems and field technologies needed to support grid operations in an environment with increasing DER penetration. These systems and technologies are discussed in detail through the Grid Operations section.

Figure 15: Enabling Technologies[44]



Implementation Plan, Schedule, and Investments

Current Progress

The Company's approach to meeting the system needs of the DSP provider requires the implementation of new control systems and algorithms which will integrate with and leverage existing systems and related data. An Advanced Distribution Management System ("ADMS") is the foundational platform that must be developed and integrated with other real-time systems and data sources, such as the Company's comprehensive GIS, the Customer Information Management System ("CIMS"), the EMS, a DSCADA system, DA devices, substation equipment, AMI customer data, and the Outage Management

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

System ("OMS"). This integration will enhance electric delivery system situational awareness, M&C to improve reliability, resiliency, and efficiency.

The Company is developing and enhancing its capabilities to evolve into the role of DSP provider while also maintaining high levels of reliability by (1) making necessary changes to processes and organization structure, (2) making key investments in advanced systems and technologies to modernize the grid, and (3) establishing new programs and demonstration projects to enable DER integration and future market development. The Company is also adapting the way that it operates the grid to address the opportunities and challenges associated with increased DER penetration. Such changes include enhanced monitoring of the system to understand and realize the impacts of DERs in near real-time when facing contingencies and other forms of system stress and determine the potential for leveraging local DER solutions to address specific operating conditions.

The Company is continuing to expand its ability to collect and analyze both system and customer data through improved field sensors and AMI. The information gained from the analysis of this data will provide the Company with the insight to more effectively manage the electric delivery system and develop more dynamic markets so that customers, the Company, and DER providers can reap the benefits that DERs may provide.

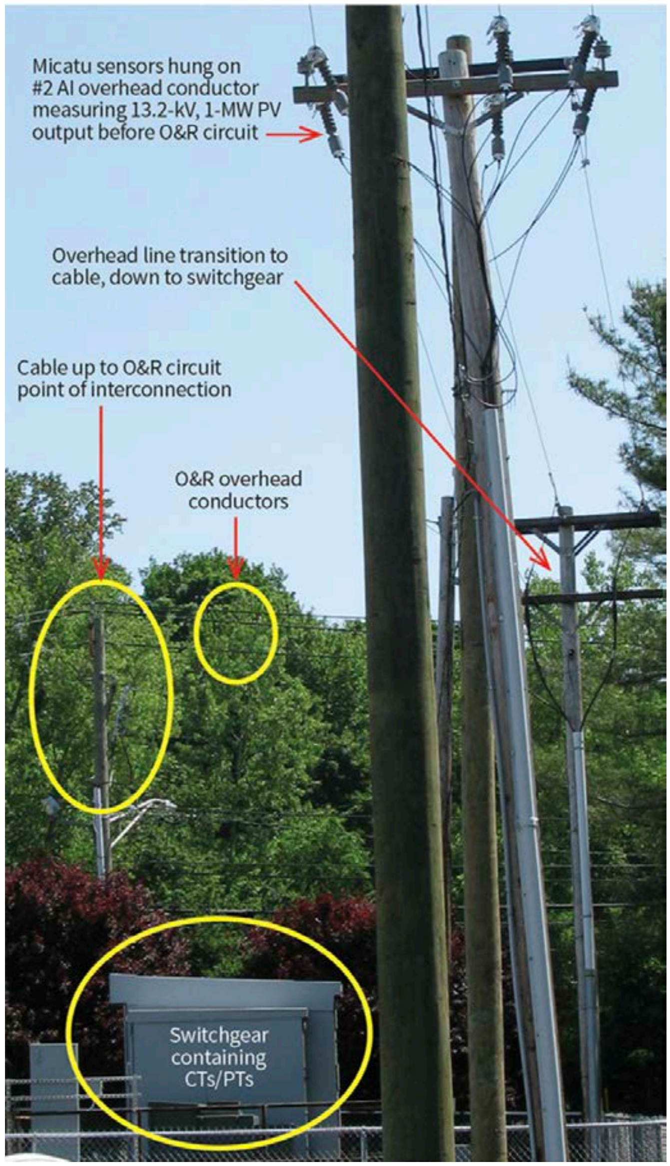
The Company's grid modernization R&D and Lab efforts, such as the use of the Micatu sensing technology, are enabling the Company to cost-effectively progress its grid modernization

Finally, O&R is progressing advanced automation efforts and implementing impactful research and development ("R&D") projects that have and will continue to meet and solve grid challenges through the establishment of a dedicated laboratory environment ("Lab"), which provides the Company an extensive and technically proficient environment with the capabilities to test new systems, equipment and end-to-end operational integration to better ensure equipment and systems will operate as intended prior to mass deployment. The Company can validate the functionality of the operational capabilities of equipment and systems, seeking modifications or re-designs as necessary. The Company can take off-the-shelf vendor products and solutions through a process that integrates and engineers Company focused solutions to meet safety practices, optimize maintenance costs, and promote stable grid operations. The Lab work is enabling the Company to cost-effectively progress its grid modernization efforts and continue to meet REV requirements.

The process the Company has used to achieve these grid modernization initiatives and R&D work efforts have been refined through the implementation of many projects over the past several years. A cross-functional team of engineers with specific but overlapping responsibilities and skill sets provides the rigorous evaluation, testing, and modifications required to realize the potential of new products, equipment, and systems. Vendors typically do not have access to utility construction and operational environments. However, the Company works with vendors to develop or refine package-able solutions on a real system environment that address safety concerns, minimizes future construction and maintenance costs, and which may provide future cost savings when considering the vast number of equipment deployments attendant with grid modernization across the service territory.

A recent example of O&R's engineering efforts to achieve grid modernization initiatives is the co-development and testing of next-generation distribution sensing devices. O&R has been working on a multi-year project with a New York-based vendor and NYSERDA for the successful development of an advanced, fiber optic-based sensor (Micatu) that will be more accurate and cost-effective than current commercially available alternatives. As seen in the figure below, Micatu sensors are suspended on overhead wires before the O&R circuit and switchgear measures the same volts and amps.

Figure 16: Micatu Sensing Application At The Clarkstown Photovoltaic Test Facility[45]



Additional details regarding the use of Micatu sensors is provided in the sections that follow.

Initial installations of new equipment and devices often have performance or installation challenges which must be overcome. Field crews, technicians, and engineers will evaluate and troubleshoot these early field installation locations and, along with Lab developed solutions, propose product updates and modifications to the vendors. The field devices will be operated and monitored through SCADA to confirm the installed solutions provide the improvements expected. Findings from the initial installations are communicated to vendors and other stakeholders as necessary. Ultimately, O&R acquires the confidence required for the product to be deployed as needed.

The O&R Lab team attends and participates in key industry conferences, and expositions such as DistribuTECH and Institute of Electrical and Electronics Engineers ("IEEE") trade shows to review the latest

[45] Laglenne, J. P.*et al., Next-Gen Sensors for the Modern Grid*, T&D World (July 18, 2018).

technology available, discuss industry trends reflected in commercially available products, and interact with vendors to find early stage development projects that could potentially meet O&R's needs. O&R will meet and discuss combined integrated solutions with multiple vendors and initiate development projects to combine best in class capabilities or produce an integrated joint product. The O&R Lab team has achieved the following accomplishments:

- Implementation of an integrated distribution SCADA system, remote terminal units ("RTU") programming logic, radio gateways and radio remote schemes, and communications network;
- Development, testing, integrating, and troubleshooting new technologies as a subset of the integrated Lab automation system;
- Completed proof of concept testing for the Department of Energy Smart Grid project proving a model-centric auto restoration and voltage control system;
- Developed the data management scheme between controllers and RTU to minimize communication errors during large-scale system disturbances;
- Developed an advanced "smart" capacitor bank controller;
- Developed "smart" motor-operated air break switches with fault detection logic;
- Developed a pilot SCADA regulator control, with a second-generation SCADA regulator control under development;
- Developed with an underground switch manufacturer, a switch control with enhanced protection logic and capability that can be integrated with the Company's SCADA network;
- Investigated 4G capabilities for specific automation communications alternatives;
- Investigated higher speed RTUs that could take advantage of a quicker SCADA network;
- House the base stations for the Company's GPS-enabled phase identification system; and,

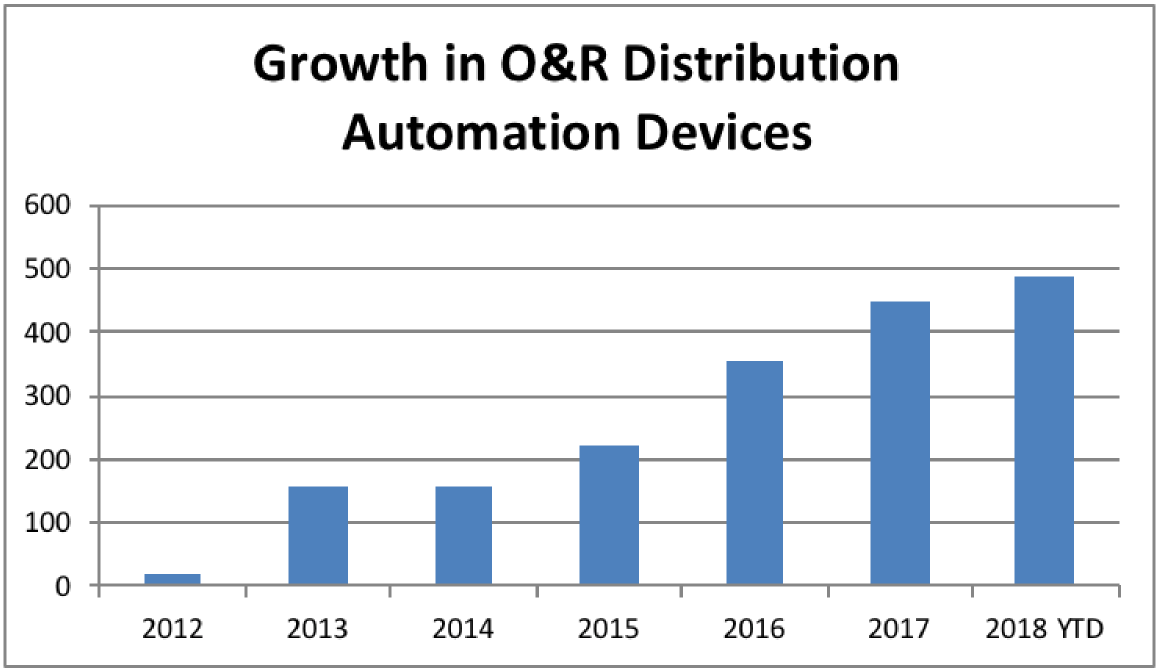
O&R's Lab team is focused on initiatives ranging from individual device capabilities to integrating and progressing high level targeted and specific programs. The Company believes these efforts have yielded substantial accomplishments and will continue to do so as the Company progresses with its grid modernization and DSP plans.

Distribution Automation

DA equipment coverage at the sub-circuit level has almost doubled from 2016 to 2018

The Company has been implementing DA equipment since the 1990's. Commencing in 2012 the Company established and began executing an enhanced DA and Technology expansion program. The program consists of the installation of automated field devices such as reclosers, motor-operated air break switches ("MOABS"), capacitor controls, regulator controls, sensors, and power quality nodes. The automated devices combined with auto-loop design reduce customer outages and provide the DCC with immediate notification of system issues. The Company's technology and automation expansion efforts have also increased the collection of granular system data and enhanced the understanding of distribution circuit performance.

Figure 17: Total Number of O&R DA Devices



Currently, 65% (138 of 242) of the total circuits in O&R's service territory have DA devices installed; approximately 35% (85 of 242) of the total circuits are in auto-loop configurations thereby enhancing reliability. This equates to about 20% of the circuits are fully Smart Grid-ready (auto-loops and MOABs) with a plan to complete an additional 10% of the system each year. With this rate of expansion, the O&R territory will be fully Smart Grid-ready in approximately 7-8 years.

ADMS

O&R completed its ADMS Scoping Study in 2016, which confirmed its original position that an ADMS is a core foundational investment that will deliver significant benefits with operational efficiencies through grid optimization, leveraging investments in DA and AMI. An ADMS can identify, monitor, perform real-time analysis, and record data from abnormal system conditions resulting from planned and unplanned events that modify the design configuration of the electric delivery system. An ADMS will enhance situational awareness, and through M&C, improve reliability, resiliency and system efficiency. It will also act in near real-time to coordinate through external interfaces, equipment and communications to administer FLISR, VVO, and eventually a DERMS to integrate and optimize the control of DER with the Company's devices and electric delivery system operation. These capabilities will be accomplished utilizing a dynamic model of the electric delivery system and by leveraging key SCADA and AMI meter information. It will have a near real-time reference of the electrical system operating parameters, which will be the basis of local system analysis study to inform switching plans and mitigate contingency situations in near real time.

As part of the scoping study, the Company held workshops to develop a roadmap for the deployment of an ADMS that would help set the direction for the Company to move forward and adapt to industry challenges in the future through improved integration of critical systems such as OMS, DSCADA, and GIS. The workshops produced many important benefits, including:

- Confirmation that an ADMS is necessary to provide near real-time visibility into the electric delivery system, improve system reliability and performance, and potentially enable O&R to realize future opportunities to be made available by DER integration and the company's AMI implementation;

- Identification of other potential benefits for customer service, engineering, and asset management (*e.g.,* predictive maintenance);
- Identification of key drivers for implementation including replacement of the DSCADA system; implementation of advanced technology to support the DSP infrastructure, and implementation of advanced technology and operational control that will benefit from AMI meter data;
- Identification of the ADMS platform functional requirements and specifications necessary to solicit adequate and robust vendor proposals; and,
- Recognition that ADMS will enable the convergence of current engineering and planning processes and tools.

Communications

The communications infrastructure serves as a critical piece to the Company's planned automation deployment and DSP evolution over the next several years. As such, the Company's Communications Infrastructure Expansion Program is focused on expanding its high-speed communications infrastructure to provide a robust and secure solution throughout the service territory, which will provide for critical utility and customer data transport between data centers, server farms, remote data collectors, and devices. Last mile radio communications are being addressed through analysis and planning for a diverse mix of 200 and 900 MHz frequency tower coverage, and the potential to utilize portions or an expansion of the new AMI communications infrastructure that is currently being installed.

In addition to the Communications Infrastructure Expansion program, the Company continues to expand its DA devices and is in the process of deploying a new ITRON AMI network and infrastructure. Since July 2017 the Company has deployed over 102,000 meters (electric smart meters and gas modules) and is on track to complete the entire deployment of 363,000 meters by December 2020. Details on how the AMI communication infrastructure may be leveraged for other communication purposes is provided later in this section.

Additional Improvements

In both the initial and supplemental DSIPs in 2016, the Company emphasized the need for utility workers protection while performing maintenance activities on an electric delivery system with DERs. To prevent the DER from unintentionally islanding and back feeding into an isolated zone, the Company previously required the DER to be taken offline while performing maintenance activities. The Company reviewed this practice and has since developed a solution that, when applied to the recloser at the point of common coupling, allows the DER to remain operational while performing the Company performs electric delivery system maintenance. If an inadvertent trip occurs, the recloser opens immediately and isolates the DER. This new practice takes into consideration the need for worker protection while being sensitive to the financial ramifications of a DER being offline.

Future Implementation and Planning

The evolution of the Company as a DSP provider requires investments in infrastructure, processes, systems, and people to integrate DER and to facilitate value optimization for all customers. The Company's initial technology investments have focused on building the necessary interfaces to engage customers, increase the volume and granularity of data, enable greater DER penetration, and improve system reliability and operating conditions. The Company plans to continue investing in grid modernization capabilities and DSP enabling technologies commensurate with the level of DER penetration increases over time. Details regarding such plans are provided in the sections that follow.

New DSCADA and ADMS

For optimal grid operations, the ADMS will serve as the core platform to organize and manage the data and functionality required to provide near real-time visibility and control of grid assets and DERs on the system. The collection of additional system data will also facilitate the Company's forecasting and planning processes and near real-time operational awareness of system parameters. This data will be provided via the expansion of various equipment, sensors, and communications that report back through a DSCADA and other means, such as AMI when more fully deployed. It will be another tool that may assist DER providers with information about locations where DERs can deliver the most benefit to the electric delivery system. The Company also plans to enhance its FLISR and VVO capabilities to improve system reliability and maintain acceptable voltage levels, power factor, and operating efficiencies throughout the distribution system under a broader range of operating conditions.

To deploy ADMS in a measured and effective way, the Company plans to implement the system functionality in stages. The initial stage will include the replacement of the Company's existing DSCADA system with a significantly more robust DSCADA application that can accommodate the breadth and scope of the envisioned future state. The Company's existing DSCADA system is near the end of its useful life and does not have the functionality or capability to accommodate the type and number of interface points that the Company is building out in the near-term, let alone what is ultimately envisioned. Later stages will include additional and expanded system improvements and modular integration as required to enable enhanced operational capabilities, expanded operation of the system onto portions of the electric delivery system as they become smart grid ready through the Company's continued expansion of advanced equipment and applications with automation control, and eventually market functionality through systems, date requirements and analytics to be determined.

Fault Location, Isolation, and Service Restoration

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

The Company has implemented and continues to expand the number of field-based fault location, isolation, and restoration automation schemes, utilizing automated switches and reclosers on the feeders, which include auto-loop schemes that will isolate the fault energy in cycles. Expansion of these auto-loops as part of the Company's Smart Grid philosophy provides additional MOABs that enable the circuit to be sectionalized into segments of 250 or fewer customers per segment after the initial fault is cleared. The combination of the fast-acting auto-loops and the MOAB devices are what will allow FLISR to improve customer restoration and system reliability. Based on the Company's progress with DA and Smart Grid, FLISR will be the first significant initiative and reliability improvement to be realized after the successful implementation of the ADMS system and the new upgraded DSCADA system.

Volt/VAR Optimization

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

With respect to the distribution system, the Company has been and continues to install smart-SCADA ready capacitors as part of the enhanced automation program described above. This is the most significant effort to provide voltage control actionable devices on the distribution system, as the Company more extensively utilizes capacitors and distributed devices to control voltage. O&R has a small number of regulators on its system and has a plan to make them SCADA ready in the near future as well.

With respect to the substation environment, over the past several years the Company has performed numerous SCADA RTU upgrades, replaced key substation equipment, and built several new substations. Some of the equipment and devices that have been installed or upgraded include LTC controls and transformer monitoring devices that can provide tap position indications, flexible setpoint control capabilities, and other critical data back to the EMS. New distribution circuit relay package installations are scalable with provisions for providing critical operating data such as MW/ Mega Volt Amps (Reactive) (“MVAR”), voltage, power quality, and reliability data necessary to implement a successful VVO program. A 2018 EMS upgrade is currently being implemented for which the latest hardware and software technology will be utilized for enhanced VVO capabilities. EMS factory acceptance testing has proven the capability of integrated SCADA M&C capabilities between the substation and distribution environments that will allow for the seamless integration of the EMS and other O&R systems and applications such as DSCADA and ADMS.

The preferred near-term solution is to implement elements of VVO that will take advantage of current capabilities, such as automated local controller set points on substation Load Tap Changers (“LTCs”), advanced substation distribution relays, RTUs, distribution capacitors, and distribution regulators with the availability of remote manual LTC control at substation banks that currently have this capability. Further integration and synergies between the EMS and distribution devices will be explored to achieve some VVO capabilities while being compliant with the NERC Critical Infrastructure Protection (“CIP”) cyber-security regulatory requirements. These efforts will provide valuable insights into VVO capabilities and requirements; however, the Company must develop a more structured and integrated approach to realize long-term VVO designs and capabilities.

As such, the Company is planning to start VVO on a smaller scale to allow for the implementation and integration of the systems necessary to realize the required end-state functionality and control. After testing and confirming the appropriate systems, control algorithms, and equipment capability and control actions are in place, the Company will then implement targeted VVO. Through actual operational results and data, a BCA analysis will be completed to determine the scale of cost-effective expansion throughout the service territory. Toward that end, O&R will implement two targeted projects in the 2019-2023 timeframe. First, the Company will determine design requirements to allow for the upgrade of regulators to make them smart SCADA–ready devices. There are approximately 100 voltage regulators that are presently operating on the Company’s distribution system that will need to be upgraded. The Company anticipates upgrading 33% of these regulators to be SCADA capable in next three to four years. Second, the Company will target a small number of distribution and substation breaker relays that will be upgraded to test full VVO functionality requirements. These breaker relay upgrades will be done in an area where the distribution system is smart grid ready, so that the full integration of control systems, substation, and distribution devices capable of VVO control can be tested as an integrated system.

Based on the initial "pilot" results of the Company's field trials, the Company will determine the extent of its VVO implementation efforts. Based on a successful and cost-effective evaluation, the Company will target expansion of VVO capabilities initially on portions of the system where sufficient DA and smart grid equipment has already been or is being deployed. This will allow for the immediate realization of the benefits from the equipment installations as this expands through the electric delivery system.

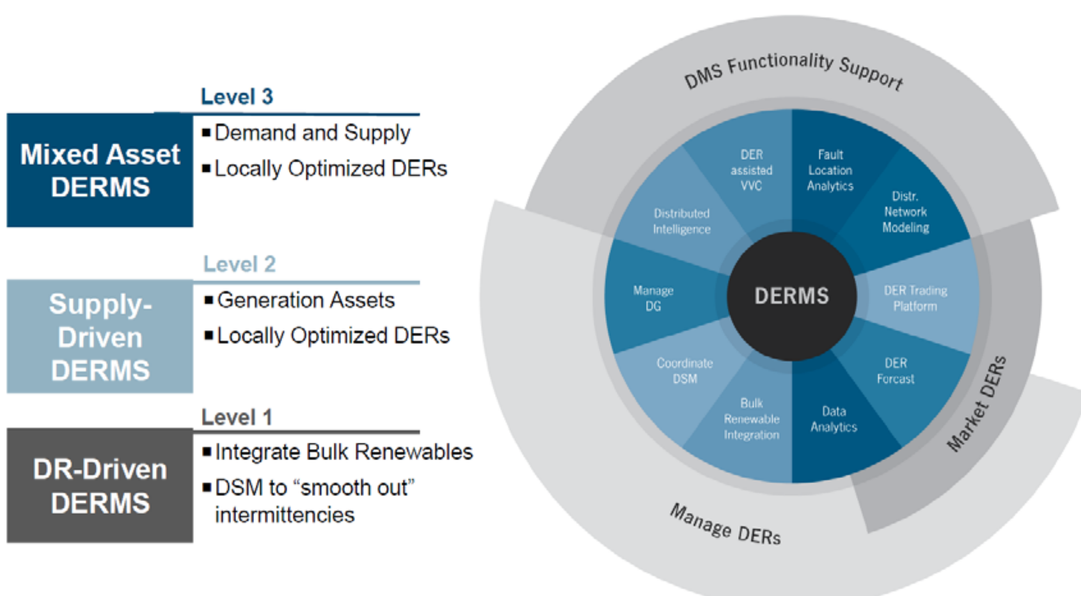
Future enhancements to VVO will be toward understanding the ability and cost-effectiveness for DERs to provide potential ancillary benefits for system operations, such as local power factor changes and voltage control to assist operating conditions. As these equipment upgrades and advanced technologies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

DERMS

DERMS is envisioned to be a software-based solution that will substantially improve a system operator's real-time visibility of DERs and provide targeted operational control of these assets. Through a DERMS platform, O&R expects it can 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 though bi-directional exchange of information. The Company expects first functionality to be operationally based and focused, but eventually envisions DERMs will also support and facilitate optimized market-based transactions.

According to GTM Research (now, Wood Mackenzie), a leading electric industry market analysis firm, the DERMS market can be segmented into three distinct groups as shown in the following figure:

Figure 18: DERMS Segmentation Diagram



While the market can be generalized in these three segments, there is limited standardization in platform capabilities. A standard for DERMS is still being defined and the DERMS definition may differ between utilities based on their individual needs. The DERMS vendor eco-system, although diverse, tends to offer solutions that are highly customizable. By enabling the full capability of DERMS platform a utility may be able to achieve the following:

- Enable further DER market participation
- Simplify the interconnection process
- Identify how DERs can be optimized while at the same time minimizing any detrimental impact on distribution system reliability
- Address intermittency of specific DER technologies
- Reduce system losses by enabling control and utilization of local DERs
- Enhance DER optimization capability by analyzing real-time bi-directional power flow modeling
- Effectively manage DERs as they participate in various marketplaces (*e.g.,* ancillary markets spinning reserve, frequency regulation etc.)
- Improve forecasting and co-ordination amongst DERs located within the electric delivery system
- Reduce overall electricity cost by reducing peak plant operation

The Company plans to implement DERMS functionality in the later stages of its ADMS implementation plan. Once the DERMS market, platforms and functionality are better defined, O&R will explore in more detail the various benefits that a DERMS platform can provide to identify features and implementation strategies that are best suited for the Company. As mentioned earlier, there is no current standard definition of DERMS functionality. DERMS platforms will be highly modular and customizable to ensure the platforms and functionality fit the needs of a specific utility.

To define the overall vision for DERMS, it is important to understand the DER landscape. With the proliferation of more DER assets, the utility will need full system visibility and control to address local and bulk system constraints. Keeping the overall vision in mind, the Company need to ensure that the DERMS platform has a combination of the following capabilities:

- Model DER asset by technology type and by location, size, availability, and any associated hidden loading
- Aggregate DERs to both distribution and transmission nodes as needed
- Monitor the output of DERs (MW, MVAR, Power Factor)
- Control the DER in real time and dispatch those assets to benefit the overall electric delivery system
- Prioritize DER dispatch based on economic optimization
- Leverage a DERs reactive power output for automatic local voltage and VAR support
- Seamlessly interact with individual DERs, third-party aggregators, and microgrids
- Provide insight into current and near-future operational constraints
- Forecast DERs both in aggregation by node and by single DER assets
- Schedule and dispatch DER assets, so that they can participate in various marketplaces (*e.g.,* NYISO day ahead ancillary services market)
- Ability to do an offline study to understand how DERs can affect abnormal configurations of the electric delivery system
- Provide for robust reporting to depict the result of offline studies and translate the findings into an actionable report
- Provide help in calculating hosting capacity and integration with PowerClerk

- Understand and implement different operating modes for DERs depending on system configurations

All of this in combination is hugely complex and will become increasingly more so as the number of controllable assets increases. The integration of a DERMS platform with ADMS will be vital to realizing the functionality and advanced operating states envisioned above, but it will be more critical to ensure that the initial ADMS implementation and integration with other core systems is accomplished and established correctly to provide the appropriate foundation that will allow for the future integration of DERMS type platforms. The Company's methodical and staged approach to developing and expanding these systems and functionality will support its effective evolution into its role as a DSP provider.

AMI

When fully deployed, the AMI communications network will provide a ubiquitous capability to gather granular system data that will be used for real-time analytics, long-term planning, and visibility of small DER sites. As stated previously, the Company is rapidly deploying AMI communications devices, smart meters, and gas modules across the service territory. Deployment completion is expected in late 2020. The Company is currently investigating the potential for the AMI communications network and equipment to be leveraged for distribution and substation automation M&C requirements, system redundancy, and potential data backhaul capability.

Distribution Automation

The Company will continue to install and commission DA devices on the electric delivery system. These installations will enhance and expand the Distribution Control Center's ("DCC") capability to monitor and control the distribution system and quickly address system and operational issues. The Company will continue to actively research new technologies that will enhance the ability to monitor and control the system.

The DA program is focused on installing and upgrading field devices with monitoring and command and control capabilities. The philosophy is a three-tiered approach:

- The first tier, circuit optimization, includes designing an efficient system through the use of smart capacitors and power quality monitoring sensors. Smart capacitors provide some VVO capabilities while advanced sensors provide visibility into circuit behavior. These capabilities help the distribution system to automatically compensate for any adverse effects DERs might have on the system.
- The second tier is field automation, and this includes the installation of automatic operating field devices to fully automate the system and allow for automatic fault isolation via recloser auto-loop design. These auto-loop schemes reduce customer outages and provide the DCC with immediate notification of system issues.
- The last and overarching tier is centralized automation control. By utilizing advanced control systems in the DCC, the operator can gain visibility into system statistics and field device status. The ability to communicate with the field devices also gives the operator the ability to segment damage locations and restore customers without field personnel being on site. One of the true benefits of advanced control systems in the DCC is the ability for the system to self-heal. The system will have the capability to gather information from the field devices and sensors and make decisions to isolate damage locations and restore customers automatically. This last stage will be fully realized after the implementation of ADMS with the system under full automation and FLISR control.

As DER penetration continues to increase, DA tools serve as critical components and building blocks for grid optimization. Automation becomes necessary for crucial system functions such as switching plans and real-time contingency analysis, DR, and, ultimately, live line clearance management. Paired with ADMS and AMI, DA tools provide the Company with enhanced visibility into the system, allowing operators to gather, monitor, and analyze more granular near real-time information across the system. These automated devices and control systems also allow DER assets to continue to operate in times of system maintenance, while also protecting the field worker performing the work. With these devices, the DCC can conduct switching operations from the control room and restore outage situations quickly, allowing DER assets to resume operations quicker during times of system stress.

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

Substation Automation

The next generation of distribution and substation automation will assist to facilitate further integration of DERs into the system through enhanced M&C capabilities. Substation automation will also help O&R to integrate VVO, FLISR, and DA capabilities, and will play a critical role in fully leveraging AMI and DR capabilities. O&R is currently undertaking various substation automation initiatives to enable increased functionality.

Advanced substation automation will allow for more efficient and reliable delivery of service while still integrating with SCADA/EMS and ADMS platforms. This integration will enable further automation of the distribution system infrastructure.

VVO will foundationally rely on communications and control between substation transformer LTCs, controllable capacitor banks, and controllable voltage regulators with DSCADA control. Controlling capacitor banks and regulators to manipulate distribution system voltage for VVO measures may result in impacts to the substation transformers LTC operations. Having a clear line of sight to LTCs via substation automation will help reduce these inefficiencies, better control and regulate feeder voltage as part of an integrated system, and control logic that will provide VVO functionality by minimizing the feeder voltage required along the length of the feeder and throughout the load cycle, thereby reducing load and losses and improving system efficiency.

Enhanced M&C capabilities of substation equipment will also enable the utility to determine real-time load flow, identify phase imbalances, and alarm such when detected. Substation automation will also help O&R's capability to support interoperability with neighboring substations as situations require cascading load considerations.

Communications

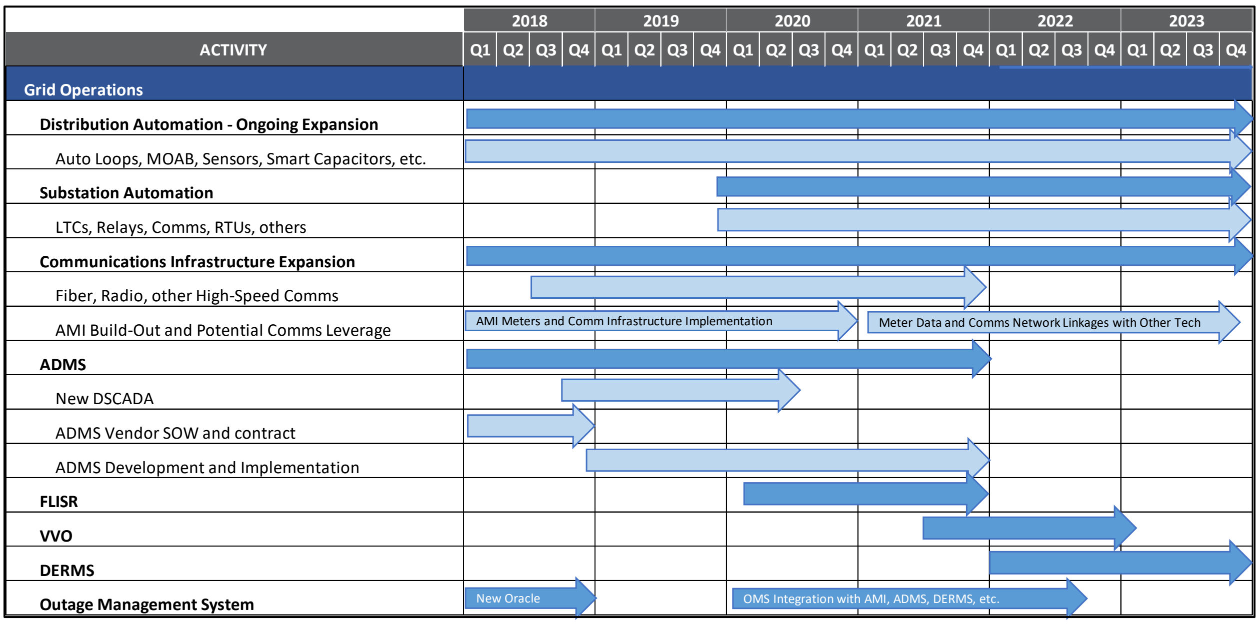
The communications infrastructure currently in use for distribution and substation automation has bandwidth limitations. Expansion of the communications infrastructure is needed given the rapid growth of distribution and substation automation devices, and the growing requirements for securing data for real-time analytics. High-speed data collection and transport facilities need to be established throughout the service territory to enable and realize the intended end-state of the modernized grid.

The Company plans to continue to develop and execute a Communications Infrastructure Expansion program, expand its DSCADA devices, and identify opportunities to leverage its AMI communication infrastructure and software for DA and other purposes. Additional details on future plans for communications infrastructure are provided later in this section

Five-Year Plan

The current Grid Operations five-year plan is provided in the following table. This forecast is provided as a means of depicting sequencing and timing relationships between the various grid modernization initiatives. Actual start and completion dates for many of these elements are the Company best estimate at this time. Some initiatives are and will continue to be in flight, and some will be dependent on the successful completion and integration of other critical path items.

Table 6: O&R Grid Operations Five-Year Plan



Risks and Mitigation

O&R's current communications infrastructure for both grid operations and grid optimization are limited in both capacity and geographic reach. The full benefits of the Company's grid modernization efforts will not be realized until the communications infrastructure is enhanced. O&R's communication infrastructure expansion efforts will serve to mitigate this risk during the DSIP five-year planning horizon.

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

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

Additionally, cybersecurity remains of paramount importance as digital technologies are added to the grid. Emerging cybersecurity concerns or requirements have the potential to impact the implementation timeline to manage risk. The Company, along with Con Edison, closely follows cybersecurity developments at NERC and is actively engaged in industry discussions. See the Cyber Security section within Chapter 2 for more details.

Stakeholder Interface

O&R has worked with many stakeholders in its efforts to modernize and strengthen the electric delivery system and infrastructure, increase grid-edge M&C capabilities, and adapt the way that the grid is operated to enable DER penetration and future market development. These stakeholders include hardware and software technology vendors, industry groups, EPRI, the JU and associated stakeholders, DPS Staff, NYISO, and others.

O&R and the JU have been working with stakeholders and the DER community on M&C requirements and potential lower-cost M&C solutions. These efforts will continue to provide the optimum lowest cost solutions while maintaining the functionality required for the intended installation.

The JU also hosted a stakeholder engagement session in October 2017 to communicate the progress made in working with NYISO on coordination issues and to gather additional input. Defining new operational coordination requirements among the DSP, NYISO, DER aggregators, and individual DERs makes greater DER integration and market participation possible, including expanding the ability of DERs to access and be compensated for multiple value streams. Each utility will not only need to expand its historical level of coordination with NYISO, but also build upon, and in some cases, establish new forms of coordination with DER aggregators and individual DERs. The Commission has highlighted that, "many complex and nearly continuous interactions will need to occur among NYISO, the DSPs, and DER operators."[46] The JU agree, and have worked with NYISO, DPS Staff, and stakeholders to define required information exchanges and operational coordination among the various entities.

[46] DSIP Proceeding, DSIP Order, p. 7.

Additional Detail

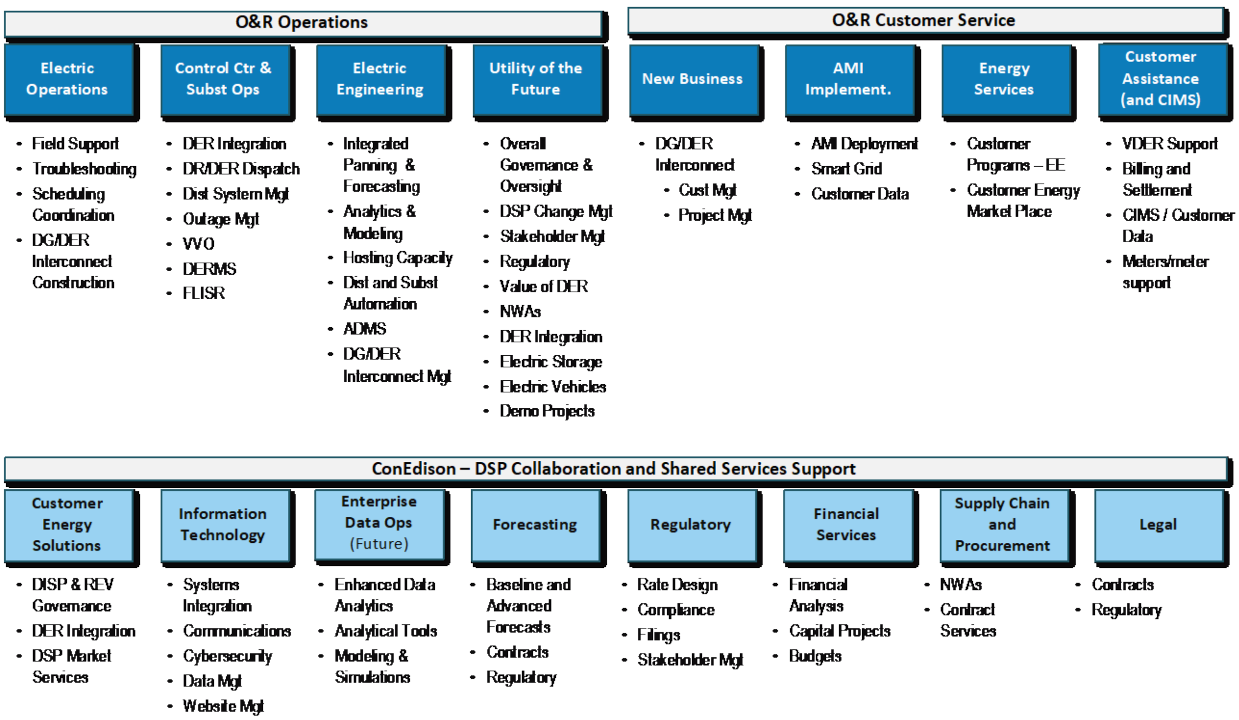
This section contains responses to the additional detail items specific to Grid Operations.

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.

Overview - O&R DSP Functional Roles and Responsibilities

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

Figure 19: O&R DSP Functional Roles and Responsibilities



As penetration of DER increases on O&R's electric delivery system, the impacts that DER impart on the system will have to be managed in real-time. Much of the near-term DSP functionalities surrounding the management of DERs on the system will be handled by the DCC, which is part of the Company's System Operations Group. The DCC in particular will be the organization that carries out the DER M&C functions as part of the DSP and will include engagement and oversight of the following initiatives.

Real-Time DER Management

The increase in DER penetration on the distribution system will present a number of opportunities and challenges, as outlined in the System Operations section of the Distribution Grid Operations section of this DSIP. Within the DCC, monitoring, controlling, and dispatching DERs is presently outside of the normal functions of the operators. This will likely eventually result in the need for new skillsets and resources to monitor, manage, and take advantage of the benefits provided by DERs on the system. Micro-grids, CHP sites, battery storage, and reverse flow through substations will become more prevalent on the system and the coordination of these technologies with providers will require more focused attention.

Additionally, in order to operate the grid more dynamically, increased technical skills will be needed within the DCC to analyze sensor inputs, coordinate load shifting, and likely monitor and control certain DERs that are having an impact upon the system. While many of these functions have the potential and are anticipated to be automated through an ADMS, higher skillsets, and an engineering background will be needed to fulfill functions including the monitoring, dispatch, control, and curtailment of large DERs on the system as needed in order to better understand operational scenarios and mitigate system impacts. Additionally, there could potentially be an interface between the DCC and third-parties in order to monitor and control BTM aggregated DERs.

NWA Execution

In addition to the M&C of DERs described above, the DCC will also be responsible for the real-time deployment of NWA solutions. Depending on the nature of the need and solution, some portions of DERs may need to be dispatched real-time, such as to meet normal loading states or a contingency need.

VVO Execution

Once full VVO capabilities are established, it will fall to the DCC to provide management and oversight to automated system-wide VVO. This will likely be accomplished through the development of a VVO module within ADMS.

The utility's primary responsibility is to preserve distribution system safety, acceptable operating parameters and reliability. The utility has coordinated with DER aggregators and the NYISO to define operational coordination requirements, including specific roles and responsibilities for each party, to ensure the utility can continue to preserve safety and reliability for a system characterized by increasing amounts of DERs. As part of distribution system programs (*e.g.,* DR) and procurements (i.e., NWA), the utility requires participants (*i.e.,* DER aggregators) to sign a contractual agreement that defines the roles and responsibilities for both the utility and DER aggregator. For example, contracts typically specify the amount of advanced notification the utility will provide the DER aggregator prior to an event, and separately they define all reporting and settlement requirements for the DER aggregator.

In addition to operational coordination for DER participating as part of utility programs and procurements, the JU have developed a *Draft DSP Communications and Coordination Manual*[1] to define the roles and responsibilities among the utility, NYISO, DER aggregators, and individual DERs to enable DER wholesale market participation while preserving system safety and reliability. For example, as part of NYISO's bidding and scheduling process, the DSP will analyze the dispatch feasibility of individual DERs and DER aggregations (as provided by the DER aggregator) to ensure wholesale market participation does not jeopardize system safety or reliability. The JU have also developed a *Draft DSP-Aggregator Agreement for NYISO Pilot Program*[47] to further define the roles and responsibilities between the DSP and DER aggregators.

[47] *Draft DSP-Aggregator Agreement for NYISO Pilot Program* (Draft Version). http://jointutilitiesofny.org/wp-content/uploads/2017/10/DRAFT-Joint-Utilities-DSP-Aggregator-Agreement-for-NYISO-Pilot-Program-2017-10-23.pdf

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

The types of roles and responsibilities defined within the utility's programs and procurements are the requirements the utility, in coordination with third-parties, has defined as being necessary for effectively addressing utility needs while providing DER aggregators and individual DER actionable information to help maintain a safe and reliable distribution system. As more DERs are integrated into the distribution system, the utility will look to refine and update their processes to provide additional guidance that is clear and easy to adapt.

With respect to DER wholesale market participation, the JU have coordinated with the NYISO and will continue to do so 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. The JU held a stakeholder engagement session in October 2017 to update stakeholders on progress they have made in their coordination with NYISO and will continue to update stakeholders on future progress. Similarly, input received through the NYISO stakeholder process has informed the development of these defined roles and responsibilities.

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, the utilities will continue to capture all roles and responsibilities within contractual agreements with relevant parties. The JU continue to coordinate on opportunities to align the procurement process, which may help inform a more standardized set of roles and responsibilities across the utilities. While the high-level roles and responsibilities will generally be consistent across the utility's programs and procurements, the unique nature of each system need may result in differences (*e.g.,* pre-defined time periods in which the DER portfolio is required to be available for performance). Each NWA area is different depending on the distribution need. The Company continues to refine and streamline processes wherever possible (*i.e.,* vendor pre-qualification) in order to expedite the procurement process, as well as continuing coordination with the NYISO and various vendors to make sure their input and feedback is considered as processes are streamlined.

With respect to operational coordination for DER wholesale market participation, the JU have developed a *Draft DSP Communications and Coordination Manual*[48] to define the coordination requirements between the DSP, NYISO, DER aggregator, and individual DERs. As DERs more actively participate in the wholesale market, there may need to be enhanced coordination across four major functions: (1) registration, (2) planning, (3) operations, and (4) settlement. The JU have also developed a *Draft DSP-Aggregator Agreement for NYISO Pilot Program* to (1) close the operating and communication gap between the utility interconnection agreements or tariffs and NYISO tariffs and (2) provide DER aggregators with transparency into how they need to coordinate with the DSP to maximize the ability of DER aggregations to deliver value across different services. While the utility may use this as part of the NYISO pilot program, the agreement is meant to inform the development of a full DSP-DER aggregator operational agreement for use once the NYISO fully implements its DER participation model.

With the deployment of ADMS and eventually a DERMS platform, DSPs will have a clear line of sight to local DERs, due to added M&C capabilities. As information is continuously getting transferred

[48] *Draft DSP Communications and Coordination Manual* (Draft Version)(October 23, 2017) http://jointutilitiesofny.org/wp-content/uploads/2017/10/DRAFT-Joint-Utilities-DSP-Communications-and-Coordination-Manual-2017-10-23.pdf

among the DSP, NYISO, and DER aggregators, the utility DSPs will be able to make more informed decisions. This will lead to more DERs being leveraged for distributed system needs and also will make it easier for DERs to participate in the NYISO marketplaces, as the DSPs will be able to identify any constraints in advance, allowing DERs adequate time to adjust their offering in the NYISO marketplace as needed.

As mentioned earlier, the deployment of these technologies will follow a phased approach. The company understands that it will be challenging to obtain M&C capability for all DERs in the distribution system, particularly the DERs that are already in service.

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 is interpreting the other party in this question to be the wholesale system operator or NYISO. O&R coordinates with NYISO and the DER aggregators to lay out the coordination requirements. In order to maintain O&R's high safety and reliability standards, O&R will also set up project specific governance to clarify each party's roles and responsibilities. Maintaining reliability and safety will be key as more DERs are getting integrated into the utility's distribution system. The company adheres to an extensive internal collection of standard operating procedures and specifications for electric system planning and operations.

O&R is also modernizing the DCC to proactively manage and optimize a more complex distribution grid. Modernizing the DCC will bring significant enabling benefits for integrating the latest technology and leveraging the technology to optimize the local distribution system, leverage local DER assets for resiliency purposes, and standardize processes, including establishing a centralized functional area of responsibility to deploy advanced distribution management functionalities to manage the overall system in near real-time. As these new technologies platforms are deployed, O&R's system operators will have more enhanced M&C capabilities of the local DER assets.

b) Operating policies and processes;

In order to maintain safety and reliability of the local power system, O&R develops and maintains operating guides for Company personnel that describe the policies and procedures for performing a range of operational functions. As the Company implements new processes and functionalities, such as the IOAP, NWA evaluation criteria and hosting capacity map, the Company reflects on lessons learned from early stages of deployment and integrates those learnings into the relevant policies and procedures, as appropriate.

O&R works cohesively with representatives across the organization to present a unified viewpoint when it comes to operations policy and processes. In that way, the company ensures that critical viewpoint from all internal stakeholders are considered. The Company works collaboratively to develop, institutionalize, monitor, and enforce operating policies and processes. See the DSIP Governance section in Chapter 3 of this DSIP update for more details on DSP and REV governance and oversight.

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

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

Further, near-real time monitoring of DERs will be essential for the Company to track DER performance and capabilities, both to make same day operational decisions and for near-term forecasts and scenario planning. As the amount of information gathered grows, the need for a system that will aggregate, analyze, validate, and display the information to the operator increases. Information will have to move among systems on a common information model as it becomes increasingly integrated with data sources, historical measurements, and advanced applications.

Additional system data collection will be required relating to the DER nodal generation. Devices, meters, communications, and SCADA costs will be incurred to monitor and provide visibility into the interaction of the additional DER contributions with respect to maintaining appropriate operating conditions, including real and reactive power, voltage, and power quality. The availability of this system data with advanced analytical capabilities will be the basis for evaluating system impacts on the overall circuit and within local load pockets. Aggregating all this information, visibility, and control within a core system that can be modularly expanded to facilitate future enhancements, and tie to other critical systems and sources of information, is essential to achieving this type of foundational functionality.

The ADMS will be the foundational platform that is developed and integrated with other systems and near real-time data sources to enhance electric distribution system situational awareness, analysis, M&C to improve reliability, resiliency, and efficiency.

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

- PowerOn Reliance GE SCADA EMS
- GIS with customer and asset connectivity
- Customer Information and Management System (“CIMS”)
- Distribution SCADA system (“DSCADA”)
- Distributed Energy Management Systems (“DERMS”)
- Outage Management System (“OMS”)
- Distribution Engineering Workstation (“DEW”)
- Expanding and comprehensive DA consisting of M&C devices including:
    - Reclosers
    - MOAB switches
    - Capacitor Controls
    - Regulator Controls
    - Sensors/Power Quality Nodes
- Substation Intelligent Equipment
    - LTC upgrades
    - Microprocessor relay/data and RTU upgrades
- AMI smart meters, communications infrastructure, and customer/meter data
- Robust radio frequency and communications infrastructure

An ADMS will expand the planning model of the Company's electric system into real-time operations. Coordinating through integrated systems and the external interfaces as described above, an ADMS will act in near real-time to modify both Company and customer equipment appropriately, to achieve system states that maintain appropriate and efficient operating conditions. It will also provide the platform to realize VVO and FLISR functionality that have the capability to substantially improve system efficiency and reliability through expansive implementation. ADMS will do this through its dynamic model of the electric delivery system and near real-time operations through SCADA feedback and control. It will have a near real-time reference to the current state electrical system, which will be the basis for analyzing and executing on appropriate future system states for switching plans and contingency situations. An ADMS will be able to identify, monitor, and record data from abnormal system conditions resulting from planned and unplanned events that modify the design configuration of the electrical system.

In addition to the ADMS, a DERMS will understand and manage the unique status and capabilities of diverse DERs to present these capabilities to other supporting applications for enhanced monitoring, control, and operation of the electric delivery system. The tool will be used in response to system operational events, environmental/weather and equipment conditions, and eventually market conditions. It will also be used to track and report on the growth of DERs in the Company's service territory. DERMS will provide visibility and control of a diverse portfolio of resources to address local constraints while flexibly addressing system-wide concerns. This system can be a standalone solution exchanging information with ADMS or integrated directly into the suite of programs included in an ADMS. It is envisioned that such a system will visualize, predict, and optimize DR and DG at the circuit, feeder, or segment level, presented in a dashboard suitable for operational use. In the long term, the Company envisions a single, comprehensive DER data repository (DER Management System or module). It will be fully integrated with the operating and planning systems described above as a platform to work with ADMS functionality and a defined operating user interface environment.

d) Data communications infrastructure;

O&R acknowledges the need to expand its IT communications infrastructure given the rapid growth of field automation and requirements for securing data for real-time analytics. High-speed data collection and transport facilities need to be established throughout the service territory, with Company substations playing a key design role. As monitored data increases, the communications infrastructure will need to encompass both primary and alternate data centers. Host systems need to be developed and implemented to reach out to the edges of the system creating a network management environment to ensure reliable transmissions of data. The transition to near real-time, automated distribution management requires high bandwidth speeds and a robust redundant design. In addition, as third-party inverters start interacting with the O&R distribution system, the infrastructure needs to be able to handle the additional data.

Given this, the Company has initiated a Communications Infrastructure Expansion program for the expansion of corporate fiber-optic infrastructure to several of its electric substations and radio tower facilities. The project covers engineering design requirements and the physical expansion of the Company's fiber-optic infrastructure. The fiber-optic infrastructure expansion will offer increased reliability, network capacity, and cybersecurity controls at all fiber and data communication facilities under this plan. Once upgraded, these facilities will act as high-capacity data networking access points and will become part of the Corporate Communications Transmission Network ("CCTN"). CCTN is comprised of the Company's fiber-optic and microwave systems and is the Company's data communications backbone for high-capacity connectivity to all data centers and server farms. The CCTN will support and secure sensitive data for several critical systems and functional applications, including

DA, AMI, ADMS, and EMS applications. As the Company continues to expand its automation programs, the CCTN will play a major support role. The Company also plans to upgrade a portion of its microwave network to deliver higher bandwidth for data and provide an additional level of diversity to transmit data across multiple mediums.

O&R also continues to expand deployment of DA devices and replace their old DSCADA infrastructure with newer and more robust DSCADA equipment. The continued expansion of the DSCADA puts an added burden on the network. It will be important to update the DSCADA infrastructure to accommodate these added data points. The Company continues to find suitable areas to expand tower site communications infrastructure. The Company also plans to leverage communication routes by leveraging combination of fiber-optic ground wire where currently installed or for future installations along transmission rights of way and utilizing leased dark fiber.

The Company is also in the process of deploying the new ITRON AMI network and plans to evaluate the network infrastructure for its DA applications. The Company is in discussions with its AMI vendor on solutions that could potentially leverage the AMI communications infrastructure and software for distribution management purposes.

All these enhancements in the communication infrastructure will help to set up a communication backbone that can be leveraged to efficiently and effectively monitor and control all distributed assets in the electric delivery system, including localized DERs.

e) Grid sensors and control devices;

Grid sensors and control devices provide the real-time information and equipment automation capabilities needed for operating and optimizing the distribution system and the DER assets themselves. Such sensors and control devices include:

- Reclosers
- MOAB switches
- Capacitor Controls
- Regulator Controls
- Sensors and Power Quality nodes, including the Company’s efforts to develop and make field ready highly advanced fiber-optic based sensors working with a New York based vendor (“Micatu Sensors”). Additional information on the use and benefits of Micatu sensors is provided later in this section.
- AMI smart meters, devices
- Substation Intelligent equipment
    - LTC upgrades
    - Breaker data upgrades

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

As described previously, O&R plans to automate many of the gang operated air breaks around the service territory with motor operated air break switches.

The use of solid-state transformers for grid or micro-grid applications or power flow controllers on the distributions system is still in the conceptual/R&D stage and the commercial and operational capabilities are still an unknown. O&R has no immediate plans to pursue this technology and will re-evaluate in the future as or if it becomes viable and necessary.

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

The SDSIP outlined a common and comprehensive approach to managing cybersecurity risks in the evolving REV environment. The JU Cyber and Privacy Framework[49] focuses on people, processes, and technology to maintain data security. The Framework requires the implementation of an industry-approved risk management methodology and an alignment of control implementations with the control families in the National Institute of Standards and Technology ("NIST") Special Publication (SP) 800-53 rev. 4. The JU periodically assess the need for updates to the Framework. The current version, as filed in the SDSIP, remains relevant with no updates required. As technology evolves, security controls will be aligned to the protocols stated in the Framework. See the Cybersecurity section in Chapter 2 of this DSIP update for more details.

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

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

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

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

The Company currently implements Volt/VAR control to maintain certain levels of efficiency by operating the system through automated local controller set points on substation LTCs, capacitor banks, and voltage regulators through remote manual LTC control by system operators. Watt and VAR readings for the majority of the Company's substation transformer banks are available through the SCADA system. Monitoring and voltage support infrastructure on existing equipment is limited. Although LTCs are connected back to the EMS and thus can see voltage changes, only newly-built substations have the required monitoring and voltage support equipment.

It is the utility's responsibility to ensure that voltage remains within acceptable limits after VVO operation has taken place. The company plans to leverage AMI in the future to provide voltage monitoring capabilities. AMI will enable more granular monitoring capability for grid operators in the future which in turn will lead to better voltage controlling capability by the operators. In both technical and economic terms, AMI will enable O&R to capture the energy loss and demand reductions achieved with the utility's automated VVO capabilities.

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

O&R presently lacks the extensive monitoring capability necessary to make accurate calculations of energy and demand loss reductions stemming from existing substation and distribution circuit devices that provide Volt/VAR functionality. The ability to accurately determine energy and loss reductions on both a technical and an economic basis are dependent upon the future grid modernization/M&C infrastructure enhancements being in place (*e.g.,* AMI meters, ADMS, substation M&C at a circuit level, communications infrastructure, etc.).

[49] DSIP Proceeding, Supplemental DSIP, pp. 148-160

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

The Company is currently conducting research and analysis on the benefits and capabilities associated with system-wide VVO close loop operations. A Substation Automation and Communication template is being designed as a part of this research for purposes of incorporating into future distribution and substation automation design and technology. Refer to the information provided in the Volt/VAR Optimization Section for more details.

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

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

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

O&R envisions a phased approach to implement more advanced VVO capability and realize results through the deployment of various supporting equipment, the incorporation of AMI, and the implementation and development of an ADMS. In the near term, VVO will likely be limited based on ADMS implementation timelines and the availability of infrastructure. As such, VVO capabilities are to be implemented at new substations first, where sufficient DA and smart grid equipment is being deployed. As these equipment upgrades, and advanced technologies proliferate across the system, the Company ultimately envisions a near real-time integrated Volt/VAR Control System employing SCADA M&C. The preferred near-term solution is to implement elements of VVO along with automated local controller set points on substation LTCs, advanced substation distribution relays, RTU, distribution capacitors, and distribution regulators with the availability of remote manual LTC control. Refer to the information provided in the Volt/VAR Optimization Section for more details.

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

In the long term, the Company envisions deployment of the necessary monitoring and communications to enable automated VVO, controlled and adequately adjusted and maintained through an EMS and ADMS. Future enhancements to VVO will be toward understanding the ability and cost-effectiveness for DERs to provide potential ancillary benefits for system operations, such as local power factor changes and voltage control to assist operating conditions. As these equipment upgrades, and advanced technologies proliferate across the system, the Company ultimately envisions ADMS providing a near real-time integrated Volt/VAR control system employing SCADA M&C of the field equipment as described above and potentially integrated with control of DERs and other customer sited equipment.

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

As described in the response to question #5.b. above.

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

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

Alarm index and events tagging are currently done in SCADA at the substation circuit source. Current and voltage measurements are available through O&R's SCADA system, which covers 98% of the Company's substations. However, there is no power quality or frequency monitoring at the circuit level. A DSCADA system monitors and controls DA equipment, including reclosers, motor operated air break switches, capacitors, and regulators. DA equipment coverage at the sub-circuit level has grown from approximately 10% of the entire system in 2016 to about 20% of the whole system today

The Company's ability to monitor and control large DG is limited to interrupting larger PV sources only, with reclosers at the point of interconnect. Switching plans and real-time contingency analyses are conducted by distribution planners and system operators, though the process is entirely manual. There is presently no centralized logic or technical capability for automating FLISR control. Some existing DR and EE customers have advanced metering, but there is presently no automation of aggregation or program integration in this area, although the Company's AMI deployment will advance data availability and functionality toward these ends.

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

Additional system data collection will be required relating to the DER nodal generation. Devices, meters, communications, and SCADA costs will be incurred to monitor and provide visibility into the interaction of the additional DER contributions for maintaining appropriate operating conditions, including real and reactive power, voltage and power quality. The availability of this system data with advanced analytical capabilities will be the basis for evaluating system impacts on the overall circuit and within local load pockets. Aggregating all this information, visibility, and control within an ADMS that can be modularly expanded to facilitate future enhancements, and tie to other critical systems and sources of information, is essential to achieving this type of foundational functionality.

Initial planning for the appropriate incorporation of DER must be integrated with a sophisticated, near real-time ADMS. The ADMS must provide monitoring, control, and analysis for normal states, anticipated alternatives, unusual or abnormal states, and data collection with advanced analysis capabilities. These ADMS functions will enable operators (or the ADMS system) to automatically reconfigure the system in near real-time to plan for and affect changes necessary to operate a safe, reliable, and economically efficient system.

The Company has been researching a cost-effective, highly accurate, distribution system monitoring and power quality ("PQ") nodal solution. The Company is working with Micatu Inc. to finalize the design of line suspended, fiber optic sensors which are able to gather system information and transmit it back to the DCC via the DSCADA system. These sensors are highly accurate (within 2% of Utility grade revenue meters) and will be used as PQ nodes along the distribution system (tying into the future ADMS) as well as a low-cost monitoring solution DER sites. This will enhance electric distribution system situational awareness as well as M&C to improve reliability, resiliency and efficiency. Specific benefits are as described in the response to question #6.d. below.

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

The Company continues to build out its DA capability throughout the service territory as part of the Company's DA and Technology expansion deployment. The DA program is focused on installing and upgrading field devices with command and control capabilities. The philosophy is a three-tiered approach: (smart circuit)

- The first tier, circuit optimization, includes designing an efficient system through the use of smart capacitors and power quality monitoring sensors. Smart capacitors allow for VVO while advanced sensors give visibility into circuit behavior. This functionality allows the distribution system to automatically compensate for any impacts the DER might have on the system.

- The second tier is field automation, and this includes the installation of automatic operating field devices to fully automate the system and allow for automatic fault isolation via recloser auto-loop design. These auto-loop schemes reduce customer outages and provide the DCC with immediate notification of system issues.
- The last and overarching tier is centralized automation control. By utilizing advanced control systems in the DCC, the grid operator can gain visibility into system statistics and field device status. The ability to communicate with the field devices also gives the operator the ability to segment damage locations and restore customers without the need for on-site maintenance personnel. Another benefit of advanced control systems in the DCC is the ability of the system to self-heal. The system will have the capability to gather information from the field devices and sensors and make decisions to isolate damage locations and restore customers automatically.

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

Benefits from deploying additional monitoring and DA devices in the field include:

- Reclosers
    - Allows the Distribution Control Center ("DCC") to monitor the output of the DER thus helping protect the grid from adverse effects caused by the DER
    - Allows the DCC to disconnect the DER in the event the DER is causing adverse effects on the grid (Control)
    - Enables the DER to maintain operations during system maintenance while ensuring maintenance crew safety
- DA
    - Helps the system self-heal by automatically isolating faulted segments of the grid.
    - The DER will either 1) only see a momentary outage while the system self-heals or 2) will be restored quicker due to the DCC having the ability to control these devices remotely
- MOABs
    - Gives the DCC the ability to isolate faulted segments of the grid allowing for faster restoration of customers including DER sites.
    - Allows the DCC to move segments of the grid to alternate sources, thus providing DERs the opportunity provide support to portions of the grid that are reaching their upper design limits.
    - Provides monitoring points in the grid which can provide real-time system data used for short and long-term forecasting, and help better identify areas of the grid that will benefit from DER.
- Micatu Sensors
    - Circuit head end visibility
    - Accurate voltage, current, power factor and other system information providing real-time system data which will allow the DCC to monitor DER Backfeed into the stations more closely. This information can be used to integrate with hosting capacity technologies, potentially facilitating increasing amounts of DER to be connected to the system.
    - Ability to feed data into DSCADA/ADMS/DERMS directly from the distribution system

- Integration into advanced control systems gives the ability to make automatic decisions regarding load flows, power quality, and circuit behavior. Advanced control of DERs allow the company to utilize DERs in the most efficient way possible.
- Provides circuit analytics including historical circuit behavior and statistics
- Provides real-time system data useful for short and long-term forecasting, and help better identify areas of the grid that will benefit from DER.

- Smart Capacitors
  - Helps the system compensate for small variations in voltage and VAR levels which may allow the DER to stay online through short variations in the site's output.

As DER penetration continues to increase, DA tools serve as a critical component for grid optimization. Automation becomes necessary for critical system functions such as switching plans and real-time contingency analysis, DR, and, ultimately, live line clearance management. Paired with ADMS and AMI, the DA tools provide the Company with enhanced visibility into the system, allowing operators to gather, monitor, and analyze more granular near real-time information across the system. These automated devices and control systems also allow DER assets to continue to operate in times of system maintenance, protecting the field worker performing the work. With these devices, the DCC can conduct switching operations from the control room and restore outages quickly, allowing DER assets to resume operations quicker during times of system stress.

O&R is establishing the capability needed to dynamically interface with, control, or modify operating parameters for certain types of DER (*e.g.,* storage solutions) as appropriate, thus enhancing the reliability of the system.

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

O&R does not currently have an ADMS in operation. The initial implementation of the Company's ADMS will commence in early 2019 with current plans to be operational over the next 24-36 months as outlined in the Future Implementation and Planning section above. The Company does, however have all the necessary components in place or in progress for the implementation and systems integration required to realize a successful and robust ADMS solution as described below:

- A foundational, accurate, and complete GIS with customer and asset connectivity, which updates an engineering analysis system model daily containing all customer load data, system data, DER, and device configurations;
- SCADA data that is available for 98% of the Company's substations, and an increasing number of sub-circuit devices, M&C (currently at 19% of the Company's distribution circuits and increasing at a rate of approximately 8% of the circuits annually);
- An expanding and comprehensive DA/smart grid program that has more than 450 devices deployed and will build out at a rate of approximately nine circuit pairs per year (within the New York portion of the Company's service territory) with M&C functionality;
- A robust radio frequency and communication infrastructure which can support DA and facilitate ADMS command and control throughout the territory in the near-term. The Company is also investigating the potential to leverage its AMI communications network for certain last mile grid automation functionality and data transfer; and

- The deployment of the AMI communications and smart meters infrastructure which will provide for extensive and granular sensing and measurements that will be used as a robust feedback loop to refine and improve the calculated values in the state estimation and power flow results in near-real time.

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

As described in the Future Implementation and Planning section above, to execute ADMS in a measured and effective way, the Company plans to implement the system functionality in stages. The initial stage will include the replacement of the Company's existing DSCADA system with a significantly more robust DSCADA application that can accommodate the breadth and scope of the envisioned future state. The Company's existing DSCADA system is near the end of its useful life. It does not have the functionality or capability to accommodate the number and type of interface points the Company is building out in the near-term, let alone that which is ultimately envisioned.

During this initial stage, the Company will develop the foundational system platform with the selected vendor, integrate critical systems and data, and apply advanced model M&C over the portions of its system that have been readied for Smart Grid operation. These efforts will allow the Company to identify and resolve initial implementation issues before expansion to a more significant portion of the Company's service territory.

Later stages will include system improvements or module integrations as needed to enable the Company's continued expansion of enhanced operational capabilities and market functionality across the electric delivery system. Some of the applications that will be available as a result of mapping, modeling, and DA, Substation Automation, and SCADA coverage are listed below:

- Switching Switch Plans and contingency analysis including curtailment criteria;
- State Estimator Integrated System Model with Load Flow based on SCADA measurements;
- Relay Protection devices and settings Model the capacity and behavior of equipment;
- Reliability Analysis;
- Demand Management Tracking;
- Demand Management Analytics;
- Data Reliability and Quality Control;
- Contingency Analysis;
- Fault Location Isolation and Service Restoration;
- DR Management;
- VVO; and
- DERMS

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

As stated in the Current Progress section, O&R is progressing advanced automation efforts and implementing impactful R&D projects that have and will continue to meet and solve grid challenges through the establishment of a dedicated Lab which provides the Company an extensive and technically proficient environment with the capabilities to test new systems, equipment and end-to-end operational integration, to better ensure equipment and systems will operate as intended prior to mass deployment. The Company can keep manufacturers of equipment and systems honest to their claims of operational capabilities and functionality by Lab testing and seek modifications or re-designs as necessary. The Company can take off the shelf vendor products and solutions through a process that integrates, and engineers Company focused solutions to meet safety practices, optimize maintenance costs, and promote stable grid operations. The Lab work is enabling the Company to cost-effectively progress its grid modernization efforts and continue to meet REV requirements.

O&R will continue to leverage and use lessons learned from our demonstration and pilot projects to prove out the conceptual elements that will be needed to advance grid operations in the future. The Company sees this as a necessary environment to partner with leaders in technology development to refine our software and technology roadmap as the Company moves closer to full DSP functionality.

Energy Storage Integration

Introduction/Context and Background

O&R anticipates having approximately 12MW/46MWh of energy storage online by the end of 2019

Energy storage has the potential to transform the electric system. Unlike other DER technologies, energy storage can provide a wide range of capabilities whether as a distribution resource, a customer-sited resource or even a generation resource capable of participating in wholesale markets. Energy storage is an enabling technology and a key to supporting many of the goals of the REV initiative through its ability to provide a variety of benefits to multiple stakeholders across the system. In addition, energy storage is a critical element of a resilient and efficient grid. Energy storage can provide energy management, distribution capital project deferral, backup power, load management, frequency regulation, voltage support, increased DER integration and grid stabilization. All of this means a more efficient, more reliable system for O&R's customers.

Multiple initiatives are currently underway that will enable New York to become a leader in the development and integration of energy storage. The statewide energy storage target of 1,500 MW by 2025, announced by Governor Cuomo in January 2018, is one of the country's most aggressive storage targets and puts New York on par with California, Massachusetts, and New Jersey in leading the way for energy storage. The recent New York State Energy Storage Roadmap[50] lays out a proposed path that utilities and other stakeholders can follow in meeting energy storage policy goals. O&R played an active role in the development of the Roadmap and anticipates continuing its involvement throughout the stakeholder process. The Company will use the plans coming from the roadmap to guide the Company's long-term energy storage strategy and the identification of areas of opportunity for energy storage resources.

At the national level, forecasts continue to indicate significant growth in energy storage both for utility-scale and customer-sited resources. In February 2018, the FERC issued Order 841[51] requiring that all Regional Transmission Organizations ("RTOs") and Independent System Operators ("ISOs") develop market participation models for energy storage. These market models will enable energy storage to participate in wholesale markets similar to traditional generation assets. Enabling wholesale market participation is widely seen as a necessary step to removing barriers to energy storage development. It will drive cost-beneficial project economics due to the additional revenue earning potential of energy storage assets that can participate in wholesale markets.

O&R is at the forefront of many of the changes taking place. The Company is committed to achieving New York's goal of becoming a leader in the development of energy storage. It is actively working to integrate energy storage into all facets of its grid operations. Through the Company's Innovative Storage Business Model ("ISBM") demonstration project, it is working with partners to develop innovative business models for driving down the cost of energy storage investments by enabling the assets to participate in multiple markets, providing benefits and incentives to multiple stakeholders. In addition, the Company is pursuing energy storage to defer the construction of traditional wires projects through several of its NWA procurements. Lastly, O&R is working directly with its partners in the JU, the DPS,

[50] Energy Storage Proceeding, Roadmap.

[51] FERC Docket Nos. RM16-23-000 and AD16-20-000, Order 341, *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators* (issued February 15, 2018), p.1. https://ferc.gov/whats-new/comm-meet/2018/021518/E-1.pdf

NYSERDA and NYISO to collaborate on solutions needed to solve the challenges of integrating energy storage into New York's electric system.

Implementation Plan, Schedule, and Investments

Current Progress

O&R is actively working to integrate energy storage into all facets of grid operations and is currently in the process of procuring energy storage systems to defer the construction of two substations

In the two years since its IDSIP, O&R has been working to facilitate the integration of energy storage on its system. The Company has been an active participant in discussions with a variety of stakeholders including energy storage developers and integrators, NYISO, DPS Staff, NYSERDA as well as the JU working groups on energy storage and interconnection. In addition, the Company has been working to incorporate energy storage into its NWA process and as a result, currently has two NWAs in development. The Company has also been working to launch two demonstration projects that will drive adoption of storage and provide lessons on effectively integrating, operating and planning for the addition of future energy storage resources on its system. As discussed below, the Company is in the process of implementing between 6-8 energy storage systems as part of its NWAs and ISBM demonstration project and anticipates having approximately 12MW/46MWh online by the end of 2019.

NWAs

O&R has two open procurements for energy storage systems to meet distribution system needs in place of traditional wires solutions. The first is the Monsey NWA, which will defer the upgrade of the Monsey substation by utilizing a portfolio of DER solutions, one of which is a 5MW energy storage system. The second is the Pomona NWA, which will defer the construction of a new substation to meet forecasted load growth in the Pomona area with a 2MW energy storage system. Both projects are in the procurement phase and are described in detail in the following sections.

Demonstration Projects

As discussed in the Innovation section, the Company has begun two demonstration projects which will prove key principles related to driving the future growth of energy storage. The ISBM demonstration project will aim to prove a new business model by testing the hypothesis that storage can provide a range of services across multiple applications (*e.g.*, deferred T&D costs, wholesale revenue, and demand charge reduction). By maximizing storage utilization, the business models that follow will allow for sharing of costs and benefits across multiple stakeholders (*e.g.,* grid benefits for utilities and reduced demand charges for customers), which will, in turn, drive more cost-effective project economics.

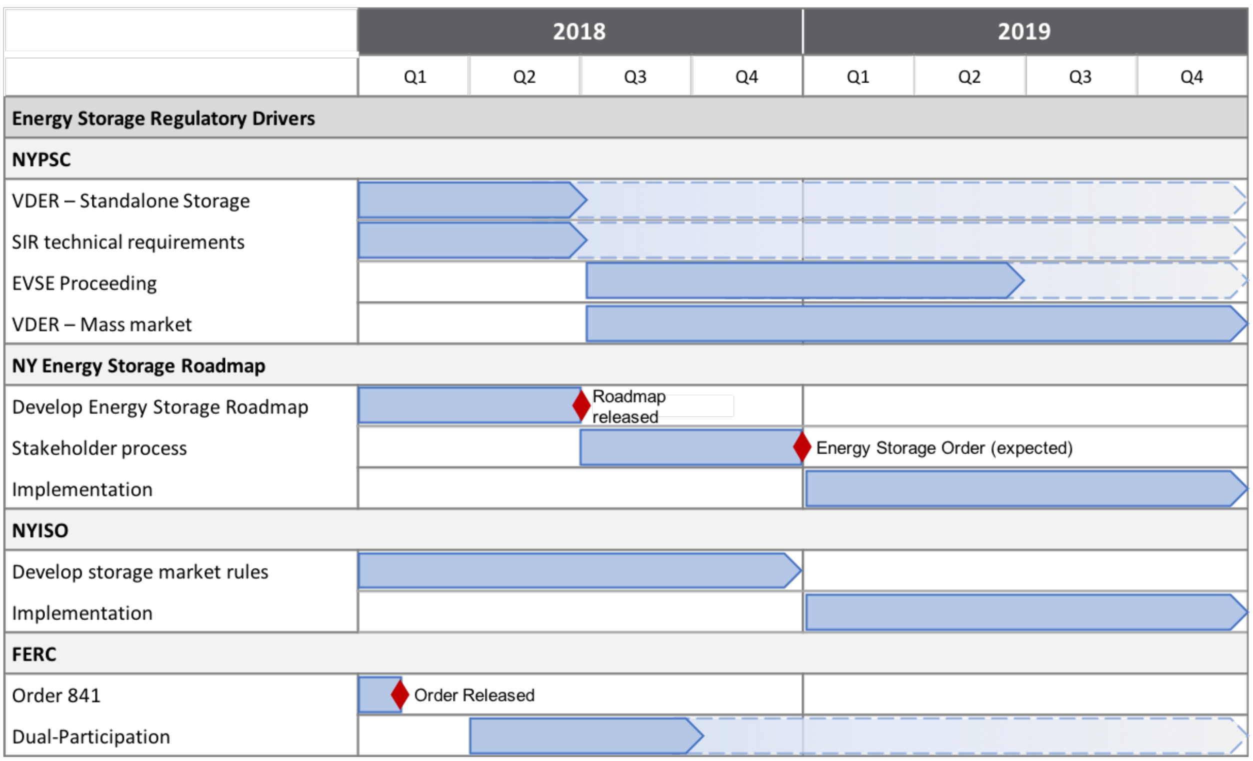
The Company is also working on an SHR demonstration project that will evaluate innovative new rate designs and test the feasibility of sophisticated residential rates coupled with price-responsive home automation technologies such as behind-the-meter ("BTM") residential energy storage. The demonstration project will allow the Company to collect and study data on participant responses and their characteristics (*i.e.*, manage their load consumption and electric usage) and gauge market opportunities. This project is in the requirement gathering stage and is being executed in conjunction with CECONY.

Future Implementation and Planning

Over the next five years, the Company expects a significant number of energy storage resources to be added to its system as a result of ongoing implementation efforts, organic growth of behind the meter ("BTM") systems and regulatory drivers aimed at increasing the amount of energy storage in New York.

Many external drivers, in particular regulatory initiatives at the and federal level, will determine the pace of energy storage growth in the Company's territory. Energy storage participation in wholesale markets, driven by FERC Order 841, the New York State energy storage target of 1,500MW by 2025, the recent New York Energy Storage Roadmap, and the outcome of the Value of DER Proceeding which will impact compensation for mass market customers post-Phase One net energy metering ("NEM"), will all play a role in the growth of energy storage on the Company's system. The following figure illustrates the sequence of these regulatory drivers.

