Central Hudson Distributed System Implementation Plan

Revised June 30, 2023

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Central Hudson

A FORTIS COMPANY

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Acronyms and Abbreviations

Acronyms and abbreviations are used extensively throughout this report and are presented here for ease of reference.

ACRONYM	DEFINITION
ADMS	Advanced Distribution Management System
ALT	Automatic Load Transfer
AMI	Advanced Metering Infrastructure
AREGCB	Accelerated Renewable Energy Growth and Community Benefit Act
ASCR	Aluminum Conductor Steel-Reinforced Cable
BESS	Battery Energy Storage System
BEV	Battery Electric Vehicle
BCA	Benefit Cost Analysis
CAC	Climate Action Council
CCA	Community Choice Aggregators
CDD	Cooling Degree Days
Central Hudson (Company)	Central Hudson Gas and Electric Corporation
CEII	Critical Energy Infrastructure Information
CESIR	Coordinated Electric System Interconnection Review
CGPP	Coordinated Grid Planning Process
CHP	Combined Heat and Power

CIP	Critical Infrastructure Protection
CIS	Customer Information System
CLCPA	Climate Leadership and Community Protection Act
Commission or PSC	Public Service Commission
CVR	Conservation Voltage Reduction
DA	Distribution Automation
DAF	Data Access Framework
DCFC	Direct Current Fast Charger
DERs	Distributed Energy Resources
DLP	Data Loss Prevention
DMS	Distribution Management System
DPS	Department of Public Service
DR	Demand Response
DRV	Demand Reduction Value
DSCADA	Distribution Supervisory Control and Data Aquisition
DSIP	Distributed System Implementation Plan
DSO	Distribution System Operations
DSP	Distributed System Platform

EAM	Earnings Adjustment Mechanism
EDI	Electronic Data Interchange
EE	Energy Efficiency
EMS	Energy Management System
EPRI	Electric Power Research Institute
ESCO	Energy Service Companies
EV	Electric Vehicle
EVSE	Electric Vehicle Supply Equipment
FAT	Factory Acceptance Testing
FERC	Federal Energy Regulatory Commission
FLISR	Fault Location, Isolation, and Service Restoration
GAPP	Generally Accepted Privacy Principles
GHG	Greenhouse Gas
GIS	Geographic Information System
HDD	Heating Degree Days
IED	Intelligent Electronic Device
IEDR	Integrated Energy Data Resource
IEEE	Institute of Electric and Electronics Engineers
IOAP	Interconnection Online Application Portal

IPV	Initial Public Viewing
IPWG	Interconnection Policy Working Group
ISM	Integrated System Model
ITWG	Interconnection Technical Working Group
JU	Joint Utilities
JUNY	Joint Utilities of New York
LSC	Load Serving Capabilities
LSRV	Locational System Relief Value
M&V	Measurement & Verification
MDM	Meter Data Management
MVP	Minimum Viable Product
NERC	North American Electric Reliability Corporation
NIST	National Institute of Standards and Technology
NMS	Network Monitoring System
NOPR	Notice of Proposed Rulemaking
NWA/NWS	Non-wire Alternative/Non-wire Solution
NYISO	New York Independent System Operator
NYSERDA	New York State Energy Research & Development Authority

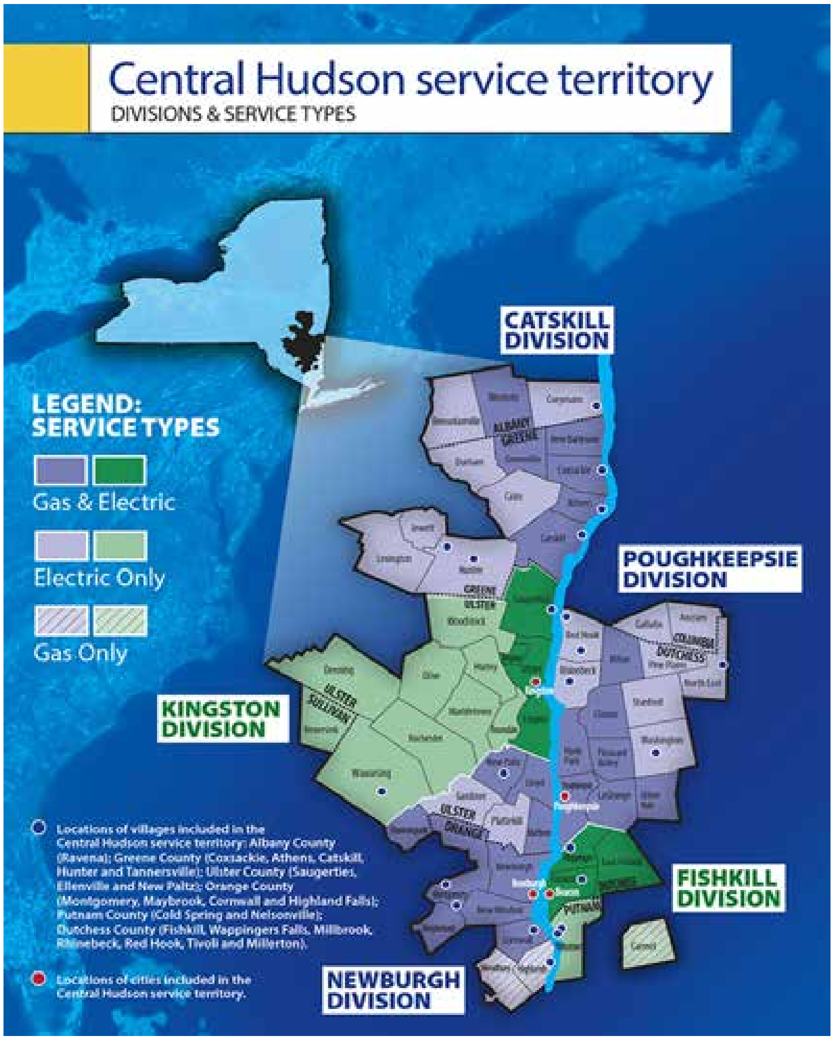
NYSSIR	New York State Standardized Interconnection Requirements
NYTO	New York Transmission Owner
O&M	Operations and Maintenance
OMS	Outage Management System
OTS	Operator Training Simulator
PCC	Primary Control Center
PDS	Program Development System
PHEV	Plugin Hybrid Electric Vehicle
PSC	Public Service Commission
PV	Photovoltaic
QAS	Quality Assurance System
REV	Reforming the Energy Vision
SAT	System Acceptance Testing
SCADA	Supervisory Control and Data Acquisition
SIR	Standardized Interconnection Requirements
T&D	Transmission and Distribution
UBP	Uniform Business Practices
UTEN	Utility Thermal Energy Network
VDER	Value of Distributed Energy Resources

VVO	Volt/VAr Optimization

I. Executive Summary

Central Hudson Gas and Electric Corporation (Central Hudson or Company) is a regulated gas and electric utility serving the Mid-Hudson Valley of New York State. The Company provides electric and gas transmission and distribution (T&D) services to approximately 309,000 electric customers and 84,000 natural gas customers. Figure 1 illustrates the Central Hudson territory, which extends from the suburbs of metropolitan New York City north to the Capital District at Albany, covering approximately 2,600 square miles. The electric system is comprised of approximately 9,400 miles of transmission and distribution lines.

Figure 1: Central Hudson Service Territory



As a result of slowdowns in the regional and state economy (not related to COVID-19), energy efficiency (EE) programs, and the integration of primarily small-scale photovoltaic (PV) systems, the electric system peak remains flat or declining in recent years. The actual system peak in 2022 was 1,109 MW. Due to the continued forecasted economic weakness in the Hudson Valley, the normalized peak forecast for 2028 is projected to be 1,116 MW; when the effects of DER and electrification are included the system peak drops to 1,068 MW. For comparison, Central Hudson's all-time electric system peak demand of 1,295 MW was set in 2006. As a result of the observed and forecasted reduction in system demand growth, the Company's electric capital expenditures remain focused on replacing existing infrastructure based on condition assessment and Grid Modernization efforts.

The Company has continued its efforts in implementing several large-scale transformational projects designed to improve the intelligence of its system and provide tangible benefits to its customers. These efforts include the installation of a Distribution Management System (DMS), increased levels of Distribution Automation (DA), and an enterprise Network Strategy communication system that allows field devices to communicate with corporate operational technology assets, including the DMS and the Energy Management System (EMS). The transformation of its Customer Information System, called Project Phoenix, has also been a major effort to bring additional functionality to Central Hudson's business processes with the aim of improving the customer experience, supporting emerging customer expectations, and laying the groundwork for future capabilities compelled by the CLCPA. These deployments were approved in the Company's prior rate cases and are foundational to meet the targets of the Climate Leadership and Community Protection Act (CLCPA) and Reforming the Energy Vision (REV).

Finally, the Company has completed an expansion of its existing Primary Control Center in 2019 to accommodate the growing needs of the Distribution System Operation Center and is implementing the design and construction of a new Primary Control Center that will be able to fully accommodate the needs of the Distribution System Operation Center as the DA and DMS efforts are completed.

The original Order Adopting Distributed System Implementation Plan (DSIP) Guidance, issued on April 20, 2016, describes the need to develop a more transactional, distributed electric grid that meets the demands of the modern economy and includes improvements in system efficiency, resilience, and carbon emissions reductions. In response to the transitioning utility model, the Commission defined a set of functions of the modern utility that are called the Distributed System Platform (DSP). The DSP functions combine planning and operations with the enabling of the markets. The process by which improved planning and operations are defined and implemented is the DSIP.

Since that Order, New York State has set forth the boldest clean energy policies in the nation aimed at reducing carbon emissions to address climate change. One of the foundational elements of the State's REV initiative is increasing the amount of distributed energy resources – such as wind, solar, and battery storage – and increasing energy efficiency. In July 2019, New York passed the nation-leading CLCPA, which includes: an 85% reduction of all greenhouse gas emissions by 2050, achieving 70 percent of all electric generation produced by renewable resources by 2030, and a carbon-neutral electric generating sector by 2040.

Central Hudson is committed to a cleaner energy future by supporting the CLCPA targets and REV policies — reshaping the state's energy landscape toward a more-distributed, less-carbon intensive system. Central Hudson continues to strongly believe that maintaining affordability must be a part of the solution.

Central Hudson continues to put significant effort into progressing the DSP as outlined in its initial DSIP filing. In addition to establishing an internal team of subject matter experts to develop the filing, the Company works collaboratively with various stakeholder groups as well as the state's jurisdictional electric utilities. As such, this DSIP Update benefits from a collaborative process with the Joint Utilities of New York, DPS Staff, and stakeholders. The Joint Utilities are working collaboratively to progress the DSPs as consistently as possible across the state while recognizing the inherent differences of each of the utility's systems. To facilitate the review of each utility's DSIP Update, the Joint Utilities continue to present their plans in alignment with a standard table of contents and leveraging common language and figures. Where appropriate, the language and figures may be adapted to reflect the progress and plans of a specific utility.

The filing is segregated into four main sections:

Section II Progressing the Distributed System Platform: This section provides a high-level summary of the Central Hudson vision of the DSP and the progress made in the DSP through the Joint Utility efforts and by Central Hudson in the areas of DER Integration, Market Services, and Information Sharing. The progress Central Hudson has made in its transformation efforts, including the investments in DA, ADMS, Network Strategy, an electric geographic information system (GIS) project, Project Phoenix, and various research programs related to forecasting, Storage, and DERMs.

Section III DSIP Update Topical Sections: This section provides updates on various topical sections, including Integrated Planning, Advanced Forecasting, Grid Operations, Energy Storage Integration, Electric Vehicle Integration, Clean Heat Integration, Energy Efficiency Integration and Innovation, Data Sharing, Hosting Capacity, Billing and Compensation, DER Interconnections, Advanced Metering Infrastructure, and Beneficial Locations for DERs and Non-Wires Alternatives.

Section IV Other DSIP Information: Included in this section is an overview of the DSIP Governance, which details how the plans and actions from the DSIP are implemented through the Company, the summary of the Marginal Cost of Service Study, and the Benefit-Cost Analysis Manual.

Section V Appendices: This section includes a number of detailed subsections that provide further information and support for our efforts and direction, including Load and DER forecasting, the Avoided T&D Cost Study, the BCA Handbook, Central Hudson Long Range System Plan, and Tools and Other Resources for customers and developers.

Central Hudson, through its implementation of the DSIPs, has made significant improvements in the areas of Distributed Energy Resource (DER) Integration, Information Sharing, and Market Services. Additionally, significant improvements have been made in the focus areas of Distribution System Planning, Grid Operations, and Market Operations.

Foundational Investments to a Smarter Grid

In the Initial DSIP and its prior and subsequent rate plans, Central Hudson outlined Foundational Investments as part of its Grid Modernization Program designed to improve system reliability, improve system and customer efficiency, further enable DER integration, defer distribution capital investment by leveraging redundancy, and position itself for the transition from a static to a dynamic distribution operating system. Central Hudson's Grid Modernization Program is comprised of six major components:

1. Distribution Automation (DA) – automated devices, distribution infrastructure (poles and wires)
2. ESRI System Model Geographic Information System (GIS) – providing a single consolidated mapping and visualization platform
3. Distribution Management System (DMS) – the centralized software "brains"
4. Distribution System Operations (DSO) – the organization responsible for the use of the DMS
5. Network Communications Strategy (NS) – the two-way communication system between the DA devices and DMS

6. Substation Metering Infrastructure – Substation feeder metering upgrades required for accurate DMS power flow calculations

Central Hudson continues this integrated Grid Modernization Program to develop Network Communications and a Distribution Management System, install Distribution Automation equipment and monitoring, and create ESRI-based GIS models of the distribution system. Central Hudson has successfully implemented its Distribution Automation in two of its five operating areas and is on a path to complete this implementation system-wide by 2027. In addition to the hardware and software efforts, Central Hudson has also developed a plan to address the personnel and operational needs through the development of a Transmission and Distribution System Operations control center and training academy. This dual-purpose facility will allow for the full development of the facilities and staff needed to implement the Grid Operations aspect of the DSP. This will be the primary focus of Central Hudson's enabling investment in the DSP over the next five years.

Forecasting and Planning with DER

As outlined in the prior DSIP filings, Central Hudson has progressed its Integrated System Planning Process from the more traditional deterministic peak load forecast and planning process to a more probabilistic granular hourly load forecasting and planning process. As part of this DSIP update, Central Hudson has continued to advance this effort through the development of a more probabilistic and granular DER forecast for Energy Efficiency, Electric Vehicles, Distributed Generation, and Storage. In addition, the Company has continued to make significant progress on system modeling, capturing components across all areas of the system including: conductor size and length, protective elements, phasing, and key customer transformer information. This information continues to be updated in the OMS and GIS systems, and in turn, the Planning load flow models. The data is critical in the rollout of devices and needed system reinforcements for the implementation of Distribution Automation. This data is also critical as an input to the Coordinated Grid Planning Process (CGPP) and in consideration of needed system investments to meet the needs of the CLCPA.

Satisfying the Developers' Data Needs

Central Hudson, primarily working in conjunction with the Joint Utilities and now the IEDR Development Team, continues to make improvements in the areas of accessible Customer and System Data. The Company has developed various GIS map-based data portals that provide access to granular 8760 load data (both historical and forecasted) and Hosting Capacity data. In addition to these portals, data maps including beneficial locations and Non-Wire Alternative areas, as well as links to other resources such as reliability data, capital plans, DSIP plans, DER interconnections, and aggregated customer data, have all been developed and made publicly available through Central Hudson's website or the Joint Utilities' website. With the pivot in regulatory direction, Central Hudson and the Joint Utilities have been working closely with DPS Staff and NYSERDA in the Integrated Energy Data Resource and Data Access Framework efforts to further refine the data provided and how this data is made accessible. Central Hudson looks forward to working collaboratively with DPS Staff and NYSERDA in the implementation of an Integrated Energy Data Resource to help achieve a useful and valuable statewide and consistent resource for DER developers, customers, and other stakeholders.

Improving the Interconnection of DER

Central Hudson has also made progress in Hosting Capacity and DER Integration, along with the other Joint Utilities. Central Hudson played a lead role in the development of the Hosting Capacity Roadmap by refining the information provided in the roadmap, adding new data elements that were requested by stakeholders, and providing a consistent format to be used across the utilities. Central Hudson also continues to support the efforts in DER Integration on both the Interconnection Policy Working Group and Interconnection Technical Working Group. Through these efforts, Central Hudson has developed a method for managing the SIR queue, created consistent requirements for interconnection, and implemented and improved the PowerClerk portal for interconnection applications. These efforts resulted in greater clarity for developers in the state, allowing for much more efficient DER development. Although capital projects that also provide an opportunity to increase hosting capacity are considered in the Capital Investment Plan as an additional benefit, there currently exists no planning process specifically aimed at increasing hosting capacity. As an aspect of our system planning studies, the Company now considers improving the system hosting capacity when sizing substation transformer being installed or replaced, as the benefits in improved hosting capacity are high when compared to the incremental cost. As a part of this DSIP filing, DER forecasts were developed at the substation and transmission levels separate from net loads as an additional step towards further integrating DERs into the planning process. Central Hudson looks forward to working with the PSC, NYSERDA, and Joint Utilities in developing a focused planning process to increase DER integration.

Advancing New Forms of DER

In the areas of Energy Storage Integration, Electric Vehicle Integration, and Clean Heat Transformation, consistent with the actions by the Commission, Central Hudson has begun a new strategic focus to advance the understanding of the role of the utility in these markets.

Central Hudson has been active in the various policy cases and joint utility activities in these areas and will continue to actively participate in the PSC Cases. As for Electric Vehicle Integration, Central Hudson worked externally with the Joint Utilities to implement the Direct Current Fast Charger (DCFC) Incentive program and is working collaboratively with DPS Staff on Electric Vehicles Make Ready, Managed Charging, and Technical Specifications all designed to improve this beneficial electrification. With what has been learned over the past few years and this new strategic focus, Central Hudson is poised to progress on both of these aspects of the DER market at a rapid pace.

Investing in Infrastructure

Central Hudson's service territory continues to show an overall reduction in system peak with few areas showing any load growth. Central Hudson's Capital Investment Plans remain primarily focused on addressing infrastructure issues related to needed equipment replacement or upgrades and on grid modernization efforts. In doing so, Central Hudson can leverage these investments to improve system reliability and resiliency, hosting capacity, and operating flexibility, all of which will enhance the functionality of the distribution system and position the Company for the continued growth of DERs in the service territory. One area where Central Hudson continues to focus is how the forecasted DER or loads due to electrification will impact the system and how proactive planning and investments may need to be developed to meet these new needs driven by the CLCPA. Initial investments in planning tools and processes will lead to system investments to meet these new needs.

Advancing Non-Wire Alternatives

As for the areas where Central Hudson has seen system growth, these are being addressed by the implementation of Non-Wire Alternatives as appropriate. Since the inception of its Non-Wire Alternative program in 2014, Central Hudson has identified and/or implemented four Non-Wire Alternative projects covering approximately 15% of our load areas. While this has led to the deferral of capital projects related to growth in those areas and an increase in DERs, it has also resulted in a continued reduction in the broader system Locational System Relief Value and the Demand Reduction Value.

In summary, Central Hudson continues to progress the DSP through its individual efforts as well as the collective efforts of the Joint Utilities and in collaboration with DPS Staff and NYSERDA. The Company remains fully supportive of working with the stakeholders, the Commission, and the other utilities on improving data sharing through the Integrated Energy Data Resource and Data Access Framework. Additionally, Central Hudson strives to meet the objectives of the REV and the CLCPA in a cost-effective manner for all customers and with full transparency of all costs, including both supply and delivery.

II. Progressing the Distributed System Platform

A. Introduction

Central Hudson and the Joint Utilities have focused the implementation efforts of the Distributed System Platform (DSP) into three core aspects of the platform: Distributed Energy Resource (DER) Integration, Information Sharing, and Market Services. These core aspects include the basic focus areas from the DSIP: Distribution System Planning, Grid Operations, and Market Operations. The progress achieved in these areas and described in this DSIP benefit customers and market participants by (1) quality and ease in obtaining the needed information to help stakeholders make informed decisions and market choices, (2) stimulating DER deployment by facilitating the realization of value streams and clearing the barriers related to DER development, and (3) implementing changes in planning and operational methodologies and infrastructure investment that allows higher DER penetration levels while keeping the system safe and reliable.

The results of these DSP efforts will be more DERs on the system and across New York and the potential for improved system efficiency, resource diversity, lower emission of greenhouse gases, and the animation of market services beyond the current market construct. DERs will have better access to market value through multiple market mechanisms, and in turn, the system should benefit from an enhanced ability of DERs to provide grid services.

Given the expected growth across clean energy technologies, the Company has incorporated into its vision an understanding that enhanced flexibility in the distribution system – a longstanding focus of DSP enablement efforts – will be even more necessary to achieve CLCPA targets. In particular, the future grid will require enhanced flexibility to coordinate transmission system needs given the likelihood that economic incentives will drive further bulk-level interconnections of utility-scale solar PV and wind and the continuing expansion of pathways for DER to participate in the wholesale market. As the link between the bulk power system and the end-user, the DSP will play a critical role in enabling the interconnection, integration, and reliable dispatch of all clean energy resources, with the goal of optimizing system and customer value.

Core to Central Hudson's DSP vision is the goal of attaining clean energy targets at the lowest possible cost for customers. As such, the long-term DSP vision is rooted in competitive market design that leverages the NYISO wholesale market and provides competitive pricing signals for distribution value. The sophistication and granularity of these distribution market pricing signals will grow as DER participation increases, technology advancements are adopted, and grid modernization technology is deployed. As these critical elements are put in place, the DSP market services will evolve from tariff- and procurement-based mechanisms to more competitive and cost-efficient market mechanisms.

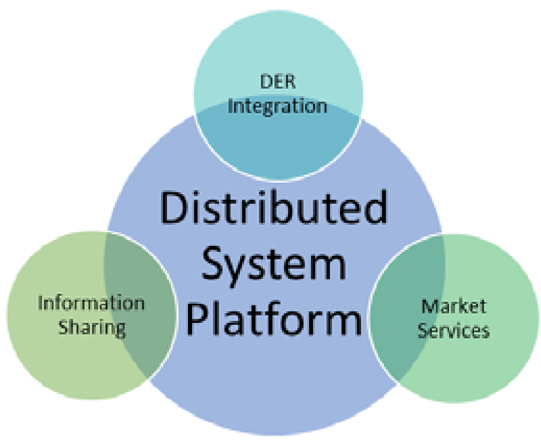
The progress outlined in this DSIP will also advance Central Hudson and the Joint Utilities toward the Vision of the DSP as discussed below.

B. Vision

1. Summary: Our Vison Remains Consistent While DSP Functions Are Evolving

Central Hudson and the Joint Utilities vision of the DSP is to facilitate the development of distributed energy resources through the three core DSP functions of DER integration, market services, and information sharing, so that our ongoing investments in grid technologies, advanced planning, and grid operations methods can empower communities and customers to actively manage their energy needs and participate in the marketplace, and the state can achieve its policy goals.

Figure 2: Core DSP Functions



While that overall vision remains the same since the last DSIP, there have been changes in state and federal policy that will impact the way we perform the core DSP functions. Accordingly, we have incorporated those changes into our vision.

This kind of adjustment has been a continuous process for our company. Starting with REV and through subsequent state policy initiatives, the Commission has been advancing an evolving set of goals for New York's energy future that include enhancements to system efficiency, reliability and resilience, market animation, utility business models, customer empowerment, and GHG emissions reduction. We have continually strived to maintain a complementary vision for our role as DSP.

Our updated vision now incorporates four areas of greater focus that reflect such new or expanded initiatives – one in each of the core DSP functions of DER integration, market services, and information sharing, and a fourth reflecting a new, broader policy emphasis on how to facilitate electrification through investments in enabling technologies and utility capacities.

2. DER Integration: Deliver Benefits of Technologies; Provide Safe, Reliable Electric Service; and Achieve Greater Integration with Bulk System Planning

a) Our Vision in This DSP Function

Our long-term vision for the DSP is to achieve ever more seamless integration of DER into our system while continually evolving our planning process to preserve system safety and reliability and maximize DER benefits.

b) Implementation Since the Last DSIP

Our efforts toward reaching our vision for DER integration and system planning in the past few years have been fruitful.

We have continued enhancing the process for interconnecting DER to allow for faster DER interconnection approval and making tailored requirements specific to DER types and locations. We have taken important steps like collaborating with industry stakeholders on a "Comprehensive CESIR Analysis Evaluation Initiative," worked with the other Joint Utilities to develop a smart inverter roadmap that includes bulk power support and voltage support smart inverter settings released earlier in 2023, and developed and proposed storage metering architectures for various technology configurations.

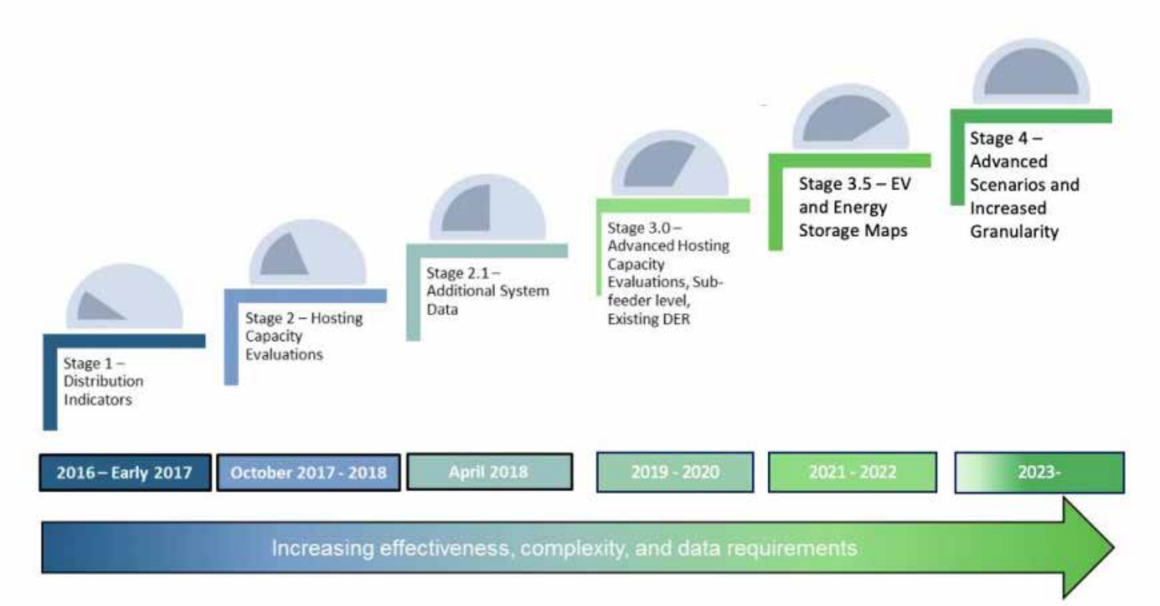
AREAS OF GREATER FOCUS IN OUR UPDATED 2023 VISION

- **DER Integration:** Integration of planning processes with the bulk system.
- **Information Sharing**: Expansion through the IEDR and DAF into a statewide effort.
- **Market Services:** FERC 2222 implementation opening new channels for DER value
- **Meeting State Goals:** Greater focus on electrification and identification of enabling investments.

We have also made significant progress in integrating DERs into our planning and operational processes. We envision a more dynamic operation of the distribution system, where local constraints can be eliminated with company assets or DER. Storage and load transfers can respond to dispatch, operational control, or price signals for real and/or reactive needs. We are taking steps to prepare for this increasingly dynamic grid by analyzing M&C and operational system requirements, developing new monitoring parameters, and coordinating with the NYISO to define operational coordination processes needed to facilitate DER wholesale market participation.

We have also progressed through the planned stages of our Hosting Capacity (HC) Roadmap shown below to achieve ever greater functionality and insight for DER developers to help them make efficient decisions that maximize system benefits.

Figure 3: Hosting Capacity Roadmap



We published Stage 1 of Storage HC Maps in spring 2022 showing feeder-level hosting capacity, additional system data, downloadable feeder-level summary data, sub-transmission lines available for interconnection, and reflect existing DER in circuit load curves and allocations. And in recent months, we completed updated HC maps to provide: sub feeder level information for the storage HC map, nodal constraints (criteria violations) on PV and storage HC maps, six-month updates for circuits that increased in DG above 500kW, Cost Share 2.0 Items, and DG connected since our last HC refresh.

c) Updates to How We Achieve Our Vision Since the Last DSIP

The environmental policy objectives and related requirements set forth in the CLCPA and the Accelerated Renewable Energy Growth and Community Benefit Act (AREGCB Act) have changed the utilities' roles in coordinated system planning and investment, and hence our vision for DER integration.

The Commission has specifically directed the Utilities to undertake planning assessments and make investment proposals to facilitate cost-effective development of renewable and emissions-free resources while maintaining the State's electric grid reliability. A major focus is greater integration of distribution-level planning processes with the bulk system. The initial phases of this work were described in the Joint Utilities' *Coordinated Grid Planning Process Proposal*, which explained how the utilities had developed an approach informed by the input of stakeholders gained through nine technical conferences, ensuring that Bulk and Local Transmission and Distribution (LT&D) project development opportunities are informed by the best data available and refined modeling approaches.

The Utilities envision fulfilling the goals of the CGPP much in the way that we have approached the DSP and DSIP filings: as an iterative process of improvement and refinement, including through continued opportunities for stakeholder input and direction. We have worked to align the CGPP and DSIP processes accordingly, with the forecast assumptions reflected in this DSIP mirroring those used in the CGPP process, and the CGPP forecast (once produced) feeding into future DSP planning activities.

Therefore, our vision for this function as a DSP now incorporates an understanding that we will be integrating DER in this broader system planning context.

3. Information Sharing: Delivering Useful, Market-Enabling Information that Enhances Customer Value, Now Through a Statewide System

a) Our Vision in This DSP Function

Our vision for the information sharing function of the DSP is to provide systems that measure, collect, analyze, manage, and display granular customer and system data so that customers and other market participants can be empowered to make efficient, cost-effective market decisions. Part of the information sharing function is protecting customer privacy and security, and that remains a core Company responsibility and an element of our vision.

b) Implementation Since the Last DSIP

In our 2020 DSIP, we emphasized the need to achieve more uniform information access across the New York utilities. We have made substantial progress in recent years toward that objective through the inception of the Integrated Energy Data Resource (IEDR). We are proud to be a key stakeholder in the IEDR and to support its development. We have worked collaboratively with stakeholders to develop and shape the use cases that are now being advanced, as well as the overall platform, including the three use cases recently included in the Initial Public Version (IPV) of the platform: Installed DERs, Planned DERs, and Consolidated Hosting Capacity Maps. Our ongoing contribution of data to the IEDR, including information on grid performance, energy usage, and outage data, helps to inform decision-making related to grid operations, planning, and policy development.

c) Updates to How We Achieve Our Vision since the Last DSIP

The IEDR, launched in 2019 by the New York State Energy Research and Development Authority (NYSERDA), is now a critical component of New York's Reforming the Energy Vision (REV) initiative. As it continues to expand, the IEDR will be an essential tool for promoting a more transparent and data-driven energy system. The IEDR includes comprehensive data on energy consumption, production, and storage, as well as information on the electric grid, weather, and demographics.

The IEDR and the associated Data Access Framework (DAF) are therefore now a key part of our vision for information sharing. We recognize that our data, insights, and collaboration with stakeholders will be critical to improving the performance and efficiency of New York's electric grid, and we are committed to ensuring that the IEDR is used to its full potential.

4. Market Services: Enabling a Robust Marketplace for DER to Access Value at All Levels of the Grid, With a New Avenue at the Wholesale Level

a) Our Vision in This DSP Function

As in years past, our DSP vision continues to be a future energy marketplace where competitive market signals play a greater role in achieving accurate pricing and compensation for distribution system value, so that all participants can benefit from an efficient market.

b) Implementation Since the Last DSIP

As in 2020, the Company continues to offer DER compensation through broad tariff mechanisms (i.e., VDER and Value Stack), demand-side management (“DSM”) programs, and direct contracting with resources (i.e., non-wires alternatives, NWA or NWS). In previous years, we summarized these mechanisms as the three “P’s” of incorporating and compensating DER: pricing, programs, and procurement. Each of these plays an important role in DER adoption, and we have seen continued or growing participation in all three in the past three years. The Company remains an active participant in proceedings at the Commission regarding the compensation of resources at various sizes.

c) Updates to How We Achieve Our Vision Since the Last DSIP

We have been able to accelerate progress toward our vision substantially by working collaboratively to help NYISO implement its forthcoming DER Market.

Under an initiative to implement FERC 2222 requirements, our company has been working with NYISO to develop and support the launch of the DER Market Participation Model. We have updated processes and systems to prepare for market launch, including refining the exchange of information related to registration, enrollment, operational coordination, and data exchanges providing input on draft NYISO manual revisions and resolving process concerns related to Q2 2023 market launch. We have also been actively coordinating with stakeholders along the way, for example, in a 2022 stakeholder session with DER community members focused on necessary telemetry requirements for safe and reliable operation of the distributed grid.

With full FERC 2222 participation not anticipated to begin until December 31, 2026, the fully mature role of the NYISO market in DER compensation remains very much a work in progress and a part of our future vision. In the coming years, there will be an evolving role for the DSP in market services, where we provide a smaller share of overall market compensation for DER directly through our programs and procurements and provide relatively more by helping to facilitate the functioning of the NYISO DER market. This will require an increased ability to use grid modernization technologies, which may include further investments in AMI, ADMS, and grid automation.

5. Greater Focus on Electrification and Identification of Enabling Investments to Continue Progress on Clean Energy Goals Through Enhanced DSP Capabilities

a) Our Vision in This DSP Function

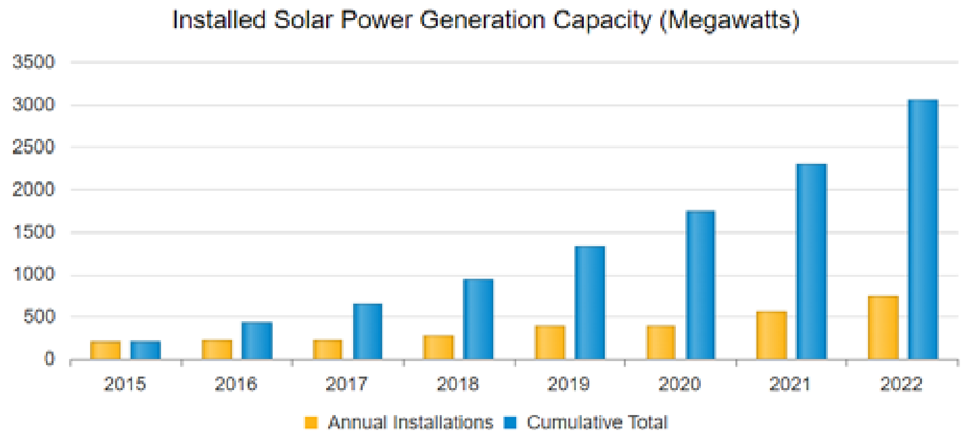
While not relating directly to one of the three core functions of the DSP, our vision also includes an understanding that this company and all of the utilities that function as DSPs have a critical role to play in achieving state policy goals by making enabling investments and delivering programs that help customers decarbonize their overall energy usage through distributed energy resources.

b) Implementation Since the Last DSIP

In our 2020 DSIP, we considered how recent developments in New York's clean energy policy would foster adaptations in our own vision for the future. As State policy emphasized greater decarbonization through larger-scale resources such as offshore wind and utility scale solar and demand shifts toward electrification – as called for in the CLCPA – we detailed how our company had incorporated new approaches to the core aspects of the DSP that would enable these changes.

We also showed how these kinds of actions were paying off in growing deployment of distributed energy resources. Those investments and our continued collaborative work with stakeholder have continued to pay dividends. As shown in Figure 4 below, there has been a significant step forward in the deployment of distributed solar PV, with a 50% increase in the amount of solar PV installed or in development on the distribution system in New York between the end of 2020 and December 2021. The cumulative installed solar power generation in 2022 reached 3,942 megawatts, which is more than double the amount installed in 2020. The annual installations of solar power generation (megawatts) continue to increase year over year.

Figure 4: Installed Solar Capacity by Year



While the growth of distributed solar PV is promising, there is still a lot of work to be done to achieve the CLCPA goal of 10,000 MW or more from solar projects under 5 megawatts by 2030. Further investments will be needed to manage the increase in distribution-level solar PV and enhance flexibility to operate an increasingly dynamic distribution system.

In addition, by April 2022, 56 MW of energy storage systems had been installed, or were in the process of being installed, to defer costs associated with electric transmission, distribution, or generation needs.

Since the Joint Utilities' The Electric Vehicle Make-Ready Program ("EV Make-Ready Program") launched in 2020, New York has also made significant progress in increasing the adoption of electric vehicles. The state has seen a record increase in the number of EVs sold, bringing the total number on the road in 2021 to approximately 120,000. Meanwhile, the number of charging stations in the state increased to more than 10,000 in 2021, including Level 2 and fast chargers.

c) Updates to How We Achieve Our Vision Since the Last DSIP

Recent years have brought an even greater state policy focus on electrification and the utilities' role in enabling a broader transition to electric power and heating, particularly in transportation. Our company has added a commensurate focus to our vision on the investments and program elements that we can deliver.

The Joint Utilities' planning, forecasting, and strategic investment remain instrumental in facilitating the development of electric infrastructure to accommodate an increased deployment of EVs. The EV Make-Ready Program is currently supporting the development of electric infrastructure and equipment necessary to accommodate an increased deployment of EVs within New York State by reducing the upfront costs of building charging stations for EVs. The Joint Utilities also continue to work with stakeholders on advancing a highly flexible framework that will help facilitate the achievement of the light-duty make-ready program goals.

It is also notable that our company, along with the other Joint Utilities, are championing an equitable transition to electrified transportation by supporting investment in EV infrastructure to provide access to EV charging facilities in disadvantaged communities (defined as communities that bear burdens of negative public health effects, environmental pollution, impacts of climate change, and possess certain socioeconomic criteria or comprise high concentrations of low- and moderate-income households). $206 million of the $701 million EV Make-Ready program budget directly benefits disadvantaged communities.

In addition to investments, the Joint Utilities are in the process of addressing other important aspects of transportation electrification. Developing EV charging load management, in particular residential managed charging, is central to maintaining reliability and controlling costs as EV adoption scales up. Rate design is another tool to both encourage EV adoption and manage charging loads. The Joint Utilities are exploring rate designs that send price signals to customers indicating charging times for efficient grid operation, and seek to mitigate the impact of demand charges for low load factor charging stations that can impact the cost effectiveness of EV charging for customers.

We are committed to using markets to procure new energy products at lower costs to customers than the alternatives. This is an important element in achieving the State's clean energy targets at the least possible cost for customers.

6. Other Areas of Increased Focus in This DSIP

Other areas of increased focus since the 2020 DSIP that are reflected in this DSIP and in our vision for the future operation of the DSP include:

- Climate Action Council (CAC) Scoping Plan
- Utility Thermal Energy Networks (UTEN)
- Solar/storage roadmap
- Billing: Our company, along with the other Joint Utilities, has significantly adapted our approach to the various DER-related billing and compensation programs that we maintain or have begun in the past three years. We are working on an additional two programs – volumetric net crediting and wholesale value stack – that will be implemented in the near future.

C. DSP Progress and Implementation Roadmap

a) DER Integration

DER Integration encompasses the planning, operational, and infrastructural initiatives associated with implementing the DSP. This includes, but is not limited to, distribution system infrastructure upgrades, the evolution of planning methodologies, operational changes, and general 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, enabling 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.

Prior to the outset of REV, utilities invested in technologies that could be considered foundational to the functioning of the DSP. Planning methodologies and processes at the time (including DER interconnection, forecasting, and capital investment planning) were calibrated to accommodate the prevailing level of DER market penetration and had not yet been aligned with REV goals regarding enablement and management of a high-DER environment.

Since the 2020 DSIP, the Joint Utilities have continued to meet with stakeholders through a variety of stakeholder engagement sessions. This includes, but is not limited to, the ITWG, IPWG, and Hosting Capacity Group. As the goal of these groups is to streamline processes and enable higher DER deployment on the system, DSP enablement plans continue to evolve based on stakeholder priorities. Through June 2023, Central Hudson and the Joint Utilities have implemented several key DER Integration initiatives, which are summarized in the figure below.

Figure 5: Actions and Results in DER Integration through June 2023

Actions		Results
Expanded deployment or demonstration of foundational communications and operations infrastructure: AMI, sensors, DSCADA, Distribution Automation, ADMS	à	Facilitates improved network performance and increased DER integration
Held stakeholder sessions to enhance hosting capacity map functionality. Released updated HC PV maps sharing information such as sub-feeder level HC data and nodal constraints. Published Storage HC Map	à	Stakeholder sessions allow for third party input into the prioritization of the hosting capacity map enhancements in both the near and long-term. Hosting Capacity Maps provide stakeholders with additional detailed information to create a more streamlined DER interconnection process and improve beneficial, cost-efficient siting of storage and PV
Collaborated with members of industry on a "Comprehensive CESIR Analysis Evaluation Initiative"	à	Better stakeholder understanding of how to help projects pass successfully through the CESIR process, and a re-examination of the voltage flicker calculation which is anticipated to result in an increase in projects passing the CESIR Screen H
Collaborated with EPRI to make significant progress on understanding effective grounding practices and policies for DER.	à	Improved interconnection study capabilities and safety measures which will enhance project success
Developed and proposed storage metering architectures for various technology configurations to serve as a guide for developers	à	Gives developers a better sense of the metering configurations that could be used for their projects

Developed and released bulk power system support and voltage support settings/ setpoints for smart inverters, as part of the Phase 1 activity of companies' joint Smart Inverter Roadmap	à	After January 1, 2023, DER projects installed in New York State will be equipped with IEEE 1547-2018 compliant and UL 1741- SB certified inverters. These inverters offer advanced functionality, including voltage and frequency disturbance ride-through and the ability to specific voltage – reactive power and voltage – active power setpoints (among other functionality). Such inverters will aid integration of more DER to the grid while ensuring safety and reliability.
Developed a monitoring requirements document to describe the key monitoring parameters and points required from inverter-based resources.	à	Advances the JU's goal of potentially using smart inverters as a low-cost monitoring solution, decreasing system and developer costs.
Updated matrix of common infrastructure upgrade costs	à	Provides additional insight to DER developers as to estimated costs of infrastructure upgrades. The updated DER technical guidance/ requirement matrix and cost matrix provide indicative estimates of various scopes of work and the relevant costs associated with the interconnection of DER on an individual company basis to help aid integration of more DER to the grid while ensuring safety and reliability.
Collaborated on updates to the NY SIR	à	Provides stakeholders with latest guidance on UL 1741-SB certified inverters and will aid in improving the efficiency of the interconnection process.

As outlined in the 2020 DSIP, Central Hudson continues down its well-established path of developing a smarter and more functional electric distribution system. An advanced distribution system provides the ability to use smart grid devices and functionality, two-way communication and near real time monitoring, along with advanced system modeling and automated response to changing system conditions. Additionally, an ADMS provides the ability to integrate customer-owned DER in such a way as to not only to accommodate the additional DER, but to utilize this DER in such a way as to maximize its value to both the customer and the DSP through improved efficiency and operation of the distribution system.

Central Hudson outlined the Foundational Investments that will allow for this functionality. One area that remains unclear is how liquid a market can develop within the DSP considering this new functionality and the increased level of DERs. A dominant factor in the evolution of this market is the value of DERs to the distribution system and whether this value, in a utility service territory where electric load growth is scattered and relatively low, will ever be enough to allow for a DER market to grow beyond tariff-based programs or targeted NWA solicitations. Central Hudson will continue to work with the Joint Utilities, Stakeholders, and the PSC to develop a common understanding and definition for the Value of DER and how this value can be best offered to the market. Central Hudson will also work with the Joint Utilities and the NYISO to ensure that any market developed within the DSP is well-coordinated and complementary to the wholesale market administered by the NYISO and regulated by FERC.

In the interim, Central Hudson's vision for the DSP is one where increased functionality, visibility, and control of the distribution system will allow for improved operation, efficiency, reliability, and increased DER interconnection and we will be poised for whatever DER market changes develop in the future.

While these are outputs described in greater detail in later sections, some highlights are described briefly below.

Central Hudson continues to refine and improve the IOAP as more experience is gained, using the software and new updates provided by Clean Power Research. Since the 2020 DSIP, Central Hudson has implemented the following improvements to the portal; added the next step and new deadline details to the bottom of each external form to provide applicants with further insight into the progression of their interconnection application, screen results were enhanced with an additional description, CESIR screen result tracking was setup to report quarterly to ITWG, and Cost Share 2.0 requirements were integrated where applicable.

The Electric Planning and Interconnection group is currently overseeing the implementation of new load flow software to meet the needs of increased modeling complexity related to DERs, hosting capacity analysis, as well as future electrification requirements. The Company is currently undergoing contract negotiations with an anticipated in-service date of Q1 2024 for Phase 1 Base Integration. Additionally, Central Hudson plans to implement a Phase 2 Integration with the Company's Interconnection Online Application Portal (IOAP) starting in the second half of 2024.

Additionally, as Central Hudson is seeing a high penetration of DER systems in localized areas of both the transmission and distribution system, the Company in the early stages of a research and development project related to deploying a Distributed Energy Resource Management System (DERMS). The purpose of the DERMS would enable Central Hudson to better manage grid performance with a high penetration of DER, particularly for transmission voltage levels that the NYSIO does not secure.

Central Hudson and the Joint Utilities have also collaborated in shared learning on more advanced forecasting approaches, including the incorporation of probabilistic methodologies. Enhanced forecasting is supporting more granular Marginal Cost of Service studies, which underlie more accurate and updated Locational System Relief Values (LSRV) as part of the Value of DER (VDER) Phase 1 tariff. These improved forecasting initiatives are helping to more accurately align DER compensation with grid value through price signals, one of the core goals of the DSP.

Central Hudson, both individually and in conjunction with the Joint Utilities, will continue to advance and expand both internal and stakeholder-facing shared learning opportunities in the deployment of advanced metering and DER management systems, as well as through the operation of REV demonstration projects exploring flexible interconnection, storage, online marketplaces, and transportation electrification. These initiatives are critical foundations for understanding how to most effectively integrate new technologies, projects, and policies to enable rapidly increasing DER penetration.

Through 2028 and beyond, further advancements in DER integration will drive continued progress towards the next phases of the DSP. Ongoing demonstration and deployment of foundational DSP technologies (such as ADMS including forecasting methods for both load and DER, DERMS, smart inverters, Energy Storage, EV charging infrastructure, and expanded monitoring and control capabilities through direct utility control, third-party aggregators, and the wholesale market operations) will enable active management and coordination of DERs on the distribution system. In addition to these technical factors, IOAP 3.0 and improved coordination with the NYISO and utility interconnection processes will further streamline the DER interconnection process through increased automation, and DER forecasting will become a standard part of Central Hudson's planning process.

b) Market Services

While the distributed system platform 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 system and be compensated based on that value through enhanced market mechanisms. This has also been a major focus for the Joint Utilities in the past two years. In DSP 1.0, the goal of the market services aspect of the platform has been to provide DERs greater access to market value through advances in the "3 P's" (pricing, programs, and procurement), and the Joint Utilities have implemented steps in each of these areas to accomplish this goal.

At the outset of REV, none of the New York utilities had yet incorporated NWAs into their distribution procurement processes. DERs were limited in their ability to offer services as an alternative to traditional utility infrastructure investments and to offer new services to customers. A significant volume of DERs on the system – mostly distributed photovoltaic systems – were compensated based on net energy metering, a system that represented a useful provisional assessment of value but one that had not yet been finely calibrated to the grid services provided by these resources. Through June 2023, Central Hudson and the other Joint Utilities have implemented several key Market Services initiatives, which are summarized below.

Figure 6: JU Actions and Results in Market Services through June 2023

Actions		Results
Identified and developed non-wires opportunities	à	Developing projects and portfolios of DER solutions that provide value to customers; streamlining the non-wires solicitation process across the Joint Utilities; more projects give opportunities to support/improve system reliability
Worked closely with NYISO to develop and support the launch of the DER Market Participation Model, including refining the exchange of information related to registration, enrollment, operational coordination, and data exchanges providing input on draft NYISO manual revisions and resolving process concerns	à	Provides opportunity for DER to access value for both distribution-level services and wholesale market to potentially reduce wholesale prices through increased competition
Coordinated with stakeholders on NYISO DER Market Participation including on telemetry requirements	à	Enables DER to access more value through wholesale markets while preserving system safety and reliability. Identified need for lower cost solutions to be developed in near future.
Expanded implementation of advanced customer programs for demand-side management (EE, DR)	à	Allows for greater DER market participation and increases DSP flexibility to meet system needs
Continued implementation of nine compensation programs including Phase 2 Value Stack, remote crediting, remote net metering	à	Provides expanded set of market signals to DER about the locational and temporal value of operation and a wider array of compensation avenues
Made significant progress toward automation of crediting and billing of CDG	à	Supports the widespread adoption of CDG projects and provides timely and accurate billing and compensation for DGs and retail customers. From 2020-2023, the number of VDER CDG project hosts in NY has more than doubled
Engaged in the DPS Market Design and Integration Working Group (MDIWG)	à	Charting out potential paths forward to enable a New York energy marketplace that achieves clean energy deployment, customer empowerment, and cost

		savings while providing grid level, distribution level and edge level products and services
Implementation of utility programs for LDV Make-Ready Program, MHDV Pilot, Transit Authority Pilot, DCFC PPI Program, and Residential Managed Charging	à	Removing upfront cost barriers to adoption through direct make-ready incentives and futureproofing, ongoing cost barriers to adoption through direct operating incentives, knowledge and technical barriers to adoption through fleet assessments and technical assistance, and soft cost barriers to adoption through ongoing coordination and stakeholder engagement

Since the release of the utility planning procedures that apply the proposed NWA Suitability Criteria and identifying projects in each utility's five-year capital plan that meet these criteria, Central Hudson has focused on targeting local infrastructure upgrades through NWAs. To date, Central Hudson's active NWA projects account for approximately 15% of its service territory based on percent of load.

In procurement, the Joint Utilities have made substantial progress, as informed by discussions with stakeholders. Multiple stakeholder meetings detailing the proposed NWA sourcing process both before and since the Supplemental DSIP have generated important feedback on stakeholders' desired timeframes for notification of NWA opportunities, as well as standardization of required data and requirements in response to requests-for-proposals (RFPs). Incorporating this feedback, the Joint Utilities produced a set of NWA Suitability Criteria as a standard framework for evaluating potential utility NWA investments, as well as a more detailed filing on the DER sourcing process. The Joint Utilities are continuing to work toward increased standardization and simplification of that process.

As a result, four NWA opportunities have been identified in Central Hudson's service territory since the inception of this process improvement, and information about these opportunities has become available sooner and through centralized online locations. Developers can now expect to see increasing standardization of the elements of RFPs, making responding easier and faster. These NWA opportunities have been offered as technology-neutral, and as energy storage becomes more cost-effective or able to access value from the wholesale markets, Central Hudson expects to see energy storage added to the more traditional technologies of Demand Response, Energy Efficiency, and Distributed Generation.

In pricing, as noted above, the Joint Utilities have worked to incorporate multiple work streams, including new forecasting techniques and an understanding of NWA suitability to provide inputs to the VDER Value Stack working group. This group is advancing the work within that proceeding to craft a tariff that is more aligned with DER grid value and provide greater certainty of bankable revenue streams that support the financing of projects. The Joint Utilities have also put forward a longer-term vision for the relationship and role in the marketplace between NWAs and tariffs like VDER, to help clarify the pathways through which DERs can be developed and compensated.

The Joint Utilities have also worked on market services regarding specific DER technologies. One area of focus has been supporting the adoption of electric vehicles and the deployment of electric vehicle supply equipment (EVSE). Central Hudson had instituted a new strategic focus on EVs and will be developing internal program leadership and a cross-functional team to advance utility infrastructure and rate design discussions, vehicle charging equipment needs, and advocacy and education for both company employees and the public. On April 24, 2018, the Commission commenced a proceeding to consider the role of electric utilities in providing infrastructure and rate design to accommodate the needs and electricity demand of EVs and EVSE. In addition, on May 31, 2018, the Governor announced a new $250 million electric vehicle expansion initiative, EVolve NY, with the New York Power Authority. Since that time, the Joint Utilities have implemented the DCFC incentive program, incentivizing more than 1000 DCFC plugs from 2019 through 2025. In addition, in early 2020 the DPS Staff issued a white paper for a potential make ready program for light duty vehicle DCFC and Level 2 charging. Central Hudson has been working with the DPS Staff, NYSERDA, the Joint Utilities, and Stakeholders to refine the program described in the whitepaper and develop a statewide charging infrastructure program to assist in enabling the electrification of the transportation sector.

In addition to Electric Vehicles, Central Hudson is very supportive of utilizing clean electric heating technologies as a carbon reduction strategy. The Company launched its first heat pump conversion program in 2018 and has achieved early success.

According to the Energy Efficiency Order, utility-specific mechanisms within electric rates or surcharges would be used to fund its heat pump programs. Central Hudson's originally authorized 2020-2025 heat pump program provided a budget of $43.2M and cumulative savings target of 255,292 MMBtu. Customer demand for the program has been exceptionally strong. By the end of 2022, the program fully exhausted its available funds, having achieved 175% cumulative savings target, or approximately 450,000 MMBtu at a unit cost lower than the average unit cost derived from the budgets and targets authorized in the Energy Efficiency Order. To support the immediate continuation of the program into 2023, the company leveraged $4.6M of prior years' unspent funds from its electric energy efficiency portfolio. In February of 2023, the Company petitioned the Commission for additional funds to support the program through 2025. In June 2023, the Commission, through its Order Approving Funding for Clean Heat Program authorized the Company an additional $21.2M to support the program through mid-2024. With these additional funding sources of $25.8M, the Company anticipates achieving approximately 303,000 MMBtu of energy savings through its Heat Pump program. Although the bill impact of this initiative may appear manageable in the short term, the Company is concerned about the long-term sustainability of funding this and other beneficial electrification initiatives primarily through electric bills. Additional advancements in market services up to and beyond 2023 will continue to progress the DSP's role in enabling and appropriately compensating DER participation through various market mechanisms. One such mechanism is VDER Phase Two, in which compensation for distribution value will be enhanced beyond the current version of DRV/LSRV components. The market platform will also facilitate higher DER value through direct or aggregated participation in NYISO wholesale markets, a more standardized NWA procurement process, more flexible interconnection, and near-real-time distribution-level services. Further enhancements to probabilistic load and DER forecasting methods, along with greater temporal and locational granularity of data, will allow market participants to realize value more effectively from DER investments and transactions through the DSP.

c) Information Sharing

Expanded access to more transparent, granular, and accessible data sources empowers retail consumers, developers, and other stakeholders to make smarter decisions in planning, development, and operation of DERs. By providing insights into how to bring the right technologies and services to the right customers at the right time, DSP providers can advance information sharing as a fundamental DSP to create value for stakeholders across the DER ecosystem. At the inception of the REV process in 2014, information sharing was characterized by the provision of traditional downloadable datasets, as aligned with developer needs at the time. Because DERs did not yet constitute a significant proportion of system load or capacity, hosting capacity analysis methodology was still under development. Customer data privacy standards varied and were not yet calibrated to the needs of a growing market for distributed energy services. Through June 2023, the Joint Utilities have implemented several key Information Sharing initiatives, which are summarized below.

Figure 7: Actions and Results in Information Sharing Through June 2023

Actions		Results
Updated hosting capacity to stage 3.5	à	Improved data access and granularity to increase value of data driven by stakeholder and developer feedback. Applicability to additional stakeholders (storage).
Identified available data points that were not included in the DAF Order datasets, filed Data Access Implementation Plan, recommended enhancements to existing cyber protections, and filed IEDR Order petition for rehearing to clarify consent and access to customer data.	à	Preserved and enhanced customer data security and privacy as the state moves to a statewide information sharing platform
Filed a Green Button Connect (GBC) User Agreement	à	Unified quality standards for customer data via GBC
Shaped IEDR use cases, including the initial Public Version (IPV), and delivered data transfers.	à	Responded to stakeholder-requests to provide useful information that relate to the highest-priority use cases
Submitted quarterly IEDR reports since Q4 2021	à	Increased transparency in progress, process, and investments.

Collaborated with NYSERDA, DPS Staff, and stakeholders on IEDR development and implementation	à	Achieved an IEDR IPV that meets stakeholder and market needs as efficiently and effectively as possible
Annual reports for EV make-ready program and DCFC PPI	à	Shows how the make-ready efforts progress state EV adoption goals
Hosting capacity map refreshes	à	Maps reflect more current conditions
Cost sharing 2.0 information	à	Providing stakeholders cost sharing information (substation, type of upgrade, amount of capacity added, cost, and timeline of upgrades) to facilitate additional DER integration

Over the past two years, the Joint Utilities, guided by stakeholder engagement, including focused outreach to understand developer use cases, have developed and implemented a comprehensive set of information sharing enhancements. These include the creation of centralized portals both on the Joint Utilities' website and through REV Connect to provide system data and access to NWA and other RFP opportunities. These portals enable increased access to and usability of stakeholder-requested information and enhance efficiency for developers seeking to participate in NWA and other opportunities.

The Joint Utilities have also made progress in achieving greater uniformity and shared understanding of privacy standards, including the 4/50 data privacy standard for whole building aggregated data, which the Commission approved in its April 19th, 2018, UER Order.[2] This alignment secures individuals' utility data, fulfilling the critical need to protect customer privacy while also simplifying planning for stakeholders, who can now anticipate and design approaches based on a shared privacy standard.

The Joint Utilities have also collaborated to address other priorities related to information sharing, stemming from the Supplemental DSIP filing and related Orders, which are building blocks towards more evolved information sharing services within the DSP.

The Joint Utilities system data working group has advanced through the second step of a three-step process to review and standardize the formatting of publicly available data. Once completed, this more uniform approach will assist developers and other stakeholders who have identified shared formats as a priority. The group has also completed other important steps, such as proposing an annual needs assessment, classifying data based on the sensitivity of the information, and working collaboratively with stakeholders regarding requests for additional data elements. Since the filing of the Initial DSIP, Central Hudson and the Joint Utilities, in conjunction with the feedback received from various stakeholder sessions, have made significant progress in the development of System Data Portals for DER developers to gather valuable system data. In addition, during the past two years, the Joint Utilities have been working together to develop a greater understanding of system data needs and studying use cases, however these discussions have not resulted in significant changes in the amount of available data nor in the way this data is accessed.

To propose the next steps to enable access to useful energy data, on May 29, 2020, the DPS Staff released a whitepaper - Recommendation to Implement an Integrated Energy Data Resource. Central Hudson looks forward to working collaboratively with DPS Staff and NYSERDA to help achieve a useful and valuable resource.

The customer data working group has also completed several steps, including developing approaches for aggregated building data collection and dissemination – some of which were addressed in the 4/50 privacy standard proposal – as well as a process to track aggregated data requests and responses, allowing for more efficient identification and response to non-standard, high-value data requests from stakeholders.

On May 29, 2020, the DPS Staff issued a whitepaper regarding a Data Access Framework. As proposed by Staff, the Data Access Framework would serve as a single source for data access policies and provides uniform and consistent guidance on what is needed for access to, and the availability of, energy-related data. In addition, the proposed Data Access Framework would provide a more workable approach that is designed to provide access to data, while preserving all the necessary protections, to fully enable the intentions of the Commission. Central Hudson looks forward to working collaboratively with DPS Staff on the development of the Data Access Framework, allowing customers interested in sharing accessing and sharing their data to be able to do so in a safe and reliable manner.

In addition, the forecasting implementation team has worked to fulfill ongoing tasks related to information sharing, including coordination with NYISO and soliciting input from stakeholders on potential use cases for forecast data. This work has included alignment on understanding the use cases for 8760, or hourly substation-level load and DER forecasts, which are provided shortly following this filing. Central Hudson has been providing this level of detail since the 2016 DSIP filing and continues to make improvements in its DER forecasting that are reflected in this year's updates.

Increased access to data sources and standardized, easily understandable formats will characterize information sharing through 2023 and beyond. Additional value-added data services will be established, and Stage 4 hosting capacity visualizations will enable streamlined interconnection of new DER projects.

D. Grid Modernization and the DSP Technology Platform

Central Hudson proposes system investments in alignment with state objectives to provide safe and reliable service and create net positive customer value. In recent years, many such investments in utility systems both in New York and elsewhere have been associated with grid modernization efforts and have also been described as foundational to the DSP, or DSP-enabling.

Grid modernization investments are investments that improve the reliability, resiliency, efficiency, and automation of the transmission and distribution system. Such investments generally include various groupings of assets: the sensors, communications networks, and data repositories 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 of any grid investment strategy. They provide the basis for increased operational flexibility, can enable efforts toward achieving state policy goals, such as the integration of various types of DERs, and are beneficial for any resource mix.

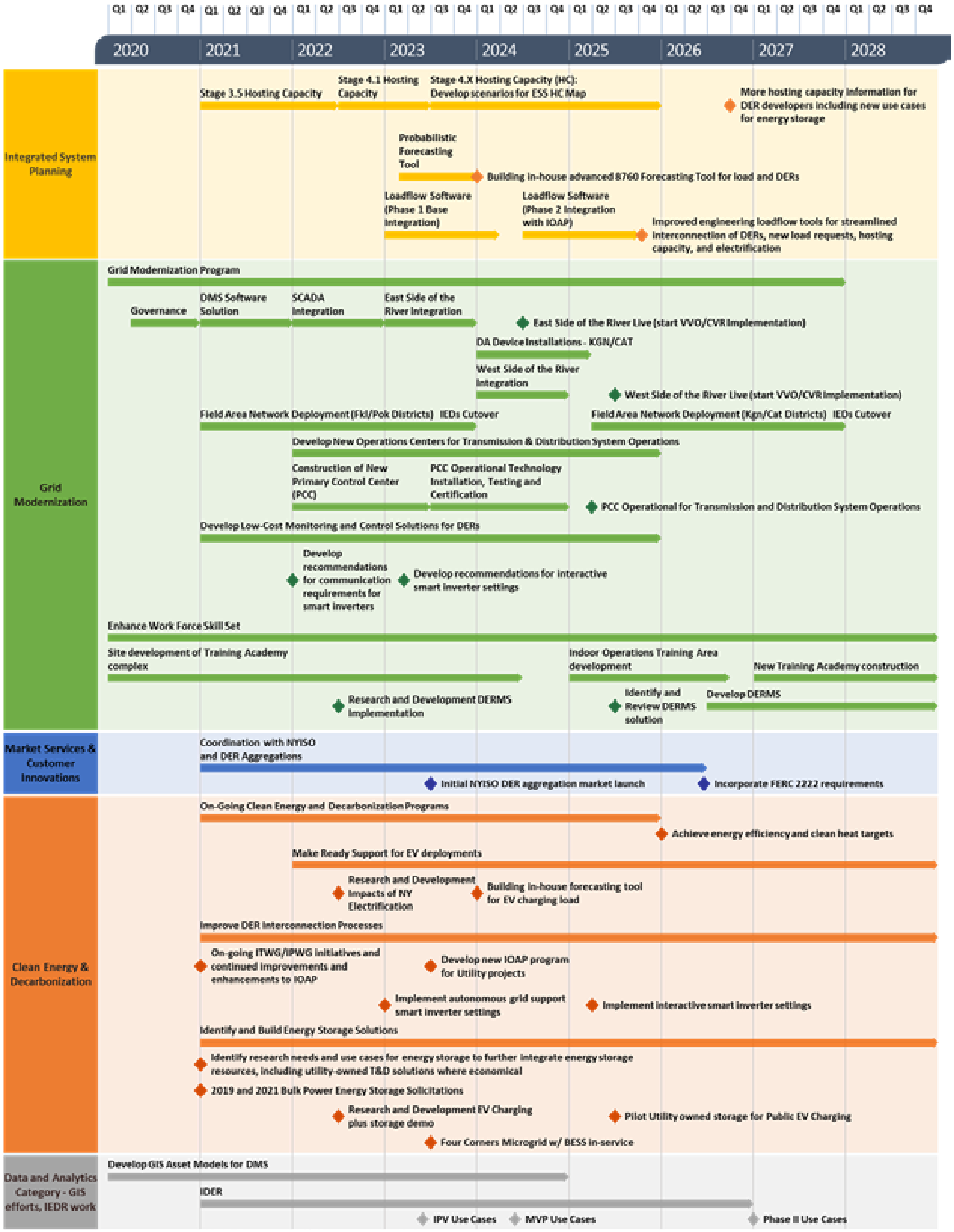
Central Hudson, along with the other New York utilities, has been proposing and implementing investments that meet this definition of grid modernization since before the commencement of REV and continue to do so. Upon the initiation of REV, the utilities have worked to align planned and proposed investments with identified REV objectives. Because REV goals are subsumed within overall state energy and environmental policy goals, all grid modernization investments planned and proposed by the Company are aligned with REV, though not necessarily driven by REV.

Many grid modernization investments have mutually reinforcing benefits, such as those that provide reliability or operational benefits while also supporting DER integration, and therefore contribute to meeting multiple objectives. This is why many current Stage 1 investments are described as "foundational" in the context of the DSP. Foundational Investments are a subset of grid modernization investments that enable grid capabilities to provide or support applications that increase reliability, resiliency, safety, and enhanced situational awareness and operational flexibility. These Foundational Investments are required to enable more advanced functions related to DSP enablement and DER integration. Foundational Investments are, therefore, "no regrets" actions that can support both current and future functions, such as integration and utilization of DERs, in a modular fashion.

Future functions, which typically fall into Stage 2, are variously described as DSP enablement, DER integration, DER utilization, or value capture activities. DSP enablement is an overarching term that, in the grid investment context, refers to ensuring that the DSP can manage the growing penetration of DERs for both bulk system and distribution operations while maintaining safety and reliability. This description has significant overlap with enabling DER integration, which refers to ensuring that the grid can integrate DERs with the necessary communication, cyber security, and physical security protocols, in order for DERs to be included in system planning grid operation processes. DSP enablement also allows the DSP to improve DER utilization and value capture, which means that the DSP can make use of DERs to meet system resource needs and enhance system efficiency while providing system and economic benefits.

Taken together, these investments support the functions and capabilities of the DSP, which Central Hudson has defined as the set of people, processes, and systems that enable the utility to integrate DERs, share information, and provide market services while preserving safe and reliable system operation.

Figure 8: Grid Investments in Relation to Grid Functions



III. DSIP Update Topical Sections

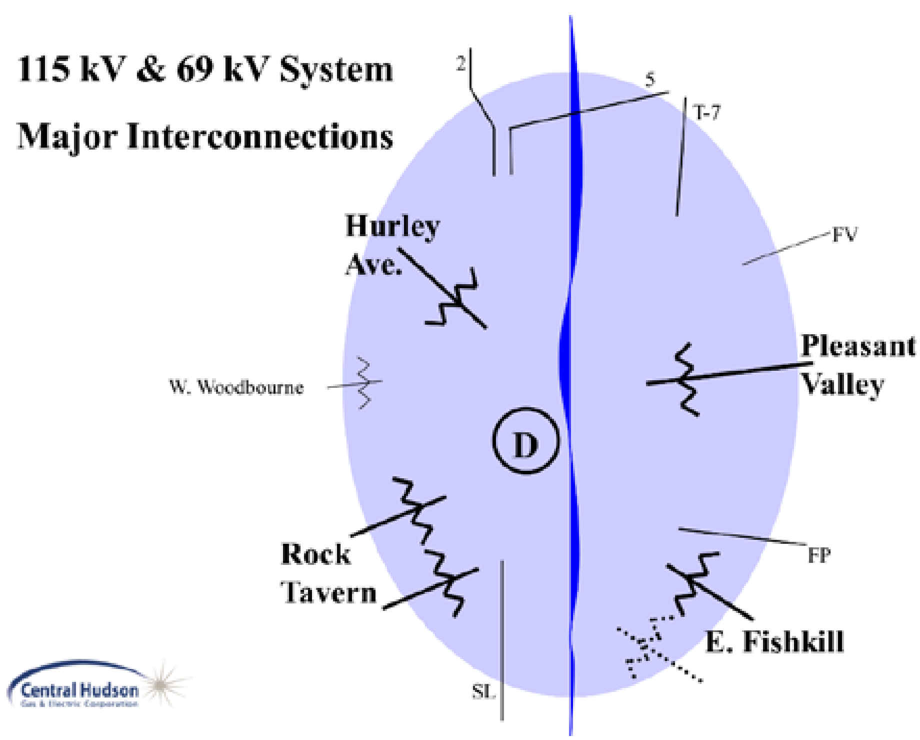
A. Integrated Planning

1. Context and Background

Central Hudson's service territory includes a total of approximately 65 distribution load serving substations, 59 of which are fed from the transmission system, and approximately 269 circuit feeders. For planning purposes, substations are grouped into ten load areas, and most load transfers occur between substations and circuit feeders in the same area. Central Hudson also operates and plans its interconnected transmission system within the service territory. There are also a total of eleven transmission areas, or load pockets, where transmission lines and generators affect power flow. During 202219, Central Hudson served approximately 270,170 electric residential customers and 46,340 electric non-residential customers. Combined, they were billed for 5,004 GWh of electricity and produced a peak demand of 1,109 MW.

Central Hudson's electric transmission system is tied to the bulk electric transmission system at the 345 kV voltage level operated by the New York Independent System Operator (NYISO). These interconnections are at four major substations that are shown, along with the major 115 kV & 69 kV interconnections supplying Central Hudson's electric transmission system, in Figure 9.

Figure 9: Major Interconnections



These interconnections also include connection to the transmission systems of National Grid, New York State Electric & Gas, Consolidated Edison, New York Power Authority, Eversource, NY Transco, and First Energy. The main criterion describing the capability of the transmission system is System Load Serving Capability (LSC). The determination of LSC includes consideration of facility outages while maintaining flows and voltages within appropriate limits. Currently, Central Hudson's System LSC is 1,470 MW[1]. NY Transco's NYES project would lower this to 1290 MW[2], therefore, Central Hudson has initiated some minor station upgrades to increase the System LSC to 1495 MW[3]. In comparison, Central Hudson's all-time peak load was 1,295 MW, which occurred on August 2, 2006, and the current forecasted peak in 2028 of 1,116 MW.

The distribution system includes all assets outside of the substation fence operating at 34.5 kV and below. However, load transfers within the distribution system are sometimes utilized to manage substation and transmission infrastructure, operational and thermal constraints, and the transmission and substation systems that provide the backbone of the distribution system. Therefore, the integrated planning process includes both transmission and distribution components, as well as distributed energy resources.

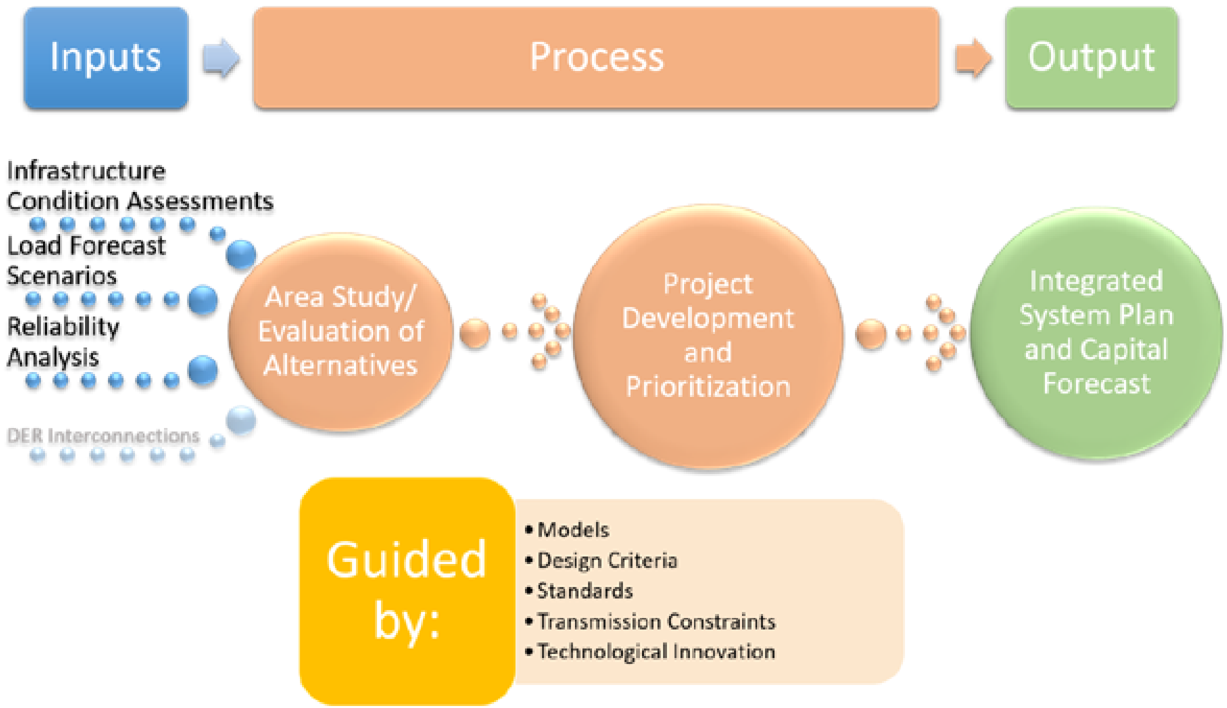
The System Planning function at Central Hudson has served customers well by safely planning for a reliable electric system while moderating cost pressures. System planning is accomplished by leveraging system knowledge, forecasting, models, new technologies, and innovation to continuously enhance reliability, improve customer satisfaction, and support design, construction, and operations within the utility. Along with maintenance processes and programs, the primary outputs of the planning process are an Integrated Long Range Electric System Plan (Appendix C) and Capital Investment Forecast.

Figure 2 illustrates the current components of the Integrated Distribution System Planning process at Central Hudson and how they flow together. Discussion on these components follows the figure. More detail regarding specific components of the process can be found in Central Hudson Gas & Electric's Electric System Planning Guides, issued in October 2013, with periodic updates to sections as required.

[1] Based on the 115 kV East Fishkill – Shenandoah EF line at Summer Long Term Emergency (LTE) Rating following the loss of the 115 kV Pleasant Valley - Manchester M Line with no internal generation.
[2] Based on the 115 kV East Fishkill – Shenandoah EF line at Summer Long Term Emergency (LTE) Rating following the loss of the 115 kV East Fishkill – Fishkill Plains HF Line with no internal generation.

[3] Based on the 115 kV East Fishkill – Fishkill Plains HF line conductor at Summer Long Term Emergency (LTE) Rating following the loss of the 115 kV East Fishkill – Shenandoah EF Line with no internal generation.

Figure 10: Integrated Distribution System Planning Process



Inputs

Inputs to the planning process are described below:

1. Infrastructure Condition Assessment

   Central Hudson complies with the Electric Safety Standards Order[4], identifying and addressing infrastructure concerns that arise through the transmission and distribution system inspection process. Additional thermographic inspections are also completed on an annual basis for substations and the distribution system. An inspection and testing schedule is also followed for each substation asset. As a result of these inspections and additional comprehensive condition assessments of transmission and distribution infrastructure, the Electric Long Range System Plan was developed (see Appendix C for additional detail) to manage replacement programs

[4]Case 04-M-0159, *Proceeding on Motion of the Commission to Examine the Safety of Electric Transmission and Distribution Systems*, Order Granting in Part Petition to Modify Electric Safety Standards (issued January 13, 2015).

associated with individual asset classes. Trends of failing equipment are also considered. As any major components are scheduled for replacement from a transmission, substation, or distribution perspective, an integrated plan is developed considering items such as:

- Remaining life/condition of other assets in the substation;
- Environmental, land use, accessibility, and right-of-way status;
- Distribution and substation modernization program needs;
- Forecasted load in the area;
- Safety, reliability, and power quality considerations;
- Anticipated new customers and DERs, including improvement in hosting capacity;
- Current standards;
- Transmission constraints; and
- Other scheduled projects in the same vicinity.

2. Load Forecast Scenarios

The load forecast for the area being studied is a key driver of the process, not only for projects driven by load growth but also for properly designing infrastructure and reliability-based projects for the long term. Currently, net peak load is the primary consideration, but, as discussed throughout the remainder of this section and in Implementation Plan, the process is evolving to consider forecasts of distributed energy resources (DERs), as well as multiple scenarios.

3. Reliability Analysis

Central Hudson maintains reliability criteria for the planning and operation of its electric transmission and distribution (T&D) systems. For the transmission system (voltages greater than 34.5kV), these criteria are documented in internal Central Hudson guidelines and within applicable external regulatory body documents/guidelines. These documents include the following: Central Hudson's Transmission Planning Guidelines, the Northeast Power Coordination Council (NPCC) Regional Reliability Reference Directory #1 – Design and Operation of the Bulk Power System, New York State Reliability Council – Reliability Rules & Compliance Manual For Planning and Operating the New York State Power System, and North American Electric Reliability Corporation (NERC) Standard TPL-001-4 – Transmission System Planning Performance Requirements. The Company's distribution system reliability planning criteria are outlined within the Central Hudson Gas & Electric's Electric System Planning Guides, issued in October 2013, as well as Section IV of the Central Hudson Initial Distributed System Implementation Plan[5]. Analysis is completed based upon these criteria, and if the criteria are not met, project alternatives are evaluated as part of the Integrated Planning Process.

4. DER Interconnections

Although proposed DER interconnections are reviewed by the Electric Planning and Interconnections department, they are not a direct part of the current Integrated Planning Process (other than to consider on-going project construction due to DERs). Infrastructure projects that also provide an opportunity to increase hosting capacity are considered in the Capital Investment Plan. Additionally, as a part of this DSIP filing, DER forecasts were developed at the substation and transmission levels separate from net loads as an additional step towards further integrating DERs into the planning process.

Process

Depending upon the extent of additional considerations, a final integrated plan may be developed along a continuum from an informal meeting with appropriate stakeholders to a formal, comprehensive Area Study. The result is the development of recommendations to maintain and improve reliability of service and support the capital budget plan. At any level of formality, the process relies on local system knowledge and experience, and it includes an evaluation of project alternatives, the age and condition of the infrastructure, and an assessment of electric service reliability. Projects are prioritized based upon the Capital Prioritization Guidelines[6].

While Central Hudson's electric capital plan is predominately comprised of condition-based infrastructure-type projects, a number of these existing projects also provide incremental hosting capacity benefits. As new project needs are studied, renewable penetration levels and potential hosting capacity improvements are included in the analysis to determine the recommended solution. While DER is currently included as a criterion within the capital prioritization plans, in order to meet NY State's renewable goals, this process has continued to evolve to further integrate DER into the planning and prioritization process. Since the 2020 DSIP, this has included identifying capital projects where applicable, as Phase 1 or Phase 2 projects. Phase 1 projects are capital projects that satisfy reliability, safety, and compliance while also addressing bottlenecks or constraints that limit renewable energy delivery. These are projects that are funded as part of the utility's normal capital rate plan. Phase 2 projects are capital projects that are not currently in the utility's capital plans and increase hosting capacity on the local transmission and distribution system. These projects are funded under the FERC load ratio share

[5] Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Central Hudson Gas & Electric Corporation's Distributed System Implementation Plan ("Initial DSIP"), (filed June 30, 2016).
[6] *Ibid,* Appendix G.

methodology. Phase 1 projects will continue to be identified as part of the current system planning and capital forecast processes. Phase 2 projects will continue to be identified as part of the more comprehensive Coordinated Grid Planning Process (CGPP) and will facilitate the attainment of these goals based on system constraints and forecasted renewable penetration levels.

Supporting Tasks

In addition to completing the planning process, the key tasks that are a part of the current Electric Distribution Planning function include:

- Establishing and maintaining design and operating criteria to minimize risk and plan for a safe and reliable system;
- Performing analysis of reliability and power quality data and leveraging the use of new technology to continuously improve the T&D systems;
- Developing an asset inspection, repair, and replacement program;
- Complying with all federal, state, and local codes, standards, and regulations;
- Maintaining relationships with local DER developers and municipal officials to stay abreast of and support new residential and commercial economic development;
- Preparing, maintaining, and analyzing electric system models to ensure compliance with voltage, thermal, protection, and reliability standards;
- Forecasting demand and energy growth at the system level and apportioning demand growth into more granular load growth areas;
- Evaluating DER applications and determining what system upgrades will be required to facilitate interconnection; and
- Developing a capital forecast and identifying where a non-wires alternative may be considered based upon suitability criteria.

Outputs

After projects are prioritized, they are incorporated into the annual Capital Forecast, and non-wires alternative(s) are pursued as appropriate. Additionally, system-wide asset management and capital plans are documented in the Long Range Electric System Plan (Appendix C).

Historically, electric grids were engineered to accommodate the flow of electricity from centralized generation to end users. Generation, transmission and distribution infrastructure was sized to meet the aggregate demand of end users when it was forecast to be at its highest (peak demand) while allowing for forced outages. At the system level, electricity supply must meet demand instantaneously with sufficient reserve (spinning, quick-start, etc.) levels to avoid outages due to the loss of generation. Substation transformer and distribution infrastructure, however, was, and generally still is, sized based on local peaks, which can be quite diverse and often are not coincident with system peaks that drive generation infrastructure.

While the core System Planning functions will continue to maintain and improve the safety and reliability of the electric system, sophisticated technology and changing customer expectations are increasing the complexity of this role. The Integration of DERs at both the transmission and distribution levels, and alternatives to traditional utility investments, must be included in the Integrated System Planning Process. Stakeholders are expecting higher levels of reliability and resiliency, along with information transparency. Forecasting methodologies must evolve to an integrated approach that is probabilistic in nature; foundational investments, such as distribution automation, must continue to progress; asset management must be improved as infrastructure ages; and system modeling must become more granular and be refreshed at a much faster rate.

Foundational Technologies

To embark on the efforts described in the previous section, key investments in Foundational Technologies are required. Enabled by more sophisticated system modeling, investments in these technologies will allow for the integration of DERs and a smarter grid. These investments also require a significant Distribution Planning effort to determine the required upgrades to the distribution grid and software systems. Distribution Automation (DA) has been the focus of foundational investments from an integrated planning perspective. Externally, the evolution of decentralized, automated devices, along with the commercialization and integration of sophisticated modeling, geographic information systems mapping, and Distribution Management Systems have helped propel DA solutions. Internally, DA has gained momentum as a solution to address system considerations resulting from the exponential growth of solar among the Company's customer base. Additionally, DA will address infrastructure replacement due to age and condition, increasing levels of limited redundancy and operational flexibility, and reliance on communication systems providers whose core business models have shifted away from hard-wired lines.

A centralized approach with modern modeling techniques will also improve system efficiency and defer capital investments by leveraging the distribution system for redundancy and upgrading infrastructure that has reached the end of its useful life. Further benefits include improved reliability and power quality, integration of DERs, reduced system losses, and enhanced switching safety. To achieve the benefits described, Central Hudson had identified several gaps in its current approach. Figure 11 shows the gaps identified, along with a desired future state.

Figure 11: Identified Gaps and Future State

Gaps Identified:		Future State:
Peak day system model with asset gaps	***Transition began in 2011 via Pilot Projects and Cross-Functional Teams***	Real time system model with detailed asset information
No remote control of distribution devices		Two-way communication with control via Operations Center
Decentralized communications with many platforms		Centralized communications through single platform
Asset communications driven by vendor		Central Hudson led communications via vendor partnership
Does not integrate customer-owned devices		Integrates customer-owned DERs

To test a more integrated approach, Central Hudson partnered with a vendor and NYSERDA to develop an Integrated System Model focused on 8760 analysis, including both the transmission and distribution system. The Company tested and developed conservation voltage reduction (CVR), a prototype for a DMS, and Fault Location Isolation and Service Restoration (FLISR) to avoid an outage to over 8,000 customers fed by a substation served by a radial transmission line through challenging terrain, avoiding transmission system investments by better leveraging the distribution system. Central Hudson began a pilot CVR trial on one feeder in 2012 and a second feeder in 2013, using a "day on, day off" approach with a variety of customer load groups. Applying the results along with studies completed in several national labs, Central Hudson anticipates a 1.39-1.73% reduction in energy usage, in addition to loss reduction. Tools such as solar impact analysis and efficiency benefit analysis were developed through the process, and the pilot helped inform the process of selecting a vendor for the Distribution Management System (DMS).

With successful pilots in progress, Central Hudson fine-tuned and began implementing its integrated Grid Modernization strategy. This program is developing a DMS to improve reliability, system safety, and system efficiency. Central Hudson is creating detailed electric models in the ESRI GIS system to use as the asset database. It will also have links to the DMS and Engineering Planning tools, which will, in turn, link to the Outage Management System (OMS), as well as a designer tool to synchronize proposed changes and actual as-built maps between Engineering, Design, and Operating groups. Over 1600 Intelligent Electronic Devices (IED; e.g., electronic reclosers, switched capacitors, and voltage regulating devices) and sensors are being installed through DA and other programs, which will provide real-time data to the DMS so that it can make centralized decisions based on current system conditions rather than anticipated peak loads. DERs also must be monitored, and in some cases, controlled, as a critical input to the DMS per the requirements established by the Interconnection Technical Working Group[7]. Along with system-wide implementation, there is a large infrastructure improvement plan to create robust mainline feeders that can be looped through switching to restore customers after an outage or optimize and balance feeders during normal operations, as well as improve hosting capacity.

The Grid Modernization Strategy is also foundational to REV. VVO and FLISR modules that will be included in the DMS are consistent with the REV policy goals of improving efficiency, reliability, resiliency, and may enable for increased utilization of our two transformer substations when fully implemented. Once fully deployed, the system will consider the impact of DERs in switching and voltage optimization decisions utilizing generation profiles. The DMS is being developed so DERs can be integrated into the system for monitoring and control through additional modules as needed, as well as weather forecasting, to improve resource diversity and animating markets in the future. While the monitoring, control, and market mechanisms surrounding DERs are still being defined through other proceedings, the DMS will be critical to any level of coordination, as well as the safety and reliability of the electric distribution system, as its complexity increases. In addition, the ability to add AMI at the customer level is being incorporated into the Network Communications Strategy. The DMS system in the future will also be integrated with a Distributed Energy Resource Management System (DERMS) or combined into a single operating system as technology advances.

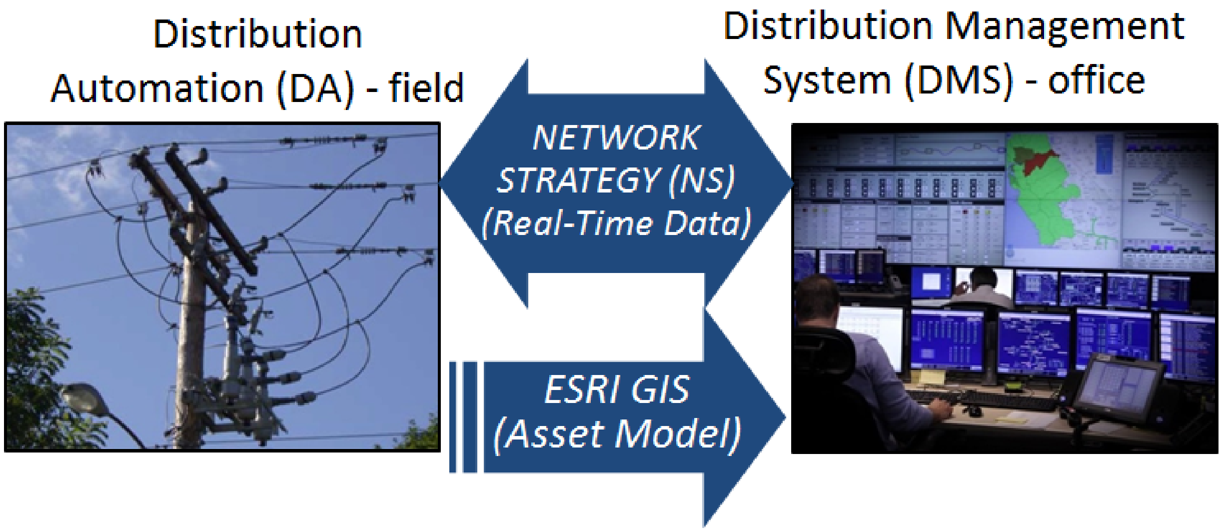
Central Hudson's Grid Modernization Strategy is comprised of six critical components:

1. Distribution Automation (DA) – automated devices, distribution infrastructure (poles and wires)
2. ESRI System Model Geographic Information System (GIS) – provides a single consolidated mapping and visualization system
3. Distribution Management System (DMS) – the centralized software "brains"
4. Distribution System Operations (DSO) – the organization responsible for the use of the DMS
5. Network Communications Strategy (NS) – the two-way communication system between the DA devices and DMS
6. Substation Metering Infrastructure– substation feeder metering upgrades required for accurate DMS power flow calculations.

Figure 12 illustrates how these projects interact, along with the underpinning ESRI Geographic Information System (GIS) Asset Model.

[7] *Monitoring and Control Requirements for Solar PV Projects in NY,* September 1, 2017.

Figure 12: Smart Grid Projects



The Planning aspects of DA and the asset model will be discussed in this section. For additional details on the Grid Modernization strategy, please see Grid Modernization and the DSP Technology Platform.

Since the initial DSIP filing in 2020, the Company has made progress in transitioning to a more integrated planning process. Traditionally, Central Hudson applied a deterministic approach to the development of a peak load forecast. Central Hudson also engaged a vendor to deliver a robust probabilistic load forecasting tool (see Advanced Forecasting). This tool is being further developed with an expected in-service date of December of 2023 to provide a better user interface with dashboards to perform probabilistic forecasts for base load including DERs and the ability to analyze both lumped loads and NWAs. The Company also added two additional team members to the Electric Distribution Planning area beginning in 2021, who have been focused on distribution planning and assisting with incorporating DERs into the planning process.

As part of the Grid Modernization Strategy, the Work and Asset Management group has continued to focus on system modeling, with an anticipated completion date of December 2024. This group works closely with the DMS Model Manager to ensure successful integration of the GIS data into the DMS model. The ESRI GIS data is also a critical component in performing Distribution Planning and Interconnection load flow analysis.

The Electric Planning and Interconnection group is currently overseeing the implementation of new load flow software to meet the needs of increased modeling complexity related to DERs, hosting capacity analysis, as well as future electrification requirements. The Company is currently undergoing contract negotiations with an anticipated in-service date of Q1 2024 for Phase 1 Base Integration. Additionally, Central Hudson plans to implement a Phase 2 Integration with the Company's Interconnection Online Application Portal (IOAP) starting in the second half of 2024.

The first three years of the Distribution Automation plan were approved as detailed in the Order Approving Rate Plan, issued and effective June 17, 2015, with a contingency of meeting milestones that Central Hudson and Department of Public Service Staff mutually agreed on. Due to Central Hudson's success during the prior rate plan, the current rate plan, continues with the implementation of not only Distribution Automation, but the DMS and Network Communications Strategy as well. Since the 2020 DSIP, in March 2021 the Electric Engineering Services group saw a reorganization creating two separate groups, one focused on overall system planning and interconnections (both transmission and distribution) and another maintaining a focus on reliability, resiliency, and distribution operations, including the responsibility for ongoing DA plans. The Distribution Automation group therefore was separated from the Distribution Planning group and now has four team members who report through the Distribution Engineering organization. These groups primary focus is to assist with further planning of DA projects and additional cleansing of distribution system models.

Central Hudson's service territory is comprised of five operating districts. All components of DA will be modeled, analyzed, planned, field designed, and constructed in parallel on a district-by-district basis, with the process separated into two phases for some districts. Since the 2020 DSIP, DA plans for the remaining district, Kingston, were finalized in July of 2021. As available, devices will be simultaneously integrated with the network communication radios and DMS. Vendors were selected for each component, and construction standards have been developed. However, the ongoing evaluation of emerging products and technologies may result in continuous improvement, particularly in the sensor area. Additional products, such as solid-state transformers that allow for voltage control, will be continuously monitored for economic applicability on Central Hudson's system, to further enable feeder voltage reduction or mitigate impacts of solar PV installations.

2. Implementation Plan

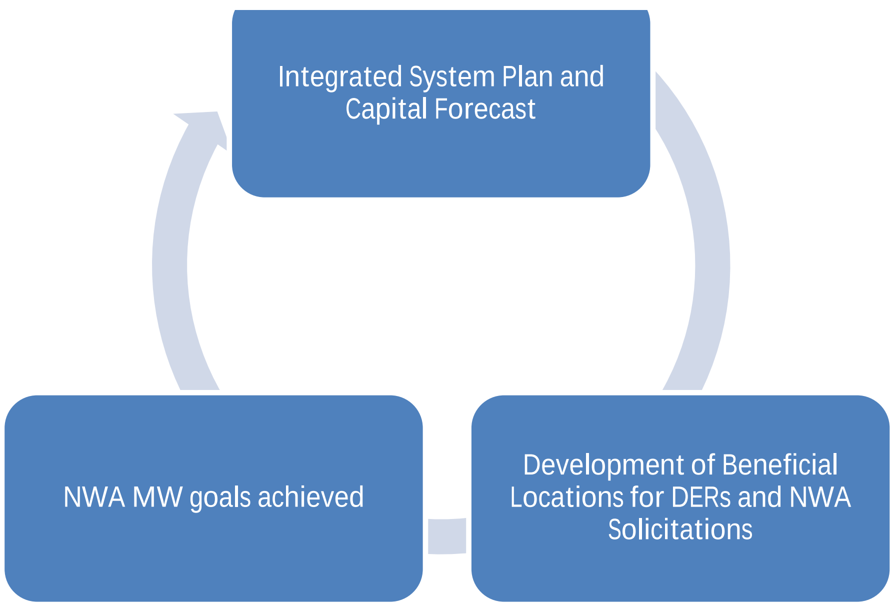
a) Current Progress

As described above, Central Hudson is in the process of bringing in a probabilistic planning tool and new load flow software in which Engineers will be trained to utilize once implemented.

The planning process does not end with the development of a Capital Forecast. As illustrated in Figure 13, the output of the Distribution Planning process has expanded from the Integrated Capital Budget to include beneficial locations to install DERs, which will become more ingrained in the process as the Company gains experience with and evaluates the results of existing non-wires alternative projects. Once acceptable criteria are developed, the capital plan will result in the development of beneficial locations to install DERs, along with solicitations for NWAs to defer or eliminate the need for some of the identified capital investments. Note that this is not currently presented in conjunction with hosting capacity maps, which will have their own roadmap described in Hosting Capacity will identify areas where interconnection is easier but will not necessarily coincide with beneficial locations to alleviate a system constraint.

To further integrate DERs into the planning process, in 2023, the Electric Planning and Interconnections team began updating planning processes to consider DER impacts. This included a methodology to identify native load at the substation level. An analysis was performed to track the generation output of the larger interconnections at the point of interconnection via the electronic recloser. Curves were established for time and month for each location by operating district. A percent output was established and applied across all solar interconnections at the substation level and added back to the substation load to establish a native load during peak. This process will continue to be refined as historical data is established.

Figure 13: Capital Forecast development with NWAs



Finally, as described in Stakeholder Interface, stakeholders have access to 8760 load data, where available, in addition to NWA solicitations.

Additionally, while the overall planning process tends to focus on longer-term system needs, both Planners and Electric Operations Engineers are responsible for reviewing near-term requirements of new service requests for individual spot loads. Electric Planning and Interconnections utilizes EPRI's DRIVE tool to assist with the planning and integration of DER, such as energy storage and EVs. Additional information on EPRI's DRIVE tool can also be found in Hosting Capacity.

Central Hudson's efforts to bring the probabilistic planning forecast tool in-house will enable engineers to internally identify areas where non-wires alternatives may be suited as well as beneficial locations to site DERs. As forecasting large, lumped loads is difficult to do, the tool will provide engineers with the ability to incorporate large, lumped loads as necessary to appropriately identify the most cost-effective capital solutions that serve customers current and future needs. Additionally, implementing a new load flow software will provide the engineering team with the ability to analyze more complex load flow scenarios, including smart inverters, timeseries analysis as well as electrification impacts. The new software is also anticipated to provide time savings related to conducting hosting capacity analysis.

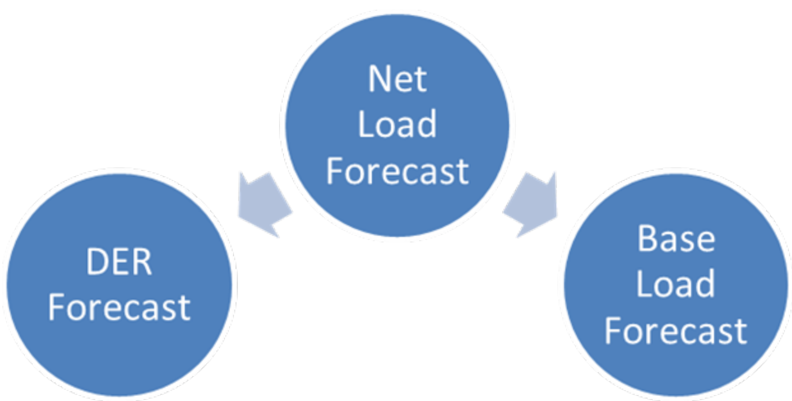
Additionally, as part of the current planning process as well as Cost Share 2.0 requirements, Central Hudson seeks to upsize capital investment upgrades within current plans, such as transformers when DER development interest is identified. This is performed when time within the design stage permits, and ultimately helps to increase hosting capacity.

b) Future Implementation and Planning

While the Integrated T&D System Planning Process functions to provide for the safety and reliability of the system will remain, the tools applied and the complexity of the process are rapidly evolving. Currently, the interconnection of DERs is evaluated separately from the long-term T&D Planning process. With the increased intermittency associated with many DERs, the application of a linear forecast, even with engineering knowledge and judgment, will be insufficient to recognize the range of potential generation and load scenarios.

As discussed previously, Central Hudson has utilized a T&D System Planning process to incorporate probabilistic and more granular elements. While in the past a net load forecast was sufficient for planning, the forecast going forward is separated into DERs and base load, as shown in Figure 14.

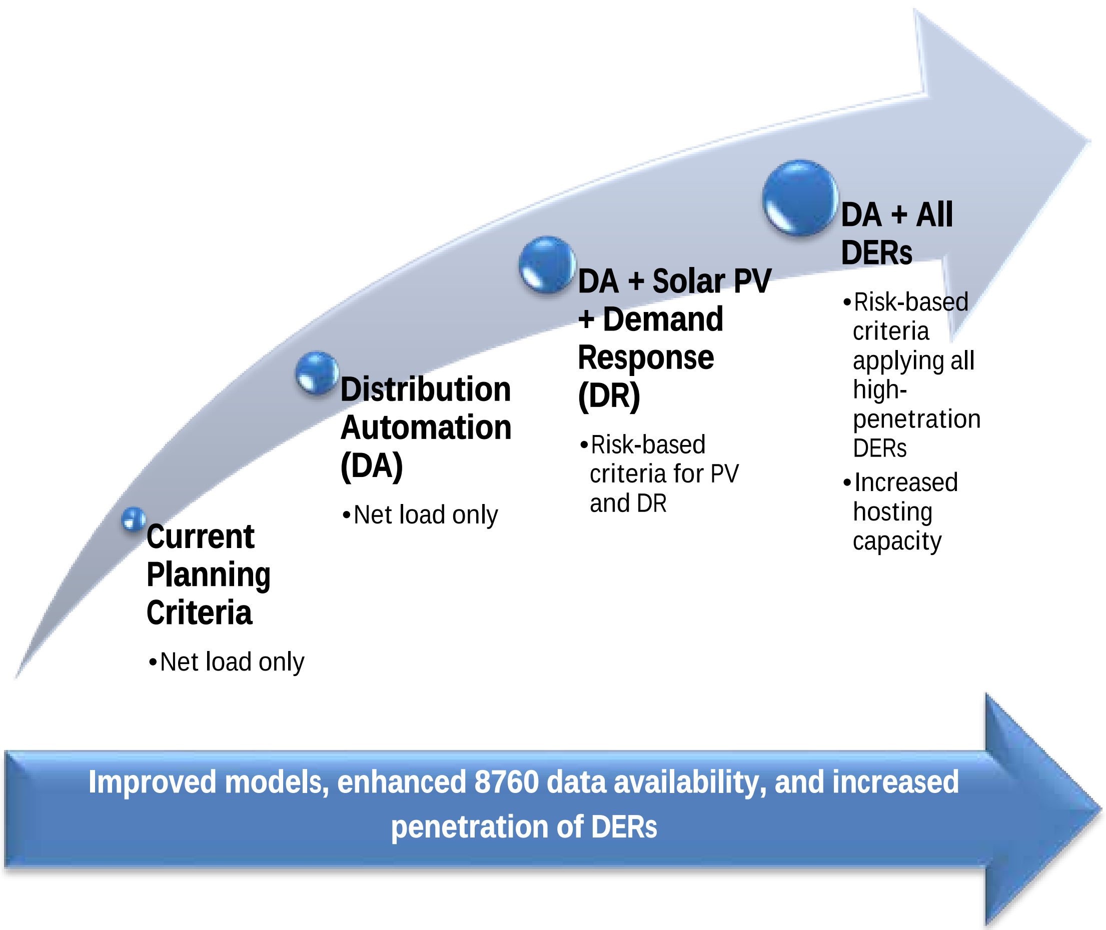
Figure 14: Forecasts Must Separate DERs and Base (Gross) Loads



During this transition to a probabilistic approach, when an area of need is identified through traditional planning methodology, base load and DER forecasts will be developed with separate scenarios for each. DER forecasts consider not only technical drivers of load shapes, but also current and anticipated policy decisions and interconnection queues that will impact the penetration of DERs. Although interconnection studies consider the impact of individual DERs, smaller distributed generation and energy storage systems are not scrutinized as closely. Still, their aggregate impact over time will be important to consider and will also inform the interconnection process of the future. The separation of gross and net load is currently being used for certain applications where it is appropriate for accurate results. This includes hosting capacity analysis, DER integration studies where DER interconnected penetration levels are high, as well substation load forecasts.

This information is applied to understand the system needs and scenarios and to develop alternatives and a final solution. To apply the DER forecasts that were developed on a widespread basis, the T&D Design criteria used to assess needs will require updates. Figure 15 provides a roadmap of this evolution.

Figure 15: Evolution of T&D Planning Criteria



Currently, Central Hudson has moved beyond the traditional current planning criteria and has implemented probabilistic forecasting, using more granular data, and more sophisticated models. Central Hudson's future efforts intend to further incorporate DER into the planning process, including identifying risk-based criteria for DERs with areas of high penetration. Using the in-house probabilistic forecasting tool currently being developed, engineers will have better capability to forecast load and DER impacts to identify cost-effective capital improvements.

As with current implementation, improvements to data, modeling software and further integration of DERs into the planning process provides for the ability to identify and address system requirements that consider customer and stakeholder needs.

Operating Criteria will need to evolve to integrate the Foundational Investments (i.e., DA and DMS) as well as DERs, and DA rollout will continue. This is discussed further in Grid Operations and will continue to improve as the ESRI platform, DMS, and system planning tools become more tightly integrated and as distribution designer software ties to the platform to accelerate the closure of new work orders, so that a more "real time" model is available.

Table 1 summarizes the gaps in today's Integrated Planning Process and the steps and timelines to address them. While the overall planning process will not change from Figure 15, it will become significantly more complex. Completion of the roadmap will require hiring additional technical resources to develop sophisticated analytical and software application skills, uniquely blended with power system knowledge.

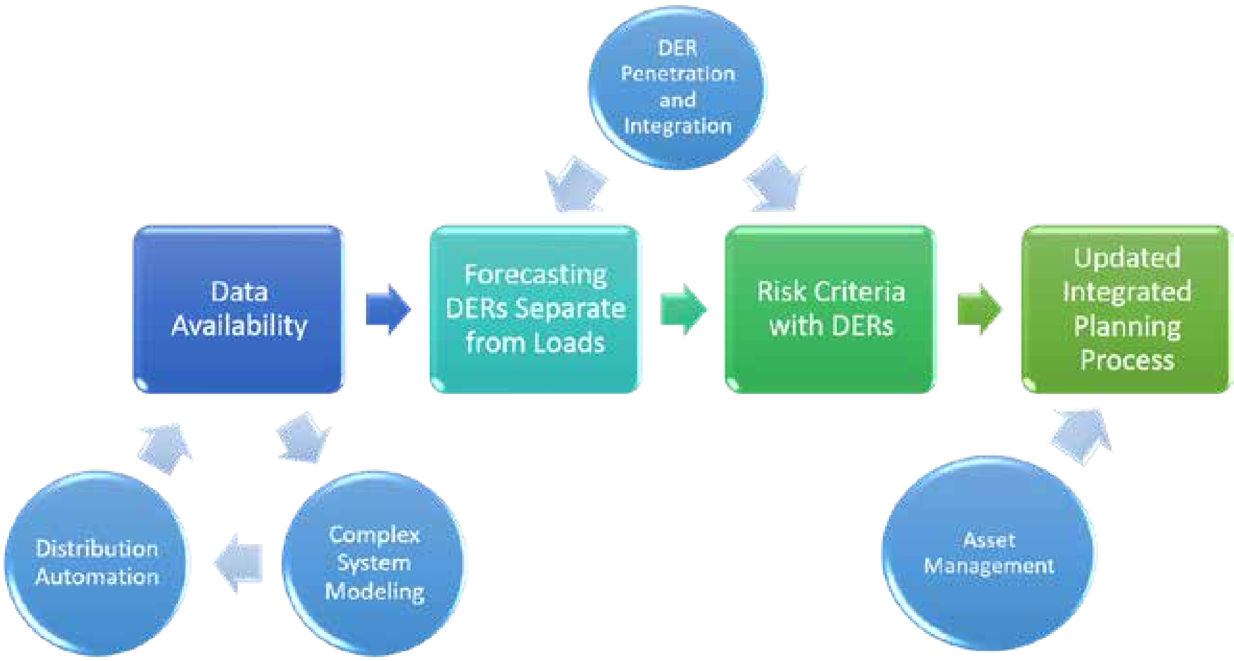
Table 1: Integrated System Planning Gaps and Roadmap

Action Item	2023	2024	2025	2026	2027	2028	2029+
Improve 8760 Data Availability							
Load	>97%	>98%	>99%	>99%	>100%	>100%	100%
Distributed Generation	>500kW; smart inverter availability	>500kW; smart inverter availability	>500kW; smart inverter availabilit y	>500kW; smart inverter availabili ty	>500kW; smart inverter availabili ty	>500kW; smart inverter availabili ty	>500kW; smart inverter availabilit y
Electric Vehicles	ü	ü	ü	ü	ü	ü	ü
Battery Storage	>500kW smart inverter availability	>500kW smart inverter availability	>500kW; smart inverter availabilit y	>500kW; smart inverter availabili ty	>500kW; smart inverter availabili ty	>500kW; smart inverter availabili ty	>500kW; smart inverter availabilit y
Develop Substation Level Probabilistic Forecasting by Load/Generation Type							
Load, Solar, Energy Efficiency, and Electric Vehicles	Vendor ü	Central Hudson ü	Central Hudson ü	Central Hudson ü	Central Hudson ü	Central Hudson ü	Central Hudson ü
Other DERs	As Needed						
NYISO Market Considerations		ü	ü	ü	ü		
Integrate into Planning Process	ü	ü	Other DERs As Needed	Other DERs As Needed	Other DERs As Needed	Other DERs As Needed	Other DERs As Needed
Improve System Modeling Capabilities							
Improve 8760 Modeling Capabilities	ü	ü	ü	ü	ü	ü	ü

Enhance Designer Software to improve Work Order Process			ü				
Improve model based upon real-time DMS data	On-Going						
Integrate T&D constraints				On-Going			
Improve Asset Management and Reliability Analysis							
Maintain Cascade for Distribution Assets		On-Going					
Leverage analytical tools along with mapping features	ü	ü	ü	On-Going			
Develop Risk-Based Planning Design Criteria		ü					
Solar PV, Energy Efficiency and Demand Response	ü	ü	ü				
Battery Storage		ü	ü				
Electric Vehicles		ü	ü				
Other DERs			As Needed				
Scenario Planning		ü	ü	ü			
	Note: Requires Consideration of Operating Procedures						
Integrate DER Interconnections							
Maintain Technical Guidelines	On-Going						
Develop Operating Guidelines	On-Going per Section III.C						
Complete Hosting Capacity Roadmap	On-Going per Section III.M						
Complete Distribution Automation Project	ü	ü	ü				
Update Integrated Planning Process		ü	ü				

Figure 16 illustrates the interdependencies of these items. While some of these items are being completed as a part of this DSIP update (e.g., substation-level probabilistic forecasts for load, solar, and energy efficiency), they are not yet integrated into the planning process and therefore do not have a future date associated with them.

Figure 16: Interdependency of Planning Process Roadmap Items



The CGPP and DSIP are filings with overlapping but distinct scope. The CGPP will detail the evolution of distribution planning processes needed to meet CLCPA goals, align with transmission planning processes, and ensure that planning is integrated. The DSIP describes implementation of the much broader set of DSP activities and projects, and how those activities holistically align with CGPP and CLCPA goals. The CGPP will be more singularly focused on a process to identify distribution system needs to meet CLCPA State goals and develop a distribution investment plan, including capital projects, to meet those needs. Planned capital investments, including technology platform investments and how they will be leveraged will be included in the DSIP (e.g., AMI, automation, ADMS, etc.) and the results of executing the processes will be used to inform the CGPP.

The CGPP is aimed at developing a "CLCPA-focused planning process," including "the State's bulk transmission, local transmission, and distribution planning processes." The goal is to improve planning processes to better coordinate the studies performed by the Utilities with the NYISO's bulk-power system planning and generation interconnection processes; improve the integration of Local Transmission and Distribution (LT&D) and bulk system studies with NYSERDA's renewable generation and storage procurements; and improve forecasting of renewable generation development for specific locations on the LT&D and bulk transmission grid. As part of the December 2022 CGPP proposal, one of the key inputs to the CGPP process is the generation build-out scenarios identified by the Energy Policy Planning Advisory Council (EPPAC). While forecasting practices for the CGPP and DSIP are aligned, the scenarios identified by the EPPAC may result in different forecasts than those completed as part of the DSIP. The output of the CGPP thus may result in the identification of Phase 2 capital projects that are not already identified in current rate plans. Although capital projects identified within the CGPP are intended to be funded under the FERC load ratio share methodology, these Phase 2 projects once approved will be incorporated and used to inform the normal DSIP and planning processes.

c) Integrated Implementation Timeline

Refer to Figure 8 under Grid Modernization for the implementation timeline related to Integrated System Planning.

3. Risks and Mitigation

While the Integrated Planning process allows more stakeholders to actively contribute to Central Hudson's system needs, the complexity and inclusion of many new parties and technologies add to the risk of the system. The process of the future is dependent upon the System Forecasting process, which will be driven not only by uncertainty in base system loads, but also uncertainty regarding the connection of DERs. The utility has very limited control over most elements that drive when a DER will interconnect to the grid or whether a project will ultimately be completed. Policy decisions or pricing changes can impact a forecast overnight. Moreover, many DERs (such as solar photovoltaics) operate intermittently and have limited restrictions on when they may disconnect and the notifications required, both temporarily and permanently, further challenging the forecasts. Also, DERs participating in NYISO markets may be driven by economic signals that need to be balanced with local distribution system reliability.

To mitigate the risk, the Company has transitioned to a probabilistic based forecasting methodology, which separates DERs from base load forecasts. This allows the Company to better assess scenarios of forecast uncertainty for up to ten years in advance and consider a plan that may be required for those cases. For nearly all transmission load pockets and substations, the risk of exceeding thermal limitations is very low, either because loads are declining or flat or because there is amply capacity, net of DERs. The risk is concentrated on a limited number of locations that are growing and have limited capacity to accommodate additional growth. Although peak load forecasts were critical in the past, minimum load forecasts are now crucial to understand when equipment may be back fed or when other system risks may occur. This is particularly important because of the aggregation of several clustered, small DER projects that may not have been rigorously studied. Additionally, with the anticipation of electrification impacts and NY State projecting to become a winter peaking state, it is important to differentiate forecasts for both summer and winter periods. Therefore, 8760 summer peak and winter peak forecasts have been completed for all substations, and Central Hudson will continue to produce these forecasts in the future. Additionally, operational processes and procedures will also mitigate the risk as the Distribution Management System (DMS) becomes fully integrated. By establishing a Distribution Energy Resources Management System (DERMS) in the future Central Hudson can further control DERs when needed. As the DMS is further developed, processes and procedures will need to be prepared to incorporate this functionality and integrate planning and operational aspects.

Implementation of probabilistic forecasting and the Grid Modernization strategy involves complex projects that do carry scheduling risk, but due diligence, progress to date, and the continuation of current processes until an appropriate cutover time has mitigated some of that risk.

4. Stakeholder Interface

The NYISO, with input from Market Participants, is responsible for analysis of the New York Control Area's (NYCAs) Bulk Power Transmission Facilities, and the Transmission Owners are responsible for developing solutions to any identified Transmission Security issues. As part of the NYISO's Comprehensive System Planning Process, the NY TOs provide their Local Transmission Plans (LTP) at least biennially. For Central Hudson, the LTP is based on the transmission system projects contained in the Electric Capital Forecast.

For facilities that fall outside of the NYISO's jurisdiction, the stakeholder interface with the Integrated Planning process primarily includes the inputs and outputs of the process, rather than the process itself. Stakeholder engagement regarding load forecasting is described further in DER Interconnections and Hosting Capacity analysis and their potential ties to the Integrated Planning process. Much of the System Data used to drive the Integrated System Plan is publicly available, as described in Data Sharing.

The key output of the Integrated Planning Process is the Electric Capital Forecast. The 5 Year Capital Budget plan is filed annually with the Public Service Commission and is publicly available. Projects which meet the NWA Suitability Criteria are considered through the NWA Procurement Process described in Beneficial Locations for DERs and Non-Wires Alternatives.

As previously indicated, the stakeholder interface with the Integrated Planning process primarily includes the inputs and outputs of the process, rather than the process itself. Stakeholder engagement regarding load forecasting is described further in DER Interconnections and Hosting Capacity and their potential ties to the Integrated Planning process. Additionally, much of the System Data used to drive the Integrated System Plan is publicly available, as described in Data Sharing.

5. Additional Detail

a) Means and methods used for integrated system planning

The means and methods used for integrated system planning are described throughout this section, and any other sections that are referenced, as well as noted in documents such as the Electric System Planning Guides.

b) How the utility's means and methods enable probabilistic planning which effectively anticipates the inter-related effects of distributed generation, energy storage, electric vehicles, beneficial electrification, and energy efficiency.

Central Hudson has transitioned to probabilistic, granular forecasting. By design, the approach includes:

1. Tracking of when, where, and who adopts individual DERs.

2. Using the data on adoption to fit adoption diffusion curves and forecast aggregate adoption with uncertainty.

3. Estimating the propensity of customers to adopt different types of DERs at granular level, typically for individual premises.

4. Assessing the impact of the adoption of DERs on individual substation and transmission areas. This is grounded on layering hourly (8760) DER load shapes on substation and transmission area loads.

For most DERs – energy efficiency, solar, and electric vehicles – Central Hudson has already quantified which customers and locations have a higher propensity to adopt specific DERs based on characteristics such as energy use patterns, weather sensitivity, customer size, participation in other programs, ownership of other DERs, and geographic location. The estimates reflect the interrelated effects of DERs. For example, customers with distributed solar are more likely to adopt electric vehicles and vice versa. The Appendix B provides additional details regarding Central Hudson's T&D and DER forecasting methodology. These probabilistic forecasting methodologies must be integrated into Central Hudson's planning process per the roadmap in Table 3.

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

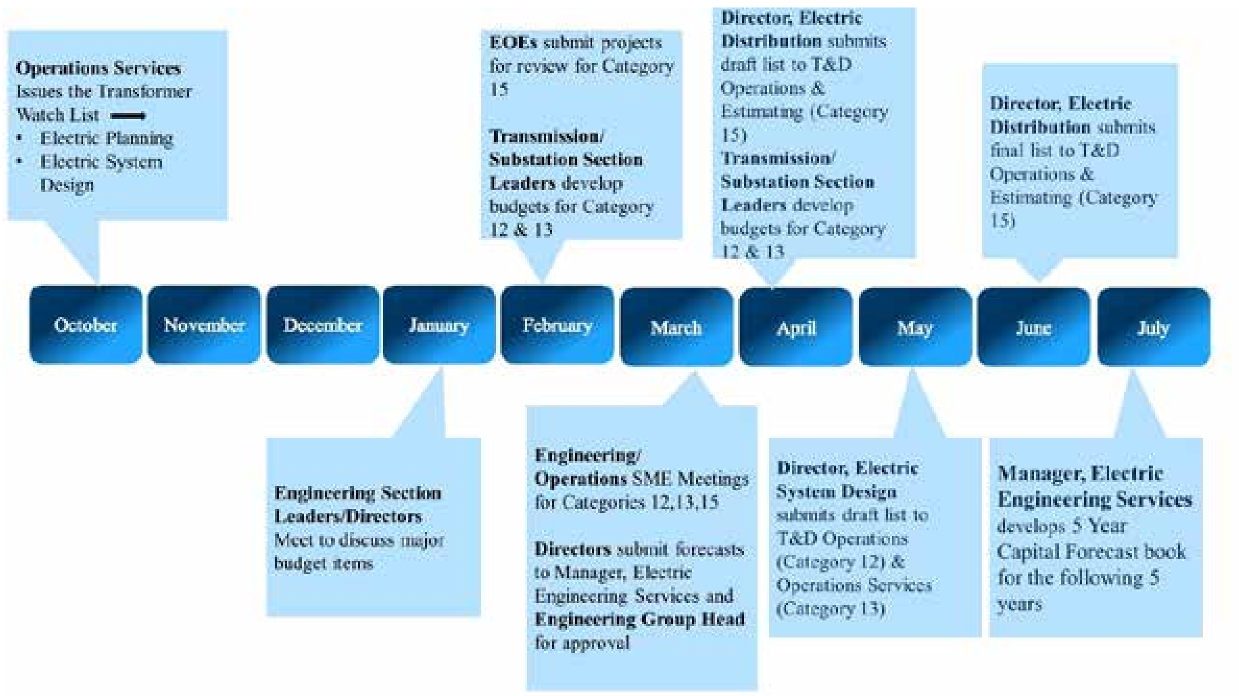
The key inputs to integrated system planning are: (1) load forecasts, (2) infrastructure assessments, and (3) reliability data.

The (1) load forecasts are highly dependent upon the availability of substation metering data and the DER inventory. The Electric System Planning Guides describe the process for updating metering data. Where electronic hourly data is available, it must also be spot checked to resolve any inaccuracies. As described in Section III.J, the inventory of distributed generation and energy storage systems is maintained through the Company's Interconnection Online Application Portal and filed with the Public Service Commission on a monthly basis. Distributed Generation and Energy Storage Systems are also mapped in our ESRI GIS model. Program-based energy efficiency information is also tracked and readily available.

Transitioning to (2) infrastructure assessments, the Electric System Planning Guides document the analysis that is required. Finally, (3) reliability data is heavily scrutinized to reconcile outage information and report the information to the Public Service Commission every month. Annually, a detailed System Reliability Report is filed with the Public Service Commission that includes data by distribution feeder.

The process for developing the Capital Investment Forecast is documented in the Capital Prioritization Guidelines[8]. Figure 17, which is included in the aforementioned guidelines and reproduced below, illustrates the development timeline.

Figure 17: Electric Capital Forecast Development Timeline



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

Sensitivity analysis is typically applied when scenario-based models are employed, when key inputs are based on assumptions, or when there is substantial uncertainty around critical drivers of results. Since Central Hudson is transitioning to a probabilistic approach where feasible, Central Hudson will not typically apply this analysis.

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[8] *Initial DSIP*, Appendix G.

Central Hudson's objective is to rely on data-driven, probabilistic analysis, which minimizes assumptions and, by definition, models the range of likely outcomes. When and where possible, Central Hudson has shifted away from scenario-based models, which are more suitable for sensitivity analysis. The uncertainty for key inputs, such as load growth, were explicitly quantified based on the available data, and the implications of the uncertainty on outcomes were quantified based on Monte Carlo simulations, showing the full range of potential outcomes.

Sensitivity analysis still plays an important role for technologies in a nascent stage or experiencing truly disruptive innovation(s). Because historical data for those technologies is limited, any current projections rely on assumptions or data from proxy technologies. For example, for electric vehicles, Central Hudson employed data on the adoption of proxy technology, green vehicles overall, which includes hybrids, EVs, and plug-in hybrids. To explore the potential of higher penetration rates, the models were pressure tested by assuming that the penetration of electric and plug-in electric vehicles would double that of hybrids. A similar approach will be employed for battery storage once enough data is available.

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

The process for Central Hudson to adjust its plans in the short term is not likely to vary from the process in place today. Emerging needs will be addressed by reprioritizing projects within the existing Capital Plan or by releasing contingency funding as necessary. Similarly, if load does not materialize in an area where a load-based project is required, that project will not move forward unless there are other drivers (e.g., infrastructure considerations). The Capital Prioritization Guidelines were finalized in May 2015 and are also included as Appendix G to the Initial DSIP filing.

In the longer term, the probabilistic-based forecasting methodology will provide insight into some of the potential variability from the predicted forecast so that the Company can monitor and more proactively plan for worst case scenarios. The substation loading forecasts provide an annual check on what areas of the system may require reevaluation. But when an NWA is already contracted for a project, it is more challenging to undo. Still, a project may have an opportunity for further deferral if load does not materialize, or a traditional solution may have to be accelerated if load grows more quickly than anticipated or DERs do not come to fruition as expected.

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

The integration of aging infrastructure into the Integrated Planning Process is described at the beginning of this Section, including reference to the Long Range Electric System Plan in Appendix C that is an output of the process. Although Central Hudson's long-term experience is not specific to electric vehicles (EV) and beneficial electrification, the Company's existing processes are well equipped to manage load growth. Multiple EV charging stations have been successfully installed throughout Central Hudson's service territory. Based on preliminary analysis both EVs and Electrification have shown that they are most likely to have an impact on service laterals and service transformers which can be upgraded via our normal process. Central Hudson is currently reviewing minimum service lateral and transformer requirements. Small conductor distribution lines may also require upgrades and Central Hudson has programs within its Distribution Capital Budget to address these typically aged distribution lines consisting of #4 Cu or 4800 V construction. As EVs are in the early stages of development and the Company has latent capacity available on its system, it would not be prudent to overinvest in anticipation of EVs and other technologies that are undergoing electrification. However, as part of the April 20, 2023, Order instituting a proceeding on addressing barriers for medium and heavy-duty EV charging infrastructure (Case 23-E-0070), Central Hudson will participate as a stakeholder to identify areas where proactive utility planning may be prudent. Section III.E describes the initial steps the Company is taking to begin developing a framework for the future as EV penetration increases. As a part of the Current Rate Plan, Central Hudson continues to advocate for beneficial electrification, especially for programs and rate design that encourages improved load factor and system efficiency, such as expanding the use of geothermal technology as well as actively funding heat pump electrification projects. The Company continues to monitor other technologies considering electrification through participation in Electric Power Research Institute programs.

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

Similar to other DERs, the impact of energy efficiency must be considered as a part of the forecasting process. A system-wide forecast is developed at the corporate level, both with and without the impacts of energy efficiency, which can then be allocated to the substation level. The range of forecasts will allow System Planners to monitor longer-term system needs and develop planning alternatives depending upon how much of the energy efficiency comes to fruition. Additional detail regarding Energy Efficiency Integration and Innovation can be found in Energy Efficiency Integration and Innovation.

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

Central Hudson actively participates with the Electric Power Research Institute's Distribution Planning and Operations program. Through attendance at semi-annual conferences, Planning interest group meetings, and webinars, the Company stays abreast of the latest developments in System Planning and integrates learnings into its processes as appropriate.

Central Hudson also participates in the NYISO's Interconnection Process. Through this process, Central Hudson is made aware of projects proposing to connect to its transmission system and neighboring transmission systems. As part of the NYISO Interconnection Process, Central Hudson reviews and contributes to the analyses of these proposed projects. Through the NYISO's Electric System Planning Working Group, Central Hudson continues to participate and advocate for improvements to the planning and interconnection process on the bulk electric system and the alignment of those processes within the DSP.

The Joint Utilities of New York and the NYISO also hold periodic meetings and conference calls to discuss the inputs and outputs of the various planning processes, such as forecasting, hosting capacity, interconnection, and non-wires alternatives, at both bulk system and non-bulk levels.

B. Advanced Forecasting

1. Context and Background

A vital role of Central Hudson is to ensure that the electricity supply remains reliable by projecting future demand and reinforcing the transmission and distribution network, so the capacity is available to meet local needs as they grow over time. Proper design of the electric grid is critical to ensure that power can be delivered from where it is produced to where it is used.

The forecast and planning are done on a system-wide basis and for individual components of the system, including distribution circuits, substations, and transmission areas. Historically, electric grids were engineered to accommodate a unidirectional flow of electricity from centralized generation to end users. Generation, transmission, and distribution infrastructure components were sized to meet the aggregate peak demand of the customers connected to specific grid components. In addition, the planning process ensures that power can be rerouted in case of prolonged or temporary outages.

The electricity industry is experiencing rapid technological change, particularly with the introduction of distributed energy resources and the electrification of heating and transportation. The shift affects both (1) how, when, and where customers use electricity and (2) how, when, and where electricity is produced. Several factors have the potential to influence electric grid planning:

- The adoption of electric vehicles;
- Building electrification initiatives;
- The adoption of distributed solar including community solar;
- The introduction of battery storage;
- Customer growth and migration patterns;
- Behavioral changes regarding how and when customers use electricity;
- New appliance and building codes and standards;
- Program-based introduction of energy efficiency; and
- Increased penetration of connected devices, such as smart thermostats, where the power use can be remotely controlled and response automated.

If properly harnessed and directed, technological change can improve the utilization of existing resources, either by shifting the use of power away from peak periods or by injecting power into the grid when and where it is needed most. However, several of these technologies are in their nascent stages, making their adoption and impact on the electric grid challenging to predict. Almost by definition, disruptive technologies are difficult to identify and predict in advance.

a) Forecasting Principles

No one knows precisely when loads will reach levels that trigger infrastructure upgrades. However, linear forecasts assume precise knowledge. In practice, actual growth trajectories are rarely linear, and growth patterns trend across time.

Forecasts inherently include uncertainty and become more uncertain further into the future. The uncertainty for a forecast ten years out is larger than the uncertainty for a forecast one year out. Because a linear forecast assumes exact knowledge, no risk is assigned to the years before the linear forecast exceeds levels that trigger infrastructure upgrades. Probabilistic methods, on the other hand, reflect the potential reality that infrastructure upgrades could be triggered earlier or later.

Because no one knows exactly what the future holds, Central Hudson has embraced probabilistic planning and adopted five guiding principles:

1. Forecast T&D loads, adoption of DERs, and beneficial electrification;
2. Produce location-specific forecasts as granular as realistically possible;
3. Track adoption of DERs regularly in as granular a manner as possible;
4. Embrace probabilistic methods and produce forecasts that appropriately reflect uncertainty, and;
5. Connect the probabilistic forecasts to the assessments of T&D deferral potential and value.

While the approach requires a substantial amount of effort, the results are grounded in empirical data and better reflect the limitations of what we know about changes in T&D loads and the adoption of DERs and beneficial electrification.

b) System Level Forecasts

Central Hudson's Initial DSIP filing provided a comprehensive discussion of the system-wide forecast prepared by the Company, which begins with the development of energy sales projections along multiple electric sectors. These projections are aggregated with a projection of system losses to produce a forecast of net energy which, in turn, is paired with a peak demand forecast to yield an annual system electric load forecast. While the overall forecasting process has not changed since the 2016 DSIP filing, continued refinements in the econometric models, updates to the data used to develop the forecasts, and methodological modifications for addressing DER have been made.

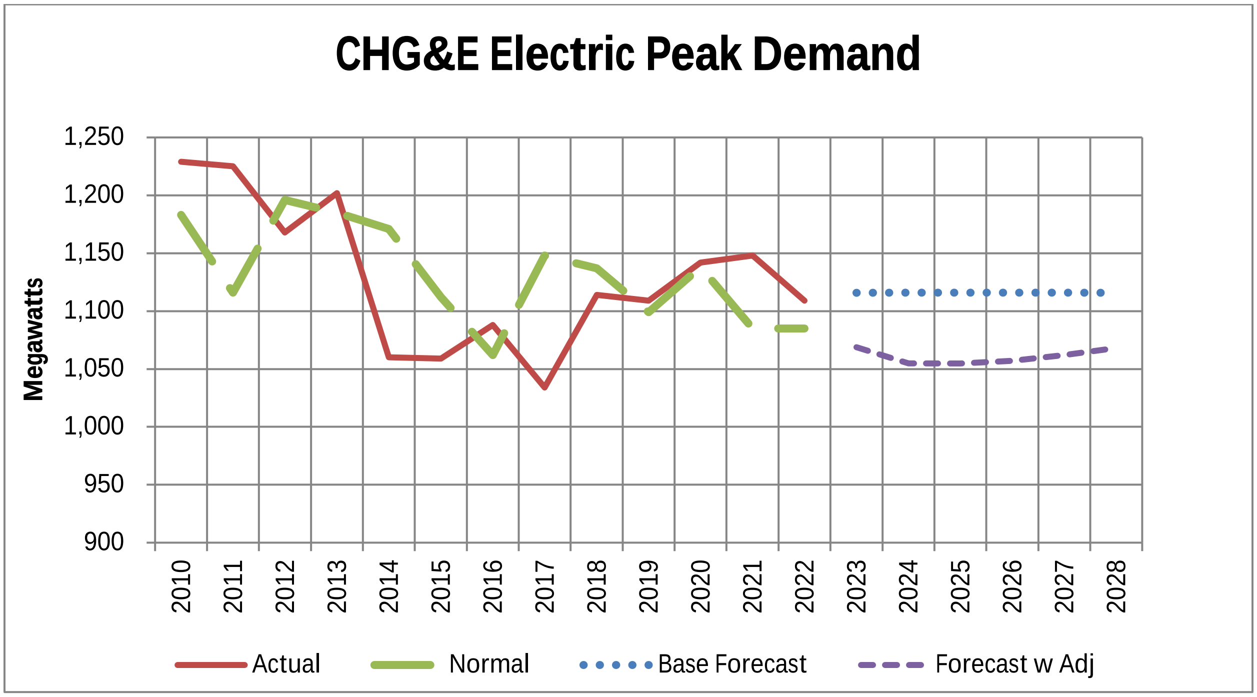
While forecasts of monthly customers, sales and revenue, and annual peak demand are developed on request, they are also routinely developed on an annual, scheduled basis for integration along financial, accounting, energy procurement, regulatory and system planning purposes. The majority of the sales projections and the peak demand projection are developed through econometric analysis.

Historically, both EE and PV interconnected to the distribution system and were addressed external to the sales modeling process. This prevented the sales regression models from assuming that the historical EE and PV growth patterns would continue in the future, thus allowing the growth patterns to be altered and applied as a post-forecast adjustment. The results of recent analyses indicate that EE cumulative savings are expected to continue on the same trajectory as historic cumulative savings. As a result, the most recent sales and annual peak demand forecasts do not contain explicit EE adjustments instead the forecasts are shaped by the historic EE savings embedded in actual billing and peak system data. The forecasts also formally address initial statewide efforts to stimulate electrification through implementation of a heat pump program and continued, albeit very modest, penetration of electric vehicle transportation.

The 5-year top-down System Level Forecast, shown in Figure 18, reflects a level of DER that was derived from various sources that differ from the sources and assumptions that were used in the development of the granular level forecast. One of the primary differences stems from the focus of the System Level Forecast on billed sales and peak metered load in contrast to the focus of the granular level forecast on the loading of individual components of the Company's electric system. As a result, there is a difference in how DERs are reflected in each of the forecasts. For example, DERs that are subject to net energy metering reduce the system-wide forecast of billed sales and metered peak, while DERs subject to monetary compensation for exports, such as community distributed generation (CDG), do not impact metered consumption. In contrast, the granular level forecast addresses the system loading impacts of the various DERs. However, where possible the granular forecasting methodology was aligned with the top-down system forecast.

The Company continues to see significant solar penetration. Moreover, electrification, mainly in the heating and transportation sectors, is increasingly affecting system throughput. As a result, the Company continues to assess the frequency, method, and content of its system sales and demand forecasts to provide more accurate and timely information to address the estimation of sales impacts resulting from these various initiatives.

Figure 18: Preliminary Peak Demand (MW) Forecast



While the aforementioned system-wide forecasts and the location-specific forecasts discussed below continue to be developed independently of each other, they are both utilized within the integrated planning process. The bottom-up, location-specific forecasts are aligned with the system-wide forecasts and any differences are reconciled.

c) *Location-Specific Forecasts*

The integration of DERs requires significant changes to how distribution planning takes place and how it is coordinated with system forecasts. Before the DSIP process was initiated in 2016, the approach was to develop load growth forecasts for each broader area within Central Hudson's territory and apply them to the specific peak loads for substations and transmission areas. Central Hudson has evolved its planning process to produce granular, location-specific, probabilistic forecasts.

A potential key barrier, however, is that not all feeders and substations have meters collecting hourly or sub-hourly data. Once meters are installed, several years of data need to be collected to estimate local annual growth trends. For Central Hudson, this barrier has been eliminated through ongoing infrastructure replacement programs. Currently, Central Hudson has hourly metering data available for approximately 97% of its cumulative system load, an improvement over 95% for the 2020 DSIP and the achievement of a goal laid out in the 2020 DSIP.

The bottom-up granular forecasts have been designed to isolate the key drivers of change in loads. Specifically, to isolate load growth trends from solar interconnections, historical solar production is added back to the observed historical loads. The objective is to quantify the growth in gross loads separately from the growth in distributed generation, which reduces net loads but does not reduce gross energy usage. In addition, the forecasts separately track gross loads, solar, battery storage, building electrification, electric vehicle loads, and incremental energy efficiency (including codes and standards). The approach allows Central Hudson to combine the various components for different planning applications, such as the Avoided T&D Costs Study loads (which do not include distributed energy resources that have not yet been built).

Table 2 illustrates the components of the bottom-up load forecasts. A similar forecast is produced for each of Central Hudson's transmission areas, substations, and circuit feeders. The granular forecasts can be summarized for the coincident (territory-wide) or non-coincident (local) summer and winter peak at different levels of geographic granularity. They also can be shown for the single peak hour, for peak days, or for the full 8760 hours per year and each level of geographic granularity. The Granular Load and Distributed Energy Resource Forecasting report (Appendix B) includes two electronic appendices with the planning forecasts for the local coincident hour and the 24-hour forecasts for summer and winter peaks by year and location.

Table 2: Summer and Winter Territory-Wide Load Forecast with and without DERs and Beneficial Electrification (2023-2028)

Season	Year	(a) Gross Load Forecast	(b) EV Load	(c) Building Electrification	(d) EE & C&S	(e) Solar PV	(f) Storage Net Load	(g) Planning Load a + b + c + d + e + f
Summer	2023	1,115.4	8.8	-1.4	-7.2	-27.0	-8.1	1,080.5
	2024	1,115.9	13.1	-2.8	-13.6	-31.7	-8.4	1,072.4
	2025	1,116.7	19.1	-4.7	-21.2	-36.8	-9.5	1,063.6
	2026	1,118.1	27.2	-7.1	-28.8	-42.9	-10.2	1,056.3
	2027	1,119.9	37.7	-9.8	-36.2	-49.9	-11.2	1,050.5
	2028	1,122.2	50.8	-13.0	-43.7	-55.9	-12.3	1,048.1
Winter	2023	945.0	5.9	9.3	-7.1	-2.7	-8.1	942.3
	2024	945.5	8.8	19.0	-13.4	-3.2	-8.3	948.4
	2025	946.3	12.9	32.2	-20.9	-3.7	-9.4	957.4
	2026	947.6	18.5	48.1	-28.3	-4.3	-10.1	971.4
	2027	949.2	25.7	66.5	-35.6	-5.1	-11.1	989.7
	2028	951.2	34.7	87.5	-43.0	-5.7	-12.3	1,012.6

[1] The peak values displayed in the table are coincident with the planning load for Central Hudson service territory

Table 3 shows the forecast used for the Avoided T&D study, which is different from the forecasted or expected loads. By design, the study's objective is to identify T&D upgrades that would occur if additional or incremental distributed resources – solar, battery storage, and energy efficiency – were not added, and to quantify the deferral value associated with reductions in demand (or local power injections). Thus, the avoided T&D study forecasts include existing DERs, and the impact of electric vehicles and building electrification, but does not include DERs that had not yet been built. The Location Specific Transmission and Distribution Avoided Cost report (Appendix D) includes two electronic appendices with the T&D avoided costs forecasts for the coincident hour and the 24-hour forecasts for summer and winter peaks by year and location.

Table 3: Summer and Winter Territory-Wide Avoided T&D Cost Forecast (2023-2028)

Season	Year	(a) Econometric Forecast	(b) EV Load	(c) Building Electrification	(d) Avoided T&D Cost Forecast a + b + c
Summer	2023	1,127.2	8.6	-1.6	1,134.2
	2024	1,127.4	12.8	-3.2	1,137.0
	2025	1,128.1	18.6	-5.5	1,141.3
	2026	1,129.3	26.5	-8.2	1,147.6
	2027	1,131.0	36.8	-11.4	1,156.4
	2028	1,133.2	49.6	-15.1	1,167.7
Winter	2023	943.8	5.9	9.3	959.0
	2024	944.3	8.8	19.0	972.1
	2025	945.1	12.9	32.2	990.3
	2026	946.4	18.5	48.1	1,012.9
	2027	948.0	25.7	66.5	1,040.3
	2028	950.0	34.7	87.5	1,072.3

[1] The peak values displayed in the table above are coincident with the avoided T&D cost forecast peak for Central Hudson territory

As described above, the bottom-up, location-specific forecasts are reconciled with the system-wide forecasts to ensure that any differences are minimal and explained by line losses.

Location-Specific Forecast Methodology for Loads

The forecasting process can be summarized in five main steps. These steps are:

1. **Clean and fill the data**. Historically, data quality for substations and circuit locations has been a barrier to their use for more granular load forecasting due to lack of metering, meter data gaps, and abnormal system operations or configurations. This step required extensive use of data analytics to identify and remove load transfers, outages, data gaps, and data recording errors. Load transfers were of particular importance since they can be confused with load decreases or growth. After identifying anomalous data, gaps were filled with synthetic data predicted from neighboring areas' loads and temperature conditions. For five substations with no interval data at all, we estimated growth patterns based on annual sales of customers at these locations.

2. **Add back solar production.** Historical solar production is added back to the observed historical loads to isolate load growth from growth in distributed generation which reduces net loads but does not reduce gross energy usage. Central Hudson tracks when and where solar installations occur, and the magnitude of the installations. It also collects interval data on solar production for larger installations in its service territory. Thus, the process adds back the estimated hourly solar hourly production based on the amount of solar installation at each circuit feeder and each date.

3. **Estimate historical load growth trends and noise**. The objective was to estimate historical load growth for each year in 2018–2022 in percentage terms. The year-to-year growth patterns were then used to assess the growth trend and the variability of load growth patterns; the degree of growth in a given year was related to growth during the prior year – technically known as autocorrelation. The econometric models were purposefully designed to both estimate historical load growth and allow for the weather normalization of loads for 1-in-2 weather peaking conditions. The key to this process was to model the natural log of the daily peak loads as the dependent variable and include time-specific coefficients to estimate the percent change in loads, after controlling for other factors. By using the natural log as the dependent variable, the time-specific coefficients estimate the annual percent change in loads after controlling for differences in weather conditions, day of week effects, and seasonality.

4. **Weather adjust loads for 1-in-2 conditions**. Based on historical patterns, years 2012 and 2006, respectively, reflect the 1-in-2 and 1-in-10 summer weather conditions. Years 2022 and 2004, respectively, reflect the 1-in-2 and 1-in-10 winter weather conditions, which were selected and modeled separately given the expected increase in electrification and its effect on winter peak loads. Econometric models were used to weather normalize the loads and remove the inherent variation of weather across years.

5. **Simulate potential load growth trajectories**. The load growth forecasts were developed using probabilistic methods – Monte Carlo simulations – that produced the range of possible load growth outcomes by year. This exercise simulates the reality that the near-term forecast has less uncertainty than forecasts ten years in the future. A total of 5,000 simulations were performed for each transmission area and substation. Each simulation produced a distinct growth trajectory that took into account the historical trend, variability in growth patterns, and the fact that growth patterns are auto-correlated.

6. **Add in DER forecasts.** The final step is to incorporate the DER forecasts into the

Transmission Historical Loads and Forecasts

The historical peak demands, room for growth, and growth trajectories vary widely across transmission areas. Most areas are experiencing declining loads, but a few areas are growing. Actual historical peak demand levels are first summarized, followed by the presentation of weather normalized historical peaks and forecasts for each location.

Table 4 shows the historical peaks and growth rates for each of Central Hudson's ten transmission areas. Table 5 shows weather normalized historical and forecasted peaks. Locations with loading factors closer to 100% have less room for growth. Most transmission areas are experiencing declining loads or limited growth or else have low loading factors. However, two transmission areas – RD RJ Lines and Westerlo Loop – are currently loaded above 75%, are experiencing positive growth at or above 0.5% per year, and have a 5% or greater likelihood of triggering an infrastructure investment by 2033. The RD-RJ lines peak in the summer and Westerlo Loop peaks in the winter. Both locations would require infrastructure upgrades to meet the higher loading predicted in the forecast.

Finally, Table 5 shows the historical peaks, normalized for 1-in-2 weather conditions alongside the forecasted local peak used for the T&D avoided cost study, e.g. (corresponding to column d from Table 3). This T&D avoided cost study forecast was developed by adding the end use load forecast based on historical growth trends to load growth expected from vehicle and building electrification . Area loading is the load as a percent of the area rating, which includes contracted Non-Wires Alternatives (NWAs). Importantly, load reducing distributed energy resources (DERs) are not subtracted from this load estimate, because they are not contracted and are therefore uncertain. Further, if these uncertain reductions are assumed to show up, their value is essentially removed from the load reduction valuation. Note that in Table 4 and Table 5 the Westerlo Loop area is nested within the NW 69 Area and the NW 69 Area is nested within the NW 115-69 Area. Not all substations are located within a transmission area. For these two reasons, the sum of the transmission areas will not equal the total system load. Finally, the ratings shown in Table 4 and Table 5 correspond to 2022 ratings, and all ratings shown include active Non-Wires Alternative project capacity. Transmission areas can peak in either the summer or the winter. In Table 4 and Table 5 transmission areas with a winter peak in 2028 (5 years into the forecast) are indicated with an asterisk (*).