Table 7: Regulatory Drivers of Energy Storage in NY



In addition to NWA and demonstration projects discussed above, the Company has 125.8kW of small (<50kw) energy storage projects in its interconnection queue, the majority of which are residential BTM projects.

Table 8: Energy Storage Resources in the Queue

Energy Storage Resources in the Queue (as of July 26, 2018)	
Location	Nameplate Capacity (AC kW)
Blooming Grove	5.0 kW
Chester	5.0
Circleville	5.0
Congers	5.0
Middletown	5.0
Middletown	5.0
Middletown	5.0
New City	5.0
New City	5.0
Pearl River	5.0
Stony Point	5.0
West Nyack	5.0
Upper Nyack	5.8
Goshen	10.0
Grandview	10.0
Monsey	10.0
Otisville	10.0
Valley Cottage	10.0
Warwick	10.0
Mount Hope	5 MW
Total (MW)	**5.126 MW**

Risks and Mitigation

Despite the promise that energy storage brings, the Company sees some risks to the successful implementation of energy storage in New York. The participation of energy storage resources in wholesale markets is often needed for the financing of many energy storage projects due to the necessity of an additional revenue stream to drive overall cost-effectiveness. As a result, the ability of energy storage to participate in wholesale markets is necessary for energy storage to realize its potential. With FERC Order 841, requiring RTOs/ISOs to develop market participation models for energy storage, the Company feels that it is increasingly likely that there will be some opportunity for energy storage to realize wholesale market benefits in New York in the mid- to long-term. However, until NYISO finalizes the details of various wholesale market products and participation rules (including the level of compensation), there is still uncertainty about the impact of energy storage in New York's wholesale markets. The NYISO Energy Storage Roadmap, expected in the late fall of 2018 followed by DER Aggregation Roadmap anticipated to be published by mid-2019, will be essential steps in mitigating this risk.

Although the Company is new to implementing energy storage projects, siting and permitting have emerged as an area that could significantly impact project development. This challenge is mostly due to the relative lack of familiarity of local jurisdictions with energy storage technologies, in particular, lithium-ion. Execution of siting and permitting processes often take from weeks to months for traditional projects. The addition of energy storage presents new challenges in terms of ensuring that local authorities are informed and knowledgeable about the benefits and risks of the technology. The Company has taken the initiative to address these concerns by meeting with local officials to discuss energy storage, its role, and its impact on their communities. As part of the Company's NWAs and demonstrations projects, O&R will be working with its vendors and partners to continue the education and outreach process.

As discussed in more detail below, the Company has seen recent growth in the residential BTM storage market and believes that this trend will continue, driven in part, by combined residential solar plus storage offerings by third-party developers. O&R believes that two trends could affect this growth: the progression of Phase 2 of the Value of DER Proceeding, which will impact the economics of mass market solar customers who are currently on net metering and broader solar market trends. The outcomes of the Value of DER Phase 2 process will influence the degree to which residential customers perceive a benefit to installing BTM energy storage systems, either in isolation or in combination with rooftop solar systems. It is anticipated that if the rooftop solar market begins to slow, whether driven by international trade or other market factors, it could have similar consequences for residential storage.

Lastly, advanced energy storage is a rapidly evolving technology still in its nascent stages. As with many new technologies, advances can occur that alter the dynamics of the market. As new energy storage technologies emerge, it is possible that lower cost or safer systems will be developed that change the cost-effectiveness or public perception of the technology increasing or decreasing demand. The Company will stay abreast of industry trends and developments to keep up with these changes as they occur.

Stakeholder Interface

Since the IDSIP in 2016, O&R has actively engaged a variety of stakeholders including project developers, industry representatives, regulatory bodies, customers, and community leaders in its energy storage development efforts. As part of its NWA process, the Company posts all potential NWA projects to its website and engages developers and energy storage integrators through the RFP process wherein it shares detailed information regarding potential distribution capital project deferral opportunities. As the procurement process continues, top competitive bidders meet with the Company to give vendor presentations which provide the opportunity to have one-on-one conversations between O&R and energy storage project developers. These conversations, even for unsuccessful bidders, have resulted in a greater understanding and stronger relationships between the Company and the development community and will help O&R improve future procurement processes.

As part of the ISBM demonstration project, the Company, along with its partner, Tesla, is engaging with demand-billed commercial and industrial (C&I) customers to discuss the potential demand charge savings through participation in the demonstration project. This has included working with customers to understand the benefits that BTM energy storage systems can have on their bills by reducing their demand charges and working with them to share usage data for bill savings modeling. Further details on the demonstration project are described in the relevant sections below.

As discussed in the risks section above, O&R has been proactively engaging local officials as part of its process to mitigate potential siting and permitting challenges. Reaching out to community leaders early has been an effective way to address any issues and open a dialogue regarding the benefits of energy storage resources in local communities. The Company will continue this engagement throughout NWAs and demonstration project development as well as for future projects.

An important component of the Company's stakeholder engagement efforts has been its work with stakeholders, peers and regulators in the development of a variety of JU and state-level energy storage initiatives. The Company regularly participates in JU interconnection and energy storage working groups where it has worked to share energy storage lessons learned across utilities and develop new a SIR for energy storage. At the state-level, the Company has actively engaged NYISO as part of its efforts to integrate energy storage assets into the wholesale market. Work in this area has included meetings with NYISO staff to review potential energy storage use cases, market products, potential energy storage participation models, and NYISO's views on the operation, monitoring, and control of energy storage assets. Another area of coordination at the state-level has been with the DPS Staff and NYSERDA in the development of the New York State Energy Storage Roadmap. The Roadmap, discussed above, kicks off a stakeholder process designed to develop and implement the policy changes needed to drive the development of energy storage in New York.

Lastly, O&R has made a concerted effort over the last two years to reach out to its peers across the country to learn from the experiences of similar utilities in planning for, procuring, integrating, and operating energy storage on their systems. Through this process, O&R has been able to learn from the experiences of others and incorporate best practices into its processes.

Additional Detail

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

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

O&R recognizes the importance of integrating energy storage on the distribution system and is committed to the development of the underlying capabilities to plan for and operate energy storage on its system. As of July 26, 2018, the Company had 20 energy storage systems totaling 147.6kW of interconnected energy storage resources online and an additional 5.13MW in the queue.

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

Table 9: O&R Installed Energy Storage Resources

Installed Energy Storage Resources (as of July 26, 2018)		
Date Installed	Location	Nameplate Capacity (AC kW)
6/1/17	Warwick	5.0
10/4/17	Goshen	5.0
11/13/17	Blauvelt	5.0
12/5/17	Bloomingburg	5.0
12/20/17	Sloatsburg	10.0
1/5/18	New City	5.0

Installed Energy Storage Resources (as of July 26, 2018)		
Date Installed	Location	Nameplate Capacity (AC kW)
1/25/18	Middletown	5.0
2/12/18	West Nyack	5.0
3/6/18	Stony Point	7.6
3/8/18	Highland Mills	5.0
3/14/18	Middletown	5.0
3/20/18	Monroe	10.0
4/10/18	Westtown	5.0
4/11/18	Monroe	5.0
4/20/18	Sloatsburg	5.0
4/23/18	Circleville	20.0
4/25/18	Chester	10.0
5/22/18	Monsey	15.0
5/31/18	Glen Spey	10.0
6/20/18	Middletown	5.0
	Total (kW)	**147.6**

Although the Company does not yet have any utility-scale energy storage resources on its system, it is in the process of developing three energy storage projects which will consist of 6 - 8 energy storage systems, the first of which is expected to be online in late 2018 or early 2019. These projects, including their locations, types, capacities, configurations and functions are discussed in the following sections.

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

As discussed previously, O&R is in the process of deploying between 6 - 8 energy storage systems which are expected to be online in late 2018 and early 2019. Descriptions of each project are included below:

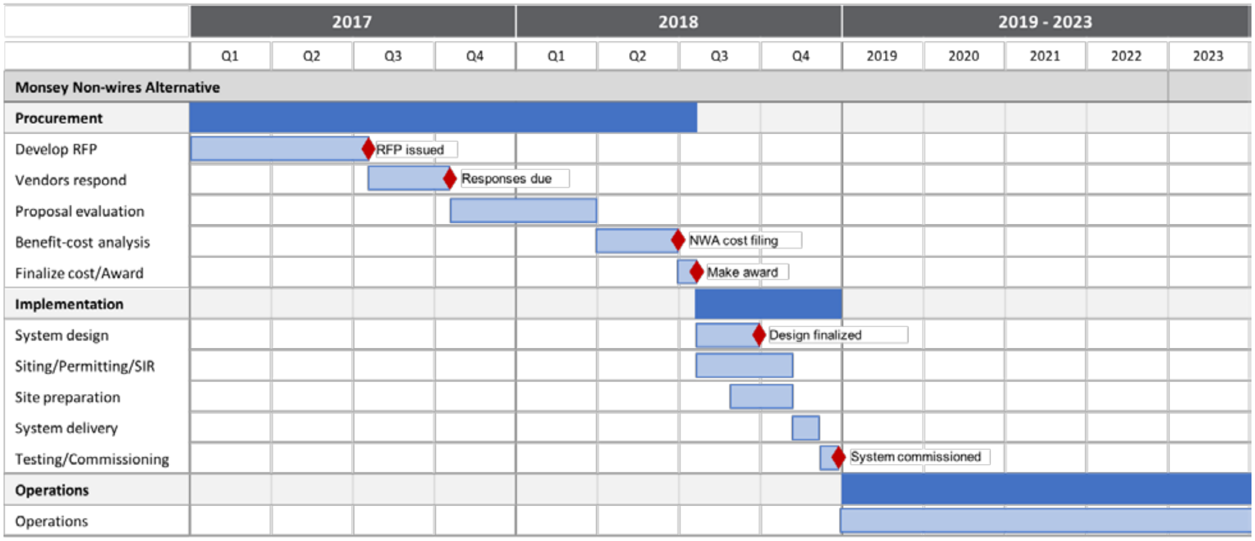
Monsey NWA

a) Description

The Monsey Substation is located in the hamlet of Monsey, in the Town of Ramapo, in Rockland County. The area is experiencing significant residential and business growth that has led to heavily loaded circuits and substation transformer banks. The Company is planning to defer the distribution capital spending for Monsey by implementing an NWA solution consisting of a portfolio of DER technologies including a 5MW/26MWh battery energy storage system in late 2018 or early 2019 and a second 5MW/16MWh battery energy storage system in 2023.

b) Project schedule

Table 10: Monsey NWA High-level Schedule



c) Current project status

The Company issued an RFP in August 2017 for providers with the ability to deliver innovative NWA solutions to provide load relief in the Monsey area. In October 2017, the Company received proposals from multiple vendors representing a variety of NWA solutions including DR, Energy Storage, EE, and DG. The Company reviewed the proposals for technical, construction, cost, timelines, and permitting feasibility, with the intent of identifying and selecting a robust portfolio that will meet the required demand reduction needs.

The Company then performed a BCA on the portfolio using the methodology outlined in the Company's BCA Handbook. The Company will ultimately decide whether to proceed with the NWA solution(s), after considering the BCA, societal cost test ("SCT"), utility cost test ("UCT") and rate impact mechanism ("RIM") tests, as well as potential additional internal cost and customer bill impact evaluations before moving forward in the process.

Once the project BCA and costs have been finalized and deemed cost beneficial to proceed, the Company will award the project to the selected vendors and move forward with the design and implementation of the NWA project as shown in the timeline above.

d) Lessons learned

Lessons learned across projects are summarized at the end of this section

e) Project adjustments and improvement opportunities identified to-date

The Company has made initial outreach to communities with potential NWA projects to begin discussions around the energy storage permitting process. These discussions have been fruitful; however, the siting and permitting process may take an extended period of time due to the newness of the technologies involved.

f) Next steps

The immediate next steps for the Monsey NWA project are to finalize the BCA and file the project's final costs as required in the Commission's Order on O&R's Program Advancement Petition[52]. It is anticipated that this will be accomplished in early Q3 2018. Once approved, the Company will make the award to the vendors participating in the Monsey NWA portfolio and begin contract negotiations with its partners with the goal of commissioning the project by the end of 2018 or early 2019.

Pomona NWA

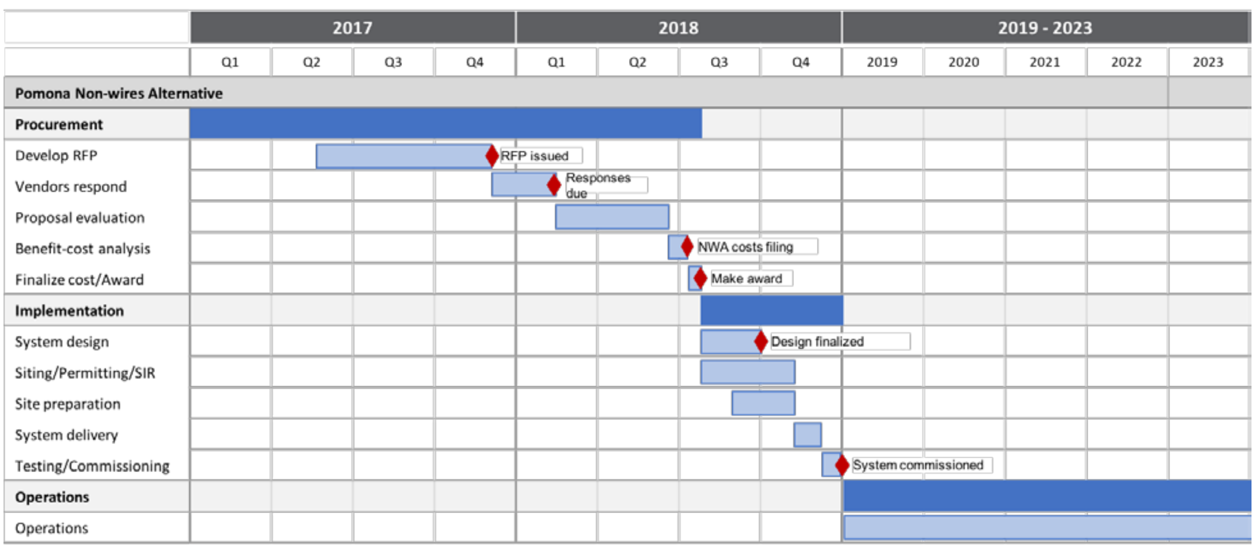
a) Description

The Pomona NWA was begun in 2015 to defer construction of new utility infrastructure in the Pomona area by providing up to 6MW of load relief through a portfolio of EE, DR, and energy storage. In addition to the EE and DR assets, the Company is proposing to meet the need in the Pomona area with a 2MW/12MWh battery energy storage system scheduled for installation in late 2018 or early 2019.

b) Project schedule

The high-level schedule for the energy storage component of the Pomona NWA is as follows:

Table 11: Pomona NWA High-Level Schedule



c) Project status

In December 2017, O&R issued an RFP seeking proposals for Distributed Energy Storage Systems ("DESS") to provide load relief in the Pomona area. Submissions were received on February 7, 2017. The Company reviewed the proposals for technical, construction, cost, timeliness and permitting feasibility, with the intent of identifying and selecting a proposal that will meet the required load reduction needs. Vendor presentations were conducted in early June and the pool of potential proposals was narrowed down to the top two vendors. The Company is in the process of performing a BCA and finalizing project costs in preparation for filing with the Commission in Q3 2018. Progress updates are filed quarterly to

[52] Case 17-M-0178, *Petition of Orange and Rockland Utilities, Inc. for Authorization of a Program Advancement Proposal* ("PAP Proceeding"), Order Granting Petition in Part (issued November 16, 2017)("PAP Order").

update the commission of the NWA progress. The company also updates the project implementation plan with various initiatives as they come to fruition.

d) Lessons learned

Lessons learned across projects are summarized at the end of this section.

e) Project adjustments and improvement opportunities identified to-date

Same as described for the Monsey project.

f) Next steps

The Company is in the process of performing a BCA and finalizing project costs in preparation for filing with the Commission in Q3 2018. Once approved, the project implementation plan will be updated to include the timeline as illustrated above. Status updates will be included in the project's regular quarterly updates.

Innovative Storage Business Model Demonstration Project

a) Description

Despite the technical potential of energy storage, there are currently few projects demonstrating sustainable business models that fully exploit the flexible capabilities energy storage can deliver across multiple stakeholders.

In February 2016, CECONY and O&R jointly released a Request for Information ("RFI") soliciting responses from third-parties on delivering innovative energy storage solutions that provide value for key stakeholders, including customers, shareholders, and project partners. As an outcome of the RFI, O&R entered into a collaboration with Tesla, Inc. to test different business models to determine how to take full advantage of the benefits provided by energy storage assets, with a particular focus on enabling the wide-scale deployment of energy storage in the future.

The goals of the Project are to test the hypothesis that batteries can provide a range of services across multiple applications (*e.g.,* deferred T&D costs, wholesale revenue, and reduced demand charges) by maximizing storage utilization and to develop the business model that allows for sharing of costs and benefits across multiple stakeholders (*e.g.,* grid benefits for utilities and reduced demand charges for customers). Furthermore, the Project will develop and test methods to mitigate storage implementation barriers to support the acceleration of storage deployment in New York.

The Project consists of a 4MW/8MWh portfolio of aggregated batteries. Individual battery sites are distributed and located either BTM within C&I customers or co-located with distribution-connected remote solar projects in O&R's service territory. All battery installations will be developed, designed, installed, operated, and maintained by Tesla. O&R will retain dispatch rights and operational priority for the portfolio.

The Company retains the primary dispatch benefits and operational priority of the entire aggregation through a contract with Tesla for energy storage grid services. Batteries deployed BTM of C&I customers will also reduce the host customer's demand charges. Tesla is working with O&R to develop innovative, multi-use operations strategies to balance dispatch among the various stakeholder groups. These stakeholder groups include participating customers, the distribution system, wholesale/bulk power system and Tesla. These strategies are guided by algorithms and protocols, designed by Tesla, to deliver optimal dispatch for the aggregated portfolio, maximizing the portfolio value among customers, the distribution grid, the bulk electric system and Tesla. Under this demonstration, the flexible operating characteristics of distributed energy storage are employed to obtain the highest value use of the resource at any point in time.

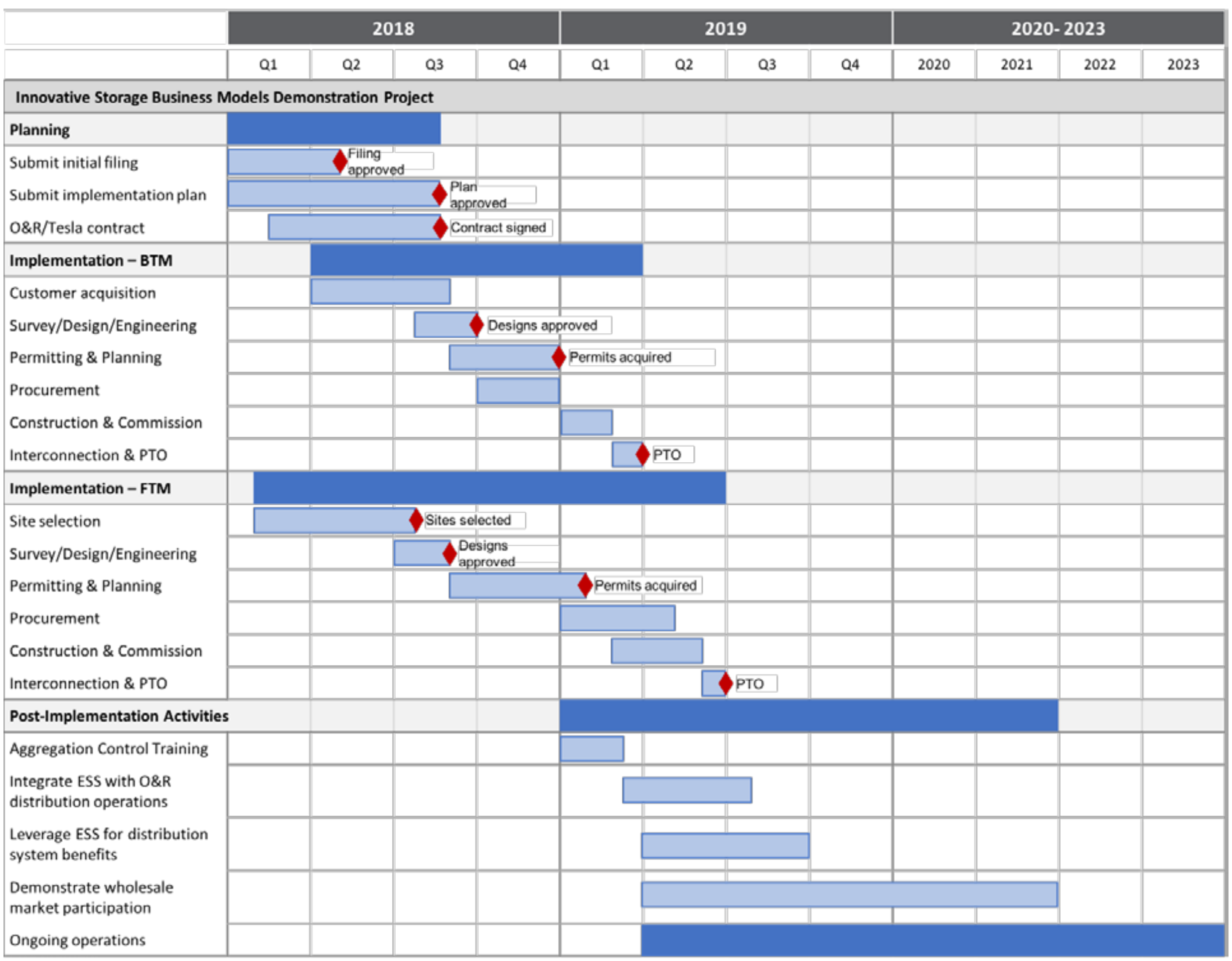
The Project will demonstrate the unique range of services that distributed energy storage can provide to multiple stakeholders (*i.e.,* the electric delivery system, C&I customers and NYISO wholesale system) to achieve a diversity of "stacked" value streams. Stacking storage value streams improves economics over single-use models and reduces barriers to deployment. Maximizing stacked values requires operational flexibility and coordination across multiple parties which does not currently exist today. This Project seeks to demonstrate these processes and the role of the utility as the DSP provider in order to enable and achieve the multiple value streams tested under the project.

b) Project schedule

The project will be executed in three separate stages. Phase 1 centers on customer acquisition and site selection. Phase 2 concentrates on the technical performance of asset response and flexibility. Phase 3 focuses on additional market participation and stacking value streams. The phases overlap to promote the efficient execution of the project.

The high-level schedule of the ISMB project is as follows:

Table 12: ISBM High-Level Schedule



c) Project status

On February 6, 2018, O&R filed its proposal for the Innovative Storage Business Model demonstration project with the Commission. On May 30, 2018, DPS Staff issued their Demonstration Project Assessment Report filing, approving the project to move forward. On June 29, 2018, the Company filed its Demonstration Project Implementation Plan and continued work with its partner, Tesla, on finalizing the project terms and conducting customer and site selection and acquisition activities.

d) Lessons learned

Lessons learned across projects are summarized at the end of this section.

e) Project adjustments and improvement opportunities identified to-date

In the Project, batteries located at BTM customer sites as well as front-of-meter ("FTM") batteries paired with remote solar sites may also participate in NYISO markets. NYISO markets were initially established primarily to support participation by large centralized generation connected to the transmission system. While the NYISO has taken steps to allow DER to play a larger role in NYISO markets, there are still potential barriers that may prevent these projects from fully participating.

For storage assets located at remote solar locations, there are fewer barriers to participation in NYISO markets. Since these assets are not located behind a customer meter, they are expected to have direct access to NYISO markets, as long as they can provide energy and capacity for the minimum duration required by NYISO. The Project team will work with NYISO to find opportunities to streamline and coordinate NYISO and O&R rules for distribution-connected storage that participates in NYISO markets.

Since storage technology and business models are still relatively new, there are many potential challenges related to identifying good candidate sites and obtaining all required permits and approvals. Challenges include the availability of customer load data, structural and space requirements, and lengthy approval processes.

O&R and Tesla will collaborate to address existing and emerging challenges.

f) Next steps

The Company is working with its partner, Tesla, on a variety of initiatives in anticipation of receiving approval of the project implementation plan. Work is ongoing to identify remote solar sites for the FTM systems that will have the maximum opportunity to provide distribution system benefits. Once the sites have been identified, the system design and siting/permitting process will begin. For the BTM portfolio, work is ongoing to identify potential customers who have load profiles that will offer the most benefit from demand charge management. Once customers have been selected and agree to partner with O&R on the project, work will begin to design and build the storage systems.

Lastly, the Company is continuing its efforts to engage DPS Staff and the NYISO to advance discussions around wholesale market participation models and dual participation. The Company anticipates these discussions to continue throughout the first two phases of the project as the Commission and NYISO develop roadmaps and market models for energy storage in New York.

Lessons Learned

Although the Company is still in the early stages of implementing energy storage projects on its system, it has already begun accumulating lessons learned from some of its projects. These lessons learned are then incorporated into O&R energy storage procurement processes and applied to future projects. These lessons learned are summarized below.

NWAs

O&R has received proposals from two solicitations for energy storage as NWAs and is continuing to learn from its experiences issuing RFPs for energy storage and evaluating those proposals. For example, in the Pomona NWA RFP, the Company included detailed energy storage system parameters and locational specifics that were not included in the Monsey RFP. The additional details provided operational and siting information to developers allowing them to tailor their proposals to the specific requirements. The Company anticipates additional learnings as it continues through the procurement process including in areas such as siting and permitting, design and construction, and interconnection. Additional lessons learned pertaining to NWAs are discussed in the Procuring NWAs section.

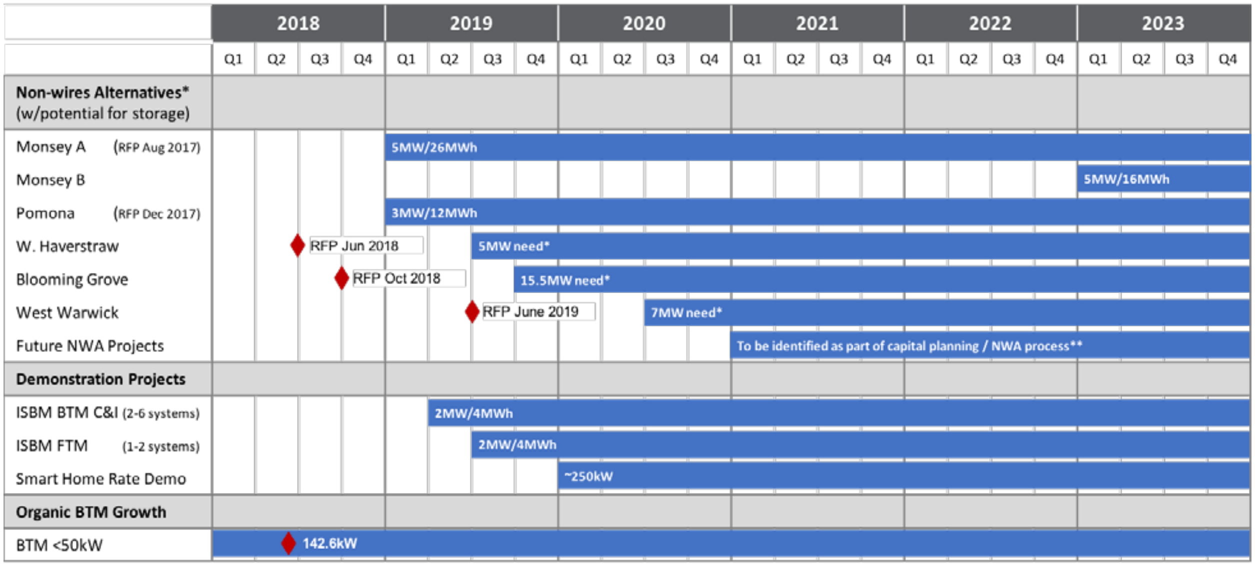
ISBM

Although the ISBM demonstration project is still in its early stages, the Company has identified some lessons that can be learned and applied to future energy storage and demonstration projects. The first, is the contracting challenge that assigning multiple benefits to multiple stakeholders presents in developing this new storage business model. Although not yet complete, understanding when and how benefits should accrue to one stakeholder versus another has emerged as a legal as well as technical hurdle. Another lesson learned so far is the challenge in identifying customers who will benefit from demand charge savings in areas where the system will also experience load reduction benefits. These and other learnings will be further described in the project's quarterly reports.

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

The Company is anticipating continued growth in energy storage deployed on its electric distribution system driven by state energy storage goals, changes expected to wholesale market rules, Value of DER Proceeding Phase 2, and additional NWA project opportunities. However, the Company expects this growth will likely be non-linear and may occur unevenly as regulatory changes and other drivers take effect. A five-year forecast of energy storage projects is shown in the following figure.

Table 13: O&R Forecast Energy Storage Deployment



*NWA opportunities represent forecasted deferral need, but may be comprised of a portfolio of NWA technologies   **1,500 MW Target ➡ 2025**

NWAs

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

Table 14: Currently Identified NWA Projects

Project/Name Description	Project Type	Required Load Relief	Need-by Date	Anticipated RFP Release
Monsey	Load Relief / Reliability	2.5 - 3MW	2021	**Issued**
Pomona	Load Relief	<6 MW	2025	**Issued**
West Haverstraw	Reliability	5 MW	2021	**Issued**
Blooming Grove	Load Relief / Reliability	15.5 MW	2021	Q4-2018
Sterling Forest (Tuxedo Park)	Load Relief / Reliability	746 kW	2021	Q3-2019
West Warwick	Load Relief / Reliability	7 MW	2022	Q3-2019
Mountain Lodge Park (Blooming grove)	Load Relief / Reliability	280 kW	2022	Q4-2019

The Company's limited experience with storage in NWA indicates that these types of project opportunities in the Company's service territory are viewed as attractive opportunities by the storage industry and initial BCAs suggest that storage, in some cases, can be cost-competitive with other technologies as well as traditional wires solutions.

The Company believes that currently identified NWA opportunities could add approximately 10-12MW of advanced energy storage on the O&R system over the next two years. As discussed in the planning and forecasting sections, as new NWA candidate projects are identified, the Company believes that this opportunity will continue to grow, and energy storage is expected to continue to play a significant role in the Company's NWA procurements.

Regulatory Drivers

As discussed above, the Company believes that in addition to NWAs and the Company's ISBM demonstration project, regulatory drivers, both at the state and federal levels, will play the most significant role in driving the development of energy storage on O&R's distribution system.

In January 2018, Governor Cuomo announced as part of a "comprehensive agenda to combat climate change,"[53] a 1,500 MW storage target for New York. On a share-of-load basis, the Company estimates its contribution to this target to be approximately 80MW. In addition, as part of his address, the Governor directed the DPS and NYSERDA to jointly develop a roadmap for energy storage for New York. The New York Energy Storage Roadmap was released on June 21, 2018[54] beginning a months-long stakeholder process which will result in a 2030 energy storage goal and policy changes needed to drive the achievement of that target.

On the federal level, FERC 841, which requires RTOs and ISOs to develop market participation models for energy storage resources will drive the participation of energy storage in wholesale markets, in particular, the NYISO. FERC 841 will also allow smaller sized energy storage assets to participate in the NYISO marketplace, which opens up a new window of opportunity for additional assets that may not have been eligible to participate before.

Lastly, the Company believes that, based on industry research, that organic BTM residential storage market is poised to take off. As discussed in Question 1, there is 125.8kW of energy storage in the O&R interconnection queue that is being driven organically as residential and small commercial customers are incented to add energy storage to their homes and businesses. O&R's growth in energy storage under 50kW reflects that all but one system has been added since Q4 2017. GTM research reported in June that for the first time, residential storage capacity added in Q2 of 2018 exceeded commercial additions and nearly beat out utility-scale storage capacity.[55] The Company believes that residential BTM storage will continue to grow as part of a desire for greater resiliency and due to third-party solar developers adding storage as part of their offerings.

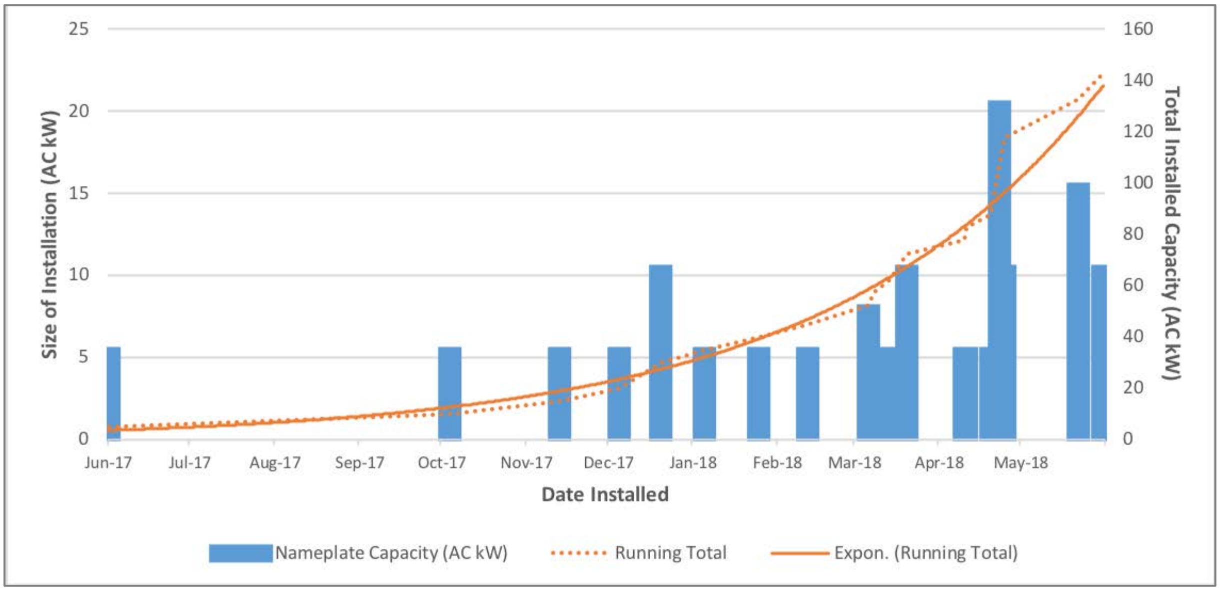
---

[53] Governor Cuomo Unveils 20th Proposal of 2018 State of the State: New York's Clean Energy Jobs and Climate Agenda: https://www.governor.ny.gov/news/governor-cuomo-unveils-20th-proposal-2018-state-state-new-yorks-clean-energy-jobs-and-climate

[54] Energy Storage Proceeding, Roadmap.

[55] "*Residential Batteries Almost Beat Out Utility-Scale Deployments Last Quarter*," Greentech Media, June 6, 2018, https://www.greentechmedia.com/articles/read/residential-batteries-almost-beat-utility-scale-deployments-last-quarter#gs.CWUtPL4

Figure 20: Installed Energy Storage in O&R Territory (as of June 11, 2018)



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.**

O&R believes energy storage has significant potential to provide value to utility customers, the distribution system as well as to provide benefits to the bulk power system, all of which provide societal benefits. The technology's value lies in its ability to provide grid flexibility and shift electricity supply from times of peak load, as well as providing a wide range of services to the power system as a generation, transmission and distribution (T&D), and BTM resource. The Company believes that the applications for storage that have the most potential depend on timing driven by market opportunities and customer adoption/value proposition for residential BTM applications.

In the near term, energy storage can provide immediate value to the distribution system by providing system benefits as NWAs or other grid assets that can, when either paired with renewable generation or as a standalone asset, provide peak management services to the Company allowing for either deferral of traditional infrastructure solutions or more efficient use of system resources. Future system benefits the Company is anticipating include improved power quality, VVO, voltage control, increased hosting capacity/renewable integration, local contingency support, resiliency and participation in wholesale energy, capacity and ancillary services markets.

Table 15: Energy Storage Opportunities

Energy Storage Opportunities	
Near-Term Opportunities	**Future Opportunities**
• Distribution Deferral NWAs • Demand Charge Management • Backup Power Resiliency • Contingency Response	• Wholesale Market Participation • Power Quality Voltage Control • Hosting Capacity Renewable Integration

A summary of the beneficial uses of energy storage is shown on the following page:

Table 16: Summary of Beneficial Use of Energy Storage on the Distribution System

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

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

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

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

The energy storage market in O&R's territory is still in its infancy and the Company has limited experience working with energy storage assets on its electric delivery system. Nevertheless, the Company has begun the process of understanding how energy storage resources will need to be integrated into its operations and determining the resources and functions that will be needed to plan for, implement, monitor and manage energy storage resources on its system.

As discussed in more detail in the Integrated Planning section, changes have been made to the planning process to determine the suitability of capital investments for alternatives to traditional infrastructure solutions including energy storage. In addition to process changes, the Company is exploring the development of tools to facilitate the analysis and evaluation to assess the potential for DER technologies within the Company's service territory including the potential for leveraging energy storage for NWAs. As familiarity with the capabilities of energy storage grows, the Company expects energy storage to be applied to meet a wider variety of system needs that take advantage of the unique properties and operating characteristics of energy storage.

Similarly, operational investments in an Advanced Distribution Management System (ADMS) and DERMS, as discussed in the Grid Operations section, will be important steps in the near real-time management of energy storage resources throughout the electric delivery system.

Lastly, the Company's experience with early energy storage systems through its NWA projects and the ISBM demonstration project will be instrumental in informing the Company's understanding of how energy storage resources can be planned for, the challenges associated with implementing storage systems, and the Company's ability to monitor and manage energy storage. In particular, O&R's experience as the scheduling coordinator in determining the optimal dispatch of an aggregation of both BTM and FTM energy storage assets is expected to provide crucial insights into the need for near real-time asset M&C.

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.**

Because of the limited nature of the storage market in O&R's territory, the means and methods for monitoring energy storage resources on the O&R system are in still development and closely linked to the Company's grid modernization efforts. In the short-term, the Company plans to work with the vendors to deploy a stand-alone module (as supported by the vendor) to monitor and control these local storage assets. However, the Company is taking steps to improve its ability to monitor and control DER including energy storage. Additional information can be found in the Grid Operations section.

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.**

Forecasting is a key part of the Company's ability to plan for the proliferation of DERs on the electric delivery system. However, because energy storage possesses a range of characteristics unique among DERs (*e.g.*, its ability to act as either supply or load) it poses a challenge to traditional forecasting methods. The Company is in the process of exploring changes that will be needed to its forecasting process to accommodate DERs including energy storage that will provide more granular and location-specific information about how DERs such as energy storage will impact the system. The means and methods for forecasting the status, behavior and effect of energy storage resources on the O&R distribution system are discussed in the Advanced Forecasting section.

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

O&R has made early progress in identifying the types of customer and system data that are needed to plan, implement and manage energy storage assets on the electric delivery system. Although not yet complete, work on NWAs and the ISBM demonstration project has given O&R insight into some of the data that is required from a planning and implementation perspective.

In developing NWAs, system load data is essential in understanding the deferral need for the NWA. This translates directly to the desired system capacity, duration and placement of these storage assets. System peaks that exceed design tolerances must be mitigated by appropriately sized and sited energy storage resources. This information is communicated to energy storage developers and stakeholders through the RFP process as well as its Hosting Capacity maps wherein the deferral need and locations are specifically identified. The mechanisms the Company uses to make this data available to developers and other stakeholders is described in detail in the Customer Data and System Data sections.

Similarly, in implementing the Company's ISBM demonstration project, the need to adequately understand customers' load profiles in terms of potential customer identification and acquisition emerged as key, as customers with peaky loads are best suited for demand charge management programs.

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

O&R is committed to the achievement of New York's state energy goals including the initiative to deploy 1,500MW of storage by 2025. The Company's efforts in developing energy storage projects are aligned with the State goals and the Company has been engaged with the DPS Staff, NYSERDA, and the NYISO in discussions about how to meet the goal of implementing energy storage onto the O&R electric delivery system. As discussed above, energy storage systems are currently being deployed as part of the Company's Monsey and Pomona NWA projects as well as part of the ISBM and SHR demonstration projects. Each of these projects is expected to add to the Company's experience in deploying storage on its system, in addition to identifying key learnings that can be applied to future projects.

As part of its efforts to implement the ISBM demonstration project, the Company has been working in close coordination with the NYISO on its efforts to integrate energy storage into wholesale markets. The ISBM project will, in part, test the hypothesis that energy storage assets deployed on the electric delivery system can provide additional value through participation in wholesale markets. The Company, in conjunction with NYISO, is working to better understand the scenarios and use cases in which energy storage assets can provide customer, electric delivery system, and wholesale market benefits. The outcomes of the project are expected to inform NYISO storage participation models and address issues such as asset optimization, scheduling coordination and other technical challenges associated with dual-participation.

Lastly, the Company was actively engaged with DPS Staff and NYSERDA in the development of the New York State Energy Storage Roadmap. The Company participated in a variety of stakeholder sessions as well as one-on-one meetings to discuss the progress of the New York State Energy Storage Study and Roadmap development. With the release of the Roadmap on June 21, 2018, the Company is eager to continue this engagement throughout the stakeholder process laid out in the Roadmap.

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

The JU formed an internal working group to coordinate on energy storage implementation efforts. As part of this working group, the JU have shared information regarding efforts to deploy storage assets across their footprints. These coordination efforts have focused on aspects such as permitting considerations, the technologies being deployed and the applications that energy storage will serve in each case. This coordination will inform current and future energy storage efforts and help the utilities design a diverse portfolio of projects targeting a diversity of applications. The JU remain committed to continuing this coordination to further support the diversity of energy storage applications and technologies across the State.

EV Integration

Introduction/Context and Background

The Company estimates there will be over 48,000 EVs in its territory by 2027 due to an increase in consumer offerings, more competitive pricing, and favorable policies

Electrification of transportation is crucial to achieving New York State's clean energy goal of reducing GHG emissions by 40% by 2030 and 80% by 2050 from 1990 levels.[56] New York State and the Commission have taken several steps recently to encourage adoption of EVs within the State. These include the Charge NY program, which aims to put 30,000 to 40,000 EVs on the road and install 2,500 additional public and workplace charging stations by 2018;[57] the Multi-State Zero Emission Vehicle ("ZEV") Action Plan, which sets a collective goal for 3.3 million ZEVs by 2025, including 800,000 ZEVs on the road in New York;[58] a $70 million NYSERDA initiative to provide rebates for the purchase of EVs of up to $2,000 per vehicle, to install new charging stations throughout the , and for consumer education awareness,[59] and; the recently announced NYPA Evolve NY initiative to invest up to $250 million to expand fast-charging infrastructure and make EVs more user-friendly for all New Yorkers.

Moreover, the Commission recently commenced a new proceeding to explore electric utilities' role in providing infrastructure and rate design to accommodate the needs and electricity demand of EVs and electric vehicle supply equipment ("EVSE"). The proceeding will explore utility roles in supporting the deployment of charging infrastructure, potential rate design enhancements, and charging systems' value to the electric system including participation as a DER. The Company is committed to fully participating in the new proceeding and provided its perspective to the DPS Staff during the July 18-19, 2018 technical conference to support the development of DPS Staff's whitepaper on EV issues.

The Company believes there is tremendous potential for growth of EVs. Recent data indicates that there were already up to 1,000 EVs in the Company's service territory as of 2016 and the Company estimates there will to be over 48,000 EVs in its territory by 2027. The Company supports New York State's efforts to increase EV adoption and is committed to developing the appropriate tools, processes, and capabilities to further EV market growth. The Company's programs outlined in this DSIP filing are designed to act as a catalyst for EV adoption and address the unique nature of the Company's service territory.

Utilities are particularly well-suited to spur the development of EVs and since the 2016 IDSIP filing, the Company has undertaken multiple initiatives to support the development of the EV market. The Company has partnered with a leading auto manufacturer to promote a manufacturer's rebate to the Company's customers on an all-EV and has developed online tools to facilitate informed decision-making when considering the purchase of an EV. The Company has also been participating in industry forums that include various utilities and stakeholders focused on promoting EV adoption in the region, such as the New Jersey ChargEVC initiative, of which O&R is a founding member. The Company plans to leverage lessons learned from the initiative for implementation of EV programs in New York.

[56] CES Proceeding, CES Order.
[57] Charge NY, https://www.nyserda.ny.gov/All-Programs/Programs/Drive-Clean-Rebate/About-Charge-NY
[58] Multi-State ZEV Action Plan, 2018 – 2021. https://www.rtoinsider.com/wp-content/uploads/2018-zev-action-plan-1.pdf
[59] "State Of New York Says 5,750 Drive Clean Rebates Claimed In First Year," Insideevs: https://insideevs.com/state-new-york-says-5750-drive-clean-rebates-claimed-first-year/

The Company has also continued to assess its EV-related system needs and planning by incorporating EV load into its bottom-up forecast methodology. In 2016, the expected contributions of EV load to the system peak forecast was less than 1 MW over the next five-year period. The Company's current system peak load forecast projects EVs contributing 5 MW over the next five-year period which clearly illustrates the growth potential of EVs and the increasing trend that is beginning to take place. Additional discussion of the Company's load forecasting related to EVs and beneficial electrification can be found in the Integrated Planning and Advanced Forecasting sections.

The Company continues to partner with third-parties to accelerate EV adoption and improve grid integration of EVs

Additionally, the Company participated with the JU as part of the EV working group in the development of the EV Readiness Framework which focused on what the utilities can do to become "EV Ready." This includes identifying, prioritizing, and executing actions in the near- to mid-term to unlock the potential of transportation electrification as a broader initiative. Both the framework and the working group were developed to meet the JU commitment, outlined in the SDSIP. The SDSIP also included a set of guiding principles co-developed with stakeholders for utility involvement in supporting the increased adoption of EVs and charging infrastructure, all of which helped inform the development of the joint Framework. [60]

Implementation Plan, Schedule, and Investments

Current Progress

As noted above, the Company has been engaged in multiple initiatives to encourage the adoption of EVs in its service territory. These include education and outreach initiatives, such as partnering with an auto manufacturer and developing online tools to facilitate informed decision-making. The Company has also actively participated in EV-related industry forums including the JU EV working group.

Education and Outreach

Partnerships with Manufacturers to Offer Rebates on EVs

The Company partnered with a leading auto manufacturer to promote a ten-thousand-dollar manufacturer's rebate for O&R's customers and employees from June 1, 2017, through September 30, 2017, for the purchase of an all-EV. The promotion was advertised on the Company's website as well as through social media. The information distributed also informed customers of the federal and NYSERDA rebates available to them, which provided additional savings to customers and employees. Expanding on this partnership, the Company began promoting a new manufacturer's rebate on May 1, 2018, for its customers and employees on the purchase of an all-EV with an increased range.

EV Webpage and Communication

As part of its outreach and education efforts, the Company has developed an EV website[61] that helps customers identify the type of EV that will be right for them, as well as calculate potential changes to their energy bill. The site contains information on different types of vehicles, chargers and has an interactive EV calculator that compares customers' internal combustion engine ("ICE") vehicles with the

---

[60] DSIP Proceeding, JU Supplemental DSIP, pp. 115 - 117.

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

latest PEV models. The interactive calculator utilizes customer-specific inputs (*e.g.,* daily driving miles, ICE vehicle's mileage per gallon, and cost per gallon) to provide insights on fuel cost savings and reduced carbon emissions resulting from the customer's EV use.

The Company has established a designated email address, "EV@ORU.COM" where customers can send their EV-related questions. These customer queries provide the Company with direct insights into customers' EV needs and concerns, and help inform the design of Company's EV programs, rates, and rebates.

EVSE Charging Application

The Company has developed an online EVSE Charging Application that helps collect information on charging units deployed in its service territory. This application allows customers to enter specific details about customer-owned charging units and their locations, both residential and commercial. As EV adoption increases, this information will prove valuable in enhancing the Company's distribution planning and forecasting capabilities. In the future, this information will be reviewed by Distribution Engineering to certify that the distribution transformer, service equipment and circuit capacity are adequate to accommodate the increased load by EVSE. Although significant distribution-level impacts are possible as a result of EV clustering and charging at discrete locations (*e.g.,* with significant fast-charging demands), the Company anticipates that the grid impacts can be addressed through normal infrastructure without an extension of investments given the expected power and energy demands of EVs in the near-to-mid-term as included in the Company's load forecasts.

The EVSE Charging Application is embedded in the Company's PowerClerk Interconnect Software, which the Company installed in April 2016 to facilitate timely DER application processing and interconnections. The information collected through the application will assist the Company in the forecasting and trending of substation and circuit loads, as well as in forecasting system-level loads at a granular level. The Company's current system forecast includes EV load as a system modifier to the peak electric load forecast. The EVSE Charging Application will significantly improve this forecasting process by helping collect data on specific locations of EV charging units including those installed for residential and commercial charging purposes. Moreover, the Company may leverage this data in the future for better execution of its DR programs.

Third-party Partnerships

The Company continues to develop partnerships with third-party providers to introduce innovative solutions for its customers. In February 2018, the Company partnered with a third-party vendor and another New York State utility on NYSERDA's Program Opportunity Notice ("PON") 3578 PEV – Enabling Technology Development and Demonstration. The Company proposed an innovative program in its PON application to accelerate PEV adoption and improve grid integration of EVs in the Company's service territory. Because selecting the right EVSE for home charging options can be a pain point for many customers, the Company will leverage its CEMP to provide convenience and value for customers and help reduce barriers to adoption through education, emails and an incentivized EVSE with bundled program enrollment offering. The program will help the Company meet its goals of carbon emission reduction and accelerate PEV adoption in New York State. The PON is currently in the solicitation process.

Industry Participation

The Company continues to participate in monthly transportation electrification calls with utilities across the country held by the Edison Electric Institute ("EEI") as well as other groups focused on promoting vehicle electrification across their service territories on the East Coast. Participation in these focus groups, as well as stakeholder engagement meetings as part of the Joint Utility working group, helped the Company identify its plans to move forward.

The Company also participates in the ChargEVC coalition in its New Jersey service territory through its New Jersey subsidiary, Rockland Electric Company. ChargEVC is a coalition aimed at accelerating EV adoption in New Jersey. Rockland Electric is a founding member of the coalition since 2016 and sees great benefits in continuing this partnership. ChargEVC is unique in that it is the only EV coalition in New Jersey that consists of all of the New Jersey electric utilities, automotive retailers, clean energy advocates and other stakeholders. The Company leverages lessons learned and information received as part of this coalition in development of the EV programs to be implemented in New York.

JU EV Readiness Framework

In January 2018, the JU completed a draft of the EV Readiness Framework and circulated it with interested stakeholders for feedback. In early February 2018, the JU held a stakeholder meeting focused on aspects of the framework and provided an opportunity for stakeholders to ask questions and offer additional input on the document. The final version of the Framework was posted on the JU website in March 2018.[62]

The JU, with input from stakeholders, have agreed upon a clear path toward EV readiness that reflects a more proactive stance by utilities in the EV market. Utilities are advancing EV demonstrations, pilot projects, and programs, and are continuing to work with regional groups, associations, and governments to advance EV initiatives and infrastructure awareness.

The objectives of EV readiness planning are to identify, prioritize, and execute actions in the near- to mid-term to unlock the potential of transportation electrification. The framework describes the hurdles to widespread deployment of EV infrastructure (and vehicles, where appropriate). Hurdles referenced in the framework include, but are not limited to, the higher price of EVs compared to conventional vehicles, lack of public EV charging infrastructure, lack of consumer awareness of EV benefits, and lack of coordination among stakeholders.

Given the limited size of the current EV market, the JU believe that the framework, complemented by demonstration projects and active education and outreach efforts, is the most effective way for utilities to facilitate increased EVSE deployment and EV adoption. The framework reflects significant stakeholder input and the Company has adopted it as part of its EV promotion efforts.

The framework addresses near-term priorities resulting from the stakeholder engagement sessions, with a focus on:

- EV charging infrastructure planning and forecasting EV growth to assess and mitigate potential system impacts;
- Streamlining charging infrastructure deployment in New York, which is characterized by reviewing service connection requirements; outlining local ordinances, building codes and design guidelines that can help reduce barriers to infrastructure installation; and highlighting the value of interoperability and standardization of charging equipment;
- Advancing rate design considerations that will improve the customer experience while minimizing impacts to utility system operation; and

[62] http://jointutilitiesofny.org/wp-content/uploads/2018/03/Joint-Utilities-of-New-York-EV-Readiness-Framework-Final-Draft-March-2018.pdf

- Conducting education and outreach efforts that improve customer awareness about the benefits of EVs.

The role of the utility varies considerably across the core elements of the Framework. In some cases, readiness will be achieved through proactive measures, while in others, utilities remain in a position of information gathering. The utilities will continue to use the Framework to identify useful indicators for assessing market performance and continue to update internal assessments related to determining the thresholds at which distribution system impacts or benefits of EVs may become more significant. While the JU have developed a common framework, the specific EV programs, implementation plans and timelines taken by individual utilities will vary due to utility and service territory-specific factors.

O&R EV Readiness

O&R is committed to following the framework and assisting in the deployment of EVSE throughout its service territory which will ultimately result in increased EV adoption and the system and societal benefits that are created through that adoption. As discussed earlier, the EV market is poised for significant growth over the next several years due to increased consumer offerings, more competitive vehicle pricing, and favorable policies. The potential number of EVs in the Company's service territory are projected to grow rapidly from approximately 1,000 vehicles in 2017 to 48,500 vehicles by 2027, and to 175,500 vehicles by 2037. These projections are predicated on the continuation of EV manufacturers' initiatives (*e.g.,* increased model offerings, proper price signals), the evolution of comprehensive EV charging infrastructure, and appropriate education and outreach programs to assist consumers in their decision making when purchasing a vehicle.

The Company will continue its efforts in educating its customers on the benefits of EVs and providing them tools to facilitate informed decision making. However, the Company believes it must be proactive concerning the deployment of EV charging infrastructure to ensure that it is EV-ready and its initiatives serve as a catalyst for increased EV adoption throughout the Company's service territory. For example, EEI's recent report on Accelerating EV adoption,[63] referenced in the framework, presents four major ways utilities can engage in EV charging deployment. These include: (1) "Business as Usual" where the utility only funds distribution-level upgrades; (2) "Make Ready" where the utility funds the installation and supply infrastructure costs up to the charging equipment; (3) "Charger Only" where the utility funds and/or owns the charging equipment utilizing the existing infrastructure, and; (4) "Full Ownership" where the utility funds and/or owns the full installation up to and including charging equipment.

The evolving EV market requires EVSE investments to be made today to yield both immediate and longer-term benefits. The Company supports utility ownership of EVSE so that the utility can lead in navigating through the challenges of a developing EV market in its service territory. Considerations, such as the type of charger (*i.e.*, Level 2 or DC Fast Charger) and its location (*e.g.*, workplace, commercial, multi-family, or other), must be carefully evaluated in order to create benefits for both EV users and other customers. The quality of EVSE deployments is essential because poorly-chosen locations could yield low returns and have a negative impact on EV adoption. Further, the anticipated high rate of adoption of EVs will put additional strain on the distribution system, requiring utilities to play a managing role in EV charging. To minimize the impact to the distribution system, EVs should be charged during off-peak hours when there is adequate system capacity and the energy price is low.

---

[63] Edison Electric Institute, *Accelerating Electric Vehicle Adoption* (February 2018). http://www.eei.org/issuesandpolicy/electrictransportation/Documents/Accelerating_EV_Adoption_final_Feb2018.pdf

Considering these challenges, in its 2018 base rate case, the Company proposed a utility ownership model to support near-term EV adoption that includes utility installation and ownership of early EV charging infrastructure in its service territory. In addition, the Company will also expand its EV education and outreach efforts, and has proposed new rate designs, including expanded TOU rates and the PEV Quick Charging Station Program. The Company's proposed programs are in early stages of development and are pending Commission approval in the rate case.[64] Once approved, the Company will begin the process of outlining detailed project schedules, improvement opportunities, timelines, and deliverables. These programs are described in detail in the Future Implementation and Planning section below.

Future Implementation and Planning

As noted in the 2017 DSIP Order, "the Commission expects the Utilities to continue investigating EV-related infrastructure effects and modifications in anticipation of a potential future when the range of needs and demands for EVs is substantial." [65]More recently, the Commission recognized "the electric system benefits of well-managed deployment and operation of EV supply equipment as distributed resources." [66]

As part of its utility ownership plan, O&R proposed an initiative to own, operate and deploy charging infrastructure in its service territory in its 2018 base rate case. This program will provide a means for EVSE deployment until significant EV adoption allows a sustainable business model to exist for third-party EVSE providers. The initiative will accelerate the adoption of EVs in the Company's service territory and help bring the State closer to its goal of installing at least 10,000 EV charging stations by the end of 2021. The program is expected to help fulfill the charging infrastructure needs of the rapidly growing EV market are being adequately fulfilled, while also providing the Company an opportunity to explore the operation of EVSE as a DER. Additionally, the Company will continue its EV education and outreach efforts and has proposed new rate designs including expanded TOU rates and the PEV Quick Charging Station Program.

EV Supply Equipment

The Company has proposed an EVSE program to own, operate and deploy a combination of Level 2 PEV chargers and DC Fast chargers to be located in non-residential, publicly accessible locations. The Company plans to coordinate with municipal and commercial entities to identify mutually-beneficial siting opportunities. The EVSE program will also offer rebates for Level 2 chargers to prospective residential PEV buyers. The rebates will be similar to those offered by other utilities around the country, which have been shown to drive EV adoption in those states. The Company envisions utilizing the CEMP to offer approved charging units and to deploy the rebates. These approved chargers will allow the Company to obtain information on EV charging habits specific to O&R customers and associated rate structures. This data will be critical in providing more granular forecasting in future models.

According to Smart Electric Power Alliance ("SEPA"), 69% of utilities in the United States are considering deploying EV chargers to manage EV charging as adoption rates increase.[67] Even though the EV market is nascent currently, utilities will need to be involved and should start planning now to shape

[64] O&R Electric Rate, Electric Rate Panel Direct Testimony (filed January 26, 2018).
[65] DSIP Proceeding, DSIP Order, p. 9.
[66] EVSE Proceeding, EVSE Order, p. 2.
[67] *Utilities and Electric Vehicles: The Case for Managed Charging*, Smart Electric Power Alliance, April 2017

relevant future policies, regulations, and standards for the future. The Company is being pro-active by implementing this program, thereby gathering a more in-depth knowledge of EV customers' interests and expectations allowing it to communicate the needs of its customers and its grid to vendors, recommending the most efficient and cost-effective strategies for common communication and other interoperability standards.

As the Company makes plans to encourage EV adoption in its service territory, it recognizes the market is emerging with non-standardized EVSE protocols and technology configurations. The Company, along with the JU, is aware that interoperability and standardization are keys to providing a seamless and positive customer experience, regardless of the technology, which is essential to removing barriers to EV adoption. The Company, aligned with the JU, will continue industry engagement and ongoing progress toward common standards.

Education and Outreach Programs

The Company's 2018 base rate case includes a proposal for an education and outreach program to educate and inform current and potential PEV customers of the benefit opportunities, including those associated with TOU rates. The education and outreach programs will expand its current offerings and will seek to inform consumers about key EV topics – including ownership costs, environmental benefits, charging options, and available incentives – through various channels such as bill inserts, social media, e-mail, and a dedicated EV page on the Company's website. The program will also include engagement with local and municipal governments, auto dealers, manufacturers, and Drive-and-Ride events. The stakeholders that will benefit from this education and outreach include both prospective and current PEV owners in residential, commercial, government and municipal sectors. While PEV is not a new technology, many customers are not aware of the capabilities of the new models available today. Most consumers have misconceptions about PEVs based on exposure to outdated technologies. A focused outreach and public education campaign can help erase these misconceptions. Educating and informing a broader set of consumers will lead to higher adoption of PEVs.

Rate Design Solutions

Considerations

As noted above, when EV charging is unmanaged, there is potential for increased cost to utility customers, especially if charging occurs coincident with peak demand. Utility rates have proven to be an effective way to encourage EV drivers to charge at preferred times. [68] As the EV population grows, this shift could also help improve system efficiency. With EV deployment in its early stages, utilities can begin to explore effective rate design considerations.

The Company, in collaboration with the JU, seeks to align rate design with the following key considerations in mind:

- Comply with the requirements of Assembly Bill 288 that requires each New York investor-owned utility to file a residential tariff for recharging EVs;[69]
- Minimize the costs of EV charging and potential distribution system impacts;
- Encourage EV drivers to charge at preferred times using price signals;

---

[68] *See, e.g.*, NYSERDA (M.J. Bradley & Associates, LLC), *Electricity Pricing Strategies to Reduce Grid Impacts from Plug-in Electric Vehicle Charging in New York State*, NYSERDA Report 15-17 (June 2015).
[69] Full text of the legislation is available online: http://legislation.nysenate.gov/pdf/bills/2017/A288

- Provide EV charging rates that drivers can easily understand; and
- Provide EV drivers with a cost-competitive rate when compared to the standard/flat rate, and the potential to realize cost savings relative to gasoline.

TOU Rates

The Company has offered several rate designs beneficial to the EV market. [70] These include a modified TOU residential rate which will provide a "price guarantee" to residential customers who register their PEVs with the Company and are served under the voluntary TOU rate. After one year of service, the Company compares the customer's bills on the TOU rate with a bill recalculated using the SC-1 residential rate and refund the difference if the customer paid more under the TOU rate. This price guarantee will allow customers to try the TOU rate which could provide significant savings when charging the EV during off-peak hours and may also encourage customers to examine other opportunities to move their electrical usage to off-peak times. [71]

Additionally, the Company has proposed a separate customer account for PEV charging under the TOU rates. The separate account will allow SC-1 customers with separately metered PEV chargers to take service under a second customer account billed under TOU rates solely for PEV charging. Customers could enjoy significant savings when charging their PEV during off-peak hours, while also providing system efficiency benefits. The Company has not proposed any price guarantee for a customer with separate customer accounts since there is no risk of a higher bill for the non-PEV metered account.

The deployment of AMI further supports the Company's innovative rate structures. As discussed in the AMI section of this DSIP update, the Company is the first utility in New York State to receive Commission approval for Smart Meter deployment and is on track to deploy smart meters across its entire service territory by December 2020. AMI provides a foundation of information and communications capabilities that will enable the Company's customers to become informed and engaged energy consumers. Through the AMI technology, the Company's customers will have access to hourly usage data which they can leverage to charge EVs at off-peak times and gain substantial cost savings through TOU pricing structures.

Quick Charging Station Rate Program

The Company has also proposed a *"Quick Charging Station Rate Program."* This program will encourage third-party deployment of Level 2 and 3 chargers by offering a delivery rate discount for EV charging stations installed at publicly accessible locations.[72] To implement this program, the Company proposes to modify its Economic Development Rider, Rider H of its tariff, to allow demand-billed participants that construct and own a publicly accessible charging station with a minimum of 65 kW of aggregate charging capacity to receive a 20% delivery rate discount under Rider H. This program has a maximum 2 MW participation threshold. Examples of locations for publicly accessible stations are supermarkets, shopping malls and retail outlets, train stations, hotels, restaurants, and parking garages and parking lots where PEV quick charging is open to the general public. As is applicable to any other Rider

[70] The Company's actions are consistent with the requirements of Assembly Bill 288, effective October 23, 2017. The new law required New Yok electric utilities to file with the Commission a residential tariff for eligible EVs to recharge such vehicles. Full text of the legislation is available online: http://legislation.nysenate.gov/pdf/bills/2017/A288

[71] O&R Electric Rate Case. Electric Rate Panel Direct Testimony (filed January 26, 2018).

[72] O&R Electric Rate Case. Electric Rate Panel Direct Testimony (filed January 26, 2018).

H applicant, a PEV quick charging station must receive a comprehensive package of economic incentives conferred by the local municipality or state authorities.

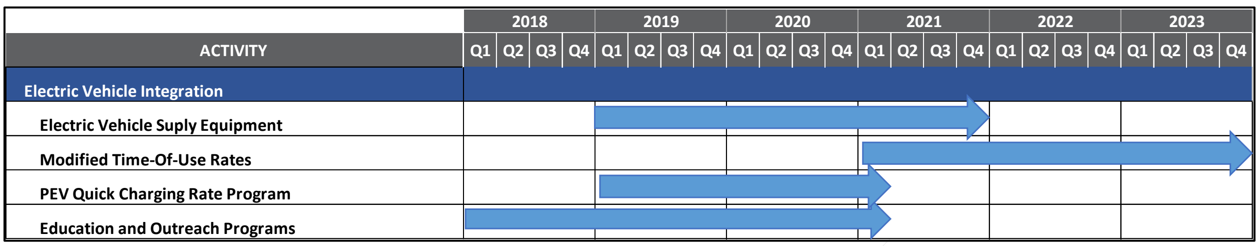
Additional Programs

The Company is also considering additional EV programs for future deployment. These include but are not limited to workplace charging and fleet charging programs.

Five-Year Implementation Plan

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

Table 17: O&R EV Integration 5-Year Plan



Risks and Mitigation

The EV market is poised for significant growth over the next several years driven, in part, by expanded vehicle offerings and increased charger availability. Competitive pricing compared to ICE vehicles, as well as addressing consumer anxiety about the range of an EV's charge, are significant factors impacting EV adoption rates. While the load growth from EV adoption may be considered a benefit to the electric industry, there are also significant risks for utilities associated with poor load management and lack of EV readiness that need to be considered. These are outlined below.

System Impact

Increasing EV adoption may result in peak load increases, transformer and substation impacts, and reliability issues. The increasing load may also result in necessary infrastructure upgrades that could have otherwise been avoided with the properly managed installation of charging infrastructure.

The Company recognizes the reliability risks of increasing loads that are not properly managed. The Company plans to mitigate these risks through its proposed EVSE program that allows the Company to own, operate, and deploy charging infrastructure. The program will allow the Company to site charging units at locations where there is a need and the distribution system can handle the loads. This approach will reduce reliability risks and grid impacts from new deployments, while also providing Company valuable insights into load characteristics of these charging units. Moreover, by having direct control over the charging units, the Company will be able to facilitate PEVs charging during off-peak times, thereby reducing stress on the grid as well as the need for new peak generation. The Company has also proposed TOU rates to encourage EV charging during off-peak hours when there is excess system capacity and the energy price is low. This will mean minimal strain on the distribution system from increasing loads.

EVSE Business Model

The EV market faces a "chicken-and-egg" situation where EV adoption and deployment of charging infrastructure are interdependent. Lack of early EV adoption may result in under-utilization of charging infrastructure; and on the reverse, lack of adequate charging infrastructure may result in slowing down of EV adoption in the Company's service territory.

To mitigate the risk of low customer participation, the Company has proposed a modest EVSE program, while maintaining the potential to quickly scale this project in the future, depending on the aggressiveness of future EV adoption. The Company has also proposed the "Quick Charging Station Rate Program" to encourage the deployment of Level 2 and 3 chargers at publicly accessible locations by third-party providers. These programs will provide adequate charging infrastructure is in place to support the growth of the EV market.

Stakeholder Interface

The Company, with the JU, has been continually engaged with stakeholders to share and inform about EV-related initiatives, and gather stakeholder feedback on these initiatives. In 2016, the JU formed an EVSE working group to collaborate with each other and stakeholders on EV and EVSE-related issues. The EVSE working group has conducted multiple stakeholder engagement sessions since 2016. The JU EV Readiness Framework has been developed in collaboration with the stakeholders and addresses the near-term priorities resulting from the engagement sessions. The Company also agrees with the JU on the importance of working together on developing communication channels to help customers understand the numerous benefits of EV adoption. As a result, the EVSE Working Group will continue advancing efforts outlined in the 2016 SDSIP, including:

- Design and conduct individual utility engagement activities with local governments and municipalities;
- Continue to work with regional groups, associations, and governments to advance EV initiatives and infrastructure awareness; and
- Continue to support the identification and implementation of EV demonstration and pilot projects.

The JU will continue to solicit feedback from a diverse group of stakeholders to help inform their efforts as they advance their customer engagement strategies. In addition, the JU will work with DPS Staff to offer incentive programs and position the utility as a resource to work closely with local groups to host events to spread consumer awareness of the benefits of EVs.

The Company will also collaborate with stakeholders in the new Commission proceeding to encourage greater penetration of EVs and EVSE in New York State.[73] The proceeding will consider the role of electric utilities in providing infrastructure and rate design to accommodate the needs and electricity demands of EVs and EVSE.[74] As a first step, DPS Staff in collaboration with NYSERDA convened a technical conference on July 18-19, 2018 to solicit stakeholder input, identify issues to be addressed, and to establish the scope of a subsequent Staff whitepaper.

[73] EVSE Proceeding, EVSE Order.
[74] *Id.*, p. 3.

Additional Details

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

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

The Company has collaborated with the JU to develop the EV Readiness Framework, which identifies key strategies to support EV adoption through utility action, engagement, and collaboration. The common framework envisioned is a detailed EV charging infrastructure siting analysis. The EV market in the Company's territory is still in its initial stages and the Company has limited experience working with EVs. However, the Company believes its AMI deployment will play an integral role in providing insights and necessary data on customer charging patterns.

The Company has also proposed an EVSE program, as described above, whereby the Company will own, operate and deploy a combination of Level 2 PEV chargers and DC Fast chargers to be used in the non-residential marketplace. This initiative will help the Company better understand customer charging patterns in workplaces and public locations. Specifically, the program will allow the Company to gain insight into how and when customers will charge their PEVs, and any additional behaviors that the Company can benefit from learning.

Since the Company has limited data related to EV charging scenarios in its service territory, only a high-level understanding of the charging scenarios is provided below.

Each scenario identified should be characterized by:

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

The Company envisions specific market segments and locations to shape the O&R EVSE landscape. These include single family, multi-family and workplace charging for private property sited locations and publicly accessible locations including shopping malls, shopping centers, rest stops, municipal curbside, and municipal parking areas.

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

The Company has limited data available related to EV charging scenarios in its service territory. The Company is in the early stages of fully understanding the data needs for the Company's EV-related planning efforts and developing the required capabilities to collect such data.

The Company finds publicly available industry data from entities such as EPRI, NYSERDA and the U.S. Department of Energy ("DOE") to be appropriate sources to gain insights into the EV market within the Company's service territory until such time data exists to allow for internal analysis. EVSE data from external sources include; location, number of chargers, charger type and other useful information.

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

Currently, the Company does not forecast anticipated instances of each charging scenario with spatial granularity. The Company is in the early stages of fully understanding the data needs for the Company's EV-related planning efforts and developing the required capabilities to collect such data. The Company's proposed EV programs will be leveraged to collect this data as appropriate.

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

The Company expects light-duty vehicles to be the predominant class of EVs in its service territory. This will include a mix of privately-owned residential, commercial and municipal fleets. The Company assumes that these light-duty vehicles will charge at private and public charging locations.

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

Currently, the Company does not collect EV charging data by vehicle and typical location. The Company's proposed EV programs will be leveraged to collect this data as appropriate.

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

Currently, the Company does not collect data on customer charging behaviors in its service territory. However, the Company believes its AMI deployment and proposed EVSE ownership program will help the Company develop capabilities to better understand the charging patterns and develop plans to address future customer needs.

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

The Company does not forecast the number of chargers at a typical location in its planning scenarios. Industry data which provides vehicle-to-charger ratios may be utilized in the future as it is further developed.

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

Currently, no energy storage systems are being utilized with EV charging in the O&R territory. Demonstration projects currently underway in other utilities along with industry data will be useful in determining the future benefits energy storage will have on EV charging.

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

The Company does not currently forecast the hourly profile of a location's aggregated charging load over a one-year period. However, the Company believes its AMI deployment and proposed EVSE ownership program will help the Company develop capabilities to better understand the charging patterns and develop plans to address future customer needs.

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

The type and size of the existing utility service varies based on the location, customer type, and customer demand profiles. Generally, existing service for residential and commercial customers can support Level 1 or Level 2 chargers.

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

The Company's service and infrastructure may need enhancements based on the EV charging demands and load profiles. For example, quick charging and/or deployments of several Level 2 chargers may require service upgrade and/or network reinforcement. The appropriate level of service will likely become more evident as the Company receives more service requests at different locations and in varying design configurations.

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

The Company seeks to maintain proactive measures to support EV adoption in a nascent market while helping achieve, and where possible, accelerate the long-term potential of transportation electrification. The Company has prioritized streamlining charging infrastructure deployment in New York, proposing innovative rate designs and conducting education and outreach efforts to raise EV awareness. These initiatives are designed to improve the customer experience and remove barriers to EV adoption, while also minimizing impacts to the Company's system operation.

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

EV Supply Equipment: The Company has proposed an EVSE program that will have a broad impact on non-residential EV charging scenarios in the Company's service territory. The Company has proposed the EVSE program to own, operate, and deploy a combination of Level 2 PEV chargers and DC fast chargers to be used in the non-residential marketplace. These chargers will be located at publicly accessible locations and the Company plans to coordinate with municipal and commercial entities to identify siting opportunities. In addition, the EVSE program will offer rebates for Level 2 chargers to prospective residential PEV buyers.

TOU Rates: The Company has proposed a modified TOU residential rate which will support EV charging at home. The TOU residential rate will provide a "price guarantee" to residential customers who register their PEVs with the Company and are served under the voluntary TOU rate. After one year of service, the Company will compare the bills of the TOU rate with an SC-1 residential rate and refund the difference if the TOU rate costs more than the SC-1. This price guarantee will allow customers to try the TOU rate which could provide significant savings when charging the EV during off-peak hours and may also encourage customers to examine other opportunities to move their electrical use to off peak times.

Quick Charging Station Rate Program: The Company has proposed a "Quick Charging Station Rate Program" that will support EV charging in public areas. This program will encourage third-party deployment of Level 2 and 3 chargers by offering a delivery rate discount for EV charging stations installed at publicly accessible locations.

Additional Programs: The Company is also considering other EV programs for future deployment, which will focus on specific charging scenarios. These include but are not limited to workplace charging and fleet charging programs.

Education and Outreach Programs: The Company's education and outreach program will seek to inform consumers about important EV topics including the charging options for customers' EVs.

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

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

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

The Company is in the early stages of planning, implementing, monitoring, and managing EV charging as it relates to the distribution system. The adoption of EVs is a high priority for the Company and it will be required to dedicate additional resources and functions as the EV market further develops.

The Company has existing processes to manage current EV charging needs but anticipates enhancements to address future EV-related needs. The Company will provide more detail on the resources and functions in its next DSIP filing, as Company's programs further mature.

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.

As noted previously, the Company is in the early stages of planning, implementing, and managing EV charging infrastructure and services. There are a variety of customer and system data that will be necessary for planning, implementing, and managing EV charging infrastructure and services. The Company, along with JU, has identified a subset of the higher priority data that will be required, as noted below.

- **Customer load profile**: The Company will need to know the customer load profile, including charging capacity pre-installation of EV charging infrastructure, to help understand the impact on the customer as well as on the system.
- **EV charging demand**: In workplace or other non-residential types of EV charging, the Company will need to know the anticipated charging demand, including how many EVs are likely to be charging and at what level (*e.g.,* Level 2 charging versus DC fast charging). This information will help characterize the charging capacity required at the facility. For a residential installation, the Company will need to know the level of charging that the customer is seeking, namely Level 1 or Level 2.
- **Distribution asset load profile**: The Company will need to know the load profile on the nearest substation, feeder, or similar distribution asset to understand the likely impact that may arise from increased load attributable to EV charging. The local load profile will enable the Company to update its asset management strategy for that distribution asset.
- **Potential location of EV charging infrastructure**: The Company will need to know the potential location of charging infrastructure as the costs of such infrastructure will vary by location. For example, the trenching and cutting costs associated with the installation of EVSE at existing facilities can vary significantly depending on the location of the planned installation relative to the point of connection with utility service.

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

As noted above, New York has taken a number of steps recently to encourage adoption of EVs within the , including the Multi-State ZEV Action Plan, which sets a collective goal for 3.3 million ZEVs by 2025, including 800,000 ZEVs on the road in New York. The Company anticipates significant growth of EVs over the coming years and is supportive of New York State's efforts to increase EV adoption. As described above, the Company is engaged in multiple initiatives to meet the State targets via the following means and methods:

- **Customer Outreach and Education**: Outreach and education activities are key to informing consumers about key EV topics – including ownership costs, environmental benefits, charging options, and available incentives. While EVs are not a new technology, many potential customers are not aware of the capabilities of the new EVs available today. Many consumers have misconceptions about EVs based on exposure to outdated technologies. A focused outreach and public education campaign can help erase these misconceptions. Educating and informing a broader set of consumers will lead to higher adoption of PEVs.

- **Innovative Rate Design**: Innovative rate design will be essential to driving the adoption of EVs. As noted above, when EV charging is unmanaged, there is potential for increased cost to utility customers, especially if charging occurs coincident with peak demand. Utility rates have proven to be an effective way to encourage EV drivers to charge at preferred times. In addition, effective TOU rates can help drive EV adoption by mitigating rate risk for consumers as well as by giving customers greater control over their energy use. In addition, business incentive or economic development rates can help commercial charging infrastructure grow in the early stages of market development.
- **Charging Infrastructure**: Publicly available charging infrastructure is often cited as a necessary first step to alleviating range anxiety among potential EV customers. Utility development of early charging infrastructure can help to plug the gap in early stages of the market by rate-basing charging assets and by siting charging stations in high visibility areas that may increase customer awareness. In addition, utility involvement in EV infrastructure development can help minimize grid impacts and required distribution system upgrades by integrating with existing utility investment and planning processes, as described in previous sections.

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

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

b) The original project schedule;

c) The current project status;

d) Lessons learned to-date;

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

f) Next steps with clear timelines and deliverables;

The Company's current efforts to plan, implement, and manage EV-related projects are discussed in detail above in the EV Integration section. The Company's proposed programs are in early stages of development and/or are pending Commission approval in the rate case.[75] Once the programs are approved, the Company will start outlining the detailed project schedules, improvement opportunities, timelines, and deliverables.

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

The Company and the JU recognize that practical demonstration projects will likely form the basis of planning related to transportation electrification moving forward. Further, the JU have noted that rapid technological advances and the diversity of EVs in the market today requires utilities to begin planning for charging infrastructure today for the EV deployment of tomorrow. In order to develop a better understanding of the most effective way to engage in transportation electrification, the JU continue to be

[75] O&R Electric Rate Case, Electric Rate Panel Direct Testimony (filed January 26, 2018).

involved in a wide array of demonstration and pilot projects, many of which are highlighted in the EV Readiness Framework. The diversity of those EV-related projects reflects the diversity of approaches that utilities have developed with respect to transportation electrification. This approach was recently demonstrated in a recent JU REV Connect EV Sprint conducted to bring utilities together with companies proposing demonstration projects aimed at increasing EV adoption.

The EV Working Group provides a platform for collaboration and coordination on EV-related issues for the JU. As previously discussed, most recently the Company, as part of the EV working group, developed the EV Readiness Framework, which documents a consistent approach to EV integration, considering input from stakeholders. The document also highlights a summary of utility EV demonstration and pilot projects. While each individual utility advances EV-related projects within its service territory subject to internal business decisions and resource prioritization, the JU will continue to use the EV Working Group as a platform for collaboration and sharing lessons learned. This approach will help facilitate the sustained diversity of EV integration use cases and the technologies and methods employed in such cases.

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

The Company, along with JU, is proactively engaged with NYSERDA, NYPA, DEC, and DPS Staff, particularly through the development of the EV Readiness Framework. Multiple staff members from these organizations were active participants in the two stakeholder meetings, held in September 2017 and February 2018. Further, the Company and JU invited staff from these organizations to present to the EV Working Group several times over the past 12 months—including on issues such as the costs and benefits of EV deployment in New York State and the role of demand charges in DC fast charging use cases.

Moreover, the Company is committed to fully collaborate with all stakeholder parties in the new proceeding[76] commenced by the Commission. The Company recently participated in the July 2018 technical conference and provided its perspective to the DPS Staff to support the development of the Staff's whitepaper on EV issues.

[76] EVSE Proceeding, EVSE Order.

Energy Efficiency

Introduction/Context and Background

O&R has been implementing comprehensive Energy Efficiency ("EE") programs since 2009. These programs have reduced energy by 149,000 MWh and 119,000 Dth, and peak demand by 32 MW. Over 26,000 customers have participated in these programs, received over $25 million in rebates, and realized $26 million in bill savings. These savings are equivalent to reducing carbon emissions by 103,000 tons and taking over 22,000 cars off the road.

Utility efforts are a critical component of REV and achievement of New York State's CES goals, including reduction of GHG emissions by 40%, 50% of electricity from renewable sources, and 600 trillion BTU increase in statewide EE by 2030. In the Track One Order, the Commission directed the utilities to file Energy Efficiency Transition Implementation Plans ("ETIPs") describing specific programs, measures, and approaches that will be used to achieve EE goals. The Commission also directed utilities to file Budget and Metrics ("BAM") plans detailing EE annual budgets and targets on a three-year rolling cycle.[77] O&R's most recent BAM on June 1, 2017,[78] and ETIP on December 22, 2017.[79]

Since 2009, EE programs offered by O&R have resulted in savings equivalent to reducing carbon emissions by 103,000 tons and taking over 22,000 cars off the road

The Company's current ETIP portfolio consists of three electric programs and one gas program designed to provide energy and peak demand savings across the service territory. Integrated into the planning and forecasting process, EE is a critical component of the Company's business.

In 2016, the Company launched its online Customer Engagement Marketplace Platform ("CEMP") to help customers buy EE products and services, and better understand their energy use. Through the CEMP, the Company has begun to integrate EE and DR initiatives to provide for a more streamlined customer experience. By purchasing products from the Company's Residential Efficient Products Program through the CEMP, customers are able to apply for instant rebates at checkout, instead of filling out a rebate application and waiting 4-6 weeks for a rebate check.

In 2019, O&R plans to transition the ETIP into the System Energy Efficiency Plan ("SEEP") pursuant to the Commission's direction.[80]

New York State EE Targets

On April 20, 2018, Governor Cuomo announced an acceleration of EE in New York,[81] including a comprehensive plan to achieve a new target for significant GHG emission reductions, decrease consumer

[77] REV Proceeding, Track One Order, pp. 75 - 82.

[78] Utility Energy Efficiency Proceeding, Orange and Rockland Utilities, Inc. 2018-2020 Budgets and Metrics Plan (filed June 1, 2017).

[79] Utility Energy Efficiency Proceeding, Orange and Rockland's Final Energy Efficiency Transition Implementation Plan (ETIP) 2017-2020 (filed December 22, 2017).

[80] Id.

[81] Case 18-M-0404, In the Matter of a Comprehensive Energy Efficiency Initiative, Press Release - Governor Cuomo Announces New Energy Efficiency Target to Cut Greenhouse Gas Emissions and Combat Climate Change (filed April 20, 2018).

energy costs and new job opportunities. The proposed target and related details were set forth in the *New Efficiency: New* York whitepaper ("EE Whitepaper") prepared by DPS Staff and NYSERDA.[82] Meeting the proposed new EE target will deliver nearly one-third of the GHG emissions reductions needed to achieve New York's climate goal of 40% reduction by 2030. This announcement and the EE Whitepaper propose a statewide EE target of 185 TBtu of cumulative annual site energy savings relative to forecasted energy consumption in 2025. The new target shifts to an EE target based on site energy, which is the amount of heat and electricity consumed by a building as reflected in utility and fuel bills. In its March 15, 2018 "Order Authorizing Utility-Administered Energy Efficiency Portfolio Budgets and Targets for 2019-2020", the Commission began to outline a five-year goal for utilities to integrate EE planning fully into their forecasted system plans and evolve their ETIP into the SEEP.[83]

To meet the 50% renewable energy goal of New York electric supply to be generated by renewable sources by 2030, and to reduce statewide GHG emissions by 40% by 2030, energy use must also decline by 2,227 GWh annually statewide. As such, utility ETIP programs will need to reduce approximately 1.2% of sales from 2017-2020, 1.4% of sales from 2021-2025, and the 2.0% of sales from 2026-2030 in order to meet the 2,227 GWh annual reduction. The Company's current annual ETIP program represents approximately 0.5% of 2015 energy sales; Company EE efforts will also need to increase by 240% in order to achieve the higher target.

To meet the more aggressive target, the Company will need to move beyond low upfront energy cost measures such as energy efficient lighting within the C&I segments to more expensive energy cost measures and technologies. For example, in the 2016-2017 ETIP period, 94% of the C&I project savings came from low cost energy efficient lighting at $0.095/kWh, representing over 61% of the electric portfolio. Moving forward, the Company will need to rely on expanded programs targeting the residential sector which is currently at $0.346/kWh for the same period.

The Company is planning to increase the MWh savings produced by existing ETIP programs by expanding and supplementing the existing ETIP programs. The Company will further coordinate efforts with the JU and NYSERDA to increase participation in these programs and engage with third-parties to provide customers with the products and services necessary to achieve the more aggressive energy savings targets.

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

The CSRP has 47 C&I customers enrolled that have pledged a total of 14.3 MW, with an additional 2,332 residential customers enrolled in the BYOT, for a potential summer peak load reduction of 16.6 MW. The Distribution Load Relief Program has 50 C&I customers that have pledged 25.5 MW for contingency events that can be called with 2 hours' notice.

[82] Case 18-M-0404, New Energy: New York ("Whitepaper")(filed April 26, 2018).
[83] Case 15-M-0252 - *In the Matter of Utility Energy Efficiency Programs*, Order Authorizing Utility-Administered Energy Efficiency Portfolio Budgets and Targets for 2019-2020 (issued March 15, 2018).

Implementation Plan, Schedule, and Investments

Current Progress

O&R is proposing four new residential and five new C&I EE programs to meet the ambitious New York EE goals

As described in detail in the Integrated Planning section of this DSIP update, as part of O&R's annual planning process, the Company investigates whether alternative and less costly non-traditional/NWA can substantially defer, reprioritize or eliminate major capital infrastructure investments. The Company's EE programs have been a vital part of that process and the solutions, even before REV as evidenced by its successful efforts to reduce peak demand by implementing EE programs in Pomona, an NWA solution. The Company's extensive experience in and understanding of EE allows for continued improvement and successful targeting of measures and customer segments to support these deferrals. As described in the Advanced Forecasting section and further below in this section of this DSIP, O&R is also expanding the granularity and detail of EE into forecasting and planning that will allow for even more accurate leveraging the value of EE.

As part of the Pomona NWA Program, the EE team worked with the UotF and Planning teams to implement EE as part of the portfolio of solutions. The Company took a holistic approach to implement EE as part of the solutions, meeting with nearly every C&I customer in the load pocket on a one-on-one basis to explain the problem and help identify customer-sided EE solutions to directly measuring and verifying demand savings through data loggers to ensure the further accuracy of savings. These efforts resulted in exceeding the 1 MW reduction goal from the installation of EE measures coincident with the peak, directly supporting the deferral of the Pomona Substation. Based upon the learnings from the Pomona NWA, the Company is continuing to include EE as the initial least cost solution for future NWAs.

Before REV, the Company utilized a software screening tool to determine if energy efficiency could provide the potential demand savings to defer capital projects. The Pomona NWA project and the resulting implementation plan that included energy efficiency and demand response as solutions were developed using this tool. The Company has recently partnered with Navigant Consulting to perform a DER potential study and develop a targeted tool to help identify the potential savings from energy efficiency and other DER solutions in NWA areas.

The Company has recently installed a new DSM tracking tool to monitor the energy and demand savings resulting from the installation of residential and C&I efficient measures. The tool provides for the impact of energy and demand reductions to be seen at the electric delivery system circuit and segment level thus better informing the planning and forecasting process. This functionality provides a more granular view of impact of energy efficiency and demand response programs on the system.

The Company's ETIP portfolio has programs targeting both residential and C&I customers. Below is a summary of the Company's electric portfolio of programs.

The **Residential Efficient Products Program** provides rebates for residential customers that purchase ENERGY STAR® appliances upgrades, as well as arranging for the recycling of replaced and secondary refrigerators, freezers and room air conditioners.

The **Small Business Direct Install Program** provides businesses with EE solutions in the hard-to-reach small business market segment. This program offers a turn-key streamlined customer experience to business customers with an average monthly peak demand of less than 110 kW, starting with the completion of a free on-site audit, covers up to 70% of the installed cost of a measure and targets lighting, refrigeration, and cooling end-uses.

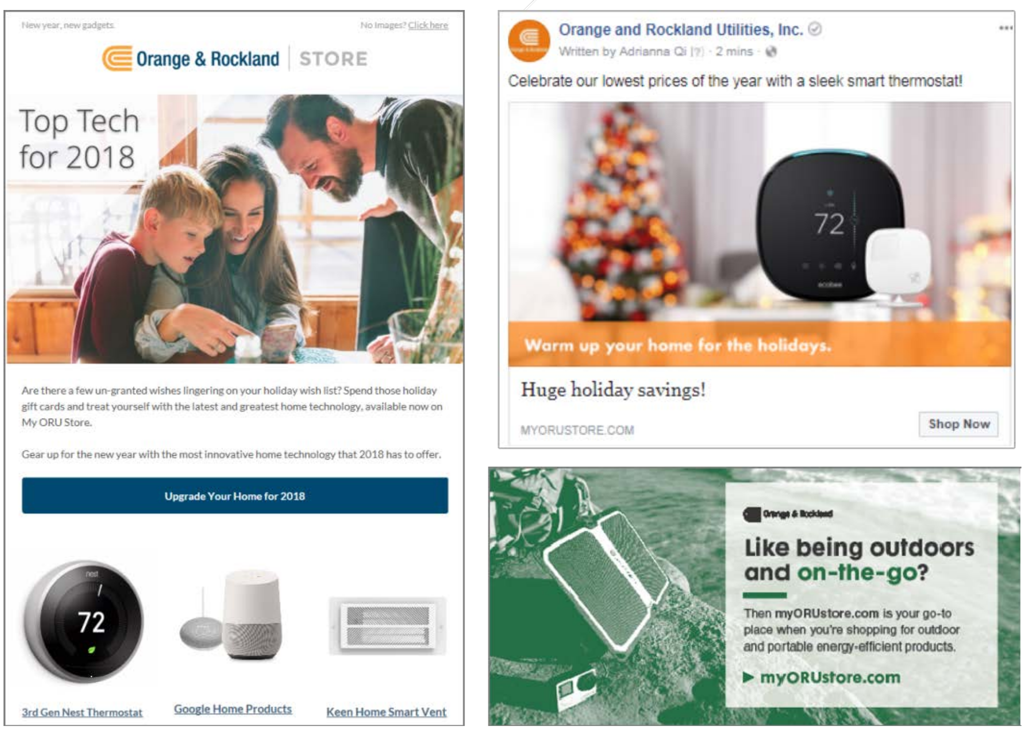
The **C&I Electric Rebate Program** provides prescriptive and custom rebates to encourage C&I customers to identify energy-saving opportunities, develop a building performance improvement plan, and implement cost-effective retrofit upgrade projects. The program includes rebates for high-efficiency lighting and controls, HVAC measures, and variable speed drives, along with rebates for custom efficiency projects typically for industrial processes, building management systems, and other technologies beyond traditional lighting and HVAC upgrades.

The Company's online marketplace, My ORU Store, will expand into a robust DER and EE marketplace for customers

The **My ORU Store,** the Company's online customer Marketplace, offers energy efficiency products and services. The Marketplace (link) delivers a branded experience offering customers energy-wise products, home services, program enrollments, instant rebates, and information—all from a single online platform. My ORU Store product categories include LED lighting, advanced power strips, water-energy saving devices, Wi-Fi thermostats, connected home products, portable power, electric vehicle chargers and home services provided by local contractors. The Company also collaborates with the local water utility, Suez, to promote both energy and water conservation via the Marketplace and school programs that engage students from kindergarten to high school through classroom instruction.

My ORU Store products and information examples are provided in the figure below.

Figure 21: My ORU Store Product and Information Examples



Future Implementation and Planning

O&R's EE portfolios continue to expand to engage customers on a more personal level by providing: (1) tools to help them understand how they use energy; (2) recommendations on how to better manage their energy needs; and (3) a streamlined customer experience designed to increase participation in the EE programs.

To meet the policy goals above, in its 2018 electric and gas base rate cases the Company proposed the expansion of its portfolio of EE program offerings to electric and gas customers. The expansion of the electric programs supports the goals of the Commission's CES Order. The Company's goal is to expand its existing ETIP EE offerings and to introduce new programs that will increase the adoption of new EE and related technologies.

The Company proposed the introduction of the following four new energy efficiency programs for residential customers and five new programs targeting C&I customers to support the State Energy Plan and REV goals:

Residential Marketplace Enhancement Program

The **Residential Marketplace Enhancement Program** expands the existing Residential Efficient Products and Gas Rebate Programs to better integrate them into the My ORU Store. This integration will allow the Company to promote EE upgrades and establish a one-stop shopping experience, including instant rebates, which will make purchasing EE equipment quick and seamless. Use of the My ORU Store will eliminate the market barriers of higher upfront purchase costs and provide customers with instant rebates, access to product information, and various manufacturer product services and offerings. Instant rebates will be expanded to include larger appliances such as central air conditioning, heat pumps, mini splits, pool pumps, dishwashers, washing machines, furnaces, boilers, water heaters, and refrigerators.

Behavioral software analytics will also be integrated into the My ORU Store messaging to provide customers with a web-based platform that analyzes customer-specific energy data and demographics to help customers better manage their energy use. For example, recommendations for no-cost or low-cost upgrades will be provided along with suggestions for potential longer-term energy upgrade investments. Customers can then compare payback scenarios for investing in different types of EE products or upgrades. The Company will explore new and innovative ways that customers can more readily participate in programs and pay for energy upgrades through a combination of low-interest financing and bill savings.

Residential Behavioral Software and Education Program

The **Residential Behavioral Software and Education Program** leverages the My ORU Store and MY ORU Advisor as the platforms to implement a residential behavioral program to engage all residential customers further to manage their energy use. All residential customers will have the ability to enroll in this behavioral platform and receive messages via a mobile device or computer to participate in overall energy reduction or peak system events. The behavioral messaging will target both electric and gas energy behaviors, as the majority of the Company's customers are dual fuel electric/gas customers.

The program will continue to use gamification (*i.e.,* the application of elements of game playing – such as accumulating reward points and competing among others online - to encourage engagement with a product or service) to further encourage energy efficiency and demand response behaviors. Since the original launch in Q2 2016, My ORU Advisor has provided customers with updated individual usage data reports as well as personalized tips and recommendations for reducing their usage. This portal makes saving energy fun and engaging through a unique points and rewards system. Points are given to customers as a reward for reading and adopting energy conservation tips, completing home profile questions, enrolling in utility programs and purchasing energy efficient products or services offered through the My ORU Store. Many customers have redeemed points for gift cards to a wide range of available merchants.

Engaging more customers on a personalized level reinforces the energy savings impact by modifying energy behaviors and provides customers with the ability to better manage their overall energy use. Customers will also be more informed about their ability to realize additional energy savings by shifting load to off peak hours through TOU rates. The behavioral platform will be integrated with the other EE and DR programs to increase participation and customer satisfaction by validating energy savings over time, and after the installation of specific measures.

Residential New Construction Program and Home Performance

The **Residential New Construction Home Performance Program**, in partnership with NYSERDA's existing low-rise new construction program, will identify and promote new construction and home performance EE opportunities in the residential market. By offering new construction and home performance incentives, the program will capture otherwise lost opportunities as it encourages EE from building inception and renovations. Incentives will be coordinated with NYSERDA and be offered to builders and customers to encourage building to the New York ENERGY STAR® Certified Homes standard and beyond to achieve maximum economic efficiency.

Residential Upstream Program

The **Residential Upstream Lighting Program** will increase the Company's efforts to partner with NYSERDA, trade allies, retailers, distributors and other utilities to implement an upstream lighting initiative for residential customers along with HVAC and water heating equipment that lends itself nicely to this delivery model. Market transformation through a managed upstream approach will develop and enhance relationships with trade allies, distributors, contractors, and retailers through cooperative marketing and outreach efforts. Distributors, retailers, and the Company will engage in co-branding efforts to promote efficient LED lighting and introduce incentives to buy down the cost of LED lights at the point of purchase. By providing upstream rebates to electric distributors for a selection of high- efficiency measures, the Company will begin to transform the market so that the EE products on retailer shelves and distribution channels are at an affordable price point. Program incentives are provided directly to the distributor or retailer so that these measures become the recommended solution as opposed to a less efficient, less costly measure.

Commercial Software Data Analytics and Education Program

The proposed **Commercial Software Data Analytics and Education Program** will use monthly and hourly usage data and software analytics to deliver energy saving insights to C&I customers that are on a real-time pricing rate. These insights will accelerate and expand the adoption of EE upgrades, optimize EE and DR programs, and boost customer engagement and satisfaction. In addition, the integration of software data analytics, which is specifically designed to analyze individual customer facilities to determine cost and savings associated with EE improvements, will provide a customer platform that supports the utility's role as a trusted energy advisor. This more holistic and analytical approach will generate deeper savings beyond lighting, as customers will have the information they need to develop long-term plans to implement cost-effective energy savings. The Company will also facilitate the potential of pairing customers with low-interest financing options available through NYSERDA's Green Bank, the New York Power Authority ("NYPA"), or other financial institutions.

The Company plans to offer incentives for advanced and emerging technologies that have the potential to save energy, reduce peak demand, or shift demand to off-peak periods (*e.g.,* energy storage, cooling storage, building management systems) in the C&I sector. For example, as hourly usage is analyzed, the Company can make recommendations on the effectiveness of building management systems, energy storage or cooling storage to reduce load based on price signals or shift load to off-peak periods. The Company will offer increased rebates to encourage the adoption of these emerging and advanced technologies designed to reduce or shift load and are complementary with other Company initiatives such as NWAs, and DR programs.

Commercial Midstream Lighting Program

The **Commercial Midstream Lighting Program** will provide point of sale rebates for LEDs at the wholesale or retail level for C&I customers along with upstream rebates for HVAC and water heating equipment. Distributors, retailers, and the Company will engage in co-branding efforts to promote efficient LED lighting and introduce incentives to buy down the cost of LED lights. By providing midstream rebates to electric distributors to buy down the cost of EE measures, the Company will begin to transform the market so that the EE products offered by retailers are at an affordable price point. For example, O&R may partner with distributors to offer contractors and/or commercial lighting customers discounted pricing on LED lamps and select types of LED fixtures for C&I applications. Program incentives will be provided directly to the distributor so that these measures are in stock and become the recommended solution, as opposed to a less efficient and less costly measure. To broaden the scope and improve the effectiveness of this program, the Company plans to explore a partnership with CECONY, NYSERDA, and other JU.

Commercial Demand Reduction Program

The **Commercial Demand Reduction Program** will provide enhanced rebates that target demand savings and load curtailment which will coincide with the system peak demand. The Company will offer incremental rebates to incentivize the installation of measures that will reduce distribution load constraints. For example, for locations that peak during evening hours, EE outdoor lighting may be incentivized through a higher rebate to reduce the evening peak. For locations with daytime peaks, office lighting and HVAC improvements may be rebated at higher levels to encourage the upgrade of equipment and the permanent reduction of peak demand. On-site audits will be conducted at no cost to the customer so that potential equipment replacements or upgrades are identified, and customized rebates offered based on the existing equipment at the facility. Areas identified for NWAs will be addressed primarily through an NWA solicitation and coordinated with the Commercial Demand Reduction Program.

Commercial New Construction Program

The **Commercial New Construction Program**, in partnership with NYSERDA's existing new construction program, will promote an initiative to identify new construction opportunities to eliminate lost energy saving opportunities in new and renovated commercial buildings. By offering new construction and remodeling incentives, this integrated approach captures otherwise lost opportunities as it encourages EE from inception of the building. In addition, the incorporation of building management systems at the time of construction is less costly than installing in an existing building. DR and energy conservation can be incorporated into building design so that the individual(s) responsible for managing new buildings can respond to price signals and better manage energy use. The Company will coordinate with local municipalities to drive new construction building requirements for commercial building beyond existing levels and establish incentives to offset the higher costs of construction.

EE Provider Solicitation Program

The **EE Provider Solicitation Program** involves inviting third-parties to provide the Company with energy savings similar to a standard offer solicitation to deliver energy savings in a specific customer market segment or for specific advanced EE technologies. A standard offer or RFP process will set a price for the energy savings delivered, and third-parties will submit proposals outlining how they intend to provide the required level of savings. The Company may also use reverse auctions to set the price paid for energy savings in a specific market or for specific advanced technology. RFPs will be issued to engage third-parties in meeting particular energy reductions in targeted customer segments. For example, hospitals may be a targeted market segment for energy savings and a specific $/kWh may be offered to third-parties for energy reductions at hospitals.

ETIP to SEEP transition

In March 2018, the Commission outlined a five-year goal for utilities to integrate EE planning fully into their forecasted system plans and evolve their ETIP into the SEEP.[84] The SEEP will replace the ETIP and ultimately describe the entirety of the Company's expanded reliance on and use of cost-effective EE to support distribution system and customer needs. The Commission Order indicated that the initial SEEP should describe and quantify the Company's full investment in EE and expected benefits, inclusive of its base EE programs (*i.e.,* ETIP) and non-ETIP programs and initiatives, such as expanded rate case programs, demand reduction programs, non-wire and non-pipe alternative efforts, REV demonstration projects, and other REV initiatives. The SEEP will also address the ambitious goals outlined in the Staff DSIP Update Whitepaper.

Energy efficiency is a cornerstone of New York State's national leadership role on clean energy and climate. O&R's programs will be expanded, and new initiatives proposed in the SEEP to achieve the energy and carbon reduction goals. More specifically, the Company will partner with NYSERDA, other NY utilities, and third-parties to increase program strategies and participation to reduce energy by 3% of sales by 2025 and deliver the associated GHG reduction to achieve the 2030 goal.

Customer Engagement Marketplace Platform

As described in the Innovation section of this DSIP update, the CEMP was designed to build partnerships with a network of third-party product and service providers to increase customer awareness and understanding of energy consumption, motivate customers to participate in Company programs, increase the distribution and adoption of EE and DER products and services, and develop new revenue streams for the Company and its partners.

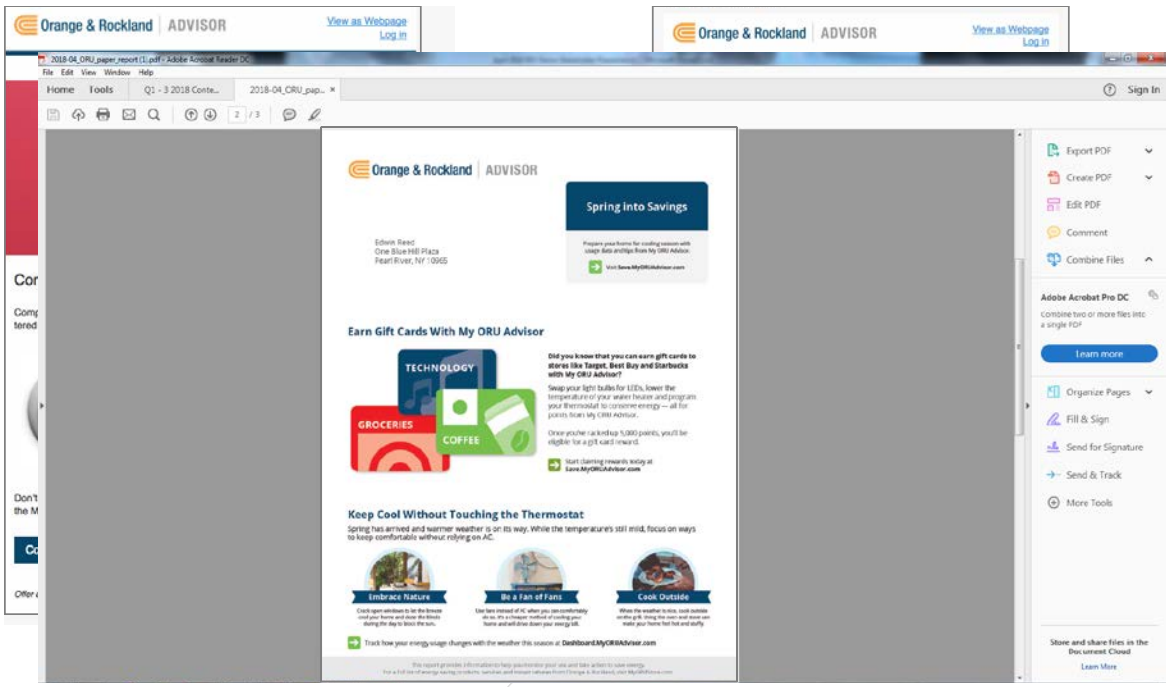
The Company's CEMP project is comprised of two components; the My ORU Store and the My ORU Advisor. The My ORU Store, described earlier in this section, is an online environment where customers can purchase DER products and services. To drive awareness and interest, customers receive weekly emails about new product and service offerings, special offers, and messaging on how to reduce energy consumption and save money.

The My ORU Advisor, is an interactive, behavior-based portal that provides tips and energy usage insights. This portal also includes a virtual home tour explaining how energy is typically consumed within each room and by each appliance in a typical home. Customers are encouraged to explore energy tips, view and analyze their energy consumption data, share information and interact with others to earn

[84] Utility Energy Efficiency Proceeding, Utility-Administered EE Order, pp. 29 - 31.

points and rewards for taking energy savings actions. Customers are also provided with home energy reports on a monthly basis. These reports provide customers with individual monthly electric usage information and an individual energy comparison rating that is based on how the customer's energy usage compares to a similar home as well as an EE home. Examples of content from MY ORU Advisor is shown in the following figure:

Figure 22: My ORU Advisor



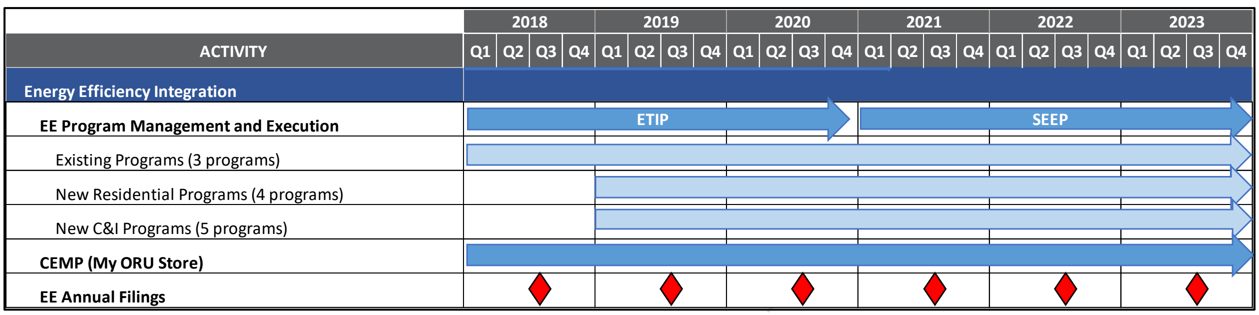
Thus far, experience with the various components of the CEMP, has proven to be successful. Product purchases fluctuate on a monthly basis but overall, they remain strong. Customers have responded positively to promotional advertisements and periodic messaging, as demonstrated by the combination of repeat visitors and the increasing number of new user visits to the site. The Company believes the myORUstore.com and its expanding product line, coupled with third party service provider offerings and the ability of customers to apply instant EE rebates will continue to attract the interest of customers.

The Company has begun to integrate energy efficiency and demand response initiatives to provide for more streamlined customer experience, particularly for those customers using My ORU Store. The Company will also investigate the potential for integrating the robust AMI data in conjunction with My ORU Store offerings. For example, analytics may identify that a customer's central air conditioning unit may not be operating efficiently, and the customer will provide a targeted offering for an air conditioner tune-up that they could schedule on the My ORU Store website. By offering products from the Company's Efficient Products Program through My ORU Store, customers can apply for instant rebates at checkout, as opposed to filling out a rebate application and waiting 4-6 weeks for a rebate check.

Over the next four years, the Company anticipates that My ORU Store will continue to transition into a robust marketplace where customers can purchase DER and EE products and services. My ORU Store will become a resource that will be more frequently used by customers interested in evaluating and selecting a service provider to install EE solutions and/or equipment or perform periodic maintenance/repairs on existing equipment such as heating and air conditioning systems. The Company expects that offerings available via My ORU Store will extend to additional EE and water conservation products including water heaters, in-home battery storage systems, home security devices, in-home energy controls, and expanded line of lighting products and controls for both residential and commercial customers. In addition, the Company expects that My ORU Store will expand the service offerings to include solar installations and additional third-party service provider installation services. Advertising sponsors on the My ORU Store website will expand to include product manufacturers, EE and gas conversion programs offered by the Company and the addition of third-party service provider advertising for both fixed and variable fee services. Given the interconnectedness between water and electricity, the Company expects to continue its partnership with Suez well into the future.

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

Table 18: O&R EE 5-Year plan



Risks and Mitigation

The EE Whitepaper outlined ambitious goals for utilities and NYSERDA to achieve by 2025, which will be approximately 3% of utility sales for a combined utility and NYSERDA goal. While these goals are not only ambitious, low-cost lighting savings which have provided the majority of the Company's historical savings will diminish as a result of the new federal lighting standards. Therefore, the Company will need to rely on other end-use as explained above, albeit at a higher cost to achieve these goals as demonstrated in the new programs that the Company is planning. The Company is currently achieving energy savings of 0.5% of its sales from the current ETIP portfolio implementation; therefore, the Company will need to quadruple its current EE efforts quickly to reach the 2025 savings target. The Company's programs as discussed above have been designed to assist in the mitigation of this risk.

Stakeholder Interface

CEAC Working Group and New York State Energy Research and Development Authority ("NYSERDA")

The Company has participated in Clean Energy Advisory Council ("CEAC") working groups to help promote EE in the low and moderate-income sector, to coordinate the effectiveness of NYSERDA and Company EE programs, and to identify REV best practices. The Company is meeting with NYSERDA to investigate the potential of co-branding marketing materials and leveraging NYSERDA funding to provide technical support and resources for energy upgrades.

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

Organizations

Company support of organizations that support sustainable EE and DR programs is essential, and as a result, the Company has representation on the Boards of the Association of Energy Services Professionals ("AESP") and the Rockland County Cornell Cooperative Extension ("CCE"). 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 Company is also a member of the Peak Load Management Alliance, a community of experts and practitioners dedicated to sharing knowledge focusing on DR and 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.

Outreach Activities

Marketing and outreach tools consist of corporate communications assets; advertising, including bill inserts, cable and radio spots; digital advertising; social marketing; and exhibiting at networking events. The Company plans to continue presenting on energy efficiency at home shows, street fairs, community walks and races, business events, school events and earth day events. The Company has created educational partnerships with the Piermont BOCES program and sponsored several STEM[85] related events. The Company will continue to reach out to customers via its social media platforms of Facebook and twitter, which has proved successful in the past.

The Company also recognizes trade allies/contractors that support the Company's efforts and successfully promote energy efficiency programs to our 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 energy efficiency rebates into their initial proposals to customers to provide a competitive price. In the recent past, the Company has held award ceremonies for these trade allies as they are an integral part of O&R's energy efficiency delivery mechanism that will be utilized to achieve the ambitious EE goals.

Additional Detail

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

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

The Company is performing a DER Potential Study (as discussed in the NWA Procurement section of this DSIP update and is exploring an NWA tool that will identify the potential energy and demand savings based on the demographic profiles of circuit found in an NWA area, and the estimated cost of the EE solution, to determine if the NWA should move forward with a DER solution. EE currently plays a crucial role in reducing system peak and deferring infrastructure investments through existing programs and the proposed enhanced programs in the future. The result is a cost-effective solution to defer infrastructure investment while implementing a least-cost solution for the Company and the customer.

The EE team has been working alongside various other departments to effectively employ EE as a resource integrated into planning processes. Through close coordination with the UotF organization,

---

[85] STEM reference to Science, Technology, Engineering and Math disciplines.

Forecasting, and Planning teams responsible for identifying and executing NWAs, EE has contributed to successes already by targeting EE programs.

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

The Company will use the results of the DER Potential Study in conjunction with the new NWA software tool to identify potential savings found on specific circuits in NWA areas. In addition, the Company recently installed a new DSM tracking software tool that tracks the EE program performance at the measure level by customer to determine the achieved energy and demand savings based on the New York Technical Resource Manual. [86] The DSM tracking system identifies the measures installed at each customer's premise and the associated energy and demand savings along with an associated circuit and segment on our system. Therefore, the Company can identify the amount of energy and peak load reductions attributed to each measure at the circuit and segment level. For example, in the Pomona NWA, the Company is measuring the energy and demand savings from installed energy efficiency measures by customer and installing devices that track energy use at sites where projects were estimated to produce significant savings.

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

The Company develops its short and long-term forecast using econometric models, and then both the historic and future energy and demand reductions are used as modifiers to the load forecast. The Company assumes that it's future energy and peak load reductions will come from its NWA and existing ETIP portfolio of programs. The EE team will then share the impact of those programs with those preparing the forecast. The level of reduction is commensurate with the energy goals and historical demand reduction from the current ETIP programs. Because the Company's ETIP program is offered system-wide, these impacts are spread over the entire New York service territory forecast. See the Advanced Forecasting section within Chapter 2 of this DSIP update for more details.

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

The Company is currently conducting a DER potential study to determine the amount of technical, economic, and achievable potential from DER measures, including EE, in the Company's O&R service territory. On-site and phone surveys were performed to determine the baseline for O&R to determine the savings that could be realized when measures are upgraded to high-efficiency measures. The Company is also investing in an NWA tool that will identify the potential energy and demand savings based on the circuit demographics found in the NWA area and the cost of the energy efficiency solution to determine if the NWA should move forward with a DER solution or the infrastructure upgrade. The result will allow the Company to maximize savings from energy efficiency programs in these areas as one of the highly cost-effective solutions to defer infrastructure investment while ensuring a least-cost solution for the Company and the customer.

[86] New York Standard Approach for Estimating Energy Savings from Energy Efficiency Programs – Residential, Multi-family, and Commercial/Industrial Measures, Version 6 (issued April 16, 2018, effective January 1, 2019). http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/72c23decff52920a85257f1100671bdd/$FILE/TRM%20Version%206%20-%20January%202019.pdf

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

As described above, the Company recently installed a new DSM tracking tool to monitor the energy and demand savings resulting from the installation of residential and C&I efficient measures. The tool provides for the impact of energy and demand reductions to be seen at the electric delivery system circuit and segment level thus better informing the planning and forecasting process.

As described in the DER Procurement and System Data sections of this DSIP update, the Company is providing detailed system data in NWA solicitations that will provide information and insight to a third-party vendor, including EE providers, on how they could tailor their programs to effectively target customers for the need.

As discussed in the Customer Data section, the Company role out of both AMI and Green Button Connect allows for additional and more granular customer usage data available to registered third-party providers. NYSERDA's Utility Energy Registry ("UER") will make aggregated customer data at the municipal and county level available to the public. The UER is an online platform "intended to promote and facilitate community-based energy planning and energy use awareness and engagement." [87]

6) How the utility's accomplishments and plans are aligned with New York State climate and energy policies and incorporate innovative approaches for accelerating progress to ultimately align with a new 2025 EE target called for in Governor Cuomo's 2018 State of the State Address?

As detailed above, in its 2018 electric base rate filing, the Company proposed to increase the scope of the EE portfolio from 19,302 MWh to begin a ramp-up to meet the 's goal of 40% reduction in GHGs from 1990 levels and 50% of generation from renewable resources by 2030. The ramp-up process includes increasing the current EE portfolio savings level from 0.5% of annual sales to approximately 1% of sales or 37,000 MWh by 2021.[88] Subsequent rate filings will include further acceleration of program targets to achieve 2% of yearly sales or 80,000 MWh in EE program savings by 2025. The Company will continue to expand the residential EE portfolio, focusing on changing customer usage behavior, expanding My ORU Store by incorporating lessons learned through the demonstration project, incorporating midstream programs, and incorporating data analytics to identify residential retrofits. The installation of smart meters will also create more robust behavioral energy reduction and DR programs by enabling customers to understand how and when they use energy and the real-time price impact of shifting usage. Programs will also be expanded to include locational-based heat pump rebates for areas without access to natural gas facilities.

The use of data analytics will provide insight and focus on commercial retrofits aiding in the transition beyond lighting and providing more focus on deeper whole building energy savings. Incentives tailored to encourage efficient new building construction, coupled with NYSERDA's efforts to enhance building codes will provide deeper energy savings. Commercial midstream programs will encourage the sale and purchase of high-efficiency lighting and heating and air conditioning products. Additionally, vendors will be incentivized to come to market with new and innovative solutions that when deployed in commercial locations provide deep energy savings and reduce operation and maintenance spending.

[87] Utility Energy Registry Proceeding, Utility Energy Registry Order, p. 2.
[88] O&R Electric Rate Case, Testimony of Energy Efficiency Panel (filed January 26, 2018).

These solutions may include building management systems, cooling storage and advanced energy system controls.

The Company will also work with customers and vendors using pay-for-performance contracts in various customer segments to achieve maximum energy savings at minimum cost. The Company will continue to evaluate opportunities for partnering with NYSERDA to explore innovative program delivery models that increase the impact of programs and focus on EE pilot programs for low-income customers and multifamily building owners. In addition, continuing O&R's partnership with the local water utility company, the Company will employ a holistic approach for saving on utility bill costs and increasing the environmental impact of our programs.

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

As described previously, the CEMP is an online environment where customers can purchase EE and DER products and services. O&R rolled out the CEMP as a REV demonstration project and has a long-term vision to continue the marketplace beyond the demonstration phases as a centralized digital platform providing all customers energy-wise product solutions, home services, and program enrollments through seamless customer engagement and transactional experience. Our vision is to continue to build out the marketplace and to improve the customer experience, by including comprehensive products and information that can be used to facilitate large DER purchases such as PEVs, solar, home battery storage and other new technologies as they emerge as described above in this section. Collaboration between CECONY and the other JU have helped to provide valuable feedback about the diverse platforms.

The demonstration project had three hypothesizes as outlined in the REV Demonstration Project CEMP implementation plan[89]. One of the main hypotheses of the CEMP demonstration project is that a marketplace that matches specific DER and EE solutions to eligible customers will launch the adoption of DER products in the market. This has been achieved through direct sales of more than 9,000 product and services sold through My ORU Store. Currently, there are more than 170 products and services in nearly 10 different categories, available to customers at affordable prices, many with instant EE rebates at the point of purchase. Through the sale of these efficient products, more than 1,000 MWh and 3,700 Dth of energy have been saved since program launch.

Another hypothesis is that a combined marketplace that provides customers with DER and EE offerings, instantaneous and enhanced rebates, easy to use interactive tools and options, and access to recommended third-party installers, will deliver a rewarding customer experience leading to ongoing customer interactions. The majority of customers want to learn more about EE from O&R as opposed to another source with a majority of those customers preferring emails and bill inserts. Expanding the contractor network has been challenging, and fixed price services are limited. The business model must be extended beyond fixed price offerings to allow for more flexible contractor pricing, and to provide customers with a greater selection of turn-key contractor services. Residential EE customers are price sensitive and respond to sales promotions and incentives when offered, and that interest in newer technology and various other DER offerings require more touchpoints to increase adoption.

[89] REV Proceeding, Distributed Energy Resources Residential Offering Platform Demonstration Project (filed July 1, 2015).

As described previously, My ORU Store offers EE and DER product and service offerings to customers as solutions to help them better manage their energy usage and utility costs. Regular emails are sent to customers containing educational content, and the My ORU Store website contains informative buyer guides, product comparisons, and instructional product videos. Customer inquiries are serviced through phone support or live chat. O&R uses post-purchase surveys, a net promoter score indicator, third-party evaluations and an online customer community to provide feedback on the customer experience. To date, there have been more than 150,000 site visits and over 440,000 pages viewed on the website. Survey results indicate a net promoter score of 53, which is considered excellent in the retail industry. Through the MY O&R Advisor behavioral pilot, high electric usage customers are provided personalized home energy insight reports along with an online, reward-based platform that provide a range of experiences.

The Company has learned that consistently offering of new products and services keeps customers engaged and drives repeat visits to the marketplace. Utilizing data to target customers and customize message content are necessary strategies used to increase customer interest, build a better understanding of energy consumption and drive lasting engagement. Continuously exploring options to obtain customer feedback remains a critical component to provide customer satisfaction and help O&R invest in the best customer solutions.

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

The Company has been coordinating its REV demonstration project, the MY ORU Store, and efforts with its energy efficiency programs to maximize the value of the CEMP and enhance the energy savings for its residential ETIP programs. The residential program offerings were aligned with the CEMP to ensure that instant rebates could be offered at the time of checkout to create a one-stop shopping experience for high-efficiency measures. The Residential Efficient Products and Gas HVAC programs provide instant rebates on the CEMP and claim the associated energy savings. The plan for the CEMP is an expansion with the larger appliances offered in the residential programs, including central air conditioners, heat pumps, refrigerators, furnaces, water heaters, and potential expansion into the commercial and industrial sector where contractors could compete to win bids for identified energy efficiency project upgrades. C&I customers could issue requests for proposals from several contractors and select the one that best meets their needs. Customers could also rank contractors and provide testimonials on their experience to help guide customers decisions moving forward.

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

The Company continues to work with NYSERDA to further enhance existing programs and develop new programs that are complementary to NYSERDA offerings. Conversations with NYSERDA have focused on also improving the effectiveness of the EMPOWER program to streamline customer communications and produce outreach and education materials for delivery to the low-income customer on a more frequent schedule. In addition, the Company and NYSERDA are collaborating to further enhance the EMPOWER program by exploring opportunities to expand current program offerings. These expanded offerings may include NYSERDA's focus on building envelope measures such as insulation, air sealing, and weather stripping in combination with O&R's focus on EE measure upgrade rebates such as appliances, LED lighting, wi-fi thermostats, and low flow devices.

O&R and NYSERDA will explore a pay-for-performance and neighborhood aggregation model to minimize program costs and maximize program savings for the low-income community. Consolidation of co-branding and marketing efforts help to enhance program participation and further reduce program costs. Coordination between O&R and NYSERDA will continue as future opportunities are identified which meet the needs of commercial and industrial customers, including collaborating on data center projects. Collaboration on large-scale projects will prove beneficial for reducing costs through coordinated and complementary efforts. Furthermore, utility partnerships with NYSERDA will assist in both the residential and commercial new construction lost opportunities markets, beginning at the design phase with municipality codes and standards levels, and will incorporate low-energy and carbon reduction initiatives through the demonstration of advanced building technologies and practices.

Distribution System Data

Introduction/Context and Background

The collection and sharing of system data has been a central theme of REV since its inception. The Commission reiterated this theme with respect to the DSIP: "At the core of the new model is improved information improved both in its granularity, temporal and spatial, and in its accessibility to consumers and market participants."[90] Availability of system data to third-parties may assist in facilitating market participation and DER deployment by signaling where DER products and services can provide the greatest value to customers and the grid, aiding in the development of DER business cases, and guiding investment decisions of third-parties and customers.

Distribution system data includes data such as load, voltage, power quality, capacity, equipment and operating detail. DER information such as location, operating characteristics, and reliability are also forms of system data. System data can be collected at various levels including the feeder, substation, and system level and can vary in frequency and granularity across the service territory. Historically, system data has been used by utilities to generate useful information to aid in internal planning and operations functions. For example, distribution system operators use system data to facilitate grid operation decisions and maintain system reliability and service quality, including reducing the frequency and duration of outages. System planners use system data to perform planning analysis, such as load flow analyses, load forecasting, investment planning, and other needs-based analyses.

System data may also have value to DER providers. Providers could use some types of system data as inputs to their technical and business decisions, such as where to market services or locate resources to support grid needs, and how to best respond to NWA solicitations. For example, as discussed in the NWA section of this DSIP, in the Company's recent RFP for Monsey NWA, the Company provided projected load growth by year for the next 10 years for the area as well as customer segment breakdown by distribution circuit, in order to allow for an opportunity for the providers to provide a more tailored solution for the NWA need.

O&R supports providing DER providers with system data and more specifically, information resulting from, and in context with, the utility planning processes performed by utility distribution planners. In the IDSIP, the Company proposed providing DER providers with information with as much granularity as possible, as an output from the planning processes. For some different data types to be insightful and useful, they must be processed, analyzed, and interpreted. For example, distribution system planners with a high level of local system knowledge and experience will review and cleanse raw substation load data to accurately interpret and transform it into meaningful information for both internal and third-party use. Individual data points and raw data streams about the Company's distribution system are generally not self-explanatory. For example, if the system is not in normal configuration due to either scheduled or emergency outages, the load may appear distorted during these times at the circuit or bank level to a third party unaware of these conditions. The data will have to be scrubbed to "normalize" these conditions or at a minimum should be "flagged". By sharing insights with DER providers instead of raw data or data without context, concerns of data security and sensitivity can be more appropriately managed.

The IDSIPs largely served as a vehicle for collecting and sharing information that facilitates retail market development, including data related to distribution system planning and distribution grid

[90] REV Proceeding, DSIP Staff DSIP Update Whitepaper, p. 2.

operations. The Company's IDSIP included an extensive discussion on current practices and presented several datasets identified by the Commission as essential for improving the transparency of utility planning and operations and aiding market growth. The Company continues to provide system data related to hosting capacity, beneficial locations, planned investments, NWA opportunities, and DER queue and DER already connected.

Implementation Plan, Schedule, and Investments

Current Progress

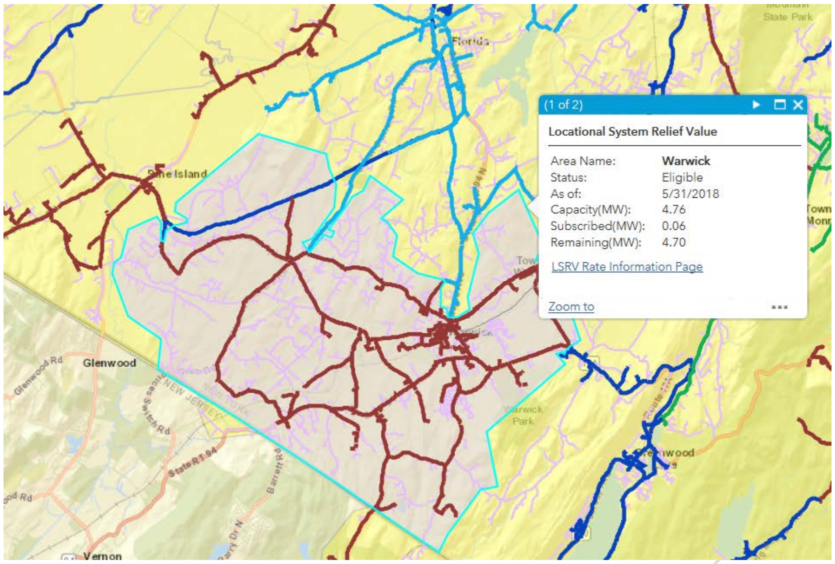
Since the 2016 IDSIP, the Company has continued to support system data sharing efforts, by enhancing its efforts to make useful system data available through three channels: (1) the hosting capacity map, (2) the Company Portal/Website, and (3) the JU Central Data Portal. The hosting capacity map provides developers with a visual representation of system data and is one of the tools available via the Company portal. Beyond the map, the portal provides access to additional relevant system data including DER queue and Value of DER tranche information not currently displayed on the map. The JU portal serves as a one-stop shop for utility-specific system data, as it houses all the relevant utility system data links in one easily accessible location.

O&R is enhancing its efforts to make system data more accessible through three channels: (1) the hosting capacity map, (2) the Company Portal, and (3) the JU Central Data Portal

As discussed in the Hosting Capacity section of this DSIP update and in the Additional Detail section below, the Company has incorporated a wealth of system data into its hosting capacity maps allowing developers to access granular historical, actual, and forecasted data. These maps provide developers with an easy to use platform to visualize and overlay relevant system data. The platform also provides pop-up data and links to other pertinent system information not directly stored on the map. Beyond hosting capacity information, the additional system data available includes:

- LSRV and NWA designated areas with relevant data pop-ups as shown below;
- Five-year system level forecast;
- 8760 historical and forecast load data by substation load area; and
- 2015 actual minimum 24-hour load curve by substation load area.

Figure 23: LSRV Information Available



More information on the details of the map is available in the Hosting Capacity section.

In addition to the system data available via the hosting capacity map, the Company website (link) provides access to other relevant system data. The website includes:

- NWA Opportunities and descriptions and timelines as visualized on the map;
- Interconnection information such as queue waterfall and queue reset; and
- DER/Private Generation Tariff information such as Value of DER Tranche status and rates (link).

Together, the Company website and hosting capacity map provide stakeholders with access to a host of relevant system data to include as inputs to their technical and business decisions.

O&R, together with the JU and as part of the 2017 stakeholder engagement efforts, hosted two stakeholder engagement sessions focused on better understanding system data sharing needs. During the first session in April 2017, the JU presented the system data “catalog” and screenshots of example data files to inform stakeholders on the types of system data publicly available, how to locate the information, and the format and granularity of the data. The system data catalog included location, granularity, format and refresh frequency for the following categories:

- Capital Investment Plans
- Load Forecast
- Load Data
- Distribution Indicator Maps for Hosting Capacity (Stage 1 Indicators)
- Reliability Statistics
- Planned Resiliency Reliability Projects
- Beneficial Locations
- DER Already Connected
- Data in Queue Application DER
- NWA Opportunities
- SIR Pre-Application Information

During these stakeholder sessions, the JU solicited feedback from stakeholders on the system data catalog, the types of data made available and the ease of access. Some of the feedback included:

- Requests for improved ease of access to system data through a utility-central data portal
- Comments about the difficulty in locating utility CapEx plans and pulling out useful information and the possibility of extracting key CapEx project information in a common format (*e.g.,* CSV or Excel) to allow users to sort and filter
- Requests for more transparent details on each line item within the CapEx including the rationale and cost
- Suggestions for more details about the system need and the geographic footprint to be available prior to application of NWA criteria so that developers could analyze and make proposals
- Requests for third-parties to have the ability to search by address on the interactive maps and get a feeder number as a result and questions about whether the maps will obviate the need for portions of the interconnection process in the long-term
- Requests to have preexisting conditions on a circuit (*e.g.,* voltage violations) displayed

In response to stakeholder feedback, O&R, together with the JU, developed a central data portal on the JU website in June 2017 with links to utility-specific web portals with available system data (link). While most of the data provided on the JU portal is already accessible directly through the Company Portal and Hosting Capacity map, the portal serves as a one-stop shop for all the necessary utility-specific links.

As part of the 2017 stakeholder engagement efforts, the JU also met with interested stakeholders to co-develop initial business use cases. In targeted one-on-one use case discussions, stakeholders worked with the JU to develop five initial business use cases which were presented at the August 2017 stakeholder engagement session. These use cases are described in the Additional Detail section below.

Future Implementation and Planning

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

Table 19: O&R System Data 5-Year Plan

	2018				2019				2020				2021				2022				2023			
ACTIVITY	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Distribution System Data																								
Accessible via the hosting capacity map																								
8760 Historical																								
8760 Forecast																								
LSRV																								
NWA																								
Accessible via DCX enhancements																								
ORU.com enhancements																								
Identify data sharing needs and opportunities																								

The Company plans to continue to update the provided system information as needed or required so that the information is up to date and relevant for third-parties and customers. For example, as values and areas are identified through updated studies and the progression of the Value of DER proceeding, the website and hosting capacity maps will be updated accordingly.

In addition to maintaining the access to the system data information already being collected and shared as identified above, the Company is continuing to increase its collection of granular system data through SCADA as part of the Company's grid modernization effort. This is being accomplished in part through the deployment of additional and improved substation level metering data and through the deployment of AMI. Further detail on the Company's SCADA and grid modernization efforts can be found in the Grid Operations section of this DSIP update.

O&R is enhancing the granularly of its system data through distribution automation, grid modernization, and the deployment of AMI Smart Meters and communication devices

As O&R collects more granular system data, the Company will also continue to work closely with the JU to establish consistency in distribution system data sharing with third-parties. Additionally, via the JU working groups, the Company will continue to refine and expand system data use cases to better meet the evolving needs of stakeholders.

Risks and Mitigation

As the Company continues to share more system data, there is a risk of those relying on this data unknowingly misinterpreting it or developing false conclusions or assumptions. To mitigate this risk, O&R, along with the JU, believes that system information sharing should incorporate relevant data commentary and data analytics to provide useful information leading to meaningful results. For the data to be useful, distribution system planners must process, analyze, and interpret the data. 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 also recognizes the risks associated with malicious software attacks and maintains a comprehensive cybersecurity program as outlined in the Cybersecurity section of this filing. This program is designed to protect Company computers, servers, business applications and data, and high-value networks from unauthorized access and control from both external and internal threats.

Stakeholder Interface

As discussed above, since filing the IDSIP, O&R, via the JU, has engaged stakeholders, both individually and as a group, to focus on the development of a consistent level of sharing of system data and analysis generated through the use of system data. Additionally, the JU formed a collaborative cross-utility System Data working group to consider a variety of issues related to the collection, analysis, and release of data collected and maintained by the utility.

Additional Detail

This section contains responses to the additional detail items specific to Distribution System Data.

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

As mentioned above, the JU 2017 stakeholder engagement efforts included meetings with interested stakeholders to better understand who is using system data, for which purposes, and how often specific data is being used. This was accomplished through one-on-one conversations with data users about business use cases. Through these targeted use case discussions, interested stakeholders worked together with the JU to co-develop five initial business use cases and identify the "need to have" and "nice to have" data that enables each use case. The following Table is a summary of the use cases identified and presented at the August 17, 2017 stakeholder engagement session.

Table 20: System Data Use Case Descriptions

#	Stakeholder Use Case
UC-1	Interconnection Cost Estimates Pre-Coordinated Electric System Interconnection Review (CESIR)
UC-2	Evaluating Development Risks for Potential Projects
UC-3	Microgrid Development
UC-4	Integrated Distribution Planning
UC-5	Storage

Across the use cases outlined, there were five data types consistently discussed:

1. Historical load data (feeder/circuit)
2. Forecasted load data (feeder/circuit)
3. Customer demographics (type, load data, tariff)
4. Interconnection costs estimates
5. Reliability Statistics: SAIDI, SAIFI

In many cases, the data requested by stakeholders was publicly available, but stakeholders have had difficulty accessing the information. As a result, the JU enhanced the accessibility and similarity of the information provided, with the understanding that granularity may vary across utilities. In parallel, the JU delved further into specific information requested by developers and the business reasons behind the requests and have since made progress in providing additional information that is of greater value to developers.

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

As discussed in the Hosting Capacity section, in October of 2017, the Company updated its hosting capacity map to include hosting capacity information for all circuits 12kV and above (link). After this initial update, the Company incorporated additional system data into these hosting capacity maps allowing developers to access:

- LSRV designated areas with relevant data pop-ups;
- NWA designated areas with relevant data pop-ups;
- Five-year system level load forecast;
- 8760 (2017) historical load data by substation load area;
- 8760 (2018, 2019 and 2020) forecast load data by substation load area; and
- 2015 actual minimum 24-hour load curve by substation load area.

O&R, as part of the JU, also developed a central data portal on the JU website in June 2017 with links to utility-specific web portals. This central portal came as a result of stakeholder engagement sessions with the JU that determined that though the Company had a significant amount of information available to developers in various forms, there was no single location where developers could go to find it.

The website (link) includes utility-specific links to an expanded range of information, including:

- DSIPs
- Capital investment plans
- Planned resiliency and reliability projects
- Reliability statistics
- Hosting capacity
- Beneficial locations
- Load forecasts
- Historical load data
- NWA opportunities
- LSRV locations
- Queued and installed DG
- SIR pre-application information

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

As discussed above and in the Hosting Capacity section, stakeholders can readily access, navigate, view, sort, filter, and download system data via the Company web portal and hosting capacity maps.

The following table summarizes each of the data elements available and the format in which users can download and export it.

Table 21: Format of Available System Data

Data	Format
LSRV designated areas	Hosting Capacity data pop-up box
NWA designated areas	Hosting Capacity data pop-up box
Five-year system level load forecast	PDF
8760 (2017) historical load data by substation load area	Excel
8760 (2018, 2019 and 2020) forecast load data by substation load area	Excel
2015 actual minimum 24-hour load curve by substation load area	PDF

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

The Company currently provides information to DER providers consistent with the Commission's direction on the SIR.[91] As stipulated in those requirements, once a potential applicant requested an interconnection Pre-Application Report and provided the Company with the required $750 fee, the

[91] Case 18-E-0018, *In the Matter of the Proposed Amendments to the New York State Standardized Interconnection Requirements (SIR) for Small Distributed Generators* ("SIR Proceeding"), Order Granting Clarification (issued July 13, 2018)("Clarification Order").

Company provides the Pre-Application Report including circuit peak load, circuit minimum load, and voltage data, among other information.

As discussed in the Hosting Capacity section, and above, the Company provided a large amount of information on the Company's service territory and distribution system in its IDSIP. Additionally, the Company has enhanced it hosting capacity map accessible via the O&R Solar and DG website and includes:

- LSRV designated areas with relevant data pop-ups;
- NWA designated areas with relevant data pop-ups;
- Five-year system level load forecast;
- 8760 (2017) historical load data by substation load area;
- 8760 (2018, 2019 and 2020) forecast load data by substation load area; and
- 2015 actual minimum 24-hour load curve by substation load area.

The maps are a customer-friendly digital tool that provides insight into where there could potentially be higher value for a developer's resource in the future and where the developers may see solicitations for DER resources. O&R will continue to work with the JU and stakeholders to identify, understand, and evaluate evolving system data sharing needs.

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

As discussed above, as part of the 2017 stakeholder engagement efforts, the JU met with interested stakeholders to better understand who is using system data, for which purposes, and how often specific data is being used. In most cases, the system data available appears to largely meet the stakeholder needs. If developers want access to sensitive distribution system data, like the system network model mentioned in Use Case #4, the Company may share the data with the third-party under the terms of a Non-Disclosure Agreement.

6) Identify each type of distribution system data which is/will be provided to third-parties and whether the utility plans to propose a fee.

The definitions of what constitutes basic and value-added data continue to evolve. In 2017, the Commission approved nominal fees for the provision of aggregated customer data provided for CCA programs, revised the definitions of basic and value-added data put forth in the Track Two Order and the SDSIP.[92] The Commission set the expectation that categorizing data as basic or value-added will be done on a case-by-case basis given specific situations and use cases, however, it also offered general guidelines.[93] For example, the Commission stated that basic data is data that is "retained and stored by way of the companies' enterprise systems and is not readily or reasonably available by other means, but the provision of that data is essential for fundamental customer/provider relationship (*e.g.*, billing) or provides broad system-wide benefits."[94] In contrast, data is considered value-added when it is provided in the context of "customized requests and requests by market participants to pursue market opportunities."[95]

---

[92] Case 14-M-0224, *Proceeding on Motion of the Commission to Enable Community Choice Aggregation Program,* Order Establishing Community Choice Access Fees (issued December 14, 2017)("CCA Data Access Fees Order").
[93] *Id.,* p. 19.
[94] *Id.,* p. 19.
[95] *Id.,* p. 19.

The JU expect that the classification of data elements as value-added will develop over time as the utilities continue to enhance their data management systems and analytical capabilities. Further, the JU propose that "value-added" data be available for a fee determined through utility-specific fee structures. These fees may vary by utility based on the value to the consumers and market. To date, O&R has not proposed a fee for any "value-added" data sets.

7) Describe in detail the ways in which the utility's means and methods for sharing distribution system data with third-parties are highly consistent with the means and methods at the other utilities.

As described in the response to question #2 above, in reply to stakeholder feedback, the JU developed a central data portal on the JU website in June 2017 to serve as a single location where developers can find available system information. This portal, in addition to hosting the links to the enhanced utility-specific web portals, has increased access to and improved the usability of stakeholder-requested information. The JU have advanced their efforts to release additional data in more accessible formats, and stakeholders now have a better understanding of the data currently available through utility-specific web portals. This data provides greater transparency into locations on the distribution system where DER integration may have higher-value relative to other locations, greater insight into areas with potentially lower interconnection costs, and greater visibility into system characteristics and needs, which fosters market development.

Through the business use case work, and in response to stakeholder comments, the JU are evolving the system data effort to focus more on user experience, data presentment, and potentially more analytic information presentment.

The JU System Data Working Group will continue focusing on updates to and consistency of individual utility data portals, as well as refining and expanding system data use cases to better meet stakeholder needs. The JU will also continue engaging stakeholders on business use case discussions, which will also continue to identify potential value-added information. This may offer more value to stakeholders when compared to directing business developers to the necessary data resources needed to derive required information on their own. As identified in some use case discussions, some of this information may already exist or could be easily created without requiring additional effort and cost to the utilities and their customers.

8) Describe in detail the ways in which the utility's means and methods for sharing distribution system data with third-parties are not highly consistent with the means and methods at the other utilities. Explain the utility's rationale for each such case.

O&R, via the JU, has worked closely with the other New York utilities to establish distribution system data sharing consistency with third-parties. The Company is not aware of any which its means and methods for sharing distribution system data are not highly consistent with other utilities.

Customer Data

Introduction/Context and Background

The Company's implementation of the Digital Customer Experience ("DCX") is bringing an enhanced online experience for customers to better serve their changing needs and expectations

Making customer data available is important to support the goal of market development under REV. Providing customers with more granular and timely usage and cost data improves energy literacy and empowers customers to make better energy choices. For DER developers and third-parties, authorized access to customer data can help them tailor their products and services, as well as better inform business prospecting. Customer data can also be relevant to local governments, state agencies, and academic institutions to analyze the impacts of policies and develop action plans in support of clean energy and other initiatives.

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. O&R, along with the JU, has been actively exploring different ways to improve access to more customer-specific and aggregated data to support market development, while also protecting individual customers' privacy.

At the time of the IDSIP filing in 2016, the Company was providing customer data to customers through various channels including their bill, the O&R My Account portal, and the Customer Care Portal. The O&R My Account portal provides the customer with access to manage and analyze their usage and account. The portal requires a username and password and is accessible via desktop, computer, tablet or telephone as O&R uses mobile web capabilities and a Phone App accessible by iPhones and Android cell phone technology. The Customer Care Portal allows Full-Service Mandatory Hourly Pricing Customers with usage over 300 kW to review their interval data (in hourly or fifteen-minute intervals) on a one-day lag and perform various modeling exercises with the interval data.

Historically, Electronic Data Interchange ("EDI") has been the mechanism for sharing data with Energy Service Companies ("ESCOs") to support and implement retail access. The New York Uniform Business Practices ("UBP"),[96] which govern the process by which ESCOs are granted access to customer data, require ESCOs to obtain a customer's consent to share their data. ESCOs can also access customer data via the Retail Access Information System ("RAIS"), an O&R web interface that displays account-level information. In addition, each member of the JU has provided NYSERDA with access to EDI, which allows NYSERDA to access specific customer data with customer consent. Several data fields are available to NYSERDA via EDI, including but not limited to service address, electric account number, customer's number of meters and meter numbers, usage type, and electric interval usage data.

Customer consent to the dissemination of customer-specific information to third-parties is essential to maintaining customers' trust. Additional information on O&R's approach to data privacy and security is provided in the Cybersecurity section and below in the Additional Detail section, answer 2d.

---

[96] Case 98-M-1343, *et al.*, *In the Matter of Retail Access Business Rules*, Order Adopting Uniform Business Practices and Requiring Tariff Amendments (issued January 22, 1999). http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/8dd2b96e91d7447e85257687006f3922/$FILE/UBP%20Manual%20Feb%202016%20Clean.pdf.

Implementation Plan, Schedule, and Investments

Current Progress

Since 2016, the Company has increased the type and granularity of available customer data and improved both the ease of access to customer data, as well as the overall customer digital experience. Ongoing investments in AMI, Green Button Connect ("GBC"), and other digital platforms are resulting in more data being available in a format that is more usable to third-parties, thereby supporting market development.

O&R has increased the types and amount of customer data accessible to customers and third-parties via Green Button Connect, Electronic Data Interchange, and the Utility Energy Registry

O&R and its affiliate, CECONY, continue to improve their customers' digital experience with the implementation of the Companies' Digital Customer Experience ("DCX"), a multi-year program to deliver an improved online experience for customers. This foundational investment enables the Company to better serve the changing needs and expectations of its diverse and increasingly digitally-connected customer base. The ongoing DCX effort includes the redesign of all the Company's customer-facing digital platforms, including its website oru.com, mobile website, *My Account* portal, and mobile application to enhance and provide easy-to-use access to information. Improving the customer experience included the redesign of the following transactions:

- Bill paying
- Data Visualization – including AMI data for customers with smart meters installed
- Bill comparison tools, including anonymized neighbor comparison
- Report and check outage status

The Company has begun implementation of a single sign-in multi-factor authentication protocol whereby a customer will have one user ID and password to log in to all of the O&R portals, adding a layer of security to a customer's transactions with the Company.

Green Button Download and Green Button Connect

The Company implemented Green Button Download in May 2016 giving customers the ability to obtain and analyze up to 13 months of energy use data in a simple spreadsheet. This data can be used by customers for a variety of purposes, such as measuring EE impacts, and analyzing and reviewing solutions to cost-effectively manage their energy usage. In addition, it provides the customer the ability to download their energy usage data in an Extensible Markup Language ("XML") standard format file, making it easier for customers to analyze their data because the XML format is a default file type for Microsoft programs (*i.e.*, Word, PowerPoint, and Excel). 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.

As part of the Company's AMI deployment and the accompanying Customer Engagement Plan, the Company is improving its customer data sharing capabilities through the implementation of GBC. GBC is a national data sharing standard that allows customers to authorize registered third-parties to access the customer's energy data through an automated process in machine-readable format. It provides a reliable protocol for customer authorization, data transfer, data formatting, and data exchange.[97]

O&R is using a phased approach to implementing GBC in order to incorporate best practices and lessons learned from other utilities. The first phase of GBC implementation was finalized in December 2017, in coordination with CECONY, under the branding of *Share My Data*. This first phase focused on the ability to view and share customers' energy usage data with third-parties through their *My Account* portal. More information on the data available via GBC can be found under "Green Button Connect Capabilities" below.

Third-parties interested in GBC must complete an onboarding process, which includes completing an online registration form, Data Security Agreement ("DSA"), and Self Attestation ("SA"), as well as receiving technical training on the system. Once this is completed, the third-party is listed as a DER provider on *My Account* and is ready to receive customer data. As of July 1, 2018, 16 third-parties have expressed interest in accessing GBC and 3 have initiated the technical onboarding process and submitted materials. As of July 1, 2018, 16 third-parties have expressed interest in accessing GBC and 3 have initiated the technical onboarding process and submitted materials.

Electronic Data Interchange

As of late 2017, certified DER providers have access to EDI, subject to the UBP for DERS[98] and satisfaction of registration requirements. The Company established a process for certifying DER suppliers and launched a webpage[99] that describes the testing and certification process required to access customer data through EDI. Testing includes the exchange of connectivity information, submission of a statement of EDI readiness, connectivity testing, and transaction set testing. [100]

Utility Energy Registry

NYSERDA's UER will make aggregated customer data available to the public. The UER is an online platform offering "streamlined public access to aggregated community-scale data"[101] for electricity and natural gas customers, subject to privacy standards, and segmented by customer type, municipality and county. "The UER is intended to promote and facilitate community-based energy planning and energy use awareness and engagement" and "will also assist the development of Community Choice Aggregation ("CCA") programs."[102]

The Company has provided data to populate the UER and will continue to provide information semi-annually.[103] As discussed in the Additional Detail content below, data elements included in the UER

---

[97] Cases 15-E-0050 et al., ConEdison and Orange and Rockland AMI Customer Engagement Plan (filed July 29, 2016).

[98] 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)("UBP for DERS Order").

[99] https://www.oru.com/en/business-partners/become-an-energy-service-company-partner/how-to-become-an-electronic-data-interchange-certified-distributed-energy-resource-supplier

[100]A similar process exists for ESCOS. See https://www.oru.com/en/business-partners/become-an-energy-service-company-partner/energy-service-company-electronic-data-interchange

[101] Utility Energy Registry Proceeding, Utility Energy Registry Order, p. 2.

[102] *Id.*

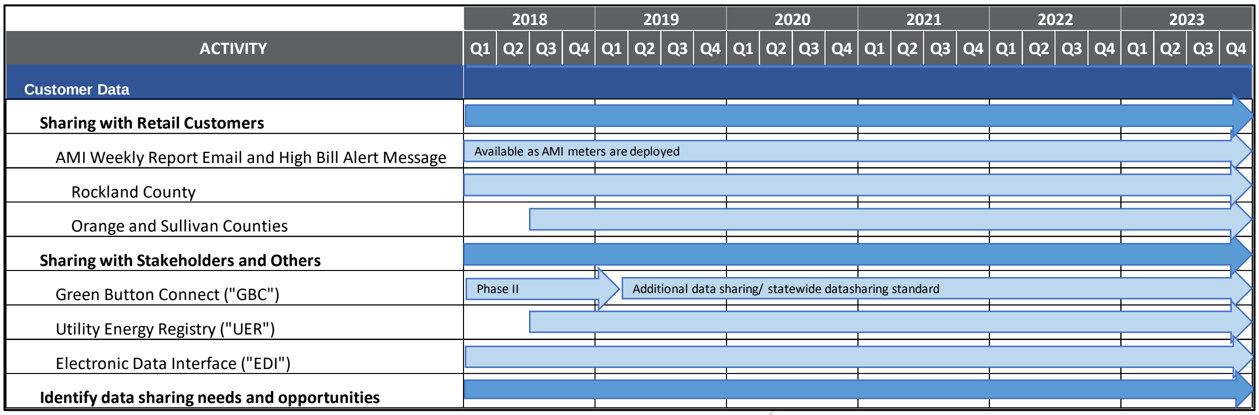
[103] *Id.*, pp. 26-29.

meet some of the data sharing requests identified by stakeholders during business use case discussions with the JU.

Future Implementation and Planning

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

Table 22: O&R Customer Data 5-Year Plan



The Company will continue to enhance its data sharing capabilities while complying with required customer data protections. For all GBC and EDI transactions, the Company requires all parties to execute a DSA and submit a SA prior to receiving customer data. The self-attestations are designed to expeditiously identify any material gaps in current best practice cybersecurity controls.[104] As an example of enhanced data sharing, the interval data available through *Share My Data* will be available in near-real time (*i.e.,* 30-45 minutes after the interval ends) by the end of 2018. The Company's GBC Phase II plan[105] is currently scheduled to go live by the end of 2018 and is discussed in the Additional Detail section below. Additional datasets provided beyond GBC Phase II will depend on customer and third-party feedback, the evolution of the statewide data sharing standard, changes to national GBC specifications, and technological developments.

Moreover, the Company is establishing an organization focused on providing data analytics tools and resources to business areas, in conjunction with CECONY. This organization will enable business areas to leverage analytical models and data generated by other departments and corporate systems, increasing integration prediction, simulation, and projection into business processes. The vast amount of data that will be generated from the advancement of automation and grid modernization, including AMI, will provide significant opportunities to improve how the Company operates and how customers manage their energy usage.