Table 4: Transmission Area Historical Gross Load Growth Estimates (2019-2022)

Transmission Area	Rating (MVA)	Historical Peak (MVA)				Loading	Annual Growth	Std. Error
		2019	2020	2021	2022			
Ellenville*	130.0	61.4	63.6	60.1	66.5	48.7%	-0.3%	1.5%
Hurley-Milan*	232.0	82.7	79.8	77.9	83.9	30.6%	-1.6%	1.3%
Mid-Dutchess	230.0	114.7	115.6	105.6	112.4	48.9%	-1.9%	0.9%
NW 115-69 Area*	179.8	129.0	133.6	119.8	128.9	76.0%	-1.3%	1.7%
NW 69 Area*	200.5	106.8	101.1	101.4	107.9	55.7%	1.2%	1.2%
Pleasant Valley 69	107.0	69.3	71.3	67.3	72.4	74.6%	0.4%	1.8%
RD-RJ Lines	144.0	114.4	114.8	113.1	113.6	92.0%	1.1%	3.4%
Southern Dutchess	211.0	148.5	146.5	151.3	146.1	84.1%	-0.1%	2.4%
WM Line	68.0	49.0	52.6	49.6	55.0	79.7%	0.0%	1.5%
Westerlo Loop*	83.6	62.6	61.7	59.7	60.9	76.0%	0.5%	1.7%

[1] The peak values displayed in the table above reflect the T&D avoided cost forecast and are coincident with the avoided T&D cost forecast peak for each transmission area

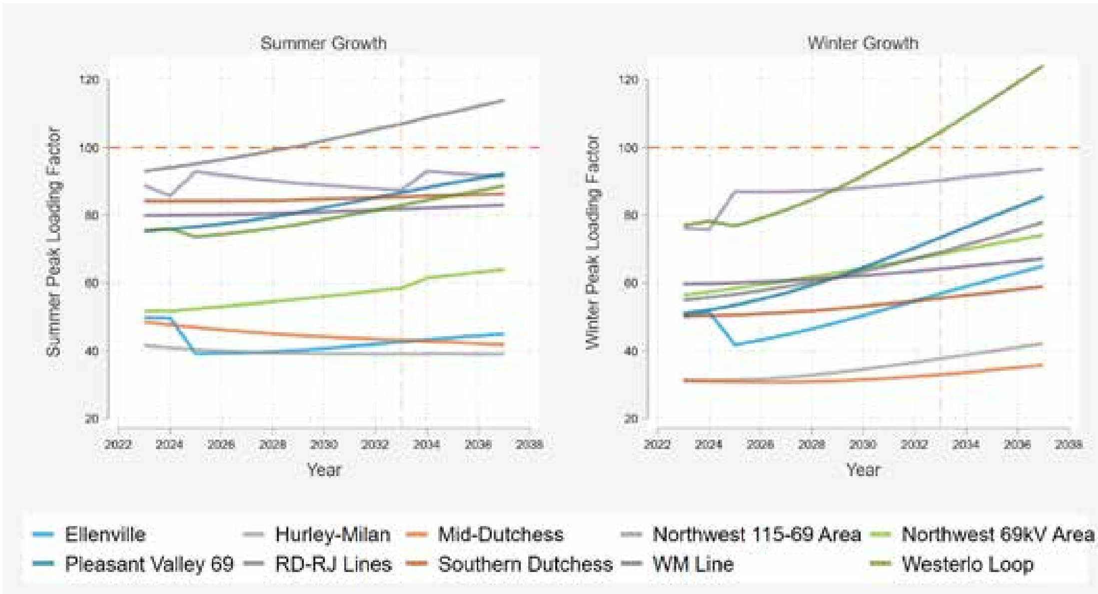
Table 5: Transmission Area Normalized Peak Load Estimates, Historical (2018-2022) and Avoided T&D Forecast (2023-2028)

Transmission Area	Historical 1 in 2 Annual Peak (MVA)				Forecasted 1 in 2 Annual Peak (MVA)						Rating (MVA)
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	
Ellenville*	64.9	64.7	64.5	64.3	65.3	66.9	68.9	71.2	73.8	76.7	130.0
Hurley-Milan*	84.6	83.3	81.9	80.6	80.1	78.9	78.0	77.2	76.5	76.2	232.0
Mid-Dutchess	119.1	116.8	114.6	112.4	111.6	109.7	107.9	106.3	104.8	103.5	230.0
NW 115-69 Area*	142.2	140.4	138.5	136.7	137.0	136.3	135.8	135.6	135.8	136.1	179.8
NW 69 Area*	107.8	109.1	110.3	111.6	113.1	115.0	117.1	119.2	121.5	123.9	200.5
Pleasant Valley 69	78.8	79.2	79.5	79.8	80.7	81.3	82.0	82.9	83.9	85.1	107.0
RD-RJ Lines	128.6	129.9	131.1	132.5	133.8	135.4	137.1	138.8	140.8	142.9	144.0
Southern Dutchess	178.4	178.0	177.6	177.4	177.8	177.8	177.8	177.8	178.0	178.3	211.0
WM Line	54.3	54.2	54.2	54.2	54.3	54.4	54.4	54.5	54.6	54.8	68.0
Westerlo Loop*	62.7	62.9	63.2	63.5	64.4	65.4	66.9	68.8	71.0	73.6	83.6

[1] The peak values displayed in the table above reflect the T&D avoided cost forecast and are coincident with the avoided T&D cost forecast peak for each transmission area

Figure 19 shows expected (50th percentile) forecasted transmission area loads as a percentage of the LTE rating from 2023 to 2033 by season, including sharp changes from year to year represent changes to ratings and/or NWA expirations. Because most transmission areas are experiencing declining loads or limited growth, the risk of repeatedly exceeding LTE ratings and triggering an infrastructure upgrade is minimal. The RD-RJ Lines area stands out for being the only location where the peak load exceeds the LTE rating during the summer forecast period, which is driven by a positive expected load growth rate (1.1% per year) and high loading in 2022 (84%). The Westerlo Loop is the only location where the peak load exceeds the LTE rating during the winter forecast period, which is largely due to electrification. All other areas either have no or negative growth or have ample room for growth during the forecast period. Even when looking at the top 90th percentile of growth trajectories, only the RD-RJ Lines and Westerlo Loop exceed the design ratings, with loads for other areas being flat or declining or else substantially below the design rating.

Figure 19: Expected Loading as Percentage of Transmission Area Rating from Avoided T&D costs study, Including NWAs



Appendix B further discusses the transmission area forecasts and how they were used to identify locations with T&D deferral potential.

Substation Historical Loads and Forecasts

Central Hudson developed hourly (8760) forecasts for its ten distinct transmission areas and all distribution load-serving substations. Some substations either lacked data or had lower quality data, which prevented the estimation of location-specific forecasts for all substations. Table 6 through Table 12 compare the historical loading factor and growth rate for each of Central Hudson's substations with at least three years of hourly historical data. Locations with a loading factor closer to 100% have less room for growth. Similar to the transmission areas, most of the substations have ample room to accommodate additional load growth. Substations can peak in either the winter or summer, or the peak can change over time. Substations with a winter peak in 2028 are indicated with an asterisk (*). Table 13 shows historical and forecasted peak loads for all substations, normalized to 1 in 2 weather conditions. Just as with the transmission areas, this T&D avoided cost study forecast was designed to allow for planning to isolate the components of the load growth forecast, including existing loads, electric vehicles, building electrifications, solar, storage, and energy efficiency (including codes and standards). The loading factor is the load as a percent of the substation long-term emergency (LTE) rating, which includes contracted Non-Wires Alternatives (NWAs). Importantly, for the avoided T&D costs study, load reducing distributed energy resources (DERs) are not subtracted from this load estimate, because they have not yet been built. Including DERS that have not yet been built into the avoided T&D cost study dilutes and undercounts the value of load reducing distributed energy resources.

Table 6: Ellenville Area – Historical Load Growth Estimates (2019-2022)

Substation	Rating (MVA)	Historical Peak (MVA)				Loading	Annual Growth	Std. Error
		2019	2020	2021	2022			
Clinton Ave*	11.6	1.7	1.4	1.5	1.6	15.6%	3.4%	3.9%
Greenfield Rd*	23.3	7.2	7.7	7.4	6.6	28.7%	-4.2%	2.2%
Grimley Rd	7.2	5.4	7.0	6.5	7.0	99.2%	4.1%	4.8%
High Falls*	34.5	20.0	19.5	19.2	19.4	56.1%	0.2%	1.6%
Honk Falls	21.1	5.8	5.8	6.2	5.5	28.9%	0.6%	1.9%
Kerhonkson*	47.3	10.6	9.9	10.3	10.8	22.3%	2.2%	1.9%
Neversink*	7.4	3.7	4.2	3.9	3.5	48.1%	-2.0%	2.3%
Sturgeon Pool*	40.3	2.9	2.9	2.7	2.7	6.6%	0.7%	2.1%
Overall	N/A	45.1	43.1	44.2	44.4	.	1.1%	1.4%

[1] The peak values displayed in the table above reflect the T&D avoided cost forecast & are coincident with substation peak

Table 7: Fishkill Area – Historical Load Growth Estimates (2019-2022)

Substation	Rating (MVA)	Historical Peak (MVA)				Loading	Annual Growth	Std. Error
		2019	2020	2021	2022			
Fishkill Plains	50.4	45.0	44.8	49.0	43.0	95.1%	1.6%	2.4%
Forgebrook	47.4	28.3	27.3	28.8	29.4	62.3%	0.7%	1.2%
Knapps Corners	47.8	18.5	17.3	17.6	18.0	39.4%	-1.7%	1.3%
Merritt Park	52.2	30.7	31.9	31.4	30.5	62.2%	-1.1%	1.3%
Myers Corners	35.1	20.4	19.3	20.2	19.9	61.7%	-3.0%	1.6%
North Chelsea	48.3	19.9	20.1	19.2	18.6	44.0%	-3.4%	1.6%
Sand Dock-D	6.0	4.9	4.7	4.7	4.6	82.9%	-4.3%	1.7%
Shenandoah-D	18.9	13.7	13.0	12.6	12.7	71.2%	-1.8%	1.6%
Tioronda	28.7	18.1	16.6	15.2	15.7	60.2%	-0.7%	1.7%
Overall	N/A	196.5	190.9	194.7	186.5	.	-1.0%	1.3%

[1] The peak values displayed in the table above reflect the T&D avoided cost forecast and are coincident with substation peak

Table 8: Kingston-Saugerties Area – Historical Load Growth Estimates (2019-2022)

Substation	Rating (MVA)	Historical Peak (MVA)				Loading	Annual Growth	Std. Error
		2019	2020	2021	2022			
Boulevard*	44.8	17.7	15.5	19.6	19.0	37.2%	0.2%	2.3%
East Kingston	48.0	15.9	16.3	16.1	16.9	36.7%	1.1%	1.4%
Hurley Ave*	28.4	19.7	18.7	18.6	18.8	60.1%	-0.5%	2.2%
Lincoln Park	84.0	38.8	38.3	38.4	38.6	46.2%	-2.2%	1.1%
Saugerties*	70.5	22.0	23.5	22.1	22.6	28.8%	0.5%	1.7%
Woodstock*	23.9	21.3	19.5	20.4	21.6	93.8%	1.0%	1.6%
Overall	N/A	129.2	126.3	130.6	132.4	.	-0.7%	1.2%

[1] The peak values displayed in the table above reflect the T&D avoided cost forecast and are coincident with substation peak

Table 9: Modena Area – Historical Load Growth Estimates (2019-2022)

Substation	Rating (MVA)	Historical Peak (MVA)				Loading	Annual Growth	Std. Error
		2019	2020	2021	2022			
Galeville*	28.7	11.3	11.6	11.5	12.4	37.4%	-0.7%	1.5%
Highland*	37.3	20.0	19.5	19.6	19.4	50.4%	-0.4%	1.4%
Modena	21.1	14.6	14.9	14.3	14.8	75.7%	-0.5%	1.5%
Ohioville*	34.2	21.9	21.2	23.2	22.2	56.4%	-1.4%	1.3%
Overall	N/A	66.6	66.4	65.0	66.9	.	-1.2%	1.1%

[1] The peak values displayed in the table above reflect the T&D avoided cost forecast and are coincident with substation peak

Table 10: Newburgh Area – Historical Load Growth Estimates (2019-2022)

Substation	Rating (MVA)	Historical Peak (MVA)				Loading	Annual Growth	Std. Error
		2019	2020	2021	2022			
Bethlehem Rd	47.8	35.9	36.1	36.0	35.7	82.2%	-0.2%	1.5%
Coldenham	47.8	20.2	24.3	26.0	22.2	49.3%	2.1%	1.6%
East Walden	26.2	16.0	14.5	15.5	16.1	61.6%	-0.9%	1.5%
Marlboro	30.9	21.1	20.7	21.1	21.2	72.1%	-0.5%	1.6%
Maybrook	20.9	19.1	21.7	20.2	20.5	101.7%	-1.0%	1.4%
Montgomery	24.0	4.8	5.1	5.2	4.7	20.0%	-2.3%	1.5%
Union Ave	94.5	63.0	59.9	67.6	65.7	70.7%	1.4%	1.5%
West Balmville	47.8	37.7	35.1	35.0	35.4	76.2%	-1.1%	1.3%
Overall	N/A	202.8	213.7	218.1	220.3	.	-0.2%	1.1%

[1] The peak values displayed in the table above reflect the T&D avoided cost forecast & are coincident with substation peak

Table 11: Northeastern Dutchess Area – Historical Load Growth Estimates (2019-2022)

Substation	Rating (MVA)	Historical Peak (MVA)				Loading	Annual Growth	Std. Error
		2019	2020	2021	2022			
East Park	30.4	13.7	14.0	14.1	13.2	48.3%	-0.2%	1.7%
Hibernia	23.7	13.3	13.6	14.1	13.6	61.1%	1.7%	2.0%
Milan*	38.2	10.7	10.9	12.1	11.1	29.4%	0.9%	2.2%
Millerton*	13.0	5.4	5.1	5.2	5.9	41.8%	-2.3%	1.7%
Pulvers 13	7.2	5.3	5.4	5.6	5.6	83.1%	2.4%	1.8%
Pulvers 34*	26.7	2.8	2.8	3.0	3.2	11.2%	-0.7%	1.4%
Rhinebeck*	47.8	29.9	28.2	27.7	27.3	53.8%	-2.6%	1.5%
Smithfield*	8.7	1.8	1.8	2.0	2.0	22.5%	1.8%	1.0%
Staatsburg	28.9	9.1	9.3	9.5	10.6	36.4%	2.3%	1.6%
Stanfordville*	24.5	4.5	4.3	4.4	5.6	20.8%	7.8%	3.2%
Tinkertown	19.1	15.0	15.5	14.2	17.4	83.0%	0.1%	1.9%
Overall	N/A	**108.0**	**106.2**	**104.7**	**109.0**	.	-0.1%	1.2%

[1] The peak values displayed in the table above reflect the T&D avoided cost forecast and are coincident with substation peak

Table 12: Northwest Area – Historical Load Growth Estimates (2019-2022)

Substation	Rating (MVA)	Historical Peak (MVA)				Loading	Annual Growth	Std. Error
		2019	2020	2021	2022			
Coxsackie*	24.8	6.7	12.1	11.2	9.8	42.3%	4.3%	5.0%
Freehold*	25.0	7.4	7.3	8.1	8.1	31.9%	1.8%	2.9%
Hunter*	21.2	10.7	12.3	10.7	11.0	49.8%	-3.2%	5.6%
Lawrenceville*	19.3	12.1	15.2	12.7	12.8	72.9%	-0.2%	4.3%
New Baltimore	28.7	11.4	13.4	12.7	12.9	47.3%	5.4%	1.7%
North Catskill	35.1	24.8	25.9	26.1	27.0	80.0%	1.0%	1.7%
South Cairo*	29.4	12.1	11.8	13.1	14.0	45.0%	2.5%	1.4%
Vinegar Hill*	21.3	10.4	9.2	9.9	10.8	52.0%	-0.3%	3.1%
Westerlo*	35.0	8.7	8.3	8.2	8.5	24.1%	0.5%	2.0%
Overall	N/A	**88.0**	**94.6**	**93.4**	**98.1**	.	3.1%	1.4%

[1] The peak values displayed in the table above reflect the T&D avoided cost forecast and are coincident with substation peak

Table 13: Poughkeepsie Area – Historical Load Growth Estimates (2019-2022)

Substation	Rating (MVA)	Historical Peak (MVA)				Loading	Annual Growth	Std. Error
		2019	2020	2021	2022			
Inwood Ave	51.2	24.4	25.6	23.5	31.0	53.3%	2.4%	2.2%
Manchester	47.8	32.1	32.6	30.9	30.2	67.4%	-3.5%	1.3%
Reynolds Hill	47.8	36.0	41.4	40.5	41.9	85.5%	1.7%	1.1%
Spackenkill	47.8	33.5	33.4	33.1	32.8	72.1%	-0.5%	1.4%
Todd Hill	47.8	26.7	25.9	25.4	24.6	54.5%	-0.4%	1.6%
Overall	N/A	**148.5**	**154.0**	**146.7**	**155.7**	.	-0.1%	1.1%

[1] The peak values displayed in the table above reflect the T&D avoided cost forecast and are coincident with substation peak

Table 14: Substation Normalized Peak Load Estimates, Historical (2019-2022) and Avoided T&D Forecast (2023-2028)

Load Area	Substation	Historical 1 in 2 Annual Peak (MVA)				Forecasted 1 in 2 Annual Peak (MVA)						Rating (MVA)
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	
Ellenville	Clinton Ave*	1.6	1.7	1.8	1.8	1.9	1.9	2.0	2.1	2.2	2.3	11.6
	Greenfield Rd*,**	7.6	7.3	7.0	6.7	6.7	6.5	6.5	6.6	6.6	6.8	23.3
	Grimley Rd	6.3	6.6	6.8	7.1	7.2	7.5	7.8	8.1	8.5	8.8	7.2
	High Falls*	20.0	20.0	20.0	20.0	20.3	21.0	21.8	22.7	23.8	24.9	34.5
	Honk Falls	6.0	6.0	6.1	6.1	6.1	6.2	6.2	6.3	6.3	6.4	21.1
	Kerhonkson*	10.2	10.4	10.6	10.9	11.0	11.6	12.2	12.9	13.7	14.5	47.3
	Neversink*,**	3.8	3.7	3.7	3.6	3.6	3.7	3.8	3.9	4.1	4.4	7.4
	Sturgeon Pool*	2.8	2.8	2.9	2.9	2.9	2.9	3.1	3.2	3.3	3.5	40.3
	Total	**44.4**	**44.9**	**45.4**	**45.8**	**46.2**	**46.8**	**47.4**	**49.2**	**52.0**	**55.1**	**N/A**
Fishkill	Fishkill Plains	45.8	46.5	47.2	48.0	48.6	49.6	50.6	51.7	52.9	54.2	50.4
	Forgebrook	29.0	29.2	29.3	29.5	29.8	30.1	30.4	30.8	31.2	31.6	47.4
	Knapps Corners	19.8	19.5	19.2	18.8	18.8	18.5	18.2	18.0	17.8	17.6	47.8
	Merritt Park	33.6	33.2	32.8	32.5	32.5	32.1	31.9	31.7	31.5	31.4	52.2
	Myers Corners	23.7	23.0	22.3	21.7	21.6	21.0	20.4	19.9	19.5	19.1	35.1
	North Chelsea	23.6	22.8	22.0	21.2	21.1	20.4	19.8	19.2	18.7	18.3	48.3
	Sand Dock-D	5.7	5.4	5.2	5.0	4.9	4.7	4.6	4.4	4.2	4.1	6.0
	Shenandoah-D	14.2	14.0	13.7	13.5	13.5	13.4	13.2	13.1	13.0	12.9	18.9
	Tioronda	17.7	17.5	17.4	17.3	17.4	17.3	17.3	17.2	17.2	17.3	28.7
	Total	**208.3**	**206.1**	**204.0**	**201.9**	**203.0**	**201.5**	**200.2**	**199.2**	**198.4**	**198.0**	**N/A**
Kingston-Saugerties	Boulevard*	18.6	18.7	18.7	18.7	18.9	19.0	19.1	19.2	19.4	20.0	44.8
	East Kingston	17.0	17.2	17.4	17.6	17.7	17.9	18.1	18.3	18.5	18.8	48.0
	Hurley Ave*	19.9	19.7	19.6	19.5	19.7	19.6	19.6	19.6	19.6	20.1	28.4
	Lincoln Park	41.4	40.5	39.7	38.8	38.5	37.7	36.8	36.0	35.3	34.6	84.0
	Saugerties*	22.9	23.0	23.1	23.2	23.4	23.6	23.8	24.0	24.5	25.6	70.5
	Woodstock*	21.8	22.0	22.2	22.4	23.6	24.5	25.7	26.9	28.3	29.8	23.9
	Total	**133.9**	**133.0**	**132.0**	**131.0**	**131.3**	**130.5**	**129.7**	**128.9**	**130.0**	**133.5**	**N/A**
Modena	Galeville*	12.4	12.4	12.3	12.2	12.3	12.2	12.2	12.2	12.5	12.9	28.7
	Highland*	20.1	20.0	19.9	19.8	19.9	19.9	20.0	20.5	21.2	21.9	37.3
	Modena	16.2	16.1	16.0	16.0	16.0	15.9	15.9	15.9	15.9	15.9	21.1
	Ohioville*	23.8	23.5	23.1	22.8	22.8	22.4	22.1	21.9	21.6	22.0	34.2
	Total	**71.1**	**70.3**	**69.4**	**68.6**	**68.9**	**68.1**	**67.5**	**66.9**	**68.2**	**70.2**	**N/A**
Newburgh	Bethlehem Rd	39.5	39.5	39.4	39.3	39.4	39.4	39.4	39.5	39.6	39.7	47.8
	Coldenham	22.1	22.6	23.1	23.5	23.8	24.4	25.0	25.6	26.3	27.0	47.8
	East Walden	16.6	16.4	16.3	16.1	16.2	16.1	16.0	16.0	16.0	16.0	26.2
	Marlboro	22.7	22.5	22.4	22.3	22.4	22.3	22.2	22.2	22.2	22.3	30.9
	Maybrook	21.9	21.7	21.5	21.2	21.2	21.1	20.9	20.7	20.6	20.5	20.9
	Montgomery**	5.2	5.0	4.9	4.8	4.8	4.7	4.5	4.4	4.3	4.2	24.0
	Union Ave	64.0	64.9	65.8	66.8	67.2	68.2	69.2	70.3	71.4	72.5	94.5
	West Balmville	37.6	37.2	36.8	36.4	36.4	36.1	35.7	35.4	35.2	34.9	47.8
	Total	**225.1**	**224.7**	**224.2**	**223.8**	**224.4**	**224.2**	**224.2**	**224.4**	**224.8**	**225.3**	**N/A**
Northeastern Dutchess	East Park	14.8	14.7	14.7	14.7	14.7	14.7	14.8	14.8	14.8	14.9	30.4
	Hibernia	13.8	14.0	14.3	14.5	14.7	14.9	15.2	15.6	15.9	16.3	23.7
	Milan*	11.0	11.1	11.1	11.2	11.5	11.8	12.1	12.4	12.8	13.3	38.2
	Millerton*	5.9	5.8	5.6	5.5	5.5	5.4	5.4	5.4	5.5	5.6	13.0
	Pulvers 13	5.6	5.7	5.8	6.0	6.0	6.2	6.3	6.5	6.6	6.8	7.2
	Pulvers 34*	3.0	3.0	3.0	3.0	3.1	3.2	3.3	3.6	3.8	4.2	26.7
	Rhinebeck*	30.6	29.8	29.0	28.3	28.2	27.5	26.9	26.3	26.1	26.5	47.8
	Smithfield*	1.9	1.9	1.9	2.0	2.0	2.0	2.1	2.1	2.2	2.3	8.7
	Staatsburg	9.8	10.1	10.3	10.5	10.7	11.0	11.2	11.5	11.9	12.2	28.9
	Stanfordville*	4.1	4.4	4.7	5.1	5.4	5.9	6.5	7.2	8.0	8.8	24.5
	Tinkertown	15.8	15.8	15.8	15.9	16.0	16.0	16.1	16.2	16.3	16.4	19.1

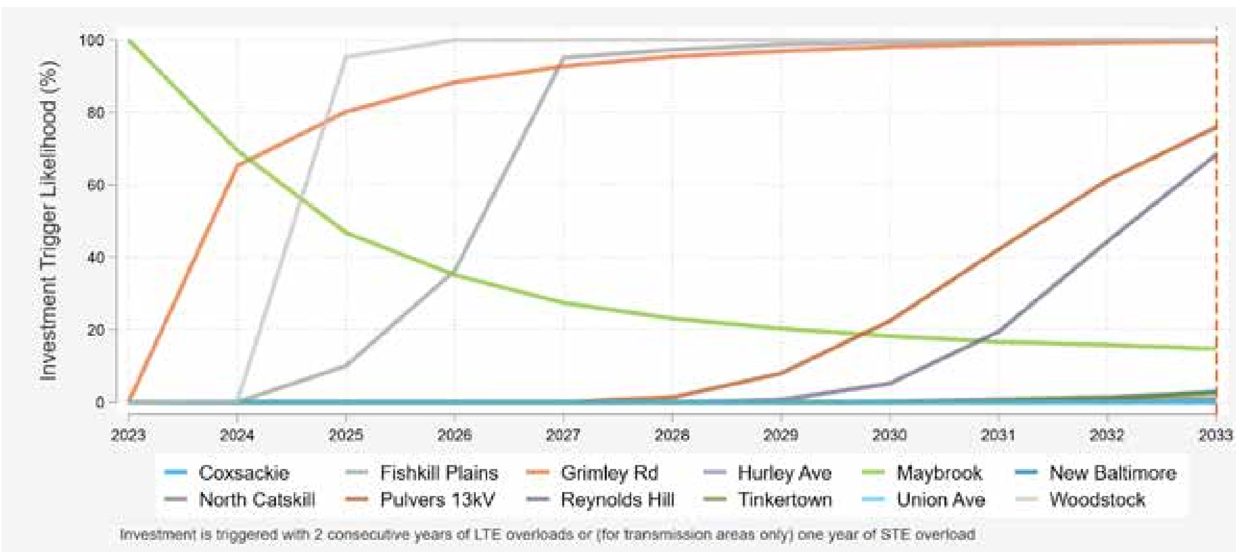
Load Area	Substation	Historical 1 in 2 Annual Peak (MVA)				Forecasted 1 in 2 Annual Peak (MVA)						Rating (MVA)
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	
	Total	**109.8**	**109.6**	**109.5**	**109.3**	**109.7**	**109.7**	**109.7**	**109.8**	**112.3**	**115.8**	**N/A**
Northwest	Coxsackie*,**	9.3	9.7	10.1	10.5	10.8	11.4	12.1	12.8	13.7	14.6	24.8
	Freehold*	8.1	8.2	8.4	8.5	8.6	8.8	9.0	9.2	9.6	10.1	25.0
	Hunter*	11.7	11.3	10.9	10.6	10.4	10.1	9.9	9.6	9.4	9.3	21.2
	Lawrenceville*	14.1	14.1	14.1	14.0	14.1	14.1	14.2	14.2	14.4	14.5	19.3
	New Baltimore	11.6	12.2	12.9	13.6	13.9	14.7	15.5	16.3	17.3	18.3	28.7
	North Catskill	27.3	27.6	27.8	28.1	28.3	28.6	28.9	29.2	29.5	29.9	35.1
	South Cairo*	12.3	12.6	12.9	13.2	13.5	14.0	14.6	15.2	16.0	16.8	29.4
	Vinegar Hill*	11.2	11.2	11.1	11.1	11.1	11.1	11.2	11.3	11.4	11.5	21.3
	Westerlo*	8.3	8.4	8.4	8.4	8.6	8.7	9.0	9.3	9.7	10.2	35.0
	Total	**95.6**	**98.5**	**101.5**	**104.6**	**105.7**	**109.7**	**114.2**	**119.1**	**124.5**	**130.4**	**N/A**
Poughkeepsie	Inwood Ave	25.5	26.1	26.7	27.3	27.7	28.4	29.1	29.9	30.8	31.7	51.2
	Manchester	35.8	34.6	33.4	32.2	31.9	30.8	29.8	28.8	28.0	27.3	47.8
	Reynolds Hill	38.8	39.5	40.2	40.8	41.1	41.9	42.6	43.3	44.1	44.9	47.8
	Spackenkill	35.0	34.8	34.6	34.5	34.6	34.5	34.4	34.3	34.3	34.3	47.8
	Todd Hill	26.4	26.3	26.2	26.1	26.2	26.1	26.1	26.1	26.2	26.3	47.8
	Total	**155.3**	**155.2**	**155.1**	**155.0**	**155.3**	**155.3**	**155.3**	**155.5**	**155.7**	**155.9**	**N/A**

[1] The peak values displayed in the table above reflect the T&D avoided cost forecast and are coincident with substation peak

Figure 20 summarizes the likelihood of triggering an infrastructure upgrade due to load growth, assuming two consecutive years where the long-term rating is exceeded, assuming 1-in-2 weather conditions. Based on the trajectory and variability in load growth, a total of seven substations (Fishkill Plains, Woodstock, Grimley Road, Reynolds Hill, New Baltimore, Maybrook, and Pulvers 13kV) exhibit more than a 5% probability of triggering a growth-related upgrade over the next 10 years, with the remaining substations having less than a 5% probability of triggering a growth-related upgrade.

Among the locations with greater than a 5% probability of loads exceeding ratings, potential overloads can be easily addressed through existing infrastructure projects that are already planned for four substations (Fishkill Plains, New Baltimore, Maybrook, and Pulvers 13kV). However, for three substations there are limited possibilities of load transfer and there are no current infrastructure upgrades planned in the next two years. Therefore, these three substations (Woodstock, Grimley Road, and Reynolds Hill) all are considered for deferral, leaving an opportunity for beneficial DERs.

Figure 20: Probability of Growth-Related Substation Infrastructure Upgrade from Avoided T&D study



Appendix B further discusses the substation forecasts and how they were used to identify locations with T&D deferral potential.

Circuit Historical Loads and Forecasts

As a continued advancement of the methodologies utilized in this study, growth rate estimates were completed at the more granular circuit level for the first time. Figure 21 compares the annual load growth rate to the loading factor (weather-normalized peak divided by the location's circuit design criteria: Normal Design Rating + 1 MVA) for each of Central Hudson's circuits. Due to the noise in the circuit data, the circuit growth rates are the growth rates that were estimated for the circuit's substation. Therefore, the growth rate for circuits is the same as the growth rate for the substations. Unlike substation and transmission areas, circuits utilize a design criteria, which includes a normal and emergency design rating, but do not have an LTE rating. The design criteria are tied to operational requirements to maintain flexibility at the substation level and is more conservative than the actual thermal rating of the distribution asset on the feeder. Central Hudson utilizes several standard design ratings for circuits (i.e., 6/9 MVA or 9/12 MVA high capacity for 13.8kV circuits). This circuit design rating does not represent the thermal capability for the circuit which is typically higher and provides for local operating flexibility. Therefore, for this initial analysis the circuit's normal rating + 1 MVA was used to determine the circuit's capability. Based on the more dynamic nature of the distribution system, the ability to transfer loads more easily between circuits to maintain load balancing amongst area circuits in addition to addressing reliability and the potential shorter timeframe required to complete upgrades, circuit overloads are treated differently from substations and transmission areas, with some circuits operating above their design criteria, but never exceeding their thermal rating. The plans for determining criteria for triggering an upgrade and providing deferral value are discussed in greater detail later in this section.

Figure 21: Circuit Growth Rates Versus Room for Growth from Avoided T&D Study

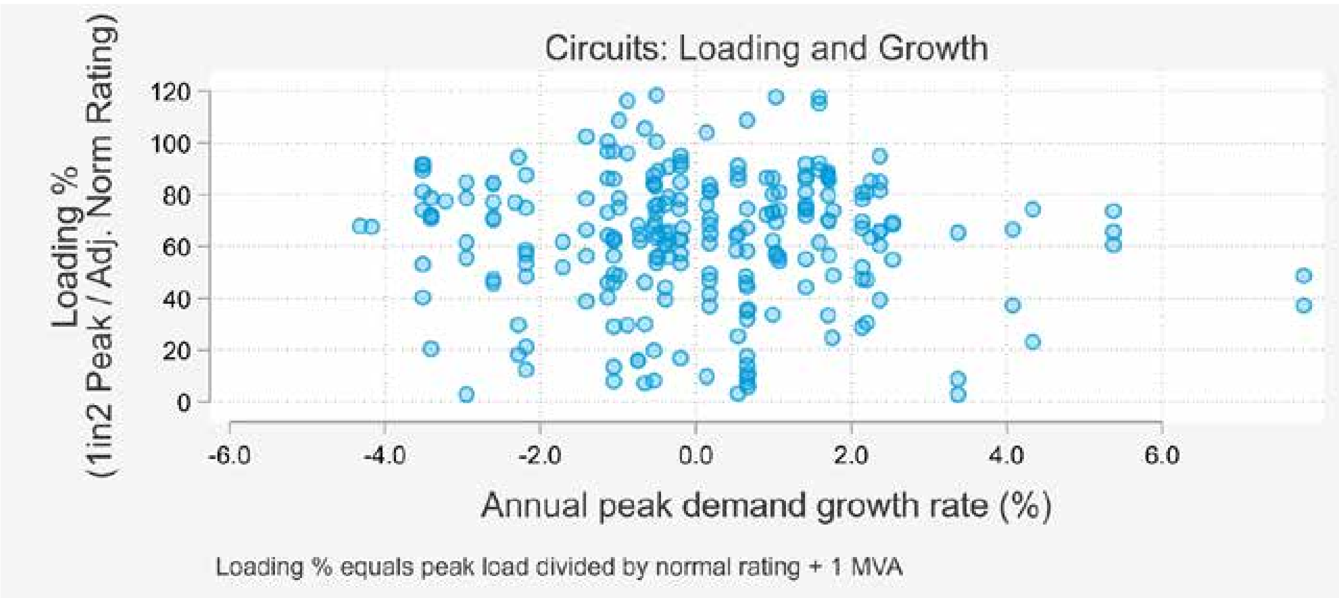


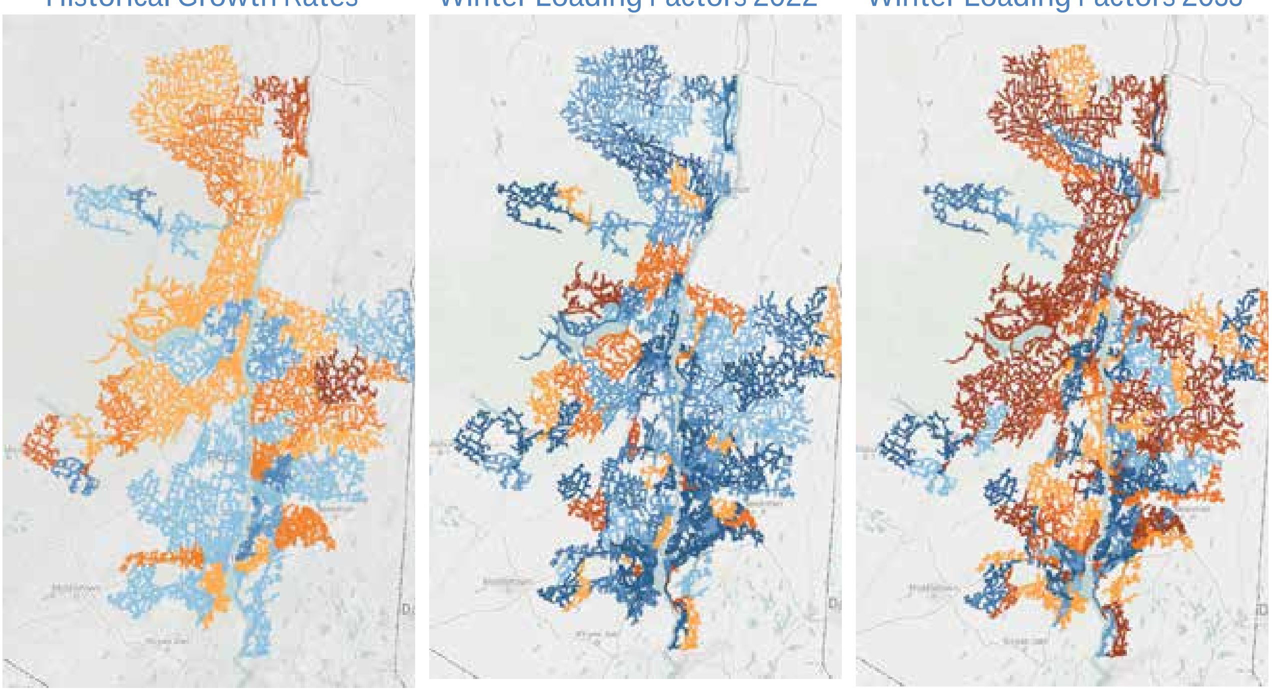
Figure 22 and Figure 23 show heat maps of the growth rate and the summer and winter loading factor (peak / design rating) for each of Central Hudson's circuits. Darker orange colors indicate higher growth rates and higher loading factors. Summer loading does not change dramatically between 2023 and 2033, despite projected growth in electric vehicles, while winter loading increases substantially due to the addition of building electrification. Heating loads tend to coincide and are highest across households on the same day and around the same time of day. By contrast, electric vehicle loads are more diverse. Not all customers charge on the same day or at the same time. They are also less likely to coincide with summer (or winter) peaks.

Figure 22: Map of Substation Growth Rates and Summer Loading from Avoided T&D Cost Study

Historical Growth Rates | Summer Loading Factors 2022 | Summer Loading Factors 2033

Figure 23: Map of Substation Growth Rates and Winter Loading from Avoided T&D Costs Study

Historical Growth Rates | Winter Loading Factors 2022 | Winter Loading Factors 2033



As discussed above, the circuit ratings were adjusted to account for the fact that it is not abnormal for a circuit to exceed its normal design rating. The table below depicts the unadjusted and adjusted ratings for the different circuit ratings. Most circuits have a normal design rating of 6 MVA, or an adjusted rating of 7 MVA.

Table 15: Circuit Normal Design Rating Adjustments (MVA)

Number of Circuits	Unadjusted Circuit Rating	Adjusted Circuit Rating
15	1.5 MVA	2.5 MVA
257	6 MVA	7 MVA
18	9 MVA	10 MVA
1	17.2 MVA	18.2 MVA
1	18.8 MVA	18.8 MVA
1	19.3 MVA	20.3 MVA

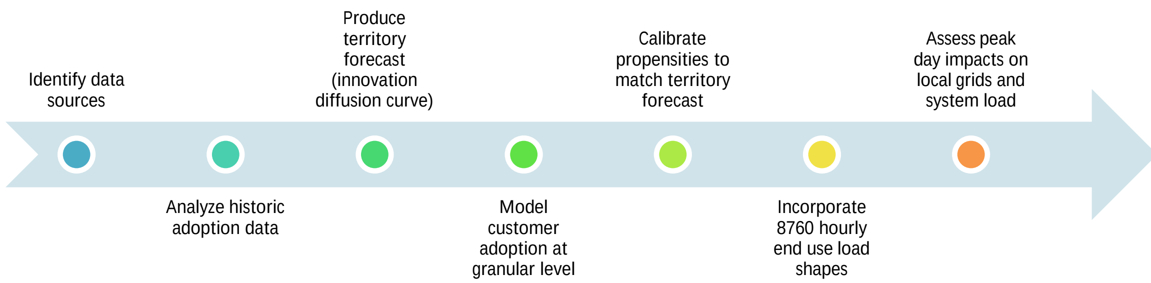
This initial analysis at the more granular level identified a total of 80 circuits that have a greater than 5% likelihood of exceeding their design criteria in the summer and 75 circuits that have a greater than 5% likelihood of exceeding their design criteria in the winter. Using the same definition as utilized for Transmission Areas and Substations of having a greater than 5% likelihood of exceeding their rating for more than 2 years in a row, a total of 69 circuits would trigger a deferral. As indicated, this is the first time the methodologies outlined in this report were utilized to analyze loading at the more granular distribution circuit level. The design criteria (circuit's normal rating + 1 MVA) utilized for this initial analysis were very conservative. The Company is utilizing the data from this initial analysis in conjunction with localized planning knowledge to further refine the methodology.

d) Distributed Energy Resources and Electrification Forecasting

The adoption of distributed energy resources by customers outside the planning process introduces significant uncertainty and creates a challenge for long-term planning. As a result, load forecasts must now incorporate predictions of DER growth, building electrification, and transportation electrification, which require careful tracking, frequent model refining, and forecast updating. Further, the adoption of different DERs, building electrification, and electric vehicles, varies by location, necessitating granular estimates to anticipate system impacts.

Figure 24 provides a high-level overview of the forecasting process for DERs. Central Hudson has applied this process for building electrification, electric vehicle adoption, distributed solar, distributed battery storage, and energy efficiency (including codes and standards), producing forecasts and 8760 end use load forecasts for each transmission area, load-serving substation and circuit feeder in its territory.

Figure 24: Granular DER and Electrification Forecasting Process



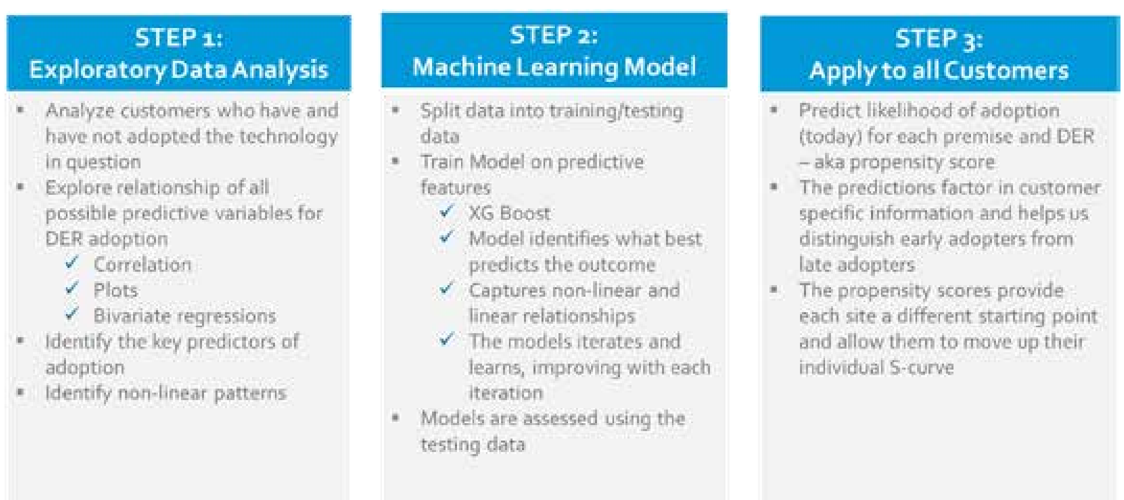
The nuances of the forecasts vary slightly for different DERs and electrification technologies, but the process is similar. The steps are discussed in more detail below.

1. **Identify data sources.** In some instances, Central Hudson has extensive data regarding which customer adopted heat pumps, electric vehicles, solar battery storage, and energy efficiency due to existing rebate programs or interconnection requirements. For many resources, such as solar, battery storage, heat pumps, and energy efficiency, Central Hudson also tracks the magnitude of the resources, and when those resources were deployed. In other cases, such as electric vehicles, Central Hudson only has partial visibility into information about when, where, and how many electric vehicles and plug-in hybrids were adopted and must rely on external data sources such as NYSERDA vehicle rebate data and New York vehicle registration data, which includes details regarding all registered vehicles in New York down to the zip code where the vehicle is registered.
2. **Analyze historical adoption data.** For each DER, Central Hudson analyzed how penetration grew over time and the geographic locations of the resources. In some instances, such as electric vehicles, the distribution of key inputs, such as vehicles across years, rate of new vehicle entry, and flow of new vehicles across the vehicle stock were also analyzed. A key objective of the historical analysis is to understand the building or vehicle stock, and assess if innovation diffusion curves (S-curves) can be fit to historical data.
3. **Forecast territory-wide adoption.** Where and when possible, Central Hudson relied on fitting innovation diffusion curves to historical data – a non-linear regression often referred to as S-curves. When implemented properly, innovation diffusion curves use historical data to estimate, with uncertainty, the future trajectory of cumulative adoptions and the overall market adoption rate. Fitting innovation diffusion curves requires a sufficient history of adoption. For DERs in their nascent stages or those experiencing truly disruptive innovation, fitting innovation diffusion curves is not always feasible. For instance, Central Hudson tied battery storage adoption to future solar adoption since batteries are rarely installed on their own. In cases where an empirical estimate of adoption trends was not feasible, the forecasts defaulted to the NYISO 2023 Gold Book forecasts, scaled for Central Hudson service territory. Overall, two sets of forecasts were developed: the Central Hudson

forecasts based on the empirical adoption data inside the service territory, and a policy forecast linked directly to the 2023 NYISO Gold Book.

4. **Model adoption propensity at a granular level** (dispersion modeling). Estimating where and how much of specific DERs are likely to be adopted is critical for assessing where and when they will influence distribution and transmission loads and infrastructure upgrades. Early adopters of distributed energy resources, electric vehicles, and building electrification can be clustered, leading to pockets where adoption is initially higher. The propensity modeling relies on data about customers who have and have not adopted the technology in question, and additional characteristics or features that help distinguish early adopters from late adopters. For nearly all resources data was available that enabled Central Hudson to predict which customers had a higher propensity for adoption based on characteristics such as energy use patterns, weather sensitivity, customer size, participation in other programs, and geographic location, square footage, year built, building type, etc. Not all variables were predictive, so different predictive models were employed for different technologies and for residential and non-residential customers. The process enabled scoring of customers into groups with a higher or lower likelihood of adoption by technology, which in turn allowed for the estimation of whether expected adoption rates are higher or lower for specific circuit feeders, substations, or transmission areas. For new technologies, such as medium and heavy duty electric vehicles and buses, we instead relied on data about the geographics dispersion of the existing stock across Central Hudson territory rather than premise level adoption propensity scores.

Figure 25: Propensity Adoption Models Overview



5. **Calibrate the granular adoption propensities to the territory forecast.** The propensity scores are an estimate of adoption likelihood for each individual premise/customer in Central Hudson's service territory. For each forecast year, the adoption likelihood for each technology was calibrated to the sum across all sites add up to the aggregate forecast for the service territory. In effect, the calibration produces a highly granular forecast down to the premise level that is consistent with the service territory wide forecasts. The process is non-linear and each individual premise is effectively moving up their individual S-curve with different starting points (e.g., early versus late adopter). The calibration was performed for years 2023 through 2043 and for two scenarios, Central Hudson forecast and NYISO consistent forecast. Next the propensities for each technology were aggregated by feeder, providing the forecasted quantity of the technology and the forecasted electricity use of the that technology for each individual feeder and forecast year.

6. **Incorporate 8760 hourly end use load shapes.** The main objective of the study was to understand how DERs, electric vehicles, and heat pumps are expected to influence distribution and transmission loads. A critical step, therefore, was to combine hourly end use load shapes of each technology with the feeder level forecasts. The hourly end use technology load shapes were merged with the feeder level technology forecast and scaled to produce 8760 hourly end use load forecasts by circuit feeder for year 2023 through 2033. The granular data allows planners to view each component side by side, including native loads (the econometric forecasts), electric vehicle loads, building electrification, solar, battery storage, and energy efficiency. It thus also allows Central Hudson to identify the loads coincident at various planning levels – circuit feeder, substation, transmission area, or territory wide. The 8760 hourly end load shapes were collected from six main sources:

   - NRELs residential and commercial end use load shapes data, which is available by building type, end use and county. These load shapes were used for energy efficiency and heat pump technologies.

   - NRELs EV Lite Pro tool which produced electric vehicle home, workplace, public, and fast charging hourly load shapes under different weather conditions for the Poughkeepsie-Newburgh metro area.

   - LBNL's HEVI-LOAD tool. While the tool is still under development, the team has published load shapes for various medium and heavy-duty vehicles and buses.

   - Directly metered end use data. Central Hudson has historical hourly solar production data for 63 larger sites within its territory, reflecting actual solar production pattern. For residential battery storage, data from over 1800 batteries were aggregated to produce behind the meter load shapes.

   - Simulated data. For large battery storage, DSA contractor simulated the battery dispatch to align with the NYISO daily hourly prices.

7. **Assess technology impacts on local grid peaks.** The final step was to asses impacts of distributed resources and electrification local peaks – including circuit feeders, substations, transmission areas – as well as territory wide. The distributed energy and electrification loads were combined with forecasted native T&D loads and the coincident (territory wide) and local peak days at different local grid levels were identified. Thus, the outputs are tables that include all components of the forecasts – native loads, EVs, building electrifications, distributed solar, distributed battery storage, and energy efficiency – at three levels of granularity:

   ü 8760 hourly forecasts by location for the forecast year

   ü 24-hour forecasts for coincident (territory wide) and non-coincident (local) summer and winter peak days by location for the forecast years.

   ü Single hour forecasts for coincident (territory wide) and non-coincident (local) summer and winter peak days by location for the forecast years. These tables are similar to the Gold Book tables produced for NYISO forecasting.

Appendix B provides additional detail regarding the development of granular, spatial, and temporal forecasts by DER. The tables below show the 5-year DER forecasts for EE, PV, Storage, and EV granular by load area. Load areas are groups of adjacent substations with loads that can be transferred between the substations.

Table 16 and Table 17 show the cumulative impact of forecasted DERs relative to 2022 on local load area peaks and on system coincident peak, for summer and winter. Because of differences in when local peaks occur, the sum of individual loads areas does not equal the system coincident peak savings. The econometric load forecast is the sum of granular 8760 forecasted loads. Because these were hourly 8760 forecasts, they can be summed to derive a coincident system peak. First, end use load was forecast using the load growth estimates detailed in the transmission area and substation sections.

Table 16: Load Area Summer Load Forecast with and without DERs and Electrification (2023-2028)

Load Area	Year	(a) Gross Load Forecast	(b) EV Load	(c) Building Electrification	(d) EE & C&S	(e) Solar PV	(f) Storage Net Load	(g) Planning Load
								a + b + c + d + e + f
Ellenville	2023	45.3	0.6	-0.2	-0.3	-0.1	-0.0	**45.2**
	2024	45.7	0.9	-0.3	-0.6	-0.2	-0.0	**45.4**
	2025	46.2	1.3	-0.6	-1.0	-0.2	-0.1	**45.7**
	2026	46.8	1.8	-0.8	-1.5	-0.2	-0.1	**46.0**
	2027	47.3	2.6	-1.1	-1.9	-0.3	-0.1	**46.6**
	2028	47.8	3.5	-1.3	-2.3	-0.3	-0.1	**47.2**
Fishkill-D	2023	206.8	1.3	-0.2	-1.5	-11.9	-0.5	**194.2**
	2024	204.9	2.0	-0.4	-2.7	-12.1	-0.5	**191.2**
	2025	202.8	2.9	-0.7	-4.1	-12.5	-0.5	**187.9**
	2026	191.1	5.0	-0.9	-5.4	-4.1	-0.5	**185.3**

Load Area	Year	(a) Gross Load Forecast	(b) EV Load	(c) Building Electrification	(d) EE & C&S	(e) Solar PV	(f) Storage Net Load	(g) Planning Load a + b + c + d + e + f
	2027	189.2	6.9	-1.2	-6.7	-4.3	-0.5	**183.3**
	2028	187.2	9.3	-1.7	-7.9	-4.5	-0.6	**181.7**
Kingston-Saugerties	2023	123.0	1.2	-0.3	-1.2	-0.3	-0.1	**122.4**
	2024	122.2	1.8	-0.6	-2.3	-0.3	-0.1	**120.7**
	2025	121.3	2.6	-1.0	-3.4	-0.4	-0.1	**119.1**
	2026	120.5	3.7	-1.4	-4.5	-0.4	-0.1	**117.7**
	2027	119.6	5.0	-1.8	-5.6	-0.5	-0.1	**116.6**
	2028	118.8	6.7	-2.3	-6.7	-0.6	-0.1	**115.8**
Modena	2023	67.8	0.8	-0.2	-0.5	-1.0	-0.3	**66.6**
	2024	67.0	1.1	-0.4	-0.9	-1.5	-0.3	**65.1**
	2025	66.3	1.6	-0.7	-1.4	-1.9	-0.3	**63.6**
	2026	65.5	2.2	-0.9	-1.9	-2.2	-0.3	**62.4**
	2027	62.1	2.9	-1.0	-2.2	-0.2	-0.1	**61.5**
	2028	61.4	3.8	-1.3	-2.7	-0.2	-0.1	**61.0**
Newburgh	2023	220.8	1.1	-0.1	-1.0	-5.6	-0.8	**214.5**
	2024	220.4	1.7	-0.2	-1.9	-6.5	-0.8	**212.7**
	2025	220.1	2.6	-0.4	-3.1	-7.4	-0.8	**211.0**
	2026	219.7	3.7	-0.7	-4.2	-8.2	-0.9	**209.5**
	2027	219.3	5.3	-1.0	-5.4	-9.1	-1.0	**208.2**
	2028	218.9	7.3	-1.4	-6.5	-9.8	-1.1	**207.4**
Northeastern Dutchess	2023	109.7	1.2	-0.2	-0.6	-2.7	-0.3	**107.1**
	2024	106.1	1.7	-0.3	-1.2	-0.2	-0.1	**106.1**
	2025	106.0	2.5	-0.5	-1.9	-0.3	-0.1	**105.8**
	2026	105.8	3.5	-0.8	-2.6	-0.3	-0.1	**105.6**
	2027	105.7	4.8	-1.1	-3.3	-0.4	-0.1	**105.6**
	2028	105.6	6.4	-1.4	-4.0	-0.4	-0.1	**105.9**
Northwest	2023	88.1	0.5	-0.1	-0.5	-0.1	-0.0	**87.9**
	2024	90.9	0.8	-0.2	-0.9	-0.1	-0.0	**90.4**
	2025	93.7	1.2	-0.3	-1.4	-0.1	-0.0	**93.1**
	2026	96.5	1.9	-0.5	-1.9	-0.1	-0.1	**95.9**
	2027	99.5	2.7	-0.7	-2.4	-0.2	-0.1	**98.9**
	2028	102.6	3.8	-0.9	-2.8	-0.2	-0.1	**102.2**
Poughkeepsie-D	2023	157.4	0.8	-0.1	-0.8	-5.4	-1.9	**149.9**
	2024	157.2	1.2	-0.2	-1.5	-5.6	-1.9	**149.2**
	2025	157.1	1.8	-0.4	-2.4	-5.8	-1.9	**148.4**
	2026	157.1	2.6	-0.7	-3.3	-6.4	-2.0	**147.3**
	2027	151.8	3.8	-0.9	-4.5	-1.9	-1.9	**146.5**
	2028	151.7	5.1	-1.2	-5.4	-2.0	-1.9	**146.2**
System	2023	1,115.4	8.8	-1.4	-7.2	-27.0	-8.1	**1,080.5**
	2024	1,115.9	13.1	-2.8	-13.6	-31.7	-8.4	**1,072.4**
	2025	1,116.7	19.1	-4.7	-21.2	-36.8	-9.5	**1,063.6**
	2026	1,118.1	27.2	-7.1	-28.8	-42.9	-10.2	**1,056.3**
	2027	1,119.9	37.7	-9.8	-36.2	-49.9	-11.2	**1,050.5**
	2028	1,122.2	50.8	-13.0	-43.7	-55.9	-12.3	**1,048.1**

[1] The peak values displayed in the table above reflect the planning forecast and are coincident with load area planning peak

Table 17: Load Area Winter Load Forecast with and without DERs and Electrification (2023-2028)

Load Area	Year	(a) Gross Load Forecast	(b) EV Load	(c) Building Electrification	(d) EE & C&S	(e) Solar PV	(f) Storage Net Load	(g) Planning Load a + b + c + d + e + f
Ellenville	2023	41.0	0.4	1.3	-0.3	-0.3	-0.4	**41.8**
	2024	41.5	0.6	2.6	-0.7	-0.3	-0.4	**43.3**
	2025	41.9	1.0	4.2	-1.2	-0.4	-0.8	**44.7**
	2026	42.4	1.4	5.9	-1.6	-0.5	-0.9	**46.7**
	2027	40.5	2.0	8.7	-2.0	-0.1	-0.1	**49.0**
	2028	40.9	2.8	10.9	-2.4	-0.1	-0.1	**52.0**
Fishkill-D	2023	139.8	1.1	0.9	-1.3	-0.4	-0.5	**139.6**
	2024	138.4	1.7	1.9	-2.5	-0.4	-0.5	**138.6**
	2025	136.9	2.4	3.5	-3.8	-0.4	-0.5	**138.2**
	2026	135.6	3.5	5.6	-5.0	-0.5	-0.6	**138.6**
	2027	134.2	4.8	8.2	-6.2	-0.5	-0.6	**139.8**
	2028	132.8	6.4	11.1	-7.3	-0.5	-0.7	**141.8**
Kingston-Saugerties	2023	117.5	1.0	2.5	-1.3	-0.4	-3.4	**115.9**
	2024	116.7	1.5	4.9	-2.4	-0.4	-3.4	**116.9**
	2025	115.8	2.1	7.8	-3.6	-0.4	-3.5	**118.2**
	2026	115.0	3.0	11.0	-4.8	-0.5	-3.6	**120.0**
	2027	114.2	4.1	14.6	-6.0	-0.6	-3.7	**122.6**
	2028	113.4	5.5	18.5	-7.2	-0.7	-3.9	**125.6**
Modena	2023	60.6	0.6	1.5	-0.5	-0.1	-0.4	**61.7**
	2024	59.9	0.8	2.9	-0.9	-0.2	-0.4	**62.2**
	2025	59.2	1.2	4.5	-1.5	-0.2	-0.4	**62.8**
	2026	58.5	1.7	6.2	-2.0	-0.3	-0.6	**63.5**
	2027	57.9	2.3	8.1	-2.6	-0.3	-0.7	**64.6**
	2028	57.2	3.0	10.1	-3.1	-0.4	-0.7	**66.1**
Newburgh	2023	168.4	0.8	0.7	-0.9	-0.4	-0.8	**167.8**
	2024	168.1	1.2	1.4	-1.7	-0.5	-0.8	**167.8**
	2025	167.8	1.9	2.6	-2.7	-0.6	-0.8	**168.2**
	2026	167.6	2.7	4.2	-3.8	-0.6	-0.9	**169.2**
	2027	167.3	3.8	6.1	-4.8	-0.7	-1.0	**170.8**
	2028	167.0	5.3	8.5	-5.8	-0.8	-1.1	**173.0**
Northeastern Dutchess	2023	101.6	0.9	1.0	-0.7	-0.3	-0.6	**102.0**
	2024	101.5	1.3	2.2	-1.4	-0.3	-0.6	**102.7**
	2025	101.3	1.9	3.9	-2.2	-0.4	-0.6	**103.9**
	2026	101.2	2.7	6.0	-3.1	-0.5	-0.7	**105.7**
	2027	101.1	3.7	8.4	-3.9	-0.5	-0.7	**108.1**
	2028	100.9	5.0	11.2	-4.7	-0.6	-0.7	**111.0**
Northwest	2023	105.2	0.4	0.7	-0.8	-0.4	-0.2	**104.9**
	2024	108.5	0.7	1.4	-1.4	-0.5	-0.3	**108.3**
	2025	111.8	1.1	2.7	-2.1	-0.7	-0.9	**111.9**
	2026	115.2	1.7	4.3	-2.8	-0.9	-0.9	**116.5**
	2027	118.8	2.4	6.2	-3.5	-1.1	-1.1	**121.6**
	2028	122.4	3.3	8.5	-4.2	-1.3	-1.4	**127.2**
Poughkeepsie-D	2023	117.2	0.7	0.6	-0.9	-0.2	-1.9	**115.4**
	2024	117.1	1.0	1.3	-1.7	-0.2	-1.9	**115.5**
	2025	117.0	1.5	2.5	-2.8	-0.2	-2.0	**116.0**
	2026	117.0	2.1	4.0	-3.8	-0.3	-2.0	**117.0**
	2027	116.9	2.9	5.8	-4.9	-0.3	-2.0	**118.5**
	2028	116.8	4.0	8.0	-5.9	-0.3	-2.0	**120.5**
System	2023	945.0	5.9	9.3	-7.1	-2.7	-8.1	**942.3**
	2024	945.5	8.8	19.0	-13.4	-3.2	-8.3	**948.4**
	2025	946.3	12.9	32.2	-20.9	-3.7	-9.4	**957.4**
	2026	947.6	18.5	48.1	-28.3	-4.3	-10.1	**971.4**
	2027	949.2	25.7	66.5	-35.6	-5.1	-11.1	**989.7**
	2028	951.2	34.7	87.5	-43.0	-5.7	-12.3	**1,012.6**

[1] The peak values displayed in the table above reflect the T&D avoided cost forecast and are coincident with substation peak

2. Implementation Plan

a) Current Progress

The implementation plan for T&D forecasting of loads and DERs as outlined in prior DSIPs is complete. The granular data on existing resources and forecasted loads will be publicly posted by August 2023.

Table 18: Implementation Plan

	Implementation Step	T&D Loads	Distributed Solar	Battery Storage	Energy Efficiency	Electric Vehicles	Heat Pumps
1.	Identify data sources	100%	100%	100%	100%	100%	100%
2.	Develop granular forecasting methodology	100%	100%	100%	100%	100%	100%
3.	Test methodology	100%	100%	100%	100%	100%	100%
4.	Scale methodology for all substations and transmission areas	100%	100%	100%	100%	100%	100%
5.	Produce forecasts	100%	100%	100%	100%	100%	100%
6.	Make forecasts publicly available	August 2023	August 2023	August 2023	August 2023	August 2023	August 2023

b) Future Implementation and Planning

Central Hudson was one of the first utilities to implement granular location specific forecasts of T&D loads, distributed resources, and beneficial electrification. While the granular growth rates, forecasted loads, and distributed resource and electrification forecasts are incorporated into T&D planning, historically, the updates are performed bi-annually to coincide with the DSIP filing. Moving forward, Central Hudson's plan is to automate and continually update in-house the forecasts and tracking of DERs and behavioral electrification, to the extent possible, starting in 2024. In specific, Central Hudson is working a on tool with four main modules:

1. **Module to Track and visualize historical loads, DERs, and electrification.** This module will produce plots and summary statistics for historical loads, and DERs for the feeders, substations, or transmission area selected. The tool will be continually updated with new T&D interval data and information about the adoption of DERs, electric vehicles, and heat pumps.
2. **Module to estimate gross load growth.** This module is designed to produce updated forecasted growth estimates for feeders, substations, and transmission areas, as selected. The module will allow Central Hudson planners to view and download data for specific feeders, substations, and transmission areas. It will also allow T&D planners to visualize projected loading factors over time with and without incremental DERs or electrification.
3. **Granular DER forecast module.** The module will estimate propensity adoptions for solar, battery, electric vehicles, battery storage, heat pumps, and energy efficiency, and generate adoption forecasts over time that align with system wide forecasts.
4. **T&D deferral value module.** The module will allow T&D planners to analyze individual feeders, substations, and/or transmission areas, simulate the effect of lump loads and load transfers, estimate the likelihood of the need for upgrades, and estimate the T&D deferral value.

3. Risks and Mitigation

The load forecasts influence decisions about whether to reinforce or upgrade T&D infrastructure. Thus, the risk is double-edged. If the forecasts are too high, it can lead to expansion of T&D infrastructure that is either too early or too large. If the forecasts are too low, it can lead to overloaded T&D equipment, degradation of the equipment life, and degradation of reliability for Central Hudson's customers. The risks are largest for T&D upgrades with significant lead times to build since forecasts further into the future are inherently more uncertain than near term forecasts. The largest forecasted changes in Central Hudson loads are arising from the growth in electric heating loads, large distributed solar installations, and lump loads. While electric vehicles add to load, they do not pose as large a risk to planning because they are inherently more diverse and predictable.

Central Hudson is undertaking the following steps to mitigate the risk associated with forecasting:

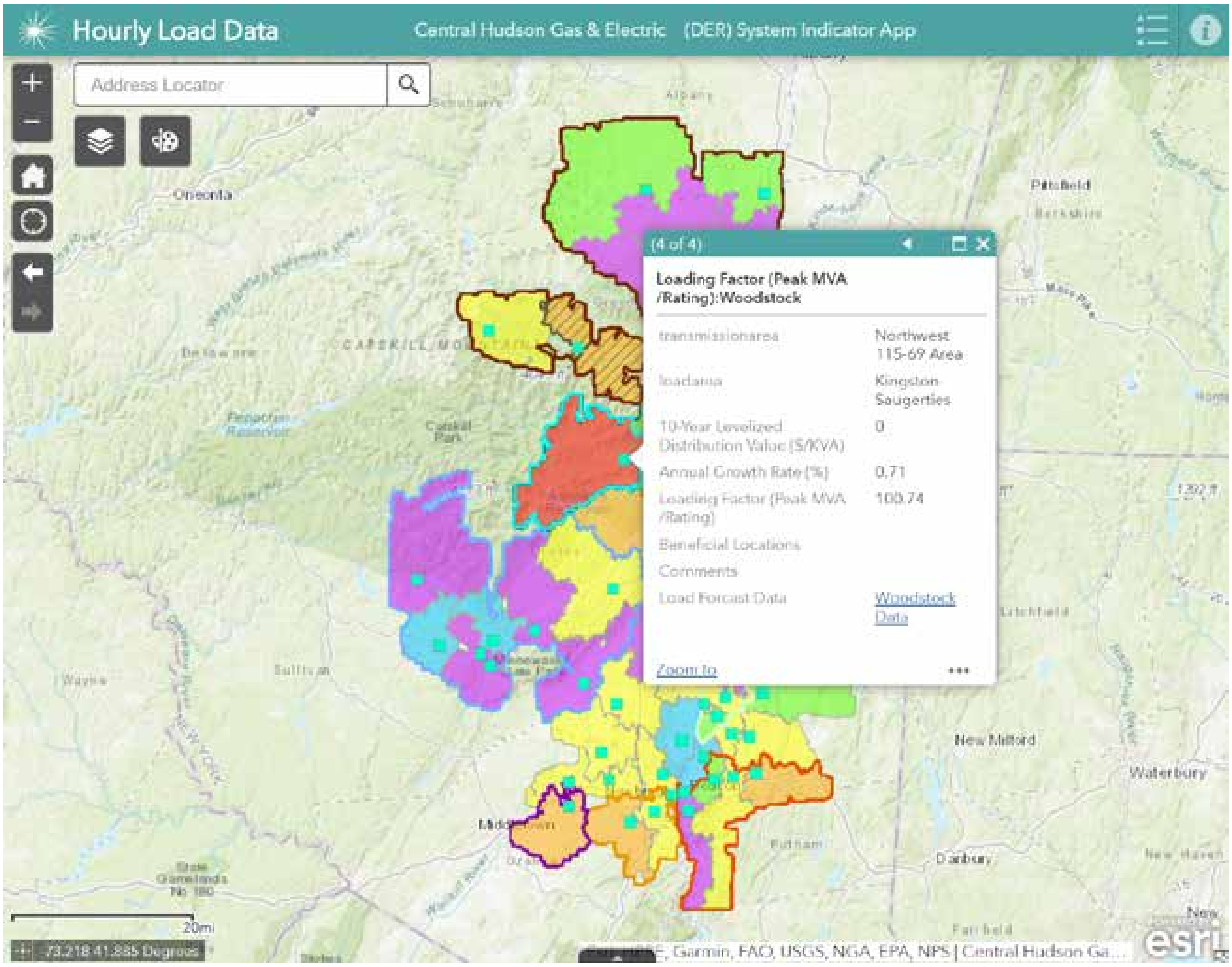
- **Continuously updating T&D forecasts.** Doing so provides the most up to date information to enable better decisions.
- **Continuously tracking DER and electrification installation at a granular level.** As discussed earlier, the adoption of electric vehicles and heat pumps is clustered, with some part of the Central Hudson's territory experiencing faster and deeper adoption than other areas. By tracking the adoption and connecting to the different distribution planning levels – transmission, substations, and circuit feeders – Central Hudson can better identify the locations where electrification will trigger upgrades.

- **Explicitly quantifying uncertainty.** By quantifying the uncertainty, Central Hudson avoids over reliance in point estimates and has a realistic understanding of the risk posed by load growth.
- **Avoiding expanding T&D infrastructure too early.** The build lead times for different T&D resources are known, which allows Central to balance the risk of overbuilding against the reliability risk.
- **Revising models to improve accuracy.** Central Hudson is relying on a training and testing model framework to improve the accuracy of the forecast models. The data is split into training data used for model development and then used to predict out of sample using the testing data. The accuracy is assessed by comparing the predicted versus actual values using the testing data.

4. Stakeholder Interface

The stakeholder interface will be hosted on Central Hudson's website and it will be map-based (CenHud Hourly Load Data). The maps, as illustrated in Figure 26, are interactive. The main display is a choropleth map, often referred to as a heat map, which shows which locations have higher or lower T&D deferral value potential. The map includes popup information boxes that, when clicked, provide users details regarding the name of the substation, expected T&D deferral value, growth rate, loading factor, and Long-Term Emergency ratings. The popup boxes include links that allow users to download historical and forecast 8760 data as a CSV file.

Figure 26: Central Hudson Stakeholder Interface



5. Additional Detail

a) 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.

Central Hudson has developed a System Data Portal on its public website at www.cenhud.com, under My Energy and Solar and Distributed Energy. The System Data Portal provides substation and transmission area load and supply forecast for five years on an hourly basis. Additionally, historical 8760 load data is available for distribution feeders.

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

In discussions held by the Joint Utilities' Load Forecasting Working Group and System Data Working Group, stakeholders identified that historical hourly load data to the circuit level and forecasted hourly load data at the substation level would be sufficient for their purposes. Also, in these discussions, the stakeholders expressed a desire to have the DER forecasts at the same level of granularity.

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

Central Hudson currently provides load and DER forecasts for five years down to the Substation level and makes these forecasts available for third-party use through its system data portal.

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

Central Hudson's forecasts for both load and DER are provided for five years at the Substation and Transmission Area level and for 8760 hours. The forecasts provide detail about the components including gross native loads, electric vehicles, heat pumps, solar, battery storage, and energy efficiency.

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

Central Hudson develops separate forecasts for load and DERs, including energy efficiency, electric vehicles, heat pumps, distributed energy storage, and distributed solar.

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

Central Hudson currently produces probabilistic load forecasts and probabilistic DER forecasts for EE, EV, Energy Storage, and Solar. Central Hudson made significant progress in the development and implementation of probabilistic forecasting capabilities as part of the 2016 DSIP filing. Central Hudson has continued to advance these methodologies since this time, as outlined in this section and within Appendices B (Load and DER Forecasts) and D (Location Specific T & D Cost Report). The use of probabilistic methods has been integrated into Central Hudson's normal forecasting and planning process.

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

Central Hudson's existing probabilistic forecasting methods incorporate existing DERs into the forecasts capturing the inter-related effects. In addition, the use of this probabilistic forecasting approach on load and DER forecasting produces a wide range of forecast possibilities that incorporate the impacts of variability, codependence, and accuracy. Because the forecasts quantify 8760 T&D loads and 8760 hourly end use technology loads by year and location, it allows tracking of how new technologies influence the magnitude and timing of summer and winter location specific and territory wide peaks.

h) 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 current forecasts for utility use are still primarily granular transmission area, substation, and circuit level peak load forecasts. The transition to probabilistic hourly load forecasts for load and DER will also allow Central Hudson's planning process to transition to utilize this information for more granular planning of the distribution system, the impacts of DER, and the identification of system issues beyond peak load-serving capability.

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

Central Hudson utilizes self-generated datasets or publicly available datasets to the extent that they are available and provide the information necessary to produce granular hourly load and DER forecasts. Central Hudson has at least three years of valid hourly load data from 57 of our 62 distribution load-serving substations encompassing approximately 97% of its cumulative system load. Through the latest Load and DER forecasting process, there were a number of enabling assumptions made regarding the ability of DER in the queue to complete development, the location of future DER development, and the synthesizing of missing data. These assumptions, while enabling the development of the current forecast, will be the focus of future efforts to refine data through experience or expanded data sets.

Central Hudson has collected 8760 hourly end load shapes for solar, battery storage, light-duty electric vehicles (at home, at work, public charging, and fast charging), medium and heavy-duty electric vehicles, heat pumps (cooling, heating, and water heating), and for significant end uses targeted by energy efficiency. Where possible, the technology end-use profiles are specific to Central Hudson territory and weather. Central Hudson will update the library of end-use profiles used for planning as better and more accurate data becomes available.

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

See this Section above and Appendices B and D for the details on the methods used to produce substation level load and DER forecasts.

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

See this Section above and Appendices B and D for details on the levels of accuracy of the various components of the load and DER forecasts.

l) 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.

Central Hudson provides load and DER forecasts at the substation level for five years on an 8760 hourly load basis. This will provide DER developers with the locational granularity and load shapes needed to understand the area's loads, expected DER development, potential for future DER development, and, when coupled with other available data elements such as hosting capacity or circuit capacity, an estimate of the available headroom for DER development (both maximum and minimum).

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

Central Hudson utilizes a probabilistic forecasting methodology that relies on a wide range of forecasts and probabilities to reflect the impact of variability and does not use sensitivity analyses in this method.

Sensitivity analysis is typically applied when scenario-based models are employed, when key inputs are based on assumptions, or when there is substantial uncertainty around critical drivers of results. Central Hudson is transitioning to a probabilistic approach, where feasible, and will not typically apply this analysis.

Central Hudson's objective is to rely on data-driven, probabilistic analysis, which minimizes assumptions and, by definition, models the range of likely outcomes. When and where possible, Central Hudson has shifted away from scenario-based models, which are more suitable for sensitivity analysis. The uncertainty for key inputs, such as load growth, was explicitly quantified based on the available data, and the implications of the uncertainty on outcomes were quantified based on Monte Carlo simulations, showing the full range of potential outcomes.

Sensitivity analysis still plays a vital role for technologies in a nascent stage or experiencing truly disruptive innovation(s). As discussed in Appendix B, while the policy goals for heat pumps are clear, the adoption curve is highly uncertain at this point. Likewise, there is limited data regarding the adoption rate of medium-heavy duty electric vehicles. Planning for those two technologies will require sensitivity analysis until adoption patterns and trends become more predictable.

n) 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.

As previously mentioned, Central Hudson utilizes self-generated or publicly available datasets to the extent that they are available and provide the information necessary to produce granular hourly load and DER forecasts. Central Hudson does use information from DER development activities in the service territory (such as projects in the queue and project payments) but has not solicited direct input from DER developers to further inform its forecasting efforts.

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

As part of the REV process, Central Hudson has actively worked with the other JUs in a number of areas to share lessons learned and identify best practices both in New York and in other jurisdictions. One of the JU groups is focused on forecasting processes both in New York and other jurisdictions. Central Hudson will continue to be actively engaged in these types of initiatives on an ongoing basis. Central Hudson also remains very actively engaged in the NYISO working groups and committee structures. As the NYISO makes advances in the area of load and DER forecasting, Central Hudson will remain involved, to learn from this work and ensure that it is consistent with the more granular Central Hudson processes.

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

Central Hudson already separately forecasts energy efficiency, distributed solar, distributed battery storage, electric vehicles, and heat pumps outside of the load model, but will continue to refine its forecasting methodologies and the accuracy of these forecasts, first through continued market experience using traditional methods to predict market adoption and saturation, and second, to develop more granular forecasts by technology and market to further define the expected DER impacts.

C. Grid Operations

1. Context and Background

The growing penetration of DERs has impacted and will continue to impact the Company's grid operations. As DER penetration causes multi-directional power flows across the grid, it will become increasingly important to execute more complex grid functions. To enable these functions, the Company will require enhanced levels of DER monitoring, control, and measurement – all of which will support DERs' ability to provide value to customers and the system.

Central Hudson, through its Grid Modernization Program, is taking significant steps to accommodate DERs and model the system impacts of DERs in order to preserve distribution system safety and reliability. Critical to these efforts are a set of foundational investments that will support DSP capabilities. Central Hudson's Grid Modernization Program is comprised of six critical projects:

1. Distribution Automation (DA) – automated devices, distribution infrastructure (poles and wires)

2. Geographic Information System (GIS) – Common Information Model, provides a single consolidated mapping and visualization system

3. Distribution Management System (DMS) – the centralized software solution with state estimation that enables SCADA telemetry and control

4. Distribution System Operations (DSOPs) – the organization responsible for monitoring and controlling the electric distribution system through the use of the DMS

5. Network Communications Strategy (NS) – the two-way communication system between the DA devices and DMS

6. Substation Metering Infrastructure– Substation feeder relay metering and transformer LTC upgrades required for accurate DMS power flow calculations.

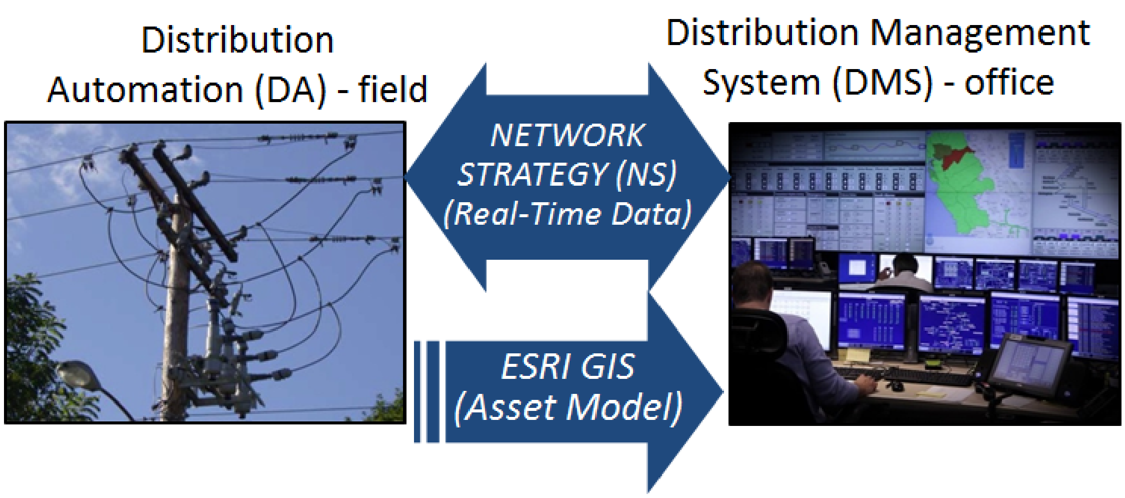
Over 1,600 Intelligent Electronic Devices (IED; e.g. electronic reclosers, switched capacitors and voltage regulating devices) and sensors are being installed through DA and other projects. These devices provide real time data to the DMS, which enables it to make centralized decisions based on current system conditions rather than anticipated peak loads. DERs also must be monitored, and in some cases, controlled, as a critical input to the DMS. The Network Communications Strategy equipment enables communication between the DA equipment and the DMS. These critical components are described in detail below.

As described above, GIS is a key project of Central Hudson's Grid Modernization Program. Central Hudson's enterprise-wide GIS is an ESRI based platform that provides a single consolidated mapping and visualization system capable of storing important information on facilities and assets, including DERs, such as geospatial location and other asset properties. GIS enables new capabilities for Central Hudson, including developing accurate distribution grid models (potentially down to the customer meter) and enabling calculation and visualization of DER installations and hosting capacity.

Distribution System Operations staff will utilize DA devices to regularly feed live electrical system data into the DMS, as shown in Figure 27. GIS will support many DMS capabilities, including:

- Greater operational efficiency with improved automation management;
- Preservation of safety and reliability in real-time operations through integration of disparate data sources; and
- Improved interaction with SCADA devices, including distribution feeder breakers, substation load tap changers and DERs.

Figure 27: Interplay between Central Hudson's DA and DMS



The continued implementation of these supporting technologies and systems will enable Central Hudson to produce more robust system models that incorporate the impact of DERs and ultimately allow it to utilize DERs better to provide value to the grid and customers. In the near term, Central Hudson's Grid Modernization Program aims to accommodate DERs through increased monitoring and, in some cases, control. Over the longer term, Central Hudson may seek to dispatch DERs in real time to preserve distribution system safety and reliability or provide other services of value to the grid.

In addition to its individual efforts to accommodate DERs, the Company has helped establish DER M&C requirements through its active role in the Joint Utilities Monitoring and Control (M&C) Working Group. These requirements aim to minimize developer costs while preserving system safety and reliability. Central Hudson's efforts to increase M&C directly supports the Company's goals of integrating DERs, maintaining power quality, optimizing system operations, and enhancing grid resiliency. Additionally, enhanced M&C can increase the dispatchability of DERs, which in turn can promote system efficiencies and support the ability of DERs to provide their full value to the system. Overall, an appropriate level of M&C is required to ensure that new DER interconnections will not jeopardize system safety or reliability.

The focus on M&C also has touchpoints with other groups Central Hudson participates in: (1) the Joint Utilities ISO-DSP Coordination Working Group, (2) the DPS- and NYSERDA-led Interconnection Technical Working Group (ITWG), and (3) the NYISO Market Issues Working Group (MIWG). Central Hudson continues to engage in these groups to harmonize M&C requirements, to the extent possible, for varying DER market and operational use cases to promote a consistent approach throughout the State.

Finally, Central Hudson and the Joint Utilities continue to engage with NYISO, both through direct interaction and the NYISO stakeholder process, on defining operational coordination requirements for wholesale-participatory DERs, including roles, responsibilities, and procedures.

2. Implementation Plan

a) Current Progress

Today, the distribution system is operated on a decentralized basis. Each of the Company's five operating districts has operational responsibilities for their respective geographic-based operating regions. The system operates predominantly in an autonomous mode where intelligent devices such as Automatic Load Transfer (ALT) teams, switched capacitors, voltage regulators, electronic reclosers, fault indicators, and voltage sensors make decisions on their own or only communicate information in one direction.

During the summer of 2023 over 90% of IEDs within the Fishkill Operating District will be fully integrated to the DMS for full End-to-End (E2E) testing of all components/projects within the Grid Modernization umbrella. E2E testing includes a complete GIS network model that represents all pertinent Substation and Distribution circuits with IEDs within the DMS software. Monitoring and control of IEDs will be tested over the FAN to demonstrate real-time connectivity and situational awareness. This will pave the way for transitioning E2E testing into the Poughkeepsie Operating District and user acceptance testing within the distribution control room. Additionally, pilot field testing of Conservatory Voltage Reduction and Volt-VAR Optimization functions will be completed over the summer to better articulate operating circuit formulations.

The in-service or go-live of CVR and VVO functions is scheduled for Q4 2024 in the Fishkill and Poughkeepsie Operating Districts. Once complete, it will deliver our circuit optimization strategy and will be applied year-round via the DMS to realize savings that will be directly passed on to our customers.

As additional DERs are integrated into the system, there is limited visibility regarding the status of these resources. The continued operation of the distribution system in this decentralized approach will result in operating issues that limit the ability to integrate increasing levels of DER without significant system upgrades. While this mode of operation has allowed the system to work safely and reliably for many years, new system requirements such as bi-directional power flow and better utilization of existing infrastructure call for changes to existing grid operations.

To safely, reliably, and efficiently operate the distribution system in the future with increasing levels of DERs, the system will no longer be able to run on a decentralized and autonomous basis and will need to have the ability to react to and manage the changing conditions that may result from these DERs. Recognizing this, the Company embarked on the development of a Grid Modernization Program, which includes investments in six foundational projects: DA, GIS, DMS, DSOps, NS, and SMI. The deployment of these systems is currently underway, and the details of these deployments are described below.

The DA components of the Grid Modernization Program include distribution system infrastructure upgrades and the installation of IEDs and sensors. The distribution system infrastructure upgrades will develop ties between adjacent feeders or upgrade existing ties with larger conductors. Coupled with IEDs, additional sensors, and the intelligence of the DMS, this will increase switching capabilities between load pockets, improving feeder management by flattening voltage profiles for further voltage reduction and reducing losses. The upgrades will also reduce the frequency and duration of interruptions and increase the ability to defer significant transmission system investments. Through DA, Central Hudson also will address two radial transmission feeders that do not meet the design criteria of 7 MVA of unreserved load. As an alternative to constructing a redundant transmission feed, this DA solution was sought and will be implemented once the DMS is fully functional. While the IEDs provide voltage and current data, additional sensors or select AMI data with even greater accuracy may be required to verify models at fringe points and provide metering information at feeder heads and key locations where substation automation is not yet available.

To achieve the benefits of DA, two key advanced applications will be implemented along with the infrastructure upgrades: VVO and FLISR. The installation of substation-level metering points, which includes per phase data reporting, is necessary to implement both VVO and FLSIR schemes accurately.

(1) Volt/VAR Optimization

The concept of VVO revolves around the implementation of voltage reduction and optimization of reactive power flow to improve power quality and efficiency. Applying sophisticated, detailed distribution system models, switched and fixed capacitor locations are selected to flatten the voltage profile across a feeder while ensuring that the power factor is maintained in an optimal range and losses are reduced. Then, voltage regulating devices (load tap changers or voltage regulators) are sited to lower overall voltage. As the voltage is reduced, the associated energy and carbon emission reductions occur reducing energy usage while not impacting the customer’s energy end use, making these savings transparent to the customer other than lower kWh usage.

Locations for installation are selected to leverage existing device locations whenever feasible, but new installations are frequently required. Once installed, the devices must be programmed with initial settings, which are coordinated and controlled centrally through a DMS to ensure the settings are accounting for current system conditions. Voltage regulators and substation load tap changers will need to be retrofitted with two-way communications and control. End of line voltage sensors or select AMI locations must be connected and communications must be added to verify the DMS model and ensure voltages are maintained within the ANSI C84.1 acceptable ranges. Operating the distribution system more efficiently will result in decreased line losses, reduced greenhouse gases, and decreased customer demand.

While Central Hudson currently complies with all existing CVR orders, implementing sophisticated modeling with a DMS and two-way communications and control will enable the Company to achieve the incremental benefits described in the business case provided to DPS Staff as a part of the Case 14-E-0318 Rate Case discovery process. This centralized approach will also provide a platform to integrate DERs. Initially, the impact will be considered from a technical perspective in terms of switching and conservation voltage reduction. In the longer term, control of third-party devices could be included with enhancements to the DMS if monitoring, control, and markets change in that direction.

(2) Fault Location, Isolation, and Service Restoration

Central Hudson has been utilizing ALT teams for approximately fourteen years. Autonomous teams are currently limited by the need for the devices to be in close proximity and the complexity of the design - required by the current decentralized approach. With the installation of the DMS, decisions can be made on a centralized basis and consider data from a much wider geographic basis. When a fault occurs, the IEDs will transmit information to the DMS to locate the section in which the fault occurred, isolate it by opening adjacent IEDs and then close IEDs to restore service to as many customers as possible. With sufficient distribution feeder ties and automated switches, an entire substation can even be restored in the event of a fault on a radial transmission line, avoiding significant transmission system investment to provide a backup feed to these stations. The DMS will also recommend additional manual restoration that can be performed where appropriate and provide potential fault locations to reduce patrol time.

Additional electronic reclosers will need to be installed along feeders and at mid-point ties, and supervisory control of feeder head breakers must be added where not currently available.

(3) Other Functionality

The addition of stronger tie points will enable Distribution System Engineers to employ the same devices that are applied to FLISR during other periods of system stress, such as low voltage conditions or when thermal limitations are exceeded. Alarm points will be triggered on the DMS and the Distribution Operators will remotely initiate switching to manage these situations.

Since the 2020 DSIP, Central Hudson has completed the construction of DA devices for the Fishkill and Newburgh Districts and approximately half of the Poughkeepsie District. DA plans for the Catskill District were completed in 2019 with partial construction underway starting in 2020. DA plans for the Kingston District (Phase 1) were completed in 2021, with partial construction underway starting in 2021. DA plans for the Kingston District (Phase 2) were completed in 2022, with partial construction underway starting in

2023. Table 19 illustrates the accomplishments through June 2023. As of June 30, 2023, Catskill construction is 24% complete and Kingston construction is 18% complete (Phase 1 and Phase 2 combined). It is projected that by the end of 2023, Catskill construction will be 46% complete and Kingston construction will be 36% complete. Both Catskill and Kingston construction is scheduled to be 100% complete in 2024.

Table 19: Distribution Automation Roll-Out through June 2023

District	2015 Q3–Q4	2016 Q1–Q2	2016 Q3–Q4	2017 Q1-Q2	2017 Q3-Q4	2018 Q1-Q2	2018 Q3-Q4	2019 Q1-Q2	2019 Q3-Q4	2020 Q1-Q2	2020 Q3-Q4	2021 Q1-Q2	2021 Q3-Q4	2022 Q1-Q2	2022 Q3-Q4	2023 Q1-Q2
Fishkill Phase 1	P, D, C	C	I	-	-	-	-	-	-	-	-	-	-	-	-	-
Fishkill Phase 2	-	P, D, C	D, C	I	-	-	-	-	-	-	-	-	-	-	-	-
Newburgh Phase 2	-	-	P, D	D, C	D, C	D, C	C	C	C	I	-	-	-	-	-	-
Poughkeepsie Phase 1	-	-	-	-	P, D	D, C	D, C	D, C	D, C	D, C	C	C	C	C	C	C
Poughkeepsie Phase 2	-	-	-	-	-	P	P	D, C	D, C	D, C	D, C	D, C	C	I	-	-
Catskill	-	-	-	-	-	-	-	P	P, D	D	D, C	D, C	D, C	D, C	D, C	D, C
Kingston Phase 1	-	-	-	-	-	-	-	-	-	P	P	D	D	D, C	D, C	D, C
Kingston Phase 2	-	-	-	-	-	-	-	-	-	-	-	P	P	D	D	D, C
P = Planning; D = Design (field); C = Construction; I = Implemented																

The DMS components of the Grid Modernization Program include:

- Distribution level SCADA (Supervisory Control and Data Acquisition),
- Advanced System Modeling,
- Near Real-time Load Flow, and
- Contingency Analysis Capabilities.

While the DMS is anticipated to support further integration of DER systems, current DMS algorithms related to VVO and FLISR do not currently incorporate DER as part of these schemes. Additionally, the level of control of these systems needs to be further understood, including when a hybrid approach of decentralized vs. centralized control of DER is appropriate. As a result, Central Hudson jointly worked on a NYSERDA PON with EPRI, Schneider Electric, and a PV partner, to test advanced inverter functionalities within the DMS. The goal of this project was to compare a centralized DER control logic to a newly developed hybrid control approach, which borrows key beneficial traits of each control approach, centralized and decentralized. This project involved testing the centralized and hybrid control approaches via digital modeling simulations along with a live field demonstration within Central Hudson's service territory. This project was completed in Q4, 2021 and resulted in the following key lessons learned:

1. The hybrid control approach produced comparable results to the centralized method in the OpenDSS digital simulations.

2. The hybrid control approach required fewer control commands to be issued to the field devices compared to the centralized control during field demonstration test days.

3. The hybrid control approach required fewer tap and position changes in the Volt VAr devices, compared to the centralized approach, when achieving the optimal solution for the Volt VAr control and voltage reduction objectives.

4. Both the hybrid and centralized control methods, through the DMS Volt Var optimization (VVO), were found to increase the potential to add additional DERs to the substation and test circuits with significant PV penetration which were previously primarily voltage constrained.

5. Communication between the control center and field devices was found to be challenging due to the many interfaces needed to communicate from point to point. This resulted in increased latency and/or missed commands.

Project Architecture

The DMS is comprised of a distributed computing environment with open system architecture. The architecture and configuration of the system is described in the sections that follow.

The DMS has five separate environments: Within the Primary Control Center (PCC), Production (PROD), Quality Assurance System (QAS), Distribution Operator Training Simulator (DOTS), Program Development System (PDS) and an alternate Production System within the Alternate Control Center (ACC). The PCC and Backup Control Center environments are highly reliable, fully redundant and scalable, and contain stringent security features to prevent access by unauthorized personnel.

The Quality Assurance and Program Development System environments are used to perform database and display maintenance activities and to test new patches/releases received from the vendor.

Primary Control Center System

The PCC system is the primary real-time environment of the DMS. The platform provides the SCADA capability, which provides the interfaces and functionality required to monitor and control the distribution system. This system also hosts the advanced applications that provide the functionality needed to ensure the efficient and reliable operation of the distribution system.

The PCC is a high availability system characterized by high-speed data collection and presentation functions. The PCC is a fault-tolerant system with redundant server architecture. All storage devices are redundant and hot-swappable so that no downtime is incurred for replacing a failed disk.

Alternate Control Center System

The ACC system includes all of the functions and features provided with the PCC system, is a replica of the PCC system hardware, and as an operating control system must have 24/7 redundancy.

Quality Assurance System

The Quality Assurance System (QAS) supports the development and testing of all components of the DMS. This system provides a platform for testing system upgrades, system patches, network model updates, and other features. The hardware and software in this system are closely modeled to the PCC system.

The QAS is used to test all new components and modifications of existing DMS applications. The QAS has the capability to receive real-time data (i.e., from the EMS and DA devices) concurrently with the PCC system. This process does not interfere with or degrade the performance of the DMS. Control commands issued from the QAS are not communicated to field devices.

Program Development System

The Program Development System (PDS) supports display creation, tune-up, and configuration of the DMS. The PDS has substation one-line diagram generation capabilities and also includes all of the administration tools. The PDS is used to help in the validation of the SCADA and DMS databases, system upgrades, system patches, network model updates, network connectivity, land-based completeness, substation one-line diagram accuracy, and applications accuracy.

The PDS supports:

- Database and display development tools,
- Substation one-lines development tools,
- Data acquisition to perform testing with field devices using Sensus or DNP3/IP, and
- Distribution Network Applications.

The PDS is configured as a non-redundant, stand-alone system. The PDS is of the same server and console hardware as in the Production environment. The PDS retains its individual identity, although it is networked with the other components of the DMS.

Distribution Operator Training Simulator

A DOTS facilitates personnel training for the operation of the DMS. The DOTS provides introductory-level training as well as advanced instruction and includes all of the necessary user interfaces and computing capability to train individual operators and/or an entire control room crew.

The DMS will interface with numerous external systems that have been implemented by Central Hudson, some of which are noted below.

Geographic Information System

The DMS will interface with Central Hudson's enterprise GIS to import the as-built geographically connected representation of the electric distribution network and land-based map data.

The enterprise GIS consists of two Oracle database servers with GIS data logically split up amongst various schemas. Gas transmission, gas distribution, electric transmission, electric distribution, and land-based map data are all stored in the two databases in various schemas.

The Electric Distribution GIS contains a connected geometric model of all facilities from the substation breakers down to the customer transformers and service points. The data is stored in the standard Telvent/Schneider Electric ArcFM Distribution Data model. The geometric representation is as geographically accurate as possible, with allowances made for separation between devices so that independent connectivity can be maintained.

In addition to electric data, the GIS also contains a large amount of base mapping data and gas transmission/distribution data. It contains a comprehensive, land-based map dataset with streets, railroads, hydro features, political districts, operating districts, circuit map grids, and other features. Central Hudson maintains and updates the street data as well to incorporate new developments and road rebuilds. Tax parcel and building footprint data from the counties are also contained in the GIS land data. Elevation rasters, aerial Ortho imagery, and many more reference data layers are available.

Outage Management System

The existing OMS is based on GE's PowerOn Version 4.3.14 and resides on the corporate network. The long-range plan is to replace the existing OMS with a system that will operate within the DMS.

Energy Management System

The DMS will interface with the existing EMS to exchange real-time operational data for substations. Remote Terminal Units acquire data from substations and provide controls to substation devices. The majority of Remote Terminal Units are connected to the EMS such that all data and controls for substations are available via the EMS. Telemetry and control points for substation transformer Load Tap Changers and 15kV level breakers will be shared from the EMS to the DMS through ICCP links.

In addition to measurements, statuses, and controls, the DMS and the EMS are being developed to exchange operational information, such as quality codes and tags.

The DMS also contains a DMZ Environment. The DMZ Environment supports Cyber Security applications, such as antivirus protections, security event logging, and Disaster Recovery applications including backup and restore.

Central Hudson has developed internal cybersecurity policies modeled after North American Electric Reliability Corporation's (NERC) Critical Infrastructure Protection (CIP) Version 5 Standards and Requirements for the DMS and Network Strategy projects. Applicable standards were modified, as necessary, to align more closely with the Company's performance and business objectives. The DMS will be compliant with all relevant cybersecurity standards and requirements.

Project Schedule

The new DMS is being implemented in a phased approach as it relies on the completion of the five other critical projects listed earlier in this Section and these components are tightly intertwined. Much of the work on the DMS has been completed, including product acceptance in 2021 and the beginning of integration with the EMS system.

The plan of implementation for the DMS will be staged to take advantage of opportunities in several sections of the service territory. To achieve optimal benefits, implementation will be focused on an operating district basis in the following order: Fishkill, Poughkeepsie, Newburgh, Catskill, and Kingston.

Communications Network

The Network Communication Strategy components of the Grid Modernization Program include:

- Out of scope for Grid ModFAN (Medium Capacity Network),
- FAN (Low Capacity Network - Future),
- Network Routers to support MPLS and TDM, and
- Network Monitoring Systems.

Background

The Company formed a task force in April 2011 to review communication issues and develop recommendations for improvement. The Network Strategy Team developed the following problem statement: "A well-defined plan to leverage technologies for current and future communication needs does not exist. This absence has led to a patchwork of infrastructure and technologies that lacks adequate documentation and results in poor reliability for some applications. A long-term, cost-effective strategy is needed to establish robust systems that provide reliable and secure communications."

Scope

The scope of the Communications Network is among Central Hudson's fixed assets. These fixed assets include the Company's corporate offices, gas gate and regulator stations, electric substations, electric system DA equipment, and large customer meter installations. Technical applications such as SCADA, transmission line protection, security (video and card access), will use the network, as well as general traffic supporting internet use and Voice over Internet Protocol. The Communications Network will also enable Central Hudson to broadly implement DA. Additionally, the network acts as the underlying two-way communications system between the DMS and IEDs in the field. The system is designed with expansion capability to allow for communication with smart meters, for Central Hudson to eventually build out this capability in the future.

Topology Overview

Central Hudson's planned topology is a tiered network. The WAN is the high bandwidth backbone connecting the most critical substations as well as other strategic sites. The WAN will be a combination of existing and new fiber optic cables and microwave connections. Most of the sites on the WAN network will also serve as gateways for connection to the FAN network. FAN is the medium bandwidth network. FAN will be a mesh radio network for communication with DA equipment, electric substations, gas regulator stations, and large customer meter installations. The system is designed with the provision for a future expansion of a low bandwidth network that could reach additional endpoints on the network.

WAN

As noted, WAN is the high bandwidth backbone connecting the highest-priority sites in the system. The WAN is a combination of existing and new fiber optic cables and microwave connections.

The Physical Layer (Layer 1) for the WAN network is a fiber optic cable and licensed wireless point-to-point microwave operating at 6 GHz through 18 GHz. The current plan for the WAN Network includes approximately 194 nodes. The nominal capacity of the microwave is 350 MB/s. Several specific paths of microwave associated with the connection between the PCC and the Alternate Control Center have nominal capacities of 700 MB/s. The nominal capacity for the fiber optic cable links will be 1,000 MB/s with future plans of 10,000 MB/s.

The Data Link Layer (Layer 2) for the WAN network is Ethernet. The Network Layer (Layer 3) for the WAN network is Multiprotocol Label Switching (MPLS). Together, these operate at Layer 2.5. Physically, the Company has chosen to use the Aviat CTR 8611 router to implement Multiprotocol Label Switching for the fiber optic and microwave Tier 1 Network. This enables the deployment of Layer 2 Virtual Private LAN Service for certain critical applications such as SCADA and Layer 3 IP for less critical applications such as Voice over Internet Protocol. Future plans include an upgrade to Cisco IR8340 routers.

FAN

The FAN is the medium bandwidth network. The FAN will be a mesh radio network for communication with DA equipment, electric substations, gas regulator stations, and large customer meter installations. Gateways for connection to the FAN network would be located at the endpoints or nodes of the WAN Network.

The Physical Layer (Layer 1) for the FAN network is an unlicensed wireless point to multi-point mesh radio operating at both 2.4 GHz and 5.8 GHz. The range for the 2.4 GHz radio is 2,400 – 2,473 kHz and the range for the 5.8 GHz radio is 5,150 – 5,850 kHz. The current plan for the FAN Network includes approximately 5,000 nodes. The nominal capacity of the Tier 2 radios is 50 MB/s at the gateways, dropping down to 0.75 MB/s at the endpoints of the mesh.

FAN Expansion

As mentioned above, the FAN is envisioned to expand to a low bandwidth network. The Company does not have any current plans to further expand the FAN network. However, a future possibility for the further expansion of the FAN network would be a mesh radio network similar to the FAN network. Most likely, this network would be operated at either 900 MHz or 2.4 GHz. Current FAN locations would be used as gateways for the expanded FAN network. The remainder of the expanded FAN network mesh radios could be located within electric meters to support an AMI system.

Network Monitoring System

As part of the Pilot Project, a Network Monitoring System (NMS) was established at the South Road Headquarters in Poughkeepsie, NY. The hardware for the NMS consists of a high-availability server separated from the corporate network by a firewall. The NMS includes software for the WAN microwave equipment, the WAN Multiprotocol Label Switching system, and the FAN radio mesh system. The NMS provides for remote configuration of the WAN and FAN systems. The NMS also provides for monitoring of the system. Alarms generated remotely by the network equipment are accumulated at the NMS. The NMS has the capability to generate email notifications of alarms. Central Hudson established an alternate NMS at the Alternate Control Center in Newburgh, NY. The new control center under construction in Kingston is intended to be the primary control center. Poughkeepsie will become the alternate control center while the Newburgh site is prepared for decommissioning.

Cyber Security

Central Hudson developed internal cybersecurity policies modeled after NERC CIP Version 5 Standards and Requirements for the DMS and WAN and FAN projects. Applicable standards were modified, as necessary, to align more closely with the Company's performance and business objectives. The projects are compliant with all relevant cybersecurity standards and requirements.

Project Schedule

In 2014, Central Hudson initiated a pilot project termed Network Strategy. The Network Strategy Tier 1 component of the pilot project included the construction of microwave links between the South Road

Headquarters in Poughkeepsie, NY, and the Hurley Avenue Substation in Kingston, NY. This connection included three separate microwave links and two intermediate locations. The microwave connection went into service in January 2015. The Network Strategy Tier 2 component of the pilot project included the installation of 18 mesh radios in the Town of Ulster, NY. The company tested two different manufacturers and three different radio frequencies, including both licensed and unlicensed frequencies. This work was completed in 2015.

In 2015, Central Hudson began construction of the Tier 1 Network. Six microwave links were installed to expand the existing microwave portion of the network and connect to several existing fiber optic cable portions of the network in the Fishkill District. In 2016, Central Hudson added distribution ADSS fiber in the Newburgh and Poughkeepsie Districts and in 2017 added transmission OPGW fiber in the Newburgh District.

In 2016, Central Hudson began construction of the Tier 2 Network in the Fishkill District. Construction of the Tier 2 Network is closely linked with the development of the DA program.

Since 2016, Central Hudson continues to construct the communications network. The current network consists of 440 miles of fiber (OPGW, distribution and IRU), with 231 future miles. Microwave radio links cross 134 miles amongst 16 sites.

Table 20 shows the planning, design, and construction phases through June 2023.

Table 20: WAN and FAN Network Implementation through June 2023

District	2015	2016	2017	2018	2019	2020	2021	2022	2023
Kingston Pilot Area	P, D	P, D ,C	C						
WAN Fishkill		P, D ,C	P, D ,C	P, D ,C	P, D ,C	P, D ,C	P, D ,C	P, D ,C	
FAN Fishkill		P, D ,C	P, D ,C	P, D ,C	P, D ,C	P, D ,C	P, D ,C		
WAN Newburgh		P, D ,C	P, D ,C	P, D ,C	P, D ,C	P, D ,C	P, D ,C	P, D ,C	P, D ,C
FAN Newburgh				P	P, D ,C	P, D ,C			P
WAN Poughkeepsie			P, D ,C	P, D ,C	P, D ,C	P, D ,C	P, D ,C	P, D ,C	P, D ,C
FAN Poughkeepsie				P	P, D ,C	P, D ,C	P, D ,C	P, D ,C	P, D ,C
WAN Catskill						P, D ,C	P, D ,C		P, D ,C
FAN Catskill					P	P, D ,C			P
WAN Kingston		P, D ,C				P, D ,C			P, D ,C
FAN Kingston	P, D ,C								P
P = Planning; D = Design (field); C = Construction Complete									

Central Hudson is continuing the process of developing Distribution System Operations as outlined in the Distribution System Operations Whitepaper (originally developed prior to the 2016 DSIP and updated for the 2018 DSIP). Above all, the mission of Distribution System Operations is to provide for the safe and reliable operation of the distribution system. This includes minimizing the impacts of DERs on the safe and reliable operation of the distribution system. Distribution System Operations is the organization responsible for the use of the Distribution Management System. The Distribution System Operations Whitepaper addressed staffing, position descriptions, the Operational Authority of the distribution system, and how operations will be conducted in normal and emergency operating modes.

Central Hudson has made significant progress on (1) enhancing M&C capabilities and promoting DER accommodation through the implementation of its Grid Modernization Program and (2) identifying lower-cost M&C solutions through its involvement with the Joint Utilities M&C Working Group and ITWG.

Central Hudson's Grid Modernization Program

The Company's Grid Modernization Program will enable it to enhance M&C capabilities and accommodate increasing levels of DERs. While the development of advanced M&C capabilities is in its nascent stages, it will allow the Company to more effectively utilize DERs based on existing or forecasted system conditions.

In the Initial DSIP, and further outlined above, Central Hudson detailed its plans for various enabling technologies to support DSP capabilities, including monitoring systems, control systems, and distribution infrastructure upgrades. As mentioned above, the Company's planned investments in various DA technologies, including devices (i.e., reclosers, regulators, and switched capacitors), circuit mainline reinforcements, circuit monitoring, and distributed telemetry, will enable the DMS to receive real-time data. As a result, the DMS will be able to use applications like Volt/VAR control and FLISR to further accommodate, and eventually actively utilize, DERs. Central Hudson anticipates ultimately automating the execution of distribution switching orders for unplanned work (i.e., fault restoration) with the DMS using the FLISR application. To promote the integrity and safe operation of the DMS, the Company will afford it the same cybersecurity protection as it does for the Energy Management System (EMS). Central Hudson will protect Operational Technology Assets with its Cyber Security for Operational Technology, which is closely modeled after the North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) standards.

Central Hudson is also investing more broadly in its Distribution System Operations to enhance its ability to fully leverage these supporting technologies and systems.

Lower-Cost Monitor & Control Efforts

Central Hudson has been meeting with the Joint Utilities Monitor and Control (M&C) Working Group since 2017 to understand and define M&C requirements that support safe and reliable operation of the distribution system. Through this working group, the Joint Utilities have discussed implementation issues, lower-cost M&C solutions, and the possibility of integrating new M&C technologies. The M&C Working

Group produced several technical documents for ITWG consideration, including proposed interim requirements for anti-islanding and M&C informed by benchmarking against other utilities and direct operational experience.

Through discussions with stakeholders, the M&C Working Group recognizes that M&C requirements have the potential to strain project economics, particularly for smaller projects. In follow-up Working Group discussions, the Joint Utilities have identified three primary drivers of M&C cost:

- Available communication methodologies in a geographic area;
- Engineering, design and drafting; and
- Site installation, back-office integration, testing and commissioning.

The Joint Utilities believe the most significant opportunity for reducing M&C cost will come through the standardization of design and/or functionality for equivalent business and technical use cases. Achieving this level of standardization will result in fewer engineering, design, drafting, installing, testing, and commissioning hours while also allowing for economies of scale.

To facilitate M&C cost reductions, the Working Group previously benchmarked potential low-cost M&C solutions and engaged in focused, internal discussions with subject matter experts in metering, telemetry, security requirements, and engineering, installation, and commissioning (EIC). These efforts produced four main takeaways:

- M&C may refer to real-time use cases, such as for traditional utility operations and SCADA devices and non-real-time use cases, such as for planning purposes. Distinguishing between these two time dimensions will drive communications backhaul discussions (e.g., periodicity and data payload size).
- Each utility has typically relied on utility-owned assets for M&C for SCADA operations (i.e., real-time). However, less critical operations have been able to use third-party systems for M&C as long as they have appropriate interfaces within the utility back office. While the increased penetration of these third-party systems will provide enhanced visibility, Central Hudson also acknowledges there will be complexities for integrating these systems from both a technological and process perspective.
- There is still a significant level of uncertainty around lower-cost M&C solutions as to their security and ability to integrate into real-time operations and planning processes. To maintain the cybersecurity of the entire Central Hudson system, the Company must ensure that all digital systems have the same security provisions throughout the service territory. Although this is an important consideration for utilities when adopting new technologies and processes, they often overlook it when solely focusing on a "low-cost M&C hardware" approach.

- The utilities have an opportunity to standardize low-cost M&C solutions during future pilots and R&D energy storage projects. This will allow the utilities to test these solutions in a controlled environment prior to authorizing them for commercial interconnection applications.

Since the 2020 DSIP, within the JU M&C working group the JU collaborated to develop a monitoring requirements document to describe the key monitoring parameters and points required from inverter-based resources based on IEEE 1547-2018. The JU anticipate publicly releasing this document in 2023. This development of this document is aligned with the JU's goal of potentially using smart inverters as a low-cost monitoring solution. Additionally, the JU have also been re-examining the "Monitoring and Control Requirements for Solar PV Projects in NY" document for appropriate edits. The JU anticipate releasing a revised version of this document in 2023. The company maintains that lower cost M&C can be achieved through effective leveraging of foundation technology investments of Distribution Automation, Distribution Management System and Network Communications Systems. Additionally, Central Hudson supported a NYSERDA PON led by Quanta Technologies related to the design, testing, and commercialization of a next generation DER gateway that further supports identifying lower cost M&C options, particularly for smaller DER < 500kW. Results of this project concluded in September 2021. As part of this project, the team developed a prototype for a DER gateway that was integrated via a field area network. To demonstrate the benefits, three widely deployed grid modernization applications were considered: fault location, isolation and service restoration (FLISR); Volt - Var optimization (VVO), and DER dispatch. Furthermore, a hybrid distribution state estimator was also integrated in the demonstration to take advantage of the DER measurements and existing phasor measurement unit measurements to improve situational awareness. The concept was demonstrated with three gateways running on real hardware, and the distribution state estimator running on a separate server integrated with a real-time simulator representation of the utility's distribution system. Results from the controller hardware-in-the-loop RTS demonstration showed the gateway provided value to each of the applications and is viable from a technical perspective.

While the Quanta DER Gateway project provided insight into the viability of DER gateway from a lab perspective, additional research is required to identify commercially available DER gateways as well as associated costs. As a result, Central Hudson is working with EPRI to on a two-year R&D project anticipated to kick-off in the second half of 2023 on the "Commercial Evaluation and Economic Feasibility Analysis of Secure DER Gateways." This proposal will study, design, test and prove specific features to address current DER integration gaps, without adding substantial cost to the gateway. It will develop tools to help utilities articulate their DER gateway related needs in interconnection agreements and RFPs, provide resources to the industry to accelerate adoption of this technology, and provide a core set of capabilities needed, while leaving room for innovation from researchers and vendors. The project will consider the overall cost of the system and evaluate barriers to economic and technical feasibility, so they can be tackled.

While Central Hudson and the M&C Working Group make progress toward leveraging smart-inverter communication capability for M&C in the interim Central Hudson has continued to evaluate low-cost M&C solutions for <500 kW interconnections. to monitor these sites in real-time for Operations, but also to have the ability to remotely disconnect these interconnections under abnormal circuit conditions. Central Hudson is designing a potential solution that leverages a secondary meter (<600 V), shunt-trip breaker control (transformer low-side), and the Sensus cellular communication platform. As a major cost contributor to low-cost M&C was requiring metering and control on the primary-side of the interconnection, for example, the utility point of interconnection at 13.2 kV line-to-line, this solution implements a meter on the secondary side of the transformer (<600 V) that has a form-C dry contact capable of being implemented within a shunt-trip breaker control circuit. The meter leverages DNP3 protocol to communicate via Sensus so that the utility has operational visibility into the interconnection. The same communication channel over Sensus used for monitoring can send a signal to the meter to trip the shunt-trip breaker, thus disconnecting the interconnection. This proposed solution is still in the design and test phase with plans to install at a standalone, 300 kW, PV interconnection in 2023.

How does the current implementation support stakeholders' current and future needs.

Central Hudson's current and future progress towards Grid Modernization Program will enable the Company to enhance M&C capabilities and accommodate increasing levels of DERs which support NY State's energy goals. Additionally, as previously described in the above sections, VVO and FLSIR components have direct benefits to customers by reducing energy usage and ultimately costs through VVO, as well as improving reliability through FLISR automation.

b) Future Implementation and Planning

Central Hudson, as detailed in the previous section, will continue its implementation efforts for key enabling technologies, such as DA, DMS, OMS, and the Network Communications Strategy projects. Additionally, the Company will continue to make progress towards low-cost M&C solutions, including leveraging smart inverters. Further details on smart inverter requirements, including the NY JU roadmap can be found in Section X. DER Interconnections. The Company has also identified the need to include a DERMS within the Grid Modernization roadmap; however, implementation for this is not anticipated to commence until 2027, with some pre-planning expected to occur in the second half of 2026.

The Company's current progress towards Grid Modernization Program will enable the Company to enhance M&C capabilities and accommodate increasing levels of DERs which support NY State's energy goals. Additionally, as previously described the above sections, VVO and FLSIR components have direct benefits to customers by reducing energy usage and ultimately costs through VVO, as well as improving reliability through FLISR automation.

The work and investments along with the timing and sequence of these investments are described further below.

Distribution Automation will continue to be rolled out per the schedule shown in Table:21.

Table:21 Distribution Automation Roll-out after July 2023

District	2023	2024
Poughkeepsie Phase 1	C, I	
Catskill	D, C	C, I
Kingston Phase 1	D, C	D, C, I
Kingston Phase 2	D, C	D, C, I
P = Planning; D = Design (field); C = Construction; I = Implemented		

Completion of Newburgh and Fishkill models and integration of SCADA points DA and EMS were completed in Q2 2022 and Q1 2023, respectively. The DMS will continue to be rolled out per the schedule shown in Table:22.

Table:22 Future Objectives

Objectives	Dates
Completion of Poughkeepsie Model and integration of SCADA points DA and EMS	Q3 2023
OMS Upgrade and Integration with DMS	Q4 2026
Completion of Catskill Model and integration of SCADA points DA and EMS	Q22024
Completion of Kingston Model and integration of SCADA points DA and EMS	Q4 2024
Begin researching/identifying DERMS solutions and vendors	Q3 2026
Begin implementation of DERMS	2027

Network Communication Strategy will continue to be rolled out per the schedule shown in Table 23.

Table 23: FAN Network Roll-out after July 2023

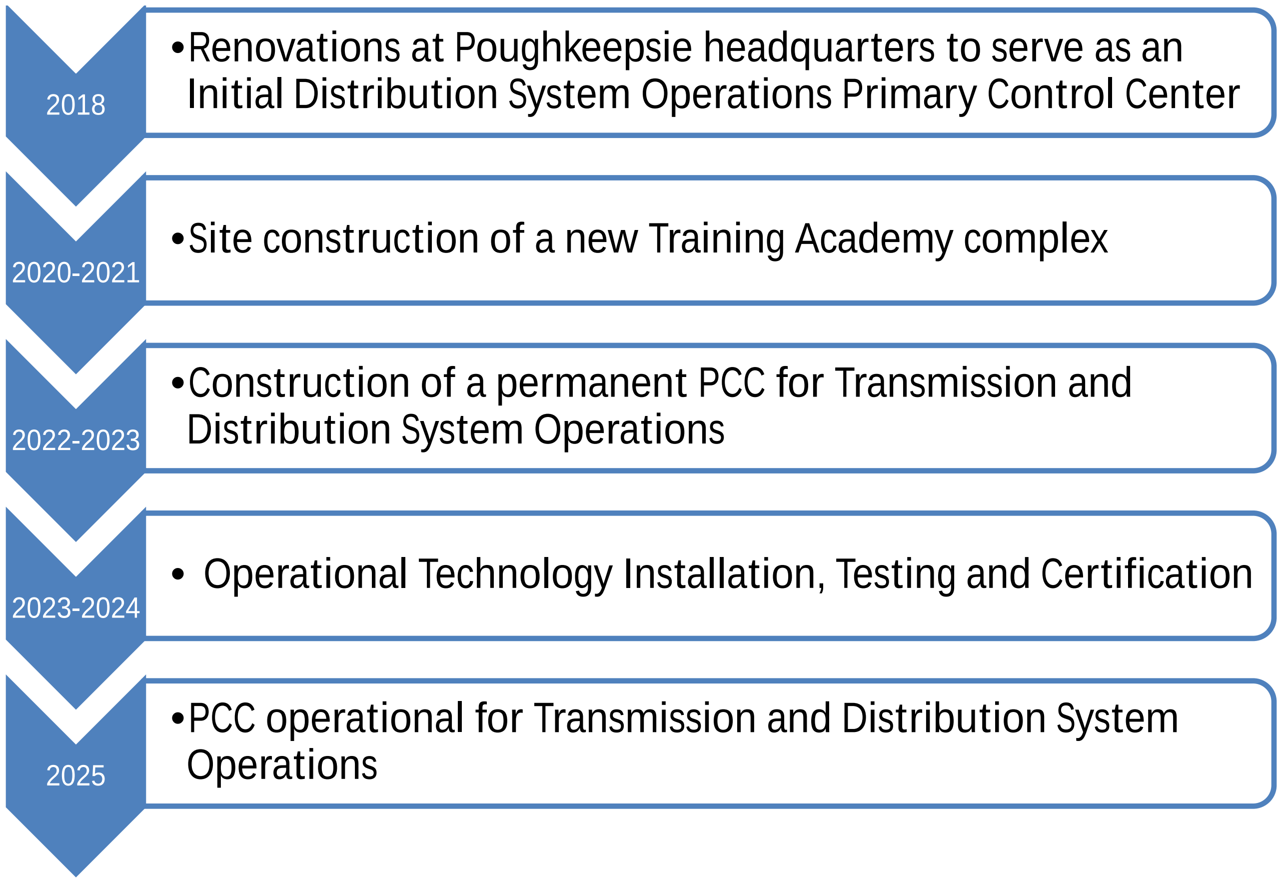
District	2023	2024	2025	2026
Poughkeepsie	D, C, I			
Newburgh	P, D	D, C, I		
Catskill		P, D	D, C, I	
Kingston		P, D	D, C	D, C, I
P = Planning; D = Design (field); C = Construction; I = Implemented				

The transition to Distribution System Operations will include the addition of two Distribution System Engineers and twelve Distribution System Operators. This will create the need for both additional office space in the Distribution Control Center and additional workstation space to hold the necessary computer monitors. This extra space must be included as part of the overall considerations for this project.

In 2018, Central Hudson renovated Building 810, Floor S1 at its Poughkeepsie Headquarters, to serve as its Initial Distribution System Operations Primary Control Center (PCC). The Transmission System Operations Primary Control Center is currently located in Building 810 on Floor S2. The current available space in Building 810 on the S1 floor is 2,350 square feet. A study performed in 2017 estimated that 7,245 square feet were needed for Distribution System Operations (not including space for support staff, data center space, or mechanical space). In addition, the low ceiling height in this room does not allow for a map board that would be used to improve situational awareness. The Initial Distribution System Operations PCC, although lacking in space for the long term, will serve to help with developing an understanding of what works and what doesn't work. Lessons learned from this Initial PCC will help shape the design of subsequent facilities that will host Distribution System Operations.

In 2020, Central Hudson started site construction on a new Training Academy complex; construction of the adjoining Primary Control Center began in 2022. Construction of the Primary Control Center is expected to take twelve months, followed by twelve months of commissioning. The PCC will be operational for Transmission System Operations and Distribution System Operations iQ1 2025. At that time, the facilities in Poughkeepsie will become the Transmission and Distribution Alternate Control Centers and the current Alternate Control Center in Newburgh will be retired. Figure 28 summarizes the progression of investments Central Hudson plans on making to construct a permanent Primary Control Center (PCC) for Distribution and Transmission System Operations.

Figure 28: Timeline for PCC Construction for T&D System Operations



In addition to its company-specific efforts, Central Hudson will continue to participate in the M&C Working Group to provide support and input into relevant forums (e.g., ITWG, ISO-DSP Coordination Working Group, and NYISO's MIWG). As part of this, the JU have embarked on discussions for the most appropriate control use cases (from a utility perspective) and the associated smart inverter functions that can enable these use cases. These activities are aligned with the tasks envisaged by the JU in the smart inverter roadmap. Additionally, the Working Group will continue focusing on opportunities to implement low-cost M&C solutions for DERs within utility pilots, including harmonizing requirements across different market and operations use cases. Through the continued efforts of this Working Group, Central Hudson remains committed to identifying M&C requirements that balance cost savings for DER developers and improved utilization of DERs while preserving system safety and reliability.

Central Hudson and the Joint Utilities will further address grid operations topics through the development of a separate Market Design and Integration Report, which "identifies, describes, and explains their jointly planned market organization and functions along with the policies, processes, and resources needed to support them." As part of this, the Joint Utilities formed a working group with NYISO, DPS, and NYSERDA identified as the Market Design and Integration Working Group (MDIWG), to complete a set of tasks on various topics, including grid operations, in order to address market transformation adjacent to or outside the NYISO Tariffs. Central Hudson, as part of the Joint Utilities, will remain actively engaged in the MDIWG to inform the development of the Market Design and Integration report which is expected later in 2023.

The CGPP and DSIP are filings with overlapping but distinct scopes. The CGPP will detail the evolution of distribution planning processes needed to meet CLCPA goals, align with transmission planning processes, and ensure that planning is integrated. The DSIP describes implementation of the much broader set of DSP activities and projects, and how those activities holistically align with CGPP and CLCPA goals. The CGPP will be more singularly focused on a process to identify distribution system needs to meet CLCPA State goals and develop a distribution investment plan, including capital projects, to meet those needs. Planned capital investments, including technology platform investments and how they will be leveraged, will be included in the DSIP (e.g., AMI, automation, DMS, etc.) and the results of executing the processes will be used to inform the CGPP.

The CGPP is aimed at developing a "CLCPA-focused planning process," including "the State's bulk transmission, local transmission, and distribution planning processes." The goal is to improve planning processes to better coordinate the studies performed by the Utilities with the NYISO's bulk-power system planning and generation interconnection processes; improve the integration of Local Transmission and Distribution (LT&D) and bulk system studies with NYSERDA's renewable generation and storage procurements; and improve forecasting of renewable generation development for specific locations on the LT&D and bulk transmission grid. As part of the December 2022 CGPP proposal, one of the key inputs to the CGPP process is the generation build-out scenarios identified by the Energy Policy Planning Advisory Council (EPPAC). While forecasting practices for the CGPP and DSIP are aligned, the scenarios identified by the EPPAC may result in different forecasts than those completed as part of the DSIP. The output of the CGPP thus may result in the identification of Phase 2 capital projects that are not already identified in current rate plans. Although capital projects identified within the CGPP are intended to be funded under the FERC load ratio share methodology, these Phase 2 projects once approved will be incorporated and used to inform the normal DSIP processes.

3. Risks and Mitigation

In order to continue building the suite of capabilities needed to support advanced grid operations, including advanced monitoring and control, Central Hudson will continue to make sustained investments towards enabling grid modernization technologies, including Distribution Automation, the Distribution Management System, and the Network Communications Strategy projects. Consequently, the amount of available funding for these efforts will impact the timing and extent of implementation. Implementation of these assets is a core competency from an Engineering and Construction perspective, which will significantly minimize this risk.

Staffing is going to be challenging. The Distribution System Operator positions are anticipated to be very technical and may require a two-year engineering degree. The Distribution System Operators will be required to work on a rotating shift schedule. Experience with other rotating shift schedule positions has shown that not all candidates find this desirable, which limits the applicant pool. If necessary, Central Hudson will expand recruitment efforts to increase the candidate pool and consider additional benefits to make the positions more desirable.

Space limitations will be an issue for the short term. Although the Company has long term plans to construct a Distribution System Operations Primary Control Center (PCC), this will not be available until Q1 2025. In the short term, the Company will use space at the newly-expanded Distribution System Operation Center at the South Road headquarters.

An additional risk, as mentioned above, is the continued cybersecurity of the entire distribution system. As the Company continues to integrate both utility-owned and third-party technologies, it will be critical to adequately address any cybersecurity concerns to minimize risk. Central Hudson continues to monitor cybersecurity developments as provided in the Joint Utilities Cyber and Privacy Framework filed in the Supplemental DSIP and is actively engaged in industry discussions. Central Hudson has also developed a set of internal standards for the Cyber Security of Operational Technology (CSOT) and is in the process of implementing these standards throughout the enterprise. More detail on the CSOT initiative is discussed in the Energy Efficiency section.

4. Stakeholder Interface

Stakeholders related to grid operation initiatives include customers, the PSC, DER developers and aggregators, as well as the NYISO.

Stakeholder engagement related to grid operations technology investments occur under a few different forums. For M&C requirements, the JU have continued to engage with stakeholders to identify barriers to and opportunities for lower-cost M&C solutions. The Joint Utilities will continue coordinating with the DER community to identify mutually-beneficial solutions and maintain transparency into utility M&C requirements. These engagements occur through the ITWG. For details on the means, methods and goals related to M&C, including leveraging smart inverters as a lower cost solution, refer to the Section on DER Interconnections.

The Joint Utilities continued to host stakeholder engagement sessions since the 2020 DSIP to communicate the progress made through working with NYISO on coordination issues and to gather additional input. These included efforts associated with the MIWG as well as FERC 2222 wholesale market participation. Defining new operational coordination requirements between 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. In the Order on Distributed System Implementation Plan Filings ("DSIP Order"), the Commission highlights that "many complex and nearly continuous interactions will need to occur among NYISO, the DSPs and DER operators." The Joint Utilities agree and have worked and will continue to work with NYISO, DPS Staff, and stakeholders to define required information exchanges and operational coordination among the various entities. Specific to FERC 2222, the JU held two separate stakeholder sessions in 2022 to provide an overview of distribution utilities plans to support the implementation of NYISO's DER Participation model as well as to review telemetry requirements for communication between the aggregators and distribution utilities/transmission owners.

Central Hudson has been promoting its foundational technology investments, including Distribution Automation, the Distribution Management System, and its Network Communication Strategy programs at various forums such as the Company's DSIP stakeholder conference, GE Orchestrate Conference, and the Joint Utility Stakeholder Conferences.

Central Hudson also reviews its foundational technology investments with the PSC and other stakeholders during rate filings, with the most recent having occurred under Case 20-E-0428. During this, stakeholders have opportunities to review, question, and comment on the Company's plans. Included in those plans are the capital investments in foundational technologies as well as the planned Training Academy / Primary Control Center.

5. Additional Detail

a) 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.

The utility's primary responsibility is to preserve distribution system safety 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., demand response) 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.

As part of FERC 2222, DERs are anticipated to begin to participate in a NYISO wholesale market starting in 2023. The Joint Utilities have developed a Draft DSP Communications and Coordination Manual to define the roles and responsibilities between 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 Joint Utilities have also developed a Draft DSP-Aggregator Agreement for NYISO Program to further define the roles and responsibilities between the DSP and DER aggregators. Most of the communication and coordination as part of these efforts have been captured or will be captured in the NYISO Tariffs or manuals.

Deployment of technology platforms like the Distribution Management System (DMS) and Distributed Energy Resources Management System (DERMS) will give the Distribution System Operators (DSOs) added monitoring and controlling capability of the local DER assets. Continued rollout of Central Hudson's foundational technology investments, including Distribution Automation, the Distribution Management System, and its Network Communication Strategy programs, will also create better visibility of local DER assets. The deployment of these technologies will follow a phased approach. The Company understands that it will be a challenge to obtain monitoring and controlling capability for all DERs in the distribution system, especially the DERs that are already in service.

The DSOs can use these technology platforms to coordinate with NYISO and third-party stakeholders to provide guidance on how to leverage local DERs to benefit the local distribution system and also provide a pathway for these local assets to participate in the NYISO wholesale markets.

b) 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 necessary for effectively addressing utility needs while providing DER aggregators and individual DERs actionable information to help maintain and operate a safe and reliable distribution system. These requirements are defined by the utility in coordination with third parties. 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 adaptable.

With respect to DER wholesale market participation, the Joint Utilities have coordinated with the NYISO on an ongoing basis to define the roles and responsibilities for relevant parties to facilitate DER wholesale market participation in a safe and reliable manner. The Joint Utilities continued to hold stakeholder engagement sessions since the 2020 DSIP to update stakeholders on progress they have made in their coordination with NYISO as part of MIWG efforts and will continue to update stakeholders on future progress. Similarly, input received through the NYISO stakeholder process has informed the development of these currently defined roles and responsibilities.

c) 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. Central Hudson and the Joint Utilities will 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 different utilities' 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).

Concerning operational coordination for DER wholesale market participation, the Joint Utilities have developed a Draft DSP Communications and Coordination Manual to define the coordination requirements between the DSP, NYISO, DER aggregator, and the individual DER. 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 Joint Utilities 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. Most of the communication and coordination as part of these efforts have been captured or will be captured in the NYISO Tariffs or manuals.

With the deployment of DMS and DERMS platforms, DSOs will have a clear line of sight to local DERs, due to added monitoring and controlling capabilities. As information is continuously getting transferred between the DSO, NYISO, and DER aggregators, the utility DSOs 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 DSOs 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 a challenge to obtain monitoring and controlling capability for all DERs in the distribution system, especially the DERs that are already in service.

d) 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:

(1) organizations;

(2) operating policies and processes;

(3) information systems for system modeling, data acquisition and management, situational awareness, resource optimization, dispatch and control, etc.;

(4) data communications infrastructure;

(5) grid sensors and control devices;

(6) grid infrastructure components such as switches, power flow controllers, and solid-state transformers;

Linked to Central Hudson's foundational technology investments (which include Distribution Automation, the Distribution Management System, and its Network Communication Strategy programs) are the changes that will be necessary to operate this system on a real time 24/7 basis and have greater visibility into the operation of the DERs. With regard to the changes that will be made to operate the system, Central Hudson plans to centralize the operation of the distribution system with DSOs similar to how the transmission system is operated today. These DSOs will monitor the operation of the distribution system and the decisions being made by the DMS and intervene as needed. This significant change in how the system will be operated will require substantial organizational changes regarding policies and procedures, as well as how the system will be operated during major weather events. The Electric Distribution System Operations Whitepaper (last updated and filed with the 2018 DSIP) provides policy changes and resource changes that will be needed to transition to this structure. In addition to safely and reliably operating the system with the increased level of DERs, the ability to have greater visibility and control the output or voltage of especially the larger system will be critical.

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

(1) Identify the existing level of system monitoring and distribution automation.

The Energy Management System (EMS) provides for monitoring of the transmission system and most of the distribution feeder breakers. The distribution feeder breaker monitoring within the EMS typically includes breaker position (Open or Closed) and feeder analog values, including MW, MVAr, and distribution bus voltage. Throughout the service territory, approximately 769 distribution automation devices including ALT switches, reclosers, switched capacitor banks and voltage regulators are currently deployed and monitored by Sensus.

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

The planning of Distribution Automation device locations is completed through a detailed modeling and analytical process. The Company plans to monitor additional distribution circuits in the DMS. Additional Fishkill District circuits will be added coincident with the development of the GIS model that supports the GIS. This will be continued in the remaining four districts as the distribution automation devices and network communication are installed and the GIS models are developed. The Company plans to eventually implement monitoring of the entire distribution system in the DMS.

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

Additional monitoring of the distribution system within the DMS is dependent on the installation of distribution automation devices and network communication equipment and the development of the DMS GIS models. This is currently underway. Costs associated with this deployment can be found in Central Hudson's 2024-2028 Capital Forecast.

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

Additional monitoring of the distribution system will allow for expanded use of FLISR and Volt/VAR control as well as accommodate additional DERs.

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

Significant progress has been made in the commissioning of a new GE ADMS V3.11. Contract was executed in December 2020, design workshop meeting kick-off in January of the following year, and final delivery of a PDS March 2021. Central Hudson later completed Factory Acceptance Testing in June 2021 followed by Site Acceptance Testing in November 2021 Site Acceptance Testing replicated and build upon the capabilities within the report that was filed with the Commission in March 2018

The DMS had been used to simulate advanced applications such as Volt/VAR control and Fault Location Isolation System Restoration of the distribution circuits. Following system integration, communication cutover onto the FAN, Volt/VAR control will be tested and implemented Q3-Q4 2023. The circuits in Fishkill remain controllable to date via the DMS. The Company has modeled the Fishkill District and is in the process of completing the DMS model for the Poughkeepsie District. Integration of the SCADA points for the DA equipment installed in Fishkill is substantially complete. These efforts will continue over the next several years as the remaining operating districts are added to the DMS.

The current use of the DMS is helping to shape grid operations policies and procedures. Building off of the Distribution System Operations Whitepaper, the experience with the DMS will help to advance the development of these policies and procedures.

Staffing added since the 2020 DSIP includes the Distribution System Operators who were onboarded in the distribution control room in 2022 and are engaged in computer-based training and monitoring of the distribution network with the DMS. Senior Distribution Operators, control room supervisors onboarded started in 2021will aid in policy/procedure development, as well as training plan development for Operators. The DMS is currently being used to advance the development of the GIS model. The DMS is used to verify GIS model accuracy and connectivity. The ability for power flow calculation to converge in the DMS is used to verify the GIS model, reports of severely under loaded or overloaded transformers, for example, are utilized to identify where customer service point records are not accurate. The DMS is currently also used as a training tool. With the addition of the Distribution System Engineer and the DMS Model Manager, the DMS is a critical component of their development plan. The Senior Distribution Operator will assume the role of the Distribution System Engineer and will be responsible for the training of the Distribution System Operators starting in 2023 and will have primary responsibility for the use of the DOTS in the DMS.

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

Over time, additional circuits will be modeled and monitored, which will allow for the eventual use of FLISR, closed loop VVO, and monitoring and control of DERs. The timing of this will be tied to the addition of Distribution System Operators and the installation of DA equipment and associated network communication equipment. All of these capabilities will be phased in over the next three years as described above. Additionally, as part of the results of a previous SUNY New Paltz ESS + PV system R&D project, Central Hudson has identified the importance of and need to develop advanced forecasting capabilities as a future functionality within the DMS. As a result, the Company is currently supporting a NYSERDA PON jointly with Electrical Distribution Design (EDD) and University of Albany related to forecasting both load and DER systems, as well as extreme weather conditions that may result in outages. The Company has also been performing research to understand the number and distances in which irradiance sensors will need to be installed and fed back into the DMS, in order to forecast solar PV systems accurately.

(7) Identify Capabilities currently provided by DER Management Systems (DERMS)

As described earlier within Section III.C., Central Hudson's current focus is implementing the Grid Modernization strategy which includes finalizing DMS and Network Strategy integration. Following the OMS upgrade and integration with DMS in 2026, the Company anticipates being able to commence implementation of a DERMS starting in 2027, with some pre-planning likely to begin in the second half of 2026.

(8) Describe how DERMS capabilities will increase and improve over time.

Although the implementation of a DERMS is not on Central Hudson's roadmap until 2026-2027, the Company initiated an R&D project in 2021 related to DERMS functionality to help inform decisions for future DERMS implementation. The goal of this project is to provide Central Hudson with guidance and framework on three DERMS use cases: 1. manage equipment capacity and voltage constraints during normal grid states, 2. manage constraints during abnormal grid states, 3. and coordinate operation of DER across the transmission and distribution grid. There are various deliverables as part of this project which is broken down into three phases: Phase 1 – Scenario Creation, Requirements, and Algorithm Development; Phase 2 – DERMS Lab Testing; and Phase 3 – Field Demo, Economic Assessment and Gap Analysis. This R&D project is a partnership with EPRI, Smarter Grid Solutions (SGS), GE, and Nexamp to evaluate corrective vs. predictive DERMS as well as demonstrate the DERMS capabilities via a field demo. EPRI is overseeing the project and received funding from NYSERDA via PON 4128. GE is demonstrating predictive DERMS within the EPRI test lab environment and SGS is demonstrating the corrective DERMS through a field demo between Central Hudson and the PV site owner, Nexamp. Central Hudson is currently finalizing Phase 2 of this project and is expected to kick-off the Phase 3 field demo in July 2023. As with any technology, as DERMS capabilities and functionalities continue to evolve, Central Hudson will stay up-to-date through industry research as well as collaboration with the NY JU.

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

Based on future DER technologies that allow for greater functionality, the business cases to install these DERs may lead to Central Hudson's desire to operate them in a more refined manner through the DMS or a future DERMS or as part of its energy resource procurement. As these functionalities are developed, the Company can test the capabilities through pilot projects. As mentioned in Section III.C.f)(8) Central Hudson is currently working with EPRI on the NYSERDA PON related to deploying a DERMS. The goal of this DERMS research will be to better manage grid performance, particularly in instances where DER penetration has caused the system to exceed thermal and voltage limitations. As described in DER Interconnections, the Company has seen high penetration of DER in localized areas from DER systems looking to interconnect to the distribution system, medium voltage substation bus, as well as the transmission system. In order to increase the hosting capacity for these locations, Central Hudson seeks to understand if a DERMS solution will be sufficient to address these issues. This effort will also seek to develop and test NYISO and Distribution System Operations coordination frameworks when DER are providing market services.

D. *Energy Storage Integration*

1. Context and Background

Energy Storage Systems, especially Battery Energy Storage Systems (BESS), are recognized as an important element of the grid of the future. BESSs represent flexible energy resources that have the ability to operate as both a source and load for energy and capacity. This operating flexibility has the potential to create a number of value streams for the BESS as both a standalone system and when paired with other energy resources (i.e., battery + PV applications). As recognized in *New York's 6 GW Energy Storage Roadmap: Policy Options for Continued Growth in Energy Storage*[9], energy storage will need to play a critical role in supporting New York's decarbonized electric grid by integrating large quantities of variable renewable energy, reducing curtailment, and storing renewable generation for times when it is needed most.

While Central Hudson has had limited direct experience with energy storage systems, since the 2020 DSIP Central Hudson has engaged in numerous initiatives to evaluate energy storage deployment and potential use cases. As with all of its investments, a key driving element is the overall cost effectiveness of any solution. The Company's evaluations have explored the costs and benefits of energy storage systems as compared to traditional T&D solutions. These analyses have included the potential additional wholesale market revenues storage systems can generate and as part of on-going and future work will look to identify additional benefits that may be prudent to incorporate, such as societal benefits. Based on current cost and market data and current incentive levels, both analysis and past experience with the Bulk Energy Storage Scheduling and Dispatch Rights, Request for Proposal (RFP) have indicated that energy storage systems typically do not represent lower cost solutions to meet operational or capacity needs on the Central Hudson system. However, Central Hudson is in the process of completing the most recent 2021 Bulk Energy Storage Scheduling and Dispatch Rights RFP which may result in an Energy Storage Services Agreement and is also participating in various R&D projects associated with energy storage. These efforts will provide additional insight into BESS costs and operational capabilities. While BESSs were previously projected to drop in cost based on advances in battery manufacturing, technological advances, lessons learned, and overall industry experience, over the past few years, BESS costs have increased. Per NYSERDA's Energy Storage Roadmap[10] drivers for this included supply chain constraints, material price increases, and increased competition for battery cells. While the drivers of these cost increases are expected to persist until at least 2025, Central Hudson will continue to track the system costs and overall cost effectiveness of these solutions. As costs come down, Central Hudson envisions that BESSs will have a growing role as a flexible resource on both transmission and distribution systems in the future. As recommended in NYSERDA's Energy Storage Roadmap, the JU were directed to

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[9] https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/Programs/Energy-Storage/ny-6-gw-energy-storage-roadmap.pdf

[10] In the Matter of Energy Storage Deployment Program (Case 18-E-0130), NYSERDA and DPS New York's 6 GW Energy Storage Roadmap: Policy Options for Continued Growth in Energy Storage, December 28, 2022.

study the potential of utility-owned energy storage to provide non-market transmission and distribution services that are cost-effective when compared to traditional alternatives. Central Hudson's efforts as well as collaborative JU efforts on this are discussed further below.

2. Implementation Plan

a) Current Progress

Central Hudson has several ongoing initiatives regarding the implementation of BESSs. These initiatives are geared towards integrating BESSs into transmission and distribution systems and gaining additional learnings on the costs, the economic valuation, and the technical applications of BESSs. Each of these initiatives is briefly described below.

- **Request For Proposals (RFP) for Bulk Power Energy Storage Scheduling and Dispatch Rights** – In September 2019, to meet the requirements of Case 18-E-0130, In the Matter of Energy Storage Deployment Program ("Storage Order"), Central Hudson issued a Request For Proposal (RFP) to procure scheduling and dispatch rights for a total of at least 10MWs of bulk connected energy storage within the service territory. While none of the proposals passed Central Hudson's benefit cost analysis. , a number of processes and documents were developed as a result of the RFP and evaluation processes that will facilitate the deployment of energy storage on the system. These documents and lessons learned supported the latest 2021 RFP described further below. Processes and documents developed as part of the initial 2019 RFP included:

    1. A set of energy storage (ES) RFP documents for future use were developed.
    2. An ES RFP solicitation and evaluation process was developed.
    3. An ES RFP team of Subject Matter Experts (SMEs) for evaluating bidders' ES project proposals was established. These SMEs cover the following areas:
        a) Bidders' Credit Rating and Financials.
        b) Land and Property.
        c) Project Construction Schedule.
        d) Electric Interconnection.
        e) Legal.
        f) Economic Evaluation.

4. An ES project Economic Evaluation model, with Central Hudson vendors' support for this model was created. This Economic Evaluation model can be used to evaluate and forecast the potential revenue which may be obtained from owning the dispatch rights to an in-front of the meter ES project that participates in the NYISO market. This potential revenue is based on the following revenue categories:

    a) Net Electric Energy Arbitrage revenue.

    b) Ancillary Service revenue.

    c) Electric Capacity revenue.

    d) Central Hudson Transmission & Distribution (T&D) Deferral value.

    e) NYSERDA funding.