Finally, as the JU continue to increase the available customer data, they share the Commission's interest and long-standing policy of protecting the confidentiality of customer information and evaluating disclosure exceptions. The Company continues to collaborate with the JU and stakeholders to strike the right balance between advancing clean energy objectives and maintaining customer privacy and data security, using actual data user needs and requests to inform privacy standards. For example, as part of

---

[104] Case 18-M-0376, *Proceeding on Motion of the Commission Regarding Cyber Security Protocols and Protections in the Energy Market Place* ("Cyber Security Proceeding"), Order Instituting Proceeding (issued June 1, 2018).

[105] Case 15-E-0050, Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc. Green Button Connect My Data® Phase 2 Report, filed October 2, 2017 ("GBC Phase II Report").

the Customer Data working group, the JU have developed a common process for tracking aggregated data requests and responses and use this information to catalog non-standard aggregations requested by stakeholders and identify additional high-value aggregated customer datasets.

Risks and Mitigation

With the increase in data sharing, there is also the risk of security breaches. As discussed in the Cybersecurity section, to protect individual customer data, the utilities will follow current practices, which require express customer authorization for data to be released to other than utility contractors or vendors or by law or Commission order. The JU have also developed a common Cyber and Privacy Framework to manage cybersecurity risks that applies to the expanded data sharing in the evolving DSP environment.[106] The framework focuses on people, processes, and technology as being the foundation for a comprehensive cybersecurity and privacy governance program.

In addition, the Company manages data security risks by requiring all parties utilizing or accessing the Company's systems to sign the DSA, an agreement between the Company and the third party that governs the exchange of customer data. The DSA terms and conditions include, but are not limited to, an attestation that the third party has received the customer's consent to access the data, notice requirements to report a data security incident, and the SA, whereby third-parties attest to meeting the data security procedures and requirements listed therein.

The Commission's UBP for DERS also lay out the terms under which the JU are expected to share customer data with DERS. O&R has incorporated these requirements into its tariffs and created processes for DERS to begin receiving customer data via EDI.

Stakeholder Interface

During the last two years, the Company, in collaboration with the JU Customer Data working group, have continued to advance several customer data efforts, including:

- Submitting several joint filings on customer privacy standards and approaches
- Defining data sets and costs in support of CCA efforts through the development and filing of CCA tariffs
- Evaluating potential opportunities for aggregated data automation
- Soliciting feedback from stakeholders to inform future customer data needs and means of accessing that information

In addition, the Customer Data working group held one-on-one stakeholder meetings to explore additional use cases that can support customer choice, the development of DER markets, and broader REV objectives.

The Company, in collaboration with the JU and the Customer Data working group, will continue to engage with stakeholders to identify and evaluate additional customer data needs and process improvements to support greater customer choice, DER market development, and the broader REV objectives. As processes are developed to provide additional data, the Company will update its website accordingly. The Customer Data working group will continue to monitor the ongoing customer data-

[106] DSIP Proceeding, Supplemental DSIP, pp. 148-160

related proceedings, such as the CCA proceeding[107], the UER proceeding,[108] the Value of DER proceeding,[109] Cybersecurity in the Energy Market Place proceeding,[110] and groups, such as the DER Sourcing working group.

The JU plan to host another stakeholder engagement session focused on customer data later in 2018 as a means of providing updates on customer data sharing procedures and gathering feedback on new datasets and the processes to deliver them.

Additional Detail

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

1) Date Types, Description and Management Processes

a) Describe the type(s) of customer load and supply data acquired by the utility.

O&R captures customer load (use) and supply (injection from DER) data that the customer meter(s), which may be interval, AMI, or register-read meters, measures and records. There are differences in the type and granularity of the customer load and supply data acquired based on customer types and metering. As the Company proceeds with the deployment of AMI and the corresponding capture of more granular (interval) data, it will support the evolution of the data sharing mechanisms and standards, as appropriate.

Depending on the types of customer and meter, the customer load and supply data captured includes some or all of the following:

- kWh
- Instant kW
- Instant Power Factor
- kVARh Leading
- kVARh Lagging
- kW
- kWh Delivered
- kWh Received
- Peak/Max Demand
- kWh Net

b) Describe the accuracy, granularity, latency, content, and format for each type of data acquired.

All utility meters are revenue grade meters that meet the metering performance requirements and specifications outlined in the DPS16 NCRR Part 92 Operating Manual, which establishes the guidelines for testing and maintaining electricity meters to promote a high degree of metering performance and are approved by the Commission for use within the State. The Companies' Validation, Estimation, and Editing

[107] Case 15-E-0050, Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc. Green Button Connect My Data® Phase 2 Report, filed October 2, 2017 ("GBC Phase II Report").
[108] UER Proceeding, UER Order.
[109] Value of DER Proceeding, VDER Phase One Order.
[110] Cyber Security Proceeding.

("VEE") of the meter data management system ("MDMS") is the process that continually keeps smart grid data accurate and complete.

The granularity and latency of the customer load and supply data captured through the customer meter vary depending on the type of customer and meter.

Table 23: Granularity and Latency of the Customer Load and Supply Data

Customer and Meter Type	Granularity
Customers without AMI or interval meter	Monthly
Customers with a legacy interval meter	15 minutes
Residential customers with an AMI meter	15 minutes
Commercial customers with an AMI meter	5 minutes

In general, customers can access up to 24 months of data on a one-day lag. Customers with AMI meters can view their near-real time data on *My Account* at a latency of 30-45 minutes after the end of each 15-minute interval. Near-real time data will be available for customer authorized third-parties at the end of 2018 through *Share My Data*.

Depending on the types of customer and meter, the customer load and supply data captured includes some or all of the following:

- kWh,
- Instant kW,
- Instant Power Factor,
- kVARh Leading,
- kVARh Lagging,
- kW,
- kWh delivered,
- kWh received,
- Peak/Max Demand,
- kWh Net

c) Describe in detail the utility's means and methods for creating, collecting, managing, and securing each type of data.

As described above, customer load and supply data produced and collected by the Company depend on the customer and meter type.

O&R's AMI implementation plan[111] includes three major components: the meters (and associated communication devices); a communications network; and a headend system that manages the communications and operation of the devices in the field. Along with the principal AMI components, the solution incorporates parts of the Company's information systems, communications network, and

[111] DSIP Proceeding, IDSIP, Appendix B, pp. 275

information technology infrastructures (including security assets) and requires integration with other Company business/operations applications.

O&R, in alignment with its affiliate CECONY, expanded its original AMI project in 2017 to include a new MDMS. The MDMS serves as the central repository of meter data for the utility and can be used along with features of the AMI headend system to support meter data management requirements. The MDMS solution provides complete and valid data to other systems in the format and frequency the systems require. It also streamlines and consolidates meter-related data (measurements, events, status, attributes) that will otherwise be distributed across several legacy data systems. The MDMS is the integration hub where multiple systems can access validated meter data. The new MDMS supports advanced meter data management requirements associated with complex rates, data presentment, extensive customer engagement, and market animation in the distribution grid. The MDMS houses meter data from AMI meters as well as non-interval meters.

Meter data from legacy interval meters is collected in the MV90 system, in the form of pulses. The system processes the pulses via the VEE procedure that continually keeps meter data accurate and complete prior to the export of that meter data to the Load Profile Data System (LPDS). LPDS then stores the pulses and multiplier for the associated meter and recorder ID. Data in LPDS can be requested for a particular date and time period. Data from legacy interval meters will be in MDMS in the first quarter of 2020.

The Company recognizes the risks associated with malicious software attacks and maintains a comprehensive cybersecurity program as outlined in the Cybersecurity section of this filing. This program is designed to protect Company computers, servers, business applications and data, and high-value networks from unauthorized access and control from both external and internal threats. As discussed above, execution of a DSA and SA will further enhance protection of customer data.

2) Data Uses, Access and Security

a) Describe the means and methods that customers and their properly designated agents can use to acquire their load and supply data directly from their utility meters without going through the utility, should they want to.

If a customer wishes to monitor their energy consumption on a "real-time" basis, one option is to request that the Company install a pulse output on the existing company meter. Once installed, the company meter will provide pulse outputs proportional to kWh usage and then the customer, with their equipment, will directly collect the pulse count over a time period for total usage. As there are many opportunities for error, such as lost pulse counts by the customer, this can generally only provide an estimate, albeit a good one, for energy usage. It cannot be used as a billing instrument.

In addition to this, the Company provides several methods for customers and their properly designated agents to acquire a customer's data automatically, without a written or verbal request to the Company. These include EDI transactions and *Share My Data*.

b) Identify and characterize the categories of legitimate users beyond customers and their properly designated agents who will be provided access to each type of data.

As O&R continues to evolve in its role as the DSP and the REV marketplace grows, it is the Company's expectation that multiple types of third-parties will need access to customer data in order to participate in the distributed market. For DER developers and third-parties, access to customer data can help them tailor their products and services, as well as better inform business prospecting. Local governments, state agencies, and academic institutions may use customer data to analyze the impacts of policies and develop action plans in support of clean energy and other initiatives. Aggregated data will be accessible to third-parties on NYSERDA's UER. This platform will allow a third-party access to municipal and county level data aggregated by residential and commercial groupings and subject to the Commission's privacy standards. Other types of aggregated data are made available to certain parties, such as aggregated whole-building data, which is only shared with a building's owner or its designated agent, and CCA data, which is only shared with CCA Administrators and/or municipalities and their contracted ESCO(s).

c) For each type of data, describe how its respective users will productively apply the data and explain why the data provided will be sufficient to fully support each type of application.

O&R, in collaboration with the JU and the Customer Data Working Group, has been proactively engaging with stakeholders to share its proposals for providing aggregated customer data consistent with Commission approved privacy standards, its progress in improving the type of data, and the process for accessing customer specific data with proper customer authorization. In addition, the JU are conducting one-on-one conversations with DER developers to better understand their specific customer usage data needs, share current practices, and inform their future data sharing plans. Through the targeted conversations, utilities not only understand the underlying basis for the requests, but stakeholders gain insight to the information currently available and how to access it.

Below is a summary list of the initial business use cases:

Table 24: Customer Data Initial Business Cases

#	Stakeholder Use Case
UC-1	Aggregation Prospecting (ESCOs)
UC-2	Aggregation Pricing (ESCOs)
UC-3	Customer-Specific (ESCOs)
UC-4	Access to Customer Bill PDFs
UC-5	Prospecting for DR Program Participation
UC-6	Enrollment in DR programs
UC-7	Prospecting for Development Opportunities/Evaluating Utility Non-Wires Solicitation

Much of the use case needs are being met currently by the Company. The UER will provide data that ESCOs and DR providers can use when prospecting for CCA and DR program opportunities, respectively. Specifically, the UER will provide aggregated usage data, aggregated installed capacity ("ICAP") data, total customer count as well as the number of residential and small commercial customer accounts ineligible for a CCA. The data will be grouped by residential, small commercial and other commercial, by municipality and county. All of this data is subject to privacy standards, and rules for additional levels of aggregating groupings that do not meet the privacy standard, as set forth by the Commission.[112]

Once a CCA is authorized by the Commission and Staff as approved the disclosure of data, customer-specific data is provided to the chosen ESCO pursuant to the CCA Order. In addition, Both ESCOs and DR providers can receive customer usage data via GBC, as authorized by the customer. The granularity of the usage data provided will depend on the customer and meter type. GBC Phase II will provide more

[112] UER Order.

of the information that is seen on a customer's bill, including utility bill costs per billing period, customer account number, service address, ICAP tag, demand (kW), and tariffed service class. Data processed according to GBC standards does not include any Personally Identifiable Information ("PII").

Third-parties responding to O&R's NWA solicitations receive total load profiles for impacted circuit/substation as well as the associated residential, and commercial and industrial customer counts.

d) For each type of data, describe in detail the utility's policies, means, and methods for securely providing legitimate users with efficient, timely, and useful access to the data. Include information which thoroughly describes and explains the utility's approach to providing customer data to third-parties who will use the data to identify and design service opportunities which benefit the utility and/or its customers.

NYSERDA's UER is an avenue for accessing aggregated customer data. The UER is a free publicly-available online platform offering streamlined access to aggregated data for electricity and natural gas customers, segmented by customer type, municipality, and county. Data included in the UER for each segment passing the applicable privacy screen includes total load, ICAP Tag, customer counts, and the number of residential and small commercial customers ineligible for CCA. In addition to the UER, aggregated customer data is available from O&R by request.

Authorized ESCOs and DER Suppliers can obtain data through EDI, as per the UBPs and the UBP for DERS, respectively. Authorized ESCOs can also obtain data through O&R's RAIS. Third-parties, including ESCOs and DER Suppliers, can obtain data via GBC once they are on boarded and authorized as described above.

The following table details information that can be obtained via EDI, RAIS, and GBC by authorized third-parties:

Table 25: Information Available

Data Field	Channel
Reactive Power (kVAR)	GBC
Net kWh	GBC
5-minute interval data (commercial customers with AMI meter)	GBC
15-minute interval data (residential customers with AMI meter)	EDI, GBC
15 or 30-minute interval data (commercial customers with legacy interval meters)	EDI, GBC, RAIS
Actual vs estimated read	EDI
Bill amount	EDI
Customer name	EDI
ESCO status	EDI, RAIS
Hourly interval data	EDI, RAIS
Hourly meter indicator	EDI

Data Field	Channel
ICAP tag	EDI, RAIS
Industrial code	EDI
ISO load zone	EDI, RAIS
Load profile ID	EDI
Meter number	EDI, GBC
Net meter status	EDI, RAIS
Next read date	RAIS
NYPA indicator	email
Percent residential	EDI
Recharge NY status	email
Service address	EDI, RAIS
Summary kWh history	EDI
Tax status	EDI
Bill Group schedule	EDI

Both EDI and *Share My Data* involve machine-to-machine protocols to transmit data, which provides third-parties with timely access to customer data. The North American Energy Standard Board Energy Services Provider Interface standard is the basis for *Share My Data*, which requires that a customer first authenticate itself on the utility portal with a login and password before explicitly granting permission to a third party and enabling the secure transfer of data.

Privacy Standards and Protocols for Sharing Customer Data

As the JU continue to make more customer data available, they share the Commission's interest and long-standing policy of protecting the confidentiality of customer information and evaluating disclosure exceptions. The protection of customer information, including energy usage data and PII, is part of all utilities' responsibilities and commitment to their customers.

The Company does not share customer-specific information without customer consent, except where 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.[113] For all GBC and EDI transactions, the Company requires all third-parties to complete the SA and execute the Data Security Agreement. The Data Security Agreement is also used in conjunction with CCA requests.

The Company's 2016 DSIP included a commitment to offer a new data exchange for interested 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 will be available to ESCOs by the end of 2018 and include all of the datasets available to third-parties through *Share My Data*, including near real-time interval data.

[113] https://www.oru.com/en/privacy-statement

Data Privacy Standard for Aggregated Data

The Commission's DSIP Order[114] adopted a 15/15 privacy standard for general aggregated datasets, including data provided for purposes of community planning and CCA. The 15/15 standard provides that an aggregated dataset may be shared only if it contains at least 15 customers, with no single customer representing more than 15% of the total load for the group. The Commission acknowledged that the 15/15 standard is conservative and further directed the JU to track all aggregated data requests and be prepared to report on the number of requests that do not clear the 15/15 standard.[115]

To date, O&R has not received any requests for aggregated data. The JU developed an internal inventory of actual aggregated customer data requests to understand the volume and types of standard aggregations requested by stakeholders and opportunities to potentially automate the request and delivery of these aggregated data reports. The JU will continue to track aggregated data requests as they arise and will use the inventory process to track instances where some or all of a requested aggregated data set does not pass the applicable privacy standard.

The Commission's UER Order[116] confirmed that the 15/15 privacy standard will apply to the aggregation of residential customer data and a 6/40 privacy standard will apply to the aggregation of both the small commercial grouping and the other commercial grouping when providing aggregated data to NYSERDA's UER. The 6/40 standard requires the grouping to have at least six accounts where no single account represents 40% or more of the total load for the grouping.

Data Privacy Standard for Whole-Building Aggregated Data for Building Energy Management and Benchmarking

The Commission adopted[117] the JU proposed 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. The 4/50 privacy standard requires the building to have at least four accounts where no single account represents 50% or more of the annual energy usage of the building. 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 as required by the Whole Building Order.[118]

e) Describe how the utilities are jointly developing and implementing uniform policies, protocols, and resources for controlling third party access to customer data.

The JU are actively working through numerous processes to develop and implement uniform policies and approaches to provide customer data to third-parties. Since the IDSIP filings, the JU have collaborated in the Customer Data Working Group to advance several customer data efforts, including:

- Submitting two joint filings on customer privacy standards and approaches
- Defining data sets and costs in support of CCA efforts through the development and filing of CCA tariffs

---

[114] DSIP Proceeding, DSIP Order.
[115] DSIP Proceeding, DSIP Order, pp. 26-27.
[116] UER Proceeding, UER Order, p. 24.
[117] DSIP Proceeding, Order Adopting Whole Building Energy Data Aggregation Standard (issued April 20, 2018) ("Whole Building Order").
[118] DSIP Proceeding, Whole Building Order.

- Working with DPS Staff and NYSERDA to establish the UER and appropriate privacy standards
- Implementing the UBPs for DER Suppliers
- Evaluating potential opportunities for aggregated data automation and developing whole-building owner aggregated data access and privacy standards, including the filing of proposed Terms and Conditions for access to whole-building data
- Engaging with stakeholders, both at utility sponsored engagement sessions and conversations with individual third-parties, to solicit feedback and inform future customer data needs and means of accessing that information

Currently, there are a number of channels that the utilities use to share customer data with customers and their authorized third-parties. These include utility bills, GBD, GBC, EDI, UER, Secure File Transfer Protocol, and online third-party data platforms. Each data sharing platform may be designed with a different user audience in mind, have unique access requirements, and be used to convey different kinds of information.

To support the REV initiative, the JU formed the Customer Data working group to coordinate on all issues related to customer data. As outlined in the SDSIP, in addition to complying with the regulations established by the Commission regarding third-party access to customer data, the JU have "developed a common approach to managing these new cybersecurity and privacy risks in the evolving REV environment," which includes the JU Cybersecurity and Privacy framework[119] and the ESCO proceeding [120]

The Commission's UBP for DERS also lays out the terms under which the JU are expected to share customer data with DER suppliers. Each utility has incorporated these requirements into its tariff and established processes for DER suppliers to begin receiving customer data via EDI. In addition, O&R, along with the JU, have developed a common process to manage data security risks. This includes a data security agreement that will be required by all third-parties using or accessing utility systems. The DSA is an agreement between the Company and the third party that governs the exchange of customer data. The DSA 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.

f) Describe in detail the utility's policies, means, and methods for rigorously anticipating data risks and preventing loss, theft, or corruption of customer data.

In coordination with the JU, O&R has developed and implemented a process to manage risks associated with third-party access to customer data. All parties using or accessing utility systems must sign the DSA, an agreement between the utility and third party that governs the exchange of customer data. The DSA 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 and the notice requirements when there is a data security incident. The DSA includes data security requirements for ESCOs, EDI vendors, DER suppliers and all parties accessing utility systems. The DSA also includes the SA, whereby third-parties attest to meeting the data security procedures and requirements listed therein.

Privacy policies and standards applicable to aggregated customer data have been developed to maintain the anonymity of customer-specific data. To inform the development of these policies and standards, the JU have conducted benchmarking and worked with stakeholders. These efforts have

[119] DSIP Proceeding, JU Supplemental DSIP, p. 148.
[120] ESCO Proceeding Order.

produced three aggregated data privacy standards that are applied to specific use cases. Each privacy standard consists of a two-part test, a customer count threshold and a usage threshold, as described in the response to question #2.d. above.

The Company ensures the proper handling of customers' PII in accordance with the Commission's order[121] and as provided for in its applicable Corporate Instruction. All hard copy PII information is filed in secured cabinets or drawers within each department. All electronic copies retained are password protected. PII identified beyond the point which it is needed is destroyed in accordance with Company policy.

As discussed above, the Company takes the protection of customer information very seriously. The Company does not share customer-specific data without customer consent, except where required by Commission order or as permitted by the Commission to carry out utility EE programs.

g) Identify each type of customer data which is/will be provided to third-parties at no cost to the recipient, and the extent to which the practice comports with DPS policies in place at the time, as appropriate.

The Company shares the customer data listed in the Information Available table via EDI, RAIS, and GBC at no cost to the recipient. In addition, the Company provides historical aggregated monthly usage data to NYSERDA's Utility Energy registry on a semi-annual basis. The data, which is arranged into residential, small commercial, and other groupings with the potential to combine groupings if the aggregated data does not pass the approved privacy standard discussed above, is provided at no cost. Additional data provided includes total installed capacity and a customer count, including the number of customers ineligible for a CCA, is also provided at no cost. Further, whole building data that passes the applicable privacy standard will be provided to the building owner, or its agent, at no cost.

h) Identify each type of customer data which the utility proposes to provide to third-parties for a fee, and the extent to which the practice comports with DPS policies in place at the time, as appropriate. For each data type identified, describe the proposed fee structure and explain the utility's rationale for charging a fee to the recipient.

In the REV Track Two Order, the Commission allowed utilities to charge for information beyond basic customer data and stated utilities may "continue to charge ESCOs and other vendors for providing monthly customer data for a period in excess of 24 months. Utility charges may also be assessed for data that is more granular and/or more frequent than the basic data described below."[122] The definitions of what constitutes basic and value-added data continue to evolve. The Commission's CCA Data Fees Order revised the definitions of basic and value-added data put forth in the Track Two Order and the SDSIP. As authorized by the Commission in the CCA Data Fees Order,[123] O&R currently charges $0.80 per account for CCA data, as set forth in the Company's tariffs.[124] Moreover, customer data and system data can be categorized as basic data or value-added data.

---

[121] Case 13-M-0178, *In the Matter of a Comprehensive Review of Security for the Protection of Personally Identifiable Customer Information,* Order Directing the Creation of an Implementation Plan (issued August 19, 2013).
[122] REV Proceeding, Track Two Order, p. 140.
[123] CCA Proceeding, Order Establishing Community Choice Data Access Fees (issued December 14, 2017)("CCA Data Fees Order").
[124] https://www.oru.com/en/ny-rates-tariffs. See Statement of Community Choice Aggregation Data Access Fees

i) Describe in detail the ways in which the utility's means and methods for sharing customer data with third-parties are highly consistent with the means and methods at the other utilities, and the extent to which these practices comport with DPS policies in place at the time, as appropriate.

As discussed in the SDSIP, the JU are committed to establishing a statewide standard around customer data and "plan to enhance their respective customer data platforms to address data sharing needs in a consistent manner."[125] However, each utility may be on a different schedule for AMI implementation, resulting in utilities implementing customer data platforms at different times. While O&R and CECONY (the "Companies") are ahead of the other utilities in implementing the GBC standard (i.e., "*Share My Data*"), other utilities that are pursuing AMI investments have plans for implementing GBC or an alternate standard in alignment with their AMI implementation. On October 2, 2017, the Companies filed their GBC Phase II Report, which outlined the additional datasets that will be made available to customer-authorized third-parties. In developing the GBC Phase II Report, the Companies coordinated with the JU to affirm that the proposal outlined in the Phase II Report aligned with the anticipated evolution of the statewide data sharing standard. The additional datasets to be provided through *Share My Data* represent an incremental step that will be incorporated in the broader statewide data sharing standard.

j) Describe in detail the ways in which the utility's means and methods for sharing customer data with third-parties are not highly consistent with the means and methods at the other utilities. Explain the utility's rationale for each such case.

O&R is not aware of any significant inconsistencies. O&R shares customer data with third-parties in a manner that is highly consistent with the other JU. To achieve this result, the utilities worked closely to establish highly consistent means for customer data sharing with third-parties.

3) Green Button Connect Capabilities

a) Describe where and how DER developers, customers, and other stakeholders can readily access up-to-date information about the areas where customer consumption data provided via Green Button Connect ("GBC") is available or planned.

As part of the Company's AMI deployment and as expressed in the AMI Customer Engagement Plan, the Company is improving its customer data sharing capabilities through the implementation of GBC. O&R is using a phased approach to implement GBC in order to incorporate best practices and lessons learned from other utilities that have implemented GBC.

The first phase of GBC implementation included 14 key activities and was finalized in December 2017, in coordination with CECONY, under the branding of *Share My Data*. *Share My Data* leverages the more granular data available from AMI to allow customers to authorize registered third-parties to access their energy data through an automated process in machine-readable format. Datasets available include meter number, energy or net energy usage data (kWh, net kWh, CCF), and reactive power (kVAR). Third-parties are able to request 15-minute interval data for residential customers with AMI meters and five-minute interval data for commercial customers with AMI meters. *Share My Data* provides up to 24 months of interval data, currently at a one-day lag, with plans to move to near real-time (*i.e.*, 30-45 minutes after the interval ends) by the end of 2018. Customers who do not yet have AMI meters are able to share

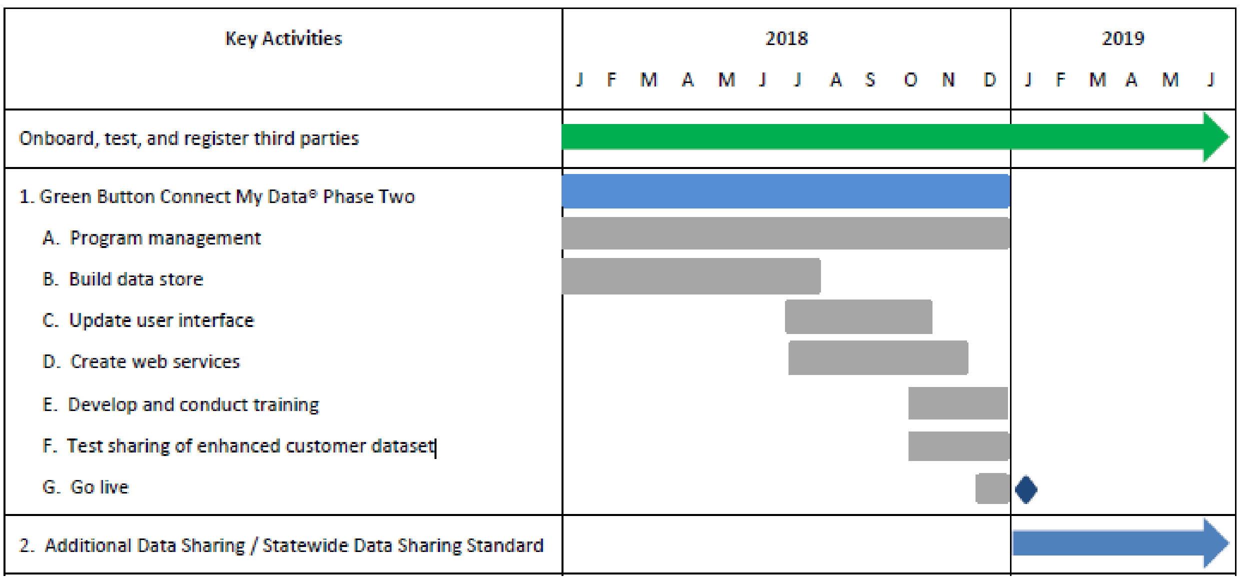
[125] DSIP Proceeding, JU Supplemental DSIP, p. 141.

monthly energy usage data with authorized third-parties while those with AMI meters are able to share more granular energy usage data.

On October 2, 2017, the Company filed, in conjunction with CECONY, a GBC Phase II Implementation Plan[126] which is currently scheduled to go live by the end of 2018. Phase II is an incremental step toward full evolution of a statewide standard. It will expand the datasets automatically available to registered third-parties, including electric and gas utility bill costs per billing period (current and previous), customer account number, service address, ICAP tag, demand (kW), and tariffed service class.

The figure below shows the phased implementation of GBC Phase II.

Figure 24: GBC Phase II Implementation Timeline



Additional datasets provided beyond Phase II will depend on customer and third-party feedback, the evolution of the statewide data sharing standard, changes to national GBC specifications, and technological developments. The Company will continue to engage stakeholders, in collaboration with the JU and the Customer Data working group, to identify and evaluate additional customer datasets to support customer choice, the development of DER markets, and broader REV objectives.

The Company has developed several webpages where DER developers, customers, and other stakeholders can readily access up-to-date information about *Share My Data*.[127] The Company has developed Frequently Asked Questions for customers and third-parties that provide information about the consumption data provided via *Share My Data*. The Company plans to further develop and build out these webpages based on feedback from customers, developers, and other stakeholders.

---

[126] Case 15-E-0050, *et al.*, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service*, GBC Phase II Report.

[127] https://www.oru.com/en/accounts-billing/share-energy-usage-data/share-my-data

b) Describe how the utility is making customers and third-parties aware of its GBC resources and capabilities.

The Company plans to implement a targeted email and social media campaign when there are several third-parties available that have successfully completed the registration process. Customers and third-parties can also readily access up-to-date information about *Share My Data* at (link).

c) Describe the utility's policies, means, and methods for measuring and evaluating customer and third-party utilization of its GBC capabilities.

The Company plans to track the number of customers who share their data via GBC in a given time period and the number of customers that continue to share in subsequent periods. This comparison will help the Company understand the value placed on the tool by customers.

In addition, customers that authorized third-parties to receive data via GBC can receive a monthly report including the names of third-parties accessing account information and the number of times the third-party accessed account information.

Cybersecurity

Introduction/Context and Background

Cybersecurity and the prevention of security breaches and cyber events are essential responsibilities and priorities of the JU. The SDSIP outlined a common and comprehensive approach to managing cybersecurity risks in the evolving REV environment. The JU Cyber and Privacy Framework[128] focuses on people, processes, and technology to maintain data security. The Framework requires the implementation of an industry-approved risk management methodology and alignment of control implementations with the control families in the NIST SP 800-53 revision 4. The JU periodically assess the need for updates to the Framework. The current version, initially published in the SDSIP, remains relevant with no updates required.

The cybersecurity industry continues to evolve, as does technology. The trend is for former best practices to become essential components of a cybersecurity program over time. As an example, several years ago, companies viewed cyber insurance as optional and discretionary. Now cyber insurance is considered essential, with the question being how much cyber insurance coverage is sufficient. It is the same with technology. Multi-factor authentication used to be voluntary protection, and now it is considered a baseline requirement.

The JU are working together to keep pace with evolving cyber needs. For example, the JU use vendor risk forms to assess the cyber-preparedness of its partners and vendors. After a recent incident related to an ESCO, the JU have undertaken an effort to improve the cybersecurity posture of ESCOs and EDI providers because these entities “touch” utility systems. This effort is ongoing but will result in improved cybersecurity for the ESCOs and the utilities.

Implementation Plan, Schedule, and Investments

Current Progress

In the SDSIP, the JU committed to maintain an active individual cyber and privacy management program and participate in industry working groups, including the New York State Security Working Group ("SWG"). Consolidated Edison, Inc. (“CEI”) has taken a leadership role within that group, serving as the current vice chair. The Company is also involved in several other industry efforts to share best practices and intelligence, including collaboration with the Edison Electric Institute, American Gas Association, the federal Department of Energy, the federal Department of Homeland Security, Northeast Power Coordinating Council, Inc., Electricity Information Sharing and Analysis Center, and New York City. The Company is also coordinating with the NERC and actively participated in NERC’s GridEx IV, which is a sector-wide grid security exercise designed to simulate a cyber/physical attack on electric and other critical infrastructures across North America. The Company also participated in the development of the NERC CIP-013-1 (Supply Chain Risk Management).

The JU have also agreed to share lessons learned and advancements in security technology among themselves.

[128] DSIP Proceeding, JU Supplemental DSIP, pp. 148-160.

Future Implementation and Planning

As noted above, the JU periodically assess the need for updates to the Framework. The current version continues to satisfy needs, with no updates required at this time.

Risks and Mitigation

The Company has robust cybersecurity protections already in place and is continuously monitoring and responding to emerging cybersecurity risks.

Stakeholder Interface

As noted above, CEI is engaged in a number of industry efforts to share best practices and intelligence and participates security exercises organized by NERC. The Customer Data section discusses the protection of customer data and the vetting of third-parties who seek access to customer data.

Additionally, the Company meets with the Staff quarterly at the NYS SWG and meets annually to evaluate privacy protections. The Company also provides a cybersecurity update to Staff as needed either specifically for cyber or as part of our risk discussions and communicates with Staff via phone as needed. The Company is willing to establish a more frequent cadence of cybersecurity updates, should Staff find that valuable.

Additional Detail

This section contains responses to the additional detail items specific to Cybersecurity:

1) **Describe in detail the utility policies, procedures, and assets that address the security, resilience, and recoverability of data stored and processes running in interacting systems and devices which are owned and operated by third-parties (NYISO, DER operators, customers, and neighboring utilities). Details provided should include:**

    a) **the required third-party implementation of applicable technology standards;**

    b) **the required third-party implementation of applicable procedural controls;**

    c) **the means and methods for verifying, documenting, and reporting third-party compliance with utility policies and procedures;**

    d) **the means and methods for identifying, characterizing, monitoring, reporting, and mitigating applicable risks;**

    e) **the means and methods for testing, documenting, and reporting the effectiveness of implemented security measures;**

    f) **the means and methods for detecting, isolating, eliminating, documenting, and reporting security incidents; and,**

    g) **The means and methods for managing utility and third-party changes affecting security measures for third-party interactions.**

CEI recognizes the increased cybersecurity supply chain risks, especially with regard to data the Company's vendors and partners store and process. The Company has built robust processes to mitigate this risk through vendor risk assessments, cybersecurity requirements within terms and conditions, architecture reviews, cybersecurity insurance mandates, and the use of Defense in Depth strategy for vendor system implementations. In addition, CEI built strong partnerships with third-parties and implemented tools and processes to identify, alert, and respond to, potential vulnerabilities and immediate cybersecurity concerns.

2) Describe in detail the security, resilience, and recoverability measures applied to each utility cyber resource which:

a) contains customer data;

b) contains utility system data; and/or,

c) Performs one or more functions supporting safe and reliable grid operations.

The Company adheres to strict standards for the protection of system and customer data and will continue to actively mitigate growing risks in part through careful attention to cyber and privacy practices. The Company maintains a Cybersecurity and Privacy Program to manage cybersecurity risk to an acceptable level, in line with the REV cybersecurity Framework developed by the JU and published in the SDSIP. The Framework focuses on people, processes, and technology as the foundation for a comprehensive cybersecurity and privacy governance program. The Framework requires the implementation of an industry-approved risk management methodology and alignment of control implementations with the control families in the NIST SP 800-53 revision 4. The JU periodically assess the need for updates to the Framework. The current version, as filed in the SDSIP, remains relevant with no updates required.

3) For each significant utility cyber process supporting safe and reliable grid operations:

a) Provide and explain the resilience policy which establishes the utility's criteria for the extent of resource loss, damage, or destruction that can be absorbed before the process is disrupted;

b) Provide and explain the recovery time objective which establishes the utility's criteria for the maximum acceptable amount of time needed to restore the process to its normal state;

c) Provide and explain the plan for timely recovery of the process following a disruption; and,

d) Describe each process, resource, and standard used to develop, implement, test, document, and maintain the plan for timely process data recovery.

CEI has developed incident response and recovery plans, which are practiced on a regular basis for the Company's key processes, systems, and departments.

4) Identify and characterize the types of cyber protection needed for strongly securing the utility's advanced metering resources and capabilities. Describe in detail the means and methods employed to provide the required protection.

AMI devices add risk to the Company as they are outside the Company's physical security controls. Accordingly, the design of all external devices and systems supports the integrity of the network and data sent back to company managed systems. Cyber protection follows the standards described above, as well as the following requirements for all physically uncontrolled devices (meters, battery storage systems):

- The manufacturing process must identify all devices intended for the Company's system
- Authentication to and use of dedicated, encrypted networks for the secured transmission of data from external devices

- The Company collects and temporarily stores all external data in a “Low Trust” zone until it pulls it into the corporate environment from a “High Trust” zone
- All control/change activities initiated from management systems to external devices authenticate to the external device
- The Company receives all software/firmware updates from the vendor via secured and validated means
- Authorization and authentication controls from the management system initiate all physical access to external devices for a defined period of time
- Logs of all approved changes/commands with alerting of unauthorized activities

The Company reviewed the AMI vendor cybersecurity practices as part of the RFP process and incorporated them into the terms and conditions of the Company’s contract with its selected vendor.

5) Identify and characterize the requirements for timely restoring advanced metering resources and capabilities following a cyber disruption. Describe in detail the means and methods employed to provide the required recovery capabilities.

As described in the Company’s response to question #3, CEI has developed incident response and recovery plans, including for AMI, which it practices on a regular basis for key Company processes, systems, and departments.

DER Interconnection

Introduction/Context and Background

O&R is committed to simplifying the process for customers and third-party developers to interconnect DERs. In removing barriers to interconnection, O&R can facilitate greater penetration of DERs on the electric delivery system, enhance the developer experience, and drive enhanced customer satisfaction. Since the IDSIP filing, the Company has made significant progress in improving the interconnection process and meeting the goals of the Track One Order which called for utilities to: (1) streamline their interconnection processes for distributed generation ("DG") projects; (2) increase the transparency of their interconnection approval processes; and (3) adequately prepare for greater amounts of DG deployment. [129]

Specifically, the Commission directed the Utilities to each develop an Interconnection Online Application Portal ("IOAP"), where to the extent possible, will be capable of automatically performing impact studies, such as load flow, voltage flicker, and fault potential, in order to issue a decision on interconnection in a timelier manner. Following the Order, the Commission and NYSERDA engaged the EPRI to define functional requirements for the IOAP and outline an implementation plan, identifying both near-term and longer-term activities. As a result, EPRI published its New York IOAP Functional Requirements in September 2016, proposing the portal be developed in three phases, with increasing automation as outlined below:

- Phase I – Automating application management
- Phase II – Automating Standard Interconnection Requirement ("SIR") technical screening
- Phase III – Full automation of all processes

The IOAP phased improvements build on the New York State SIR, established in 1999, to provide a framework for processing applications to interconnect DER systems. Since 2016, the Commission has issued a number of SIR updates intended to improve the interconnection process and reduce the interconnection queue backlog. The current SIR lays out the mandated steps and associated timelines for utilities to process interconnection applications for systems up to 5 MWs.[130] As more DERs are interconnected to the system, providing more lessons learned and best practices, the SIR will continue to evolve.

In April 2016, prior to the release of the EPRI IOAP functionality requirements, O&R was the first utility in New York to begin using Clean Power Research's PowerClerk® Interconnect software ("PowerClerk") to streamline and automate its DER application process. PowerClerk is a hosted, web-based application that allows customers to log in, enter application information, attach supporting documents, and electronically submit their applications. O&R's transition to PowerClerk established key foundational capabilities necessary to implement the subsequent IOAP requirements. The early transition to the software allowed the Company to more quickly adopt the automated functionality outlined in Phase I.

Since its IDSIP, O&R has continued to make improvements to its Interconnection Online Application Portal ("IOAP and DER energization process, which has allowed the Company to cut its interconnection application process for most projects from months to weeks. In addition, O&R has been

[129] REV Proceeding, Track One Order, pp. 92-93.
[130] SIR Proceeding, Clarification Order.

involved in variety of innovative interconnection projects such as DOE ENERGISE – one of only thirteen projects awarded nationally aimed at improving the electric grid's ability to accommodate power generated from renewable energy sources, as well as being awarded the NYSERDA PON 3026 and PON 3397 grants to accelerate technology innovation that may reduce the time, cost, and complexity of interconnecting DER.

Implementation Plan, Schedule, and Investments

Current Progress

O&R has processed over 3,700 interconnection applications since 2016

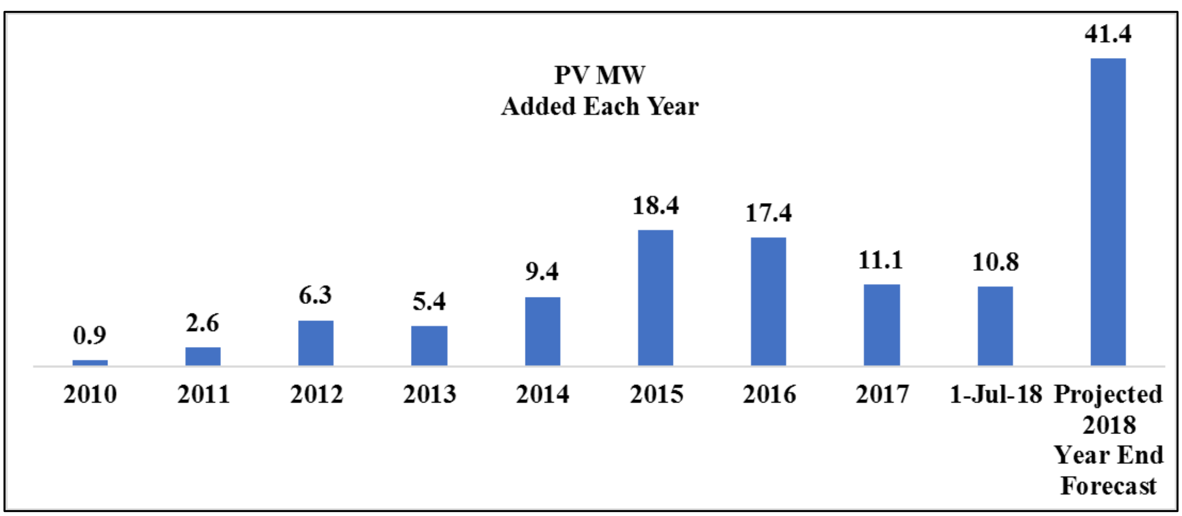
O&R's achievements in streamlining its interconnection process are apparent when looking at the number of installations the Company has completed to date. As of June 2018, the Company has performed a total of 6,406 photovoltaic ("PV" or "solar") installations in its New York service territory, interconnecting a total of 69.9 MWs. In addition, there are 465 projects currently being proposed, totaling an additional 149.4 MWs of capacity, 139.5 MWs of which will be Community Distributed Generation ("CDG") projects.

Table 26: PV Installations in NY

	Number of Installations	MWs of Installation	Categories of MWs		
			Net Metering	Remote Net Metering	Community DG
Total # of installations	6,406	69.9	57.6	12.3	0.0
Total # proposed installations	465	149.4	4.2	5.6	139.5
Grand Total of Active Projects	6,871	219.3	61.8	17.9	139.5

In addition, in 2018 the Company has already interconnected 10.8 MWs and projects a total of 41.4 MWs by the end of the year; a record high for the Company.

Figure 25: # of MWs Added Each Year



O&R is committed to continuing the enhancement of its processes and supporting interconnection efforts beyond those outlined in the SIR and has demonstrated its commitment to that vision through continued enhancements to its portal, participation in new technology initiatives and demonstrations, industry participation, and ongoing stakeholder engagement.

Portal Enhancements and IOAP requirements

In October 2017, O&R completed its IOAP Phase I implementation. Phase I entailed the automation of the application process. This included work to integrate site availability and installation readiness validations (system requirement checks and sizing compatibilities) into the Company's existing interconnection application processing database and systems for applications up to 5 MWs. The Company accomplished this by licensing PowerClerk to serve as a customer facing the interconnection application management portal. All applications received by O&R after April 29, 2016, were received through the portal and the Company converted all legacy applications to PowerClerk in January 2017. Phase I was an important and landmark initial step toward reducing the application processing time and simplifying the communication with DER developers and customers while providing visibility into the study process.

Phase II includes the full automation of the SIR defined screens. This requires more data than Phase I as well as additional detail pertaining to the distribution feeders and integration with existing utility tools. To accomplish Phase II, O&R integrated the public facing IOAP with customer information systems, GIS, and tools used to perform technical analysis and review. The Phase II implementation timeline was originally set for completion in 2017, however recognizing that many of the required capabilities are not commercially available and require significant development work, the timeline continues to evolve for O&R as well as the JU to continue to develop and evolve the functionalities envisioned. Despite this uncertainty, O&R has completed the automation of the following preliminary technical screens:

- Screen A: Is the Point of Common Coupling on a Networked Secondary System?
- Screen B: Is Certified Equipment Used?
- Screen C: Is the Electric Power System ("EPS") Rating Exceeded?
- Screen D: Is the Line Configuration Compatible with the Interconnection Type?
- Screen E: Simplified Penetration Test
- Screen F: Simplified Voltage Fluctuation Test

The automation of these technical screens will help to further reduce the time needed to conduct an interconnection study.

New Technology

O&R received an award for research aimed at improving the electric grid's ability to accommodate renewable energy—one of only 13 projects awarded nationally

In addition to enhancing the online application process, O&R has also actively sought out opportunities to partner on innovative projects as a means of proving additional interconnection and grid optimization concepts and technologies. As discussed in the Grid Operations section, as the number of DERs interconnected continues to increase, the next significant challenge is to integrate these resources into distribution grid operations. In the past, system limitations and technical uncertainties have created a barrier to increased integration. With more technology performance testing and validation, new DER technologies and interconnection methods will further support safe, reliable operations. Aligned with this research and innovation effort, the Company is currently engaged in two NYSERDA PON projects and a DOE project further described below.

NYSERDA PON 3026 Project

O&R was awarded a grant from NYSERDA ("NYSERDA PON 3026") to build a DER Interconnection Assessment Application consisting of the Clean Power Research ("CPR") PowerClerk front-end integrated to the Electrical Distribution Design ("EDD") Distribution Engineering Workstation/Integrated System Model ("DEW/ISM") back-end. When complete, the Company will have a seamless end-to-end process for queuing, tracking, and managing DER interconnection requests, be able to more quickly analyze and respond to interconnection requests and integrate connected DER into engineering and operating models more seamlessly and efficiently.

Participation in the NYSERDA PON 3026 has and will continue to also assist the Company in meeting the IOAP requirements. The automation capabilities outlined as part of the IOAP phased requirements align with the three-step technical evaluation process summarized as part of this NYSERDA effort:

1. **Initial Technical Screen**: An automated simple screen checking location, size, and existing PV in and near the requested location.
2. **Supplemental Review**: An automated, more detailed screen with power flow and step change analysis run on the feeder that includes analyzing all existing PV plus the proposed new PV site against O&R criteria based on IEEE 1547.
3. **Interconnection Requirements Study**: A semi-automated detailed analysis performed by an engineer that includes identifying mitigation strategies to reduce/eliminate criteria violations when a request fails the automated screens.

This project began in 2017 and is expected to be complete by the end of 2019.

NYSERDA PON 3397 Project

O&R has also partnered with EPRI, National Grid, and Central Hudson to win a NYSERDA award ("NYSERDA PON 3397") for Advanced Operational Solutions for Modernizing Distribution Systems. The purpose of this "Monitoring Requirements and State Estimation to Improve Distribution Visibility" project is to advance operational analytics and control algorithms such that the distribution system and DER can operate in a coordinated fashion.

As discussed in the Grid Operations section, to effectively realize DER benefits, it means using DER as any other resource on the distribution system; considering and leveraging DER capabilities and limitations. M&C capabilities will need to evolve to address the challenges presented by high penetration DER, while also realizing the operational benefits of these new measurement and control assets. This project will provide recommendations for the proper combination of sensing devices and monitoring requirements to establish distribution performance visibility. With new distribution system state estimation ("DSSE") methods implemented in the DMS, this project will provide O&R improved situational awareness and network topology recognition.

O&R began its project tasks in Q1 2018 and is expected to be complete its tasks by the end of 2019. By partnering with EPRI, National Grid, and Central Hudson, O&R can share and learn from the project tasks performed by its peers. These shared learnings will enable improved grid planning and operation and provide a method for all utilities to operate the grid more effectively.

DOE ENERGISE Project

The Company is also partnering on an innovative project developed at the University of Vermont ("UVM") and received a $1.8 million award in 2017 from the DOE SunShot Initiative ("SunShot") for research aimed at improving the electric grid's ability to accommodate renewable energy. The award is one of only thirteen awarded nationally and is part of the Enabling Extreme Real-time Grid Integration of Solar Energy ("ENERGISE") program.

As more solar is connected to the grid, O&R will have to manage an increasingly variable power supply, which creates challenges for maintaining reliable, resilient, and economic grid operations. The UVM-led project seeks to overcome these challenges by adapting advanced real-time control and optimization tools, reducing one of the barriers to DER interconnection.

This project will provide a tiered, multi-time-scale, distributed model-predictive control ("MPC") architecture to coordinate and manage interconnected distribution system resources. This MPC architecture will include control of utility actionable devices such as transformer load tap changers, switched capacitors, and regulators, in coordination with customer-sited devices and technologies such as DERs, and batteries with smart inverters, in order to enable conditions that seek to optimize the economical, safe, and reliable operation of the electric delivery system under high PV penetration. With appropriate control algorithms and actionable devices, the Company will have the capability to better operate and optimize the distribution system as DERs continue to interconnect.

The Company and the associated project team is making significant strides and is expected to complete this project by the end of 2020.

Industry Participation and Working Groups

In addition to pursuing innovative opportunities through NYSERDA and other industry partnerships, O&R is also an active member of EPRI, the IPWG and the ITWG. The IPWG focuses on non-technical process and policy issues, while the ITWG focuses technical concerns affecting the DG community, the interconnection process, and the interconnecting utility grid. Through active participation in these groups, the Company is able to identify innovation opportunities and gain insights on best practices in the industry.

O&R, as part of the ITWG, developed several technical documents addressing ITWG priorities as a means of clarifying and formalizing aspects of the interconnection process, including:

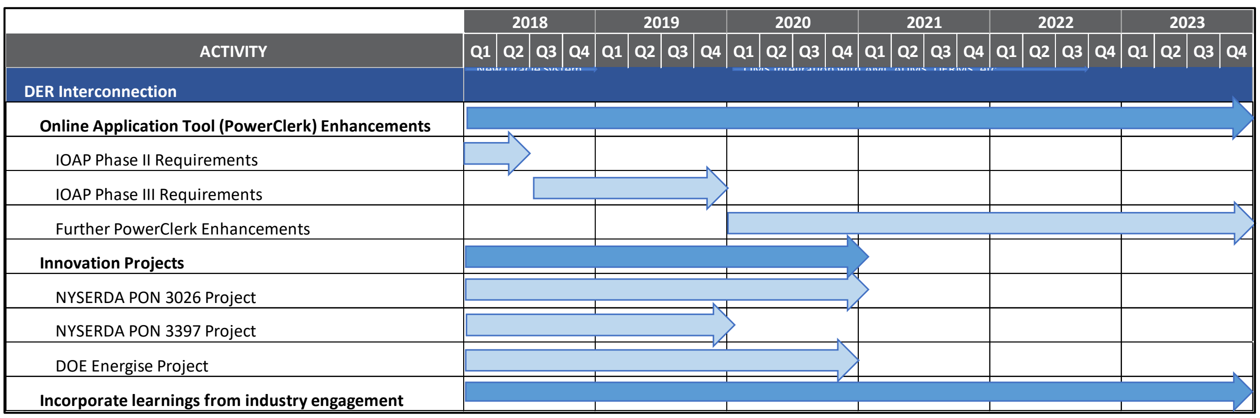
- Interim requirements on anti-islanding;
- M&C requirements;
- Recommended changes to EPRI's proposed modifications to the SIR screens to improve effectiveness and support future automation;
- Documentation specific to voltage issues and voltage flicker in support of the SIR revisions; and
- Proposed energy storage application requirements and SIR review updates.

Given the growing interest in energy storage, O&R continues to work with the JU to reduce barriers to energy storage interconnections. By developing a standardized technical screening process for storage applications, the materials required from developers and customers at the time of the application will be consistent and the review process formalized to help streamline storage applications. The JU are also discussing the potential need to restructure the timing and cost structure of the SIR review for energy storage due to the heightened complexity of storage projects relative to solar PV. The additional time and resources necessary to adequately evaluate the protection and controls required to provide safe and reliable interconnection under various operating conditions is of particular concern. O&R, as a member of the ITWG, is working to resolve these issues to allow energy storage applications the appropriate level of review without making the process too costly or burdensome to the customer. While energy storage is a growing focus for the ITWG, the Company continues to support the ITWG's goals of reducing barriers to entry for all DER types and is working collaboratively with DPS Staff and stakeholders to provide greater predictability of interconnection costs to customers.

Future Implementation and Planning

O&R plans to continue to demonstrate its support of interconnection efforts through continued IOAP enhancements, new technology initiatives and demonstration projects, industry participation, and stakeholder engagement. In addition, the Company's NYSERDA PON and DOE research and development projects will lead to further improvements in the interconnection process, and additional lessons learned will inform future refinements. The following graphic highlights the Company's five-year plan specific to Interconnection.

Table 27: O&R Interconnection 5-Year Plan



Continued Portal Enhancements and IOAP requirements

As discussed above, Phase I entailed the automation of the application process, and Phase II involved the full automation of the SIR defined screens. As of July 2018, O&R has completed both Phases I and II.

Phase III, to the extent possible, will further automate all application and portal processes, integrating the application processing for larger systems with distribution planning, hosting capacity results, and feeder analysis. Implementation will depend upon closing data gaps while integrating feeder analysis and planning with DG penetration data. The timing of this deliverable will be contingent upon the delivery of EPRI screening modifications, and integration of the Company's GIS and distribution planning systems.

O&R continues to work with Staff and the ITWG to understand and overcome challenges to the screen automation required for Phase III. As the SIR changes are formalized and supplemental screens are updated or clarified, the Company can proceed with exploring additional automation.

New Technologies

As the NYSERDA and DOE projects are completed, O&R plans to continue to seek out opportunities to partner and innovate on projects to prove out and improve both interconnection and grid optimization concepts.

Optimal Export Demonstration Project

O&R's Optimal Export Demonstration Project was approved in December 2017, and the Company plans to commence in Q4 2018. Using traditional planning and interconnection criteria, there is typically a limit to the amount of DER that can be interconnected to the grid without requiring significant system upgrades to mitigate potentially detrimental impacts to the distribution system. This project will test whether advanced inverter functionality and third-party M&C hardware and software can maximize a proposed DER's ability to export without negatively impacting reliability, power quality, and/or distribution system performance, while potentially reducing developer/customer interconnection costs. The Company will explore customer and third-party interest and acceptance of active DER management solutions as an alternative to incurring higher cost system interconnection expenses.

This project will enable the Company to validate the use of these new technologies, gain insight into the value proposition, and better understand developer willingness to employ such technologies as an alternative to higher cost interconnection arrangements.

SIR Updates

The SIR is expected to continue to change over time as the number of interconnection applications increases, further experience is gained, and utility and developer needs evolve. Potential modifications to the SIR will continue to be vetted in the ITWG and IPWG. Similar to the solutions reached on anti-islanding and M&C, future interim requirements developed by the ITWG will be made publicly available online for use until they can be added to the individual utility or state-level interconnection requirements. As resolutions are reached by the ITWG and standardized at the individual utility level, interconnecting customers can expect benefits such as faster application turnaround times and reduced interconnection costs.

Industry Participation and Working Groups

O&R plans to continue to be an active member of EPRI, the IPWG, the ITWG and remain engaged in the NYISO Taskforce and the NY Prize efforts with NYSERDA. NY Prize is a first of its kind competition to help communities create community microgrids. Although no communities in the O&R service territory have been awarded, the Company continues to engage in the process.

The growing focus on energy storage and smart inverter technology, will drive future JU working group discussions. As directed in the recent New York State Energy Storage Roadmap, the ITWG and IPWG will work with NYSERDA to develop a schedule for soliciting energy storage bids to research and examine inverter-based solutions that can adequately limit reverse power flow. Such solutions eliminate the need for additional relays for systems below an established threshold (*e.g.*, 1 MW) by December 2018. Results shall be available so that a recommendation may be considered before the end of 2019. Additionally, the JU, through the ITWG and IPWG, shall work collaboratively with stakeholders to identify possible alternative approaches for increasing hosting capacity.

Risks and Mitigation

As more DERs are integrated into the Company's distribution system, it will become increasingly important for the Company to have a robust and efficient interconnection process. As the volume and complexity of projects increase, the ability to connect DER quickly, safely, and reliably relies on the Company's ability to continue to fully automate processes, as outlined in IOAP Phase III and identify new technology alternatives. Any delays in automation and/or limitations in available technology could impact the Company's ability to implement Phase III and subsequently integrate large volumes and complex DER in a timely manner.

O&R is mitigating this risk by continuing to work with the ITWG to understand the hurdles of further automation and NYSERDA and the DOE to vet new technologies and prove out interconnection and grid optimization concepts.

Stakeholder Interface

As described above, O&R has engaged with many stakeholders throughout the interconnection development process including EPRI, the ITWG and IPWG, and vendor/technology firms.

Additional Detail

This section contains responses to the additional detail items specific to Interconnection.

1) A detailed description (including the Internet address) of the utility's web portal which provides efficient and timely support for DER developers' interconnection applications.

O&R's interconnection information, beneficial to developers in preparation for submitting an application, is available at the following (link). Developers have access to the:

- NY SIR, outlining the interconnection requirements in NY
- Hosting Capacity map, providing system data and indicating areas for less costly interconnection
- Value of DER tranche information, highlighting available capacity for compensation
- Queue reset, displaying the status of large projects (>50kW)
- 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 as well. 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. To assist in navigating PowerClerk, the Company promoted the software's YouTube "How-To Guides" ahead of the software transition in April 2016. O&R's Corporate Communications Team also redirected traffic from the old site to the new portal.

2) **Where, how, and when the utility will implement and maintain a resource where DER developers and other stakeholders with appropriate access controls can readily access, navigate, view, sort, filter, and download up-to-date information about all DER interconnections in the utility's system. The resource should provide the following information for each DER interconnection:**

   a) **DER type, size, and location;**

   b) **DER developer;**

   c) **DER owner operator;**

   d) **DER operator;**

   e) **The connected substation, circuit, phase, and tap;**

   f) **The DER's remote monitoring, measurement, and control capabilities;**

   g) **The DER's primary and secondary (where applicable) purpose(s); and,**

   h) **The DER's current interconnection status (operational, construction in-progress, construction scheduled, or interconnection requested) and its actual/planned in-service date.**

Most of this information is available via the Commission website (link) in a redacted format for projects installed, as well as projects in queue. The website includes:

- DER type and size
- DER developer
- Connected substation and circuit
- Actual in-service date

With the PowerClerk software, developers are also able to review their portfolio of projects upon logging into the software for the projects they manage. In PowerClerk, if entered with the application, developers can also see:

- DER type, size, and location
- DER developer
- DER owner operator
- DER operator
- Connected substation and circuit
- DER's current interconnection status (operational, construction-in-progress, construction scheduled, or interconnection requested)
- Actual in-service date

The following information is not collected by O&R during the interconnection application process:

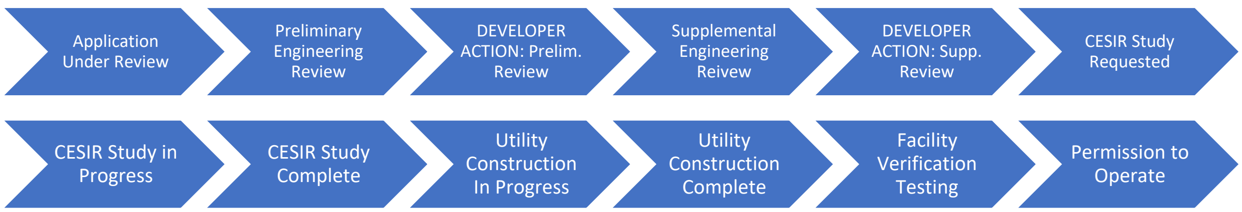
- Phase and tap
- Remote monitoring, measurement, and control capabilities
- Primary and secondary purpose(s)

With the proper customer consent, O&R is amenable to collecting and disclosing additional information, if requested by developers and other stakeholders.

3) **The utility's means and methods for tracking and managing its DER interconnection application process to ensure achievement of the performance timelines established in New York State's SIR.**

The PowerClerk software is utilized as the primary means and method for tracking compliance with the SIR in the application process. Each SIR compliant milestone is linked to either a status or data tag within the PowerClerk workflow. Alerts, deadlines, and milestones related to SIR compliance are embedded within the PowerClerk software to guide users and the Company through the process. As deadlines approach, O&R (via PowerClerk) notifies the developer of the upcoming deadline. The same notifications are utilized internally for O&R for utility-sided work related to the interconnection. The SIR timelines are auditable by running reports within the software for performance as well. Any deviations or over-rides of dates is captured within the software to ensure data integrity and reportable findings.

Figure 26: SIR Timelines



4) **Where, how, and when the utility will provide a resource to applicants and other appropriate stakeholders for accessing up-to-date information concerning application status and process workflows.**

O&R recognizes detailed instructions available for application submission, access to current status and milestones and administrative support as key elements required for a successful interconnection process. Detailed focus in these areas was key to laying the foundation for delivering the critical requirements in the SIR process and enhancing the customer experience. As part of the expanded vision for interconnections and grid automation, the Company hired and trained dedicated resources within the newly formed Technology Engineering department to assist customers in the interconnection process. The Technology Engineering department is available to provide support to developers throughout the interconnection application process. For projects greater than 50kW, once O&R has received payment from the developer as outlined in the SIR and an application for service has been submitted, in addition to the Technical Engineering support, a New Business project manager is assigned.

Additionally, stakeholders can view up-to-date information regarding the status of their project in PowerClerk. The tool allows the applicant/developer insight into the milestones, workflows and deadlines throughout the process.

5) **The utility's processes, resources, and standards for constructing approved DER interconnections.**

In late 2016, O&R mapped the workstream associated with bringing a DG asset online from the application approval through construction and the issuance of a final acceptance letter. The initial review and implementation of roles and responsibilities in the process was completed in Q1 2017, and the Company conducted a table-top simulation exercise in March 2017 with all the relevant departments. Roles within the New Business, Engineering, Customer Services, and Operations areas were defined and aligned to assist in the construction of the Company's interconnection facilities for developers. The process from application to energization was documented with roles and responsibilities communicated to all participants. The process includes five key steps as shown below:

Figure 27: DER Interconnection 5-Step Process

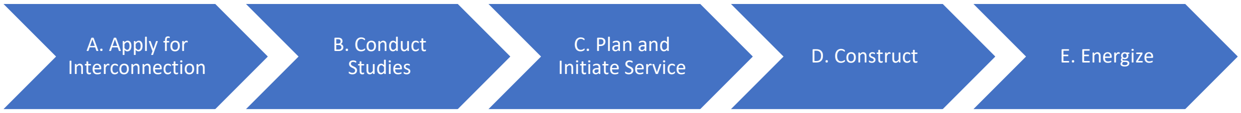
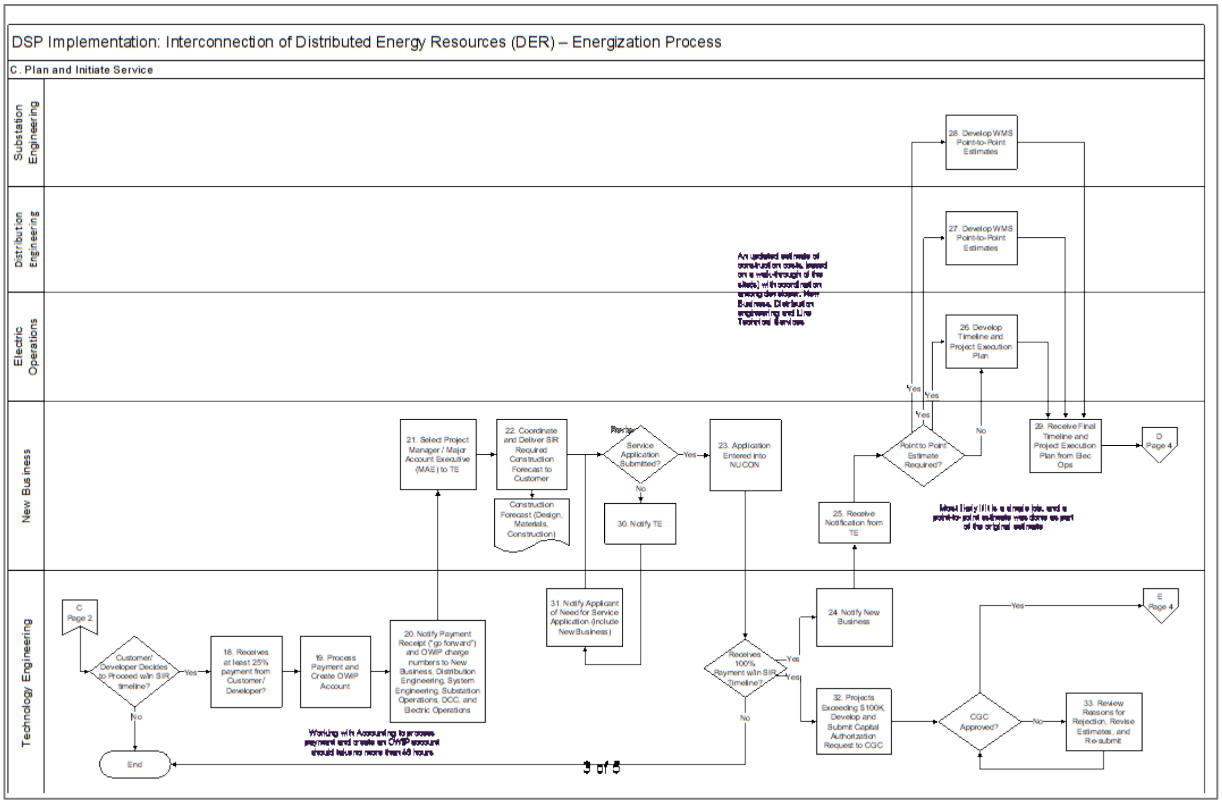


Figure 28: Excerpt from DER Interconnection Process Workflow



As part of Step C, Plan and Initiate Service, once a large project developer (greater than 50kW) decides to move forward and makes an initial payment for interconnection and 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. 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 set, 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, 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 permission to operate and allowed to generate per the SIR.

6) The utility's means and methods for tracking and managing construction of approved DER interconnections to ensure achievement of required performance levels.

The Company plans to utilize Oracle's Primavera P6 software as the tool for tracking and managing utility interconnection construction activities by Q3 2018. This software, already used in other areas of the Company, will assist the project managers, engineers and project owners in prioritizing, planning, managing, and delivering successful projects, programs, and portfolios. The software also provides stakeholders with more visibility into construction status, milestones, and deadlines.

The software will provide visibility to the construction deadlines and milestones. The added visibility will allow all engaged internal parties to be updated on the construction progress.

7) Where, how, and when the utility will provide a resource to DER developers and other stakeholders for accessing up-to-date information concerning construction status and workflows for approved interconnections.

Stakeholders can currently view up-to-date information regarding the status of their project via PowerClerk. The tool allows the applicant/developer insight into the milestones, workflows and deadlines throughout the process.

Additionally, O&R's Technology Engineering department is available to provide support to developers throughout the interconnection application process. For projects greater than 50kW, once O&R has received payment from the developer as outlined in the SIR and an application for service has been submitted, a New Business project manager is assigned. Paired together the New Business project manager and Technology Engineering support contact work together to assist during field construction. This direct contact with a project manager is established to guide the customer through project requirements all the way through energization.

Advanced Metering Infrastructure

Introduction/Context and Background

O&R began the Smart Meter journey in early 2015 as the first utility in New York to receive Commission approval[131] to move forward with a Smart Meter AMI program (heretofore referred to as "AMI Program"). Approval of the initial phase of O&R's AMI Program paved the way for O&R's installation of an AMI communications infrastructure and deployment of electric smart meters and gas AMI modules (collectively known as "the meters") across Rockland County. In late 2017 the Company received Commission approval[132] to implement the AMI Program throughout the remainder of its service territory (Orange and Sullivan Counties).

Since July 2017 the Company has rapidly deployed over 112,600 meters and is on track to complete the entire deployment of 363,000 meters by December 2020. Throughout deployment, the O&R AMI team actively monitors and manages installation safety, quality, customer engagement, and the Opt-Out process.

The backbone of any AMI project is the technology. O&R, in collaboration with CECONY, deployed the AMI Head-End System, Meter Asset Management System (associated data conversion and inventory KIOSKS), Meter Data Management System, Profield Meter installation system and customer system changes in May 2017. These system changes, which the Company continues to monitor closely, are working well in support of the meter deployment, billing, and customer engagement efforts.

Along with producing tangible operational benefits, the AMI project will drive improvements in the convenience, speed, and quality of the services that the Company provides to all of its customers both during routine business activities and during outage situations. AMI also provides a foundation of information and communications capabilities that will enable the Company's customers to become informed and engaged energy consumers. Operating in concert with an advanced web portal, the AMI will provide customers with the information and controls necessary to help them manage their energy usage, control costs, and help the environment. Additionally, in a separate program, DCX, the Company, along with CECONY, is continuing to design and implement features in its new advanced web portal that leverage state of the art digital technologies to enhance customer engagement and communication.

The O&R AMI Program is on schedule and on budget. O&R continues to support and engage both internal and external stakeholders regarding the AMI project.

Implementation Plan, Schedule, and Investments

O&R's AMI Program implementation encompasses three main areas: AMI communications equipment, AMI smart meters, and AMI technology and systems.

---

[131] Case 14-E-0493, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric Service*; Case 14-G-0494, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Gas Service*, Order Adopting Terms of Joint Proposal and Establishing Electric Rate Plan (issued October 16, 2015)
[132] PAP Proceeding, PAP Order.

AMI Communications Equipment

O&R is leveraging AMI communications infrastructure to support grid modernization initiatives

O&R began communications equipment deployment in Rockland County (92 pole mounted Access Points and 42 Relays) in February 2017 and completed deployment in May 2017. O&R expects to begin similar deployment in Orange and Sullivan Counties (235 pole mounted Access Points and 220 Relays) in July 2018 with expected completion in the first quarter of 2019.

To date, the communication devices have been working well with only one device powering off during the significant March 2018 winter storms. As part of the O&R AMI project plan, the Company is deploying an "Extended" battery solution to support communications devices located in harder-to-access areas such distribution lateral lines, or spurs, extending off mainline distribution circuits. The standard battery for these devices provides up to eight hours of battery backup power. The Extended battery solution provides up to six days of battery backup. The extended battery solution will be installed in 164 communication device locations across New York, or approximately 28% of the total.

A summary of communication device deployment, both current and forecasted, is provided in the figure below:

Table 28: O&R AMI Program Communication Equipment Deployment Summary

County/Equipment	Deployed Communication Devices	Communication Devices to be Deployed	Total Communication Devices
Rockland Relays	42	0	42
Rockland Access Points	92	0	92
Orange & Sullivan Relays	0	220	220
Orange & Sullivan Access Points	0	235	235

AMI Smart Meters

Since 2017, O&R has deployed over 112,000 AMI meters and is on track to complete the entire deployment of 363,000 meters in 2020

The Company began the deployment of AMI electric meter and gas modules (collectively, the meters) in July 2017. As of June 2018, the Company had deployed just over 112,600 meters across the service territory. At the current pace, the deployment effort is on track and expected to increase at a higher rate, due to more favorable summer weather conditions. The O&R AMI Team continues to actively monitor installation safety, quality, customer interaction, customer engagement, and the Opt-Out process. Rockland County meter deployment, which is being directed from a warehouse in Stony Point, NY is expected to be complete by August 2019. The Company will direct Orange and Sullivan County meter deployment from a warehouse in Waywayanda, NY. The Company expects to commence full field deployment of meters in Orange and Sullivan Counties in August 2018 and complete such deployment by December 2020.

A summary of AMI meter deployment, both current and forecasted, is provided in the table that follows:

Table 29: O&R AMI Meter[133] Deployment Summary (as of June 13, 2018)[134]

County	Deployed Meters	Meters to be Deployed	Total Meters
Rockland	110,309	97,191	207,500
Orange & Sullivan	2,318	152, 782	155,100

AMI Technology

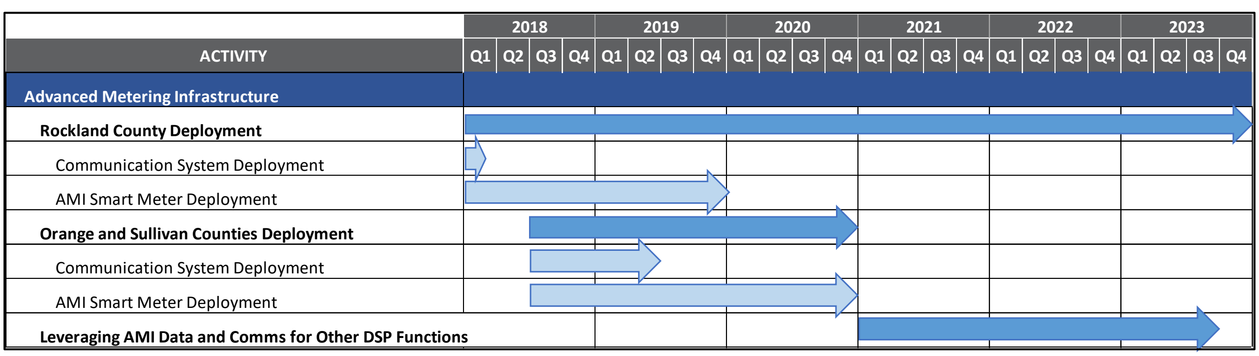
AMI technology and systems including the AMI Head End System, Meter Asset Management System, Meter Data Management System, Profield Meter installation system, and other customer system changes have been implemented in collaboration with CECONY. The collaboration has provided a useful platform from which to install and maintain all of the integrated systems making up “AMI”.

The Company is deploying strategically phased software updates and system enhancements (“Releases”) to further enhance AMI. The second Release of AMI functionality occurred in May 2018. This Release included automated meter hot socket alarms and utility employee-initiated meter interactions such as Power Status Verification, On Demand Reads and Remote Connect/Disconnect. The third Release of AMI functionality, scheduled for September 2018, will include support for methane sensor deployment and AMI data integration into the OMS. The third Release will also provide support for the Company’s Smart Home Rate (“SHR”) demonstration project by providing the hourly usage data required to implement the proposed innovative pricing structures. The fourth Release is scheduled for early 2020 and will support the conversion of “Large Power” customers from legacy interval meters to AMI interval meters.

Five Year Forecast

The AMI Program five-year forecast is provided in the table below:

Table 30: O&R AMI Program 5-Year Forecast



Risks and Mitigation

O&R's AMI Program is a multi-year, capital-intensive project that "touches" virtually every customer served by O&R. As with any extensive project, proactive identification, management, and

[133] Meters includes both electric AMI meters and gas AMI modules.
[134] Customer Information Management System AMI Meter Actions Daily Report.

mitigation of risks and emerging threats is a fundamental project management task. O&R accomplishes this through weekly meetings with project leaders and with the ongoing coordination and alignment of O&R's AMI efforts with those of CECONY. Having two large AMI projects working in concert allows for significant sharing of ideas as well as the identification and management of risks that may be common to both efforts. The Company's transition to a DSP is dependent upon many elements including successful Smart Meter deployments, and as such, actively managing and where possible preventing risk is essential.

Managing safety risks is a top priority for O&R in every facet of work. With such a significant portion of the AMI Program effort performed in the field in an unforgiving environment (electricity and gas), safety is paramount. O&R emphasizes safety every day, and in every facet of the AMI Program, and will continue to do so.

Cybersecurity

The Company recognizes the risks associated with malicious software attacks and maintains a comprehensive cybersecurity program as described in Chapter 2 (Cyber-Security). This program is designed to protect Company computers, servers, business applications and data, and high-value networks from unauthorized access and control from both external and internal threats. O&R also recognizes that the threat landscape continually evolves and expands and that it is critical to continuously improve the Company's defense posture through investments in technology, improvements in our cybersecurity processes and collaboration with law enforcement, regulatory and industry resources. The customer engagement plan provided a data privacy review based on cybersecurity standards.

The Company's cybersecurity program is built upon a formal cybersecurity policy using the International Standardization Organization (ISO) Standard 27002 as a reference model. The foundation of ISO 27002 is to protect the confidentiality, integrity, and availability of systems and data through a process to regularly evaluate all aspects of the program, including a review of policies, standards, and procedures in addition to the actual implementation of technical controls. These objectives support the Company's goal to provide reliable electric and gas service to businesses, government agencies, and consumers.

Stakeholder Interface

The customer continues to be a primary focus for the Company on this project. To date, the Company has employed numerous focus groups, surveys, customer education events, Home Shows and meetings with elected officials in the communities to inform and engage customers and answer questions about AMI. Through these events, the Company is seeing a definite shift toward deeper customer engagement. The focus groups, surveys, and home show interactions have also demonstrated an understanding of AMI by a broader section of the customer base. The studies showed an increase in customer understanding of AMI from 33% in 2016 to 59% in 2017. Home Show attendees, in particular, were more confident in their knowledge and awareness of AMI and often expressed eagerness as to when meters will be installed in their area.

Over the past year, the Company has participated in a multitude of outreach events and community forums to discuss the Company's AMI Program and answer questions. The Company is planning similar events in other communities as the deployment expands to Orange and Sullivan Counties. The following table sets forth the date and audience of the events through July 2018.

Table 31: AMI Program Stakeholder Outreach Summary

Date	Location	Audience
04/17/17	Spring Valley	DPW and Public Safety Employees, Rotary Club on 10/04/17
04/20/17	Rockland County	Fire Department Chiefs (also on 2/5/18)
04/27/17	Town of Ramapo	Police and Building Departments
05/08/17	Village of Wesley Hills	Municipal Employees
05/11/17	Village of Pomona	Mayor, Municipal Employees
05/12/17	Orange County	Mayors, Supervisors, Clerks, Police, Highway, Building Officials
05/17/17	Orange & Rockland	Company Retirees
05/31/17	Town of Haverstraw	Municipal Employees
06/08/17	Town of West Haverstraw	Municipal Employees and Senior's Association (9/21/17)
06/08/17	Village of Haverstraw	Mayor, DPW and Municipal Employees
06/22/17	Village of Montebello	Municipal Employees
06/26/17	Village of Suffern	Mayor, Municipal Employees
06/27/17	Village of Airmont	Mayor, Municipal Employees
07/03/17	Village of New Square	Mayor, Municipal Employees, Code Enforcement
07/05/17	Village of New Hempstead	Municipal Employees
07/26/17	Orangeburg	Fire Department
08/10/17	Town of Stony Point	Municipal Employees
08/30/17	Village of Monsey	Religious Leaders
02/15/18	N/A	Senator David Carlucci's Senior Advisory Committee
02/23/18	Rockland County	Home Show (2/23-2/25)
03/16/18	Orange County	Home Show (3/16-3/18)

O&R has received positive feedback regarding its in-person customer engagement efforts as well as engagement efforts via social media. Customers look to the utility as the experts on the functionality and usefulness of the AMI program and seek information from the O&R representatives. Stakeholders most often seek information that enables them to make informed decisions about their energy usage. The Company recognizes the importance of stakeholder feedback it is receiving and continues to adjust its engagement efforts moving forward based on suggestions and comments as received. Additionally, the Company has continued to modify its process for "recovering" customers that "opt-out" of the Smart Meter program. The Company works to identify each specific customer concern that initiated the opt-out and explicitly address that concern with the customer. This individualized approach takes additional time but generates better results; 41% of the time a customer’s interests are elevated and discussed, the customers opt to have an AMI meter. Overall the Smart Meter opt-out percentage is less than 0.4%.

Finally, the Company recognizes that strong partnerships with its municipalities, elected officials, and emergency services organizations are a crucial step toward moving forward with successful customer engagement. In addition to reaching out directly to O&R, customers will make inquiries to the local municipal officials. By meeting with officials across the service territory and providing them with pertinent AMI Program information they can act as "co-messengers" along with the Company to inform customers.

Additional Detail

1) Provide a summary of the most up-to-date AMI implementation plans, including where AMI has been deployed to date.

See the O&R AMI Program Communication Equipment (as of June 13, 2018) and AMI Meter Deployment Summaries previously provided.

2) Describe in detail where and how the utility's AMI provides capabilities which:

a) Help the utility integrate DERs into its system and operations;

Accurate measurement of the energy supplied by DERs is needed to support the connection and use of DERs. O&R's AMI infrastructure (meters and communication network) enables bi-directional energy measurement and retrieval of measurement data from the DER device (or devices) and associated equipment (*e.g.,* sub-metering). The granularity of usage data and the speed by which that data is made available is an AMI capability that will help integrate DERs into O&R's system and operations.

Recognizing the value of granular usage data provided by AMI meters, O&R has accelerated AMI deployment in specific locations where DG is scheduled to be interconnected with the Company. For example, the Company is developing an approach to install AMI equipment around several interconnection sites in Orange County ahead of plan, without having to deploy the entire AMI mesh network. Strategically deploying AMI in this manner improves the use of the interconnection sites more rapidly than originally planned.

b) Help DER developers plan and implement DERs;

The use of customer profile load shapes (8,760 hours) to estimate kW demand and kWh energy usage patterns for customers and equipment, and the resulting impacts on distribution feeders and generation requirements is a process used by developers to site DER. Customer load shapes in use today are often built with limited granular usage data and averaged across a large number of customers. The granularity of AMI data (*e.g.,* 15-minute intervals) breaks this limitation and provides the opportunity to utilize customer profiles built using actual, real-time data.

Additionally, hosting capacity calculations for a given area are often developed today using average customer profile load shapes. The more accurate the load shapes, the more certainty a DER developer (and the Company) have as to whether or not a given DER solution is optimal for a specific loading condition or geographic location.

As an example, a battery storage solution may appear to be a good solution based on averaged load shapes and the expected peaking periods for a given area. However, once the load shapes using actual AMI usage data are available, it may be determined that the peaking period of some customers may change the performance requirements of the solution.

c) Help DER operators plan and manage operation of their DERs;

The potential for DER to leverage AMI communications infrastructure to provide M&C capabilities for DERs is increasing as the deployment of DERs, and smart meters grows. Usage data helps operators more readily determine specific load pocket needs, and the two-way communications infrastructure necessary for AMI deployment can enable the increased use and improved management of DERs within the Company's service territory by allowing expanded M&C capabilities as ADMS or DERMS systems are developed.

One example of this is the use of AMI communications infrastructure to provide M&C (M&C) capabilities for the deployment of a battery energy storage systems. In this case, leveraging AMI communication infrastructure may allow system operators to have increased M&C capability of energy storage assets by allowing the storage assets' proprietary battery management systems to use the AMI communications infrastructure to provide system operators greater visibility into the assets than otherwise will be possible. The Company is in the early stages of exploring this concept which represents an opportunity for O&R to gain additional experience operating DERs such as storage while more advanced M&C systems are developed.

O&R's Innovative Storage Business Model (“ISBM”) demonstration project is putting this concept into practice. The Company is engaging with its partner, Tesla, and the Company’s smart meter infrastructure vendor, Itron, to jointly develop an understanding of how data from the project's energy storage assets can be incorporated into the Company's DCC in the short term using the AMI’s communication infrastructure while the Company develops a long-term strategy, where assets such as storage and other DER will be integrated into ADMS and DERMS platforms. Learnings from this project, and others will inform how the Company manages DERs in the short-term as well as the development of advanced M&C capabilities and systems in the long-term.

d) Enable or enhance the utility’s ability to implement and manage automated Volt-VAR Optimization (VVO);

The Company is presently investigating, with its AMI vendor, potential solutions that leverage or enhance the AMI communications infrastructure and software for DA purposes such as VVO and FLISR. The communications infrastructure currently in use for DA is radio frequency technology that has certain coverage and bandwidth limitations. AMI communications infrastructure may improve coverage gaps, provide redundancy, and improve data backhaul capability and bandwidth.

The Company is continuing to expand its ability to collect and analyze both system and customer usage data through improved field sensors, and through customer and system information gleaned from AMI. AMI increases the amount of information available to grid operators and planners. Once the Company has the required control systems, communications and field equipment capable of enabling VVO, O&R will utilize AMI data with other system sensors to better control voltage across the system, leading to a reduction in overall energy consumption. As a result, the Company will be able to reduce the amount of power purchased and consumed, reducing the amount of electricity generated along with the associated carbon emissions.

M&C capabilities are vital to enabling grid optimization. Grid optimization aims to find a high degree of balance between reliability, availability and the optimal dispatch of localized DER resources depending on various considerations such as, efficiency, and cost. In order to enable these optimal scenarios, the grid must first be modernized to capture all the necessary data points and have actionable devices to execute these optimal condition states. AMI and other modernized DA devices, working in concert, will capture all of the necessary data required for grid optimization efforts. Ultimately, near real-time monitoring of DER will be essential for the Company to be able to perform as the DSP, tracking DER performance and capabilities both to make same-day operational decisions and for near-term forecasts and scenario decisions.

e) Improve the utility’s ability to prevent, detect, and resolve electric service interruptions;

In early 2018, O&R’s service territory experienced significant electric service interruptions as a result of back-to-back Nor’easters winter storms in March as well as a strong thunderstorm in May. The AMI meter deployment was in the early stages with approximately 40,000 AMI meters deployed in

Rockland County in March and an additional 10,000 AMI meters deployed in Rockland County in May. During the March event, nearly 12,000 AMI meters were manually "pinged" with power on response returned by nearly 4,000 meters (thereby saving many truck rolls normally required to determine service status). During the May event, 160 AMI meters were "pinged" with power on response being returned by nearly 120 meters.

The Company sees this as an early indicator that even with the lack of AMI/OMS system integration the AMI meters and communication devices provide invaluable information. Not only is the Company able to more accurately determine meters are out of service but also identify meters that do not require a field visit as a result of power being on, which allows for more efficient use of field crews during restoration efforts.

Once AMI information is fully integrated into the OMS the Company's management of storm restoration will be enhanced as it can more quickly and accurately determine restoration times, more efficiently utilize field crews, improve on single service restoration times and work toward the elimination of nested outages. Storms can often cause "nested" outages in which there are two or more breaks in the power lines within an area, some of which may be below (or "nested' within) the others. A utility may fix the break closest to a substation without knowing about the second outage. AMI software can "ping" all meters on a particular circuit to verify restoration and also notify the utility if some of the smart meters are still out of power. Prevention of outages will also see improvements as all AMI meters are deployed with internal alarms to communicate "hot socket" conditions. Once a meter has reached a temperature threshold that indicates abnormal activity an alert will be sent to the Company and a field crew can be quickly dispatched to resolve the condition.

O&R is pursuing opportunities to repurpose the AMI communications infrastructure to support other initiatives in grid modernization. As stated previously, the communications infrastructure technology currently in use for DA has bandwidth limitations. In an effort to pursue alternatives, the Company is in discussions with the AMI vendor on solutions that will re-use the AMI communications infrastructure and software for DA purposes. This solution is currently utilized by a number of utilities across the Country. The Company is developing a proof of concept at one of the Company's facilities.

f) Improve the utility's ability to implement rate programs which facilitate and promote customer engagement, DER development, and EV adoption;

Traditional rate engineering of new rate structures is performed using averaged load shapes, rarely do utilities have actual load shapes for every customer. Smart Meter data provides near real-time actual usage data in 15-minute increments. The advent of this type of granular usage data allows for the development of more dynamic rate structures designed to support more granular customer classes and profile types. For example, the electric needs and usage patterns of customers with EVs is drastically different than customers without the need to charge EVs. Likewise, customers who are retired may need to perform more household chores during mid-day hours than those who work. Enabling customers to fully utilize AMI Smart Meter data and the tools necessary to present and use such data for customer-specific needs is the first step. Innovative rate structures which price service reflecting such granular usage profiles is the next step. The Company is working closely with CECONY, utilizing lessons learned through the Innovative Pricing Pilots currently underway and how the results from those pilots can be applied to benefit O&R customers.

With fully enabled AMI, all customers will have access to their interval electricity usage data, which may increase their ability to adjust their consumption patterns to reduce their electricity bill. As a result, customers will have the ability to participate in new rate pilots such as the SHR demonstration project. SHR will provide insight on how residential customers and customer-sited DER assets respond to innovative pricing signals designed to manage the grid better and deliver benefits to customers. The project seeks to provide price-responsive home automation technology options and collect empirical data on a participant's responses that help gauge market opportunities. O&R has defined two SHR tracks. Track one is a rate comparison track paired with smart thermostats. Track two is a storage plus solar track paired with dynamic, time-varying components that closely reflect cost drivers for electric supply and delivery. The implementation timeline consists of phases beginning 2nd quarter of 2017, through 1st quarter of 2020.

3) Describe in detail how the AMI enables secure communication with and among devices at customers' premises to support customer engagement, EE, and innovative rates.

The Company is deploying all residential Smart Meters equipped with ZigBee chips. These chips allow Smart Meters to communicate to Home Area Networks ("HAN"). Customers can purchase HAN equipment along with ZigBee-enabled home appliances. Creating an environment that not only allows for appliances to communicate to a central device controlled by the customer but also relays information about the volume of energy consumed by each appliance will engage customers to more actively control how their home is consuming electricity. Currently, the O&R Smart Meter project does not provide for any HAN, but the Company is not preventing any customers from purchasing them on their own.

As an alternative the Company's DCX platform along with the granular usage data from Smart Meters provides customers with a macro level view of how their home consume electricity within 15-minute increments of every day. This type of data, although not appliance specific, can engage customers to be more aware of their energy consumption. In the future the Company plans to investigate the potential for integrating the granular AMI usage data with My ORU Store offerings. For example, analytics may help identify that a customer's central air conditioning unit may not be operating efficiently, and the Company could provide a targeted offering for an air conditioner tune-up that they could schedule on the My ORU Store website.

Finally, whether via ZigBee, WIFI, or communications through the AMI communications infrastructure (the meter) customers who wish to manage their energy proactively will be able to take advantage of additional rate structures being explored by the Company. Price signals, TOU/time of day and critical peak pricing are all options that can be supported and utilized as a result of the granular usage.

As stated previously, the basic infrastructure that is deployed around Smart Meter programs is the Smart Meter, Smart Meter Communication devices and software/hardware at the Utility. In this deployment, these devices are only passing information related to the customer's total usage consumed at the home/commercial location. No data about customer devices or appliances in the home and how much energy each consumed is measured, passed along, or made available to anyone, including the customer. Detailed discussions with stakeholders and customers are required before such information could become available. The cybersecurity methodologies used by the Company (and described in other sections within this DSIP update) to secure these devices and systems are the same methodologies that will be used secure any other devices that are introduced into that environment. Describe where and how DER developers, customers, and other stakeholders can access up-to-date information about the locations and capabilities of existing and planned smart meters.

O&R consistently provides AMI Program meter deployment information through multiple communication channels. The Company's website (ORU.com) contains a high-level map listing the approximate dates and locations during which meters are being deployed across the service territory. Every customer receives postcards 90 and 45 days in advance, informing them of their upcoming smart meter installation. Each customer is also contacted ten days in advance via a telephone call.

O&R Customer Service Representatives ("CSRs"), as well as other organizations throughout the Company have regular communications with DER developers and customers on the status and progression of AMI meter installations. Finally, numerous external stakeholder presentations have been delivered (and will continue to be offered) during the AMI deployment effort. This method is the most impactful as the Company can provide AMI messaging across a broad landscape and utilize communication channels that will not typically be available to the Company. A list of the stakeholder presentations through July 2018 was previously provided in this section.

Hosting Capacity

Introduction/Context and Background

O&R continues to enhance its hosting capacity capabilities and provide system data which is useful to third-parties for integrating DER into the distribution system. The primary use case for hosting capacity data is to help guide DER investments and marketing activities to areas of the grid where the costs of interconnection are likely to be the lowest. Hosting capacity information is of particular interest to stakeholders as it allows prospective interconnection customers to make more informed business decisions before committing resources to an interconnection application.

O&R met the targets for releasing Stage 2 hosting capacity analysis and is on track for a Stage 3 release no later than October 2019

Leveraging O&R's robust mapping and distribution modeling systems, the Company was able to establish an automated hosting capacity analysis process. This automated analysis uses an integrated model which is now being replicated across the country in other utility and vendor systems.

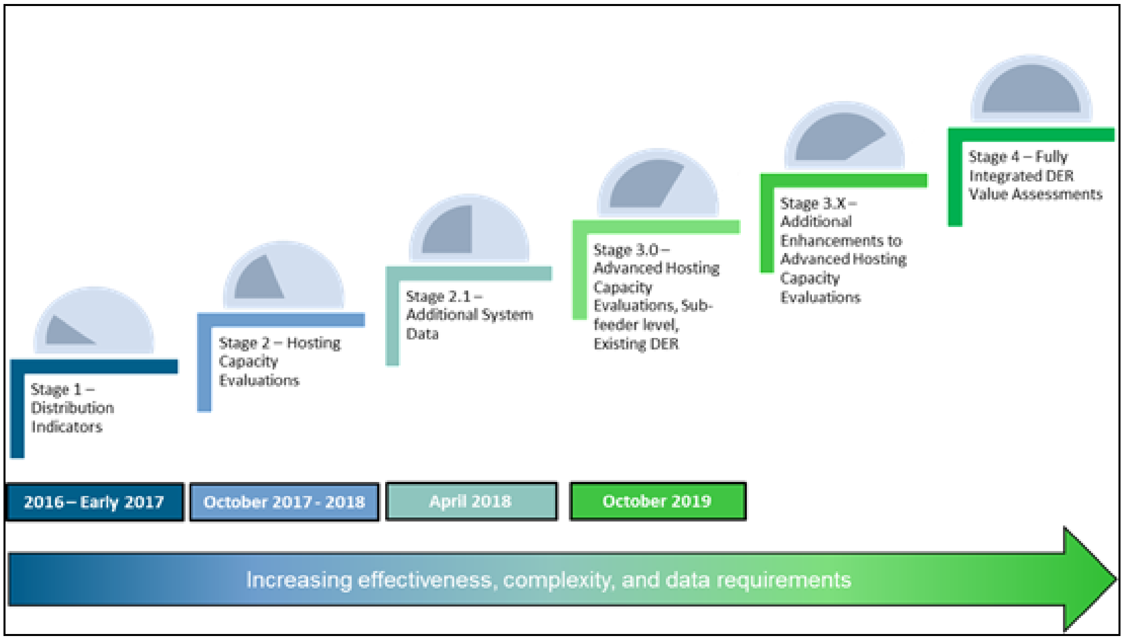
Hosting capacity, as defined by EPRI, is the amount of DER that can be accommodated without adversely impacting power quality or reliability under existing control configurations and without requiring infrastructure upgrades to the primary line and secondary network systems.[135] Hosting capacity can vary across different circuits, as well as segments, within a distribution circuit itself. Hosting capacity will also change over time as the distribution system infrastructure and operations change.

O&R calculates each circuit's hosting capacity by evaluating potential power system criteria violations as a result of interconnecting large solar PV systems[136] to three-phase distribution lines. This approach was deliberately chosen to deliver value in a timely manner to DER developers in New York. The analysis increases visibility into hosting capacity for larger-scale solar PV systems that often target rural areas where land is available, but where hosting capacity can vary substantially from site to site.

The Company's efforts to provide hosting capacity and interconnection information to stakeholders have been following the four-stage approach defined by EPRI[137], adopted by the JU, and reflected in the Initial and SDSIP filings. The four stages are shown in the following figure.

[135] Electric Power Research Institute, *Defining a Roadmap for Successful Implementation of a Hosting Capacity Method for New York State*, Report Number 3002008848 (June 2016)("EPRI Roadmap") p. 2. http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002008848 .
[136] Large solar has an AC nameplate rating starting at and gradually increasing from 300 kW.
[137] EPRI Roadmap, p. 5.

Figure 29: JU Hosting Capacity Roadmap



This approach to hosting capacity complies with the Commission's requirements for calculating and displaying hosting capacity data.[138] O&R met the Commission's targets for releasing Stage 2 hosting capacity analysis, which centers on circuit-level hosting capacity for all relevant three-phase circuits. The JU provided an update with additional system data in their Stage 2.1 release in mid-April 2018.[139] O&R will publish an annual update to the circuit-level hosting capacity by October 1, 2018 and the Company is on track for a Stage 3.0 release by no later than October 1, 2019 that will provide sub-circuit level hosting capacity and incorporate existing DER into the modeling.[140]

The evolution to this more granular hosting capacity analysis allows better visibility into hosting capacity for sub-circuit segments. Developers will be able to identify specific locations with higher levels of hosting capacity and potentially lower interconnection costs. The JU will evaluate additional enhancements to the hosting capacity portal following the publication of the Stage 3.0 analysis. The future Stage 3.X releases could include enhancements such as increased analysis refresh frequency and additional information such as forecasted hosting capacity evaluations.

[138] DSIP Proceeding, DSIP Order, pp. 43-46.
[139] DSIP Proceeding, JU Supplemental DSIP, p. 54.
[140] The impacts of all existing DER are reflected in the underlying circuit load curves and load allocations of the analysis in Stage 2. This enhancement incorporates the interconnected DER to date into the circuit models used for the hosting capacity analysis with a priority on large PV, which remains the DER technology with the most significant impacts on hosting capacity.

Implementation Plan, Schedule, and Investments

Current Progress

O&R was the first utility in the nation to integrate EPRI's DRIVE tool into an automated process

Since filing the IDSIP and the SDSIP which incorporated input from several months of stakeholder engagement, O&R released and updated its Stage 1 red zone distribution indicator maps. The Company completed the Stage 2 hosting capacity analysis for all radial distribution circuits at and above 12 kV by October 1, 2017, as required by the Commission,[141] using the EPRI Distribution Resource Integration and Value Estimation ("DRIVE") tool. The DRIVE tool was chosen to support further alignment and a common approach among the JU, as it leverages existing circuit models in a utility's native distribution planning software to carry out an analysis of hosting capacity.

O&R is a pioneer in setting up an automated hosting capacity analysis process and its integrated model is being replicated within other utilities and vendors across the country. This automated process follows all of the required steps needed to calculate hosting capacity for the entire O&R NY territory. These steps include obtaining the initial mapping data, generating required files with the power flow calculated, and then running the files through the DRIVE tool. O&R began to lay the foundation for this method when it worked to update its mapping and power flow simulation systems. The experience and information gained from previous projects has allowed O&R to create the modelling files for DRIVE that permit an accurate analysis to be run in a shorter amount of time as compared to other methods. To bolster this analysis process, O&R worked with multiple vendors to integrate all of these tools together into one process that can be run in a fully automated fashion without any human interaction.

The hosting capacity map displays pop-up boxes which provide system data, including minimum and maximum total three-phase circuit hosting capacity, voltage, and installed and queued DG values. The JU worked collaboratively with stakeholders to identify additional hosting capacity data elements that could further enhance the value of the data displayed to developers. The Company, in collaboration with the JU, agreed to provide those additional data elements at the substation level[142] as part of a "Stage 2.1" release, and include:

- Installed and queued DG;
- Total DG (sum of installed and queued DG);
- Data refresh date; and,
- 2017 peak load.

In addition, as described in the System Data section of this DSIP update, in July 2018, the Company again enhanced the data provided on the maps by updating and including the following data:

- LSRV designated areas with relevant data pop-ups;
- NWA designated areas with relevant data pop-ups;
- 5-Year system level load forecast;
- 8760 (2017) historical load data by substation load area;
- 8760 (2018, 2019 and 2020) forecast load data by substation load area; and,

[141] DSIP Proceeding, DSIP Order, p. 14

[142] Substation-level information may be provided at the individual substation transformer bank level when appropriate. A unique identifier is included noting the specific substation transformer bank in those instances.

- 2015 actual minimum 24-hour load curve by substation load area.

Future Implementation and Planning

Following the Stage 2.1 release, O&R will begin preparing for the release of Stage 3.0. Consistent with the SDSIP and in alignment with stakeholder feedback, the Stage 3.0 release will include modeling of existing DER and sub-circuit level hosting capacity analysis. These enhancements will provide more valuable information to developers using the hosting capacity maps. For example, although the impact of existing DER on-circuit load curves was already reflected in the modeling in Stage 2, the Stage 3.0 release will directly indicate installed DER in the circuit models to better reflect their impact on PV hosting capacity. In addition, the increased granularity of data in the Stage 3.0 release will provide more locational-specific sub-circuit level information to inform developers.

Subsequent Stage 3.X releases will further enhance the information provided on the hosting capacity portal. O&R is evaluating options to further improve hosting capacity analysis and will continue to solicit input from stakeholders on the continued evolution of the JU hosting capacity roadmap. Possible enhancements for inclusion in Stage 3.X releases identified thus far include:

- Forecasted hosting capacity;
- Increased analysis refresh frequency;
- Circuit reconfiguration assessments and operation flexibility;
- Upstream constraints such as 3V0; and,
- Incorporation of use cases for energy storage.

O&R's automation provides a refresh of hosting capacity data on a monthly basis, exceeding the current annual refresh requirement

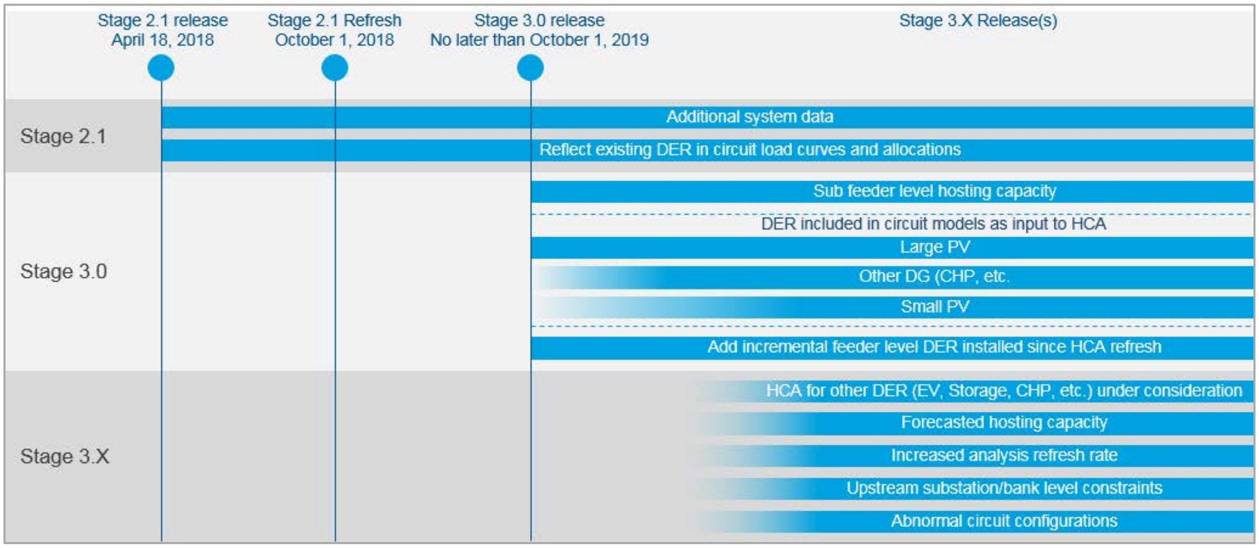
The Company, along with the other JU, will evaluate options for forecasting hosting capacity that consider the accuracy of such an analysis given the uncertainty in the location, timing, and configuration of DER adoption forecasts, projected changes to individual customer loads and any upgrades or changes to the utility system. The roadmap for forecasting hosting capacity must incorporate models of future utility system configurations, gross load forecasts, and DER forecasts. The different planning approaches are discussed in Chapter 2, Integrated Planning section, of this DSIP update. These concepts must be integrated to produce a forecast, with the necessary level of granularity to be useful to third-parties and yet limit the amount of uncertainty in the forecast.

In addition, the Company will continue its efforts to work with EPRI on further development of the DRIVE tool roadmap to evaluate options for including characteristics such as upstream constraints and operational flexibility in future Stage 3.X releases.

O&R Five Year Hosting Capacity Roadmap

O&R's Hosting Capacity 5-year Roadmap is aligned with that of the JU and is depicted in the figure below.

Figure 30: JU Roadmap for HCA Stages 2.1, 3.0, and 3.X



Risks and Mitigation

The hosting capacity analysis requested by the Commission and stakeholders contains a level of detail that has never been done before. The software and calculation tools for hosting capacity analysis are still evolving to meet the information demanded. Delays in the development of the DRIVE program or other supporting tools necessary for future hosting capacity analysis could extend the Stage 3.0 release and subsequent release timelines.

O&R is mitigating this risk by continuing to engage with EPRI on the DRIVE tool refinement. The information and requirements currently being gathered for the second version of the EPRI DRIVE tool are allowing O&R to work with third-party vendors in developing tools that incorporate all of the required data. O&R has performed work in the past to create, clean, and maintain GIS mapping information which will expedite the process of implementing the needed supporting tools.

Stakeholder Interface

The JU conducted stakeholder engagement sessions on April 28, 2017, and November 2, 2017, to solicit input on future enhancements to Stage 2 as well as on the development of Stage 3. A list of the stakeholder recommendations for Stage 3 was captured, summarized, and made available on the JU website. The JU continue to view stakeholder feedback as a critical input to further improvements to the hosting capacity analysis and displays.

To help shape future releases, the JU will engage stakeholders to solicit their input on these approaches to further inform the continued expansion of the roadmap for hosting capacity. In the case of hosting capacity analysis for energy storage, input on developer use cases will help inform the appropriate work product that will be most beneficial to stakeholders. This input will be especially valuable given the broad range of energy storage technologies, applications, and operating characteristics that such analyses could reflect. Forecasted hosting capacity will likewise benefit from stakeholder input given the level of complexity of the analysis that impacts the accuracy and precision of its results.

Similar to the approach in 2017, the JU plan to hold stakeholder engagement sessions corresponding with the release of each stage to provide an update to stakeholders on progress to date and solicit input on future stages. O&R looks forward to continuing open discussions with stakeholders via the engagement group sessions beyond the Stage 3.0 release. As described in the SDSIP, completion of Stages 3 and 4 of the hosting capacity roadmap is intended to be a long-term focus for utilities based on lessons learned from previous stages and the availability of enhanced analytical tools to conduct this degree of analysis.[143] Continued input from stakeholders throughout this longer-term focus on Stages 3 and 4 will be essential to providing the high-value results required for users.

Additional Detail

This section contains responses to the additional detail items specific to Hosting Capacity.

1) The utility's current efforts to plan, implement, and manage projects related to hosting capacity. Information provided should include:

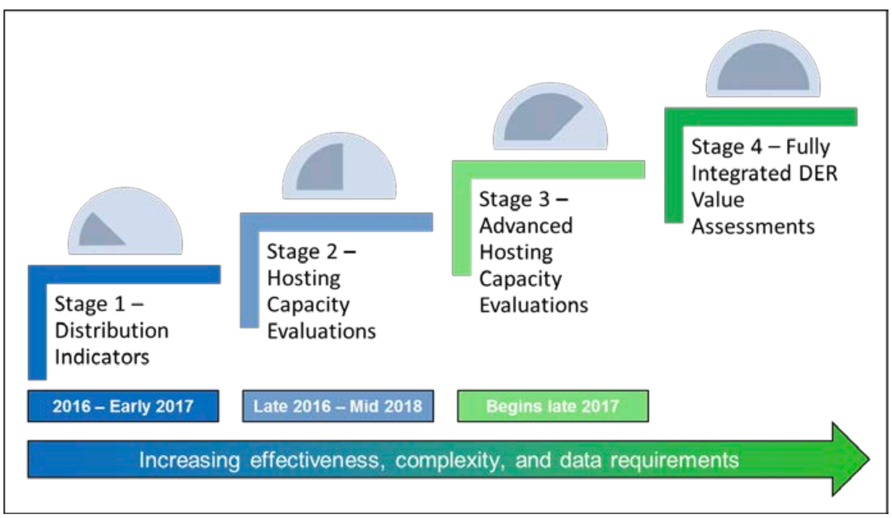
a) A detailed description of each project, existing and planned, with an explanation of how the project fits into the utility's long-range hosting capacity plans

O&R is moving forward with the JU to develop requirements for the Stage 3 hosting capacity analysis previously described. O&R has worked closely with EPRI to develop the required inputs needed for existing DER to be considered in the DRIVE program. The Company is also working on developing the optimal methods for providing sub-circuit, granular level hosting capacity information while maintaining the performance of the displayed maps.

b) The original project schedule

The original JU Hosting Capacity Roadmap and schedule[144] is shown in the following figure:

Figure 31: Original Hosting Capacity Project Roadmap/Schedule



[143] DSIP Proceeding, JU Supplemental DSIP, p. 56.
[144] DSIP Proceeding, JU Supplemental DSIP, p. 48

c) The current project status

The current project status is reflected in the JU Roadmap for HCA Stages 2.1, 3.0, and 3.X shown in a previous figure. In April 2018 O&R published the Stage 2.1 maps containing substation information in additional pop-up boxes. O&R is currently engaged with EPRI and the JU to determine the best way to calculate Stage 3 results. Work has been completed to build preliminary models to assist in determining feasible methods.

d) Lessons learned to-date

Higher levels of analysis with more data than what is currently available is needed by stakeholders and customers to support their business model. To determine the feasibility of this request, O&R used the DRIVE program to develop draft models of existing hosting capacity results at the sub-circuit level of individual circuits. O&R has determined that these changes are possible and will provide better information to stakeholders.

e) Project adjustments and improvement opportunities identified to-date

Adjustments to the hosting capacity maps have provided better visibility and additional information to the public, developers, and stakeholders. Improvements in data gathering, analysis time requirements, program roll-outs, and the incorporation of stakeholder and regulatory requests will all contribute to lessen the lead times for delivering future hosting capacity stages.

O&R has provided feedback to EPRI stating the types of DER that are installed on the system along with accessible characteristics. With the current stage of EPRI DRIVE, O&R is developing an in-house tool to take mapping data of existing DER and incorporate it into existing models that feed into the DRIVE program. The new developments from EPRI which will be released in a DRIVE Version 2 which will require new files and programs. The Company is engaged in meetings and detailed reports of the new version to be prepared for the program even before it is released. These changes will allow for more advanced results containing higher-resolution anti-islanding analysis, substation mapping, consideration of adjacent circuits, and exportable nodal-level hosting capacity files.

The Commission's DSIP Order required that hosting capacity data be refreshed on an annual basis.[145] However, recognizing the importance and need for the data, O&R invested additional time and effort during the development of Stage 2 to build an automated process for hosting capacity analysis and as a result is now able to refresh the hosting capacity data on a monthly basis. Additionally, through collaborated efforts with EPRI, these results are reflected within the maps along with the mandated monthly installed and queued DER values.

f) Next steps with clear timelines and deliverables

Timelines and deliverables for Stage 2.1 Refresh, and Stage 3 Release are reflected in the five-year forecast previously provided.

2) Where and how DER developers/operators and other third-parties can readily access the utility's hosting capacity information

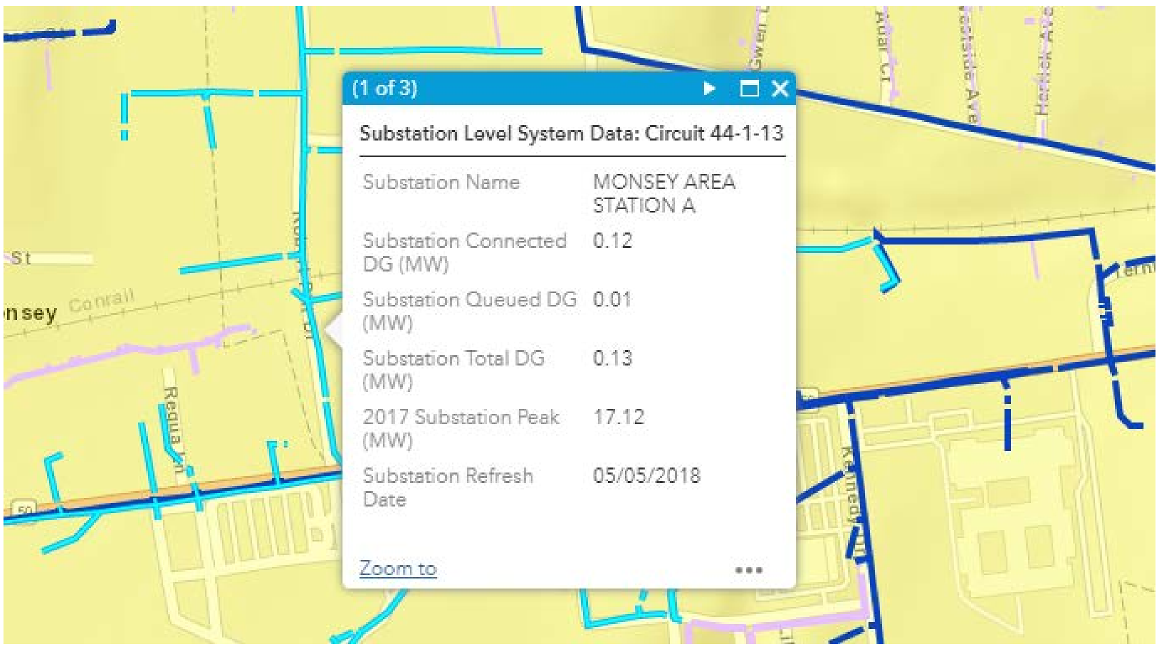
In Stage 2, the Company updated the hosting capacity information to reflect the results of a hosting capacity analysis for all 13.2kV and above distribution circuits. The updated information provides DER developers/operators with a higher level of granularity with distribution circuit-level specificity. The

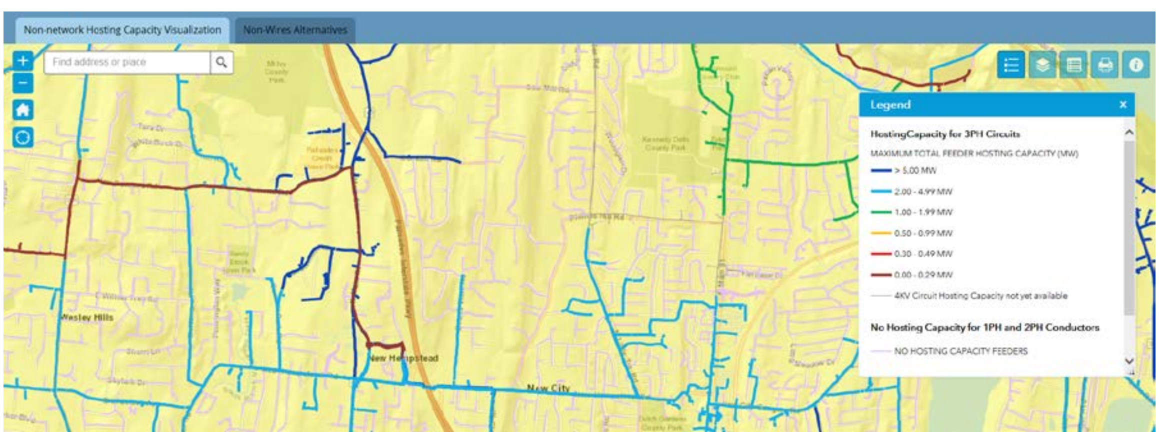
[145] DSIP Proceeding, DSIP Order, p. 15.

hosting capacity map, reflecting this analysis is posted and accessible on the Company's website at https://www.oru.com/en/business-partners/hosting-capacity.

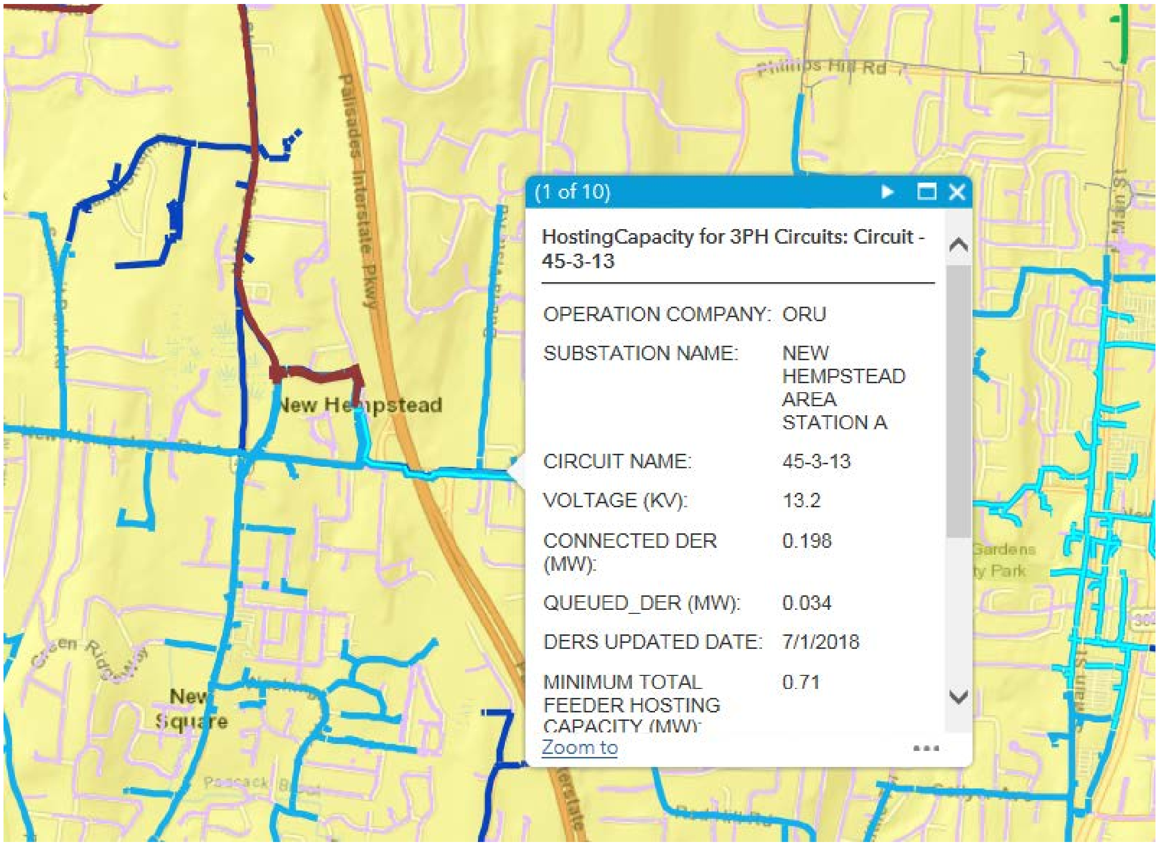
Additional displays with tabulated data are also included in the form of data pop-up displays to indicate that the hosting capacity may be lower at any given location. Existing DER were not considered in this stage of the hosting capacity analysis, and the data pop-ups were intended to provide additional context to the displays. For these reasons, the Company included and updates the installed and queued DG values in the data pop-ups on a monthly basis. Various screenshots reflecting the hosting capacity map and data pop-ups are shown in the following figures.

Figure 32: O&R Hosting Capacity Screenshots with Data Pop-Ups





Orange & Rockland



HostingCapacity for 3PH Circuits: Circuit - 45-3-13

OPERATION COMPANY:	ORU
SUBSTATION NAME:	NEW HEMPSTEAD AREA STATION A
CIRCUIT NAME:	45-3-13
VOLTAGE (KV):	13.2
CONNECTED DER (MW):	0.198
QUEUED_DER (MW):	0.034
DERS UPDATED DATE:	7/1/2018
MINIMUM TOTAL FEEDER HOSTING CAPACITY (MW):	0.71
MAXIMUM TOTAL FEEDER HOSTING CAPACITY (MW):	4.1
HOSTING CAPACITY UPDATED DATE:	7/1/2018

AREA STATION LOAD CURVE

8760 HISTORICAL DATA

Substation Level System Data: Circuit 45-3-13

Substation Name	NEW HEMPSTEAD AREA STATION A
Substation Connected DG (MW)	1.45
Substation Queued DG (MW)	0.31
Substation Total DG (MW)	1.76
2017 Substation Peak (MW)	30.82
Substation Refresh Date	07/01/2018

Release of Stage 2.1 was completed in April of 2018, fulfilling the requirement to provide substation level data of existing and queued DER. The Company also included the 2017 Substation Peak load and the data refresh rate to the pop-up display.

The Company will complete Stage 3, with an analysis of the full system and the complete maps, by October 2019. This stage of the hosting capacity roadmap will fulfill the requirement in the Staff DSIP

Update Whitepaper calling for substation level hosting capacity data[146] and will provide this information at a higher level of granularity with distribution circuit-level specificity.

3) How and when the existing hosting capacity assessment information provided to DER developers/operators and other third-parties will increase and improve as work progresses

Stage 3 will continue to build on the existing advanced hosting capacity analysis. Advanced capabilities to the hosting capacity analysis to be provided in Stage 3 include:

- Sub-circuit level hosting capacity;
- Substation level hosting capacity; and
- Reflect existing DER.

4) The means and methods used for determining the hosting capacity currently available at each location in the distribution system

In Stage 2, the Company used the DRIVE tool to complete a hosting capacity analysis for all circuits 12 kV and above, which represents approximately 98% of the circuits.

For the Stage 2 displays, the Company determined each circuit's hosting capacity by evaluating the potential power system criteria violations as a result of large PV solar systems with an AC nameplate rating starting at, and gradually increasing from, 300 kW interconnecting to three-phase distribution lines. The analyses represented the overall circuit level hosting capacity only and did not account for all factors that could impact interconnection costs (including substation constraints). It is noted that issues related to circuit protection require further analysis to make a definitive determination of hosting capacity, and the data is provided for informational purposes only and is not intended to be a substitute for the established interconnection application process.

5) The means and methods used for forecasting the future hosting capacity available at each location in the distribution system

The analysis needed for calculating forecasted hosting capacity at each location of a circuit is a significant undertaking. O&R, along with the JU, have been in discussions of how this type of calculation can be performed to provide the most accurate information possible to the public, developers, and stakeholders. Currently, O&R is planning on using multiple data-streams incorporated into its integrated system model to generate the base platform needed for the forecasted hosting capacity calculation. These data-streams include; forecasted load, forecasted DER adoption, and Company upgrades including phase-balancing, low-voltage upgrades to 13.2kV, and mainline reconductoring.

6) How and when the future hosting capacity forecast information provided to DER developers/operators and other third-parties will begin, increase, and improve as work progresses.

O&R is in the process of categorizing existing data that may be helpful in calculating the forecasted values of hosting capacity. As it is today, manual, detailed analysis of each circuit will be needed to provide accurate and useful amounts of DER that can be incorporated in the future. Next steps following the existing plan are to continue the engagement with the JU in the analysis process to determine the method of calculating the forecasted hosting capacity. Implementation is planned to start in Q2 of 2019.

7) The utility's specific objectives and methods to:

[146] DSIP Proceeding, DSIP Order, pp. 10-11.

a) **Identify and characterize the locations in the utility's service area where limited hosting capacity is a barrier to productive DER development**

By reviewing the hosting capacity portal on the Company's website, stakeholders can see the amount of DER capacity readily available for interconnection from the DRIVE calculations. As discussed in EPRI documentation and during stakeholder engagements, hosting capacity is going to be limited in sections of a circuit with a relatively large amount of impedance between the specified location and the power source along with the minimum power that a circuit will provide to its customers.

b) **Timely increase hosting capacity to enable productive DER development at those locations**

The Company is actively engaged in projects that increase hosting capacity. Such programs include circuit-level phase balancing for 3-phase inverters, upgrades of low-voltage distribution to 13.2 kV, and reconductoring of circuit mainlines. Goals set-forth by the Company for effective increases to hosting capacity in the future are the investment in an ADMS and DERMS, and fast-acting storage facilities to help compensate for adverse power-quality conditions.

In 2016, the Commission directed O&R to initiate a Demonstration Project to examine emerging technologies which can increase hosting capacity.[147] On December 19, 2017, the Commission approved O&R's Optimal Export Demonstration Project[148] which will explore the advanced control and inverter functionality of solar PV systems. This functionality will allow PV systems to optimize its output which will eliminate the need to mitigate distribution system constraints. Acquisition of solar project partners is currently underway for this demonstration project.

[147] DSIP Proceeding, DSIP Order, p. 45.
[148] REV Proceeding, Demonstration Project Proposals, Letter to Mr. Carley (issued December 19, 2017).

Beneficial Locations for DERs and NWAs

Introduction/Context and Background

O&R takes appropriate steps to identify, characterize, and make information available to stakeholders about the locations in its service area where DER and/or EE measures might provide benefits to its electric system. The value of DER to the electric distribution system, and ultimately the customer, depends on DER's location on the grid. In addition, the duration, timing, size, and quality of service provided by DER factors significantly into the benefits they provide. Based on their technology, attributes, location, and operation, DER may have net benefits or net costs to the electric system. To rely on DER as part of the planned-and-operated local distribution grid, the Company has developed procurement approaches intended to acquire DER with particular attributes, scales, and locations on the grid.

An opportunity for great value resides with the ability of a particular DER technology and/or application (or a portfolio of DER) to defer specific distribution-system upgrades, and to do so with the same degree of necessary reliability and/or functionality afforded by traditional distribution investments. As discussed in detail in the Integrated Planning section of this DSIP update, O&R implements an integrated planning process and methodology whereby it not only reviews and identifies traditional infrastructure projects, but also screens and reviews these major capital investment projects with respect to targeted non-traditional alternative DER measures. The Company also reassesses previously identified needs and project solutions that have not yet been initiated to confirm the need and timing of the solution.

Since its IDISP, the Company has made three changes to its process for screening projects for potential deferral or replacement with an NWA that have improved its ability to identify beneficial locations for NWAs, as described in detail in the Integrated Planning section. These changes include 1) the implementation of a new NWA suitability criteria matrix, 2) the evaluation of portfolios of NWA solutions, and 3) the use of a BCA analysis for its NWA opportunities. For information on each of the Company's NWA projects, see the Procuring NWAs section.

O&R is completing a new MCOS study and updating values in the Company's BCA Handbook to improve the Company's ability to identify grid values

In addition to updating and advancing its NWA processes, the Company has developed methodologies for identifying Locational System Relief Value ("LSRV") areas and calculating Demand Reduction Values ("DRV") on its system as required by the Commission in the Value of Distributed Energy Resources ("Value of DER") Order.[149] The Commission required that all utilities develop proposals for the calculation and compensation of a DRV based on the value of reduced delivery costs associated with demand reduction across their service territories and calculated based on disaggregation of utility marginal cost of service ("MCOS") during the ten peak hours. The Value of DER Order also directed all utilities to identify LSRV areas where DER has the potential to provide additional benefits, both of which the Company has done as described in the Additional Details section below.

The following table provides information on each of the Company's LSRV areas based on projects currently in the queue.

[149] Value of DER Proceeding, VDER Phase One Order, pp. 111-119.

Table 32: LSRV Areas Based on Projects Currently in Queue

LSRV Area	MW Available for LSRV as of May 1, 2017	Total AC Nameplate MW Claimed	MW Claimed After Coincident Factor[150]	MW Remaining Under Cap as of June 19, 2018
Blooming Grove	3.40	1.98	0.35	3.05
Highland Falls	10.50	0.00	0.00	10.50
Monsey	2.50	5.00	0.88	1.62
Port Jervis	4.30	5.94	1.05	3.25
Warwick	4.70	0.02	0.00	4.70

Implementation Plan, Schedule, and Investments

Current Progress

New suitability criteria, evaluation of portfolio solutions, and BCA analysis have improved the Company's ability to implement non-wires alternatives

O&R has made a number of process changes, as described throughout this DSIP update, which will assist in the Company's ability to identify beneficial locations for DERs and EE measures. These changes include the enhancement of its planning process to expand to a ten-year planning horizon, which is expected to better facilitate consideration of NWA opportunities and/or other potential traditional solutions by providing the Company additional time to identify and analyze all reasonable and effective solutions. The Company will also be able to implement solutions far enough in advance to mitigate associated operating risk prior to critical need timeframes and other potential commitment dates. Details on this change can be found in the Integrated Planning section of this DSIP update.

Another refinement currently being developed is a modification of the current planning process to account for the growth of DER and other load modifiers. This refinement is expected to help the Company better understand how system needs are impacted by load modifiers, particularly at a more granular level, and better identify areas that could potentially benefit from the implementation of a NWA. Details on this change can be found in the Advanced Forecasting section of this DSIP update.

Future Implementation and Planning

O&R envisions that its current and prospective future efforts to evolve to a state that will enable the performance of probabilistic forecasting and planning will further enhance and improve its ability to identify beneficial locations for DER and EE measures. As the Company continues to improve its understanding of load modifiers and their growth trends and impacts, it will better understand where these impacts might more granularly appear on the electric delivery system, and consequently where the best opportunities for DERs are and should be located. For additional detail on these topics, please refer to the Integrated Planning and Advanced Forecasting sections of this DSIP update. In addition, the

[150] MW counted toward LSRV area cap based on coincident factor of 17.6%, so that sufficient capacity is available to meet requirements coincident with the time of system need.

Company expects to gather lessons learned from its current NWA projects and use those to identify future improvement opportunities in its processes for identifying beneficial locations.

O&R has identified LSRV areas in support of the Value of DER Proceeding and has added its LSRV and NWA areas to the O&R hosting capacity maps

To better assist in identifying LSRV areas and their associated values, the Company plans to complete its MCOS study and revise its BCA handbooks based on the values established in the MCOS study. The Company's new MCOS study approach is expected to improve the granularity of marginal costs based on targeted projects identified in areas requiring capacity increases due to upcoming, or already realized, load growth. The new study will reflect different marginal costs structures at the appropriate levels of the electric delivery system.

Risks and Mitigation

As the policies and processes for properly valuing DER in beneficial locations are in development, shifts in current policies that reduce or change incentives for DERs in beneficial locations could impact the Company's processes, necessitating changes and delays in its ability to effectively identify beneficial locations. To mitigate this risk, O&R will collaborate with various key stakeholders to identify any such situation and plan to address any issues or concerns as they arise.

Changes to BCA calculation methodology and/or components could also change the nature of which potential NWA projects are selected and the Company's process for selecting them. To mitigate this risk, O&R will work with the JU, Staff, and stakeholders to understand how changing various inputs to the BCA affect the NWA procurement process.

In addition, the Company plans to review Staff's upcoming Value of DER whitepaper and make adjustments to its processes as may be required.

Stakeholder Interface

Through its work with stakeholders, the Company has received feedback and suggestions related to the communication of beneficial locations. The JU met with stakeholders twice in 2017 to provide insight into the NWA solicitation processes and request input on future solicitations. O&R participated in a stakeholder engagement meeting on April 20, 2017, in New York City which reviewed outcomes of the 2016 stakeholder engagement process on NWA suitability criteria and DER sourcing. Presented at that meeting were the JU implementation efforts planned for 2017 based on the commitments made in the SDSIP. The meeting included the JU presentation and discussion of the NWA sourcing process, which provided stakeholders an opportunity to ask questions and provide input. During this session, stakeholders encouraged the use of broader channels to share announcements of upcoming NWA opportunities, such as industry associations and conferences, and as a result, O&R has implemented pre-bid webinars and posts NWA opportunities via its website. Stakeholders also suggested that a central portal with links to each utility's NWA opportunities will be a valuable resource. In response, the JU published web pages with links to utility-specific portals that contain notifications of NWA opportunities and NWA RFPs as described previously in this DSIP update. The JU link brings stakeholders to the O&R page where all O&R NWA opportunities are located. The JU received valuable input from stakeholders through these engagement meetings and will continue to incorporate feedback into their processes as they evolve.

O&R is also an active member of the JU DER Sourcing/NWA Suitability Criteria working group, which is a forum designed to promote collaboration on 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.

The engagement of stakeholders on beneficial locations is a part of the Company's broader efforts to engage stakeholders and solicit feedback on the overall NWA procurement process, which is described in greater detail in the subsequent Procuring NWAs section.

Additional Detail

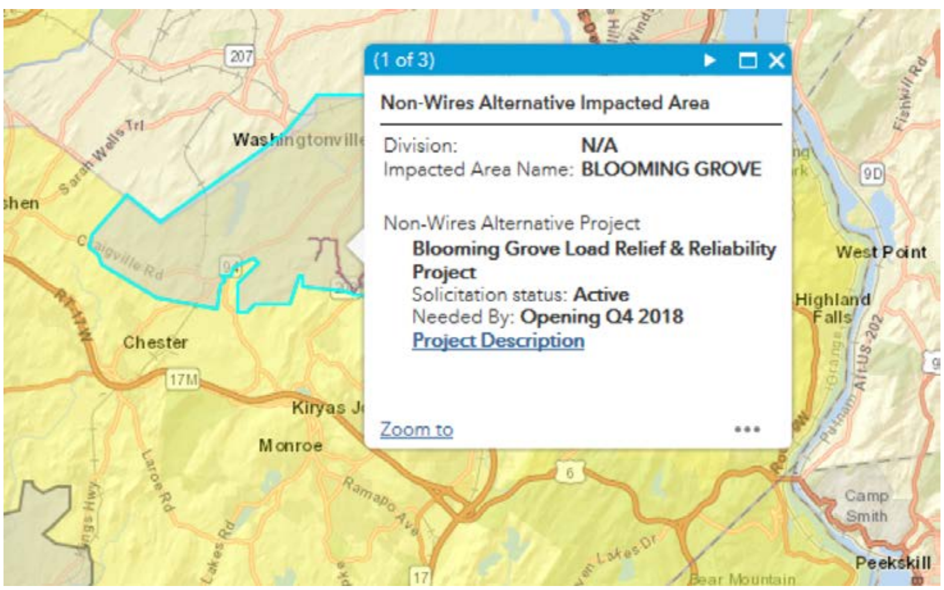
This section contains responses to the additional detail items specific to Beneficial Locations.

1) The resources provided to developers and other stakeholders for:

a) Accessing up-to-date information about beneficial locations for DERs and/or energy efficiency measures

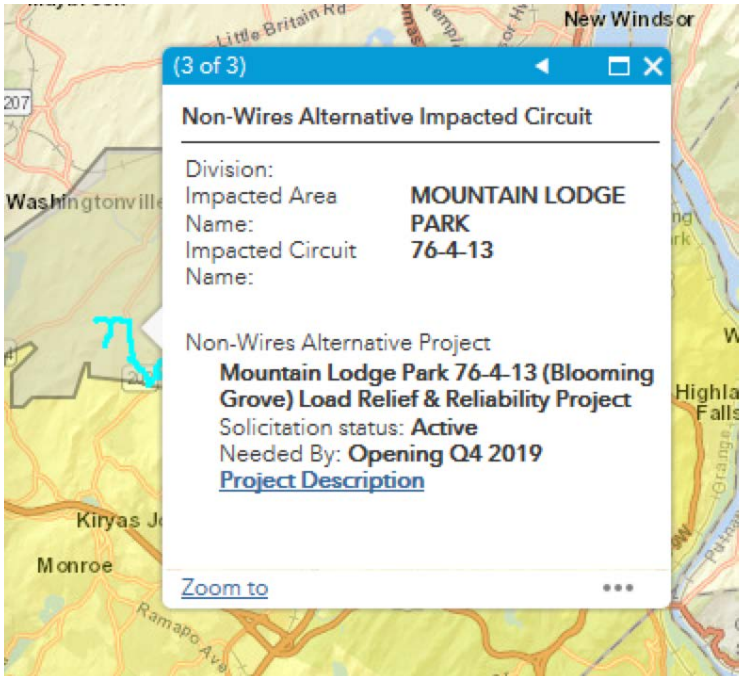
The primary resource O&R provides to developers and other stakeholders for accessing up-to-date information about beneficial locations for DERs is its Hosting Capacity and System Data portal (link). The Company's hosting capacity maps offer an interactive interface for users to both view and download information about NWA opportunities and LSRV areas. In addition to its hosting capacity maps, O&R provides information on its NWA opportunities on its company website (link) and through REV Connect (link). The following figure provides an example of how NWA opportunity locations are visualized on the Company's hosting capacity maps.

Figure 33: NWA Area Display and Popup Box Information



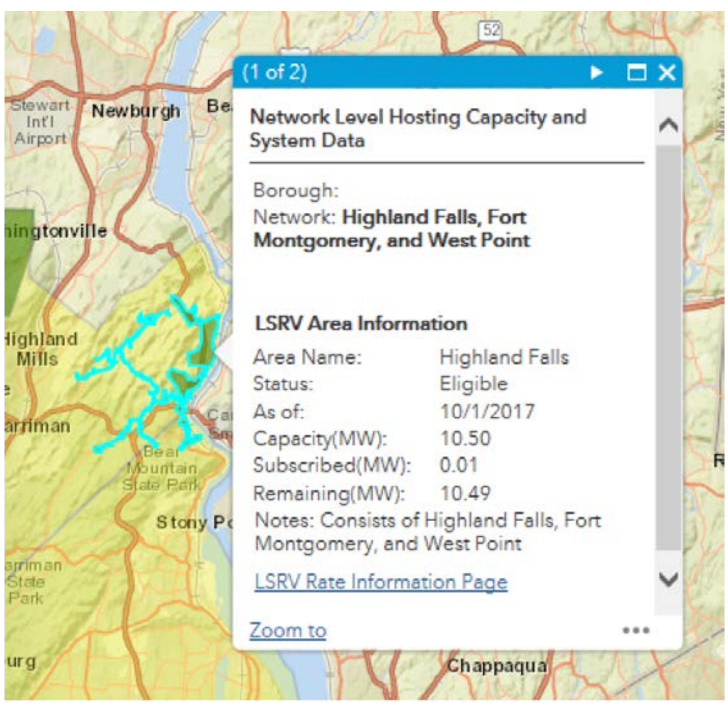
Once stakeholders identify a NWA location on the map, they can click on the popup box for additional information, such as a more detailed description of the NWA opportunity and information about circuits impacted by the NWA opportunity as shown in the following figure.

Figure 34: NWA Circuit Popup Box Information



The Company's hosting capacity maps also show locations for LSRV areas with information about the area and a link to LSRV rate information, as shown below in the following figure.

Figure 35: LSRV Area Display and Popup Box Information



O&R also provides location information on its website for areas with increased incentive rates under its Distribution Load Relief Program, as described in the response to question #3.a. below.

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.

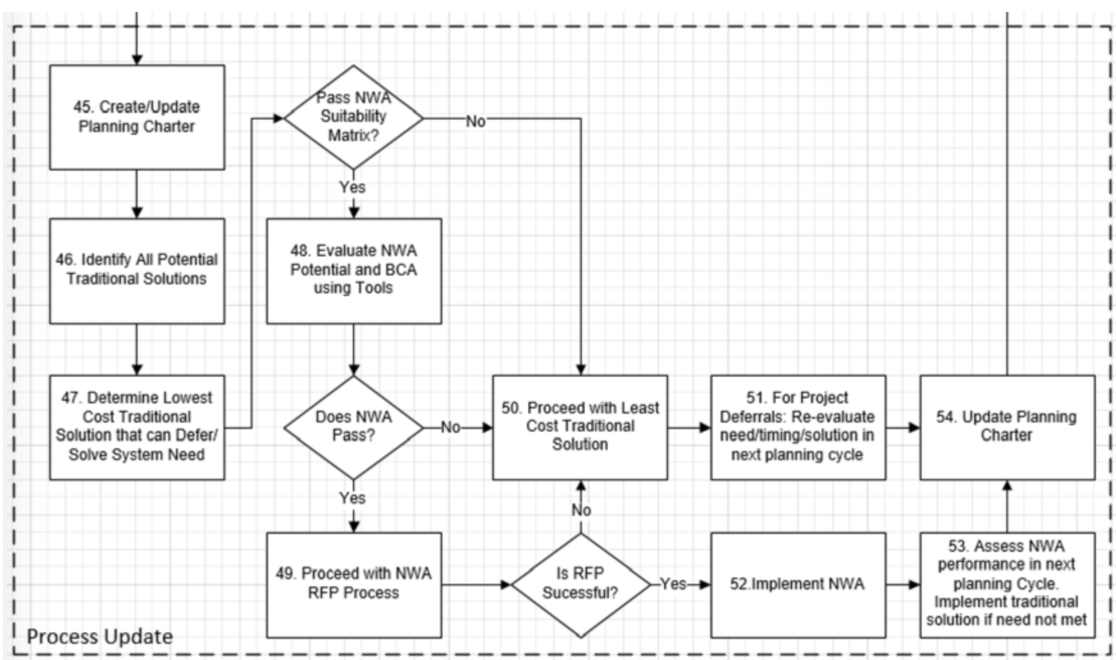
The Company's hosting capacity maps allow users to filter for the information they seek by selecting an area or circuit of interest on the hosting capacity map. As shown in the figures above, users are presented with information on each NWA and/or LSRV area they select.

2) The means and methods for identifying and evaluating locations in the distribution system where:

a) A NWA comprising one or more DERs and/or energy efficiency measures could timely reduce, delay, or eliminate the need for upgrading distribution infrastructure and/or materially benefit distribution system reliability, efficiency, and/or operations

Beneficial locations for NWAs are identified through the Company's planning process as described in detail in the Integrated Planning section of this document. Energy Efficiency measures are one of many possible solutions considered in the Company's portfolio approach to securing sufficient capacity to meet the requirements for a potential NWA. The excerpt below from the Company's planning process illustrates the key steps used to identify potential NWA opportunities and evaluate their suitability for implementation to address system constraints. The process of identifying beneficial locations for NWAs begins with the identification of an area expected to exceed a system constraint. The Company evaluates these areas to both identify the lowest cost traditional solution and the suitability of a NWA to address the identified need. Areas that pass the preliminary BCA and the Company's suitability criteria are communicated to developers and other stakeholders through the Company's website, REV Connect, and the Company's Hosting Capacity and System Data portal.

Figure 36: Process to Identify Beneficial Locations for NWAs



b) **One or more DERs and/or energy efficiency measures could reduce, delay, or eliminate the need for upgrading bulk electric system resources and/or materially benefit bulk electric system reliability, efficiency, and/or operations.**

The Company uses the same process to identify potential NWA projects, as described in the response to question #2.a. above, for all levels of its electric delivery system.

3) Locations where energy exported to the system, or load reduction, will be eligible for:

a) Compensation under the utility Value of DER Value Stack tariff

O&R has and will continue to take the appropriate steps required to identify locations eligible for compensation under the Value of DER tariff. As explained at the April 5, 2017 Technical Conference of the Value of DER proceeding,[151] in determining LSRV areas the Company examined load areas where it plans investments and/or has system constraints, driven by either already realized or potential future load growth, and resultant reliability deficiencies as a result of its most recent planning process results and as identified in its five-year capital investment plan. The Company has identified these planned investments in part by applying its design standards to determine if its existing electric facilities will be operating outside of acceptable tolerances with respect to equipment loading, operating parameters and customer exposure within the upcoming ten-year planning period. The LSRV areas identified in the Company's hosting capacity maps represent high-value areas where DER can benefit the electric delivery system by providing load relief that could assist existing facilities and equipment to operate at improved capacity and thermal levels to reduce operating risk. Areas were chosen that align with potential infrastructure projects that are typically and minimally three or more years in the future, and where there will be longer-term value for implementing DER over time.

In some cases, there is the potential for LSRV, NWAs, or other price mechanism signals and programs to target and relieve the same locational constraints. In such instances, LSRV will work in conjunction with the Company's NWAs and other programs and mechanisms to encourage the construction and operation of DER projects that can operate at the time of the local area's distribution systems' constraint to potentially defer distribution investments. Therefore, such LSRV projects will need to be considered by the Company when determining the MW need for future NWA solicitations. To avoid double payments, projects receiving LSRV will not be compensated by additional NWA procurement mechanisms. The Company will determine actual qualification for the LSRV on a project-by-project basis depending on the location of the project and the date the project executes its interconnection agreement.

Using the above-described methodology, O&R previously designated geographic areas that represent over 140 MW of existing normalized load, on a peak load weighted basis (or approximately 12% of the Company's total New York system load), as eligible for LSRV. These LSRV areas are made available to developers and other stakeholders through the Company's Hosting Capacity and System Data portal as described in the response to question #1.a. above. In addition, as noted earlier in this section, the current values and methodology with be superseded after the Company completes its new MCOS study and related updates to its BCA handbook.

b) Utility dynamic load management programs, including the Commercial System Relief Program, Distribution Load Relief Program, and Direct Load Control Program

---

[151] Value of DER Proceeding, Notice of Technical Conference on Phase One of Value of Distributed Energy Resources (issued March 17, 2017).

O&R currently implements several EE and DR customer incentive solution programs across its New York service territory, including the Commercial System Relief Program (“CSRP”), Distribution Load Relief Program (“DLRP”), Small Business Direct Install (“SBDI”) program, Commercial and Industrial Existing Buildings program (“C&I”), Efficient Products Program, and the Direct Load Control – Bring Your Own Thermostat (“BYOT”) program. These programs are available to all New York customers to coincide with the spirit and goals for energy efficiency and GHG reduction, as outlined by REV proceedings.

The DLRP includes a higher incentive for Tier 2 Areas, which are areas of the system identified as higher priority for increased demand response resources. Tier 2 Areas are defined through the planning process, in which Distribution Engineering, Planning, and Customer Energy Services work together to examine the circuits and areas where load curtailment is most valuable. Customers who fall within these areas are designated with Tier 2 status for DLRP, receiving a $5/kW pledged incentive compared to Tier 1 incentive rates of $3/kW pledged. Before each capability period, the Company goes over historical data, forecasting, enrollment and curtailment predictions to determine if Tier 2 areas should be modified from the year prior. These incentive area locations are posted on the Company’s website.[152] The Company may propose applicable changes to future year DLM incentive payment rates as updated MCOS studies become available and as the Value of DER proceeding develops.

The programs can also be tailored as required to support specific NWA opportunities. For example, the Company can leverage the Direct Load Control Program to allow for turnkey direct installation of equipment solutions in targeted areas because the cost of deferral can support the higher cost, providing the Company with valuable demand reduction allowing the potential deferral of capital investment, while simultaneously providing a service to our customers, often at no cost. O&R is currently exploring implementing this DLC program expansion in its Pomona NWA and expects to finalize those plans by Q3 2018. Another example is the successful use of targeting customers in the NWA locations for program enrollment. Through this approach, the Company was able to enroll over 1 MW of permanent demand reduction from its SBDI program to meet the needs of the Pomona NWA.

c) And/or, increased value-based customer incentives for energy efficiency measures with load profiles that align with the system needs through utility energy efficiency programs or NYSERDA’s Clean Energy Fund (CEF) programs, while ensuring utility-NYSERDA coordination.

O&R identifies beneficial locations for NWAs as described in the response to question #2.a. above. As part of the procurement process, the Company is tasked with identifying various local DERs that can be leveraged to potentially defer or eliminate a capital project. EE is considered a part of the available portfolio of DER technologies. The Company conducts an EE adoption analysis to understand the amount of EE reduction it can achieve in the NWA area, identifying possible customers and EE measures that provide the maximum load reduction for the most beneficial cost. Based on the amount of EE reduction the Company can achieve, O&R allocates incentives for the customers in the particular NWA area. If a customer’s potential load reduction is coincident with the timeframe when the NWA requires load reduction, the customer may be offered an added incentive to install the EE measures designed to produce the desired load reduction results. The Company believes providing this added incentive is economically beneficial to achieving load reductions in heavily loaded NWA areas, and the added incentive will give customers additional motivation to pursue the EE measure.

---

[152] https://www.oru.com/en/save-money/energy-saving-programs/choose-smart-usage-rewards/smart-usage-rewards-payment-options

Procuring NWAs

Introduction/Context and Background

A primary goal of the REV initiative is to increase the utilization of DER as alternatives to traditional infrastructure solutions. Since its IDSIP, O&R has developed new processes for identifying non-traditional solutions to infrastructure needs into its planning and procurement processes. NWAs can be any action or strategy that addresses the defined system need while deferring, reducing, or eliminating the need to construct or upgrade distribution infrastructure. NWAs offer an opportunity to defer traditional "wires" investments, resulting in cost savings or other benefits for customers while maintaining system reliability and resiliency. Identified through the capital planning process, NWAs rely on market mechanisms to provide cost-effective non-traditional solutions and are sourced through RFPs, sole source contracts, and other market-based procurement vehicles.

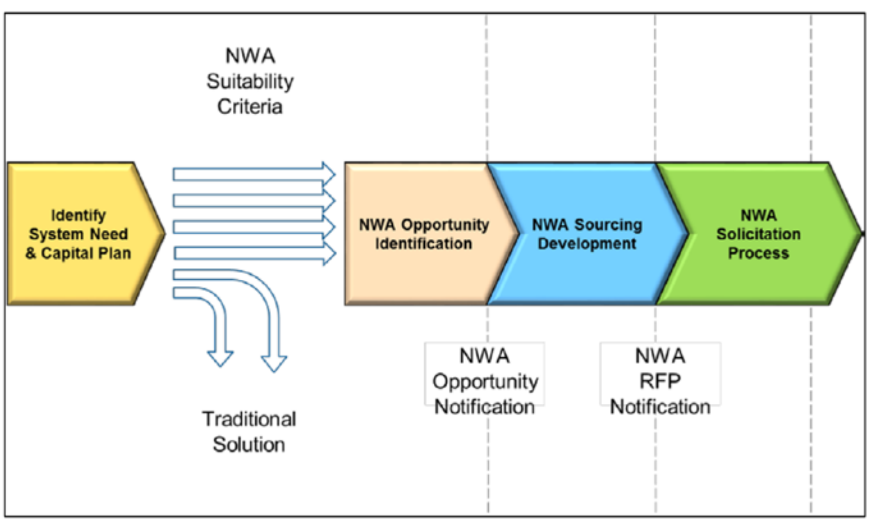
The Company implemented a new RFP platform and evaluation criteria making it easier for vendors to access and respond to NWA solicitations

As described in detail in the Integrated Planning section, O&R has made significant changes in the way it identifies and procures NWAs. Beginning with the annual planning process, the Company identifies traditional infrastructure projects using a ten-year planning horizon and evaluates them against a suitability criteria framework consisting of project type, timeline, and cost to determine if alternative and less costly non-traditional/NWA solutions, such as distributed generation, demand response, energy storage, and energy efficiency can substantially defer costlier major capital infrastructure investments.[153]

NWA Identification and Sourcing Process

The graphic below illustrates the key components of the Company's overall NWA process. Since the SDSIP filing, the Company has made numerous improvements in many of these areas as described below.

Figure 37: NWA Identification and Sourcing Process



[153] DSIP Proceeding, NWA Filing.

NWA Opportunity Identification

O&R identified its first NWA opportunities in its IDSIP. Since that time, the Company has developed a more robust capacity for identifying potential NWA projects than it did just two years ago. That process has resulted in the identification of seven NWA opportunities, three of which are currently in the procurement process. In 2017, the Company developed O&R-specific NWA suitability criteria to aid in the assessment of traditional projects for potential NWAs. The implementation of the Company's suitability criteria has improved its ability to identify more viable potential NWA projects for further evaluation by the Company.

O&R is developing a software toolkit to enable the creation of more granular DER portfolios and improve cost analysis of NWAs

In addition, beginning in 2018, the Company moved to a ten-year planning horizon allowing it to assess long-term projects which may have the potential to benefit more from an NWA approach. The Company anticipates that this longer view will allow it to grow the number of NWA solicitations over the coming years.

Table 33: O&R NWA Suitability Criteria

Criteria	Potential Elements Addressed	
Project Type Suitability	• Project types include Load Relief or Load Relief in combination with Reliability. Other categories have minimal suitability and will be periodically reviewed for potential modifications due to State policy or technological changes.	
Timeline Suitability	**Large Project** (Projects that are on a major circuit or substation and above)	• 36 to 60 months
	Small Project (Projects that are feeder level and below)	• 18 to 24 months
Cost Suitability	**Large Project** (Projects that are on a major circuit or substation and above)	• No cost floor
	Small Project (Projects that are feeder level and below)	• Greater than or equal to $450k

NWA Sourcing Development

O&R has successfully developed the processes needed to turn potential projects into NWA solicitations. O&R's UotF group works with Distribution Engineering to develop RFPs for potential NWA projects that pass the Company's suitability criteria. RFPs contain information specific to the system need including the MW deferral required, the duration and time period of the needed deferral, customer demographic information (customer types, etc.), siting information, and relevant system data. RFPs are released, and the vendor process is managed, by the Company's Procurement department, which is a shared service with CECONY.