5. From the review of the bidders' ES project proposals, Central Hudson gained firsthand experience, knowledge, and a better understanding of the ES systems that are currently available in the marketplace and of these ES systems' electrical and physical characteristics and capabilities.

6. Central Hudson has compiled a list of ES RFP bidders that can be used for future RFP solicitations or for Central Hudson to contact to obtain answers to questions in regards to ES systems.

As part of the October 2021 RFP, Central Hudson issued their second RFP to procure scheduling and dispatch rights for a total of at least 10MWs of bulk connected energy storage within the service territory. The projects must be operational by December 31, 2028. The RFP utilized a three-round approach to streamline the process for all participants. Round 1 included a review of financial viability and qualification. Round 2 included refinements to financials as well as a look into interconnection feasibility, cost, and project management composition and experience. Round 3 included an adjusted evaluation of weightings to consider additional functions such as adherence to terms & conditions, site control, project management schedule and permitting milestones. Central Hudson is in the process of completing the most recent RFP, which may result in an Energy Storage Services Agreement.

- **Advanced Technical Working Group Storage RFP** – The Advanced Technical Working Group (ATWG) was formed as result of the NY Public Service Commission's January 2022 Order on Power Grid Study Recommendations. The ATWG serves to address the "challenge of identifying and removing barriers to the deployment of advanced technologies." [11] The ATWG consists of members from each of the Joint Utilities of NY and is supported by multiple organizations including EPRI, LIPA, NYISO, NYPA and NYSERDA. One of the focus areas of the ATWG has been to identify use cases for energy storage. As part of this, the ATWG established the Energy Storage Task Force (ESTF) to prioritize and develop an RFP for conducting an energy storage potential study focused on Transmission and Distribution (T&D) applications. In May 2023, NYSERDA on behalf of the ATWG submitted an RFP, seeking a consultant to perform an Energy Storage Potential Study for Electric Transmission and Distribution Applications in New York. This study aims to determine the potential for energy storage to support the NY utilities T&D systems by 2030 and 2040. As part of the study, three main use cases have been identified as required, these include transmission energy storage systems, distribution energy storage systems, and mobile energy storage systems. Within each of these use cases, the following were also specified to be addressed as part of the study: problems or grid needs to be addressed, functional characteristics of an energy storage system, benefits provided, interconnection location, roles and responsibilities involved, and use case names. Contracts for this RFP are currently anticipated to be awarded by July 2023. As a member of the ATWG, Central Hudson will continue to follow the progress and outcomes of this RFP.

- **Utility Energy Storage Use Case Work With EPRI, AGILe and NYSERDA** – Central Hudson is in the early stages of working with EPRI and AGILe lab through NYSERDA funding, to complete analysis for energy storage use cases. As part of the study, EPRI will complete an analysis to determine the technical and economical applicability of energy storage to resolve current and future constraints in two locations of Central Hudson's system. These areas include Central Hudson's Westerlo Loop and Maybrook/Montgomery area. For the Westerlo Loop, this northern portion of Central Hudson's territory has seen a high penetration of DER, both solar and storage. As part of the energy storage use case, EPRI will seek to apply energy storage as a mitigation to resolve the thermal and voltage impacts as a result of DERs, in order to enable higher penetration. For Maybrook/Montgomery, this area is currently seeing an influx of large, lumped loads proposed which has caused the distribution substation transformer to exceed its long-term emergency rating as well as the transmission transformer to approach its normal and long-term emergency ratings. EPRI will seek to apply energy storage as a mitigation for peak shaving capabilities at the substation, as well as storage in lieu of a 115kV-69kV transformer replacement to alleviate post-contingency transmission concerns. Additionally, strategic location and sizing of the storage should be considered to potentially provide additional operational flexibility for distribution circuits nearing or at their current design ratings. Both studies will review the economic value and cost benefit analysis, including a cost comparison to alternate mitigations. In addition to EPRI's

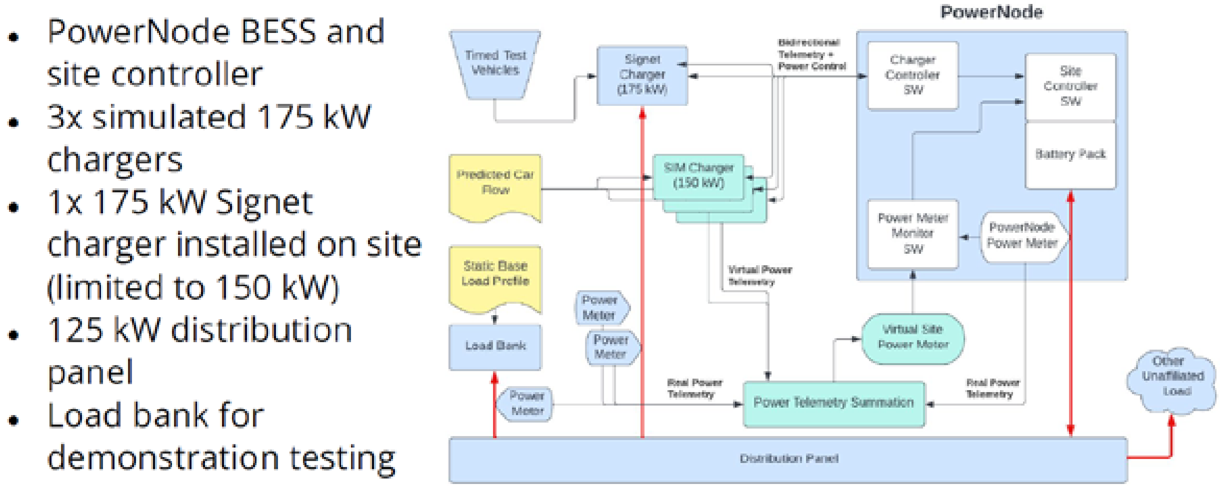
[11] Case 20-E-0197, Order on Power Grid Study Recommendations, State of NY Public Service Commission, January 20, 2022.

analysis, AGILe will develop dynamic models with transient-stability and/or electromagnetic-transient software tools to run several simulation scenarios within their lab for each of these areas. The scope of work has been finalized for the Westerlo Loop area and a separate scope of work for the Maybrook/Montgomery area will be developed. These projects are anticipated to kick off in the second half of 2023.

- **DERMS for Managing Grid Constraints** – Central Hudson is currently working with EPRI on an R&D project related to the implementation of a DER management system (DERMS) to manage the reliability of the electric grid with a high DER penetration. The goal of this project is to provide Central Hudson with guidance and framework on three DERMS use cases: 1. manage equipment capacity and voltage constraints during normal grid states, 2. manage constraints during abnormal grid states, 3. and coordinate operation of DER across the transmission and distribution grid. There are various deliverables as part of this project which is broken down into three phases: Phase 1 – Scenario Creation, Requirements, and Algorithm Development; Phase 2 – DERMS Lab Testing; and Phase 3 – Field Demo, Economic Assessment and Gap Analysis. As part of the lab simulations and testing completed by EPRI, this project does incorporate storage as an asset within DERMS to control based on a formulated dispatch plan, to help address violations. Central Hudson is currently in Phase 2 of this project with preparation ongoing to commence Phase 3 during the summer of 2023.

- **PowerNode Electric Era Technologies R&D Project** – In 2022, over the course of 16 weeks, Central Hudson partnered with Electric Era, EPRI, Fortis BC, and Xcel Energy on a research and development project to demonstrate Electric Era's PowerNode battery energy storage system and PowerNode Command Console. This demo project vetted the PowerNode's capabilities as a non-wires solution to minimize costs and grid impacts related to EV fast charging. The demonstration site consisted of the following layout identified in Figure 29. Numerous vehicles were charged as part of the demonstration at EPRI's testing lab in Knoxville, TN, including Mustang Mach-E, Tesla Model S, Rivian R1T, Kia EV6, and Polestar 2. Results of the testing concluded that PowerNode can successfully provide battery-backed DC fast charging operation in grid-constrained scenarios. Part of this included observing all vehicles successfully charged with a maintained 90kW grid limit, no throttling of vehicles under the 150kW offered by the charger, and a minimum of 37% battery state of charge was observed during the back-to-back charging.

Figure 29: Electric Era PowerNode Demonstration Setup



- **Four Corners Microgrid Project** – The Four Corners Microgrid project is part of a FEMA Grant program following Superstorm Sandy. This project was submitted to the Department of Homeland Security (DHS) by the New York State Department of Public Service on behalf of Central Hudson. The project includes the installation of a microgrid to enhance reliability in the Four Corners Area of the Central Hudson service territory. The Phase 1 Engineering Design was submitted to the DHS on August 14, 2018. This design included a 2MW lean-burn natural gas turbine and a 2MW/1MWh BESS to facilitate block loading. The battery is sized to pick up the area load during the initial loss of utility service while the lean burn gas generator ramps up to speed and assumes the load. The project will include optionality to use the BESS for other services (i.e., demand reduction, frequency regulation) during parallel operation. Figure 30 below shows a one-line diagram of the affected system; Figure 31 shows a simplified diagram of the microgrid layout.

Figure 30: One-Line

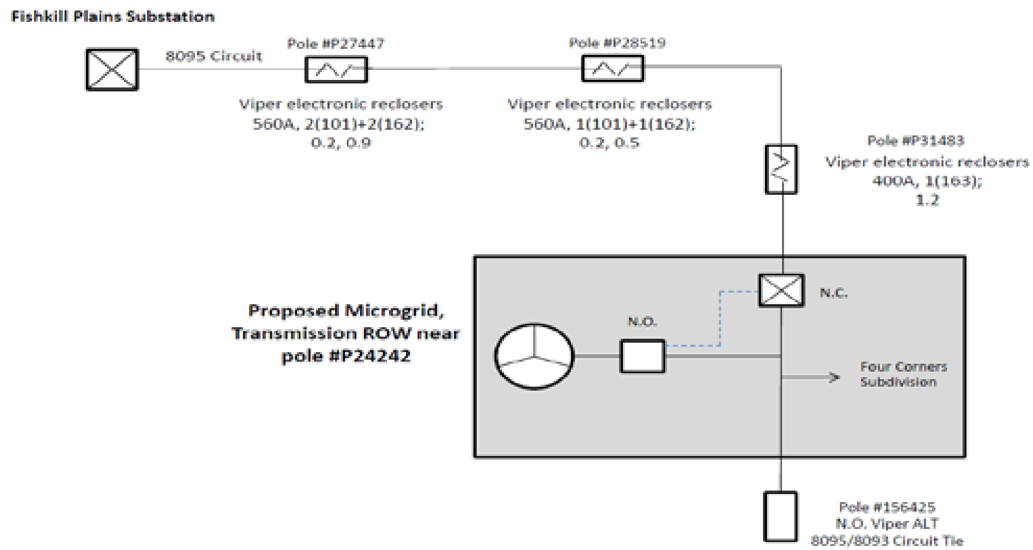
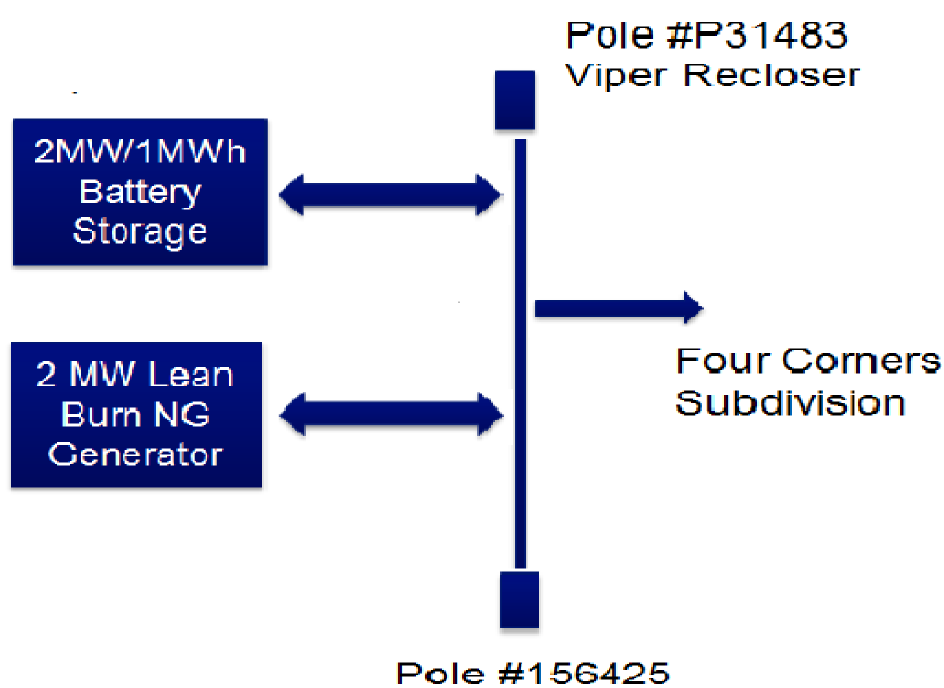


Figure 31: Microgrid Layout



The Phase 1 design was approved by DHS, and on February 15, 2019, Central Hudson received approval from DHS to proceed with Phase II, project construction. In February 2020, Central Hudson issued an RFP to complete Phase II permitting and construction work. Bids were received and Central Hudson engaged with one of the bidders to begin construction in November 2020. This project deviated from the initial construction schedule due, that resulted in delays to the overall project. Two of the top drivers for the delays included a significant increase in lead times for the Powell circuit breakers as well as shortages in microprocessor components and trucking delays associated with the CAT engine and generator. Construction was completed in March 2023, and upon completion of functional testing, which is currently in progress, the site will become operational.

Central Hudson's current initiatives related to BESSs support stakeholders' current and future needs by building the Company's technical understanding of BESSs; enhancing the Company's understanding of integrating BESSs into transmission and distribution systems and their impact on our transmission and distribution systems; and identifying potential transmission and distribution use cases the that are cost-effective when compared to alternative solutions. These learnings will be applied to future implementations of BESS that support meeting NY State's 6GW energy storage goal. This includes NWA evaluations, interconnection requests, procurement of BESS scheduling and dispatch rights and potentially utility-owned use cases.

b) Future Implementation and Planning

Central Hudson has one active energy storage project as indicated above, as well as various research projects and Joint Utility initiatives underway. Outcomes and learnings from these projects will continue to support Central Hudson's knowledge and understanding of use cases for energy storage, including potential future storage deployments. There are also a number of distribution-level energy storage systems interconnected to the Central Hudson system and several energy storage systems in the NYSSIR, Central Hudson and NYISO queues, including some of significant size (20MW to 200MW range). As part of the Interconnection Technical Working Group (ITWG), the JU are currently working with industry stakeholders to discuss energy storage use cases and schedules to enable higher penetrations of energy storage onto the electric system, while ensuring utilities can successfully manage and track these systems. As discussed previously, in October 2021, Central Hudson issued a second RFP to procure at least 10MWs of bulk power energy storage scheduling and dispatch rights. The completion of this RFP and any Energy Storage Service Agreement may provide the Company with additional insight in operating and utilizing energy storage for system needs. Central Hudson will continue to track the evolution of energy storage as the costs and benefits change with technology and markets. Central Hudson may issue additional RFPs in the future for bulk energy storage scheduling and dispatch rights. In addition, as these systems become economically competitive with other technologies, Central Hudson will continue to evaluate use cases for storage including potential applications for NWAs. Central Hudson remains technology agnostic in its solicitation process for NWAs, allowing for energy storage solutions, and may modify future solicitations to accommodate storage solutions better.

In addition to the items identified above, Central Hudson has several corporate initiatives that will support the future implementation and planning for Energy Storage integration as indicated on the Integrated Timeline. These initiatives include the system-wide roll out of an ADMS, advancement of ESS Hosting Capacity mapping functionality; Load Flow software advances; coordination with NYISO on DER aggregations (FERC 2222); Improving the DER Interconnection process and the future development of a DERMS.

As described in Current Progress, Central Hudson's BESS initiatives support the Company's knowledge development which will be applied to future implementations of BESS to help meet NY State's 6GW energy storage goal. The larger corporate initiatives will help support stakeholder's needs by improving the Company's capabilities to plan, integrate and manage increasing levels of energy storage in the distribution system.

As described in Current Progress, continued research and development projects and tracking of BESS costs are required to progress from the current to future implementation. The work and investments needed to progress the additional corporate initiatives identified in the Hosting Capacity and Grid Operations sections of this filing

Future Implementation and Planning describes the planned timing and sequence of on-going initiatives and investments needed to progress from current implementation to future implementation. The planned timing and sequence of work and investments needed to progress the additional corporate initiatives identified in the sections above are outlined in the pertinent sections (i.e. Hosting Capacity, Grid Operations) sections of this filing.

The CGPP and DSIP are filings with overlapping but distinct scopes. The CGPP will detail the evolution of distribution planning processes needed to meet CLCPA goals, align with transmission planning processes, and ensure that planning is integrated. The DSIP describes implementation of the much broader set of DSP activities and projects, and how those activities holistically align with CGPP and CLCPA goals. The CGPP will be more singularly focused on a process to identify distribution system needs to meet CLCPA State goals and develop a distribution investment plan, including capital projects, to meet those needs. Planned capital investments, including technology platform investments and how they will be leveraged, will be included in the DSIP (e.g., AMI, automation, ADMS, etc.) and the results of executing the processes will be used to inform the CGPP. Additionally, an understanding of the existing energy storage, both third-party owned and utility-owned energy, will be an important input into the analysis as part of the CGPP.

The CGPP is aimed at developing a "CLCPA-focused planning process," including "the State's bulk transmission, local transmission, and distribution planning processes." The goal is to improve planning processes to better coordinate the studies performed by the Utilities with the NYISO's bulk-power system planning and generation interconnection processes; improve the integration of Local Transmission and Distribution (LT&D) and bulk system studies with NYSERDA's renewable generation and storage procurements; and improve forecasting of renewable generation development for specific locations on the LT&D and bulk transmission grid. As part of the December 2022 CGPP proposal, one of the key inputs to the CGPP process is the generation of build-out scenarios identified by the Energy Policy Planning Advisory Council (EPPAC). While forecasting practices for the CGPP and DSIP are aligned, the scenarios identified by the EPPAC may result in different forecasts than those completed as part of the DSIP. The output of the CGPP thus may result in the identification of Phase 2 capital projects that are not already identified in current rate plans. Although capital projects identified within the CGPP are intended to be funded under the FERC load ratio share methodology, these Phase 2 projects once approved will be incorporated and used to inform the normal DSIP and interconnection processes. This includes ensuring any upgrades identified as part of the CGPP that energy storage systems may benefit from are included within appropriate planning and interconnection analyses.

c) Integrated Implementation Timeline

Refer to Figure 8 under Grid Modernization to for the implementation timeline related to energy storage integration which includes efforts and investments as part of Integrated System Planning, Clean Energy & Decarbonization, and Grid Modernization.

3. Risks and Mitigation

For all emergent technologies, Central Hudson evaluates the technical risks associated with the technology and also the overall project financial viability/risk profile. Battery technologies have been available for quite some time and are advancing at a rapid rate. The lithium-ion technology utilized in battery energy storage systems is well-developed. Central Hudson feels that the risk profile for the technologies is relatively limited and therefore manageable. These technical risks can be managed as part of the deployment of the systems (redundancy, fail-safe designs, etc.) and with the warranty conditions specified. The applications of BESS to both the transmission and distribution systems represent a greater risk profile as utilities and the industry continue to gain technical learnings on the system interactions and use cases available to BESSs and their ability to meet the identified needs. The different use case assumptions, including the risk that energy storage does not begin to see a reduction in both battery and balance of systems costs or reductions, continue to occur at a much slower rate than previously anticipated, represent higher levels of risk. There are also risks associated with the market revenue forecasts for these installations. The shared learnings among the Joint Utilities as storage projects are implemented should provide data and operational experience to help understand and quantify the risks associated with storage projects. As experience is gained and the applications/markets mature, these risks will be better understood, and appropriate mitigation strategies can be developed.

4. Stakeholder Interface

Central Hudson has actively engaged with stakeholders in several different forums concerning energy storage applications. These areas include:

- Central Hudson was actively involved with the joint NYSERDA/DPS/Utility working group reviewing the development of the solicitation for Bulk Power Energy Storage Scheduling and Dispatch Rights in each utility's service territory. This included discussions and improvements toward RFP implementation. More recently, this group focused was to develop joint comments in response to NYSERDA's Storage Roadmap 2.0.

- Central Hudson remains very active in both the Interconnection Technical Working Group (ITWG) and the Interconnection Policy Working Group (IPWG). These New York State working groups include Joint Utilities, developers, and policy makers. These groups continue to meet regularly and work to advance both technical (ITWG) and policy (IPWG) issues related to interconnections. Most recently this includes discussions with Industry on energy storage deployment principles, challenges, and phased development in NYS.

- As described further in Section III.I Hosting Capacity, Central Hudson has developed granular hosting capacity maps for energy storage since the 2020 DSIP and remains engaged in further developing these maps as part of bi-annual stakeholder discussions.

- Central Hudson is very active in NYISO committee workings and has played a significant role in Joint Utility – NYISO work to facilitate dual participation in wholesale and retail markets by DER providers, which as identified in the Storage Roadmap, will be critical to making the use cases for storage economical.

- Central Hudson has worked collaboratively with the New York State Joint Utilities on a number of stakeholder engagement initiatives associated with CLCPA initiatives. Section III.B outlines the Joint Utilities collaborative efforts on stakeholder engagement.

- Central Hudson was an active participant in the DPS lead Utility Infrastructure working group. Kicked off in January 2020, the group was tasked with identifying ways to facilitate the CLCPA targets and the goals outlined in the "Accelerated Renewable Energy Growth and Community Benefit Act." The primary goal of the working group was to identify new transmission development and policy changes necessary to facilitate the interconnection of large-scale renewables. The working group was broken down into three work streams – a technical study working group to identify potential required transmission system upgrades (currently inactive); a policy working group to identify changes necessary to facilitate the interconnection work and transmission upgrades (currently awaiting PSC Order); and an advanced technologies working group to identify potential innovative solutions to new to increase system efficiency / asset utilization, grid flexibility and hosting capacity while reducing system costs (currently active). In addition to participating on the steering committee, Central Hudson has representatives on all three of these work groups. Central Hudson participated in numerous DPS Technical Conferences to inform and solicit comments from stakeholders of the working groups' work products.

As there are numerous forums and stakeholders that cover energy storage, please refer to the following sections for more details and answers to questions on Stakeholder Interface: Hosting Capacity, DER Interconnections, and DSIP Governance.

5. Additional Detail

a) 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.

As mentioned in previous DSIP filings, working with industry partners, Central Hudson was part of the energy storage installation project located on the SUNY New Paltz main campus which was completed in March 2020. The campus is located in New Paltz, New York within Ulster County. The storage system was interconnected to the Central Hudson 5025 distribution circuit emanating from the Ohioville Substation. This was a PV + Battery storage project which includes the following components:

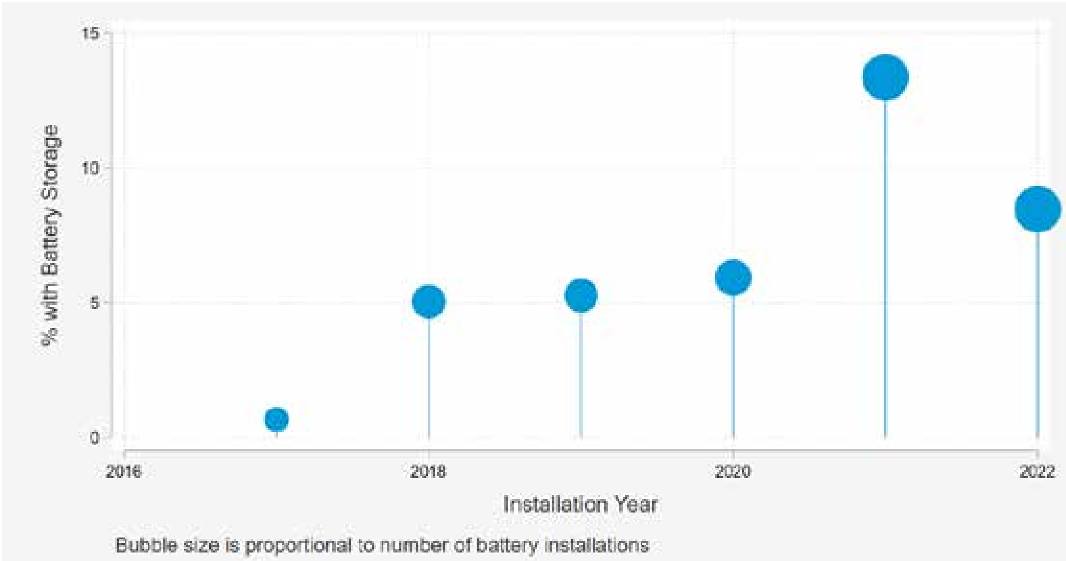
- Solar PV
  - 100kW Princeton Power Smart Inverter
  - 100.65kW CSUN Solar Modules
- Battery Storage
  - 100kW Princeton Power Smart Inverter
  - 200kWh Samsung SDI Li-Ion Battery Bank

As indicated in the 2020 DSIP, this R&D project had numerous lessons learned and key findings which have been incorporated into Company processes.

Central Hudson has a number of customer-sited battery storage systems interconnected to the distribution system, including a large increase in these systems since the 2020 DSIP. These are smaller, behind the meter installations co-located with residential or small-commercial PV systems and customer load. Central Hudson currently has 446 of these installations spread throughout the service territory, 10 of which are residential stand-alone battery storage systems only. In addition, there are another 48 of these systems in the queue. While customer-sited, it is believed these units are installed to provide customer resiliency and potentially demand reduction. In addition to these storage projects, there currently are 2 solar PV + energy storage CDG projects interconnected with a capacity and energy of 6MW/26MWhr, and another 3 in queue with capacity and energy of 15MW/549MWh. An additional 25 projects going through the NYISO interconnection process with a total capacity of 2,452 MW; the 18 energy storage projects have a total capacity and energy of 2,242MW/8768 MWhr. An additional 4 projects with total capacity and energy of 54 MW/199 MWhr currently are in the Central Hudson interconnection process.

Figure 32 shows the share of solar installation paired with battery storage by year. In 2021, 12.5% of residential solar installations were paired with battery storage. The share of sites installing battery storage with solar decreased in 2022, however, and it is unclear if it's a normal variation or a trend.

Figure 32: Share of Residential Solar Installations Paired with Battery Storage



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

(1) a detailed description of each project, existing and planned, with an explanation of how the project fits into the utility's long range energy storage plans; see above

(2) the original project schedule;

(3) the current project status;

(4) lessons learned to-date;

(5) project adjustments and improvement opportunities identified to-date; and,

(6) next steps with clear timelines and deliverables.

Central Hudson has actively worked to identify cost beneficial utility energy storage applications for implementation. These systems would help further develop the Company's working knowledge of the potential benefits both in terms of value-added services and technical advances. As previously identified, there are numerous on-going initiatives to support the implementation of energy storage. Central Hudson currently has two R&D projects in the early stages of implementation as well as one construction project in commissioning which incorporates energy storage applications (Four Corners Microgrid). In addition, Central Hudson is a participant within the ATWG and supported the completion of the RFP for energy storage uses cases as well as recently completed a solicitation for bulk power energy storage scheduling and dispatch rights for 10MWs or greater of energy storage.

Bulk Power Energy Storage Scheduling and Dispatch Rights RFP

(1) A detailed description of this project is included above under Section III.B.2.a) Current Progress. This project fits into Central Hudson's long range energy storage plans for the integration of increased levels of ES within the service territory. This work effort enabled Central Hudson to develop processes and a set of documents which can be utilized to determine energy storage project overall economics/economic viability within the service territory. This project provided Central Hudson with valuable experience in the ES RFP process – this is discussed in more detail in item d) below. Central Hudson issued an Energy Storage (ES) Request for Proposal (RFP) on 10/4/2021, with bidder qualifications for evaluation to be received no later than 10/26/2021. Round 1 offers were due no later than 12/21/2021 and Round 2 offers were due no later than 5/2/2022. Central Hudson is currently in the process of completing Round 3 of this RFP which may result in an Energy Storage Service Agreement.

(2) As a result of the 12/13/2018 New York State Public Service Commission (NYSPSC) "Order Establishing Energy Storage Goal and Deployment Policy" and subsequent 4/16/2021 "Order Directing Modifications to Energy Storage Solicitations" in Case 18-E-0130, Central Hudson developed and issued on 10/4/2021 its second ES RFP to solicit ES project proposals with an ES project Commercial Operations Date of on or before 12/31/2025. Bidder qualifications were due back by 10/26/2021. Round 1 offers were due no later than 12/21/2021, with bidders notified by 3/4/2022 and Round 2 offers were due no later than 5/2/2022, with bidders notified by 7/25/2022. Central Hudson is currently in the process of completing Round 3 of this RFP which is expected to conclude with a PSC filing by December 31, 2023.

(3) The RFP process followed the initial bid scheduled as identified in (2) above, and Central Hudson is currently in the process of completing this RFP as part of Round 3 requirements, which is expected to conclude with a PSC filing by December 31, 2023.

(4) The following is a list of lessons learned to-date from both the first (9/30/19) and second (10/4/2021) ES RFPs:

  a. A set of energy storage (ES) RFP documents for future use were developed.

  b. An ES RFP solicitation and evaluation process was developed.

  c. An ES RFP team of Subject Matter Experts (SMEs) for evaluating bidders' ES project proposals was established. These SMEs cover the following areas:

i. Bidders' Credit Rating and Financials.

ii. Land and Property.

iii. Project Construction Schedule.

iv. Electric Interconnection.

v. Legal.

vi. Economic Evaluation.

d. An ES project Economic Evaluation model, with CH vendors' support for this model was created. This Economic Evaluation model can be used to evaluate and forecast the potential revenue which may be obtained from owning the dispatch rights to an in-front of the meter ES project that participates in the NYISO market. This potential revenue is based on the following revenue categories:

i. Net Electric Energy Arbitrage revenue.

ii. Ancillary Service revenue.

iii. Electric Capacity revenue.

iv. CH Transmission & Distribution (T&D) Deferral value.

v. NYSERDA funding.

e. From the review of the bidders' ES project proposals, Central Hudson gained a firsthand experience to increase Central Hudson's knowledge and understanding of the ES systems that are currently available in the marketplace and of these ES systems' electrical and physical characteristics and capabilities.

f. Central Hudson has compiled a list of ES RFP bidders that can be used for future RFP solicitations or for Central Hudson to contact to obtain answers to questions in regards to ES systems.

(5) Based on discussions and working with ES bidders that responded to Central Hudson's first ES RFP issued on 9/30/2019, Central Hudson adjusted the deadlines associated with the most recent 10/4/2021 ES RFP deadlines to provide qualified bidders with a little more time to create and submit their ES project proposals. As part of the 10/4/2021 RFP, Central Hudson also conducted the RFP in a three-round approach to streamline the process for all participants.

(6) As described in items (2) and (3) above, Central Hudson is in the process of completing Round 3 reviews which has an anticipated conclusion by December 31, 2023.

Advanced Technical Working Group Storage RFP

(1) A detailed description of this project is included in Section III.2.a). This project fits into Central Hudson's long range energy storage plans by providing technical learnings in the application of storage systems for transmission, distribution, and mobile energy storage use cases. More importantly, the project will also identify an economic framework that each NY utility can apply in a consistent manner but tailored to its service territory for assessing the economics of various use cases.

(2) This RFP is anticipated to be submitted in May 2023, with an award date by July 2023, final report by November 2023 and summary presented to the ATWG by December 2023.

(3) The project is currently following the original project schedule identified in (2).

(4) This project is currently awaiting bids as part of the RFP process and does not have documented lessons learned to-date.

(5) This project is currently awaiting bids as part of the RFP process and does not have project adjustments and improvement opportunities identified to-date.

(6) This project is currently following the original project schedule identified in (2).

Utility Energy Storage Use Case Work With EPRI, AGILe and NYSERDA

(1) A detailed description of this project is included in Current Progress. This project fits into Central Hudson's long-range energy storage plans by providing technical learnings in the application of storage systems to resolve current and future constraints related to two use cases which include high penetration of DER integration as well as peak shaving and operational flexibility. In addition to identifying technical applicability, the project will also identify the economic viability of energy storage to resolve the real-world constraints Central Hudson is facing today.

(2) This project is estimated to take approximately 24 months to complete. Kick-off is anticipated to occur in the second half of 2023, pending contract negotiations that are currently underway.

(3) The project is currently following the original project schedule identified in (2).

(4) This project is currently awaiting kick-off and does not have documented lessons learned to-date.

(5) This project is currently awaiting kick-off and does not have project adjustments and improvement opportunities identified to-date.

(6) This project is currently following the original project schedule identified in (2).

DERMS for Managing Grid Constraints

(1) A detailed description of this project is included in Current Progress. This project fits into Central Hudson's long range energy storage plans by providing technical learnings in relation to utilization of a DERMS to manage reliability of the electric grid due to DER penetration. While this project is not solely geared towards energy storage, one component of this project includes simulating storage as a utility asset within DERMS to address violations.

(2) The following provides the initial schedule for the three phases of this project:

   a. Phase 1: Scenario Creation, Requirements and Algorithm Development – September 2021 thru June 2022
   b. Phase 2: DERMS Lab Testing – July 2022 thru February 2023
   c. Phase 3: Field Demo, Economic Assessment and Gap Analysis – March 2023 thru December 2023

(3) The following provides the current schedule for the three phases of this project:
   a. Phase 1: Scenario Creation, Requirements and Algorithm Development – Completed June 2022
   b. Phase 2: DERMS Lab Testing – July 2022 thru March 2024
   c. Phase 3: Field Demo, Economic Assessment and Gap Analysis – June 2023 thru December 2023

(4) As part of Phase 1 learnings EPRI published preliminary results in the form of two reports titled "Implementing DERMS to Manage Grid Constraints" and "Analyzing Telecommunications Systems for DER Integration." The first report is based in part on lessons learned while working on this project and is a primer on the drivers of DER growth, the grid implications that result when large numbers of solar generator systems, battery electric storage systems, electric vehicle chargers, and other DER are interconnected, and how DERMS can help manage a reliable grid. It also provides guidance utilities need to craft precise DERMS requests for proposals including the three prominent use cases mentioned previously. The second paper conducted an analysis using Central Hudson's existing utility telecommunication network. The results confirmed legacy utility networks will support DER management. As Phase 2 and 3 are currently in progress, there are no learnings to report on to-date.

(5) Phases 2 and 3 of this project adjusted from the original schedule. For Phase 2 this included deploying two separate lab environments with SGS and GE. SGS lab testing was initiated in July 2022 and was completed at the end of May 2023. EPRI is currently awaiting the deployment of the GE system to commence lab testing which is anticipated to start in Q3 2023 and finalize testing in March 2024. Phase 3 testing is anticipated to commence in June

2023 and conclude in December 2023. The main delays for Phase 3 have been related to IT/OT requirements for establishing communications between the solar PV site, SGS gateway, SGS DERMS, and EMS/DMS historian.

(6) Next steps for this project include finalizing Phase 2 and Phase 3 based on the timelines identified in (3) above. Additionally, following the completion of Phase 3, final written documentation of the overall project findings and lessons learned will be provided by EPRI.

Four Corners Microgrid

(1) A detailed description of this project is included in Current Progress. This project fits into Central Hudson's long range energy storage plans by evaluating investment opportunities including reliability-based projects on an overall cost benefit basis. The project incorporates a BESS as part of the overall solution.

(2) The original project schedule was to have Phase 1 design complete by August 14, 2018. Phase 2 (construction) was scheduled for completion in February, 2022.

(3) Construction commenced in November 2020 and was completed in March 2023. Upon completion of functional testing, which is currently in progress, the site will become operational.

(4) The project is in the final stages of functional testing and while the system does not have operational lessons learned to date, the project did provide logistical learnings which will better prepare Central Hudson for future design and construction of microgrid systems.

(5) This project deviated from the initial construction schedule due to a few drivers that result in delays to the overall project. Two of the top drivers included a significant increase in lead times for the Powell circuit breakers as well as shortages in microprocessor components and trucking delays associated with the CAT engine and generator. Once the system is operational, Central Hudson will evaluate whether adjustment or improvements to the system's operation are necessary.

(6) Upon final functional testing and the system becomes operational, Central Hudson will monitor the operation of the Four Corners Microgrid system, ensuring the system is operating as intended as well as review the potential for the system to provide any additional benefits to the electric grid.

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

Battery storage is a technology capable of improving system and distribution utilization by storing energy from low-cost periods for use when prices are high or capacity is short. Battery storage can shave peak loads, fill valleys to flatten energy demand, and deliver a range of grid services that require flexibility and fast response. Because the cost of energy storage was prohibitive in the past, generation, transmission, and distribution infrastructure was sized to meet extreme peak demand. With the costs of battery storage assumed to decline starting in 2025 and the state's focus on integration of energy storage, this has led to an increased focus on energy storage.

Battery storage can be directly connected to the bulk transmission system or it can be located behind-the-meter at customer facilities or on utility property such as substation pads. The focus of this section is on distributed energy storage which is connected to the distribution grid. At the bulk transmission level (69 kV and above), a total of 2,242 MW with a total of 8,768 MWh of capacity currently are going through the NYISO's Interconnection Process within Central Hudson's territory. However, distribution connected storage and, more specifically, behind-the-meter storage adoption is dictated by customer preferences and their ability to monetize benefits.

One of the most unique attributes of battery storage is that they affect multiple aspects of the electricity grid's infrastructure and deliver benefits to customer and utilities. Energy storage can provide concrete benefits to customers – in the form of increased reliability (similar to back-up generator), the ability to manage bills by reducing demand charges and shifting of loads from high priced periods to lower priced periods. It can also provide concrete benefits to the electric grid, including: reductions in the need to build additional generation, transmission and distribution infrastructure; the ability to store cheaper electricity generated off-peak for use during higher cost periods; and, fast response services required to ensure reliability and integrate variable resources such as wind and solar.

Central Hudson is currently experiencing flat to no load growth in most of the service territory, with a few exceptions. For most distribution substations and primary feeders, Central Hudson has enough load serving capability to meet peak demands. The most current Avoided T&D Cost Study (found in Appendix D) identified very limited Locational System Relief Value (LSRV) areas. Based on this data, Central Hudson expects storage deployment within the service territory to be driven by customer preferences rather than significant changes in the benefits and pay-back period of battery storage. As per the Energy Storage Roadmap, Central Hudson will look to see if future solicitations for NWAs can better take into consideration the benefits of energy storage systems.

Historical Adoption of Distribution Connected Energy Storage

Battery costs have become more stable and predictable over the past decade, resulting in increased deployment. In nearly all cases, battery storage has been paired with solar. To date, there has been virtually no adoption of standalone distribution connected storage.

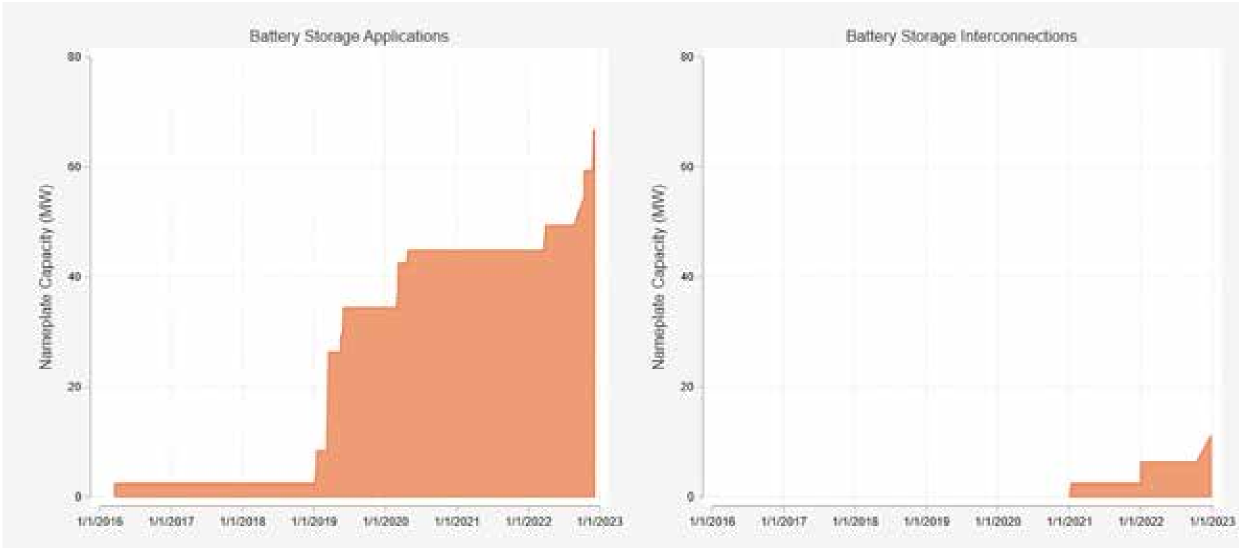
Table 24 shows the annual historic solar and storage interconnection capacity for the residential, non-residential, and community and remote solar from 2018 to 2022, calculated from the historic interconnection data. Storage installations peaked in 2021, and accounted for 10.2% to 11.6% of the nameplate solar capacity, depending on the installation type.

Table 24: Historic Residential and Non-Residential Solar and Storage Capacity Interconnections

	Residential			Non-Residential			CDG or Remote		
Year	Storage Capacity (kW)	Solar Capacity (kW)	Storage Capacity %	Storage Capacity (kW)	Solar Capacity (kW)	Storage Capacity %	Storage Capacity (kW)	Solar Capacity (kW)	Storage Capacity %
2018	210	6,559	3.2%	-	1,023	0.0%	-	8,996	0.0%
2019	395	7,117	5.6%	-	1,266	0.0%	-	41,667	0.0%
2020	452	7,503	6.0%	5	1,936	0.3%	-	36,804	0.0%
2021	1,088	10,703	10.2%	263	2,262	11.6%	6,500	62,540	10.4%
2022	1,235	19,619	6.3%	31	2,620	1.2%	5,000	48,760	10.3%
TOTAL	3,380	51,502	6.6%	299	9,108	3.3%	11,500	198,768	5.8%

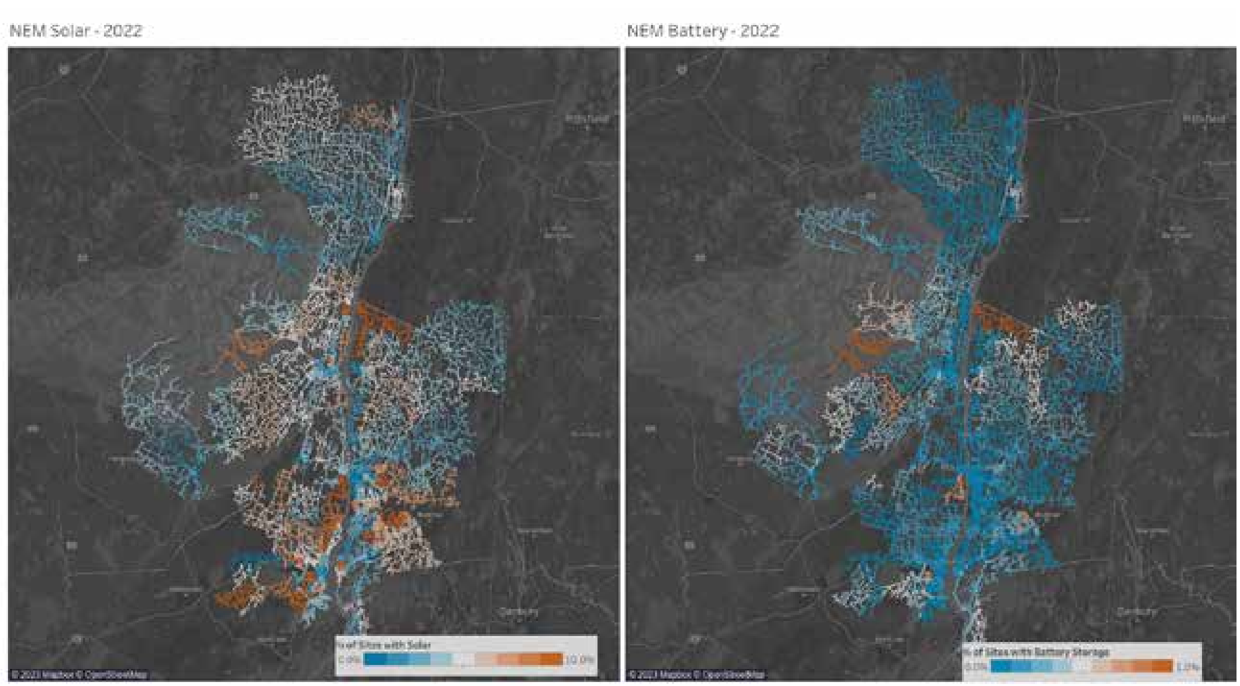
While smaller residential project applications are more numerous, the largest share of the installed nameplate capacity is for community solar and remote net metering applications, which often include battery storage. As discussed in Appendix B, because of their scale and build lead time, a small share of solar and battery applications are eventually completed and interconnected. However, the historical data on the number and size of energy storage units included in the interconnection applications is useful for forecasting future energy storage. Figure 33 shows the cumulative applications and installations of these larger projects over time, using nameplate capacity.

Figure 33: CDG and Remote Battery Applications and Interconnections (Nameplate MW)



Historically, the geographic concentration of solar and battery storage has been higher in specific parts of Central Hudson's territory, reflecting housing age, homeownership, ability of homeowners to afford solar, and environmental inclinations. Figure 8 shows the penetration of net metered solar and battery storage by circuit.

Figure 34: 2022 Penetration of Net Metered Solar and Battery Storage by Circuit



Forecasted Adoption of Distribution Connected Energy Storage

Because it's a relatively new technology, market potential estimates for battery storage are inherently uncertain. Most of the growth in the next five years is expected to come from community solar projects with battery storage. Figure 35 shows the forecasted adoption of battery storage from these larger projects. However, the forecasts have a substantial amount of uncertainty as shown by the confidence bands. Table 6 depicts forecasted adoption of both residential and non-residential NEM storage by year.

Figure 35: CDG and Remote Battery Storage Capacity Forecast with 95% Confidence Interval

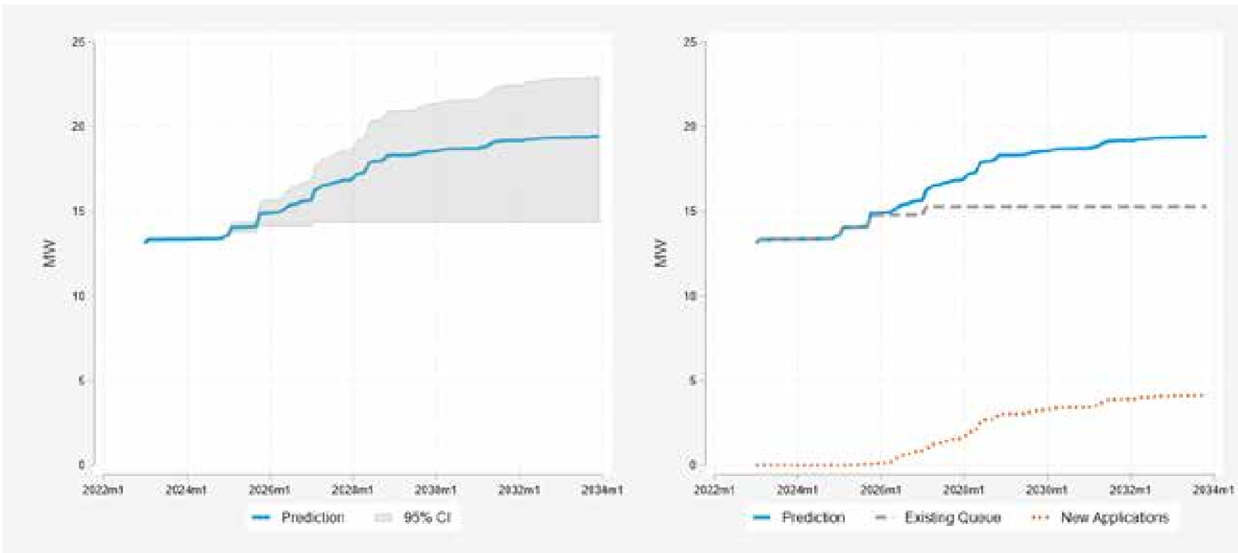


Table 25: Residential and Non-Residential NEM Battery Storage

Year	Residential NEM Battery (Nameplate MW)	Non-residential NEM Battery Storage (Nameplate MW)
2023	4.9	0.2
2024	6.1	0.2
2025	7.5	0.2
2026	8.9	0.2
2027	10.3	0.2
2028	11.6	0.2
2029	12.7	0.2
2030	13.7	0.2
2031	14.4	0.3
2032	14.8	0.3
2033	14.9	0.3

Figure 36 and Figure 37 show the expected locations for battery storage. The granular battery storage projections are tightly woven to expected completion rates of community solar projects. As noted earlier, roughly four fifths of community solar applications are eventually withdrawn and are not completed. Thus, the substation level forecasts are highly uncertain. For any specific substation, the magnitude of battery energy storage resources could be zero or several orders of magnitude larger than the location specific forecast, depending on which projects are eventually completed.

Figure 36: CDG and Remote Battery Storage Forecast Nameplate Capacity by Substation December 2028

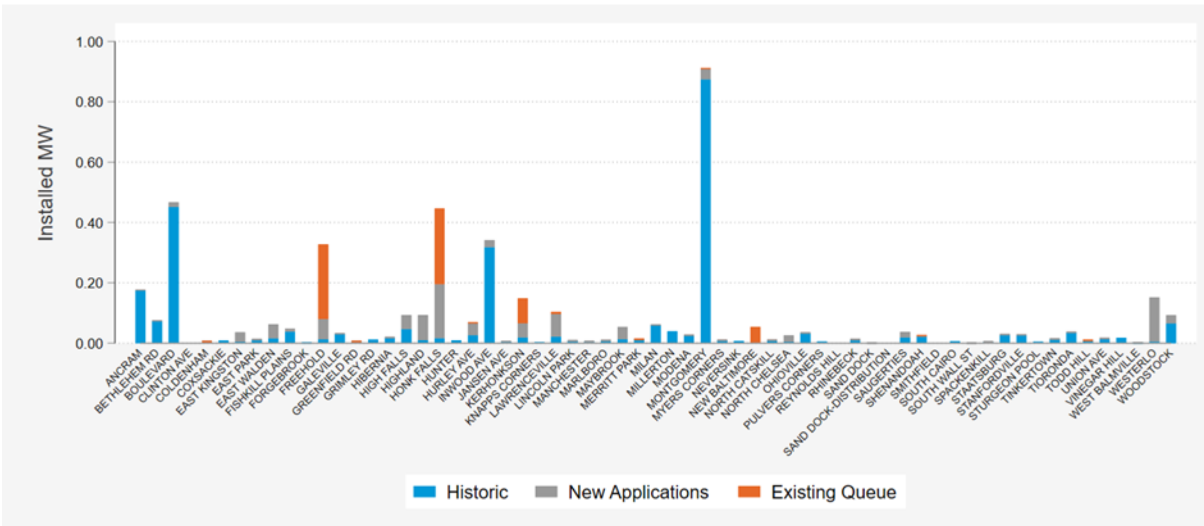
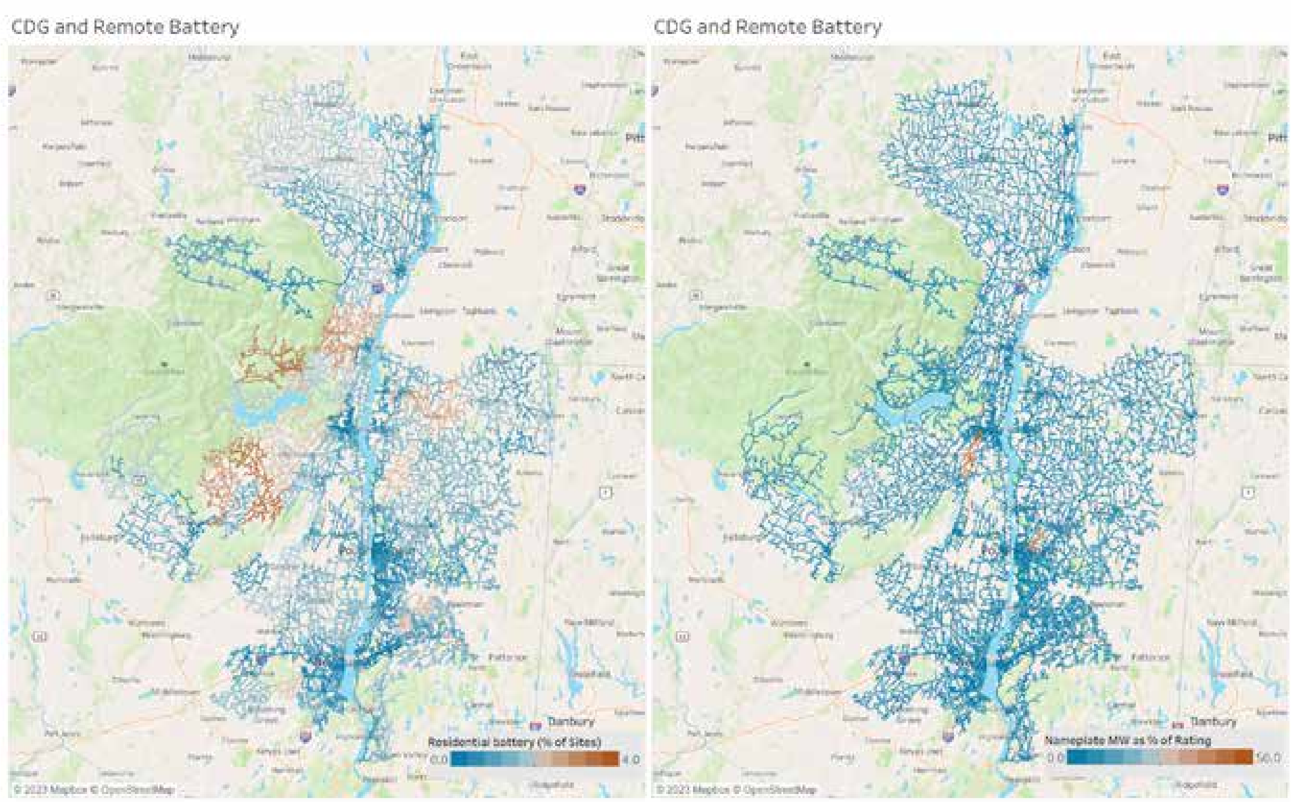


Figure 37 shows the territory served by each individual substation and the projected penetration of battery energy storage. The color varies to reflect the battery storage installed capacity as share of the peak demand at the substation.

Figure 37: 2028 Battery Energy Storage Forecast by Feeder



Ongoing Monitoring

As part of its normal course of business, Central Hudson continuously processes both distribution and transmission interconnection requests. Central Hudson utilizes this data to monitor the activity level for potential third-party energy storage systems on the system. To date, there are a number of smaller residential type systems paired with PV and a limited number of commercial and CDG systems proposed. In addition to these storage projects, there currently are 18 energy storage projects going through the NYISO interconnection process with a total capacity and energy of 2,242 MW/8,768 MWhr; an additional 4 projects with total capacity and energy of 54 MW/199 MWhr currently are in the Central Hudson interconnection process.

Central Hudson will continue to monitor both cost components and use case applications of these systems and actively participate in the continued development and implementation of the New York Energy Storage Roadmap by the Department of Public Service and New York State Energy Research and Development Authority Staff. Utilizing this information with the storage system queue data from its interconnection processes, and refining the evaluation processes developed in its studies to date, Central Hudson will continue to evaluate energy storage applications as system needs develop. When the overall installed costs of these systems become comparable to alternative technologies or when additional revenue streams materialize to adequately offset system costs, Central Hudson will develop appropriate implementation plans. The evaluation of these installations will include both transmission and distribution sited BESSs in varying capacities and configurations based on the system needs, applications, and revenue streams.

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

(1) its location;

(2) the energy storage capacity (power and energy) provided;

(3) the function(s) performed;

(4) the period(s) of time when the function(s) would be performed; and,

(5) the nature and economic value of each benefit derived from the energy storage resource.

In alignment with the *New York's 6 GW Energy Storage Roadmap: Policy Options for Continued Growth in Energy Storage*[12] Central Hudson recognizes the three market segment groupings (bulk, retail and residential for storage deployment applications. Central Hudson continues to review needs on its local transmission and distribution systems to identify potential storage projects that provide cost-effective services when compared to traditional alternatives.

Consistent with the roadmap, Central Hudson recognizes retail bill management, demand response, storage paired with PV, and resilience as potential customer-sited use cases. The Data Sharing section of this filing identifies customer-level data available and the privacy and security issues related to providing this data. The available data can be utilized to help identify potential opportunities for the cost-effective application of customer-sited storage. In addition, Central Hudson's System Data Portal provides 8760 historic circuit load data, where available, (for over 275 distribution circuits) and 8760 historic and forecast load data for 58 of the 63 load serving substations where available on the system (see Section III.I.5.i) for additional information).

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[12] https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/Programs/Energy-Storage/ny-6-gw-energy-storage-roadmap.pdf

(1) The location of the energy storage for these use cases would vary and would be on customer-sited locations.

(2) The energy storage capacity provided would vary by need and application.

(3) The function would be retail demand management, demand response and storage paired with PV.

(4) The period of time when the function would be performed would vary by each particular application/use case.

(5) The nature and economic value of each benefit derived from the energy storage resource would be customer-specific but would predominantly be customer bill reduction.

For the distribution system use cases, Central Hudson identifies both NWA areas and LSRV areas and determines a system-wide demand reduction value (DRV). There are currently three existing Non-Wire Alternative areas in the service territory. These areas provide the opportunity for the beneficial use of energy storage to eliminate or defer the need to complete growth-related T&D capital projects (i.e., capital deferral). To date, storage solutions have not been cost competitive with either demand response or energy efficiency solutions in these areas. The storage applications that have been assessed to date would require a long operational life to approach the point of being economical. Such long-term certainty is not feasible within the Company's current NWA solicitations that are designed for shorter term deferral of assets. Additionally, the currently available revenue streams are generally not significant enough to justify the appropriate interconnection requirements and costs for larger scale applications when compared to distributed, behind the meter DERs. However, additional revenue streams through the wholesale markets for storage assets that are deployed to meet utility needs would have a positive influence on project economics or at a minimum offset the costs of projects whose primary purpose is for utility needs.

As part of this filing (see Appendices), Central Hudson completed a new Avoided T&D Cost Study. This analysis provides an updated system-wide DRV and identified potential areas where the application of energy storage systems may be beneficial.

(1) The location of the energy storage for these use cases would be within one of the five locations: RD-RJ Line and Westerlo Loop transmission areas and Grimley Road, Reynolds Hill, and Woodstock distribution substations.

(2) The energy storage capacity provided would vary by need, location and application.

(3) The function for these applications would be demand reduction for system capital deferral.

(4) The period of time when the function would be performed would vary by each particular application/use case. For the LSRV areas, compensation is based on the resource's prior year performance during the top ten highest usage areas within each particular location.

(5) For the potential LSRV areas, the economic value would be the LSRV values as determined by the 2023 Avoided T&D Cost Study (see Appendices). Note – Central Hudson will continue to utilize the values from the 2016 Avoided T&D Cost Study as the Commission ordered until new MCOS results are adopted by the Commission.[13]

e) 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.

Central Hudson is utilizing the New York's 6 GW Energy Storage Roadmap: Policy Options for Continued Growth in Energy Storage and Department of Public Service / New York State Energy Research and Development Authority Staff Recommendations as a guideline for the planning of energy storage systems. As one of the recommendations in the Energy Storage Roadmap, the JU were directed to study the potential of utility-owned energy storage to provide non-market transmission and distribution services that are cost-effective when compared to traditional alternatives. As a result, Central Hudson has been working on various initiatives as identified earlier, including supporting the ATWG's RFP on Energy Storage Potential Study for Electric Transmission and Distribution Applications in New York. Energy storage T&D use cases have unique parameters that will continue to be evaluated to determine the cost benefit within Central Hudson's service territory. Central Hudson also utilizes the output of the Avoided T&D Cost Study to determine the system wide DRV and to identify the LSRV areas on the Central Hudson system. This data helps inform the projected number of potential storage systems in response to these values. Based on the results of the current study, an increase of storage systems based on these value streams is not anticipated at this time. Another data point Central Hudson utilizes as a planning resource is the energy storage applications within the different interconnection queues (NYSSIR, NYISO, and Central Hudson). This provides a high-level view of potential energy storage systems of various sizes within the service territory. As storage systems with net positive value for customers are identified, Central Hudson would utilize its current processes for system implementation.

In conjunction with the DRV and LSRV areas, as noted previously, Central Hudson maintains a System Data Portal that provides 8760 historic circuit load data, where available, (for over 275 distribution circuits) and 8760 historic and forecast load data for 58 of the 63 load-serving substations where available on the system (see Section G for additional information). This publicly accessible data can be utilized by stakeholders for planning and implementing energy storage at multiple levels in the distribution system.

[13] Order Adopting Program Changes with Modifications and Making Other Findings Case 15-E-0190 and 0190

Central Hudson also maintains a public-facing Hosting Capacity Map that can be utilized for planning purposes. This map provides hosting capacity information for both PV and energy storage systems. Additional information regarding the hosting capacity maps can be found in Hosting Capacity.

For system interconnection review, energy storage is considered a type of DER. Central Hudson's current planning processes incorporate the effects of different types of DERs – predominately PV, EE, and demand response at this time. See Section III.2.a) of this DSIP filing for additional information on current status of Central Hudson's integrated planning efforts. Due to the minimal level of storage currently installed on the system, standalone/dedicated systems for the monitoring and management of energy storage assets are not required at this time. Through the New York State SIR and the NYISO Interconnection process, new storage systems will be studied as they go through the interconnection process. New storage installations will be evaluated to determine the required monitoring and management systems. Central Hudson will have monitoring and control as part of its DMS. As the energy storage systems become more prevalent, to the extent dispatch of these assets is necessary, it will become important to invest in a Distributed Energy Resource Management Systems (DERMS) designed specifically for DER and energy storage management. It is expected that this type of system will either be an extension/enhancement of the current DMS or a standalone system that interacts with the DMS. While Central Hudson has preliminary identified the implementation of a DERMS to begin in 2027, with some pre-planning to start in the second half of 2026, this system is not defined in Central Hudson's current investment plans.

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

The resources and functions outlined above support Central Hudson's needs by providing a statewide roadmap for energy storage and distribution system locational values for DERs. The current plan to implement a DMS with the ability to increase functionality as needs arise supports the current levels of penetration and permits Central Hudson to add functionality as energy storage levels increase.

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

The resources and functions outlined above support stakeholders' needs by providing a statewide roadmap for energy storage and distribution system locational values for DERs. These resources provide data to help determine the potential value streams for calculating project economics for energy storage assets. The system data portal provides both historical and forecasted 8760 load data at a sufficiently granular level to enable stakeholders to identify potential areas on the system where their specific use case may be cost beneficial. In addition, the interconnection process provides a standard process for determining the interconnection requirements and the timeline to interconnect to the distribution system. Central Hudson's DMS and network strategies initiatives will provide a cost effective and readily available means to provide the required monitoring and control functionality for these systems to interconnect to the system. The Company's hosting capacity maps provide developers with a graphical interface suppling a number of key data points for the system, including: the circuit's ID, operating voltage level, number of phases, local hosting capacity values, interconnected and proposed DG in queue, NYISO Load Zone, as well as DG installed since last hosting capacity refresh. Additional information on substation data is also provided including: the substation ID, interconnected and proposed DG in queue, prior year substation peak, and substation back feed protection status. Additional information regarding the hosting capacity maps can be found in Hosting Capacity.

f) 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 could include:

(1) the amount of energy currently stored (state of charge);

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

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

(4) 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,

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

(1) through (4) Central Hudson currently has no energy storage assets interconnected to the system that require means and methods for determining the real-time status, behavior, and effect of energy storage resources in the distribution system. For the Four Corners Microgrid, which is nearing completion, the system has an RTU that will feed into the DMS system. This includes MW and MVAr analog points that show the real and reactive power imported and exported for the energy storage system. Currently, only the battery storage MW and MVAr analog points, along with the breaker status will be retrieved through the RTU. Central Hudson is unwilling to invest in additional infrastructure and systems for this until this type of information is necessary based on penetration levels.

(5) Central Hudson utilizes its existing planning and operational practices to determine the capacity of the distribution system to deliver or receive power at a given location and time.

Energy storage resources interconnected to the distribution system are considered a type of DER. As such, Central Hudson follows the current standards and practices for monitoring the interconnected DERs on its distribution system. These practices have been developed to ensure that Central Hudson maintains the visibility and control necessary to safely and reliably operate the distribution system.

As energy storage systems are interconnected to the system, they will typically fall within three areas or applications which, along with their size and location, will dictate their operation. These applications are bulk/transmission systems that follow the NYISO interconnection process, distribution-level systems that Central Hudson controls or has the ability to dispatch, and storage coupled with other DERs which is under the control of the interconnecting customer. Bulk/transmission systems will be dispatched by the NYISO. Central Hudson will require sufficient visibility and monitoring of these facilities to operate the system in a safe and reliable manner.

Distribution systems that Central Hudson controls or has the ability to dispatch, including the Four Corners Microgrid system, will be managed through the distribution operations area. It is envisioned that for a number of years, these systems will be managed by simple on/off instructions or curtailment based on system constraints.

The overwhelming majority of the systems controlled by the interconnected customer will be able to operate at full output only limited by customer requirements or distribution system abnormal conditions. Abnormal distribution systems may dictate that the system remains offline until the distribution system returns to normal.

In addition, Central Hudson has several ongoing initiatives that will enable increased functionality in response to higher penetration levels of DERs, including energy storage. As indicated in prior sections, Central Hudson is in the process of implementing a Distribution Management System in conjunction with rolling out a Distribution Automation program and a Network Strategy communications platform. These systems will provide the Company with significantly increased visibility into the distribution system and, ultimately, the ability to operate the distribution system in real-time, As the number of smart distribution devices with monitoring capability installed on the system grows, Central Hudson's overall system visibility and awareness will continue to increase. As indicated previously in this document, the distribution of operational data from smart devices will be transmitted to the DMS via the communications network. In addition to data provided by distribution smart devices, data from DERs as determined by the operational requirements to reliably and safely operate the distribution system will also be integrated into the DMS, and starting in 2027, Central Hudson anticipates the implementation of a DERMS with some initial planning expected to commence in the second half of 2026. This will include the necessary data and analytics to determine the information outlined above (amount of energy currently stored (state of charge); the time, size, duration, energy source (grid and/or local generation), and purpose for each charging event; the time, size, duration, consumer (grid and/or local load), and purpose of each energy storage discharge; 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 the capacity of the distribution system to deliver or receive power at a given location and time) as required by the specific application.

Overall, consistent with current practices, the level and complexity of any monitoring required will vary with the size, location, and application of the DERs on the Central Hudson system. Energy storage systems represent additional complexity because of their ability to both supply and consume energy. As use cases for storage are expanded, the level of monitoring may need to change to meet specific applications.

g) 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:

(1) the amount of energy stored (state of charge);

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

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

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

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

Due to the very limited amount of energy storage resources currently installed within the service territory, Central Hudson does not currently require or have the means and methods for specifically forecasting the status, behavior, and effect of storage resources at future times. Central Hudson is in the process of implementing a DMS and has plans for a real-time distribution operations center. Advanced capabilities of the DMS will be evaluated, tested, and implemented as required. As the number and size of DERs and storage resources interconnected to the system grow, both the status and control of these resources will be incorporated into the DMS as necessary as well as a future DERMS Based on the current interconnection process under the NYS SIR, the distribution system would be able to accommodate energy storage charging and discharging as defined in the Interconnection Agreement at all times. The ability to forecast items such as the state of charge, the net effect of charge and discharge operations on the distribution system, and the capacity of the distribution system to deliver or receive power at a given location and time will be incorporated into the DMS when the penetration levels necessitate this functionality. This centralized system will permit Central Hudson to forecast the items identified above as this capability is needed.

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

As described earlier in Section c), the majority of the energy storage systems currently interconnected are at the residential level paired with solar PV. Two additional larger CDG projects are also currently interconnected, and DC coupled with PV. As these projects are eligible and compensated under VDER, there are no additional resources and functions currently needed, outside of the existing VDER compensation process, required for storage. As Central Hudson begins to see further integration of energy storage, including standalone or AC coupled storage, additional metering may be required to ensure appropriate compensation. Depending on the size of the energy storage system, in some cases a separate service for auxiliary/HVAC loads may be necessary and for Utility and NYISO projects, additional telemetry may also be required.

i) 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.

Depending on the use case, there are different types of customer and system data that may be necessary for planning, implementing, and managing energy storage. This data includes:

- Customer count by rate class;
- Historical load by customer type;
- Load shape by customer type;
- Capital investment plans;
- Planned resiliency and reliability projects;
- Reliability statistics;
- Hosting capacity;
- Beneficial locations;
- Load forecasts;
- Historical load data;
- NWA opportunities;
- Locational System Relief Value (LSRV) locations; and
- Queued and installed DG.

Much of this data is readily available to developers and other stakeholders and is typically publicly available. In response to stakeholder feedback, the Joint Utilities developed a central data portal on the Joint Utilities' website in June 2017 with links to utility-specific web portals with available system data and customer data is also being made available through UER. Additional energy data will also be available as part of the state-wide IEDR initiative. The Joint Utilities' website (https://jointutilitiesofny.org/system-data/) includes utility-specific links to the system data listed above.

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

- Central Hudson's plans are aligned with the objectives established in New York State's initiative to deploy 6,000 megawatts of energy storage in New York State by 2030 as demonstrated by the following:

- In October 2021, to meet the requirements of Case 18-E-0130, In the Matter of Energy Storage Deployment Program ("Storage Order") and subsequent 4/16/2021 "Order Directing Modifications to Energy Storage Solicitations", Central Hudson issued a Request for Proposal (RFP) to procure a total of at least 10 MWs of scheduling and dispatch rights for bulk connected energy storage within the service territory. Per the Commission, the project(s) must be operational by December 31, 2028. Central Hudson is currently undergoing evaluation as part of Round 3 requirements, which may result in an Energy Storage Services Agreement.

- Central Hudson was an active participant on the DPS Utility T&D Investment Working Group, with representatives on the steering committee and each of the three identified working groups – Transmission Policy Working Group (TPWG), the Technical Analysis Working Group (TAWG) and the Advanced Technologies Working Group (ATWG). Kicked off in January 2020, the group is identified ways to facilitate the CLCPA targets and the goals outlined in the "accelerated renewable energy growth and community act". The primary goal of the working group was to identify new transmission development and policy changes necessary to facilitate the interconnection of large-scale renewables.

- Central Hudson was an active participant in the use case development in the New York Energy Storage Roadmap and Department of Public Service / New York State Energy Research and Development Authority Staff Recommendations, providing input and feedback during the process. This included providing recommendations in March 2023 in response to DPS's and NYSERDA's New York's 6GW Energy Storage Roadmap: Policy Options for Continued Growth in Energy Storage filed December 28, 2022.

- Central Hudson has been a leader within the state in collaboratively working with the Joint Utilities, developers, and policy makers to advance interconnection process improvements. Central Hudson has been very actively engaged in both the Interconnection Technical Working Group (ITWG) and the Interconnection Policy Working Group (IPWG). Improvements in the timeline and efficiency of the interconnection process facilitate the integration of DERs onto the distribution system and help improve their business cases. Most recently, ITWG discussions have included energy storage deployment principles, challenges, and phased development in NYS. These efforts should help increase the deployment of energy storage within the state.

- Central Hudson has been very actively involved in working with the other Joint Utilities and the NYISO to facilitate dual participation of DERs, including energy storage assets. This work will help energy storage assets gain access to additional/multiple value streams including wholesale markets. As the type and number of benefits the energy storage systems are eligible for increase, the greater the likelihood that these assets will pass the cost benefit test thereby increasing their financial viability and spurring additional deployments helping achieve the State goals.

- Central Hudson has reviewed and processed interconnection applications in an efficient and cost-effective manner. Central Hudson is committed to facilitating the interconnection of all types of DERs onto its distribution system. This includes the installation of customer-owned/sited storage systems, either as standalone systems or paired with renewable resources and larger scale storage projects proposing to interconnect to the transmission system.

- In its NWA areas, Central Hudson engages with energy storage providers to identify potential cost-effective solutions that may meet the program needs and, as part of the Storage Roadmap, will evaluate what additional value streams can be realized by energy storage solutions.

- Central Hudson is in the process of implementing a DMS in coordination with DA and Network Strategy programs. This system and the future integration of a DERMS will significantly expand the visibility and control of the distribution system. Greater real-time awareness and control will ultimately enable the system to better plan for, accommodate, and control (where required) all types of DER assets including energy storage interconnected to the system.

- Central Hudson will continue to track the cost effectiveness of transmission and distribution storage use cases through research initiatives as detailed within Section III.D.a). As the storage assets become cost effective, Central Hudson will incorporate these assets into its investment plans.

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

The Joint Utilities formed an internal working group to coordinate on energy storage implementation efforts. In response to the Commission's February 6, 2023 Notice Seeking Public Comment regarding NY's 6GW Energy Storage Roadmap, Central Hudson jointly filed comments along with NYSEG/RGE and National Grid in March 2023. This provided five recommendations to support achievement of NY's energy storage objectives. The recommendations included: 1. Enabling utility ownership under appropriate use cases; 2. Establishment of a regulatory process enabling the utilities to expeditiously and efficiently develop emergent projects; 3. Establishment of retail and residential incentive programs for storage proposed in the Roadmap; 4. Allow utilities to continue implementing Bulk Storage Dispatch Rights; and

5. Long-duration storage (LDS) demonstration projects incorporate technologies that enable storage of electricity longer than ten hours and guide the most cost-effective solutions. Additionally, in April 2023, Central Hudson, NYSEG/RGE, and National Grid filed response comments to other parties' initial comments on the 2022 Storage Roadmap. 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 Joint Utilities remain committed to continuing this coordination to further support the diversity of energy storage applications and technologies across the state.

In support of the “Storage Order” and subsequent 4/16/2021 “Order Directing Modifications to Energy Storage Solicitations”, the Joint Utilities formed a working group to review the requirements of the order. The group worked closely with DPS and NYSERDA Staff during the development of Order, providing input to the RFP process and NYSERDA’s bridge incentive program. The group continued to meet throughout the RFP development and review process ensuring best practices and lessons learned were shared across utilities. Additionally, the group petitioned and gained approval from the Commission (issued and effective March 16, 2023) to extend the Original Order’s commercial operation date from 12/31/2025 to 12/31/2028 and the acceptable dispatch rights contract duration from up to 10 years to up to 15 years.

E. Electric Vehicle Integration

1. Context and Background

Electrifying transportation offers numerous benefits for customers and communities, including increased efficiency, improved sustainability, energy security, and the opportunity to relieve long-term rate pressure in an environment of stagnant sales growth. According to the U.S. Energy Information Administration, the transportation sector accounts for 42% of New York State's greenhouse gas (GHG) emissions.[14] Therefore, electrification of the transportation sector is a critical component to meet the State's clean energy goals. New York State signed on to the Multi-state Zero Emissions Vehicle Memorandum of Understanding ("ZEV MOU") in 2013, committing to establish the infrastructure necessary to support 850,000 zero emission vehicles registered in the State by 2025.[15] In 2019, the State enacted the Climate Leadership and Community Protection Act ("CLCPA"), setting a target of net zero GHG emissions by 2050.[16] New York State has adopted ambitious statewide electrification targets, including enacting policy goals for MHDV decarbonization through the Advanced Clean Trucks (ACT)[17] rule, Advanced Clean Cars II,[18] the potential adoption of the Advanced Clean Fleets Rule[19] in the State, the Zero- Emission School Bus requirement in the State's FY '23 Budget[20] (ZEV School Bus Requirement) and requirements outlined in the Climate Leadership and Community Protection Act (CLCPA).[21] Additionally, a recent influx of federal support and funding, including the Inflation Reduction Act[22] and the Infrastructure

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[14] U.S. Department of Energy, Energy Information Administration, "State energy related carbon dioxide emissions by sector" (accessed December 5, 2022)

[15] State Zero-Emission Vehicle Programs, Memorandum of Understanding available at: dec.ny.gov/docs/air_pdf/zevmou.pdf

[16] Chapter 106 of the Laws of 2019. See also, the Climate Act Fact Sheet, available at: https://climate.ny.gov/-/media/CLCPA/Files/CLCPA-Fact-Sheet.pdf.

[17] ACT will require between 40 and 75 percent zero-emission MHDV sales by 2035, with steadily increasing interim targets starting for sales in 2024 for model year 2025. https://www.dec.ny.gov/docs/air_pdf/emer218hdomnibu.pdf .

[18] NYSERDA, *All New Cars, Pickup Trucks, and SUVs Sold In New York To Be Zero-Emission by 2035*, https://www.nyserda.ny.gov/About/Newsroom/2022-Announcements/2022-12-29-DEC-Announces-Adoption-of-Advanced-Clean-Cars-II.

[19] The California Air Resources Board recently approved the Advanced Clean Fleets (ACF) Regulation, and it is expected that similar regulation will pass in New York State. A summary of the ACF can be found here: https://ww2.arb.ca.gov/resources/fact-sheets/advanced-clean-fleets-regulation-summary#:~:text=State%20and%20local%20government%20fleets,are%20zero%2Demission%20by%202027.

[20] New York State Budget for FY '23 mandates all new school bus purchases by 2027 must be zero-emissions and all school buses on the road be zero-emissions by 2035. https://www.budget.ny.gov/pubs/press/2022/fy23-budget-clean-energy.html

[21] The CLCPA Scoping Plan proposes goals of 50% ZEV sales of medium-duty vehicles by 2030, and 80% ZEV sales of heavy-duty by 2035, https://climate.ny.gov/resources/scoping-plan/

[22] Congress.gov. "Text - H.R.5376 - 117th Congress (2021-2022): Inflation Reduction Act of 2022." August 16, 2022. https://www.congress.gov/bill/117th-congress/house-bill/5376/text/rh.

Investment and Jobs Act[23], is accelerating the deployment of EVs in New York State. To achieve these goals, the State must build the EV charging infrastructure required to electrify the transportation sector. EV adoption and mainstream support for EVs continue to grow in response to these state and federal policy goals, and as battery costs decline and more vehicle makes and models become available to customers.

An important factor in adoption, the range of EVs is increasing and, according to the U.S. Department of Energy, the median range of battery electric vehicles (BEVs) was 243 miles in 2021. This represents a 110% increase over the median range of 2018 BEVs. Studies have shown that a significant barrier to EV adoption continues to be "range anxiety." A study by the New York State Energy Research and Development Authority ("NYSERDA") identified upfront cost, technical feasibility, and access to charging primary barriers to increased EV adoption.[24]

The EV supply equipment (EVSE) market is a classic example that may warrant public investment and the involvement of regulated utilities. Investment in charging infrastructure, including the financial and non-financial support of infrastructure upgrades to help customers electrify, is an appropriate and necessary activity for utilities and is a natural extension of their existing infrastructure.

Utilities Continue to Play a Key Role in Transportation Electrification

- The Joint Utilities (JU)[25] recognize EVs as one of many valuable tools to help achieve state clean energy objectives and seek to support and encourage EV adoption across the New York State.
- The JU have an important role to play in jump-starting EV adoption in New York. Utilities have been advancing EV demonstrations, pilot projects, and programs, and continue to work with stakeholders such as customers, regional groups, associations, and governments to promote EV initiatives and charging infrastructure awareness.
- The JU envision many different roles for themselves in supporting EV charging infrastructure deployment, with the utility role likely varying by market segment and by geography.
    - The utilities may serve more of an enabling role, for example, investing in make-ready infrastructure and/or chargers or offering incentives.

[23] Congress.gov. "H.R.3684 - 117th Congress (2021-2022): Infrastructure Investment and Jobs Act." November 15, 2021. https://www.congress.gov/bill/117th-congress/house-bill/3684.
[24] https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/Publications/Research/Transportation/21-06-New-York-State-Transportation-Electrification-Report.pdf
[25] The Joint Utilities are Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric and Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas & Electric Corporation.

- The utilities may serve customers with education, technical assistance, and resources to help customers through their electrification journey.

Utilities Seek Flexibility in the Development of Infrastructure Investment Strategies

- The EV market remains in its early stages of growth and may develop differently in various parts of the State due to many factors such as demographics, population, building and housing density, the location of major thoroughfares, and propensity for third party infrastructure investment.
- Given the significant differences among communities across the State, it is appropriate for utilities to develop charging infrastructure investment strategies that reflect such differences.
- The JU seek to learn more about where, when, and for how long drivers will charge their EVs, and adapt their investment strategies accordingly.
- The JU recognize that investment strategies may need to be progressive and proactive and may outpace the immediate market need. Rate treatment and recovery that is consistent with current practices for prudent recovery of approved program costs and incentives for meeting specified goals should be globally applied to utility programs.
- A variety of creative business arrangements can be developed within and around these fundamental roles with the goal of advancing the deployment of EV charging infrastructure.

Utility Investment Strategies and Measuring Success

- Growth of EV adoption is subject to a number of forces outside of the utility's control, such as vehicle costs and performance, gasoline and other fuel prices, consumer preferences, and public policies.
- Utility success in the EV market should be determined by objective measures specific to the type of utility investment. In the case of investment in EV charging infrastructure, this includes using metrics such as installed charging capacity, number of charging ports deployed, and costs of deploying charging infrastructure.

Since the 2020 DSIPs, EV integration remains one of the most active segments in the development of the DSP, primarily driven by regulatory activity and the implementation of Commission-approved programs. The JU have continued to meet weekly to discuss technical topics, including EV market developments, utility EV customer programs, rate modification proposals, fleet electrification, education and outreach, and program reporting and implementation issues, and to discuss positions on emerging issues to share with Department of Public Service (DPS) Staff and stakeholders.

On April 24, 2018, the Commission initiated an EV Proceeding, resulting in a Make-Ready Order on July 16, 2020.[26] The Make-Ready Order acknowledged that Commission and utility attention was needed to remove "inappropriate obstacles to adoption and ensure critical [electric vehicle supply equipment (EVSE)] and infrastructure is in place to support the state's ZEV targets."

To complement these initiatives, on July 16, 2020, the NYS PSC issued an Order in Case 18-E-0138 outlining a Light-Duty Make-Ready Program that addresses much of the infrastructure investment through carefully structured utility collaboration and incentives. Central Hudson's Light-Duty EV Make-Ready Program includes an incentive offering designed to reduce the cost of preparing sites to install EV chargers for light-duty vehicles across Central Hudson's service territory. The incentives are intended to increase public access to EV charging stations and are contingent upon site accessibility, universal usability requirements, and the number of chargers at each project site. The Program seeks to offer incentives for make-ready costs of 3,204 Level 2 (L2) chargers and 69 Direct Current fast chargers (DCFCs) across Central Hudson's territory. The Program also includes utility-side make-ready incentives for medium- and heavy-duty (MHD) EV charging through the MHD Pilot, as well as technical assistance for fleets through the Fleet Assessment Service. In addition to the Light-Duty Make-Ready Program, the Commission issued an Order on July 14, 2022, approving Central Hudson's proposed Managed Charging Programs with Modifications.[27] On September 26, 2022, the Company filed its Residential Managed Charging Implementation Plan for passive and active managed charging programs. Central Hudson plans to begin accepting participant applications during the second half of 2023.

There are several key pending milestones that may significantly shift the policy landscape and impact how Central Hudson's portfolio of transportation electrification investments is shaped over the next year. These include:

- Commission decision on EV Rate Design proceeding for commercial managed charging and DCFC cost relief solutions:
- EV Rate Design January 2023 Order;
    - Immediate solution including:
        1. Transition of DCFC PPI funds to a demand management solution

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[26] Case 18-E-0138, Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure (EV Proceeding); and Case 18-E-0138, Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure (EV Proceeding), Order Establishing Electric Vehicle Infrastructure Make-Ready Program and Other Programs (issued July 16, 2020) (Make-Ready Order).

[27] Case 18-E-0138, Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure (EV Proceeding); Order Approving Managed Charging Programs with Modifications (issued July 14, 2022) (Managed Charging Order).

2. Demand charge rebate solution

- o Near-term solution

3. Phase-in rate
4. Upstate commercial managed charging

- Changes to Make-Ready Program scope, targets, and budget following Midpoint Review;
- Medium- and heavy-duty vehicle (MHDV) make-ready proceeding.

2. Implementation Plan

a) Current Progress

Central Hudson has developed a strategic focus on EV initiatives to increase EV adoption through stakeholder participation and advocacy and demonstrate leadership in EV policy. The strategic approach will now focus on utility infrastructure and make-ready incentive implementation, vehicle charging station plans and deployment, and advocacy and education. Ongoing priority actions include:

- Continue implementing current programs with a focus on customer experience and achieving program targets;
- Continued program leadership through cross-functional teams;
- An employee program focused on education and adoption;
- Expanding existing advocacy efforts through annual events and webinars;
- Ongoing outreach to local counties and municipalities.
- Addressing rate design issues and proposing solutions that advance the program; and

Central Hudson wants to play a lead role in deploying EV charging infrastructure in the Hudson Valley and encouraging the transition from gasoline-powered vehicles to EVs. Central Hudson supports the State's goals to increase electrification and reduce emissions (see the Powering the Path to a Cleaner Future[28] initiatives) and is working with stakeholders to make public.

What is Central Hudson doing?

[28] https://www.cenhud.com/globalassets/pdf/my-energy/powering_the_path_to_a_cleaner_future.pdf

Implementing EV Enablement Programs: Central Hudson is implementing the currently approved DCFC Per-Plug Incentive and the LDV Make-Ready Program with incentives, technical assistance, and outreach and education. Progress on those programs is reported through Central Hudson's annual reports, which can be found through the DPS website under Case 18-E-0138. Central Hudson is also implementing the Residential Managed Charging Program with a 2023 launch.

Planning and Investments: Central Hudson is facilitating private EV charging infrastructure through planning and investments in the electric distribution system, industry collaboration in innovative rate design, and directly assisting local governments and private parties in planning and installing EV charging stations.

Fleet Assessment Service: The Fleet Assessment Service is available to all light-, medium- and heavy-duty fleet operators in Central Hudson's territory free of charge. Fleet managers can apply through the Joint Utilities' website. Following an initial consultation, a Central Hudson representative conducts a site visit to assess feasibility for EV charging infrastructure. Together, the representative and fleet manager compile the necessary data on fleet vehicles, use patterns, and operating costs. This data is then analyzed to identify potential conversion scenarios and conduct a rate analysis to inform fleet managers' decisions.

Customer Resources and Mapping: Central Hudson publishes an EV Hosting Capacity Map as a resource for customers and developers to determine whether their site potentially has feeder and circuit-level headroom to install EV charging stations. Central Hudson also publishes a Disadvantaged Communities boundary map to assist customers and developers identify sites that are within a Disadvantaged Community.

Incentives, Rate Structure: Central Hudson, along with the Joint Utilities, the New York Public Service Commission, and the New York Power Authority have jointly and successfully developed an incentive for fast charger deployment in the State, effective March 1, 2019. Central Hudson is also supportive of rate designs that encourage recharging during periods that support the electric system, for example, coupling charging with solar production and offering EV time-of-use rate incentives, and rate designs that support operating cost relief for customers.

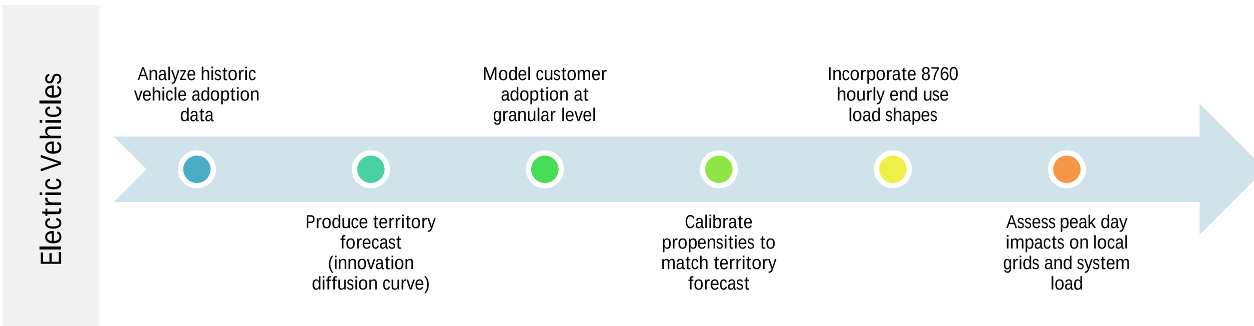
EV Penetration Forecasting Approach and Methodology

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. While near-term levels of light-duty EV adoption do not significantly impact utility system planning scenarios, Central Hudson monitors ongoing developments in the market and the state goals and policies that may impact the related distribution system investment plans necessary to serve new EV load. The assumptions are consistent with industry-wide experience, which shows the majority of light-duty EV charging will occur at home. While electric vehicles are a substantial load when plugged in, not all vehicles plug in at same time or on the same day.

Overall, the penetration of electric vehicles in Central Hudson is driven by share of new vehicles that are electric, the rate of entry of new vehicles, and how newer vehicles flow through the vehicle stock over time. Central Hudson has experienced a notable increase in the share of new vehicles that were electric. in 2019, roughly 1.5% of new model year vehicles were full electric or PHEVs. By 2022, nearly 5.8% of new model year vehicles were full electric of PHEVs.

Figure 38 provides a high-level overview of the granular forecasting process. Central Hudson's EV forecasting assumptions, methodology, and results are listed in the appendices (Appendix B).

Figure 38: Electric Vehicles Forecast Process Overview



Projected Utility System Impacts and Investment

Figure 39 shows the historic geographic penetration of electric vehicles in Central Hudson’s service territory. The map was produced by associating the NYSERDA electric vehicle rebate with Central Hudson accounts (via spatial matching) and circuit feeders. While it does not reflect the full electric vehicle population, it indicates that adoption is higher in specific pockets of Central Hudson territory.

Figure 39: 2022 Penetration of Electric Vehicles by Circuit Feeder

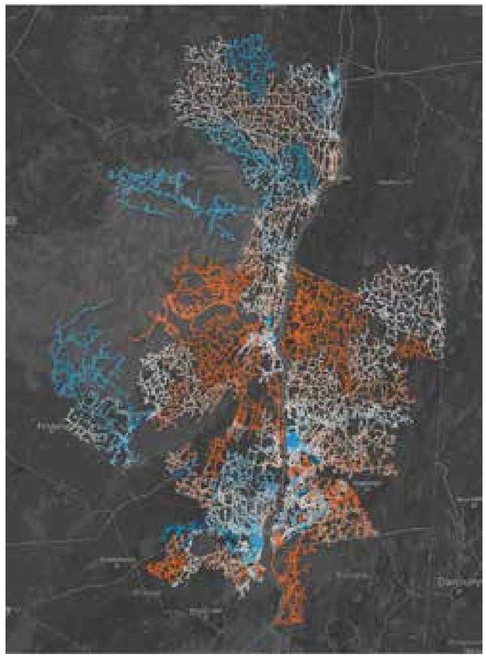


Table 26 shows the electric vehicle forecasts for 2023 to 2033, and provides details about vehicle counts annual MWh. Overall, 80% of energy consumption for light duty vehicles is assumed to occur via home charging, and 20% via public, workplace, or fast charging. Since there is limited data for medium and heavy duty vehicles and buses, there is substantially more uncertainty in those estimates.

Table 26: Electric Vehicle Forecast

		Vehicles			Annual MWh				
scenario	year	EV Light Duty	EV Medium Heavy Duty	EV Buses	EV Light Duty	EV Medium Heavy Duty	EV Buses	LDV Public Charging (L2 and DCFC)	Total MWh
CH Forecast	2023	9,331	50	69	24,057	2,485	1,000	4,511	32,052
	2024	13,605	97	81	35,365	4,821	1,100	6,631	47,916
	2025	19,533	165	94	51,139	8,201	1,300	9,589	70,228
	2026	27,503	261	111	72,462	12,972	1,600	13,587	100,620
	2027	37,814	384	129	100,188	19,085	1,800	18,785	139,857
	2028	50,572	541	147	134,659	26,888	2,100	25,248	188,895
	2029	65,620	732	171	175,497	36,380	2,400	32,906	247,183
	2030	82,535	960	196	221,599	47,712	2,800	41,550	313,661
	2031	100,719	1,226	228	271,366	60,932	3,200	50,881	386,379
	2032	119,522	1,522	261	323,034	75,643	3,700	60,569	462,946
	2033	138,353	1,858	297	374,981	92,343	4,200	70,309	541,833

To study the impacts of incremental DCFC through 2025 and beyond, Central Hudson has estimated for locations and installations first along main travel route exits and travel plazas, then shopping centers, then travel plaza build-outs, and finally at population centers. For the L2 public chargers, the locations were spread based on the residential population and for L2 workplace chargers, the locations were spread based on commercial account population. This distributed additional loading can be used to assess the impact of public and workplace DCFC and L2 charging on circuit loading and the need for peak reduction strategies. Future assessment of utility system impacts and investment is expected to include MHD EV load.

Service Connection Requirements and Processes

The Joint Utilities EV Working Group is collaborating by sharing best practices to reduce the barriers to deploying charging infrastructure and improve their existing individual service connection processes to provide a more positive user experience. To date, Central Hudson has utilized its standard service connection process for DCFC and L2 chargers, but will evaluate this going forward to see if there are ways to streamline the process, short of developing a separate process.

Local Ordinances, Building Codes, and Design Guidelines

Local zoning and parking ordinances, building codes, and design guidelines for EVSE may enable easier and less costly installation. Central Hudson intends to work with the Joint Utilities to engage local and regional government stakeholders seeking to adopt "EV ready" policies and plans, and provide support where possible. The Company has also assessed its own service standards to ensure that new services are capable of serving EV charging load.

Rate Design Considerations

With EV deployment in its early stages, utilities can begin to explore effective rate design considerations. Central Hudson does not believe that the elimination of demand charges for low load factor loads is sustainable in the long term and is committed to finding solutions that address short-term economic challenges that enable the growth of the market.

Central Hudson has adjusted its rate design with the following key considerations in mind:

- Comply with the requirements of Assembly Bill 288;
- Minimize the costs of EV charging, interconnection costs, and potential distribution system impacts;
- Encourage EV drivers to charge at preferred times using price signals;
- 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.

Designed for residents with EVs, the EV Time of Use Rate enables owners to purchase electricity at lower rates during times when home vehicle charging is expected to be most frequent – after 7 p.m. and prior to 2 p.m. This optional billing method converts a residential electric account to a time-based rate, billed at a higher cost during peak demand periods (2 to 7 p.m.) and at a lower one all other times. By charging the vehicle during periods of lower demand, and shifting the majority of other energy use to this same time structure (when choosing the whole home option), customers may benefit from a lower bill. The rate is available on a Whole Home option with Bill Protection for the first year, or with a separate meter exclusive to EV charging.

EV service providers and other stakeholders have expressed explicit concern about the potential negative impacts of demand charges on DCFC use cases. Central Hudson recognizes that DCFCs can help achieve higher rates of EV adoption through the reduction of range anxiety and is actively seeking solutions to improve the business case. However, Central Hudson does not support the waiving of Demand Charges for EV charging stations or the shifting of EV chargers from demand to non-demand rates, especially for equipment that will likely have a negative impact on the circuit and system load factor. However, Central Hudson remains open to discussing this as part of the PSC proceeding and is willing to explore other rate design considerations or equipment supply options, such as EVSE coupled with Battery Storage, as a way to address both the system impact and economics of EVSE.

Education and Outreach

Central Hudson is an advocate for the adoption of EVs and acts as a resource for customers. At community events, including the Dutchess County Fair, Central Hudson customers have the opportunity to learn about our EV Make-Ready Program, fleet assessment services, available chargers at popular tourist destinations with an interactive map Central Hudson created, and how and where to charge elsewhere in our service territory. Customers are educated on the types of electric vehicles available, types of batteries, driving ranges and what Central Hudson is doing to expand electric vehicle adoption. In addition, during the 4th quarter of 2022, Central Hudson hosted a virtual discussion on costs, rebates, benefits and the charger installation process.

Employees are provided hands-on opportunities to increase their knowledge of EVs and help to encourage EV adoption within the communities served. The Company currently owns a small fleet of BEVs that are used to educate customers and showcase at local events such as county fairs. The fleet is also available for employees to test drive for an approved period and then essentially become ambassadors promoting the technology.

b) Future Implementation and Planning

Central Hudson's primary focus for EV Integration will be to implement the installation of public charging infrastructure through the Make-Ready Program. Central Hudson will advance this work either through a future rate case proposal or through future Commission Proceeding and action following the Make-Ready Program Midpoint Review.

Finally, Central Hudson will be working with its Fortis Affiliates to more fully understand the impact that EV charging at home and at the workplace may have on service and distribution equipment. This research effort may result in changes to service standards, distribution design, and inform how controlled charging can be valued and implemented to ensure that the electrification of the transportation sector does not negatively impact the grid and Central Hudson's ability to supply reliable service.

c) Integrated Implementation Timeline

Refer to Figure 8 under Clean Energy & Decarbonization for an implementation timeline related to electric vehicle integration.

3. Risks and Mitigation

Central Hudson recognizes a number of risks with its plans for EV Integration. While the EV market is poised for significant growth, there are many factors beyond the control of Central Hudson that will ultimately dictate the level of EV penetration and the associated impacts on the electric distribution system. Central Hudson will continue to update its forecast of EV adoption so that it will be able to use its normal planning processes to identify system impacts, needs, and potential solutions as changes occur, either due to market changes or technology improvements.

Central Hudson's approach will be to balance the need for EVSE, match the supply equipment need with the EV adoption, and build in advance of the need, so that it can address the issue of range anxiety and ensure there will be enough charging equipment in place to meet demand. Careful planning and coordination with State and municipal officials will be needed to avoid building unnecessary or poorly placed equipment, ensure that the correct charging equipment is installed as technologies advance, and minimize the chance that deployed equipment will become obsolete.

Another risk is that EV adoption will develop quickly, especially in the MHDV market, and that the impact on Central Hudson's infrastructure would be significant. To avoid this, Central Hudson will participate in the MHDV Proceeding through the Joint Utilities and will remain apprised of EV technology and research to ensure that as this market develops, the system impacts and potential mitigation measures are understood well in advance of the need.

4. Stakeholder Interface

Central Hudson gathered feedback through technical conferences with stakeholders and public comments filed during the Make-Ready Program Midpoint Review, which directly informed Central Hudson's prioritization of work. Additionally, the Company directly engaged with stakeholders, including an active Make-Ready Program contractor network, and with businesses and local governments who have established EV charging deployment goals as part of their sustainability commitments.

Through the Joint Utilities EV Working Group, Central Hudson participates in the preparation of joint comments, weekly discussions, and targeted developer outreach to ensure that the programs being considered are feasible and well-vetted. In addition, the Joint Utilities continue working with other JU working groups, including the Information Sharing WG and the Integrated Planning WG on data mapping and planning issues related to EV.

5. Additional Detail

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

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

(2) the number and spatial distribution of existing instances of the scenario;

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

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

(5) the number of vehicles charged at a typical location, by vehicle type;

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

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

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

(9) an hourly profile of a typical location's aggregated charging load over a one-year period;

(10) the type and size of the existing utility service at a typical location;

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

The common framework envisioned in this directive is a detailed electric vehicle charging infrastructure siting analysis. Initially, the Joint Utilities had developed the EV Readiness Framework, which identified key strategies to support EV adoption through utility action, engagement, and collaboration. While the framework envisioned in this directive is an analytical precursor to investment or engagement at a large scale, for forecasting purposes, Central Hudson has developed a forecast which contemplates the number of light duty EV in the service territory and estimates their location, the percentage of at home charging, and the number and location of DCFC and Public/Workplace L2 chargers, and then uses industry load curves to estimate the impacts on the distribution system.

Central Hudson's approach is to monitor adoption closely, update forecasts continuously, and be responsive to the customer connection requests and demand. The exact timing is uncertain and the impact on upgrades will also depend on the growth of load reducing distributed resources such as solar, battery storage, and energy efficiency.

The growing penetration of electric will require upgrades at different levels of the transmission and distribution. Unlike heating and air conditioning, electric vehicle is diverse and is not coincident. Different vehicles charge at different times, and they do not all charge on the same day. Thus, the immediate effects will occur in pocket with high penetration of electric vehicles or a high concentration of vehicle charging.

The initial impacts will be home panel upgrades and the need for larger pad mount and pole top transformers in locations were EVs are clustered. The impact on upgrades to primary feeders and substations will initially be limited to locations with fast charging, bus depots, and truck depots, which require larger connection and draw larger amounts of power.

Central Hudson anticipates that the initial infrastructure needs will mirror the current locations with high adoption level or existing public or fast charging. Figure 40 shows where light duty electric vehicles are registered, the location of DCFC and public charging (including workplace charging) and the location of know bus depots and garages. Figure 57 shows the expected spatial distribution of vehicle charging in 2028 (5 years) and 2033 (10 years). The color legend is adjusted to show the high of penetration from 2033. The plot includes all sources of charging, including at home, public, and fast charging and all vehicle classes, including light duty vehicles, medium and heavy-duty vehicles (MDHV), and buses. While there is limited historical data on electric MHDV and buses, the location of the currently vehicle stock is known at the zip code level. Central Hudson mapped data on vehicle registration zip codes to circuit to understand where they are likely to influence charging loads.

Figure 40: Geographic Location of Electric Vehicle Charging

Light Duty Vehicle Adoption | **DCFC and Public Charging** | **Know Bus Depots and Garages**

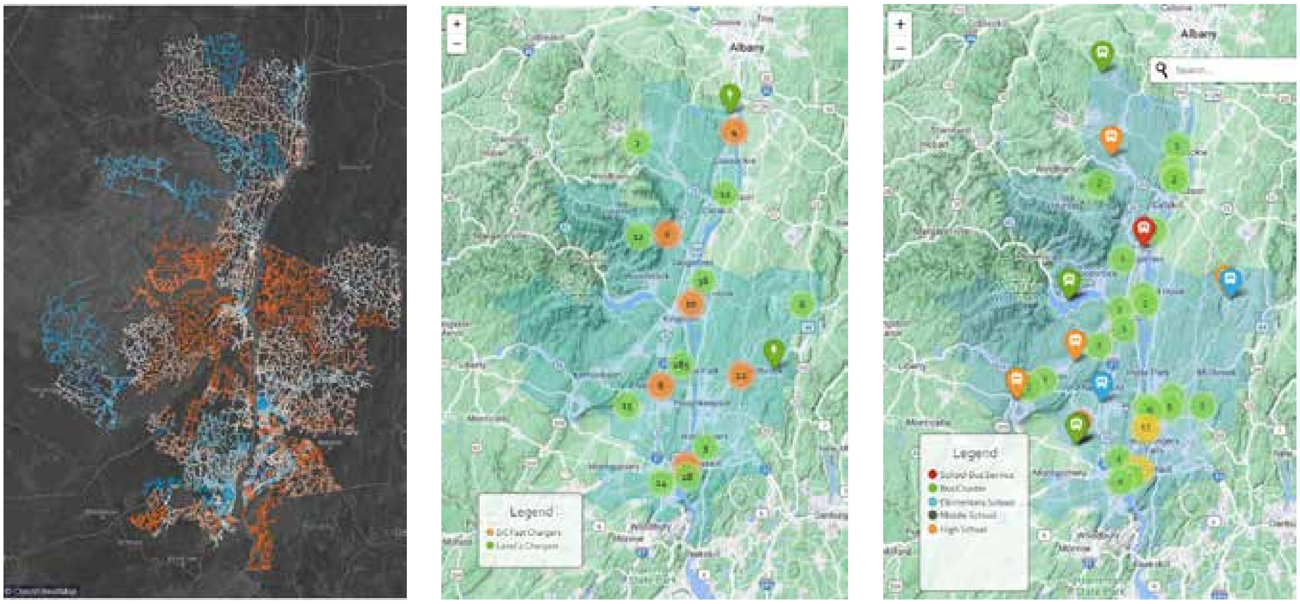
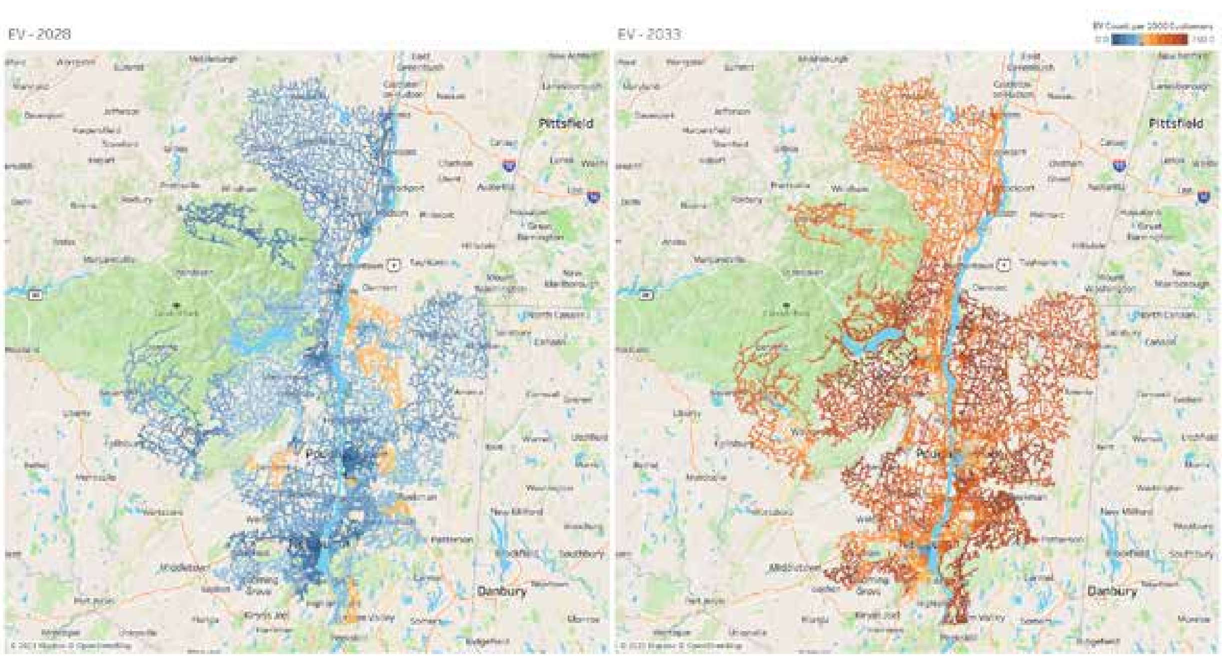


Figure 41: Spatial Distribution of Vehicle Adoption (2028 and 2033)



The DSIP guidance also requested information about the type(s) of vehicles charged at a typical location (commuter car, bus, delivery truck, taxi, ride-share, etc.) and the number of vehicles charged at a typical location, by vehicle type. Central Hudson receives charging data from chargers installed via the Make-Ready program, but will need to investigate if the data provided allows Central Hudson to identify the types of vehicles charging at each location.

Figure 42 shows the electric vehicle charging demand patterns for the summer or winter peak day across all substations in the Central Hudson territory for light-duty vehicles, medium and heavy duty vehicles, and buses. The figures reflect the forecasted charging loads. The light duty vehicle profiles include at home, workplace, public and fast charging are based on load profiles on NREL's EV Lite Pro tool. The MHDV and bus profiles draw from profile made public as part of LBNL's HEVI-LOAD tool, which is still under development.

Figure 42: Vehicle Charging Demand Patterns from Summer and Winter

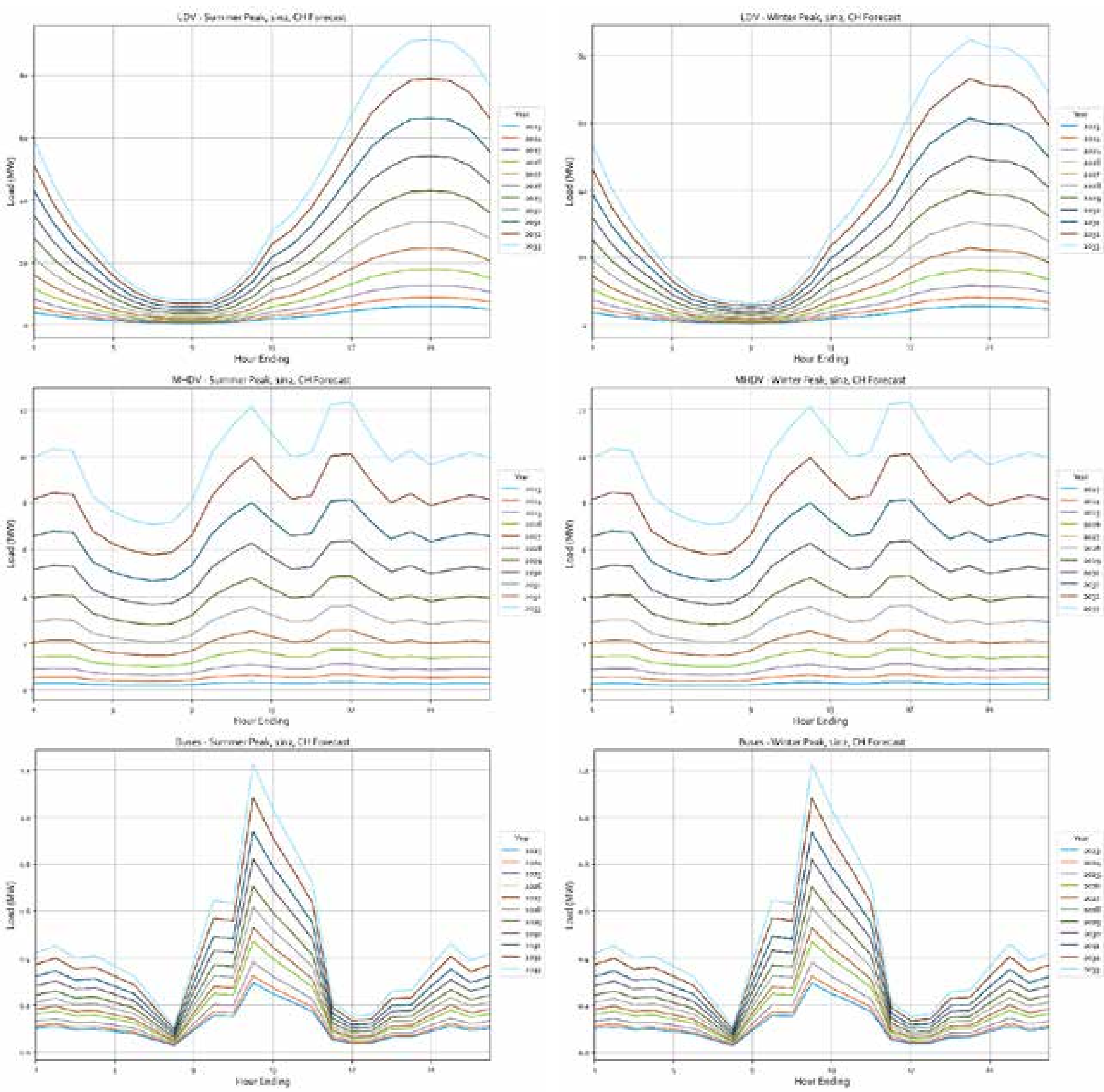


Table 27: Public Charging and DCFC Forecast shows the number of existing and forecasted public and fast charging ports. The forecasts were developed using NREL's EV Lite Pro tool and assume that fast charging is built three years ahead of the projected need.

Table 27: Public Charging and DCFC Forecast

Year	Public Level 2	DCFC
Existing	439	77
2024	523	103
2025	751	130
2026	1,053	161
2027	1,445	195
2028	1,661	231
2029	2,154	267
2030	2,503	304
2031	3,043	339
2032	3,603	372
2033	4,164	404

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

Central Hudson and the Joint Utilities will undertake measures that will support EV adoption in a nascent market, helping to achieve and, where possible, accelerate the long-term potential of transportation electrification. The Joint Utilities of New York have prioritized planning for charging infrastructure, streamlining infrastructure deployment in New York, advancing rate design considerations that will improve the customer experience while minimizing impacts to utility system operation, and conducting education and outreach efforts that raise awareness about EVs.

The role of the utility varies considerably across the core elements of the EV market, in some cases, readiness will be achieved through proactive measures, while in others the utilities remain in a position of information gathering. Consider, for instance, rate design – utilities are proactively seeking to encourage behavior that supports and improves prospects for increased EV adoption and addresses the state goals by improving system load factor and minimizing peak demand growth. On the other hand, utilities are tracking initiatives that promote interoperability and standardization, rather than spearheading them.

c) 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.

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

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

Up to this point, the modest adoption of EVs to date has not warranted dedicated resources and functions; rather, utilities have generally been able to manage EV charging via existing processes. The Joint Utilities in this DSIP filing provide more detail on the resources and functions required for planning, implementing, monitoring, and managing EV charging. The Load and DER Forecast specifically highlights the impacts of both at home charging and station charging on the distribution system under both expected EV penetration levels. In addition, Central Hudson will be deploying tool for T&D planners to enable the tracking and continuous updating of loads from distributed energy resources, electric vehicle charging, and building electrification.

d) 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 Joint Utilities are in the early stages of planning, implementing, and managing EV charging infrastructure and services. Through use case discussions held with Stakeholders, it was determined that there are a variety of customer and system data sources needed to complete this process. The Joint Utilities have identified a subset of the higher priority data that will be required, as noted below.

- **Customer load profile**. The utility will need to know the customer load profile, including charging capacity prior to the installation of EV charging infrastructure to help understand the impact on the customer as well as system-level impacts.
- **Likely EV charging demand**. In workplace or other non-residential types of EV charging, the utility would need to know the anticipated charging demand (e.g., how many EVs are likely to be charging) and at what level (e.g., L2 charging vs DCFC; more likely the former). This will help characterize the charging capacity required at the facility. For a residential installation, the utility would need to know the level of charging that the customer is seeking, namely Level 1 (L1) or L2. Note that it is unlikely that the utility plays a substantive role in deploying L1 charging infrastructure.
- **Distribution asset load profile**. The utility will need to know the load profile on the nearest substation or similar distribution asset to understand the likely impact that may arise from

increased load attributable to EV charging. This will enable the utility to update its asset management strategy for that substation, feeder, etc.

- **Potential location of EV charging infrastructure.** To the extent that "implementation" of EV charging infrastructure is inclusive of installation, the layout of the proposed installation, namely the location of the physical hardware referred to as Electric Vehicle Supply Equipment (EVSE), will help determine the associated costs. More specifically, 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.
- **Distribution asset normal and emergency ratings**. The equipment normal and emergency are critical to understanding if the asset can accommodate the forecasted loads.

At this time, there are no formal mechanisms for utilities to share customer data with third parties. In some cases, customer load data may be shared with the consent of the site host. Central Hudson makes five year hourly (8760) load forecasts publicly accessible for transmission areas, substations, and feeders, including subcomponents such as electric vehicle loads.

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

What is unclear at this stage are distinct changes need to be made to billing to accommodate electric vehicles. Central Hudson is awaiting guidance on EV rate design from staff and will assess how the EV rate design impacts billing systems, if at all.

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

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

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

f) 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.

Central Hudson's plans are aligned with the policy objectives set forth in the "Multi-State ZEV Task Force" which established an organization-wide goal of 3.3 million ZEVs by 2025 and an estimated 850,000 for New York State by 2025 as demonstrated by the following:

- The current EV forecasts have scenarios based on the current market growth projections as well as a high market growth scenario
- The current forecast for number of LDVs in the service territory by 2030 is 82,525 (see Table 28), 960 medium and heavy-duty vehicles, as well as 196 EV buses, which are in the same magnitude as other projections that will meet the ZEV goals.

Table 28: Electric Vehicle Forecasts

		Vehicles			Annual MWh				
scenario	year	EV Light Duty	EV Medium Heavy Duty	EV Buses	EV Light Duty	EV Medium Heavy Duty	EV Buses	LDV Public Charging (L2 and DCFC)	Total MWh
CH Forecast	2023	9,331	50	69	24,057	2,485	1,000	4,511	32,052
	2024	13,605	97	81	35,365	4,821	1,100	6,631	47,916
	2025	19,533	165	94	51,139	8,201	1,300	9,589	70,228
	2026	27,503	261	111	72,462	12,972	1,600	13,587	100,620
	2027	37,814	384	129	100,188	19,085	1,800	18,785	139,857
	2028	50,572	541	147	134,659	26,888	2,100	25,248	188,895
	2029	65,620	732	171	175,497	36,380	2,400	32,906	247,183
	2030	82,535	960	196	221,599	47,712	2,800	41,550	313,661
	2031	100,719	1,226	228	271,366	60,932	3,200	50,881	386,379
	2032	119,522	1,522	261	323,034	75,643	3,700	60,569	462,946
	2033	138,353	1,858	297	374,981	92,343	4,200	70,309	541,833

- Using these forecast scenarios, and other information regarding the granularity of the existing EV ownership, Central Hudson is assessing the impacts on system demand and energy growth down to the substation level.

- Central Hudson will be using this information in its planning process to assess the impact of EVSE on the broader distribution system.
- In addition, Central Hudson has run "pressure test" scenarios in its forecasts to assess the impact of EV at even higher levels of penetration.

Additionally, in 2020, the New York Public Service Commission filed an "Order Establishing Electric Vehicle Infrastructure Make-Ready Program and Other Programs" that established programs to support the estimated 20,000 to 50,000 additional public L2 ports, 35,000 to 80,000 additional workplace L2 ports, and 1,000 to 4,000 additional direct current fast charger ports New York will need.

To address these barriers to EV adoption, Central Hudson is currently offering a portfolio of EV programs to its customers including the MRP, Residential Managed Charging Program, EV Time-of-Use Rate, and Demand Charge Rebate. The Company is also in the process of developing a Commercial Managed Charging Program, Demand Management Technologies Program, and an EV Phase-in Rate pursuant to the Commission Order in Case 22-E-0236.

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

(1) 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;

(2) the original project schedule;

(3) the current project status;

(4) lessons learned to-date;

(5) project adjustments and improvement opportunities identified to-date;

(6) next steps with clear timelines and deliverables;

Central Hudson has developed a strategic focus on Electric Vehicle Integration as a way to improve system efficiency, greenhouse gas reduction, and improved revenues. The program's priority initiatives are as follows:

- Continued program implementation leadership through cross-functional teams that collaborate and support transportation electrification;
- Expanding existing advocacy efforts through annual events and webinars;

- Ongoing outreach to local counties and municipalities.

- Addressing rate design issues and proposing solutions that advance the program.

Of the priority items, the program leadership and cross functional team has been established and efforts on increasing and improving consumer outreach are underway. The employee workplace chargers and fleet chargers were completed in 2020.

Some lessons learned to date include:

- Development of charger sites takes a lot more time than anticipated, much of which is not related to utility service or processes;
- Site types reflect Central Hudson's territory of small businesses dotting the Hudson Valley region;
- Statewide program has helped contractors and customers with multiple properties work seamlessly across the JU territories;

- There is a need to look for new and creative ways to engage and support active approved contractors and attract new contractors to participate.

Central Hudson has proposed several adjustments or improvement opportunities in the DCFC Incentive program based on lessons learned and unintended consequences.

The Company is in the process of developing a Commercial Managed Charging Program, Demand Management Technologies Program, and an EV Phase-in Rate pursuant to the Commission Order in Case 22-E-0236. Additionally, the Company intends to continue with the following:

Help Develop the Local Electric Vehicle Market

We support transportation electrification through a number of beneficial commercial incentive and rate programs. Central Hudson's Light-Duty EV Make-Ready Program includes an incentive offering designed to reduce the cost of preparing sites to install EV chargers for light-duty vehicles across Central Hudson's service territory. The incentives are intended to increase public access to EV charging stations and are contingent upon site accessibility, universal usability requirements, and number of chargers at each project site. The Program seeks to offer incentives for make-ready costs of 3,204 L2 chargers and 69 DCFCs across Central Hudson's territory. The Program also includes utility-side make-ready incentives for medium- and heavy-duty (MHD) EV charging through the MHD Pilot and technical assistance for fleets through the Fleet Assessment Service. In addition to the Light-Duty Make-Ready Program, the Commission issued an Order on July 14, 2022, approving Central Hudson's proposed Managed Charging Programs with Modifications. On September 26, 2022, the Company filed its Managed Charging Implementation Plan for passive and active managed charging programs. Central Hudson plans to begin accepting applications during the second half of 2023.

Electric Vehicle Education and Advocacy

Central Hudson continues to be an advocate for the adoption of electric vehicles and acts as a resource for its customers. The Company runs an active electric vehicle education program through its website, social media, e-newsletters, direct mail, printed handouts, and events, including Company hosted webinars, National Drive Electric Week community events, and public showcase events such as county fairs. Information on electric vehicle technology, benefits, purchasing incentives, and charging options is provided, intended to build awareness and adoption of EVs and help meet New York State carbon reduction objectives. Company representatives also continue to participate in state and local events focused on electric vehicles and charging infrastructure. The Company intends to expand efforts through the development of an enhance online fleet assessment tool for fleet managers, a fuel cost comparison calculator, dealer-based marketing and educational materials to better support customers in their decision-making process.

DCFC EVSE Incentive

During the first quarter of 2019, Central Hudson launched the Direct Current Fast Charger Incentive program in response to the Public Service Commission's Order Establishing Framework for Direct Current Fast Charging Infrastructure Program issued and effective February 7, 2019 in 18-E-0138. Application requirements of this seven-year program are reviewed as needed, to ensure compatibility with current PSC orders and other market influences.

Workplace Charging

In 2019, Central Hudson initiated a workplace charging program to expand the availability of Level 2 chargers to five of its district locations, including Poughkeepsie, Fishkill, Kingston, Newburgh, and Catskill, thus enabling employees and campus visitors the ability to charge their vehicles. Construction was completed early in 2020 with a projected total of 60 Level2 plugs and 2 DCFC plugs installed.

EV Suitability Assessment and Integration of Electric Vehicles to Fleet

Central Hudson plans to spend at least 10 percent of its annual vehicle capital budget on the procurement of fully electric or Battery Electric Vehicles (BEV) and/or Plug-in Hybrid Electric Vehicles (PHEV) through 2025 and up to 50 percent by 2030. Central Hudson’s goal is to reach 10 percent fleet electrification by 2025 and 50% fleet electrification by 2030. Currently the Company has two fully electric line trucks and is researching the optimal charging configurations for these and future resources.

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

The Joint Utilities were proactively engaged with NYSERDA, NYPA, DEC, and DPS staff through the development of the EV Readiness Framework published in March 2018. Multiple staff members from these organizations actively participated in the two stakeholder meetings, held in September 2017 and February 2018. Since the Make-Ready Order was issued in 2020, these state agencies have continued to participate in stakeholder meetings and technical conferences with the Joint Utilities and DPS, to the extent possible and when relevant to the ongoing implementation of current programs and new proceedings. For example, NYSERDA has continued to be a key stakeholder due to the related and stackable EV incentives available through their programs. Central Hudson and the Joint Utilities have engaged directly with NYSERDA to discuss the future of state-level incentive programs, including but not limited to, the Charge Ready NY Program and opportunities to support school districts with their electrification plans.

In addition, Central Hudson and the Joint Utilities are actively participating in all Commission EV cases, including attending any technical conferences hosted by DPS in order to advance the Commission's understanding of the nuances of rate design, infrastructure needs, and ownership models, and system impacts.

F. Clean Heat Integration

1. Context and Background

Central Hudson has been promoting air-source heat pumps within its Environmental Beneficial Electrification program, which incentivized ASHP installations in residential fuel-switching applications, since July 2018. On January 16, 2020, a Statewide Heat Pump initiative was established in the Order Authorizing Utility Energy Efficiency and Building Electricity Portfolios Through 2025 from the State of New York Public Service Commission in Case 18-M-0084[29]. The NYS Clean Heat Program is an initiative between the New York State electric utilities to deliver incentives to both customers and qualified participating contractors for the installation of eligible heat pump technologies. The Clean Heat Program provides a uniform incentive structure with shared eligibility between all utilities to foster adoption of heat pump technologies throughout the state.

The January 2020 Order also authorized an incremental $43.2 million to support the achievement of approximately 255,000 MMBtu of energy savings through heat pump electrification. Heat pump technologies present a great opportunity in meeting the ambitious statewide greenhouse gas reduction goals due to their ability to provide efficient heating and cooling for residences and businesses alike. Heat pumps are approximately three times as efficient as electric resistance heating, offer cost-savings for fuel-switching oil and propane consumers, and can fully decarbonize heating energy usage when paired with renewable technologies. As of April 1, 2020, the Clean Heat program replaced all existing Central Hudson heat pump initiatives. Central Hudson implemented the statewide structure, which allows participation of all electric customers and addresses the MMBtu savings targets within the statewide program.

The measures within the NYS Clean Heat Program include incentive rebates for partial space heating and full load installations of 90-120% heating capacity for qualified “cold climate” air-source and geothermal (ground-source or water-source) heat pumps. In addition, incentives for efficient heat pump water heaters across residential and commercial classes are included.

2. Implementation Plan

Central Hudson utilized its existing trade ally network to promote cold climate air-source heat pumps, ground source heat pumps, and heat pump water heaters to residential and commercial customers throughout the service territory. Under the statewide framework, prescriptive ASHP and GSHP projects were incentivized on a $/10,000 MMBtu of heating capacity, while Heat Pump Water Heaters are incentivized on a $/unit basis and custom projects based on a $/MMBtu of savings. Qualifying systems are eligible for rebates regardless of the original fuel source therein, and the prescriptive vs custom measures are defined by system size as opposed to a strict residential vs commercial descriptor.

[29] https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?Mattercaseno=18-M-0084

Central Hudson, the joint utilities ("JU") and NYSERDA collaborated to provide heat pump education and institute market enablement initiatives to grow the qualified labor force for Clean Heat and expand the heat pump marketplace. As the Clean Heat program progressed, Central Hudson leveraged its existing trade ally network to achieve nearly 450,000 MMBtu of annual energy savings, 175% of its program target of 255,292 MMBtu through 2022.

Table 29: Central Hudson Clean Heat Program Spend and Achievement 2020-2022

Category	Spend ($)	Savings (MMBtu)
Cumulative 2020-2022 Spend/Achievement	$43,469,522	447,752
Cumulative NE:NY 2020-2025 Budget/Target	$43,221,312	255,292
Share of NE:NY Budget/Target Realized Through 2022	101%	175%

In December of 2022, Central Hudson expended its cumulative Clean Heat Program budget for the years 2020-2025. Pursuant to the budget flexibility authorized in the NENY Order, The Company utilized a total of approximately $4.6 million in unspent funds from the Non-LMI Electric portfolio for Clean Heat, having achieved the annual electric portfolio targets for years 2018-2022 without spending the full budget in each year.

In February 2023, in a request to provide additional funding beyond the transfer of unspent funds, the Company petitioned the Commission for the authorization to transition $13.5 million of its cumulative electric energy efficiency budget to Clean Heat. As a contingency to the authorization, Central Hudson demonstrated its potential to still achieve its NENY ordered cumulative electric EE savings target even after the transfer of these funds. In June 2023, the Commission, through its Order Approving Funding for Clean Heat Program authorized the Company an additional $21.2M to support the program through mid-2024. With these additional funding sources of $25.8M, the Company anticipates achieving approximately 303,000 MMBtu of energy savings through its Heat Pump program.

Moving forward, Central Hudson continues to engage in market enablement initiatives, provide Quality Assurance education and work with key stakeholders, including key distributors and manufacturers, to increase access to heat pump space and water heating technologies.

3. Risks and Mitigation

Known risk factors to heat pump adoption include the lack of consumer awareness, upfront installation costs, contractor availability, and customer perception about heat pumps and their potential benefits and cost savings. Central Hudson and the Joint Utilities, in collaboration with NYSERDA, have launched targeted marketing campaigns highlighting the benefits and cost-effectiveness of heat pumps for homes and business alike. Within the statewide Clean Heat framework, the utilities have deployed rebate levels to impact consumer behavior and eliminate barriers to adoption of heat pumps on a project-level. To meet increased demand because of available rebates and increased awareness, the Joint Utilities have worked to provide on-demand training for active and interest participating contractors to grow the workforce capable of completing projects that meet the required quality assurance standards within the Clean Heat program.

4. Stakeholder Interface

Central Hudson regularly interacts with stakeholders to continuously develop and enhance its Clean Heat program. This includes interaction with participating contractors, customers, distributors, manufacturers, advocacy groups, DPS Staff and more.

Central Hudson and the Joint Utilities conduct a quarterly Participating Contractor and Industry Partners ("PCIP") meeting to discuss program progress, receive stakeholder feedback, announce program changes, and more. Following these meetings, Central Hudson and the JU prepare a brief report summarizing the input received items addressed, to be published on the NYS Clean Heat Resources webpage.

The Clean Heat webpage contains a dedicated page for onboarding of new participating contractors and new distributor enrollment. In addition, the Clean Heat webpage contains a Contractor Resources page, containing all relevant program documents and updates for continued reference throughout program operations.

5. Additional Detail

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

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

Table 30: Clean Heat Installations by Category

Category	Sector	New?	Total # of Projects	# of Dwelling Units	Total Energy Savings (MMBtu net of increased MWh usage)
Category 1 ASHP: Partial Load Heating	Res	Existing	1,186	1,186	41,675.18
		New Construction	32	32	934.17
	MF	Existing	19	95	637.64
	Comm	Existing	42	-	1,611.82

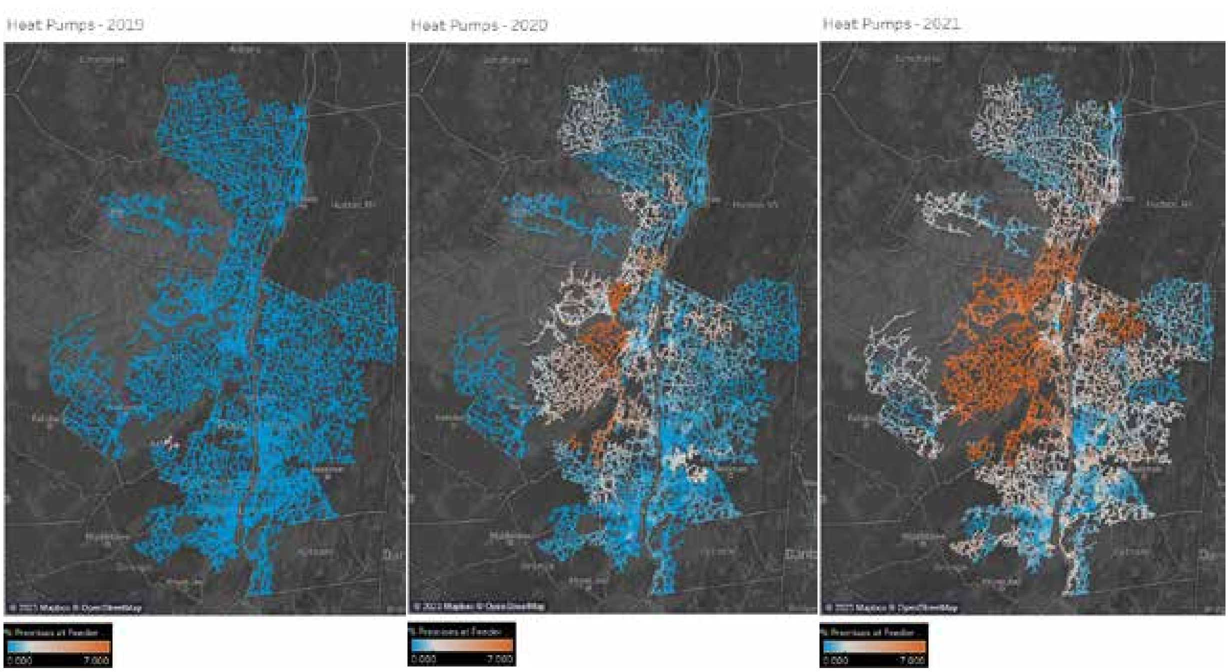
		New Construction	3	-	43.78
Category 2 ASHP: Full Load Heating	Res	Existing	3,847	3,847	285,658.27
		New Construction	235	235	13,432.08
	MF	Existing	77	385	4,697.72
		New Construction	9	45	1,145.52
	Comm	Existing	158	-	6,754.30
		New Construction	30	-	687.24
Category 2a w/ integrated controls	Res	Existing	3	3	230.60
Category 2b w/ decommissioning	Res	Existing	690	690	56,777.87
		New Construction	6	6	376.06
	MF	Existing	3	15	176.72
	Comm	Existing	13	-	503.85
		New Construction	2	-	79.59
Category 3 GSHP: Full Load Heating	Res	Existing	144	144	14,360.52
		New Construction	41	41	3,429.97
	MF	Existing	5	25	448.65
Category 4 Custom Space Heating Applications	Res	Existing	2	2	487.74
	MF	Existing	1	5	1,256.47
		New Construction	2	10	2,093.74
	Comm	Existing	8	-	19,679.17
		New Construction	3	-	1,162.78
Category 5 HPWH (up to 120 gal)	Res	Existing	1,156	1,156	14,098.67
		New Construction	12	12	103.26
	MF	Existing	6	30	89.05
Category 7 GSHP Desuperheater	Res	Existing	48	48	3,868.59
		New Construction	15	15	1,113.60
	MF	Existing	2	10	170.29
Category 8 Dedicated DHW WWHP	Res	Existing	5	5	64.08
		New Construction	3	3	21.71
	MF	Existing	1	5	4.15
	Res	Existing	253	253	3,583.02

Category 9 Simultaneous Install of Space & Water Heating		New Construction	12	12	122.46
	MF	Existing	1	5	13.19
	Comm	Existing	3	-	46.50

(2) The number and spatial distribution of existing instances of the scenario;

Figure 43 shows the historical adoption rates of heat pumps by feeder. The clean heat program went through major policy shift in 2020 when statewide Heat Pump adoption goals were initiated. This is evident in the historical adoption rate increase between 2019 and the end of 2020.

Figure 43: Historical Heat Pump Adoption Rates by Feeder



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

Figure 44 shows the forecasted heat pump adoption rate by feeder. The scale for the forecasted adoption rates ranges to an upper limit of 30%, while the historical adoption rate scale in the previous figure was capped at 7%. By 2028, we expect to see relatively high adoption of heat pumps across Central Hudson's service territory with a concentration in Woodstock, East Kingston, and Kerhonkson.

Figure 44: Forecasted Heat Pump Adoption Rates by Feeder

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

Table 31 shows the types of clean heat solutions installed from 2019 through 2022. New York heat pump goals went into effect in 2020, reflected by the strong increase in heat pump adoption from 2019 to 2020.

Table 31: Mix of Clean Heat Solution Installed

Year	ASHP	GSHP	HPWH	Mini-Split
2019	0	2	1	8
2020	162	86	306	2,532
2021	449	109	626	5,545
2022	156	79	547	4,093

(5) An hourly profile of a typical location's aggregated clean heating load over a one-year period;

Figure 45 shows the 8760 Load Shape for Whole Home Heat Pumps. These loads are scaled to the average home that installed heat pumps. You can see increased load over the winter months with relatively low loads in the summer evening hours. Figure 46 show the 8760 load shape for Mini-Splits. This load shape considers the average number of installed mini-splits.

Figure 45: 8760 Load for Whole Heat Pump Profile

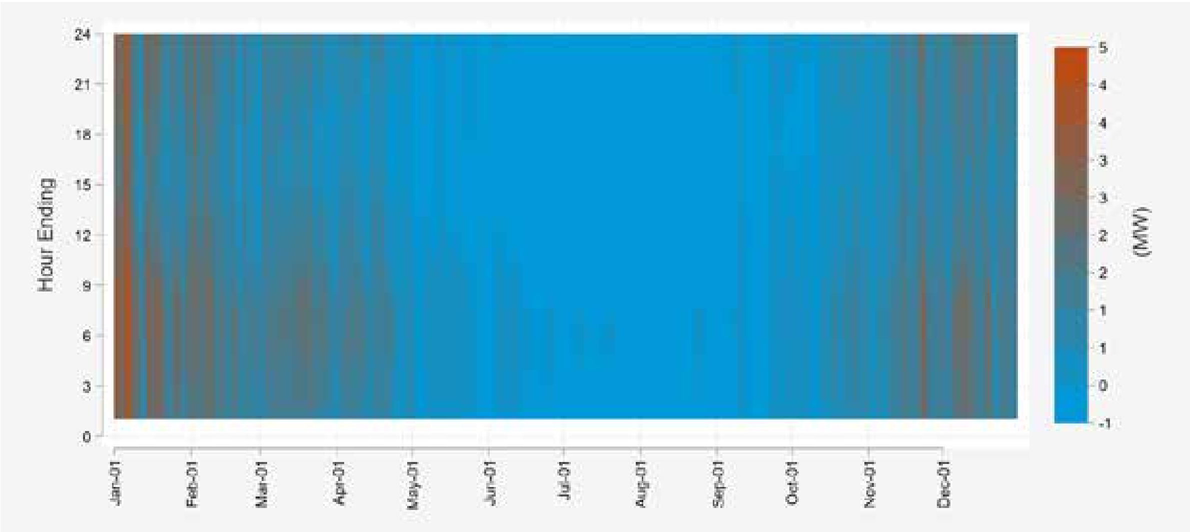
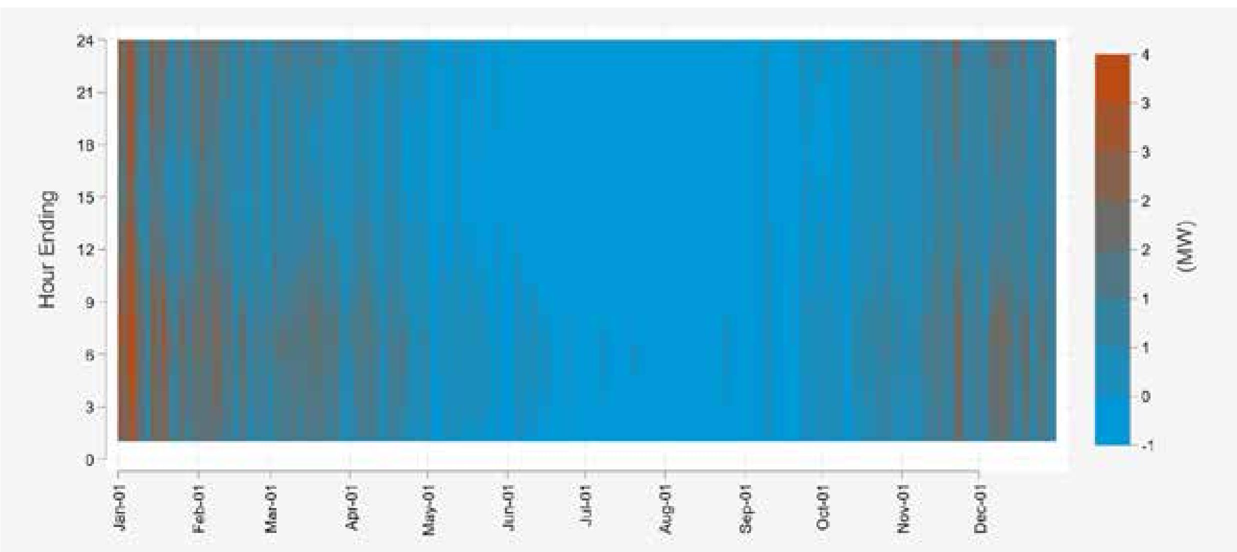


Figure 46: 8760 Load Shape for Mini-Splits



(6) the type and size of the existing utility service at a typical location

Table 32 below shows the breakout of primary heating fuel as a percent of premises. In Central Hudson territory, the primary heating fuel is oil at 60% of premises, followed by electricity at 18%, and gas at 12%.

Table 32: Percent of Premises with each heating fuel type

Existing Heating Fuel	Premises
Electricity	18%
Gas	12%
Oil	60%

Propane	9.5%
Wood	0.5%

(7) the type and size of utility service needed to support the clean heating use case.

Most homes that upgrade to heat pumps require an upgrade to a 200-amp panel. Most of homes that are fuel conversion from oil, gas, propane, and wood are older and have smaller panels that cannot support heat pump heating without an upgrade.

In addition, as the penetration of heat pump grows, the feeders, substations, and transmission areas will convert to winter peaking. The exact timing is uncertain and the impact on upgrades will also depend on the growth of load reducing distributed resources such as solar, battery storage, and energy efficiency. In addition, Central Hudson needs to calculate design ratings and criteria for winter peaking loads particularly for feeders.

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

Central Hudson is undertaking measures to accelerate heat pump adoption in its service territory and support long term heating electrification. Along with the Joint Utilities, Central Hudson prioritized consumer awareness and contractor education to cultivate the long-term potential of the heat pump marketplace.

Central Hudson and the JU are also working with distributors to increase heat pump and water heater stock to promote midstream adoption and increase heat pump availability in the broader market. Through increasing awareness of the benefits and ability of heat pumps to improve customer perception, targeted contractor education to improve workforce readiness, and distributor partnerships to increase availability, Central Hudson and the JU are laying the framework for long term, stable heat pump adoption to meet ambitious New York State goals.

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

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

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

Central Hudson is setting up tools to actively track penetration of building electrification, transportation electrification, and distributed energy resources down to the circuit feeder level. The tool is updating forecasts continuously and converting the forecasted heat pump penetration into hourly loads for T&D planning.

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

The granular heat pump forecast data will be posted on Central Hudson's website and available starting August 1, 2023.

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

Central has met and exceeded targets for heat pump installations set by New York State. Central Hudson promoting training and incentivizing contractors to install heat pumps. In addition, Central Hudson is collaborating with other New York utilities to pool aggregated historical data on heat pump incentives and volume to better understand the relationship. Quantifying the relationship between incentive levels and participation in heat pump programs will allow Central Hudson to calibrate and optimize incentive levels to better attain state-wide goals.

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

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

(2) the original project schedule;

(3) the current project status;

(4) lessons learned to-date;

(5) project adjustments and improvement opportunities identified to-date; and

(6) next steps with clear timelines and deliverables.