O&R has released three initial NWA solicitations and has received positive feedback on the structure and format of its initial RFPs from many of the vendors who regularly bid on its NWA projects. General feedback from vendors is that the Company's RFPs are of overall high quality, complete, and easy to understand, which simplifies the proposal process. O&R values the feedback it has received on its RFPs and will continue to work with developers and other stakeholders to continue to evaluate and improve its RFP development process.

NWA Solicitation Process

To facilitate a more streamlined procurement process, the Company implemented a new Oracle software platform designed to be the central hub for communication between O&R and vendors about its RFPs. The Oracle platform makes it easier for vendors to access and respond to the Company's RFPs and also informs the vendors of activities related to the RFPs, such as webinars and additional data requests. For each solicitation, O&R holds a webinar focused on discussing and clarifying the scope of the potential NWA project with developers. NWA webinars are the result of the Company's efforts to modify its processes to be more transparent and provide more information to developers regarding its NWA solicitations. Subsequent clarifying questions or inquiries from developers are collected through the Oracle platform and are responded to by O&R's UotF group. The Company's responses to questions from developers are posted on the NWA RFP website so they are available to all bidders. O&R has seen active participation from developers in its NWA webinars which has resulted in higher quality proposals and improved solicitations.

Once proposals have been received, the Company screens them for completeness and relevance before beginning the evaluation process. Since its IDSIP, O&R has developed and implemented NWA evaluation criteria including the feasibility of the proposed solution, its cost, the ability of the proposed solution to be implemented within the required timeframe. These criteria are published in the RFPs and are used to evaluate RFP responses, providing a common framework for the Company to use to identify proposals that will best address the identified system need. Additional detail on the evaluation criteria can be found in the Beneficial Locations section of this DSIP update.

Benefit Cost Analysis

Following the evaluation process, the Company conducts a BCA analysis on the top proposals in accordance with the procedures approved by the Commission in the BCA Handbook to determine the cost-effectiveness of each of the proposals, or group of proposals, relative to the cost of the traditional solution. Since filing the SDSIP, the Company has actively worked with the JU, DPS Staff, and developers to refine its methodologies for calculating BCAs for non-wires alternatives, particularly those that involve energy storage resources. The result is the development of a dynamic NWA BCA model that allows the Company to account for and compare project costs and benefits as part of its evaluation of project proposals.

Although the current process is highly manual, the Company has been working with vendors to explore the development of a tool to streamline and automate its BCA process. Further details regarding this tool and others are described in subsequent sections. O&R continues to incorporate lessons learned from the use of its BCA methodology to revise its NWA RFPs, including requests for additional information from vendors that enhances the Company's analysis.

Implementation Plan, Schedule, and Investments

Current Progress

As discussed above, since its IDSIP, O&R has made substantial progress toward developing its processes for identifying and procuring NWAs. As a result, the Company currently has seven identified NWA projects, three of which are in the procurement process. These projects are shown in the table below. A short description of each of the in-flight projects followed by its current status is described below.

Table 34: Currently Identified NWA Opportunities

Project/Name Description	Project Type	Required Load Relief	Need-by Date	Anticipated RFP Release
Monsey	Load Relief / Reliability	2.5 - 3MW	2021	**Issued**
Pomona	Load Relief	<6 MW	2025	**Issued**
West Haverstraw	Reliability	5 MW	2021	**Issued**
Blooming Grove	Load Relief / Reliability	15.5 MW	2021	Q4-2018
Sterling Forest (Tuxedo Park)	Load Relief / Reliability	746 kW	2021	Q3-2019
West Warwick	Load Relief / Reliability	7 MW	2022	Q3-2019
Mountain Lodge Park (Blooming grove)	Load Relief / Reliability	280 kW	2022	Q4-2019

Monsey

The Monsey Substation is located in the Hamlet of Monsey, in the Town of Ramapo, in Rockland County. The area is experiencing significant area residential and business growth that has led to highly loaded circuits and substation transformer banks. As a result, the Company expects non-compliance with its distribution design standards under normal and contingency conditions in the near future. To defer or eliminate construction of the new substation, NWA load reductions will be needed starting in 2020. Approximately 2.5 to 3.0 MW of load reduction will be needed by 2021, depending on actual future load growth.

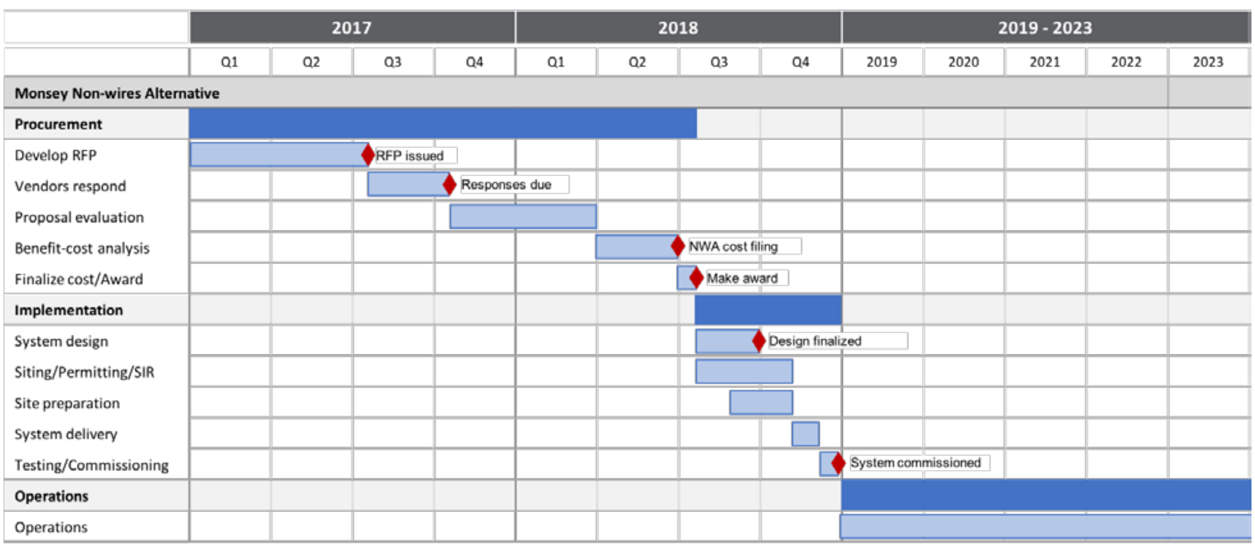
The Company issued an RFP in August 2017 for qualified and experienced NWA providers with the capability to deliver innovative NWA solutions. These NWA solutions could potentially provide capacity alternatives in the Monsey substation area with the distinct goals of (1) reducing peak electric load within the area served by the Monsey Substation and Banks 144 and 244 for bank contingency purposes; and (2) reducing peak electric load on Monsey distribution circuits 44-2-13, 44-3-13, 44-6-13 and associated distribution circuit ties for single distribution circuit contingency purposes.

In October 2017, the Company received proposals from multiple vendors representing a variety of NWA solutions including demand response, energy storage, energy efficiency, and distributed generation. The Company reviewed the proposals in accordance with the evaluation criteria described above with the intent of identifying and selecting a robust portfolio that will meet the required demand reduction needs.

The Company then performed a BCA on the portfolio using the methodology outlined in the Company's BCA Handbook. The Company will ultimately decide whether to proceed with the NWA solution(s), after considering the BCA, SCT, UCT, and RIM tests, as well as potential additional internal cost and ratepayer bill impact evaluations before moving forward in the process.

Once the project BCA and costs have been finalized, the Company will award the project to the selected vendors and move forward with the design and implementation of the project as shown in the timeline below.

Table 35: Monsey NWA Anticipated Project Schedule

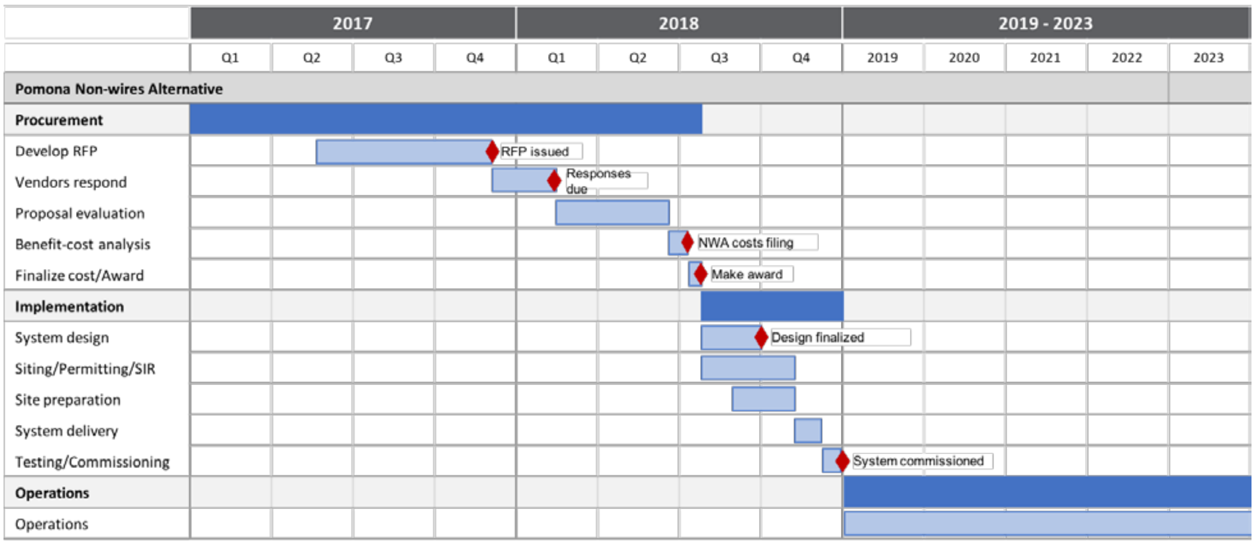


Pomona

The Pomona NWA was begun in 2015 to defer construction of new utility infrastructure in the Pomona area by providing up to 6MW of load relief through a portfolio of EE, DR and energy storage. The Company's traditional solution would have been the construction of a new substation with increased capacity in the Pomona area to accommodate increased load growth and cover distribution circuit contingencies. To defer construction of the new substation, the Company is planning to meet the need in the Pomona area with a battery energy storage system to complement existing EE and DR programs.

In December 2017, O&R issued an RFP seeking proposals for DESS to provide load relief in the Pomona area. Submissions were received on February 7, 2017. The Company reviewed the proposals for technical, construction, cost, timeliness and permitting feasibility, with the intent of identifying and selecting a proposal that will meet the required load reduction needs. Vendor presentations were conducted in early June, and the pool of potential proposals was narrowed down to the top two vendors. The Company is in the process of evaluating the proposals before selecting a vendor in early Q3 2018.

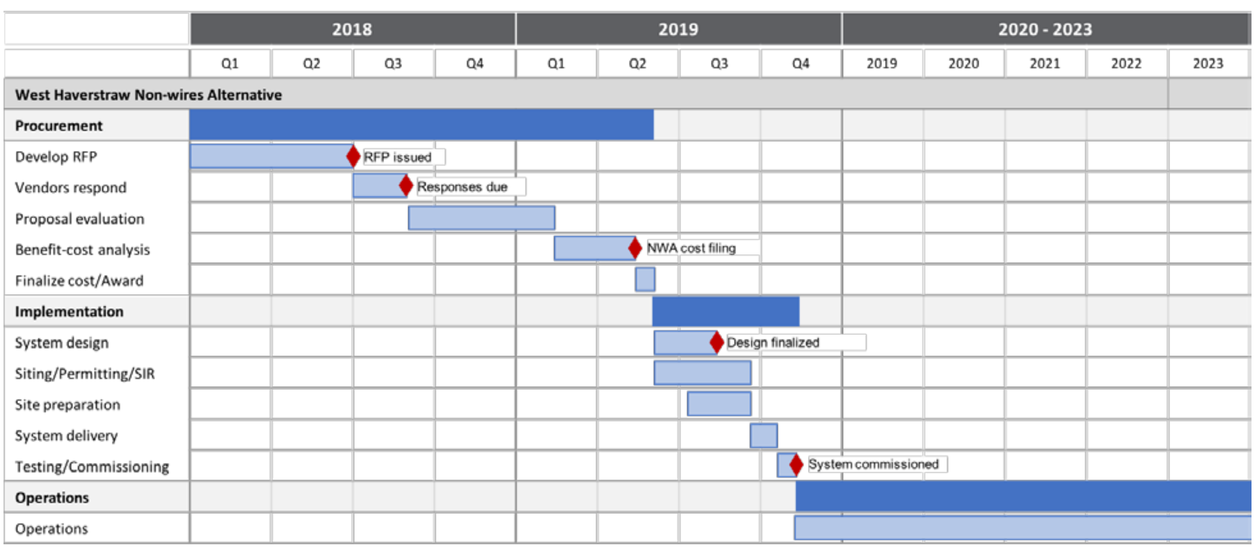
Table 36: Pomona NWA Energy Storage Anticipated Project Timeline



West Haverstraw

The Company evaluated an opportunity to leverage an NWA to reduce loading on three area circuits to improve transfer capability during contingency scenarios. To defer the traditional utility project, the Company will need to reduce load by approximately 5 MW by the summer of 2021. On June 29, 2018, the Company issued an RFP for potential NWAs. Proposals are due by August 31, 2018.

Table 37: West Haverstraw NWA Anticipated Project Schedule



As shown in the previous table future NWA RFPs will be released in the fourth quarter of 2018 and throughout 2019. As the planning process proceeds, additional NWA opportunities are expected to be added to this list and will be posted to the Company's NWA website as described below.

Future Implementation and Planning

Although O&R has made significant progress in its NWA procurement processes since its IDSIP, the Company sees additional areas for improvement and is looking forward to continuing to improve these processes over the next five years. These areas for improvement are described below.

NWA Process Toolkit

To further increase efficiency and reduce the amount of time required for the NWA planning and review process, O&R is exploring the development of a software toolkit that facilitates the analysis for each of the key steps in the Company's updated NWA planning and evaluation process. This toolkit will enable the Company to streamline the assessment of potential NWA opportunities. Further, the toolkit is designed to enable the Company to conduct analyses with increased temporal granularity (*i.e.,* hourly) and locational granularity (*e.g.,* circuit-level). In addition, these tools will allow O&R to automate the BCA process and apply the BCA Handbook in a consistent manner in order to determine if NWA alternatives are cost competitive as compared to specific traditional solutions.

In 2017, O&R engaged Navigant Consulting, Inc. (Navigant) and Energy and Environmental Economics, Inc. (E3) to develop a set of customized software tools and processes to enable O&R to create and analyze more granular portfolios of DER for the purposes of analyzing the feasibility and cost-effectiveness of NWAs. As part of this project, Navigant and E3 will also generate DER potential forecasts for EE, DG, and energy storage.

The impact of these tools will be to: (1) improve the granularity of load forecasting within the Company's territory to drive improved peak load reduction requirements and timing, (2) enhance the Company's ability to assess the suitability of an NWA solution to meet an identified system need, (3) develop a notional portfolio of DER required to meet a system need in order to assess the potential value of an NWA to the system, and (4) provide a public tool to allow DER vendors to develop potential NWA portfolios utilizing the same tools that the Company will use.

The combined impact of these changes will be to improve stakeholder visibility into RFP requirements, facilitate the identification and resolution of issues related to the RFPs, and reduce the overall time required to complete the RFP process for the benefit of the Company and DER developers. In addition, these tools will facilitate a consistent way to analyze bids through a competitive bid process using the BCA Handbook's methodology.

Evolution of the BCA

O&R is committed to meeting the Commission's goal of maximizing DER as a cost-effective alternative to traditional infrastructure investments. As such, in collaboration with the JU, the Company has developed a BCA methodology to comply with the Commission's Order Establishing the Benefit-Cost Analysis Framework.[154] That methodology and the associated templates have been combined with Company-specific data to develop O&R's BCA Handbook. The BCA Handbook, filed in conjunction with the Company's IDSIP,[155] is being incorporated into the integrated planning process, as well as the forecasting and modeling tools described above.

---

[154] REV Proceeding, BCA Order.

[155] Case 16-M-0412, Benefit Cost Analysis Handbook, Revised Benefit Cost Analysis Handbook (filed August 22, 2016) ("BCA Handbook").

The BCA Handbook illustrates the Company's support for the evaluation and deployment of NWAs, where they can serve as cost-effective alternatives to traditional investments. The Handbook also serves as an integrated part of the Company's updated electric delivery system planning process, from forecasting to implementation of DER as potential solutions and deferrals for traditional solutions, in a manner that best serves the Company's customers, manages risk, and maintains the safety and reliability of the grid.

Looking forward, O&R anticipates continued refinement and improvement to its BCA model and process. As it continues to develop its BCA process, the Company is working with stakeholders including DPS Staff, the JU and external experts to further refine the assumptions and values included in the BCA Handbook and add new benefits as they are identified such as the value of optionality as recently directed in the New York State Energy Storage Roadmap.[156]

Notional Portfolios

O&R is focused on executing on the projects in its NWA portfolio as well as identifying new NWA projects. The Company expects to leverage lessons learned from these projects to identify and execute on further improvements to its NWA processes. In the future, the Company anticipates preparing hypothetical portfolios of NWA solutions as part of the NWA identification process to determine whether it can obtain enough capacity to satisfy the project need. If it determines that it can, the Company will conduct a BCA and other economic evaluations to assess the cost-effectiveness of the portfolio, as well as associated potential customer rate and bill impacts before the RFP. If the Company decides to go forward with an NWA or non-traditional alternative, it will issue an RFP to assess actual market solutions and assess the RFP responses using the evaluation criteria discussed previously in this document. This approach will allow the Company to focus on further refining, streamlining, and automating its NWA processes.

Risks and Mitigation

Some of the risks to the Company's plans for procuring NWAs are the same as those discussed in the previous section on Beneficial Locations. These risks include changes to regulation or policy impacting incentives for DERs and changes to BCA requirements. The mitigations to these risks are the same as described in the previous section.

An additional risk to the Company's plans for procuring NWAs is change to the vendor landscape on which O&R relies for NWA solutions. This could impact the Company's current projects through the loss of vendors with which it has already contracted or could impact the options the Company has for procurement of future NWA solutions required to meet system needs. To mitigate this risk, O&R will need to identify a broad pool of vendors that provide each type of solution the Company uses to build the portfolios of solutions on which it relies to meet NWA project needs.

Lastly, due to the market-based approach of NWAs, the cost-effectiveness of NWAs is highly dependent on the cost of non-traditional technologies such as energy storage. Although, for the most part, the costs of these technologies are expected to fall with increased adoption, unforeseen increases in DER costs could potentially have a negative impact on the ability of NWA projects to pass BCAs and consequently provide cost savings to the Company's customers.

[156] Energy Storage Proceeding, Roadmap, pp. 42-44.

Stakeholder Interface

Vendor Interface

Stakeholder interface is a crucial component of O&R's NWA procurement process. Providing developers with accurate, timely and transparent information about each solicitation helps to ensure accurate proposals which more closely align with the Company's NWA needs and facilitates a fair RFP evaluation process. The Company regularly solicits feedback from developers on its RFPs, so that lessons learned can be incorporated into future procurements.

Information about NWA opportunities that pass the Company's suitability criteria screening is made available to stakeholders through multiple channels. Details around NWA opportunities and NWA RFPs are published on the following web pages with links to O&R-specific portals. The Company uses these portals to provide information about its potential RFP opportunities, including a brief description of each opportunity and when they are expected to go to RFP.

- O&R NWA portal link;
- JU of New York central data portal link ; and,
- REV Connect portal link.

As discussed above, O&R conducts a bidder's conference for each NWA procurement to allow potential respondents an opportunity to hear from the Company specifics relating to the project and ask any questions that they may have before submitting a proposal. In addition, a formal clarification question process is undertaken to answer any additional questions or clarify any ambiguities that may be in the RFP. Both processes help provide potential bidders with all the information necessary to submit quality proposals that best meet the deferral need.

As part of the evaluation process, O&R invites the top vendors from each solicitation to make a vendor presentation to the Company. These presentations allow for respondents to present additional details about their proposal and answer any questions the Company's evaluation team has regarding the proposed solution. The ability to have this give-and-take improves the quality of the evaluations and facilitates a fair and transparent selection process.

Joint Utilities

In addition to O&R vendor interface, the Company continues to coordinate with the JU as part of the DER Sourcing/NWA Suitability Criteria working group to develop and share best practices for NWA procurement. The JU continue to engage stakeholders to produce useful information about stakeholder needs and utility plans that have resulted in greater alignment. As noted in the Beneficial Locations section, the JU met with stakeholders twice in 2017 to provide insight into the NWA solicitation processes and request feedback on future solicitations. These meetings included discussion about the NWA sourcing process, which provided stakeholders an opportunity to ask questions and provide input and led to suggestions adopted by the JU. As an example, stakeholders suggested that a central portal with links to each utility's NWA opportunities will be a valuable resource. In response, the JU published webpages with links to utility-specific portals that contain notifications of NWA opportunities and NWA RFPs as described previously.

The JU also hosted a stakeholder webinar on November 9, 2017, to discuss challenges in past solicitations and to identify potential improvements to the RFP process. During this session, the JU shared some of the challenges that surfaced during current solicitations, and how they are addressing these challenges to improve the NWA RFP process. A key objective of the webinar was to learn more about the experiences of stakeholders who have participated in the NWA RFP processes. Stakeholders recognized the value in regular communication during the solicitation process, requested clear and specific requirements about system need and the supporting information, and emphasized the need for clarity around the award process.

Prior to the webinar, the JU offered stakeholders the opportunity to provide feedback through focused discussions regarding their experiences with the NWA RFP process. Discussions with DER developers were captured in presentations, which helped facilitate more productive two-way discussions on the topics presented during the webinar. A summary of the questions and responses obtained during the webinar are posted on the JU website.[157]

As the NWA solicitation process evolves, O&R will continue to invite input from stakeholders through direct discussions and broader stakeholder engagement meetings. The Company will continue to share experiences and lessons learned among the JU to achieve a consistent set of best practices and improve its solicitation processes to be more consistent and user-friendly. This includes reviewing the non-wires suitability criteria as part of the annual planning process, reviewing how system needs are identified, and evolving how NWA can address those needs. As O&R gains more experience with NWA solutions, the Company sees great value in working together with the JU, DER developers and other stakeholders to make NWA solicitations consistent, repeatable, and effective.

Additional Detail

This section contains responses to the additional detail items in the Staff guidance specific to Procuring NWAs:

1) **How the NWA procurement process works within utility time constraints while enabling DER developers to properly prepare and propose NWA solutions, which can be implemented in time to serve the system need.**

Due to long project development timelines, it is essential to provide as much insight into the pipeline of NWA projects as possible, both to facilitate developer planning and to allow time for the traditional solution to be built in the event a cost-beneficial NWA solution cannot be found. As a result, both the Company and developers have a common interest in identifying potential NWA projects as early as possible.

The Company's expansion of its planning horizon to include a ten-year outlook, as described in detail in the Integrated Planning section, will facilitate consideration of NWA opportunities by providing the Company additional time to identify potential NWA opportunities, additional time for developers to prepare and propose NWA solutions, and additional time for the Company to evaluate and implement solutions prior to critical need timeframes.

This aligns with the Company's timeline suitability criteria which requires a project to have lead time requirements (*i.e.,* 36 months for a large project or 18 months for a small project) before the project's commitment date. By identifying potential NWA projects earlier in the planning cycle, the Company has more time to conduct the NWA procurement process before needing to implement a solution.

The Company has made numerous improvements to its NWA procurement processes to streamline them and make them more efficient for the Company and developers. The Oracle software platform described earlier in this section has helped to simplify and improve the Company's RFP process,

[157] http://jointutilitiesofny.org/joint-utilities-of-new-york-engagement-groups/

helping to reduce the amount of time required to execute the solicitation and increase the likelihood NWA solutions can be implemented in time to meet system needs.

In addition, O&R has achieved efficiencies and time-savings through enhancements to its evaluation process, incorporating various subject matter experts ("SMEs") feedback from all over the company early in the process. Aggregating SME input led to a cohesive and comprehensive evaluation of the vendor proposal. The revised review process and early involvement of a broader range of SMEs help to identify potential issues with NWA integration earlier in the process resulting in a more expeditious evaluation process.

2) The NWA procurement means and methods; including:

a) How the utility and DER developers' time and expense associated with each procurement transaction are minimized

Most of the changes, as described in the response to question #1 above, also help to minimize the time and expense associated with NWA procurement transactions, including the development and communication of the Company's suitability criteria, new NWA portals, changes to the Company's RFP processes, and the development of new software tools.

In addition, in order to advance small projects more quickly, the Company will use a streamlined BCA to expedite the process. As for large projects, the streamlined BCA will compare the present value of the costs associated with the traditional infrastructure project with the present value of costs associated with implementing the NWA. However, the streamlined BCA will not include non-energy benefits other than CO_2 reductions (based on the CES Renewable Energy Credit compliance value) or benefits associated with the traditional infrastructure project that is being deferred.

In addition, O&R continually solicits feedback from developers on the quality and completeness of its RFPs and adjusts them as required to support an efficient RFP process for developers and the Company. Clear and concise RFPs that articulate the need minimize the steps needed to develop competitive RFPs and increase the likelihood that the proposal will pass the initial screening.

b) The use of standardized contracts and procurement methods across the utilities.

To enhance the DER integration process, the JU continue to share lessons learned from developing and implementing specific NWA RFPs (including supporting data) and resultant contract terms and conditions to work toward a more consistent approach to NWA procurement across utilities. Although each NWA contract is unique due to the individual nature of each project, standardized contract elements, common across utilities may present an opportunity for exploration as RFP and contracting processes for NWAs as they become business-as-usual.

As the JU work through their initial NWA solicitations, best practices will be developed based on lessons learned gathered to streamline and standardize the process for developers where possible. For example, successful NWA contracts should clearly state assumptions, incentives, and expectations for the intended use of the resource by the utility, expectations that a resource may have to generate additional revenue streams through participating in other markets (*e.g.* wholesale), and operational and commercial requirements including expected performance and corresponding payment terms. Through information sharing across utilities, the JU have agreed that contracts should also include the clear and consistent use of key terms and descriptions across NWA solicitations.

3) Where, how, and when the utility will provide a resource to DER developers and other stakeholders for accessing up-to-date information about current NWA project opportunities. For each

opportunity, the resource should describe the location, type, size, and timing of the system need to be addressed by the project.

O&R provides DER developers with up-to-date information on current NWA opportunities through the REV Connect portal (link) and its Company website (link). Via the REV Connect portal, O&R provides the NWA opportunity name/area of need, the MW needed, date needed, and the RFP status. From the REV Connect portal, developers also have the option to click on the "Identified Non-Wires Opportunities" link, which will take them to the Company's website where additional information can be found. In addition to the information found on the REV Connect site, O&R's website contains links to more detailed project descriptions for NWA opportunities that have not yet been released to RFP. For in-flight projects, the Company also includes links to RFP documents as they become available; these documents include the RFP, RFP questionnaire, pre-bid conference presentation, and responses to RFP clarification questions.

4) **How the utility considers all aspects of operational criteria and public policy goals when selecting which DERs to procure as part of a NWA solution.**

The Company considers all relevant operational criteria when selecting DERs for an NWA solution through use of its proposal evaluation criteria. As discussed above, since the SDSIP filing, the Company has developed and implemented the following four NWA evaluation criteria: 1) technical, 2) feasibility, 3) cost, and 4) timeliness. These criteria are used to evaluate proposals received by the Company in response to its NWA RFP solicitations, helping the Company identify proposals that will best address the identified system need.

The two evaluation criteria used to assess the operational aspects of a proposed NWA solution are technical and feasibility. The technical evaluation criterion addresses the potential solution's technical ability to meet the needs of the specific targeted area, at the time needed, while being dispatchable by O&R, and scalable to meet changing demands. The feasibility evaluation criterion assesses the feasibility of implementing the proposed solution from the beginning to the end of the implementation process, including customer acquisition, community perception, siting, permitting, construction, interconnection, and operational feasibility considerations. The Company plans to refine and update its evaluation criteria over time based on lessons learned from the evaluation and implementation processes.

In the case of DER, such as energy storage, that have operational capabilities that may allow them to provide benefits beyond the needed load relief, those characteristics are captured in the Company's BCA analysis in the form of additional benefits and through direct conversations with vendors who are encouraged to seek out all potential benefit streams.

In addition to the evaluation of operational criteria for potential new NWAs, O&R incorporates public policy goals into its BCAs, as practical, and considers specific policy goals as part of its broader evaluation and selection process. In BCAs, public policy goals are considered primarily through some elements of the SCT, which include avoided generation cost of capacity, environmental criteria, carbon reduction, SOx, and NOx. As part of its broader evaluation and selection process, the Company considers policy goals, like New York State's goal to have 1,500 MW of battery storage installed by 2030 to the degree to which the proposed solution is cost-effective.

5) **Where, how, and when the utility will provide DER developers and other stakeholders with a resource for accessing up-to-date information about all completed and in-progress NWA projects. The information provided for each project should:**

   a) **Describe the location, type, size, and timing of the system need addressed by the project**

As described in the response to question #3 above, O&R currently provides DER developers with up-to-date information on current NWA opportunities through the REV Connect portal and the O&R website. As NWA projects progress past the RFP stage and begin construction and are completed, the Company plans to keep these projects on its website and to update them as appropriate until they are completed. Completed projects will be posted on its website so developers and third-parties can review them as examples of completed NWA projects in the Company's service territory.

O&R plans to share the following information about each of its NWA projects:

- Project Name/Location;
- Project Type;
- Substation ID;
- Circuit ID;
- Solicitation Status;
- Need Year;
- Project Description URL (containing additional information about the project); and,
- Name of the selected vendor/solution provider

In addition, the Company is investigating the possibility of including information about NWAs on its hosting capacity maps to serve as another means for developers and other third-parties to find information about NWA projects in its service territory.

b) Describe the location, type, size, and provider of the selected alternative solution

As described in the response to question #5.a. above.

c) Provide the amount of traditional solution cost which was/will be avoided

In compliance with its Operating Procedure for Calculation of Financial Incentives for Non-Wires Alternatives[158] and the Public Service Commission's Order Granting Petition in Part[159], wherein it approved the Company's proposed NWA framework with modifications, the Company will provide the amount of a traditional solution cost to be avoided through implementation of an NWA when it has entered into contracts with the NWA solution providers for the entire NWA portfolio, or when, in consultation with Staff, it determines with reasonable certainty the costs of the NWA solution.

Additionally, this amount will be included in the Company's BCA and will be updated if there is an increase or reduction in the MW of the NWA solution or the length of the deferral period for the traditional infrastructure, per the Operating Procedure.

d) Explain how the selected alternative solution enables the savings

As described in the response to question #5.c. above, the Company calculates the savings, or "Net Benefits" of an NWA solution over the traditional solution as part of the BCA process. The Company calculates these savings or "Net Benefits" differently for large and small NWA projects.

For large projects, the BCA will include a comparison of the present value of the net costs and benefits associated with implementing the traditional infrastructure project, with the present value of the

[158] Case 17-M-0178, *Petition of Orange and Rockland Utilities, Inc. for Authorization of a Program Advancement Proposal*, Orange and Rockland Utilities, Inc. Operating Procedure for Calculation of Financial Incentives for Non-Wires Alternatives (filed December 18, 2017).
[159] PAP Proceeding, PAP Order.

net costs and benefits associated with implementing the NWA solution. The difference between the two present values will represent the “Initial Net Benefits” resulting from implementing the NWA solution to defer or avoid building the traditional infrastructure project.

As described above, to advance small projects more quickly, the Company uses a streamlined BCA also comparing the present value of the costs associated with the traditional infrastructure project with the present value of costs associated with implementing the NWA. However, the streamlined BCA will not include non-energy benefits other than CO_2 reductions (based on the CES Renewable Energy Credit compliance value) or benefits associated with the traditional infrastructure project that is being deferred.

In the case of both large and small projects, the initial net benefits will be calculated when the Company has either entered into contracts with the NWA solution provider(s) for the entire NWA portfolio or when the Company and Staff agree there is reasonable certainty regarding the likely cost of the NWA project portfolio. At this time, the costs and projected savings of the NWA will be filed with the Commission. If a future assessment results in either an increase or decrease in the amount of MW needed to achieve the intended deferral or avoidance of the traditional infrastructure solution, the Company will file an updated BCA.

e) Describe the structure and functional characteristics of the procurement transaction between the utility and the solution provider(s).

To promote transparency, the Company plans to provide DER developers and other third-parties with information about completed procurement transactions such as notification that a contractual agreement has been made, the vendor, the MW size of the agreement, the impacted location(s), and technology to be used.

However, the Company is aware of its responsibility to protect confidential commercial information contained in the terms of the transaction and must balance the need to share information with the proprietary nature of its partners’ business information.

ORANGE AND ROCKLAND UTILITIES, INC.

2018 Distributed System Implementation Plan

Chapter 3 - Other DSIP-Related Information

DSIP Governance

O&R's transition to a DSP services provider is changing people, processes, and technologies across the Company. These changes are focused on providing the services outlined earlier in this DSIP update:

- DER Integration Services;
- Information Sharing Services; and
- Market Services.

The initiatives that are being implemented to meet the Company's goals in these areas span across all the Company's organizations and include support functions that are shared with CECONY. These changes require a uniform and consistent approach to the myriad of requirements put forth by the various REV proceedings and orders. From the development of policy positions which impact divergent organizations, to the implementation of granular engineering and customer data solutions to animate markets, and advocacy and rate design, REV necessitates progressive yet disciplined solutions which challenge the status quo thinking of the industry in order to create new markets, opportunities, and cost savings for customers. The changes require a centralized governance for REV-related efforts. In order to understand and coordinate the multitude of requirements of REV, especially their interaction with one another, and organize the Company's efforts to implement the DSP, O&R established the UotF organization in 2015 as a centralized governance for REV-related efforts.

O&R's UotF organization is leading the transformation to the DSP provider by uniting policy, business, operational, and technical experts from across O&R's organizations and functions

The UotF organization has governance and oversight for the initiatives that the Company undertakes to implement the DSP and provisions of the REV proceedings. The organization manages both internal and external coordination of activities. UotF is responsible for informing other internal Company organizations on the various REV requirements so that they are able to implement individual REV requirements in a manner that moves the Company forward to create the desired results to support DER integration services, information sharing services and market services. In addition, UotF works so that O&R is well coordinated with the activities of the JU including aligning with the JU on strategic issues such as the development of the market and the DER roadmap work with the NYISO. Further, UotF coordinates participation in a myriad of technical conferences and working groups on REV-related topics so that the Company's perspectives are presented in these statewide forums. UotF also represents the Company in stakeholder outreach performed by O&R or as part of the JU.

The UotF organization is also responsible for aligning REV initiatives with other corporate priorities, such as the Company's current electric base rate case. It is critical that all of these workstreams are centrally managed because the Company must execute on REV-related initiatives in an integrated manner. The UotF group reports to the Vice President, Operations and the Company's leadership receives frequent briefings on REV initiatives, including the DSP. All of these functions and activities align organizations across the Company and ultimately with CECONY to move cohesively toward implementation of REV and other New York State 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

The DSIP update serves as a core planning document for the Company, outlining its plans across DER integration, information sharing, and market services over the course of the next five years based on current Company and New York State priorities and objectives. The DSIP is provided as a roadmap for DER providers, third-parties, customers and the Commission detailing the Company's path to becoming the DSP provider. Details about the various plans and initiatives making up the DSIP are included in Chapters 1 and 2 of this DSIP update.

DSP Participant Roles and Responsibilities

Primary participants in the planning, development, and implementation of the various functions making up a DSP include:

- Utilities – New York electric utilities managing and coordinating the build and evolution of the DSP and their individual roles as DSP providers. O&R's DSP activities in coordination and concert with other New York utilities and stakeholders as described below.
- Customers – End-use electricity customers that reap a number of benefits from DSP implementation including products and services that can be tailored and bundled to meet individual preferences, the ability to shop among different service providers, and the availability of granular information on usage, cost, reliability, and emissions.
- Market Participants – The various developers, vendors, aggregators, and other entities that provide DERs through O&R's DSP. These entities reap a number of benefits from DSP implementation including streamlined interconnection, co-optimization of wholesale and distribution market value, regular NWA procurement and incorporation of wholesale value, billing and settlement services, and access to granular customer information (with customer consent)
- Stakeholders – Various entities that provide input, guidance, and advocacy to help/influence the ongoing DSP evolution and transformation. Stakeholders include the JU along with a wide cross-section of government agencies, consumer advocates, vendors, and customers including: The New York State 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, and organizations representing large and small commercial and residential customers.
- Third-Parties – Various outside consultants, contractors, and support organizations that are responsible for providing input and technical guidance and expertise to guide implementation. ScottMadden Inc. is an example of a third party engaged by O&R for these purposes; ICF is a similar third-party engaged by the JU to provide technical support and share relevant experience from other states.

2) Describe the nature, organization, governance, and timing of the work processes that comprise the utility's current scope of DSIP work. Also describe and explain how the work processes are expected to evolve over the next five years. Workflow diagrams that show significant internal and external dependencies will be especially useful.

DSP functions and capabilities are progressing through different stages, or phases, as described in the JU SDSIP.[160] A phased approach aligns the pace of investment with the speed of DER adoption, recognizing that some capabilities are not required until DER penetration reaches significantly higher levels. In addition, a phased approach provides the Company with an opportunity to learn from demonstration projects in New York and from experience in other states and countries.

As described in Chapter 1 (Vision) of this DSIP update, the JU established a framework for understanding and navigating three phases of DSP functionality and capability. DSP 1.0 refers to the first, and current, phase of DSP development. DSP 2.0 refers to a second phase, with enhanced integration, information, and market services. DSP 2.x refers to a longer-term phase of DSP development, characterized by the emergence of transactional distribution markets.

Each of the functions and activities that make up DSP platform services (*e.g.,* interconnection services) must be planned, developed, and implemented, all of which require significant change management for the utility. Given the phased nature of DSP platform progression, at any given point in time functions making up the core DSP services will be at varying stages of planning, development, or implementation. Implementation is often done in stages (*e.g.,* hosting capacity) which brings additional layers of complexity to the growing complement of DSP activities. Governance and oversight of these and other initiatives required to stand up the DSP is critical.

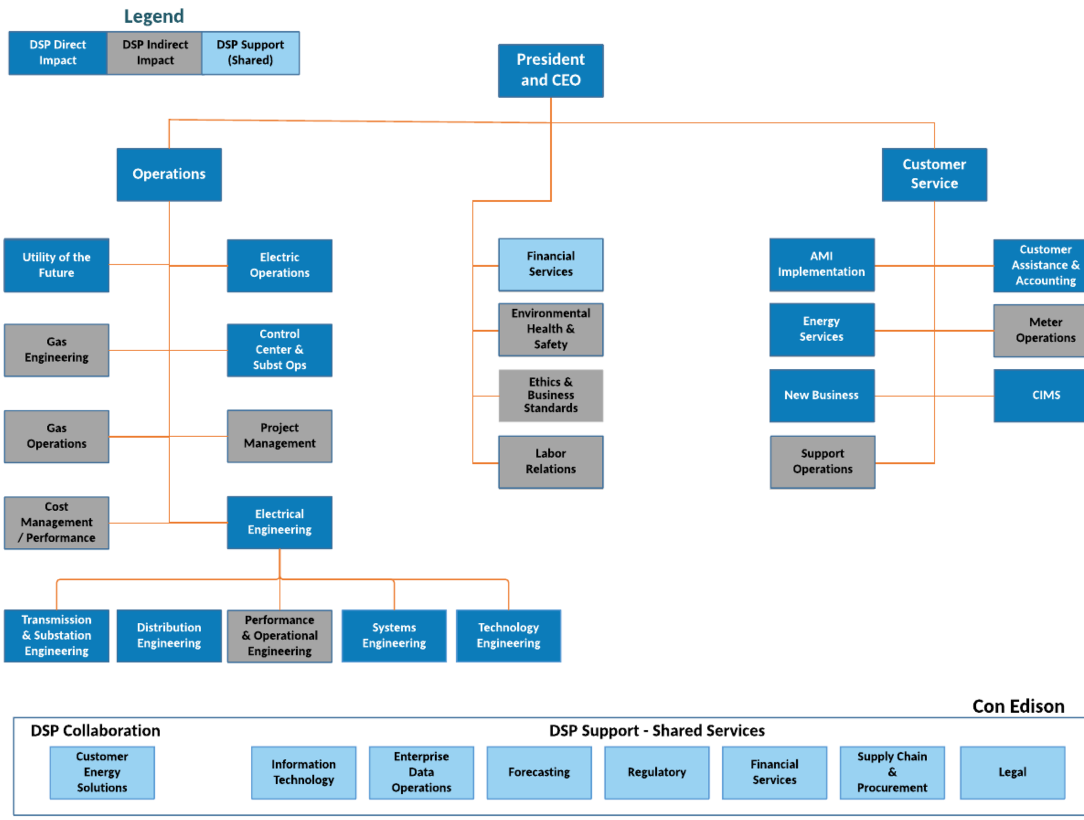
The Company's transition to the DSP provider is impacting people, processes, technologies, and organizations, all of which require rigorous and ongoing change management

DSP Organization, Roles, and Responsibilities

The following figure depicts O&R's organization today. Organizations in dark blue are those directly impacted by or heavily involved in DSP and REV activities. Organizations in gray are those that are less involved and indirectly impacted. Organizations in light blue are those that provide DSP support services. In most cases these support organizations are shared by O&R and CECONY. Also shown is CECONY's Customer Energy Solutions organization (formerly Distributed Resource Integration) which is the governing organization for CECONY's DSP initiatives.

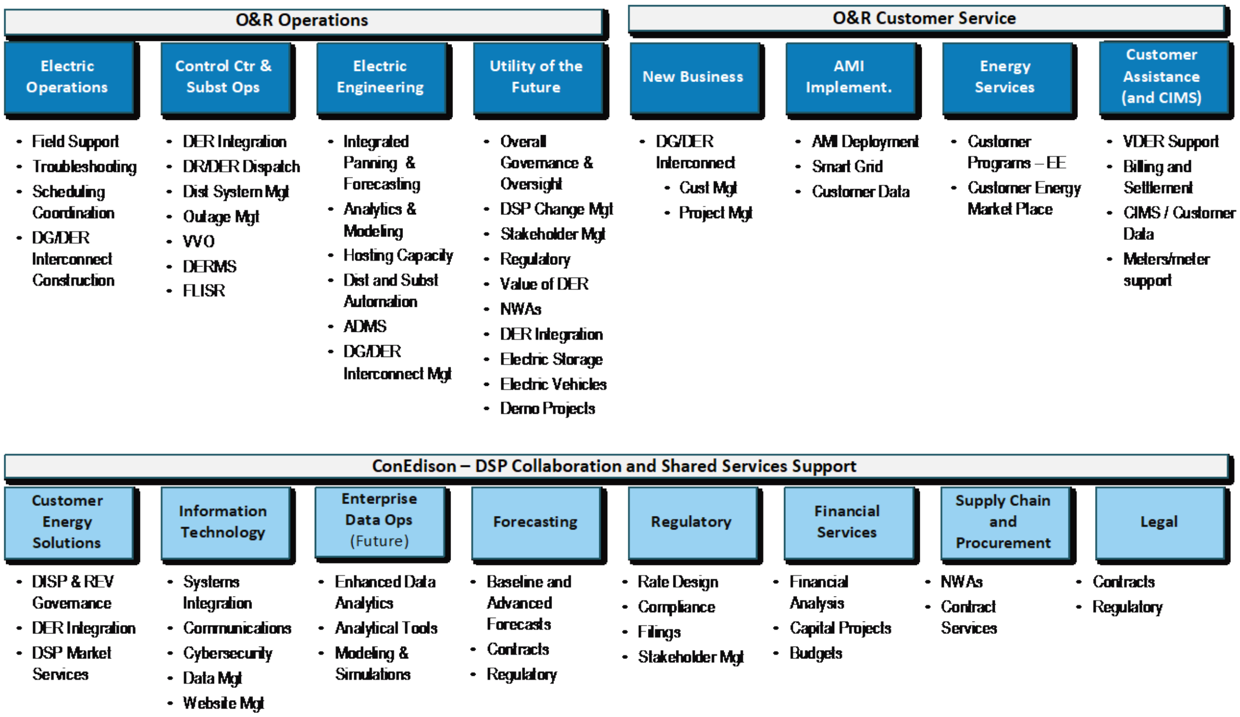
[160] DSIP Proceeding, JU Supplemental DSIP.

Figure 38: O&R Organizations Impacted by DSP



As noted above, the DSP provider delivers market services, DER interconnection services, and information sharing services to market participants, customers, and stakeholders. The initial phase of DSP evolution has been primarily focused on planning and developing the foundation to enable these services, such as a modernized grid, more granular and accessible data, hosting capacity and interconnection management. A few of the DSP functions have moved from planning and development to early stage implementation, such as hosting capacity and interconnection services. As such, the O&R organizations responsible for the DSP initiatives and workstreams are required to perform multiple DSP roles at varying stages of development or implementation and will continue to do so for the foreseeable future. The following figure reflects the DSP functional roles and responsibilities carried out by each of the O&R organizations as they exist today.

Figure 39: O&R DSP Functional Roles and Responsibilities



As described in Chapters 1 and 2 of this DSIP update, a steady flow of new DSP capabilities (*e.g.,* more automation in distribution grid) will emerge over the next five years. Business and operational model changes are expected to emerge as well. The extent to which the changes will impact current work activities, processes, functions, and organizational structures is not known at this time. What is known, however, is that integrated and ongoing change management is needed to ready people, processes, and technologies in advance of the roll-out of the new capabilities. Work process documentation, communication, and training can be expected as new DSP capabilities are introduced. Stakeholders of such change management include employees, stakeholders, market participants, and third-parties.

DSP Governance

There are various initiatives, proceedings and filings that make up the REV proceedings and O&R's transition to a DSP service provider. Governance and oversight for O&R's efforts to implement the DSP and provisions of the REV proceedings are the responsibility of the UotF organization. In this role, UotF is responsible for:

- Coordinating with the JU on REV and DSP strategy and policy matters so that the Company's views are well represented. This role includes bringing strategic and policy issues back to O&R senior leadership to ensure internal alignment to the REV vision.
- Organizing and providing oversight for the various REV and DSP initiatives underway so that the timelines set by the Commission are met and that O&R advances in developing the DSP, and,
- Aligning REV initiatives with other corporate priorities, such as the Company's current electric base rate case.

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 the DSP and other REV priorities. UotF's combination of cross-functional internal governance and oversight, and external strategic alignment, have helped coordinate and align O&R's REV and DSP efforts to be responsive to Commission requirements.

UotF is an active participant and coordinator of the Company's involvement and engagement in each of the nine JU implementation working groups. UotF's JU coordination role includes participation in myriad technical conferences and working groups on REV-related topics so that the Company's perspectives are included in these statewide forums. This coordination includes aligning with the JU on strategic issues such as the development of the market and the DER roadmap work with the NYISO. UotF also represents the Company in stakeholder outreach performed by O&R or as part of the JU.

UotF centrally unites policy, business, operational, and technical experts within the organizations and functions shown in the previous figures to implement REV initiatives, build the DSP platform, and improve the customer experience. The cross-functional nature of O&R's approach to DSP development requires strong governance, oversight, and work-stream coordination by the UotF organization so that O&R meets the goals and targets for all DSP and REV-related work. Project managers within each of the organizations manage individual DSP work streams (*e.g.,* interconnection) while coordinating with members of UotF to provide proper integration and alignment across all DSP and REV activities. Change management activities such as communication and training are also governed and coordinated by UotF to afford common messaging and proper training are being afforded to all impacted O&R employees.

The UotF organization is also responsible for aligning REV initiatives with other corporate priorities, such as Company's current electric base rate case. It is critical that all of these workstreams be centrally coordinated because the Company must execute on REV related initiatives in an integrated manner. The UotF group reports to the Vice President, Operations, and the Company's leadership receives frequent briefings on REV initiatives and the DSP. This aligns organizations across the Company and ultimately with CECONY.

DSP Work Processes

As a DSP provider, O&R is developing the capabilities, processes, and systems that enable key DSP functions: integrated planning, DER interconnection, and DER management (DER integration services); information management and customer engagement (information sharing services); and procurement, market coordination, wholesale tariff, and settlement and billing (market services). Impacts from these changes are seen in changes to work processes, people skillset requirements, and technologies. A sampling of the work processes (existing and new) impacted by DSP include:

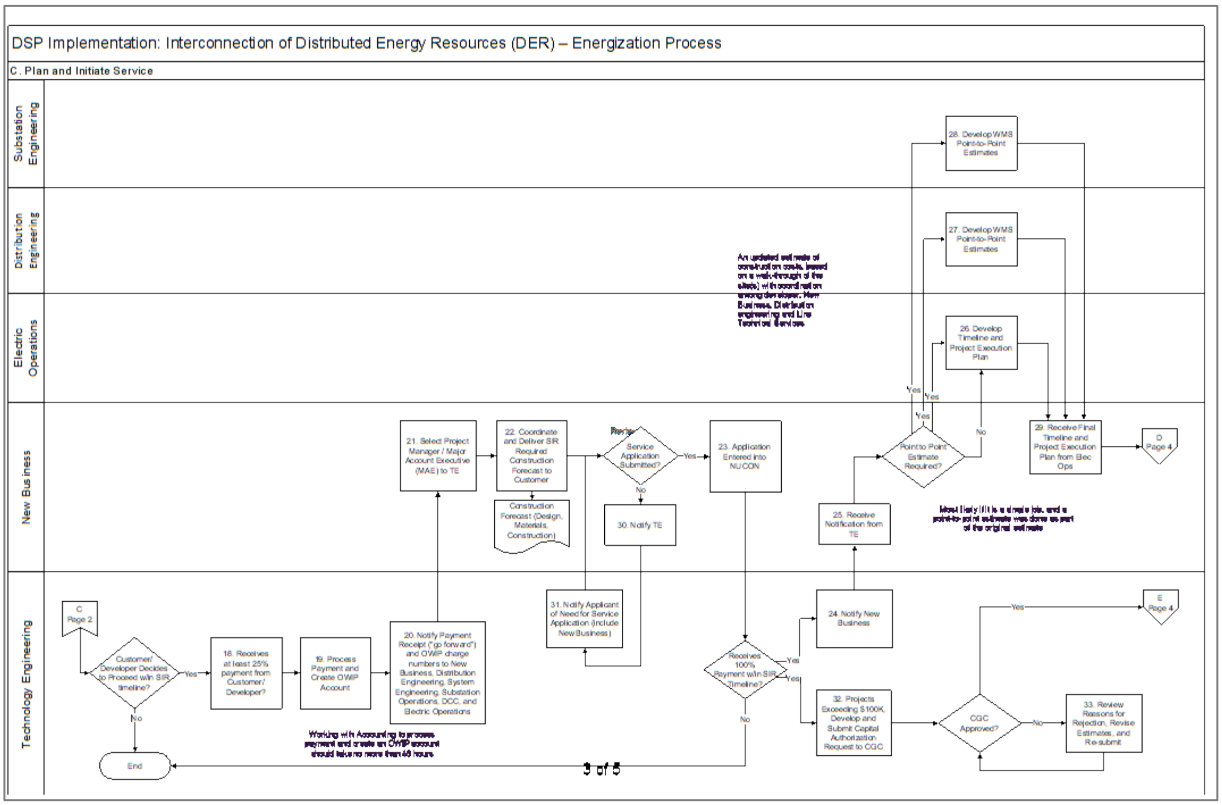
- Longer horizon Integrated planning process with more granular forecasting data;
- DR/DER interconnection management, construction, and energization processes;
- Grid operation, management, and outage processes reflecting increasing visibility, monitoring, automation, and control capabilities;
- DR/DER operational integration and management processes;
- System data, customer data, and hosting capacity portal development and management processes;
- Hosting capacity map update process;
- NWA identification, management, and procurement processes;
- EV and energy storage program processes;
- Value stack customer billing and credit calculation process (Value of DER);
- AMI deployment process and resulting impacts on meter reading, service order, and outage management work processes;
- Demonstration project development and execution processes;

- New EE program development and implementation processes; and,
- New rate design processes.

Details surrounding these and other DSP functional and capability impacts on work processes are provided throughout Chapters 1 and 2 of this DSIP update (*e.g.,* see Hosting Capacity section for details on hosting capacity update process). Managing the rapid pace of such impacts on processes, functions, and organizations is an ongoing effort requiring strong cross-functional and cross-organizational coordination, governance, and oversight. As stated previously, the UotF organizational is responsible for such coordination and oversight.

As a means of illustrating the cross-functional work process impact on O&R's organization, a small excerpt from the DER interconnection process is shown below.

Figure 40: Excerpt from DER Interconnection Process Workflow



The "accountability" swim lanes show that cross-functional coordination extends not only to planning and development activities but also to the actual implementation and execution of DSP services. Similar impacts can be seen when examining the work processes developed and being executed for NWAs and Value of DERs. Cross-functional accountabilities for each of these processes depends upon the central governance and oversight of the UotF organization to execute and deliver effective DER services.

3) **Identify and describe in detail the tools (*i.e.,* project management, collaboration, and content management software) and information resources currently employed internally by the utility and/or presented for stakeholder use. Also describe and explain how the tools and information resources are managed and how they are expected to evolve over the next five years.**

The UotF organization utilizes a project management approach to plan, execute, monitor and control, and document the requirements set forth by the REV and DSP initiatives. The team assesses project risks, engages stakeholders, collaborates with partners and uses various tools to execute on and control the progress of the DSP and associated REV requirements.

The Company has developed a number of tools and information resources for use internally and for external presentation purposes, many of which have been developed in collaboration with the JU. A detailed listing of these tools and resources is provided in the Appendix to this DSIP update. A *sampling* of these tools and resources is provided below:

- JU central data portal on the JU website (https://jointutilitiesofny.org/system-data/) with specific links to a range of O&R information, including:
    - DSIPs;
    - Capital investment plans;
    - Planned resiliency and reliability projects;
    - Reliability statistics;
    - Hosting capacity;
    - Beneficial locations;
    - Load forecasts;
    - Historical load data;
    - NWA opportunities;
    - LSRV locations;
    - Queued and installed DG; and
    - SIR pre-application information.
- Hosting Capacity and System Data;
- EPRI Drive tool;
- PowerClerk;
- REV Connect;
- Green Button Connect;
- Electronic Data Interchange; and,
- Oracle Primavera P6 project management tool.

Details surrounding the development, maintenance, and use of these tools for both internal and stakeholder use are provided in Chapters 1 and 2 of this DSIP update (*e.g.,* PowerClerk is described in the Hosting Capacity section).

In addition to these tools and materials, the UotF organization performs a number of REV and DSP project and content management tasks and activities in its effort to provide overall DSP and REV governance and oversight. A sampling of these tasks includes:

- Ongoing briefings to O&R executives on REV-related policy matters and activities, DSP initiatives status, and coordination with the rate case and other regulatory filings;
- Weekly DSP project status calls with functional managers and SMEs responsible for the various DSP initiatives and workstreams;

- Collaboration with other utilities and stakeholders including participation on the JU steering committee, REV leadership team, and REV policy committees, and collaboration and coordination with O&R representatives on the various working JU working groups; and,
- Ongoing management and development of REV and DSP-related messaging and information used for training and other change management efforts required as the DSP continues to evolve.

As the DSP develops and the capabilities continue to grow or improve, the project management requirements – especially those surrounding communications, resource management, and change management – will grow. Tools being used today will be replaced with others that have more functionality, leading to a more systematic and institutionalized approach within the DSP platform itself. For example, the New Business organization is beginning to use the Oracle Primavera P6 project management software as a means of managing interconnection projects and construction schedules.

4) Describe the JU of New York Website contents and functions which support aspects of the utility's implementation program. Provide specific examples to explain how those contents and functions help both the utility and its stakeholders.

The JU collectively maintains and regularly update their website (link) with valuable resources for interested parties. A summary of current JU DSP enablement activities is posted to the website homepage each month to keep third-parties informed of individual company efforts to advance DSP implementation. The JU have also enhanced their website by developing central portals with utility-specific links for hosting capacity, system data, and NWA opportunities, which has helped to increase transparency, usability, and availability of information. The granularity and availability of information provided on the website has been improved through targeted conversations with DER developers. The website also serves as a valuable repository for stakeholder information, providing key policy and regulatory documents, detailing past stakeholder meetings, summarizing inputs that stakeholders have previously provided and next steps for addressing them, and providing links to other resources such as REV Connect. The JU welcome suggestions to enrich the website through their email.

5) Describe and explain the planned sequence and timing of key DSIP management activities and milestones. Using calendars, Gantt charts, and narrative text, provide information addressing management functions, collaborative processes (stakeholder engagement and JU coordination, for example), and development and maintenance of program tools and information resources.

In 2016, the Commission directed that the DSIP process should include active collaboration among utilities, stakeholders, and Staff to promote the transition of the utilities to DSPs.[161] Building on the structure established in 2016 in the course of the preparation of the IDSIPs and the SDSIP, the JU have continued to collaborate to enhance communication channels with stakeholders to develop the 2018 DSIP updates.

To support consistency, the JU aligned around a common definition of the platform, which includes the three core DSP services of DER integration, information sharing, and market services. Information and updates organized around these three aspects of the platform were presented in a conference with stakeholders on November 30, 2017. The JU then developed a common outline for the 2018 DSIP filings in order to align with the requests for information provided in the Staff DSIP Update Whitepaper to make it easier for stakeholders to access the same information across utility filings. The JU

---

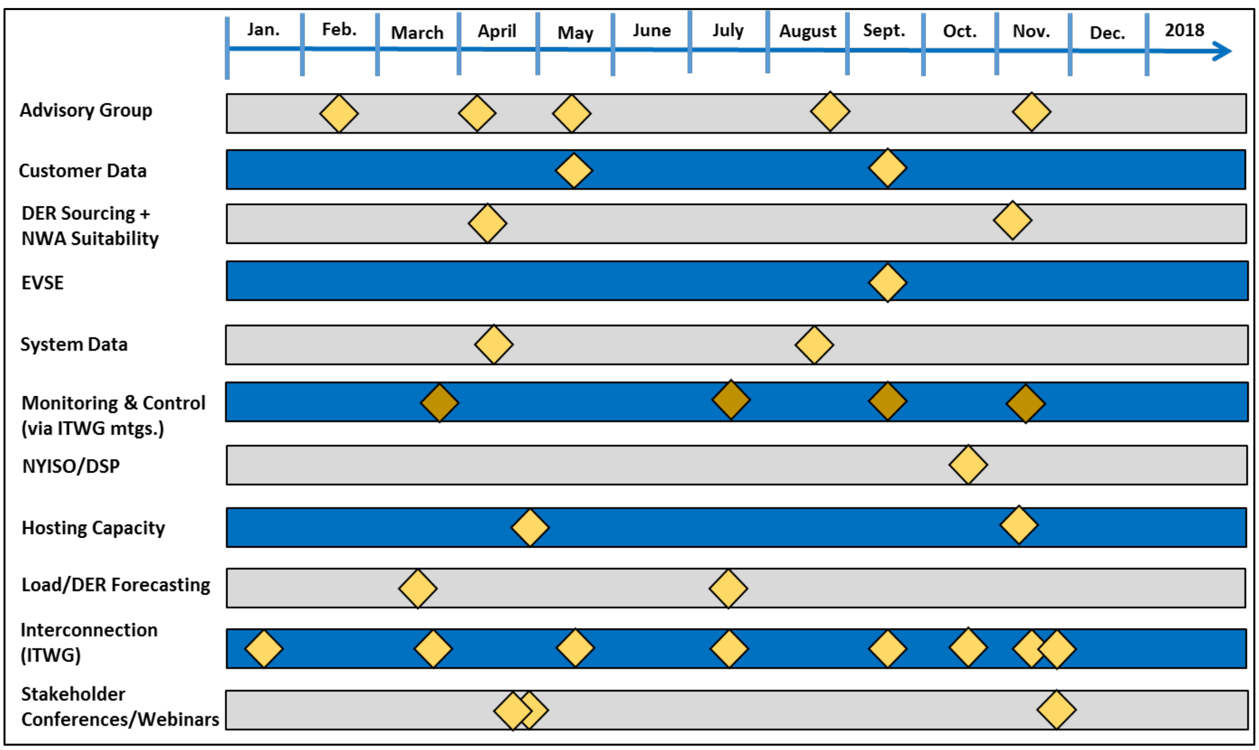
[161] DSIP Proceeding, DSIP Staff DSIP Update Whitepaper, p. 2.

also shared timelines and key milestones for filing development in order to support continued comparison and consistency.

In 2017 and during the first six months of 2018, the JU focused on implementation efforts based on commitments made in the SDSIP and individual 2016 DSIP filings. The JU maintained nine implementation working groups. These groups allowed the utilities to share information, jointly develop consistent methodologies and JU filings, and work with stakeholders to solicit feedback on those methodologies and filings. As a result, the approaches described in the 2018 DSIP filings have greater uniformity, and stakeholders will experience DSPs and market functions that are more consistent across the utilities. For example, hosting capacity displays will include the same information and visual elements across utilities. To support these collaborative processes across the six utilities, the JU retained ICF to provide project management office functions and technical expertise, as well as coordination of the implementation working groups and related stakeholder engagement efforts.

The JU also continued to collaborate on stakeholder engagement, both through the stakeholder Advisory Group as well as through meetings organized around specific topics across the nine working groups.[162] The 2017 implementation teams and stakeholder engagement meeting schedule are summarized in Figure 44 below.

Figure 41: 2017 Stakeholder Engagement Efforts

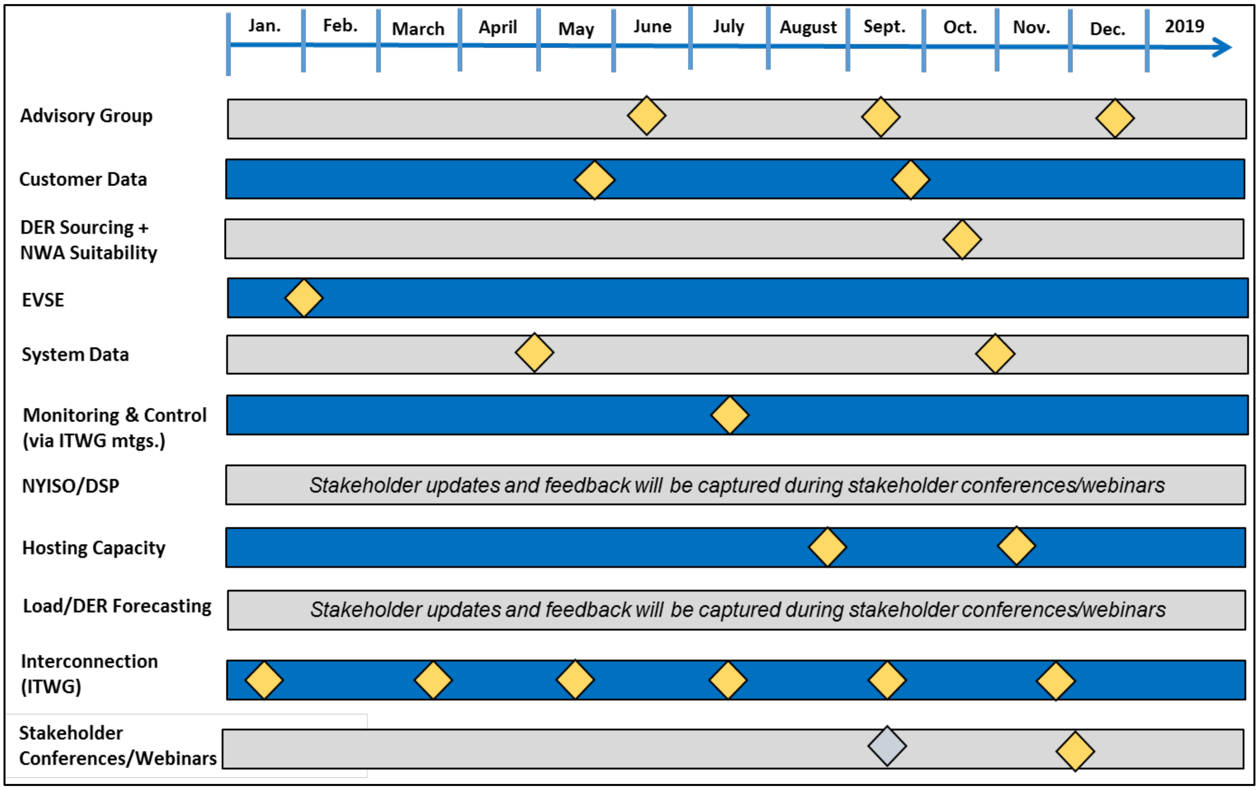


As the JU advanced development of the DSPs into 2018, they continued to engage stakeholders, as needed, in parallel with the working group efforts. Each utility is holding utility-specific meetings with stakeholders in the third quarter of 2018. The JU anticipate holding a larger stakeholder conference in the

[162] The Advisory Group, made up of approximately 15 representative companies, is an open forum for stakeholders who are actively engaged in the REV process and the DSIP filings to advise the JU on a productive and collaborative stakeholder engagement process.

fourth quarter of 2018 to discuss implementation efforts since the 2018 DSIP updates and preview plans for 2019. The anticipated stakeholder engagement efforts for 2018 are summarized in Figure 45 below:

Figure 42: Anticipated 2018 Stakeholder Engagements Efforts



6) Describe and explain the planned sequence and timing of the notable activities, dependencies, milestones, and outcomes affecting implementation. Using calendars, Gantt charts, and narrative text, provide information addressing all significant utility processes, resources, and capabilities. Explain how each notable outcome enables one or more significant DSP applications.

O&R's consolidated five-year forecast for the various elements making up the DSP is shown in the following three figures. The activities and timelines provided are estimated as of July 2018 and are subject to change as the DSP continues to evolve. A number of externalities may emerge that will impact the tasks, milestones, or timing. Examples include DER market changes or shifts, technology changes, and regulatory changes. The topical sections within Chapter 2 of this DSIP update contain the details underlying the activities, timelines, dependencies, and milestones depicted in the figures below.

Figure 43: O&R 5-Year Consolidated DSP Implementation Plans

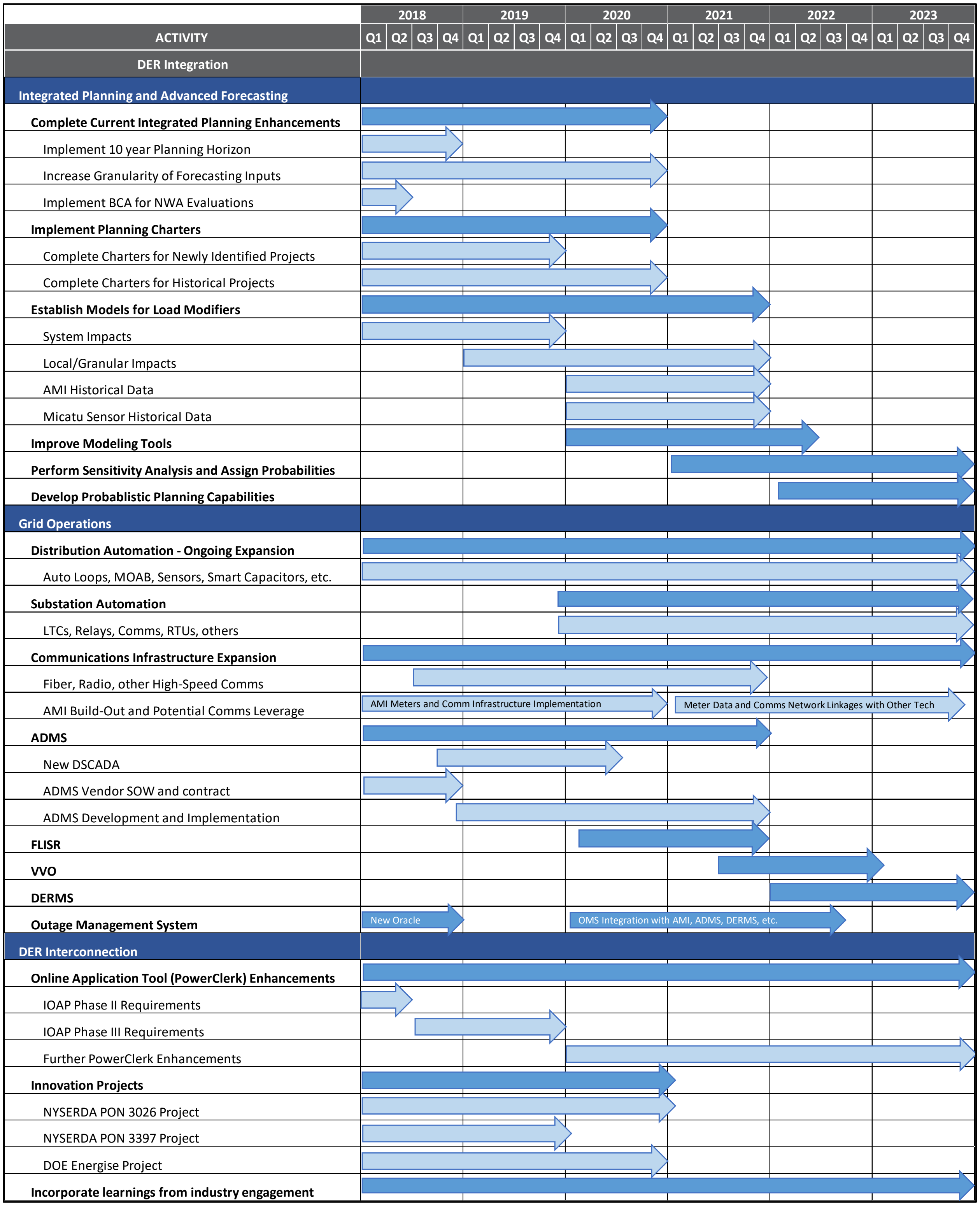


Figure 44: O&R 5-Year Consolidated DSP Implementation Plans (Cont'd)

Figure 45: O&R 5-Year Consolidated DSP Implementation Plans (Cont'd)

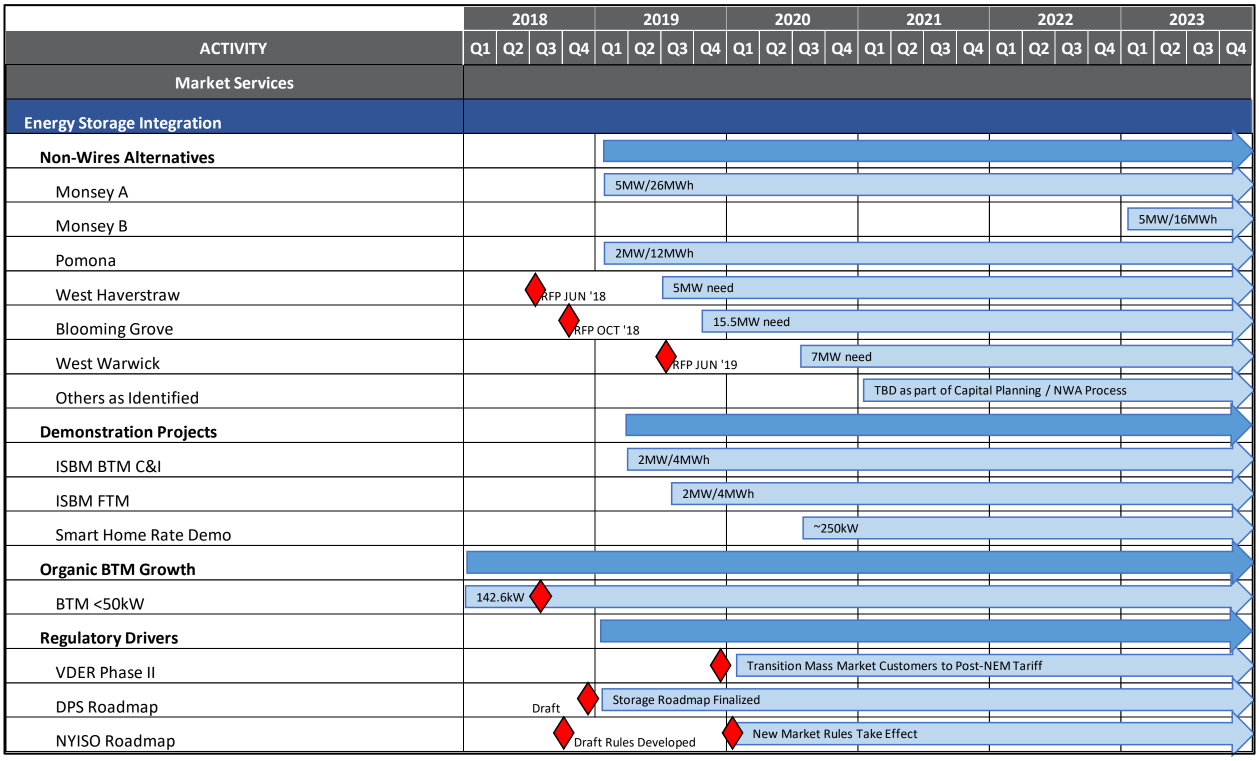
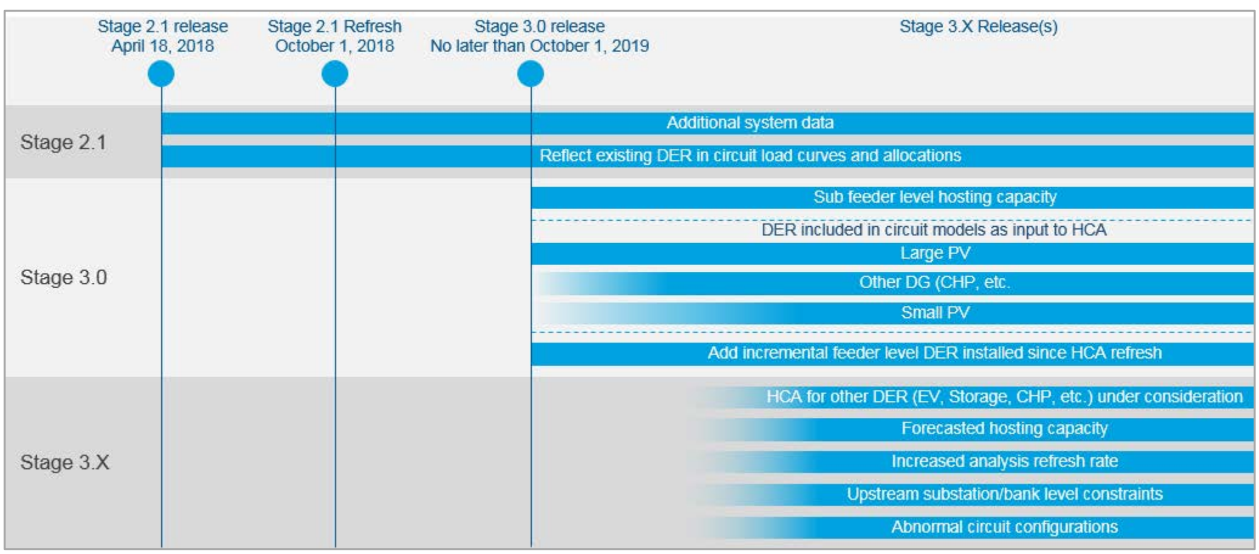


Figure 46: O&R 5-Year Hosting Capacity Implementation Plans



Marginal Cost of Service Study

The latest version of O&R's MCOS Study is publicly accessible via the following web link: http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={CD46904E-F70F-4936-BA5F-8A9C54CA83A4}

Benefit Cost Analysis

The latest version of O&R's BCA Handbook is publicly accessible via the following web link: http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=14-m-0101&submit=Search+by+Case+Number

2018 Distributed System Implementation Plan

Appendices

Appendix A: Peak Load and DER Forecast Details

This appendix provides additional details on the Company's system peak demand, load area peak demand, and DER forecasts.

System Peak Demand Forecasts

Forecast of System Peak Demand Growth

Every year, following the summer peak season, the Company produces a series of forecasts to guide the next planning cycle. Commencing with the 2017-18 planning cycle, this will include a ten-year overall electric system peak demand forecast and a ten-year substation forecast.

These forecasts are developed using a hybrid of top-down and bottom-up methodologies, which improves forecasting accuracy by allowing for cross-referencing of meter data and queued projects with overall macroeconomic trends. Additionally, by comparing the top-down system-wide peak load analysis to the bottom-up network 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, commercial, and government sectors to the most recent summer weather adjusted peak ("WAP"). In addition to sector demand growth, non-sector-specific technology-driven load growth is also added, such as EVs.

To determine residential sector growth, the residential top-down econometric model considers the number of households, saturation of A/C, coincident use of A/C, household occupancy, and hourly use per A/C unit. To determine commercial sector demand growth, the commercial top-down econometric model considers the number of customers by service classification, the price of electricity, and other macroeconomic measures. Governmental sector demand growth is calculated by aggregating announced projects for the initial years of the system forecast (bottom-up methodology), before switching to a top-down approach.

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 network 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,[163] and the assumed average kW usage per vehicle.

As noted above, the sector forecasts generally use a top-down methodology, which takes a holistic view of macroeconomic conditions that influence electric demand. Bottom-up methodologies are

---

[163] M.J. Bradley & Associates, *Plug-in Electric Vehicle Cost-Benefit Analysis: New York*, (December 2016), https://www.mjbradley.com/sites/default/files/NY_PEV_CB_Analysis_FINAL.pdf.

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

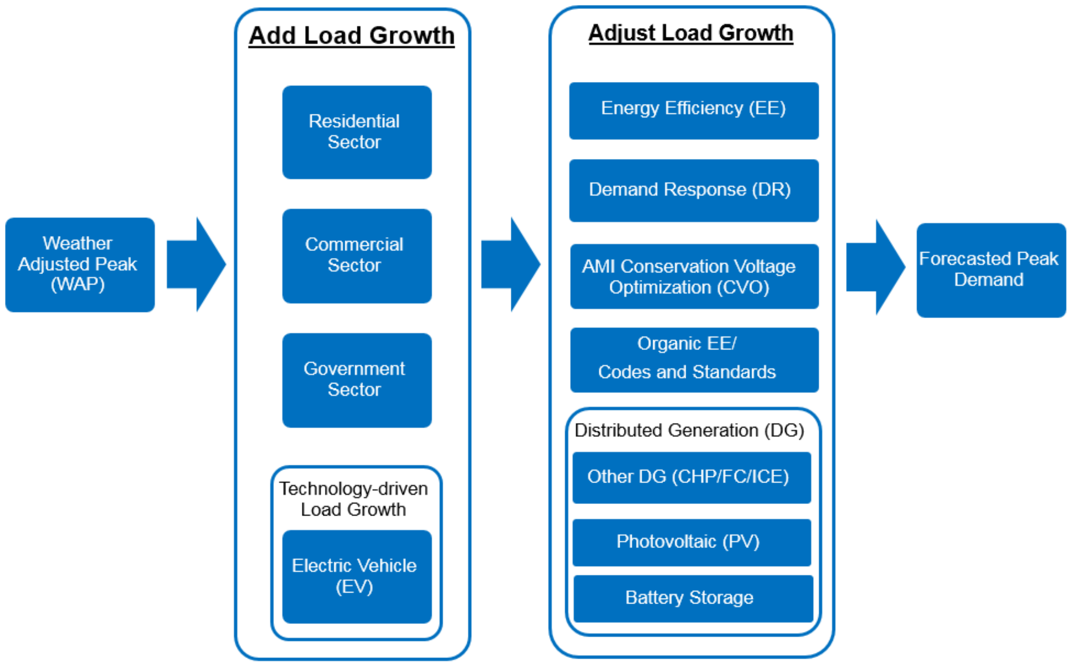
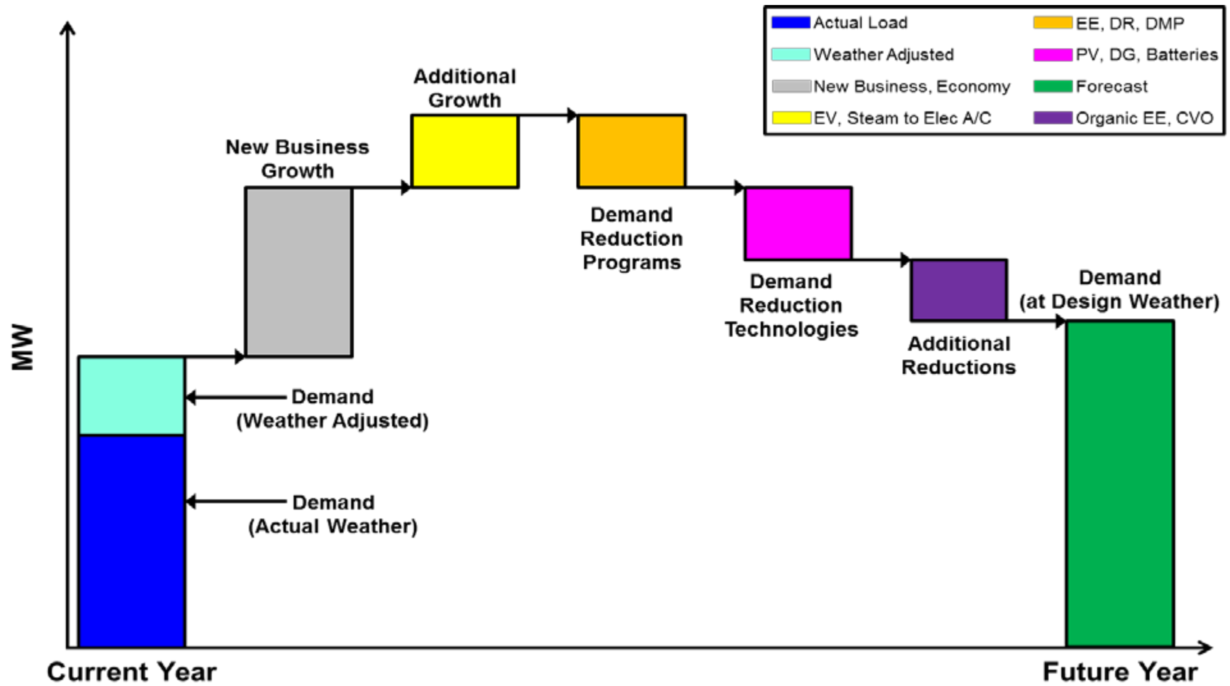


Figure 48: Illustrative Process of Adjusting Forecasting (not to scale)



The Company continues to improve the accuracy of its forecasts, with deviations between forecasts and actuals being minor.

Load Area Peak Demand Forecasts

O&R prepares substation transformer and circuit level peak demand forecasts, which roll up to the substation level. The substation-level forecasting process is similar to the system-level with some notable exceptions. The Company also develops its long-term Substation Electric-Peak Demand forecasts by using internally developed models to determine the weather-normalized ("WN") load and top-down econometric forecasts provided by the Company's Shared Services Forecasting group.

As with the system peak, O&R Distribution Planning assesses the previous summer's temperature variable ("TV") and actual peak demands of the load area, and accounts for impacts on the substation's peak hour from reduced load from load reduction programs, interruptions, or PV. Stations are then grouped into load areas based on switching capability to adjacent stations to minimize/eliminate the chance of load transfers affecting the forecasted growth rate. Historical peak loads are then regressed against the TV and population to determine the weather-normalized load for the load area.

Based on the previous year's peak load, the responsibility factor of each source in the load area is calculated. The source includes the banks and any portion of a circuit/bank that has been transferred to/from another load area. The responsibility factor is then applied to the WN load of the load area for the respective year to determine the coincidental WN load of the bank. The negative load modifiers are removed from the weather normalization process.

The quotient of the bank's coincidental peak and individual peak from the previous year is used to calculate the coincidental factor. Future WN loads are divided by this coincidental factor to determine the bank's individual WN forecasted peak load. Any known New Business loads or transfers are considered to develop the circuit/bank's WN future loads.

From the bank's coincidental peak load, the circuit's WN coincidental peak load is determined. After applying the circuit's responsibility factor to determine the circuit's WN forecasted peak load, the% imbalance for each phase is applied to provide the circuit's high-phase. The Company then accounts for known block loads or transfers in various areas. On an annual and going-forward basis, a ten-year forecast of the system and banks, and two-year forecast of the circuits are completed. The bank and system loads are utilized by Transmission Planning where a contingency analysis with respect to design standards is performed on the transmission system.

After obtaining the ten-year Bank level native forecast, the load modifier forecasts are developed at the Bank and circuit level.

DER Forecasts

Increased adoption of DER will introduce 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, DM 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 and DM programs are distributed across the electric networks 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 excluded from the forecasts, although these effects are captured in a separate load modifier ("Organic EE/Codes and Standards").

For DM and DR programs, forecast data is derived from internal program managers who gather information from their implementation contractors and market participants. 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 network forecasts based on the size and diversity of enrollments in each load area. DR programs are not included in the volume forecast because the energy savings are both uncertain (programs may or may not be called) and *de minimis* (even if events are called).

DG

DG is included in demand and energy forecasts. For purposes of forecasting, DG is defined as DER capable of operating in parallel with the grid and exporting power into the electric delivery system, including solar PV, CHP, and other rotating generation, fuel cells, and energy storage, which represent the overwhelming majority of DG in the O&R service territory.

Solar PV

The forecasting of solar PV, as with other DER, involves determining both the impact of the DER and the future growth rate. To assess the impact of currently deployed solar PV, the Company collects AC nameplate kW capacity and application of PV jobs in the interconnection queue from PowerClerk. The Company also analyzes available solar output per hour data and the location of the PV projects. The solar output for each hour is determined by reviewing interval data and is representative of four summer months of data (June 1 – September 30) across a sample set of large PV sites with SCADA data. The following figure shows a typical output curve.

Figure 49: Measured Solar Output Curve Using Sampled Interval Meter Data

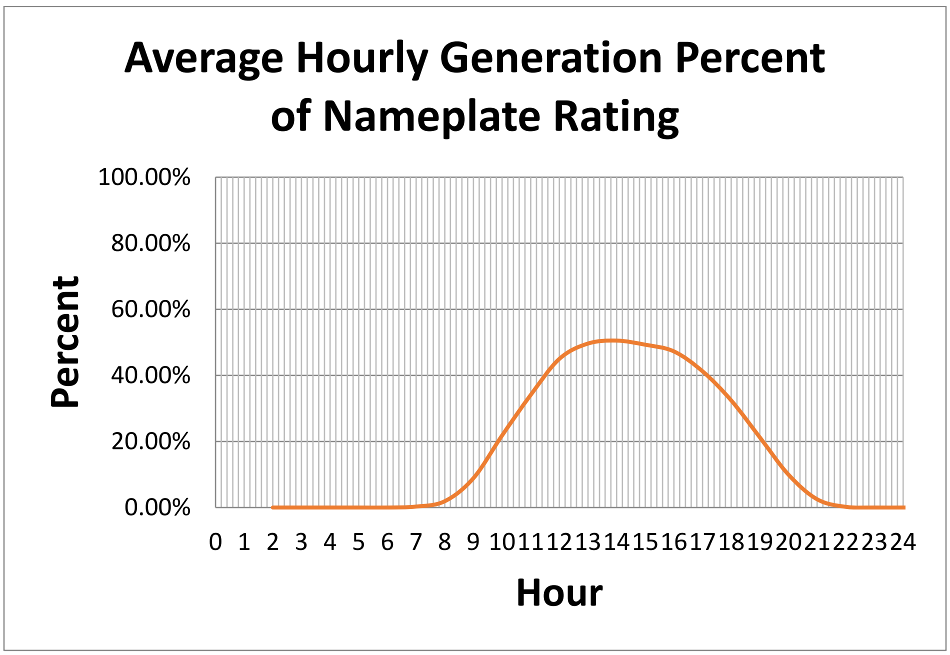


Table 38: Average Summer Solar Output as a Percentage of Nameplate Capacity (AC)

Hour Ending	Average	Hour Ending	Average
0:00:00	0.00%	12:00:00	50.10%
1:00:00	0.00%	13:00:00	49.90%
2:00:00	0.00%	14:00:00	48.30%
3:00:00	0.00%	15:00:00	44.20%

Hour Ending	Average	Hour Ending	Average
4:00:00	0.00%	16:00:00	36.80%
5:00:00	0.10%	17:00:00	26.80%
6:00:00	1.10%	18:00:00	15.60%
7:00:00	5.40%	19:00:00	6.20%
8:00:00	15.30%	20:00:00	1.30%
9:00:00	27.90%	21:00:00	0.10%
10:00:00	39.50%	22:00:00	0.00%
11:00:00	47.30%	23:00:00	0.00%

To assess the growth rate of solar PV installations, the initial two years of growth is based on the interconnection queue. For the years beyond the queue, the Company uses a probabilistic approach, including historical growth, and attrition rates.

Fifty kW was selected as an approximate divider for residential and commercial projects versus large projects in order to apply the lead times of large and small PV projects to the forecast. The lead time assumptions for residential and commercial PV jobs are based on an analysis of average completion cycles of projects past projects.

Electric Forecasting works closely with the DG Ombudsman and employees in O&R Technology 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 along with the teams.

The projections for the upcoming three years are generally based on new and existing applications in the queue, provided by O&R Technology Engineering group. The growth rates beyond the first three year's forecast are developed after careful review of local and state policies impacting DER interconnections, tax incentives, consumer economic models, new programs policies, technology evolution and historical growth rates analyzed by O&R's Technology Engineering group. The group also reviews NYISO (NY Sun) and Energy Information Administration (EIA) forecasts and actual interconnections as a sensitivity check.

With the assumptions below, the PV capacities (DC kW) are estimated for next 10 years. The AC coincident factor during the peak hour provided by Distribution Engineering is applied to develop the PV peak forecast.

The assumptions for PV forecast are as below;

1. Forecast was created using the following methodologies
   a) Large DG projects (>= 50 KW in AC Nameplate)

i) Short term (1 – 3 years): reviewed pending jobs in queue with the best estimated completion dates provided by DG Ombudsman & Technology Engineering Team.

ii) Long term (4 – 10 years): utilize local and state policies impacting DER interconnections, tax incentives, consumer economic models, new programs policies, technology evolution and historical growth rates

b) Residential and commercial projects (< 50 KW in AC Nameplate): use tax incentive credit policies and historical growth rates analyzed by O&R Technology Engineering group at system and substation level; each substation/bank/circuit is distributed by a probabilistic approach including the installed and pending jobs AC nameplate capacity.

2. Summer solar output curve is applied to capture the peaking hour impact for every substation/bank/circuit level– it is important to ensure the correct solar curve is used for each season, which can be verified with Distribution Engineering in CECONY until O&R has their own solar output curve. The peak hour needs to be updated for each forecast by Distribution Engineering in O&R
3. DC nameplate to AC conversion factor = 79%
4. Jobs were derived from existing queue at the end of June every year.

CHP and Other Generation

CHP and other forms of rotating generation preceded the wide-scale 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 Combined Heat and Power (CHP), Internal Combustion Engine (ICE), Gas & Steam Turbines, and Fuel Cells. Photovoltaics and Batteries will be accounted for separately.
2. All DG are assumed to be on throughout the peak load periods and full credit (-) will be taken to reduce load.
3. All DG jobs in the queue will be assigned with the associated circuit and the best estimated completed/installed year by DG ombudsman.
4. For each DG project, a performance factor was not applied yet but will be considered by DG ombudsman in future.
5. Forecast was created using the following methodologies:

a) Short term (usually years 1-3): Bottom-up approach using jobs in queue
b) Long term (usually years 4-10): Bottom-up approach using jobs in queue plus a reconciliation with system level DG growth (weighted by SS/Bank/Circuit's WAP).

Energy Storage

Energy Storage is a separate line item in the DG forecast. While storage is still a small component of the forecast, advancements in technology will likely result in many more storage devices, primarily batteries, installed throughout O&R territory over time. Energy storage penetration and growth information is derived from the Company's interconnection queue, which provides a near-term view of proposed and under-construction projects.

The Company recognizes that distributed energy storage is a relatively new technology with limited but growing data on technical and market potential in the Company's service territory. The Company has identified factors for adoption that it believes will indicate the future pace of distributed energy storage. These signposts include energy storage pricing (by technology type), installed cost, policy treatment (*e.g.,* net energy metering ("NEM")/value stack, tax credits), and local municipal permitting, and will be used to inform the forecasting process going forward. The Company is evolving toward a probabilistic approach that incorporates historical growth rates of DER technologies with similar characteristics, such as space requirements, as indicative of 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.

Due to the limited visibility of installed storage as of 2017, the Company lacks adequate data to model the effect on peak load. The Company recognizes that several factors require further study, including 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.

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 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 DMP and REV Demonstration projects, discussed elsewhere. These programs are administered by the Company and provide greater visibility and impact to peak demand. Depending on storage capacity, technology, and project economics, utility-owned storage projects may also be capable of bidding into NYISO DR and/or ancillary services markets.

The Company currently does not quantify the specific contribution of distributed energy storage to energy reduction due to the limited number of installations and disparate impacts of storage on energy use based on how the storage is charged. For example, charging from the grid will have a positive (additive) impact to delivered energy, while a resource charging from BTM generation will have no impact on delivered energy. Other factors that could affect energy usage are the load curve of customers who adopt distributed energy storage, as well as their charging cycle and frequency, and capacity utilization of the storage resource.

EV

The EV forecast is introduced to reconcile the impact of electric vehicles on coincident system peak. The most recent data available from DMV statistic reports are used to analyze the current and projected number of EVs to develop the EV coincident system peak forecast.

Appendix B: Tools and Information Sources

Tools and Information Sources by Source

Resource Name and Link	Topic(s) Covered
Joint Utilities of New York Links	
Overview of Currently Accessible System Data	Advanced Forecasting
JU of NY: Overview of Currently Accessible System Data	Advanced Forecasting
The JU Cyber and Privacy Framework	Cybersecurity
Overview of Currently Accessible System Data	Distributed System Data
JU of New York 2016 SDSIP	DSIP Governance
EV Readiness Framework	EV Integration
JU DSP Communications and Coordination Manual	Grid Operations
Draft DSP-Aggregator Agreement for NYISO Pilot Program	Grid Operations
Utility-Specific Non-Wires Alternatives (NWA) Opportunities	Procurement of NWAs
JU of New York Engagement Groups	Procurement of NWAs
New York REV and Assorted NY Government Links	
BCA Postings	BCA
REV Connect	Beneficial Location
Commission SIR Inventory Information	DER Interconnections
Assembly Bill 288 residential tariff for recharging EVs	EV Integration
DPS Staff Whitepaper: Guidance for 2018 DSIP Updates, April 26, 2018	Executive Summary
Case 15-M-0252: In the Matter of Utility Energy Efficiency Programs	Executive Summary
Case 18-E-0130 – In the Matter of Energy Storage Deployment Program	Executive Summary
Case 18-E-0138 – Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure	Executive Summary
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	Executive Summary
Case 15-E-0302 et al., Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard	Executive Summary
Case 15-E-0751 et al., In the Matter of the Value of Distributed Energy Resources	Executive Summary

Resource Name and Link	Topic(s) Covered
Case 18-M-0404, In the Matter of a Comprehensive Energy Efficiency Initiative	Energy Efficiency
Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to REV	Integrated Planning
Case 16-M-0411, In the Matter of DSIPs	Integrated Planning
Case 16-M-0412, BCA Handbook	Integrated Planning
REV Connect: Non-Wires Alternatives portal	Procurement of NWAs
Governor Cuomo Unveils 20th Proposal of 2018 State of the State: New York's Clean Energy Jobs and Climate Agenda	Progressing The DSP
O&R Utilities Links	
Hosting Capacity and System Data	Advanced Forecasting
O&R: Smart Meters	AMI
Hosting Capacity and System Data	Beneficial Locations for DERs and NWAs
Green Button Connect (Customer Energy Data)	Customer Data
How to Become an EDI-Certified Distributed Energy Resource Supplier	Customer Data
Energy Service Company EDI (EDI)	Customer Data
Statement of Community Choice Aggregation Data Access Fees	Customer Data
Share My Data	Customer Data
O&R Using Private Generation Energy Sources	DER Interconnections
Distributed System Platform	Distributed System Data
Hosting Capacity and System Data	Distributed System Data
Electric Vehicles Information	EV Integration
Electric Vehicle Questions Email Address	EV Integration
O&R: Hosting Capacity and System Data	Hosting Capacity
Non-Wires Alternatives Opportunities portal	Procurement of NWAs
Other Links	
NERC CIP Reliability Standards	Cybersecurity
National Institute of Standards and Technology ("NIST") Special Publication (SP) 800-53 revision 4	Cybersecurity
PowerClerk	DER Interconnections

Resource Name and Link	Topic(s) Covered
PowerClerk	Grid Operations
EPRI: Defining a Roadmap for Successful Implementation of a Hosting Capacity Method for NY State	Hosting Capacity

Tools and Information Sources by Topical Update Section

Topic(s) Covered	Resource Name and Link
Advanced Forecasting	Hosting Capacity and System Data
	Overview of Currently Accessible System Data
	JU of NY: Overview of Currently Accessible System Data
AMI	O&R: Smart Meters
BCA	BCA Postings
Beneficial Locations for DERs and NWAs	Hosting Capacity and System Data
	REV Connect
Customer Data	Green Button Connect (Customer Energy Data)
	How to Become an EDI-Certified Distributed Energy Resource Supplier
	Energy Service Company EDI
	Share My Data
	Statement of Community Choice Aggregation Data Access Fees
Cybersecurity	The JU Cyber and Privacy Framework
	NERC CIP Reliability Standards
	National Institute of Standards and Technology ("NIST") Special Publication (SP) 800-53 revision 4
DER Interconnections	O&R Using Private Generation Energy Sources
	PowerClerk
	Commission SIR Inventory Information
Distributed System Data	Distributed System Platform
	Hosting Capacity and System Data
	O&R Using Private Generation Energy Sources
	Overview of Currently Accessible System Data
DSIP Governance	JU of New York 2016 SDSIP
EV Integration	Electric Vehicles Information
	Electric Vehicle Questions Email Address
	Assembly Bill 288 residential tariff for recharging EVs

	EV Readiness Framework
Executive Summary	DPS Staff Whitepaper: Guidance for 2018 DSIP Updates, April 26, 2018
	Case 15-M-0252: In the Matter of Utility Energy Efficiency Programs
Grid Operations	JU DSP Communications and Coordination Manual
	Draft DSP-Aggregator Agreement for NYISO Pilot Program
	PowerClerk
Hosting Capacity	O&R: Hosting Capacity and System Data
	EPRI: Defining a Roadmap for Successful Implementation of a Hosting Capacity Method for NY State
Integrated Planning	Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to REV
	Case 16-M-0411, In the Matter of DSIPs
	Case 16-M-0412, BCA Handbook
Procurement of NWAs	Non-Wires Alternatives Opportunities portal
	REV Connect: Non-Wires Alternatives portal
	Utility-Specific Non-Wires Alternatives (NWA) Opportunities
	JU of New York Engagement Groups
Progressing The DSP	Governor Cuomo Unveils 20th Proposal of 2018 State of the State: New York's Clean Energy Jobs and Climate Agenda

Appendix C: Acronyms

Acronym	Description
ADMS	Advanced Distribution Management System
AESP	Association of Energy Services Professionals
AMI	Advanced Metering Infrastructure
API	Application Program Interface
BAM	Budget and Metrics
BCA	Benefit Cost Analysis
BTM	Behind-The-Meter
BYOT	Bring Your Own Thermostat
C&I	Commercial and Industrial
CAIDI	Customer Average Interruption Duration Index
CCA	Community Choice Aggregation
CCE	Cornell Cooperative Extension
CCTN	Corporate Communications Transmission Network
CDG	Community Distributed Generation
CEAC	Clean Energy Advisory Council
CECONY	Consolidated Edison Company of New York
CEF	Clean Energy Fund
CEI	Consolidated Edison, Inc.
CEMP	Customer Engagement Marketplace Platform
CES	Clean Energy Standard
CHP	Combined Heat and Power
CIMS	Customer Information Management System
CIP	Critical Infrastructure Protection
CPR	Clean Power Research
CSR	Customer Service Representatives
CSRP	Commercial System Relief Program
DA	Distribution Automation
DCC	Distribution Control Center
DCX	Digital Customer Experience
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management System
DEW	Distribution Engineering Workstation
DG	Distributed Generation
DLRP	Distribution Load Relief Program
DOE	Department of Energy
DPS	Department of Public Service
DR	Demand Response
DRIVE	Distribution Resource Integration & Valuation Estimate
DRV	Demand Reduction Value
DSA	Data Security Agreement

Acronym	Description
DSCADA	Distribution Supervisory Control and Data Acquisition
DSIP	Distributed System Implementation Plan
DSM	Demand Side Management
DSP	Distributed System Platform
DSSE	Distribution System State Estimation
EDD	Electrical Distribution Design
EDI	Electronic Data Interchange
EE	Energy Efficiency
EEI	Edison Electric Institute
EMS	Energy Management System
ENERGISE	Enabling Extreme Real-time Grid Integration of Solar Energy
EPRI	Electric Power Research Institute
EPS	Electric Power System
ESCO	Energy Service Company
ETIP	Energy Efficiency Transition Implementation Plan
EV	Electric Vehicle
EVSE	Electric Vehicle Supply Equipment
FERC	Federal Energy Regulatory Commission
FLISR	Fault Location, Isolation, and Service Restoration
FTM	Front-of-The-Meter
GBC	Green Button Connect
GHG	Greenhouse Gas
GIS	Geographic Information System
HAN	Home Area Network
ICAP	Installed Capacity
ICE	Internal Combustion Engine
IDSIP	Initial Distribution System Implementation Plan
IEEE	Institute of Electrical and Electronics Engineers
IOAP	Interconnection Online Application Portal
IPPNY	Independent Power Producers of NY
IPWG	Interconnection Policy Work Group
ISBM	Innovative Storage Business Model
ISM	Integrated System Model
ISO	International Standard Organization, Independent System Operator
IT	Information Technology
ITWG	Interconnection Technical Work Group
JU	Joint Utilities
LPDS	Load Profile Data System
LSRV	Locational System Relief Value
LTC	Load Tap Changer
M&C	Monitoring and Control
MCOS	Marginal Cost of Service

Acronym	Description
MDMS	Master Data Management System
MOAB	Motor Operated Air Break
MPC	Model-Predictive Control
MVAR	Mega Volt Ampere Reactive (Reactive Power)
MW	Megawatts
NEM	Net Energy Metering
NERC	North America Electric Reliability Corporation
NIST	National Institute of Standards and Technology
NWA	Non-Wires Alternatives
NYISO	New York Independent System Operator
NYPA	New York Power Authority
NYSERDA	New York State Research and Development Authority
O&R	Orange and Rockland Utility
OMS	Outage Management System
PEV	Plug-in Electric Vehicle
PII	Personally Identifiable Information
PON	Program Opportunity Notice
PQ	Power Quality
PV	Photovoltaic
R&D	Research and Development
RAIS	Retail Access Information System
REV	Reforming the Energy Vision
RFI	Request for Information
RFP	Request for Proposal
RIM	Rate Impact Measure
RTO	Regional Transmission Organization
RTU	Remote Terminal Unit
SA	Self-Attestation
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SBDI	Small Business Direct Install
SCADA	Supervisory Control and Data Acquisition
SCT	Societal Cost Test
SDSIP	Supplemental Distributed System Implementation Plan
SEEP	System Energy Efficiency Plan
SEPA	Smart Electric Power Alliance
SHR	Smart Home Rate
SIR	Standardized Interconnection Requirements
SME	Subject Matter Expert
SWG	Security Working Group
T&D	Transmission and Distribution
TOU	Time-Of-Use

Acronym	Description
TV	Temperature Variable
UBP	Uniform Business Practices
UCT	Utility Cost Test
UER	Utility Energy Registry
UotF	Utility of the Future
UVM	University of Vermont
VEE	Validation, Estimation, and Editing
VVO	Voltage VAR Optimization
WAP	Weather Adjusted Peak
WN	Weather Normalized
XML	Extensible Markup Language
ZEV	Zero Emissions Vehicle

Appendix D: List of Figures & Tables

List of Figures

List of Tables

Appendix E: BCA Handbook

Orange & Rockland

Benefit Cost Analysis Handbook

July 31, 2018

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

BACKGROUND

New York's Joint Utilities[1] collaboratively developed a Standard Benefit-Cost Analysis Handbook Template 1.0 in 2016 and have collaboratively worked to develop a revised 2018 Standard BCA Handbook Template 2.0 which reflects revisions to the 2016 filing. The purpose of the BCA Handbook Template 2.0 is to provide interested parties a consistent and transparent methodology to calculate the benefits and costs of potential projects and investments. The 2018 Standard BCA Template 2.0 serves as the common basis for each utility's individual BCA Handbook.

The 2018 Handbooks present applicable BCA methodologies and describe how to calculate individual benefits and costs as well as how to apply the necessary cost-effectiveness tests identified in the *Order Establishing the Benefit Cost Analysis Framework*).[2] The BCA Handbooks also present general BCA considerations and notable issues regarding data collection required for project and investment benefits assessments. Definitions and equations for each benefit and cost are provided along with key parameters and sources.

[1] The Joint Utilities are Consolidated Edison Company of New York, Inc., Orange and Rockland Utilities, Inc., Central Hudson Gas & Electric Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, New York State Electric and Gas Corporation, and Rochester Gas & Electric Corporation.

[2] Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Order Establishing the Benefit Cost Analysis Framework (issued January 21, 2016)(BCA Order").

TABLE OF CONTENTS

ACRONYMS AND ABBREVIATIONS

Acronyms and abbreviations are used extensively throughout the BCA Handbook and are presented here at the front of the Handbook for ease of reference.

AC	Alternating Current
AGCC	Avoided Generation Capacity Costs
BCA	Benefit-Cost Analysis
BCA Framework	The benefit-cost framework structure presented initially in the "Staff White Paper on Benefit-Cost Analysis" and finalized in the *BCA Order*.
BCA Order	Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Establishing the Benefit-Cost Analysis Framework (issued January 21, 2016).
CAIDI	Customer Average Interruption Duration Index
CARIS	Congestion Assessment and Resource Integration Study
C&I	Commercial and Industrial
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
DC	Direct Current
DER	Distributed Energy Resources
DR	Demand Response
DSIP	Distributed System Implementation Plan
DSIP	Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to
EE	Energy Efficiency
Guidance	Reforming the Energy Vision, Order Adopting Distributed System
Order	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 Energy Metering
NPV	Net Present Value

NO_x	Nitrogen Oxides
NWA	Non-Wires Alternatives
NYC	New York City
NYISO	New York Independent System Operator
NYPSC	New York Public Service Commission
NYSERDA	New York State Energy Research and Development Authority
O&M	Operations and Maintenance
PV	Photovoltaic
REV	Reforming the Energy Vision
REV Proceeding	Case 14-M-0101 – *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*
RGGI	Regional Greenhouse Gas Initiative
RIM	Rate Impact Measure
RMM	Regulation Movement Multiplier
ROS	Rest of State
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAM	System Advisor Model (National Renewable Energy Laboratory)
SCC	Social Cost of Carbon
SCT	Societal Cost Test
SENY	Southeast New York (Ancillary Services Pricing Region)
SO_2	Sulfur Dioxide
T&D	Transmission and Distribution
UCT	Utility Cost Test

1. INTRODUCTION

The State of New York Public Service Commission ("NYPSC" or "Commission") directed the Joint Utilities ("JU") to develop and file Benefit-Cost Analysis ("BCA") Handbooks by June 30, 2016 as a requirement of the Order Establishing the Benefit-Cost Analysis Framework ("*BCA Order")*.[3] The BCA Framework included in Appendix C of the *BCA Order* is incorporated into the BCA Handbooks. These handbooks are to be filed contemporaneously with each utility's initial Distributed System Implementation Plan ("DSIP") filing and with each subsequent DSIP, scheduled to be filed every other year.[4] The 2018 BCA Handbooks are to be filed on July 31, 2018 with each utility's 2018 DSIP.

The purpose of the BCA Handbook is to provide a common methodology for calculating benefits and costs of projects and investments. The *BCA Order* requires that a benefit-cost analysis be applied to the following four categories of utility expenditure:[5]

1. Investments in distributed system platform ("DSP") capabilities
2. Procurement of distributed energy resources ("DER") through competitive selection[6]
3. Procurement of DER through tariffs[7]
4. Energy efficiency programs

The BCA Handbook provides methods and assumptions that may be used to inform BCA for each of these four types of expenditure.

The *BCA Order* also includes key principles for the BCA Framework that are reflected in this 2018 BCA Handbook. Specifically, the Commission determined that the BCA Framework should:[8]

1. Be based on transparent assumptions and methodologies; list all benefits and costs including those that are localized and more granular.
2. Avoid combining or conflating different benefits and costs.
3. Assess portfolios rather than individual measures or investments (allowing for consideration of potential synergies and economies among measures).
4. Address the full lifetime of the investment while reflecting sensitivities on key assumptions.
5. Compare benefits and costs to traditional alternatives instead of valuing them in isolation.

1.1 Application of the BCA Handbook

The BCA Handbook provides a common methodology to be applied across investment projects and portfolios. The 2018 version of the BCA Handbook is meant to inform investments in DSP capabilities, the

[3] REV Proceeding, BCA Order.

[4] REV Proceeding, Order Adopting distributed System Implementation Plan Guidance (DSIP Guidance Order) (issued April 20, 2016), p. 64.

[5] REV Proceeding, BCA Order, pp. 1-2.

[6] Also known as non-wires alternatives (NWA").

[7] These may include, for example, demand response tariffs or successor tariffs to net energy metering (NEM").

[8] REV Proceeding, BCA Order, p. 2.

procurement of DERs through tariffs, the procurement of DERs through competitive solicitations (*i.e.,* non-wire alternatives) and the procurement of energy efficiency resources. Common input assumptions and sources that are applicable on a statewide basis (*e.g.*, information publicly provided by the New York Independent System Operator ("NYISO") or by Department of Public Service ("DPS") Staff as required in the *BCA Order*) and utility-specific inputs (*e.g.*, marginal costs) that may be commonly applicable to a variety of project-specific BCAs are provided within. Individual BCAs for specific projects or portfolios are likely to require additional, project-specific information and inputs.

Table 1-1 lists the statewide values and respective sources to be used for BCA and referenced in this Handbook. Source references are included in the footnotes below.

Table 1-1. New York Assumptions

New York Assumptions	Source
Energy and Demand Forecast	NYISO: Load & Capacity Data[9]
Avoided Generation Capacity Cost ("AGCC")	DPS Staff: ICAP Spreadsheet Model[10]
Locational Based Marginal Prices ("LBMP")	NYISO: Congestion Assessment and Resource Integration Study Phase 2 (CARIS Phase 2)[11]
Historical Ancillary Service Costs	NYISO: Markets & Operations Reports[12]
Wholesale Energy Market Price Impacts	DPS Staff: To be provided[13]
Allowance Prices (SO_2, and NO_X)	NYISO: CARIS Phase 2[14]
Net Marginal Damage Cost of Carbon	DPS Staff: To be provided[15]

[9] The 2018 Load & Capacity Data report is available in the Planning Data and Reference Docs folder at: http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Documents_and_Resources/Planning_Data_and_Reference_Docs/Data_and_Reference_Docs/2018-Load-Capacity-Data-Report-Gold-Book.pdf

[10] The ICAP Spreadsheet Model is found under Case 14-M-0101 at the Commission's website: http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=14-M-0101&submit=Search

[11] The finalized annual and hourly zonal LBMPs from 2018 CARIS Phase 2 will be available by December 2018 on the NYISO website in the CARIS Study Outputs folder within the Economic Planning Studies folder. Until such time that the finalized a 2018 CARIS 2 data is published, the utilities will employ the 2016 CARIS Phase 2 results: http://www.nyiso.com/public/markets_operations/services/planning/planning_studies/index.jsp.

[12] Historical ancillary service costs are available on the NYISO website at: http://www.nyiso.com/public/markets_operations/market_data/custom_report/index.jsp. The values to apply are described in Section 4.1.5.

[13] DPS Staff will perform the modeling and file the results with the Secretary to the Commission on or before July 1 of each year.

[14] The allowance price assumptions for the 2018 CARIS Phase 2 study will be available on the NYISO website in the CARIS Input Assumptions folder within Economic Planning Studies at: http://www.nyiso.com/public/markets_operations/services/planning/planning_studies/index.jsp. Until such time that the finalized 2018 CARIS 2 data is published, the utilities will employ the 2016 CARIS Phase 2 results

[15] DPS Staff will perform the modeling, file the results with the Secretary to the Commission on or before July 1 of each year and post the results on DMM under Case 14-M-0101.

Utility-specific assumptions include data embedded in various utility published documents such as rate cases. Table 1-2 lists the suggested utility-specific assumptions for the BCA Handbook.

Table 1-2. Utility-Specific Assumptions

Utility-Specific Assumptions	Source
Weighted Average Cost of Capital	ORU Rate Case 14-E-0493
Losses	ORU Electric Loss Report for Case 08-E-0751
Marginal Cost of Service	ORU Rate Case 14-E-0493 Exhibit DAC-E3
Reliability Statistics	DPS: Electric Service Reliability Reports[16]

The New York general and utility-specific assumptions that are included in the 2018 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 2018 BCA Handbook provides techniques for quantifying the benefits and costs identified in the *BCA Order*. Interim revisions will be limited to material changes to input assumptions and/or new guidance or orders.

1.3 Structure of the Handbook

The remaining sections of the Handbook explain the methodology and assumptions to be applied under the BCA Framework:

Section 2. General Methodological Considerations describes key issues and challenges to be considered when developing project-specific BCA models and tools based on this BCA Handbook.

Section 3. Relevant Cost-Effectiveness Tests defines each cost-effectiveness test included in the BCA Framework. These include the Societal Cost Test (“SCT”), the Utility Cost Test (“UCT”), and the Rate Impact Measure (“RIM”). The *BCA Order* specifies the SCT as the primary measure of cost-effectiveness.

Section 4. Benefits and Costs Methodology provides detailed definitions, calculation methods, and general considerations for each benefit and cost.

Section 5. Characterization of DER profiles discusses which benefits and costs are likely to apply to different types of DER and provides examples for a sample selection of DERs.

Appendix A. Utility-Specific Assumptions includes value assumptions to be applied to the quantifiable energy and non-energy impacts of projects and portfolios.

2. GENERAL METHODOLOGICAL CONSIDERATIONS

This section describes key issues and challenges that must be considered when developing project- or portfolio-specific BCAs. These considerations are incorporated into the benefit and cost calculation methods presented in Section 4.

2.1 Avoiding Double Counting

A BCA must be designed to avoid double counting of benefits and costs. Doubling-counting can be avoided by (1) careful tracking of the value streams resulting from multiple investment elements in a project, program, or portfolio and 2) clearly defining and differentiating between the benefits and costs included in the analysis.

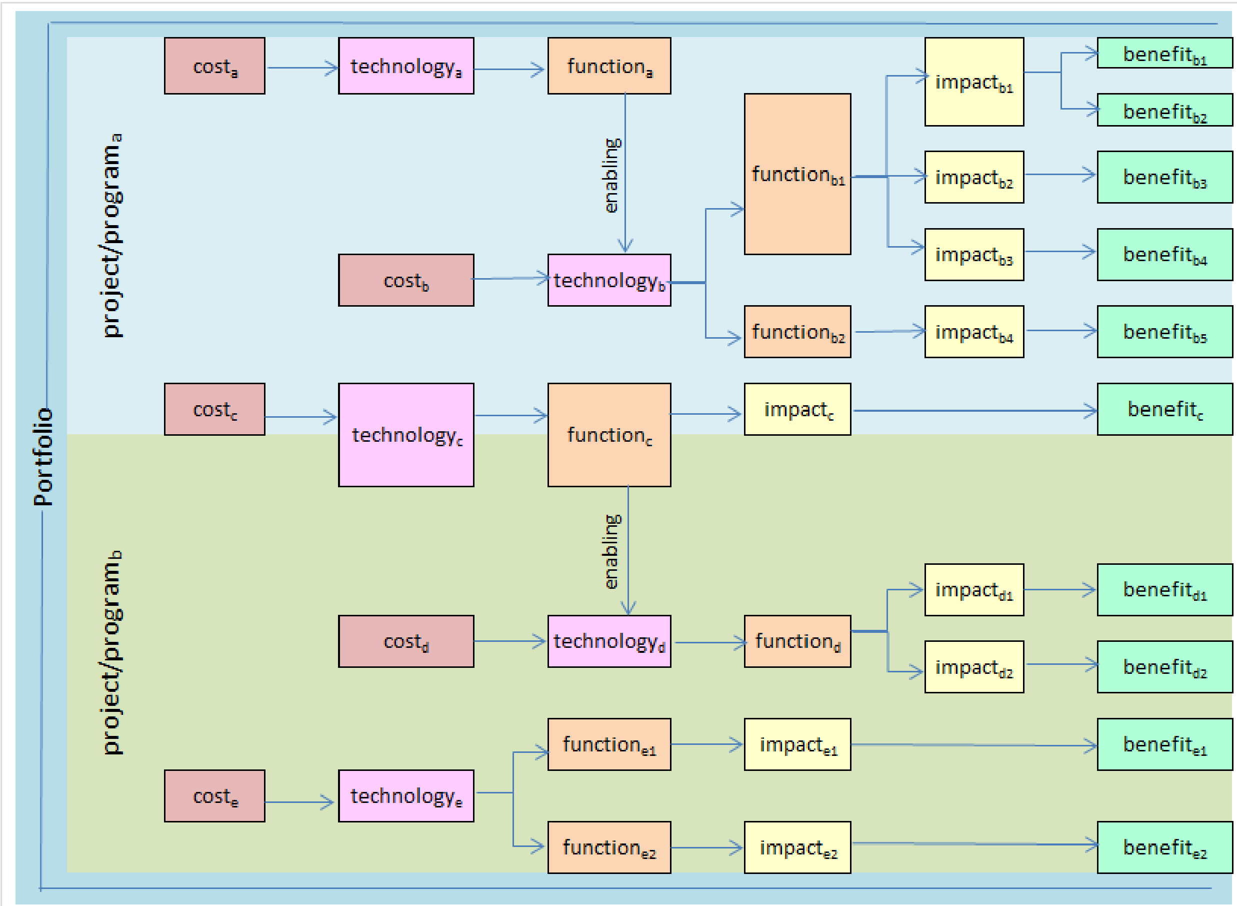
Sections 2.1.1 and 2.1.2 discuss these considerations in more detail.

2.1.1 Accounting of Benefits and Costs Across Multiple Value Streams

The BCA Handbook provides a methodology for calculating the benefits and costs resulting from utility investments as portfolios of projects and programs or as individual projects or programs. A project or program will typically involve multiple technologies, each associated with specific costs. Each technology provides one or more functions and that results in one or more quantified impacts and are valued as monetized benefits.

Figure 2-1 is an illustrative example of value streams that may be associated with a portfolio of projects or programs.

Figure 2-1. Illustrative Example of Value Streams That May Be Associated with a Portfolio of Projects or Programs



Investments may be made in technologies that do not result in direct benefits but instead function to enable or facilitate the realization of benefits from additional measures or technologies (*e.g.* technology$_b$ in Figure 2-1). Some technologies may both enable or enhance the benefits of other technologies and result in direct benefits though a parallel function (*e.g.,* technology$_c$ in Figure 2-1). It is important not to double-count benefits resulting from multiple measures or technologies functioning together to achieve an impact. Determination of which impacts and benefits are derived from which investment elements will often depend on how and/or in what order the elements are implemented.

Benefits and costs should also be allocated properly across different projects within a portfolio. This may present challenges especially in the case of enabling technologies. For example, the investment in technology$_c$ in Figure 2-1 is included as part of project/program$_a$. Some direct benefits from this technology are realized for project/program$_a$, however technology$_c$ also enables technology$_d$ that is included as part of project/program$_b$. In this example, the costs of technology$_c$ and the directly resulting benefit should be accounted for in project/program$_a$, and the cost for technology$_d$ and the resulting incremental benefits should be accounted for in project/program$_b$.

Enabling technologies such as an advanced distribution management system or a communications infrastructure are often crucial in achieving the impact and benefits of grid modernization projects. These infrastructure investments may be necessary for the implementation of other technologies, projects, or programs, and in some cases the same investments could also enable a given asset to achieve additional benefits beyond what that asset may have been able to achieve on its own. Overtime, investments made as part of previous projects or portfolios may also enable or enhance new projects. The *BCA Order* states that utility BCA shall consider incremental T&D costs “to the extent that the characteristics of a project cause additional costs to be incurred.”[17]

Multiple technologies may result in impacts that produce the same benefits. For example, there are many ways in which distribution grid modernization investments could affect the frequency and duration of sustained outages. Advanced meters equipped with an outage notification feature, an outage management system, automated distribution feeder switches or reclosers, and remote fault indicators are some examples of technologies that could all reduce the frequency or duration of outages on a utility’s distribution network and result in Avoided Outage Cost or Avoided Restoration Cost benefits.

The utility BCA must also address the non-linear nature of grid and DER project benefits. For example, the impact on Avoided Distribution Capacity Infrastructure of an energy storage project may be capped based on the interconnected load on the given feeder. For example, if there is 1 MW of potentially deferrable capacity on a feeder with a new battery storage system, installation of a 5-MW storage unit will not result in a full 5 MW-worth of capacity deferral credit for that feeder. As another example, the incremental improvement in reliability indices may diminish as more automated switching projects are in place.

Finally, the BCA should situations where costs are incurred for a core technological function that benefits two programs as well situations where costs are incurred for a technology with more than one core function that benefits more than one program.

2.1.2 Benefit Definitions and Differentiation

A key consideration when performing a BCA is to avoid double counting of benefits and costs by appropriately defining each benefit and cost.

As discussed in Section 3, the *BCA Order* identified 16 benefits to be included in the cost-effectiveness tests. The calculation methodology for each of these benefits is provided in Section 4. Two bulk system benefits, Avoided Generation Capacity Costs (“AGCC”) and Avoided LBMP, result from system coincident peak demand reduction and energy reduction impacts respectively, with avoided cost values derived from multiple components. These impacts and embedded component values included in the AGCC and Avoided LBMP benefits should not be confused with other benefits identified in the *BCA Order* that must be calculated separately.

Sections 2.1.2.1 and 2.1.2.2 below define the avoided transmission and distribution loss impacts resulting from energy and demand reductions that should be included in the calculations of the AGCC and Avoided LBMP, and differentiate them from the impacts that should be counted as separate Avoided Transmission Losses and Avoided Distribution Losses benefits. Sections 2.1.2.1 and 2.1.2.2 also provide differentiation

[17] *BCA Order*, Appendix C pg. 18.

between the transmission capacity values embedded as components of the AGCC and Avoided LBMP values, as well as differentiation between the CO_2, SO_2, and NO_x values embedded in Avoided LBMP values and those values that must be applied separately in the Net Avoided CO_2 and Net Avoided SO_2, and NO_x benefits calculations.

Table 2-1 provides a list of potentially overlapping AGCC and Avoided LBMP benefits.

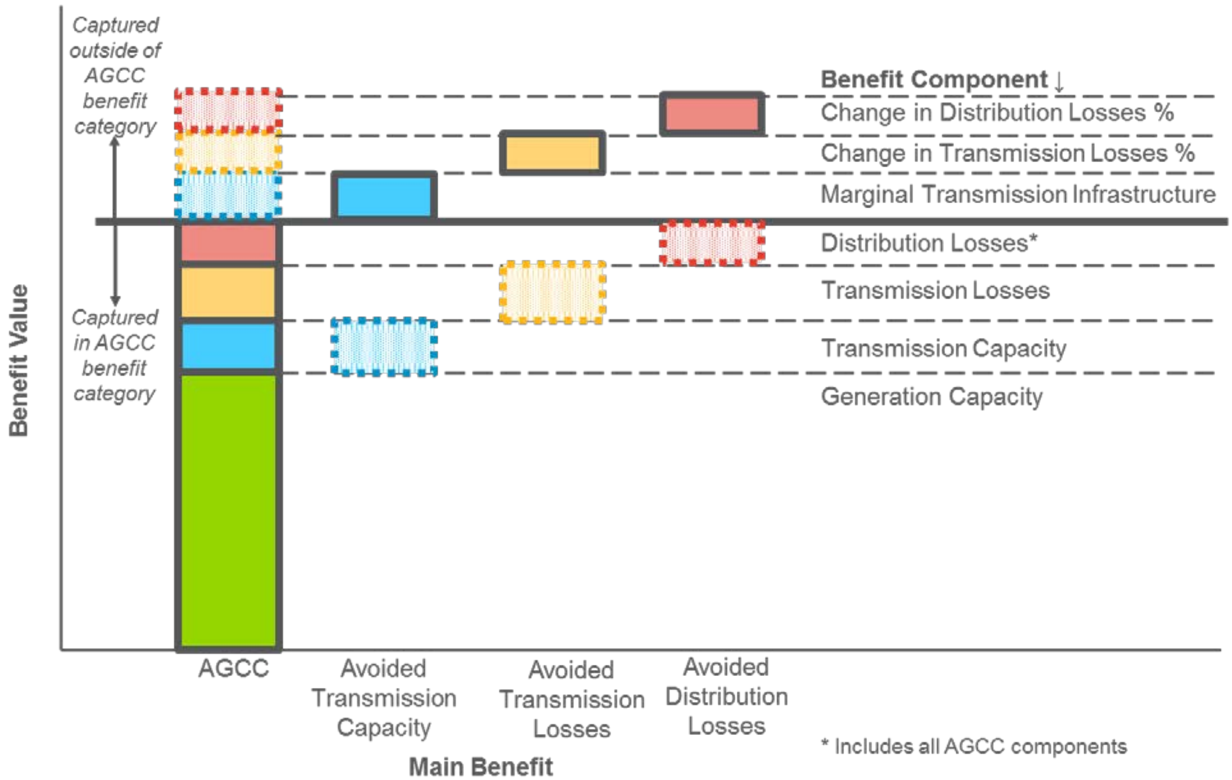
Table 2-1. Benefits with Potential Overlaps

Main Benefits	Potentially Overlapping Benefits
Avoided Generation Capacity Costs	• Avoided Transmission Capacity • Avoided Transmission Losses • Avoided Distribution Losses
Avoided LBMP	• Net Avoided CO_2 • Net Avoided SO_2 and NO_x • Avoided Transmission Losses • Avoided Transmission Capacity • Avoided Distribution Losses

2.1.2.1 Benefits Overlapping with Avoided Generation Capacity Costs

Figure 2-2 graphically illustrates potential overlaps of benefits pertaining to the AGCC.

Figure 2-2. Benefits Potentially Overlapping with Avoided Generation Capacity Costs (Illustrative)



In this stacked column chart, the boxes with solid borders represent impacts and embedded values included in the calculation of the main benefit, while boxes with dotted borders represent impacts not contained in the main benefit but reflected in the calculation of a separate benefit. The benefit shown above, Avoided Generation Capacity Costs, includes multiple components that are captured in the AGCC value. These include – ICAP including reserve margin, transmission capacity, and transmission losses.[18] Additionally, a project's location on the system can affect distribution losses and the calculation of AGCC.[19] The AGCC calculation accounts for these distribution losses.

If a project changes the electrical topology and, therefore, the transmission loss percent, the incremental changes in transmission losses would be allocated to the Avoided Transmission Losses benefit. Similarly, any incremental changes to distribution loss percent as a result of the project would be included in the Avoided Distribution Losses benefit. These benefits are calculated separately from the AGCC benefit.

2.1.2.2 Benefits Overlapping with Avoided LBMP

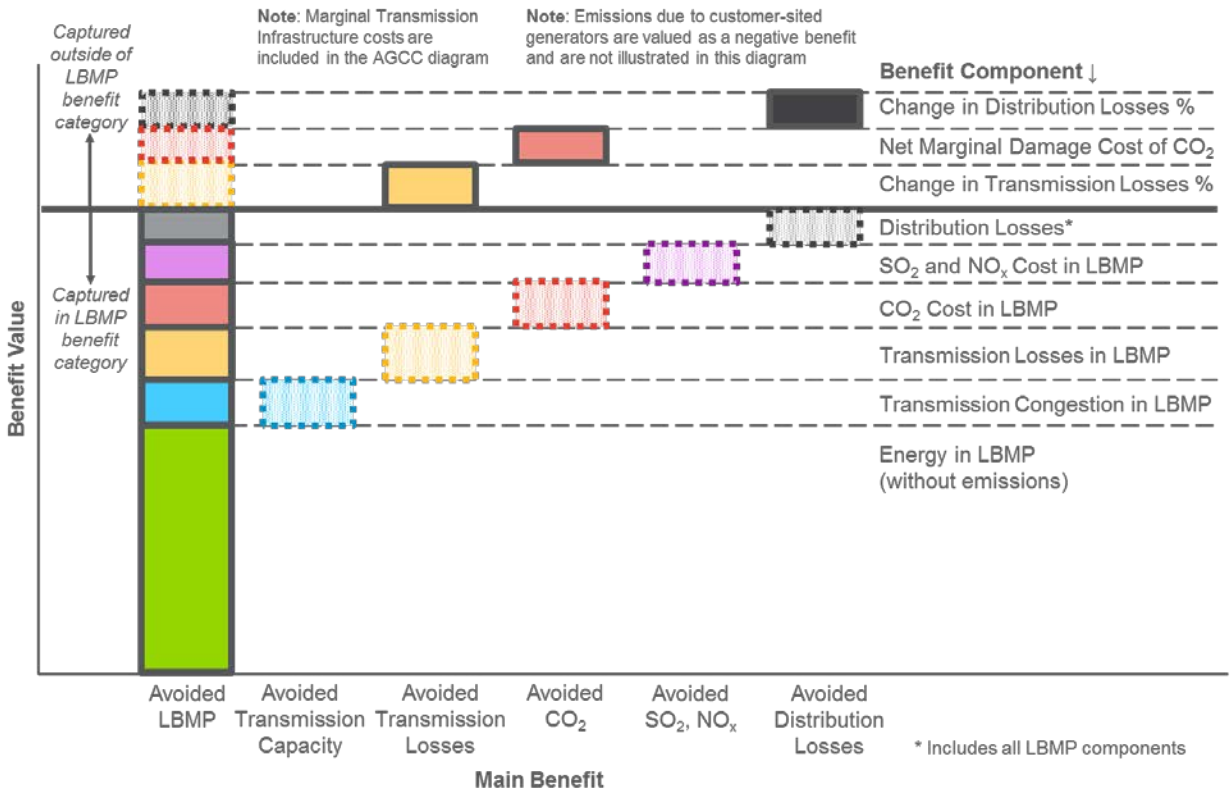
Figure 2-3 graphically illustrates potential overlaps of benefits pertaining to Avoided LBMP.

---

[18] The AGCC includes a portion of avoided transmission capacity infrastructure costs as zonal differences in the ICAP clearing price.

[19] For example, an impact on the secondary distribution system compared to the primary system will have a higher impact on the AGCC due to higher losses.

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:

- Avoided transmission capacity infrastructure costs built into the transmission congestion charge which are embedded in the LBMP
- Transmission-level loss costs which are embedded in the LBMP
- Compliance costs of various air pollutant emissions regulations including the value of CO_2 via the Regional Greenhouse Gas Initiative and the values of SO_2 and NO_x via cap-and-trade markets which are embedded in the LBMP

Depending on a project’s location on the system distribution losses can also affect LBMP purchases, and this effect should be reflected in the calculation of LBMP benefits.[20] To the extent a project changes the electrical topology and the distribution loss percent, the incremental changes in distribution losses would be allocated to the Avoided Distribution Losses benefit. Similarly, there may be projects that would specifically impact Avoided Transmission Capacity or change the transmission loss percent. In these instances, the impacts would be captured outside of the Avoided LBMP benefit.

[20] For example, an impact on the secondary distribution system compared to the primary system will have a higher impact on the LBMP purchases due to higher losses.

2.2 Incorporating Losses into Benefits

Many of the benefit equations provided in Section 4 include a parameter to account for losses. In calculating a benefit or cost resulting from load impacts, losses occurring upstream from the load impact must be accounted for to arrive at the total energy or demand impact. Losses can be accounted for either by adjusting the impact parameter or the valuation parameter. For consistency, all equations in Section 4 are shown with a loss adjustment to the impact parameter.

The following losses-related nomenclature is used in the BCA Handbook:

- **Losses (MWh or MW)** are the difference between the total electricity send-out and the total output as measured by revenue meters. This difference includes technical and non-technical losses. Technical losses are the losses associated with the delivery of electricity of energy and have fixed (no load) and variable (load) components. Non-technical losses represent electricity that is delivered, but not measured by revenue meters.
- **Loss Percent (%)** are the total fixed and/or variable[21] quantity of losses between relevant voltage levels divided by total electricity send-out unless otherwise specified.
- **Loss Factor (dimensionless)** is a conversion factor derived from “loss percent”. The loss factor is 1 / (1 - Loss Percent).

For consistency, the equations in Section 4 follow the same notation to represent various locations on the system:

- “r” subscript represents the retail delivery point or point of connection of a DER, for example distribution secondary, distribution primary, or transmission[22]
- “i” subscript represents the interface of the distribution and transmission systems.
- “b” subscript represents the bulk system which is the level at which the values for AGCC and LBMP are provided.

Based on the notation described above, if a residential customer is connected to distribution secondary the loss percent parameter called $\mathrm{Loss\%}_{\mathrm{b\to r}}$ 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

[21] In the BCA equations outlined in Section 4 below, project-specific energy and demand impacts at the retail delivery point are adjusted to the bulk system (or other relevant system location) based on *only* the variable component of the loss percent. In cases where the transmission or distribution loss percent is altered due to a project, the fixed and/or variable loss percent impacts are considered.

[22] Transmission in this context refers to the distribution utility’s sub-transmission and internal transmission.

model-based projections, or comparison/control groups (*e.g.,*, similar feeders and households) during the course of the project.

Sound baseline data is crucial in measuring the incremental impact of the technology deployment. The benefits of grid modernization projects accrue over many years; thus, baselines must be valid across the same time horizon. This introduces the following considerations:

- **Forecasting market conditions**: Project impacts as well as benefit and cost values are affected by market conditions. For example, the Commission has directed that Avoided LBMP should be calculated based on NYISO's CARIS Phase 2 economic planning process base case LBMP forecast. However, the observed benefit of a project will be different if the wholesale energy market behaves differently from the forecasted trends.
- **Forecasting operational conditions**: Many impacts and benefits are tied to how the generation, transmission, and distribution infrastructure are operated. In this example, the Commission indicated that benefits associated with avoided CO_2 emissions shall be based on the change in the tons of CO_2 produced by the bulk system when system load levels are reduced by 1%. It is important to note that this impact calculation is an approximation and it is still very difficult to determine the actual CO_2 reductions at the bulk system level from the impacts of projects implemented at the distribution system level. Project-specific reductions are tied to dispatch protocols based on the optimized operation of the bulk system given a set of preventive post-contingency settings. In addition, the carbon intensity of the generation mix will inevitably change over time independent of any investment at the distribution level.
- **Predicting asset management activities**: Some impacts and benefits, such as Avoided Distribution Capacity Infrastructure, are affected by distribution-level capital investments that may be made independent of the projects being evaluated. In this example, the amount of available excess capacity may change if key distribution assets are replaced and uprated.
- **Normalizing baseline results**: Baseline data should be normalized to reflect average conditions over the course of a year. This is likely to involve adjustments for weather and average operational characteristics.

There are significant uncertainties surrounding the benefits and costs. Regulatory approvals, technological advances, operational budgets, and other business conditions all affect the cost of deployment and/or expected system performance. As such, the utility may re-evaluate and revise its baseline data as significant events or developments alter the assumed or implied conditions of the current baseline.

2.4 Establishing Appropriate Analysis Time Horizon

The duration over which the impact and benefits of new grid and DER investments accrue varies significantly. The time horizon for the analysis must consider several factors, including differences among the lengths of expected useful life of various hardware and software across multiple projects and how to reconcile the differences in these lengths of expected useful lives. The analysis timeframe should be based on the longest asset life included in the portfolio/solution under consideration.[23]

2.5 Granularity of Data for Analysis

The most accurate assumptions to use for performing a BCA would leverage suitable locational or temporal information. When the more granular data is not available, an appropriate annual average or system average may be used, to reflect the expected savings from use of DER. While more granular locational or temporal assumptions are always preferred to more accurately capture the savings from use of a resource, the methodology included in the BCA Handbook would accommodate appropriate system averages in cases where more granular data is not available.

2.6 Performing Sensitivity Analysis

The *BCA Order* indicates the BCA Handbook shall include a "description of the sensitivity analysis that will be applied to key assumptions."[24] As Section 4 indicates a sensitivity analysis may be performed on any of the benefits and costs by changing selected input parameters.

The largest benefits for DER are typically the bulk system benefits of Avoided LBMP or AGCC.
A sensitivity of LBMP, $/MWh, could be assessed by adjusting the LBMP by +/-10%.
In addition to adjusting the values of an individual parameter as a sensitivity, the applicability of certain benefits and costs would be considered as a sensitivity analysis of the cost-effectiveness tests. For example, inclusion of the Wholesale Market Price Impacts in the UCT and RIM would be assessed as a sensitivity.[25]

[23] REV Proceeding, BCA Order, p. 2.

[24] REV Proceeding, BCA Order, Appendix C, p. 31.

[25] REV Proceeding, BCA Order, p. 25.

3. RELEVANT COST-EFFECTIVENESS TESTS

The *BCA Order* states that the Societal Cost Test ("SCT"), Utility Cost Test ("UCT"), and the Rate Impact Measure ("RIM") make up the relevant cost-effectiveness tests to be used in the BCA. These cost-effectiveness tests are summarized in Table 3-1.

Table 3-1. Cost-Effectiveness Tests

Cost Test	Perspective	Key Question Answered	Calculation Approach
SCT	Society	Is the State of New York better off as a whole?	Compares the costs incurred to design and deliver projects, and customer costs with avoided electricity and other supply-side resource costs (*e.g.*, generation, transmission, and natural gas); also includes the cost of externalities (*e.g.*, carbon emissions and other net non-energy benefits)
UCT	Utility	How will utility costs be affected?	Compares the costs incurred to design, deliver, and manage projects by the utility with avoided electricity supply-side resource costs
RIM	Ratepayer	How will utility rates be affected?	Compares utility costs and utility bill reductions with avoided electricity and other supply-side resource costs

The *BCA Order* positions the SCT as the primary cost-effectiveness measure because it evaluates impact on society as a whole.

The role of the UCT and RIM is to assess the preliminary impact on utility costs and customer bills from the benefits and costs that pass the SCT. The results of the UCT and RIM test are critical in identifying projects that may require a more detailed analysis of their impact to the utility and customers. Some projects may not provide benefits to the utility and ratepayers, even if it is beneficial to society as a whole. It is important to note, however, that if a measure passes the SCT but its results do not satisfy the UCT and RIM tests, the measure would not be rejected unless a complete bill impact analysis determines that such impact is of a "magnitude that is unacceptable".[26]

Each cost-effectiveness test included in the BCA Framework is defined in greater detail in the following subsections. Which of the various benefits and costs to include in analysis of individual projects or investment portfolios requires careful consideration, as discussed in Section 2 General Methodological Considerations.

[26] REV Proceeding, BCA Order, p. 13.

Table 3-2 summarizes which cost-effectiveness tests can be applied to the benefits and costs included in the *BCA Order*. The subsections below provide further context for each cost-effectiveness test.

Table 3-2. Summary of Cost-Effectiveness Tests by Benefit and Cost

Section #	Benefit/Cost	SCT	UCT	RIM
	Benefit			
4.1.1	Avoided Generation Capacity Costs†	✓	✓	✓
4.1.2	Avoided LBMP‡	✓	✓	✓
4.1.3	Avoided Transmission Capacity Infrastructure†‡	✓	✓	✓
4.1.4	Avoided Transmission Losses†‡	✓	✓	✓
4.1.5	Avoided Ancillary Services*	✓	✓	✓
4.1.6	Wholesale Market Price Impacts**		✓	✓
4.2.1	Avoided Distribution Capacity Infrastructure	✓	✓	✓
4.2.2	Avoided O&M	✓	✓	✓
4.2.3	Avoided Distribution Losses†‡	✓	✓	✓
4.3.1	Net Avoided Restoration Costs	✓	✓	✓
4.3.2	Net Avoided Outage Costs	✓		
4.4.1	Net Avoided CO_2‡	✓		
4.4.2	Net Avoided SO_2 and NO_x‡	✓		
4.4.3	Avoided Water Impacts	✓		
4.4.4	Avoided Land Impacts	✓		
4.4.5	Net Non-Energy Benefits***	✓	✓	✓
	Cost			
4.5.1	Program Administration Costs	✓	✓	✓
4.5.2	Added Ancillary Service Costs*		✓	✓
4.5.3	Incremental T&D and DSP Costs	✓	✓	✓
4.5.4	Participant DER Cost	✓		
4.5.5	Lost Utility Revenue			✓
4.5.6	Shareholder Incentives		✓	✓
4.5.7	Net Non-Energy Costs**	✓	✓	✓

† See Section 2 for discussion of potential overlaps in accounting for these benefits.
‡ See Section 2.1.2.1 for discussion of potential overlaps in accounting for these benefits.
** The amount of DER is not the driver of the size of NYISO's Ancillary Services markets since a change in load will not result in a reduction in the NYISO requirements for Regulation and Reserves as the requirements for these services are set periodically by NYISO to maintain frequency and to cover the loss of the largest supply element(s) on the bulk power system. Therefore, there is no impact within the SCT as the overall Ancillary Services requirement remains unchanged. DER has potential to provide new distribution-level ancillary service. However, it is uncertain whether such service can be cost-effectively provided.*
*** The Wholesale Market Price Impacts in the UCT and RIM would be assessed as a sensitivity.*
**** It is necessary to identify which cost-effectiveness test should include the specific benefit or cost in the Net Non-Energy Benefit or Net Non-Energy Cost as it may apply to the SCT, UCT and/or RIM.*

Performing a cost-effectiveness test for a specific project or a portfolio of projects requires the following steps:

- **Select the relevant benefits** for the investment.
- **Determine the relevant costs** from each cost included over the life of the investment.
- **Estimate the impact** the investment will have in each of the relevant benefit categories for each year of the analysis period (*i.e.*, how much it will change the underlying physical operation of the electric system to produce the benefits).
- **Apply the benefit values** associated with the project impacts as described in Section 4.
- **Apply the appropriate discount rate** to perform a cost-effectiveness test for a specific project or portfolio. The discount rate is the utility weighted average cost of capital to determine the present value of all benefits and costs.
- **Treat inflation consistently** by discounting real cash flow by real discount rates and nominal cash flows by nominal discount rates. A 2% annual inflation rate should be assumed unless otherwise specified.

3.1 Societal Cost Test

Cost Test	Perspective	Key Question Answered	Calculation Approach
SCT	Society	Is the State of New York better off as a whole?	Compares the costs incurred to design and deliver projects, and customer costs with avoided electricity and other supply-side resource costs (*e.g.*, generation, transmission, and natural gas); also includes the cost of externalities (*e.g.*, carbon emissions, and net non-energy benefits)

Most of the benefits included in the *BCA Order* can be evaluated under the SCT because their impact applies to society as a whole. This includes all distribution system benefits, all reliability/resiliency benefits, and all external benefits.

Lost Utility Revenue and Shareholder Incentives do not apply to the SCT, as these are considered transfers between stakeholder groups that have no net impact on society as a whole.

Similarly, the Wholesale Market Price Impact sensitivity is not performed for the SCT because the price suppression is also considered a transfer from large generators to market participants.[27]

[27] *BCA Order*, pg. 24

3.2 Utility Cost Test

Cost Test	Perspective	Key Question Answered	Calculation Approach
UCT	Utility	How will utility costs be affected?	Compares the costs incurred to design, deliver, and manage projects by the utility with avoided electricity supply-side resource costs

The UCT looks at the impact to utility costs associated with energy, capacity, generation, T&D, overhead, and general and administrative. For this reason, external benefits such as Avoided CO_2, Avoided SO_2 and NO_X, and Avoided Water and Land Impacts are not considered in the UCT. Utilities in New York do not currently receive incentives for decreased CO_2 or other environmental impacts. Benefits related to avoided outages would go to customers and not utilities, so this benefit also does not apply to the UCT.

Participant DER Cost and Lost Utility Revenue are not considered in the UCT because the cost of the DER is not a utility cost and any reduced revenues from DER are made-up by non-participating DER customers through the utility's revenue decoupling mechanism or other means.

3.3 Rate Impact Measure

Cost Test	Perspective	Key Question Answered	Calculation Approach
RIM	Ratepayer	How will utility rates be affected?	Compares utility costs and utility bill reductions with avoided electricity and other supply-side resource costs

The RIM test can address rate impacts to non-participants. External benefits such as Avoided CO_2, Avoided SO_2 and NO_X, and Avoided Water and Land Impacts are not included in the RIM as they do not directly affect customer rates. Benefits related to avoided outages go to customers but, again, would have no effect on rates.

Participant DER cost does not apply to the RIM because the cost of the DER is not a utility cost. However, any reduced revenues from DER are included as increased costs to other customers as Lost Utility Revenue because of revenue decoupling or other means that transfer costs from participants to non-participants.

4. BENEFITS AND COSTS METHODOLOGY

Each subsection below aligns with a benefit or cost listed in the *BCA Order*. Each benefit and cost includes a definition, equation, and a discussion of general considerations.

Four types of benefits are addressed in the subsections below:

- Bulk System: Larger system responsible for the generation, transmission and control of electricity that is passed on to the local distribution system.
- Distribution System: System responsible for the local distribution of electricity to end use consumers.
- Reliability/Resiliency: Efforts made to reduce duration and frequency of outages.
- External: Consideration of social values for incorporation in the SCT.

There are also four types of costs considered in the BCA Framework and addressed in the subsections below. They are:

- Program Administration: Includes the cost of state incentives, measurement and verification, and other program administration costs to start, and maintain a specific program
- Utility-related: Those incurred by the utility such as incremental T&D, DSP, lost revenues and shareholder incentives
- Participant-related: Those incurred to achieve project or program objectives
- Societal: External costs for incorporation in the SCT

The 2018 BCA Handbook 2.0 assumes that all energy, operational, and reliability-related benefits and cost,[28] occur in the same year. Thus, there is no time delay between benefit/cost impacts. However, for capacity and infrastructure benefits and costs,[29] it is assumed that impacts generate benefits/costs in the following year of the impact. For example, if a project reduces system peak load in 2018, the AGCC benefit would not be realized until 2019.

---

[28] Energy, operational, and reliability-related benefits and costs include: Avoided LBMP, the energy component of Avoided Transmission Losses, *Avoided Ancillary Services*, the energy portion of *Wholesale Market Price Impact*, *Avoided O&M*, *Avoided Distribution Capacity Infrastructure*, *Net Avoided Restoration Costs*, Net Avoided Outage Costs, the energy component of *Distribution Losses*, *Net Avoided* CO_2, *Net Avoided* SO_2 *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*. .

[29] Capacity, infrastructure, and market price-related benefits and costs include: Avoided Generation Capacity Costs, the capacity component of Avoided Transmission Losses, Avoided O&M, the capacity component of Distribution Losses, Avoided Transmission Capacity Infrastructure and Related O&M, the capacity portion of the Wholesale Market Price Impact, Added Ancillary Service Costs, and Incremental Transmission & Distribution and DSP Costs.

4.1 Bulk System Benefits

4.1.1 Avoided Generation Capacity Costs

Avoided Generation Capacity Costs are due to reduced coincident system peak demand. This benefit is calculated by NYISO zone, which is the most granular level for which AGCC are currently available.[30] It is assumed that the benefit is realized in the year following the peak load reduction impact.

4.1.1.1 Benefit Equation, Variables, and Subscripts

Equation 4-1 presents the benefit equation for Avoided Generation Capacity Costs. This equation follows “Variant 1” of the Demand Curve savings estimation described in the 2015 Congestion Assessment and Resource Integration Study (“CARIS”) Appendix. Each NYISO zone is mapped to one of the four NYISO localities as follows: ROS = A-F, LHV = G-I, NYC = J, LI = K.

Equation 4-1. Avoided Generation Capacity Costs

$$\text{Benefit}_{Y+1} = \sum_{Z} \frac{\Delta\text{PeakLoad}_{Z,Y,r}}{1\text{-Loss\%}_{Z,Y,b\rightarrow r}} * \text{SystemCoincidenceFactor}_{Z,Y} * \text{DeratingFactor}_{Z,Y} * \text{AGCC}_{Z,Y,b}$$

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

$\Delta\text{PeakLoad}_{Z,Y,r}$ (△MW) is the project’s expected maximum demand reduction capability, or “nameplate” impact at the retail delivery or connection point (“r”), by zone if applicable. This input is project or program specific. A positive value represents a reduction in peak load.

$\text{Loss\%}_{Z,b\rightarrow r}$ (%) 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

---

[30] For a portfolio of projects located within multiple NYISO zones, it may be necessary to calculate weighted average across zones to obtain a benefit value.

(*e.g.*, due to clouds) of a solar array which could limit its contribution to system peak load reduction. This input is project specific.

$\mathbf{AGCC_{Z,Y,b}}$ **($/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.[31] The Reserve Margin is determined annually by New York State Reliability Council. Minimum LCR, set by NYISO, are applicable to several localities (NYC, LI, "G-J" Region) and account for transmission losses. See NYISO Installed Capacity Manual[32] for more details on ICAP.

AGCC benefits are calculated using a static forecast of AGCC prices provided by Staff. Any wholesale market capacity price suppression effects are not accounted for here and instead are captured in Wholesale Price Impacts, described in Section 4.1.6.

Impacts from a measure, project, or portfolio must be coincident with the system peak and accounted for losses prior to applying the AGCC valuation parameter. The "nameplate" impact (*i.e.,* $\Delta PeakLoad_{Z,Y,r}$) should also be multiplied by a coincidence factor and derating factor to properly match the planning impact to the system peak. The coincident factor quantifies a project's contribution to system peak relative to its nameplate impact.

It is also important to consider the persistence of impacts in future years after a project's implementation. For example, participation in a demand response program may change over time. Also, a peak load reduction impact will not be realized as a monetized AGCC benefit until the year following the peak load reduction, as capacity requirements are set by annual peak demand and paid for in the following year.

The AGCC values provided in Staff's ICAP Spreadsheet Model account for the value of transmission losses and infrastructure upgrades. In instances where projects change the transmission topology, incremental infrastructure and loss benefits not captured in the AGCC values should be modeled and quantified in the Avoided T&D Losses and Avoided T&D Infrastructure benefits, below.

[31] 2017 CARIS Phase 1 Study Appendix. https://www.nyiso.com/public/webdocs/markets_operations/services/planning/Planning_Studies/Economic_Planning_Studies_(CARIS)/CARIS_Final_Reports/2017-Report-CARIS2017-Appendix-B-J-FINAL.pdf

[32] http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Operations/icap_mnl.pdf

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

$$\mathrm{Benefit_Y} = \sum_{Z} \sum_{P} \frac{\Delta \mathrm{Energy_{Z,P,Y,r}}}{1 - \mathrm{Loss\%_{Z,b \rightarrow r}}} * \mathrm{LBMP_{Z,P,Y,b}}$$

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

$\mathbf{\Delta Energy_{Z,P,Y,r}}$ **(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 $Loss\%_{Z,b \rightarrow r}$ parameter. This input is project- or program-specific. A positive value represents a reduction in energy.