Central Hudson has not experienced winter peaks that have triggered T&D projects to date. However, several substations and circuit feeders are projected to be heavily loaded over the next five years. Table 33 summarizes the Load Area and the corresponding Substations that are expected to have winter peaks by 2028. All load areas except for Fishkill, Newburg, and Poughkeepsie are expected to have at least one winter peaking substation by 2028. Importantly, load reducing distributed energy resources (DERs) are not subtracted from this load estimate, because they are not contracted and are therefore uncertain. Further details on this can be found in the Avoided T&D Cost Study Section in the Appendix. Central Hudson is in the process of developing project plans and updating its design criteria and ratings to better accommodate and plan for winter peaks.

Table 33: Locations with Forecasted Winter Peaks by 2028

Load Area	Substation	Historical 1 in 2 Annual Peak (MVA) 2019	2020	2021	2022	Forecasted 1 in 2 Annual Peak (MVA) 2023	2024	2025	2026	2027	2028	Rating (MVA)
Ellenville	Clinton Ave	1.6	1.7	1.8	1.8	1.9	1.9	2.0	2.1	2.2	2.3	11.6
	Greenfield Rd	7.6	7.3	7.0	6.7	6.7	6.5	6.5	6.6	6.6	6.8	23.3
	High Falls	20.0	20.0	20.0	20.0	20.3	21.0	21.8	22.7	23.8	24.9	34.5
	Kerhonkson	10.2	10.4	10.6	10.9	11.0	11.6	12.2	12.9	13.7	14.5	47.3
	Neversink	3.8	3.7	3.7	3.6	3.6	3.7	3.8	3.9	4.1	4.4	7.4
	Sturgeon Pool	2.8	2.8	2.9	2.9	2.9	2.9	3.1	3.2	3.3	3.5	40.3
Kingston-Saugerties	Boulevard	18.6	18.7	18.7	18.7	18.9	19.0	19.1	19.2	19.4	20.0	44.8
	Hurley Ave	19.9	19.7	19.6	19.5	19.7	19.6	19.6	19.6	19.6	20.1	28.4
	Saugerties	22.9	23.0	23.1	23.2	23.4	23.6	23.8	24.0	24.5	25.6	70.5
	Woodstock	21.8	22.0	22.2	22.4	23.6	24.5	25.7	26.9	28.3	29.8	23.9
Modena	Galeville	12.4	12.4	12.3	12.2	12.3	12.2	12.2	12.2	12.5	12.9	28.7
	Highland	20.1	20.0	19.9	19.8	19.9	19.9	20.0	20.5	21.2	21.9	37.3
	Ohioville	23.8	23.5	23.1	22.8	22.8	22.4	22.1	21.9	21.6	22.0	34.2
	Milan	11.0	11.1	11.1	11.2	11.5	11.8	12.1	12.4	12.8	13.3	38.2
	Millerton	5.9	5.8	5.6	5.5	5.5	5.4	5.4	5.4	5.5	5.6	13.0
	Pulvers 34	3.0	3.0	3.0	3.0	3.1	3.2	3.3	3.6	3.8	4.2	26.7
	Rhinebeck	30.6	29.8	29.0	28.3	28.2	27.5	26.9	26.3	26.1	26.5	47.8
	Smithfield	1.9	1.9	1.9	2.0	2.0	2.0	2.1	2.1	2.2	2.3	8.7
	Stanfordville	4.1	4.4	4.7	5.1	5.4	5.9	6.5	7.2	8.0	8.8	24.5
Northwest	Coxsackie	9.3	9.7	10.1	10.5	10.8	11.4	12.1	12.8	13.7	14.6	24.8
	Freehold	8.1	8.2	8.4	8.5	8.6	8.8	9.0	9.2	9.6	10.1	25.0
	Hunter	11.7	11.3	10.9	10.6	10.4	10.1	9.9	9.6	9.4	9.3	21.2
	Lawrenceville	14.1	14.1	14.1	14.0	14.1	14.1	14.2	14.2	14.4	14.5	19.3
	South Cairo	12.3	12.6	12.9	13.2	13.5	14.0	14.6	15.2	16.0	16.8	29.4
	Vinegar Hill	11.2	11.2	11.1	11.1	11.1	11.1	11.2	11.3	11.4	11.5	21.3
	Westerlo	8.3	8.4	8.4	8.4	8.6	8.7	9.0	9.3	9.7	10.2	35.0

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

Central Hudson has recurring discussions with the Joint Utilities, NYSERDA, DPS Staff and other key stakeholders to address strategic marketing campaigns and materials to increase customer awareness of the benefits of heat pump technologies. In addition, the Joint Management Committee works with implementation vendors and NYSERDA to make available on-demand training materials and conduct training sessions for new and existing Clean Heat participating contractors to reinforce workforce development and keep Clean Heat technologies as a top option for consumers throughout the state. To address availability in addition to education and training initiatives, the Joint Management Committee continues to grow a network of distributor partnerships throughout the state to increase stock of Clean Heat space and water heating technology in all territories.

G. Energy Efficiency Integration and Innovation

1. Context and Background

Central Hudson has been administering a portfolio of energy efficiency programs continually since 2009. During that time, the portfolio has expanded into new technology areas and customer segments. Central Hudson is proud to implement programs that offer customers opportunities to reduce their energy use, manage their energy bills, and contribute to the achievement of the State's ambitious clean energy goals. Central Hudson has designed its programs with a focus on maximizing value by seeking innovative ways to reduce the cost of the Energy Efficiency portfolio while increasing the quantity of MWh savings attained.

This section provides context and background starting with the New Efficiency: New York Order as well as an overview of Central Hudson's company-specific energy efficiency portfolio and collaborative Low-to-Moderate-Income programming, followed by a description of Central Hudson's Earning Adjustment Mechanisms.

New Efficiency: New York

Energy efficiency is one of the cornerstones in New York State's national leadership on clean energy and combatting climate change. Through a new comprehensive strategy issued in 2018, New York State embarked on a path to accelerate energy efficiency and reduce greenhouse gas emissions, decrease consumer energy costs, and create job opportunities.[30]

As part of this initiative, New York's utilities are called upon to achieve significantly more in their energy efficiency activities, in both scale and innovation. The New York State Public Service Commission's (PSC) Order Adopting Accelerated Energy Efficiency Targets ("December 2018 Order")[31] adopted significantly accelerated utility energy efficiency targets, which doubled utility energy efficiency targets from 2019 to 2025.

The PSC's subsequent January 2020 Order ("NE:NY 2020 Order")[32] directs Central Hudson to achieve an incremental 68,753 MWh and 51,797 MMBtu of natural gas savings above previously approved levels by 2025. The January 2020 Order also authorizes $15.2 million of incremental energy efficiency funding to

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[30] New Efficiency: New York, NYSERDA. https://www.nyserda.ny.gov/About/Publications/New-Efficiency

[31] Order Adopting Accelerated Energy Efficiency Targets, Issued and Effective December 13, 2018, Case 18-M-0084. https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={B330F932-3BB9-46FA-9223-0E8A408C1928}

[32] Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios Through 2025, Issued January 16, 2020, Case 18-M-0084. https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={06B0FDEC-62EC-4A97-A7D7-7082F71B68B8}

achieve these targets, including $3.0 million specifically allocated to serve the low-to-moderate income ("LMI") market.

Central Hudson Energy Efficiency Programming

Central Hudson currently implements a comprehensive portfolio of electric and gas energy efficiency programs, which include a variety of solutions for residential, commercial, and industrial customers, as outlined in Table 34. Central Hudson's Energy Efficiency PortfolioTable 34.

Table 34. Central Hudson's Energy Efficiency Portfolio

Program	Portfolio	Description
Residential		
Retail Lighting Program	Electric	Utilizes an upstream strategy to increase the penetration of efficient lighting in customer homes by incentivizing the purchase of LED lighting at retail.
Residential HVAC and Efficient Products Program	Electric and Gas	Offers incentives for energy efficient residential HVAC and water heating systems, thermostats, and appliances.
Appliance Recycling	Electric	Offers an incentive to residential electric customers to recycle their used refrigerators or freezers.
Behavior Modification	Electric and Gas	Customers are automatically enrolled to receive paper and emailed communications about their energy use and opportunities for energy saving with the goal of reducing energy consumption of the treatment group relative a control group.
Non-Residential		
Commercial Custom and Prescriptive	Electric and Gas	Offers non-residential customers incentives for a range of efficient technologies including lighting and HVAC systems.
Small Business Direct Install	Electric	Provides traditionally hard-to-reach small business customers with a turn-key retrofit solution including a facility audit, project design and proposal, measure installation, and beyond. Includes lighting and refrigeration measures.
Municipal Streetlights Program	Electric	Incentivize municipal customers to upgrade streetlights to new efficient LED fixtures.

Collaborative Low-to-Moderate-Income Programming

Central Hudson works collaboratively with NYSERDA and the New York Joint Utilities on Low-to-Moderate-Income programming.

As described in the Statewide Low- to Moderate Portfolio Implementation Plan ("LMI IP")[33], in response to the January 2020 Order, Central Hudson is collaborating with Joint Utilities (JU) across New York State and NYSERDA to deliver coordinated statewide efficiency initiatives targeting LMI customers. Specifically, Central Hudson has taken an active role in the development of each of the initiatives presented in the LMI IP participating in stakeholder engagement, requesting transparency of data assumptions and inputs to be used in the development of savings projections and budget development. Central Hudson also seeks to ensure all LMI customers have equal access to all programs regardless of the funding source for the full duration of the LMI IP. Furthermore, Central Hudson strives to streamline burdensome administrative processes while maintaining utility independence to best serve customers e.g., leveraging local and trusted partnerships to reach LMI customers. The current iteration of the LMI IP, which was filed on May 1, 2023, includes the following initiatives:

- One to Four Single Family Homes
- Affordable Multifamily Buildings
- Affordable New Construction
- Partner-Based Programs

The portfolio also includes funding for customer engagement and pilots with new approaches for the adoption of energy efficiency for LMI residents and communities. More detailed information can be found in the LMI IP.

Central Hudson's Earnings Adjustment Mechanisms

On November 18, 2021, the PSC issued an "Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plan," ("Rate Plan Order") under Cases 20-E-0428 and 20-G-0429, which establishes new Earnings Adjustment Mechanisms ("EAMs"). There are three categories of EAMs comprised of seven electric EAM performance metrics. Central Hudson could earn pre-tax earnings adjustments once minimum targets are achieved and on a prorated basis for performance between minimum and midpoint performance levels, and between the midpoint and maximum performance levels. The EAMs are intended to provide the Company with incentives to:

- Increase achieved electric and gas energy efficiency;

[33] Statewide Low- to Moderate-Income Portfolio Implementation Plan Version 3, Filed November 1,2022, Updated May 1, 2023, Cases 18-M-0084 and 14-M-0094. https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={60C1D887-0000-C81F-829F-F33F45BE6207}.

- Increase system efficiency through peak reduction and distributed energy resource utilization;
- Reduce carbon emissions through increased penetration of beneficial electrification technologies such as Heat Pumps, Electric Vehicle ("EV") Adoption, Electric Vehicle Special Equipment ("EVSE").

Central Hudson believes these EAMs place significant emphasis on the value of producing results through new and innovative approaches to achieving the State's objectives. Specifically, the EAMs associated with Energy Efficiency, Peak Reduction, Energy Intensity, DER Utilization, and Environmental Beneficial Electrification directly support the "New Efficiency: New York" targets of reducing carbon emissions by achieving 185 TBtu of building energy savings by 2025 and reducing overall carbon emissions by 40% by 2030.

The Energy Efficiency EAM is composed of two metrics: Share the Savings for market rate offerings and a distinct EAM for savings achievements benefitting LMI customers for both gas and electric. Additionally, the Rate Plan Order established targets for the System Efficiency EAM and Beneficial Electrification EAM, which are also discussed below.

The 2021 Rate Plan authorizes the Share the Savings ("STS") EAM metric in the calculation of the Company's non-LMI electric energy efficiency, non-LMI gas energy efficiency, and heat pump portfolio EAMs. The STS metric measures performance based on reductions in the unit cost of lifetime energy savings as compared with the targets as approved by the Public Service Commission, as well as the overall level of energy savings achieved. The energy savings achieved utilize the application of the Verified Gross Savings policy. The Company will be awarded 30% of unit cost savings realized from the Company's acquired savings once the Company has met minimum lifetime savings targets, as provided in the Authorized Targets table below.

The Non-LMI Electric Energy Efficiency EAM utilizes the Share the Savings ("STS") metric. This metric will be measured by the sum of MWh savings from all of Central Hudson's administered electric energy efficiency programs.

The Non-LMI Gas Energy Efficiency EAM utilizes the Share the Savings ("STS") metric. This metric will be measured by the sum of MMBtu savings from all of Central Hudson's administered gas energy efficiency programs.

The LMI EAM is based on total lifecycle energy savings achieved within Central Hudson's LMI Energy Efficiency portfolio. The targets are based on combined electric and gas MMBtu achieved cumulatively between January 1, 2022, and December 31, 2024. Each year's lifecycle savings contribution will be computed using the prior calendar's portfolio EUL.

The Company has six system efficiency EAMs. Electric Peak Reduction, Gas Peak Reduction, and DER Utilization are eligible for earnings while Load Factor, Residential Electric Energy Intensity, and

Commercial Electric Energy Intensity are tracking-only metrics with no specific targets or earnings eligibility.

The Electric Peak Reduction ("EPR") EAM incentives the Company to reduce its New York State Independent System Operator ("NYISO") Zone G-J Locality Peak. To the extent that there is a decline in the actual weather normalized NYISO Zone G-J coincident electric peak below the baseline level established for the EPR EAM, the Company will receive an incentive under the EPR EAM.

The Gas Peak Reduction EAM incentivizes the Company to achieve gas system peak reductions that provide additional system benefits and lower supply costs to customers. To the extent that there is a decline in the actual weather-adjusted gas system peak below the prior rate year baseline level established for the Gas Peak Reduction ("GPR") EAM, the Company will receive an incentive under the GPR EAM. (NOTE: Weather-adjusted refers to the extrapolation of realized historic data up to the design day temperature to take into account the level to which the Company plans the necessary capacity, supply, and demand response system resources to meet firm customer demand during extreme winter peaks.)

The Load Factor EAM tracks the deployment of energy storage and other DERs. The company will track changes to load factor over time and monitor the potential impacts to load factor that results from the utilization of DERs throughout the system. This EAM is a tracking-only (scorecard) EAM. The Company has an annual process to prepare substation operation data for analysis. The Company will address the effect of incremental DERs by also calculating a "counterfactual" load factor, including the development of 8,760 load shapes, by backing out incremental additions of solar, demand response, heat pumps, EVs, and energy storage. This approach is detailed further in the table below.

The Residential Electric Energy Intensity EAM and the Commercial Electric Energy Intensity EAM will track Central Hudson's reductions to residential (Service class 1 and 6) customers' total usage on a per-customer basis. This metric will be evaluated as the sum of weather-normalized annual residential MWh sales adjusted for Community Distributed Generation allocations and increased sales due to beneficial electrification technologies, such as heat pumps and electric vehicles, divided by the 12-month average number of residential customers.

The Commercial Electric Energy Intensity EAM metric tracks reductions to commercial (Service class 2 non-demand) customers' total usage on a per-customer basis. This metric will be measured as the sum of the weather-normalized annual commercial MWh sales adjusted for Community Distributed Generation allocations and increased sales due to beneficial electrification technologies such as heat pumps and electric vehicles, divided by the 12-month average number of commercial customers.

The DER Utilization EAM metric incentivizes Central Hudson to work with third parties to expand the use of DER resources in the Company's service territory. This metric measures the sum of the annualized megawatt hours ("MWh") from DER in Central Hudson's service territory. The technologies included in this metric are Solar PV (Community Distributed Generation or “CDG”) and Battery Storage. DER Utilization (MWh) = CDG PV MWh annualized production + Battery storage MWh annualized discharge + Battery storage MWh annualized charging.

The Company has four Beneficial Electrification EAMs. EVSE DCFC, EVSE Level 2, EV Adoption, and the Heat Pump EAMs are eligible for earnings.

The EVSE (Electric Vehicle Supply Equipment) EAM promotes performance within Central Hudson’s Electric Vehicle (“EV”) Make-Ready Program (“EV Make-Ready Program”) is to support the development of electric infrastructure and equipment necessary to accommodate an increased deployment of EVs within New York State by reducing the upfront costs of building charging stations for light-duty EVs. Through this EV Make-Ready Program, those seeking to install or participate in the installation of Level 2 (“L2”) and/or Direct Current Fast Charging (“DCFC”) chargers can earn incentives that will offset a large portion of, or in some cases, all of the infrastructure costs associated with preparing a site for EV charger installation.

The Electric Vehicle (“EV”) adoption EAM incentivizes the Company to reduce greenhouse gas (“GHG”) emissions by facilitating greater penetration of EVs. EVs reduce GHGs relative to traditional internal combustion engine vehicle technologies that rely on emissions-intensive fuel sources like gasoline and diesel. The EV Adoption metric is an outcome-based metric and will be measured as the incremental lifetime metric tons (“tons”) of avoided CO2 from incremental EVs registered in Central Hudson’s service territory. EVs are defined as battery electric vehicles (“BEVs”) and Plug-in hybrid electric vehicles (“PHEVs”). BEVs and PHEVs have lifetime avoided emissions factors due to their distinct fueling profiles, where BEVs displace a greater number of gasoline miles annually than do PHEVs.

The Heat Pump EAM utilizes the Share the Savings (“STS”) metric. This metric will be measured by the sum of MMBtu savings from Central Hudson's administered Clean Heat program.

The annual electric EAM targets associated with Energy Efficiency, System Efficiency, and Beneficial Electrification are shown in the following chart.

Table 35: Energy Efficiency, System Efficiency, and Beneficial Electrification EAM Targets

EAM		2022	2023	2024
Non-LMI Electric Energy Efficiency (MWh)		62,602	66,332	69,076
Electric Energy Efficiency LMI (MWh)		224	284	359
Electric Peak Reduction (MW)	Minimum	1,071	TBD	TBD
	Midpoint	1,059	TBD	TBD
	Maximum	1,048	TBD	TBD
Load Factor	Tracking only			
Residential Energy Intensity (MWh/customer)	Tracking only			
Commercial Energy Intensity (MWh/customer)	Tracking only			
DER Utilization (MWh)	Minimum	132,526	200,155	288,215
	Midpoint	157,769	238,280	343,113
	Maximum	189,323	285,936	411,735
EVSE&I DCFC (Midpoint-Min Plugs)		14	N/A	N/A
EVSE&I L2 (Midpoint-Min Plugs)		641	N/A	N/A
EV Adoption (Lifetime CO2 Tons)	Minimum	67,828	122,064	219,700
	Midpoint	92,072	155,864	264,380
	Maximum	116,384	189,664	309,080
Heat Pump (MMBtu)		38,850	48,190	56,479

2. Implementation Plan

a) Current Progress

Since 2009, Central Hudson has implemented a portfolio of energy efficiency programs with specific initiatives targeted at various end uses and customer segments. Central Hudson's progress in these efforts is illustrated in the chart below. As Central Hudson energy efficiency programs have evolved, the average annual MWh savings have increased by 205%, and the cost per MWh has decreased by 58%.

Table 36. Central Hudson Historical MWh Savings and Costs

Framework	Years	MWh Savings	Expenses	Avg Annual MWh Savings	$/MWh
EEPS[34]-1	2009-2011	75,133	$21,459,934	25,000	$286
EEPS-2	2012-2015	152,804	$32,393,211	38,200	$212
EET[35]	2016-2017	105,005	$13,508,138	52,500	$129
ETIP[36]	2018	81,964	$8,773,420	81,964	$107
SEEP[37]	2019	75,827	$9,155,639	75,827	$121
SEEP[38]	2020	79,455	$10,190,637	79,455	$128
SEEP[39]	2021	72,973	$7,507,492	72,973	$103
SEEP[40]	2022	76,291	$9,265,289	76,291	$121
Total		719,452	$112,253,760		

b) Future Implementation and Planning

To align with the priorities of New York's Climate Leadership and Community Protection Act (CLCPA), Central Hudson is exploring its internal programming as well as collaborating across the state to continue to implement and evaluate programs to accelerate energy efficiency and reduce greenhouse gas emissions, decrease consumer energy costs, and create job opportunities.

[34] Energy Efficiency Portfolio Standard
[35] Energy Efficiency Transition
[36] Energy Efficiency Transition Implementation Plan
[37] System Energy Efficiency Plan
[38] System Energy Efficiency Plan
[39] System Energy Efficiency Plan
[40] System Energy Efficiency Plan

Balancing Energy Efficiency and Clean Heat Programming

The 2020 NENY Order provides utilities with the flexibility to adjust portfolio budgets to maximize their effectiveness with a few key limitations: "Current practice allows utilities to shift budgets from year to year within a portfolio to accommodate the timing concerns that arise with commitments and outlays and to avoid artificial program stops and starts. Utilities may also adjust budgets and targets among programs within the same portfolio, e.g., funds may be shifted from one electric efficiency program to another. These practices will be continued, with two additional requirements: (1) heat pump targets must be maintained as separate targets within the electric utility portfolios; and (2) funds cannot be transferred from LMI to non-LMI programs. Utilities will not have general flexibility to shift funds among gas, electric, and heat pump budgets. Gas, electric, and heat pump targets are established in this Order to align with policy goals; a utility may shift funds among these portfolios only if it can demonstrate that it will meet the annual target for the portfolio from which funds are being transferred"[41].

In December 2022, Central Hudson expended its cumulative Clean Heat Program budget for the years 2020-2025. Pursuant to the budget flexibility authorized in the NENY Order, The Company utilized a total of approximately $4.6 million in unspent funds from the Non-LMI Electric portfolio for Clean Heat, having achieved the annual electric portfolio targets for years 2018-2022 without spending the full budget in each year. In February 2023, in a request to provide additional funding beyond the use of previously unspent funds, the Company petitioned for the authorization to transition $13.5 million of its cumulative electric energy efficiency budget to Clean Heat. As a contingency to the authorization, Central Hudson demonstrated its potential to still achieve its NENY-ordered cumulative electric EE savings target even after the transfer of these funds. In June 2023, the Commission subsequently granted the Company's request allowing the Company to continue meaningful savings to be accomplished in electric EE and the continued incentivizing of Heat Pump adoption in Central Hudson's territory.

Evaluation Activities

In accordance with the Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plan (Utility EE Order 2021) and The Clean Energy Guidance document CE-08: Gross Savings Verification Guidance, Central Hudson conducts periodic program evaluation. [42, 43] The evaluation strategy for each program varies based on the measures being evaluated, the size and scope of the program, and the

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[41] 2020 NENY Order, pp. 69-70.

[42] Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plan, Cases 20-E-0428 and 20-G-0429, Issued November 18, 2021. https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={359B89D8-95E5-4DF3-9EAD-8A7D4D90B47A}.

[43] New York State Department of Public Services, Gross Savings Verification Guidance, CE-08, Version 1, Issued August 23, 2019. https://dps.ny.gov/system/files/documents/2022/11/ce-08-gross-savings-verification-guidance.pdf.

available data. Individual plans outlining the evaluation activities for each program evaluation were filed prior to the evaluations under matter 16-02180. An overview of the 2019-2024 efforts is presented in Table 4.

Table 37: Planned Program Evaluation Activities

PORTFOLIO (NE:NY Electric EE)	Plan Submission Date	Start Date	Completion Date	Status
Impact Evaluation – *2023 Small Business Direct Install*	2023 Q3	2023 Q4	2024 Q2	Upcoming
Impact Evaluation – *2022 Residential HVAC and Efficient Products*	2023 Q3	2023 Q3	2023 Q4	Upcoming
Impact Evaluation – *2019 Residential Behavioral Modification*	2020 Q2	2020 Q2	2021 Q3	Completed
Impact Evaluation – *2020 Residential Behavioral Modification*	2020 Q2	2021 Q2	2021 Q3	Completed
Impact Evaluation – *2021 Residential Behavioral Modification*	2020 Q2	2022 Q2	2022 Q4	Completed
Impact Evaluation – *2019-2020 Residential HVAC*	2020 Q2	2020 Q2	2021 Q3	Completed
Impact Evaluation – *2021 Residential Retail Lighting*	2021 Q3	2022 Q3	2022 Q4	Completed
Impact Evaluation – *2020 Residential Retail Lighting*	2021 Q3	2021 Q3	2021 Q4	Completed
Impact Evaluation – *2018-2019 Residential Retail Lighting & Efficient Products*	2020 Q2	2020 Q2	2021 Q3	Completed
Impact Evaluation – *2020-2021 Commercial Custom*	2021 Q3	2021 Q3	2022 Q4	Completed
Impact Evaluation – *2021-2022 Commercial Prescriptive*	2021 Q3	2021 Q3	2022 Q4	Completed
Impact Evaluation – *2019-2020 Commercial Custom and Prescriptive*	2020 Q2	2020 Q2	2021 Q3	Completed
Impact Evaluation – *2021-2022 Small Business Direct Install*	2021 Q3	2021 Q3	2022 Q4	Completed
Impact Evaluation – *2019 Small Business Direct Install*	2019 Q2	2019 Q2	2021 Q3	Completed
Impact Evaluation – *2019 CenHub Online Store*	2020 Q2	2020 Q2	2021 Q3	Completed
Impact Evaluation – *2018-2019 Appliance Recycling*	2020 Q2	2020 Q2	2021 Q3	Completed
Impact Evaluation – 2018-2019 *Community Lighting*	2020 Q2	2020 Q4	2021 Q3	Completed
Impact Evaluation – 2018-2019 *Municipal Streetlights*	2020 Q2	2020 Q3	2021 Q3	Completed
Process Evaluation – 2021-2022 *Commercial Custom and Prescriptive*	2021 Q3	2021 Q3	2022 Q4	Completed
Process Evaluation – 2019-2020 *Commercial Custom and Prescriptive*	2020 Q3	2020 Q3	2021 Q3	Completed
Process Evaluation – 2021-2022 *Small Business Direct Install*	2021 Q3	2021 Q3	2022 Q4	Completed
Process Evaluation – 2019-2020 *Residential Retail Efficient Products*	2020 Q3	2020 Q3	2021 Q3	Completed
Process Evaluation – 2019-2020 *CenHub Online Store*	2020 Q3	2020 Q3	2021 Q3	Completed
Baseline Study	2019 Q3	2019 Q3	2019 Q4	Completed
Potential Study	2019 Q3	2019 Q3	2020 Q3	Completed

PORTFOLIO (NE:NY Electric EE)	Plan Submission Date	Start Date	Completion Date	Status
Free-ridership and Attribution Studies	2020 Q3	2020 Q3	2021 Q3	Completed
Program Support and Planning	N/A	2019 Q1	Ongoing	Ongoing

3. Risks and Mitigation

The utility industry is undergoing a dynamic change including declining energy efficiency potentials, increased unit costs, and changes to local, state, and federal level energy priorities.

- **Declining savings potential from lighting.** Historically, Central Hudson has successfully garnered apply savings from offering energy efficient lighting to its residential and commercial customers. However, the 45 lumen/watt federal minimum efficiency standard for the sale of general service lamps goes into effect July 2023, reflecting an increased baseline efficiency which will result in fewer savings from lighting. Leading up to and following this shift market transformation is occurring with high percentages of energy efficient lighting saturation in both residential and non-residential buildings, which will also contribute to fewer savings from lighting.
- **Unit Cost increases.** Marginal cost increases have been experienced in the Electric EE portfolio measures and additional uncertainties remain ahead with continued increases in inflation. For example, in 2022, the Company effectuated several limited-time offers ("LTO") to provide a much-needed stimulus to program activity. These LTOs accomplished meaningful savings contributions towards the Company achieving its NENY savings targets but came with an above-average unit cost to the programs. Additionally, the portfolio's Appliance Recycling Program is expected to have unit cost increases by approximately 15% from 2022 to 2023 with its deemed savings for its standard measures decreasing. Similar cost increases have been seen in some efficient products measures as well as our Small Business Direct Install program.
- **Shifting statewide priorities.** New York State has large carbon reduction goals that emphasize building electrification as a key component for meeting greenhouse gas emission reduction targets. For example, the New York State's Climate Leadership and CLCPA Draft Scoping Plan proposes that all new sales of commercial heating systems be heat pumps by 2035.[44] In addition, Governor Hochul has proposed legislation that would require zero on-site greenhouse gas emissions for new construction no later than 2027.[45] Furthermore, the Strategic Advisory Group set up to advise the New York State Public Service Commission on the direction of energy efficiency and building electrification programs in 2022 shared a recommendation that energy efficiency programs end incentives for most new commercial gas HVAC equipment.[46] This final point underscores how the current portfolio structure may be viewed as competitive:

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[44] New York State Climate Action Council Draft Scoping Plan. December 30, 2021. Available at https://climate.ny.gov/Our-Climate-Act/Draft-Scoping-Plan

[45] New York State Energy Research & Development Authority. "Governor Hochul Announces Plan to Achieve 2 Million Climate-Friendly Homes By 2030." January 5, 2022. https://www.nyserda.ny.gov/About/Newsroom/2022-Announcements/2022-01-05-Governor-Hochul-Announces-Plan-to-Achieve-2-Million-Climate-Friendly-Homes-By-2030

[46] Strategic Advisory Group - Gas Energy Efficiency Program Evolution Recommendations. Matter 20-01201. Filed March 30, 2022. Available at https://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=284259&MatterSeq=62776.

electrification vs. energy efficiency, Clean Heat vs. gas energy efficiency leading to budget constraints opposed to complementary.

The Company's mitigation strategy involves diversifying portfolio measures, working collaboratively with statewide stakeholders to expand electrification initiatives and align utility and statewide priorities.

4. Stakeholder Interface

Central Hudson continues to engage its stakeholders ranging from energy efficiency program champion trade allies to interested vendors, customers, and Department of Public Service (DPS) staff. These engagements inform Central Hudson program design, implementation, and priorities.

Vendor and Trade Ally Interfaces

Central Hudson regularly interacts with prospective and current vendors and trade allies. The Company regularly participates in industry conferences such as those facilitated by the Association of Energy Service Professionals ("AESP"). Through these events, the Company keeps abreast of best practices in the industry as well as new offerings from a multitude of energy efficiency vendors. Additionally, Central Hudson participates in various energy efficiency-related working groups, which provide an opportunity to interface with stakeholders. For example, as part of its participation in various LMI working groups (see *Joint Utility and DPS Staff Interfaces* subsection below) Central Hudson engages with interested trade allies and vendors through PCIP webinars to engage interested stakeholders in programmatic developments and progress.

Furthermore, when Central Hudson determines a service provider is needed, a request for proposal (RFP) will be sent out. The RFP contains detailed information about the Company and the services required. As part of the RFP process, Central Hudson allows responders to submit questions and discuss relevant topics during at least one pre-bid meeting. Finally, Central Hudson works with trade allies to implement various energy efficiency programs and has sponsored various training events and feedback sessions.

Customer Interfaces

Central Hudson is committed to providing customers with accessible avenues to achieving energy efficient homes and businesses, saving on their utility bills, and contributing to a clean energy future.

Central Hudson strives to engage customers through a variety of education and outreach activities such as the Company website, Contractor Webinars, Trade Ally events, its Energy Ambassador program, company Open House events, and presenting to students at traditional and vocational schools. In addition, as part of its commitment to continuous improvement, Central Hudson conducts process evaluations to ensure that programs are operating as intended and to provide information that can enable improvements in both program design and implementation. Process evaluations assess customer understanding, attitudes about, and satisfaction with programs, individual offerings, and other educational activities through primary data collection with participating customers.

Joint Utility and DPS Staff Interfaces

As part of the NYS Joint Utilities, Central Hudson participates in multiple LMI and Clean Heat working groups in partnership with the other NYS Joint Utilities and NYSERDA. The working groups engage regularly with DPS staff. Through these efforts, the Company strives to create coordinated programming across the state to enhance customer engagement across sectors, end-uses, and fuel types.

5. Additional Detail

a) The resources and capabilities used for integrating energy efficiency within system and utility business planning.

Central Hudson's NWA solicitations are technology agnostic, so energy efficiency may be utilized as a part of a solution if it's determined to be a good fit for a particular project. In September 2018, the Company launched a targeted C&I energy efficiency initiative within two of its three existing NWA locations. The initiative has continued through 2019 and is designed to impact locational loads by concentrating efficient retrofit projects within NWA areas. High adoption rates are achieved using enhanced incentives and marketing. This initiative has supplemented load reductions achieved through other demand management initiatives.

System-wide load constraints are minimal for Central Hudson. The marginal avoided costs associated with peak load reductions, as determined through a recent comprehensive study, are considered as a benefit within EE initiatives, but are not a significant driver of initiating projects.

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

Central Hudson's energy efficiency portfolio is designed to meet the targets set forth within the NENY proceedings. The Commission has set new targets within the Joint Proposal. For most energy efficiency projects, the Company tracks the location of each participant and can readily identify the overall impacts on the local system at the circuit or substation level. Load reductions are assessed using the New York State Technical Resource Manual, where applicable. In some cases, custom computations are used to calculate the impacts of certain measures on peak load. Within the Company's upstream and midstream delivery programs, aggregate participation data is obtained, such as by vendor or local store, as opposed to individual end-user. Geographic distribution estimates may be developed based on the available data.

c) A high-level description of how the utility's accomplishments and plans are aligned with New York State climate and energy policies and incorporate innovative approaches for accelerating progress to ultimately align with the CLCPA.

Clean Heat: Through the Clean Heat program, Central Hudson has promoted energy efficiency and decarbonization of the heating sector by incentivizing the adoption of cold climate heat pump technologies. As of the end of 2022, the Program had already achieved more than 175 percent of its cumulative 2020-2025 savings target achieving over 500,000 annual MMBtu savings in a three-year period. By collaborating with key stakeholders to increase consumer awareness, provide accessible workforce education opportunities, and increase the stock of heat pump technologies in all territories, Central Hudson and the Joint Utilities created a sustainable framework for long-term heat pump adoption in New York State. More information on Central Hudson's Clean Heat program can be found under the DSIP Topical Section of Clean Heat Integration.

Electric Vehicle Adoption and Charging Equipment: As of April 30, 2023, Central Hudson incentivized the installation of 21 DCFC and 137 L2 chargers in its territory at unit cost well below its prescribed targets within the Public Service Commission's "Order Establishing Electric Vehicle Infrastructure Make-Ready Program and Other Programs". The Company's Electric Vehicle Special Equipment ("EVSE") program has a target of installing 3,204 Level 2 (L2) chargers and 69 DC fast chargers (DCFCs) throughout the service territory by 2025.

As of December 31, 2022, an additional 1,412 Battery Electric Vehicles and 962 Plug-in Hybrid Electric vehicles have been registered into Central Hudson's territory resulting in a reduction of 85,216 lifetime tons of CO_2. Strong marketing efforts and the EVSE make-ready program are used to promote the benefits of electric vehicles. Marketing and events promoting EV adoption will continue into the near future. More information on Central Hudson's efforts to promote EV adoption and the proliferation of charging equipment can be found under the DSIP Topical Section of Electric Vehicle Integration.

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

As discussed in the Context and Background section above, Central Hudson has been offering customers energy efficiency programming since 2009. Table 38 and Table 6 below, provide an overview of the 2019-

2022 electric and gas energy efficiency portfolio actuals and 2023-2025 planned spending and savings. Additional details can be found in the 2022 SEEP.[47]

Table 38. Central Hudson Electric Energy Efficiency Portfolio Actual and Planned Spend and Savings (2019-2025)

Program	Actual Spend 2019-2022	Planned Spend 2023-2025	Actual Savings MWh 2019-2022	Planned Savings MWh 2023-2025
Retail Lighting	$9,205,094	$3,597,481	138,807	52,835
Residential HVAC and Efficient Products	$1,012,798	$415,113	3,322	2,365
Appliance Recycling	$1,721,397	$991,662	9,021	4,281
Behavior Modification	$2,015,835	$229,530	59,319	18,080
CenHub Online Store*	$416,110	$0	3,867	0
Commercial Customer and Prescriptive Program	$5,727,489	$3,344,846	43,261	21,594
Small Business Direct Install	$13,263,988	$ 7,773,416	46,453	29,450
Municipal Streetlights	-$514	$48,966	333	310

* This program was discontinued in 2021.

[47] Central Hudson Gas & Electric System Energy Efficiency Plan, Filed April 28, 2023, Case 18-M-0084. https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={D023C987-0000-C047-B5F0-FBE50A5A79DD}.

Table 39. Central Hudson Gas Energy Efficiency Portfolio Actual and Planned Spend and Savings (2019-2025)

Program	Actual Spend 2019-2022	Planned Spend 2023-2025	Actual Savings MMBtu 2019-2022	Planned Savings MMBtu 2023-2025
Residential HVAC and Efficient Products	$2,204,639	$2,823,140	58,082	33,783
Behavior Modification	$280,336	$76,510	117,653	30,980
CenHub Online Store*	$169,126	$0	13,018	0
Commercial Customer and Prescriptive Program	$1,407,576	$1,162,732	111,161	71,243

* This program was discontinued in 2021.

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

As referenced in the Collaborative Programming section above, Central Hudson will continue working with NYSERDA and the Joint Utilities to plan and implement LMI programming, as well as continue to engage with the NY DPS.

H. *Data Sharing*

1. Context and Background

Significant emphasis has been placed on the role of system data in facilitating market development and greater DER adoption and customer data in support of the development of new energy products and services, while also protecting customers' privacy. The DSIPs were largely intended to serve as a vehicle for collecting and sharing information that facilitates retail market development, including data related to distribution system planning and grid operations. The Company's focus over the past two years has included extensive discussion and development of the datasets identified by the Commission as essential for improving the transparency of utility planning and operations and aiding market growth. In addition, the Company's efforts have been guided by the regulatory shift in this area with the statewide data-sharing effort.

Since the filing of the Initial DSIP, Central Hudson and the Joint Utilities, in conjunction with the feedback received from various stakeholder sessions, have made significant progress in the development of System Data Portals for DER developers to gather valuable system data. Prior to 2020 the Joint Utilities had been working together to develop a greater understanding of system data needs and studying use cases. However, these discussions had not resulted in significant changes in the amount of available data or in the way this data is accessed.

Since launching REV, the Commission has continued to work on numerous data-related initiatives encompassing both customer and system data access. Nonetheless, DER providers and customers are still unable to efficiently access most of the data that would be useful to them. Without such access, the State will not be able to implement the dynamic, reactive, and efficient distribution system envisioned in the REV.

To propose the next steps to enable access to useful energy data, on May 29, 2020, the Department of Public Service Staff released a Whitepaper - Recommendation to Implement an Integrated Energy Data Resource. Central Hudson looks forward to working collaboratively with DPS Staff and NYSERDA to help achieve a useful and valuable resource.

In 2020, the New York Public Service Commission (NY PSC) centralized data access topics in Case 20-M-0082 *Proceeding on Motion of the Public Service Commission Regarding Strategic Use of Energy-Related Data*. In 2021, the NY PSC issued two important data orders within this proceeding – the Integrated Energy Data Resource (IEDR) Order[48] and the Data Access Framework (DAF) Order[49].

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[48] Case 20-M-0082, Order Implementing an Integrated Data Energy Resource (issued February 11, 2021) (IEDR).
[49] Case 20-M-0082, Order Adopting a Data Access Framework and Establishing Further Process (issued April 15, 2021) (DAF).

On February 11, 2021, the NY PSC issued an Order approving the design and implementation of a statewide Integrated Energy Data Resource (IEDR) platform to centralize data access, including utility data (customer and system data) and other energy-related data (i.e., EV registration, building characteristics, DER operations) in support of New York's clean energy goals. Phase 1 will enable the development of at least five priority data use cases over 24-30 months (Q4 2023), while Phase 2 will enable 40+ additional data use cases over 30-36 months (2026). The New York State Energy Research and Development Authority (NYSERDA) will serve as the Program Sponsor for this effort and form the Steering Committee with the Department of Public Service (DPS) Staff. The Order approved Phase 1 budget of $67.5 million for the utilities and NYSERDA, and described a program schedule, governance structure, and reporting requirements.

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

- Ordered the implementation of a statewide Data Ready Certification (DRC) to be administered by a third-party vendor and operational in 2022. This DRC will be needed for third parties soliciting non-public information from the IEDR.
- Adopted data quality and integrity standards for data sets delivered by the utility to third parties.
- Adopted data performance metrics categories to measure the effectiveness of data delivery.
- Removed registration for hosting capacity maps.
- Removed data fees for customer energy usage under 24 months old.
- Adopted a statewide data privacy aggregation standard of 4/50.
- Required eight joint and individual utility filings over July-September 2021.

In addition to these substantial regulatory changes related to information sharing, there were two other orders that refined some of the outstanding issues related to data sharing. On May 17, 2021, the DAF Matrix was approved, mapping the existing Commission-authorized cybersecurity and privacy requirements to the various combinations of purpose, access mechanism, and data type. The Matrix includes the components of all the existing Data Security Agreements and the Self-Attestation, as well as the other existing data access requirements. Each requirement is listed with a name, description, where it originated from, indicators for access mechanism and/or data sets, and the use case applicability.[50] And on August 12, 2021, the Commission addressed the UER Status Report and directed NYSERDA to form a standing UER working group to manage and publish versions of the NY UER Protocols, identify

[50] Case 20-M-0082, Data Access Framework Matrix (issued May 17, 2021) p.1.

refinements and additions to the structure of the reported data fields, and rebalance the application of UER use case specific privacy screens. [51]

2. Implementation Plan

a) Current Progress

Prior to the 2016 DSIP, there was only traditional availability and accessibility of system data to third-party developers, there were no online portals dedicated to system data, the data available was often not available in machine-readable formats, there was no generalized hosting capacity information, and there was limited developer insight into areas with greater locational value.

Since the 2016 DSIP, Central Hudson and the Joint Utilities have made extensive progress in the development of online machine-readable data and data portals with map visualizations. The data available through Central Hudson's website or through links on the Joint Utilities website include:

- DSIP Filing Documents;
- Annually updated five-year Capital Investment Plans as filed with the PSC;
- Planned Resiliency / Reliability Projects as filed with the PSC;
- Reliability Statistics at the circuit level as filed with the PSC;
- Hosting Capacity Maps for all circuits above 12 kV;
- Beneficial Locations Maps;
- Load Forecasts- 8760 hourly by substation and transmission area for five years;
- Historical Load Data- 8760 hourly by circuit, substation, and transmission area;
- NWA Opportunities (directs to separate JU-specific webpage) and Maps;
- Queued and installed DG; and
- SIR Pre-Application Information.

The historical and forecasted load and DER data contained in this DSIP is an enhancement of the extensive system data available through Central Hudson's online data portals, which are linked to the Joint Utilities central data portal. 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. Together, these factors foster market development.

The Joint Utilities' stakeholder engagement sessions identified (1) the desire for and the broad value of information and (2) how the utilities could work to enhance what information is provided. In 2017, the Joint Utilities enhanced their individual data portals and the Joint Utilities' central data portal to improve the accessibility and usefulness of this high-value information. Links to the utility-specific websites with available system data can be found on the Joint Utilities of New York website shown in (

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[51] Case 17-M-0315, Order Adopting Utility Energy Registry Modifications (issued August 12, 2021) p.3.

Figure 47http://jointutilitiesofny.org/system-data/). These data resources remain active and in place today, providing a stable resource of needed data for DER developers and other stakeholders.

Figure 47: Overview of Currently Accessible System Data

Utility System Data Portal

Public System Information

View below for information on available utility data for developers and customers.

System Data Type	What's Included?	Update Frequency
Distributed System Implementation Plans	Information on the utilities' recent progress, current activities, and future plans to continue the transition towards a clean, resilient, distributed, modern, and customer-centric electricity system	Biennial
Capital Investment Plans	Projected capital expenditures for utilities over the next 5 years	Annual
Electric Reliability Reports	Overview of planned resiliency and reliability projects, as well as utility reliability statistics	Annual
Hosting Capacity Analysis (HCA) Maps	Estimates of the amount of DER that may be accommodated on the grid under current configurations and without requiring infrastructure upgrades	Biannual
Beneficial Locations	High-priority locations where there is a potential for localized DER deployment to address system needs	Annual
Load Forecasts	Hourly or 8760 load forecasts by substation and/or feeder area	Annual
Historical Load Data	Hourly or 8760 historical load data by substation and/or feeder area	Annual
NWA Opportunities	One type of beneficial location - provides developers with information on where future DER opportunities may exist in advance of a formal RFP solicitation for non-wires solutions	Annual
Queued DG	Utility interconnection queue data such as type of technology, installed capacity, location, and status	Monthly
Installed DG	Utility interconnection queue data including installation status	Monthly
SIR Pre Application Information	Forms, documents, and information needed to complete an interconnection application and avoid project delays	As needed

To better understand how data is utilized and what data is necessary to meet their needs, the Joint Utilities and stakeholders co-developed multiple business use cases and identified the "need to have" and "nice to have" data that enables each use case. Although the Joint Utilities System Data Working Group continues to engage stakeholders on the business use cases, this effort has now shifted to the statewide effort known as the Integrated Energy Data Resource (IEDR) for system data and customer data, identifying and prioritizing use cases and defining the data needed to meet those use cases and the datasets to share.

Central Hudson is committed to sharing relevant information with customers and developers to advance New York's clean energy goals. Central Hudson, through the Joint Utilities, continues to collaborate in various venues with NYSERDA, DPS Staff, and stakeholders to define data use cases that provide value and to push forward the process of creating a robust and dynamic source of information for everyone. [52]

As NYSERDA moves forward with the Integrated Energy Data Resource (IEDR) and the modifications to the Utility Energy Registry (UER), the utilities continue to join working meetings to support the design and implementation process.

While Central Hudson is fully supportive of sharing helpful information to achieve New York's clean energy goals, customer privacy and cybersecurity must also be given careful consideration. As such, the utilities are coordinating additional discussions with DPS Staff and NYSERDA to put in place the necessary mechanisms consistent with New York privacy laws and regulations.

[52] Joint Utilities of New York website, Distributed System Platform (DSP) Enablement Quarterly Newsletter (March 2022) p.6-7

IEDR Resources

Table 40: NYSERDA IPV Use Case Summary

Initial Public Version (IPV) Use Cases	Use Case Summaries	Expected Completion Timeframe
Large installed DERs	This use case will enable access to, and the ability to manipulate, data that shows all installed DERs that utilities have data on (e.g., over 300kw). So users can site new DERs and monitor the state of DER development in New York.	Q1 2023
Large installed DERs (interconnection queue)	This use case will enable Utilities, DER Aggregators, DER Providers, and Government Agencies to view the most important Queued DER attributes in a table (e.g., DER Type, DER Status, DER Status Rationale, etc.), and as graphics that display the types and statuses of DERs, so users can accurately forecast future projects and easily retrieve key information.	Q1 2023
Consolidated Hosting Capacity Maps	This use case will support DER developers, DER owners and/or utilities to view all hosting capacity maps for the entire state in one map view with consistent data so that end users can site new DERs and monitor the state of DER development in New York accurately.	Q1 2023
Machine-Readable Rate and Tariffs Data	This use case will support government agency or distributed energy resource (DER) Providers' efforts to help customers generate savings through demand response, (programs and DER installations through access to utility rate tariffs / rate books in a machine-readable format initially), and then through more advanced functions like a bill calculator or historical tariff rate information.	Q1 2023

Table 41: NYSERDA MVP Use Case Summary

Minimum Viable Product (MVP) Use Cases	Use Case Summaries	Expected Completion Timeframe
Aggregated consumption energy data for CCA	As a Village, town, city constituent / government employee, I want to understand energy consumption for my community so that we can decide where to source our electricity from and do so at a competitive price.	Q2 2023 - Q4 2023
Consent for already identified customers	As a DER Provider, Building Electrification Provider, I want to request and access the energy consumption and billing information for accounts that have indicated interest in my organization's products (e.g., through sales process, filling out online form, etc.).	Q2 2023 - Q4 2023
Utility Upgrades Project Information	As a DER developer, DER owner and/or utility, organization that sites DERs (e.g., land trust) I want to access planned dates for local distribution upgrade / recent requests to utilities for service upgrades.	Q2 2023 - Q4 2023
Non-Utility Data for DER Siting (Solar)	This use case will support local governments and community solar developers who would want to accelerate the process for identifying, selecting, and negotiating site agreements for community solar projects in order to deploy available capital more quickly and increase the amount of clean energy available to NY electricity customers.	Q1 2023 - Q4 2023
Aggregate Building Energy Consumption - Building Manager	As a building manager / property management company / product service provider I want access to whole building energy data for the buildings that I manage.	Q2 2023 - Q4 2023
Aggregate Building Energy Consumption - Government Agency	As a government agency I want access to whole building energy data for all buildings that meet the criteria for not needing customer consent.	Q2 2023 - Q4 2023

A summary of Central Hudson's activities related to the IEDR can be found in quarterly reports linked below.

- CHGE IEDR Utility Quarterly Progress Report_Q3 2021
- IEDR Utility Q4 2021 Progress Report (CH)
- IEDR Utility Q1 2022 Progress Report (CH)
- IEDR Utility Q2 2022 Progress Report (CH)
- IEDR Utility Q3 2022 Progress Report Central Hudson
- IEDR Utility Q4 2022 Quarterly Progress Report Central Hudson

UER Resources

On October 13, 2021, the Joint Utilities submitted individual UER proposals in accordance with Ordering Clauses No. 2, 3, and 5 of the New York State Public Service Commission's August 12, 2021, *Order Adopting Utility Energy Registry Modifications*. The Joint Utilities will continue to participate in the UER Working Group and coordinate with the other utilities to prepare the modifications to the UER semi-annual reports. [53]

- Order Adopting Utility Energy Registry Modifications
- CHGE UER Compliance Filing

b) Future Implementation and Planning

Central Hudson will continue to work with the Joint Utilities System Data Working Group on updates to and the consistency of individual utility data portals, as well as refining and/or expanding system data use cases to better meet stakeholder needs. The Joint Utilities System Data Working Group will continue to coordinate with stakeholders and the Joint Utilities Customer Data Working Group to advance the definitions and implications of basic and value-added system data and customer data.

Central Hudson agrees with the need to provide access to useful energy data to enable achievement of the State's energy policy goals. The time to provide such access has become urgent with the recent adoption of the CLCPA. Utilities will not be able to meet the needs of NY State's energy industry stakeholders efficiently and effectively by simply evolving the existing fragmented framework.

While Central Hudson agrees with the premise and will work collaboratively with the DPS Staff and NYSERDA, and associated development, build, and implementation process. Central Hudson applauds the Staff for recognizing the complexities involved in IEDR development and encourages them to remain flexible to take advantage of new information during the development process, including knowledge gained or legitimate concerns expressed in comments.

c) Integrated Implementation Timeline

Refer to Figure 8 under Data and Analytics for the implementation timeline regarding Data Sharing.

[53] Joint Utilities of New York website, Distributed System Platform (DSP) Enablement Quarterly Newsletter (November 2021) p.9.

3. Risks and Mitigation

Central Hudson continues to be responsive to developers through the stakeholder process in developing an understanding of the System Data elements needed to enhance stakeholder ability to access and utilize available system data. There are several risks related to the System Data function of the DSP that must be recognized, including Critical Energy Infrastructure Information (CEII) data, customer privacy, data refresh frequency, data accuracy, and the benefits and costs of providing data elements. Central Hudson will continue to address the risks associated with CEII and customer privacy by applying its policies and procedures to protect sensitive data.

Regarding the data refresh and accuracy, Central Hudson will continue to improve the processes used to create the System Data. This will be accomplished through the continued investment in station and distributed metering, internalizing the process of historical data cleansing and forecasting, and refinements to Central Hudson's planning processes to ensure accuracy.

Lastly, Central Hudson will continue to work with DPS, NYSERDA, and the DER Industry Group through the newly established Case 20-M-0082 Proceeding on Motion of the Commission Regarding Strategic Use of Energy Related Data on the Implementation of an Integrated Energy Data Resources to ensure that the effort made to develop this information and make it publicly available is justified. Additionally, future data elements should be thoroughly vetted to ensure that they are needed, used, and are worth the effort to develop, share, and update.

To ensure that this is done effectively and adds value to stakeholders, Central Hudson joined with the other utilities in offering some guiding principles.

- Enhancing customer value should be the guiding principle for designing a statewide data platform.
- The JU recognizes that a statewide data platform may have benefits, but to make it work well and be valuable for all parties, it is critical to first understand the specific goals that such a data platform strives to achieve.
- Security and governance of data are paramount.
- Understand the steps needed, use cases, benefits, and costs.
- System planning and operations must remain with the utility as the DSP.
- A collaborative approach aimed at crafting a practical plan to meet data availability goals, based on lessons learned from pilots and other data initiatives, should be adopted.

4. Stakeholder Interface

Through the Joint Utility Information Working Group, extensive stakeholder engagement has been used to progress the understanding of and access to DSP System and Customer Data.

Twice a year, the Joint Utilities of NY hosts a webinar to update stakeholders and take questions on matters relating to Distributed System Platform (DSP) services. The most recent webinar was held on December 16, 2022. The Joint Utilities shared news about electric vehicle deployment efforts, progress on working with stakeholders and NYISO on implementing FERC Order No. 2222, changes to the Hosting Capacity Roadmap, and more.

5. Additional Detail

a) Provide a functional overview of the planned IEDR;

On February 11, 2021, the NY PSC issued an Order approving the design and implementation of a statewide Integrated Energy Data Resource (IEDR) platform to centralize data access, including utility data (customer and system data) and other energy-related data (i.e., EV registration, building characteristics, DER operations) in support of New York's clean energy goals. Phase 1 will enable the development of at least five priority data use cases over 24-30 months (Q4 2023), while Phase 2 will enable 40+ additional data use cases over 30-36 months (2026). The New York State Energy Research and Development Authority (NYSERDA) will serve as the Program Sponsor for this effort and form the Steering Committee with the Department of Public Service (DPS) Staff. The Order approved Phase 1 budget of $67.5 million for the utilities and NYSERDA, described a program schedule, governance structure, and reporting requirements.

b) provide an overview of NYSERDA's IEDR implementation program, including information pertaining to stakeholder engagement;

On May 24, 2021, NYSERDA, as the IEDR Program Sponsor, issued a notice inviting stakeholders to provide comments identifying, characterizing, and prioritizing a preliminary set of potential Use Cases for Phase 1 implementation of the IEDR. The Joint Utilities and other stakeholders submitted IEDR Use Case comments on July 23, 2021. The Joint Utilities proposed Use Cases that would benefit stakeholders across New York State from their perspective, as noted by NYSERDA's instructions, but emphasized that the IEDR should prioritize Use Cases from developers and other stakeholders that maximize societal value. NYSERDA guided the prioritization and selection of the Use Cases to move forward with Phase 1 of the IEDR design and implementation.

The IEDR Program Team selected the following use cases for the IEDR Initial Public Version (IPV) to be released by Q1 2023.

- Large Installed DERs
- Large Planned DERs (Interconnection Queue)
- Consolidated Hosting Capacity Maps
- Machine Readable Rate and Tariffs

The IEDR Program Team selected the following use cases for the IEDR MVP (MVP) to be released by Q4 2023.

In Q3 2022, NYSERDA announced the selection of E Source Companies, LLC (E Source) to lead the Development Team for the IEDR. The Development Team, led by E Source, will also include UtilityAPI, Flux Tailor, TRC Companies, and HumanLogic. Together, the team will be responsible for designing, building, and operating the IEDR platform to accomplish the policy goals and program outcomes as described in the Commission's IEDR Order in a cost efficient and expeditious manner. The Development Team will leverage E Source's OneInform and UtilityAPI's Green Button Connect offerings to enable the data access, governance, querying, analysis, and consent processes that will be required to deliver the full benefit of stakeholder submitted use cases.

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

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

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

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

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

On February 28, 2022, each utility submitted responses to the Notice of Utility Data Requirements (UDR) issued by NYSERDA on February 7, 2022. The UDR requested an approach to deliver preliminary data elements to the IEDR by May 2022. While the Joint Utilities are fully supportive of sharing useful information to achieve New York's clean energy goals, customer privacy and cybersecurity must also be given careful consideration. As such, the utilities coordinated additional discussions with DPS Staff and NYSERDA to put in place the necessary mechanisms consistent with New York privacy laws and regulations.

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

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

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

Central Hudson has securely transferred publicly available data to the IEDR team in support of the three (3) IPV use cases - Large Installed DERs, Large Planned DERs, and Consolidated Hosting Capacity Map use cases. The IPV data is publicly available information from utility hosting capacity maps and DER data inventories. In February and March 2023, Central Hudson Gas & Electric transferred updated IPV data to the IEDR Development Team using a Secure File Transfer Protocol (SFTP) connection.

Additionally, the Joint Utilities hosted a call with UtilityAPI, a member of the IEDR Development Team responsible for managing customer consent. The Joint Utilities engaged Utility API to understand if existing Green Button Connect functionality could be leveraged as part of the IEDR. As UtilityAPI will be managing customer consent, there will not be cross-over.

In February 2023, the IEDR Development Team provided the Joint Utilities with data specification sheets for the customer and network data. These data specification sheets outline the format for utilities to provide data in support of upcoming MVP use cases, as well as other characteristics (e.g., frequency of data transfer). Central Hudson Gas & Electric is currently coordinating with the IEDR Development Team on utility-specific changes to the data specification sheets.

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

To date Central Hudson has been providing publicly available system data related to Hosting Capacity, DER installed and in Queue, and machine-readable tariffs. These are all related to the IPV and are only portraying publicly available information. As we move into the MPV, the use cases may contain customer information, usage, or other non-public data. Ensuring that this data is anonymized and kept secure will be a key consideration in the data delivered to the IEDR.

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

The Microsoft Azure Platform has been identified as the planned solution through the execution of a Proof-of-Concept project that provided the Company insight into the technical capabilities of the platform. This platform allows for a robust and flexible data warehouse with sufficient data ingestion opportunities that will enable the Company to pull from the various sources where data is available.

By leveraging the Microsoft Azure Platform, the Company can synergize skill sets within the Technology organization and leverage current technology investments for both the IEDR and for internal Enterprise Data & Analytics use cases.

In the interim, Central Hudson currently leverages the Netezza platform. This platform will be used as an interim solution, until such time that the Microsoft Azure platform, along with its operating and governance models have been implemented. The hardware has reached end of life and is currently being replaced.

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

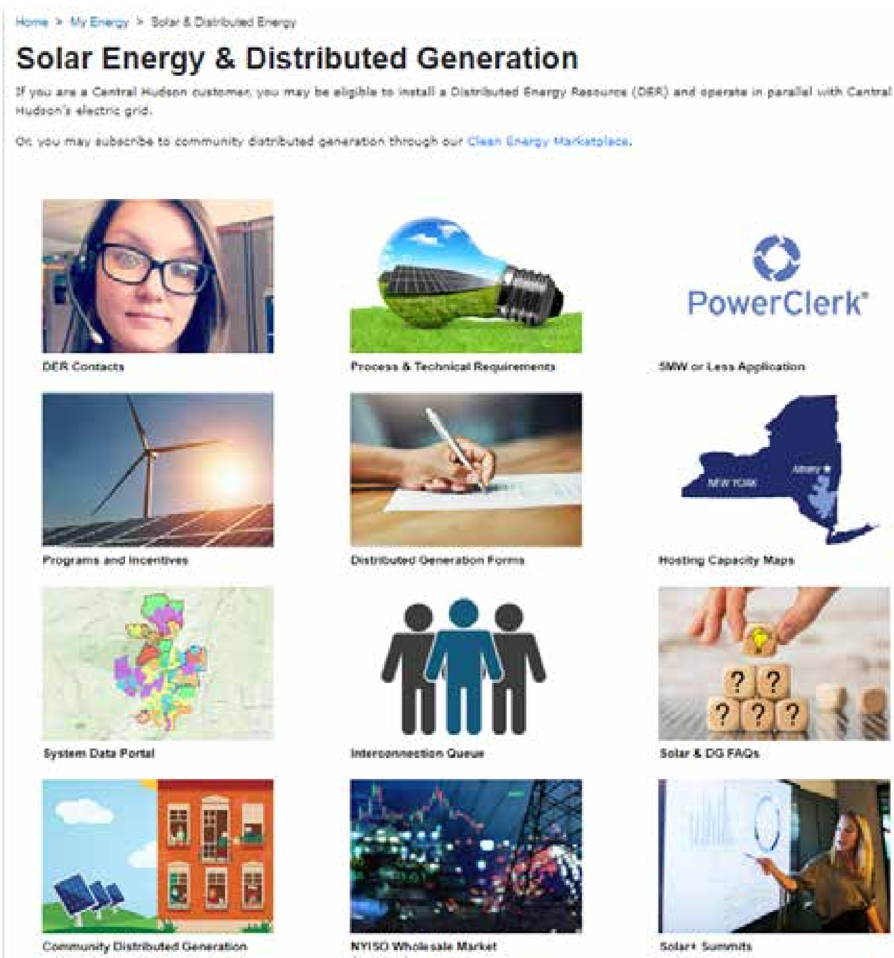
At this stage, the Company will continue to make ready a production platform targeting completion by Q3 2024. This will ensure a technology environment is prepared for ingestion of available data for the IEDR program. Collect any additional scope/data sets for IPV delivery in Q1 2023 brought forth by potential changes from the development team to leverage data, data streams, and geospatial/relational data from our ESRI databases and systems Continue working on MVP Use Cases, as they are identified by the IEDR Program Team.

Central Hudson is beginning to prepare for SSO integration with the IEDR platform internally, as well as having meetings with the JU and IEDR Program team as needed.

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

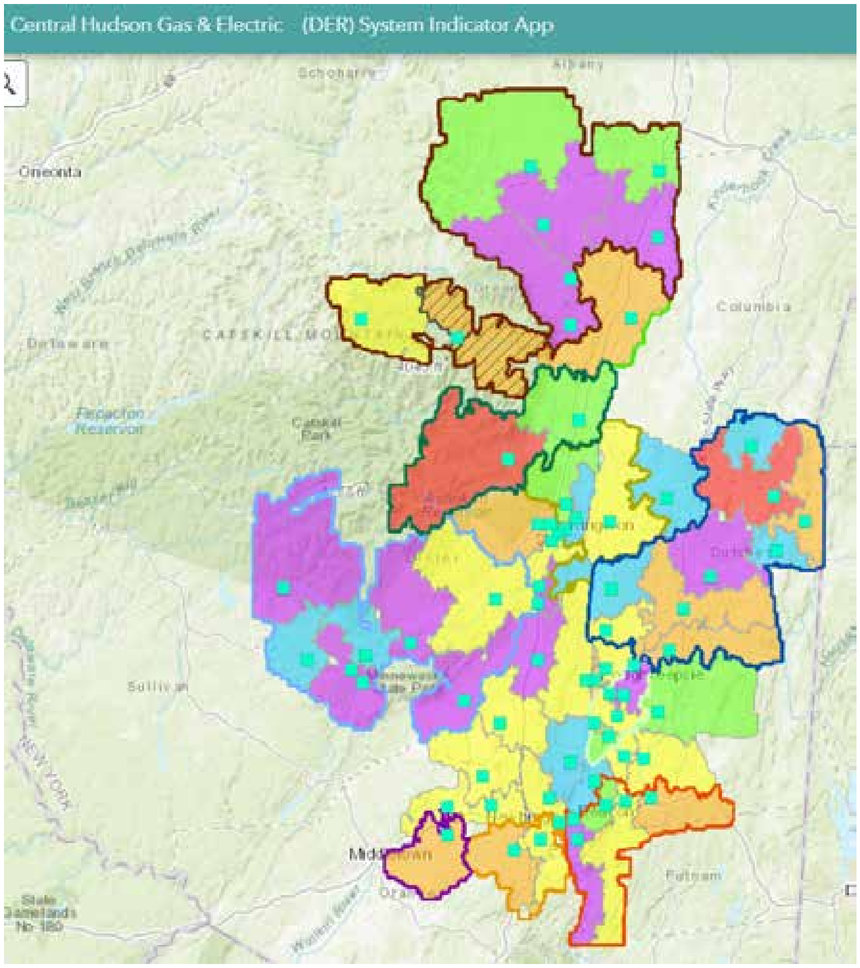
Central Hudson provides System and access to Customer data primarily through its public website at www.cenhud.com. On the My Energy page in the menu of the home page, customers can find access to their usage data, tariffs and rates, and energy options. Also, developers can find a myriad of information in the solar energy and distributed energy sections, including interconnection application documents, technical requirements for interconnection, and links to the PowerClerk interconnection portal, the Hosting Capacity Map, the interconnection queue, and the System Data Portal (belowFigure 48). Other data, such as the DSIP regulatory filings, reliability data, Capital Expansion Plans, and DER interconnection data, is included on the Joint Utilities System Data portal at (http://jointutilitiesofny.org/system-data/).

Figure 48: Central Hudson Website – Solder & Distributed Energy Page



The System Data portal is a GIS map-based data portal providing historical and forecasted load data by location. See Figure 49 Figure 49for an example.

Figure 49: System Data GIS Map



By clicking on a circuit, substation, or transmission area, a pop-up screen will appear that provides details on the circuit or station and reveals a link to the historical and forecasted load data in Excel file format. See Figure 50 for an example.

Figure 50: Historic and Forecasted Load Example

date	hour	mva	estimate	substation	year	month	tempf_1in	mva_1in2	mva_p01	mva_p05	mva_p10	mva_p25	mva_p50	mva_p75	mva_p90	mva_p95
1/1/2013	1	4.816827	0	STAATSBU	2013	1	35.96	4.38822	4.298005	4.324433	4.338522	4.362063	4.38822	4.414376	4.437918	4.452006
1/1/2013	2	4.481281	0	STAATSBU	2013	1	33.98	4.164555	4.078938	4.104019	4.11739	4.139731	4.164555	4.189378	4.211719	4.22509
1/1/2013	3	4.329494	0	STAATSBU	2013	1	35.96	4.073923	3.990169	4.014705	4.027784	4.04964	4.073923	4.098206	4.120061	4.133141
1/1/2013	4	4.203004	0	STAATSBU	2013	1	35.96	4.06331	3.979774	4.004246	4.017292	4.03909	4.06331	4.087529	4.109328	4.122373
1/1/2013	5	4.304238	0	STAATSBU	2013	1	35.96	4.173105	4.087312	4.112445	4.125843	4.148231	4.173105	4.197979	4.220366	4.233764
1/1/2013	6	4.320101	0	STAATSBU	2013	1	35.96	4.396927	4.306533	4.333014	4.34713	4.370718	4.396927	4.423135	4.446723	4.46084
1/1/2013	7	4.430614	0	STAATSBU	2013	1	37.04	4.667696	4.571736	4.599848	4.614833	4.639874	4.667696	4.695519	4.72056	4.735546
1/1/2013	8	4.779088	0	STAATSBU	2013	1	37.04	4.923841	4.822615	4.852269	4.868077	4.894492	4.923841	4.95319	4.979605	4.995413
1/1/2013	9	5.193162	0	STAATSBU	2013	1	37.04	5.004168	4.90129	4.931428	4.947494	4.974339	5.004168	5.033996	5.060841	5.076907
1/1/2013	10	5.624557	0	STAATSBU	2013	1	37.04	5.072093	4.967819	4.998366	5.01465	5.04186	5.072093	5.102325	5.129536	5.14582
1/1/2013	11	5.884081	0	STAATSBU	2013	1	37.04	5.067095	4.962924	4.993441	5.009709	5.036892	5.067095	5.097298	5.124482	5.14075
1/1/2013	12	5.929034	0	STAATSBU	2013	1	37.04	5.098444	4.993628	5.024333	5.040702	5.068054	5.098444	5.128833	5.156185	5.172554
1/1/2013	13	5.796375	0	STAATSBU	2013	1	37.04	5.162618	5.056483	5.087575	5.10415	5.131845	5.162618	5.19339	5.221087	5.237661
1/1/2013	14	5.851172	0	STAATSBU	2013	1	37.04	5.162425	5.056294	5.087385	5.103959	5.131654	5.162425	5.193196	5.220891	5.237465
1/1/2013	15	5.878343	0	STAATSBU	2013	1	35.96	5.186447	5.079822	5.111057	5.127708	5.155532	5.186447	5.217361	5.245185	5.261836
1/1/2013	16	5.992133	0	STAATSBU	2013	1	35.06	5.438532	5.326724	5.359478	5.376939	5.406115	5.438532	5.470949	5.500125	5.517585
1/1/2013	17	6.80878	0	STAATSBU	2013	1	33.08	6.199911	6.07245	6.10979	6.129695	6.162955	6.199911	6.236866	6.270127	6.290031
1/1/2013	18	7.117798	0	STAATSBU	2013	1	32	6.542593	6.408088	6.447491	6.468496	6.503595	6.542593	6.581591	6.61669	6.637695
1/1/2013	19	7.092557	0	STAATSBU	2013	1	30.92	6.416113	6.284208	6.32285	6.343449	6.37787	6.416113	6.454358	6.488778	6.509377
1/1/2013	20	7.052381	0	STAATSBU	2013	1	30.02	6.289248	6.159951	6.197828	6.21802	6.25176	6.289248	6.326735	6.360476	6.380667

Data map | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021

I. Hosting Capacity

1. Context and Background

In order to encourage further DER integration, Central Hudson provides estimates of their system's hosting capacity, or 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 or secondary network system.[54] This 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.

Central Hudson calculates each circuit's hosting capacity by evaluating potential power system criteria violations that could result from interconnecting large solar PV and/or Energy Storage systems[55] to three-phase distribution lines. This approach was deliberately chosen to deliver value in a timely manner to DER developers that are most active in New York State. The analysis increases visibility into hosting capacity for larger-scale solar PV and/or Energy Storage systems that often target rural areas where land is available, but where hosting capacity can vary substantially from site to site. The primary use case for hosting capacity data in New York 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.

Since the 2020 DSIP, Central Hudson has made significant updates to hosting capacity maps. The following is an updated roadmap of the Hosting Capacity milestones for the Joint Utilities:

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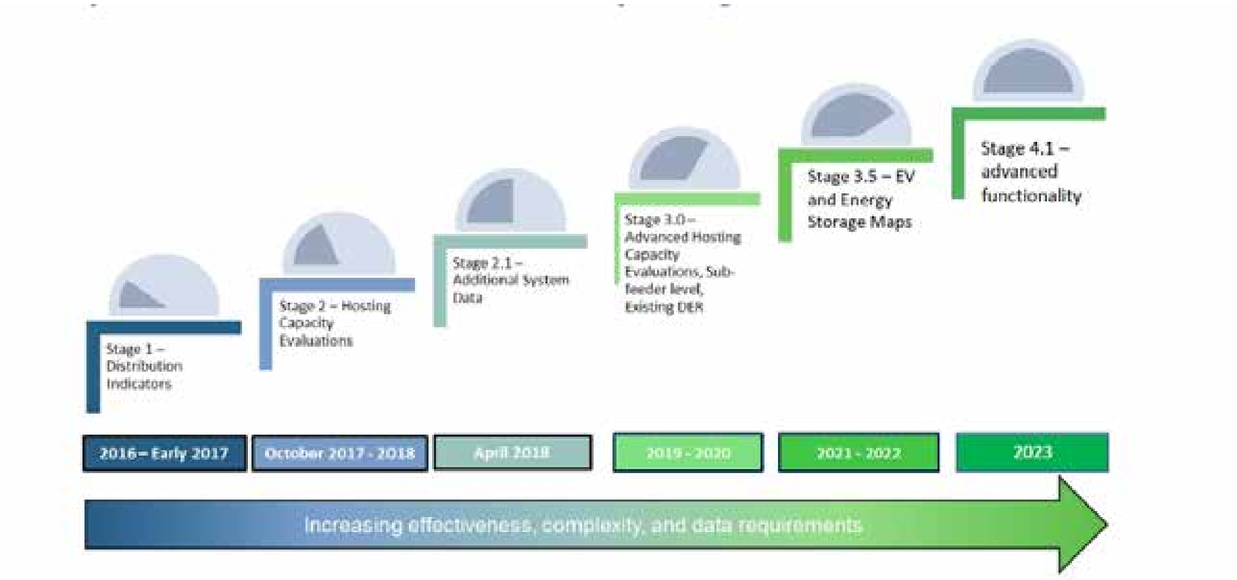
[54] Electric Power Research Institute ("EPRI"), Defining a Roadmap for Successful Implementation of a Hosting Capacity Method for New York State, Report Number 3002008848 ("EPRI Roadmap"), June 2016, p. 2. http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002008848.

[55] Solar and/or Energy Storage with an AC nameplate rating starting at and gradually decreasing from 6000 kW.

Figure 51: Joint Utilities Hosting Capacity Roadmap



EPRI's DRIVE tool continues to be utilized to conduct hosting capacity analysis, in order to support alignment and a common approach across the Joint Utilities, while enabling utilities to leverage existing circuit models in a utility's native distribution planning software.

In 2020, the JU was on stage 3.0 of the Hosting Capacity Roadmap, shown above. Since 2020, the JU has initiated and completed stage 3.5 of Hosting Capacity Roadmap and completed Stage 4.1.[56] As part of stage 3.5 of the Hosting Capacity Roadmap, the JU published the first iteration of Energy Storage Hosting Capacity Maps in April 2022. The first iteration of Energy Storage Hosting Capacity Maps showed feeder-level hosting capacity (min/max), additional system data, downloadable feeder-level summary data, sub-transmission lines available for interconnection, and reflected existing DER in circuit load curves and allocations. The second iteration of Energy Storage Hosting Capacity Maps, as part of Stage 4.1 published in April 2023, shows nodal-level hosting capacity and nodal constraints (violation criteria) for available feeders. The Energy Storage Hosting Capacity Maps have separate layers for load (charging) and generation (discharging) and the feeder nodes are color-coded based on the minimum hosting capacity value of the four violation criteria: Over/Under Primary Voltage, Primary Voltage Deviation, Regulator Voltage Deviation, and Thermal Charging/Discharging capacity. Between October 2022 and April 2023, the JU also published the nodal constraints (violation criteria) for the PV Hosting Capacity Maps as part of Stage 4.1, adding insight into which feeder constraint is driving the Hosting Capacity value at a specific location.

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[56] A full list of the stakeholder recommendations for Stage 4 is available on the Joint Utilities website. See Joint Utilities of New York Stakeholder Engagement Group information here http://jointutilitiesofny.org/joint-utilities-of-new-york-engagement-groups/

In April 2023, the JU published the second iteration of the Energy Storage Hosting Capacity Maps and made updates to the PV Hosting Capacity Maps. This included additional functionality such as:

- Sub Feeder Level for Energy Storage Hosting Capacity Map
- Nodal Constraints on PV and Energy Storage Hosting Capacity Maps
- Six-month updates for circuits that interconnect DER projects > 500kW
- Cost Share 2.0 Items
- DER Connected since last Hosting Capacity Analysis (HCA) Refresh

With the April 2023 update, the PV and Energy Storage Hosting Capacity Map pop-ups now share the following information:

- Section Hosting Capacity for PV and Section Hosting Capacity for Storage Charging/Discharging
    - Substation:
    - Feeder:
    - Section ID:
    - Section Voltage (kVLL):
    - Section Hosting Capacity Charging/Discharging (MW):
    - Flicker Value Generation (MW):
    - Primary Over/Under-Voltage Deviation Charging (MW):
    - Primary Voltage Deviation Charging/Discharging (MW):
    - Regulator Deviation Charging/Discharging (MW):
    - Thermal from Charging/Discharging (MW):
    - Anti-Islanding Limit (Generation) (MW):
    - DG Connected (MW) (Circuit):
    - DG In-Queue (MW) (Circuit):
    - NYISO Load Zone:
    - HCA Refresh Date:
    - DG Connected/In-Queue Refresh Date (Circuit):
    - DG Installed Since Last HCA Refresh (MW) (Circuit):
    - Notes:
- Substation Level System Data
    - Substation/Bank Installed DG (MW):
    - Substation/Bank Queued DG (MW):
    - Substation/Bank Total DG (MW):
    - 2022 Substation/Bank Peak (MW):
    - Substation/Bank Thermal Capacity (MVA):
    - Estimated 3V0 Protection Threshold (MVA):
    - Substation Back feed Protection:
    - DG Connected/In-Queue Refresh Date (Substation):
    - DG Installed Since Last HCA Refresh (MW) (Substation):

- HCA Refresh Date:

Central Hudson updates pop-up data fields for installed, queued, total DG, and DG installed since last HC refresh on a monthly basis and updates peak load information annually. Where appropriate, 3V0 upgrade information is updated annually or upon major changes for relevant circuits.

Following the 2020 DSIP, the JU met with stakeholders in May 2021, August 2021, and November 2021. In 2022, the Hosting Capacity Working Group held stakeholder engagement sessions in May and November, which were structured corresponding to the release of the Stage 3.5 displays and look-ahead to future releases. Due to these stakeholder sessions, the JU added functionality to the Energy Storage HC as follows:

- Show the additional DG connected on a monthly basis consistent with how PV is presented.
- Add to the map sub-transmission circuits that can host distributed generation.
- Show output consistent with the Cost-Share 2.0 order.

After the JU published the first iteration of the Energy Storage HC Maps, stakeholders requested that the maps utilize use cases that reflect developer business models. Currently, the use-case incorporated for the existing energy storage capacity map is solar PV paired with storage, and includes a worst-case scenario for charging. To share use-cases that better reflect developer business models, the JU has invited stakeholders to share their business-use cases with the Interconnection Technical Working Group (ITWG). The goal is to align the use cases identified as part of the ITWG with the hosting capacity maps in order to utilize use cases that benefit developers while also balancing utility efforts.

2. Implementation Plan

a) Current Progress

Since the 2020 DSIP, Central Hudson has continued working with Electric Distribution Design to maintain the automation of the file extraction from the Distribution Engineering Workstation (DEW) load flow software to the EPRI DRIVE tool for HC analysis. The mechanisms to automate this process are in place and are currently being utilized.

Utilizing internal resources, Central Hudson will continue to publish an annual refresh of the PV Hosting Capacity Map by October 1st of each year with a bi-annual update by April 1st of each year which includes circuits with more than500 kW DG interconnected and may include major circuit reconfigurations. Central Hudson will continue to publish an annual refresh of the Energy Storage Hosting Capacity Map by April 1st of each year with a bi-annual update by October 1st of each year for circuits with more than 500kW DG interconnected. Additionally, Central Hudson will continue to update queue information within the pop-ups on a monthly basis. Since the 2020 DSIP, Central Hudson has provided REST API access to Hosting Capacity Map GIS data via a REST URL. The REST URL allows stakeholders to overlay hosting capacity data and complete queries and filtering within their own GIS platforms. This data is available for download via the same website Developers utilize to view the hosting capacity maps, for both solar PV and energy storage.

Following the transition to Stage 4.1, and the significant updates that were made to both the PV and ESS hosting capacity maps on April 1, 2023, the NY Joint Utilities hosted a stakeholder session in May 2023 outlining the recent changes and proposed next steps. Stakeholders that attended included DG Developers, Interest Groups, and NY DPS. Stakeholders were pleased with the progress the JU has made to sub feeder level hosting capacity, nodal constraints (violation criteria), and Cost Share 2.0 implementation. Stakeholders were notified that the next steps include reviewing additional ESS scenarios, which will be recommended by the Interconnection Technical Working Group.

The JU holds stakeholder sessions twice a year. These sessions provide JU the ability to better understand developer needs and receive direct feedback from stakeholders on items worth incorporating into the maps that the JU may not have considered. For example, in the most recent hosting capacity update this included incorporating criteria violation for both the solar PV and storage maps.

After the JU published the first iteration of the Storage HC Maps, stakeholders requested that the maps utilize use cases that reflect developer business models. Currently, use-cases for the storage capacity map are worst-case scenario. To share use-cases that better reflect developer business models, the JU has invited stakeholders to share their business-use cases with the ITWG in order to align hosting capacity maps with these use cases.

b) Future Implementation and Planning

The Stage 4.1 release of nodal hosting capacity and violation criteria for both the PV Hosting Capacity Map and Energy Storage Map was a significant update that has enhanced the information provided to stakeholders. The Joint Utilities are evaluating options to improve the analysis further, and will continue to solicit the input from stakeholders on the development of the JU hosting capacity roadmap. Based on feedback received during stakeholder sessions and survey results, near-to-medium term enhancements the JU plan to focus efforts include:

- Additional scenarios based on ITWG working group collaboration with stakeholders
- Continued granularity

To support the progress of hosting capacity advancements, the JU will need to invest in the following:

- Continued JU collaboration to identify lessons learned, and to progress the maps.
- Continued bi-annual stakeholder sessions to better understand and respond to stakeholder needs.
- Continued automation across the JU to streamline updates and to enable the provision of further functionality.

The JU collaborates with stakeholders to prioritize developer needs. As such, there is no prescriptive long term implementation timeline. Instead, the JU continuously works with stakeholders to enhance the hosting capacity maps in the near term. This provides many benefits including:

- Stakeholder Input: Continuous collaboration allows stakeholders and developers to provide input on the hosting capacity maps, ensuring that the maps reflect the needs and concerns of the community. This can help to build trust and transparency between the JU Integrated Planning Working Group and the community.

- Identifying Opportunities: Collaboration with stakeholders and developers can also help identify opportunities for new functionality. By working together, the JU and stakeholders can identify areas where hosting capacity maps can be improved, which can help to accelerate the usefulness of the maps to developers.

- Better Decision Making: Collaboration with stakeholders and developers ensures that the hosting capacity maps are informed by a wide range of perspectives and expertise. This can help to improve decision-making by incorporating diverse viewpoints and ensuring that decisions are based on the best available and most up-to-date information.

Figure 52 below illustrates the hosting capacity implementation timeline through 2024.

Figure 52: Hosting Capacity Timeline Through 2024

The goal of the HC maps is to help stakeholders understand how much hosting capacity is available at a given location. While it is not meant to replace the interconnection process, it is meant to assist developers in initiating the process. Continued granularity will support stakeholders in this process.

Hosting capacity maps are useful for developers and stakeholders because they provide critical information about the ability of the electric grid to accommodate new distributed energy resources (DERs) such as solar panels, wind turbines, and energy storage systems. These maps help identify areas where DERs can be added to the grid without causing reliability or safety issues.

Developers can use hosting capacity maps to identify areas where there is available capacity for new DER projects. This information can help developers make informed decisions about where to site new projects, which can reduce costs and save time. By avoiding areas with limited hosting capacity, developers can reduce the need for expensive upgrades to the grid infrastructure.

To support the future vision, the JU will need to continue and ramp up a few work streams as follows

- Continued JU collaboration to identify lessons learned, and to progress the maps
- Continued bi-annual stakeholder sessions to better understand and respond to stakeholder needs
- Continued automation across the Joint Utilities to streamline updates and to enable the provision of further functionality.

The JU continue to meet on a weekly basis to discuss hosting capacity initiatives and updates and hold two stakeholder sessions each year. As the group is awaiting direction from the ITWG on the use cases for energy storage which will continue into the second half of 2023, the outcome of these discussions will be used to inform the next steps and efforts for energy storage hosting capacity maps. Additionally, as previously mentioned the implementation of a new load flow software, expected to be completed by Q1 2024 for Phase 1, will help provide efficiencies in conducting hosting capacity analysis on the current annual and bi-annual refresh schedule.

The CGPP and DSIP are filings with overlapping but distinct scope. The CGPP will detail the evolution of distribution planning processes needed to meet CLCPA goals, align with transmission planning processes, and ensure that planning is integrated. The DSIP describes implementation of the much broader set of DSP activities and projects, and how those activities holistically align with CGPP and CLCPA goals. The CGPP will be more singularly focused on a process to identify distribution system needs to meet CLCPA State goals and develop a distribution investment plan, including capital projects, to meet those needs. Planned capital investments, including technology platform investments and how they will be leveraged will be included in the DSIP (e.g., AMI, automation, ADMS, etc.) and the results of executing the processes will be used to inform the CGPP. This includes planned investments that support increase in hosting capacity (i.e., Phase 1 projects).

The CGPP is aimed at developing a “CLCPA-focused planning process,” including “the State’s bulk transmission, local transmission, and distribution planning processes.” The goal is to improve planning processes to better coordinate the studies performed by the Utilities with the NYISO’s bulk-power system planning and generation interconnection processes; improve the integration of Local Transmission and

Distribution (LT&D) and bulk system studies with NYSERDA's renewable generation and storage procurements; and improve forecasting of renewable generation development for specific locations on the LT&D and bulk transmission grid. As part of the December 2022 CGPP proposal, one of the key inputs to the CGPP process is the generation build-out scenarios identified by the Energy Policy Planning Advisory Council (EPPAC). While forecasting practices for the CGPP and DSIP are aligned, the scenarios identified by the EPPAC may result in different forecasts than those completed as part of the DSIP. The output of the CGPP thus may result in the identification of Phase 2 capital projects that are not already identified in current rate plans. Although capital projects identified within the CGPP are intended to be funded under the FERC load ratio share methodology, these Phase 2 projects once approved will be incorporated and used to inform the normal DSIP and hosting capacity process. This includes ensuring the upgrades identified as part of the CGPP that increase hosting capacity are included within appropriate analysis.

c) Integrated Implementation Timeline

Refer to Figure 8 under Grid Modernization for the implementation timeline related to hosting capacity which includes efforts and investments as part of Integrated System Planning.

3. Risks and Mitigation

The risks to Hosting Capacity Analysis are primarily driven by software and analytical capabilities, availability of data, and the accuracy and speed of model updates. To mitigate this risk, Central Hudson participates in the EPRI DRIVE user's group to help influence the development and prioritization of software capabilities to align with the needs of stakeholders in New York. Since the 2020 DSIP update, Central Hudson has continued to refine the load flow models of its entire distribution system to facilitate hosting capacity analysis, as well as distribution automation and the availability of hourly load data, including minimum load data required for hosting capacity analysis, which continues to improve along with the execution of the capital plan. As a part of the Company's ESRI GIS roadmap, there will be improved integration of distribution design work into the ESRI platform, so that field changes can be more quickly incorporated into the GIS model and other interfacing software, such as the load flow models that drive hosting capacity analysis. However, there will still be limitations to incorporating the impacts at the substation and transmission level into these models.

There is also risk involved in integrating newer DER technologies into hosting capacity analysis. While initial hosting capacity analysis was focused on solar photovoltaics; as energy storage technology which has distinct operating characteristics has been introduced, the process has become more complex. While the JU are working with the ITWG to identify valuable energy use cases that can be incorporated into the hosting capacity maps, the additional scenarios will ultimately require additional labor and resources. The balance between complexity, speed, and accuracy must be considered to provide the most timely and effective information to stakeholders. Additionally, depending upon the extent to which Stage 5 is implemented, supplementary GIS resources may be required to close out work orders at an accelerated pace and update system models. Supplementary Electric Planning & Interconnection resources may also be required to manually reconfigure circuits to consider alternate configurations and incorporate additional DERs with their own complex set of operating characteristics.

4. Stakeholder Interface

Most stakeholders to the Integrated Planning working group are DER developers, including but not limited to storage and PV. We also engage with non-profits seeking to accelerate the adoption of clean energy, such as the Interstate Renewable Energy Council (IREC).

The Joint Utilities continue to view stakeholder feedback as a critical input to further improvements to the hosting capacity analysis and displays. The Joint Utilities will continue to engage stakeholders for their input on these approaches to further inform expansion of the hosting capacity roadmap, although the group may need to grow to include emerging developers and those representing other types of DERs. 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 important, given the broad range of energy storage technologies, applications, and operating characteristics that such analyses could reflect.

The Joint Utilities will continue to hold two stakeholder engagement sessions a year, corresponding with the release of each stage to provide an update to stakeholders on progress to date and solicit input on future stages. The Joint Utilities plan to continue facilitating open discussions with stakeholders via the engagement group sessions beyond the Stage 3.5 and Stage 4.0 release. The longer-term focus on Stage 4.0 complements the Joint Utilities' interest in engaging stakeholders to provide the highest value results for users.

The JU supports the shared goal by developers and non-profits to accelerate the adoption of clean energy and DERs. The JU seeks to actively participate in the green energy transition, while continuing to provide safe, reliable, and affordable service.

The JU continuously collaborates with stakeholders to provide updates to the HC maps in an iterative manner. The JU will continue to provide enhanced functionality based on stakeholder requests yearly.

The JU is highly on continued stakeholder engagement. Collaboration with stakeholders enables the JU to provide additional functionality to the HC maps. The HC maps are developed to assist stakeholders and as such, stakeholder input is integral to HC Maps success.

The JU hosts two stakeholder sessions per year. During these stakeholder sessions, the JU provides stakeholder an update and also encourages discussion, suggestions and feedback.

Prior to each stakeholder session, the JU updates the JU stakeholder calendar to share the upcoming stakeholder session. The JU also send out an email invite to a list of over 500 stakeholders. The JU checks in with key stakeholders such as representatives from IREC and NY Best to ensure their availability before scheduling.

After each stakeholder session, the JU emails stakeholders a copy of the slide deck used during the meeting, with the addition of recorded Q&A; and follow-up to the Q&A with any updates to JU plans based on stakeholder feedback.

The JU also provides information on their website sharing all the most recent updates and important links.

Through continuous engagement with stakeholders, an active webpage, JU designated contacts for integrated, and the official JU email address; stakeholders have many different pathways to express concern. The JU actively monitor stakeholder engagement and ensure that where possible, they act in alignment with stakeholder needs.

5. Additional Detail

a) The utility's current efforts to plan, implement, and manage capital infrastructure projects related to hosting capacity. Information provided should include:

(1) 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;

(2) the original project schedule;

(3) the current project status;

(4) lessons learned to-date;

(5) project adjustments and improvement opportunities identified to-date; and,

(6) next steps with clear timelines and deliverables

Central Hudson has initiated and completed several projects that increase the hosting capacity of DERs on its system. Energy Storage Integration describes the Energy Storage projects or research that have been completed or are currently being evaluated at Central Hudson. Central Hudson has been participating with consultants and other vendors in smart inverter research and projects, which has high potential to increase hosting capacity across the service territory without requiring extensive upgrades to the electric system infrastructure. Please refer to Hosting Capacity for more detail.

Although not the primary project driver, Central Hudson has initiated and completed several T&D infrastructure projects that increase the hosting capacity of DERs on its system. As shown in detail in Central Hudson's 2024-2028 Electric Capital Plan filed July 2023, there are many programs Central Hudson will execute over the next five years that will convert areas from 4kV to 13.2kV operation or reconductor wire to reduce voltage drop. All of these projects have the added benefit of increasing hosting capacity. A significant amount of circuitry will be reconductored as a part of the copper wire replacement program, operating/infrastructure programs, and distribution automation program. Finally, the Distribution Automation/Distribution Management System projects described in further detail in DER Interconnections will allow for enhanced monitoring and control of DERs, while increasing hosting capacity. These projects will be fully designed, managed, and completed following Central Hudson's Project Management Guidelines.

b) Where and how DER developers/operators and other third parties can readily access the utility's hosting capacity information.

Hosting capacity maps are available on Central Hudson's Distributed Generation website at: http://www.cenhud.com/dg.

c) How and when the existing hosting capacity assessment information provided to DER developers/operators and other third parties will increase and improve as work progresses. This should include discussion of the transition of hosting capacity information access from the utility's current hosting capacity information portal to the statewide hosting capacity solution in development of the IEDR.

Details on how existing hosting capacity information will be provided to DER developers/operators as work progresses is described above. Additionally, NYSERDA is leading the development of the Integrated Energy Data Resource (IEDR), which will be a single statewide platform that securely collects and integrates a large and diverse set of energy-related data, including hosting capacity map data developed by the JU. The IEDR team at Central Hudson has already begun working with the hosting capacity team (Electric Planning & Interconnections and GIS) to transfer HC data to the statewide IEDR platform. Central Hudson's implementation plan for IEDR can be found within the DSIP in the Data Sharing section. For more information on the IEDR, please visit About IEDR – NYSERDA.

d) The means and methods used for determining the hosting capacity currently available at each location in the distribution system.

Central Hudson developed an interactive map that illustrates hosting capacity for its distribution circuits. The analyses presented in these displays provide the nodal level hosting capacity for distribution circuits emanating from a substation at 12kV and above. The analyses were conducted under current configurations and prior to infrastructure upgrades such as: installing a recloser or remote terminal unit at the Point of Common Coupling, replacing a voltage regulating device or controller to allow for reverse flow, substation-related upgrades including 3V0 protection, or other protection-related upgrades. Violation criteria dictating the hosting capacity at each node is provided in the pop-up display, this provides insight into which system constraint is limiting the hosting capacity. Additionally, 3V0 upgrade information is included in a separate pop-up display on the map.

For the Stage 4.0 displays, each circuit's hosting capacity is determined by evaluating the impacts of large, centralized solar PV installations (300kW and greater) along the three-phase distribution mainline. These analyses include nodal level hosting capacity and relevant hosting capacity data at the substation level, and introduced the explicit modeling of existing solar PV or energy storage.

Issues related to circuit protection require further analysis to make a definitive determination of hosting capacity. This hosting capacity data is being provided for informational purposes only and is not intended to be a substitute for the established interconnection application process. Tabulated data is included in the form of data pop-up displays to indicate the hosting capacity, dictated by violation criteria, at any given location; violation criteria include Primary Over-Voltage Deviation, Primary Voltage Deviation, Regulator Deviation, and Thermal.

The installed and queued DER values, as well as how much DER has been interconnected on each specific feeder since the last refresh, are included within the data pop-ups and are updated monthly.

Figure 53: PV Hosting Capacity Map for Central Hudson's Service Territory

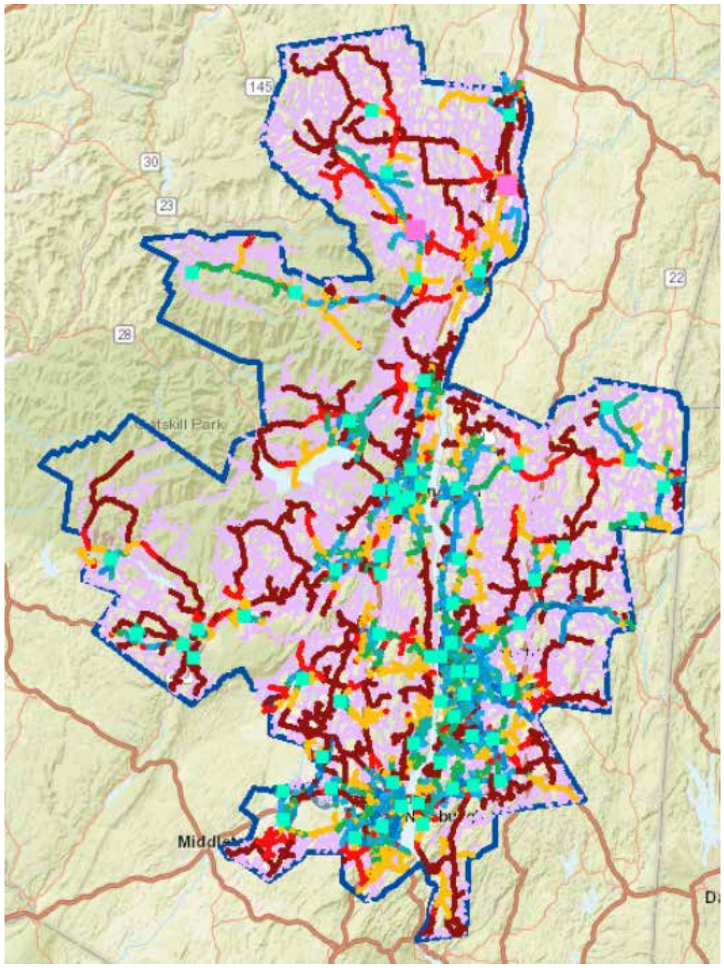
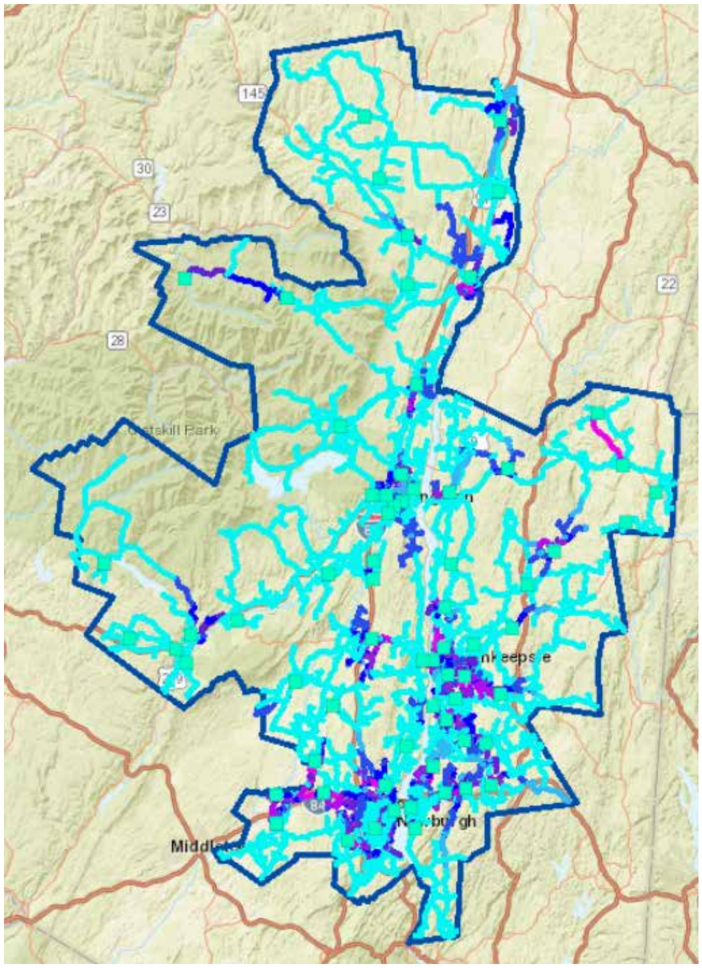


Figure 54: Storage (Charging) Hosting Capacity Map for Central Hudson's Service Territory



Once in the map, as shown in Figure 53 and Figure 54 above, a user can utilize the address search toolbar in the top left corner to zoom into a specific address and click on the primary segments displayed to bring up additional information about the circuit. This s information includes the circuit's ID, operating voltage level, number of phases, nodal minimum hosting capacity, hosting capacity value per each violation criteria, interconnected and proposed DG in queue, as well as the amount of DER interconnected since the last annual refresh. Information on substation is also provided, including the substation ID, interconnected and proposed DG in queue, prior year substation peak, substation bank thermal capacity, 3V0 protection status, and estimated 3V0 protection threshold if applicable. A legend is included in the top right corner of the map. Since the 2020 DSIP, the PV Hosting Capacity Map legend has added information about Capital Infrastructure Projects (CIP) that increase hosting capacity and the ESS Hosting Capacity Map legend allows the user to toggle between charging (load) and discharging (generation) layers.

The operating voltage may denote voltages below 12kV such as: $2.4kV_{Line\text{-}Gnd}$, $4.16kV_{Line\text{-}Gnd}$, $4.8kV_{delta}$, or $7.62kV_{Line\text{-}Gnd}$. Hosting capacity values, however, are only included for the three-phase mainline of distribution feeders, which emanate from a substation operating at 12kV and above. Voltages below 12 kV classification indicate locations served by one or two phases, or located downstream of a step-down transformer (e.g., transformation from 13.2kV to 4.16kV).

e) The means and methods used for forecasting the future hosting capacity available at each location in the distribution system.

The detailed means and methods will be determined if forecasting of hosting capacity is further defined and prioritized within the Hosting Capacity Stakeholder Sessions.

f) 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.

Central Hudson will update the http://www.cenhud.com/dg website with additional hosting capacity information and maps as they are available. Additionally, along with the Joint Utilities, Central Hudson, will host stakeholder webinars as needed to roll out new features of the analysis.

g) The utility's specific objectives and methods to:

(1) identify and characterize the locations in the utility's service area where limited hosting capacity is a barrier to productive DER development; directing users to the CGPP filing for further information and,

While the hosting capacity maps identify the approximate capacity available to interconnect solar PV and energy storage, these maps are intended to be used as a reference and do not replace the interconnection process. While some utility infrastructure upgrades may be identified as part of the interconnection process, they do not always result in a barrier to DER development.

Central Hudson is improving the System Planning Process through a transition in forecasting methodologies and the application of a more probabilistic approach to integrate DERs into the risk and growth profiles. This process will encompass both how asset replacements are determined and the methods used to optimize the portfolio of projects and programs. Also, in recognition of the State's aggressive renewable goals as identified in the Climate Leadership and Consumer Protection Act (CPCPA) and the Accelerated Renewable Energy Growth and Community Benefit Act, the Company is modifying its planning process to better align with these goals. As noted, the electric capital plan is predominately comprised of condition-based infrastructure type projects. A number of these existing projects provide incremental hosting capacity benefits and are identified as Phase 1 projects. As new project needs are studied, renewable penetration levels and potential hosting capacity improvements are included in the analysis to determine the recommended solution. Finally, as part of the NY JU's proposed Coordinated Grid Planning Process (CGPP), the CGPP is intended to identify Phase 2 projects, which are capital plans that increase hosting capacity on the local transmission and distribution system and funded under the

FERC load ratio share methodology. For more information on the CGPP proposal refer to the JU filing December 27, 2022 under Case 20-E-0197.

(2) timely increase hosting capacity to enable productive DER development at those locations, directing users to the IEDR platform when applicable for more information.

As previously described, Central Hudson currently updates hosting capacity maps on an annual basis for all circuits 12kV and above, and a bi-annual basis for circuits with >500kW DG interconnected since the last refresh. The Company also updates queue information on a monthly basis. Additionally, by July 1st of each year, as part of the Cost Share 2.0 Order, the Company identifies on the hosting capacity maps, capital investment projects that are planned for construction within two years and create additional hosting capacity beyond the system baseline. As part of NY State's Integrated Energy Data Resource (IEDR) initiative, hosting capacity data is one of the items included within this platform. As the IEDR platform is still within the nascent state of implementation, Central Hudson is not currently referring users to the platform. However, once implementation is finalized Central Hudson will refer to the IEDR platform on the Company's website. For more information on IEDR efforts visit NYSERDA's website at https://iedr.nyserda.ny.gov/.

J. Billing and Compensation

1. Context and Background

Our company, along with the other Joint Utilities, has significantly adapted our approach to the various DER-related billing and compensation programs that we maintain or have begun in the past three years. The Company currently bills and/or compensates customers under the following tariff-based/on-bill programs which are generally encompassed under the Value of Distributed Energy Resources (VDER) umbrella:

- Volumetric net metering
- Monetary net metering
- Phase 1 NEM
- Phase 1 Value Stack
- Phase 2 Value Stack
- Remote net metering
- Remote crediting
- Community Distributed Generation
- Net crediting
- Customer Benefit Contribution Charge

In addition, the Company has two additional programs generally designed for larger DERs not eligible for VDER – standby service and buyback service – however no customers are served under these programs at this time. Several additional programs are expected to be implemented in the future including:

- Volumetric net crediting
- Host Community Benefit Program
- Wholesale Value Stack
- Wholesale Distribution Service through FERC

It is important to note that setting up, testing, and maintaining each program can be complex, especially when considering interactions with other programs, so the Company continues to devote time and resources to support each of these programs from design, programming, and implementation to on-going IT and administrative maintenance. We also devote substantial work, along with stakeholders, to considering the interaction between these and other non-DER related programs such as time of use and budget billing, as well as opting-in, opting-out, switching, and banking.

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

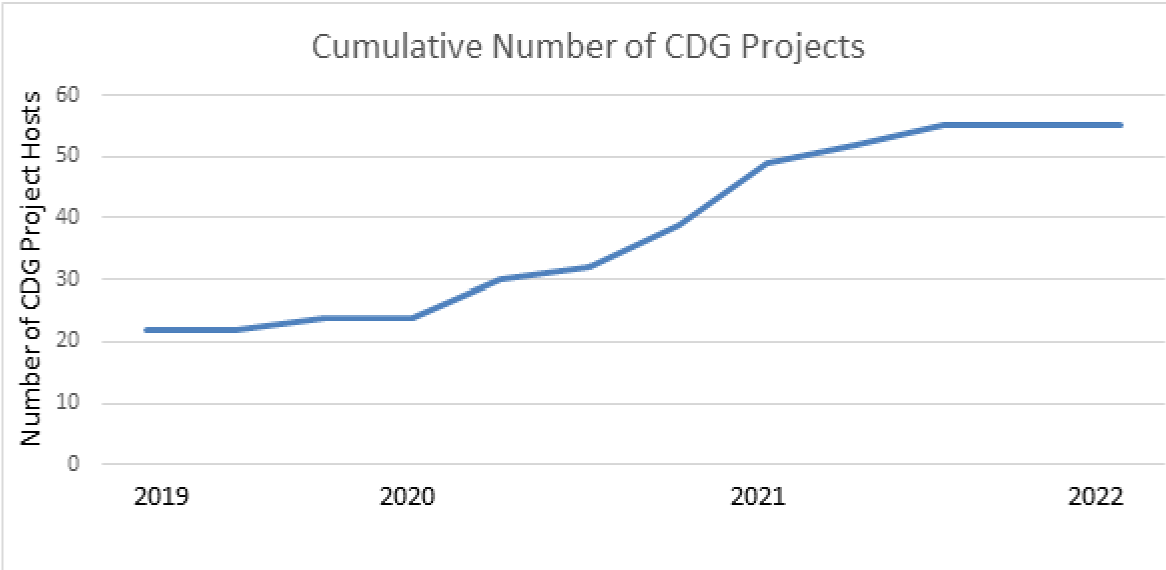
Prior to this DSIP period, the Joint Utilities had each implemented changes to their retail programs to create the Value Stack mechanism to compensate DERs based on when and where they provide electricity to the grid. This program has been operating over the course of this DSIP period, compensating enrolled resources for their eligible contributions to Energy Value (LBMP), Capacity Value (ICAP), Environmental Value (E) and Demand Reduction Value (DRV) (Central Hudson does not currently have any Locational System Relief Value (LSRV) areas). All of the JU companies have been working toward automation of the Value Stack billing process in their Customer Service System (CSS) since late 2017 upon issue of the Commission's September 17, 2017, Order on Phase One Value of Distributed Energy Resources Implementation Proposals, Cost Mitigation Issues, and Related Matters (VDER Implementation Order) in Case 15-E-0751[57]. This included the programming of all aspects of Value Stack compensation, including the multifaceted calculations of each of the Value Stack components for onsite projects, Remote Net Metered (with Remote Net Metered projects compensated via the Value Stack now converted to Remote Crediting) projects, and CDG projects, as well as the details of transferring credits to subscribers and satellites, tracking each Value Stack component in customer banks, and compiling information for both host and satellite accounts.

On October 17, 2022, the Company filed an Implementation Plan detailing its progress toward automation of crediting and billing of CDG pursuant to Ordering Clause 2 of the Commission's September 15, 2022, in Case 19-M-0463. The plan detailed the billing system constraints, the changes necessary to effectuate automated CDG billing; and the steps and timeline to achieve full automation of CDG billing.

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

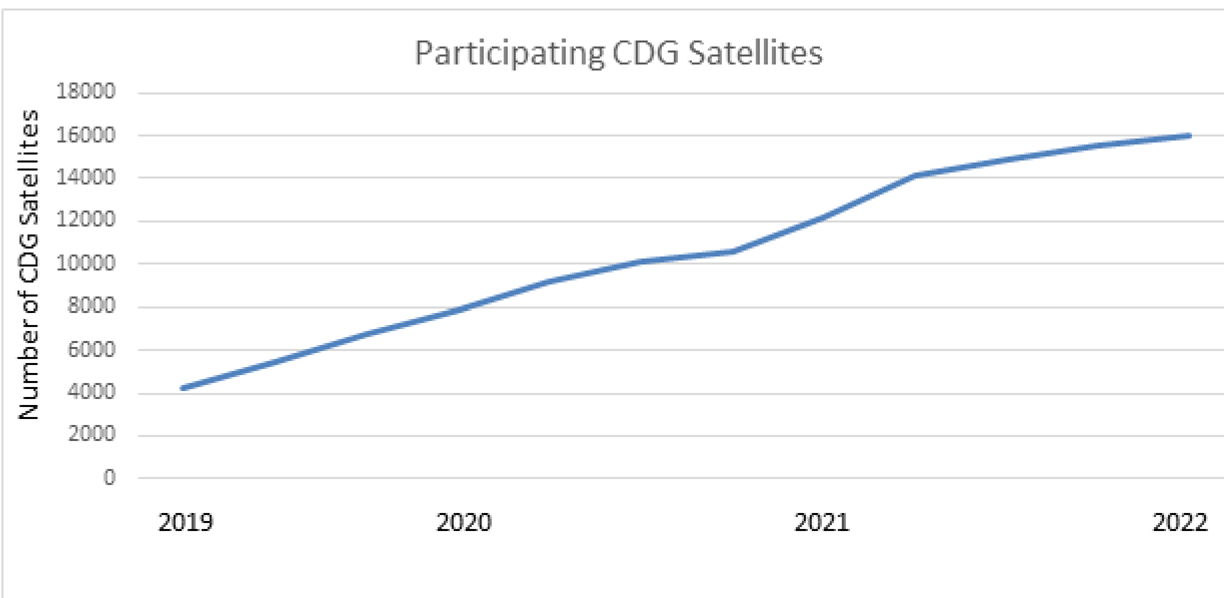
[57] https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=15-E-0751

Figure 55: Cumulative Number of CDG Projects (2019 – 2022)



Similarly, the number of customers participating in VDER CDG as satellites has also doubled.[58]

Figure 56: Participating CDG Satellites (2019 – 2022)



[58] Joint Utilities CDG Billing and Crediting Stakeholder Conference Presentation, February 27, 2023.

2. Implementation Plan

a) Current Progress

The Company was required to provide quarterly updates until automation efforts were completed pursuant to the Commission's order on September 15, 2022, in Case 19-M-0463. The first quarterly update was filed on January 13, 2023, and provided the progress on implementation. As of this filing, the Company is continuing to work toward automated CDG billing. The Company will soon implement a semi-automated process in Q3 2023 as it works on additional coding changes necessary for full automation of all aspects of CDG billing.

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

b) Future Implementation and Planning

Future implementation efforts are underway for several different programs. Wholesale market developments to address FERC Order 2222, the host community benefit program, grandfathered NEM crediting, and the new solar for all program will all be deployed by 2028. Each of these programs is discussed in further detail below.

Wholesale Market Developments

The Joint Utilities have continued to interface with the NYISO as it prepares to launch its DER market design, which FERC accepted in April 2020. The NYISO is on track to launch this new market in 2023. With FERC Order 2222 having been issued after FERC acceptance of the NYISO's initial DER market design, NYISO will launch a market in 2023 that is fully compliant with FERC Orders 2222 and 841 by 2026. Joint Utilities discussions with the NYISO have centered on developing processes and handoffs between the NYISO and the utilities in enrolling, assessing, tracking, monitoring, and compensating DER Aggregations participating in the market. Over the course of this discussion with the NYISO, the utilities have continued to evolve their own corresponding internal processes, including those related to compensation and billing systems administration. The utilities have each implemented the appropriate changes in their internal billing systems administration and are ready, from a process and technology standpoint, for the NYISO's market launch this year.

The utilities have reviewed and identified tariff changes that will be necessary to enable NYISO's 2023 market launch and its later implementation of a fully FERC 2222 and 841 compliant market. The utilities filed amended tariffs with the Public Service Commission in September of 2022 which were subsequently approved and will take effect July 1, 2023. In substance, the changes are meant to preclude dual market participants from receiving duplicative compensation in both wholesale and retail markets concurrently.

Further, the Joint Utilities are coordinating on individual filings which each utility will file with FERC to make revisions to existing/implement new Wholesale Distribution Service tariffs on file with FERC. Moving forward, the Joint Utilities will continue to interface with the NYISO as it prepares for its 2026 market launch. In parallel, the utilities will continue to assess and implement as appropriate any supporting utility compensation and billing practices to enable DER participation in the 2026 market launch.

Host Community Benefit Program

The program will provide an annual bill credit to residential electric utility customers with premises located in a renewable Host Community for each of the first ten years that a Major Renewable Energy Facility (greater or equal to 25MW) operates in that Community. The Renewable Owner of a Facility will fund the credits by paying an annual fee of $500 per megawatt (MW) of nameplate capacity for solar facilities, and $1,000 per MW for wind facilities. The fees paid by the Facility, less utility administrative fees, will be distributed equally among the residential utility customers within the Host Community. The utilities filed Implementation Plans with draft tariff leaves on September 30, 2021, as directed by the Order Adopting A Host Community Benefit Program[59], issued on February 11, 2021. The Companies await further approval by the Commission of the Implementation Plans and tariff leaves.

Grandfathered NEM Net Crediting

Central Hudson began offering Net Crediting (also known as Consolidated Billing) for monetary Value Stack customers in March 2021 providing an alternate payment and crediting methodology for CDG Hosts and CDG Satellites that eliminated the need for a separate participation payment from the CDG Satellite to the CDG Host. The program facilitates crediting the CDG Satellite's bills directly for the net credit and the paying the CDG Host the remaining value of the credit, less a utility administrative fee. However, the same program rules do not apply to grandfathered volumetric projects that currently allocate kWh to CDG satellites. The Companies are currently working with DPS Staff and stakeholders to develop an alternative Net Crediting program for these types of projects.

New Solar for All

Solar for All is a New York State utility bill assistance program for income-eligible households the opportunity to take advantage of community solar. The program provides monthly credit for participants assigned to a community solar project. In May 2023 Department of Public Service Staff issued a proposal on a new version of the Solar for All program and it is expected that Central Hudson along with the other utilities will submit comments in August 2023 and continue to work with Staff and stakeholders on this evolving program.

[59] https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterSeq=62773

3. Risks and Mitigation

The primary risk to timely implementation is the comparative challenge of making the complex changes to billing that are often needed. New programs or program requirements involve changes to the billing system. Most of New York's complex billing programs cannot be met with commercially-available customer information systems without custom programming, and each new change can interact with other recent changes or other complex billing rules to add complexity. For example, just for a single residential service classification, a customer could have the option of: 1) having on-site DER, 2) subscribing to a CDG or 3) being a satellite of a RNM. For each type of DER participation that customer could be compensated via: 1) net metering, 2) Phase One NEM or 3) Value Stack (Phase One or Phase Two). That same customer could also participate in additional programs or be subject to other charges requiring any of the following complex billing rules: 1) they purchase their supply from an ESCO, 2) they opt for budget billing, or 3) they are subject to the CBC. The more than 50 permutations of complex billing rules possible by the scenarios described would only be further complicated, for example, if the customer participated in multiple Remote Crediting projects or had their own on-site system in addition to Remote Crediting participation. For this reason, custom programming requires multiple iterations of testing – each of which needs adequate time to complete – and subsequent changes to billing can require restarting the testing process. Another consideration is that throughout the implementation process, manual shadow billing is required until new systems are verified to work as intended. Integrating large numbers of customers and being able to scale quickly for increased adoption rates before the automation process presents additional challenges.   Our company mitigates the risk of delay by engaging additional employees to complete the work and communicating with stakeholders and regulators about the process to establish a complete understanding of the steps and timeline involved.

4. Stakeholder Interface

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

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

5. Additional Detail

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

The Company offers the aforementioned VDER-related billing and compensation programs which began with Net Energy Metering and Remote Net Metering, expanded to Community Distributed Generation in 2015, and which have evolved beginning in 2017 to implement a VDER tariff to transition from NEM to Value Stack Phases One and Two and introduce several new compensation programs since then that modify or combine existing program rules.

In 2022, Remote Crediting was introduced which offered an opportunity for existing Remote Net Metering projects compensated via the Value Stack as well as for CDG projects to convert to Remote Crediting. Remote Crediting is similar to CDG but 1) limits the number of subscribers, 2) allows subscribers to also have onsite solar, and 3) provides subscribers the ability to subscribe to multiple projects.

Also in 2022, the Customer Benefit Contribution Charge (CBC) was introduced pursuant to the Commission's July 2020 Order in Case 15-E-0751 for projects interconnecting on or after January 1, 2022. The CBC is a $/kW charge on the bills of mass market customers with onsite DER and is assessed on the size of their DER system in kW DC. The CBC recovers the costs of certain public benefit programs.

Finally, effective July 1, 2023, the Company will offer an alternate version of Value Stack compensation for DERs participating in the wholesale market. Such DERs selling their energy and/or capacity directly to the NYISO may continue receiving the remaining components of Value Stack compensation without the energy and/or capacity components to avoid duplicate compensation. These changes were filed by Central Hudson in order to conform with FERC Order 2222 as discussed above.

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

Expanded use, and associated billing/compensation of, DERs in the Company's service territory are generally supported by either 1) advanced metering infrastructure for onsite projects requiring net meters or meters capable of recording hourly consumption and 2) billing system functionality to automatically calculate, bill and/or track applicable costs or credits associated with onsite billing/compensation programs or participation in remote or community crediting programs. Quite often this billing system functionality requires custom billing system coding by a utility as there are no commercially-available customer information systems that contain the necessary programming to deliver all of the unique requirements to implement the various customer billing/compensation programs directed by the Commission. Such design and development is then followed by unit testing and full system regression testing by users familiar with the complex billing program rules which can at times lead to the identification of issues that require coding revisions and a subsequent round of testing.

As described elsewhere in this DSIP filing, the Company is currently in the process of completing CDG billing automation as further described in the Company's quarterly billing automation reports filed in Case 19-M-0463.

For future planned program changes such as anticipated Standby and Buyback rate changes in Case 15-E-0751, the Host Community Benefit Program in Case 20-E-0249 or the anticipated Solar for All program, additional dependencies include a Commission order identifying the specific and final requirements of a new program and detailed tariff provisions, both of which provide the necessary detail to design and develop the billing system logic necessary to automate these complex billing and compensation rules.

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

The billing and compensation functions necessary to provide Wholesale Value Stack service will leverage existing processes currently utilized to bill and compensate customers under Phase 1 Value Stack and Phase 2 Value Stack with additional logic needed to exclude the energy and/or capacity components from such customers' Value Stack compensation. At the time of this DSIP filing the Company is working in coordination with the other utilities to prepare to file a Wholesale Distribution Service tariff with FERC in the third quarter of 2023. The Company's FERC WDS billing will leverage and rely on the Company's existing Standby Service and Buyback Service rates approved by the Public Service Commission which are subject to change as they are also the subject of a pending proceeding awaiting Commission action in

Case 15-E-0751. The Company is currently evaluating existing process to prepare for billing customers under either the WVS or WDS at such a time that the Company receives enrollment in either program.

d) Describe the utility's plans to implement or modify DER-related billing and compensation capabilities, including automation, to address the Community Distributed Generation (CDG) billing and crediting problems that were the focus of the Commission's September 15, 2022, Order in Cases 19-M-0463, et. al.[60]

As of the date of this DSIP filing the Company is in the process of completing CDG billing automation and as such files quarterly billing automation reports in Case 19-M-0463. As reported in the Company's last quarterly update on June 30, 2023, Central Hudson continues to undertake extensive efforts to address billing system constraints that are preventing fully automated billing mechanisms for some CDG projects. Extensive design, development, unit testing, and full system regression testing is required to ensure that there are no disruptions to current customer information system processes as incremental changes are made. The Company has dedicated additional internal resources to assist with this effort, and the vast majority of CDG bills are being provided in a timely manner during this transition.

Approximately 16,000 Central Hudson customers are subscribed to CDG. Of these customers, approximately 9,500 are billed under a fully automated process, including approximately 1,500 Net Crediting customers. Through the testing process, Central Hudson identified issues impacting the remaining customers that has prevented full automation. Significant programming changes are required to fully address the issues and create a more efficient and effective automated CDG Net Crediting process. In the interim, Central Hudson has implemented a semi-automated process that reduces the number of manual steps required, which is expected to limit potential impacts to billing timeliness and accuracy.

The Company is working with its development partners to resolve the identified issues, prioritizing those associated with host bank reports and budget billing customers. Central Hudson continues to review, identify, and address billing system constraints as they arise, and is committed to expeditiously resolving all ongoing CDG billing issues.

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

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

As described elsewhere in this DSIP filing, the Company is working through the final aspects of full automation of all aspects of the CDG billing and compensation process. The Wholesale Value Stack billing/compensation component of wholesale market participation will be able to leverage existing Value Stack billing/compensation programming however additional coding and testing will be necessary to incorporate automation of the inherent compensation differences between Value Stack and Wholesale Value Stack. Such design and development changes will need to be prioritized among other DER- or billing-related development. In addition, the automation of the Wholesale Distribution Service component of wholesale market participation is dependent on a final order from the Commission in the Company's pending Standby and Buyback draft rates filed in Case 15-E-0751 which the WDS rates are premised on, prioritization of WDS design and development changes among other DER- or billing-related development and final FERC approval of the WDS tariff still to be filed with FERC.

f) Describe how DER billing and compensation affects other prog rams such as budget billing, time of use rates, and consolidated billing for Energy Service Companies (ESCOs).

Billing and compensation for the various DER programs offered must also consider interaction with other complex billing rules from the perspective of program enrollment/de-enrollment, billing/crediting, tracking/reporting of data and bill display. The introduction of each new DER program will require testing of multiple scenarios combining these complex programs to ensure the interaction of complex rules from each program yield the desired billing/compensation results. Furthermore, as the utility is often the entity responsible for reporting data to multiple third party entities involved in these complex billing programs, the Company at times finds itself in a position of needing to provide additional stakeholder education to inform third party entities on how other complex billing programs may affect the data they receive on a particular customer that may participate in multiple programs.

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

The Company's Billing Process Exception Management (BPEM) workflow in its SAP CIS allows for identification and monitoring of billing exceptions for billing functions automated in the Company's billing system. New or modified billing and compensation functions would require full unit testing and system regression testing, including testing multiple scenarios and interactions with other complex billing rules as previously discussed.

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

As previously discussed, the Company participates in many stakeholder engagement sessions with customers and industry participants. The Company plans to continue to participate in such engagement sessions including webinars, workshops and working group sessions. In addition, the Company has a dedicated DER team that manages relationships with DER developers/operators and acts as the main point of contact at Central Hudson for these projects. Furthermore, the Company maintains a dedicated DER section on its website with detailed information and further information for customers on programs available to them and the applicable program rules.

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

CDG host to CH:

The host will reach out directly to Carrie Mullin (CMullin@cenhud.com) or Julia Castellanos (JCastellanos@cenhud.com) via email or phone to present any concerns or inquiries. The objective is to provide a response within 24 hours. If additional time is required, the host will be notified.

Subscriber to CH:

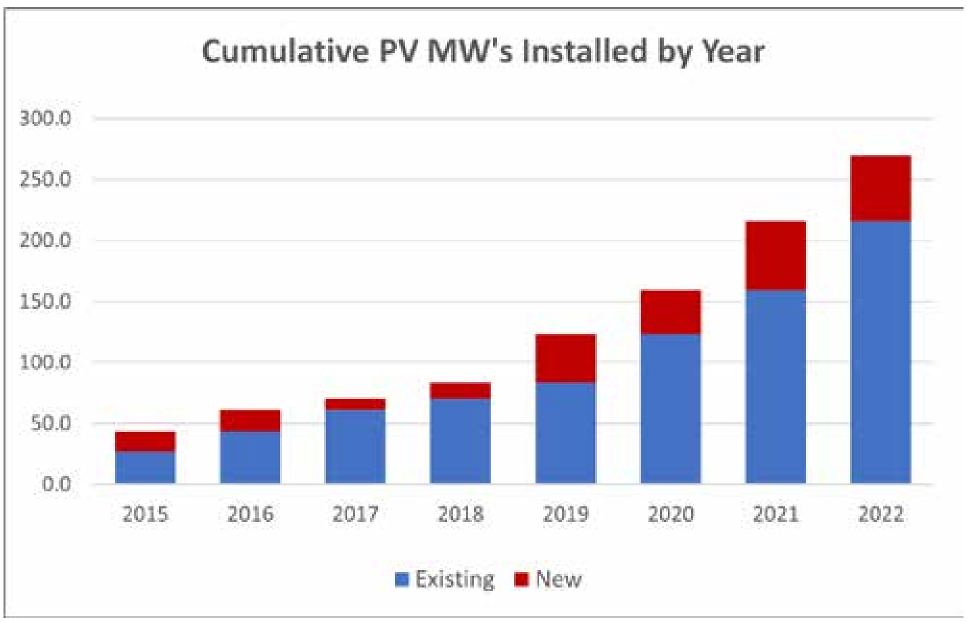
Customers will reach out to the contact center (either phone or email), to the DG email (dg@cenhud.com) or at times directly to Julia or Carrie if there has been a past interaction. When reaching out to the contact center directly (either email, phone or through the chat), there is a ticket system for escalated calls, re-routing for bill corrections, or to a specialty desk request in place to track interactions in the contact center directly. There is also the ability to schedule a callback if the customer does not want to wait on hold. If the outreach is to DG or Julia or Carrie, the same process is in place to respond within 24 hours with an update or resolution.

K. DER Interconnections

1. Context and Background

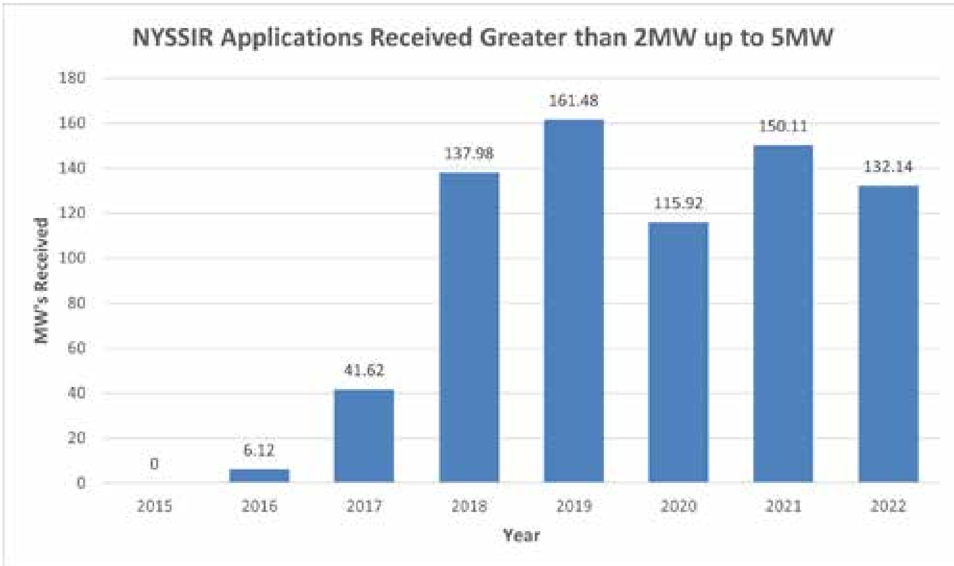
Since the 2020 DSIP filing, Central Hudson has continued to process distribution interconnection applications within the required timelines specified in the New York State Standardized Interconnection Requirements (NYSSIR). Figure 57 below shows the cumulative growth in MWs for solar photovoltaic (PV) installed from 2015-2022 through the NYSSIR. The majority of Distributed Energy Resources (DER) applications within the service territory are solar photovoltaic (PV); however, Central Hudson is also experiencing an increase of Energy Storage System (ESS) applications. In 2022, of the 55 MWs installed, 97.5% was PV, 0.2% was ESS, and 2.3% was Hybrid (PV + ESS).

Figure 57: NYSSIR PV MW's Installed 2015-2022



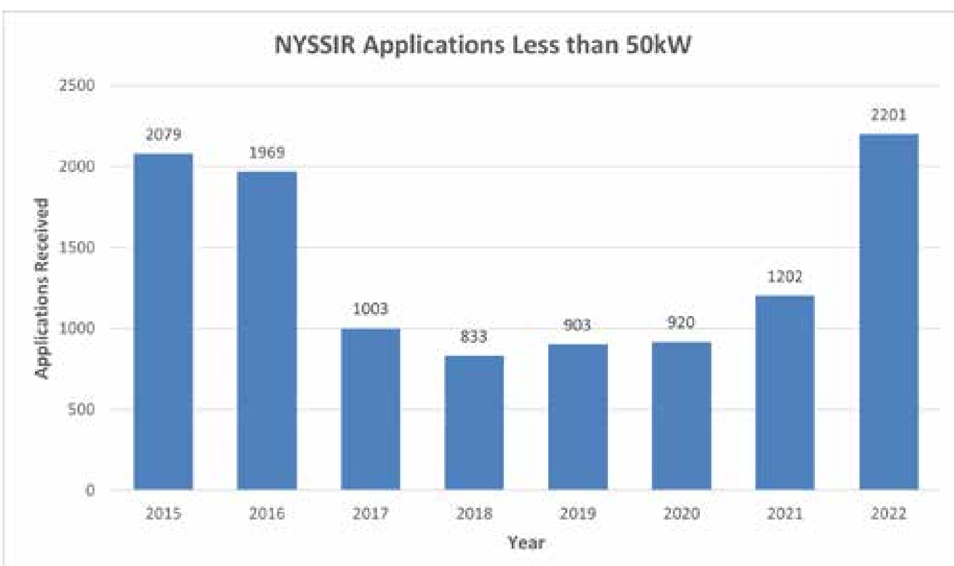
Since the 2020 DSIP, Central Hudson has continued to see a relatively high volume of large applications. Figure 58 below illustrates the total number of MWs of interconnection applications that Central Hudson has received under the NYSSIR for system sizes between 2MW and 5MW from 2015-2022.

Figure 58: NYSSIR Applications Received Greater than 2MW up to 5MW



It is also worth noting that in 2022, Central Hudson received the highest number of <50 kW interconnection applications in a calendar year: 2,201 applications. Some suspected drivers include residential customers applying for PV interconnections to gain energy independence due to energy supply cost volatility, as well as new residents to the Central Hudson territory that purchased homes during 2021 and 2022 were eager to install solar panels. Figure 59 below illustrates the total number of <50kW interconnection applications that Central Hudson has received under the NYSSIR between 2015-2022.

Figure 59: NYSSIR Applications Less than 50kW



In addition to applications submitted through the NYSSIR, Central Hudson has seen a steady amount of NYISO interconnection requests; these requests, however, have increased in size and changed from largely PV to largely storage. Table 42 below illustrates the number of interconnection and pre-application requests received over the last ten years. Prior to 2018, the Company processed approximately 295MWs of proposals; from 2020 to present, the Company has experienced approximately 2,177MWs of interconnection requests. Approximately 2,300 MW of projects are in various stages of activity.

Table 42: NYISO Interconnection and Pre-Application Requests

Year	Interconnection Requests	Pre-Application Requests
2009	1	0
2010	0	0
2011	0	0
2012	0	0
2013	0	0
2014	2	0
2015	0	0
2016	3	0
2017	6	8
2018	9	5
2019	10	9
2020	9	7
2021	8	1
2022	8	8

NYISO has initiated a discussion on interconnection process reform; this is in part in response to the FERC's NOPR on Improvements to Generator Interconnection Procedures and Agreements and in part to attempt to make the interconnection process more efficient. The NYTOs have been providing NYISO with comments and suggestions. This reform process is in the early stages and will require Market Participation consensus and NYISO Tariff filings.

While the majority of interconnection activity has been under the NYSSIR and NYISO processes, Central Hudson has also seen an interest in applications >5MW that fall outside of the NYSSIR and NYSIO and within the Company's Utility Process. Table 43 lists the number of applications received since 2018.

Table 43: Utility Projects Interconnection Application Requests

Year	# of Applications Received
2018	1
2019	10
2020	3
2021	3
2022	1

While NYISO projects follow a separate process and have primarily proposed to interconnect to the transmission system, some of these DER systems have requested service on medium voltage substation buses. In the weaker portions of the transmission system, these substation and transmission level interconnections can limit the hosting capacity of DERs on feeders, even in locations where the hosting capacity of the feeders has not been exceeded. The Company is experiencing increased penetration levels in localized areas of the service territory. This complicates the review process and presents queue coordination issues (i.e., coordination among the NYSSIR, New York Independent System Operator ("NYISO"), and Central Hudson queues). To resolve the queue coordination issues, Central Hudson worked with the NYISO, other New York Transmission Owners (TOs), and DPS Staff to establish a guideline on base case inclusion rules that helps facilitate coordination among the various interconnection queues. A straw proposal, Coordination of Inclusion Rules for Interconnection Queues[61] ("Inclusion Rules"), was completed in December 2018. Stakeholder input was received from members within the ITWG and IPWG. As Central Hudson has seen a high penetration of DER projects within localized areas, the Company has been applying the Inclusion Rules to each of the three queues.

Since the 2020 DSIP update, Central Hudson has continued to maintain and improve the Interconnection Online Application Portal (IOAP) described further below in Section E. This portal was initially established to meet the requirements of Phase 1 Automating Application Management within the PSC's March 9, 2017 DSIP Order[62] (DSIP Order). The IOAP continues to successfully run and allows DER developers to submit interconnection applications electronically. Various IOAP updates have been completed since the 2020 DSIP update to account for NYSSIR updates, including Cost Share 2.0 effective April 2022. As a result of the continued enhancements and required updates, a full-time Program Designer is employed to manage and maintain updates in the IOAP.

In addition to performing the day-to-day responsibilities associated with interconnections, Central Hudson also has an active role in collaborative working groups, including the Interconnection Technical Working Group (ITWG) and Interconnection Policy Working Group (IPWG). Since the 2020 DSIP, these groups have met on a monthly basis, focused on modifying interconnections requirements and processes based on industry concerns and benchmarking with other utilities outside of NY. These groups have also worked together to develop various joint guidelines and regulatory filings and have allowed for modifications to existing interconnection requirements including:

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[61] "Straw Proposal Coordination of Inclusion Rules for Interconnection Queues", December 31, 2018, http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/def2bf0a236b946f85257f71006ac98e/$FILE/Straw%20Proposal-Coordination%20of%20Inclusion%20Rules%20for%20Interconnection%20Queus%20-%20Draft.pdf

[62] "Order On Distributed System Implementation Plan Filings", State of New York Public Service Commission, March 9, 2017, Case 16-M-0411, http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={F67F8860-0BD8-4D0F-80E7-A8F10563BBA2}, pp. 15-18.

- Evaluating appropriate technical screens for updating the NYSSIR, including voltage flicker impacts

- Provided a comprehensive CESIR analysis evaluation to give developers a better understanding on how interconnection applications are studied under the CESIR process

- Submitting a joint proposal between NY Utilities and DER Developers for an updated NYSSIR, identified as "minor modifications" which included updates to incorporate IEEE 1547-2018 smart inverters and UL 1741 SB requirements, non-emergency disconnection considerations, and mid-point construction estimate updates; this was subsequently effective May 2023

- Made progress on understanding effective grounding practices and policies for DER, including adopting EPRI's recommended practice Development of a Voltage Regulator Subgroup to help stakeholders better understand how regulator tap operations are affected by DERs

- Established different metering options and configurations for hybrid systems

- Updated the DER technical guidance/requirement matrix and created a cost matrix to provide developers with insight into relevant costs associated with interconnection of DER

- Released bulk power and voltage support settings for smart inverters based on IEEE 1547-2018 requirements, as well as collaborated with EPRI and Industry to develop a standard file settings format

- Submitting a joint proposal between NY Utilities and DER Developers for updating the NYSSIR's Cost Share Mechanisms, identified as Cost Share 2.0; this was subsequently implemented effective April 2022 and the JU and Industry continue to discuss its effectiveness and potential modifications

Lastly, since the 2020 DSIP filing, Central Hudson has continued to maintain and improve hosting capacity maps for feeders above 12kV. Details regarding Hosting Capacity efforts and results can be found in Section III.B.

2. Implementation Plan

a) Current Progress

Central Hudson continues to refine and improve the IOAP as more experience is gained, using the software and new updates provided by Clean Power Research. Since the 2020 DSIP, Central Hudson has implemented the following improvements to the portal; added the next step and new deadline details to the bottom of each external form to provide applicants with further insight into the progression of their interconnection application, screen results were enhanced with an additional description, CESIR screen result tracking was setup to report quarterly to ITWG, and Cost Share 2.0 requirements were integrated where applicable.

As the April 19, 2018 PSC Order[63] directed the NY Joint Utilities to begin efforts for Phase 2 implementation of the IOAP, Central Hudson began working with Clean Power Research on the scope of work for integrating PowerClerk with DEW in April 2018. One of the prerequisites to meeting Phase 2 requirements was to establish a link between the Distribution Engineering Workstation (DEW) load flow software and Central Hudson's ESRI GIS system. This link was implemented in April 2019. The goal of Phase 2 of the IOAP is to automate the technical screening analysis, such that when a customer submits an application using the PowerClerk software online, the IOAP will link to DEW, pull the correct circuit model from Central Hudson's server, and run a load flow analysis to compute the results for Preliminary Screens A to F in the NYSSIR. These results will are then be transferred back to PowerClerk. This work required construction of additional fields and statuses within the IOAP as well as the development of various use cases to be tested in order to ensure the automation is working as intended. The mechanisms used to automate the applicable NYSSIR screens are currently in place. Central Hudson is upgraded to a new ESRI GIS version which required the link to DEW to undergo additional quality assurance testing. Final acceptance testing and a move into production is expected to take place by the end of July 2020. Central Hudson completed the Interconnection Online Application Portal (IOAP) functional specification Phase 2, to implement automation of the SIR preliminary screens in November 2020. Full automation however, will be in service once ESRI GIS model quality assurance is complete.

While Central Hudson, along with the Joint Utilities, have already made significant progress in improving the interconnection process in collaboration with working groups such as the ITWG and IPWG, Central Hudson continues to work with these groups to address developer and stakeholder concerns. The most current and upcoming topics for discussion within these groups include:

- Smart Inverters including verifying UL-1741 Supplement B certification and setting requirements as well as leveraging smart inverters for monitoring and control capabilities
- Cost Share 2.0 implementation, including any necessary refinements
- Revised 2023 energy storage roadmap, including use case discussions and study constraints
- Flexible interconnections including current pilot/demonstration projects
- Letter of credit in lieu of cash deposits

In partnership with the NY JU, Central Hudson implemented Stage 3.5 and 4.0 Hosting Capacity to provide nodal hosting capacity analysis, violation criteria values, as well as established a brand-new Energy

[64] "New York Interconnection Online Application Portal Functional Requirements", Electric Power Research

Storage Hosting Capacity map, first released April 2021. Details on current hosting capacity efforts can be found in Section III.B.

Due to changes related to effective grounding requirements and smart inverter functionality, Central Hudson recognized the need to update the Company's Interconnection Guidelines. Central Hudson will complete the update of the interconnection guidelines in Q3 2023. The updated document will be publicly posted on the Company's Distributed Generation website for reference by developers. This updated document also will be filed with FERC as part of the next 2024 Form 715 filing. Developers now have a more accurate technical guidance document for connecting to the Central Hudson system. Central Hudson plans to update these guidelines as needed.

Since the 2020 DSIP update, the Joint Utilities have mandated the requirement for inverter-based interconnection applications submitted after January 1, 2023 to have smart inverter functionality by requiring UL-1741 Supplement B certification and specific smart inverter settings related to reactive power support (volt-var curve), voltage and frequency ride through capability, enter service criteria, and frequency droop. Central Hudson's specific smart inverter settings can be found here CenHud_Smart_Inverter_Settings_Required_20230101.pdf (powerclerk.com) and will be incorporated into the updated Interconnection Guidelines. The UL-1741 SB and smart inverter mandate was largely driven by the NYISO which has concerns of grid stability during voltage and frequency events that may trip off hundreds of MWs of inverter-based generation. The NY DPS and Developers have been included in discussions surrounding the smart inverter mandate and specific NY JU settings since 2021 via the ITWG. As smart inverter settings are dynamic and affect the process for studying DER systems as part of the CESIR, Central Hudson has currently been working through identifying the appropriate way to study these systems in a static nature. The move to implementing a new load flow software as identified in Section III.A. Integrated Planning, is anticipated to improve the modeling capabilities of smart inverter settings.

As part of the JU Monitoring and Control (M&C) working group, since the last DSIP the JU collaborated to develop monitoring requirements documents to describe the key monitoring parameters and points required from inverter-based resources. The JU anticipate publicly releasing this document in 2023. This development of this document is aligned with the JU's goal of potentially using smart inverters as a low – cost monitoring solution. The JU are also currently re-examining the "Monitoring and Control Requirements for Solar PV Projects in NY" document for appropriate edits. The JU anticipate releasing a revised version of this document in 2023.

For systems >5MW that fall outside of the NYSSIR and NYISO processes, Central Hudson currently has a DER Project Manager to oversee these Utility Projects. Since the 2020 DSIP, Central Hudson established an application process for these systems and published the document in November 2020. The application process can be found at the following link: https://www.cenhud.com/globalassets/pdf/my-energy/dg/application-process-for-der-greater-than-5mw-2022.pdf. While the Utility Process is not subject to NYSSIR requirements, Central Hudson is currently in the process of working to establish a new

PowerClerk program, to accept these applications through the IOAP. This will not only improve the visibility and ease of submitting an application for developers, but will also provide efficiencies and better tracking for Central Hudson. Central Hudson will begin mapping workflows and processes for the Utility Projects starting in Q3 2023.

Lastly, Central Hudson has been preparing for the commencement of NYISO's Wholesale Market Aggregation as enabled by FERC 2222. While the application and requirements fall under NYISO jurisdiction, Central Hudson has established an internal process for reviewing the eligibility of proposed aggregations, as well as safety and reliability of the electric system due to aggregations. The Company is also in the process of establishing a landing page specific to FERC 2222 which will be available on the Company's Distributed Generation website starting in June 2023. The website will provide a high-level overview of wholesale market aggregation as well as details on transmission node IDs, telemetry requirements, and contact information for questions.

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

b) Future Implementation and Planning

Future work regarding interconnections will require integration with distribution planning functions as well as further integration with utility systems. This level of integration however, first requires the completion of other on-going initiatives, such as the development of software tools identified in Section III.A. Integrated Planning as well as feedback from stakeholders. Hosting capacity as indicated in Section III.B, as well as stakeholder prioritization of DER concerns, will drive future requirements in regards to interconnections.

As the JU continue to interconnect DER across the state, available hosting capacity may diminish and future interconnections may require more costly electric system upgrades. While Cost Share 2.0 was established to reduce the burden of high interconnection costs borne by one developer, flexible interconnections have also been raised by developers as a potential solution. While each utility and developer may define flexible interconnections differently, on the surface, the concept of flexible interconnections allows the utility to curtail the power output of an interconnection when grid constraints or violations are identified, i.e., curtail DER by 500 kW when a substation transformer's reverse power flow thermal limit is approaching. Enabling a flexible interconnection with curtailment capability may eliminate the costly upgrade of the substation transformer and still allow the DG to interconnect; however, it's complexity requires a significant change to the way DERs are currently handled and studied as part of the NYSSIR interconnection process today, as well as requires an economic determination by the Developer. In addition, in order to offer Flexible Interconnections across the service territory, a Distribution Energy Resource Management System (DERMS) will be required. Central Hudson is commissioning an ADMS and included in the roadmap is the implementation of a DERMS starting in

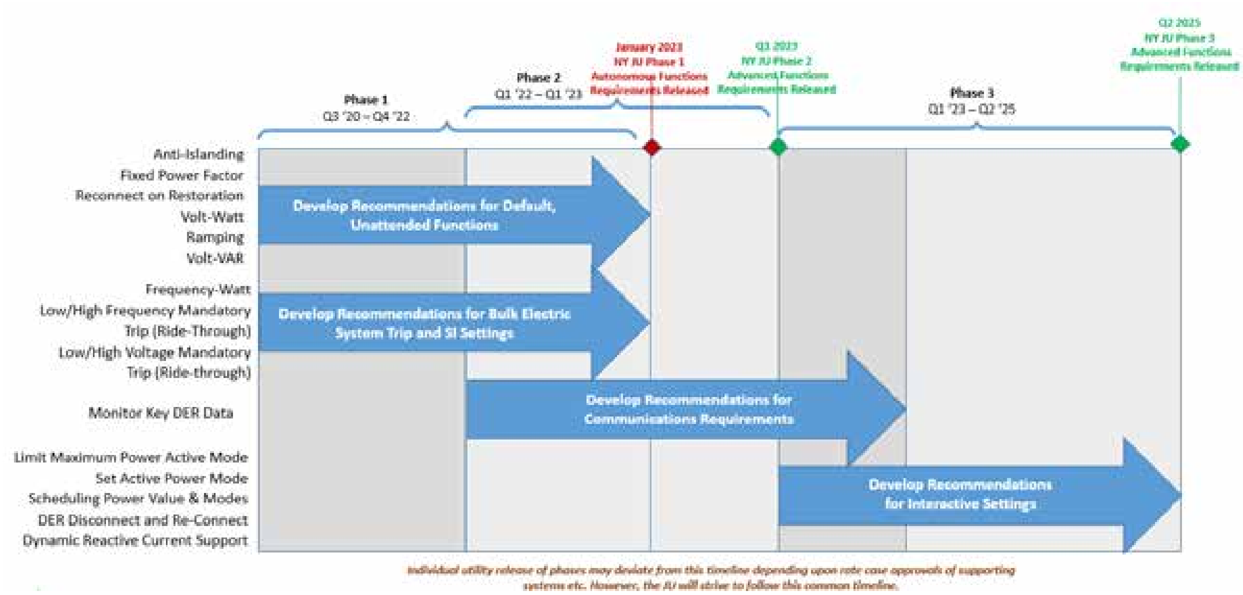
2027. Understanding that implementing a DERMS is needed in the future, in 2021 Central Hudson joined an R&D pilot project in partnership with EPRI, Smarter Grid Solutions (SGS), GE, and Nexamp to evaluate corrective vs. predictive DERMS as well as demonstrate the DERMS capabilities via a field demo. EPRI is overseeing the project and received funding from NYSERDA via PON 4128. GE is demonstrating predictive DERMS within the EPRI test lab environment and SGS is demonstrating the corrective DERMS through a field demo between Central Hudson and the PV site owner, Nexamp; field demo is expected to begin July 2023. The results of this R&D project will help inform Central Hudson on the steps required to implement a DERMS as well as consider flexible interconnections as a solution in the future.

In addition to discussing flexible interconnection as part of the ITWG, the discussion of energy storage will continue to be a significant topic. The JU and ITWG will continue to dive into the predominant use cases of energy storage, balancing the complexity that comes along with studying each individual energy storage system under their own operational schedule vs. identifying specified time periods for storage assets. The goal of these discussions is to enable higher penetrations of energy storage onto the electric system, while also ensuring utilities can successfully manage and track these systems.

The JU will continue efforts and discussions related to the use of smart inverters on the distribution system including identifying any potential smart inverter setting adjustments that may arise as the JU become more familiar with how these settings affect the electric grid. The JU roadmap for smart inverters can be found in Figure 25 below. The JU have also embarked on discussions for the most appropriate means of verifying the site performance requirements and settings of DER systems, in alignment with the requirements of IEEE Std 1547-2018. The performance requirements as specified in IEEE Std 1547-2018 require DER systems to meet the performance criteria at the Reference Point of Applicability (RPA) which may result in the need for supplemental DER system equipment to monitor and enforce the appropriate performance requirements. The JU will examine the requirement for DER system Power Plant Controllers to effectively meet the RPA requirements per IEEE Std 1547-2018.

Additionally, within the M&C working group, the JU have embarked on discussions for the appropriate control use cases (from a utility perspective) and the associated smart inverter functions that enable these use cases. While the M&C working group established key monitoring parameters and points required from inverter-based resources starting in 2022, Central Hudson will internally require additional time to work through the requirements related to integration of these systems with DMS/DERMS. Additional research and considerations are also required related to cybersecurity concerns.

Figure 60: JU Smart Inverter Roadmap



Similar to current implementation efforts, future implementation efforts support stakeholder needs and state clean energy goals by resulting in increased efficiency in the interconnection application and study processes, which in turn result in increased volumes of DER interconnections. The development of low – cost monitoring and control solutions for DER results in economic benefits to developers. Future implementation of smart inverters and DMS/DERMS functionality are anticipated to provide additional flexibility and higher integration of DERs.

Central Hudson's implementation of a new load flow software will provide efficiencies in analyzing DER interconnections including smart inverters, applicable timeseries analysis as well as hosting capacity analysis which all support the integration of DER. As part of enabling flexible interconnection in the future, there is significant work involved in both the policy and technical side. This includes investments in a DERMS, as well as well as changes to the NYSSIR in contractual obligations and study requirements.

While some of the initial conversations on flexible interconnections have begun as part of the ITWG and IPWG, this will require continued efforts over the next few years. Central Hudson currently plans to initiate the implementation of a DERMS starting in 2027, with some pre-planning efforts starting in the second half of 2026. For timing related to the smart inverter roadmap, see previous section B.i. Timing related to the integration of the new load flow software is anticipated to be completed in Q1 2024 for Phase 1.

The CGPP and DSIP are filings with overlapping but distinct scope. The CGPP will detail the evolution of distribution planning processes needed to meet CLCPA goals, align with transmission planning processes, and ensure that planning is integrated. The DSIP describes implementation of the much broader set of DSP activities and projects, and how those activities holistically align with CGPP and CLCPA goals. The CGPP will be more singularly focused on a process to identify distribution system needs to meet CLCPA State goals and develop a distribution investment plan, including capital projects, to meet those needs.

Planned capital investments, including technology platform investments and how they will be leveraged will be included in the DSIP (e.g., AMI, automation, ADMS, etc.) and the results of executing the processes will be used to inform the CGPP. Additionally, an understanding of the existing DER, particularly those sites already interconnected or considered firm, will be an important input into the analysis as part of the CGPP.

The CGPP is aimed at developing a "CLCPA-focused planning process," including "the State's bulk transmission, local transmission, and distribution planning processes." The goal is to improve planning processes to better coordinate the studies performed by the Utilities with the NYISO's bulk-power system planning and generation interconnection processes; improve the integration of Local Transmission and Distribution (LT&D) and bulk system studies with NYSERDA's renewable generation and storage procurements; and improve forecasting of renewable generation development for specific locations on the LT&D and bulk transmission grid. As part of the December 2022 CGPP proposal, one of the key inputs to the CGPP process is the generation build-out scenarios identified by the Energy Policy Planning Advisory Council (EPPAC). While forecasting practices for the CGPP and DSIP are aligned, the scenarios identified by the EPPAC may result in different forecasts than those completed as part of the DSIP. The output of the CGPP thus may result in the identification of Phase 2 capital projects that are not already identified in current rate plans. Although capital projects identified within the CGPP are intended to be funded under the FERC load ratio share methodology, these Phase 2 projects once approved will be incorporated and used to inform the normal DSIP and interconnection processes. This includes ensuring any upgrades identified as part of the CGPP that DER interconnections may benefit from are included within appropriate interconnection analyses.

c) Integrated Implementation Timeline

Refer to Figure 8 under Grid Modernization to for the implementation timeline related to DER Interconnections which includes efforts and investments as part of Integrated System Planning, Clean Energy & Decarbonization, and Grid Modernization.

3. Risks and Mitigation

Application volume for interconnections continues to vary significantly depending on regulatory changes, new initiatives, or customer demand. Drivers for volume fluctuations include NYSERDA incentives, policy changes, economics, and technology. As anticipating the volume at any given point is challenging, there are potential risks in maintaining the appropriate level of resources to be able to handle a rush of applications. Additionally, as previously mentioned, Central Hudson has seen a recent increase in smaller applications <50 kW. These applications increased in complexity with the UL-1741 SB requirements after January 1, 2023. In addition, the rise in interest in battery storage integration and hybrid (ESS + PV) systems continues to pose new challenges for the Company, in both interconnection review and future planning. As the number of smart inverters and energy storage projects increase, the complexity of the CESIR study process will also increase. The JU may need to also develop new procedures to verify ESS settings, control schemes and ensure that these are appropriately documented. Central Hudson's move to a new load flow software is anticipated to support the complexity of studying these systems. The JU will also continue to stay in touch with each other and DPS, Industry and other stakeholders to proactively identify and address issues.

Over the years, the Company has managed the fluctuation in applications by maintaining flexibility in shifting internal resources within the Company, as well as externally, to be able to support the interconnection processes. However, a rise in larger applications, as well as NYISO projects, will require greater participation with additional engineering groups within the Company, this creates a challenging work planning scenario. Based on CLCPA goals, it is anticipated that the Company will continue to experience an increase in the level of proposed and completed interconnections to the system on both the distribution and transmission level.

In addition to the incremental work associated with the actual interconnections, the Company continues to invest resources in associated processes and systems. This type of work includes the development and enhancement of hosting capacity maps and continued alterations to the Company's IOAP to stay in-sync with NYSSIR updates and reporting requirements. These factors are increasing the resource requirements required to process, review and study these interconnections.

4. Stakeholder Interface

Stakeholder interface and feedback has continued to be a significant focus for interconnections since the 2020 DSIP was filed. The ITWG meets on a monthly basis to provide stakeholders with the ability to discuss topics of concern regarding interconnections, specifically relating to technical aspects. The IPWG group has also continued to meet on a monthly basis and provides DER developers the ability to voice administrative or policy-related issues. ITWG and IPWG meetings are open to the public and consist of representatives from each of the NY JU, DPS Staff, DPS consultants, NYSERDA, project developer/industry representation as well as trade groups and associations and equipment manufacturers as necessary.

While these groups enable discussions and changes related to updating regulatory documents like the NYSSIR, they also facilitate mutual agreement and standardization of technical requirements such as flicker screening, as previously discussed in the sections above. In addition, the Joint Utilities have held numerous Hosting Capacity stakeholder engagement meetings. These meetings have led to the progression of the hosting capacity maps discussed in Hosting Capacity. Central Hudson will remain active within the ITWG and IPWG. Topics of interest which will be discussed on upcoming working group agendas are included above.

The JU leads for the ITWG and IPWG meet on a regular basis with DPS Staff and the Industry group's liaison. This activity helps to set the agenda for the monthly public meetings, identify new topics for discussion, identify any issues as they arise, and ways to address these issues. The JU members meet on a weekly basis to discuss relevant topics and deliverables as part of the upcoming monthly ITWG and IPWG meetings as well as to inform the JU lead as part of DPS Staff and Industry Liaison call.

Relevant materials are posted online prior to ITWG/IPWG meetings and are available for download. The JU will continue to update the technical documentation on the ITWG website, to ensure that stakeholders and project developers are provided with the latest information.

As the JU progresses in its efforts to integrate increasing quantities of DER, the JU will seek to continue to receive information from Industry regarding specific pain points and justification for new requests.

After new practices or process updates are implemented as part of ITWG and IPWG discussions, these topics are typically revisited shortly after implementation to identify the success of the changes or need to continue to refine solutions to meet the needs of all participants. Examples of this include updated flicker screening as well as Cost Share 2.0.

5. Additional Detail

a) A detailed description (including the Internet address) of the utility's web portal which provides efficient and timely support for DER developers' interconnection applications.

In early 2017, Central Hudson began soliciting Request for Proposals from third party software vendors in order to obtain new interconnection software that would meet the requirements listed in EPRI's IOAP Functional Requirements[64]. This software was purchased to replace Central Hudson's previous web portal that was developed in-house. Central Hudson's new Interconnection Online Application Portal (IOAP) went live on September 26, 2017. It can be found by accessing the following direct link: https://cenhuddg.powerclerk.com/MvcAccount/Login, or by visiting Central Hudson's Distributed Generation page at https://www.cenhud.com/dg.

While Central Hudson previously worked to improve the interconnection process internally, the Company ultimately decided to pursue the PowerClerk software created by Clean Power Research (CPR) to meet the requirements in the PSC Order and provide a more streamlined, user-friendly experience. Based on the interconnection portal gaps identified in the Initial DSIP, the new IOAP using PowerClerk addressed these gaps and provides better features for the application process and enables the applicant to have more visibility into the process. New updates to the IOAP since the 2020 DSIP, include but are not limited to:

[64] "New York Interconnection Online Application Portal Functional Requirements", Electric Power Research Institute, September 2016, http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/dcf68efca391ad6085257687006f396b/$FILE/EPRI%20Task%201%20Memo%20Report_Final%209-9-16.pdf.

- Additional notification automations (payment received, transformer upgrade complete & Customer eSignature received);
- Ability for Applicant to withdraw application and commence reconciliation process, if applicable;
- Ability for Applicant to correspond with Utility directly in their PowerClerk interconnection project application;
- Project Reassignment Request added;
- Auto populated detailed estimated construction payment receipt with compensation eligibility;
- Automated email sent to Applicant if submitting an expansion application, notifying that their Value Type may change;
- Added the next step and new deadline details to the bottom of each external form to provide applicants with further insight into the progression of their interconnection application;
- Preliminary and Supplemental Screen results were enhanced with an additional description, next step and associated deadlines;
- Cost Share 2.0 requirements and other various NYSSIR updates were integrated where applicable

b) 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:

(1) DER type, size, and location;

(2) DER developer;

(3) DER owner operator;

(4) DER operator;

(5) the connected substation, circuit, phase, and tap;

(6) the DER's remote monitoring, measurement, and control capabilities;

(7) the DER's primary and secondary (where applicable) purpose(s); and,

(8) the DER's current interconnection status (operational, construction in-progress, construction scheduled, or interconnection requested) and its actual/planned in-service date.

Central Hudson's IOAP provides DER developers with the ability to submit applications anytime, at their convenience. The IOAP itself provides the appropriate safeguards to ensure only developers who are given authority to act on a customer's behalf can view a particular customer's information. The PowerClerk software also uses secure logon with appropriate encryption to ensure the privacy of customer data. Employees within the Electric Distribution Planning group actively monitor applications as they come in on a daily basis and provide updates to the IOAP as part of the normal NYSSIR process to ensure the IOAP is maintained with up-to-date information. The following information is available within the IOAP:

- DER type, size, and location;
- Net-Metering type proposed by applicant and associated compensation eligibility;
- DER developer, agent, or contractor;
- The connected substation and circuit;

- Current interconnection status

The bulleted information above is also posted monthly on the NY State Department of Public Service website under Matter Number 13-00205 and is known as the Monthly SIR Inventory Report. This informational report redacts customer confidential information and can be downloaded for public use. This New York State Department of Public Service website also includes a link to the NYISO Planning Services & Requests website which contains links to interconnection documents and the interconnection queue; the NYISO's interconnection queue links back to the New York State Department of Public Service NYSSIR inventory website.

Central Hudson does not track instances where the DER owner and DER operator may be different entities. Third party lease agreements are between the DER developer and utility customer and do not impact the interconnection process, particularly when the utility customer provides the DER developer with authority to act on their behalf. The IOAP also does not provide developers or the general public with information on the primary and secondary purposes of DER system, as the primary means for interconnection for the majority of applications received under the NYSSIR are to offset load and receive compensation per the Value of Distributed Energy Resources. However, Central Hudson's IOAP does track when the use of more than one generator is provided, such as a battery storage system being installed for backup, as well as the type of net-metering system including Community DG or remote net-metering.

Central Hudson's Solar PV Hosting Capacity Map and Energy Storage Hosting Capacity Map are public resources available to developers or stakeholders, for use in determining a distribution circuit's potential hosting capacity within Central Hudson's territory. In addition to hosting capacity, the map also provides pop-up information to indicate what substation, circuit, and operating voltage currently exists at each feeder location. The following information is also available within the pop-up: interconnected and in-queue DG information for the feeder and substation, substation transformer peak load information, and 3V0 upgrade status.

Monitoring and control capabilities for each individual DER system are not provided as public information. However, current monitoring and control requirements can be found on the NYS Public Service Commission's Website under the Interconnection Technical Working Group. As of September 2017, these conditions require DER systems with nameplate ratings 500kW and above to have monitoring and control capabilities, which can be satisfied by installing a Point of Common Coupling (PCC) Electronic Recloser at the DER site. For systems smaller than this, monitoring and basic control may be required depending on system conditions and technical evaluations. The NYISO has additional requirements for resources participating in NYISO markets. Details of these requirements and processes may be found in the NYISO's Transmission Expansion and Interconnection Manual, as well as NYISO Open Access Transmission Tariff (OATT) Attachments X, S, and Z.

c) The utility's means and methods for tracking and managing its DER interconnection application process to ensure achievement of the performance timelines established in New York State's Standardized Interconnection Requirements.

With Central Hudson's IOAP software, Central Hudson has mapped out the entire interconnection process, from the initial application submittal to final interconnection and ultimately reconciliation. Through the use of various workflows and forms, the IOAP provides timestamps and application statuses to ensure applications are tracked and managed in a timely manner and as required by the NYSSIR. The utility login page of the IOAP provides a layout and breakdown of all applications statuses and type, such as application reviews, pre-applications, and CESIR study that allow Central Hudson's Engineering Technicians and Contractors to easily track the approaching deadlines for each of these projects. The IOAP is also setup to provide internal and external e-mail reminders for upcoming due dates, based on the timelines listed in the NYSSIR. Employees within the Electric Planning and Interconnections group actively monitor applications as they come in on a daily basis and provide updates to the IOAP as part of the normal NYSSIR process to ensure the IOAP is maintained with up-to-date information.

To ensure each member within the group, including new employees, have an understanding of NYSSIR timelines and importance of consistently meeting them, Central Hudson has developed detailed documentation on the process flow, including current automations within the IOAP, as well as a guideline on reviewing applications under the NYSSIR for training purposes. As the NYSSIR is updated based on ITWG/IPWG collaborations, these revisions are reviewed thoroughly and the IOAP is updated accordingly.

d) 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.

Central Hudson's IOAP allows applicants and other appropriate stakeholders to create an IOAP account in order to login and view the status of their application in real-time. Automated e-mails are also sent to applicants to inform them of when the application changes statuses, for example, when it moves from application under review to preliminary screening analysis in progress. When applications are deemed incomplete, details are provided within the IOAP to let the applicant know which documents are deficient as well as the reasoning behind such. The IOAP status also clarifies if the next steps are the responsibility of the developer or the utility.

In additional to the IOAP, Central Hudson also maintains a centralized e-mail and phone number for applicants or DER developers to contact with questions or concerns. This contact information can be found on the IOAP landing page or by visiting Central Hudson's Distributed Generation website.

The NYISO Interconnection Queue indicates the status of projects that applied for interconnection through the NYISO Interconnection Process.

e) The utility's processes, resources, and standards for constructing approved DER interconnections.

Central Hudson follows the procedures and requirements as listed within the NYSSIR. Through the use of the IOAP, the customer has the option to submit a pre-application or application as the initial step to move forward with a DER interconnection. For the application review, Central Hudson currently has two employees available to review applications for completeness and manage the interconnection administration process, including application questions and calls. For questions regarding billing and/or net-metering eligibility, the Company has one employee designated as primary point of contact. Central Hudson also has one employee designated to manage and maintain the IOAP.

For systems greater than 50kW, which are subject to technical screening, Central Hudson currently has three employees available that are able to perform these technical screens. For applications which require a CESIR, the Company currently contracts these studies out to two consultant resources, however, assistance and additional review is provided by employees within Central Hudson's Electric Planning & Interconnections Group and System Protection Group and input on cost estimates are provided by the Company's Estimating Group and Substation Engineering Group.

In addition to the interconnection requirements outlined within the NYSSIR, Central Hudson utilizes two additional documents for interconnection requirements: the Interconnection Guidelines, which were updated in December 2019 and are currently undergoing revision with an anticipated publish date in Q3 2023, and Central Hudson's Requirements for Electric Installations. Both of these documents are publicly available on the Company's Distributed Generation website. The Interconnection Guidelines include information regarding the technical requirements DER systems must meet before receiving approval for interconnection, as well as information on the interconnection process. As a part of ITWG discussions and outcomes, some interconnection requirements have also been standardized between the Joint Utilities of New York. This includes requirements for Unintentional Islanding and Monitoring and Control, a standardized template for completing preliminary screening, and CESIR studies. There is also JU reference material related to storage metering configurations and CESIR cost drivers. These documents can be found on NYS DPS's ITWG website.

For projects interconnecting through the NYISO, the NYISO's Transmission Expansion and Interconnection Manual provides details on the NYISO's processes. NYISO Open Access Transmission Tariff (OATT) Attachments X, S, & Z are also helpful in understanding the NYISO processes. These documents contain NYISO-specific requirements that are in addition to Central Hudson requirements.

For projects undergoing the Utility Process, the application process and requirements for these projects can be found at the following link: application-process-for-der-greater-than-5mw-2022.pdf (cenhud.com)

f) The utility's means and methods for tracking and managing construction of approved DER interconnections to ensure achievement of required performance levels

For systems less than 50kW where the typical upgrade is limited to a service transformer upgrade, the applicant can pay for the transformer upgrade and obtain information on it's the construction status via the IOAP or by contacting the centralized DG phone and e-mail. For applications that do not require upgrades to interconnect or new service, the applicants are automatically approved to construct their DER system once the application is deemed complete and only need to contact the utility through the IOAP again to request a meter change and submit final approval documentation.

For applications greater than 50kW that require new service or utility upgrades, these customers are provided with the contact information for a Central Hudson Project Manager. The Project Manager remains the primary point of contact for questions regarding construction and next steps, including estimated construction timelines. The Project Manager remains the liaison between the DER developer and all appropriate groups within the Company who may have a role in the construction process.

Once a project provides utility system upgrade payments (both partial and full), an automated email is sent from the IOAP to the Project Manager to inform them of this status change and to initiate appropriate next steps within the process. All real-time and current statuses of the application can also be found within the IOAP. On a monthly basis, the Electric Planning & Interconnections Group provides a status report for systems greater than 50kW. As DER system construction nears completion, the Project Manager will inform the appropriate groups within Central Hudson in order to coordinate a timely completion on any remaining Central Hudson system upgrades.

For Utility Projects, these projects are assigned a Project Manager who is responsible for tracking and managing construction from the initial application through to final interconnection.

For projects interconnecting through the NYISO, the NYISO maintains an Interconnection Queue on their website that provides information on each proposed project.

g) Describe how and when the utility will deliver and maintain its DER interconnection information to the IEDR?

As of September 30, 2022, Central Hudson is currently sending the following data related to DER interconnections to the IEDR:

- Installed DER
- DER Interconnection location
- DER interconnection cost

- Planned DER
- DER Interconnection Queue Request
- Interconnect queue position

As the IEDR is still within the nascent state of implementation, additional details and requirements related to delivering and maintaining DER interconnection information will continue to be discussed with the IEDR program team.

L. Advanced Metering Infrastructure

1. Context and Background

Advanced Metering Infrastructure (AMI) provides grid-edge measurement, data acquisition, and control capabilities which are either essential or beneficial to several important functions in a modern distribution system. Granular time-series data from smart meters and other intelligent devices at customers' premises enables advanced analyses, innovative rate designs, and customer engagement strategies which benefit both the customers and the grid. Voltage sensing and measurement functions support increased system efficiency and enable improved outage detection and restoration processes. Capabilities supporting DER measurement, monitoring, and control are essential for DER integration.

Central Hudson's Initial DSIP filing (dated June 30, 2016) contained a comprehensive analysis of the benefits and costs of implementing an advanced metering infrastructure (AMI), which was performed pursuant to the *Order Adopting Distributed System Implementation Plan Guidance* and in accordance with the *Order Establishing the Benefit Cost Analysis Framework*[65]. AMI deployment was assessed from three perspectives (societal, utility, and ratepayer), across two scenarios (full and partial deployment), and between benefit categories (operational only versus incremental AMI-enabled benefits contingent on regulatory changes).

Central Hudson's analysis recognized the potential for AMI to offer customers, market participants, and utilities increased visibility and resolution about energy usage and flow. However, the results across all scenarios of this analysis consistently indicated that the cost to integrate AMI systems with new and existing applications and devices to improve analytical capabilities and customer tools significantly exceeded the identified benefits. As a result, the analysis did not support universal implementation across the service territory. Further, the analysis pointed to several characteristics that explain the significant gap between AMI benefits and costs of full deployment:

- **Distribution Automation** – The continued deployment of approved distribution automation will capture a substantial portion of benefits, thus limiting the incremental benefits from AMI.
- **Existing Advanced Meter Reading (AMR)** – The existing and anticipated penetration of AMR will capture the benefits of more efficient meter reading and meter accuracy improvements.
- **Meter Reading Frequency** – Central Hudson's bi-monthly reading schedule for most meters results in lower reading costs than a monthly frequency.

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[65] 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 and Effective January 21, 2016; Order Adopting Distributed System Implementation Plan Guidance, Issued and Effective April 20, 2016.

- **Gas Meter Co-Location** – The presence of gas meters at approximately 25% of electric customer sites results in the imposition of AMI installation costs with little incremental benefit.
- **Remote Geography** – The larger distances between meter sites lead to reduced operational savings and increased costs due to the need for additional network infrastructure and cellular meters.

The analysis also found that a partial AMI deployment was not cost-effective by an even greater margin as the results are not only impacted by the above characteristics, but by two other primary reasons:

- **Foundational Investments** – Significant IT investments are required independent of the number of meters deployed.
- **Smaller Meter Base** – A smaller meter base translates to reduced savings for operational benefits that are proportional to meter deployment, such as meter reading and outage management.

As there have been no changes to these characteristics or significant changes in deployment costs, widespread AMI deployment continues to fail to provide a cost-effective opportunity for Central Hudson customers to incorporate these resources into the REV market.

Although the Company has decided not to pursue widespread AMI deployment, it continues to pursue and support individual initiatives that present cost-effective opportunities for customers to access and assess their energy usage data and allow the Company to support demand-side management options and DER deployment through rates and programs.

2. Implementation Plan

Central Hudson understands that AMI is a gateway technology that supports advanced analyses, innovative rate designs, demand-side management and customer engagement strategies that benefit both the customers and the grid. Refer to the Context and Background section above for more details on current progress. Recognizing that technical and economic considerations may have changed since the 2016 BCA was completed, the Company has developed an implementation plan to complete a new BCA for widespread AMI deployment. The analysis will consider the future conditions that would exist when AMI is implemented with a targeted completion date of March 2025. The table below shows detailed implementation milestones and associated timelines for this analysis.

Table 44: Implementation Plan Timeline

Activity/Milestone	Estimated Start Date	Estimated Completion Date
Identify internal AMI BCA team and lead	June 2023	June 2023
Identify current and near-term internal initiatives that would impact resources required to conduct a thorough AMI evaluation and benefit cost analysis	July 2023	July 2023
Identify current and near-term internal initiatives that would impact an AMI implementation and their sequencing timeframe	July 2023	September 2023
Evaluate the need for third-party BCA preparation	August 2023	October 2023
Identify and assess current and future external conditions	September 2023	November 2023
Monitor completion of identified internal initiatives on a monthly basis to determine impact on resource availability and timing of AMI BCA	October 2023	March 2025
Prepare and issue RFP and select consultant, as applicable	November 2023	January 2024
Compile operations and business requirements	February 2023	May 2024
Evaluate progress on/status of identified current and near-term internal initiatives that would impact an AMI implementation	April 2024	June 2024
Prepare AMI BCA	July 2024	March 2025

Based on these existing technical factors, Central Hudson believes that it may be practical to target a completion date for the AMI BCA that would allow for its inclusion in the June 2025 DSIP filing. However, as noted in the workplan an evaluation of required resources and their availability must be conducted to ensure that a BCA can be completed by June 2025, otherwise the Company may need to target the inclusion of the BCA in the 2027 DSIP.

3. Risks and Mitigation

The risks associated with implementation of this recommendation stem from the competition for resource assignment, including premature reassignment of resources to complete this project to the detriment of previously prioritized projects, and incomplete identification of environmental factors and operations/business requirements in the case of inadequate assignment of resources due to competing priorities.

Additional AMI deployment increases both safety and security risks. With a significant portion of deployment occurring in the field with the actual installation of meters, Central Hudson's commitment to customer and employee safety as top priority must remain paramount. Additionally, the Company must continue to address customer opposition to AMI, which utilizes digital and wireless technologies, as customers cite health, privacy, and security concerns. While Central Hudson maintains a comprehensive cybersecurity program as described in the Data Sharing section, it will be critical to adequately address any cybersecurity concerns, in order to minimize the risk associated with increased communications and access to data that accompanies AMI deployment.

4. Stakeholder Interface

Additional AMI deployment will require the Company to effectively engage customers to ensure that they understand how to take advantage of AMI-provided capabilities. Central Hudson will also need to expand its customer data initiatives to further collaborate with interested stakeholders to co-develop business use cases for more granular metering data, in order to develop a deeper understanding of the need and use for various types of consumption data, including public availability, private availability, and possible value-added data elements. A foundational goal of any stakeholder interface will be to ensure that the AMI resources are effectively utilized.

5. Additional Detail

a) Provide a summary of the most up-to-date AMI implementation plans, including where AMI has been deployed to date.

Central Hudson has deployed approximately 1,400 AMI meters throughout its service territory for specific use cases, including:

- **Optional Residential Advanced Metering and Data Services (Insights+)** – Between 2017 and 2020, Central Hudson offered a subscription-based service that includes the installation of an advanced meter, which captures 15-minute interval customer load data and communicates this information over a cellular network as part of the Insights+ REV Demonstration Project66. This enhanced data provided subscribing customers with the ability to view daily and hourly energy consumption, correlate energy consumption with average daily temperature, set bill and usage alerts, and participate in various rate structures/programs. While the Demonstration Project has ended in December of 2020, most of the deployed advanced meters are still in service.

Please refer to Section 2 above for a more detailed summary of the most up-to-date AMI implementation plans.

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

Deployment of advanced meters on the Central Hudson system has enabled the following capabilities:

- **Measurement and Verification (M&V):** Central Hudson and its program partner, Itron, utilize a statistical sample set of advanced meters for measurement and verification of load reductions achieved as part of the Targeted Demand Management / Non-Wires Alternative program. This program also utilizes smart measurement devices including telemetry-enabled thermostats and direct load controllers.
- **Load Research:** Load research data has been primarily used to construct load profiles for retail access and cost of service purposes. However, the Company has significantly increased its utilization of this data for rate design purposes, including the design of the alternative Residential TOU rate, proposed standby and NEM successor rate designs, and value stack considerations.
- **Value Stack:** The data from the advanced meters meet the criteria for the application of value stack compensation, and the hosted Itron MDM can accommodate the additional meters at no additional system cost.
- **Residential TOU:** The advanced meters capture data for the original TOU intervals as well as the Company's newer alternative TOU intervals.

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

AMI-acquired data is not currently available through the IEDR due to the relatively limited scale of advanced meter deployment to date.

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[66] Demonstration Project Implementation Plan Q4 2020 Status Update

d) 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.

Central Hudson does not have any immediate plans for further deployment of advanced meters, or to roll out additional capabilities, but is currently conducting an assessment for widespread AMI deployment as described above.

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

Central Hudson does not have any immediate plans for further deployment of advanced meters, or to roll out additional capabilities, but is currently conducting an assessment for widespread AMI deployment as described above.

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

AMI-acquired data are stored in the Itron MDM system and then exported to the Company's billing system. Accounts that require interval data, such as Value Stack CDG projects, are billed using the interval data. These accounts are not downloaded into the meter reading system to be read by meter readers.

Central Hudson is also in the process of converting its load research meters to AMI. Since there are still MV-90 meters in the field that are used to collect data, two different data sources are used to compile load research data. The data from MV-90 meters is obtained through a connection with the Itron MV90 system and the data from the AMI meters is obtained through a separate query for the applicable load research meters.

Currently, Central Hudson does not use AMI-acquired data for asset management, grid planning, or grid operations.

M. Beneficial Locations for DERs and Non-Wires Alternatives

1. Context and Background

NWA Non-wires alternative (NWA) solicitations are an important mechanism for bringing distributed energy resources (DERs) onto the system. They offer opportunities for developers to propose innovative solutions to meet a clearly defined system need, while also driving customer benefits. Collectively, the Joint Utilities have undertaken significant efforts to advance NWA processes and have released a number of NWA solicitations to the market. A key underlying component of this process is the identification of beneficial locations for DERs and NWAs.

As part of the initial DSIP filing in 2016, Central Hudson worked with consultants to develop a methodology utilizing probabilistic forecasting to determine location-specific transmission and distribution avoided costs. This study recognized that to avoid or defer infrastructure upgrades, DERs need to ramp up at the right time and right place. In addition, the DERs procured must target the right hours, with the right amount of availability and the right level of certainty so that infrastructure investments can be deferred. Areas with sufficient load-serving capability and areas where local, coincident peaks are declining are generally not well suited for NWA projects. Likewise, locations may not be suitable for non-wire projects if the infrastructure investments must take place either because of aging or failed equipment or because of the need to improve reliability and modernize the grid.

Beneficial locations are areas where loads are growing, but there is limited room to accommodate growth. The results of Central Hudson's Avoided T&D Cost studies to date have indicated that, with a few exceptions, most of Central Hudson's locations are either experiencing declining loads or have ample room for growth. Locations with a load growth factor above 100% are experiencing growth, and locations where the loading (peak demand /load-serving capability) was closer to 100% had less room for growth. This approach, however, is overly simplistic. It does not reflect that, all else equal, a location with a 3% annual growth rate will begin to exceed rating in 1/3 the time as a location with a 1% growth rate. It also does not factor in uncertainty and the reality that many growth trajectories are possible, and the growth pattern is less certain further into the future.

To identify beneficial locations, Central Hudson relied on the probabilistic analysis developed as part of the study. Locations were identified as potentially benefitting from DERs when there was a 5% or greater likelihood of triggering an infrastructure investment by 2033 (10 years), including electrification impacts (i.e., heat pumps and EVs). In total, this included two transmission areas (the RD-RJ Lines and Westerlo Loop) and seven substations (Woodstock, Grimley Road, Reynolds Hill, Maybrook, Fishkill Plains, Pulvers Corners, and New Baltimore). Four of the substations identified (Pulvers Corners, New Baltimore, Fishkill Plains and Maybrook) have infrastructure upgrades planned for the near term which are included as part of the Company's five-year capital plan. The planned upgrades for these locations incorporate increases in load serving capabilities. These planned upgrades are required to address infrastructure issues (Pulvers Corners), operational issues (New Baltimore and Fishkill Plains) or are required due to the development of emergent large lumped industrial loads in the areas (New Baltimore, Fishkill Plains and Maybrook). For areas that lack planned upgrades, the right type of DERs with the right availability may allow for deferral of infrastructure investment. This is the case for the other three substations, Grimley Road, Reynolds Hill, and Woodstock, as well as the two transmission areas, the RD-RJ Lines and Westerlo Loop. These locations peak during different seasons and different hours. Specifically, both Westerlo Loop and Woodstock are winter peaking – rather than summer peaking – and therefore cannot be managed by Dynamic Load Management programs designed for the summer. DERs would need to address the appropriate seasonal and peaking needs to provide values in each of these locations.

While locations can benefit from DERs, in some instances, Central Hudson can provide temporary relief through load transfer or other low-cost steps. As part of Central Hudson's planning processes, the Company evaluates alternative solutions to system needs and implements the lowest evaluated cost option. For example, in some cases, load transfers to neighboring areas, if needed, can be completed at a relatively low cost as an alternative to potential capital projects. This may postpone the timing of the upgrades and their inclusion as NWA projects.

As part of the previous DSIP filings and again as part of this DSIP filing, Central Hudson engaged with Demand Side Analytics to further develop the probabilistic forecasting methodology and complete a new study based on current loading data. The results of the 2023 study are included in Appendix D of this filing.

2. Implementation Plan

a) Current Progress

Identification of Beneficial Locations for DERs and NWAs

As noted, Central Hudson's 2023 Avoided T&D cost study (see Appendix D) helps Central Hudson determine beneficial locations for DERs and NWAs on its system. While the 2023 study focused on substation and transmission costs, as a further advancement, probabilistic forecasts were performed at the circuit level. As an additional enhancement, the 2023 study included the explicit impact of electrification (i.e., heat pumps and EVs). Overall, the study was designed to meet the following objectives:

- Analyze load patterns, excess capacity, load growth rates, and the magnitude of expected infrastructure investments at a local level;
- Develop location-specific forecasts of growth with uncertainty;
- Quantify the probability of any need for infrastructure upgrades at specific locations;

- Calculate local avoided T&D costs by year and location using probabilistic methods; and
- Identify beneficial locations for DERs.

Within this study, the T&D avoided costs estimates produced are at a local level. The study uses a bottom-up approach to quantify historical year-to-year growth patterns and the amount of variability in growth. In addition, load growth forecasts and avoided cost estimates are developed using probabilistic methods rather than straight-line forecasts. The approach considers the reality that there is much greater uncertainty ten years out than one year out, and it accounts for the risk mitigation value of resources that manage local peak loads.

As a general rule, only growth-related T&D investments that are shared across multiple customers can be avoided by DERs or demand management. As loads grow, the excess distribution capacity dwindles. If a customer helps reduce coincident demand, either by injecting power within the distribution grid or by reducing demand, the unused capacity can accommodate another customer's load growth, thereby helping avoid or defer investments required to meet load growth. Avoided or deferred T&D investments free up capital for other alternate uses, improving the efficient use of resources.

Not all distribution investments are driven by local, coincident peak loads. Some investments are tied to customer interconnection costs and are essentially fixed. Other investments must take place because of aging or failed equipment or because of the need to improve reliability and modernize the grid. These investments typically cannot be avoided by managing loads with DERs. The value of T&D deferral varies significantly across local system areas because of:

- Load growth rates and anticipated changes in load curve shapes, which affect whether growth related upgrades can be avoided and how long they can be deferred;
- The seasonality of the peak load (i.e., summer vs. winter);
- The amount of existing excess capacity or the amount of additional load that can be supported without upgrades;
- The magnitude, timing, and cost of projected system upgrades;
- The design of the distribution system; and
- The ability to make inexpensive operational changes (i.e., switching alternatives) in some cases to address constraints.

In areas with excess capacity – or areas where local, coincident peaks are declining or growing slowly – the value of capacity relief can be minimal. In areas where a large, growth-related investment is imminent, the value of capacity relief can be quite substantial, especially if it is possible to delay or defer infrastructure upgrades for a substantial time. However, many Central Hudson areas have declining or slowly growing loads, or they have sufficient capacity already built such that investments are not needed in the foreseeable future.

The key findings from the T&D study are:

- Including electrification impacts, most substations and transmission areas are experiencing declining loads or have ample room for growth over the next ten years.

- The expected avoided costs vary by location, year, season, and hour, and they are highly concentrated. Avoided costs are realized if additional resources are placed in the right locations and can deliver load relief at the right times. Without targeting, the value of distributed resources is diluted.

- For many distribution substations and transmission areas that have expected growth, the potential for avoided upgrades through DER resources is minimal because in some cases there are upgrades in the capital plan that will increase the area capacity or because there is sufficient latent capacity in the area to meet this load growth through the study period without exceeding ratings.

- The avoided cost estimates reflect the uncertainty in the forecasts and the risk mitigation value of demand management. Despite a low likelihood of exceeding design rating in the next ten years, DER resources can provide risk mitigation value at targeted transmission areas and substations if they are at the right locations, target the right hours, and are available at the right times.

- In practice, all avoided T&D costs are location specific. For system-wide untargeted values, the estimates take into account the likelihood reductions would be in locations with value due to random chance. Without precise targeting, the likelihood that reductions defer or delay transmission upgrades is relatively low.

Within the study, locations were identified as potentially benefitting from DERs when there was a 5% or greater likelihood of triggering an infrastructure investment by 2033 (ten years). In total, two transmission areas and seven substations were identified. Four of the substations identified have infrastructure upgrades planned for the near term which are included as part of the Company's five-year capital plan. The planned upgrades for these locations incorporate increases in load serving capabilities. These planned upgrades are required to address infrastructure issues and operational issues or are required due to the development of emergent large lumped industrial loads in the areas. For areas that lack planned upgrades, the right type of DERs with the right availability may allow for deferral of infrastructure investment. This is the case for the other three substations, Grimley Road, Reynolds Hill, and Woodstock, as well as the two transmission areas, the RD-RJ Lines and Westerlo Loop. Figure 61 and Figure 62 show these five beneficial locations. These locations peak during different seasons and different hours. Specifically, both Westerlo Loop and Woodstock are winter peaking – rather than summer peaking

– and therefore cannot be managed by Dynamic Load Management programs designed for the summer. DERs would need to address the appropriate seasonal and peaking needs to provide values in each of these locations.

Figure 61: Map of Beneficial Transmission Locations for DERs

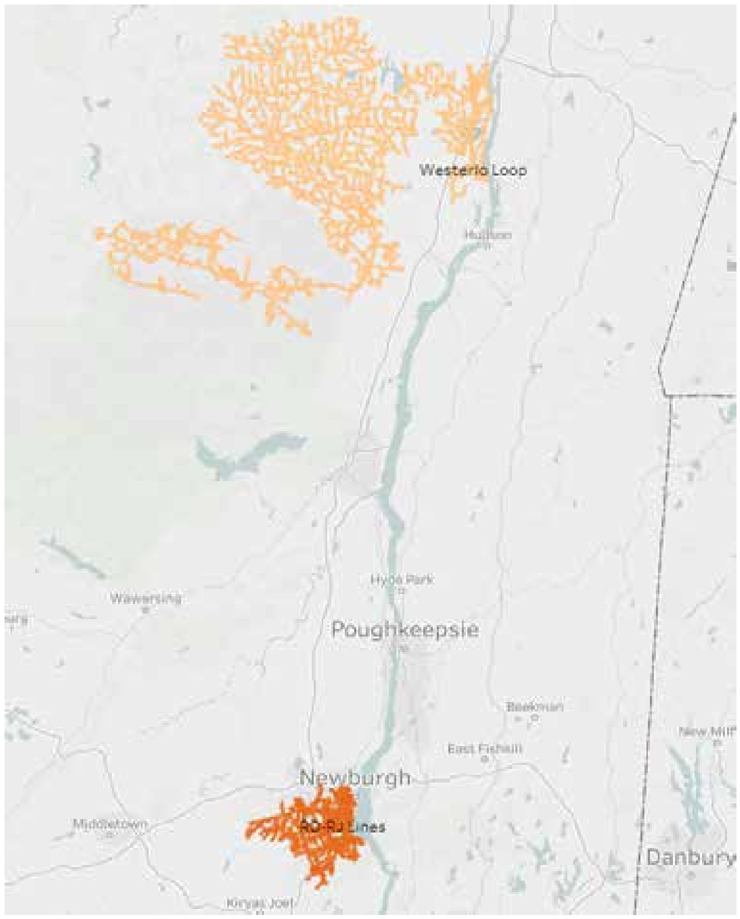
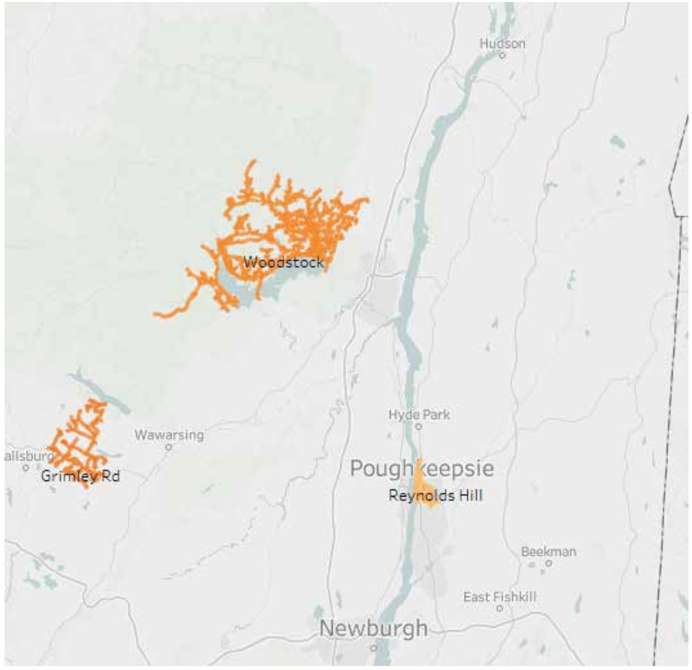


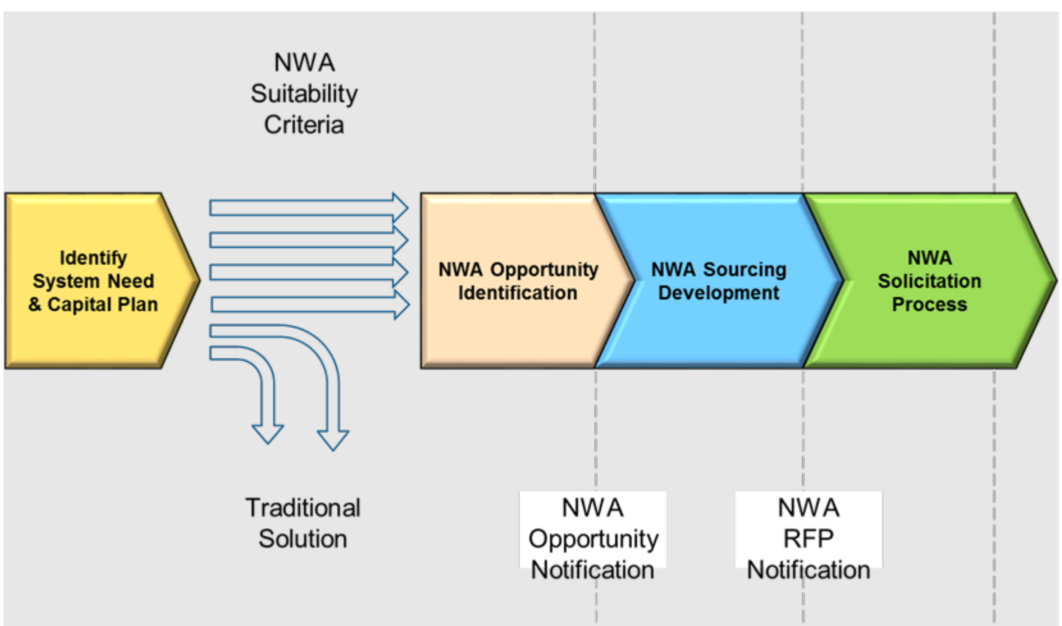
Figure 62: Map of Beneficial Substation Locations for DERs



NWA Implementation

Through stakeholder engagement, the Joint Utilities provided third parties with greater transparency and visibility into the NWA planning and sourcing processes. The planning process is shown in Figure 45Figure 63.

Figure 63: Joint Utilities Planning Process and Sourcing Overview



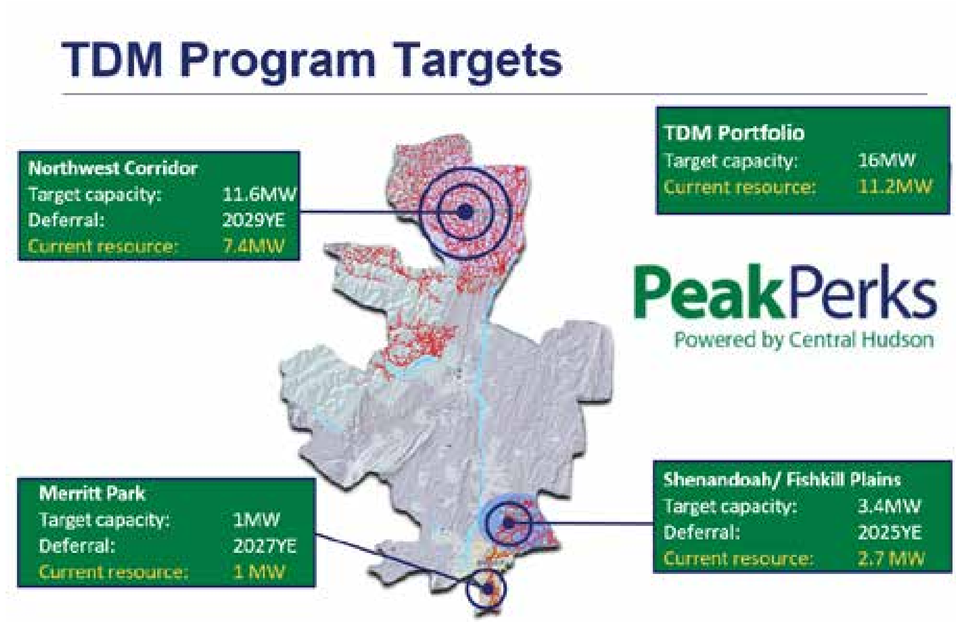
Each utility continues to coordinate with the Joint Utilities as part of the DER Sourcing / NWA Suitability Criteria Working Group to develop RFPs that have a similar structure and supporting information when possible. RFPs provide the details necessary for respondents to develop solutions and craft a proposal, and generally include a detailed project overview. The detailed project overviews may include a description of the specific need, area of need, and customer demographic information, including annualized consumption and peak and average billing demand. During the annual planning processes, utilities identify additional NWA projects that may go out for RFPs in the following year. Table 45 summarizes Central Hudson's current NWA locations and targets to date. The demand within these existing NWA areas represents approximately 15% of Central Hudson's system peak demand.

Table 45: NWA Solicitations

2017-18 NWA Projects	Targeted Load Relief (MW)	T&D Deferral Period	Date Solicitation Issued	Status
Shenandoah / Fishkill Plains	3.4MW	2025 YE	Nov 2014	NWA Ongoing NWA
Northwest Corridor / Transmission Upgrade	11.6MW	2029 YE	Nov 2014	Ongoing NWA
Merritt Park / (2) Distribution Feeder Upgrades	1MW	2027 YE	Nov 2014	Ongoing NWA

Currently there are three active NWAs implemented jointly as the Company's "Targeted Demand Response" Program or "CenHud Peak Perks" as identified in Figure 64. Combined, the Company aims to achieve a localized peak load reduction of 16MW across the three areas.

Figure 64: Current NWA Project Locations and Targets



The table below illustrates the load reductions available as of January 2022. The Company anticipates achieving the full 16MW target by the end of 2025.

Table 46: Potential Load Reductions for Current NWA Projects

Program Locations	Residential & Small Commercial	Targeted Energy Efficiency	Large Commercial & Industrial	Avoided Distribution Line Losses[67]	Total kW available
Fishkill	2,333	0	260	128	2,721
Merritt Park	276	643	7	46	972
Northwest Area	1,218	3,755	2,230	282	7,468
Total	**3,827**	**4,398**	**2,497**	**456**	**11,178**

More detail on this project can be found in Central Hudson Gas & Electric Corporation's 2022 Annual Report for the Targeted Demand Response Program, a Central Hudson Non-Wires Solution. [68]

[67]Avoided distribution line losses have been calculated by Central Hudson per the Operation Procedure
[68] https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={95705BC9-4C72-4A4B-900E-96C90D0CC44E}

NWA's benefit stakeholders by leveraging behind the meter resources to support the system at large. They provide project developers and customers with new opportunities to participate in the system as prosumers. NWAs support and improve system reliability and power quality. NWAs generally support achievement of the goals established by the CLCPA and NWAs that entail a battery storage solution support the State's goal of 6GW energy storage by 2030.

b) Future Implementation and Planning

Identification of Beneficial Locations for DERs and NWAs

Central Hudson believes the methodologies and processes outlined and followed in the Avoided T&D Cost Study (see Appendix) represent the leading edge of best practices in the determination of beneficial locations and NWA areas. The process is accurate and repeatable and provides reliable results. The study demonstrates the value of developing T&D avoided cost estimates at a local level using probabilistic methods. While Central Hudson has utilized this methodology in its three prior Avoided T&D Cost studies, it is still evolving and may benefit from future refinements and improvements. Future studies can be further bolstered by conducting additional sensitivity analyses, through the refinement of engineering rules which trigger T&D infrastructure upgrades and by increasing the granularity of the review. Central Hudson is committed to continuing to modify and enhance these methodologies and plans on repeating the analysis with current load data every two years. With continued electrification efforts in the state and the forecasted adoption of EVs, it is expected that this methodology will continue to identify potential additional beneficial locations in the future. There is also the potential shift from summer peaking to winter peaking in some areas through electrification (i.e., heat pump adoption) which may cause additional/other areas of the system to be identified.

NWA Implementation

The Company continues to integrate DERs into the planning process as a normal course of business and learn from its experiences, starting with the identification of NWA and extending through internal budgeting and accounting, evaluation of proposals, and contracting with successful bidders. As utilities gain experience with NWA solicitations, the Joint Utilities DER Sourcing / NWA Suitability Criteria Working Group will review NWA suitability criteria annually and propose modifications to the criteria, if appropriate. This working group will also engage stakeholders to review any proposed changes to the suitability criteria and provide justifications and objectives for making any changes.

The Joint Utilities continue to share experiences and lessons learned among themselves to achieve a consistent set of best practices and improve their solicitation processes to be more efficient and user-friendly. Since the 2020 DSIP filings, the JU have continued to meet on a bi-weekly basis to share updates on NW solicitations, evaluation, and contracting topics. NWA topical areas reviewed during the meetings include updates on company RFPs and existing projects; availability and potential use of utility property and interconnection cost treatment; opportunities to move towards similar contracts (including terms and conditions) and procurement methods where appropriate in response to the DSIP guidance, this included reviewing best practices in other US states; liability caps in NWA contracts; NW solicitation contract language regarding DE participation in multiple revenue streams; implications of the New York State Storage Roadmap and sharing experiences on deploying two storage projects in response to the March 9 DSIP 207 Order; leveraging existing EE programs to meet localized NWA targets; annual assessment of the NWA suitability criteria as part of the annual planning process and changes or refinements to the criteria (none were identified in 2023); commercial and performance requirements, and non-performance issues of NWA contracts.

The Joint Utilities will continue to invite input from stakeholders through direct discussions and broader stakeholder engagement meetings. As utilities gain more experience with NWAs, the Joint Utilities see great value in working together and with stakeholders to make NWA solicitations consistent, repeatable, and easy-to-use processes for developers.

- The Company will support stakeholder needs by creating pathways that alleviate load concerns at the lowest potential cost, thus reducing pressure upon ratepayers while servicing customer needs. Cost-effective pathways should prioritize the penetration of renewable energy, load flexibility, and CLCPA targets for Disadvantaged Communities (DAC) and environmental justice (EJ) regions. The Company will continue to seek opportunities to support and improve system reliability through our "Targeted Demand Management Program" by identifying areas of load constraint, considering demand management solutions as alternatives to traditional infrastructure development, and employing those solutions where appropriate.
- To progress from the current implementation to the planned future implementation of NWAs, the Company will continue to promote cross-departmental collaboration, optimize relevant BCAs, provide flexibility to allow for adjustments in NWA implementation, and hold implementation contractors accountable through clearly defined metrics. The Company will continue to collaborate with DPS Staff on its latest NWA opportunities and innovation.

- To progress from the current implementation to the planned future implementation of NWAs, the Company will look for support from oncoming state regulation and funding to facilitate project implementation and adoption. Regulatory alignment and funding coupled with the emerging availability of technology and the proliferation of local distribution chains should create the groundwork necessary for future planning.

Additionally, the Company will look to review future projects that fall outside of the currently established timeline suitability criteria. For example, deferral projects that are expected to commence in less than 18 months, or a shorter timeframe than currently specified for small projects will be evaluated and implemented at the discretion of feasibility determined by the Company.

The CGPP and DSIP are filings with overlapping but distinct scope. The CGPP will detail the evolution of distribution planning processes needed to meet CLCPA goals, align with transmission planning processes, and ensure that planning is integrated. The DSIP describes implementation of the much broader set of

DSP activities and projects, and how those activities holistically align with CGPP and CLCPA goals. The CGPP will be more singularly focused on a process to identify distribution system needs to meet CLCPA State goals and develop a distribution investment plan, including capital projects, to meet those needs. Planned capital investments, including technology platform investments along with NWAs and how they will be leveraged will be included in the DSIP (e.g., AMI, automation, ADMS, etc.) and the results of executing the processes will be used to inform the CGPP.

The CGPP is aimed at developing a "CLCPA-focused planning process," including "the State's bulk transmission, local transmission, and distribution planning processes." The goal is to improve planning processes to better coordinate the studies performed by the Utilities with the NYISO's bulk-power system planning and generation interconnection processes; improve the integration of Local Transmission and Distribution (LT&D) and bulk system studies with NYSERDA's renewable generation and storage procurements; and improve forecasting of renewable generation development for specific locations on the LT&D and bulk transmission grid. As part of the December 2022 CGPP proposal, one of the key inputs to the CGPP process is the generation build-out scenarios identified by the Energy Policy Planning Advisory Council (EPPAC). While forecasting practices for the CGPP and DSIP are aligned, the scenarios identified by the EPPAC may result in different forecasts than those completed as part of the DSIP. The output of the CGPP thus may result in the identification of Phase 2 capital projects that are not already identified in current rate plans. Although capital projects identified within the CGPP are intended to be funded under the FERC load ratio share methodology, these Phase 2 projects once approved will be incorporated and used to inform the normal DSIP and planning processes.

c) Integrated Implementation Timeline

Refer to Figure 8 under Grid Modernization to for the implementation timeline related to NWAs as part of Integrated System Planning, Clean Energy & Decarbonization and Grid Modernization.

3. Risks and Mitigation

Any forecasting technique includes inherent risks in terms of overall accuracy. The longer the period included within the forecast window, the higher the risk of inaccuracy. No one knows precisely when loads will exceed design ratings or by how much; however, linear forecasts assume precise knowledge. In practice, actual growth trajectories are rarely linear, and growth patterns trend across time – both load growth and load declines follow cyclical patterns. Forecasts inherently include uncertainty and become more uncertain further into the future. Because a linear forecast assumes exact knowledge, no value is assigned to the years before the linear forecast exceeds the risk tolerance. Probabilistic methods, on the other hand, reflect the potential reality that infrastructure could be triggered earlier. Probabilistic methods will assign value to periods earlier than the linear forecast would dictate based on the probability of triggering an earlier infrastructure upgrade.

Risks are mitigated within the methodology in several ways. The year-by-year growth estimates are estimated using econometric models designed to disentangle year-by-year growth rates from differences in weather patterns, day of week effects, and seasonality. For the most part, the year-by-year estimates of growth are relatively precise. Historical year-by-year growth does not follow a linear pattern and varies around the general trend line. This variation was used to develop the standard error of the forecast, which reflects how year-to-year growth can vary. This variability or uncertainty in the growth pattern is critical to probabilistic forecasting. Because growth and declining loads compound over time, growth patterns can deviate substantially from the straight-line forecast. An area where loads are projected to remain flat can exceed the load-serving capability five to ten years out due to the uncertainty in the forecast, though the likelihood of doing so is lower than for an area that is growing.

Overall, the probabilistic methods quantify the risk mitigation value of managing demand. The estimates produced within the report are based on 5,000 simulations of potential load growth patterns for each substation and transmission area, respectively. For each simulation, Central Hudson can assess if the relevant design rating is exceeded, identify the timing of infrastructure upgrade, quantify the magnitude of demand reductions needed to avoid the infrastructure upgrade, and calculate what the avoided costs associated with the deferral of infrastructure upgrades would be if demand reductions were in place. The detailed calculations from each of the simulations at each location are used to estimate the expected avoided costs per kW/year. That is, the probabilistic method assigns T&D avoided costs when, for example, only 5% of potential growth trajectories lead to infrastructure upgrades. This approach quantifies the risk mitigation value provided by resources that reduce demand at the right times at each location.

Through NWA's, the Company is deploying potentially new and innovative DER technologies to meet grid needs. Unlike traditional infrastructure projects, these DER solutions do not have the same proven history of reliably performing utility functions. DER solutions carry more performance risk than traditional utility solutions, and until more experience is gained, those risks cannot be precisely quantified. To mitigate this risk, the Company leverages portfolio solutions to solve NWA needs where possible. Diversification of resource types is the primary strategy to mitigate the risk associated with any individual resource.

4. Stakeholder Interface

The Company is an active participant in the "DER Sourcing" Joint Utilities working group. This group facilitates the sharing of best practices in DER procurement between New York utilities. The utilities have held various workshops to promote the sharing of ideas and feedback on existing processes directly from DER developers and other stakeholders. This feedback is utilized to optimize procurement procedures and optimize the participation experience of developers. The Company makes every effort to provide the most detailed information available directly to prospective DER providers through RFPs. For each solicitation, the Company will respond to specific questions and discuss topics requested by stakeholders during a pre-bid conference.

Detailed information on past and current solicitations can currently be found on the Joint Utility webpage, as well as Central Hudson's web page.

http://jointutilitiesofny.org/utility-specific-pages/nwa-opportunities/

https://www.cenhud.com/contractors/non-wires-alternative-opportunities/

Internal stakeholders include NWA team, distribution planning, project development, interconnection, regulatory, legal, operations, transmission planning, leadership, energy land management, marketing, government, and community outreach, procurement, environmental and sustainability coordination.

External stakeholders include developers, regulators, LMI communities, DAC communities, environmental advocacy groups, utility customers, community leaders, government officials, emergency response personnel, and the department of public safety.

At a high level, internal stakeholders will look to deliver safe, reliable, and efficient service while maintaining equity and environmental conservation. External stakeholders will look to meet customer demand while maintaining equity, safety, and environmental conservation. The goals and needs of stakeholders, whether internal or external, are identified and gathered from the SAPA process and public comment period, working groups, technical conferences, stakeholder forums, RFIs and market surveys, and emergency response planning at the municipal level. Relevant feedback will be incorporated in Central Hudson's internal planning processes.

- Stakeholder needs are met over time by prioritizing projects that are located within DAC/EJ regions, leveraging emerging technologies, providing energy efficient solutions, and limiting environmental disruption. Utilities should enable the likelihood of meeting stakeholder needs by soliciting technology agnostic RFPs that communicate clear and transparent utility requirements to increase and diversify input received from stakeholders.

- Stakeholders should provide input during public comment periods, be aware of NWA processes and procedures, and engage with projects after completion. Stakeholders can maintain awareness of public comment periods and ongoing NWA development by subscribing to utility-specific communications, staying up to date on emerging markets and technology, and collaborating with DPS Staff and the Utility directly. The need for engagement following project completion is relevant for residential projects that require customer enrollment. This engagement should be maintained through local press releases, presentations to the regional chamber of commerce, and communication with environmental advocacy groups. Sponsored partnerships enable visibility of projects and lend to the credibility of associated benefits, thus increasing customer engagement and project success.

- Stakeholders can be effectively informed and engaged during the planning, design, and implementation of an NWA by responding to RFIs associated with the RFP's planning, participating in stakeholder engagement sessions during the RFP development, and attending pre-bid meetings during the RFP's solicitation. Outside of these utility-specific meetings and RFI responses, stakeholders can also attend technical conferences, BCA-related conferences, and Q&A sessions specific to the project.

- The utility ensures that the information, tools, and engagement opportunities are effectively provided to stakeholders by sending project updates to developer(s), posting project updates and opportunities on the company website, and developing an NWA opportunity map (i.e., hosting capacity map). Received stakeholder feedback is integrated throughout the RFP process, shared with DPS Staff and included within the project's Risk Assessment.

- To ensure that the information provided to stakeholders effectively delivers the intended support and does not lead to unintended problems, the utility will incorporate regional concerns, such as the identification of environmentally protected lands and species, regional safety protocol and concerns, and consumer sentiments towards specific technologies, into its methods of communicating NWA opportunities.

5. Additional Detail

a) Describe where and how developers and other stakeholders can access resources for:

(1) accessing up-to-date information about beneficial locations for DERs and/or energy efficiency measures; and,

As indicated, Central Hudson utilizes the results of the avoided T&D cost study to identify and evaluate beneficial locations and other locations in the distribution system where an NWA compromising one or more DERs or energy efficiency measures could reduce, delay, or eliminate the need for upgrading distribution infrastructure or materially benefit distribution system operations. Appendix D provides the details of the methodologies utilized and the results of the current study. Central Hudson completes these studies every two years.

(2) 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.

Due to the unique circumstances of Central Hudson's service territory, which is characterized by flat to declining load and areas with ample capacity for growth, only four NWA opportunities have been identified since the initiation of REV, with one of these NWAs being withdrawn prior to implementation. As indicated previously, the demand in the three NWA areas represents 15% of the Central Hudson peak system demand. With this limited number of projects, there has not yet been a need to develop a process in which stakeholders are provided with advanced searching capabilities.

b) Describe the means and methods for identifying and evaluating locations in the distribution system where:

(1) an NWA comprising one or more DERs and/or energy efficiency measures could timely reduce, delay, or eliminate the need for upgrading distribution infrastructure and/or materially benefit distribution system reliability, efficiency, and/or operations; and/or,

Central Hudson utilizes the results of the avoided T&D cost study to identify and evaluate both beneficial locations and locations in the distribution system where an NWA comprised of one or more DERs or energy efficiency measures could reduce, delay, or eliminate the need for upgrading distribution infrastructure or materially benefit distribution system operations. Appendix D provides the details of the methodologies utilized and the results of the current study. Central Hudson completes these studies every two years. Based on the results of the current study, two transmission areas and seven substations were identified as potential beneficial locations. Four of the substations identified have infrastructure upgrades planned for the near term which are included as part of the Company's five-year capital plan. The planned upgrades for these locations incorporate increases in load serving capabilities. These planned upgrades are required to address infrastructure issues, operational issues or are required due to the development of emergent large lumped industrial loads in the areas. For the two transmission areas (RD-RJ Lines, Westerlo Loop) and the other three substations, (Reynolds Hill, Woodstock and Grimley Road) the right type of DERs with the right availability may allow for deferral of infrastructure investment. areas). These areas will be evaluated in future studies to determine if the NWAs should be implemented or if these areas will become eligible for LSRV compensation. A third possible option, to leverage these areas to develop an overall system-wide relief value (DRV), most likely will not be pursued because the more targeted approaches (NWA/LSRV) provide value in the areas of need and are more effective and cost effective at addressing these needs.

(2) 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 NYISO completes a Reliability Needs Assessment (RNA) to determine both the resource adequacy and the transmission security needs of the New York Control Area (NYCA) Bulk Power Transmission Facilities (BPTF). Along with Central Hudson's own analyses, the results of the RNA are utilized to determine the adequacy and security of Central Hudson's portion of the NYCA transmission system. The RNA is completed every two years and looks out across a ten-year horizon. As part of the NYISO process, the NYISO solicits market-based and alternative regulated proposals from interested parties to address any identified BPTF reliability needs. The NYISO will also designate one or more Responsible Transmission

Owners to develop a regulated backstop solution to address each identified BPTF reliability need. The most current RNA in progress identified a local reliability need within the Central Hudson System. The need is driven by the planned retirement of two Combustion Turbines (CTs) in the Westerlo 69kV transmission loop. The planned CT retirements are in response to the New York State Department of Environmental Conservation recently promulgated (March 2020) 6 NYCRR Subpart 227-3 "Ozone Season Oxides of Nitrogen (NOx) Emission Limit for Simple Cycle and Regenerative Combustion Turbines" which imposes more stringent emission standards for these units which makes the CTs at these locations uneconomic. As these units are currently required for local transmission and distribution reliability needs, capital projects are necessary to address these needs prior to the retirement of the CTs. Central Hudson has included the required upgrades within its five-year capital plan.

c) Describe how the NWA procurement process works within utility time constraints while enabling DER developers to properly prepare and propose NWA solutions which can be implemented in time to serve the system need. Details should include:

(1) how utility and DER developer time and expense are minimized for each procurement transaction;

(2) how standardized contracts and procurement methods are used across the utilities.

The timing of system needs factors into the suitability of an NWA solution being considered for that need. The Company continually monitors the T&D system to identify potential areas that could benefit from an NWA solution. When a need is identified, the Company strives to begin the solicitation process for an NWA to meet that need as early as practicable.

To enhance the DER integration process, the Joint Utilities continue to share lessons learned from developing and implementing specific NWA Requests for Proposals (including supporting data) and resultant contract terms and conditions to work towards a more similar approach for procurement within the Company and across the utilities. For example, a successful NWA contract will clearly state assumptions, pricing, applicable incentives, and expectations for the intended use of the resource by the utility, opportunities that may allow a resource 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. In terms of payment guidelines, the utility must clearly outline payment duration and schedule and include language that holds DER vendors accountable for commercial payment and ensures bids include the cost of any security instruments required. Through the information sharing across the utilities, the Joint Utilities have agreed that contracts should also include clear and consistent use of key terms and descriptions regarding the NWA DER vendor's market participation, regardless of payment cadence.

The Joint Utilities have made efforts to add consistency to NWA solicitations and contract negotiations. While there are unique needs for each utility, the Joint Utilities continue to share best practices for issuing contracts and implementing procurement methods.

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

Detailed information on past and current solicitations can currently be found on the REV Connect, Joint Utility webpage, as well as Central Hudson's web page.

https://nyrevconnect.com/non-wires-alternatives/

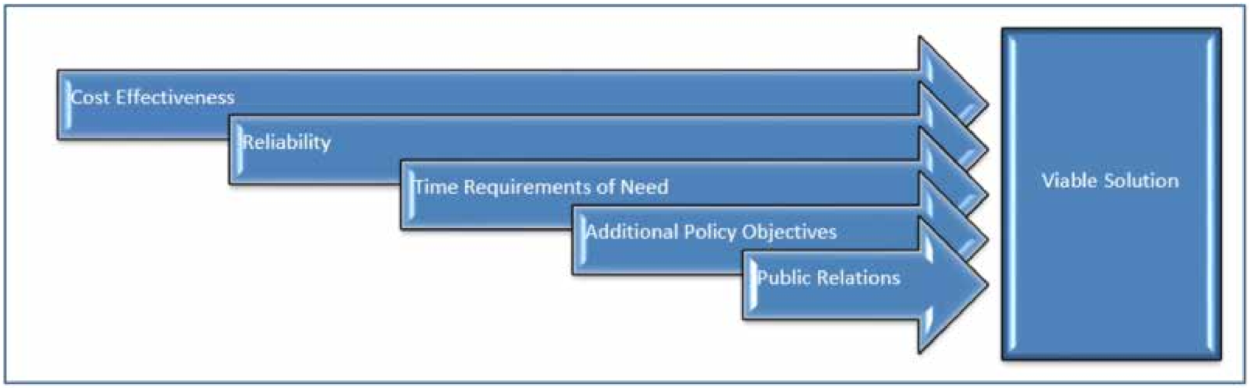
http://jointutilitiesofny.org/utility-specific-pages/nwa-opportunities/

https://www.cenhud.com/workingwithus/non-wires-alternative-opportunities

e) Describe how the utility considers all aspects of operational criteria and public policy goals when deciding what to procure as part of a NWA solution

Below are considerations for selecting a solution for an NWA:

Figure 65: Considerations for Selecting an NWA Solution



1. **Cost effectiveness**: What benefits/costs are associated with each solution? Cost effectiveness is determined in accordance with the BCA Handbook.

2. **Reliability**: How reliably will the solution(s) meet the operational needs? The main factors considered (but are not limited to) include:

- Coincidence: Does the solution perform when needed? If so, to what extent?
- Dispatch: Is the resource dispatchable? If so, what limits to the frequency and duration of dispatch exist?
- Intermittency: Is the solution available only intermittently? If so, how is that intermittency characterized? Does the resource need to be "de-rated" to account for intermittency?
- Limitations: What general and technical limitations exist for this DER?
- Timing: Can the solution be operational in time to meet a forecasted need?

3. **Time Requirements**: How timely is the need? What is the risk to the T&D system associated with failure to meet the identified need, or with any delay associated with finding a replacement technology if the initial solution were to be unsuccessful?
4. **Policy Objectives**: Will any solution(s) help this NWA meet any policy objectives in addition to fulfilling the primary grid need? What are the economic and environmental impacts of the project?
5. **Public Relations**: How does this NWA impact the Company's public relations? Does it engage customers? If so, how many and to what degree? Will the NWA improve customers' opinions of Central Hudson?

f) Describe where, how, and when the utility will provide DER developers and other stakeholders with a resource for accessing up-to-date information about all completed and in-progress NWA projects. The information provided for each project should:

(1) describe the location, type, size, and timing of the system need addressed by the project;

Detailed information on past and current solicitations can currently be found on the REV Connect, Joint Utility webpage, and Central Hudson's web page.

https://nyrevconnect.com/non-wires-alternatives/

http://jointutilitiesofny.org/utility-specific-pages/nwa-opportunities/

https://www.cenhud.com/workingwithus/non-wires-alternative-opportunities

(2) provide the amount of traditional solution cost that was/will be avoided;

Central Hudson does not provide this information, because the Company believes doing so would have a negative impact on the solicitation and procurement process. The traditional solution competes with DER solutions just as solution providers compete with each other by providing confidential bids through a solicitation.

Costs may only be provided after the NWA need is sufficiently met to account for the possibility that all/or part of the need may still need to be procured after the original solicitation in the event the primary solution is unsuccessful.

(3) explain how the selected NWA solution enables the savings; and

Detailed benefit cost analyses are developed in collaboration with DPS Staff and ultimately filed with the DPS as part of a Non-Wires Alternative project. Due to the sensitive nature of these analyses, these filings are confidential.

(4) describe the structure and functional characteristics of the procurement transaction between the utility and the solution provider(s).

The nature of the desired pricing arrangement between Central Hudson and its providers is described in some detail within each RFP. Each contract, however, is vendor-specific and reflects the unique needs of the particular project.

IV. DSIP Governance

1. Describe the DSP'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.

As has been previously described in Central Hudson's prior DSIP filings, the DSP is segregated into three main functional areas: Distribution Planning, Distribution Grid Operations, and Distribution Markets.

Central Hudson's 2023 DSIP filing provides an opportunity for the Company to share its progress to date and the roadmap going forward of key initiatives within these three main functional areas. Organizationally, Central Hudson has aligned functional responsibility under two group heads: the Vice President of Electric Engineering and Operations and the Senior Vice President of Customer Services and Gas Operations. The responsibilities under the VP of Electric Engineering and Operations include all responsibilities associated with Distribution Planning and Distribution Grid Operations. The responsibilities under the Sr VP of Customer Services and Gas Operations include more of the market function and customer engagement initiatives including NWA solicitations and implementations, demonstration projects, and development of service and rate offerings to enhance the customer experience. While these organizations work collaboratively, the Company believes that functionally separating the planning and operations functions from the market implementation functions remains important. This organizational construct is very similar to how Central Hudson operates today with transmission planning and operations and the wholesale markets. One evolution within Central Hudson was the establishment of an Energy Policy and Regulatory Group under the Vice President of Regulatory Affairs, which now provides overall support and guidance of the DSP activities. To best coordinate with the Joint Utilities and receive valuable input from stakeholders, Central Hudson has been an active participant and has played a leadership role in the Joint Utilities and the DSP Steering Committee. Central Hudson has also been active under the functional implementation working groups that fall under the Steering Committee, which include the Interconnection Technical Working Group, Interconnection Policy Working Group, and Market Design & Integration Working Group. To ensure that these work efforts stay coordinated, representatives from the new Energy Policy and Regulatory Group follow and provide regulatory support and guidance to the SMEs that participate in these various working groups. These coordinated efforts have been invaluable in providing a streamlined forum for stakeholder participation, utility collaboration, sharing experiences, and receiving valuable input from the group's consultants, who has the benefit of pulling in experiences from other jurisdictions.

2. Describe the nature, organization, governance, and timing of the work processes that comprise the utility's current scope of DSP 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.

As described above, Central Hudson has implemented an organizational structure that segregates the distribution planning and operations functions from market operations functions. As detailed in the System Planning and Grid Operations sections of the report, the Company is in the midst of a multi-year implementation of its foundational investments which include Distribution Automation, Distribution Management System, and Network Strategy communication backbone. The completion of these initiatives is currently projected to occur in 2027; detailed timelines are included in the Grid Operations Section.

Aligned with the completion of these investments is the buildout and staffing of the Transmission and Distribution Operation Center. Due to the complexity of managing and operating a distribution system with a significant penetration of DERs and two-way power flows, the Company has recognized the need to put in place a new Control Center as well as develop the resources and the procedures necessary to operate this much more dynamic and complex grid. Highlighted in the Grid Operations section (Section III.C) is a project timeline for the Operation Center, which lays the groundwork for the Company's current vision of the major operational policy and resource changes needed to make this transition.

With regard to Distribution Markets, the Company continues to work through the many established proceedings. The JU have shared their DSP roadmap of how they anticipate these markets will evolve over time. DPS Staff's issued Guidance for 2018 DSIP Updates included an additional joint filing on the DSP Market Design and Integration Working Group. This group will develop detailed recommendations for Staff, to inform a whitepaper regarding the design and implementation of the DSP market functions needed to enable and optimize operation of DERs in the utilities' electric distribution systems. The scope of the effort is to create:

- Marketable DER functions and attributes which serve the needs of the electric distribution system and/or the bulk electric system.
- Roles, responsibilities, and rules which govern the actions and interactions of all entities involved in the transaction of marketable DER functions and attributes.
- Ways and means for coordinating and performing the planning, operating, and settlement activities involving marketable DER functions and attributes.

Generic Working Group activities will include:

- identifying and evaluating information, principles, concepts, practices, policies, and laws that are relevant to designing and developing DSP market functions;
- identifying and characterizing means and methods (technical, economic, legal, or regulatory) that could enhance and/or accelerate development of DSP market functions;
- identifying and characterizing gaps, obstacles, and risks (technical, economic, legal, or regulatory) that will or might impede development of DSP market functions; and
- recommending means and methods to address identified gaps, obstacles, and risks. Central Hudson will continue work collaboratively with Staff, stakeholders, and the rest of the JU group to develop the transition and a roadmap for how the distribution level markets will evolve.

V. Appendices

Central Hudson Distributed System Implementation Plan Appendices

Revised June 30, 2023

www.CentralHudson.com

V. Appendices

A. Tools and Information Sources

The following is a listing of the various tool and information resources, and links to the various web pages for DER developers and customers to access the information:

Central Hudson Gas & Electric Corporation - www.cenhud.com

Distributed Generation Links - www.cenhud.com/dg

Interconnection Application Documents - www.cenhud.com/dg

Application Portal - www.cenhud.com/dg

Interconnection Technical Requirements - www.cenhud.com/dg

Interconnection Queue - www.cenhud.com/dg

Interconnection FAQs - www.cenhud.com/dg

Data Sharing Links

Hosting Capacity Map - www.cenhud.com/dg

System Data Portal - www.cenhud.com/dg

Joint Utilities System Data Page - http://jointutilitiesofny.org/system-data/

IEDR - https://www.nyserda.ny.gov/All-Programs/Integrated-Energy-Data-Resource-Program

Electric Vehicles Information - www.cenhud.com/electricvehicles

Programs and Incentives - www.cenhud.com/electricvehicles

Consumer Information - www.cenhud.com/electricvehicles

Charging - www.cenhud.com/electricvehicles

FAQs - www.cenhud.com/electricvehicles

Energy Efficiency - www.cenhud.com/my-energy

Programs - www.cenhud.com/my-energy

Savings Central - www.cenhud.com/my-energy

Consumer information - www.cenhud.com/my-energy

Capital Plan Link - http://jointutilitiesofny.org/system-data/

Reliability Data Link - http://jointutilitiesofny.org/system-data/

Related REV Proceedings - a listing of the related NYS PSC proceedings and efforts underway:

- Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision (Case 14-M-0101)
- In the Matter of Distributed System Implementation Plans (Case 16-M-0411)
- In the Matter of the Value of Distributed Energy Resources (Case 15-E-0751)
- VDER Working Group Regarding Value Stack (Matter 17-01276)
- VDER Working Group Regarding Rate Design (Matter 17-01277)
- VDER Low Income Working Group Regarding Low and Moderate Income Customers (Matter 17-01278)
- Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure and EV Rates Order and Medium & Heavy Duty EV Infrastructure (Case 18-E-0138, 22-E-0236, 23-E-0070)
- In the Matter of Offshore Wind Energy (Case 18-E-0071)
- In the Matter of Energy Storage Deployment Program (Case 18-E-0130)
- In the Matter of Utility Energy Efficiency Programs (Case 15-M-0252 and 18-M-0084)
- In the Matter of the Utility Energy Registry (Case 17-M-0315)
- Whole Building Energy Data Aggregation Standard (Cases 16-M-0411)
- Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and Clean Energy Standard (Case 15-E-0302)
- In the Matter of the Regulation and Oversight of Distributed Energy Resource Providers and Products (Case 15-M-0180)
- In the Matter of Proposed Amendments to the New York State Standardized Interconnection Requirements for Small Distributed Generators (Case 18-E-0018)
- Dynamic Load Management Programs (Cases 14-E-0423 and 15-E-0189)
- Proceeding on Motion of the Commission Regarding Cyber Security Protocols and Protections in the Energy Market Place (18-M-0376)
- Proceeding on Motion of the Commission to Enable Community Choice Aggregation Programs (14-M-0224)
- Proceeding on Motion of the Commission to Examine Utilities' Marginal Cost of Service Studies (19-E-0283)
- In the Matter of Consolidated Billing for Distributed Energy Resources (19-M-0463)
- Proceeding on Motion of the Commission to Consider Resource Adequacy Matters (19-E-0530)
- In the Matter of Strategic Use of Energy Related Data (20-M-0082)
- Proceeding on Motion of the Commission to Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act (20-E-0197)

- Climate Leadership and Protection Act (22-M-0149)
- New York's 10GW Distributed Solar Roadmap (21-E-0629)
- Utility Thermal Energy Network and Jobs Act (22M-0429)
- Customer Information System Investigations (22-00666, 22-E-0121, 22-M-0645)

B. Load and DER Forecast

Demand Side Analytics
DATA DRIVEN RESEARCH AND INSIGHTS

REPORT

2023 Central Hudson
Granular Load and Distributed Energy Resources Forecasts

Prepared for Central Hudson
By
Demand Side Analytics
June 2023

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ABSTRACT

The focus of the study is to present the methodology and results for granular forecasting for T&D loads, distributed energy resources (DERs), beneficial electrification, both for the Central Hudson service territory and for transmission areas, substations, and circuit feeders. In specific, the study produced 8760 profiles at the feeder level for gross electric loads, distributed solar, battery storage, building electrification, electric vehicles, and energy efficiency (including codes and standards). The granular forecasts have multiple uses for T&D planning and to estimate location-specific T&D avoided costs. The hourly 8760 forecasts are posted on the Central Hudson website as part of the 2023 DSIP.

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1 INTRODUCTION

A vital role of Central Hudson is to ensure that electricity supply remains reliable by projecting future electricity demand and reinforcing the transmission and distribution system so the capacity is available to meet local needs as they grow over time. The forecasts and planning are done on a system-wide basis and for individual components of the system, including distribution circuits, substations, and transmission areas. At each level, infrastructure components are sized to meet the aggregate peak demand of the customers connected to that portion of the distribution grid. As a general rule, transmission projects are sized to cover broader geographic regions whereas distribution infrastructure is sized to cover a local area's coincident demand, which can be quite diverse. System level, transmission, and distribution peaks do not necessarily occur at the same time or on the same day.

The electricity industry is experiencing rapid technological change, particularly with the growth in electric vehicles, building electrification, solar, battery storage, and energy efficiency. The changes affect how, when, and where customers use electricity and local peak demand patterns. As solar and electric vehicles are added to the distribution system, the peak has shifted from summer afternoons to early evening hours. As building electrification grows, distribution substation and circuits that were previously summer peaking can become winter peaking.

This report summarizes the methodology and results of granular forecasting for T&D loads, building electrification, electric vehicles, distributed solar, distributed battery storage, and energy efficiency (including codes and standards). The study produced 8,760 hourly forecasts for each feeder and in Central Hudson territory for ten (10) forecast years. The granular forecasts can be aggregated to substations and transmission areas, and thus can be incorporated both into T&D and system planning. The 8760 hourly forecasts enable T&D planners to identify when peaks are expected to occur and how the timing of peak demand evolves over time.

The bottom-up granular forecasts have been designed to isolate the key drivers of change in loads. Specifically, to isolate load growth trends from solar interconnections, historical solar production is added back to the observed historical loads. The objective is to quantify the growth in gross loads separately from the growth in distributed generation, which reduces net loads but does not reduce gross energy usage. In addition, the forecasts separately track gross loads, solar, battery storage, building electrification, electric vehicle loads, and incremental energy efficiency (including codes and standards). The approach allows Central Hudson to combine the various components for different planning applications, such as the Avoided T&D Costs Study loads (which do not include distributed energy resources that have not yet been built).

Table 1 illustrates the components of the bottom-up load forecasts. A similar forecast is produced for each of Central Hudson's transmission areas, substations, and circuit feeders. The granular forecasts can be summarized for the coincident (territory-wide) or non-coincident (local) summer and winter peak at different levels of geographic granularity. They also can be shown for the single peak hour, for peak days, or for the full 8760 hours per year and each level of geographic granularity. Planning forecasts for the local coincident hour and the 24 hour forecasts for summer and winter peaks by year and location will be publicly available on Central Hudson's data portal.

Table 1: Summer and Winter Territory-Wide Load Forecast with and without DERs and Beneficial Electrification (2023-2028)

Season	Year	(a) Gross Load Forecast	(b) EV Load	(c) Building Electrification	(d) EE & C&S	(e) Solar PV	(f) Storage Net Load	(g) Planning Load
								a + b + c + d + e + f
Summer	2023	1,115.4	8.8	-1.4	-7.2	-27.0	-8.1	1,080.5
	2024	1,115.9	13.1	-2.8	-13.6	-31.7	-8.4	1,072.4
	2025	1,116.7	19.1	-4.7	-21.2	-36.8	-9.5	1,063.6
	2026	1,118.1	27.2	-7.1	-28.8	-42.9	-10.2	1,056.3
	2027	1,119.9	37.7	-9.8	-36.2	-49.9	-11.2	1,050.5
	2028	1,122.2	50.8	-13.0	-43.7	-55.9	-12.3	1,048.1
Winter	2023	945.0	5.9	9.3	-7.1	-2.7	-8.1	942.3
	2024	945.5	8.8	19.0	-13.4	-3.2	-8.3	948.4
	2025	946.3	12.9	32.2	-20.9	-3.7	-9.4	957.4
	2026	947.6	18.5	48.1	-28.3	-4.3	-10.1	971.4
	2027	949.2	25.7	66.5	-35.6	-5.1	-11.1	989.7
	2028	951.2	34.7	87.5	-43.0	-5.7	-12.3	1,012.6

[1] The peak values displayed in the table are coincident with the planning load for Central Hudson service territory

Table 2 shows the forecast used for the Avoided T&D study, which is different than the planning forecast. By design, the study's objective is to identify T&D upgrades that would occur if additional or incremental distributed resources – solar, battery storage, and energy efficiency – were not added, and to quantify the deferral value associated with reductions in demand (or local power injections). Thus, the avoided T&D study forecasts include existing DERs, and the impact of electric vehicles and building electrification, but does not include DERs that had not yet been built. The T&D avoided costs forecasts for the coincident hour and the 24 hour forecasts for summer and winter peaks by year and location will be publicly available on Central Hudson's data portal.

Table 2: Summer and Winter Territory-Wide Avoided T&D Cost Forecast (2023-2028)

Season	Year	(a) Econometric Forecast	(b) EV Load	(c) Building Electrification	(d) Avoided T&D Cost Forecast a + b + c
Summer	2023	1,127.2	8.6	-1.6	1,134.2
	2024	1,127.4	12.8	-3.2	1,137.0
	2025	1,128.1	18.6	-5.5	1,141.3

Season	Year	(a) Econometric Forecast	(b) EV Load	(c) Building Electrification	(d) Avoided T&D Cost Forecast a + b + c
	2026	1,129.3	26.5	-8.2	1,147.6
	2027	1,131.0	36.8	-11.4	1,156.4
	2028	1,133.2	49.6	-15.1	1,167.7
Winter	2023	943.8	5.9	9.3	959.0
	2024	944.3	8.8	19.0	972.1
	2025	945.1	12.9	32.2	990.3
	2026	946.4	18.5	48.1	1,012.9
	2027	948.0	25.7	66.5	1,040.3
	2028	950.0	34.7	87.5	1,072.3

[1] The peak values displayed in the table above are coincident with the avoided T&D cost forecast peak for Central Hudson territory

The remainder of the report presents the methodology and provides additional detail for each component for the planning forecast. The forecasts used for the avoided T&D study are summarized in the Location Specific Transmission and Distribution Avoided Cost report. The remainder for the report is structured as follows.

- Section 2 provides an overview of the load forecasts for the Central Hudson system as well as for different sub-components including transmission areas and substations.
- Section 3-7 present an overview of the methodology, historical adoptions trends, and forecast results for electric vehicles, building electrification, net metered solar and battery, community and remote solar and battery, and energy efficiency. We elected to keep the section concise and provide additional technical detail in appendices to improve readability.
- The summer and winter coincident peak (single hour) and 24 hour planning forecasts by year for the territory and by transmission area, substation, and feeder will be made publicly available on the Central Hudson website.
- Appendices A, B, and C provide additional technical detail regarding the forecasting methodology for electric vehicles, building electrification, and energy efficiency.

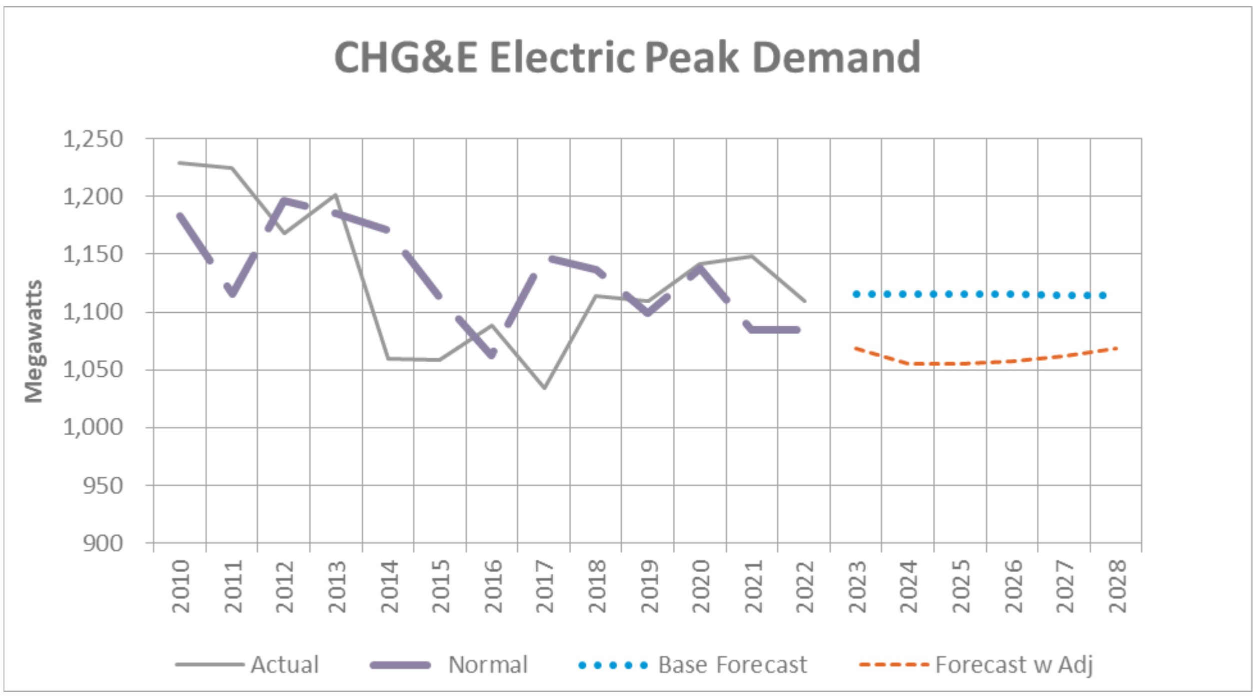
2 LOAD FORECASTS

The integration of DERs requires significant changes to how distribution planning takes place and how it is coordinated with system forecasts. Before the DSIP process was initiated in 2016, the approach was to develop load growth forecasts for each broader area within Central Hudson's territory and apply them to the specific peak loads for substations and transmission areas. Central Hudson has evolved its planning process to produce granular, location-specific, probabilistic forecasts and to separately track gross loads from solar, battery storage, building electrification, electric vehicle loads, and incremental energy efficiency (including codes and standards).

2.1 SYSTEM LEVEL FORECAST

Figure 1 provides the current 5 Year System Wide Forecast. Central Hudson peak loads have declined in recent years due in part to more efficient appliances and building, program-based energy efficiency, and increased solar adoption. Going forward, additional adoption of energy efficiency and solar are expected to result in flat to decreasing peak load patterns.

Figure 1: System Historical and Forecasted Peaks



Central Hudson has evolved its planning process to produce granular, location-specific, probabilistic forecasts. The granular forecasts were produced as part of the T&D marginal cost study and the methodology for producing them is discussed in more detail in that study. In this section, we provide forecasting results as context for the DER granular forecasting and coincidence factor results.

2.2 TRANSMISSION AREAS

Table 3 summarizes the historical year by year growth for each transmission area, the growth trend, and the variability in the growth patterns, also known as the standard error of the forecast. The growth estimates were estimated using econometric models designed to disentangle year by year growth rates from differences in weather patterns, day of week effects, and seasonality. Historical solar production is added back to the observed historical loads to isolate load growth from growth in distributed generation which reduces net loads but does not reduce gross energy usage. For the most part, the year by year estimates of growth are relatively precise. The confidence bands around those estimates and the explanatory power of the models are summarized in the Location Specific Transmission and Distribution Avoided Cost report. Historical year by year growth does not follow a linear pattern and varies around the general trend line. This variation was used to develop the standard error of the forecast, which reflects how year to year growth can vary. This variability or uncertainty in the growth pattern is critical to probabilistic forecasting. Because growth and declining loads compound over time, growth patterns can deviate substantially from the straight-line forecast. An area where loads are projected to remain flat can exceed the load serving capability five to ten years out due to the uncertainty in the forecast, though the likelihood of doing so is lower than for an area that is growing.

Table 4 and Table 5 detail the elements included in developing the load forecast used for planning for summer and winter, respectively from 2023 through 2028. First, end use load was forecast using the load growth estimate from Table 3. Next, load growth expected from vehicle and building electrification is added to the forecast. The result is the load forecast used for the avoided T&D cost study (column h) and area loading which is a key input into the identification of locations where load reduction would be beneficial. Area loading is the load as a percent of the area rating, which includes contracted Non-Wires Alternatives (NWAs). Importantly, load reducing distributed energy resources (columns d-f) are not included in this load estimate, because they are not contracted and are therefore uncertain. Further, if these uncertain reductions are assumed to show up, their value is essentially removed from the load reduction valuation. The load reducing distributed energy resources (DERs) are included in the planning forecast however (column g). While this forecast is not used for the avoided T&D cost study, we have included it below for reference. All peak values in the table are coincident with the transmission area's peak load for summer and winter, respectively. Therefore, the numbers will vary from the system-coincident peak forecast.

Finally, Table 3 shows the historical peaks, normalized for 1-in-2 weather conditions alongside the forecasted local peak used for the T&D avoided cost study, e.g. (column g) from Table 4 and Table 5. Note that the Westerlo Loop area is nested within the NW 69 Area and the NW 69 Area is nested within the NW 115-69 Area. Not all substations are located within a transmission area. For these two reasons, the sum of the transmission areas will not equal the total system load. Finally, the ratings shown in Table 3 correspond to 2022 ratings, and all ratings shown include active Non-Wires Alternative project capacity. Transmission areas can peak in either the summer or the winter. In Table 3 and Table 5, transmission areas with a winter peak in 2028 (5 years into the forecast) are indicated with an asterisk (*).

Table 3: Transmission Area Historical Load Growth Estimates (2019-2022)

Transmission Area	Rating (MVA)	Historical Peak (MVA)				Loading	Annual Growth	Std. Error
		2019	2020	2021	2022			
Ellenville*	130.0	61.4	63.6	60.1	66.5	48.7%	-0.3%	1.5%
Hurley-Milan*	232.0	82.7	79.8	77.9	83.9	30.6%	-1.6%	1.3%
Mid-Dutchess	230.0	114.7	115.6	105.6	112.4	48.9%	-1.9%	0.9%
NW 115-69 Area*	179.8	129.0	133.6	119.8	128.9	76.0%	-1.3%	1.7%
NW 69 Area*	200.5	106.8	101.1	101.4	107.9	55.7%	1.2%	1.2%
Pleasant Valley 69	107.0	69.3	71.3	67.3	72.4	74.6%	0.4%	1.8%
RD-RJ Lines	144.0	114.4	114.8	113.1	113.6	92.0%	1.1%	3.4%
Southern Dutchess	211.0	148.5	146.5	151.3	146.1	84.1%	-0.1%	2.4%
WM Line	68.0	49.0	52.6	49.6	55.0	79.7%	0.0%	1.5%
Westerlo Loop*	83.6	62.6	61.7	59.7	60.9	76.0%	0.5%	1.7%

Table 4: Transmission Area **Summer** Load Forecast with and without DERs (2023-2028)

Transmission Area	Year	(a) Gross Load Forecast	(b) EV Load	(c) Building Electrification	(d) EE & C&S	(e) Solar PV	(f) Storage Net Load	(g) Planning Load a + b + c+d+e+f
Ellenville	2023	64.9	0.8	-0.2	-0.4	-2.0	-0.4	62.5
	2024	64.7	1.2	-0.5	-0.9	-2.6	-0.5	61.5
	2025	61.6	1.6	-0.7	-1.2	-0.2	-0.1	61.0
	2026	61.4	2.3	-0.9	-1.7	-0.3	-0.1	60.7
	2027	61.2	3.2	-1.2	-2.2	-0.3	-0.1	60.6
	2028	61.0	4.3	-1.6	-2.7	-0.3	-0.1	60.6
Hurley-Milan	2023	77.3	0.9	-0.2	-0.7	-1.5	-0.2	75.6
	2024	76.1	1.2	-0.3	-1.4	-1.9	-0.2	73.6
	2025	75.0	1.7	-0.5	-2.1	-2.1	-0.2	71.8
	2026	71.3	2.2	-0.6	-2.4	-0.2	0.0	70.3
	2027	70.1	3.1	-0.9	-3.0	-0.2	-0.1	69.1
	2028	69.0	4.0	-1.1	-3.6	-0.2	-0.1	68.1
Mid-Dutchess	2023	111.1	0.5	-0.1	-0.7	-1.9	-0.1	108.9
	2024	109.0	0.8	-0.2	-1.3	-2.0	-0.1	106.3
	2025	107.0	1.3	-0.3	-1.8	-2.4	-0.1	103.7
	2026	105.0	1.9	-0.4	-2.4	-2.5	-0.1	101.4
	2027	103.0	2.6	-0.6	-3.0	-2.9	-0.1	99.0
	2028	101.0	3.5	-0.9	-3.6	-3.1	-0.1	96.8
Northwest 115-69 Area	2023	128.8	0.6	-0.2	-0.4	-0.5	-0.3	128.1
	2024	127.1	0.9	-0.3	-0.8	-0.8	-0.3	125.8
	2025	125.5	1.2	-0.5	-1.3	-1.3	-0.3	123.4
	2026	123.8	1.7	-0.6	-1.8	-1.7	-0.3	121.1
	2027	122.3	2.4	-0.9	-2.2	-2.0	-0.3	119.2
	2028	120.7	3.1	-1.1	-2.7	-2.5	-0.4	117.2

Transmission Area	Year	(a) Gross Load Forecast	(b) EV Load	(c) Building Electrification	(d) EE & C&S	(e) Solar PV	(f) Storage Net Load	(g) Planning Load a + b + c+d+e+f
Northwest 69kV Area	2023	105.9	0.2	-0.1	-0.2	0.0	0.0	105.8
	2024	107.1	0.3	-0.1	-0.3	0.0	0.0	106.9
	2025	108.4	0.4	-0.2	-0.5	0.0	0.0	108.1
	2026	109.7	0.6	-0.3	-0.6	0.0	0.0	109.4
	2027	110.9	0.9	-0.3	-0.7	0.0	0.0	110.6
	2028	112.2	1.2	-0.4	-0.9	0.0	0.0	112.0
Pleasant Valley 69	2023	78.4	0.7	-0.1	-0.4	-2.6	-0.4	75.7
	2024	78.8	1.1	-0.2	-0.8	-3.1	-0.4	75.3
	2025	79.1	1.7	-0.4	-1.4	-3.4	-0.4	75.2
	2026	75.8	2.3	-0.5	-1.8	-0.3	-0.1	75.5
	2027	76.1	3.3	-0.7	-2.3	-0.4	-0.1	75.9
	2028	76.5	4.4	-0.9	-2.8	-0.4	-0.1	76.6
RD-RJ Lines	2023	134.7	0.5	0.0	-0.4	-7.9	-0.6	126.3
	2024	136.2	0.7	-0.1	-0.8	-8.0	-0.6	127.4
	2025	137.6	1.0	-0.2	-1.3	-8.3	-0.6	128.3
	2026	139.0	1.4	-0.3	-1.7	-8.9	-0.6	129.0
	2027	140.5	2.0	-0.4	-2.2	-9.5	-0.6	129.8
	2028	142.1	2.7	-0.6	-2.7	-10.1	-0.6	130.8
Southern Dutchess	2023	170.6	0.7	-0.1	-0.4	-0.1	0.0	170.6
	2024	170.4	1.0	-0.1	-0.9	-0.1	0.0	170.2
	2025	170.2	1.4	-0.2	-1.4	-0.1	0.0	169.8
	2026	169.9	2.0	-0.3	-2.0	-0.1	0.0	169.4
	2027	169.7	2.7	-0.5	-2.5	-0.1	0.0	169.2
	2028	169.4	3.5	-0.7	-3.0	-0.1	0.0	169.1
WM Line	2023	53.8	0.1	0.0	-0.1	-0.7	0.0	53.1
	2024	53.8	0.2	0.0	-0.2	-1.3	-0.1	52.5
	2025	53.8	0.3	0.0	-0.3	-1.5	-0.1	52.2
	2026	53.8	0.4	-0.1	-0.4	-1.8	-0.1	52.0
	2027	53.8	0.5	-0.1	-0.5	-2.0	-0.1	51.7
	2028	53.8	0.7	-0.1	-0.5	-2.0	-0.2	51.7
Westerlo Loop	2023	62.9	0.3	0.0	-0.4	-0.1	0.0	62.7
	2024	63.2	0.6	-0.1	-0.6	-0.1	0.0	62.9
	2025	63.5	0.9	-0.2	-0.9	-0.1	0.0	63.1
	2026	63.8	1.3	-0.4	-1.3	-0.1	0.0	63.3
	2027	64.1	2.0	-0.5	-1.6	-0.2	0.0	63.7
	2028	64.4	2.7	-0.8	-1.9	-0.2	-0.1	64.2

Table 5: Transmission Area **Winter** Load Forecast with and without DERs (2023-2028)

Transmission Area	Year	(a) Gross Load Forecast	(b) EV Load	(c) Building Electrification	(d) EE & C&S	(e) Solar PV	(f) Storage Net Load	(g) Planning Load a + b + c+d+e+f
Ellenville	2023	63.4	0.5	1.6	-0.4	-0.2	-0.5	64.4
	2024	63.2	0.8	3.1	-0.8	-0.3	-0.5	65.5
	2025	63.0	1.1	4.9	-1.3	-0.4	-0.9	66.4
	2026	62.8	1.6	6.9	-1.8	-0.5	-1.0	68.0
	2027	62.6	2.3	9.1	-2.3	-0.6	-1.5	69.6
	2028	62.4	3.0	11.4	-2.8	-0.7	-1.8	71.6
Hurley-Milan	2023	70.4	0.6	1.0	-0.7	-0.2	-0.2	70.9
	2024	69.3	0.8	2.0	-1.3	-0.2	-0.2	70.4
	2025	68.2	1.2	3.2	-2.0	-0.3	-0.2	70.2
	2026	67.1	1.6	4.7	-2.7	-0.3	-0.2	70.3
	2027	66.1	2.2	6.4	-3.3	-0.4	-0.2	70.7
	2028	65.0	2.9	8.2	-3.9	-0.4	-0.3	71.5
Mid-Dutchess	2023	83.1	0.5	0.3	-0.5	0.0	-0.1	83.3
	2024	81.5	0.7	0.7	-0.9	0.0	-0.1	81.8
	2025	80.0	1.0	1.3	-1.5	0.0	-0.1	80.7
	2026	78.4	1.4	2.1	-2.0	0.0	-0.1	79.8
	2027	77.0	2.0	3.1	-2.5	0.0	-0.1	79.3
	2028	75.5	2.7	4.2	-3.0	0.0	-0.1	79.1
Northwest 115-69 Area	2023	135.6	0.4	1.0	-0.4	-0.1	-0.3	136.2
	2024	133.8	0.6	1.9	-0.8	-0.1	-0.3	135.1
	2025	132.1	0.8	2.9	-1.3	-0.2	-0.3	134.1
	2026	130.4	1.2	4.1	-1.8	-0.2	-0.3	133.4
	2027	128.7	1.6	5.5	-2.2	-0.2	-0.4	133.0
	2028	127.0	2.1	7.0	-2.7	-0.3	-0.4	132.8
Northwest 69kV Area	2023	112.5	0.2	0.5	-0.3	-0.1	-0.1	112.7
	2024	113.8	0.2	1.0	-0.5	-0.1	-0.1	114.3
	2025	115.2	0.4	1.5	-0.7	-0.1	-0.1	116.1
	2026	116.5	0.5	2.2	-0.9	-0.2	-0.2	118.0
	2027	117.9	0.8	2.9	-1.1	-0.2	-0.2	120.0
	2028	119.3	1.0	3.7	-1.3	-0.2	-0.2	122.2

Transmission Area	Year	(a) Gross Load Forecast	(b) EV Load	(c) Building Electrification	(d) EE & C&S	(e) Solar PV	(f) Storage Net Load	(g) Planning Load a + b + c+d+e+f
Pleasant Valley 69	2023	67.6	0.5	0.5	-0.4	-0.3	-0.4	67.5
	2024	67.9	0.8	1.2	-0.9	-0.3	-0.4	68.3
	2025	68.2	1.2	2.4	-1.4	-0.3	-0.4	69.6
	2026	68.5	1.7	3.8	-2.0	-0.4	-0.4	71.2
	2027	68.8	2.3	5.5	-2.6	-0.5	-0.5	73.2
	2028	69.1	3.2	7.4	-3.2	-0.6	-0.5	75.5
RD-RJ Lines	2023	91.4	0.4	0.2	-0.3	-0.6	-0.6	90.4
	2024	92.3	0.5	0.4	-0.7	-0.6	-0.6	91.4
	2025	93.3	0.8	0.8	-1.0	-0.6	-0.6	92.6
	2026	94.3	1.1	1.2	-1.4	-0.7	-0.6	93.9
	2027	95.3	1.5	1.8	-1.8	-0.7	-0.6	95.6
	2028	96.4	2.1	2.5	-2.2	-0.8	-0.6	97.4
Southern Dutchess	2023	125.2	0.6	0.3	-0.5	0.0	-0.2	125.4
	2024	125.0	0.8	0.6	-1.0	0.0	-0.2	125.2
	2025	124.9	1.2	1.0	-1.5	0.0	-0.2	125.3
	2026	124.7	1.7	1.5	-2.1	0.0	-0.3	125.5
	2027	124.5	2.3	2.1	-2.6	0.0	-0.3	126.0
	2028	124.3	3.0	2.9	-3.2	0.0	-0.3	126.8
WM Line	2023	47.6	0.1	0.0	-0.1	0.0	0.0	47.6
	2024	47.6	0.2	0.1	-0.2	-0.1	0.0	47.6
	2025	47.6	0.2	0.2	-0.2	-0.1	0.0	47.7
	2026	47.6	0.4	0.3	-0.3	-0.1	0.0	47.9
	2027	47.6	0.5	0.5	-0.4	-0.1	0.0	48.1
	2028	47.6	0.7	0.7	-0.5	-0.1	0.0	48.3
Westerlo Loop	2023	63.7	0.3	0.4	-0.5	0.0	-0.2	63.7
	2024	64.0	0.5	1.0	-0.9	-0.1	-0.3	64.2
	2025	64.4	0.7	1.9	-1.4	-0.1	-0.8	64.7
	2026	64.7	1.1	3.0	-1.8	-0.1	-0.8	66.0
	2027	65.0	1.6	4.5	-2.2	-0.1	-1.0	67.7
	2028	65.3	2.2	6.1	-2.7	-0.1	-1.4	69.4

2.3 SUBSTATIONS

Central Hudson groups its substations into load areas for planning. The substations within a load area generally have multiple tie points enabling load transfers.

Table 6 shows the 2028 summer peak load forecast for each substation, including each of the load forecast components. Due to the volume of substations, it is impractical to show yearly (or hourly forecasts) in a document. Thus, data will be made publicly available on Central Hudson's website for substations and years and to view results for the single peak hour, or for all 24 hours of the peak summer or peak winter day.

Table 6: 2028 Substation Summer Peak Load Forecast by Component

Load Area	Substation	(a) Gross Load Forecast	(b) EV Load	(c) Building Electrification	(d) EE & C&S	(e) Solar PV	(f) Storage Net Load	(g) Planning Load a + b + c+d+e+f
Ellenville	Clinton Ave	1.8	0.1	0.0	-0.1	-0.1	0.0	1.7
	Greenfield Rd	4.9	0.4	-0.1	-0.4	0.0	0.0	4.7
	Grimley Rd	7.6	0.1	-0.1	-0.1	-0.5	0.0	7.1
	High Falls	19.9	1.6	-0.6	-1.0	-0.1	0.0	19.8
	Honk Falls	6.3	0.2	-0.1	-0.1	0.0	0.0	6.2
	Kerhonkson	12.0	0.6	-0.3	-0.3	-0.1	0.0	11.9
	Neversink	3.0	0.3	-0.1	-0.1	0.0	0.0	3.0
	Sturgeon Pool	2.7	0.2	-0.1	-0.1	0.0	0.0	2.7
Fishkill-D	Fishkill Plains	52.1	2.5	-0.5	-2.1	-2.1	-0.3	49.7
	Forgebrook	30.8	1.3	-0.3	-1.4	-0.7	0.0	29.7
	Knapps Corners	17.4	0.5	-0.2	-0.6	-0.3	0.0	16.9
	Merritt Park	29.1	1.2	-0.2	-1.0	-1.2	-0.1	27.9
	Myers Corners	18.6	0.8	-0.2	-0.6	-0.9	-0.1	17.6
	North Chelsea	17.7	0.8	-0.1	-0.7	-0.6	0.0	17.1
	Sand Dock-Distribution	4.0	0.2	-0.1	-0.2	-0.1	0.0	3.8
	Shenandoah-Distribution	12.0	0.9	-0.2	-0.6	-0.1	-0.1	12.0
	Tioronda	16.8	0.8	-0.2	-0.7	-0.3	0.0	16.5
Kingston-Saugerties	Boulevard	18.5	0.9	-0.3	-1.1	0.0	0.0	18.0
	East Kingston	17.7	0.8	-0.3	-0.8	-0.3	0.0	17.0
	Hurley Ave	17.8	1.1	-0.3	-1.1	-0.1	0.0	17.3
	Lincoln Park	30.2	1.3	-0.4	-1.5	-0.2	0.0	29.4
	Saugerties	23.9	1.2	-0.5	-1.0	-0.1	0.0	23.5
	Woodstock	20.1	1.5	-0.7	-1.1	-0.6	0.0	19.2
Modena	Galeville	11.0	0.8	-0.3	-0.3	0.0	0.0	11.1
	Highland	18.4	0.9	-0.3	-0.8	-0.1	0.0	18.2
	Modena	14.4	0.8	-0.3	-0.4	0.0	0.0	14.4
	Ohioville	19.8	1.3	-0.5	-1.3	-0.5	-0.1	18.7

Load Area	Substation	(a) Gross Load Forecast	(b) EV Load	(c) Building Electrification	(d) EE & C&S	(e) Solar PV	(f) Storage Net Load	(g) Planning Load a + b + c+d+e+f
Newburgh	Bethlehem Rd	38.1	1.0	-0.2	-0.6	-1.9	-0.5	36.0
	Coldenham	25.0	0.7	-0.1	-0.7	-0.1	0.0	24.8
	East Walden	14.9	0.8	-0.2	-0.4	-0.2	0.0	14.9
	Marlboro	21.9	0.9	-0.2	-0.6	-0.9	-0.1	21.0
	Maybrook	18.1	0.7	-0.1	-0.5	-0.1	0.0	18.1
	Union Ave	68.0	1.8	-0.4	-2.2	-0.9	-0.2	66.1
	West Balmville	32.9	1.3	-0.3	-1.3	-0.5	0.0	32.1
Northeastern Dutchess	East Park	14.5	0.7	-0.2	-0.6	-0.5	0.0	13.8
	Hibernia	15.1	0.9	-0.2	-0.5	-0.4	-0.1	14.8
	Milan	10.3	0.5	-0.1	-0.3	0.0	0.0	10.4
	Millerton	4.5	0.3	-0.1	-0.3	-0.3	0.0	4.2
	Pulvers 34kV	2.8	0.5	-0.1	-0.2	0.0	0.0	2.9
	Rhinebeck	22.3	1.9	-0.4	-1.2	-0.1	0.0	22.5
	Smithfield	1.9	0.1	0.0	0.0	0.0	0.0	1.9
	Staatsburg	11.4	0.6	-0.1	-0.2	0.0	0.0	11.5
	Stanfordville	6.3	0.4	-0.1	-0.2	0.0	0.0	6.4
	Tinkertown	15.6	0.7	-0.2	-0.7	-0.7	0.0	14.7
Northwest	Coxsackie	12.2	0.4	-0.1	-0.3	-0.1	0.0	12.2
	Freehold	9.1	0.4	-0.1	-0.2	0.0	0.0	9.2
	Hunter	1.9	0.1	0.0	-0.1	0.0	0.0	1.9
	Lawrenceville	5.6	0.2	0.0	-0.2	0.0	0.0	5.5
	New Baltimore	16.4	0.4	-0.1	-0.3	0.0	0.0	16.4
	North Catskill	26.0	1.0	-0.3	-1.0	-0.1	0.0	25.6
	South Cairo	13.9	0.5	-0.1	-0.4	0.0	0.0	13.8
	Vinegar Hill	4.4	0.2	-0.1	-0.1	0.0	0.0	4.4
	Westerlo	8.6	0.5	-0.1	-0.2	0.0	0.0	8.7
Poughkeepsie-D	Inwood Ave	30.4	0.7	-0.1	-0.8	0.0	0.0	30.2
	Manchester	26.8	1.1	-0.3	-1.6	-1.0	-0.1	24.9
	Reynolds Hill	44.8	0.5	-0.2	-1.5	-0.6	0.0	43.0
	Spackenkill	34.5	1.1	-0.4	-0.9	-1.3	0.0	32.9
	Todd Hill	25.5	1.2	-0.3	-0.5	-0.9	0.0	24.9

Distribution Feeders

As a continued advancement of the methodologies utilized in this study, forecasting was completed at the more granular circuit level for the first time. Unlike substation and transmission areas, circuits utilize design criteria, which includes a normal and emergency design rating, but do not have an LTE rating. The design criteria are tied to operational requirements to maintain flexibility at the substation level and are more conservative than the actual thermal rating of the distribution assets on the feeder.

Central Hudson utilizes several standard design ratings for circuits (i.e. 6/9 MVA or 9/12 MVA high capacity for 13.8kV circuits). This circuit design rating does not represent the thermal capability for the circuit which is typically higher and provides for local operating flexibility.

Circuit overloads are treated differently from substation and transmission areas, with some circuits operating above their design criteria but never exceeding their thermal rating. This is due to the following:

- The distribution system is more dynamic
- Central Hudson can transfer loads more easily between circuits to maintain load balancing amongst area circuits in addition to addressing reliability
- There is a potentially shorter timeframe required to complete upgrades

Due to the noise in the circuit data, the circuit's corresponding substation was used to determine the growth rate for the circuit. Many circuits exceed their design criteria rating in 2022 as they can operate above their design criteria and remain under their thermal limits.

Additionally, Central Hudson's design criteria are a combination of thermal, economic, and reliability considerations, as well as engineering judgment, to provide a guiding foundation in developing or altering circuit configurations. Central Hudson is a summer peaking utility and since summer ratings are limiting, the design ratings were established utilizing summer ratings because they are most limiting. With electrification and the potential shift to a winter peak, Central Hudson will need to establish winter ratings for its distribution facilities at the feeder level in the future which will vary by station. These ratings will likely allow for more load serving capabilities on the distribution facilities during the winter period.

As this was the first time forecasting analysis was performed at the circuit level, Central Hudson plans on refining the criteria utilized within the analysis for future studies before providing forecasted feeder level data. Historical 8760 hourly load data can be found within Central Hudson's System Data Portal.

3 ELECTRIC VEHICLES

The goal of this section is to describe the process of producing 8760 electric vehicle (EV) load forecasts at the substation level which account for the temporal and locational variation in the adoption of electric vehicles, which include light-duty vehicles (LDV), medium and heavy-duty vehicles (MHDV), buses, and DC fast charging (DCFC) ports.

3.1 METHODOLOGY OVERVIEW

Forecasts for LDVs, MHDVs, buses, and DC fast charging stations (DCFC) were produced using the methodology described in Figure 2 and Figure 3. Figure 2 provides a high-level overview and Figure 3 provides additional detail for each step.

Figure 2: Electric Vehicles Forecast Process Overview

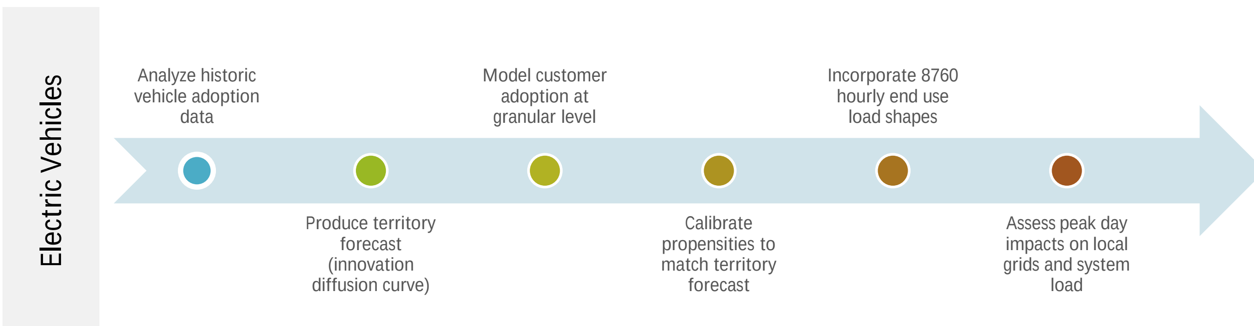


Figure 3: Electric Vehicles Forecast Process Detail

1. Analyze Historical Data

- Use NHTSA VIN decoder API to extract details about vehicle
- Assess adoption patterns over time and geographic concentration, including the electric vehicle share by model year
- Assess changes in the mix of PHEV and battery electric vehicles

2. Produce Service Territory Forecast

- Fit innovation diffusion curves with uncertainty (bass curves) to the historical data, assume 80% cap of electric share of new vehicle sales
- Predict EV market share for future model years
- Use a stock and flow model to track the turnover in vehicle stock based on new vehicle entry, and outflow.
- Convert vehicle counts to GWh sales

3. Model customer adoption propensity

- Investigate characteristics that inform adoption likelihood
- Run machine learning model (XBGoost) to quantity adoption likelihood
- Estimate propensity to adopt for each premise
- We relied on the current locational mix to set a base propensity value for public, fast charging, medium and heavy duty vehicle loads, and buses.

4. Calibrate propensities to match territory forecast

- Scale the premise level propensities so the total for each year equals the system level forecasts for that year (each site follows its individual S-curve)
- Aggregate to the circuit feeder level to get forecasted counts of residential and non-residential sites adopting EVs.
- Allocate total EV electric sales to feeders

5. Incorporate 8760 hourly end use load shapes

- Collect home, public, and fast charging load shapes from NREL EV Lite Pro tool
- Collect Medium Heavy-Duty Vehicle and bus load shapes from LBNL HEVI report
- Make EV load shapes 8760 and normalize so total for the year is 100%
- Merge with feeder level forecasts and scale load shape based on the forecasted electric vehicle energy use (MWh).
- This produced 8760 hourly EV loads by circuit feeder and forecast year

6. Assess Peak Day Impacts

- Identify the local winter and summer peak days for feeders, substations, transmission areas and territory wide using T&D hourly interval data
- Combine electric vehicle loads with forecasted T&D loads on peak days for each location (feeder, substation, and transmission area) and forecast year
- Output is location-specific EV load forecasts and local peak coincidence factors

3.2 HISTORIC ADOPTION PATTERNS IN CENTRAL HUDSON TERRITORY

New York makes available vehicle registration data for all 11 million vehicles in New York, including information about the fuel type (e.g., electric, gas, diesel, etc.), the vehicle class, model year, zip code, and VIN number. We used the National Highway Transportation and Safety Administrations to extract additional information embedded in the VIN number (e.g., hybrid and PHEV vehicle information). In addition, NYSERDA has provided Central Hudson data about electric vehicles rebates since 2018, which is associated with the Central Hudson data on electricity use and location in the grid.

The main objective of the historical analysis was to understand the total vehicles in the service territory, the rate of entry of new vehicles, the geographic locations of electric vehicles, and how the electric vehicle share (as percent of new vehicles) was changing over time.

Figure 4 shows the Vehicle stock in Central Hudson territory as March 2023 by model year. Based on the vehicle registration data, there are approximately 570,000 Light Duty Vehicles (LDV), 25,400 Medium and Heavy-Duty Vehicles, and 1,600 Buses in Central Hudson's service territory. Approximately, 43,000 new vehicles enter Central Hudson's territory per year. The rate of entry in recent years has been lower due in part to COVID and the reality that not all of 2022 model years have made it from sale lots to driveways. As vehicles age, they either flow out of Central Hudson's service territory or are retired. Thus, the overall penetration of electric vehicles is influenced most heavily by the share of new vehicles.

Figure 4: Central Hudson Vehicle Stock and Electric Vehicle Share by Model Year

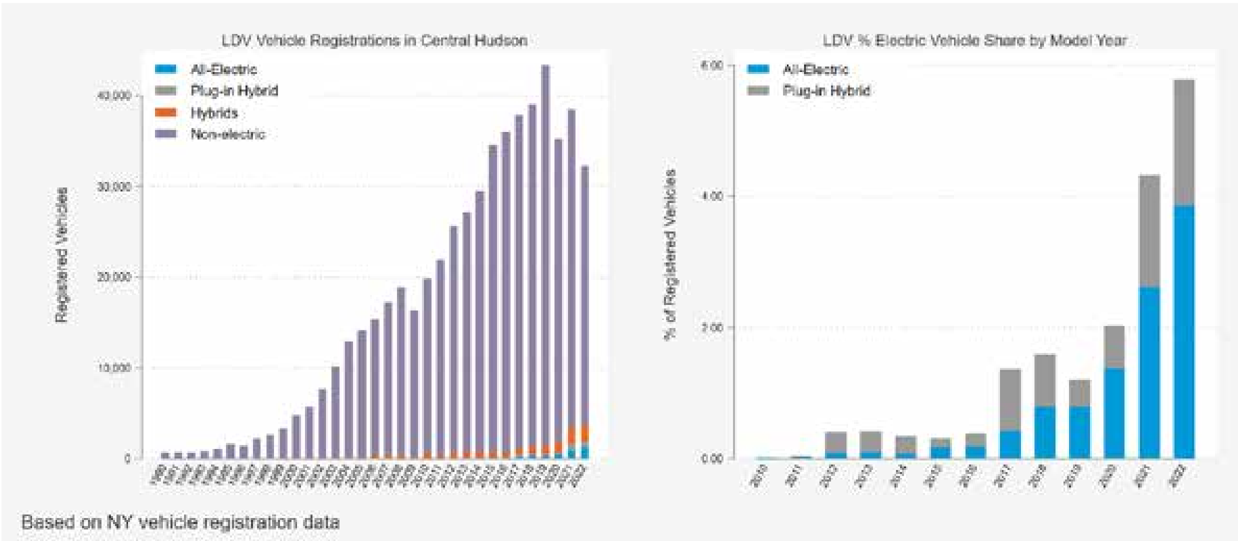


Figure 5: 2022 Penetration of Electric Vehicles by Circuit Feeder

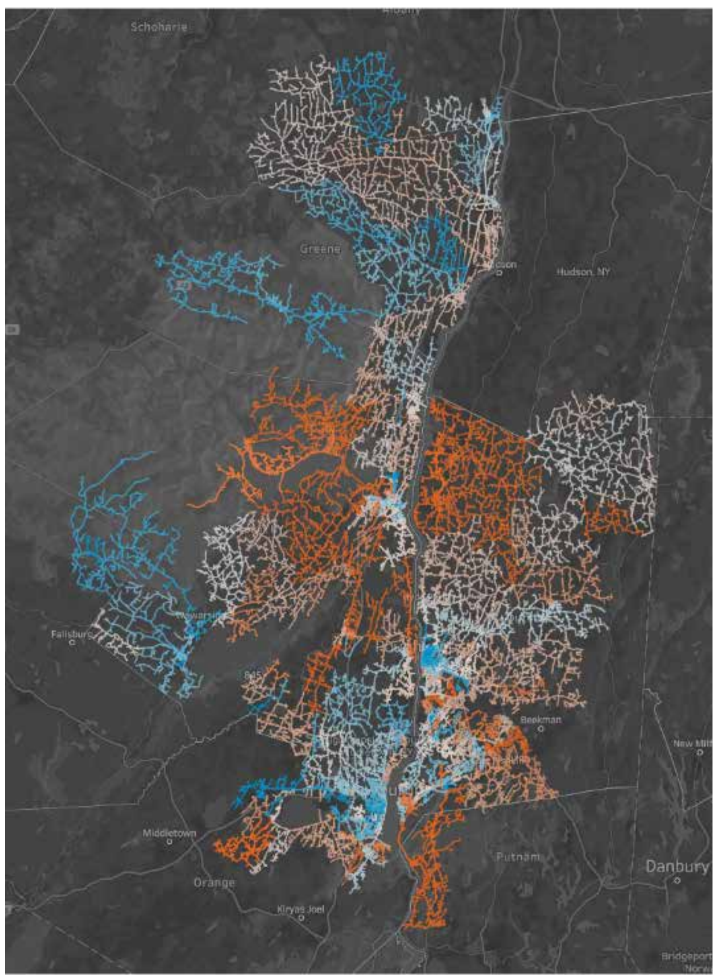


Figure 5 shows the historic geographic penetration of electric vehicles in Central Hudson's service territory. The map was produced by associating the NYSERDA electric vehicle rebate with Central Hudson accounts (via spatial matching) and circuit feeders. While it does not reflect the full electric vehicle population, it indicates that adoption is higher in specific pockets of Central Hudson territory.

3.3 FORECAST RESULTS

Table 7 shows the electric vehicle forecasts for 2023 to 2033 and provides details about vehicle counts and annual MWh. Overall, 80% of energy consumption for light duty vehicles is assumed to occur via home charging, and 20% via public, workplace, or fast charging. Since there is limited data for medium heavy duty vehicles and buses, there is substantially more uncertainty in those estimates.

Table 7: Electric Vehicle Forecast

		Vehicles			Annual MWh				
scenario	year	EV Light Duty	EV Medium Heavy Duty	EV Buses	EV Light Duty	EV Medium Heavy Duty	EV Buses	LDV Public Charging (L2 and DCFC)	Total MWh
CH Forecast	2023	9,331	50	69	24,057	2,485	1,000	4,511	32,052
	2024	13,605	97	81	35,365	4,821	1,100	6,631	47,916
	2025	19,533	165	94	51,139	8,201	1,300	9,589	70,228
	2026	27,503	261	111	72,462	12,972	1,600	13,587	100,620
	2027	37,814	384	129	100,188	19,085	1,800	18,785	139,857
	2028	50,572	541	147	134,659	26,888	2,100	25,248	188,895
	2029	65,620	732	171	175,497	36,380	2,400	32,906	247,183
	2030	82,535	960	196	221,599	47,712	2,800	41,550	313,661
	2031	100,719	1,226	228	271,366	60,932	3,200	50,881	386,379
	2032	119,522	1,522	261	323,034	75,643	3,700	60,569	462,946
	2033	138,353	1,858	297	374,981	92,343	4,200	70,309	541,833

Figure 6 and Figure 7 show the hourly EV loads for Central Hudson territory from 2023 through 2033 on summer and winter peak days, respectively. The loads factor in LDV, MDHV, and bus charging. It includes both at home charging and charging at workplaces, public chargers, and fast chargers. While electric vehicles are a substantial load when plugged in, not all vehicles plug in at same time or on the same day.

Figure 6: EV Loads Coincident with Central Hudson Summer Peak Day for years 2023 through 2033

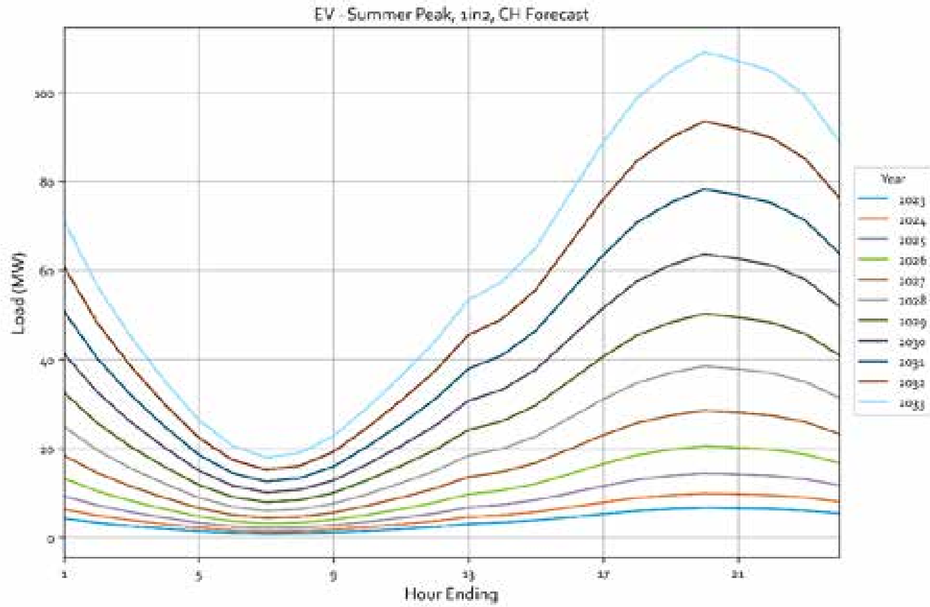


Figure 7: EV Loads Coincident with Central Hudson Winter Peak Day for years 2023 through 2033

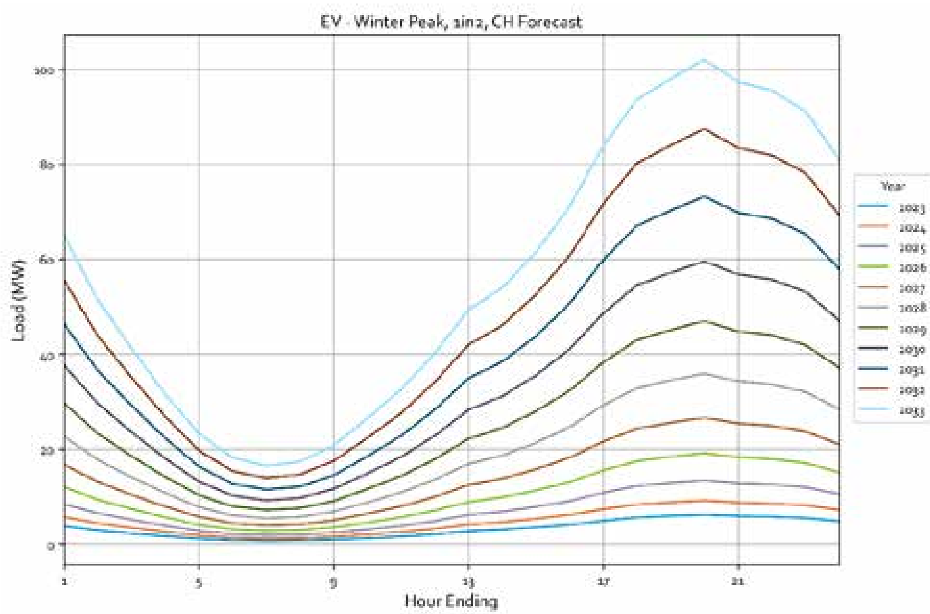


Figure 8 compares the loads coincident with local substation peaks for the summer and winter peak hour. Peak hour for each substation was defined as the hour during the summer and winter peak days during which net load forecast was highest, after factoring in all distributed resources and electrification. Only the top 20 substations with the highest expected peak impacts are shown.

Figure 8: Peak load for EVs for the top 20 substations

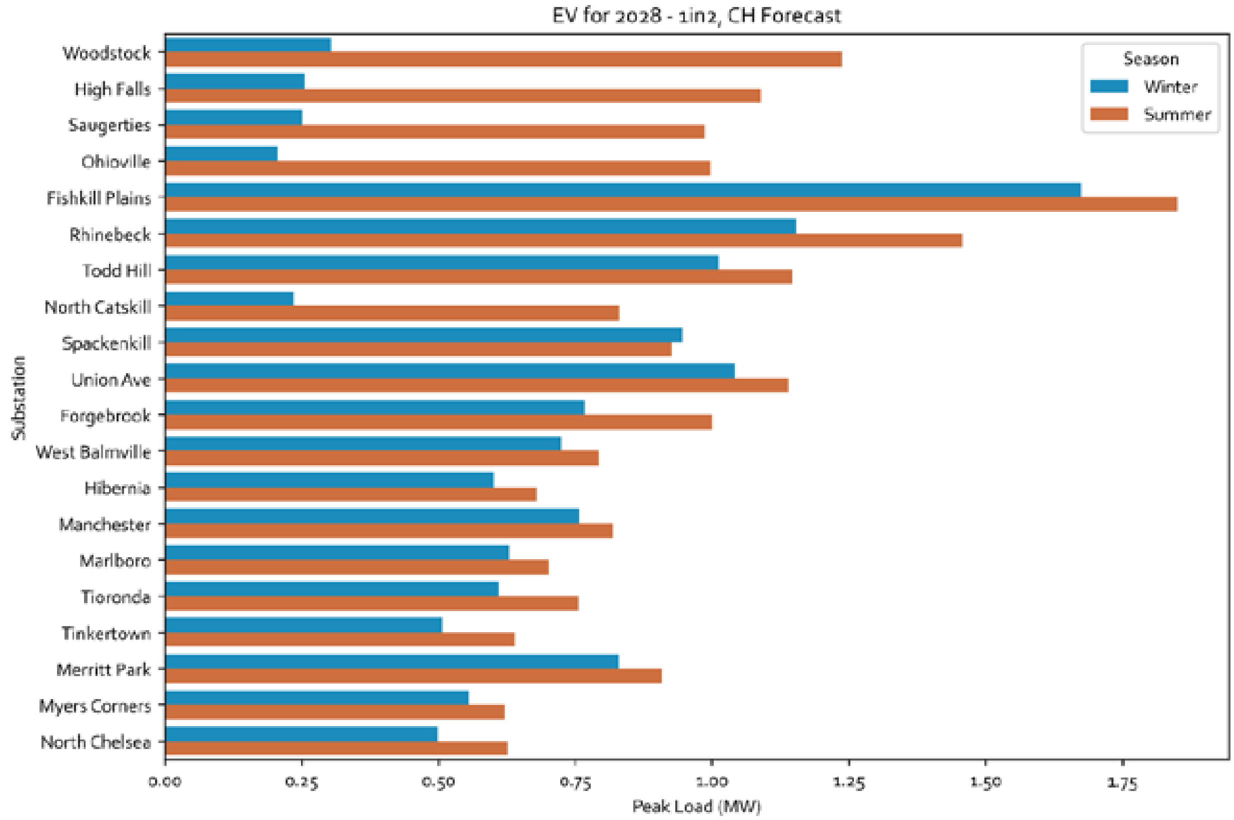
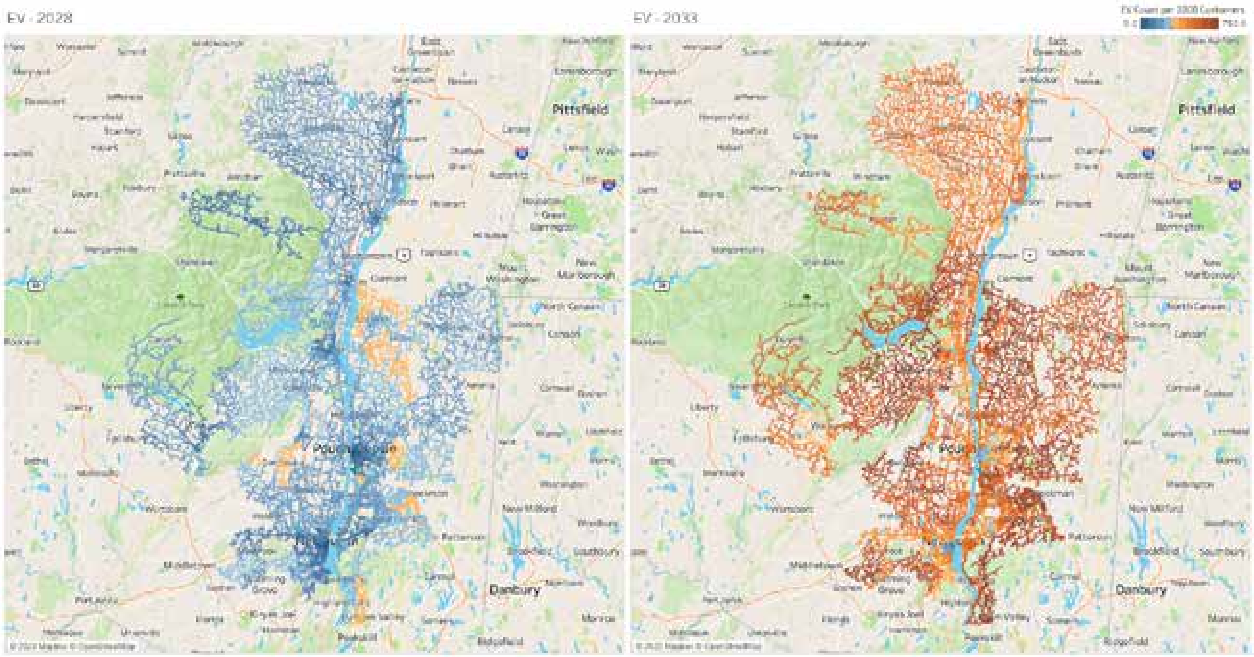


Figure 9 shows the electric vehicle coincident peak contribution forecasts by substation for 2028 and 2033. Overall, the penetration is currently low and concentrated but electric vehicles are expected to be more widespread within 10 years.

Figure 9: Geographic Penetration of Light Duty Vehicles in 2028 and 2033



4 BUILDING ELECTRIFICATION (HEAT PUMPS)

Building Electrification, in the form of heating and cooling and water heating heat pumps, is a growing load in the Central Hudson service area. As the focus of New York lawmakers shifts towards grid electrification and clean energy efforts, utilities are increasingly focused on electrifying heating and water heating end use loads. At a high level, this includes replacing traditional fossil fuel loads, such as oil, propane and gas heating, with electric heat pump technologies. In this evaluation, we specifically looked at adoption rates of heat pumps and heat pump water heaters in commercial and residential sectors. This section details the development of 8760 heat pump load forecasts at the substation level, which account for the temporal and locational variation in the adoption of heat pumps.

4.1 METHODOLOGY OVERVIEW

Figure 10 provides a high-level overview of the forecasting process for Building Electrification. Bottom-up forecasts were developed by analyzing grid impacts from building electrification measures deployed historically within each transmission area and substation and calibrating this locational dispersion of building electrification impacts to match total historical and forecasted “top-down” savings, then combining annual savings with an 8760-production profile to produce system peak day and location-specific load reductions.

Figure 10: Building Electrification Forecast Process Overview

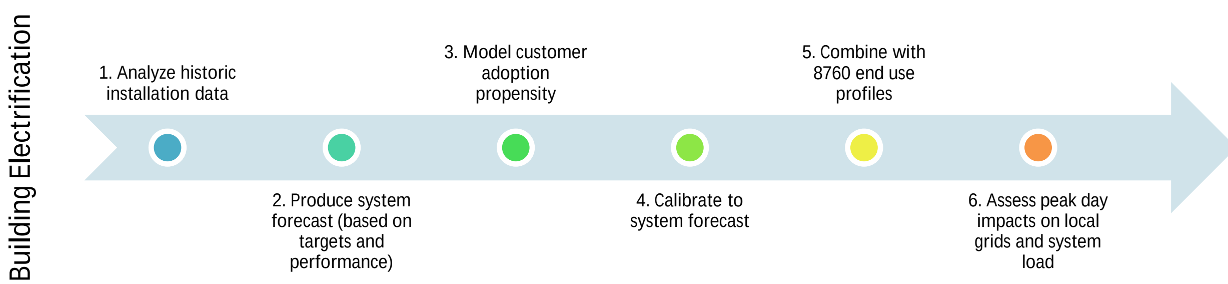


Figure 11 provides more detail on each step in the analysis. Methods are further discussed in Appendix B – Building Electrification.