$\mathbf{Loss\%_{Z,b \rightarrow r}}$ **(%)** is the variable loss percent between bulk system ("b") and the retail delivery or connection point ("r"). The loss percentages by system level are found in Table A-2.

$\mathbf{LBMP_{Z,P,Y,b}}$ **($/MWh)** is the Locational Based Marginal Price, which is the sum of energy, congestion, and losses components by NYISO zone at the bulk system level ("b"). NYISO forecasts 20-year annual and hourly LBMPs by zone. To determine time-differentiated LBMPs, for example, annual, seasonal, monthly, or hourly, leverage NYISO's hourly LBMP forecast by zone rather than developing an alternative forecast of time-differentiated LBMPs based on shaping annual averages by zone from historical data. The NYISO hourly LBMP forecast is a direct output from the CARIS Phase 2 modeling. To extend the LBMP forecast beyond the CARIS Phase 2 planning period, if necessary, assume that the last year of the LBMPs stay constant in real (inflation adjusted) $/MWh.

4.1.2.2 General Considerations

Avoided LBMP benefits are calculated using a static forecast of LBMP. Any wholesale market price changes as a result of the project or program are not accounted for in this benefit, and are instead captured in Wholesale Market Price Impacts, described in Section4.1.6.

The time differential for subscript P (period) will depend on the type of project, and could be season, month, day, hour, or any other interval. The user must ensure that the time-differentiation is appropriate for the project being analyzed. For example, it may be appropriate to use an annual average price and impact for a DER that has a consistent load reduction at all hours of the year. However, using the annual average may not be appropriate for energy storage which may be charging during non-peak hours and discharging during peak hours. In that case, it may be appropriate to multiply an average on-peak (or super-peak) and off-peak LBMP by the on-peak (or super-peak) and off-peak energy impacts, respectively.

It is important to consider the trend (*i.e.*, system degradation) of impacts in future years after a project's implementation. For example, a PV system's output may decline over time. It is assumed that the benefit is realized in the year of the energy impact.

4.1.3 Avoided Transmission Capacity Infrastructure and Related O&M

Avoided Transmission Capacity Infrastructure and Related O&M benefits result from location-specific load reduction that is valued at the marginal cost of equipment that is avoided or deferred by a DER project or program. A portion of Avoided Transmission Capacity is already captured in the congestion charge of the LBMP and the AGCC prices. Because static forecasts of LBMPs and AGCC values are used, this benefit will be quantified only in cases where a measure, project, or portfolio alters the planned transmission system investments from that level embedded in those static forecasts.

4.1.3.1 Benefit Equation, Variables, and Subscripts

Equation 4-3 presents the benefit equation for Avoided Transmission Capacity Infrastructure and Related O&M:

Equation 4-3. Avoided Transmission Capacity Infrastructure and Related O&M

$$\mathrm{Benefit}_{\mathrm{Y+1}} = \sum_{\mathrm{C}} \frac{\Delta\mathrm{PeakLoad}_{\mathrm{Y,r}}}{1-\mathrm{Loss\%}_{\mathrm{Y,b}\rightarrow\mathrm{r}}} * \mathrm{TransCoincidentFactor}_{\mathrm{C,Y}} * \mathrm{DeratingFactor}_{\mathrm{Y}} * \mathrm{MarginalTransCost}_{\mathrm{C,Y,b}}$$

The indices[33] of the parameters in Equation 4-3 include:

- C = constraint on an element of transmission system[34]
- Y = Year
- b = Bulk System

[33] In future versions of the Handbook, additional indices such as time period and voltage level can be included as this data becomes available.

[34] If system-wide marginal costs are used, this is not an applicable subscript.

- r = Retail Delivery or Connection Point

$\Delta\mathbf{PeakLoad_{Y,r}}$ **(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.

$\mathbf{Loss\%_{Y,b\rightarrow r}}$ **(%)** is the variable loss percent between the bulk system ("b") and the retail delivery point ("r"). Thus, this reflects the sum of the transmission and distribution system loss percent values, both found in Table A-2.

$\mathbf{TransCoincidentFactor_{C,Y}}$ **(dimensionless)** quantifies a project's contribution to reducing transmission system peak demand relative to its expected maximum demand reduction capability. For example, an expected maximum demand reduction capability of 100 kW with a coincidence factor of 0.8 will reduce the transmission system peak by 80 kW (without considering $DeratingFactor_Y$). This input is project specific.

$\mathbf{DeratingFactor_Y}$ **(dimensionless)** is presented here as a generic factor to de-rate the transmission system coincident peak load based on the availability of the load during peak hours. For example, a demand response program may only be allowed to dispatch a maximum of 10 events per year, which could limit the availability of the resource during peak hours. Another example is the variability and intermittence (*e.g.*, due to clouds) of a solar array which could limit its contribution to peak load reduction on the transmission system. This input is project specific.

$\mathbf{MarginalTransCost_{C,Y,b}}$ **($/MW-yr)** is the marginal cost of the transmission equipment from which the load is being relieved. It is assumed that the marginal cost of service is based on the bulk system ("b"). If the available marginal cost of service value reflects a different basis, then this parameter must first be converted to represent load at the bulk system prior to using in the equation above. Localized or equipment-specific marginal costs of service should be used in most cases. In some limited circumstances use of the system average marginal cost have been accepted, for example, for evaluation of energy efficiency programs. System average marginal cost of service values are provided in Table A-3. Orange & Rockland is in the process of completing a new marginal cost study to capture recent work experience and based on the most recent and updated planning process results. These costs will be presented as revised system wide costs, as well as on a more granular basis where appropriate. When completed, the results of this new study will be integrated into the Handbook and will be applied prospectively.

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

$$\mathrm{Benefit}_{Y+1} = \sum_{Z} \mathrm{SystemEnergy}_{Z,Y+1,b} * \mathrm{LBMP}_{Z,Y+1,b} * \Delta\mathrm{Loss\%}_{Z,Y+1,b\rightarrow i} + \mathrm{SystemDemand}_{Z,Y,b} * \mathrm{AGCC}_{Z,Y,b} * \Delta\mathrm{Loss\%}_{Z,Y,b\rightarrow i}$$

Where,

$$\Delta\text{Loss\%}_{\text{Z,Y,b}\rightarrow\text{i}} = \text{Loss\%}_{\text{Z,Y,b}\rightarrow\text{i,baseline}} - \text{Loss\%}_{\text{Z,Y,b}\rightarrow\text{i,post}}$$

The indices[35] of the parameters in Equation 4-4 include:

- Z = NYISO zone (for LBMP: A → K; for AGCC: NYC, LHV, LI, ROS[36])
- Y = Year
- b = Bulk System
- i = Interface of the transmission and distribution systems

$\text{SystemEnergy}_{\text{Z,Y+1,b}}$ (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.

$\text{LBMP}_{\text{Z,Y+1,b}}$ ($/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.

$\text{SystemDemand}_{\text{Z,Y,b}}$ (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.

$\text{AGCC}_{\text{Z,Y,b}}$ ($/MW-yr) represents the annual AGCCs based on forecast of capacity prices for the wholesale market provided by Staff. This data is posted on DMM in Case 14-M-0101[37] 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"[38] based on capacity obligations at the forecast of capacity prices for the wholesale market. Note that the AGCC values provided in this spreadsheet are in the units of $/kW-mo, which must be converted to $/MW-yr to match the peak load impact in MW. To convert units, the summer and winter $/kW-mo values are multiplied by six months each and added together, and then multiplied by 1,000 to convert to $/MW-yr.

$\Delta\text{Loss\%}_{\text{Z,Y,b}\rightarrow\text{i}}$ (∆%) 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

[35] In future versions of the Handbook, additional indices such as time period and voltage level can be included as this data becomes available.

[36] Mapping NYISO localities to NYISO zones: ROS = A-F, LHV = G-I, NYC = J, LI = K

[37] http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=14-M-0101&submit=Search

[38] "Transmission level" represents the bulk system level ("b").

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.

$\mathbf{Loss\%_{Z,Y,b\rightarrow i,baseline}}$ **(%)** is the baseline fixed and variable loss percent between bulk system (“b”) and the interface of the transmission and distribution systems (“i”). Thus, this reflects the sub-transmission and internal transmission losses pre-project, which is found in Table A-2.

$\mathbf{Loss\%_{Z,Y,b\rightarrow i,post}}$ **(%)** is the post-project fixed and variable loss percent between bulk system (“b”) and the interface of the transmission and distribution systems (“i”). Thus, this reflects the sub-transmission and internal transmission losses post-project.

4.1.4.2 General Considerations

Transmission losses are already embedded in the LBMP. This benefit is incremental to what is included in LBMP and is only quantified when the transmission loss percent is changed (*e.g.*, from 3% to 2.9%). For most projects, this benefit will be zero unless an engineering study determines otherwise.

The energy and demand impacts are based on system-wide energy and demand rather than project-specific, because this benefit is only quantified when the losses percentage is changed which affects all customers in the affected area. Transmission losses will not affect downstream distribution losses.

It is assumed that the LBMP component of the avoided losses benefit is accrued in the same year as the impact, and the AGCC component of the benefit is accrued in the following year of the benefit. This is reflected in the equation above with “Y” and “Y+1” subscripts to indicate the timing of the benefits relative to the impacts.

4.1.5 Avoided Ancillary Services (Spinning Reserves, and Frequency Regulation)

Avoided Ancillary Services benefits may accrue to selected DERs that qualify and are willing and are able to provide ancillary services to NYISO at a lower cost than conventional generators without sacrificing reliability. This benefit will only be quantified in cases where a measure, project, or portfolio is qualified to, or has the ability and willingness to provide ancillary services to NYISO. This value will be zero for nearly all cases and by exception would be a value included as part of the UCT and RIM.

As a load modifier, DER causes a reduction in load however, it will not directly result in a reduction in NYISO requirements for regulation and reserves since these requirements are not based on existing load levels but instead are based on available generating resource characteristics. Regulation requirements are set by NYISO to maintain frequency, and reserve requirements are set to cover the loss of the largest supply element(s) on the bulk power system.

Some DERs may have the potential to provide a new distribution-level ancillary service such as voltage support and power quality. However, it is uncertain whether such attributes can be cost-effectively provided by dispersed DERs. The infrastructure costs required to monitor the applicable system conditions (voltage, flicker, etc.) and individual DERs as well as the operations and communications system to effectively dispatch those DER attributes are also uncertain. It is premature to include any value in the BCA for such services until the utilities can cost-effectively build the systems to monitor and dispatch DERs to capture net distribution benefits.

4.1.5.1 Benefit Equation, Variables, and Subscripts

The benefits of each of two ancillary services (spinning reserves, and frequency regulation) are described in the equations below. The quantification and inclusion of these benefits are project specific.

Frequency Regulation

Equation 4-5 presents the benefit equation for frequency regulation:

Equation 4-5. Frequency Regulation

$$\mathrm{Benefit}_Y = \mathrm{Capacity}_Y * n * (\mathrm{CapPrice}_Y + \mathrm{MovePrice}_Y * \mathrm{RMM}_Y)$$

The indices of the parameters in Equation 4-5 include:

- Y = Year

$\mathbf{Capacity_Y}$ **(MW)** is the amount of annual average frequency regulation capacity when provided to NYISO by the project.

$\mathbf{n}$ **(hr)** is the number of hours in a year that the resource is expected to provide the service.

$\mathbf{CapPrice_Y}$ **($/MW·hr)** is the average hourly frequency regulation capacity price. The default value is the two-year historical average for day-ahead regulation capacity prices from NYISO.

$\mathbf{MovePrice_Y}$ **($/ΔMW)**: is the average hourly frequency regulation movement price. The default value is the two-year historical average for real-time dispatch of regulation movement prices from NYISO.

$\mathbf{RMM_Y}$ **(ΔMW/MW·hr)**: is the Regulation Movement Multiplier ("RMM") used for regulation bids and accounts for the ratio between movement and capacity. It is assumed to be 13 ΔMW/MW-hr.

Spinning Reserves

Equation 4-6 presents the benefit equation for spinning reserves:

Equation 4-6. Spinning Reserves

$$\mathrm{Benefit}_Y = \mathrm{Capacity}_Y * n * \mathrm{CapPrice}_Y$$

The indices of the parameters in Equation 4-6 include:

- Y = Year

$\mathbf{Capacity_Y}$ **(MW)** is the change in the amount of annual average spinning reserve capacity when provided to the NYISO by the project.

$\mathbf{n}$ **(hr)**: is the number of hours in a year that the resource is expected to provide the service.

$\mathbf{CapPrice_Y}$ **($/MW·hr)** is the average hourly spinning reserve capacity price. The default value uses the two-year historical average spinning reserve pricing by region.

4.1.5.2 General Considerations

There are no reductions in annual average frequency regulation, and spinning reserve, because those are set by the NYISO independent of load levels and DER penetration.

The average hourly prices for frequency regulation capacity, frequency regulation movement, and spinning reserve capacity can be calculated from historical pricing data posted by NYISO. The recommended basis is a historical average of interval pricing over the prior two-year period.

The NYISO Ancillary Services Manual indicates that the day-ahead market is the predominant market for regulation capacity and spinning reserves; regulation movement is only available in real-time.
The RMM is fixed by NYISO at a value of 13 ΔMW/MW per hour. While NYISO does not publish historical interval volume data to calculate actual movement, this value can be considered a reasonable proxy for actual movement.[39]

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.[40] LBMP impacts will be calculated for each NYISO zone. AGCC price impacts are developed using Staff's ICAP Spreadsheet Model.

4.1.6.1 Benefit Equation, Variables, and Subscripts

Equation 4-7 presents the benefit equation for Wholesale Market Price Impact:

Equation 4-7. Wholesale Market Price Impact

$$\mathrm{Benefit}_{Y+1} = \sum_{Z} (1 - \mathrm{Hedging\%}\ \ ) * (\Delta\mathrm{LBMPImpact}_{Z,Y+1,b} * \mathrm{WholesaleEnergy}_{Z,Y+1,b} + \Delta\mathrm{AGCC}_{Z,Y,b} * \mathrm{ProjectedAvailableCapacity}_{Z,Y,b})$$

The indices of the parameters in Equation 4-7 include:

- Z = NYISO zone (A → K[41])
- Y = Year
- b = Bulk System

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

[39] http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Operations/ancserv.pdf

[40] REV Proceeding, BCA Order, Appendix C, p. 8.

[41] Mapping NYISO localities to NYISO zones: ROS = A-F, LHV = G-I, NYC = J, LI = K

wholesale market price impacts. For BCA calculations the utilities have generally assumed that the percent of purchases hedged is 50% and equal for both energy and capacity.

$\Delta LBMPImpact_{Z,Y+1,b}$ **(Δ$/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.

$\Delta AGCC_{Z,Y,b}$ **(Δ$/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.[42] 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.[43]. As noted previously, it is assumed that the capacity portion of Wholesale Market Price Impacts will produce benefits in the year following the impact while the energy portion of Wholesale Market Price Impacts will produce benefits in the same year as the impact

4.2 Distribution System Benefits

4.2.1 Avoided Distribution Capacity Infrastructure

Avoided Distribution Capacity Infrastructure benefit results from location-specific distribution load reductions that are valued at the marginal cost of distribution system infrastructure that is avoided or

[42] As in the AGCC benefit equation, System Coincidence Factors and Derating Factors adjust the maximum load reduction of the project.

[43] The one year assumption is based on an overview of price suppression provided in the New England Regional Avoided Cost Study 2015

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

$$\mathrm{Benefit_Y} = \sum_{V}\sum_{C} \frac{\Delta\mathrm{PeakLoad_{Y,r}}}{1 - \mathrm{Loss\%_{Y,b\rightarrow r}}} * \mathrm{DistCoincidentFactor_{C,V,Y}} * \mathrm{DeratingFactor_Y} * \mathrm{MarginalDistCost_{C,V,Y,b}}$$

The indices of the parameters in Equation 4-8 include:

- C = Constraint on an element (*e.g.*, pole-mounted transformer, distribution line, etc.) of the distribution system[44]
- V = Voltage level (*e.g.*, primary, and secondary)
- Y = Year
- b = Bulk System
- r = Retail Delivery or Connection Point

$\boldsymbol{\Delta\mathrm{PeakLoad_{Y,r}}}$ **(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.

$\boldsymbol{\mathrm{Loss\%_{Y,b\rightarrow r}}}$ **(%)** 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 $\Delta\mathrm{PeakLoad_{Y,r}}$ parameter to the bulk system level.

$\boldsymbol{\mathrm{DistCoincidentFactor_{C,V,Y}}}$ **(dimensionless)** is a project specific input that captures the contribution to the distribution element's peak relative to the project's nameplate demand reduction. For example, a nameplate demand reduction of 100 kW on the distribution feeder with a coincidence factor of 0.8 would contribute an 80 kW reduction to peak load on an element of the distribution system.

.

$\boldsymbol{\mathrm{DeratingFactor_Y}}$ **(dimensionless)** is a project specific input that is presented here as a generic factor to de-rate the distribution coincident peak load based on the availability of the load during peak hours. For example, a demand response program may only be allowed to dispatch a maximum of 10 events per year, which could limit the availability of the resource during peak hours. Another example is the variability and intermittence (*e.g.*, due to clouds) of a solar array which could limit its peak load reduction contribution on an element of the distribution system.

[44] In limited cases where use of system-wide marginal cost values is required, this subscript is not applicable.

$MarginalDistCost_{C,V,Y,b}$ ($/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 efficiency programs.

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. These values 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

$$\text{Benefit}_{\text{Y}} = \sum_{\text{AT}} \Delta\text{Expenses}_{\text{AT,Y}}$$

The indices of the parameters in Equation 4-9 include:

- AT = activity type (*e.g.*, line crews to replace equipment, engineering review of DER interconnection applications, responding to calls received at call centers)
- Y = Year

$\Delta\text{Expenses}_{\text{AT,Y}}$ (Δ$): Change in O&M expenses due to a project, including an appropriate allocation of administrative and common costs. These costs would increase by inflation, where appropriate.

4.2.2.2 General Considerations

Distribution O&M benefits from DERs may be limited to instances where DERs can avoid or defer new distribution equipment, a benefit which is already captured in the Avoided Distribution Capacity Infrastructure benefit (Section 4.2.1), where the O&M costs are embedded in the marginal cost of service values. DER interconnections could increase O&M costs, while lower equipment failure rates could decrease these costs. In general, these impacts are difficult to quantify for DER investments and may be trivial in most cases.

Avoided O&M benefits would be quantifiable for some non-DER investments, such as utility investments in DSP capabilities. For example, a utility investment in advanced metering functionality may avoid truck rolls and other costs by collecting meter data remotely.

4.2.3 Distribution Losses

Avoided Distribution Losses are the incremental benefit that is realized when a project causes distribution system losses to change which in turn results in changes to both annual energy use and peak demand. Distribution losses are already accounted for in the LBMP and AGCC when grossing impacts at the project location to the price locations. Because static forecasts of LBMPs and AGCC are used, this benefit is quantified only in cases where a measure, project, or portfolio alters the distribution system losses percentage (*e.g.*, from 3% to 2.9%).

4.2.3.1 Benefit Equation, Variables, and Subscripts

Equation 4-10 presents the benefit equation for Avoided Distribution Losses:

Equation 4-10. Avoided Distribution Losses

$$\text{Benefit}_{Y+1} = \sum_{Z} \text{SystemEnergy}_{Z,Y+1,b} * \text{LBMP}_{Z,Y+1,b} * \Delta\text{Loss\%}_{Z,Y+1,i\to r} + \text{SystemDemand}_{Z,Y,b} * \text{AGCC}_{Z,Y,b} * \Delta\text{Loss\%}_{Z,Y,i\to r}$$

Where,

$$\Delta\text{Loss\%}_{Z,Y,i\to r} = \text{Loss\%}_{Z,Y,i\to r,\text{baseline}} - \text{Loss\%}_{Z,Y,i\to r,\text{post}}$$

The indices[45] of the parameters in Equation 4-10 include:

- Z = NYISO zone (for LBMP: A → K; for AGCC: NYC, LHV, LI, ROS[46])
- Y = Year
- i = Interface Between Transmission and Distribution Systems
- b = Bulk System
- r = Retail Delivery or Connection Point

$\mathbf{SystemEnergy_{Z,Y,b}}$ **(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.

$\mathbf{LBMP_{Z,Y,b}}$ **($/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.

$\mathbf{SystemDemand_{Z,Y,b}}$ **(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 $\text{Loss\%}_{Z,b\to r}$ 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.

$\mathbf{AGCC_{Z,Y,b}}$ **($/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

[45] In future versions of the Handbook, additional indices such as time period and voltage level can be included as this data becomes available.

[46] Mapping NYISO localities to NYISO zones: ROS = A-F, LHV = G-I, NYC = J, LI = K.

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.

$\mathbf{\Delta Loss\%_{Z,Y,i \rightarrow r}}$ **(Δ%)** is the change in the fixed and variable loss percent between the interface between the transmission and distribution systems ("i") and the retail delivery point ("r") resulting from a project that changes the topology of the distribution system. This value would typically be determined in a project-specific engineering study. Two parameters are provided in the equations above: one with a "Y" subscript to represent the current year, and one with a "Y+1" subscript to represent the following year.

$\mathbf{Loss}\%_{\mathbf{Z,Y,i \rightarrow r,baseline}}$ **(%)** is the baseline fixed and variable loss percent between the interface of the transmission and distribution systems ("i") and the retail delivery point ("r"). Thus, this reflects the distribution loss percent pre-project, which is found in Table A-2.

$\mathbf{Loss}\%_{\mathbf{Z,Y,i \rightarrow r,post}}$ **(%)** is the post-project fixed and variable loss percent between the interface of the transmission and distribution systems ("i") and the retail delivery point ("r").

4.2.3.2 General Considerations

Distribution losses are already accounted for in the LBMP and AGCC when grossing impacts at the project location to the price locations. Because static forecasts of LBMPs and AGCC are used, this benefit will be quantified only in cases where a measure, project, or portfolio alters the distribution system losses percentage (*e.g.*, from 3% to 2.9%). For most projects, this benefit will be zero unless an engineering study determines otherwise.

The energy and demand impacts are grossed up from retail impacts to transmission system impacts based on losses from the equations above. Impacts are based on system-wide energy and demand, not project-specific, because this benefit is only quantified when the loss percentage is changed which affects all load in the affected area. Note that distribution losses also affect upstream transmission losses. Because losses data is usually available on an annual average basis, the energy and demand impacts should be on an annual average basis as well.

It is assumed that the LBMP component of the avoided losses benefit is accrued in the same year as the impact, and the AGCC component of the benefit is accrued in the following year of the benefit. This is reflected in the equation above with "Y" and "Y+1" subscripts to indicate the time delay of benefits relative to the impacts.

4.3 Reliability/Resiliency Benefits

4.3.1 Net Avoided Restoration Costs

Avoided Restoration Costs accounts for avoided costs of restoring power during outages. For most DER investments, this benefit will not be quantified, since utilities are required to repair the cause of an outage regardless of whether the DER allows the customer to operate independently of the grid. For some non-DER investments such as automatic feeder switching, distribution automation and enhanced equipment monitoring, the utility may save time and other expenses dispatching restoration crews as a result of having improved visibility into the type and nature of the fault or system damage. Storm hardening and other resiliency investments can reduce the number of outage events, resulting in reduced restoration crew hours. Two methodologies to capture the potential value of specific programs or specific projects are identified below. Use of either methodology depends on the type of investment/technology under analysis. Equation 4-11 will generally apply to non-DER investments that allow the utility to save time and other expenses dispatching restoration crews. Equation 4-12 will generally apply to DER investments that are able to provide functionally equivalent reliability as an alternative to the traditional utility investment.

4.3.1.1 Benefit Equation, Variables, and Subscripts

Equation 4-11 presents the benefit equation for Net Avoided Restoration Costs associated with non-DER investments:

Equation 4-11. Net Avoided Restoration Costs

$$\mathrm{Benefit_Y} = -\Delta\mathrm{CrewTime_Y} * \mathrm{CrewCost_Y} + \Delta\mathrm{Expenses_Y}$$

Where,

$$\Delta\mathrm{CrewTime_Y} = \#\mathrm{Interruptions_{base,Y}} * (\mathrm{CAIDI_{base,Y}} - \mathrm{CAIDI_{post,Y}} * (1 - \%\mathrm{ChangeSAIFI_Y}))$$

$$\%\mathrm{ChangeSAIFI_Y} = \frac{\mathrm{SAIFI_{base,Y}} - \mathrm{SAIFI_{post,Y}}}{\mathrm{SAIFI_{base,Y}}}$$

SAIFI, CAIDI and SAIDI values could be utilized at the system level for non-DER projects/programs that are applicable across a total system basis. More targeted data should be substituted for localized, geographic specific projects that exhibit localized impacts. Other reliability metrics will need to be developed to more suitably quantify reliability or resiliency benefits and costs associated with localized projects or programs. Once developed, the localized restoration cost metric will be applied and included in this handbook.

There is no subscript to represent the type of outage in Equation 4-11 because it assumes an average restoration crew cost that does not change based on the type of outage. The ability to reduce outages would be dependent on the outage type.

$\boldsymbol{\Delta\mathrm{CrewTime_Y}}$ **(Δhours/yr)** is the change in crew time to restore outages based on an impact on frequency and duration of outages. This data is project and/or program specific. A positive value represents a reduction in crew time

$\boldsymbol{\mathrm{CrewCost_Y}}$ **($/hr)** is the average hourly outage restoration crew cost for activities associated with the project under consideration

$\boldsymbol{\Delta\mathrm{Expenses_Y}}$ **(Δ$)** are the average expenses (*e.g.,* equipment replacement) associated with outage restoration.

$\mathbf{\#Interruptions_{base,Y}}$ **(int/yr)** are the baseline (*i.e.*, pre-project) number of sustained interruptions per year, excluding major storms. The system-wide five-year average number of interruptions excluding major storms is available from the annual Electric Service Reliability Reports.

$\mathbf{CAIDI_{base,Y}}$ **(hr/int)** is the baseline (*i.e.*, pre-project) Customer Average Interruption Duration Index. It represents the average time to restore service, excluding major storms. The system-wide five-year average CAIDI is available from the annual Electric Service Reliability Reports. Generally, this parameter is a system-wide value. In localized project/program specific cases, it should be representative of the relevant area of the system that the measure, project, or portfolio affects.

$\mathbf{CAIDI_{post,Y}}$ **(hr/int)** is the post-project Customer Average Interruption Duration Index. It represents the average time to restore service. Determining this parameter would require development of a distribution level model and a respective engineering study to quantify appropriately.

$\mathbf{\%ChangeSAIFI_{Y}}$ **(Δ%)** is the percent change in System Average Interruption Frequency Index. It represents the percent change in the average number of times that a customer experiences an outage per year.

$\mathbf{SAIFI_{base,Y}}$ **(int/cust/yr)** is the baseline (*i.e.*, pre-project) System Average Interruption Frequency Index. It represents the average number of times that a customer experiences an outage per year, excluding major storms. The baseline system-wide value is a five-year average is available from the annual Electric Service Reliability Reports. Generally, this parameter is system-wide value. In localized project/program specific cases, it should be representative of the relevant area of the system that the measure, project, or portfolio affects.

$\mathbf{SAIFI_{post,Y}}$ **(int/cust/yr)** is the post-project System Average Interruption Frequency Index. It represents the average number of times that a customer experiences an outage per year in the post-project scenario. Determining this parameter would require development of a distribution level model and a respective engineering study to quantify appropriately.

Equation 4-12. Net Avoided Restoration Costs

$$\mathrm{Benefit_{Y}} = \mathrm{MarginalCost_{R,Y}}$$

The indices of the parameters in Equation 4-12 are applicable to DER installations and include:

- R = Reliability constraint on an element (*e.g.*, pole-mounted transformer, distribution line, etc.) of T&D system
- Y = Year

$\mathbf{MarginalDistCost_{R,Y}}$ **($/yr):** Marginal cost of the reliability investment. Because this value is project- and location- specific, a system average value is not applicable.

This benefit only applies for an individual project or portfolio of DER which is able to provide functionally equivalent reliability as compared to the reliability provided by the traditional distribution reliability investment that would have otherwise been constructed and placed in service; If the DER does not defer or avoid a traditional reliability investment, this benefit does not apply. When an individual or portfolio of DER is able to defer a distribution reliability investment, the value of the avoided restoration cost is already reflected in the Avoided Distribution Capacity Infrastructure benefit calculation.

4.3.1.2 General Considerations

The impact on SAIFI or CAIDI is due to the implementation of the project relative to a baseline rather than outside factors such as weather. The changes to these parameters should consider the appropriate context of the project including the types of outage events and how the project may or may not address each type of event to inform the magnitude of impact. For example, is the impact to one feeder or impact to a portion of the distribution system? The baseline values should match the portion of the system impacted..

In addition to being project-specific, the calculation of avoided restoration costs is dependent on projection of the impact of specific investments related to the facilitation of actual system restoration and the respective costs. It is unrealistic to expect that DER investments will limit or replace the need to repair field damage to the system, and as such, system restoration benefits attributable to DER type investments are unlikely. Application of this benefit would be considered only for investments with validated reliability results.

4.3.2 Net Avoided Outage Costs

Avoided Outage Costs accounts for customer outage costs due to a reduction in frequency and duration of outages, then multiplying that expected change by an estimated outage cost. The quantification of this benefit is highly dependent on the type and size of affected customers.

4.3.2.1 Benefit Equation, Variables, and Subscripts

Equation 4-13 presents the benefit equation for Net Avoided Outage Costs:

Equation 4-13. Net Avoided Outage Costs

$$\mathrm{Benefit}_{\mathrm{Y}} = \sum_{\mathrm{C}} \mathrm{ValueOfService}_{\mathrm{C,Y,r}} * \mathrm{AverageDemand}_{\mathrm{C,Y,r}} * \Delta\mathrm{SAIDI}_{\mathrm{Y}}$$

Where,

$$\Delta\mathrm{SAIDI}_{\mathrm{Y}} = \mathrm{SAIFI}_{\mathrm{base,Y}} * \mathrm{CAIDI}_{\mathrm{base,Y}} - \mathrm{SAIFI}_{\mathrm{post,Y}} * \mathrm{CAIDI}_{\mathrm{post,Y}}$$

The indices of the parameters in Equation 4-13 include:

- C = Customer class (*e.g.*, residential, small C&I, large C&I) – BCA should use customer-specific values if available.
- Y = Year
- r = Retail Delivery or Connection Point

$\mathrm{ValueOfService}_{\mathrm{C,Y,r}}$ ($/kWh) is the value of electricity service to customers, by customer class, in dollars per unserved kWh at the retail delivery point. The value(s) should be determined based on the customers' willingness to pay for reliability. If location-, customer class- or customer-specific values are not available, these values should default to the retail rate of electricity by customer class.

$\mathbf{AvgDemand_{C,Y,r}}$ **(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.

$\mathbf{\Delta SAIDI_{Y}}$ **(∆hr/cust/yr):** is the change in System Average Interruption Duration Index due to the project. The impact on SAIDI can be determined based on the impact on CAIDI and SAIFI.[47] Baseline system average reliability metrics are available in the Company's annual Electric Service Reliability Reports. A positive value represents a reduction in SAIDI.

$\mathbf{SAIFI_{post,Y}}$ **(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.

$\mathbf{CAIDI_{post,Y}}$ **(hr/int)** is the post-project Customer Average Interruption Duration Index; represents the impact of a project on the average time to restore service in the post-project case. Determining this parameter requires the development of a distribution level model and a respective engineering study to quantify appropriately.

$\mathbf{SAIFI_{base,Y}}$ **(int/cust/yr)** is the baseline (*i.e.*, pre-project) System Average Interruption Frequency Index. It represents the average number of times that a customer experiences an outage per year, excluding major storms. The baseline system-wide value is a five-year average that is available from the annual Electric Service Reliability Reports. This parameter is not necessarily a system-wide value. Rather, it should be representative of the relevant area of the system that the measure, project, or portfolio affects.

$\mathbf{CAIDI_{base,Y}}$ **(hr/int)** is the baseline (*i.e.*, pre-project) Customer Average Interruption Duration Index and represents the impact of a project on the average time to restore service, excluding major storms. The baseline system-wide is a five-year average that is available from the annual Electric Service Reliability Reports. This parameter is not necessarily a system-wide value. Rather, it should be representative of the relevant area of the system that the measure, project, or portfolio affects.

4.3.2.2 General Considerations

The value of the avoided outage cost benefit is customer-specific; the customer class should match or be consolidated properly between the utility and the study area to ensure that the value of reliability matches, what the customer would be willing to pay.

For this version of the BCA Handbook, the outage cost can be estimated by assuming that the customer would be willing to pay the same retail rate they pay for electricity, to avoid an outage. The full retail rate value can be found in the utility's latest tariff by customer class.

[47] SAIDI = SAIFI * CAIDI

Currently, the Standard Interconnection Requirements[48] do not allow for islanding, and therefore limit this configuration to a DER that meets the needs of a customer during an outage. Therefore, there are limited instances where DER allows the customer to supply local load in a blackout and resulting benefits would then be limited to that load picked up by DER.

4.4 External Benefits

4.4.1 Net Avoided CO_2

Net Avoided CO_2 accounts for avoided CO_2 due to a reduction in system load levels[49] or the increase of CO_2 from onsite generation. The CARIS Phase 2 forecast of LBMP contains a cost of carbon based on the Regional Greenhouse Gas Initiative ("RGGI"). Staff will provide a $/MWh adder to account for the net marginal damage cost of carbon that is not already captured in the LBMP. This adder is based on the United States Environmental Protection Agency damage cost estimates for a 3% real discount rate or the results of NYSERDA solicitations for renewable resource attributes. Staff then provides a $/MWh for the full marginal damage cost and the net marginal damage costs of CO_2. The net marginal damage costs are the full marginal damage cost less the cost of carbon embedded in the LBMP.

4.4.1.1 Benefit Equation, Variables, and Subscripts

Equation 4-14 presents the benefit equation for Net Avoided CO_2:

Equation 4-14. Net Avoided CO_2

$$\mathrm{Benefit}_{Y} = \mathrm{CO2Cost\Delta LBMP}_{Y} - \mathrm{CO2Cost\Delta OnsiteEmissions}_{Y}$$

Where,

$$\mathrm{CO2Cost\Delta LBMP}_{Y} = \left(\frac{\Delta \mathrm{Energy}_{Y,r}}{1 - \mathrm{Loss\%}_{Y,b\rightarrow r}} + \Delta \mathrm{Energy}_{\mathrm{TransLosses},Y} + \Delta \mathrm{Energy}_{\mathrm{DistLosses},Y}\right) * \mathrm{NetMarginalDamageCost}_{Y}$$

$$\Delta \mathrm{Energy}_{\mathrm{TransLosses},Y} = \mathrm{SystemEnergy}_{Y,b} * \Delta \mathrm{Loss\%}_{Y,b\rightarrow i}$$

$$\Delta \mathrm{Energy}_{\mathrm{DistLosses},Y} = \mathrm{SystemEnergy}_{Y,b} * \Delta \mathrm{Loss\%}_{Y,i\rightarrow r}$$

$$\Delta \mathrm{Loss\%}_{Z,Y,b\rightarrow i} = \mathrm{Loss\%}_{Z,Y,b\rightarrow i,\mathrm{baseline}} - \mathrm{Loss\%}_{Z,Y,b\rightarrow i,\mathrm{post}}$$

$$\Delta \mathrm{Loss\%}_{Z,Y,i\rightarrow r} = \mathrm{Loss\%}_{Z,Y,i\rightarrow r,\mathrm{baseline}} - \mathrm{Loss\%}_{Z,Y,i\rightarrow r,\mathrm{post}}$$

$$\mathrm{CO2Cost\Delta OnsiteEmissions}_{Y} = \Delta \mathrm{OnsiteEnergy}_{Y} * \mathrm{CO2Intensity}_{Y} * \mathrm{SocialCostCO2}_{Y}$$

---

[48] 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).

[49] The Avoided CO_2 benefit considers the change in energy as a result of the project by including the change in energy identified in the Avoided LBMP, Avoided Transmission Losses, and Avoided Distribution Losses benefits.

The indices of the parameters in Equation 4-14 include:

- Y = Year
- b = Bulk System
- i = Interface of the Transmission and Distribution Systems
- r = Retail Delivery or Connection Point

$\mathbf{CO2Cost\Delta LBMP_{Y}}$ **($)** is the cost of CO_2 due to a change in wholesale energy purchased. A portion of the full CO_2 cost is already captured in the Avoided LBMP benefit. The incremental value of CO_2 is captured in this benefit, and is valued at the net marginal cost of CO_2, as described below.

$\mathbf{CO2Cost\Delta OnsiteEmissions_{Y}}$ **($)** is the cost of CO_2 due to DER that is not emission-free. The cost of carbon for customer-sited emissions is based upon the gross marginal cost of CO_2, as described below.

$\mathbf{\Delta Energy_{Y,r}}$ **(ΔMWh)** is the change in energy purchased at the retail delivery or connection point ("r") as a result of the project. This parameter considers the energy impact at the project location, which is then grossed up to the bulk system level based on the $Loss\%_{b\rightarrow r}$ parameter. A positive value represents a reduction in energy.

$\mathbf{Loss\%_{Y,b\rightarrow r}}$ **(%)** 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.

$\mathbf{\Delta Energy_{TransLosses,Y}}$ **(ΔMWh)** represents the change in electricity lost on the transmission system due to the Avoided Transmission Losses benefit. Refer to Section 4.1.4 for more details. In most cases, unless the transmission system loss percent is altered due to a project or portfolio, this parameter will be zero. A positive value represents a reduction in energy lost in transmission system losses.

$\mathbf{\Delta Energy_{DistLosses,Y}}$ **(ΔMWh)** represents the change in energy lost on the distribution system due to the Avoided Distribution Losses benefit. Refer to Section 4.2.3 for more details. In most cases, unless the distribution system loss percent is altered due to a project or portfolio, this parameter will be zero. A positive value represents a reduction in energy lost in distribution system losses.

$\mathbf{NetMarginalDamageCost_{Y}}$ **($/MWh)** is the "adder" Staff will provide to account for the full marginal damage cost of carbon that is not already captured in the forecast of LBMP from CARIS. The LBMP forecast from CARIS includes the cost of carbon based on the RGGI but does fully reflect the SCC.

$\mathbf{\Delta Loss\%_{Z,Y,b\rightarrow i}}$ **(Δ%)** is the change in fixed and variable loss percent between the interface of the bulk system ("b") and the interface between the transmission and distribution systems ("i"). This represents the change in the transmission system loss factor. This value would typically be determined in a project-specific engineering study.

$\mathbf{Loss\%_{Z,Y,b\rightarrow i,baseline}}$ **(%)** is the baseline fixed and variable loss percent between the interface of the bulk system ("b") and the interface between the transmission and distribution systems ("i"). Thus, this reflects the transmission loss percent pre-project, which is found in Table A-2.

$\mathbf{Loss\%_{Z,Y,b \to i,post}}$ **(%)** is the post-project fixed and variable loss percent between the interface of the bulk system ("b") and the interface between the transmission and distribution systems ("i"). Thus, this reflects the transmission loss percent post-project, which is found in Table A-2.

$\mathbf{\Delta Loss\%_{Z,Y,i \to r}}$ **(∆%)** is the change in fixed and variable loss percent between the interface of the transmission and distribution systems ("i") and the retail delivery point ("r") resulting from a project that changes the topology of the distribution system. This represents the change in the distribution system loss factor. This value would typically be determined in a project-specific engineering study.

$\mathbf{Loss\%_{Z,Y,i \to r,baseline}}$ **(%)** is the baseline fixed and variable loss percent between the interface of the transmission and distribution systems ("i") and the retail delivery point ("r"). Thus, this reflects the distribution loss percent pre-project, which is found in Table A-2.

$\mathbf{Loss\%_{Z,Y,i \to r,post}}$ **(%)** is the post-project fixed and variable loss percent between the interface of the transmission and distribution systems ("i") and the retail delivery point ("r"). Thus, this reflects the distribution loss percent post-project, which is found in Table A-2.

$\mathbf{\Delta OnsiteEnergy_Y}$ **(∆MWh)** is the energy produced by customer-sited carbon-emitting generation.

$\mathbf{CO2Intensity_Y}$ **(metric ton of CO_2 / MWh)** is the average CO_2 emission rate of customer-sited pollutant-emitting generation. This is a project-specific input based on the type of onsite generation (1 metric ton is the equivalent of 1.10231 short tons).

$\mathbf{SocialCostCO2_Y}$ **(\$ / metric ton of CO_2)** is an estimate of the total monetized damages to society associated with an incremental increase in carbon dioxide emissions. Annual values are provided by EPA (using the 3% real discount rate) or derived from the results of NYSERDA solicitations for renewable resources attributes. EPA estimates of this cost (using a 3 percent discount rate) may be used in as part of any sensitivity analyses.

4.4.1.2 General Considerations

The equation above represents two sources of emissions based on: (1) a change in LBMP purchases, which is valued at the \$/MWh adder (*i.e.*, $NetMarginalDamageCost_Y$ parameter above) to be provided by Staff, and (2) customer-sited carbon emissions from onsite generation (*e.g.*, such as combined heat and power ("CHP")), which is valued based on the results of NYSERDA solicitations for renewable resources attributes.

The energy impact is project-specific and should be linked to the impacts determined in the Avoided LBMP benefit. The LBMP impacts due to the Avoided Transmission Losses and Avoided Distribution Losses benefits also need to be account for when determining the total change in LBMP due to a project. It is assumed that the benefit value due to an impact on emissions is accrued in the same year as the impact.

The *BCA Order* indicates "utilities shall rely on the costs to comply with New York's Clean Energy Standard once those costs are known."[50]

[50] REV Proceeding, BCA Order, Appendix C, p. 16.

4.4.2 Net Avoided SO_2 and NO_x

Net Avoided SO_2 and NO_x includes the incremental value of avoided or added emissions. The LBMP already includes the cost of pollutants (*i.e.*, SO_2 and NO_x) as an “internalized” cost from the Cap & Trade programs. Emitting customer-sited generation <25 MW will be included in this benefit since the generators do not participate in the Cap & Trade programs.

4.4.2.1 Benefit Equation, Variables, and Subscripts

Equation 4-15 presents the benefit equation for Net Avoided SO_2 and NO_x:

Equation 4-15. Net Avoided SO_2 and NO_x

$$\mathrm{Benefit}_{\mathrm{Y}} = \sum_{\mathrm{p}} \mathrm{OnsiteEmissionsFlag}_{\mathrm{Y}} * \mathrm{OnsiteEnergy}_{\mathrm{Y,r}} * \mathrm{PollutantIntensity}_{\mathrm{p,Y}} * \mathrm{SocialCostPollutant}_{\mathrm{p,Y}}$$

The indices of the parameters in Equation 4-15 include:

- p = Pollutant (SO_2, NO_x)
- Y = Year
- r = Retail Delivery or Connection Point

$\mathbf{OnsiteEmissionsFlag_{Y}}$ is a binary (*i.e.*, 0 or 1) parameter, where a value of 1 indicates that customer-sited pollutant-emitting generation <25 MW will be included in the analysis as a result of the project.

$\mathbf{OnsiteEnergy_{Y,r}}$ **(ΔMWh)** is the energy produced by customer-sited pollutant-emitting generation.

$\mathbf{PollutantIntensity_{p,Y}}$ **(ton/MWh)** is average pollutant emissions rate of customer-sited pollutant-emitting generation. This is a project-specific input.

$\mathbf{SocialCostPollutant_{p,Y}}$ **($/ton)** is an estimate of the monetized damages to society associated with an incremental increase in pollutant emissions in a given year. The allowance prices are provided in CARIS Phase 2

4.4.2.2 General Considerations

LBMPs already include the cost of pollutants (*i.e.*, SO_2 and NO_x) as an “internalized” cost from the Cap & Trade programs. Emitting customer-sited generation <25 MW will be included in this benefit since the generators do not participate in the Cap & Trade programs. This would be a benefit to the extent that the DER emits less than NYISO generation, and a negative benefit for the DER if it has a higher emissions rate than NYSO generation or emissions –free DER.

Two values are provided in CARIS for NO_x costs: “Annual NO_x” and “Ozone NO_x.” Annual NO_x prices are used October through May; Ozone NO_x prices May through September. The breakdown of energy in these two time periods must be accounted for and applied to the appropriate NO_x cost.

It is assumed that the benefit value due to an impact on emissions is accrued in the same year as the impact.

4.4.3 Avoided Water Impact

A suggested methodology for determining this benefit is not included in this version of the Handbook. This impact would be assessed qualitatively in the SCT.

4.4.4 Avoided Land Impact

A suggested methodology for determining this benefit is not included in this version of the Handbook. This impact would be assessed qualitatively in the SCT.

4.4.5 Net Non-Energy Benefits Related to Utility or Grid Operations

A suggested methodology for determining this benefit is not included in this version of the Handbook. This impact would be assessed qualitatively or if can be estimated quantitatively. It is necessary to identify which cost-effectiveness test should include the specific benefit or cost as it may apply to the SCT, UCT and/or RIM.

4.5 Costs Analysis

4.5.1 Program Administration Costs

Program Administration Costs includes the cost to administer and measure the effect of required program administration performed and funded by utilities or other parties. This may include the cost of incentives, measurement and verification, and other program administration costs to start, and maintain a specific program. The reduced taxes and rebates to support certain investments increase non-participant costs.

4.5.1.1 Benefit Equation, Variables, and Subscripts

Equation 4-16 presents the cost equation for Program Administration Costs:

Equation 4-16. Program Administration Costs

$$\mathrm{Cost}_{\mathrm{Y}} = \sum_{\mathrm{M}} \Delta\mathrm{ProgramAdminCost}_{\mathrm{M,Y}}$$

The indices of the parameters in Equation 4-16 include:

- M = Measure
- Y = Year

$\Delta\mathrm{ProgramAdminCost}_{M,Y}$ 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.”[51]

The acquisition of most DERs in the near term will be through competitive solicitations rather and standing tariffs. The BCA Order requires a fact specific basis for quantifying costs that are considered in

[51] REV Proceeding, Order Adopting Regulatory Policy Framework and Implementation Plan (issued February 26, 2015)(“Track One Order”), p. 33.

any SCT evaluation[52]. 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").[53] In this study, E3 used cost data provided by NYSERDA based on solar PV systems that were installed in NY from 2003 to 2015. This is just one example of evaluating the potential cost of solar PV technology. The Company would need to incorporate service territory specific information when developing its technology benchmarks. For a project-specific cost analysis, actual estimated project costs would be used.

Table 4-1. Solar PV Example Cost Parameters

Parameter	Cost
Installed Cost (2015$/kW-AC)[54]	4,430
Fixed Operating Cost ($/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.
2. **Fixed Operating Cost:** E3's estimate of O&M for a residential PV panel in 2015. This estimate is applied to all New York electric utilities in the NYSERDA paper.

[52] REV Proceeding, BCA Order, Appendix C, p. 18.

[53] 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).

[54] 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.

4.5.4.2 CHP Example

The CHP system used in this example is a 100 kW capacity natural gas-fired engine unit sized for commercial thermal load following applications. For this illustration cost parameter values were obtained from the EPA's Catalog of CHP Technologies[55] for this baseload CHP example based on estimations of representative system costs. There are many site-specific factors that can affect cost parameters that are not examined in this example including: property tax, local permitting, gas and electric interconnection costs, local emissions constraints and possible structural requirements. Natural gas costs would need to be considered for the natural-gas fired CHP system. All these elements would need to be reviewed and incorporated to develop the Company's service territory technology specific benchmarks.

Table 4-2. CHP Example Cost Parameters

Parameter	Cost
Installed Capital Cost ($/kW)	3,000
Variable Operating Cost ($/kWh)	0.025

Note: This illustration would change as projects and locations are considered.

1. **Capital and Installation Cost:** EPA's estimate of a reciprocating engine CHP system capital cost. This includes of the project development costs associated with the system including equipment, labor and process capital. [56]
2. **Variable:** EPA's estimate of a 100 kW reciprocating engine CHP system's non-fuel O&M costs.[57]

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[58]

Note: This illustration would change as projects and locations are considered.

---

[55] United States Environmental Protection Agency and Combined Heat and Power Partnership, *Catalog of CHP Technologies* (EPA Catalog of CHP Technologies")(March 2015). https://www.epa.gov/chp/catalog-chp-technologies.

[56] EPA CHP Report. pg. 2-15.

[57] EPA CHP Report. pg. 2-17.

[58] 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 suggested methodology for determining this benefit is not included in this version of the Handbook. In cases where non-energy impacts are attributable to the specific project or program, they may be assessed qualitatively. Net Non-Energy Costs may be applicable to any of the cost-effectiveness tests defined in the *BCA Order* depending on the specific project and non-energy impact.

5. CHARACTERIZATION OF DER PROFILES

This section discusses the characterization of DERs using several examples and presents the type of information necessary to assess associated benefits. Four *DER categories* are defined to provide a useful context, and specific example technologies within each category are selected for examination. The categories are: *intermittent*, *baseload*, *dispatchable* and *load reduction*. There are numerous potential examples of individual DERs within each category, varying by technology, size, location, customer application, and other factors. A single example DER was selected in each of the four categories to illustrate specific BCA values, as shown in Table 5-1 below. These four examples cover a useful, illustrative range of impacts that DERs can have on the various benefit and cost categories in the BCA Handbook.

Table 5-1. DER Categories and Examples Profiled

DER Category	DER Example Technology
Intermittent	Solar PV
Baseload	CHP
Dispatchable	Controllable Thermostat
Load Reduction	Energy Efficient Lighting

The DER technologies selected as examples are shown in Table 5-2. Each DER technology has unique operating characteristics that allow it to accrue some benefits and costs but not others. In some cases, the ability of a DER to provide certain benefits and incur certain costs will be driven by the operational objective of the specific DER, not the intrinsic characteristics of the technology itself. For example, DR technology in one situation may be operated to reduce the NYISO peak, which may or may not coincide with a distribution feeder peak where it is installed. Another DR technology may be operated to provide support for a distribution NWA, in which the distribution feeder or substation may not have a peak load that coincides with the NYISO peak. Thus, the operational objectives of the DR technology would result in different estimates of benefits and costs depending on this operational objective. Key attributes of the example DER technologies are provided in Table 5-2.

Table 5-2. Key Attributes of Selected DER Technologies

Resource	Attributes
Photovoltaic (PV)	PV is an intermittent resource with energy output determined by solar irradiance. The directional orientation and vertical angle of PV panels are important considerations for determining energy output and thus the corresponding coincidence factors with system-wide or local power delivery. PV energy output may also degrade over time.
Combined Heat and Power (CHP)	CHP is a resource typically sized to meet a customer's thermal energy requirements, but which also provides electrical energy. The particular customer's characteristics determine the ability of CHP to contribute to various benefit and cost categories.
Energy Efficiency (EE)	EE reduces the energy consumption for delivery of a particular service (use) without degrading or reducing the level of service delivered.
Demand Response (DR)	DR reduces energy demand for a particular service (use) during specific hours of the day—typically peak demand hours—without reducing the service to an unacceptable level. DR is typically available only for limited hours in a year (*e.g.*, <100 hrs). The operational objective of the DR determines how it may contribute to various benefit and cost categories.

Each example DER can enable a different set of benefits and incurs a different set of costs, as illustrated in Table 5-3.

Table 5-3. General applicability for each DER to contribute to each Benefit and Cost

#	Benefit/Cost	PV	CHP	DR	EE
	Benefits				
1	Avoided Generation Capacity Costs	●	●	●	●
2	Avoided LBMP	●	●	●	●
3	Avoided Transmission Capacity Infrastructure	◒	◒	◒	◒
4	Avoided Transmission Losses	○	○	○	○
5	Avoided Ancillary Services	○	○	○	○
6	Wholesale Market Price Impacts	○	○	○	○
7	Avoided Distribution Capacity Infrastructure	◒	◒	◒	◒
8	Avoided O&M	○	○	○	○
9	Avoided Distribution Losses	○	○	○	○
10	Net Avoided Restoration Costs	○	○	○	○
11	Net Avoided Outage Costs	○	◒	○	○
12	Net Avoided CO_2	●	●	●	●
13	Net Avoided SO_2 and NO_x	●	●	●	●
14	Avoided Water Impacts	○	○	○	○
15	Avoided Land Impacts	○	○	○	○
16	Net Non-Energy Benefits	○	○	○	○
	Costs				
17	Program Administration Costs	●	●	●	●
18	Added Ancillary Service Costs	○	○	○	○
19	Incremental T&D and DSP Costs	◒	◒	◒	○
20	Participant DER Cost	●	●	●	●
21	Lost Utility Revenue	●	●	●	●
22	Shareholder Incentives	●	●	●	●
23	Net Non-Energy Costs	○	○	○	○

Note: This is general applicability and project-specific applications may vary.

● Generally applicable ◒ May be applicable ○ Limited or no applicability

As described in Section 4, each quantifiable benefit typically has two types of parameters. The defined benefits established to monetize the value are generally unaffected by the DER being analyzed in the BCA (*e.g.*, AGCC in $ per MW-yr), however key parameters related to the magnitude of underlying benefit and may vary by type of DER (*e.g.*, system coincidence factor). In other words, the amount of the underlying value captured by the DER resource is driven by the key parameters. Table 5-4 identifies the parameters which are necessary to characterize DER benefits. As described in Section 4, several benefits potentially applicable to DER require further investigation and project-specific information before their impacts can be incorporated into a BCA (*e.g.*, Avoided O&M, Net Avoided Restoration Costs and Net Avoided Outage Costs, and Avoided Ancillary Services).

Table 5-4. Key Parameter for Quantifying how DER May Contribute to Each Benefit

#	Benefit	Key Parameter
1	Avoided Generation Capacity Costs	SystemCoincidenceFactor
2	Avoided LBMP	∆Energy (time-differentiated)
3	Avoided Transmission Capacity Infrastructure	TransCoincidenceFactor
4	Avoided Transmission Losses	Limited or no applicability
5	Avoided Ancillary Services	Limited or no applicability
6	Wholesale Market Price Impacts	∆Energy (annual) ∆AGCC
7	Avoided Distribution Capacity Infrastructure	DistCoincidenceFactor
8	Avoided O&M	Limited or no applicability
9	Avoided Distribution Losses	Limited or no applicability
10	Net Avoided Restoration Costs	Limited or no applicability
11	Net Avoided Outage Costs	Limited or no applicability[59]
12	Net Avoided CO_2	CO_2Intensity (limited to CHP)
13	Net Avoided SO_2 and NO_x	PollutantIntensity (limited to CHP)
14	Avoided Water Impacts	Limited or no applicability
15	Avoided Land Impacts	Limited or no applicability
16	Net Non-Energy Benefits	Limited or no applicability

Table 5-5 further describes the key parameters identified in Table 5-4.

[59] 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.[60] 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[61]	Necessary to calculate the Avoided Transmission Capacity Infrastructure benefit. It quantifies a project's contribution to reducing a transmission system element's peak demand relative to the project's expected maximum demand reduction capability. This would be evaluated on localized basis in most cases, but in some instances an assessment of coincidence with a system coincidence factor would be appropriate.
Distribution Coincidence Factor	Distribution coincidence factor is required to calculate the Avoided Distribution Capacity Infrastructure benefit. It captures the contribution to the distribution element's peak relative to the project's expected maximum demand reduction capability. This would be evaluated on localized basis in most cases, but in some instances an assessment of coincidence with a system coincidence factor would be appropriate.
CO_2 Intensity	CO_2 intensity is required to calculate the Net Avoided CO_2 benefit. This parameter is dependent on the type of DER being evaluated – emission-free or emission-generating. It is the average CO_2 emission rate of customer-sited pollutant-emitting generation. This is a project-specific input based on the type of onsite generation.
Pollutant Intensity	Pollutant intensity is required to calculate the Net Avoided SO_2 and NO_X benefit. This parameter is dependent on the type of DER being evaluated – emission-free or emission-generating. It is the average SO_2 and/or NO_X emission rate of customer-sited pollutant-emitting generation. This is a project-specific input based on the type of onsite generation.
∆Energy (time-differentiated)	This parameter measures the change in bulk system energy consumed as a result of specific DER project implementation. This value is reliant on project-specific details including location. The ∆Energy is dependent on the type of DER (*e.g.*, intermittent vs. baseload), and how the DER would be operated (*e.g.*, load reduction vs. energy conservation vs. backup generation). Thus, the ∆Energy is time-differentiated. It may be appropriate to use an annual average value for some DER, while for others it may be more appropriate to use an average on-peak hours of operation, or even hourly operation. In each case the corresponding LBMP data would be required to value the benefit. The examples provided herein discuss potential approaches to consider time-differentiation by DER type.[62]

[60] This parameter is also used to calculate the Wholesale Market Price Impact benefit.

[61] 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.

[62] 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
2011	7/22/2011	Hour Ending 5 PM
2012	7/17/2012	Hour Ending 3 PM
2013	7/19/2013	Hour Ending 6 PM
2014	9/2/2014	Hour Ending 5 PM
2015	7/29/2015	Hour Ending 5 PM
2016	8/11/2016	Hour Ending 5 PM
2017	7/19/2017	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

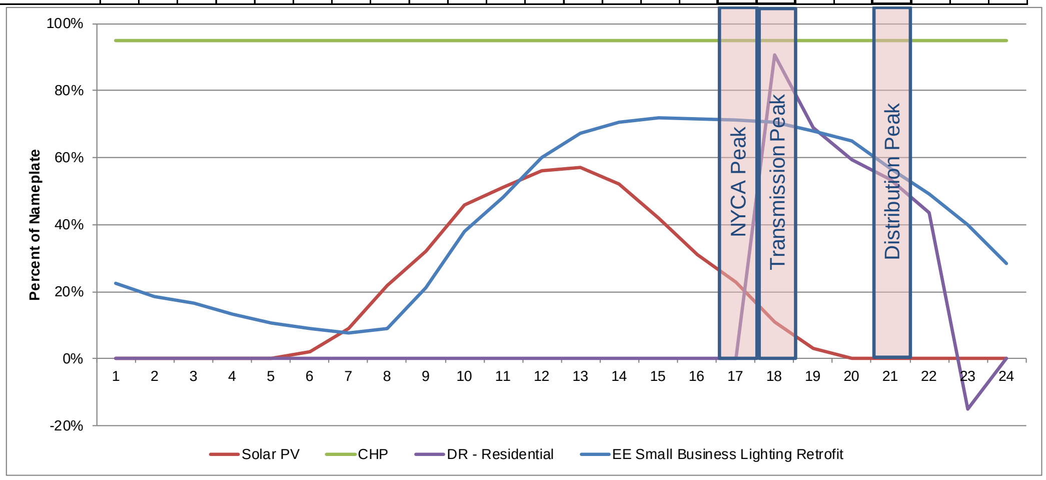
There are multiple approaches for estimating coincidence factors that apply different levels of rigor. Rigorous approaches could be defined and applied across a range of DERs; however, such an approach is likely to require a significant amount of granular information (*e.g.*, 8760 hour load shapes for 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

	Hour Ending																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Solar PV	0%	0%	0%	0%	0%	2%	9%	22%	32%	46%	51%	56%	57%	52%	42%	31%	23%	11%	3%	0%	0%	0%	0%	0%
CHP	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
DR - Residential	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	91%	69%	59%	53%	43%	-15%	0%
EE Small Business Lighting Retrofit	23%	19%	17%	13%	11%	9%	8%	9%	21%	38%	48%	60%	67%	71%	72%	71%	71%	71%	68%	65%	57%	49%	40%	29%



Source: Consolidated Edison Company of New York

Individual DER example technologies have been selected as examples and are discussed below.[63]

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")[64] 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.

[63] 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.

[64] The Benefits and Costs of Net Energy Metering in New York, Prepared for: New York State Energy Research and Development Authority and New York State Department of Public Service, December 11, 2015.

5.3 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.

5.3.2 Benefit Parameters

The benefit parameters in Table 5-7 for the intermittent solar PV example are based on information provided in the E3 Report.

E3 determined utility-specific average values for coincidence and capacity factors. The statewide weighted-averages based on electricity delivered by utility are provided in Table 5-7. These values are illustrative estimates that may be refined as more data becomes available. To determine project-specific benefit values, hourly simulations of solar generation, peak hours, and energy prices (LBMP) would need to be calculated based on the project's unique characteristics. Similarly, utility and location-specific specific information would be needed. For example, the distribution coincidence factor can vary significantly depending on time of the feeder and substation peak.

Table 5-7. Solar PV Example Benefit Parameters

Parameter	Value
SystemCoincidenceFactor	36%
TransCoincidenceFactor	8%
DistCoincidenceFactor	7%
ΔEnergy (time-differentiated)	Hourly

Note: This illustration would change as specific projects and locations are considered.

1. **SystemCoincidenceFactor:** This value represents the 'effective' percent of the nameplate capacity, 4 kW-AC, that reduces the system peak demand, resulting in an avoided generation capacity benefit. The 36% calculated from results of the E3 Report aligns with the coincidence values presented in the NYISO ICAP manual, which provides a range from 26%-43% depending on system azimuth and tilt angle.[65] 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.[66] 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. **∆Energy (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.

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").[67]

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

---

[65] NYISO ICAP Manual 4, June 2016 – Summer Unforced Capacity Percentage – Solar (Fixed Tilt Arrays) – pg. 4-23

[66] 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.

[67] https://www.epa.gov/chp/catalog-chp-technologies

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.[68]

The carbon and criteria pollutant intensity can be estimated using the EPA's publically-available CHP Emissions Calculator.[69] "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
CO_2Intensity (metric ton CO_2/MWh)	0.141
PollutantIntensity (metric ton NO_X/MWh)	0.001
∆Energy (time-differentiated)	Annual average

Note: This illustration would change as specific projects and locations are considered.

1. **SystemCoincidenceFactor:** The system coincidence factor is 0.95 under the assumption that the CHP system is always running apart from downtime for maintenance or during forced outages.
2. **TransCoincidenceFactor:** The transmission coincidence factor is 0.95 under the assumption that the CHP system is always running apart from downtime for maintenance or during forced outages.
3. **DistCoincidenceFactor:** The distribution coincidence factor is 0.95 under the assumption that the CHP system is always running apart from downtime for maintenance or during forced outages.
4. **CO_2Intensity:** This value was the output of EPA's calculator, provided in tons/year and then converted to metric ton/MWh as required for input into the BCA (Section 4.4.1).
5. **PollutantIntensity:** This value was the output of EPA's calculator, provided in tons/year and then converted to metric ton/MWh as required for input into the BCA (Section 4.4.2). There are no SO_2 emissions from burning natural gas.
6. **∆Energy (time-differentiated):** Assuming the CHP is used as a baseload resource, with the exception of downtime for maintenance, capacity factor is 95%. Because it is not possible to predict when the downtime may occur, using annual average LBMP would be appropriate.

[68] EPA CHP Report. pg. 2-20.

[69] EPA CHP Emissions Calculator https://www.epa.gov/chp/chp-emissions-calculator.

5.5 Demand Response Example

DR depicts an example of a **dispatchable** DER where the resource can be called upon to respond to peak demand.

5.5.1 Example System Description

The system dispatchable DR technology described herein is a programmable and controllable thermostat in a residence with central air conditioning that is participating in a direct load control program.

DR is a dispatchable DER because it is reduces demand on request from the system operator or utility.[70] 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.[71] This DR example is specifically for a DR event called for five hours between the hours of 5pm and 10pm. The coincidence factors can and will change based on when DR event is called, customer response (*e.g.,* overrides), device availability, load availability, and other project and technology- specific factors. Care should be taken to consider all these factors when determining appropriate coincidence factors for projects and portfolios.

The value of reduced energy use attributable to the DR asset can be calculated using the average LBMP of the top 50 hours of system peak. A more accurate energy calculation would consider the expected number of times that DR was called in a given year as well as the length of the calls beyond the peak hour itself (*e.g.*, 2 hour events, 4 hour events). This calculation will differ if the DR asset is intended to defer another peak, or if the DR program has a substantially different frequency of calls. The number of hours averaged should be based on the frequency of DR calls and the selection of those hours should be based on when the DR calls will be made.

5.5.2 Benefit Parameters

The benefit parameters described here are assumed based on the example and considerations described above. Coincidence factors might differ based on the call windows of the DR resource being evaluated.

Table 5-9. DR Example Benefit Parameters

Parameter	Value
SystemCoincidenceFactor	0.0
TransCoincidenceFactor	0.91
DistCoincidenceFactor	0.53

[70] Some DR programs may be “dispatched” or scheduled by third-party aggregators.

[71] Specifically from the July 15 – 19, 2013 heat wave

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 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.

5.6.1 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.

5.6.2 Benefit Parameters

The benefit parameters described here are based on Con Edison experience with small commercial lighting projects.

Table 5-10. EE Example Benefits Parameters

Parameter	Value
SystemCoincidenceFactor	0.71
TransCoincidenceFactor	0.71
DistCoincidenceFactor	0.57
∆Energy (time-differentiated)	~9 am to ~10 pm weekdays

Note: This illustration would change as specific projects and locations are considered.

1. **SystemCoincidenceFactor:** The system coincidence factor is 0.71 based on a recent Con Edison meter study as illustrated in Figure 5-1. The factor is highly dependent on the technology, customer type, as well as timing of the system peak.
2. **TransCoincidenceFactor:** The transmission coincidence factor is 0.71 based on a recent Con Edison meter study as illustrated in Figure 5-1. The factor is highly dependent on the technology, customer type, as well as timing of the transmission peak..
3. **DistCoincidenceFactor:** The distribution coincidence factor is 0.57 based on a recent Con Edison meter study as illustrated in Figure 5-1. The factor is highly dependent on the technology, customer type, as well as timing of the distribution peak.
4. **∆Energy (time-differentiated):** This value is calculated using the lighting hours per year, divided by the total hours in a year (8,760). This time period is subject to building operation, which, in this example is assumed between 9 am and 10 pm, 6 days a week, 50 weeks a year. This would define the corresponding period for determining an average LBMP that would be used to calculate the benefit.

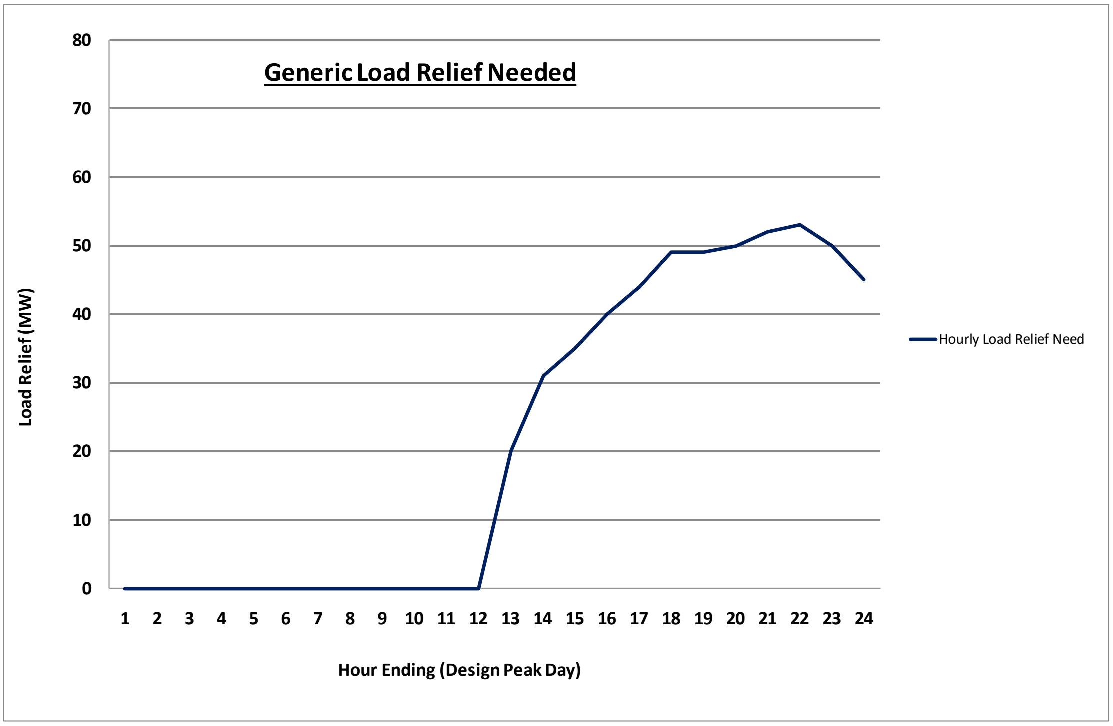
5.7 Portfolio Example

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.

5.7.1 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.

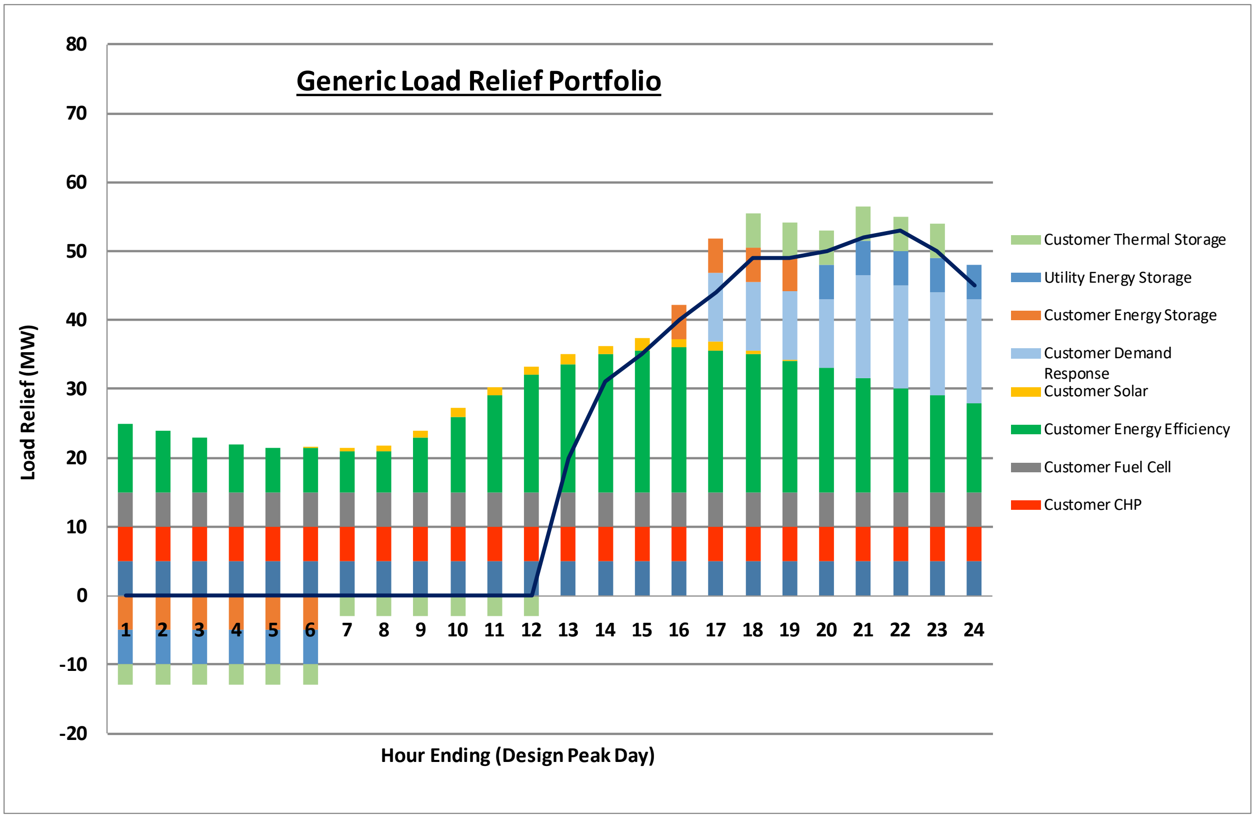
Figure 5.2. Location Load Relief Requirement



5.7.2 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 opportunity, reflecting that the detailed project schedule from contract execution to implementation and completion of projects is important for determination of feasibility.
7. Community Impacts - The positive or negative impact that the proposed solution may have on the community in the identified area (*e.g.*, noise, pollution).

8. Customer Acquisition - The extent to which a respondent's proposed solution fits into the needs of the targeted network(s), the customer segment of the targeted network(s) and the customer acquisition strategy (Preliminary customer commitments from applicable customers are highly desirable.)
9. Availability and Reliability - The ability of the proposed solution to provide permanent or temporary load relief will be considered, along with the dependability and benefits that would be provided to the grid.
10. Innovation – Innovative solution that (i) targets customers and uses technologies that are currently not part of Con Edison's existing programs, (ii) targets generally underserved customer segments, and/or (iii) is based on the use of advanced technology that helps foster new DER markets and provides potential future learnings.

APPENDIX A. UTILITY-SPECIFIC ASSUMPTIONS

This section includes utility-specific data. Each data point represents a parameter that is used throughout the benefit and cost methodologies described in Section 4.

The discount rate is set by the utility cost of capital, which is included in Table A-1.

Table A-1. Utility Weighted Average Cost of Capital

Regulated Rate of Return
7.1% for 2016, 7.06% for 2017
Source: ORU Rate Case 14-E-0493

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. The average loss percent and peak loss percent are assumed to be equal.

Table A-2. Utility Loss Data

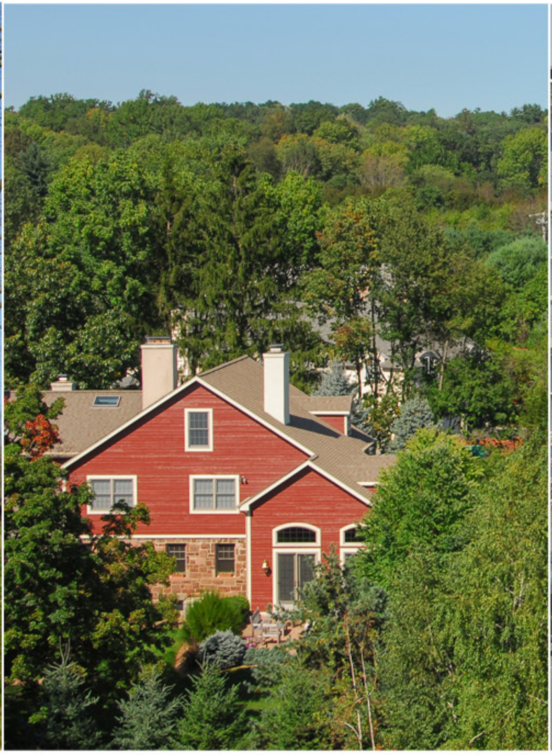
System	Variable Loss Percent	Fixed Loss Percent
Transmission	1.3%	.4%
Primary Distribution	1.08%	0%
Secondary Distribution (with transformers)	.89%	.97%
Source: ORU study for NY PSC Case 08-E-0751		

\

Utility-specific system average marginal costs of service are found in Table A-3

Table A-3. Utility System Average Marginal Costs of Service

Year	Transmission Costs Excluding TCCs ($ per kW)	Area Station and Sub-transmission Costs ($ per kW)	System Weighted Primary Feeder Costs ($ per kW)
2016	11.76	32.92	17.14
2017	20.82	31.13	17.65
2018	33.14	24.21	18.18
2019	37.87	30.7	18.72
2020	17.53	48.57	19.29
2021	18.06	38.26	19.87
2022	18.6	39.44	20.46
2023	19.16	31.7	21.08
2024	19.73	28.19	21.71
2025	20.33	52.25	22.36
2026	20.94	82.11	23.03
2027	21.56	30.71	23.72
2028	22.21	29.28	24.43
2029	22.88	32.32	25.16
2030	23.56	65.49	25.92
2031	24.27	66.65	26.7
2032	25	64.51	27.5




FOLEY'S GOSHEN HARDWARE