Figure 11: Building Electrification Forecast Process Detail

1. Analyze Historical Data

- Assess adoption of heat pumps and heat pump water heaters over time
- Estimate the relationship between incentive level and uptake
- Assess geographic patterns of heat pump adoption
- Calculate share of sites with equipment turnover that are adopting heat pump technology

2. Produce System Forecast

- Use adoption trends to estimate innovation diffusion curves (S-curves) and estimate the heat pump market share over time
- Estimate turnover of heating and water heating equipment stock
- Produce Central Hudson empirical forecasts
- Estimate change GWh based on historical heat pump and HPWH installations

3. Model Adoption Propensity

- Investigate characteristics that inform adoption likelihood
- Run machine learning model (XBGoost) to quantity adoption likelihood
- Estimate propensity to adopt heat pump and heat pump water heaters for each premise

4. Calibrate Propensities to System Level Forecasts

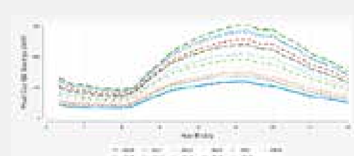
- Scale the premise level propensities so the total for each year equals the system level forecasts for that year (each site follows its individual S-curve).
- Aggregate to the circuit feeder level to get forecasted counts of residential and non-residential sites adopting heat pumps and heat pump water heaters by feeder and forecast year.

5. Incorporate 8760 End Use Load Shapes

- Weather adjust NREL load shapes to match the T&D 1-in-2 and 1-in-10 peak planning weather years for winter and summer
- Scale heating and cooling loads to match the change in electric heating and cooling usage observed in the Clean Heat program.
- Scale normalized load shapes to match feeder MWh forecasts by year.

6. Assess Peak Day Impacts

- Identify the local winter and summer peak days for feeder, substations, and transmission areas using historical hourly interval data
- Combine heat pump loads with forecasted T&D loads on peak days for each location (feeder, substation, and transmission area) and forecast year



4.2 HISTORIC ADOPTION PATTERNS IN CENTRAL HUDSON TERRITORY

Central Hudson has been offering heat pump technology rebates as part of its portfolio since 2017. However, the goals and funding of heat pump technology changed with the introduction of the Clean Heat program in mid-2020 when the goals changed from efficiency to de-carbonization of heating and conversion of oil, gas, and propane heating to electric. Thus, the penetration of heat pump technology increased substantially from mid-2020 through the end of 2022 in part due to the emphasis on Clean Heat goals and higher incentives. Most of the installed units have been mini-splits, which do not require air ducting and can be installed in wider number of sites, including those with radiant oil heating. For most residential sites, customers install multiple mini-splits, 2.4 on average. Since the Clean Heat program started in mid-2020, roughly 60.4% of installations have replaced oil heating, 9.5% have replaced propane heating, and 11.9% of installations have replaced gas heating. When electric heat pumps replace fossil fuel heating, they lead to a substantial increase in winter electric loads and a small decrease in summer loads since the heat pumps are slightly more efficient than traditional air conditioners. Another 17.9% of heat pump installation have replace existing, but less efficient, electric resistance heating units, leading to a decrease in demand.

Table 8: Historical Installation of Heat Pump Units via Central Hudson Programs

	Devices Installed				Participants	
Year	Heat Pumps	Mini-splits	HPWH	Total	Heating	Water Heating
2017	68	883	0	951	625	
2018	58	1,261	0	1,319	770	
2019	82	1,745	0	1,827	1,014	
2020	137	1,952	171	2,260	924	171
2021	702	5,934	371	7,007	2,900	370
2022	498	4,905	383	5,786	2,197	382
Total	2,827	16,680	925	20,432	8,430	923

Table 9: Clean Heat Historical Impact of Energy of Heat Pump Installations per Projects[1]

Type of Heat Pump	Change in Cooling kWh per project	Change in Heating kWh per project	Net Change in kWh per project	kW Summer Coincident per project	kW Winter Coincident per Project
Heat Pump	-382	5,584	5,168	-0.38	3.07
Mini-Split	-345	4,351	4,006	-0.21	2.39
HPWH	-	-	-459	-0.09	-0.07

The historical geographic concentration of heat pumps has been higher in specific parts of Central Hudson's territory, reflecting housing age, fuel type, ability of homeowners to replace heating, and environmental inclinations. By the end of 2022, the penetration of heat pump installations exceeded 15% at multiple feeders, as measured by participation in Central Hudson programs, even though the territory wide penetration was at 3.0%.

Figure 12: 2022 Penetration of Heat Pumps by Feeder

[1] The impacts reflect the engineering calculations conforming to the Technical Resource Manual in place at the time. Projects are typically per household and can include multiple heat pump units (e.g., 3 mini-splits).

4.3 FORECAST RESULTS

To develop the territory-wide forecast, we used the historical adoption trends to estimate heat pump market share over time and model turnover of heating and water heating equipment. Table 10 shows the heat pump forecasts for 2023 to 2033 and provides details about participants and net annual MWh.

Figure 13 shows the summer system peak day impacts due to cumulative building electrification activity for 2023 to 2033. Since heat pumps are expected to replace less efficient air conditioning, it leads to a net reduction in energy demand during summer months. Figure 14 shows the winter system peak day impacts due to cumulative building electrification activity for 2023 to 2033. Heat pumps are expected to replace fossil fuel burning units and add nearly 300 MW to winter electric peaks loads by 2033, as shown in Figure 14. Unlike electric vehicles, which do not necessarily charge on the same day or hour, heat pump winter heating loads are driven by weather with most homes generally peaking in the same hours and days. Thus, Central Hudson feeders, substations, and transmission areas may evolve from summer to winter peaking and require changes in T&D planning practices.

Table 10: Heat Pump Forecast by Equipment Type

		Participating Sites (Premises)				Net Annual MWh				
Forecast Scenario	year	Non-Residential HP	Non-Residential HPWH	Residential HP	Residential HPWH	Non-Residential HP	Non-Residential HPWH	Residential HP	Residential HPWH	Total Net MWh
Central Hudson	2023	263	37	3,492	487	1,084	-17	14,406	-223	15,250
	2024	599	95	7,958	1,258	2,471	-43	32,828	-577	34,678
	2025	1,015	181	13,491	2,407	4,189	-83	55,654	-1,104	58,656
	2026	1,516	305	20,143	4,053	6,254	-140	83,094	-1,859	87,350
	2027	2,101	477	27,912	6,340	8,667	-219	115,145	-2,908	120,685
	2028	2,766	711	36,746	9,442	11,410	-326	151,588	-4,330	158,342
	2029	3,504	1,020	46,550	13,550	14,454	-468	192,032	-6,214	199,804
	2030	4,305	1,420	57,201	18,868	17,761	-651	235,971	-8,653	244,427
	2031	5,161	1,926	68,566	25,588	21,290	-883	282,855	-11,735	291,527
	2032	6,060	2,549	80,514	33,863	25,000	-1,169	332,147	-15,530	340,448
	2033	6,995	3,296	92,928	43,790	28,855	-1,512	383,358	-20,083	390,619

Figure 13: Forecasted Building Electrification Impacts on Summer Peak Day: 2023-2033

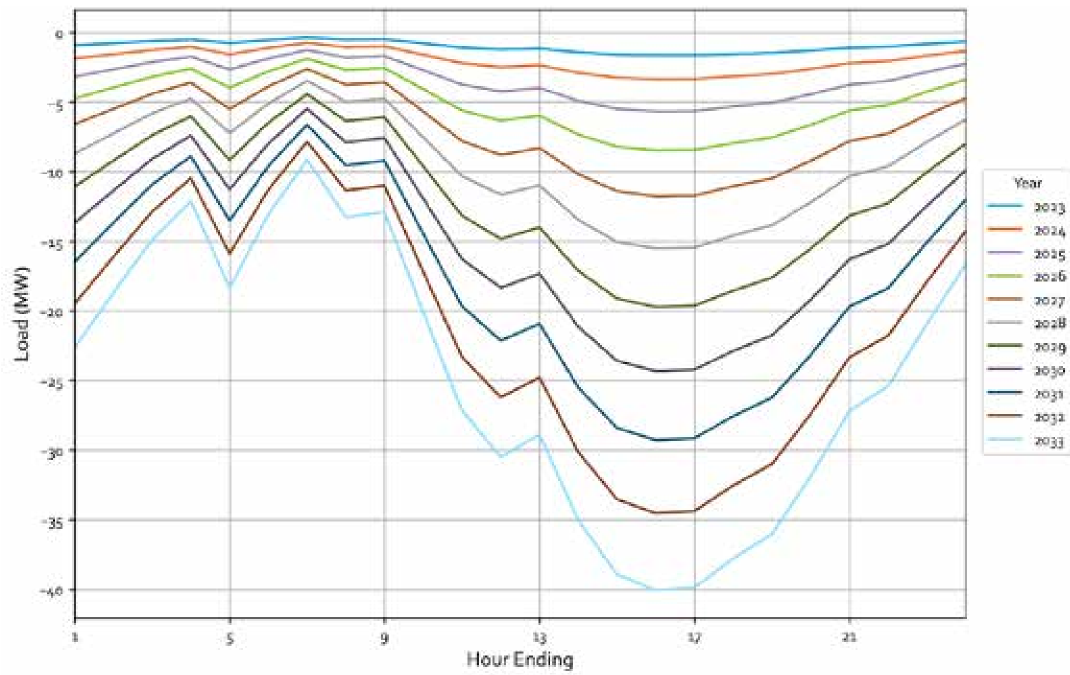


Figure 14: Forecasted Building Electrification Impacts on Winter Peak Day: 2023-2033

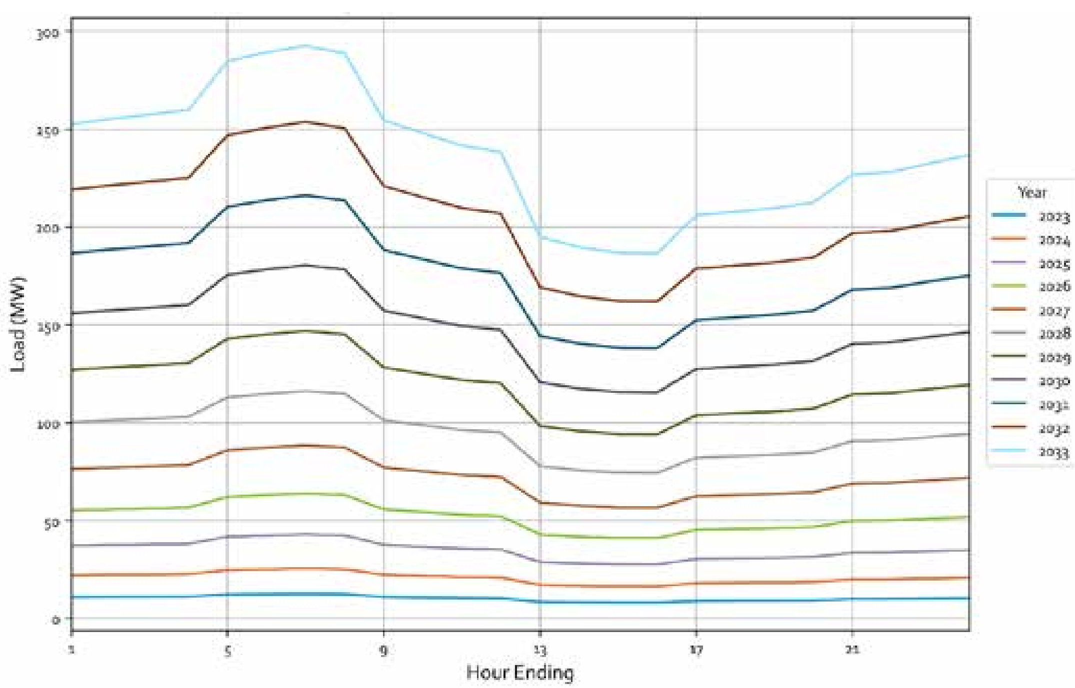
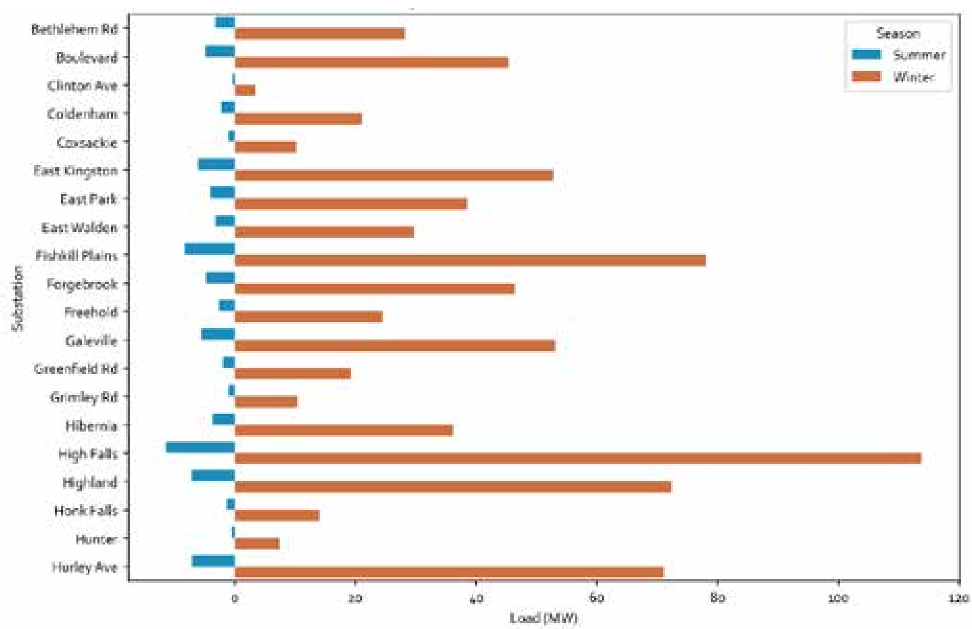


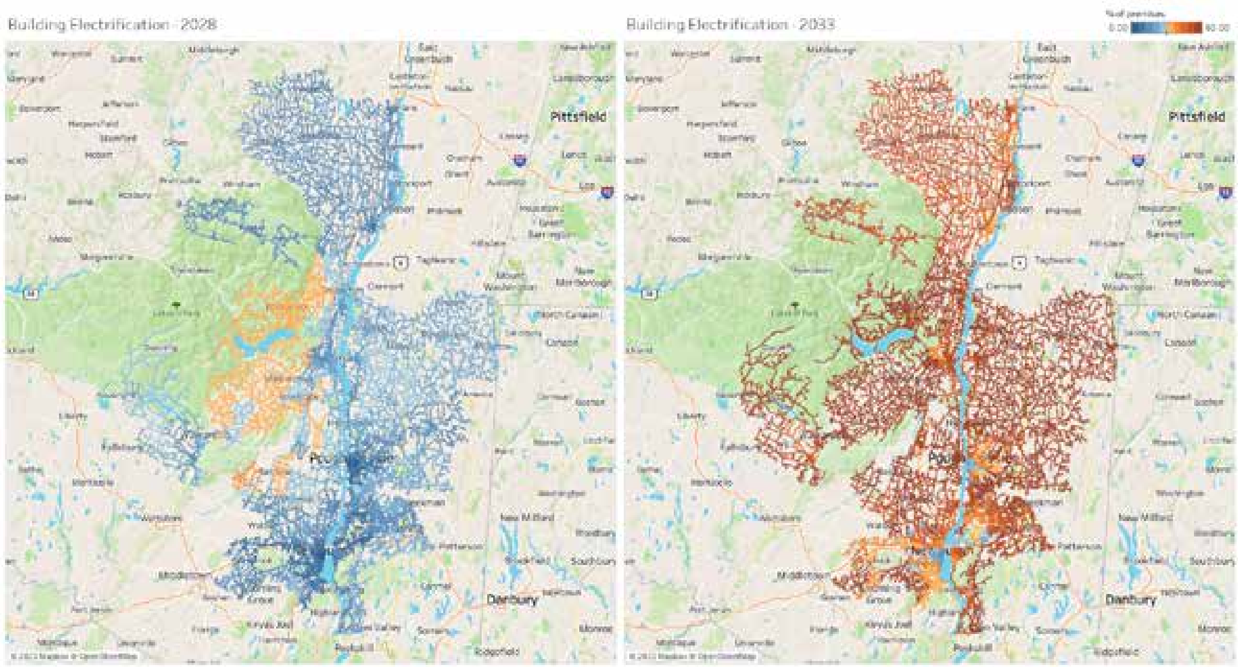
Figure 15 shows the load impact from heat pump technology on the summer and winter local peak days in 2028. It shows the impact on the 20 substations that are forecasted to experience the highest heat pump penetration. The figure demonstrates that Central Hudson can expect much larger winter loads in added electric relative to summer AC savings. With higher electrification opportunities on winter peaking end uses, Central Hudson will need to shift its T&D planning to account for higher winter peak loads.

Figure 15: Forecasted Summer and Winter BE Impacts for Top 20 Substations, 1 in 2 weather year, 2028



In addition to system-wide electric impacts, we calculated the feeder level adoption rates of heat pumps by year. Figure 16 shows the percent penetration of heat pumps and heat pump water heaters in 2028 and 2033 by feeder, expressed as a percentage of each feeder's total number of premises. Note that while the maximum penetration of the scale is set at 60%, some of the feeders are expected to exceed 70% penetration by 2033.

Figure 16: Heat Pump and HPWH Percent Penetration by Feeder – 2028 and 2033



5 RESIDENTIAL AND NON-RESIDENTIAL NET METERED SOLAR AND BATTERY STORAGE

Distributed solar in Central Hudson is comprised of smaller net metered units (NEM), and larger community solar or remote solar projects. The larger projects are typically submitted by developers and often required dedicated feeders and studies to ensure they can be interconnected without comprising the safety and reliability of the distribution system. Since the method for developing the forecasts differs, this section focuses exclusively on net metered sites.

Battery storage is a small but growing resource in the Central Hudson system. Roughly 10% of customers who installed rooftop solar in 2021-2022 also installed battery storage.

5.1 METHODOLOGY OVERVIEW

Figure 17 provides a high-level overview of the forecasting process for both solar and storage. Bottom-up forecasts were developed by forecasting solar capacity for each sector for each transmission area and substation and then summing each sector and combining with an 8760 production profile to produce system peak day and location-specific load reductions. Figure 18 provides more detail on each step.

Figure 17: BTM Solar and Storage Forecast Process Overview

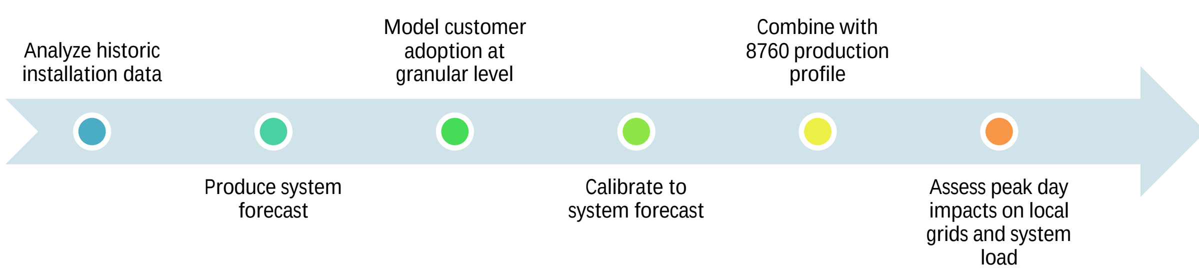


Figure 18: BTM Solar and Storage Forecast Process Detail

1. Analyze Historical Data

§ Assess adoption of residential and non-residential solar and battery storage over time

§ Assess geographic patterns of solar and battery adoption

2. Produce System Forecast

§ Use adoption trends to estimate innovation diffusion curves (S-curves) and estimate the behind the meter solar and battery storage market shares over time

§ Produce Central Hudson empirical forecasts

§ Compare Central Hudson empirical forecast with CLCPA goals and NYISO Gold Book Forecast

3. Model Adoption Propensity

§ Investigate characteristics that inform adoption likelihood

§ Run machine learning model (XBGoost) to quantify adoption likelihood

§ Estimate propensity to adopt non-residential solar and battery storage for each premise

4. Calibrate Propensities to System Level Forecasts

§ Scale the premise level propensities so the total for each year equals the system level forecasts for that year (each site follows its individual S-curve).

§ Aggregate to the circuit feeder level to get forecasted counts of residential and non-residential sites adopting solar and battery storage by feeder and forecast year.

§ Estimate the annual production (GWh) of solar for each feeder.

5. Incorporate 8760 End Use Load Shapes

§ Develop Central Hudson specific solar profiles from 63 large solar installation in Central Hudson territory with metered output

§ Develop natural battery profiles based on end use data from 1,800 residential batteries

§ Weather adjust solar and battery storage load shapes to match the T&D 1-in-2 peak planning weather years for winter and summer

§ Scale load shapes and produce MW value for each hour for each feeder and each forecast year.

6. Assess Peak Day Impacts

§ Identify the local winter and summer peak days for feeder, substations, and transmission areas using historical hourly interval data

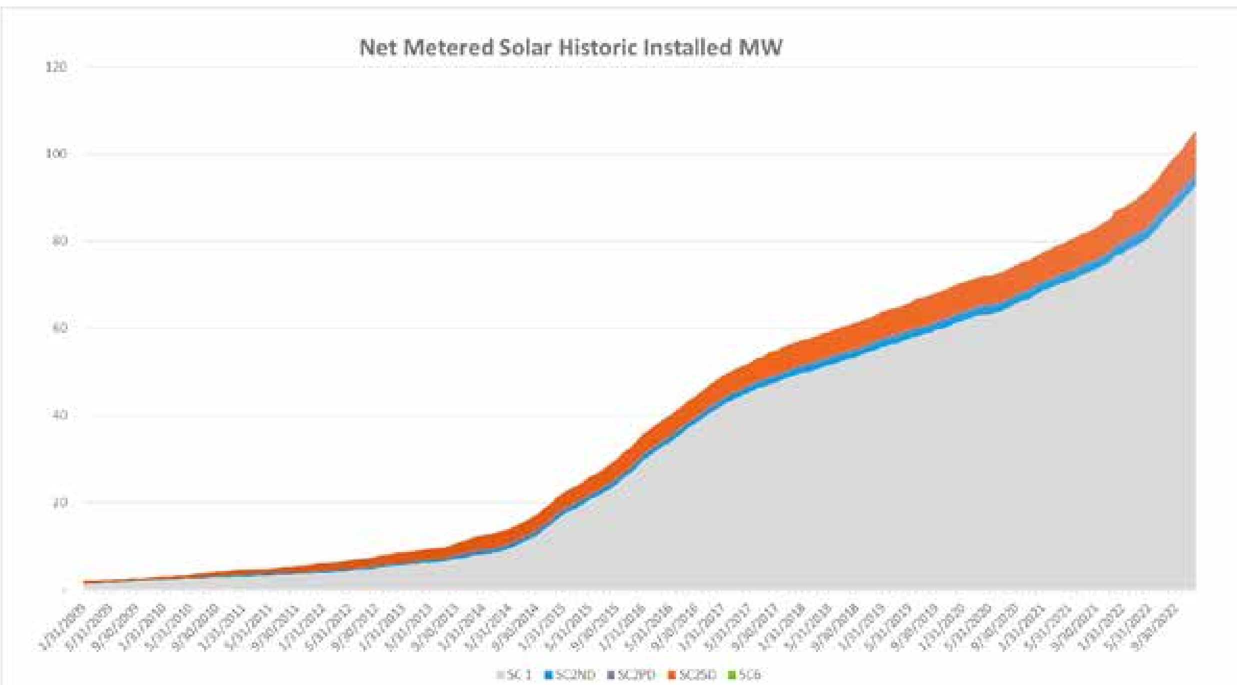
§ Combine loads with forecasted T&D loads on peak days for each location (feeder, substation, and transmission area) and forecast year

5.2 HISTORIC ADOPTION PATTERNS IN CENTRAL HUDSON TERRITORY

As of January 2023, there were 10,849 total residential solar installations in Central Hudson territory with 99.8 MW of installed capacity (DC). An additional 296 non-residential sites installed rooftop solar with 16.4 MW of installed capacity. Because solar generation is concentrated during the day and is higher in summer than in winter, the contribution to local peak relief can vary greatly by location, depending on the time and season of the peak.

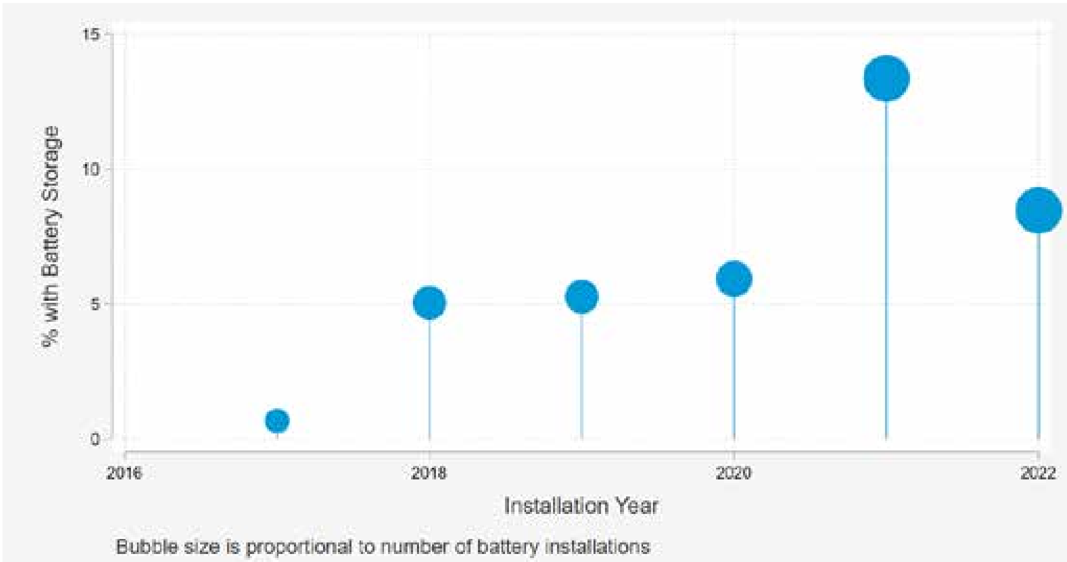
Rooftop solar technology has been available for over 30 years, but the scale of adoption grew around 2014 when the cost per watt of installed capacity declined and new financial models allowed customer to lease solar, enter into power purchase agreements, or purchase solar with zero down payments. Most rooftop, or net metered, solar installations have been on residential sites. Rooftop solar installations have grown over time and exceeded 100 MW by the end of 2022.

Figure 19: Historical Net Metered Solar Installed Capacity (MW)



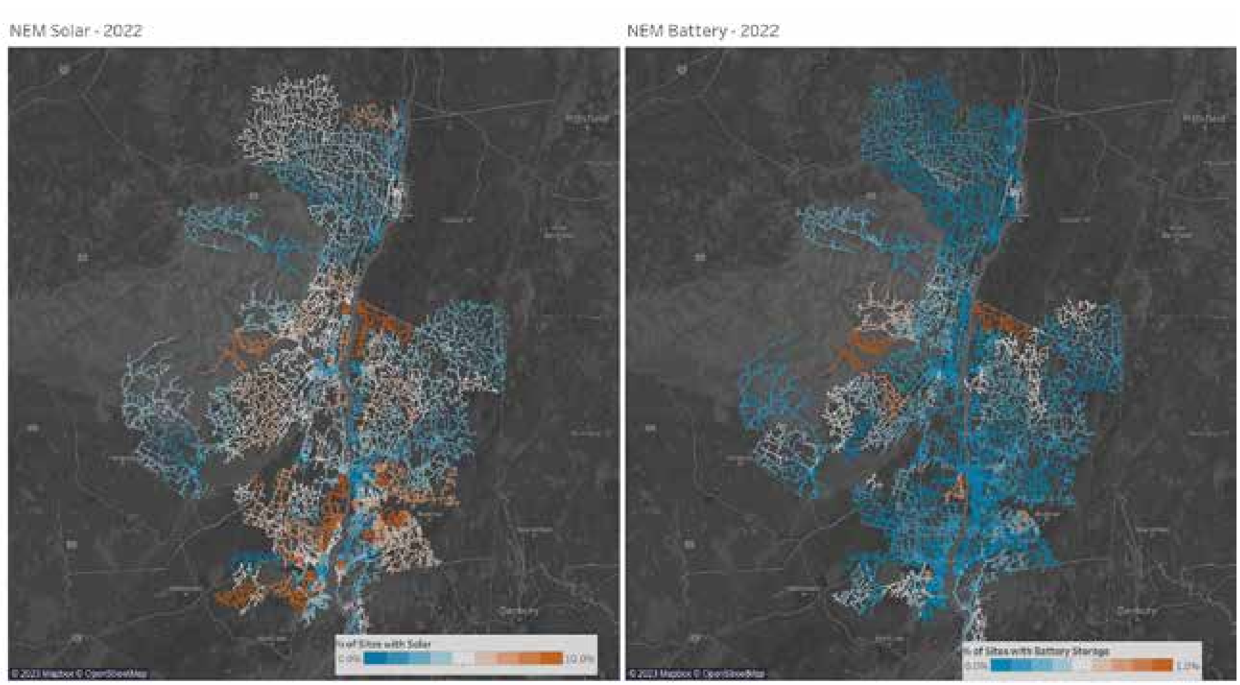
A more recent phenomenon is the installation of battery storage, which is nearly always paired with solar for net metered sites and mostly at residential sites. Figure 20 shows the share of solar installation paired with battery storage by year. In 2021, 12.5% of residential solar installations were paired with battery storage. The share of sites installing battery storage with solar decreased in 2022, however, and it is unclear if it's a normal variation or a trend.

Figure 20: Share of Residential Solar Installation Paired with Battery Storage



The historical geographic concentration of net metered solar and battery storage has been higher in specific parts of Central Hudson's territory, reflecting housing age, homeownership, ability of homeowners to afford solar, and environmental inclinations.

Figure 21: 2022 Penetration of Net Metered Solar and Battery Storage by Circuit



5.3 FORECAST RESULTS

To develop the territory-wide forecast, Central Hudson used the historical adoption trends to estimate incremental net metered solar adoption. Table 11 shows the solar net metered forecasts for 2023 to 2033 for residential and non-residential customers. Overall, the growth in solar has shifted from net metered (rooftop) solar to community solar and remote net metered projects. The forecast for battery storage is linked to solar installations and assumes that the share of customers pairing battery installations with solar grows to 25% by 2033.

Table 11: Net Metered Solar and Battery Storage Forecast (Installed MW DC)

scenario	year	Residential Solar	Non-Residential Solar	Residential Battery	Non-residential Battery
CH Forecast	2023	100.8	23.9	4.9	0.2
	2024	109.2	24.1	6.1	0.2
	2025	117.1	24.3	7.5	0.2
	2026	124.5	24.4	8.9	0.2
	2027	131.3	24.6	10.3	0.2
	2028	137.3	24.7	11.6	0.2
	2029	142.4	24.8	12.7	0.2
	2030	146.5	24.9	13.7	0.2
	2031	149.5	25.0	14.4	0.3
	2032	151.3	25.0	14.8	0.3
	2033	151.8	25.1	14.9	0.3

Figure 22 and Figure 23 show the hourly loads of net metered solar and battery units, combined for Central Hudson summer and winter 1-in-2 peak days from 2023 to 2033. The graphs show the year-by-year change in behind the meter solar and battery loads. Because solar production is substantially higher in the early afternoon, a difference of only several hours can yield significant differences in production.

Figure 22: Forecasted BTM Battery and Solar - Summer 1-in-2 Peak Day: 2023-2033

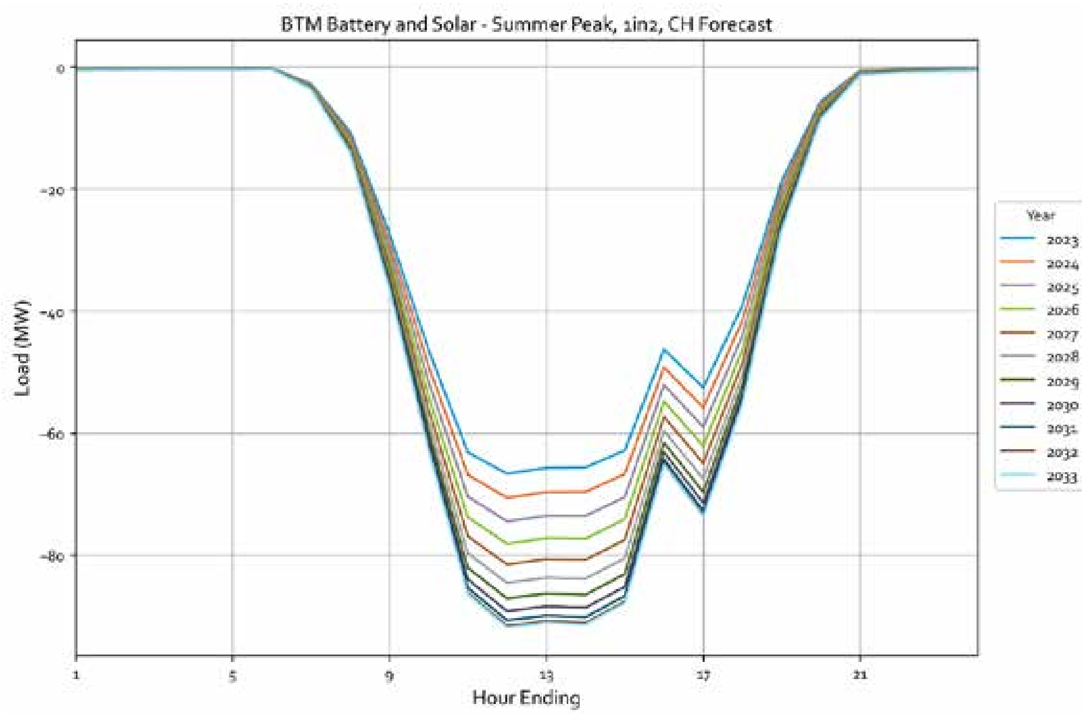
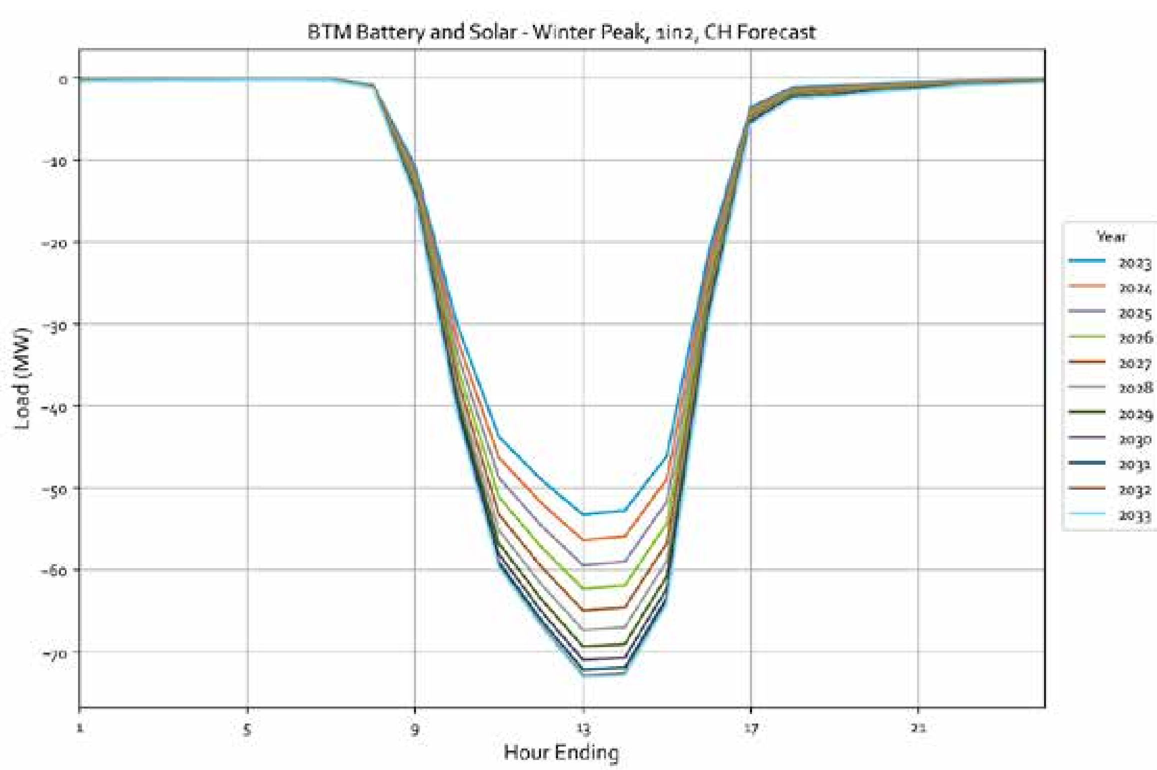
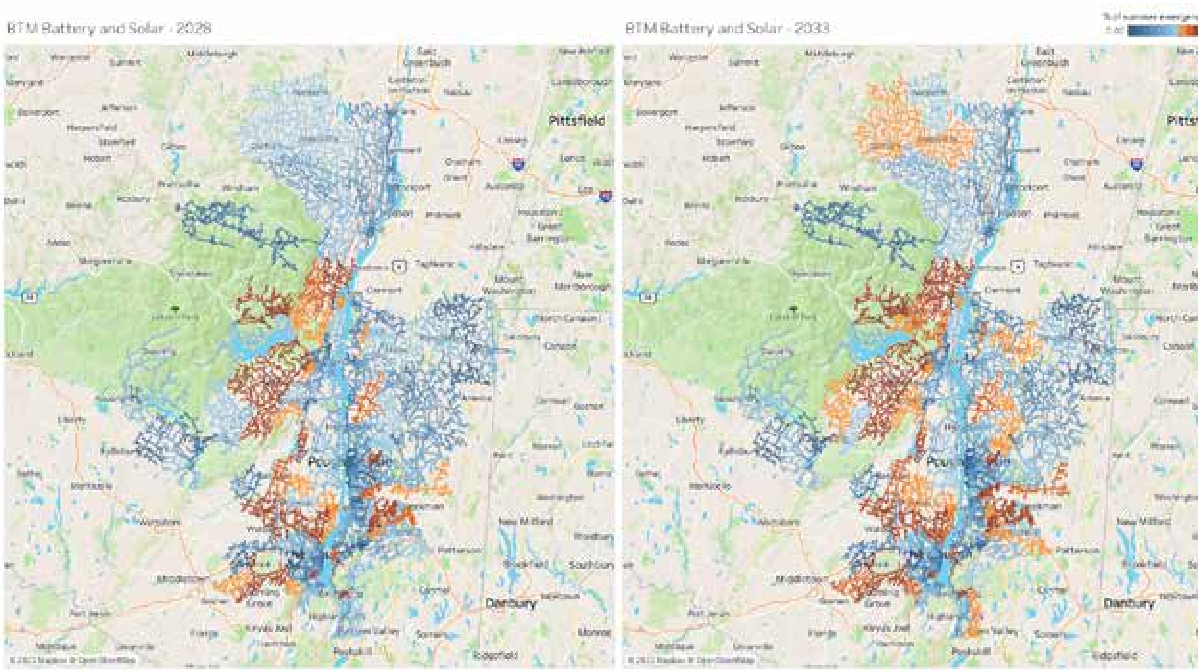


Figure 23: Forecasted BTM Battery and Solar - Winter 1-in-2 Peak Day: 2023-2033



In addition to load forecasts, we calculated the feeder-level penetration of behind the meter battery and solar for each year. Figure 24 shows the feeder-level penetration forecasted in Central Hudson territory in 2028 and 2033.

Figure 24: BTM Solar and Battery Feeder-level Penetration: 2028 vs 2033



6 COMMUNITY SOLAR AND BATTERY STORAGE

Distributed solar and battery storage in Central Hudson is comprised of smaller net metered units (NEM), and larger community or remote solar and battery projects. The larger projects are typically submitted by a developer and often exceed 1 MW installed capacity. These larger projects can require new/dedicated feeders and studies to ensure they can be interconnected without comprising the safety and reliability of the distribution system, and often have costs associated with interconnection. While Central Hudson has received voluminous applications for community solar and battery storage, only a small share of sites opt to pay permitting costs and build the proposed projects. Since the method for developing the forecasts differs, this section focuses exclusively on large community and remote solar and battery projects.

6.1 METHODOLOGY

Figure 25 provides a high-level overview of the forecasting process for both solar and storage. Bottom-up forecasts were developed by forecasting capacity in each transmission area and substation and then summing and combining with an 8760 production profile to produce system peak day and location-specific load reductions. Figure 26 provides more detail on each step.

Figure 25: COMMUNITY Solar and Storage Forecast Process Overview

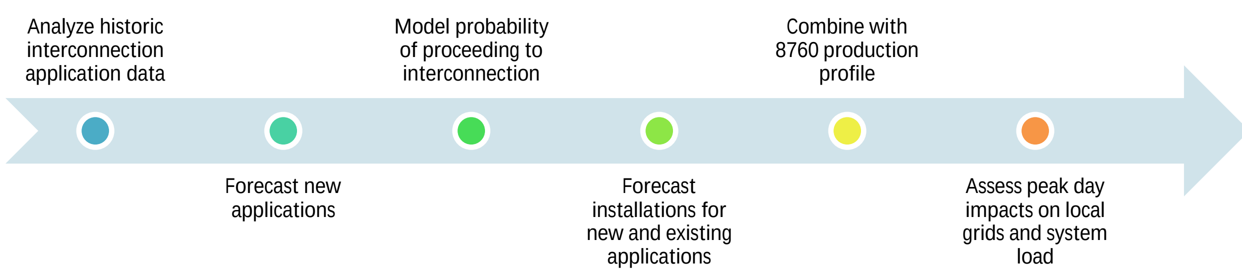


Figure 26: COMMUNITY Solar and Storage Forecast Process Detail

1. Data and Key Drivers

- § Central Hudson historic interconnection queue data (including existing projects in queue)
- § Key forecast drivers include the historic installation trend, introduction of the lease/PPA models, cost per watt, and policy incentives

2. Analyze Historical Data

- § Assess historical interconnection application and installation patterns
- § Calculate probability of application will proceed through each stage of application process (a probability transition matrix, or Markov chain)

3. Produce System Capacity Forecast

- § Predict new applications based on Bass Diffusion curve
- § Predict interconnection capacity based on Markov Chain transition matrix (not all projects in queue proceed to interconnection)

4. Granular Adoption

- § Existing applications already tied to substation
- § New application capacity based on historic distribution of applications

5. 8760 Load Shapes

- § Calculated average monthly profile based on ISO-NE actual historical solar generation data
- § Performance adjustment factor (70% Res / 75% Non-Res / 80% CDG/RNM)
- § Hourly MW output is capacity multiplied by production profile

6. Peak Day Impacts

- § Aggregate all solar category types for each substation
- § Output is location-specific forecasts and local peak coincidence factors

6.2 HISTORIC INSTALLATION PATTERNS IN CENTRAL HUDSON

As of the end of 2022, Central Hudson had 51 community solar projects with 162.6 MW of installed capacity and 74 remote net metering projects with 42.6 MW of capacity. Because solar generation is concentrated during the day and is higher in summer than in winter, the contribution to local peak relief can vary greatly by location, depending on the time and season of the peak. Battery storage is a small but growing resource in the Central Hudson system. As of the end of 2022, there were three community battery installation with approximately 11.5 MW of installed capacity.

Figure 27 shows the historic cumulative installed capacity of community and remote solar and battery storage projects. Figure 28 shows the historical applications. Community solar installations in Central

Hudson were approaching 200 MW by the end of 2022, which is substantial when compared to Central Hudson's peak demand of approximately 1,100 MW. However, Central Hudson has received application for over 2,000 MW of community solar, nearly two times the overall peak demand.

Figure 27: Historical Community and Remote Solar and Battery Installed Capacity (Nameplate MW)

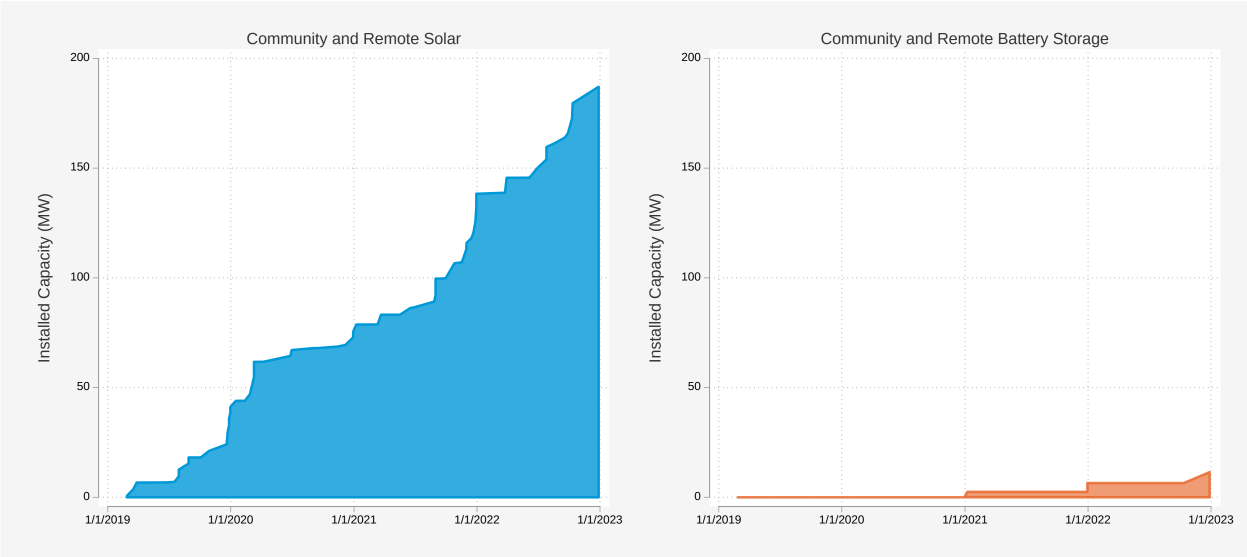
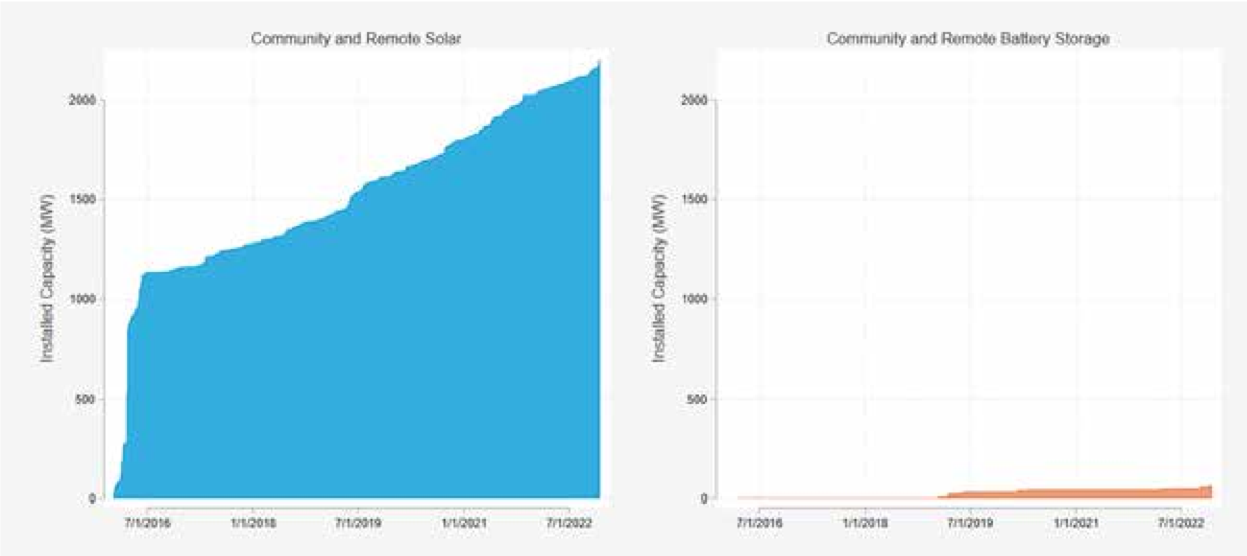


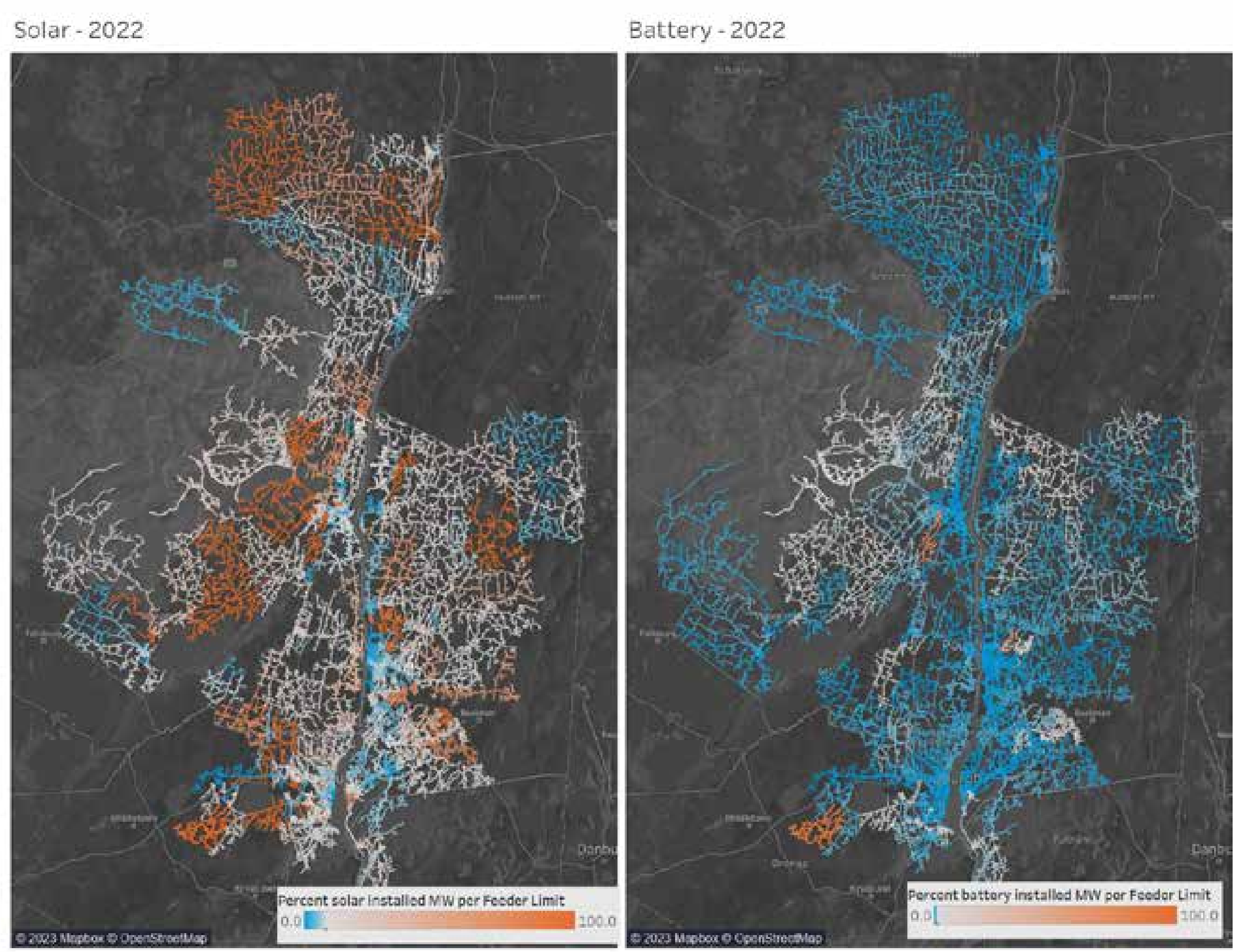
Figure 28: Historical Community and Remote Solar and Battery Applications (Nameplate MW)



When community solar became available in 2016, Central Hudson received an influx of applications exceeding 1,000 MW. Developers did not follow through projects completion, however, and only a few of those projects were actually built and interconnected. In light of this, the interconnection process was reformed to include a more detailed study, paid by the developer, and to require a 25% down payment of interconnection costs, if approved. Notably, 60% of sites that submit a down payment complete construction and interconnect. While the pace of applications has slowed since the process was reformed, applications do not automatically translate in construction and interconnection of solar and battery projects. Thus, the forecast takes into account the existing applications, the forecasted new application and the probability that application will proceed through each stage of application process (a probability transition matrix).

Figure 29 shows the geographic footprint of the projects that have been completed to date. Because of magnitude of community solar and battery storage, the installed capacity is shown as a percentage of each feeder's normal rating. The circuit feeder normal rating is not the same as the thermal rating (the limiting factor), which is typically higher. The penetration of large scale distributed solar will require Central Hudson to continue to review the possibility of solar backflow exceeding feeder and substation ratings.

Figure 29: 2022 Community and Remote Solar and Battery Penetration



6.3 FORECAST RESULTS

Figure 30 and Figure 31 show the community and remote solar and battery forecasts based on applications already in the queue and applications forecasted in the future, as well as the total forecasted MW with 95% confidence. Our estimates predict that by the end of 2030 there will be approximately 779 MW of community solar and 19 MW of community battery storage. Both estimates are of nameplate capacity.

Figure 30: Solar Storage Capacity Forecast

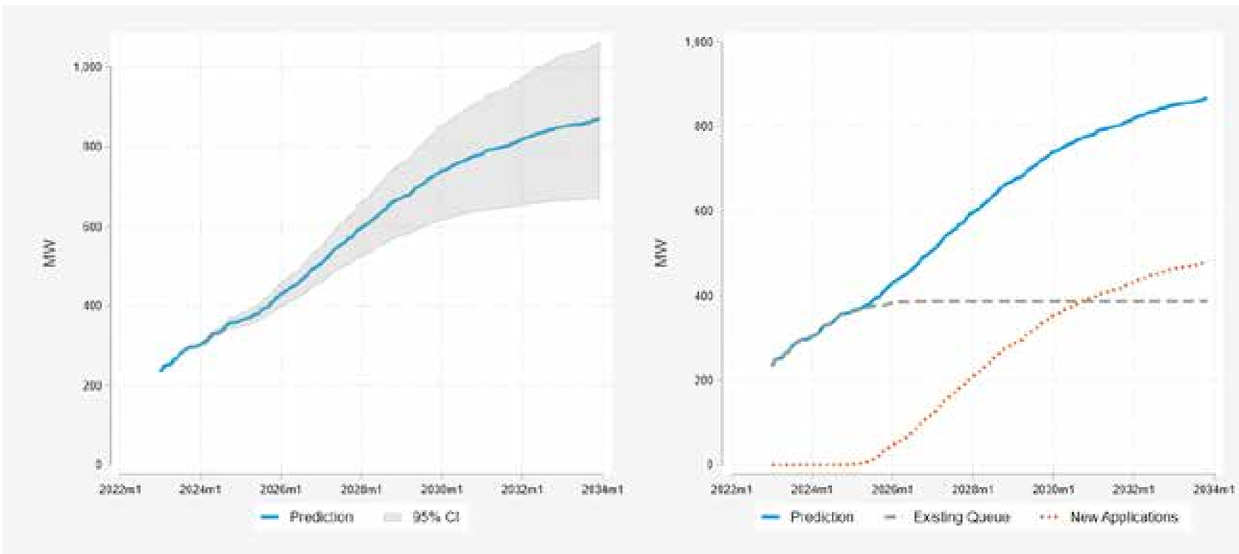


Figure 31: Battery Storage Capacity Forecast

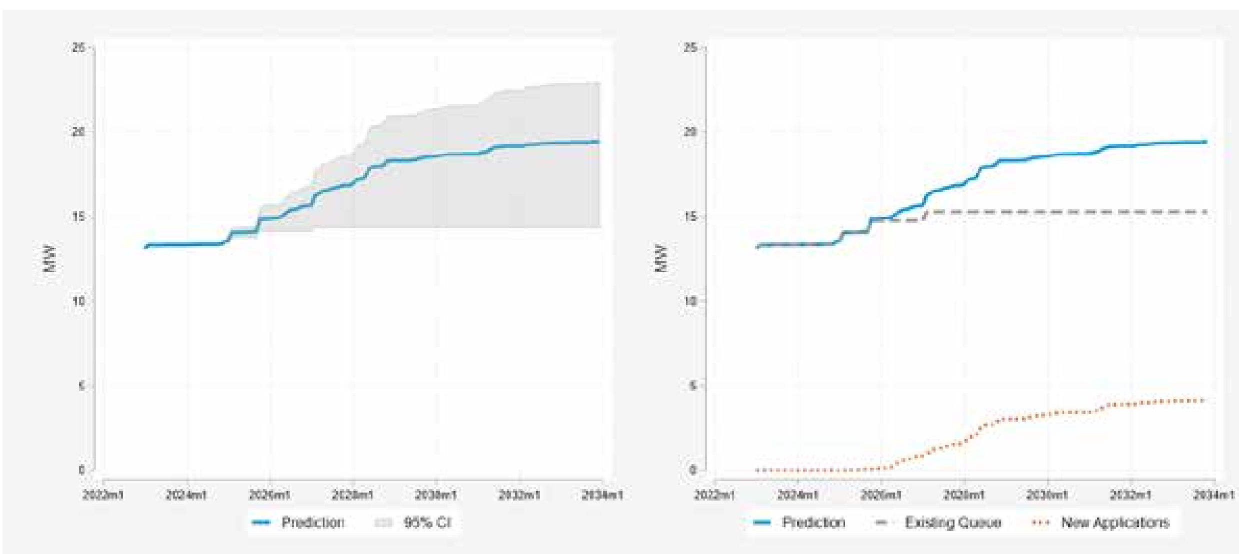


Figure 32 and Figure 33 show the cumulative forecast of COMMUNITY solar and battery production on the Central Hudson summer and winter 1-in-2 peak days from 2023 to 2033. The graphs show the year-by-year change COMMUNITY solar and battery loads. Because solar production is substantially higher in the early afternoon, a difference of only several hours can yield significant differences in production.

Figure 32: Forecasted community Battery and Solar - Summer 1-in-2 Peak Day: 2023-2033

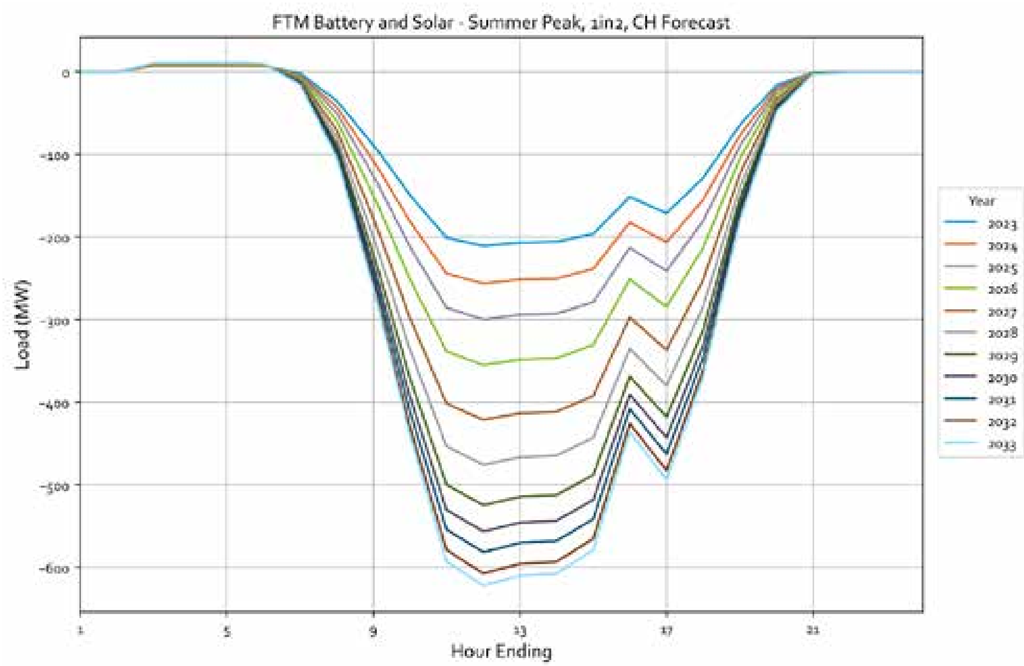
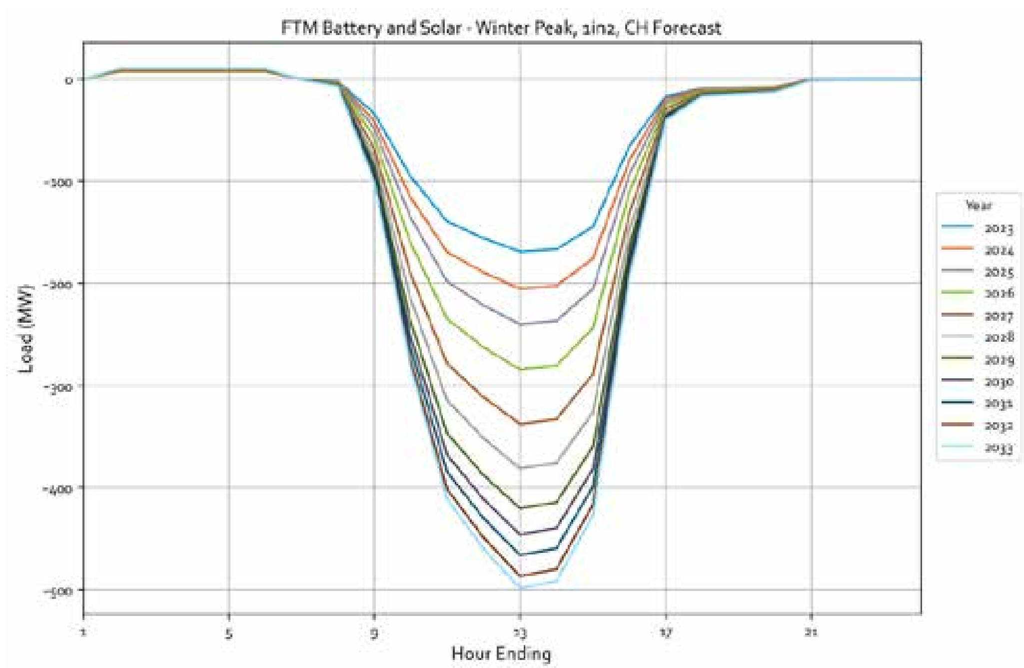
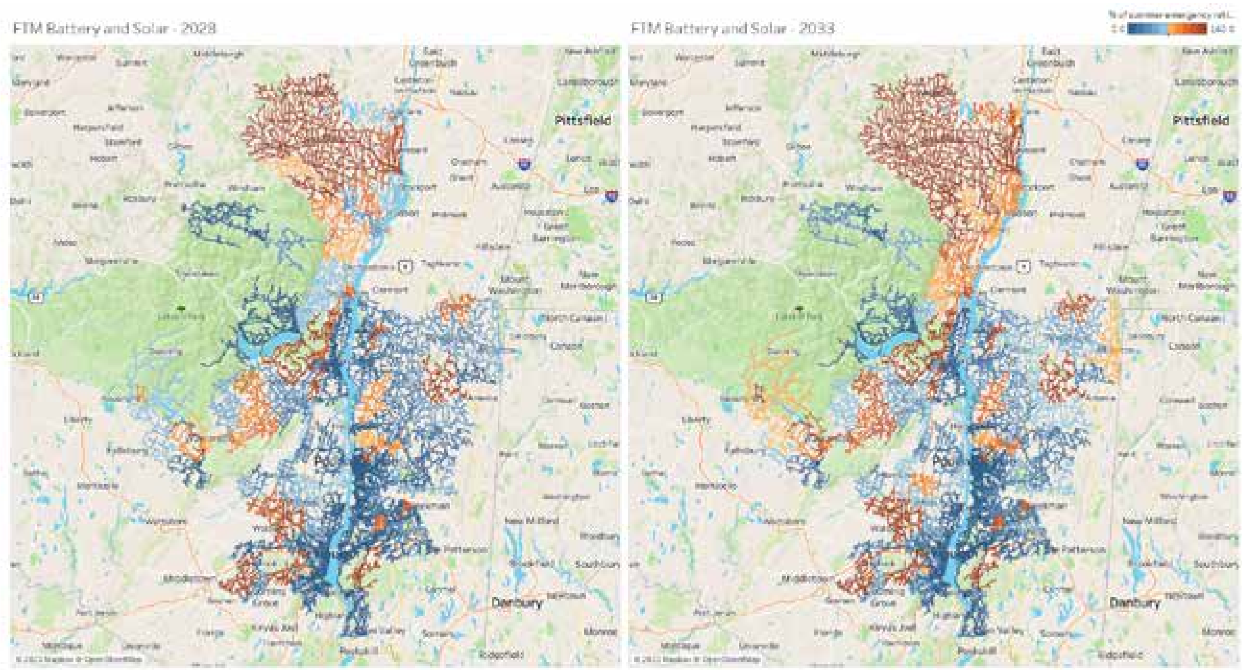


Figure 33: Forecasted community Battery and Solar - Winter 1-in-2 Peak Day: 2023-2033



In addition to load forecasts, we calculated the feeder-level penetration of community solar and battery for each year. Figure 34 shows the feeder-level penetration forecasted in Central Hudson territory in 2028 and 2033.

Figure 34: Community and Remote Solar and Battery Feeder-level Penetration: 2028 and 2033



7 ENERGY EFFICIENCY

Energy efficiency programs are the most well-established DER. However, planning and program administration are still typically at the territory-wide level. As traditional opportunities for low-cost, high-impact energy efficiency measures, such as lighting, start to phase out and more high cost measures, such as weatherization and HVAC, expand, having a more granular focus on energy efficiency implementation will be increasingly beneficial. As planning becomes more granular, it is becoming increasingly useful to understand the locational dispersion of energy efficiency and more possible to incorporate predictions of DER growth into load forecasts. The goal of this analysis is to describe the process of producing 8760 forecasts for energy efficiency for each substation, which account for the temporal and locational variation in energy efficiency savings.

7.1 METHODOLOGY OVERVIEW

Figure 2 provides a high-level overview of the forecasting process for energy efficiency. Bottom-up forecasts were developed by analyzing savings from efficiency measures deployed historically within each transmission area and substation and calibrating this locational dispersion of energy efficiency savings to match total historical and forecasted “top-down” savings, then combining annual savings with an 8760-production profile to produce system peak day and location-specific load reductions. Figure 36 provides more detail on each step in the analysis.

Figure 35: Energy Efficiency Forecast Process Overview

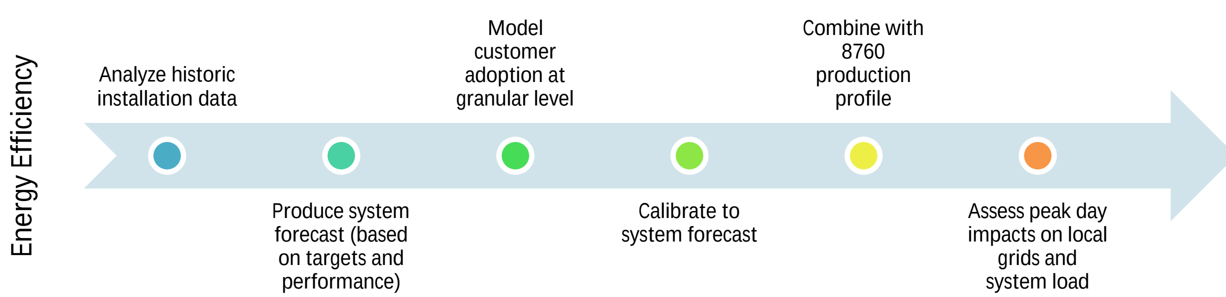


Figure 36: Energy Efficiency Forecast Process Detail

1. Analyze Historical Data

- Central Hudson billing data and historical records of energy efficiency installations and savings
- Assess energy efficiency savings over time
- Assess geographic concentration

2. Produce System Forecast

- Use historical performance variability to forecast system adoption
- Estimate turnover of heating and water heating equipment stock
- Produce Central Hudson empirical forecasts

3. Granular Adoption

- Investigate characteristics that inform adoption likelihood
- Run machine learning model (XBGoost) to quantity adoption likelihood
- Estimate propensity to adopt for each premise

4. Calibrate to System Forecast

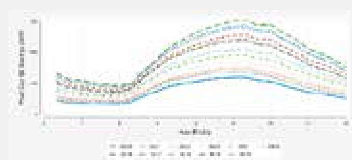
- Scale the premise level propensities so the total for each year equals the system level forecasts for that year (each site follows its individual S-curve).
- Aggregate to the circuit feeder level to get forecasted counts of residential and non-residential sites adopting Energy Efficiency by feeder and forecast year.

5. 8760 Load Shapes

- Downloaded NREL residential and non-residential end use load shapes for counties primarily within Central Hudson Territory
- Aggregate load shapes to lighting, space heating/cooling, and other for residential and non-residential
- Weather adjusted load shapes for heating/cooling to align 1 in 2 and 1 in 10 weather years for planning

6. Peak Day Impacts

- Apply load shapes to feeder level forecasts of savings by customer type and end use
- Produce feeder-level forecasts and local peak coincidence factors



7.2 HISTORIC ADOPTION PATTERNS IN CENTRAL HUDSON TERRITORY

Central Hudson has been administering a portfolio of energy efficiency programs since 2009. During that time, the portfolio has expanded into new technology areas and customer segments. Energy Efficiency programs were implemented with goals to offer customers opportunities to reduce their energy use, manage their energy bill, and contribute to the achievement of the State's ambitious clean energy goals. Central Hudson has designed its programs with a focus on maximizing value by seeking innovative ways to reduce the cost of the Energy Efficiency portfolio while increasing the quantity of

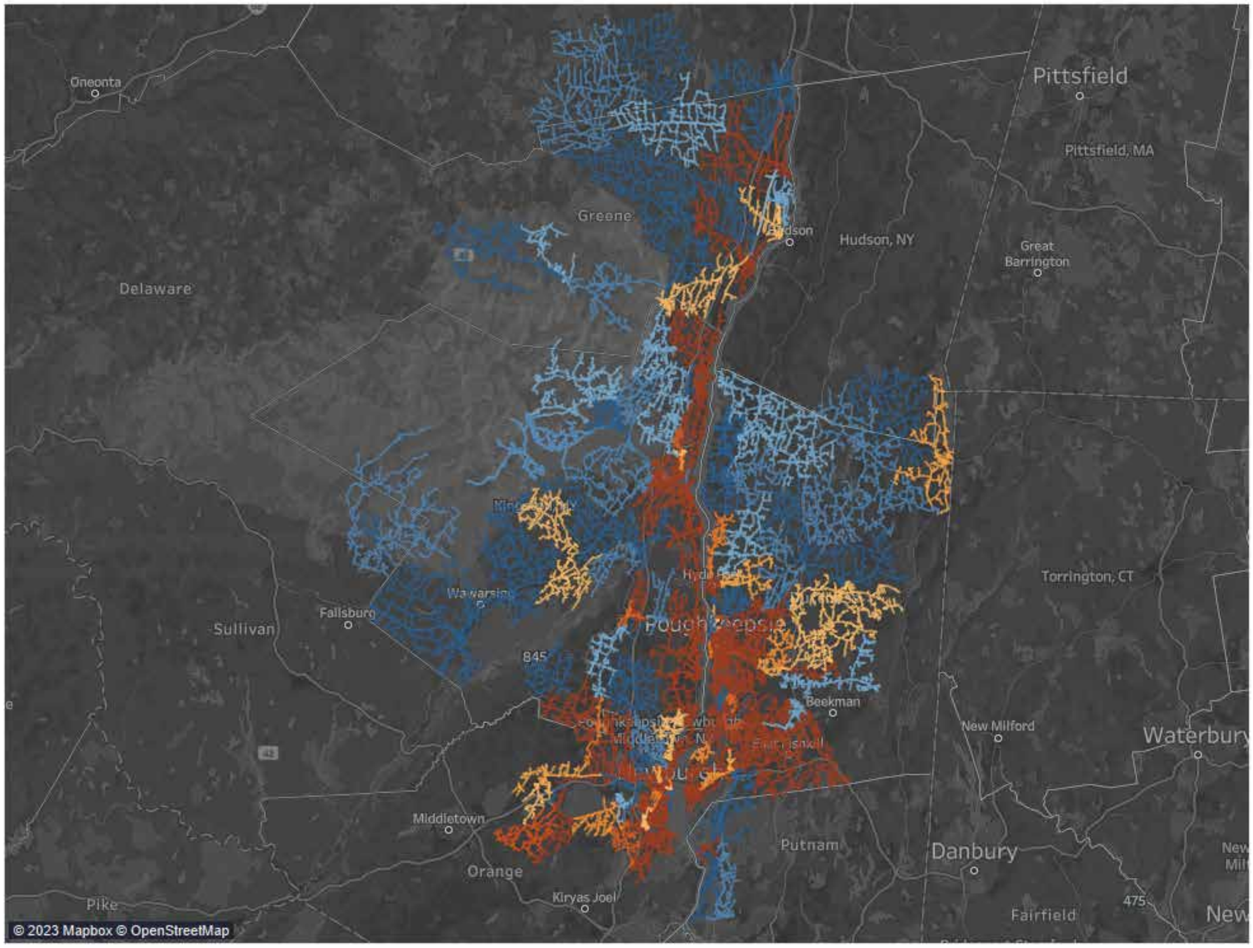
MWh savings attained. Table 12 shows the historical impact of energy efficiency as part of Central Hudson's programs.

Table 12: Historical Impact of Energy Efficiency via Central Hudson Programs

Year	HVAC kWh	Lighting kWh	Other kWh
2012	0	6,027,488	0
2013	0	9,437,432	0
2014	0	10,379,480	0
2015	14,483	18,285,308	0
2016	522,539	8,541,356	0
2017	758,041	9,010,743	176,056
2018	865,844	17,398,669	220,094
2019	731,762	16,939,274	1,042,109
2020	639,789	13,712,051	799,413
2021	487,787	14,391,545	98,567
2022	636,640	19,608,829	1,443,602
Total	4,656,885	143,732,175	3,779,841

The historical geographic concentration of energy efficiency participation has been higher in specific parts of Central Hudson's territory, reflecting housing age, fuel type, ability of homeowners to replace the energy measure, and environmental inclinations. Energy efficiency impacts are largely concentrated at feeders along the Hudson River. Some feeders accumulating over a MW in energy savings from Energy Efficiency programs, while other feeders towards the edge of Central Hudson territory have relatively low energy efficiency adoption rates.

Figure 37: 2022 MMBtu Impacts of Energy Efficiency by Feeder



Map based on Longitude (generated) and Latitude (generated). Color shows details about Cummulative MMBtu Energy Efficiency Impact Total. Details are shown for Feederid and Transmissi. The data is filtered on Subid, which keeps multiple members.

7.3 FORECAST RESULTS

Energy efficiency impacts on loads come from programs and codes and standards. A key feature of energy efficiency is that most of the savings are reported using gross savings, a metric that does not account for naturally occurring adoption of energy efficiency, which is sometimes referred to as free-ridership. The ability to meet the energy efficiency goals is also influenced by the funding for program. The NYISO Gold Book included sizeable effects of energy efficiency when scaled to Central Hudson, contributing 175 MW (17% of peak) by 2033, most of which is presumably from codes and standards. For the Central Hudson forecast, the expected savings were adjusted to 75% of the Gold Book forecast to account for the difference between gross and net savings. The saving were then allocated between residential and commercial customers, and between lighting, HVAC/shell, and other measures based on the historical share.

Table 13 shows the forecasted aggregate energy efficiency savings in GWh. Figure 38 and Figure 39 shows the forecasted summer and winter system peak day reduction due to cumulative energy efficiency activity for 2023 to 2033, respectively.

Table 13: Energy Efficiency and Codes and Standards Forecast (Annual MWh)

Year	Residential Lighting	HVAC/Shell	Other	Commercial Lighting	HVAC/Shell	Other	EE and C&S MWh
2023	25,953	9,733	3,244	22,709	1,622	1,622	64,884
2024	52,060	19,522	6,507	45,552	3,254	3,254	130,149
2025	81,066	30,400	10,133	70,933	5,067	5,067	202,666
2026	109,921	41,220	13,740	96,181	6,870	6,870	274,802
2027	138,317	51,869	17,290	121,027	8,645	8,645	345,792
2028	166,866	62,575	20,858	146,007	10,429	10,429	417,164
2029	194,193	72,822	24,274	169,919	12,137	12,137	485,483
2030	221,826	83,185	27,728	194,098	13,864	13,864	554,565
2031	249,459	93,547	31,182	218,276	15,591	15,591	623,647
2032	277,092	103,909	34,636	242,455	17,318	17,318	692,729
2033	303,808	113,928	37,976	265,832	18,988	18,988	759,521

Figure 38: Aggregate Forecasted Energy Efficiency Savings Summer Peak Day: 2023-2033

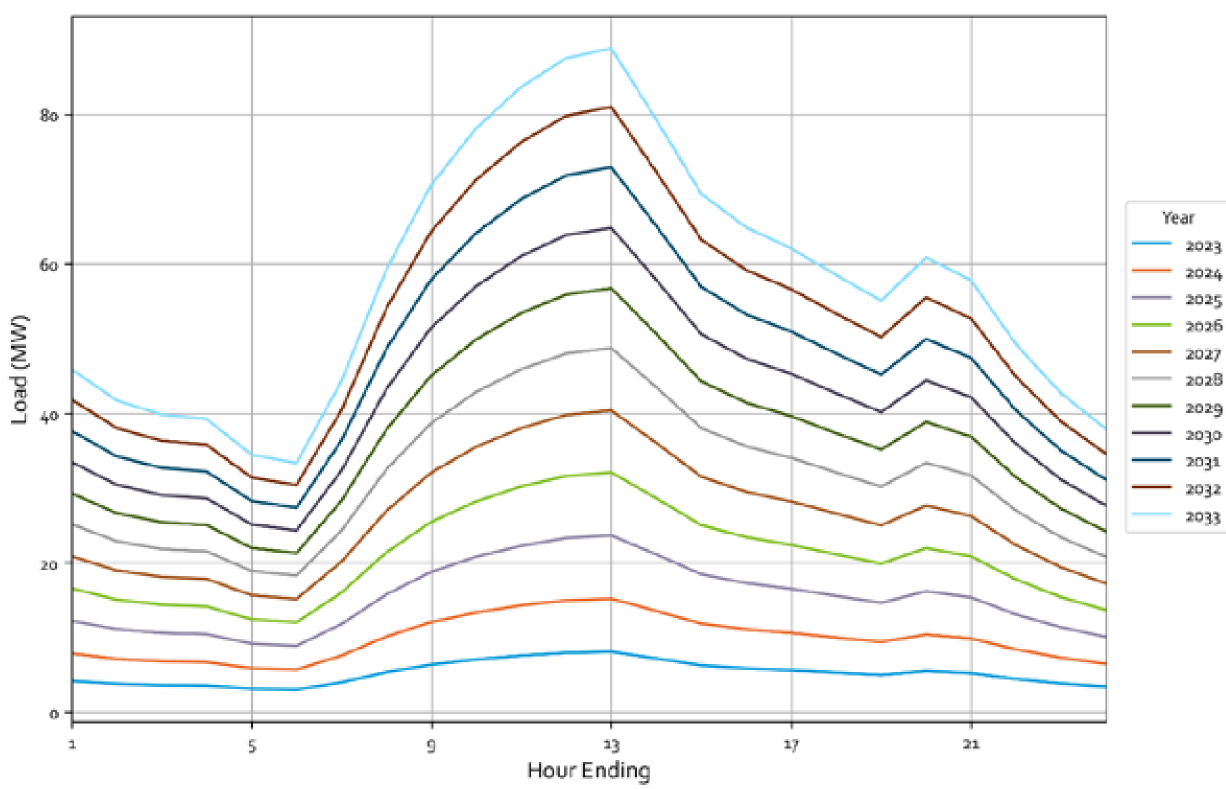


Figure 39: Aggregate Forecasted Energy Efficiency Savings Winter Peak Day: 2023-2033

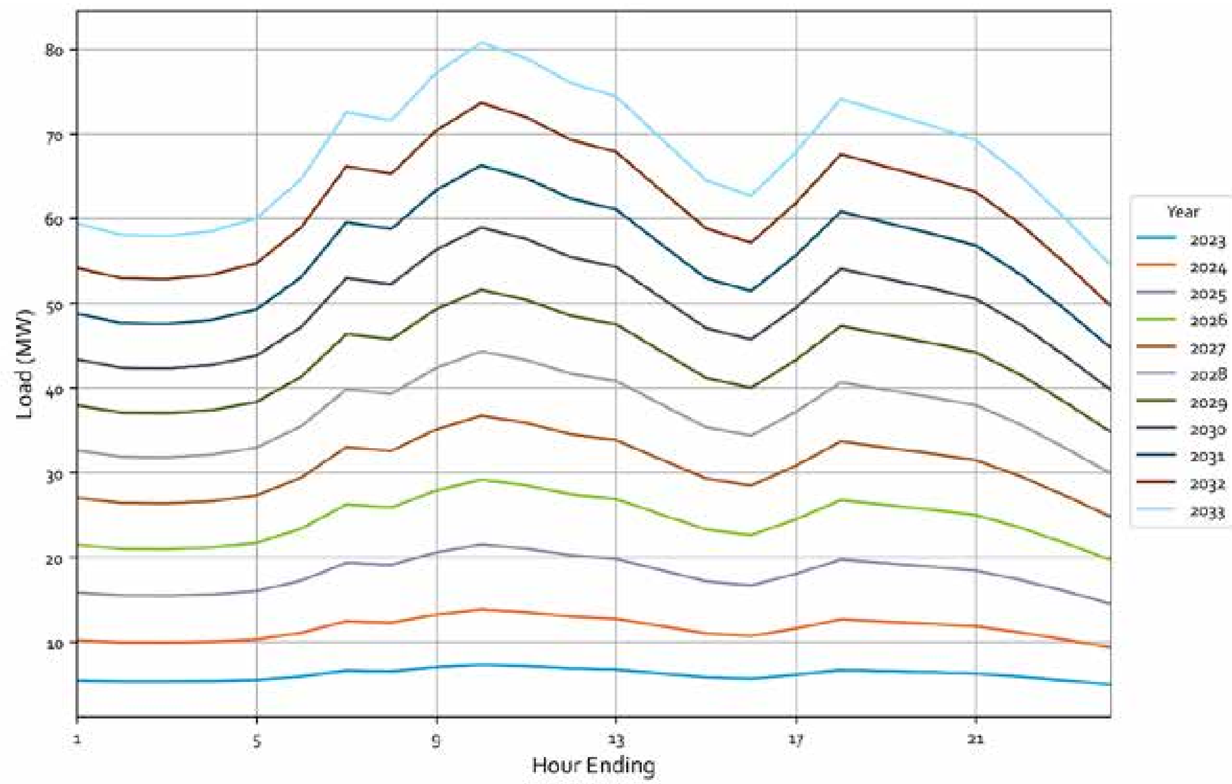
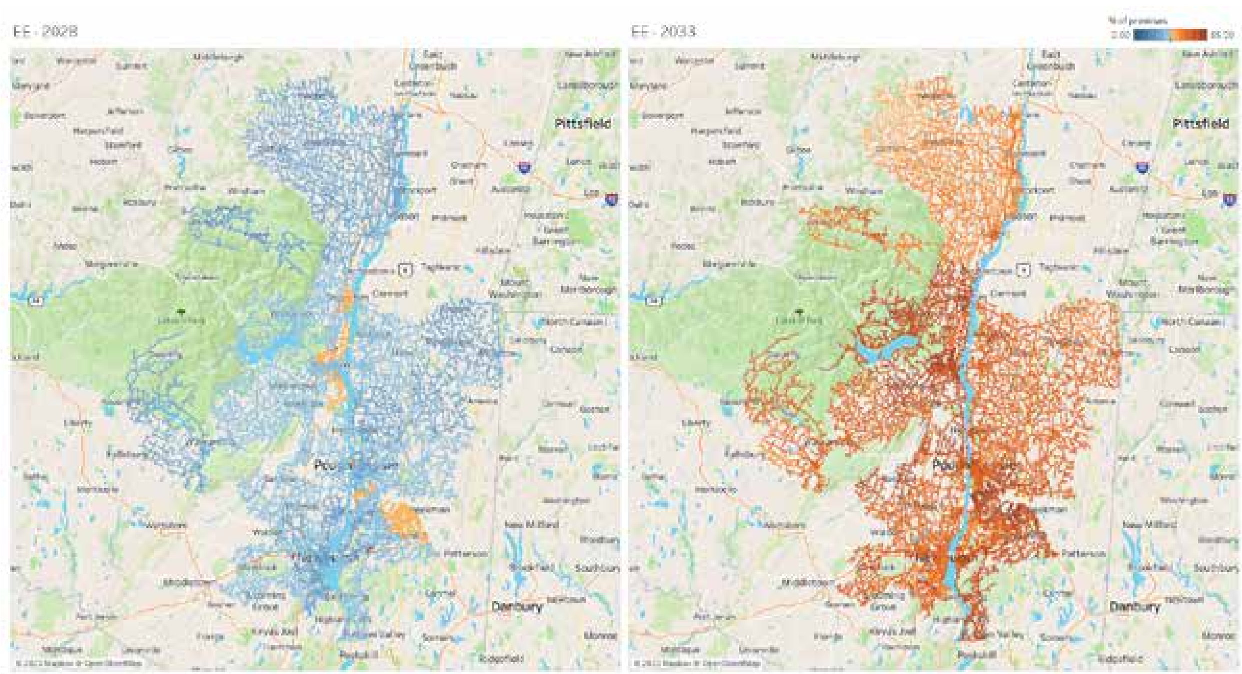


Figure 40 shows the energy efficiency measure adoption rates by circuit feeder, expressed as a percentage of each substation's total premise count in order to normalize for substation size.

Figure 40: Energy Efficiency Adoption by Feeder – 2028 and 2033



APPENDIX A – ELECTRIC VEHICLE METHODOLOGY

The granular electric vehicle forecasts were produced using the following six step process:

1. Analyze historic vehicle adoption data
2. Produce territory forecast (innovation diffusion curve)
3. Model customer adoption propensity at granular level
4. Calibrate propensities to match territory forecast
5. Incorporate 8760 hourly end use load shapes
6. Assess peak day impacts on local grids and system load

This appendix provides additional detail about the data sources, method, and techniques use at each step of the process.

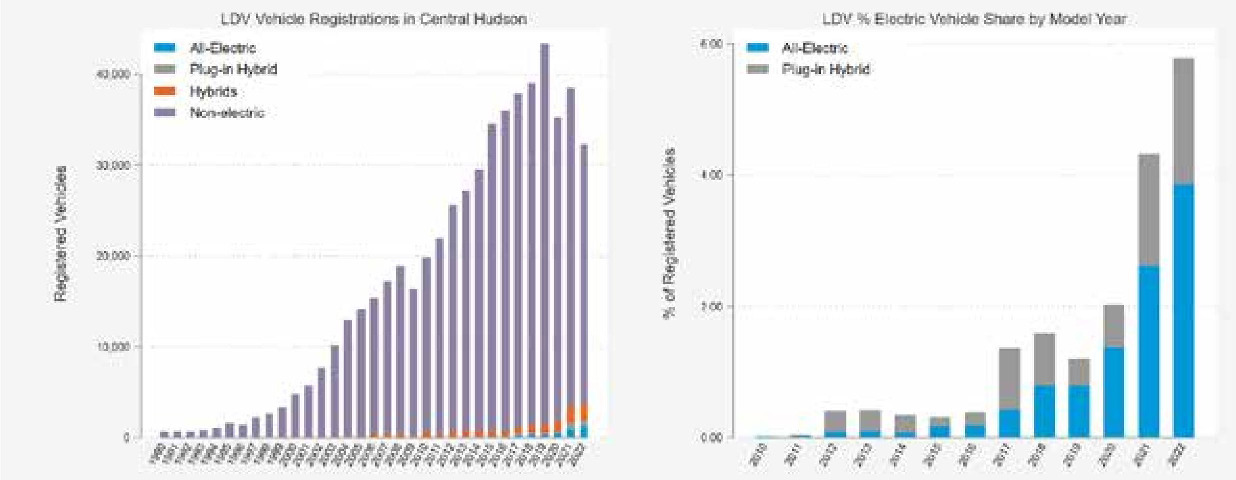
ANALYZE HISTORIC VEHICLE ADOPTION DATA

The main objective of the historical analysis was to understand the total vehicles in the service territory, the rate of entry of new vehicles, the geographic locations of electric vehicles, and how the electric vehicle share (as percent of new vehicles) was changing over time.

New York makes available vehicle registration data for all 11 million vehicles in New York, including information about the fuel type (e.g., electric, gas, diesel, etc.), the vehicle class, model year, zip code, and VIN number. We used the National Highway Transportation and Safety Administrations to extract additional information embedded in the VIN number (e.g., hybrid and PHEV vehicle information).

Figure 41 shows the Vehicle stock in Central Hudson territory as March 2023 by model year. Based on the vehicle registration data, there are approximately 570,000 Light Duty Vehicles (LDV), 25,400 Medium and Heavy-Duty Vehicles, and 1,600 Buses in Central Hudson's service territory. Approximately, 43,000 new vehicles enter Central Hudson's territory per year. The rate of entry in recent years has been lower due in part to COVID and the reality that not all of 2022 model years have made from sale lots to driveways. As vehicles age, they either flow out of Central Hudson's service territory or are retired. Thus, the overall penetration of electric vehicles is influenced most heavily by the share of new vehicles.

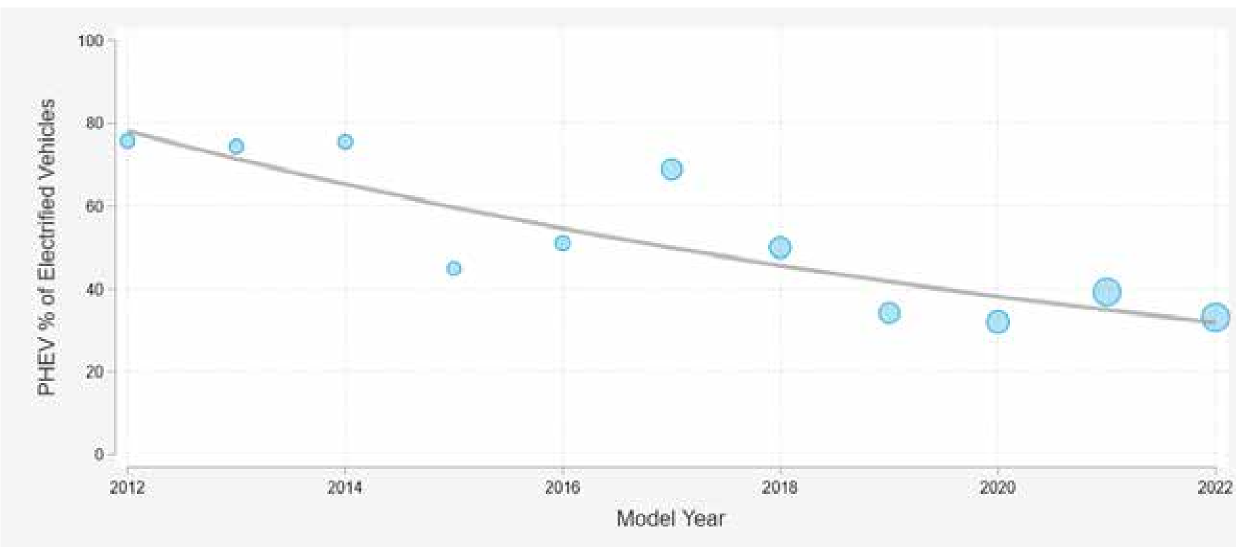
Figure 41: Central Hudson Vehicle Stock and Electric Vehicle Share by Model Year



Based on NY vehicle registration data

In addition, the historical data was used to assess how the mix of full battery electric vehicles and plug-in electric vehicles has evolved over time in Central Hudson territory. Not surprisingly, newer vehicles are more likely to be all electric as the vehicle range and charging infrastructure improves, and consumers become more comfortable with full electric vehicles.

Figure 42: PHEV Share of Electric Vehicles by Model Year



PRODUCE THE SERVICE TERRITORY FORECAST

The territory wide forecast for Light Duty Vehicles was produced using four steps:

1. **Fit an innovation diffusion curve (an S-curve) to the historical share of EVs by model year in Central Hudson.** Historical car registrations were first analyzed to determine the share vehicles, by model year in Central Hudson territory. Since the electric vehicles are still in the early staged, we had to assume a market share cap, which was assumed to be 80%.
2. **Predict EV market share for future model years and predict the PHEV share.** Fitting an innovation diffusion curve to historical adoption data, allows use to predict the share of future year car sales that are electric.
3. **Use a stock and flow model to track the turnover in vehicle stock.** A stock and flow model tracks vehicle stock by model year and calendar year. It is designed to model the changes in vehicle stock based on new vehicle entry share that is electric and decay rate or outflow. In total, roughly 43,000 new vehicle enter Central Hudson territory per year. The EV market share, or the share of new car sales that are electric vehicles, is produced by the bass-diffusion model. The decay rate is the rate at which older models of vehicles are retired and flow out of Central Hudson territory.
4. Convert vehicle counts to GWh sales. The EV forecast was then converted into GWh using inputs from the NYISO Gold Book presentations. In specific, we assumed:
    - ü Vehicle miles traveled per year: 12,600
    - ü kWh per mile: 0.28
    - ü PHEV share of miles on electric: 75%

Figure 43 show the electric vehicle market share for historical and forecast model years. The historical model year market share largely follows the innovation curve (S-curve). When fit to the data, the S-curve explained 97% of the variation. If the trajectory continues, the electric vehicle market share is projected to exceed 50% of electric vehicle sales by 2030. While the market share of new vehicles is expected to increase quickly, it still takes over a decade to fully transform the market since existing vehicles on the road need to be retired or sold elsewhere before they are replaced.

Figure 43: Historical and Forecasted Electric Vehicle Market Share by Model Year

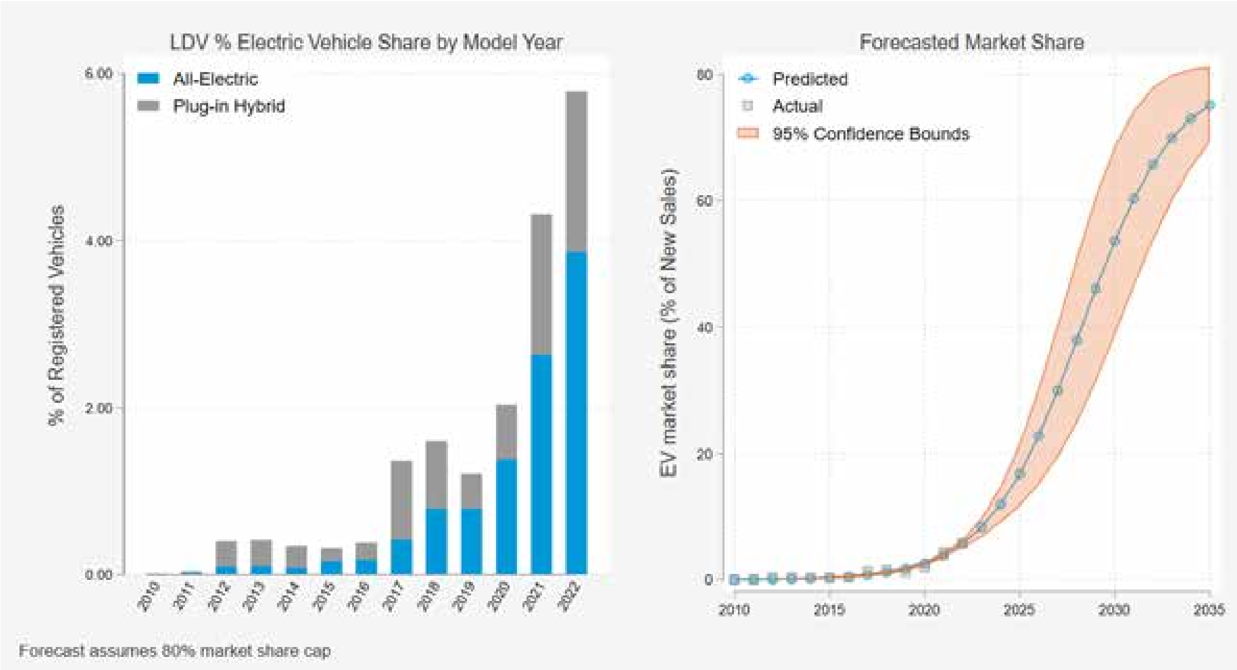


Table 14 shows the system level forecasts for LDVs, MHDVs, and buses. While the LDV forecasts were developed based on the historical data, there is limited data on the rate or overall energy use of buses. Thus, we relied on detailed assumptions about MDHV and buses presented by NYISO as part of the 2021 Gold Book and scaled them from NYISO wide numbers to Central Hudson service territory.[2]

[2] NYISO (2021). Electric Vehicle Forecast Impacts (Gold Book 2021). Available at: https://www.nyiso.com/documents/20142/19415353/04%202021%20GoldBook%20EVForecast.pdf/bc823f27-cbbd-669f-8d76-e695d59b9bed

Table 14. Service territory forecast for LDV, MHDV, and buses.

	Light Duty		Medium Heavy Duty		Schools		TOTAL	
Year	Vehicles	GWh	Vehicles	GWh	Vehicles	GWh	Vehicles	GWh
2023	9,353	30.1	50	0.7	69	1.0	9,472	31.8
2024	13,639	44.3	97	1.4	81	1.1	13,639	46.8
2025	19,583	64.1	165	2.3	94	1.3	19,583	67.7
2026	27,573	90.8	261	3.7	111	1.6	27,573	96.0
2027	37,908	125.5	384	5.4	129	1.8	37,908	132.8
2028	50,692	168.7	541	7.6	147	2.1	50,692	178.4
2029	65,765	219.9	732	10.3	171	2.4	65,765	232.6
2030	82,702	277.6	960	13.5	196	2.8	82,702	293.9
2031	100,903	339.8	1,226	17.3	228	3.2	100,903	360.3
2032	119,718	404.5	1,522	21.5	261	3.7	119,718	429.6
2033	138,556	469.4	1,858	26.2	297	4.2	138,556	499.8
2034	156,944	533.1	2,226	31.4	335	4.7	156,944	569.2
2035	174,549	594.3	2,631	37.1	377	5.3	174,549	636.7
2036	191,161	652.2	3,067	43.3	425	6.0	191,161	701.5
2037	206,666	706.5	3,536	49.9	474	6.7	206,666	763.1
2038	221,023	757.0	4,030	56.9	527	7.4	221,023	821.3
2039	234,240	803.7	4,548	64.2	586	8.3	234,240	876.1
2040	246,356	846.6	5,086	71.8	644	9.1	246,356	927.5
2041	257,428	886.0	5,672	80.0	711	10.0	257,428	976.1
2042	267,522	922.1	6,301	88.9	785	11.1	267,522	1,022.0
2043	276,709	955.0	6,918	97.6	855	12.1	276,709	1,064.7

In addition, DSA used NREL's EV Lite Pro tool to quantify the expected number of workplace, multi-family, public, and fast charging stations needed to support the electric vehicle fleet in the service territory on a year by year basis.

Table 15: Electric Vehicle Charging Port Forecast

year	Battey electric	PHEV	% PHEV	SFH ports	MF ports	Public Level 2 ports	DCFC ports
2023	6,159	3,171	34.0%	7,848	414	401	81
2024	9,356	4,249	31.2%	10,716	523	523	103
2025	13,923	5,610	28.7%	15,384	749	751	130
2026	20,228	7,275	26.5%	21,666	1,050	1,053	161
2027	28,586	9,228	24.4%	29,784	1,438	1,445	195
2028	39,160	11,412	22.6%	38,114	1,678	1,661	231
2029	51,891	13,728	20.9%	49,456	2,175	2,154	267
2030	66,482	16,053	19.4%	60,077	2,479	2,503	304
2031	82,458	18,261	18.1%	73,310	3,021	3,043	339

2032	99,271	20,252	16.9%	85,286	3,613	3,603	372
2033	116,398	21,956	15.9%	98,722	4,173	4,164	404

MODEL CUSTOMER ADOPTION PROPENSITY AT A GRANULAR LEVEL

The methodology for determining propensity scores for EV adoption at the premise level varies between EV types. For light-duty vehicles and DCFC stations, propensity scores were produced for each premise using the decision tree model XGBoost. XGBoost classifies a premise as either having an electric vehicle or not having an electric vehicle based on a set of premise features, such as the square footage of the home, the age of the home, the annual electricity usage at the premise, and whether the premise has solar or not. These predictions are then compared to the actual classification, which the model then uses to improve future predictions. Figure 44 provides additional detail about the process used to identify the features or characteristics used to score premises on the early-to-late adopter spectrum.

The geographic allocation for MHDVs and buses were developed at the feeder level instead of the premise level. Vehicle registration data provided counts of MHDVs and buses at the zip code level, which were mapped to a specific circuit in the territory by multiplying the proportion of electricity usage for each circuit within their zip code by the number of MHDVs and buses in each zip code. The electricity usage of a single MHDV or bus for each circuit was calculated by dividing this product by the total count of buses registered in the zip code. Electricity usage per MHDV or bus was summed across circuits to the feeder level, which was subsequently used as the propensity scores for the MHDV and bus DERs.

Figure 44: Development of Adoption Propensity Scores

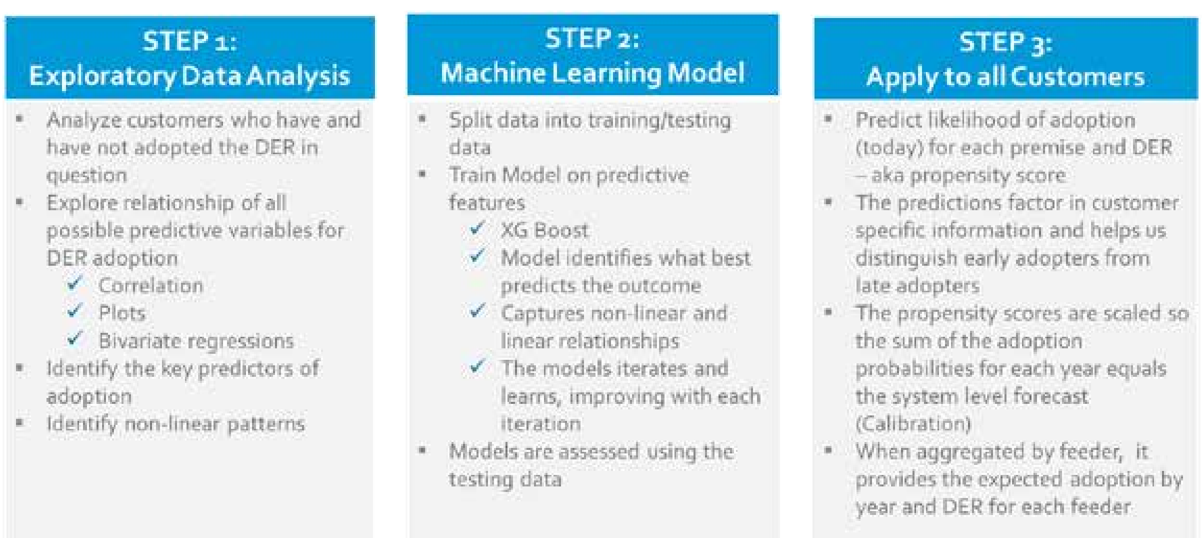


Figure 45 illustrates the relationships between some of the predictors and adoption likelihood. Overall, higher gross annual usage prior to the EV adoption, higher home square, and higher estimated income were predictive a higher probability of electric vehicle adoption. Utility customers in newer homes, with single family homes, and who previously installed solar were more likely to be early adopters. Surprisingly, whether a home was owner occupied only mildly correlated with higher electric vehicle adoption, likely because younger households are more likely to adopt EVs but less likely to be home owners. Figure 46 shows the feature importance for the final model.

Figure 45: Predictors of Electric Vehicle Adoption Propensity

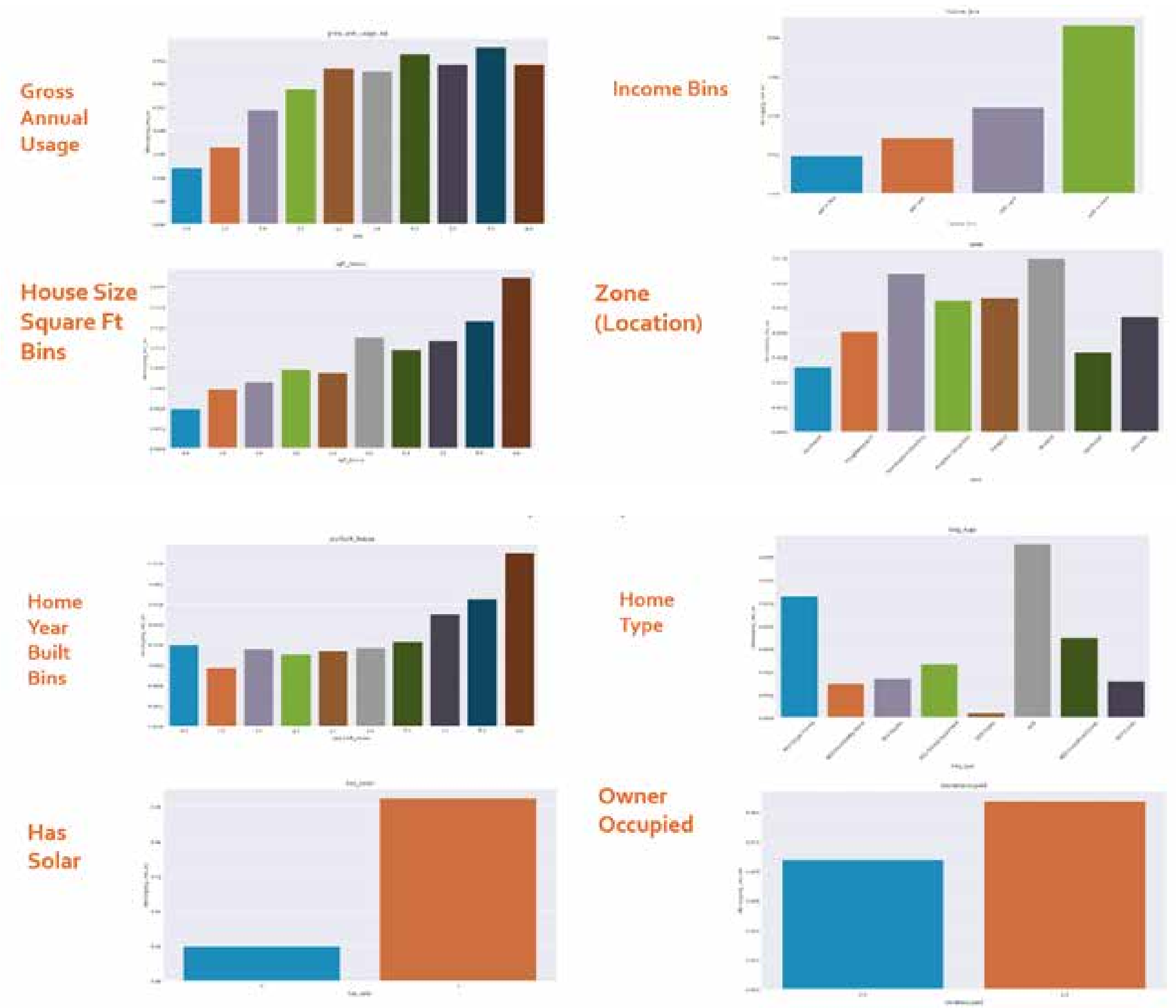
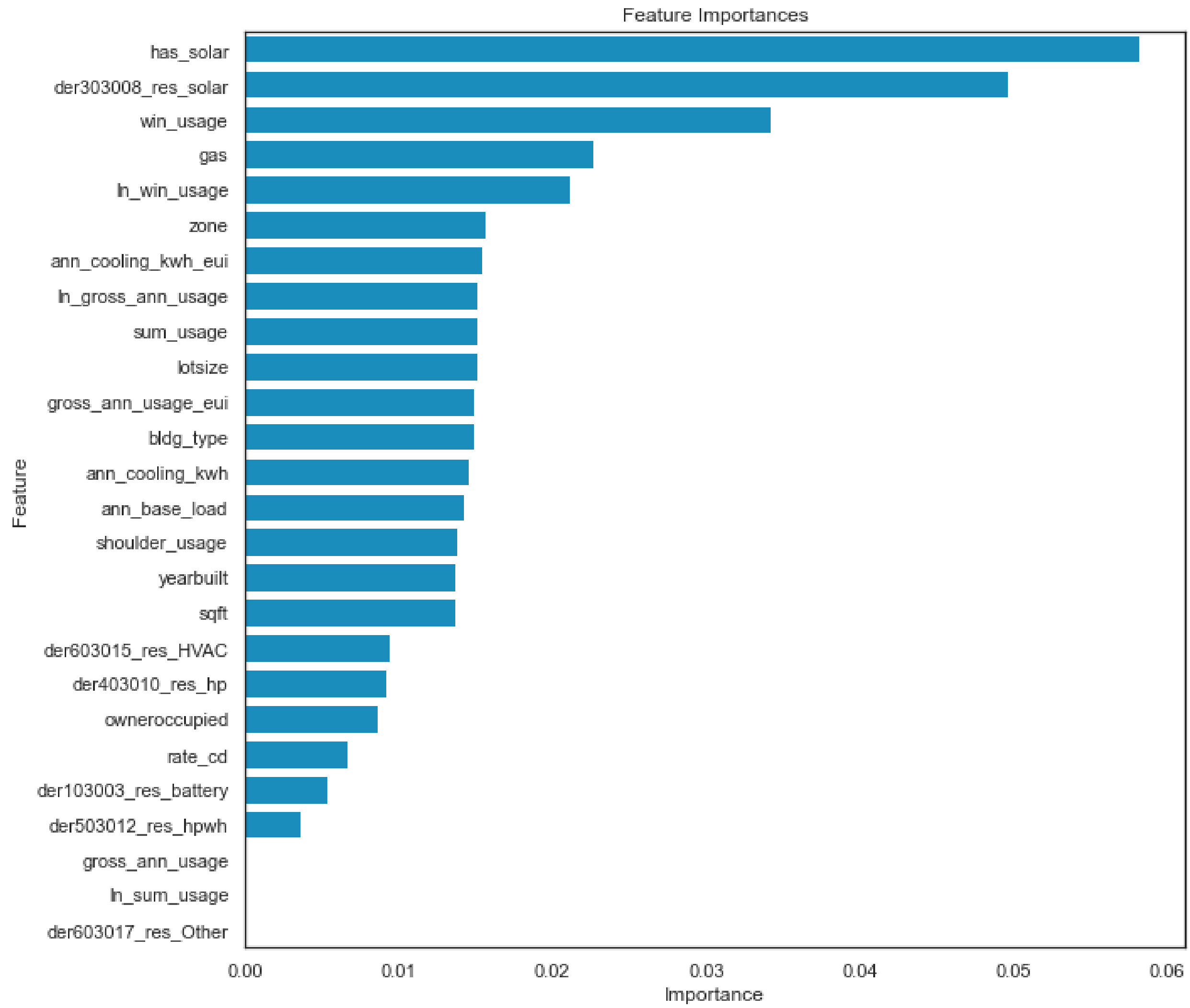


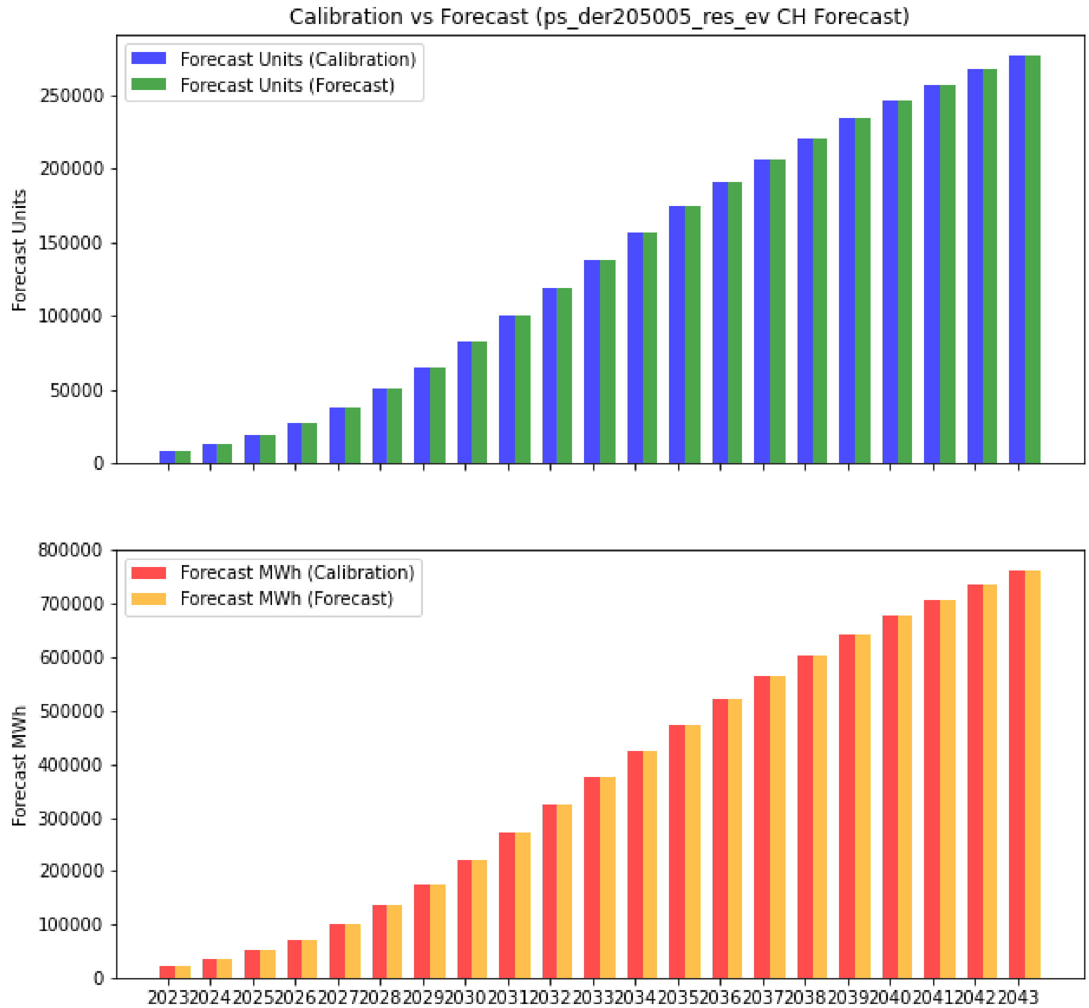
Figure 46:LDV Electric Vehicle Propensity Model Feature Importance



CALIBRATE PROPENSITIES TO MATCH TERRITORY FORECAST

Propensity scores produced for each EV type were calibrated to the system level forecast. Calibration is the process of iteratively finding an adjustment that makes the sum of the likelihood scores across each individual premise equal to the territory-wide forecast. In effect, the calibration produces a highly granular forecast down to the premise level that is consistent with the service territory wide forecasts. The process is non-linear as each individual premise is effectively moving up their individual S-curve at their own pace. The calibration was performed for the years 2023 through 2043 and for two scenarios, Central Hudson forecast and NYISO consistent forecast. Figure 47 compares the calibrated forecast and system level forecast for light-duty vehicles.

Figure 47.Comparison between Calibration and Forecast EV MWh and Units



INCORPORATE 8760 HOURLY END USE LOAD SHAPES

A key component for the electric vehicle DERs was incorporating 8760 electric vehicle charging load shapes for each electric vehicle type. Home, public, and fast charging load shapes were collected from NREL's EV Lite Pro Tool, and MHDV and bus load shapes were based on public load shapes from LBNL's HEVI-LOAD tool, which is still under development. The EV Lite Pro load shapes were specific to the Poughkeepsie-Newburgh metro. The hourly loads provided by the EV Lite Pro tool are 24 hour shapes by broad temperature conditions. They were combined with the 1-in-2 and 1-in-10 weather planning scenarios and then normalized to the total annual load, giving us the share of electricity used by each type of EV for each hour of the year – that is, the total for the charging shapes for each year was equal to 100%.

The calibration step produced forecasts of total EVs and electric consumption (MWh) by feeder, scaled to match the territory-wide forecast. The hourly charging load shapes were merged with the feeder EV electric use forecast and multiplied by the normalized load profile to produce the hourly forecasted electric vehicle loads by circuit feeder for years 2023 through 2043, 1-in-2 and 1-in-10 weather years, and CLCPA and Central Hudson forecast scenarios. The granular data allowed to combine the electric vehicle loads with native loads, building electrification, and distributed resources to identify the loads coincident at various planning levels – circuit feeder, substation, transmission area, or territory wide.

ASSESS PEAK DAY IMPACTS ON LOCAL GRIDS AND TERRITORY LOAD

The final step was to asses impacts of EV charging on circuit feeders, substations, transmission areas and territory wide. To do so, first the local winter and summer peak days were identified by feeder, substations, and transmission areas using native hourly interval data adjusted for 1-in-2 and 1-in-10 planning conditions. The underlying assumption was that the summer peak would still occur on the hottest summer days and the winter peaks would occur on the coldest winter days, but that the hour day and magnitude of the peak may change due to the growth in transportation and building electrifications, or changes in the penetration of distributed energy resources. Next, the EV loads were combined with forecasted T&D loads on coincident (territory wide) and non-coincident (local) peak days for each location (feeder, substation, and transmission area) and forecast year. Thus, the outputs are tables that include all components of the forecasts – native loads, EVs, building electrifications, distributed solar, distributed battery storage, and energy efficiency – at three levels of granularity:

- 8760 hourly forecasts by location for the forecast years
- 24 hour forecasts for coincident (territory wide) and non-coincident (local) summer and winter peak days by location for the forecast years.
- Single hour forecasts for coincident (territory wide) and non-coincident (local) summer and winter peak days by location for the forecast years. These tables are similar to the Gold Book tables produces for NYISO forecasting.

APPENDIX B – BUILDING ELECTRIFICATION

We forecasted Building Electrification for Heat Pump and Heat Pump Water Heater measures for commercial and residential sectors. Forecasts were implemented at the feeder level in order to capture geographic adoption patterns over time. The following sections outline the data used and methodology implemented in the granular forecasting evaluation.

DATA SOURCES & HISTORICAL DATA ANALYSIS

The primary data sources used in the building electrification analysis are listed below:

- Clean Heat Program measure and project level participation data and incentive levels,
- Central Hudson electric and gas usage and rate data for all customers
- Property data including square footage, year built, and type of home
- NREL residential and non-residential load shapes for Central Hudson Counties
- NYISO Zone G electrification forecasts

Central Hudson provided billing data, records of historical heat pump and heat pump water heater (HPWH) installations, incentive levels, and corresponding impacts. These data sources were used both to calculate cumulative historical heat pump and HPWH adoptions by program and the geographic adoption patterns for granular locations (transmission area, substation, and feeder). Historical building electrification goals and savings realization (based on past Central Hudson E-TIP filings) as well as future system-wide goals were used to develop a future forecast of heat pump adoptions with an uncertainty range. These forecasts were compared with NYISO electrification forecasts based on CLCPA goals. Customer characteristics and property data were used to develop premise-level heat pump propensities. The propensities were calibrated to the system level forecast to develop a location-specific heat pump forecast. Finally, end use and segment-specific load shapes sourced from the NREL database were used to develop peak day heat pump impacts and coincidence factors by location.

PRODUCE SYSTEM LEVEL FORECAST

Step 2 in Figure 11 introduces our methods to producing system level forecasts for heat pump and heat pump water heater adoption. Historical adoption trends were used to estimate innovation diffusion curves, also referred to as an S-curve. These curves are used to estimate the rate at which a population will adopt a new behavior or product, in this case they were used to estimate the rate of heat pump and heat pump water heater adoptions. This is used to estimate the heat pump market share over time. The decay rate is the rate at which fossil fuel powered heating systems are retired. This turnover of heating and water heating equipment stock informs the system level empirical forecasts for Central Hudson. Figure 48 shows the forecast results.

Figure 48: Heat Pump Forecast

MODEL CUSTOMER ADOPTION PROPENSITY

For Heat Pump and Heat Pump Water Heaters, propensity scores were produced for each premise using the decision tree model XGBoost. XGBoost classifies a premise as either having a Heat Pump or not having a Heat Pump based on a set of premise features, such as the residents' income, square footage of the home, the annual electricity usage at the premise, and whether the premise has solar or not. These predictions are then compared to the actual classification, which the model then uses to improve future predictions.

Figure 49 illustrates the relationships between some of the predictors and adoption likelihood. Overall, customer who adopted heat pumps typically had higher winter and summer usage prior adoption for the heat pump, large lots, and higher estimated income. Utility customers in single family homes or townhomes, and who previously installed solar were more likely to be early adopters. Customers with gas services were less likely to transition to heat pumps, with most of the heat adoption occurring from sites with oil heating. Surprisingly, whether a home was owner occupied had a week relationship with heat pump adoption.

Figure 49: Predictors of Residential Heat Pump Adoption

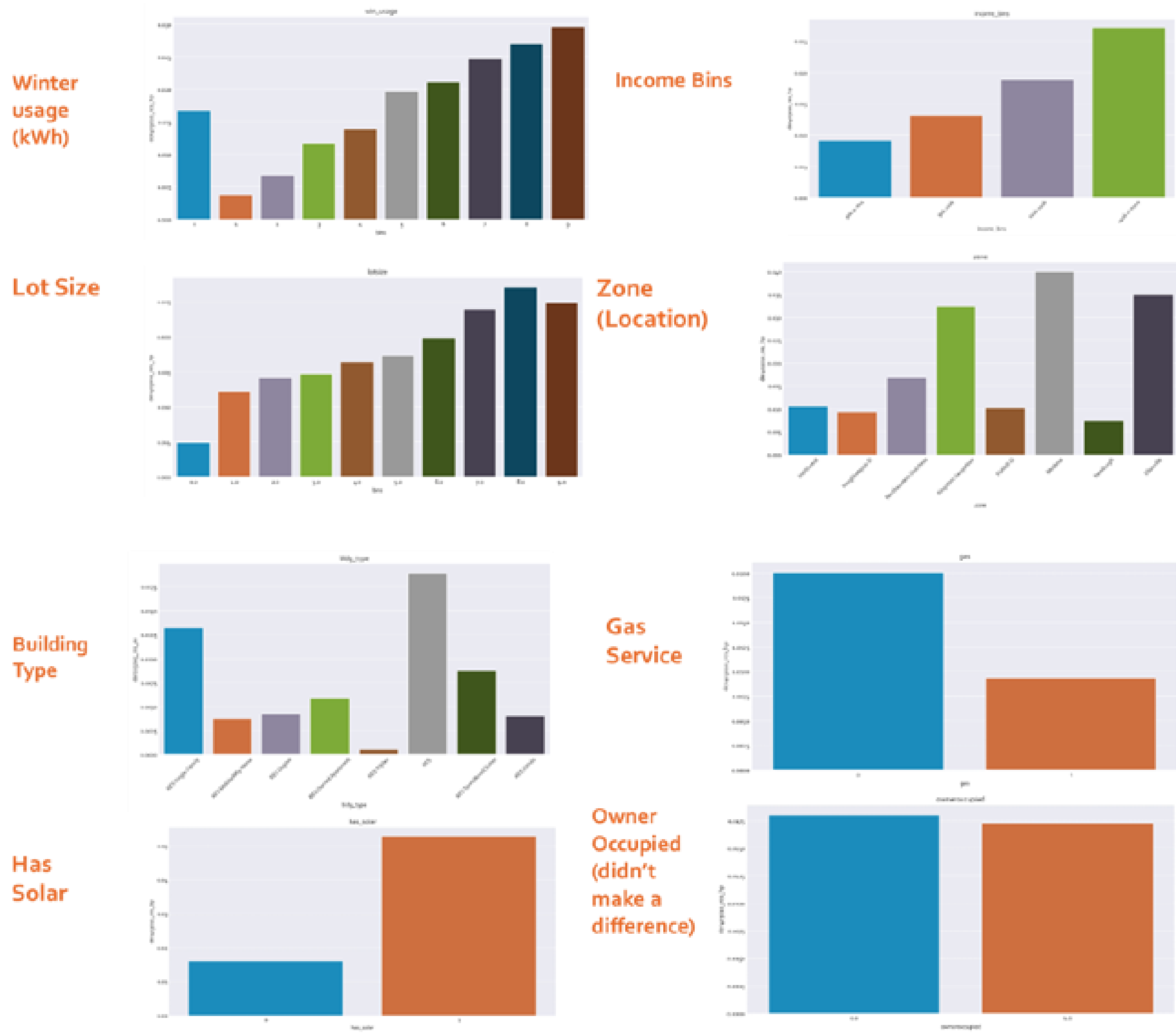
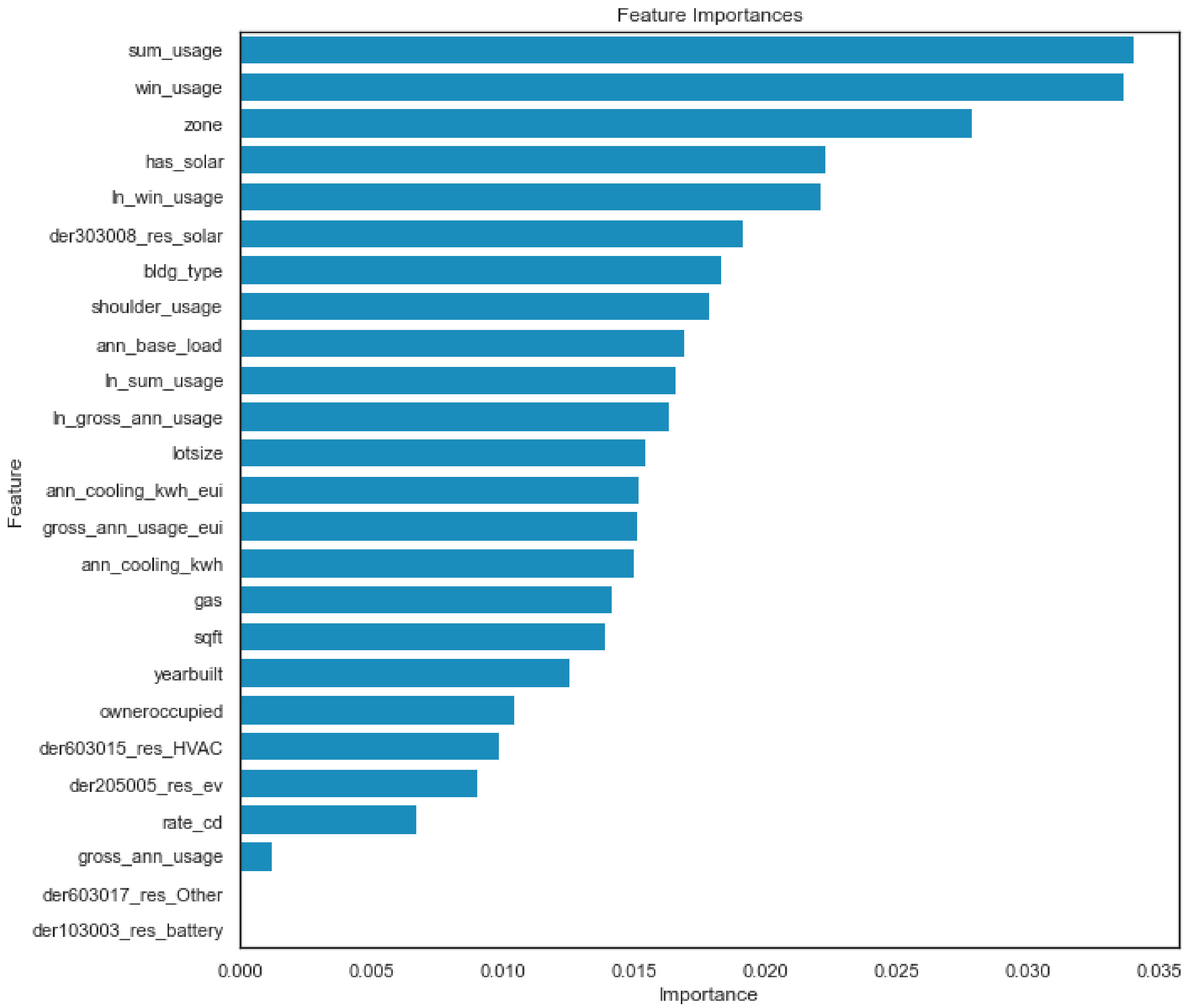


Figure 50 below shows the estimated predictive importance of each feature tested. The higher the feature the performance, the more useful it is for predicting propensities. For example, summer and winter usage had the two highest scores. These are the customers average summer kWh and winter kWh before any DER intervention. Additionally, the customer's Zone, if the participant has solar, and building type all are useful data points in capturing a customer's likelihood to participate in heat pump and heat pump water heater measures.

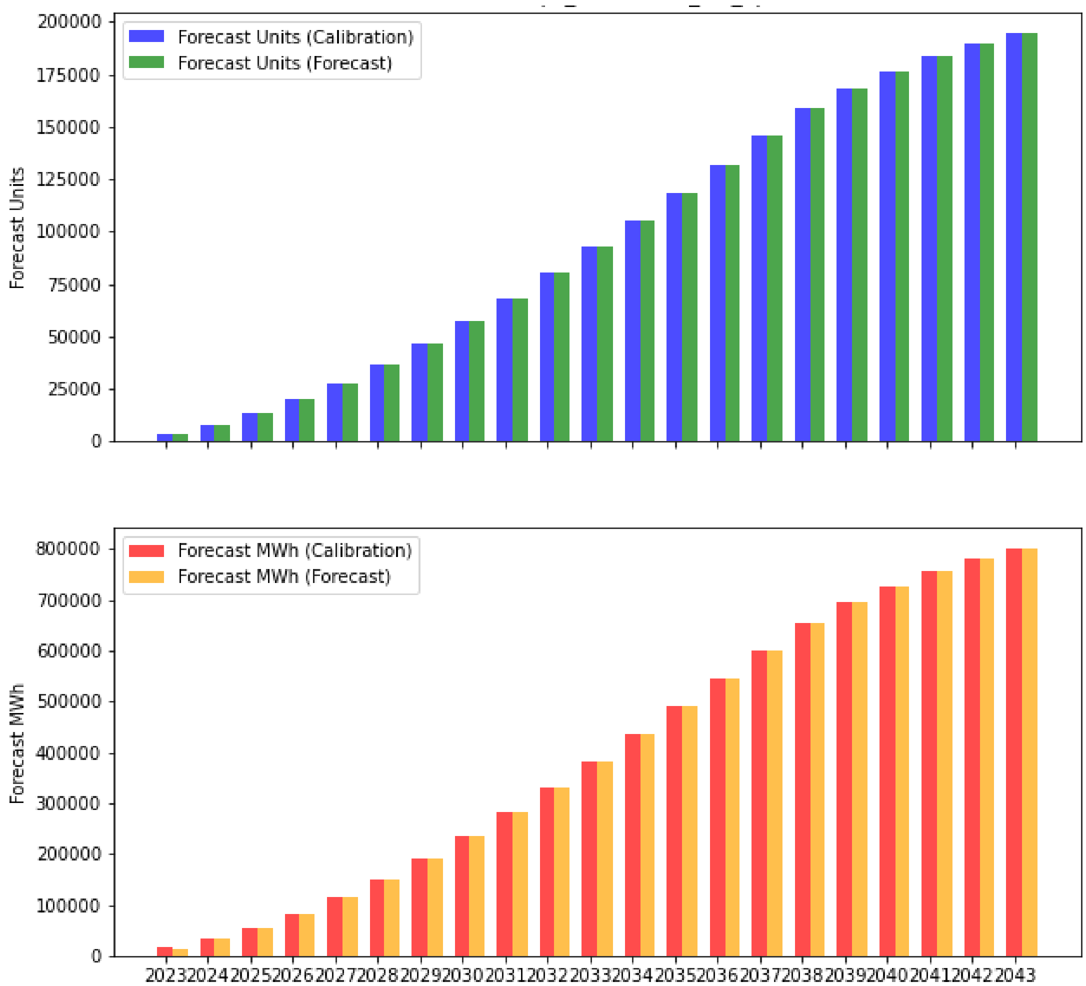
Figure 50: Building Electrification Propensity Modeling Feature Importance, Residential Heat Pump



CALIBRATE TO SYSTEM FORECAST

Next, the premise level propensities were scaled so the total for each year equals the system level forecasts for that year. Each site follows its individual S-curve. Two forecasts were generated for this evaluation, a Central Hudson forecast that was fitted to their goals, and a CLCPA forecast that was fitted to the goals established by the CLCPA. Next, these scaled results were aggregate to the circuit feeder level to get forecasted counts of residential and non-residential sites adopting heat pumps and heat pump water heaters by feeder and forecast year. Figure 51 below shows the calibrated propensity results rolled up to the forecasts at the system level for both forecasted units of heat pumps adopted and forecasted MW. You can see that at the system level, the forecasts are equal. Commercial Heat Pumps and Residential HPWHs were calibrated in the same way.

Figure 51: Calibrated Feeder Level Forecast vs. System Level Forecasts, Residential Heat Pumps



COMBINE WITH 8760 PRODUCTION PROFILE

The last component of the forecasting work was to combine forecasted adoption with end use load shapes. This provided the MW impacts expected in the year to year, feeder level forecasts. NREL residential and non-residential end use load profiles for counties in Central Hudson territory were used to combine the forecasted feeder level results with heat pump heating, cooling, and water heating load shapes. First, the load shapes were weather adjusted to match the T&D 1-in-2 and 1-in-10 peak planning weather years for winter and summer. Next, the heating and cooling loads were combined and scaled to match the change in electric heating and cooling usage observed in the Clean Heat program. These values were then normalized so the sum of the load shape for the year equals 100%. Finally, load shapes were scaled to match feeder forecasts by year of change in MWh due to heat pumps (heating/cooling) and water heaters. This produces a MW value for each hour for each feeder and each forecast year.

ASSESS PEAK DAY IMPACTS

To assess the impacts of heat pump and HPWH adoption on peak day, first the local winter and summer peak days were identified by feeder, substations, and transmission areas using historical hourly interval data. Next, heat pump loads were combined with forecasted T&D loads on peak days for each location (feeder, substation, and transmission area) and forecast year. From this, we can estimate the Building Electrification contribution to forecasted loads.

APPENDIX C – ENERGY EFFICIENCY METHODOLOGY

The granular energy efficiency forecasts were produced using the following six step process:

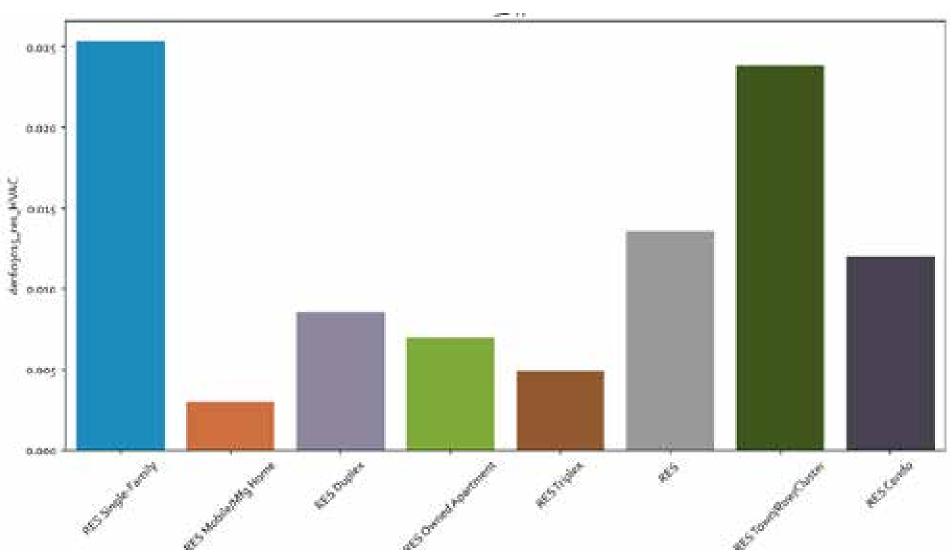
1. Analyze historic vehicle adoption data
2. Produce territory forecast
3. Model customer adoption propensity at granular level
4. Calibrate propensities to match territory forecast
5. Incorporate 8760 hourly end use load shapes
6. Assess peak day impacts on local grids and system load

This appendix provides additional detail about the data sources, method, and techniques use at each step of the process. Overall, we developed distinct models predicting adoption propensity for residential and non-residential customers and for lighting, HVAC/shell measures, and other measures.

HISTORICAL DATA ANALYSIS

In order to accurately forecast growth in energy efficiency, it is important to understand the historical trends. Central Hudson develops a detailed plan for future energy efficiency in its annual Energy Efficiency Transition Implementation Plan (ETIP). Historical information was leveraged to understand Energy Efficiency adoption patterns in the past. This information was used to inform what drives adoption rates and was incorporated into the propensity analysis for energy efficiency. Figure 52 shows the potential relationship between building type and HVAC adoption rates. Historically, we see that customers in single-family units or townhomes have been more likely to participate in HVAC Energy Efficiency upgrades.

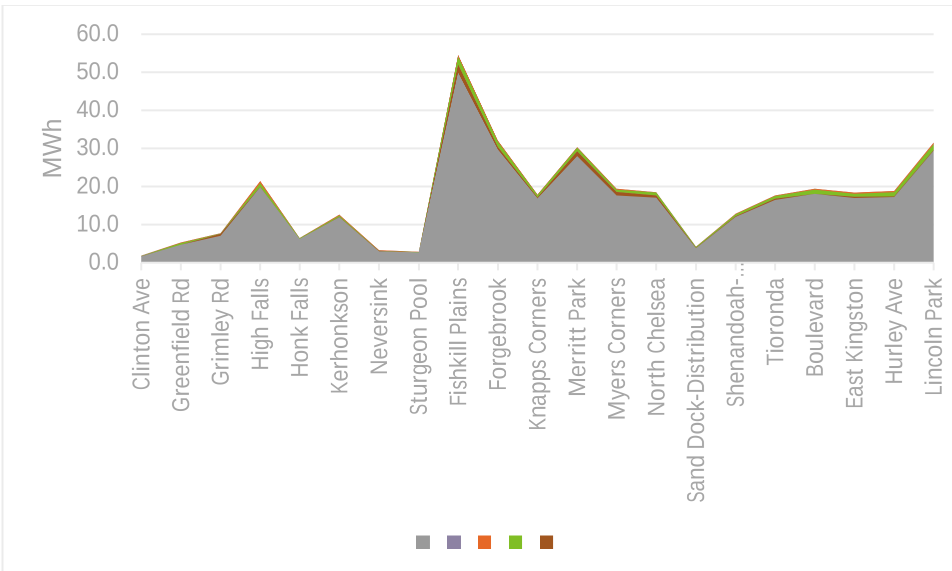
Figure 52: Residential HVAC Adoption Rates by Building Type



FORECAST SYSTEM ADOPTION

To develop an energy efficiency forecast, the 2023 Goldbook Forecasted Energy Efficiency Savings for Central Hudson was scaled for MWh, MW, and Participant count estimations for Residential and Non-Residential Energy Efficiency for three Energy Efficiency categories: Lighting, HVAC, and Other. Figure 53 shows the resulting forecasted MWh adoption rates by sector, residential or commercial, and energy efficiency category.

Figure 53: Forecasted Energy Efficiency Savings

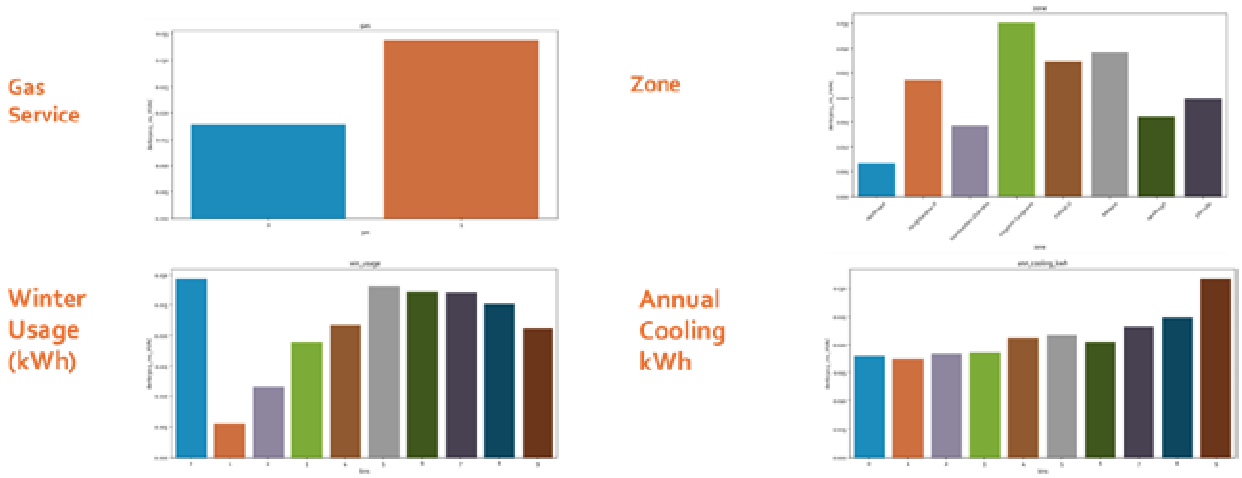


MODELING ADOPTION PROPENSITIES AT A GRANULAR LEVEL

After forecasting system-level energy efficiency, we developed adoption propensity scores for residential HVAC, residential Other, non-residential Lighting, non-residential HVAC, and non-residential Other Energy Efficiency End Uses. This was a key step for understanding how energy efficiency is distributed across the territory as well as understanding how specific types of energy efficiency coincides with local loads.

The methodology for determining propensity scores relied on machine learning. The first step was to identify characteristics or features that are related to solar via exploratory data analysis and bi-variate regression. Figure 54 illustrates the relationships between some of the predictors and adoption likelihood.

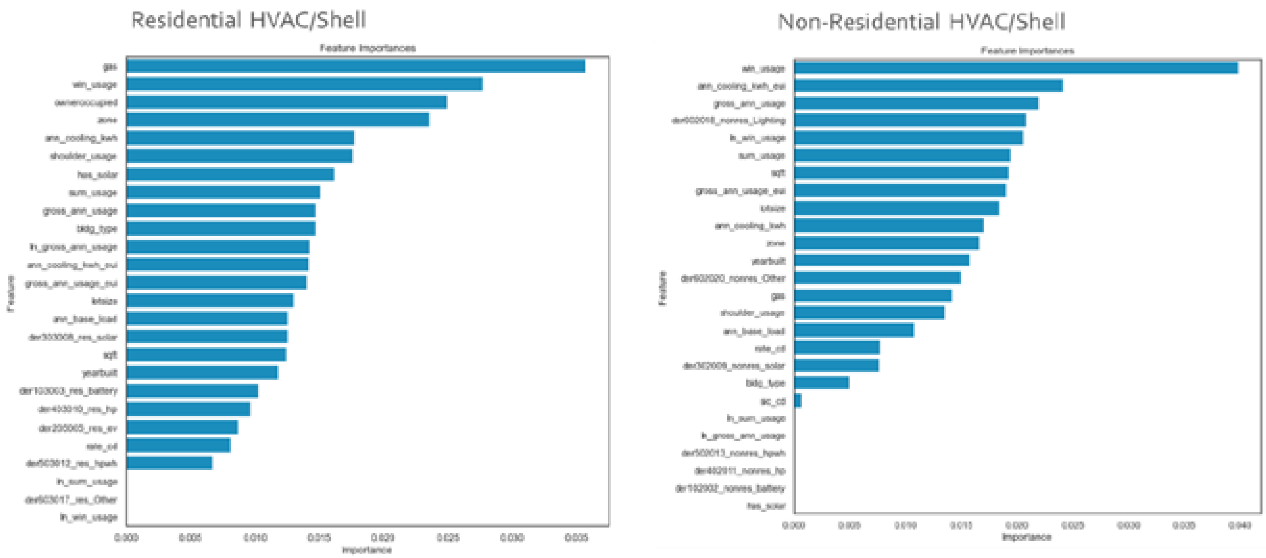
Figure 54: Exploratory Analysis of Residential HVAC/Shell Energy Efficiency



Next, we applied a machine learning model, known as XGBoost. XGBoost classifies a premise as either adopting or not adopting energy efficiency based on a set of premise characteristics or features, such as the square footage of the home, the age of the home, the annual electricity usage at the premise, etc. The model is developed by splitting the data into training and testing datasets. The training data is used to build the model used to predict out of sample, using the testing data. The accuracy of the models assessed by comparing predicted versus actual solar adoption.

Figure 55 shows the estimated predictive importance of each feature tested in the residential and non-residential HVAC energy efficiency models. The higher the feature the performance, the more useful it is for predicting propensities. For example, the top three features for the residential model were 1) if the participant uses gas, 2) what the participants winter usage was, and 3) if the home was owner occupied. Additionally, the customer's Zone and annual cooling kWh all are useful data points in capturing a customer's likelihood to participate in heat pump and heat pump water heater measures. These features were used in the final propensity model to capture other customers that have similar trends in these same features as energy efficiency participants. Those customers will be highlighted as potential future participants.

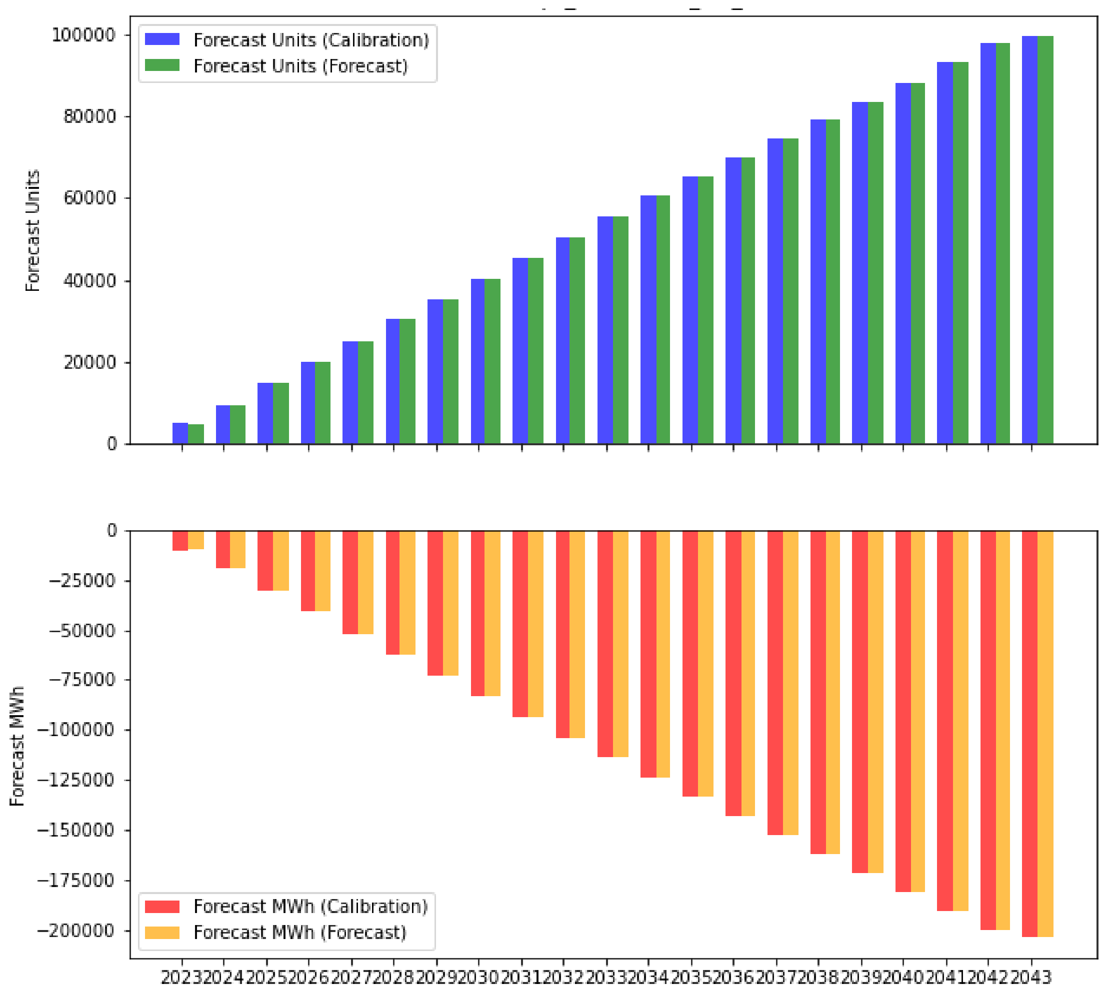
Figure 55: Energy Efficiency Models Feature Importance



CALIBRATE TO SYSTEM FORECAST

Next, the premise level propensities were scaled so the total for each year equals the system level forecasts for that year. Each site follows its individual S-curve. Two forecasts were generated for this evaluation, a Central Hudson forecast that was fitted to their goals, and a CLCPA forecast that was fitted to the goals established by the CLCPA. Next, these scaled results were aggregate to the circuit feeder level to get forecasted counts of residential and non-residential sites adopting heat pumps and heat pump water heaters by feeder and forecast year. Figure 56 shows the calibrated propensity results rolled up to the forecasts at the system level for both forecasted units of HVAC measures adopted and forecasted MWh. You can see that at the system level, the forecasts are equal. The other Energy Efficiency categories were calibrated in the same way.

Figure 56: Calibrated Feeder Level Forecast vs. System Level Forecasts, Residential HVAC



PRODUCE HOURLY LOAD SHAPES

Segment and end-use specific load shapes were extracted from NREL. These load shapes were then adjusted for Central Hudson's T&D forecasted 1 in 2 and 1 in 10 weather years and expanded to 8760. The 8760 loads shapes are normalized so that maximum load for a given end use equals 1. Finally, the calibrated forecast aligned with these load shapes in order to produce location specific load estimates.

PRODUCE AGGREGATE AND LOCATION SPECIFIC FORECASTS

The final step in the process was to apply hourly load shapes based on the end-uses of each program and measure to the adoption forecast. The output of this analysis was a ten-year location-specific hourly (8760) forecast of energy efficiency, by sector and end use. A secondary set of outputs are coincidence factors with local peaks by sector and end use.

C. 2022 Long Range Electric System Plan

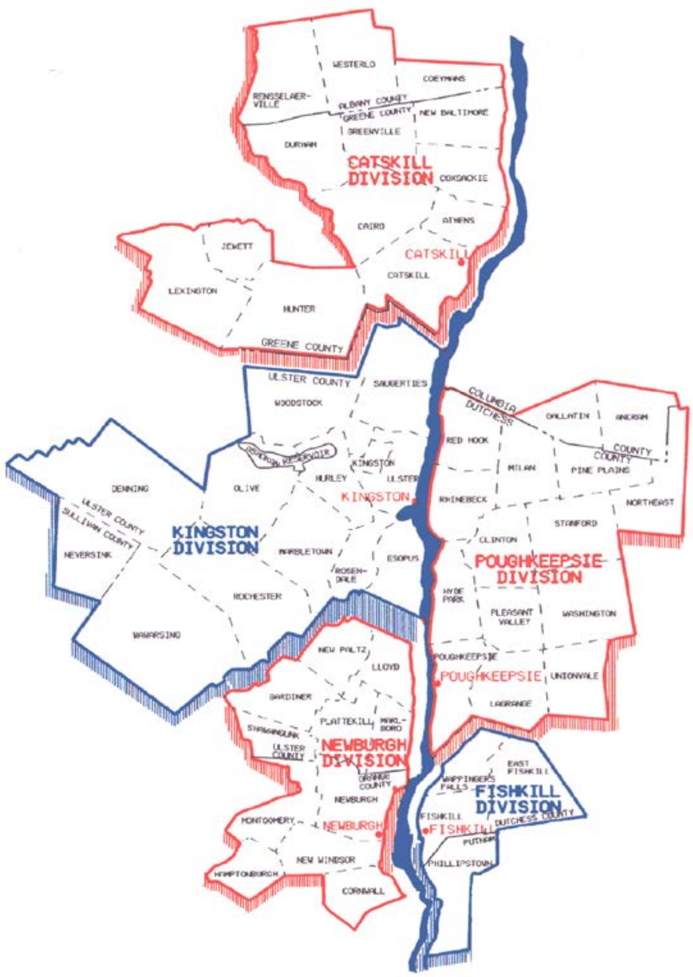
Central Hudson Gas & Electric

Long Range Electric System Plan

July 2022

1. Introduction

Central Hudson Gas & Electric Corporation is a regulated transmission and distribution utility serving approximately 309,000 electric customers and 84,000 natural gas customers in New York State's Mid-Hudson River Valley. Central Hudson delivers natural gas and electricity in a defined service territory that extends from the suburbs of metropolitan New York City north to the Capital District at Albany. Central Hudson is a leader in promoting regional economic growth, improving system reliability, and effective cost management.



Central Hudson's electric transmission system consists of approximately 580 circuit miles of line. The electric distribution system consists of 7,159 pole miles of overhead lines and 1,657 trench miles of underground lines, as well as customer service lines and meters.

The transmission system operates at voltages of 69 kilovolts, 115 kilovolts and 345 kilovolts. The distribution system operates at nominal voltages of 13.8 kilovolts, 34.5 kilovolts, 4.8 kilovolts, and 4.16 kilovolts. It also encompasses sub-transmission systems that nominally operate at 13.8 kilovolts in three urban areas of our service territory, feeding into secondary networks. Central Hudson has approximately 74 electric substations that contain power transformers that change the voltage from one level to another.

This document provides a long-term roadmap for the electric transmission, substation, and distribution system to optimize the amount and allocation of capital expenditures for the next 7 to 10 years. It is an output of the Electric System Planning Process that was developed to support corporate and departmental goals, and includes a comprehensive load and infrastructure assessment and capital budget plan. The document is broken down into nine sections subsequent to the Introduction:

(2) Purpose, Vision, Strategy, and Goals
(3) System Reliability and Infrastructure
(4) Grid Modernization
(5) Long Term System Load Forecast
(6) Transmission (Category 12) and Substation (Category 13) Areas
(7) Sub-transmission, Distribution (Category 15) and Substation (Category 13) Infrastructure and Load Growth Plan
(8) Summary of Projects
(9) Emerging Opportunities
(10) Conclusion

2. Purpose, Vision, Strategy, and Goals

2.1 Introduction – Corporate Purpose, Vision, and Strategy

Central Hudson is a well-established energy company with a tradition of business excellence and commitment to dynamic growth. Central Hudson strives to create greater value for our customers, fulfillment for our employees and profitable growth for our investors. The Company remains committed to its core values of never compromising on safety, valuing our people, putting the customer first, aiming for excellence every day, and putting energy into our communities. We believe that together, we power endless possibilities.

Central Hudson provides exceptional value to its customers by:

- Continuously improving our performance while maintaining cost effective, efficient, and secure operations.
- Investing in programs and employee development to position the organization for continued success in the future.
- Modernizing and transforming our business through electric and natural gas system investments and process improvements.
- Advocating on behalf of customers and other stakeholders.

2.2 Electric Service Reliability and Capital Expenditures – Vision and Goals

To support the corporate vision and strategy, the Electric Engineering Services division seeks to safely plan, design, construct, operate, and maintain a reliable and affordable electric transmission and distribution system that optimizes value for all stakeholders. It develops prudent capital investments and recommends evaluation of non-wires alternatives which enhance reliability, improve customer satisfaction, and reduce risk. The Electric Engineering Services division also identifies and implements process improvements that enable us to continuously improve the way in which we fulfill our purpose and moderate costs pressure that impact customer bills.

The Electric Engineering Services division accomplishes its purpose by setting challenging service reliability and net plant goals.

Reliability goals are focused on SAIFI (frequency) and CAIDI (duration), which are defined as follows:

$$\text{SAIFI} = \text{System Average Interruption Frequency Index} = \frac{\textit{Total \# of Customers Interrupted}}{\textit{Total \# of Customers Served}}$$

$$\text{CAIDI} = \text{Customer Average Interruption Duration Index} = \frac{\textit{Sum of Customer Interruption Duration}}{\textit{Total \# of Customers Interrupted}}$$

Through the Electric Ratemaking Process, the Public Service Commission (PSC) establishes targets with penalty mechanisms for each of these metrics. As of the Company's 2021 approved Joint Proposal, the 2022 PSC target for non-storm SAIFI = 1.32, and the 2022 PSC target for non-storm CAIDI = 2.50. The table below provides the current three-year PSC targets for the non-storm SAIFI and CAIDI indices. For 2022, Central Hudson's internal company target for non-storm SAIFI is 1.300 and non-storm CAIDI is 2.37.

Performance Indicator (Non-Storm)	2021 Actual	2022 PSC Target	2023 PSC Target	2024 PSC Target
SAIFI – System	1.418	≤ 1.32	≤ 1.30	≤ 1.30
CAIDI – System	2.67	≤ 2.50	≤ 2.50	≤ 2.50

To achieve a balance between reliability and affordability, a Capital Plan is reviewed and approved by Company's Board of Directors and filed with the Public Service Commission on July 1 of each year.

2.3 Electric System Planning – Mission and Goals

The mission of the Electric System Planning at Central Hudson is to safely plan for a reliable and affordable electric transmission and distribution system by identifying prudent capital investments to continuously improve our system and support design, construction, and operations, recommending evaluation of non-wires alternatives, and planning for grid automation and integration of distributed energy resources.

We strive to achieve our mission by:

- Maintaining design criteria to minimize risk and plan for reliable system growth and DER integration.
- Performing reliability analysis and leveraging the use of new technology to continuously improve our transmission and distribution system.
- Completing system studies and developing recommendations to maintain and improve reliability of service and support the capital budget and non-wires alternative investment plan.

The Electric Planning Guides provide information on the routine tasks, current and emerging programs and technologies, and design criteria that enable us to identify capital investments that achieve our mission. The results of the System Planning process are then incorporated into this document.

3. System Reliability and Infrastructure

3.1 Introduction

This section provides an overview of the basic infrastructure, reliability issues and long term plans associated with our distribution, sub-transmission, and transmission systems. The infrastructure lists are categorized by asset and provide information regarding inventory, age, condition, assessment process, plans, and costs. This section is broken down into the following subsections for each asset class: transmission lines; substations; sub-transmission; and secondary networks and distribution.

3.2 Transmission Lines

Central Hudson began constructing transmission lines in the mid 1910's and has designed its lines in accordance with the applicable National Electric Safety Code ("NESC") at the time of construction. The NESC identifies design criteria for these lines. Specifically, it identifies the minimum required clearance from ground for specified conductor loading conditions. The minimum clearance required also is a function of whether the area below the conductor is accessible by pedestrians only or is a roadway.

3.2.1 Inspection Programs

Central Hudson transitioned to CASCADE for its Transmission Line inspection repository. Inspection data is now stored in CASCADE. Results of transmission line inspections are rated by condition severity. These conditions are tracked and appropriate replacements and repairs are made as part of the High Priority Replacement Program (HPR). If inspection results indicate that greater than 50% of a particular transmission line's structures are in need of replacement, then further analysis is conducted by the Electric Transmission Planning Department to evaluate the benefits of rebuilding the line.

3.2.2 Equipment

Central Hudson's transmission lines are operated at 69 kV through 345 kV with approximate total circuit length shown in the following table:

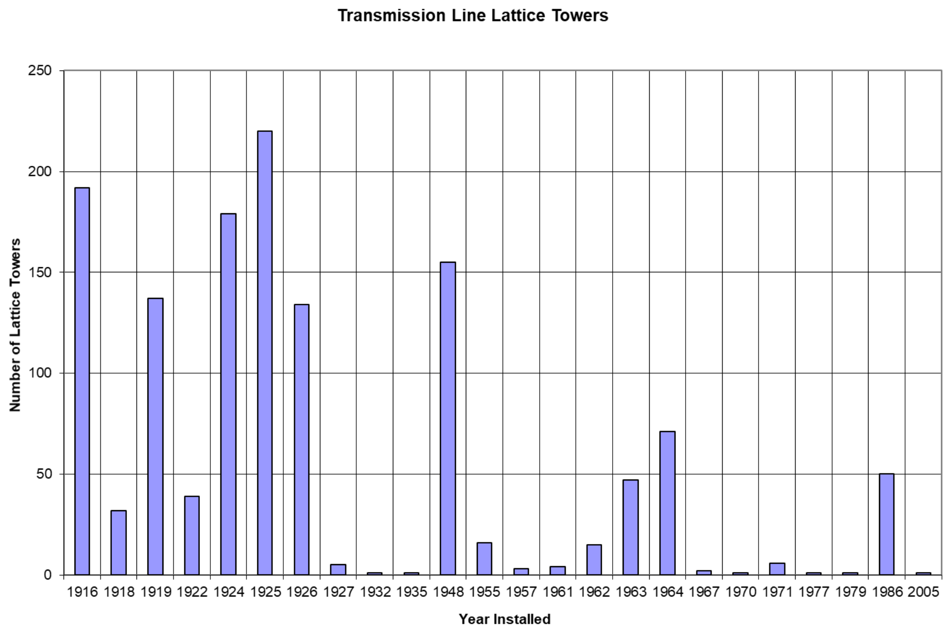
<table>
<tr><th>Operating Voltage</th><th>Design Voltage</th><th>Overhead Circuit Miles</th><th>Pipe-Type Cable Circuit Miles</th><th>Total Circuit Miles</th></tr>
<tr><td>345 kV</td><td>345 kV</td><td>76</td><td>0</td><td>76</td></tr>
<tr><td>115 kV</td><td>115 kV</td><td>211</td><td>4.1</td><td>215.1</td></tr>
<tr><td rowspan="2">69 kV</td><td>69 kV</td><td>248</td><td rowspan="2">0</td><td rowspan="2">287</td></tr>
<tr><td>115 kV</td><td>39</td></tr>
<tr><td colspan="2">Total</td><td>574</td><td>4.1</td><td>578.1</td></tr>
</table>

3.2.2.1 Lattice Towers

Inventory
Central Hudson's transmission lines include 1,313 lattice towers.

Age and Condition
Steel lattice towers typically are very long-lived. Central Hudson's lattice towers were installed in the years shown in the histogram below. One group of towers (i.e., 1920's vintage 69 kV E Line) was analyzed in detail[1] in 2004 and the results indicate significant remaining life. Central Hudson plans on completing a new assessment on the remaining tower assets in the 3-5 year time frame.

[1] EDM International, Inc. "Latticed Steel Tower Assessment for 'E' Line Reconductoring Project." December 2004.



Plans

Based upon the E Line results it appears that lattice towers are not limiting elements. Other factors likely will precipitate action. Accordingly, the approach will be to address condition of lattice towers at the time these other factors require attention.

General

In the short-term, the need to address lattice tower issues will be included in consideration of individual projects. Given that a large portion of our lattice towers were built in the 1910's and 1920's, the towers' condition will continue to be monitored to determine if it may be appropriate in the longer term to move to a more systematic approach.

H & SB Lines

Originally built in the 1920's, inspection reports indicate that 68% of the structures require replacement, repair or the addition of a mid-span structure (to correct sag issues). To remedy the numerous structure issues associated with the 12.5 mile H line & 11.4 mile SB Line, these majority lattice tower lines will be rebuilt using steel poles and 795 ACSR conductor. These projects will be completed by the end of 2025.

SL, SD, & SJ Lines

The 12.1 mile SL Line and 11.4 mile SD/SJ Common Tower Line were built in the 1920's. These lines are in poor condition, however major repairs are not planned at this time since the retirement of these lattice tower lines is planned as part of a future project. There are currently discussions on-going with third parties regarding the use of the ROWs/re-purposing of the corridors associated with these lines. Ownership of the

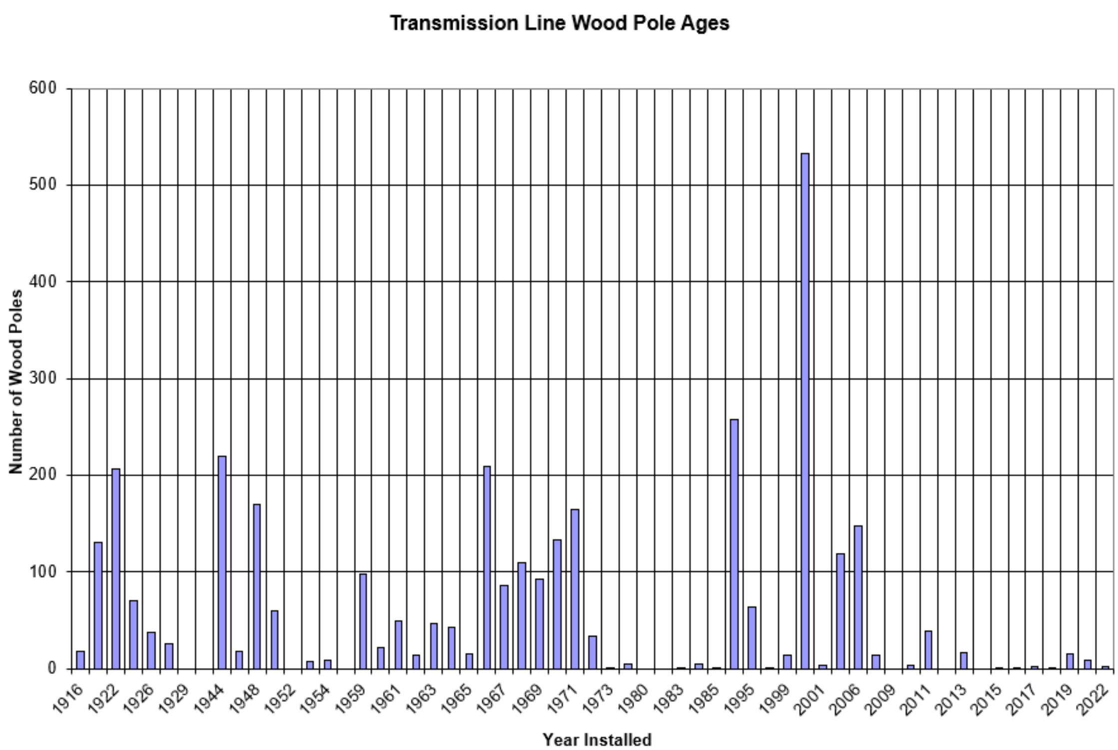
SL Line was recently (July 2022) transferred to another Transmission Owner and the corridor will be re-purposed starting in mid-2022. The SD/SJ is still projected to be either retired or similarly re-purposed depending on the result of on-going discussions by the end of 2024.

3.2.2.2 Wood Poles

Inventory
Central Hudson's transmission system includes 3,338 wood poles.

Age and Condition

General
These wood poles were installed in the years shown in the following histogram. Wood poles are relatively short-lived and often require replacement prematurely due to damage from lightning, woodpeckers, etc.



KM Line
Originally constructed in the 1920's and 1930's, the 2.85 mile KM line requires a rebuild. Inspections have identified approximately 58% of the line's wood pole structures needing replacement.

HG Line
The 16.25 mile HG line was originally built in 1937 and extended to Neversink in 1948. Recent condition assessments have shown that 54% of structures have Severity Level 3, 4, or 5 findings. This level of structure issues, considered with the operational issues for local generation during transmission outages, warrants rebuild.

TR Line
The TR line, originally constructed in the 1920's, is another of Central Hudson's oldest wood pole transmission lines. Inspections, excluding the Poughkeepsie Galleria Mall reroute, have identified more than 50% of the structures would require some level of work or need to be replaced.

Q Line
The 20.5 mile Q Line was originally constructed in 1950 and is comprised of a 4 mile section of existing lattice towers as well as a 16.5 mile section of vintage wood poles. Despite on-going maintenance activities, inspection reports still show that approximately 65% of the wood poles require replacement or repair.

SK Line
The 2.4 mile SK Line was constructed during the 1960's and is currently showing inspection findings that would require over 50% of the line to be repaired and/or replaced. The line is also off-center in the existing ROW necessitating the acquisition of additional ROW.

Plans

General
Generally, the timing of wood pole replacements would be expected to mimic the inspection program cycle. Where cyclical comprehensive inspections have recorded severe damage due to age or mechanical damage, replacements have been prioritized to remove the worst performers prior to an in-service failure. In the interest of efficiency, surrounding wood poles of similar condition and vintage are also replaced as part of the HPR Program to maximize mobilization and access costs in difficult stretches of R.O.W.

KM Line
To remedy the numerous structure issues associated with the KM line, and to increase the transmission supply to the Myers Corner Substation, the KM line will be rebuilt. The new line will employ the use of 795 ACSR conductor and an OPGW static wire. The KM line rebuild is scheduled to be completed in 2023.

HG Line
Although a number of structures on the HG line have been replaced as part of the HPR program, all sections of the HG line are over 50 years old. Due to the poor condition assessment, sag limitation, and to mitigate future generation curtailment, a complete HG line rebuild is warranted with 397.5 ACSR and an OPGW Static. This project is scheduled to be completed in 2027.

TR Line
The TR Line supplies a single large industrial customer (Tilcon). The TR Line is being considered for either retirement or rebuild based on its poor condition. A potential option being considered is the retirement of the existing TR Line and the installation of a new tapped substation with a 115/69 kV transformer on the 115kV SC Line to maintain a transmission supply to this customer. Discussions with Tilcon are currently in progress to assess the viability of this option.

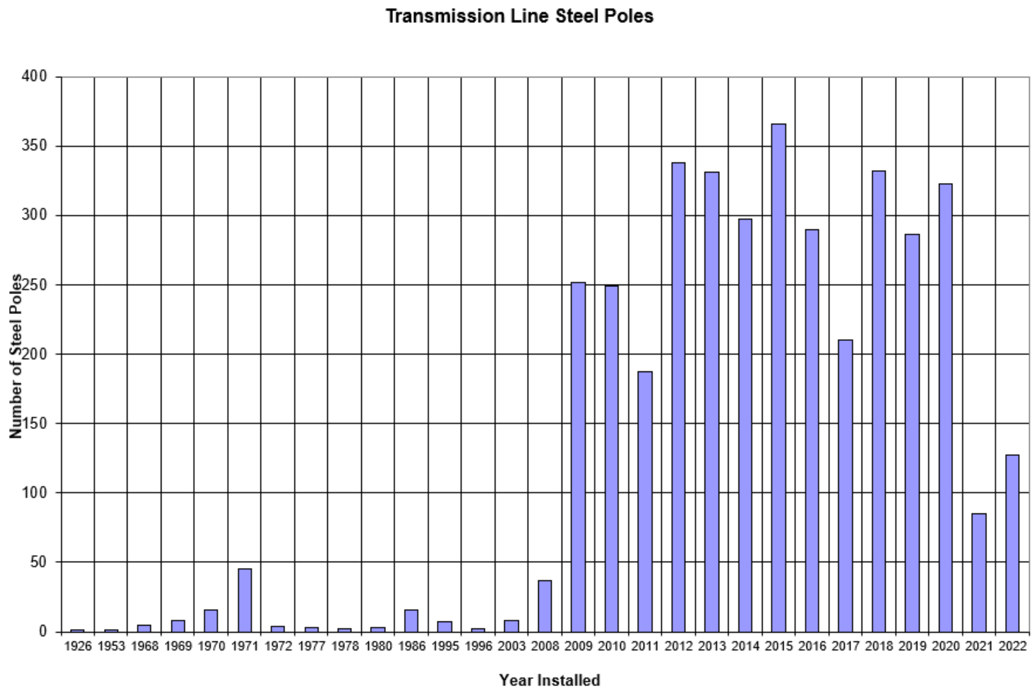
Q Line
A Planning Memo is currently underway to evaluate the best course of action to address the various inspections findings on this line.

SK Line
To address the various structure condition findings on the line as well as R.O.W. deficiencies as identified as part of CHG&E's Deficiency Program, it is recommended that the line be rebuilt and centered within the existing R.O.W. The Line will be rebuilt utilizing 1033.5 ACSR conductor and an OPGW Static. The SK Line is scheduled to be rebuilt in 2024.

3.2.2.3 Steel Poles

Inventory
Central Hudson's transmission system includes 3,831 steel poles.

Age and Condition
These steel poles were installed in the years shown in the following histogram. The increase in steel pole inventory over the past 10 years reflects a change in our standard design from wood to steel poles. This change is due to a proliferation of damage to wood poles from woodpeckers and other wood deterioration due to aging. A steel pole is a long-lived asset with lower maintenance, longer life expectancy, resistance to mechanical deformation, requires no chemical preservatives, and is more uniform than wood. The use of steel poles is consistent with Central Hudson's efforts to storm harden the transmission system.



Plans

Given the relatively young age of the steel poles there is no need at this time for a replacement plan. Central Hudson is currently investigating the implementation of a steel pole testing program to evaluate the performance of its current steel pole population and assess the need (if any) to implement supplemental maintenance practices that would ensure the complete utilization of the pole's projected lifespan. CHG&E is also enrolled and is actively participating in an EPRI supplemental project to evaluate and provide maintenance / inspection tools for weathered steel poles. At present the steel poles are inspected as part of Central Hudson's existing inspection program.

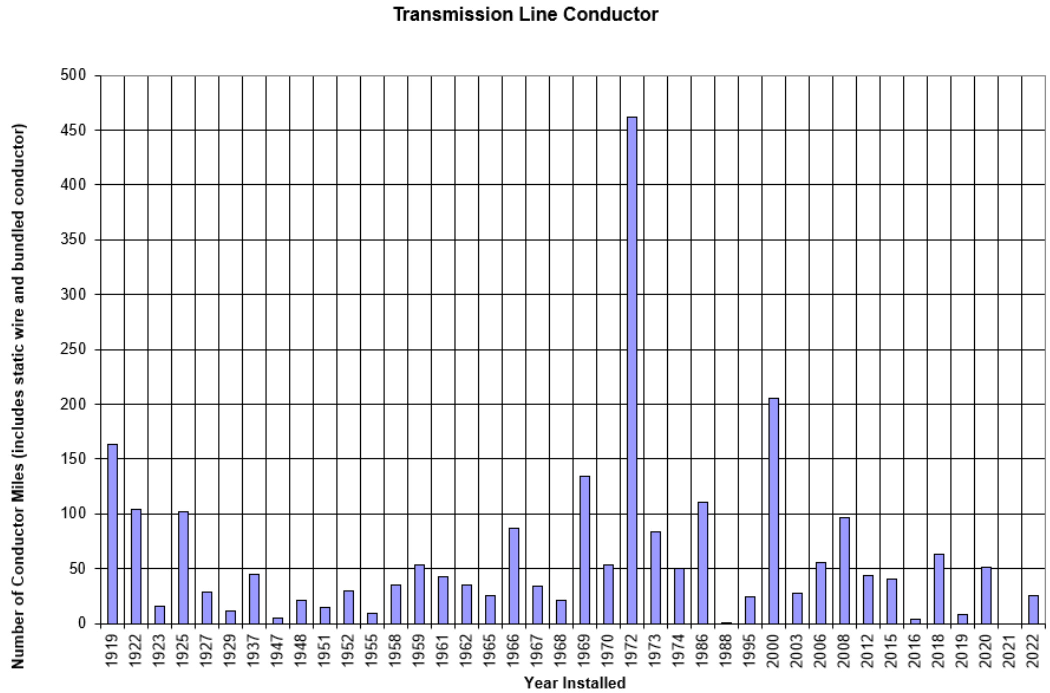
3.2.2.4 Overhead Conductors

Inventory

Phase conductors on the Central Hudson transmission system are of the following types:

Conductor Type	Percentage of System
Aluminum	12.2
ACSR	75.8
Copper	11.5

Age and Condition
These conductors were installed in the years shown in the following histogram.



For two types of conductor, steel static wire and ACSR[2] conductor, issues have been identified and either have been or are being addressed. These issues include:

- Steel Static Wire: following a failure it was determined that several lines utilized a type of wire commonly used for guying as the static wire. Several years ago, a program was established to replace this sub-par wire (4 miles total). At this point, replacement is complete.

- ACSR conductor: after several failures of this type of conductor, samples were taken and sent to NEETRAC[3] (at the Georgia Institute of Technology) for testing. Based on the results of these tests, an ACSR testing program was implemented to ascertain the general condition of ACSR conductor. Based on these test results, a systematic program has been developed to replace ACSR conductor. This is an ongoing program with conductor already having been replaced on

[2] Aluminum Conductor Steel Reinforced
[3] National Electric Energy Testing, Research & Applications Center

several lines and the remainder prioritized based upon test results and other considerations (i.e. other planned work).

No issues with other types of conductors (e.g., copper) have been identified.

Plans

FV Line
NEETRAC conductor testing on CHG&E's 4.5 mile portion of the FV Line has demonstrated evidence of steel core corrosion and some annealing of aluminum strands and fatigue. A reconductor and/or rebuild of the line is included in the Company's current capital forecast for future years.

3.2.2.5 Insulators

Inventory
No specific number is available.

Age and Condition
No specific data are available. Central Hudson has experienced very few insulator failures. Most have been a result of external causes (e.g., lightning, gunshot, etc.).

Plans
Given the good performance to-date, no specific replacement plans have been identified. Central Hudson monitors industry experience via participation in EPRI's insulator task forces. Central Hudson has and will continue to replace existing ceramic insulators in a tangent (vertical suspension) configuration with either toughened glass or polymer equivalents as a typical practice. Toughened Glass will be used in all dead-end or heavy angle applications where insulator strings are subject to higher tensile loading.

3.2.2.6 Pipe-Type Cable

Inventory
Central Hudson has 5 pipe-type cables that connect the 115 kV systems on the east and west sides of the Hudson River. These cables are as follows:

Line Desig-nation	Operating Voltage	Length (Miles)	Conductor Type	Year Conductor Installed	Year Pipe Installed
AC	115 kV	0.81	3-1/C 1250 MCM	1972	1947
DC	115 kV	0.837	3-1/C 1250 MCM	1958	1958
DR	115 kV	0.63	3-1/C 2000 MCM	1985	1985
ER	115 kV	1.28	3-1/C 1500 MCM	1988	1988
HR	115 kV	0.63	3-1/C 2000 MCM	1985	1985

Age and Condition
A 2007 condition assessment of the oldest and most heavily loaded of these cables (the AC and DC) concluded that the equivalent insulation age is approximately 30-40% less than the actual cable age. This assessment also made recommendations associated with the cables' ampacity, cathodic protection systems, and pumping plant. A memo was prepared to address these recommendations.

The ER cable was replaced in 1988 following damage from an anchor-dragging incident.

The AC/DC pumping plant was replaced in 1998 based on operational concerns with the original plant.

Based on the 2007 condition assessment of the AC and DC cables and the historic operation and maintenance of these facilities, the condition of the DR, ER and HR cables is assumed good as well.

In 2012, during Superstorm Sandy, flooding occurred at several of the pumping plant locations for the oil-o-static cable systems. This included the pumping stations for the AC and DC cables in the Danskammer switchyard, for the ER cable in the Kingston termination yard and for the HR and DR in the Reynolds Hill termination yard in Poughkeepsie. Projects on the AC, DC, DR, HR and ER pumping plants were completed in 2021 to mitigate the effects of the observed flooding.

Plans
An action plan for the pipe-type cables was developed based on the 2007 condition assessment for the AC and DC cables. The plan was developed to ensure the continued reliable operation of these systems.

Dive inspections of the AC, DC, DR, HR and ER Crossings were completed in 2019 and are currently under review to determine the need for any corrective action.

3.2.2.7 Cable Terminations (Potheads)

Inventory
Central Hudson currently has ten sets of high voltage transmission cable terminations for the river crossings.

Age and Condition
The AC and DC cable terminations were installed in the 1940's (AC) and 1950's (DC), the ER cable terminations were installed in the 1970's and the HR and DR cable terminations were installed in the mid-1980's. The AC and DC cable terminations at the Danskammer Substation are leaking and are nearing the end of their useful life. The remainder of the terminations are in acceptable condition.

Plans
The AC and DC cable terminations replacements at Danskammer and the East Shore Transition Stations are planned to be designed in 2022 with replacement completed in 2023.

3.2.3 Reliability Performance Data

The System Operation's outage database in TOA was used for this analysis. Transmission trips from 2017 through 2021 were reviewed for the purpose of identifying lines with high failure rates; substation equipment was not included. Below are the results.

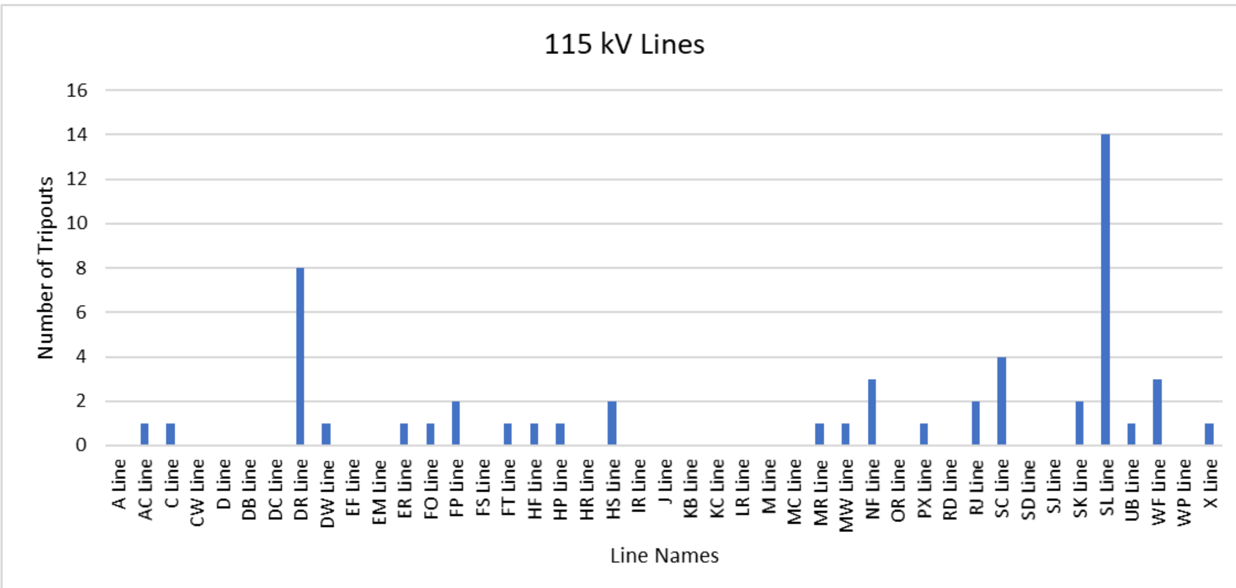
345 kV

Central Hudson owns three 345 kV lines. From 2017 through 2021, there was only 1 tripout on the 303 line. There were no tripouts on the 301 or 311 lines during this time frame.

No systemic issues, therefore, can be discerned from the data.

115 kV

The chart below illustrates the number of tripouts on our 115kV transmission lines from 2017 through 2021. This data helps identify potential negative reliability trends and areas for further study.



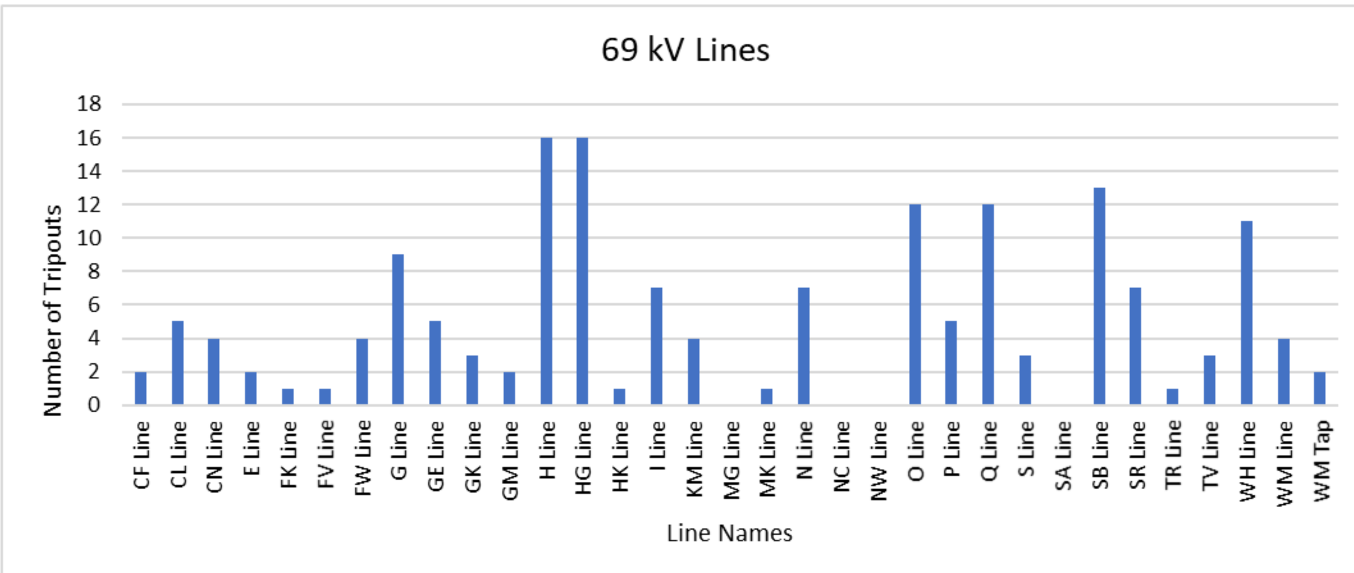
Since the SD and SJ lines are being considered for retirement and the ownership of the SL line will be transferred to NY Transco, tripouts for these lines were not examined further. The SL, SD and SJ circuit breakers at the Sugarloaf Substation were removed in 2017. The SL Line tripouts included faults that occurred on the SD and SJ lines after this was completed. Due to the high number of DR and SC line tripouts, these events were examined in greater detail and are summarized in the following table.

Cause	DR Line	SC Line
Equipment	2	
Tree		4
Lightning	1	
Unknown	5	
Total	8	4

All of the outages on the SC line were caused by trees. SC line vegetation management work was performed in 2018, 2019 and 2021.

The equipment-related outages on the DR Line were the result of damaged insulators which were replaced. It is assumed, based on the results of post-outage inspections, that the five unknown outages were also the result of faulty insulators that have been replaced. The line will continue to be monitored to track reliability trends and identify potential corrective actions if necessary.

<u>69 kV</u>
The chart below depicts the number of tripouts on our 69kV transmission lines for the period of 2017 through 2021. This data helps identify potential negative reliability trends and areas for further study.



Tripouts for the HG, Q, KM, H and SB lines were not examined further due to plans to rebuild these lines. Since the TV and CL lines have recently been rebuilt and the majority of the outages pre-date the rebuilds, tripouts for these lines were not examined further. The G line was rebuilt in 2018. Most of the outages occurred before the in-service date; therefore, this line was not examined further. Portions of the GM line will be retired or rebuilt by 2024 and portions of the O and OB lines have been retired with the remainder being re-designated the O line; for that reason, these lines were not examined further.

Due to the high number of I, N, and SR line tripouts, these events were examined in greater detail and are summarized in the following table.

Cause	I Line	N Line	SR Line
Wires Down			
Poles Down			1
Equipment			
Storm	1		
Tree	2	5	3
Lightning	2		2
Unknown	2	2	1
Total	7	7	7

- No systemic issues can be discerned from the data on the I line tripouts. The line will continue to be monitored to track reliability trends and identify potential corrective actions if necessary.
- The N line had five tree related outages. Routine maintenance was performed on the line in 2020. After 2020, there was only one tree related outage.
- Most of the events occurring on the SR line were associated with tree contacts. In 2020, tree trimming was completed on the line. Subsequently, there have been no tree related outages.

Due to the high number of tripouts on the WH line, this line was examined further. The WH line extends from Honk Falls to West Woodbourne (NYSEG) and taps off to Neversink. NYSEG owns a portion of the WH line to West Woodbourne. Central Hudson's portion of the line section from Honk Falls to West Woodbourne was rebuilt in 2018. These factors were considered when examining the tripouts in the following table.

Cause	Before Rebuild			After Rebuild*		
	Honk Falls to NYSEG	Neversink Tap	NYSEG to West Woodbourne	Honk Falls to NYSEG	Neversink Tap	NYSEG to West Woodbourne
Wires Down			1			1
Equipment						
Storm		1				
Tree		1		1	3	
Lightning	1				1	
Unknown					2	2
Insulator						1
Total	1	2	1	1	6	4

**** Note – One additional tripout noted in the "After Rebuild" timeframe with unknown location and cause which is not tallied in the chart.***

No systemic issues can be discerned from the data on the WH line tripouts. The line will continue to be monitored to track reliability trends and identify potential corrective actions if necessary.

3.2.4 Summary of Reliability Improvement and Infrastructure Replacement Programs

The High Priority Replacement and ACSR Conductor Replacement programs are described in Section 5.2.2 of Central Hudson's Electric Planning Guides.

High Priority Replacement (HPR)
As indicated in Section 3.2.1, the HPR program actively addresses inspection findings. Capital funds are allocated to HPR work within our five-year forecast based on historic findings and planned inspections.

ACSR Conductor Replacement
This program was created after testing showed aging infrastructure issues with older installations of this conductor. The remaining FV Line Re-conductor Project is summarized in section 3.2.2.4 above.

3.3 Substation

Central Hudson has approximately 75 substations spread throughout our service territory supplied predominately via 345kV, 115kV, 69kV and 14.4kV transmission and sub-transmission systems. The substations are operated and maintained by our Substation Operations Division with internal and external resources as needed.

3.3.1 Inspection Programs

Inspection cycles for substation equipment vary significantly depending on the asset class and anticipated maintenance and replacement. The current state of the major substation assets is described in this section, and additional details on the process are available in the Electric System Planning Guides.

3.3.2 Equipment

3.3.2.1 General Substation Equipment

3.3.2.1.1 Circuit Breakers

Overview
Central Hudson's electric power system consists of transmission lines, substations, and distribution lines. These lines and substation equipment are protected by relays and circuit breakers. Circuit breakers are critical parts of the electric system. A number of years ago, an overall review was performed on our existing fleet of

circuit breakers based on age, duty/duty rating, condition, criticality and availability of spare parts. It was identified at that time that many of the existing circuit breakers on the Central Hudson electric system have been in-service for over 40 years; some of these breakers were over-dutied and others no longer have spare parts available for maintenance. To maintain the current levels of reliability of our substations, an Electric Circuit Breaker Replacement Program was developed to address these issues.

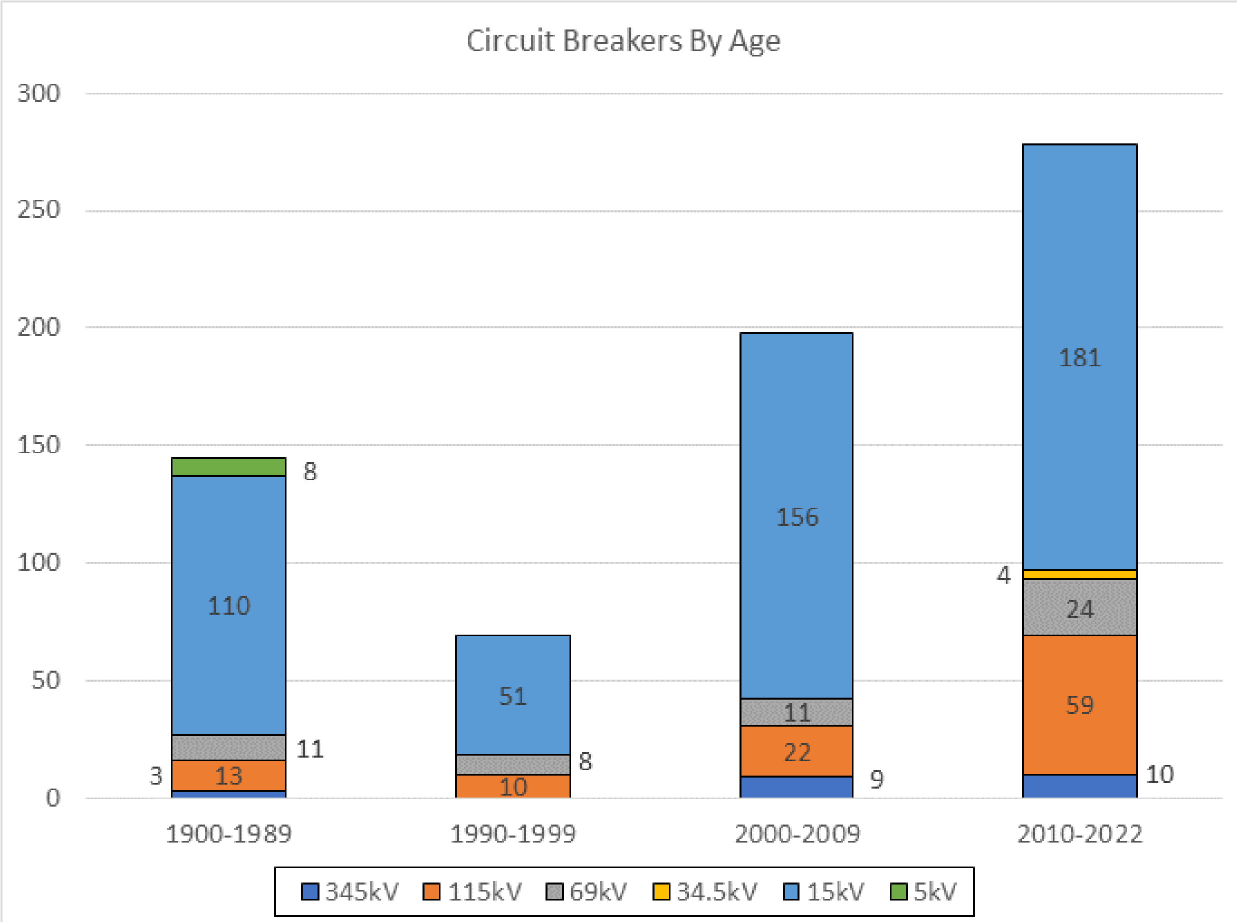
Inventory

The following chart depicts the current inventory of circuit breakers on our system (the chart does not include circuit breakers listed as retired, junked, EC spare, spare, deleted, or undated); (source Cascade).

Operating Voltage	Number
345 kV	22
115 kV	104
69 kV	54
34.5 kV	4
15 kV	498
5 kV	8
Total	690

Age and Condition

The following chart depicts the number of circuit breakers vs. date of manufacture:



The condition of the circuit breakers varies and the ability to maintain them is closely tied to their age. On the whole, ongoing O&M has kept the circuit breakers in good working order; however troubles and failures have identified several specific breaker types which should be replaced. Problematic circuit breakers, as identified by our assessment process are all part of the breaker replacement program. These specific types of breakers include:

345kV –	Westinghouse Type SFA (2)
115kV –	General Electric Type FK (4)
69kV –	Allis Chalmers Type FZO (2) General Electric Type FK (2)
15kV-	General Electric Type AM (16) General Electric Type FK (13) Westinghouse Type 150-DH (14) Westinghouse Type 150-DHP (40)

The criteria for the selection of the circuit breakers for the replacement program are prioritized as follows:

Breaker Duty: All circuit breakers with duties within 3% of their rating have been selected; highest priority is given for those circuit breakers with duties greater than 100% of their rating. All circuit breakers within 3% of their rating have been replaced. Breaker duty studies are performed as our system changes, as new breakers are installed and periodically on a system wide level. Any breakers identified as approaching their duty limit will be given priority in the replacement program.

Condition: All of the circuit breakers identified on the breaker list are given the next priority based on the recommendations from our Substation Operations Division. These recommendations are based upon operating experience or reports of failures or poor testing results.

Obsolescence: Several of the circuit breakers on our system employ outdated technology, specifically relating to interrupter design. Others suffer from extended service lives and parts are no longer available for many others.

Other Factors: Circuit breakers that meet the above breaker duty or condition criteria are selected for this replacement program if they will be replaced with new circuit breakers as part of other substation construction projects.

Program Maintenance: It is envisioned that this program will represent a living process. The circuit breakers selected at the present time represent equipment that we feel, given the current information and conditions, will require replacement. Should system conditions change, failures occur or testing results indicate problems with specific types of breakers, additional breakers may need to be added to the program and/or the order of replacements may need to be modified. Some of the breaker replacement projects from previous lists have been advanced and some have been deferred due to other emergent work, as well as revised condition assessments, priorities, and scheduling availability. As condition assessments are continuously updated, the program may need to be extended to include longer-term requirements.

Plans

As indicated, Central Hudson has an ongoing multi-year circuit breaker replacement program. The chart below outlines all of the remaining circuit breakers included in our replacement program. The current five-year forecast includes the planned replacement of approximately 109 circuit breakers.

Circuit Breaker Replacement Plan (# of breakers)				
Year	345kV	115kV	69kV	15kV
2022	1	10	7	14
2023	1	3	2	7
2024	0	0	0	11
2025	0	0	0	25
2026	0	5	0	23
Total	2	18	9	80

Based on the field condition and the above breaker replacement prioritization, it is planned to complete the breaker replacement program by 2027.

3.3.2.1.2 Disconnects and Motor Operated Switches (MOS)

Inventory

The following chart depicts the inventory of Disconnect, Motor Operated, and Ground Switches on our system:

Operating Voltage	Quantity
345 kV	137
115 kV	376
69 kV	264
34.5 kV	20
13.8 kV	290
7.5 kV	16
4.16 kV	6
2400 V	1
Total	1,110

Age and Condition

No specific data is available. Generally, ages and conditions vary. Due to the criticality of our 345kV system and identified problems, a program was previously developed to replace the 345kV TTT-7, EA, VR2 and VT-1 style motor operated disconnects. Limited to no replacement parts are available for these style switches. Additionally, the Memco EA 345kV style motor operated disconnects have experienced reoccurring hotspots.

345 kV --	Brown Boveri	Type TTT-7	(1)
	Memco	Type EA	(18)
	Memco	Type VR2	(10)

Plans
Central Hudson has developed a multi-year 345kV switch replacement program. The 345kV switch replacement program will replace twenty 345kV switches in the next five years. The breakdown of the program is as follows:

345kV Switch Replacement Plan (# of switches)

Year	345kV
2022	3
2023	5
2024	4
2025	5
2026	5
Total	22
Future	11

The program will continue addressing the remaining ~11 disconnects within the next five year cycle.

With the developing trend of issues and consideration given to the criticality of the 115kV and 69kV system, Central Hudson is evaluating a multi-year 115kV/69kV disconnect replacement program. Currently, these disconnects are replaced as needed during other major substation projects. Funds are included within the current Five-Year capital plan and a more defined program that would replace 115kV and 69kV motor operated disconnects as part of larger substation projects and as standalone projects is being evaluated.

Similar to the circuit breaker replacement program, it is envisioned that this program will represent a living process. The switches selected at the present time represent equipment that we feel, given the current information and conditions, will require replacement. Should system conditions change or failures occur the order of replacements may need to be modified and the program may need to be extended to include longer-term requirements.

3.3.2.1.3 Insulators

Inventory
No specific number available.

Age and Condition
Generally, ages and conditions vary. The general condition of this equipment is considered good. A problem with vertical pin-cap insulators in two of our substations (Marlboro and West Balmville) was previously identified. The insulators at the Marlboro Substation and West Balmville Substation have been replaced in conjunction with major rebuilds of the substations.

Plans
The insulators at Pleasant Valley Substation will be replaced as part of a larger modernization project in 2027.

3.3.2.1.4 Transformers

Inventory
The following chart depicts the inventory of Power Transformers on our system (excluding spare and retired units):

Power Transformers	
Operating Voltage	Quantity*
345 kV	8
115 kV	85
69 kV	46
34.5 kV	5
13.8 kV	9
Total	153
* Single Phase Transformers are counted individually	

Age and Condition
The condition of the power transformers varies and the ability to maintain them is closely tied to their age. The overall condition of this equipment, based on our ongoing assessment program, is considered good. During our ongoing assessment process, however, the following issues were identified:

(1) McGraw 550 Transformer Load Tap Changers. Specifically, it has been shown that significant loading and the number of operations of the 550B and 550C LTCs results in considerable contact deterioration over time. LTC filters have been installed at stations deemed necessary where McGraw 550B and 550C LTCs exist to ensure the LTC oil remains in good condition. During routine maintenance, replacement of moving and stationary parts is being completed with upgraded parts on an as needed basis.

(2) Type U bushings. The failure pattern of GE Type U bushings has been well documented and can be identified by a power factor

test of the bushing that shows an increase in capacitance of more than 5% over nameplate and with a power factor over 1.0.

(3) Transformers that have outlived their useful life. This includes transformers that receive a poor condition evaluation and/or are trending towards potential failure and higher risk. These types of repairs or replacements are handled on an as needed basis dictated by diagnostic test results and inspections.

3.3.2.1.5 Testing Plans/Inspection Programs

McGraw 550 Transformer Load Tap Changer (LTC) Rebuild Program: Using the existing LTC overhaul schedule, this program allows for a rebuild of one 550 LTC per year over the next five years.

Type-U bushing replacements: As these bushings begin to test poorly during routine power factor testing, they are scheduled for replacement.

3.3.2.1.6 Transformer Watch List and Plans

Central Hudson's Substation Operations Division utilizes a variety of preventive and predictive maintenance programs to maintain the integrity of its high voltage power transformers. Substation Operations' Annual Transformer Watch List is used to provide infrastructure condition assessment to identify a need for or to support equipment replacement, as part of Central Hudson's System Planning Process. Transformers are reviewed based on criticality factors such as: presence/severity of a problem, significance to transmission, significance to distribution, availability of sister / adequate substitute unit.

Based on condition assessment, age and risk the following transformers are within the 5 year forecast for retirement/replacement:

- Knapps Corners Substation Transformer #1, #2, and #3 (install a 56 MVA 115/69 kV autotransformer and two 22 MVA 115-13.8 kV transformers as part of the substation rebuild);
- Greenfield Road Substation Transformer #1, Phases #1, #2, #3 and Greenfield Road Substation Transformer # 2 (replace with two existing 69-13.2 kV 10MVA units);
- Clinton Avenue Substation Transformer #1 (station to be retired/transformer scraped);

- Converse Street Substation Transformer #2 (replace with new 14.4-4.16 kV transformer).

In addition to these condition based replacements, two new 56 MVA 115/69 kV autotransformers will be installed at the Kerhonkson Substation as part of the P & MK voltage conversion to 115kV, new transformers will be installed at the Coxsackie and South Cairo Substations based on the planned retirements of the Combustion Turbines at these locations and a new 12MVA 69-13.2kV transformer will be installed at the New Baltimore Substation to address reserve capability concerns and provide operational flexibility to this area.

3.3.2.1.7 Capacitor Banks

Inventory
The following chart depicts the inventory of Capacitor Banks on our system:

Substation Capacitor Banks	
Operating Voltage	Quantity
345 kV	2
115 kV	3
69 kV	6
34.5 kV	1
13.8 kV	15
Total	27

Age and Condition
No specific data available. Generally, ages and conditions vary. The general condition of this equipment is considered good.

Plans
No specific rebuild/refurbish/replacement programs identified.

3.3.2.1.8 Substation Batteries/Battery Chargers

Inventory
Central Hudson currently has 82 substation batteries and 82 substation battery chargers.

Age and Condition
Most equipment is age 20 years or less. Generally, ages and conditions vary. The general condition of this equipment is considered good.

Plans
Battery replacement program: Central Hudson replaces any batteries that have been in service for 20 years or are testing poorly due to operational or equipment failure. Currently 41 battery replacements are anticipated over the next 10 years based upon remaining service life.

As tests and inspections are conducted and additional condition information is obtained, this plan is modified.

3.3.2.1.9 Voltage Regulators

Inventory
The following chart depicts the inventory of Substation Voltage Regulators on our system:

Voltage Regulators	
Operating Voltage	Quantity
34.5 kV	3
13.8 kV	93
4.16 kV	3
Total	99

Age and Condition
Generally, ages and conditions vary. The general condition of this equipment is considered good.

Plans
Substation Voltage Regulator Maintenance Program: Central Hudson currently has a program in place to maintain all single-phase voltage regulators every 20 years or 100,000 operations.

3.3.2.1.10 Circuit Switchers

Inventory
The following chart depicts the inventory of the Circuit Switchers on our system:

Circuit Switchers	
Operating Voltage	Quantity
345 kV	1
115 kV	12
69 kV	21
Total	34

Age and Condition
No specific data available. Generally, ages and conditions vary. The general condition of this equipment is considered good.

Plans
The previous program identified to replace all S&C Mark II, III, IV circuit switchers has been completed. No specific rebuild/refurbish/replacement programs identified.

3.3.2.1.11 Substation Reclosers

Inventory
The following chart depicts the inventory of Substation Reclosers on our system:

Substation Reclosers (Three Phase Installations)	
Operating Voltage	Quantity
13.8 kV	9
Total	9

Age and Condition
No specific data available. Generally, ages and conditions vary.

Plans
No specific rebuild/refurbish/replacement programs identified for the remaining 13.8kV substation reclosers.

3.3.2.1.12 Control Houses / Switchgear

Inventory
Central Hudson currently has 59 control houses and 61 sets of switchgear.

Age and Condition
A program has been developed to evaluate the condition of both control houses and switchgears, specifically the rust, roof and wiring condition. Historically it has been shown that, to ensure that our control houses remain in good condition, we are required to refurbish 2-3 control house roofs per year.

Plans
Roof maintenance program: Control Houses and Switchgears will continue to be evaluated during routine substation inspections and refurbished or replaced as needed. On average 2-3 roof refurbishments are completed annually. In addition, as our control houses and switchgears age, candidates for replacement will be

identified as part of Substation Operations assessment process. Currently the Coxsackie Substation, Woodstock Substation, and Myers Corners Substation switchgears were evaluated and identified for replacement in 2022, 2025, and 2026 respectively.

3.3.2.1.13 Power Control Center (PCC)

Inventory
Central Hudson currently has 16 power control centers.

Age and Condition
Central Hudson began installing PCCs in 1997 and all of our PCC are less than 25 years old. Inspections of PCCs have shown that the PCCs are in good condition and functionally sound. Currently there is no formalized program for PCC replacement. PCCs will continue to be evaluated through routine substation inspection specifically for rust, roof, wiring condition, or any other form of deterioration.

Plans
PCCs will continue to be evaluated during routine substation inspections and refurbished or replaced as needed.

3.3.2.1.14 Coupling Capacitors

Inventory
The following chart depicts the inventory of Coupling Capacitors on our system:

Coupling Capacitors	
Operating Voltage	Quantity
345 kV	40
115 kV	198
69 kV	109
Total	347

Age and Condition
No specific data available. Generally, ages and conditions vary. The general condition of this equipment is considered good.

Plans
No specific rebuild/refurbish/replacement programs identified.

3.3.2.1.15 Arresters

Inventory
No specific number available.

Age and Condition
No specific data available. Generally, ages and conditions vary.

Plans
Central Hudson has a program in place to replace all spark-gap arresters with MOV type arresters. MOV arresters are an improved technology and provide lower losses and superior overvoltage protection over spark-gap arresters. At this time, almost all spark-gap arresters have been replaced with Polymer MOV type arresters. The remaining gap arresters will be identified and targeted for replacement during existing project designs.

3.3.2.1.16 Non-Electrical Assets

Inventory
Substation Fences
Central Hudson currently has 89 substation fences.

Age and Condition
No specific data available. Generally, ages and conditions vary. The general condition of this equipment is considered good. Fence condition is evaluated through routine inspections and replacement/repairs are made as identified.

Plans
No specific rebuild/refurbish/replacement programs identified.

3.3.2.2 Protective and Communication Equipment

Inventory
Central Hudson has approximately 4,000 protective relays, communication devices and network devices installed in substations. This inventory is constituted primarily of a conglomeration of generations of electromechanical and microprocessor based devices and in recent years network communication devices.

Device Type	Count	%
Microprocessor Relays	1,338	34%
Electromechanical (Non Digital) Relays[4]	720	17%
Lockout Relays	780	20%
Auxiliary Relays	342	9%
Tele-protection Units	137	3%
Transformer/Regulator Relays & Controls	391	10%
Network Devices	280	7%
Total	3,988	100%

Age and Condition

The ages and conditions generally vary. Older equipment is electromechanical, and newer equipment is microprocessor based. The majority of microprocessor-based devices are in good condition, but many are approaching 20 years old. The electromechanical relays are based on older technology but have proven to be fairly reliable. Due to their age, outdated technology and lack of event and metering capabilities, electromechanical relays are being replaced in conjunction with all appropriate capital projects.

Plans

Central Hudson's plan is to replace all electromechanical line relay packages on the 345kV system. To date all but one Alternate #1 345kV Line package, and one Alternate #2 345kV Line package have been replaced. The remaining replacements are scheduled for completion by the end of the five year forecast. Consideration on timing has been given to perform relay replacement work in conjunction with previously scheduled line work to minimize the number of line outages.

Central Hudson has proactively replaced relays in conjunction with substation upgrades. Presently 65% of the main protective relays on the Central Hudson system are microprocessor based. It is anticipated that approximately 75% of the remaining electromechanical protective relays will be replaced with microprocessor relays at the end of the five year forecast. In conjunction with other planned capital work and/or in support of Distribution Automation, electromechanical relays replacements are being added to scope where appropriate.

[4] This number represents relay systems. Electromechanical relay systems typically include three phase and one ground relay.

3.3.2.3 Substation Meter Devices

Inventory
Central Hudson currently has approximately 130 substation meter devices.

Number of Meter Points[5]			
No Meters	Chart Meters	MV-90	SCADA
4	5	24	479

Age and Condition
Microprocessor relay based (the majority of SCADA metering) and MV-90 metering devices range in age from new installations to 25 years. Generally, for these devices, conditions vary but the majority of equipment is not fully depreciated. Chart based meters are fully depreciated. There are five remaining on the system. Recorder based meters are mixed age with less than half approaching full depreciation.

The five remaining chart-type meter devices will be removed before the end of this five year forecast. Non-revenue metering will be accomplished through the microprocessor relays.

Plans
Central Hudson will continue to replace outdated metering (non-revenue) and integrate the meter functions into the microprocessor relays as part of capital improvement projects. Presently 98% of our system load is metered hourly. By the end of the five-year forecast, it is projected that 100% of our system load will be hourly metered.

3.3.2.4 Digital Fault Recorders (DFR)

Inventory
Central Hudson currently has six functioning Digital Fault Recorders (DFR). The plan is to remain with six DFR's through the five year forecast.

Age and Condition
Five of the DFRs are new (Ametek) and one is more than 15 years old (BEN/Qualitrol). The last BEN/Qualitrol DFR is scheduled to be replaced in 2023.

[5] Data source from Distribution Engineering Excel Spreadsheet: "Metering Data" 4/21/2022

3.3.2.5 Remote Terminal Units (RTU)

Inventory
Central Hudson currently has 101 Remote Terminal Units (75 main RTU's and 26 sub RTU's) in its electric substations and customer hydro facilities. The desired RTU and SCADA infrastructure to support real-time monitoring, control, and metering is in place in 69 stations at this time.

RTU Style	Count
Preferred	72
Outdated	3
NONE	2

Age and Condition
No specific data available. Generally, ages and conditions vary. DNP RTUs are in good condition. There are three Harris M4000 dialup RTUs that have reached the end of their useful life.

Plans
Central Hudson has adopted the SEL Axion as the standard and preferred replacement RTU. It is cost effective, reliable and both Engineering and field personnel have extensive experience with these RTU's. To provide the operability to support Distribution Automation, and the increasing data needs resulting from customer DER interconnections the following upgrades and replacements will be performed and completed within the forecast period: The three Harris M4000 dialups will be replaced with SEL Axions. In order to allow the Modicon BM85's to have full operability they will either be replaced with SEL Axions during planned substation upgrades or a SEL RTAC will be installed on the front end. The four Telvent 2100's will either be replaced with SEL Axions during planned substation upgrades or the CPU card will be upgraded to the 2400 version. All dialup RTU's will be replaced using real time connections via network strategy when available. Additionally, the two substations without SCADA will be reviewed on a case-by-case basis.

3.3.3 Summary of Infrastructure Programs

The infrastructure replacement programs at the substation level vary by individual piece of equipment, as well as integration with existing plans at a location.

Desired Future State:
New equipment, properly implemented and integrated, will better support current functions and create flexibility for added future functions as follows:

- ❖ Provide for robust planning capabilities and switching operations through use of trending and real-time data. Continuous meter data for the entire system will eliminate information "gaps."

- Enable more accurate forecasting of area loads to increase risk tolerance, possibly resulting in deferral of substation and distribution projects.
- Offer the needed operability for DA initiatives.
- Improve reliability and reduce CAIDI through automated event reporting and fault location.
- Provide a means of ensuring compliance with mandatory NERC Reliability and CIP Standards.

The ultimate future state is one where the minimal use of devices and space will provide all metering and fault data to engineers and operators in real-time for every available point on the system.

Standalone meters have been eliminated, except in the case of revenue/interchange meters. Metering is measured and reported through digital relays wherever possible. This design provides a cleaner, more compact design that minimizes the amount of wiring, minimizes the number of failure points.

- Event reports and metering data are transmitted to the SCADA master for use in planning, operating, and timely fault location. Real-time meter data is available by circuit for operators and engineers.

- Non-value added work, such as reading & repairing chart meters and MV-90 meter recorders and manually entering meter data is eliminated, reducing expenses.

- Central Hudson has standardized on relay equipment, limiting the variety of relays / relay manufacturers on the system. This reduction more easily increases both the technicians' and the Engineers' familiarity with the relays, leading to a quicker mastery of the relay settings, installation & testing methods, and relay operation. Also, this standardization creates a deeper familiarity with the functions of the relays, enabling more innovation in using the relays and their schemes.

- Time synchronization of all relays thru a standardized network.

- The RTU replacement program will be complete by the end of this forecast period. The remaining three Harris M4000 dial up RTUs will be replaced and the five remaining dial-up connections will be replaced with real time connections either through network strategy, or third party connections.

Plan

In order to reach the desired future state, nearly all of the program must be completed. The program is based on the premise that the majority of modernization work can be accomplished incrementally with existing Category 13 projects or through DA preparation projects. There are exceptions where the specific conditions of a substation deem it important to address the infrastructure through stand-alone projects.

3.4 Underground – Cable, Equipment and Infrastructure

This section discusses the plans and programs for all sub-transmission and secondary network infrastructure, as well as padmount transformers and switches. Replacement programs were developed based on a combination of age of equipment, data from the inspection program, operational flexibility, and reliability. Due to the nature of the underground system, infrastructure replacement plans were developed as a proactive way to maintain the reliability of the sub-transmission system.

3.4.1 Inspection Programs

The majority of the high voltage sub-transmission cables and all low voltage secondary network cables run through an underground conduit system through manholes and pull boxes. As part of the Central Hudson Facilities Inspection Program, manholes and pull boxes are inspected once every 5 years. These inspections help identify equipment and infrastructure associated with the sub-transmission system, secondary network system and underground highway crossings that need repair. A severity value is provided for the plant assessed ranging in value from 1 to 6, with 6 being the most severe. Repairs are prioritized based on this value. Items addressed include wall reinforcements, broken covers, major ceiling repair, rusted I-beams, tripping hazards, clearing of debris, cable fire-proofing, transformer oil leaks, oil switch leaks, network protector replacements and cable repairs. As repairs are needed, budget projects are developed or work orders are drawn up on an individual basis.

3.4.2 Equipment

3.4.2.1 Cable – Primary URD Cable, Underground Network Systems and Highway Crossings

There are approximately 1,656 miles of primary URD cable. The oldest URD cable asset is over 50 years, with the majority being newer. Although failures have not had a large impact on SAIFI and CAIDI, their number has been consistent over the past 5 years. The industry as a whole has been concerned with the future performance of this critical asset. Some utilities have tried cable rejuvenation, while others have opted for wholesale replacement of specific vintages of cable. Central Hudson is looking into testing as a potential means of cable health assessment in order to target specific repairs. A Research and Development project was conducted in 2017 using partial discharge detecting technology from a Company called IMCORP. The R&D program was successful and was able to prove the effectiveness of the test in finding the location of actual cable defects, which would provide the capability to target repairs. Cable sections that exhibit no partial discharge can be recertified as new and are guaranteed for 25 more years. Central Hudson is in the process of investigating the ability to utilize IMCORP's services as part of a capital program. Additional plans are outlined in Section 3.4.4.5 URD Cable Replacement and Repairs.

There are approximately 215 miles of underground network cable, 12 miles of which are primary sub-transmission feeds to the secondary networks. Portions of the primary feeders range in age from 40 to 80 years old with portions being well over 60 years old (see Table 3.4.2). The older portions of these feeders are comprised of paper-insulated-lead-cable (PILC) conductors. The underground infrastructure for both the primary and secondary network cables is in some cases older than the associated cables.

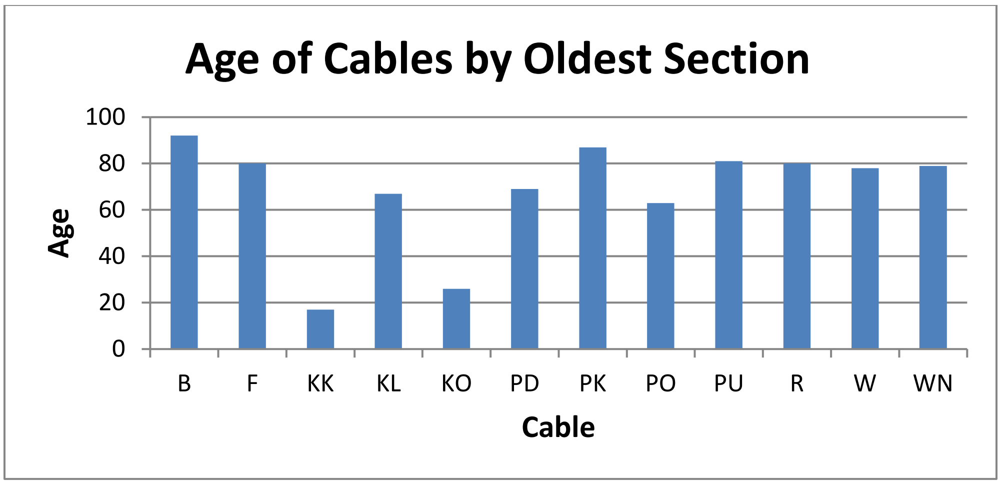


Table 3.4.2 – Age of Cables by Oldest Section (2022)

Due to an increase in failure rates of the PILC cables and failing underground infrastructure, targeted replacement programs were developed in 2008 and 2011 to address the age and condition of the primary and secondary network cables. As these programs were completed, additional ones were developed in subsequent years for inclusion in the Capital Budget. These programs are discussed in section 3.4.4.

Due to an underground cable failure crossing the Taconic Parkway, in 2014 the remaining Taconic Parkway crossings were inspected in order to update our cable and infrastructure records. Both cables and infrastructure (pull boxes and conduit) were found to be in need of repair at these locations. The program to address these repairs, as well as locate and address the remaining highway crossings on our system is discussed in section 3.4.4.2.

3.4.2.2 Network Protectors

Central Hudson currently has 40 network protectors on the system. Network Protectors are both electrically and mechanically tested once every 6 years. Their condition is assessed once every 5 years as part of the Facility Inspection Program.

3.4.2.3 Communicating Network Relays

Since 2009, Central Hudson has been monitoring the secondary networks using a system called CEMesh Meshed Network System. This system is installed at each transformer secondary bushing that monitors the total load on the transformer at any given time. The load at each transformer is collected using a Meshed Network Sensor (MNS). Data from these devices are transmitted via CDMA cellular service to a remote server, which is hosted and maintained by a company called Power Systems Integrity (PSI). The data can then be accessed through the PSI website. In 2012 it was realized that significant upgrades would be needed to the CEMesh system in order to use it for monitoring load growth and planning network upgrades. CEMesh is also limited in that it does not have the capability to collect transformer health data from oil and pressure sensors, and would not be able to communicate through our new Network Strategy communications network.

In 2014, it was determined that upgrading the existing CEMesh MNS devices, as well as the PSI server interface was not the most cost effective way to improve the network monitoring capabilities, as it would not provide additional transformer health monitoring capabilities, and access to data would still be restricted to the PSI website. After a thorough evaluation, it was decided to replace the non-communicating CMD protector relays with communicating ETI relays, along with a Sensus CDMA cellular communications system until they can be transitioned to the Network Strategy communications. Installation of these new relays began in 2014. A project to link the relays to the Network Strategy communications network is expected to begin returning data by the end of 2022. As of Quarter 1 of 2022, there are 19 of the 26 network transformers in the Poughkeepsie network successfully returning asset information over the Sensus system. The entire Poughkeepsie network is projected to have new communicating relays by the end of 2023.

The network relay replacement and communications program is a multi-year program that will enhance the value of the data obtained from each of the three secondary networks, as well as feed this data into Central Hudson's DMS system in the long term. This will assist in maintaining the reliability of the secondary networks by allowing Engineering to better prioritize equipment and infrastructure upgrades, as well as better plan for load growth. The relay replacement program is in the Capital Budget through 2027 and will include the completion of the Poughkeepsie network relay retro-fits by 2023, with the remaining 14 retro-fits in Kingston and Newburgh network following shortly after.

3.4.2.4 Manholes and Pull Boxes

Central Hudson currently has 1,224 manholes and 868 pull boxes on the system. The age and condition of this type of infrastructure is not easily determined. Some of these manholes are in excess of 60 years old and have over time been repaired. One of the issues that arise is the support structures of the ceilings tend to wear down over time due to weather conditions. Ice, salt, and water take their toll on these structures. The condition of each manhole and pull box is assessed once every 5 years. The details of the inspection process are discussed in the prior section 3.4.1.

3.4.2.5 Pad Mounted Transformers and Switches

Central Hudson has 15,224 pad-mounted transformers and switches on the system. The oldest pad mounted asset is 73 years old, with the majority being newer. Currently, there are no systemic problems with the pad mounted transformers and switches. They are inspected once every 5 years. Repairs are prioritized based on inspection severity rating. Costs for repairs are covered within the annual capital program as the need arises.

3.4.3 Reliability Performance Data

The Central Hudson sub-transmission and secondary network systems are designed for redundancy. Sub-transmission feeders supply substations that either currently supply, or at one time have supplied, low-voltage 4.16kV distribution feeders.

<u>Newburgh</u> – The B, F, R and WN sub-transmission feeds emanate from the West Balmville Substation and supply the Montgomery St. Substation, which supplies a combination of 13.2kV and 4.16kV distribution, including the Newburgh secondary network (see Figure 3.4.3-1). In 2018, an alternate plan to supply the Montgomery Street Substation with only two feeds was developed, and is further discussed in section 3.4.4.4.

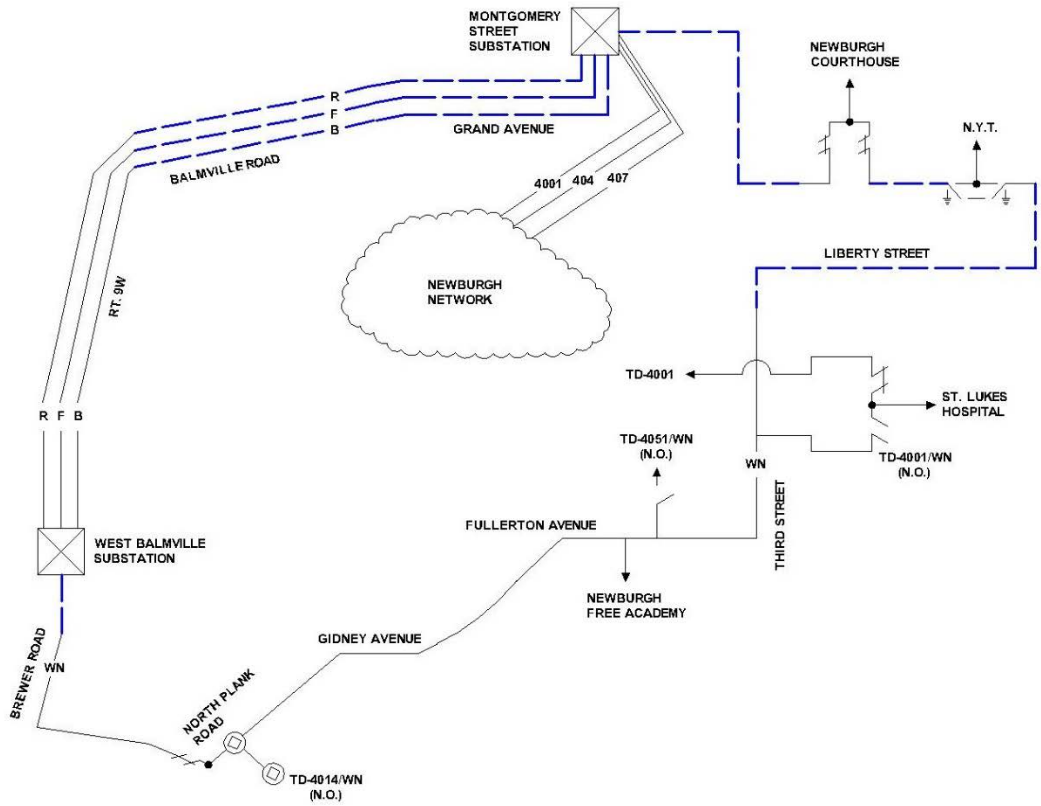


Figure 3.4.3-1: Newburgh 14.4 kV System

Poughkeepsie – As of 2020, the Poughkeepsie District has 5 sub-transmission feeds, all of which emanate from the Reynolds Hill Substation (see Figure 3.4.3-2). Three feeds (PO, PK and PU) from the Reynolds Hill Substation supply the Poughkeepsie secondary network. The PD cable feeds a portion of the Central Hudson main campus and is primarily rubber cable. The W cable is primarily overhead spacer cable and only feeds a sewage plant. There are currently no plans to upgrade the PD or W cables; however, the W cable could be reclassified for 13.2kV distribution should the need arise. Plans to replace the primary PILC cables feeding the Poughkeepsie network are discussed in Section 3.4.4.3.

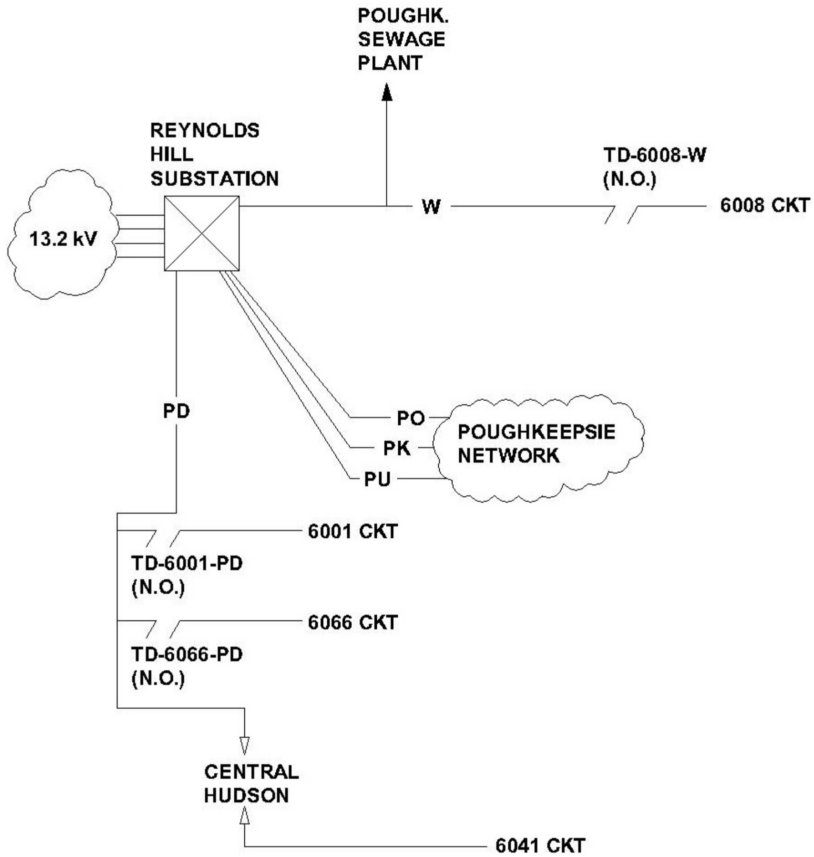


Figure 3.4.3-2 - Poughkeepsie 14.4kV System

As noted, there are three secondary networks in our system located in the cities of Kingston, Newburgh, and Poughkeepsie. Each secondary network has 3 primary feeds and consists of multiple parallel secondary cable runs that are interconnected for an electrically continuous secondary grid. The secondary network systems are designed in a manner such that a first contingency loss of any single primary feeder or loss of one or more secondary runs would not result in any customer outages. There are unique situations where a large commercial or industrial customer is tapped directly off of a sub-transmission cable. Switching procedures (either manual or automatic) are in place for these unique situations to minimize outage times in the case of contingencies for this small handful of customers.

Central Hudson has a total of 9 network feeders serving the 3 networks that serve less than 1% of our customers. All 3 networks experienced 10 primary or secondary cable failures combined in the past 10 years that have had a negative impact on network customer reliability. Both the Newburgh and Kingston networks experienced an outage in 2014 and 2015, respectively that were not due to infrastructure or equipment condition, but rather events external to the networks. The loss of the Newburgh network in 2014 was due to a City of Newburgh snowplow breaking a manhole cover and pushing it into live primary and secondary cables. The Kingston network outage in 2015 was due to inadequate fusing during a temporary switching event resulting in loss of the substation that feeds the network. The Kingston and Newburgh networks also each experienced an outage in 2018. A direct lightning strike to one of the substation transformers feeding the Kingston Network resulted in a large portion on the downtown Kingston area, both network and non-network, losing power. A tornado event caused a transmission outage to the substation that feeds the Newburgh network primary feeders, resulting in loss of the substation. When the transmission line was put back in service and the substation energized, only one of the four network primary feeders held. The other three locked out due to damage caused by the tornado. A Kingston network outage occurred in 2020 that was the result of a down overhead phase wire (external to the network) caused by a windstorm. The Converse Street Substation was being fed from an alternate source during scheduled repairs on the normal feed to the Substation when this occurred. The automatic load transfer scheme at the substation did not operate due to a coincident voltage dip on its alternate source.

<u>Cable Failure Outages</u>
The Newburgh network experienced 2 permanent outages in 2012 due to primary and secondary cable failures. A network contingency plan has been put in place and extensive inspections of the Newburgh Secondary Network underground system were completed in January 2013. Specific upgrades and improvements were identified and completed in 2015 (see section 3.4.4.2).

In 2013, a secondary cable fault on the Kingston secondary network flashed over and damaged numerous other secondary cables as well as one of the primary circuits feeding the network. The network had to be dropped to cut the damaged secondary network cable in the clear in order to isolate the damaged 121 circuit to make repairs. All permanent repairs were completed immediately. Subsequent inspections of the Kingston network were performed and areas needing repair were prioritized. More of this is discussed in the following section.

The Poughkeepsie network experienced an outage in 2017. As a result of repairs being made on the PO Cable due to a Contractor dig-in, the circuit was de-energized and the Poughkeepsie Network was being fed by the PU and PK Cables. A secondary cable failure occurred between a manhole and pull box on Catharine Street. The secondary cable was above 2 primary feeders. The explosion from the secondary fault directly impacted the remaining primary feeders. The resulting fire from the explosion caused damage to the closest network transformer. Both remaining network feeders locked out resulting in an interruption to all network customers. Work was done to put the PO Cable back into service to restore the network, since it was not impacted by the fault. A capital budget project for 2018 was developed to replace the infrastructure and cables on Catharine St. Plans for future improvements to the Poughkeepsie network are discussed in the next section.

The Newburgh network experienced an outage in 2018 when the 4001 circuit (one of the three Newburgh network feeders) experienced a cable fault in a pull box on Broadway. The fault flashed over to the 407 circuit (another one of the three Newburgh network feeders), which was in close proximity in the pull box. This resulted in two of the three Newburgh network feeders locking out, leaving only the 404 circuit feeding the network. The 404 circuit was opened due to secondary network loading concerns, dropping the entire network. Emergency switching was performed to isolate the faulted sections of the circuits and restore affected customers, for a total outage duration of 5 hours, 9 minutes.

The Poughkeepsie network experienced a single outage in 2019. In December, smoke was found to be coming out of two adjacent network manholes. The workers on the scene were able to identify from the surface burned secondary conductor in both manholes, however, they were unable to fully determine the extent of the damage without entering each structure. To allow for safe access, all three primary cable feeds to the network needed to be de-energized, which resulted in an interruption for the entire Poughkeepsie Secondary Network, Saint Mary’s Church, and the Verizon Building. There was no damage to the primary cables in either manhole. In addition to the burned secondary conductors, the workers identified several damaged conduits which required immediate replacement. Two of the primary cables were re-energized to restore the network, while the third cable feed remained out of service in order to facilitate repairs. 867 network customers experienced a 58 minute outage. A single customer experienced a 1 hour, 1 minute outage. The final customer to be restored experienced a 4 hour, 29 minute outage to facilitate repairs.

Despite the 10 network outages in the past 10 years, the reliability of the sub-transmission and secondary network systems is well above the system average reliability. Programs have been developed to address aging equipment and infrastructure. An analysis of the age and failure rate of each cable, as well as the age of the underground infrastructure was conducted to identify and prioritize replacements under these programs. This is a proactive measure to ensure that the existing level of reliability can be maintained. These programs are discussed in the next section.

3.4.4 Summary of Reliability Improvement, Infrastructure and Equipment Replacement Programs

In 2008, a 14.4kV Cable Rejuvenation Program was developed to address portions of the underground and overhead PILC primary feeders (sub-transmission feeders). Portions of these cables are over 60 years old and have experienced numerous failures due to cracks in the lead shield. Portions of the duct banks that these cables run through are in some cases even older and have been collapsing.

The following is a list of programs that have been put in place to address sub-transmission and network infrastructure, and equipment replacement.

3.4.4.1 Underground Infrastructure and Secondary Network Cable Replacement

Prior to 2013, an increase in secondary cable failures had been identified. A plan to replace missing sections of secondary runs as well as secondary runs found to be in poor condition began in 2012. Approximately $1.4 million was spent between 2013 and 2017 to address secondary cable in all three networks. This included major upgrades to the infrastructure and cables in the Newburgh Network as a result of the 2012 cable failures. An additional $400,000 was spent in related conduit, manhole and pull box repairs in all three networks.

In 2014, underground infrastructure for the Taconic highway crossings were inspected and a scope of work or repairs were identified. In 2023, all other highway crossings will be identified and inspected. Between 2024 and 2027, capital funds have been budgeted to address underground highway crossings in need of repair.

Through the inspection program, secondary network infrastructure, cable, and equipment in need of repair are continually addressed. The Poughkeepsie secondary network infrastructure along Market Street was evaluated in 2019 for inclusion in the capital budget after field inspections in 2017 and 2018 verified collapsed tile ducts without any remaining spares to accommodate new cable, as well as pull-boxes and manholes in need of repair. A five-phase plan was developed to install all new secondary network infrastructure along Market Street. In 2019, the City of Poughkeepsie announced plans to repave Market Street and repurpose it for two-way traffic. In October 2019, City officials notified Central Hudson that trenching after their project will not be allowed. It was therefore required to expedite the five phases of the secondary network infrastructure replacement, working alongside existing gas trenching that was also scheduled in the area. All five phases were completed by the end of 2020 for a total capital investment of approximately $1.74 million. Between 2022 and 2027, capital funds are budgeted for more secondary cable and infrastructure repair/replacement work, identified projects in both Newburgh and Poughkeepsie.

Secondary cable on Market street in Poughkeepsie will be installed in the newly completed duct system. The north eastern section of Broadway in Newburgh has also been identified for possible infrastructure and cable replacement. Reliability of the Newburgh network and risk of a network outage will be considered before plans for new infrastructure are finalized. Budgeted dollars were determined based on the average cost for secondary network repairs in the prior 5 years.

3.4.4.2 Poughkeepsie Network Primary Feeder PILC Cable Replacement

In 2008, a 5-year replacement program was developed to address the age and condition of the primary feeders to the Poughkeepsie Secondary Network, as well as the infrastructure. Approximately 3.6 circuit miles of mainline primary feeder cable was replaced by 2014. There are four (4) lateral branches remaining that are PILC cable. As mentioned above, in 2019, the City of Poughkeepsie announced plans to repurpose the major road (Market Street) where these lateral branches reside. As a result, it was deemed cost effective to expedite the major infrastructure repairs along Market Street, prior to the City of Poughkeepsie repurposing this area. This infrastructure work was completed in 2020. Although this work was driven by the condition of the secondary network infrastructure, extra conduits were installed to accommodate the replacement of the primary PILC cables in this area. Capital funds have been budgeted for 2022 and 2023 to replace these lateral branches with EPR rubber cable to match what has been installed in prior years.

3.4.4.3 14.4 kV Cable System Replacement

The Poughkeepsie 14.4 kV and Newburgh 14.4 kV area studies were performed to determine if the existing 14.4 kV cables (the majority of which are PILC) were still needed, and if so, to prioritize replacement based on failure rates and risk.

Poughkeepsie 14.4 kV Area Study – All of the Poughkeepsie 14.4 kV non-network PILC cables identified for retirement in the Poughkeepsie 14.4 kV Area Study have been retired. Retirement of the Maryland Avenue 4.16kV Substation was completed in 2019, eliminating the need for the MS cable.
Newburgh 14.4 kV Area Study – The B, F, R and WN cables emanate from West Balmville and feed the Montgomery Street Substation, which is a combination 13.2 kV - 4.16 kV substation that feeds the Newburgh Secondary Network. It was determined that the B, F, R cables could be retired and replaced with a single overhead circuit. This new overhead circuit would work with the WN cable to feed the Montgomery Street Substation and the Newburgh Network, provided that the WN is reconductored to match the wire and cable of the new circuit.

The project to build the new circuit to replace the B, F and R cables was divided into 5 phases. The majority of the circuit (approximately 2.9 miles) will be overhead construction. Approximately 0.8 miles will be underground cable, in part, utilizing existing, relatively new, underground infrastructure. New underground infrastructure was installed in front of the Montgomery Street Substation in 2020 for a total capital investment of

$904,000. This work was needed to accommodate the new cable, as well the upgrade to the WN PILC cable that currently runs under the Newburgh Free Library. The remaining phases of this project have been included in the capital budget for 2022 through 2027.

3.4.4.4 URD Cable Replacement and Repairs

Specific URD's have been identified in the Capital Budget as needing complete replacement due to numerous failures and loss of the primary neutral conductor. In addition to those identified repairs, Central Hudson is looking into working with IMCORP to test URD cables of specific vintages in order to proactively detect defects that may lead to failure. Three URD's were identified as potential locations to test and target repair work based on an analysis of 5 years of outage data and dollars per customer minute avoided. The scheduling of targeted repairs with no impact to customer service is preferred over reactive repairs to failures that cause customer outages. Central Hudson is reviewing the ability to utilize IMCORP's services to target repairs. In addition to reserving capital funds for potential IMCORP testing, additional funds have been budgeted for traditional cable replacements.

3.5 Distribution

This section discusses the distribution system inspection process as well as the plans and programs related to Central Hudson's overhead electrical equipment and structural equipment for voltages less than 69 kV. In addition, there is a section that focuses on Central Hudson's ongoing reliability analysis, reliability improvement and infrastructure upgrade programs.

3.5.1 Inspection Programs

As mandated by the NYS PSC Safety Standards Order 04-M-0159 and subsequent revisions, Central Hudson targets inspections on approximately 20% of company-owned facilities on an annual basis. The purpose of Central Hudson's facility inspection program is to visually evaluate equipment and verify that it is in safe, operational and reliable condition. This inspection program is ongoing and includes a reporting and documenting procedure that allows for any observed deficiencies to be recorded and prioritized for timely repair. Notable conditions found in the field as part of the inspections are categorized into specific areas relative to each facility type. Each condition finding is given a rating code that allows Central Hudson to prioritize any corrective action required.

Central Hudson uses a severity rating ranging from 1 to 6 as noted below:

Severity Rating	Description
1	Insignificant – No action needed
2	Very minor condition - No action needed at this time
3	Monitor for future action
4	Serious Condition – may cause a circuit outage or problem in the future
5	Critical Condition – likely to cause an interruption of service
6	Immediate Condition – Immediate threat to life, property, or will cause a circuit outage or problem

The following are examples of items which fall under severities 4-6:

Category	Condition	Severity Value (or Range)
Poles	Rotted	4
	Broken	5-6
	Leaning	4
	Washed Out	4
	Woodpecker Holes	4-5
	Evidence of Flashover	4
Conductor	Damaged Primary	5
	Damaged Secondary	4
	Damaged Neutral	4
	Slack Primary	5
	Slack Secondary	5
	Slack Neutral	5
	Broken Tie Wire	4
	Phase Wire off Pin	6
	Phase Wire on the Ground	5-6
	Insufficient Clearance	5-6
Trimming	Vines	4
	Needs Trimming	4
	Limb/Trees on Line	5-6
	Danger Trees	4
Hardware	Broken Guy	4
	Broken Cross Arm	5-6
	Broken Cross Arm Brace	4
	Broken Insulator	4
	Broken Cutout	5

	Broken/Blown Lightning Arrestor	4
	Rotten Cross Arm	4
	Rotten or Corroded Anchor	4

Central Hudson has continually identified the inspection process as an area for review and possible improvements. In 2012, Central Hudson began identifying 3rd party attachments on each pole as a part of the inspection process. The data is reviewed against our records to determine appropriate steps in response to unauthorized attachments. The increase in pole loading due to the unauthorized attachments not properly reviewed by Central Hudson has potentially resulted in installations that do not meet our design specifications and could contribute to pole failures during storm events. Central Hudson will continue to analyze this data and determine additional processes or programs that may be required to mitigate the impact of 3rd party attachments on pole loading that contributes to failure during storm events.

The above listed Central Hudson severity rating values correspond to the PSC Repair Priority Levels as follows:

Company Rating	PSC Rating
1	IV
2	IV
3	IV
4	III
5	II
6	I

Summary of Conditions Resulting from the Inspection Process

Year	**Priority Level / Repair Expected**		**Deficiencies Found (Total)**
2017	I	Within 1 week	7
	II	Within 1 year	262
	III	Within 3 years	3,939
	IV	N/A	5,019
2018	I	Within 1 week	18
	II	Within 1 year	262
	III	Within 3 years	8,433
	IV	N/A	5,621
2019	I	Within 1 week	7
	II	Within 1 year	192
	III	Within 3 years	6,086
	IV	N/A	6,924

2020	I	Within 1 week	3
	II	Within 1 year	171
	III	Within 3 years	5,270
	IV	N/A	7,212
2021	I	Within 1 week	1
	II	Within 1 year	318
	III	Within 3 years	2,991
	IV	N/A	7,892

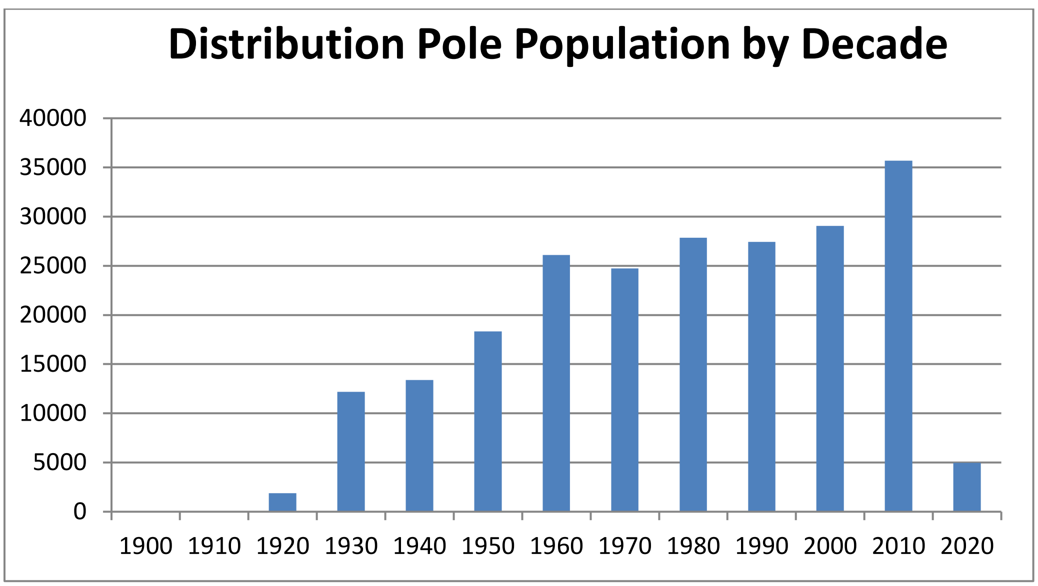
In addition, comprehensive thermal inspections of the three phase distribution system are completed annually during the summer peak season. Beginning with the 2018/2019 winter season, thermal scanning was expanded to include winter-peaking circuits and spur lines with large numbers of customers. The program was expanded again in 2020 to include heavily-loaded single phase and two-phase lines.

3.5.2 Equipment

3.5.2.1 Wood Poles

Inventory
Central Hudson currently has approximately 221,654 distribution poles. With a few exceptions, these distribution poles are composed of wood.

Age and Condition
The following chart depicts the age of Central Hudson's poles. The average age of the distribution pole plant is 39 years old.



Plans
As noted, Central Hudson has a 5-year inspection program to assess its distribution facilities, which provides a severity value in accordance with the PSC Safety Standards Order for the plant assessed ranging in value from I to IV with I needing immediate attention. As a result of this assessment program, Central Hudson replaced 2,888 poles in 2021, and approximately 3,000 poles are scheduled for replacement in 2022. In addition to the poles identified during the inspection process, there are additional poles that will be repaired or replaced throughout the year for reasons such as condition, third party attachments, relocation for road rebuilds, or as a part of larger capital projects. Central Hudson has seen a significant acceleration of distribution pole replacements based on the increased number of inspection findings. This trend is expected to continue based on the age distribution of our pole plant. As a result, Central Hudson has incorporated the impacts of this increase within the company's capital budget forecast.

3.5.2.2 Street Lights/Area Lights

Inventory
Central Hudson currently has approximately 26,436 streetlights and area lights on the distribution system.

Age and Condition
Central Hudson does not have age of these devices. However, they are visually inspected as part of the distribution circuit inspections program.

Plans
Based on reduced cost and improved energy efficiency, Central Hudson's Electric Tariff includes LED-equivalent fixtures for all non-LED streetlight and area light options. For complete fixture failures, Central Hudson replaces non-LED with LED fixtures. However, the Company is still performing maintenance and repairs to non-LED streetlights and area lights such as lamps and photo eyes. Some municipalities have elected to replace Company-owned and maintained streetlights with municipal-owned and maintained streetlights. Currently, there are ten (10) municipalities that have completed a mass LED replacement and remain Company-owned and maintained. In either case, the municipality must first pay for the stranded value of existing lights to be replaced. If the replacement is for a conversion to Rate C where the municipality takes ownership, a Public Service Commission asset purchase filing must be submitted and completed.

3.5.2.3 Pole Top Insulators

Inventory
Central Hudson currently does not have inventory of these devices.

Age and Condition
Central Hudson does not have age of these devices. However, they are visually inspected as part of the distribution circuit inspections program.

Plans
Porcelain insulators have a similar failure mechanism to that of porcelain cutouts (see Section 3.5.2.8 below), though the reliability impacts are significantly less. Porcelain insulator failures averaged approximately 0.65% of total non-storm System SAIFI between 2017 and 2021, compared to 1.1% for porcelain cutout failures over the same time period. Central Hudson will continue to inspect these devices with the Distribution Condition Assessment Program and at this time the need for a replacement program is not warranted. New installations are completed utilizing either polymer tie-top insulators or polymer vice-top insulators.

3.5.2.4 Wire (Primary and Secondary Overhead Conductor)

Inventory
The following chart depicts the inventory of wire by voltage class:

Conductor	Pole Miles of Line
34.5 kV Overhead	209
13.2 kV Single Phase	4,536
13.2 kV Multi Phase	2,126
5 kV and Under	286

Age and Condition
Age is not readily available for conductor.

Plans
Central Hudson has not had any systematic modes of failure based on wire type and as issues arise they are handled within the confines of the existing capital program. Three programs have been developed to replace conductor types that are linked to aging infrastructure.

Copper Wire Replacement
The transition from copper to aluminum overhead conductors occurred during World War II due to shortages in copper resources. The copper conductors of this vintage have lower thermal ratings which makes operational switching challenging. In addition, the pole plant on which the conductor resides is typically of advanced age and a failure risk. A Copper

Wire Replacement program was developed in 2016 to phase out this antiquated infrastructure.

Open Wire Secondary Replacement
Because most storm damage in Central Hudson's service territory is caused by trees, open wire secondary creates an increased risk of a phase to neutral contact which can result in outages to small groups of customers that require a relatively large amount of time to repair. In addition, a break in the neutral wire can cause the customer's voltage to swing out of range and damage equipment. Finally, the use of open wire secondary stopped approximately 50 years ago, so it is another source of aging infrastructure. A program was created in 2013 to replace problematic locations where open wire secondary exists.

5 kV Aerial Cable Replacement
Much of the 5 kV aerial cable in the Central Hudson service territory dates back to the 1930s and is prone to failure. The cable has also been the cause of many voltage issues on the system. Additionally, the cable typically contains lead and asbestos which pose environmental concerns. Repairs on this cable can be difficult and lengthy.

A 5 kV aerial replacement program was created to mitigate the reliability, loading, environmental, and safety concerns associated with this cable. When this type of cable is replaced, the typical practice is to convert the customers over to 13.2 kV voltage class circuitry. This aids in Central Hudson's goal to move away from 5 kV operation to flatten the voltage profile, better enabling CVR and increasing hosting capacity of DERs.

Primary and secondary overhead conductors are continually assessed as part of Central Hudson's inspection program.

3.5.2.5 Transformers

Inventory
Central Hudson currently has 85,368 overhead distribution transformers and step-down transformers on the system.

Age and Condition
The current average age of these facilities is 29 years. The overall condition of these assets is good. Newly purchased step-down transformers are equipped with Magnex breakers to limit the potential for thermal overload.

Plans
Step-down transformers limiting operational flexibility are evaluated for potential downstream voltage conversion or replacement with larger units

through the regular capital budget program. Overloaded service transformers are evaluated for replacement with larger units or splitting of services.

Transformers are included in Central Hudson's inspection cycle utilized to assess the condition of our distribution facilities. This plan will continue in the future.

3.5.2.6 Voltage Regulators

Inventory
Central Hudson currently has 598 voltage regulators installed on the distribution system not including substation regulators. Regulators installed in the substation are detailed in Section 3.3.2.1.9.

Age and Condition
The current average age of these facilities is approximately 10 years. The overall condition of these assets is good.

Plans
Regulators are used until the devices become inoperable (run to failure). They are then replaced as needed. As part of the Grid Modernization program discussed in Section 4, older control panels are in the process of being retrofitted with new electronic controls that allow for two way communication and control. Retrofitting of controllers provides the added benefit of allowing the voltage regulator to operate in cogeneration mode to manage the back feed due to distributed energy resources.

3.5.2.7 Capacitors (Fixed and Switched)

Inventory
Central Hudson currently has approximately 2,484 distribution class overhead capacitor units installed at 836 locations.

Age and Condition
The current average age of these facilities is approximately 21 years. The overall condition of these assets is good. Capacitor banks are inspected annually by distribution engineering interns.

Plans
Central Hudson's target 115/69kV transmission system power factor is 0.96. In order to achieve this, distribution feeder capacitors are deployed such that summer peaking circuits achieve an on-peak power factor of approximately 0.98 to 0.99 and winter peaking circuits achieve an on-peak power factor of approximately 1.00. Each year Central Hudson reviews the power factor needs in each Operating District. Each Operating District

submits recommendations to either install new switched capacitors or replace fixed capacitors with switched capacitors. Approximately 5-6 locations are chosen each year system-wide. Additionally, through the Distribution Automation program described in Section 4, the quantity of fixed and switched capacitors banks on each circuit is being fine-tuned to allow for Volt-VAr Optimization through the Distribution Management System that is under development. This will enable the voltage profile on the system to be flattened and then reduced to optimize customer energy usage.

3.5.2.8 Cutouts

Inventory
Central Hudson currently has approximately 49,861 distribution cutouts on the primary distribution system.

Age and Condition
The age of the cutouts is not readily available. Porcelain style cutouts have an approximate failure rate of 0.2% per year on the Central Hudson system and a change out program was developed that targeted three-phase locations that would impact 500 customers or more due to a failed cutout. This program has been completed.

Plans
On an ongoing basis, if one or more phases experience a failure of a cutout, the cutouts on the other phases are replaced during the outage. Cutouts are included in Central Hudson's inspection cycle utilized to assess the condition of our distribution facilities. This plan will continue in the future.

In addition, Central Hudson will continue to monitor the reliability impact of porcelain cutouts to determine if additional replacement programs are cost effective. New installations are completed with polymer cutouts.

3.5.2.9 Fuses (overhead primary)

Inventory
Central Hudson has approximately 43,706 fuses protecting our overhead facilities.

Age and Condition
Age of these devices is unknown and they typically do not fail due to age.

Plans
Fuses are added to the system in order to help sectionalize outages during fault conditions. This minimizes the number of customers interrupted for

an interruption in addition to decreasing the patrol area for the trouble crew.

3.5.2.10 Reclosers / Sectionalizers

Inventory
Central Hudson currently has approximately 1,688 distribution reclosers consisting of hydraulic reclosers (Type WE, L, V4L and D), electronic reclosers and FuseSavers. There are also 16 Type GV, CRS and ScadaMate Sectionalizers.

Age and Condition
The age range for most hydraulic reclosers is between 0 and 10 years and the average age range for electronic reclosers is 0 to 8 years. The overall condition of these assets is good.

Plans
Central Hudson currently replaces most hydraulic reclosers with electronic reclosers as the hydraulic reclosers approach the end of their useful lives and as major capital budget distribution improvement projects are completed in a given area. These devices have improved outage prioritization by automatically notifying key personnel of momentary and permanent interruptions. The electronic reclosers record fault data to allow for troubleshooting along with more flexible protection schemes. These devices also allow for 10,000 operations before maintenance is needed. Additional reclosers are replaced or added to the system as a part of the Distribution Automation program described in Section 4 as well as installed for monitoring, control, and protection purposes for DER systems 500kW and greater.

3.5.2.11 Automatic Load Transfer Switches (ALTs)

Inventory
Central Hudson currently has 90 individual ScadaMate Switches that operate as 39 teams and 4 sectionalizers. Also, Central Hudson has 7 padmount ALTs. In addition, Central Hudson has configured 50 additional Electronic Reclosers into 25 teams. These automated switches transfer pockets of load to alternate feeds for loss of primary feed. They have contributed to system SAIFI improvements by saving an average of 32,393 customers per year from outages over the past five years.

Age and Condition
The maximum age of the ScadaMate switches is approximately 20 years and their condition is considered fair. As units fail they are being replaced by electronic recloser-based teams. The average age of electronic reclosers within ALT teams is 7 years and their condition is considered good.

Plans
The default device utilized to create new ALT teams is now the electronic recloser. The electronic recloser ALT installations have the added value of protection in addition to providing for load transfer.

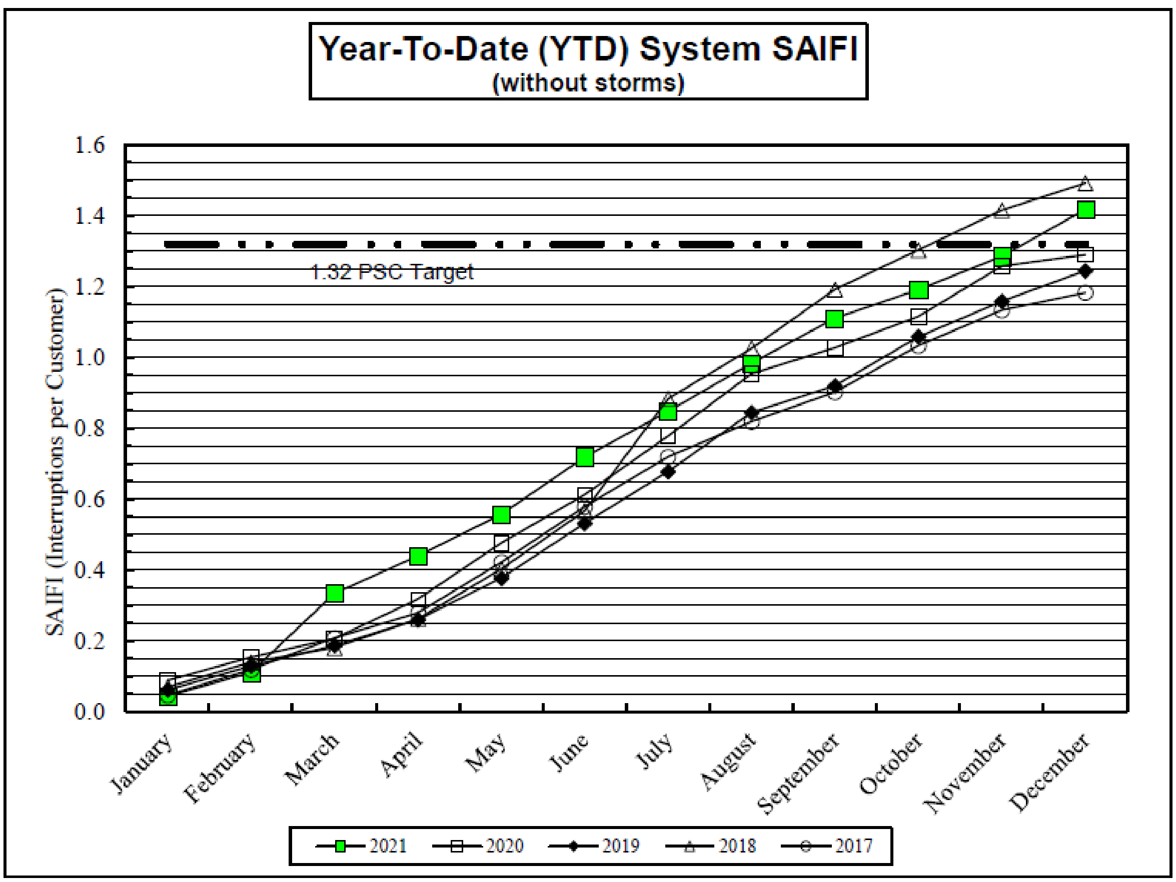
3.5.3 Reliability Performance Data

Reliability performance on the distribution system at Central Hudson is primarily measured utilizing the SAIFI (frequency) and CAIDI (duration) indices. These standard IEEE indices are defined as follows:

SAIFI = System Average Interruption Frequency Index =
Total # of Customers Interrupted
Total # of Customers Served

CAIDI = Customer Average Interruption Duration Index =
Sum of Customer Interruption Duration
Total # of Customers Interrupted

The Public Service Commission monitors these indices and can levy fines if SAIFI or CAIDI exceed predetermined thresholds (for 2021, the non-storm PSC SAIFI target was 1.32 and the CAIDI non-storm PSC target was 2.50).



Non-storm system SAIFI averaged 1.326 over the five-year period from 2017 through 2021. The highest SAIFI over this period occurred in 2018 (1.493) and the lowest occurred in 2017 at 1.183. 2021 yielded a SAIFI value of 1.418, or 7% above the five-year historical average.

3.5.4 Additional Reliability Improvement and Infrastructure Programs

The Electric Distribution and Standards organization is responsible for analyzing reliability and recommending improvement opportunities. The infrastructure assessment and replacement program and associated technology upgrades described in Section 3.5.2 are major contributors to reliability improvement. There are also several programs which are not infrastructure-related or that fall outside of the scope of the more general infrastructure replacements that are described here.

3.5.4.1 Vegetation Management Program

Trees and tree branches falling on distribution lines are consistently the number one cause of power outages for Central Hudson customers. The best way to defend against these potential hazards is with a dedicated and thorough program of tree clearing and trimming performed on a regular basis. Central Hudson's program is carefully designed to reduce the incidents of power outages due to tree damage while also protecting the natural beauty of the Hudson Valley.

The Routine Trimming Program began in its current form in 2011. After experiencing significant improvement in tree-related SAIFI as a result of the Routine Trimming Program, and despite improvement in other areas of reliability, Central Hudson began to see the trend reverse and eventually have a significant impact on Central Hudson's overall SAIFI metric beginning around 2016. This was due in part to the emergence and spread of the Emerald Ash Borer ("EAB"). To combat the negative impact of accelerating tree damage on SAIFI, Central Hudson implemented several plans to improve performance. These included beginning to collect and review tree-related data following breaker lockouts, further reviewing trends related to tree species (particularly ash trees) and establishing an effective process for identifying and removing danger trees.

In parallel with these efforts, Central Hudson also engaged a consultant in 2016 to assess Central Hudson's line clearance program. Some of the consultant's recommendations included: obtaining increased funding to return to a four-year trimming schedule, creating a separate schedule for circuits affected by the residency of protected bat species, and obtaining funding for a widespread removal of danger trees -- the majority of which are ash trees -- along three-phase circuitry in order to reduce tree mortality caused by the Emerald Ash Borer and other tree diseases. In Case 17-E-0459, Central Hudson requested incremental funding to address the recommendations from the consultant in order to improve the system reliability. This incremental funding request sought to address the following distribution vegetation management items: routine trimming backlog, general danger tree removals, Emerald Ash Borer danger tree removals, off-cycle spot trimming and completion of the original enhanced line clearance areas. Incremental funding was partially granted.

On May 5, 2017, Central Hudson petitioned the Public Service Commission ("Commission") for deferral accounting authority related to incremental funding for additional transmission line clearance and danger tree removal. The Commission ruled on this petition in Case 17-E-0250 on September 28, 2017, granting, in part, deferral accounting and recovery for this purpose. The Commission approved up to $2 million for the removal of danger trees along 262 miles of three-phase circuitry on the twelve highest-priority circuits, which was substantially completed in 2018 with some work carrying over into 2019. As part of Case 17-E-0459 filed June 29, 2018, Central Hudson requested significant additional funding for distribution vegetation management (a total of approximately $26M annual funding). A portion of the additional dollars requested was approved (a total of approximately $20M annual funding). Central Hudson saw a positive impact to tree-related SAIFI as a result of the increased funding in 2019. Tree-related SAIFI showed a significant improvement, coming in at 9% lower compared to 2018 and 8% lower than the 5-year average. Central Hudson saw a significant positive impact to tree-related SAIFI in 2020 on the circuits where danger tree removal was performed; however, poorer performance on the remainder of the system lead to an overall SAIFI increase in the tree contact category. This trend continued into 2021 and potential reliability improvements were overshadowed by tree contact outages from an exceptionally high number of minor storms that did not qualify for Code 1 status.

Distribution Engineering continues to work in conjunction with Line Clearance to identify the worst performing circuits that should be targeted for danger tree removal. To date, approximately 111 circuits have been identified and addressed. On the circuits where danger trees were removed between the program's inception in 2018 and the end of 2021, a preliminary analysis indicates a 21% non-storm SAIFI reduction for tree contact outages, on average, compared to three-year historical averages for those circuits. It will take several additional years to fully realize the effect on tree-related SAIFI as a result of the additional funding received.

Recognizing the importance of our vegetation management program to system reliability, the Company requested additional funding as part of its 2020 rate filing. Ultimately, as part of the 2021 rate agreement, Central

Hudson was granted funding to achieve a 4.5 cycle for routine on-road and off-road distribution line clearance activities. In addition, $2.5M was provided for each of the three rate years to continue addressing danger trees.

Additional analysis was completed in 2018, 2019, 2020 and 2021 to align danger tree removal with the regular trimming cycle based on historical reliability such that the greatest number of customers could be prevented from experiencing outages while minimizing setup, travel and other costs. This analysis will continue to guide line clearance work in 2022 as Central Hudson works through its planned trimming cycle, while also accounting for trimming restrictions due to protected bat species.

In light of Central Hudson's 2021 reliability performance, which was driven largely by tree contact outages occurring during non-coding weather events, additional measures are being taken in 2022 to mitigate outages in this category. Circuits planned for routine trimming in 2022 were re-prioritized in order to shift resources to the most impactful areas on SAIFI to the beginning of the year, thus maximizing SAIFI reduction. In addition, circuits out of two substations with poor reliability originally planned for trimming in 2023 were accelerated to 2022, with two substations with good reliability pushed to 2023 in their stead. Finally, several circuits with historically high SAIFI contributions are undergoing mid-cycle "hot spot" trimming based on engineering analysis and field conditions. More time is needed to fully realize the impact of these changes. Central Hudson is in the process of engaging a consultant to assess Central Hudson's routine trimming and hazard tree programs and provide additional recommendations for improvement for 2023 and beyond.

3.5.4.2 3X and Customers Experiencing Multiple Interruptions (CEMI) Outages

The 3X and CEMI programs allow engineers to focus in on areas of the distribution system that experience multiple outages per year that are not always mitigated under larger scale capital improvement programs.

The 3X Report, which is completed on a monthly basis, is designed to identify those protective devices that have operated at least three times within a rolling 12-month period. Once the initial report is compiled, each Electric Operating Engineer goes through the listed devices for their district to justify the operations and/or suggest a plan of action. This is particularly valuable in capturing non-capital improvements, such as the installation of squirrel guards and spot tree trimming that can result in dramatic reductions in the number of outages in these load pockets.

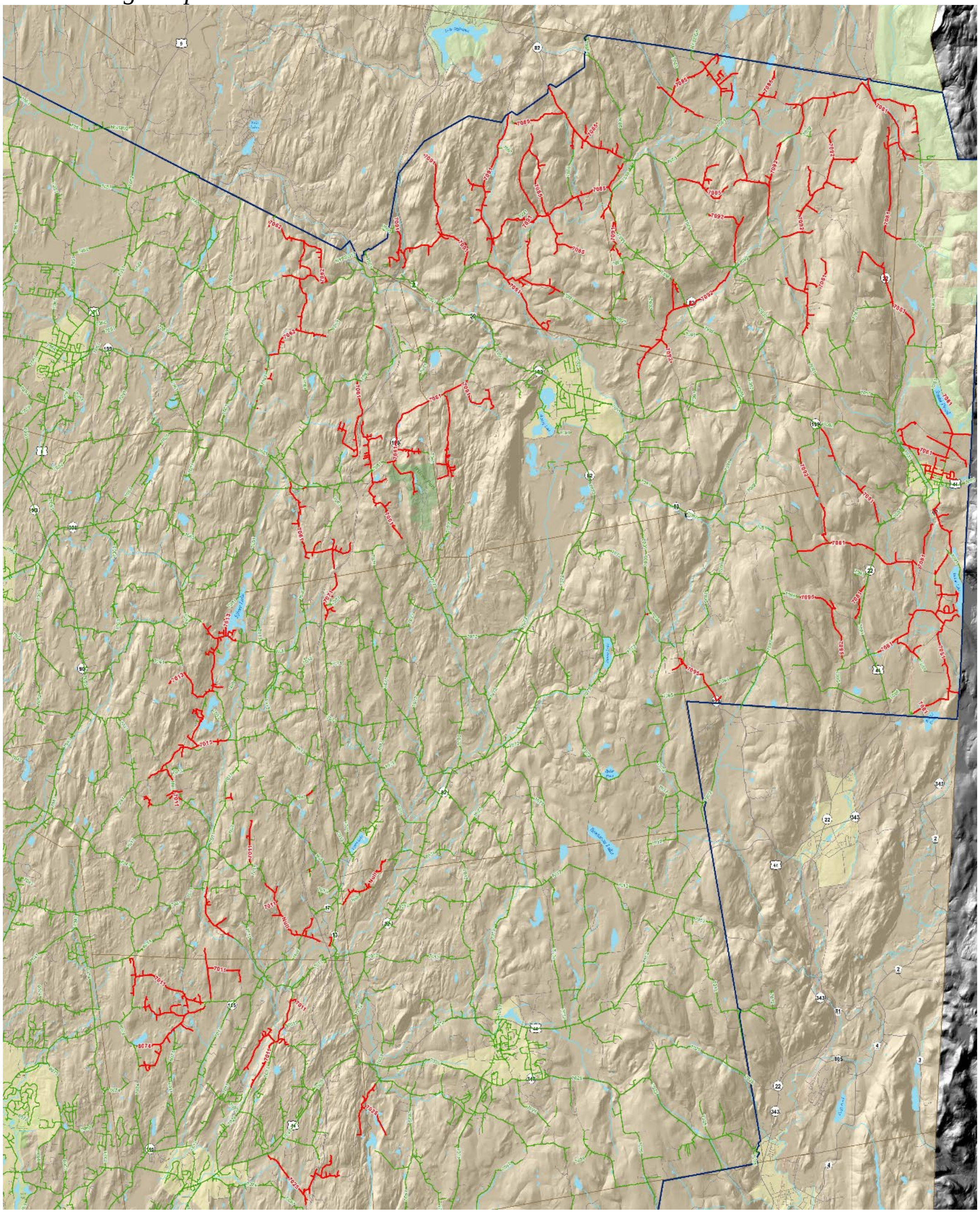
In addition to the 3X Report, the 10X Report was developed in 2008 to identify customers on Central Hudson's system that experience ten or more outages within a calendar year. The 10X Report provides Central Hudson with an opportunity to address areas that normally would not justify Capital Budget Projects, since they typically have a $/COA above the normal range for reliability projects. Over time, this has evolved to a CEMI program where lower numbers of interruptions are considered that are still well above average (e.g. 8X, 9X). In some cases, Capital Budget Projects are needed to address underlying infrastructure problems.

3.5.4.3 4800V Delta Circuitry Upgrades

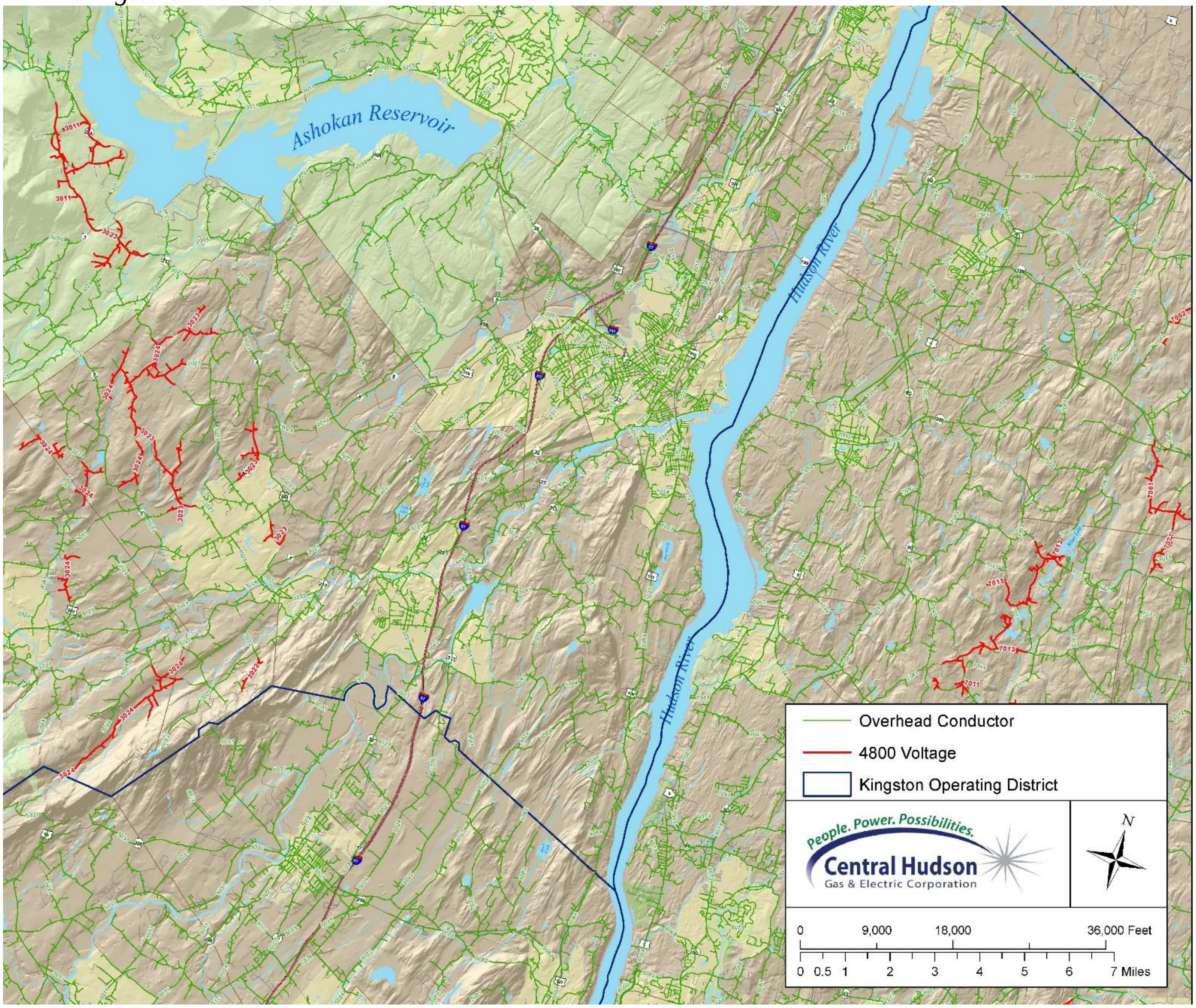
Central Hudson has approximately 252 miles of 4800V delta circuitry remaining on its distribution system. The Company abandoned the practice of installing 4800V circuitry in the 1940s, so much of the infrastructure is aged. In addition, capacity and operational flexibility is limited by the low voltage circuitry as well as by step-down transformers, and delta circuitry is more prone to faults that do not trip protective devices. Hosting capacity for DERs is also limited by this low voltage circuitry.

Approximately three-quarters of this circuitry is located in the Northeast Dutchess County area, and the Northeast Dutchess Area Study (E.P. #2012-06) recommended that a program be developed to replace this infrastructure. The following maps show the 4800V delta circuitry in red for the Poughkeepsie, Kingston, and Fishkill districts:

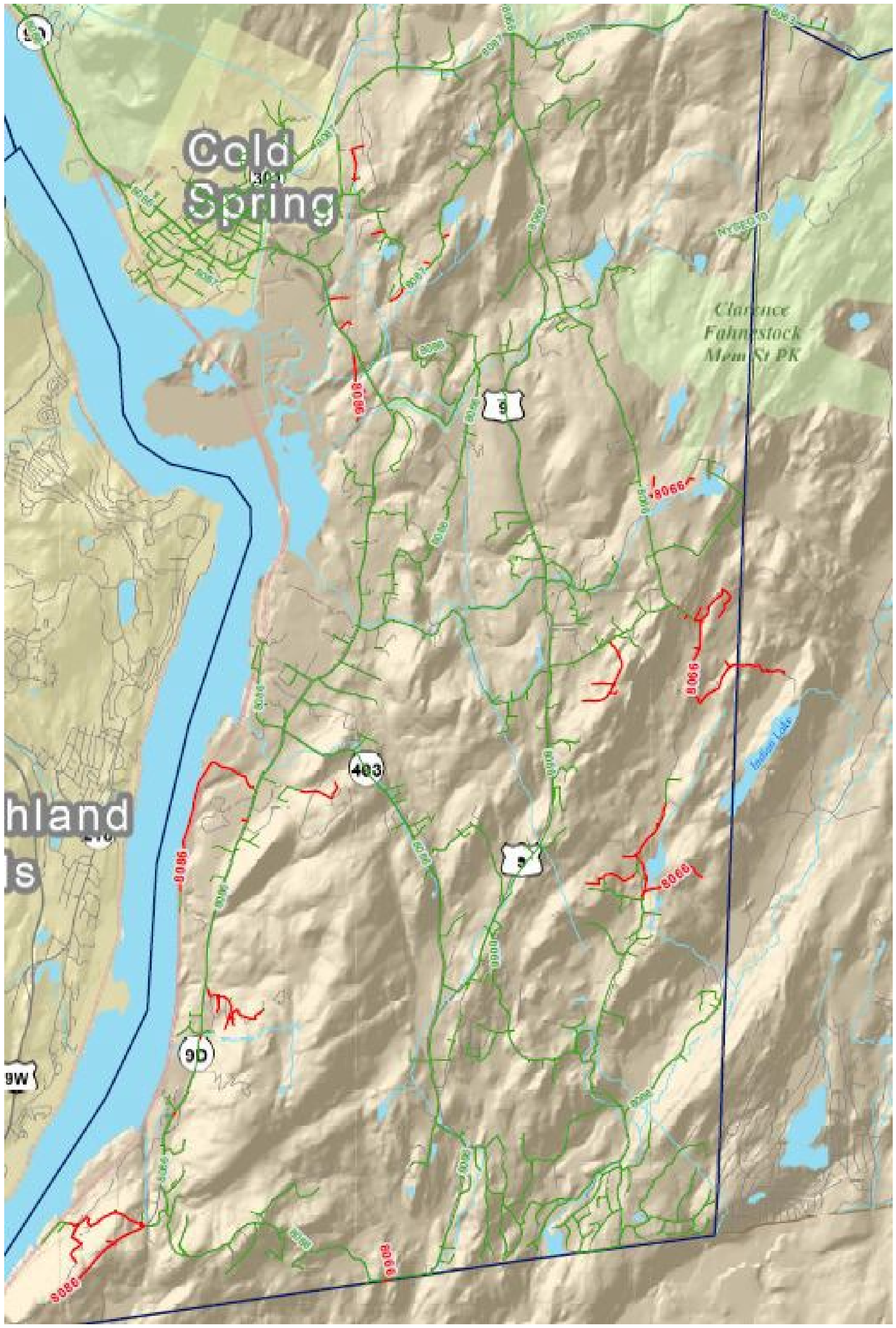
Northern Poughkeepsie District:



Kingston District:



Fishkill District:



A long term replacement program was developed beginning in 2016 to address the 4800V delta infrastructure. Replacement is prioritized based on other ancillary benefits, particularly reliability and operational flexibility, along with improved DER hosting capacity.

3.5.4.4 Worst Circuit Reports

Each year, Central Hudson analyzes the worst 5% of circuits based on 5-year weighted average SAIFI, and the worst 5% of circuits based on 5-year weighted average SAIDI. The weights are applied to maintain a stronger emphasis on new problems while still addressing recurring issues, without emphasizing special one-time events. The weights applied are as follows: previous year (50%), two years ago (25%), three years ago (15%), four years ago (5%), and five years ago (5%).

The circuits on the list are reviewed in detail to determine if any action is required in addition to the capital program. For example, spot trimming or installation of squirrel guards may be required.

3.5.4.5 Distribution Automation

The Distribution Grid Modernization program is described in detail in Section 4.

3.5.5 Summary of Reliability Improvement and Infrastructure Programs

As described within this section, Central Hudson has a reliability-centered culture and our reliability improvement programs stem from a plethora of areas that are balanced and integrated into the Electric System Plan.

3.6 Storm Hardening Techniques

Central Hudson has historically maintained a core focus on customer reliability. With this focus, Central Hudson has developed and implemented a number of programs aimed at improving reliability that date back to the early 2000s. With the increase in the number of recent major storms and cases of extreme weather events, there has been a heightened attention on storm hardening and grid resiliency. Central Hudson has ongoing programs as well as new initiatives that fall under the category of storm hardening. This section provides documentation for the various forms of storm hardening and/or grid resiliency Central Hudson utilizes in its current construction and maintenance practices.

It should be noted that any type of T&D construction is vulnerable to outages under adverse conditions regardless of construction type. Overhead systems are particularly vulnerable to weather-related events such as high winds, rain and lightning. These events commonly cause structural failure of trees which may fall on the distribution lines from outside of the right-of-way. Underground systems are vulnerable to dig-ins and flooding conditions. Both types of construction have advantages and disadvantages, and choosing the appropriate construction type should be done based on good engineering judgment, reliability analysis and economics.

Since weather-related events have the most severe impact on the distribution system, this section focuses on the storm hardening techniques specific to that system. The various components of Central Hudson's operating practices for the distribution system are broken down into the following categories:

(1) Design/Construction
(2) Enhanced Reliability Program & Distribution Automation
(3) Storm Circuit Hardening
(4) Maintenance
(5) Emergency Response & Repair
(6) Weather Prediction Tools

Each of these areas is reviewed below along with associated storm hardening practices.

3.6.1 Design/Construction

Central Hudson adheres to the NESC for its construction practices and had historically designed its distribution system to Grade C for strength and loading. In 2004, we began to shift to a Grade B design with the transition of our prior specification of standard distribution pole from a class 4 to a class 2 rating. In 2008, this became the standard installation practice. This transition was made due to the capability of the larger class poles to handle larger loads and the potential for a longer life. In addition, span lengths were shortened to further reduce pole loading and limit the effects of galloping conductors under fault conditions. In early 2022, Central Hudson was notified by pole suppliers that there was an impending shortage of Class 2 poles due to increased demand across the utility industry as well as the increased use of lumber in the construction market. Central Hudson's supply of Class 2 poles was projected to be reduced by 43%. In anticipation of the shortage, the Electric Construction Standards group developed a plan for a more targeted use of Class 2 poles while still ensuring that the reliability and resiliency goals of the Company are met.

Central Hudson has evaluated the use of steel, composite, concrete and raked poles for various reasons. Currently, concrete and composite poles are approved as alternatives to wood. Composite poles have been installed in locations where there is inadequate clearance for guying or where the need for a lighter weight pole is required due to terrain or access. Both concrete and composite poles have been evaluated against wood poles for both short term (ease of installation) and long term performance (strength retention, resistance to external damage, etc.). It is felt that in some cases these type poles may also withstand the elements better than their wood counterparts. Central Hudson will review the use of alternate pole types in specific areas within our service territory that could benefit from this type of construction.

3.6.2 Enhanced Reliability Program and Distribution Automation

Central Hudson embarked on its enhanced reliability program in the early 2000s, identifying and implementing a number of programs that would have a positive impact on reliability. All of the programs discussed below began in 2002 and the individual circuit projects were ranked and prioritized utilizing a $/COA methodology. Since the programs' inception, they have been refined to incorporate newer technologies and modern practices as appropriate, and Central Hudson's plans continue to evolve. Many of these programs have become a part of normal maintenance and construction practices, as described in other sections of this document. The following is an outline of these programs:

- **Enhanced Line Clearance**
  Initially, a program was developed to trim each circuit's first zone of protection with an Enhanced Line Clearance specification to limit tree interruptions along the three phase backbones of Central Hudson's distribution circuitry. Since the onset of that program, Central Hudson has substantially modified its routine trimming practices for all three phase mainlines as well as laterals. This program has had a direct correlation to the improvement in system SAIFI for interruptions caused by trees. In addition, Central Hudson began a targeted hazard tree program in 2018 which prioritized hazard tree removal on three-phase circuitry on circuits with the potential to positively impact SAIFI. See the "Vegetation Management" section for additional information.

- **Relocation of off-road facilities to on-road**
  The relocation of off-road distribution circuitry to on-road was also developed as a program to update aged infrastructure that ran cross-lot throughout Central Hudson's service territory. This resulted in a reduction of vegetation-related interruptions as well as a decrease in the duration of interruptions due to the ability to more quickly identify the interruption cause and make repairs utilizing on-road equipment. A secondary benefit has been significant cost reduction in maintenance trimming for locations where circuitry has been moved on-road.

  Today, relocation of off-road facilities continues to be a key component in the reliability improvement portfolio of capital budget projects. Whenever practical and cost-effective, synergies are realized to align this program with the five-year distribution inspection program to identify and relocate facilities on-road where multiple poles are also identified as rotten. Recently, there has been difficulty in obtaining necessary easements to perform these relocations.

- **Establishing three-phase ties with neighboring circuits**
  Efforts have been made to develop additional tie points between circuits throughout Central Hudson's system to allow for better maintenance and emergency planning. As a part of the Grid Modernization program, Central

Hudson continues to add stronger distribution circuit ties to improve resiliency during storms and simultaneously replace aging infrastructure.

- **Enhanced Lightning Protection**
  Areas prone to lightning were identified and additional lightning arrestors were added every quarter mile to minimize the effects of lightning strikes. This practice has become part of Central Hudson's standards for new and rebuilt construction.

- **Distribution Automation**
  Central Hudson commenced the Distribution Automation program in 2002 as a part of the Enhanced Reliability program. This program evolved with the Department of Energy's Grid Modernization initiative in 2015, and Central Hudson continues to shape this program as new technology becomes available. While there are many aspects of Grid Modernization described in detail in Section 4, this section focuses on those components which are currently incorporated into our strategy and that directly contribute to grid resiliency.

- **Installation of Automatic Load Transfer Switches**
  The installation of ALTs also began in the early 2000s to improve reliability of load pockets with nearby alternate sources. With this program, Central Hudson has installed 69 ALT teams and has seen a cumulative non-storm SAIFI improvement of 1.587 and a SAIFI improvement of 2.010 including storms through December 2021. At times, successful ALT operations have reduced the number of customers affected during weather events, preventing Central Hudson from coding those events as storm.

- **Recloser Program**
  Central Hudson began an aggressive program to install hydraulic reclosers as the first fuse points on most of its distribution feeders in 2002. As most outages on a distribution system are transient in nature, this was done to improve system SAIFI. In 2008, Central Hudson transitioned to the installation of electronic reclosers which added additional functionality and real time communication of operations and maintenance requirements. In addition, the Operating Engineers have been able to correlate recloser operations with cases of downstream fuse operations. By increasing the fuse sizes and the speed of the recloser fault clearing curves where possible, the reclosers are able to clear transient faults prior to the fuse operations preventing permanent outages.

  In 2010, Central Hudson began to leverage the communications capabilities of electronic reclosers to also perform automatic load transfer functionality at a 22% lower capital cost compared to the previous technology and with protection integrated into the device.

Hydraulic reclosers continue to be replaced with electronic reclosers on a case-by-case basis with the roll-out of Distribution Automation as part of Central Hudson's Grid Modernization program and as the distribution system evolves to include more integrated DER.

- **Micro-Grid Technology**
  In 2010, Central Hudson completed an R&D project with NYSERDA funding to install a micro-grid in one of the remote areas of the service territory. Frost Valley has historically had poor reliability and the construction of additional distribution feeders utilizing conventional distribution improvements for the limited load in this area was determined to be cost-prohibitive. The installation of a micro-grid diesel generator near the load pocket was a viable solution to restore service to this area for the loss of the mainline supplying these customers. For the loss of the preferred mainline distribution feeder, these customers are transferred to the generator as the alternate source of power. Since going into service, this scheme has operated successfully 54 times during major and minor storms, beginning with the Twin Peaks storm in February 2010.

  Central Hudson is currently working toward a similar model in the Four Corners area of East Fishkill using a natural gas-fired turbine along with battery storage. The Four Corners Microgrid project is part of a FEMA Grant program following Superstorm Sandy. This project was submitted to the Department of Homeland Security (DHS) by the New York State Department of Public Service on behalf of Central Hudson. The project includes the installation of a microgrid to enhance reliability in the Four Corners Area of the Central Hudson service territory. The Phase 1 Engineering Design was submitted to the DHS on August 14, 2018. This design included a 2MW lean burn natural gas turbine and a 2MW/1MWh BESS to facilitate block loading. The battery is sized to pick up the area load during the initial loss of utility service while the lean burn gas generator ramps up to speed and assumes the load. The project will include the optionality to use the BESS for other services (i.e., demand reduction, frequency regulation) during parallel operation.

  The Phase 1 design was approved by DHS, and on February 15, 2019, Central Hudson received approval from DHS to proceed with Phase II project construction. In February 2020, Central Hudson issued an RFP for the completion of Phase II permitting and construction work. Bids were received and Central Hudson engaged with one of the bidders to perform preliminary work based on the proposal.

  Overall, the project is progressing, however due to the delays in acquiring needed materials in addition to the earlier issues with establishing the terms of the contract between Central Hudson and the builder, Haugland, the in-service date has been pushed out to 2023. Currently, all required contracts have been signed, and all permits to construct and operate the microgrid have been obtained. Mobilization, site prep, and site design have been completed, and physical construction has begun.

Going forward, Central Hudson may evaluate additional locations where the installation of a micro-grid may be a cost-effective solution to improving reliability and providing storm hardening.

3.6.3 Circuit Storm Hardening

In 2020, Central Hudson completed a pilot project to improve the resiliency (i.e., storm harden) of the Woodstock 3012 circuit to more severe weather events. The project was completed to gain experience with the Company's proposed storm hardening program. As originally proposed, this program included performing circuit hardening within the mainline zones of the top 25 Worst Performing Circuits as determined by a metric incorporating storm (Code 1) performance. The circuit hardening includes an increased focus on vegetation management and a review and replacement of distribution equipment to bring circuits up to current construction standards, including both the build construction and replacement of failure-prone equipment in addition to ensuring proper fusing, animal protection and lightning protection. These efforts are focused on reducing outage frequency and duration during major weather events/Code 1 storms. As part of the current rate agreement, capital funds were included to complete storm hardening on approximately 15 circuits. Time will be needed following the completion of these projects to fully realize the resiliency and reliability impacts of this program.

3.6.4 Maintenance

Vegetation Management
Central Hudson maintains a 4.5-year trimming cycle for mainline and lateral distribution lines that is consistent with industry best practices. In March 2007, Central Hudson implemented new tree-related specifications to clear as much foliage from ground to sky as feasible. See Section 3.5.4.1 for additional efforts to improve vegetation management.

Damage to vegetation caused by the Emerald Ash Borer has become a problem in recent years. As stated previously in section 3.5.4.1, Central Hudson requested significant additional funding for distribution vegetation management (a total of approximately $26M annual funding). While only a portion of the additional dollars requested was approved (a total of approximately $20M annual funding), Central Hudson saw a positive impact to tree-related SAIFI as a result of the increased funding. In 2019, tree-related SAIFI showed a significant improvement, coming in at 9% lower compared to 2018 and 8% lower than the 5-year average. Central Hudson saw a significant positive impact to tree-related SAIFI in 2020 on the circuits where danger tree removal was performed; however, poorer performance on the remainder of the system lead to an overall SAIFI increase in the tree contact category. This trend continued into 2021 and potential reliability improvements were overshadowed by tree contact outages from an exceptionally high number of minor storms that did not qualify for Code 1 status. Distribution Engineering continues to work in conjunction with Line Clearance to identify the worst performing circuits that should be targeted for danger tree removal. As part of the November 2021 rate agreement, $2.5M was provided for each of the three rate years to continue addressing danger trees.

3.6.5 Emergency Response and Repair

Comprehensive emergency plans by utilities minimize the duration of weather-related outages and ensure that all key stakeholders remain informed of the utility’s actions before and during the event. Central Hudson has a complete Electric Emergency Plan that can be expanded to meet the requirements of any situation. The plan is reviewed and updated on an annual basis. Central Hudson conducts annual training and storm drills to ensure that modifications to the plan are effective and to ensure that employees understand their responsibilities during a major event.

3.6.6 Weather Prediction Tools

Central Hudson commenced work with FleetWeather on a storm prediction model in 2008. FleetWeather delivered several preliminary reports based on correlating weather data with historical outages. The study also determined that the weather data available in the Hudson Valley region was not sufficient to provide the data for a good storm prediction model, and recommended the installation of 24 weather stations. The installation of these weather stations was completed in 2012 and provides another source of weather data for the Central Hudson service territory.

Between 2016 and 2018, Central Hudson funded an R&D project to create an outage prediction tool in collaboration with researchers from the SUNY Center of Excellence at University of Albany. Central Hudson provided archived outage data and industry knowledge, while the SUNY team created an outage prediction tool based on weather forecasts and statistical modeling. Following a thorough comparison of outage predictions versus actual outages, it was determined that the model was not sufficiently accurate for production deployment. Work on this model ended with the conclusion of the R&D project. At this time, the Central Hudson Electric Emergency Plan does not dictate the use of any outage prediction model, nor is the legacy University of Albany model employed in any storm preparation activities. Although the 2016-2018 effort did not yield a successful outage prediction model, the project led to an ongoing and cordial relationship between Central Hudson, the SUNY Center for Excellence at University of Albany, and the NYS Mesnonet.

Central Hudson is currently working on a research and development project with the University of Albany and Electric Distribution Design, which leverages existing NYS Mesonet data and other data sources to create a Load, PV Generation, and Outage (LPO) prediction tool to support forecasts of extreme weather changes and/or rapid changes in generation. This project is in progress and anticipated to be completed in 2023.

3.6.7 Future Plans

Central Hudson is in the process of engaging a consultant to assess Central Hudson's routine trimming and hazard tree removal programs and provide additional recommendations for improvement. This is part of a longer-term initiative to decrease SAIFI caused by tree contacts that also includes optimization of the routine tree trimming program based on engineering analysis and a continuation of the hazard tree program.

Additionally, in response to Assembly Bill A8763, Central Hudson will be preparing a Climate Change Vulnerability Study for submission by September 22, 2023 to the Public Service Commission. This study shall evaluate Central Hudson's infrastructure, design specifications and procedures in order to better understand vulnerability to climate-driven risks, and to propose adaptation measures in order to address those vulnerabilities. Within 60 days from submission of the Climate Change Vulnerability Study, Central Hudson shall additionally submit a Climate Resilience Plan detailing storm hardening and resiliency measures to be implemented over the next 10 years and 20 years. This plan will describe how Central Hudson will incorporate climate change into its design, operations, and emergency response, as well as how the Company will manage climate change risk.

3.6.8 Summary

Central Hudson has many operating practices, procedures, and programs in place to improve grid resiliency and perform storm hardening. However, Central Hudson continuously seeks to improve its processes and investigate innovations to mitigate the impact of weather events. Central Hudson is committed to performing further storm hardening via programs that target areas with aging infrastructure and poor reliability using a data-driven approach.

4. Grid Modernization

4.1 Background

Central Hudson's Grid Modernization Program is comprised of the six major components listed below. Taken together these projects are a key Central Hudson initiative that will help create a smarter grid that will meet the changing energy landscape and prepare for the operating needs of the future. Distribution Automation, Distribution Management System, and Network Communications Strategy are discussed further in this section.

- Distribution Automation (DA) – automated devices and distribution infrastructure (poles and wires)
- ESRI System Model Geographic Information System (GIS) - provides a single consolidated mapping and visualization system
- Advanced Distribution Management System (DMS) – the centralized software "brains"
- Distribution System Operations (DSO) – the organization responsible for monitoring and controlling the electric distribution system through the use of the DMS
- Network Communications Strategy (NS) – the two-way communication system between the DA devices and DMS.
- Substation Metering Infrastructure – Substation feeder metering upgrades required for accurate ADMS power flow calculations.

Central Hudson began implementing this centralized Grid Modernization Program over the past seven years. This program aims to reduce customer bill pressure, improve system safety and efficiency, improve customer reliability and better prepare Central Hudson for the changing energy landscape including the proliferation of Distributed Energy Resources ("DERs").

Approximately 800 Intelligent Electronic Devices (IED; e.g. electronic reclosers, switched capacitors, and voltage regulating devices) and sensors are being installed through Distribution Automation and other programs along with associated Network Strategy communication equipment in order to provide real time data to the DMS. This will allow the system to become a centralized decision maker based on real time system conditions.

Please see the Distribution System Implementation Plan (DSIP), Sections III Integrated Planning and V Grid Operations, filed on June 30, 2020 for additional information.

4.2 Long Range Plan (2022-2027)

The Grid Modernization Program has made significant progress since its inauguration. The following items summarize the current progress of the program:

Distribution Automation

- Field installations of DA devices have been completed in the Fishkill area (Phase I and II).
- Field installations of DA devices have been completed in the Newburgh area (Phase I and II).

- Field installations of DA devices will be completed in the Poughkeepsie area (Phase I and II) in 2022.
- A portion of the Catskill DA devices will be installed in 2022. The remainder will be installed in 2023.
- A portion of the Kingston DA devices in Phase I will be installed in 2022. The remainder will be installed in 2023. The Kingston DA devices in Phase II will be installed in 2024.

Distribution Management System

- The DMS Factory Acceptance Testing was completed in 2021.
- The DMS Site Acceptance Testing was completed in 2021.
- The DMS 'Go-Live' milestone was reached in 2022.
- The final commissioning of the DMS is ongoing.

Network Communications Strategy

- A majority of the Tier 2 network has been completed in the Fishkill district.
- A majority of the Tier 2 network has been completed in the Newburgh district except for installing TropOS 1420 radios at Distribution Automation Devices.
- A majority of the Poughkeepsie Tier 2 network will be completed in 2022.
- A majority of the Catskill Tier 2 network will be completed in 2025 or later depending on funding.
- A majority of the Kingston Tier 2 network will be completed in 2025 or later depending on funding.

OMS/Control Center Implementation

- The Outage Management System (OMS) features of the DMS will be implemented and the beginning of the transition away from the legacy OMS is expected to take place in 2022. The scheduled in-service date is 2023.
- Construction for the new Primary Control Center for Transmission and Distribution System Operations is expected to start in 2022. Once complete, the Distribution System Operations organization is expected to be fully staffed. The facility is planned to be fully in-service in 2024.

5. Long Term System Load Forecast[6]

5.1 Introduction

The upgrade of facilities or the construction of new facilities may be driven by regulatory compliance, aging infrastructure, or load growth. This section describes the load growth scenarios that assist Central Hudson in identifying areas that may require further study. As described in more detail in Section 5.3, Central Hudson is transitioning to a probabilistic forecasting approach.

For this probabilistic approach, Central Hudson's consultant, Demand Side Analytics, performed a historic analysis of substation growth patterns as well as a probabilistic forecast of Central Hudson's distribution substations using hourly load data from 2014 through 2019.

The historic load patterns were estimated using econometric models designed to disentangle year by year growth rates from differences in weather patterns, day of week effects, and seasonality. The forecasts utilized *Monte-Carlo* simulations to predict potential load growth based on the historic analysis.

5.2 Description of Load Groups

Central Hudson's distribution substations have been categorized into 10 different load groups, as follows:

#	Name	Substations	#	Name	Substations
1	Northwest	Coxsackie Freehold Lawrenceville North Catskill New Baltimore South Cairo Westerlo	6	Northeastern Dutchess	East Park Milan Rhinebeck Staatsburg Millerton Pulvers Corners Smithfield Stanfordville Tinkertown Hibernia
2	Kingston - Saugerties	Boulevard Cement Companies East Kingston Hurley Avenue Lincoln Park Saugerties Woodstock	7	Poughkeepsie	Todd Hill Inwood Avenue Manchester Reynolds Hill Spackenkill

6 Load forecasts within this section are based on analysis completed in 2020. Forecasts are currently completed every two years to coincide with the development of Central Hudson's DSIP filing and a new Avoided T&D Cost Study. The updated analysis was planned for completion by June of 2022 to inform this plan. Due the deferral of the DSIP filing, the updated analysis and new Avoided T&D Cost Study is planned for completion in the second half of 2022. The results of this analysis may result in changes to some of the plans.

3	Ellenville	High Falls Honk Falls Kerhonkson Clinton Avenue Greenfield Road Grimley Road Neversink Sturgeon Pool	8	Fishkill	Knapps Corners Myers Corners Sand Dock Tr. 4 Trap Rock North Chelsea Fishkill Plains Forgebrook Merritt Park Shenandoah Tr. 7 Tioronda
4	Modena	Galeville Highland Modena Ohioville	9	Large Customer-Poughkeepsie	Barnegat Sand Dock (not Tr. 4)
5	Newburgh	Coldenham East Walden Maybrook Montgomery Bethlehem Road Marlboro Union Avenue West Balmville	10	Large Customer-Fishkill	Shenandoah (not Tr.7) Wiccopee
Note: Transmission System areas may include substations from only one load group or may include portions of several load groups.					

These groupings were selected largely based on the ability to transfer load among the various substations in a group. By grouping the distribution substations this way, changes in individual substation loadings due to load transfers could be excluded from any calculated growth rate since the load still would be supplied from a substation within the group.

5.3 Substation Loading Forecast Spreadsheet

The following table is used as a screening tool for the Distribution Planning department to identify areas that may become deficient and require System Planning Studies; this screening tool, by itself, is not used to determine the need for a reinforcement. The individual substation growth rates are taken from the historic load pattern analysis performed by Demand Side Analytics. As indicated, Central Hudson has transitioned to probabilistic forecasting techniques. The table below utilizes a deterministic methodology and is utilized as high-level screening tool/reference. Where hourly data was not available for a specific substation, the results of analyses for the transmission area where the substation is located were utilized.

	Substation	Type	MVA Rating		Growth Rate	MVA 2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
	Northwest Load Group																				
1	Coxsackie	13.2 kV	16.4		2.80%	12.0	12.3	12.7	13.0	13.4	13.8	14.2	14.6	15.0	15.4	15.8	16.3	16.7	17.2	17.7	18.2
1	Freehold	13.2 kV	15.78		3.50%	7.5	7.8	8.1	8.4	8.7	9.0	9.3	9.6	9.9	10.3	10.6	11.0	11.4	11.8	12.2	12.6
1	Hunter	13.2 kV	19.53	F	-5.20%	4.2	4.0	3.8	3.6	3.4	3.2	3.1	2.9	2.7	2.6	2.5	2.3	2.2	2.1	2.0	1.9
1	Lawrenceville	34.5 kV	19.272		-4.50%	6.4	6.1	5.8	5.5	5.3	5.0	4.8	4.6	4.4	4.2	4.0	3.8	3.7	3.5	3.3	3.2
1	New Baltimore	13.2 kV	25.8		5.60%	11.9	12.6	13.3	14.0	14.8	15.6	16.5	17.4	18.4	19.5	20.5	21.7	22.9	24.2	25.5	27.0
1	North Catskill	13.2 kV	35.12	F	0.40%	24.3	24.4	24.5	24.6	24.7	24.8	24.9	25.0	25.1	25.2	25.3	25.4	25.5	25.6	25.7	25.8
1	South Cairo	13.2 kV	19.9		2.50%	13.1	13.4	13.8	14.1	14.5	14.8	15.2	15.6	16.0	16.4	16.8	17.2	17.6	18.1	18.5	19.0
1	Vinegar Hill	34.5 kV	18.8		0.30%	9.3	9.3	9.4	9.4	9.4	9.4	9.5	9.5	9.5	9.6	9.6	9.6	9.6	9.7	9.7	9.7
1	Westerlo	13.2kV	32.16		1.00%	8.1	8.2	8.3	8.4	8.5	8.6	8.6	8.7	8.8	8.9	9.0	9.1	9.2	9.3	9.4	9.5
	Kingston-Saugerties Load Group																				
2	Boulevard	14.4 kV	35	F	-3.90%	18.7	17.9	17.2	16.6	15.9	15.3	14.7	14.1	13.6	13.1	12.5	12.1	11.6	11.1	10.7	10.3
2	Converse Street	4 kV	7.071	F	-3.90%	3.1	2.9	2.8	2.7	2.6	2.5	2.4	2.3	2.2	2.1	2.1	2.0	1.9	1.8	1.8	1.7
2	East Kingston	13.2 kV	47.97	F	-0.70%	16.0	15.9	15.8	15.7	15.5	15.4	15.3	15.2	15.1	15.0	14.9	14.8	14.7	14.6	14.5	14.4
2	Hurley Avenue	13.2 kV	23.1	F	1.20%	17.9	18.1	18.3	18.5	18.7	19.0	19.2	19.4	19.7	19.9	20.1	20.4	20.6	20.9	21.1	21.4
2	Jansen Avenue	13.2 kV	8	F	-1.40%	5.4	5.4	5.3	5.2	5.1	5.1	5.0	4.9	4.9	4.8	4.7	4.7	4.6	4.5	4.5	4.4
2	Lincoln Park	14.4 kV	84	F	-1.40%	35.8	35.3	34.8	34.4	33.9	33.4	32.9	32.5	32.0	31.6	31.1	30.7	30.3	29.8	29.4	29.0
2	Saugerties	13.2 kV	54.112	F	-0.20%	21.6	21.6	21.5	21.5	21.4	21.4	21.3	21.3	21.3	21.2	21.2	21.1	21.1	21.0	21.0	21.0
2	South Wall Street	4 kV	5.765		-3.90%	2.0	1.9	1.8	1.8	1.7	1.6	1.6	1.5	1.5	1.4	1.3	1.3	1.2	1.2	1.1	1.1
2	Woodstock	13.2 kV	20.9	F	1.70%	20.4	20.8	21.1	21.5	21.9	22.2	22.6	23.0	23.4	23.8	24.2	24.6	25.0	25.5	25.9	26.3
	Ellenville Load Group																				
3	Clinton Avenue	4 kV	7.687		3.60%	1.0	1.1	1.1	1.1	1.2	1.2	1.3	1.3	1.4	1.4	1.5	1.5	1.6	1.6	1.7	1.7
3	Greenfield Road	13.2 kV	15.375		2.40%	8.1	8.3	8.5	8.7	8.9	9.1	9.3	9.5	9.8	10.0	10.2	10.5	10.7	11.0	11.3	11.5
3	Grimley Road	13.2 kV	7.171	F	1.80%	4.9	5.0	5.1	5.2	5.3	5.4	5.5	5.6	5.7	5.8	5.9	6.0	6.1	6.2	6.3	6.4
3	High Falls	13.2 kV	34.5	F	1.00%	19.0	19.2	19.4	19.6	19.8	20.0	20.2	20.4	20.6	20.8	21.0	21.2	21.4	21.6	21.8	22.1
3	Honk Falls	13.2 kV	18.2		-1.90%	5.7	5.6	5.5	5.4	5.3	5.2	5.1	5.0	4.9	4.8	4.7	4.6	4.5	4.4	4.3	4.3
3	Kerhonkson	13.2 kV	44.6	F	4.80%	10.4	10.9	11.4	12.0	12.6	13.2	13.8	14.5	15.1	15.9	16.6	17.4	18.3	19.1	20.1	21.0
3	Neversink	13.2 kV	4.92		0.90%	3.5	3.6	3.6	3.6	3.7	3.7	3.7	3.8	3.8	3.8	3.9	3.9	3.9	4.0	4.0	4.0
3	Neversink	4 kV	2.46		0.90%	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5
3	Sturgeon Pool	13.2 kV	29.7		3.80%	2.6	2.7	2.8	2.9	3.0	3.1	3.2	3.3	3.4	3.6	3.7	3.9	4.0	4.2	4.3	4.5
	Modena Load Group																				
4	Galeville	13.2 kV	28.7	F	1.80%	11.0	11.2	11.4	11.6	11.8	12.0	12.2	12.5	12.7	12.9	13.2	13.4	13.6	13.9	14.1	14.4
4	Highland	13.2 kV	32.93	F	0.90%	21.4	21.6	21.8	22.0	22.2	22.4	22.6	22.8	23.0	23.2	23.4	23.7	23.9	24.1	24.3	24.5
4	Modena	13.2 kV	21.1	F	2.10%	15.0	15.3	15.7	16.0	16.3	16.7	17.0	17.4	17.7	18.1	18.5	18.9	19.3	19.7	20.1	20.5
4	Ohioville	13.2 kV	29.68	F	0.00%	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4
	Newburgh Load Group																				
5	Bethlehem Road	13.2 kV	47.8	F	-0.60%	36.7	36.5	36.2	36.0	35.8	35.6	35.4	35.2	35.0	34.8	34.5	34.3	34.1	33.9	33.7	33.5
5	Coldenham	13.2 kV	47.8	F	-2.10%	25.2	24.7	24.1	23.6	23.1	22.6	22.2	21.7	21.2	20.8	20.4	19.9	19.5	19.1	18.7	18.3
5	East Walden	13.2 kV	26.17		0.70%	15.5	15.7	15.8	15.9	16.0	16.1	16.2	16.3	16.4	16.6	16.7	16.8	16.9	17.0	17.1	17.3
5	Marlboro	13.2 kV	30.91	F	2.30%	21.4	21.9	22.4	22.9	23.5	24.0	24.6	25.1	25.7	26.3	26.9	27.5	28.1	28.8	29.5	30.1
5	Maybrook	13.2 kV	20.9	F	4.30%	20.1	20.9	21.8	22.8	23.7	24.8	25.8	26.9	28.1	29.3	30.6	31.9	33.3	34.7	36.2	37.7
5	Montgomery	13.2 kV	19.5	F	0.70%	7.9	8.0	8.0	8.1	8.1	8.2	8.3	8.3	8.4	8.4	8.5	8.5	8.6	8.7	8.7	8.8
5	Montgomery Street	13.2 kV	15.4	F	0.60%	5.0	5.0	5.1	5.1	5.1	5.2	5.2	5.2	5.2	5.3	5.3	5.3	5.4	5.4	5.4	5.5
5	Montgomery Street	4 kV	9.056	F	0.60%	4.9	4.9	4.9	4.9	5.0	5.0	5.0	5.1	5.1	5.1	5.2	5.2	5.2	5.2	5.3	5.3
5	Union Avenue	14.4 kV	94.482	F	2.00%	65.8	67.1	68.4	69.8	71.2	72.6	74.1	75.5	77.1	78.6	80.2	81.8	83.4	85.1	86.8	88.5
5	West Balmville	14.4 kV	47.8	F	0.60%	35.4	35.6	35.8	36.0	36.2	36.5	36.7	36.9	37.1	37.3	37.6	37.8	38.0	38.2	38.5	38.7

	Substation	Type	MVA Rating		Growth Rate	MVA 2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
	Northeastern Dutchess Load																				
6	Ancram	13.2 kV	4.65		0.90%	1.5	1.5	1.5	1.5	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.7	1.7	1.7	1.7	1.7
6	East Park	13.2 kV	24.2		1.20%	13.9	14.0	14.2	14.4	14.5	14.7	14.9	15.1	15.2	15.4	15.6	15.8	16.0	16.2	16.4	16.6
6	Hibernia	13.2 kV	17.84		2.70%	13.2	13.5	13.9	14.2	14.6	15.0	15.4	15.8	16.3	16.7	17.2	17.6	18.1	18.6	19.1	19.6
6	Milan	13.2 kV	25.86		3.00%	9.2	9.5	9.8	10.1	10.4	10.7	11.0	11.3	11.7	12.0	12.4	12.8	13.2	13.5	14.0	14.4
6	Millerton	13.2 kV	8.3		1.00%	4.7	4.8	4.8	4.9	4.9	5.0	5.0	5.1	5.1	5.2	5.2	5.3	5.3	5.4	5.4	5.5
6	Pulvers Corners	13.2 kV	5.765		2.30%	5.5	5.6	5.7	5.9	6.0	6.1	6.3	6.4	6.6	6.7	6.9	7.0	7.2	7.4	7.5	7.7
6	Pulvers Corners	34.5 kV	17.21		0.90%	2.9	2.9	3.0	3.0	3.0	3.0	3.1	3.1	3.1	3.1	3.2	3.2	3.2	3.3	3.3	3.3
6	Rhinebeck	13.2 kV	47.8	F	0.10%	26.3	26.3	26.4	26.4	26.4	26.5	26.5	26.5	26.5	26.6	26.6	26.6	26.6	26.7	26.7	26.7
6	Smithfield	13.2 kV	7.077		-2.40%	1.8	1.8	1.7	1.7	1.6	1.6	1.6	1.5	1.5	1.4	1.4	1.4	1.3	1.3	1.3	1.3
6	Staatsburgh	13.2 kV	26.5		1.70%	9.1	9.3	9.4	9.6	9.7	9.9	10.1	10.2	10.4	10.6	10.8	11.0	11.1	11.3	11.5	11.7
6	Stanfordville	13.2 kV	17.92		3.30%	3.9	4.0	4.1	4.3	4.4	4.6	4.7	4.9	5.0	5.2	5.4	5.5	5.7	5.9	6.1	6.3
6	Tinkertown	13.2 kV	19.125	F	1.10%	14.7	14.8	15.0	15.2	15.3	15.5	15.7	15.8	16.0	16.2	16.4	16.6	16.7	16.9	17.1	17.3
	Poughkeepsie Load Area																				
7	Inwood Avenue	13.2 kV	51.22	F	0.60%	27.7	27.9	28.1	28.2	28.4	28.6	28.8	28.9	29.1	29.3	29.5	29.6	29.8	30.0	30.2	30.4
7	Manchester	14.4 kV	47.8	F	1.30%	31.0	31.4	31.8	32.2	32.6	33.0	33.5	33.9	34.3	34.8	35.2	35.7	36.2	36.6	37.1	37.6
7	Reynolds Hill	14.4 kV	47.8	F	1.60%	40.3	40.9	41.6	42.3	42.9	43.6	44.3	45.0	45.7	46.5	47.2	48.0	48.7	49.5	50.3	51.1
7	Spackenkill	13.2 kV	47.8	F	-0.80%	33.9	33.7	33.4	33.1	32.9	32.6	32.3	32.1	31.8	31.6	31.3	31.1	30.8	30.6	30.3	30.1
7	Todd Hill	13.2 kV	47.8	F	0.20%	25.6	25.6	25.7	25.7	25.8	25.8	25.9	25.9	26.0	26.0	26.1	26.1	26.2	26.3	26.3	26.4
	Fishkill Load Group																				
8	Fishkill Plains	13.2 kV	47.8	F	1.30%	44.4	45.0	45.6	46.1	46.7	47.4	48.0	48.6	49.2	49.9	50.5	51.2	51.8	52.5	53.2	53.9
8	Forgebrook	14.4 kV	47.425	F	0.00%	28.6	28.6	28.6	28.6	28.6	28.6	28.6	28.6	28.6	28.6	28.6	28.6	28.6	28.6	28.6	28.6
8	Knapps Corners	14.4 kV	47.8	F	-1.60%	17.7	17.5	17.2	16.9	16.6	16.4	16.1	15.9	15.6	15.3	15.1	14.9	14.6	14.4	14.2	13.9
8	Merritt Park	13.2 kV	51.15	F	-0.50%	29.8	29.7	29.5	29.4	29.2	29.1	28.9	28.8	28.6	28.5	28.4	28.2	28.1	27.9	27.8	27.6
8	Myers Corners	13.2 kV	35.12	F	-1.90%	19.6	19.2	18.9	18.5	18.2	17.8	17.5	17.1	16.8	16.5	16.2	15.9	15.6	15.3	15.0	14.7
8	North Chelsea	13.2 kV	48.27	F	0.10%	19.6	19.6	19.6	19.6	19.7	19.7	19.7	19.7	19.7	19.7	19.8	19.8	19.8	19.8	19.8	19.9
8	Sand Dock	13.2 kV	8		2.80%	4.5	4.7	4.8	4.9	5.1	5.2	5.3	5.5	5.7	5.8	6.0	6.1	6.3	6.5	6.7	6.9
8	Shenandoah	13.2 kV	18		1.10%	12.9	13.1	13.2	13.3	13.5	13.6	13.8	13.9	14.1	14.2	14.4	14.6	14.7	14.9	15.0	15.2
8	Tioronda	13.2 kV	25.74		1.70%	15.9	16.2	16.5	16.8	17.0	17.3	17.6	17.9	18.2	18.5	18.9	19.2	19.5	19.8	20.2	20.5

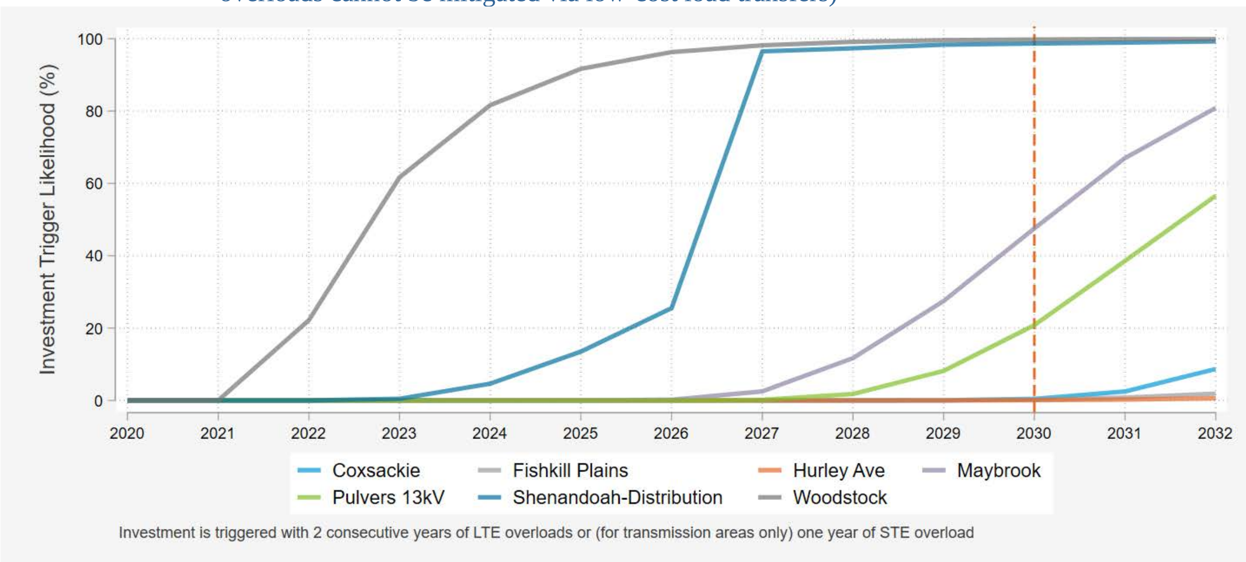
TOTAL:	**1058.3**

5.4 Probabilistic Load Forecast

As described previously, Demand Side Analytics performed a probabilistic forecast of Central Hudson's substation loads. These forecasts utilized *Monte-Carlo* simulations for each substation where load data was available. The probabilistic forecast is utilized as part the *2020 Central Hudson Location Specific Transmission and Distribution Avoided Costs Using Probabilistic Forecasting and Planning Methods Study* ("Avoided T & D Cost Study"). Within this study, a simulation was counted as needing an investment when an area's forecast load exceeded the area's LTE rating for two consecutive years or its STE rating for any one year.

As shown in the following chart, these analyses determined the potential for several substations (Shenandoah – Distribution, Woodstock, Maybrook, and Pulvers 13.8 kV) to require an upgrade due to load growth at the end of the 10-year planning horizon.

Probability of Growth Related Substation Infrastructure Upgrade
(Shenandoah-Distribution is the only location with risk of at least 5% where overloads cannot be mitigated via low-cost load transfers)



As detailed within the referenced Avoided T&D Cost Study, there are relatively low cost switching options that can be utilized to address the need for upgrades at three of these substations - Woodstock, Maybrook, and Pulvers 13.8 kV.

5.5 Probabilistic Planning Methodology

While the Electric System Forecasting function to provide for the safe and reliable operation of the system will remain, the tools applied and the complexity of the process is rapidly evolving. Central Hudson's all-time peak electric load was 1295 MW in 2006. The load has declined significantly since that time due to a downturn in the economy and industry leaving the Hudson Valley region, as well as the proliferation of DERs, including energy efficiency and solar photovoltaics. Currently, interconnection of DERs is evaluated separately from the long-term planning process. With the increased penetration of DERs, application of a linear forecast with engineering knowledge and judgment may be insufficient to recognize the range of potential generation and load scenarios. As a result, Central Hudson is currently working to bring Demand Side Analytics' probabilistic forecasting tool in-house in order to enable the Electric Planning and Interconnections team to compute probabilistic forecasting for load and DERs internally. DER forecasts will consider not only technical drivers of load shapes, but current and anticipated policy decisions and interconnection queues that will impact the penetration of DERs. Load forecasts will also consider the effects of potential large, lumped loads (i.e., commercial or industrial customers). Along with a probabilistic approach, this will provide Central Hudson with an improved ability to assess future system needs and develop alternatives and a final solution.

Please see the Distribution System Implementation Plan, Sections III Integrated Planning and IV Advanced Forecasting, filed on June 30, 2020 for additional information.

6. Transmission (Category 12) and Substation (Category 13) Areas

6.1 Introduction

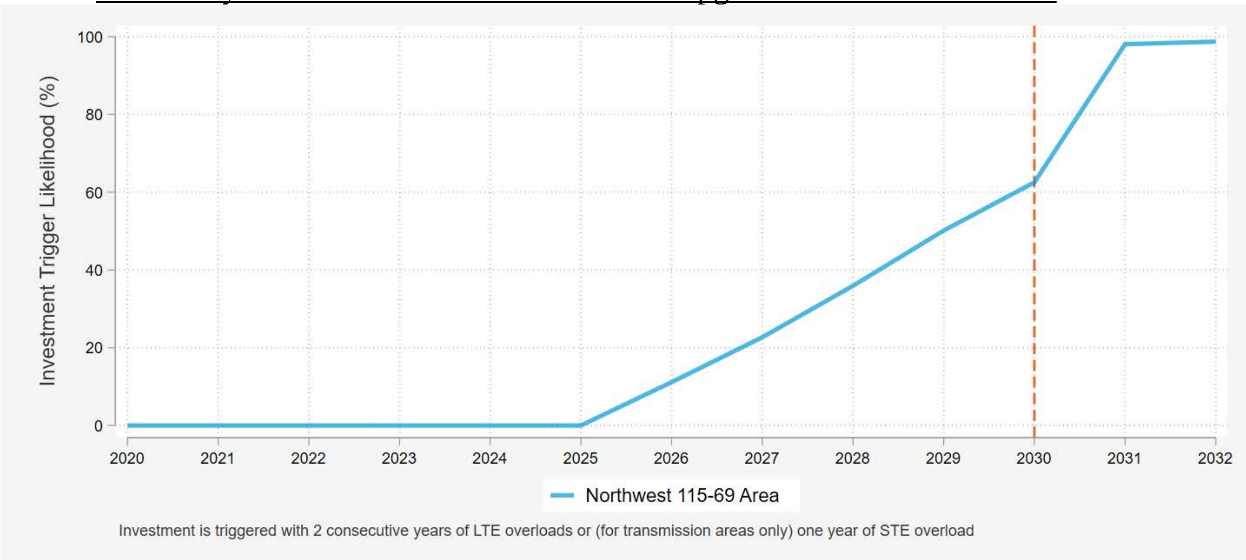
This section outlines the long-term plans for all areas of the transmission network. The long-term plans are based on current information, system conditions and load forecasts and, as such, are subject to change as additional information is obtained. Also, certain areas are in the process of being studied and modifications to the long-term plan may be made as a result of these studies.

6.2 Probabilistic Load Forecast

During 2020, Central Hudson's consultant, Demand Side Analytics, performed a probabilistic forecast of Central Hudson's transmission areas using hourly load data from 2014 through 2019. Updated analyses are completed every two years to coincide with the development of Central Hudson's DSIP filing and new Avoided T & D Cost Study. The updated analysis was planned for completion by June of 2022 to inform this plan. Due the deferral of the DSIP filing, the updated analysis and new Avoided T & D Cost Study is planned for completion in the second half of 2022. The results of this analysis may result in changes to some of plans outlined within this document. These forecasts utilized *Monte-Carlo* simulations for each transmission area. The probabilistic forecast is utilized as part the Avoided T & D Cost Study. Within the Avoided T & D Cost Study, a simulation was counted as needing an investment when an area's forecast load exceeded the area's LTE rating for 2 consecutive years or its STE rating for any 1 year.

As shown in the following chart, these analyses determined the potential for one transmission area (Northwest 115-69 kV) to require an upgrade due to load growth at the end of the 10 year planning horizon.

Probability of Growth Related Infrastructure Upgrade: Transmission Areas



6.3 Load Serving Capability (LSC)

The 115/69 kV transmission network is evaluated using the LSC analysis. Electric Transmission Planning performs system LSC analyses for both the existing and planned Transmission System; LSC analyses also are performed for various levels of internal generation. As a simple example of LSC determination, the ability of an individual substation to serve load may be easily calculated. For a typical two transformer distribution substation, the substation's LSC is set by the lowest transformer summer Long Term Emergency (LTE) rating. In this case, the LSC is based on the ability of a single transformer to serve load should the other substation transformer fail.

Similarly, determination of the LSC for "looped" local transmission systems with only two transmission inputs is similar to determination of LSC for a two transformer distribution substation; the transmission line with the lowest summer LTE rating typically sets the LSC for the area. For looped transmission systems, however, the LSC may be set by a more limiting internal element or by a voltage limit/constraint.

For the 115 kV and 69 kV transmission system as a whole, the determination of System Load Serving Capability is described in Section 3.5.1.1 of Central Hudson's Electric System Planning Guides.

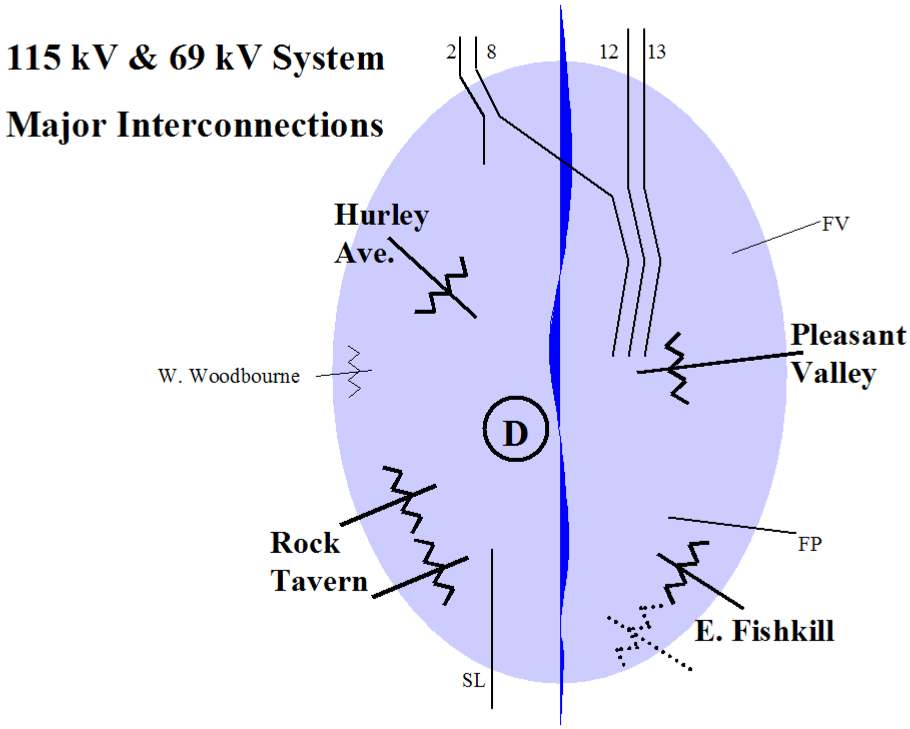
6.3.1 115/69 kV Transmission Network

The LSC of Central Hudson's transmission system is its import capability plus the available internal generation as defined in Central Hudson Gas & Electric Corporation's "Transmission Planning Guidelines." LSC is constrained by violation of a thermal or voltage limit following the contingencies specified in the "Transmission Planning Guidelines."

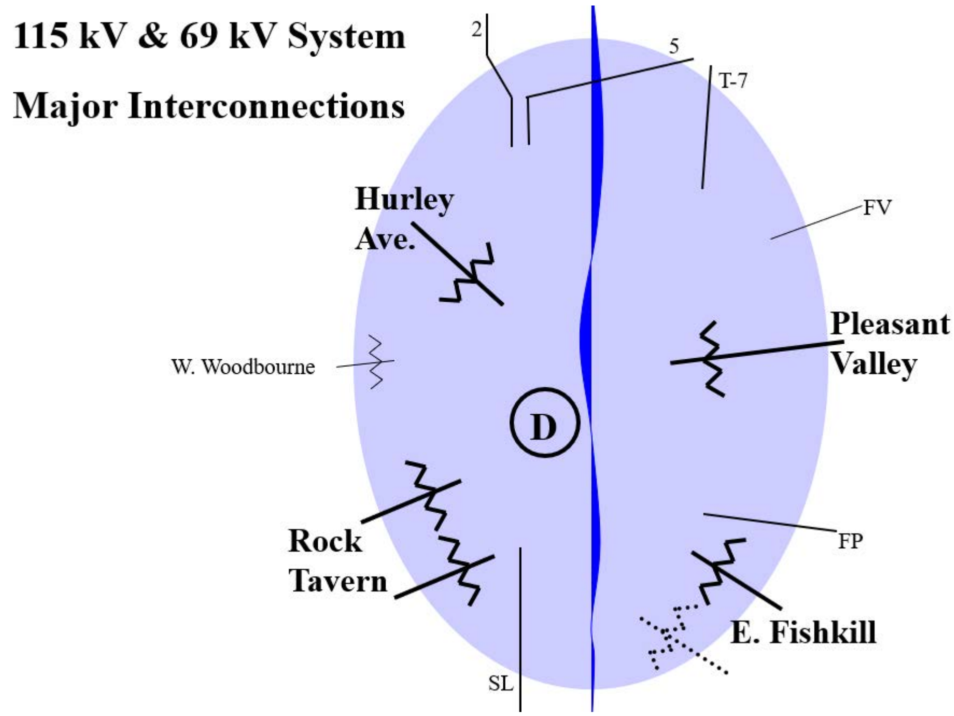
6.3.1.1 Summary of Issues

- Reference: EP2021-005 System Load Serving Capability

The major 115 kV & 69 kV interconnections supplying Central Hudson's system are shown in the picture below:



The following figure illustrates the major 115 kV & 69 kV interconnections supplying Central Hudson's system after the completion of NY Transco Segment B Transmission Project. Segment B is expected to be completed by May 2023.



Central Hudson's all-time high summer peak load was 1295 MW on August 2, 2006; summer peak loads for the last 10 years are shown in the following table:

Year	Date of Summer Peak	MW
2021	June 29 @ 1900	1148
2020	July 27 @ 1900	1142
2019	July 20 @ 1800	1109
2018	July 2 @ 1800	1114
2017	July 20 @ 1700	1034
2016	August 13 @ 1800	1088
2015	July 29 @ 1800	1059
2014	July 23 @ 1500	1060
2013	July 18 @ 1700	1202
2012	July 17 @ 1800	1168

The existing system zero Danskammer LSC (i.e., the LSC with no Danskammer generation) is limited by the 115 kV EF line station connections following the loss of the 115 kV M line at a system load of approximately 1470 MW. After the completion of the NY Transco Segment B and SL line projects, the zero Danskammer LSC will decrease to 1290 MW, limited by the 115 kV HF line station connections following the loss of the 115 kV EF line.

6.3.1.2 Summary of Recommendations

Due to the reduction of LSC following the NY Transco Segment B and SL line projects, it is recommended to upgrade the station connections at the East Fishkill Substation, Shenandoah Substation and Fishkill Plains Substation prior to the completion of the projects, which is scheduled for May 2023. The station connection upgrades will increase the system zero Danskammer LSC to 1495 MW, limited by the 115 kV HF line conductor for loss of the 115 kV EF line.

6.4 Individual Transmission Areas

6.4.1 Northwest 115/69 kV System

6.4.1.1 Summary of Issues

- Reference: EP2015-003 H&SB Lines

The transmission supply to the Northwest 115/69 kV area is from two 115 kV sources (National Grid's '2' line and 'T-7' line) and a 69 kV source (SB line). In the past, the '2' line has been at or above its summer normal rating, pre-contingency. Installation of reactors at North Catskill in series with the '2' line has mitigated these high flow conditions. The proposed 100 MW Flint Mine Photovoltaic facility in the Coxsackie area has the potential to increase 2 line flows depending on their point of interconnection; to interconnect, the developer will need to build a 5 breaker ring bus connecting both 8 and 2 lines.

The NY Transco Segment B Transmission Project will also reconfigure the North Catskill T-7 line terminal to be designated the 5 line and rerouted to the new Churchtown Substation; the T-7 will become Churchtown to Milan.

H & SB Lines
The 69 kV H & SB lines supply the North Catskill, Saugerties, Woodstock and Hurley Avenue Substations. The H & SB lines were built in 1919. Condition assessments have indicated that the lines have sufficient structural issues to warrant rebuild.

Woodstock Transmission Reserve
The only transmission supply to the Woodstock area is the 69 kV 'SR' line. Due to the amount of load served from Woodstock (2021 coincident peak = 18.2 MW), it is difficult to reserve the Woodstock Substation through existing distribution ties on peak.

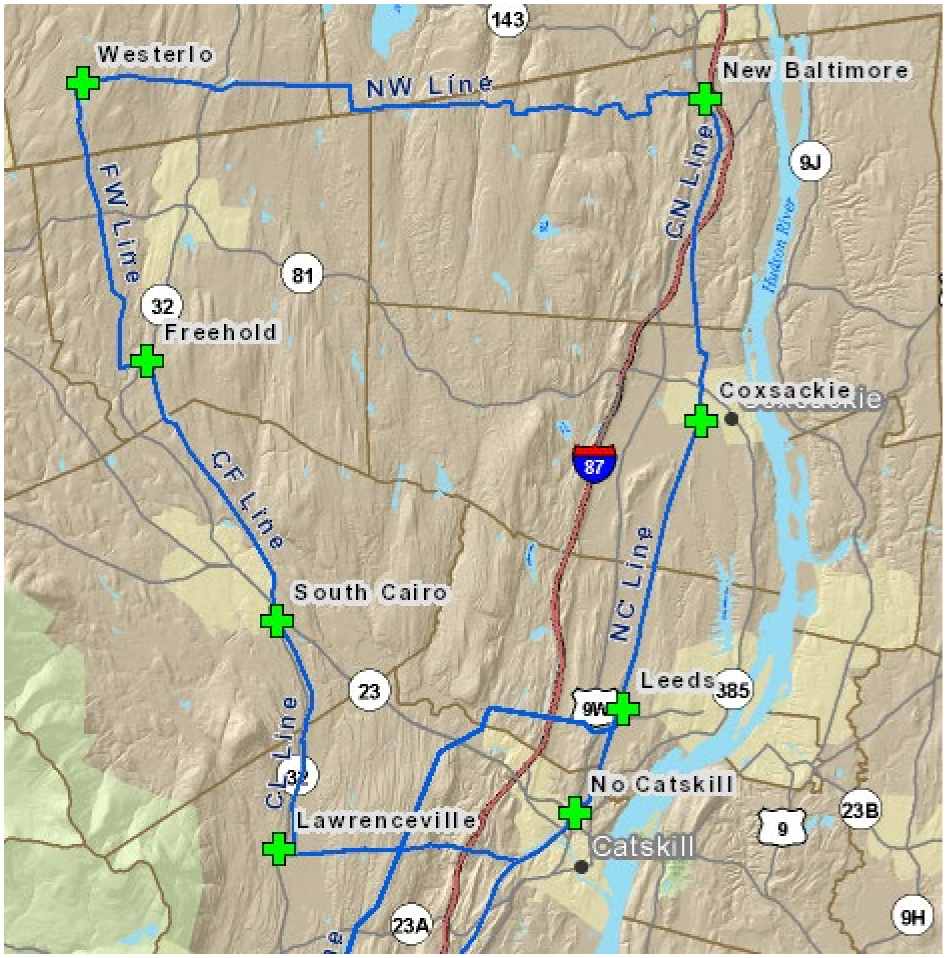
6.4.1.2 Summary of Recommendations

H & SB Lines
The H & SB lines will be rebuilt for 115 kV but continue to operate at 69 kV. This reinforcement is necessary due to infrastructure needs; however, by itself it is insufficient to provide for additional Northwest 115/69 kV area load (if any). An Article VII filing was submitted to the PSC in 2017 for the rebuild of the lines. The lines are scheduled to be rebuilt starting in 2022 and are scheduled to be completed in 2025.

Woodstock Transmission Reserve
While a second transmission supply to the Woodstock Substation would increase area reliability, no transmission reinforcement is being considered at this time. Instead, a distribution Smart Grid solution is being pursued (see Section 7.3.1).

6.4.2 Westerlo Loop

Two 69 kV transmission lines (CL line and NC line) supply the Westerlo Loop along with the Coxsackie and South Cairo generators.



Peak loads for the last ten years are shown in the following tables. The winter peaks, can be reduced by 7-8 MW if the Hunter Mountain Ski Bowl is transferred to Vinegar Hill or is requested to stop making snow.

Year	Date of Summer Peak	MW	MVAr	MVA
2021	June 29 @ 1900	56.5	-1.4	56.5
2020	July 27 @ 1900	60.9	2.5	60.9
2019	July 20 @ 1800	61.0	-3.3	61.1
2018	July 2 @ 1800	57.2	-5.6	57.5
2017	July 20 @ 1700	48	-4	48.2
2016	August 13 @ 1800	55.4	-7.4	56
2015	July 29 @ 1800	51.4	0	51.9
2014	July 23 @ 1500	49.7	7	50.2

2013	July 18 @ 1700	57.6	-6.5	58.3
2012	July 17 @ 1800	54.6	-7.3	55.1

Year	Date of Winter Peak	MW	MVAr	MVA
2021-22	Jan 22 @ 1900	52.7	-8.1	53.4
2020-21	Dec 16 @ 1800	55.9	-3.1	55.9
2019-20	Dec 19 @ 1800	62.5	-0.9	62.9
2018-19	Jan 21 @ 1800	60.0	-10.1	61.0
2017-18	Jan 6 @ 1900	55.8	-5.3	56.1
2016-17	Dec 15 @ 1800	51.7	-12.7	53.3
2015-16	Feb 15 @1900	50.2	-2.2	50.2
2014-15	Jan 7 @ 1900	52.3	-6.7	52.7
2013-14	Jan 7 @ 1900	54.8	-14.4	56.6
2012-13	Jan 24 @ 1900	58.5	-2.5	58.6

6.4.2.1 Summary of Issues

- Reference: EP2022-001 Local Transmission Plan for Replacement of Westerlo Loop Combustion Turbines

Area LSC
The area's thermal LSC is 99.5 MW (summer) and 117.4 MW (winter), assuming that one area generator will start, post-contingency.

The area is voltage limited to 83.6 MW (summer and winter) for loss of CL line.

Each generator's annual run-time, however, is severely limited by environmental/emissions limitations with the South Cairo CT being limited to 134 hours during the summer ozone season and the Coxsackie CT being limited to 230 hours during the summer ozone season.

Various large industrial customers have proposed to interconnection in this area.

DEC Peaker Rule
The emission rules contained in DEC 227-3 have resulted in a recommendation to retire the Coxsackie and South Cairo combustion turbines by year-end 2024.

Proposed Solar Interconnection Projects
For lines and substations supplied by the NC line, there are currently 130 MW of projects in the NYISO Interconnection Process. Additionally, there are approximately 20 MW in service and 26 MW in queue in the

New York State SIR process as of April 2022. The 77 MVA rated NC line will be overloaded if this large amount of solar is placed in service.

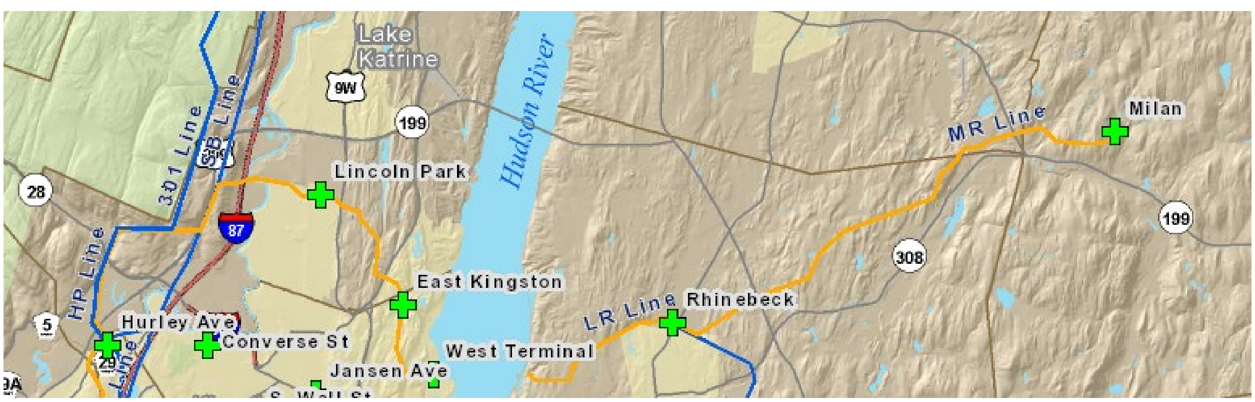
6.4.2.2 Summary of Recommendations

DEC Peaker Rule
To maintain Westerlo Loop reliability following the retirement of the Coxsackie & South Cairo CTs, system upgrades are necessary.
The installation of additional transformers at the Coxsackie and South Cairo Substations and the installation of voltage support devices at the South Cairo and Freehold Substations are recommended.

Proposed Solar Interconnection Projects (NYISO Queue)
The solar projects in the NYISO Interconnection process will undergo a NYISO Class Year Study in which System Upgrade Facilities (SUF) costs will be determined and allocated accordingly. As part of CLCPA[7] efforts in response to a PSC Order, Central Hudson recommended the NC Line rebuild as part of a Phase 2 and Area of Concern project. This included rebuilding the NC Line with larger conductor and for future 115 kV operation, though continuing to operate at 69 kV in the interim. Central Hudson is waiting for the outcome of the NYISO interconnection process (potential completion toward the end of 2022) and/or Commission Action prior to proceeding.

6.4.3 Kingston-Rhinebeck 115 kV

This area comprises the substations between Hurley Avenue in Ulster County and Milan in Dutchess County but excludes the Milan load.



Area summer system coincident peak loads are shown in the following table for the last ten years.

[7] Climate Leadership and Community Protection Act

Year	Date of Peak	MW	MVAr	MVA
2021	June 29 @ 1900	80.9	-1.9	80.9
2020	July 27 @ 1900	90.4	9.2	90.8
2019	July 20 @ 1800	83.7	7.8	84.1
2018	July 2 @ 1800	83.5	-6.2	83.7
2017	July 20 @ 1700	73.7	-10.0	74.4
2016	August 13 @ 1800	75.3	-8.3	75.8
2015	July 29 @ 1800	78.3	5.7	78.5
2014	July 23 @ 1500	82.0	-1.1	82.0
2013	July 18 @ 1700	88.6	2.2	88.6
2012	July 17 @ 1800	86.1	-0.9	86.1

6.4.3.1 Summary of Issues

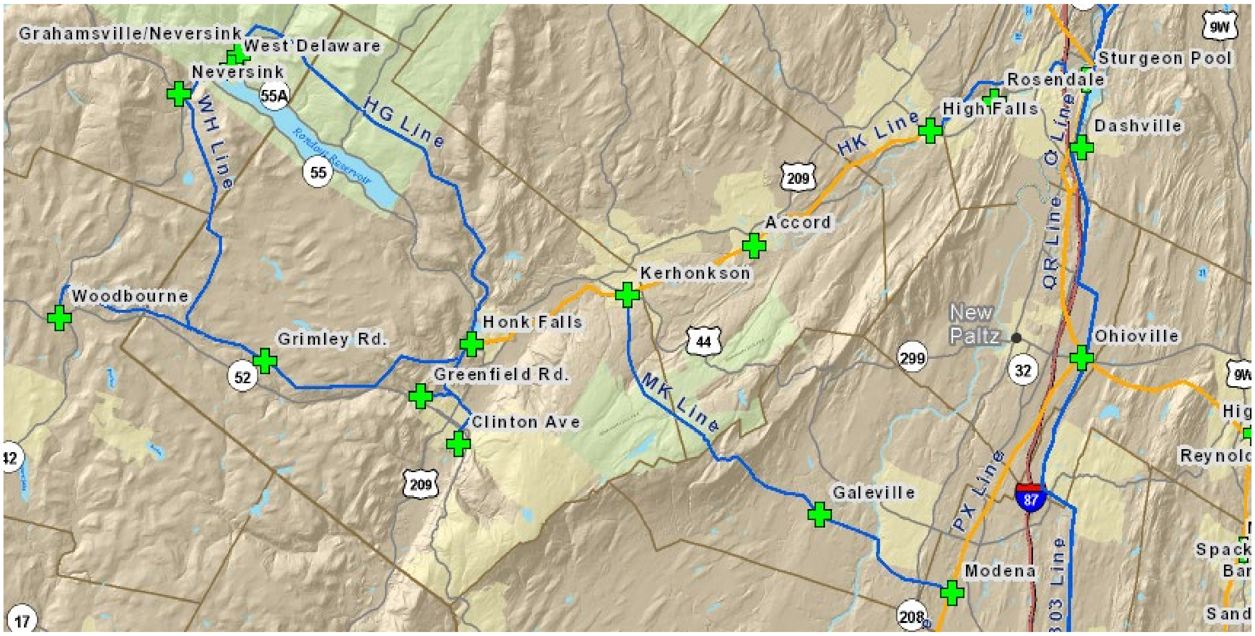
Following loss of the HP line, even with all the Lincoln Park capacitors in-service, this area is voltage limited at approximately 175 MW. Should a large (e.g., 25-35 MW) industrial load come in at Lincoln Park / Tech City, the voltage limit would be 140 MW following the loss of the HP line. The Lincoln Park Capacitors, however, are scheduled to be retired by the end of 2022.

6.4.3.2 Summary of Recommendations

No action is required at this time. For the future, a third input to Lincoln Park would improve post-contingency voltages and the area LSC.

6.4.4 Ellenville Area

Three 69 kV transmission inputs (P line, MG line and West Woodbourne 115/69 kV transformer) supply the Ellenville area.



6.4.4.1 Summary of Issues

P & MG Lines
For the Ellenville area, condition assessments (mainly the Modena 115/69 kV Transformer) have prompted a need to continue rebuilding toward 115 kV operation. Additionally, a large industrial load (~ 33MW per the developer) has been proposed for the former Schrade property that cannot be served from the existing 69 kV system.

GM Line Tap
The large industrial customer referenced above has indicated a desire to have Transmission Service. The 0.35-mile section of the GM Line required to supply this load is in poor condition and was scheduled for retirement.

HG Line
Condition assessments have indicated that the line has sufficient structural issues to warrant a rebuild.

6.4.4.2 Summary of Recommendations

P & MG Lines: Conversion to 115 kV Operation
The P & MG lines are already built for 115 kV operation. The significant remaining work includes expanding the Kerhonkson Substation to install two new 115/69 kV transformers and associated breakers, and the addition of a third 115 kV breaker at the Modena Substation. To accommodate the proposed large industrial load, the conversion to 115kV operation is

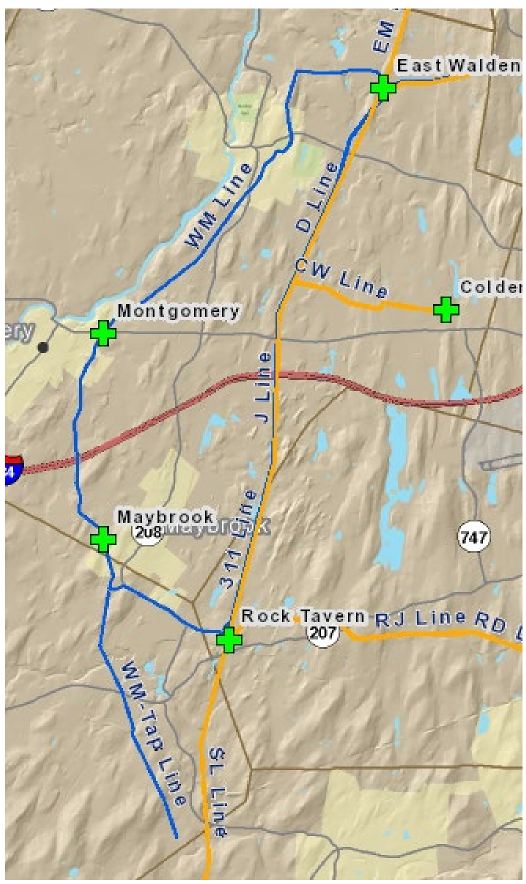
planned for completion by March 2024. The timeline may be extended depending on the timing/status of the industrial site.

GM Line Tap: Rebuild
In order to accommodate the proposed large industrial load, a 0.35-mile section of the 69 kV GM Line Tap will need to be rebuilt and a 3-way transmission line switch installed for operational flexibility. The cost of this work will be the responsibility of the customer and this work will be coordinated with the customer timeline.

HG Line
The HG Line will be rebuilt with 397.5 ACSR Ibis and OPGW static wire. This will mitigate future generation curtailment and remove the sag limitation on the line.

6.4.5 WM Line Area

This area comprises the 69 kV substations between Rock Tavern and East Walden in Orange County. There also is a tap heading south of Rock Tavern that serves as a back-up supply to Orange & Rockland utilities Blooming Grove Substation.



Area summer peak loads are shown in the following table for the last ten years.

Year	Date of Peak	MW	MVAr	MVA
2021	June 29 @ 1900	50.6	14.4	52.6
2020	July 27 @1900	50.2	14.8	52.4
2019	July 20 @ 1800	no	mdb	Data
2018	July 2 @ 1800	47.3	17.2	50.3
2017	July 20 @ 1700	41.5	11.8	43.1
2016	August 13 @ 1800	42.0	12.3	43.7
2015	July 29 @ 1800	41.8	12	43.5
2014	July 23 @ 1500	37.3	11.2	38.9
2013	July 18 @ 1700	41.9	13.6	44.1
2012	July 17 @ 1800	41.3	13.7	43.6

6.4.5.1 Summary of Issues

Central Hudson's portion of the WM Line between Rock Tavern and East Walden was rebuilt in 2012. There are no current issues with this portion of the line. Several large loads have been proposed for area served by the WM Line. The existing system, limited by the Rock Tavern Transformer, is not capable of supplying these loads.

The WM Line tap to Blooming Grove was not rebuilt and is in poor condition. This tap serves as a reserve to the Orange & Rockland (O&R) Blooming Grove Substation.

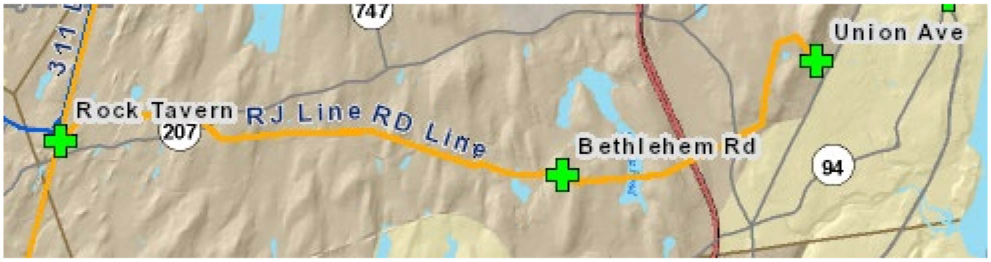
6.4.5.2 Summary of Recommendations

A planning study currently is underway to determine the most efficient way to serve additional load and is anticipated to be completed by Q3 2022.

The tap to Blooming Grove is being considered for retirement or reconfiguration. O&R has indicated that, based on current planned upgrades, the tap will not be needed for reserve in the future. Central Hudson is working with O&R on potential upgrades that would reduce Central Hudson customer risk until the tap can be retired.

6.4.6 115 kV RD-RJ Area

This area comprises the Union Avenue and Bethlehem Road Substations located in Orange County.



Area summer peak loads are shown in the following table for the past ten years.

Year	Date of Peak	MW	MVAr	MVA
2021	June 29 @ 1900	101.7	5.7	101.9
2020	July 27 @1900	93.2	5.9	93.3
2019	July 20 @ 1800	96.3	8.7	96.7
2018	July 2 @ 1800	96.3	9.7	96.8
2017	July 20 @ 1700	89.1	10	89.6
2016	August 13 @ 1800	89.4	6.0	89.6
2015	July 29 @ 1800	87.5	0.7	87.5
2014	July 23 @ 1500	82.9	5.1	83.0
2013	July 18 @ 1700	96.4	10.7	97.0
2012	July 17 @ 1800	87.0	7.9	87.3

The area LSC is 144 MW and is limited by the RD line's 336.4 MCM ACSR conductor.

6.4.6.1 Summary of Issues

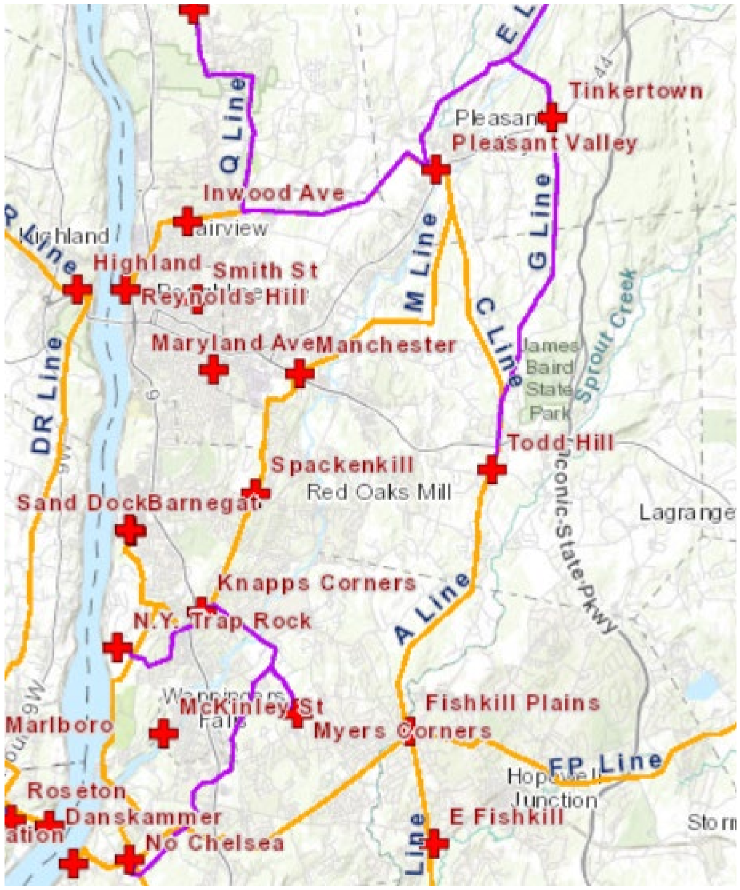
The area has sufficient LSC to provide for future load growth in the near-term. A potential long-term reinforcement option is to reconductor/rebuild the RD line using a larger conductor (potentially 795 MCM ACSR to match the RJ line).

6.4.6.2 Summary of Recommendations

There are no recommendations for this area at this time.

6.4.7 Mid-Dutchess Area 115 kV

This area comprises the 115 kV substations between North Chelsea and Pleasant Valley in Dutchess County. It includes the IBM load supplied from the Sand Dock and Barnegat Substations.



Area summer peak loads are shown in the following table for the prior ten years.

Year	Date of Peak	MW	MVAr	MVA
2021	June 29 @ 1900	160.0	19.2	161.1
2020	July 27 @1900	129.7	16.4	130.8
2019	July 20 @ 1800	112.5	11.8	113.1
2018	July 2 @ 1800	118.6	14.0	119.4
2017	July 20 @ 1700	114.5	13.2	115.2
2016	August 13 @ 1800	114.3	12.7	115.0
2015	July 29 @ 1800	118.5	14.1	119.3
2014	July 23 @ 1500	105.1	22.1	107.4
2013	July 18 @ 1700	136.8	26.6	139.2
2012	July 17 @ 1800	127.9	17.7	129.1

6.4.7.1 Summary of Issues

Two inputs (M line from Pleasant Valley and SC line from North Chelsea) supply the Mid-Dutchess Substations. The area LSC is limited to 230 MW following loss of the SC line. The LSC could be increased to 248 MW by replacing the station connections at the Manchester Substation.

Condition assessments for the SK line have indicated that the line has sufficient structural issues to warrant a rebuild.

6.4.7.2 Summary of Recommendations

There are no transmission reinforcements recommended at this time to increase the area LSC. The SK line will be rebuilt with 1033.5 ACSR to address the structural issues. This project is scheduled to be completed in 2024.

6.4.8 69 kV Q Line

This area comprises the 69 kV substations between Pleasant Valley and Rhinebeck in Dutchess County.

6.4.8.1 Summary of Issues

As described in Section 3.2.2.2, inspection reports for the 20.5 mile Q Line show that approximately 65% of the wood poles require replacement or repair.

6.4.8.2 Summary of Recommendations

A memo recommending rebuild is under review.

6.4.9 69 kV E Line Reserve

The E line substations are supplied from the Pleasant Valley Substation. Under this normal configuration, the Smithfield to Falls Village 690/FV line may be closed at each end or open at one end depending on the transfer level between New York and New England.

Area summer peak loads are shown in the following table for the prior ten years.

Year	Date of Peak	MW	MVAr	MVA
2021	June 29 @ 1900	32.6	-	-
2020	July 27 @1900	33.6	-	-
2019	July 20 @ 1800	32.2	-	-
2018	July 2 @ 1800	31.4	-	-
2017	July 20 @ 1700	40.8	-	-
2016	August 13 @ 1800	33.1	-	-
2015	July 29 @ 1800	36.5	-	-
2014	July 23 @ 1500	35.8	-	-
2013	July 18 @ 1700	32.2	-	-
2012	July 17 @ 1800	32.3	-	-

6.4.9.1 Summary of Issues

Following the loss of the Pleasant Valley to Hibernia section of the E line, only two sources are available to supply the E line load: NYSEG’s Amenia Substation via the SA line and Northeast Utilities’ Falls Village area via the 690/FV line. In the past, NYSEG has indicated that they can supply up to 13 MVA via the SA line and Northeast Utilities has indicated that they cannot supply any load from the FV line, during summer peak load conditions. Recent developments in the NYSEG area (i.e., Silo Ridge, construction power for AP Dutchess and Olivet University) suggest that NYSEG may not be able to supply the reserve on peak.

A FV line inspection has shown damage to the section of wire spanning Indian Lake that requires a conductor replacement. Due to the tower configurations, this would require not only pulling the span across Indian Lake but also several spans in both New York and Connecticut.

There have been several NYISO small generator preapplications for the Northeast Dutchess County Transmission System. For the N-1 loss of the Pleasant Valley 69kV source, the area transmission system could be supplied radially from the ISO-NE system. For this condition, ISO-NE would not have the ability to dispatch area generation.

6.4.9.2 Summary of Recommendations

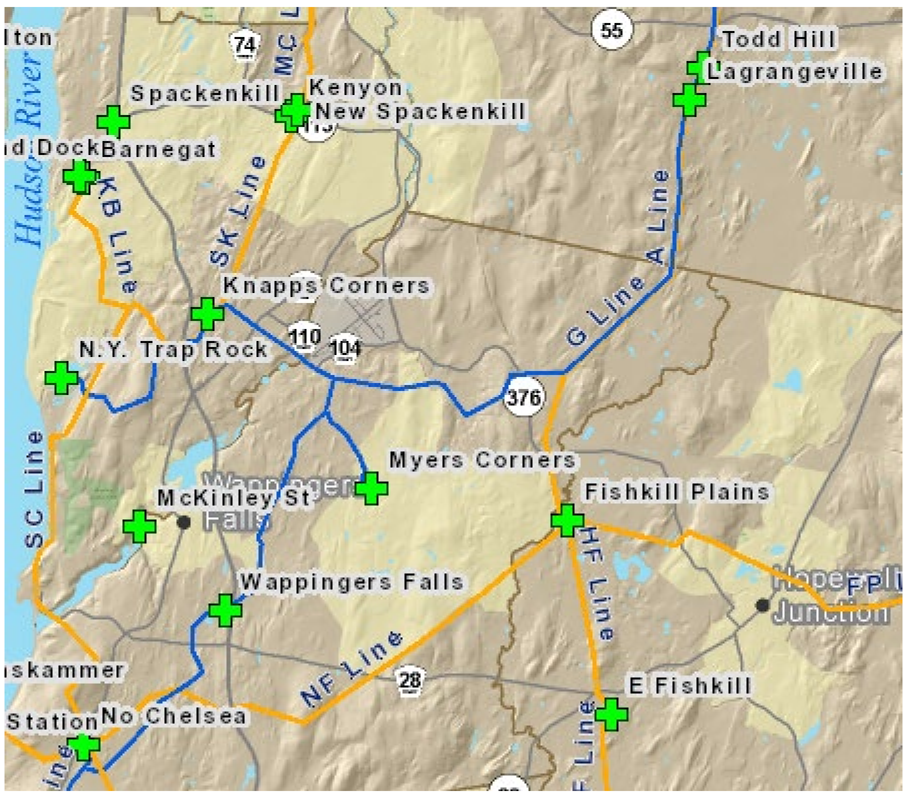
The G line provides the capability to reserve the E line for a Pleasant Valley Transformer #10 fault, 69 kV bus fault or an E/G common tower failure. This improves the ability to reserve E line loads but does not provide for reserve for all conditions. This area will be studied in the future. After recent discussions with NYSEG, several options to increase their area transmission system are being explored. One option is to rebuild the E line at 115 kV and install two autotransformers at Smithfield. Other options are also being considered.

Subsequent to the discovery of the FV line conductor damage, Eversource approached us with their plan to rebuild their transmission system in Connecticut at 115 kV and operate at 69 kV. Discussions between Central Hudson and Eversource are underway regarding these issues.

For the N-1 loss of the Pleasant Valley 69kV source, the area transmission system could be supplied radially from the ISO-NE system. For this condition, ISO-NE would not have the ability to dispatch area generation. To resolve this issue for projects participating in the NYISO market, an additional transmission supply from the NYCA system would be required.

6.4.10 Myers Corners Transmission Supply

The KM and TV lines supply Myers Corners Substation. The TV line was rebuilt in 2021.



Substation summer peak loads are shown in the following table for the prior ten years.

Year	Date of Peak	MW	MVAr	MVA
2021	June 29 @ 1900	19.6	-0.3	19.6
2020	July 27 @1900	18.7	0.3	18.8
2019	July 20 @ 1800	22.7	1.7	22.8
2018	July 2 @ 1800	23.2	1.2	23.2

2017	July 20 @ 1700	21.3	.9	21.4
2016	August 13 @ 1800	24.2	4	24.6
2015	July 29 @ 1800	24.0	4.5	24.4
2014	July 23 @ 1500	23.0	3.1	23.2
2013	July 18 @ 1700	25.8	6.8	26.7
2012	July 17 @ 1800	26.1	4.2	26.5

6.4.10.1 Summary of Issues

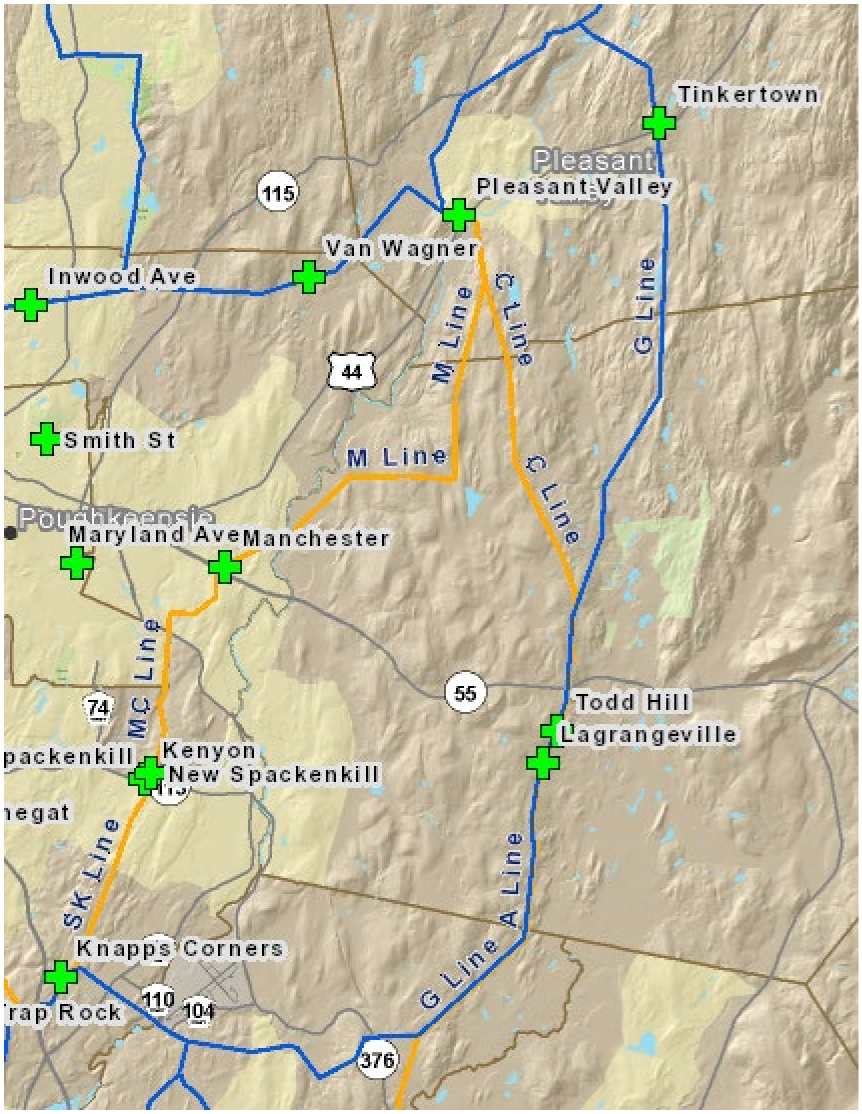
Condition assessments on the KM line have shown sufficient structural issues to warrant a rebuild.

6.4.10.2 Summary of Recommendations

The KM line will be rebuilt with 795 ACSR. This project is scheduled to be completed in 2023. Reference the Transmission Lines Section (section 3.2.2.2) for additional information on the KM line rebuild.

6.4.11 Tinkertown Substation Reserve

The Tinkertown Substation is supplied by the G line.



Substation summer peak loads are shown in the following table for the prior ten years.

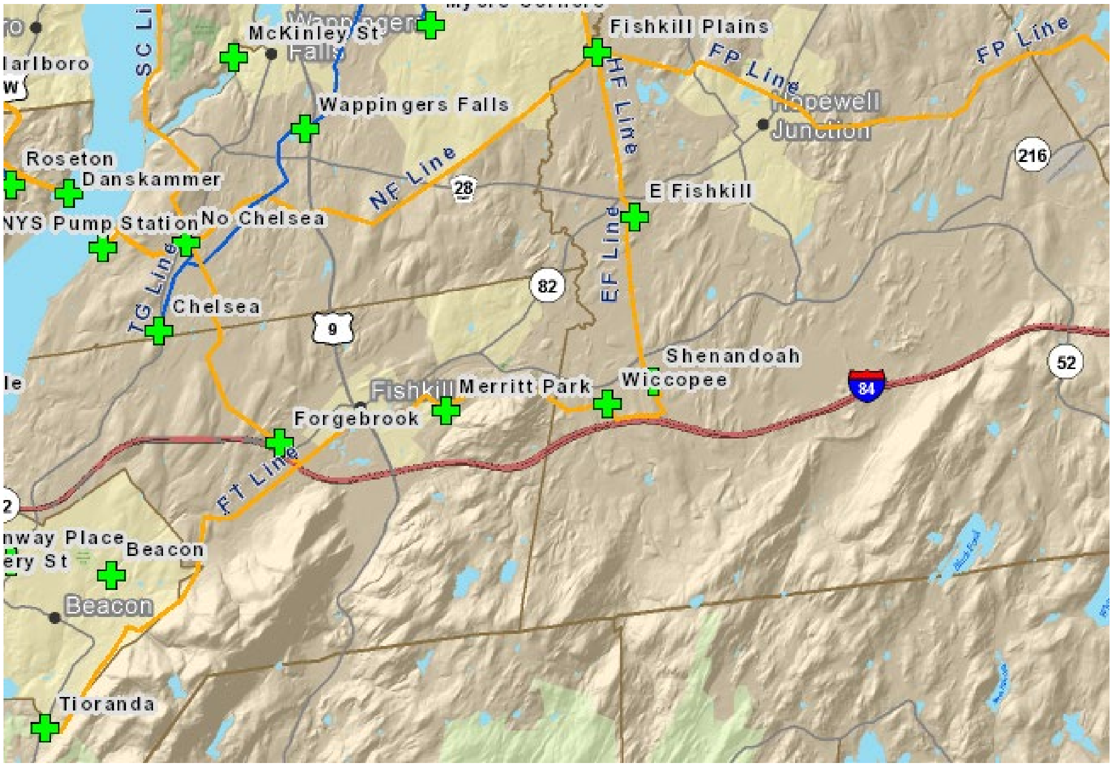
Year	Date of Peak	MW	MVAr	MVA
2021	June 29 @ 1900	14.6	0.8	14.7
2020	July 27 @1900	14.5	1.6	14.6
2019	July 20 @ 1800	14.4	1.9	14.5
2018	July 2 @ 1800	14.4	0.6	14.4
2017	July 20 @ 1700	13.1	0.8	13.1
2016	August 13 @ 1800	15.4	1.1	15.4
2015	July 29 @ 1800	13.0	0.8	13.1
2014	July 23 @ 1500	13.0	2.0	13.1
2013	July 18 @ 1700	15.2	1.8	15.3
2012	July 17 @ 1800	14.0	2.6	14.3

6.4.11.1 Summary of Issues and Recommendations

No transmission reinforcement is needed at this time.

6.4.12 Southern-Dutchess Area

This area comprises the 115 kV substations between North Chelsea and East Fishkill in Southern Dutchess County. It includes the Global Foundries load supplied from the Shenandoah Substation.



Area summer peak loads are shown in the following table for the prior ten years.

Year	Date of Peak	MW	MVAr	MVA
2021	June 29 @ 1900	146.2	17.5	147.3
2020	July 27 @1900	144.0	21.9	145.6
2019	July 20 @ 1800	146.0	23.0	147.8
2018	July 2 @ 1800	140.4	15.5	19.5
2017	July 20 @ 1700	136.3	13.4	136.9
2016	August 13 @ 1800	149.7	20.2	151.1
2015	July 29 @ 1800	140	21.5	141.7
2014	July 23 @ 1500	146.9	28.5	149.6
2013	July 18 @ 1700	159.4	34.2	163.0
2012	July 17 @ 1800	152.5	26.3	154.7

This area's all-time high coincident peak load is 213.7 MVA on August 2, 2006 (HE 1700). Subsequent coincident peaks have been lower largely due to decreased Global Foundries load at Shenandoah and the closure of IBM's West Complex that is supplied from the Wiccopee Substation.

6.4.12.1 Summary of Issues

Two inputs (115 kV FO line from North Chelsea and 115 kV EF line from East Fishkill) supply the SDA substations. With one of these two inputs out-of-service, the SDA is able to serve 211 MVA without shedding load. During the summer of 2006, the area loads exceeded the area LSC. The load has decreased since this time and significant growth is not forecast for this area. Additional load serving capability could be needed for the Southern-Dutchess Area in the future if there are significant economic development initiatives in the former IBM West Complex.

6.4.12.2 Summary of Recommendations

Continue monitoring the Southern Dutchess Area for a large load that may come to the former IBM West Complex.

7. Subtransmission, Distribution (Category 15), and Substation (Category 13) Infrastructure and Load Growth Plan

7.1 Introduction

This section depicts the plans for all areas that are anticipated to be deficient within the next 7 years due to either aging or failing infrastructure or thermal limitations due load growth in the area. The discussion of the areas is categorized by the load groups described in Section 5. Please note that not all areas within each load group are listed, only those with deficiencies.

7.2 Load Group 1 - Northwest

7.2.1 Coxsackie/New Baltimore

- Reference: EP2022-003 New Baltimore Integration Study

7.2.1.1 Summary of Issues

The Coxsackie and New Baltimore Substations are single transformer stations serving a large geographic area that is mostly rural with the exception of village centers. The areas served include the Villages of Coxsackie and Ravena, and Towns of Athens, Coxsackie, New Baltimore, and Coeymans.

The substations are single transformer stations that are loaded as follows:

Substation	Summer Normal Rating (MVA)	2021 Peak Load (MVA)
Coxsackie	16.4	12.0
New Baltimore	25.8	11.90

Although the stations operate below their firm ratings, the rural nature of the area calls for long circuits with few ties, limiting reserve capability between the Coxsackie and New Baltimore substations.

In addition to the limited reserve capability, the aging infrastructure at the Coxsackie Substation has become a concern. The Coxsackie transformer has been operating for over 60 years and the switchgear is nearing 50 years of operation. The transformer and switchgear are both nearing the end of their useful lives. Due to recent DEC emission restrictions, the combustion turbine (CT) at Coxsackie will be retired in 2025. Several new significant loads continue to be introduced to the area. Along with these, there has been a very large amount of proposed DER reaching levels of almost 45MW across both stations.

7.2.1.2 Summary of Recommendations

- In 2015, a study was drafted by Distribution Planning to address a long-term contingency plan for the area. The draft recommended the installation of a second transformer at New Baltimore and that the Coxsackie CT continues to be used as backup in the event of a transformer failure at the Coxsackie Substation. Subsequent to this study, the CT operations were impacted by the recent DEC emissions rule and the unit is now planned for retirement by 2025. A second transformer has been recommended for the Coxsackie substation to provide reserve capacity for transformer outages and the installation of D-VAR units at South Cairo and Freehold Substations are being planned for voltage support during contingencies. Final project scoping has been complete and design has begun with anticipated completion date of 2024.

- To address the aging infrastructure concerns at Coxsackie, a new switchgear installation at the Coxsackie substation and replacement of the Coxsackie transformer are planned for completion in Q1 2023. Based on area loading levels, the transformer was originally planned to be replaced with a 13.4MVA transformer. With almost 30MW of potential DER proposed onto the substation bus, a 22MVA transformer was ordered and will be installed with the incremental cost for the larger transformer being paid by a PV developer.

- As recommended in the 2022 New Baltimore integration study, the New Baltimore substation is scheduled to have a second 12 MVA Transformer in service by December 2023 to address the reserve capability concerns during contingencies along with increased area loading. Two new circuits, 1080 and 1084, have also been proposed to help offload some existing circuits in order to improve reliability, add operational flexibility and to provide service to new commercial loads in the Coeymans area. In addition to the new transformer, new relays and 15kV breakers are scheduled to be installed.

7.2.2 South Cairo/Freehold

- Reference: EP2022-001 Local Transmission Plan for Replacement of Westerlo Loop Combustion Turbines

7.2.2.1 Summary of Issues

The South Cairo Substation serves the areas of Cairo, Purling, Lawrenceville, East Durham, and Acra. The Substation is home to the South Cairo Combustion Turbine (CT) which is used as a backup for a transformer failure and to provide voltage support to the local transmission area. By 2025, due to DEC emission restrictions, the CT will be retired and South Cairo will not have a backup source in the event of a transformer failure.

7.2.2.2 Summary of Recommendations

A second transformer will be required at South Cairo substation due to the retirement of the CT to maintain reliability. As part of this retirement, the installation of D-VAR units at South Cairo and Freehold to provide voltage support for the transmission loop have been recommended. These projects are scheduled to be in service by December 2024.

7.3 Load Group 2 - Kingston

7.3.1 Woodstock

- Reference: K-2019-05 - Woodstock Substation Circuit Exits

7.3.1.1 Summary of Issues

The Woodstock Substation serves the majority of the Town of Woodstock, as well as sections of the Towns of Hurley, Olive, Saugerties, and Kingston. The SR transmission line that feeds the Woodstock Substation is a radial feed that has been plagued with outages. The line has experienced 4 permanent interruptions over the past 5 years during both storm and non-storm conditions. The outages affect approximately 8,300 customers each time.

The existing external switchgear and control house switchgear has reached the end of its useful life and replacement parts are difficult to obtain. Maintenance issues have been experienced with racking the 1947 vintage breakers in the external switchgear. Replacement parts for the racking mechanisms are also no longer available.

The dial up RTU housed inside of the control house switchgear is unreliable, and due to space constraints there is no room to add additional equipment or to replace the RTU. The 1972 vintage breakers utilize a puffer with a plastic manifold, this has been a constant maintenance issue.

The external switchgear and control house switchgear have separate DC voltage supplies, a 24 volt and a 48 volt battery system, respectively. There is no room to upgrade either battery system, and maintenance of the system is problematic.

The substation is served by two transformers, with Transformer #1 having the lower Summer LTE at 19.125 MVA. The peak load at the substation was 18.3 MVA in the summer of 2021 (taking into account the Ashokan hydro generation). The Ashokan hydro generators, located on the 3011 distribution circuit, have a nameplate rating of 4.6 MW at 0.9 power factor, but have only generated a peak of 2.5 MW, and are not necessarily available for deployment on a peak day. The Ashokan hydro facility was generating 2.04 MVA at the time of the 2021 peak. Without the generation of the Ashokan hydro the substation could exceed its summer LTE rating.

7.3.1.2 Summary of Recommendations

The external switchgear and control house switchgear will be replaced with a new Power Control Center (PCC). The PCC will contain a two bus system separated by a normally open tie breaker, 15kV breakers rated 2000A and 1200A, protective relaying, interconnection cabinet, PT's, station service transformers, RTU, and DC battery system. The PCC will contain provisions for future expansion. Distribution Engineering is currently working with Electric Operations to determine a plan for circuit exists to facilitate the new substation switchgear. This plan will take substation loading into consideration, surrounding infrastructure, and reliability.

The Woodstock Switchgear replacement has been budgeted for an in-service date of December 2025. Study will commence in the 2023 timeframe to address the integration of the circuits to the new switchgear and evaluate the area loading to identify if system reinforcements are necessary. These projects, in conjunction with the implementation of automated switching via the DMS system, are expected to improve the reliability of the customers in the area. See Section 4 – Distribution Grid Modernization for additional detail.

7.3.1.3 Anticipated Date of Study

Woodstock Integration and Load Serving Capability Study - 2023

7.3.2 Converse Street

- Reference: EP2014-003 Boulevard/Jansen Ave/South Wall St/Converse St Area Study
- Reference: Kingston Grid Network Evaluation for Possible Conversion to Spot Network MEMO

7.3.2.1 Summary of Issues

The Converse Street Substation serves the Kingston Network. It is fed from the KK cable out of the Boulevard substation. The substation is a two transformer, 14kV to 4kV station. Transformer 2 is 63 years old and is scheduled for replacement in 2027 due to a poor condition assessment after exhibiting dielectric breakdown and elevated power factor. Additional modernization of the substation and upgrading of the RTU is within the planned scope of work.

7.3.2.2 Summary of Recommendations

In 2019, a study was conducted to determine the feasibility for moving the Kingston secondary network into three secondary spot networks. Due to the high cost of conversion, design, voltage constraints, and potential negative impacts to reliability, it was recommended not to move forward with the creation of spot networks. As a result of maintaining the Kingston secondary network, it was recommended to proceed with the replacement of Converse Street Transformer 2 scheduled for 2027. In addition to the transformer replacement, replacement of the Converse Street breakers and switchgear will also be completed in 2027 due to parts constraints, wiring issues, and older generation relaying.

7.3.3 South Wall Street

- Reference: K-2019-04 111 & 112 – Retire South Wall Street Substation

7.3.3.1 Summary of Issues

The equipment at South Wall Street has reached the end of its useful life and is slated for replacement. The 46-year-old transformer was Doble-tested in 2020 and shows slight moisture content. It is recommended that a dryout be performed to address the moisture. Furthermore, the only spare replacement unit within the company is 60 years old. The station uses oil-filled hydraulic reclosers for circuit breakers as vacuum hydraulic reclosers do not fit in the circuit recloser cubicles. Central Hudson does not procure the oil-filled units anymore, and the low-profile switchgear within which they reside pose safety concerns.

7.3.3.2 Summary of Recommendations

A distribution solution would be more economical and easier to implement than completing the necessary substation work. Replacement is under review to determine the most economical option.

7.3.3.3 Anticipated Date of Study

South Wall Street Area/Integration Study – Q4 2022

7.3.4 Lincoln Park

- Reference: K-2020-05 Lincoln Park Substation Circuit Exits
- Reference: EP2021-012 Tech City Proposed Development and Glidepath Interconnection – Lincoln Park Substation

7.3.4.1 Summary of Issues

The Lincoln Park Substation serves the areas of Lincoln Park, Sawkill, Lake Katrine, and Mt Marion. Lincoln Park’s outdoor switchgear (Units #1 and #2) is in poor condition and has reached the end of its useful life. The racking of these breakers is difficult due to the deteriorated outdoor isle. Three of the four cables supplying the Tech City campus have failed and have been abandoned in place with the breakers opened.

7.3.4.2 Summary of Recommendations

A recent planning study has determined that based on local distribution load, the older switchgear (Unit’s #1 and #2) was no longer required. However, a proposed DER for this area is now requiring dedicated feeders to support their interconnection and the former Tech City campus is being repurposed as a mixed-use facility with current proposed loads of 13 MVA with the potential for additional expansion. Replacing this switchgear and creating bus ties to the indoor isle gear in order to provide reliable service is currently being designed to support the proposed DER and the potential new loads. This project has an expected in-service date of year-end 2023 to support the DER installation.

7.4 Load Group 3 - Ellenville

7.4.1 Neversink

- Reference: EP2011-004 Evaluation of Neversink Substation Site and Extension of BWS Lease

7.4.1.1 Summary of Issues

The Neversink Substation serves the Town of Neversink, as well as sections of the Towns of Wawarsing and Denning. It is served by two transformers. Transformer #3 has a Summer Normal rating of 4.92 MVA on the lowside winding (13.2kV), and 2.46MVA on the tertiary winding (4.16kV). This transformer serves the 3091 and 391 circuits, which peak around 3.5 MVA and 550 kVA respectively. Transformer #6 has a Summer Normal rating of 2.083 MVA and operates as a spare serving 100A V4L reclosers.

Overloading of the transformer or other equipment under normal conditions is not anticipated within the 10-year horizon. The substation transformers were tested and determined to be in satisfactory condition. The Neversink Substation is located in a rural area where it is unlikely there will be significant organic growth or economic development. Historical growth rates have been minimal in this area.

Additionally, our 50 year lease with the Board of Water Supply to operate our substation on their property ended in 2006 and Central Hudson is operating its facilities in the area solely under the Separation Agreement and required notice. Once Central Hudson is notified to vacate the property, Central Hudson has 18 months to complete the transition away from the site.

7.4.1.2 Summary of Recommendations

In the event that the Board of Water Supply notifies Central Hudson to vacate the property, the design and construction of the new Coombe Road Substation will move ahead. During the interim, it is recommended that Central Hudson extend the existing lease with the New York City BWS at the Neversink Substation site. Distribution Engineering is currently reviewing potential options to improve operational flexibility. Recommendations will incorporate cost-benefit analysis to determine the most appropriate solution. Additionally, solutions may be incorporated as part of the Kingston DA review. This substation previously used Gridsense for metering data. Gridsense stopped providing service in 2014 and in 2019 the SEL-351R relay installed in the Neversink Substation for feeder 3091 was added to Central Hudson's Sensus network in order to obtain metering data.

7.4.2 Greenfield Road/Clinton Avenue

7.4.2.1 Summary of Issues

- Reference: EP2016-012 Spare 10/12MVA Transformer Relocations
- Reference: EP 2019-006 Greenfield Road/Clinton Ave. Area Study

The Greenfield Road Substation currently consists of one 69/13.2 kV wye-wye (delta tertiary) transformer serving portions of the Town of Wawarsing and the Village of Ellenville. There is a large industrial customer being proposed at the old Schrade campus that will have a total connected load of 2.7 MVA on the local distribution circuit and a total proposed load of 30 MVA tapping the 69 kV GM line.

The Clinton Avenue transformer was manufactured in 1957 and has been recommended for retirement due to unsatisfactory power factor tests and high moisture levels.

7.4.2.2 Summary of Recommendations

It is recommended the Greenfield Road Substation be rebuilt entirely to operate at 69-13.2kV. The substation rebuild will involve the construction of a two 10MVA transformer substation with four circuit exits (3076, New 3077, 3078, Spare). It is recommended that the system spare 10MVA transformer from Modena and the spare 10MVA transformer from Kerhonkson be utilized at Greenfield Road. An integration study is being developed to determine appropriate circuit paths and conversion work required. If the large industrial load comes to fruition a new customer-owned substation will be constructed.

Once the Greenfield Road Substation rebuild is complete, currently scheduled for 2023, the Clinton Avenue 4kV circuitry should be converted and supplied by the Greenfield Road 13.2kV circuitry. The Clinton Avenue substation can then be retired.

7.4.2.3 Anticipated Date of Study

Greenfield Road Integration Study - 2022

7.5 Load Group 4 – Southern Ulster

7.5.1 Modena

- Reference: EP2012-013 Modena Substation Upgrade Assessment
- Reference: EP2016-012 Spare 10/12MVA Transformer Relocations

7.5.1.1 Summary of Issues

The Modena Substation consists of a newer 115kV station which includes a 115 kV-13.2 kV transformer to supply the area load and the "old" station, which is fed by a 115/69 kV transformer and includes the 69-13.2 kV system spare transformer. While stored at the Modena substation, the 69-13.2 kV system spare transformer acts as a backup for the "new" station. The station serves the load in the Town of Plattekill, as well as portions of Gardiner and New Paltz. Once the P & MK Line conversion is completed, the "old" station will be retired.

7.5.1.2 Summary of Recommendations

A backup transformer at the Modena Substation is not required for operational or thermal reasons. Our current 69-13.2 kV system spare transformer will remain at Modena until it is utilized at Greenfield Road as part of the substation rebuild.

7.6 Load Group 5 - Orange

7.6.1 Maybrook/Montgomery

- Reference: EP2011-012 Montgomery/Maybrook Area Study
- Reference: EP2018-008 Montgomery Substation Integration Study

7.6.1.1 Summary of Issues

The Montgomery Substation was rebuilt in 2019. The new substation contains two 69-13.8kV 10/12.5 MVA transformers with LTCs and is located on the prior Montgomery Substation property along Rt. 17K in the Village of Montgomery. Based on infrastructure and operational flexibility issues previously identified within a comprehensive area study, this option addressed the infrastructure issues at Montgomery and provided ability to transfer additional load from the Maybrook Substation. This solution represented a lower overall capital cost alternative to the original plan, which involved replacing the transformers at the Maybrook Substation and relocating the old Maybrook transformers to the Montgomery Substation.

While the newly rebuilt Montgomery Substation will allow for portions of the Maybrook Substation to be offloaded, there are currently several new industrial loads, as well as DER systems, proposed in this area. These loads have the potential to require additional load transfers, and substation upgrades in the near term.

7.6.1.2 Summary of Recommendations

- Additional offloading of Maybrook load to the newly rebuilt Montgomery Substation is required to address the new industrial/commercial loads that have been added to the area and have recently requested additional requirements for more power in the near term.
- Distribution Planning will be performing a study on the area load serving capability once load transfers have been completed and load letters are reviewed for the proposed additional loads. Planning will conduct an assessment of the loading of the Maybrook and the Montgomery area to review the impact of these recent and proposed interconnections.

7.6.1.3 Anticipated Date of Study

Maybrook/Montgomery Area Study - 2022

7.6.2 Newburgh Area

- Reference: EP2011-001 Newburgh 14.4kV Area Study
- Reference: EP2013-016 Montgomery Street Transformer Replacement

7.6.2.1 Summary of Issues

There is one 14.4kV loop system in the Newburgh District. It primarily feeds the City of Newburgh. This 14.4kV loop system is comprised of paper and lead cables that have experienced numerous failures, and have therefore been identified for replacement as part of the 14.4kV Cable Rejuvenation Program. The area was evaluated to determine whether or not upgrades to the remaining 14.4kV loop infrastructure are economical when compared to alternatives that may be available due to available capacity at adjacent substations.

The associated Montgomery Street 14.4kV switchgear is antiquated and in need of repair. The breakers and associated cabling is approximately 60 years old and has exceeded its useful life. The associated relaying and metering are also outdated and in need of modernization.

7.6.2.2 Summary of Recommendations

West Balmville – Montgomery Street 14.4kV Loop

- o In 2018, all four cables feeding the Montgomery Street Substation were evaluated for replacement based primarily on risk and failure rate. The cables identified for evaluation were the B, F and R cables, as well as the underground portion of the WN cable entering the Montgomery Street Substation. The overhead portion of the WN cable was already replaced as a part of the cable rejuvenation program. The area was restudied in 2019 to determine if all 4 cables were still required.

- o Based on the results of the study/evaluation a new circuit will be constructed to replace the B, F and R cables between the West Balmville and Montgomery Street Substations. This work commenced in 2020 and be completed as part of five phases, concluding in 2025.

- o The remaining portion of the WN cable feeding into the Montgomery Street substation has been partially replaced and the last segment of the replacement is scheduled to be completed in 2025.

Montgomery Street – 14.4kV Switchgear Upgrade

- The Montgomery Street 14.4kV Switchgear is scheduled for replacement in 2025/6. An integration study may be conducted prior to the switchgear replacement if reconfiguration is deemed necessary.

7.7 Load Group 6 – Northeast Dutchess

7.7.1 Northeast Dutchess County

- Reference: EP2012-006 North-East Dutchess Area Study
- Reference: Category 15 Capital Budget Project P-2011-13 – Reconductor circuitry along Rt. 82 (Phase I)
- Reference: Category 15 Capital Budget Project P-2011-17 - Reconductor circuitry along Rt. 82 (Phase II)
- Reference: EP2016-012 Spare 10/12MVA Transformer Relocations

7.7.1.1 Summary of Issues

The Northeast Dutchess and Southern Columbia County area encompasses several rural towns with village centers, such as Northeast, Ancram, Millerton, Pine Plains, Milan, Gallatin, Stanfordville, Clinton, and

Washington. The area is experiencing step-down transformer loading issues, aging infrastructure, and below-average electric service reliability. There have been minimal signs of area growth over the recent history, but the abundance of 4800V circuitry in this area poses a safety risk, constraint on operational flexibility, concerns regarding aging distribution infrastructure, and also limits hosting capacity for DERs.

The Pulvers Corners 7395 34.5kV subtransmission line feeding the Ancram Substation also has age related concerns. The line is comprised primarily of aging 1/0 ACSR conductor that is showing signs of corrosion and degradation. Portions of the line are over 70 years old and the circuit has experienced two conductor failures over the past five years. A sample of the 7395 conductor was tested externally and the analysis results were provided to Central Hudson. The test results confirm that the strength of the conductor is reduced, most likely due to visible corrosion in the steel core.

The Ancram transformer phase #3 DGA trends indicate that there was arcing in oil. The trend started in 2019 and has been stable since the H1 bushing was replaced due to poor test results. The presence of arcing gases appears to be related to the bushing, as none were present prior. Since the trend is stable, no increased monitoring of the oil is recommended. Based upon these conditions being stable the transformer will continue to be monitored under normal routine maintenance and testing. The other two phases have positive test results and a single phase unit is available as a spare.

7.7.1.2 Summary of Recommendations

- Continue the 4800V conversion program – The practice of installing 4800V circuitry was abandoned in the 1940s, and therefore the infrastructure has exceeded its useful life. It also limits the operational flexibility and hosting capacity of the area. Infrastructure needing replacement will be identified through this program.
- Complete budget project P-2011-13 and P-2011-17 to reconductor circuitry along Rt. 82 scheduled for 2024 and 2025, respectively, to improve the operational flexibility in the area.
- Distribution Planning is in the process of conducting an assessment of the Pulvers Corners/Ancram area to address the infrastructure concerns.

7.7.1.3 Anticipated Date of Study

Pulvers Corners/Ancram Infrastructure Assessment – 2023

7.8 Load Group 7 – Mid-Dutchess (North)

7.8.1 Poughkeepsie 14.4 kV System

- Reference: EP2010-002 Poughkeepsie 14.4kV Area Study

7.8.1.1 Summary of Issues

The Reynolds Hill Substation is composed of two 115-13.8 kV transformers, and in addition to distribution circuits, serves 14.4 kV feeders that supply the secondary network transformers and load in the City of Poughkeepsie. The two transformers at the Reynolds Hill Substation were identified as needing to be replaced based on condition and age. These transformers were replaced in 2018. There are four (4) lateral branches remaining of aging PILC cable on the Poughkeepsie 14.4kV system which supply the network. In 2019, the City of Poughkeepsie announced plans to repurpose the major road, Market St., where these lateral branches reside.

7.8.1.2 Summary of Recommendations

Capital funds have been allocated to address the remaining PILC lateral feeds on the Poughkeepsie 14.4 kV network for 2022 and 2023.

7.9 Load Group 8 – Mid-Dutchess (South)

7.9.1 Beacon/Conway Place

- Reference: EP2013-008 Beacon Area Study
- Reference: Category 15 Capital Budget Project F-2021-07 8018L/8085L – Beacon Conversion (Phase V)

7.9.1.1 Summary of Issues

The City of Beacon in southern Dutchess County was primarily served by the Beacon and Conway Place Substations. These stations were fed by a 14.4 kV loop originating at the Forgebrook Substation. Due to age and infrastructure condition, the Beacon Substation was retired in 2016; the CM/NM and BF sub-transmission lines were re-classified and utilized as the 8017 and 8018 13.2kV distribution circuits in 2017; the Conway Place 881 and 882 circuits were converted to 13.2kV operation; and the Conway Place substation was retired in 2019.

7.9.1.2 Summary of Recommendations

Based on the retirement of the 4kV Beacon and Conway Place Substations, the following projects are expected to be completed within the upcoming years to improve reliability:

- An automatic load transfer team was installed at the former Beacon Substation location.
- Complete capital budget project F-2021-07 to convert remaining low voltage circuitry between the 8018 and 8085 and re-establish ties has been budgeted for completion in 2025.

7.9.2 Knapps Corners

- Reference: EP2009-001 Knapps Corners Substation Breaker Study
- Reference: SR 2012-01 Knapps Corners 15kV Bus Reconfiguration
- Reference: EP2020-009 Knapps Corners Integration Study

7.9.2.1 Summary of Issues

The Knapps Corners Substation was originally put in service in 1941 and expanded in 1953. A large portion of the equipment currently in the station has exceeded its useful life. Equipment identified as in-need of replacement includes 11 breakers, 63 relays, and all associated metering. Also, the three substation transformers are mid-60s vintage units and have exceeded the accepted industry standard life of 50 years.

Additionally, when the Spackenkill Substation was placed in service in 2010, the associated Knapps Corners 14.4kV system was retired. This retirement left the existing regulators, reactors, and phase shifting transformers unnecessary and obsolete.

7.9.2.2 Summary of Recommendations

A new Knapps Corners Substation is being constructed with an expected in-service date of December 2022. When placed in service this will address all infrastructure related concerns. The new substation is being constructed on an adjacent piece of property since the existing substation cannot be removed from service during the construction of the new station and the existing footprint is constrained.

The existing Knapps Corners Substation will be retired following the in service of the new Substation. A distribution plan has been developed for circuit exits out of the new substation location and construction will be completed in coordination with substation work.

7.9.3 Myers Corners

- Reference: EP2021-014 Change to Bus Tie Configuration at Myers Corners Road Substation

7.9.3.1 Summary of Issues

The current relaying at the Myers Corners substation is antiquated and requires replacement in order to meet the current relaying and metering requirements for the Grid Modernization program. The substation currently operates with a closed 13.8kV bus tie and limits the integration of DERs due to exceeding fault current design ratings.

Additionally, it has been determined that the existing switchgear, housing, doors, and breakers in the Myers Corners Substation are nearing the end of their useful life. The substation is nearing 40 years old, and based on condition assessment the switchgear requires replacement.

7.9.3.2 Summary of Recommendations

The relaying at the Myers Corners Substation was upgraded in 2018.

Plans to create a normally open bus tie have been evaluated and recommended in order to reduce the low side bus fault currents and allow for DER projects to interconnect to the station.

Due to the condition of the switchgear, a new Power Control Center will be installed in 2026.

7.9.4 Shenandoah/Fishkill Plains – East Fishkill Area

7.9.4.1 Summary of Issues

The East Fishkill area has recently seen an increase in commercial load stemming from new warehouses such as Amazon and Frito Lays. This has caused the Shenandoah circuits to approach their design criteria. The Amazon warehouse was connected to the former “IBM Wiccopee Substation”. This station operates with a closed bus tie and has higher fault current availability. The other circuits that supply the East Fishkill area emanate from the Fishkill Plains substation and also are approaching their design criteria. This area currently has an NWA which has the ability to curtail some of the loading; however, the addition of lumped loads has caused a need to study the area’s load serve capability in the near term.

7.9.4.2 Summary of Recommendations

It is recommended that an area study be performed to address the new lumped loads. A potential solution would be to reclassify the Wiccopee Substation as a distribution substation and operate the bus tie normally open to limit the fault currents to below 8500A.

8. Summary of Projects

To optimize the expenditure of ratepayer contributions and plan for the future, the Electric Engineering Capital Budget is developed based upon Electric Planning Studies, compliance requirements, infrastructure programs, and reliability improvement programs that are integrated into this Long Range Electric System Plan. Each year, the Company develops a 5-Year Corporate Capital Forecast and an annual Capital Plan/Budget for upcoming five and one year time frames. The 5-Year Capital Budget for the Transmission (Category 12), Substation (Category 13), and Distribution (Category 15) categories serves as a summary of all of the major near-term integrated components described in this document, as well as additional minor projects identified through the Electric System Planning Process. This Capital Plan is reviewed and approved by the Company's Board of Directors and filed with the Public Service Commission on July 1 of each year. The current version of this document is the "2023-2027 Corporate Capital Forecast and 2023 Capital Budget".

9. Emerging Opportunities

Through areas like our R&D committee, industry meetings, and through benchmarking/interactions with other utilities, Central Hudson is continually identifying and evaluating new and emerging technologies that may be applicable to our business. While this document contains many emerging opportunities detailed in other sections, a number of emerging opportunities are receiving significantly increased attention based on the New York State Reforming the Energy Vision (REV) initiative, the Climate Leadership and Community Protection Act (CLCPA) and the Accelerated Renewable Energy Growth and Community Benefit Act (Accelerated Renewables Act). Specifically, Distributed Energy Resources (DER) are growing at a rapid rate and are forecast to continue to grow within the state. These resources include the following technologies: Electric Vehicles (EVs), standalone Photo-voltaic (PV systems), standalone Battery Energy Storage Systems (BESS), PV paired with BESS, Demand Response, and Energy Efficiency. Central Hudson has begun incorporating DER into our planning processes as these resources begin to have an impact on our system. There will most likely be sections dedicated to these technologies in subsequent Long Range System Plans. Please note that while Central Hudson's DSIP typically contains the current status and long-range plans for these emerging technologies, the June 30, 2022 DSIP update has been deferred until at least December 31, 2022. This deferral was requested to allow for sufficient time for collaborative stakeholder discussions and to align the DSIP process with local transmission and distribution planning processes related to efforts associated with the Commission's September 9, 2021 Order in Case 20-E-0197.

Case 20-E-0197, Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act, addresses the more recent initiatives impacting our business which include the passing of the CLCPA and the Accelerated Renewables Act. Among other topics, these documents present ambitious New York State goals in the areas of renewables (including solar, land based and off-shore wind), and energy storage. Central Hudson is actively working with the Department of Public Service (DPS), the New York State Energy Research and Development Agency (NYSERDA), Public Power Agencies (NYPA and LIPA/PSEG-LI) and the New York State investor owned utilities (Con Ed, National Grid, NYSE&G/RGE and O&R) in a number of forums to help facilitate the achievement of the goals outlined in these documents. These, and other emergent State policy initiatives will continue to inform and impact Central Hudson planning and business processes. Based on the timing, a number of uncertainties and ongoing discussions regarding these initiatives, the impacts from these acts have not been reflected to any great degree in this plan. However, it is anticipated that these initiatives will have significant impacts to our long range system plans and planning processes in the near future to meet the goals of the CLCPA and Accelerated Renewables Act.

10. Conclusion

Central Hudson has developed a comprehensive Long Range Electric System Plan that provides sufficient vision and detail to effectively evaluate and prioritize capital expenditures, while allowing flexibility to integrate emerging trends, technologies, and policies with for the benefit of our customers. This Long Range System Plan outlines our most current plans to address system and locational growth, infrastructure issues, and to plan for and accommodate significantly increased penetration levels of DER onto our transmission and distribution system into the foreseeable future.

D. Avoided Cost Study Report

DRAFT REPORT

2023 Central Hudson Location Specific Transmission and Distribution Avoided Costs

Prepared for Central Hudson
By
Demand Side Analytics
June 2023

ACKNOWLEDGEMENTS

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ABSTRACT

The focus of the study is in quantifying the T&D costs associated with an increase or decrease of kW coincident with location specific peaks. It does not include costs associated with aging or failed equipment, reliability improvements, and grid modernization. The study estimates location specific growth patterns and avoidable T&D costs for individual substations and transmission areas. The load growth forecasts and avoided cost estimates were develop using probabilistic methods and account for the reality that there is much greater uncertainty ten years out than one year out.

Most substations and transmission areas in Central Hudson territory are experiencing declining loads, have ample room for growth over the next 10 years, or are in non-wire-alternative project areas. However, three substations, Grimley Road, Reynolds Hill, and Woodstock; and two transmission areas, the RD-RJ Lines and Westerlo Loop, may require future load relief, as all five locations are either experiencing load growth or will experience increased electrification as more customers purchase electric vehicles and install heat pumps, increasing the risk of overloads and of triggering an infrastrucutre investment. Avoided costs are included for all five locations.

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1 INTRODUCTION

One vital role of the electric utility is to ensure that electricity supply remains reliable. By projecting future demand and reinforcing the local distribution network so that distribution capacity is available to meet local needs as they grow over time, costly outages are avoided.

A key focus of the New York Public Service Commission's REV proceeding is to defer or eliminate the need for traditional T&D infrastructure investments by using DERs. This requires quantifying the potential to avoid or defer infrastructure upgrades based on load growth as granularly as possible.

The growth of DERs is fundamentally changing the nature of distribution system forecasting, planning, and operations. Forecasting location specific loads and DERs using probabilistic methods is becoming increasingly critical for T&D planning. However, local demand trajectories based on historical loads are inherently uncertain and those forecasts grow more uncertain further into the future. Location specific, granular forecasts are also essential to establishing the location specific value of DERs and identifying locations where DERs are beneficial. Simply put, location specific forecasting and planning methods have direct implications for DER integration.

To our knowledge, Central Hudson was the first New York State utility to implement a location specific avoided T&D cost study that relies on probabilistic analysis and quantifies the option value of reducing peak demand. This is Central Hudson's fourth time implementing this type of study and we have looked to make enhancements with this iteration. We emphasize that the development of probabilistic load forecasts and avoided T&D costs at a granular, local level is still a relatively new endeavor and continues to be refined and improved since it was first used for the 2016 Avoided Cost Study.

The focus of the study is in quantifying the T&D costs associated with an increase or decrease of kW coincident with location specific peaks. The study focuses on substation and transmission costs (it includes circuit feeder load forecasts but not avoided costs) and was designed to meet the following objectives:

§ Analyze load patterns, excess capacity, load growth rates, and the magnitude of expected infrastructure investments at a local level

§ Develop location specific forecasts of growth with uncertainty

§ Quantify the probability of any need for infrastructure upgrades at specific locations

§ Calculate local avoided T&D costs by year and location using probabilistic methods

§ Identify beneficial locations for DERs

There are several aspects of the study that make it unique. First, the T&D avoided cost estimates are produced by substation and transmission area. Most T&D marginal cost and avoided costs studies produced system wide values or at most region specific results, often concentrating on historical T&D expenditures rather than future infrastructure investments. Second, the study estimates historical year-to-year growth patterns and variability in growth for individual substation and transmission areas. Third, load growth forecasts and avoided cost estimates are develop using probabilistic methods rather than straight-line forecasts. The approach takes into account the reality that there is much greater uncertainty 10 years out than a year out, and accounts for the risk mitigation value of resources that manage local peak loads.

As a general rule, only growth-related T&D investments that are shared across multiple customers and a small subset of reliability based projects can be avoided by DERs or demand management. When loads grow, the excess distribution capacity that may exist dwindles. If a customer helps reduce coincident demand, either by injecting power within the distribution grid or by reducing demand, the unused capacity can accommodate another customer's load growth, thereby helping avoid or defer investments required to meet load growth. Avoided or deferred T&D investments free up capital for other alternate uses, improving the efficient use of resources.

Not all investments are driven by local, coincident peak loads. Some investments are tied to customer additions and are essentially fixed. Other investments must take place because of aging or failed equipment or because of the need to improve reliability and modernize the grid. These investments typically cannot be avoided by managing loads with DERs.

The value of transmission and distribution deferral varies significantly across local system areas because of:

- Load growth rates and anticipated changes in load curve shapes, which affect whether growth related upgrades can be avoided and how long they can be deferred;
- The seasonality of the peak load (i.e., summer vs. winter);
- The amount of existing excess capacity or the amount of additional load that can be supported without upgrades;
- The magnitude, timing, and cost of projected distribution upgrades;
- The design of the distribution system; and
- The ability to make fairly inexpensive upgrades (i.e., switching alternatives) in some cases to address constraints.

In areas with excess capacity—or areas where local, coincident peaks are declining or growing slowly—the value of capacity relief can be minimal. In areas where a large, growth-related investment is imminent, the value of capacity relief can be quite substantial, especially if it is possible to delay or defer infrastructure upgrades for a substantial time. However, many Central Hudson areas have declining or slowly growing loads, or they have sufficient capacity already built, since the system peak of 1,295 MW was set in 2006 and system load has dropped significantly since that time, such that investments are not needed in the foreseeable future.

In 2016, 2018, and 2020, Central Hudson implemented location specific avoided T&D cost studies that relied on probabilistic analysis and quantified the option value of reducing peak demand. This 2023 study updates the 2020 avoided T&D costs by incorporating additional years of load data, and enhancing the previous study by forecasting circuit loads and including electrification in the forecast. In comparison to the 2020 study, the 2023 T&D avoided costs differ along the following dimensions:

- The electrification forecast was incorporated into peak loads, leading to higher peaks compared to just using econometric load forecasts in 2020;
- Forecasts were conducted separately for each season (summer and winter);

- Forecasts were developed for circuits in addition to being developed for substations and transmission areas;
- Growth rates were based on a more recent period of data, 2018-2022;
- The two locations with value in the 2020 study (Shenandoah-Distribution and Northwest 115-69 kV Area) no longer trigger upgrades, due to declining loads;
- The five locations with value in the 2023 study are all highly loaded with positive growth rates, and are expected to have increased loads due to electrification over the next ten years, resulting in a high investment trigger likelihood (in the absence of further NWAs); and
- Because all projects underlying the T&D avoided costs have not been classified for non-wire solutions, there is value from deferring all five locations.

One important note for the remainder of this document is that the T&D avoided cost forecast is different from the bottom-up load forecasts used for planning. We compare the two forecasts in the tables below for clarity. Both sets of forecasts are bottom-up, location-specific forecasts. These forecasts are reconciled with the system-wide forecasts to ensure that any differences are minimal and explained by line losses.

Table 1 illustrates the components of the bottom-up load forecasts used for planning. A similar forecast is produced for each of Central Hudson's transmission areas, substations, and circuit feeders. The bottom-up granular forecasts have been designed to isolate the key drivers of change in loads. The forecasts separately track gross T&D loads, solar, battery storage, building electrification, electric vehicle loads, and incremental energy efficiency (including codes and standards). The approach allows Central Hudson to combine the various components for different planning applications, such as the Avoided T&D Costs Study. The granular forecasts can be summarized for the coincident (territory wide) or non-coincident (local) summer and winter peak at different levels of geographic granularity. They also can be shown for the single peak hour, for peak days, or for the full 8760 hours per year and each level of geographic granularity. Over recent years, Central Hudson summer peak demand has shifted from mid-afternoon hours to the late evening. As a result, the contribution of solar on the peak hour is smaller.

Table 1: Summer and Winter Territory-Wide Load Forecast with and without DERs and Beneficial Electrification (2023-2028)

Season	Year	(a) Gross Load Forecast	(b) EV Load	(c) Building Electrification	(d) EE & C&S	(e) Solar PV	(f) Storage Net Load	(g) Planning Load a + b + c + d + e + f
Summer	2023	1,115.4	8.8	-1.4	-7.2	-27.0	-8.1	1,080.5
	2024	1,115.9	13.1	-2.8	-13.6	-31.7	-8.4	1,072.4
	2025	1,116.7	19.1	-4.7	-21.2	-36.8	-9.5	1,063.6
	2026	1,118.1	27.2	-7.1	-28.8	-42.9	-10.2	1,056.3
	2027	1,119.9	37.7	-9.8	-36.2	-49.9	-11.2	1,050.5
	2028	1,122.2	50.8	-13.0	-43.7	-55.9	-12.3	1,048.1
Winter	2023	945.0	5.9	9.3	-7.1	-2.7	-8.1	942.3
	2024	945.5	8.8	19.0	-13.4	-3.2	-8.3	948.4
	2025	946.3	12.9	32.2	-20.9	-3.7	-9.4	957.4
	2026	947.6	18.5	48.1	-28.3	-4.3	-10.1	971.4
	2027	949.2	25.7	66.5	-35.6	-5.1	-11.1	989.7
	2028	951.2	34.7	87.5	-43.0	-5.7	-12.3	1,012.6

[1] The peak values displayed in the table are coincident with the planning load for Central Hudson service territory

Table 2 shows the forecast used for the Avoided T&D study, which is different than the forecasted or expected loads. A similar forecast is produced for each of Central Hudson's transmission areas, substations, and circuit feeders, which can be found in Appendix B and Appendix C of this report. By design, the study's objective is to identify T&D upgrades that would occur if additional or incremental distributed resources – solar, battery storage, and energy efficiency – were not added, and to quantify the deferral value associated with reductions in demand (or local power injections). Thus, the avoided T&D study forecasts include existing DERs, and the impact of electric vehicles and building electrification, but does not include DERs that reduce demand and have not yet been built. For the remainder the report, the focus is on the forecasts used for the Avoided T&D Study.

Table 2: Summer and Winter Territory-Wide Avoided T&D Cost Forecast (2023-2028)

Season	Year	(a) Econometric Forecast	(b) EV Load	(c) Building Electrification	(d) Avoided T&D Cost Forecast a + b + c
Summer	2023	1,127.2	8.6	-1.6	1,134.2
	2024	1,127.4	12.8	-3.2	1,137.0
	2025	1,128.1	18.6	-5.5	1,141.3
	2026	1,129.3	26.5	-8.2	1,147.6
	2027	1,131.0	36.8	-11.4	1,156.4
	2028	1,133.2	49.6	-15.1	1,167.7
Winter	2023	943.8	5.9	9.3	959.0
	2024	944.3	8.8	19.0	972.1
	2025	945.1	12.9	32.2	990.3
	2026	946.4	18.5	48.1	1,012.9
	2027	948.0	25.7	66.5	1,040.3
	2028	950.0	34.7	87.5	1,072.3

[1] The peak values displayed in the table above are coincident with the avoided T&D cost forecast peak for Central Hudson territory

The remainder of this report is organized in five sections.

- Section 2 provides an overview of the methodology.
- Section 3 presents the historical growth estimates.
- Section 4 details the avoided costs and the risk of triggering infrastructure upgrades or load transfers by location and discusses differences between the 2020 and 2023 study.
- Section 5 summarizes the load characteristics for the five locations where additional DERs may be beneficial.
- Section 6 summarizes the key findings and conclusions.

2 METHODOLOGY

This section details the risk tolerance for different types of systems, data sources used, and key steps in developing location specific forecasts and avoided T&D cost. Before doing so, we discuss why probabilistic methods are critical not only to forecasting, but also to quantifying location specific avoided T&D costs.

2.1 T&D LOAD PATTERNS AND INFRASTRUCTURE UPGRADES

When demand exceeds normal and emergency equipment ratings, equipment can become overloaded and degrade more quickly, considerably increasing the risk of an adverse reliability event. With the exception of single transformer rural substations, most of Central Hudson's system is designed to withstand the loss of the highest rated source (e.g., the loss of a transmission line, transformer, or other component) without violating thermal or voltage limits – that is, the substation or area design rating is often equal to the lowest equipment rating. As a result, loads in excess of the load serving capability, or design rating, do not automatically result in overloads or an infrastructure upgrade. However, depending on the level of risk of impacted customers and load, Central Hudson may not wait for loads to exceed a reasonable level of risk to begin construction.

To assess future upgrade likelihood, it was necessary to define structured criteria for when upgrades might be triggered in the future. The criteria were designed to reflect the reality that forecasting load levels that have the potential to result in exceeding a normal or emergency equipment rating from time to time does not automatically trigger an infrastructure upgrade, though it does increase equipment failure risk. Specifically, the upgrade trigger was defined as occurring when a location's long-term emergency rating is forecast to be exceeded in two consecutive years; a single occurrence of the forecast exceeding the short-term emergency rating would also trigger an upgrade. The future loads for this analysis were modeled using 1 in 2 weather conditions.

Figure 1 illustrates a fundamental feature of peak energy demand. The graphs reflect the 2022 load duration curves for Central Hudson's 10 transmission areas (non-weather-normalized). Load duration curves sort electricity demand from highest to lowest and are a good way to visualize how 'peaky' a system is. The graph only shows the top 5% of hours in 2022. All of the load duration curves show hourly demand as a percent of each area's 2022 peak, allowing side-by-side comparisons for areas with a different magnitude of demand. For most locations, the top 20% of loads are associated with 2% (175 hours) or less of the hours in the year. Figure 2 shows the same load duration curves as a percent of each transmission area's design rating (including NWAs), highlighting the varying degree of loading within each transmission area. The results for individual substations are similar but with a wider range of diversity.

Figure 3 illustrates the diversity in peak day load shapes for Central Hudson using substation loads. The substations were classified as summer peaking or winter peaking based on the season of top 10 highest load days in 2022, and the plots show the average peak day hourly load profile in that season. The plots were normalized, and show the percentage of usage for the day in each hour (the area under each curve adds up to 100%), allowing comparison of substations of different sizes. For summer peaking substations, the peak falls sometime in the afternoon or early evening. Most winter peaking substations are dual peaking, with the highest load occurring in the afternoon or early evening and a secondary peak occurring in the morning.

Figure 1: Normalized Load Duration Curves – Percent of Peak Load

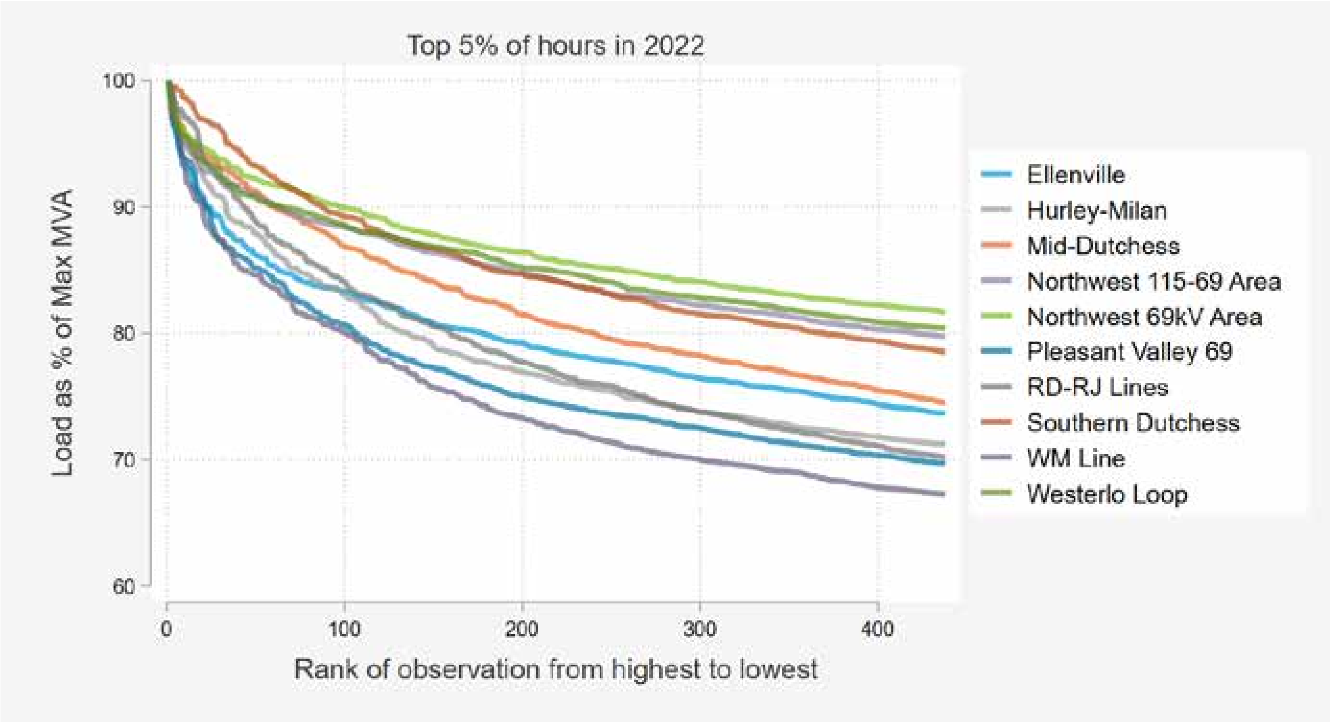


Figure 2: Normalized Load Duration Curves – Percent of Design Rating

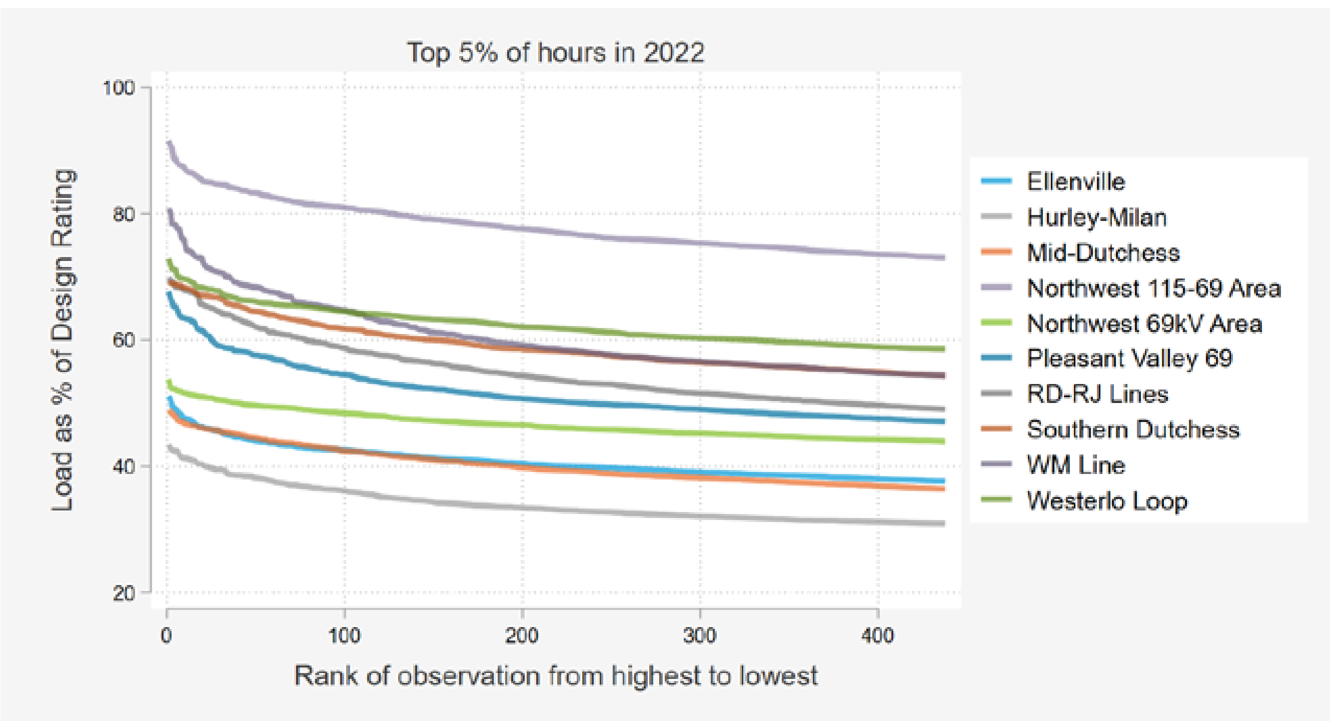
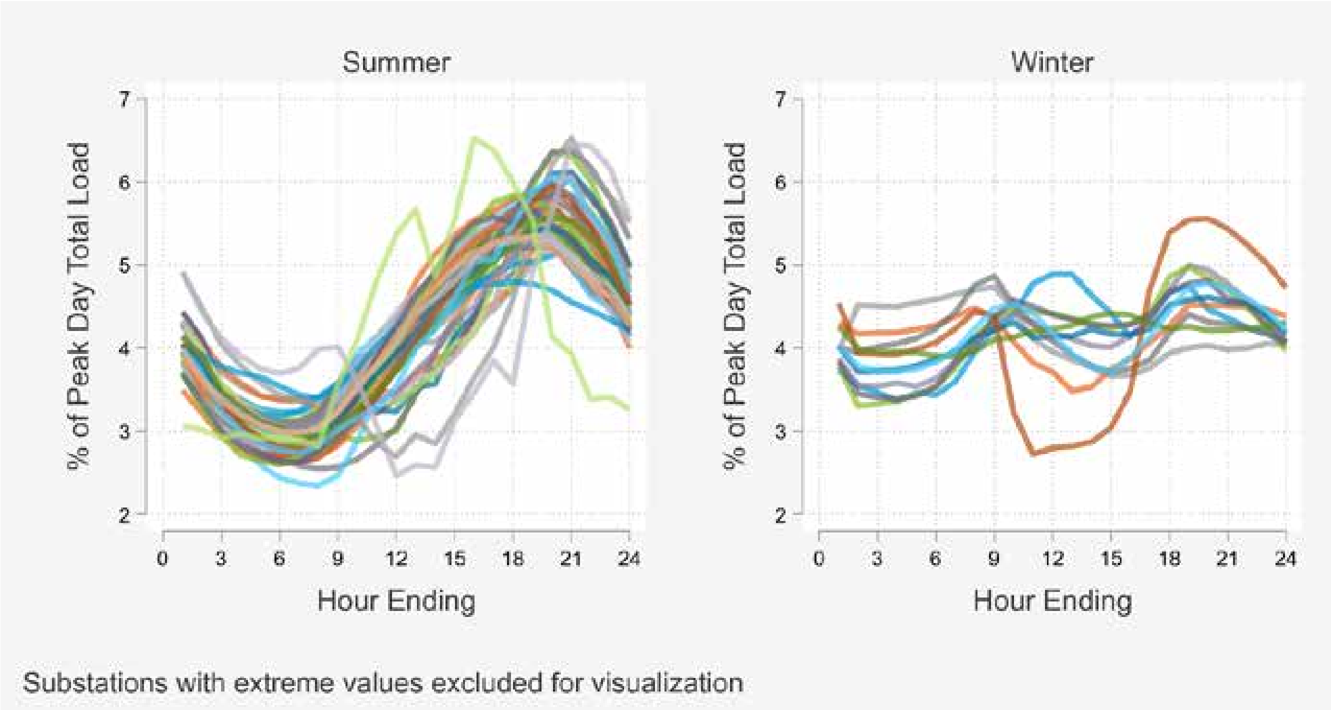


Figure 3: Central Hudson Location Specific Peak Day Load Shape Classification

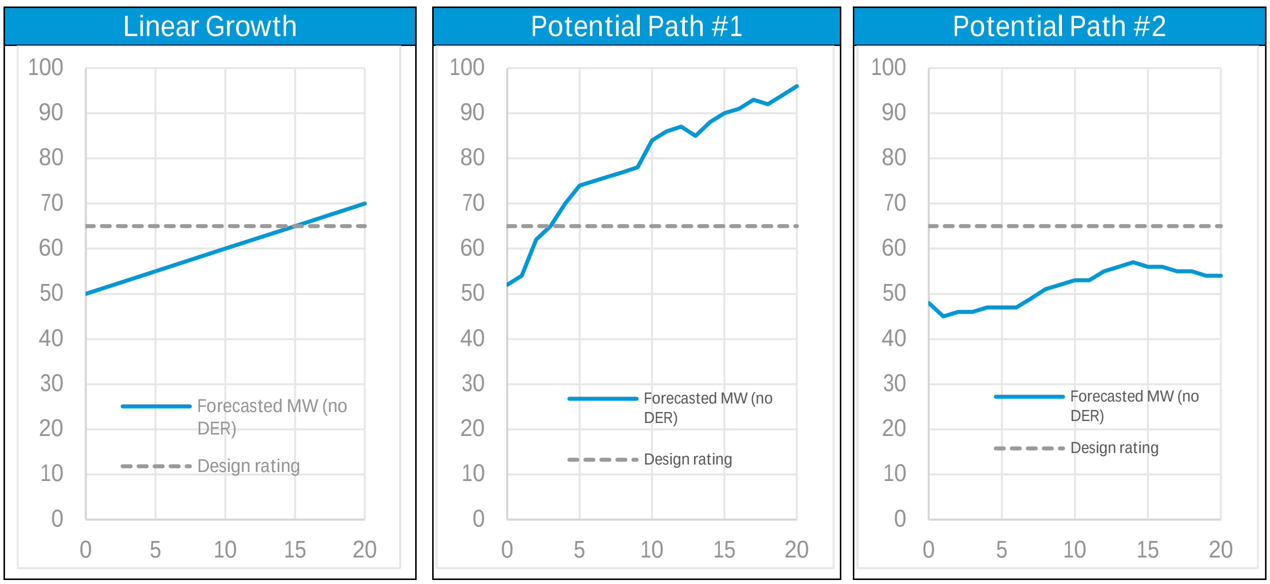


2.2 WHY USE PROBABILISTIC FORECASTING AND PLANNING METHODS?

No one knows in advance precisely when loads will exceed design ratings or by how much; however, linear forecasts assume precise knowledge. In practice, actual growth trajectories are rarely linear and growth patterns trend across time – both load growth and load declines follow cyclical patterns.

Figure 4 contrasts a linear forecast against two simulated potential growth trajectories, all using the same 1.0% growth rate. The linear forecast indicates loads will exceed the design rating in 15 years. But actual growth rarely follows a linear pattern. Loads could exceed the design and risk tolerance far earlier, as shown by Potential Path #1, or never at all, as shown by Potential Path #2. But the two potential outcomes are not equally probable.

Figure 4: Comparison of Linear Forecast and Potential Growth Patterns



Forecasts inherently include uncertainty and become more uncertain further into the future. Because a linear forecast assumes exact knowledge, no value is assigned to the years before the linear forecast exceeds the risk tolerance. Probabilistic methods, on the other hand, reflect the potential reality that infrastructure investment could be triggered earlier. Probabilistic methods will assign value to periods earlier than the linear forecast would dictate based on the probability of triggering an earlier infrastructure upgrade.

2.3 DATA SOURCES

The study relied on nine main data sources:

1. 2018-2022 hourly interval data for most circuit feeders and substations and for each transmission area;
2. 2018-2022 annual sales data for all Central Hudson accounts, mapped to the appropriate circuit feeder, substation and transmission area;
3. 2018-2022 weather data from the Dutchess County Airport;
4. 1-in-2 weather year peak conditions data;

5. 1-in-2 forecasted Central Hudson System loads;
6. Forecasted electrification loads, mapped to the appropriate circuit feeder, substation and transmission area;
7. Design rating information for each circuit feeder, substation and transmission area;
8. Detailed data on NWAs, including the division between dispatchable and non-dispatchable portions;
9. Historical solar interconnections through 2022; and
10. Costs and financial assumptions for infrastructure upgrades.

With the exception of the 2018-2022 weather data, all of the above data was supplied by Central Hudson. A few points are noteworthy, however. First, the 2018-2022 time period was selected because of data availability and due to the significant shift in loads that occurred with the COVID-19 pandemic. While data were available back to 2010, we relied on data from 2018 and later to better estimate recent growth trends.

Secondly, not all substations have hourly interval data, and the quality and availability of the data degrades when longer time spans are included. For Central Hudson, substations with hourly interval data available covers approximately 97% of the cumulative system load. The quality of the data improves for larger aggregation points, such as transmission areas, where all of the historical data is available. For four substations without detailed interval data, we relied on annual historical sales data to produce growth rates.

Third, resources that have been procured as part of Central Hudson's NWA projects are incorporated by adjusting the design rating. The additional resources reduce loads, thereby leading to additional room for growth.

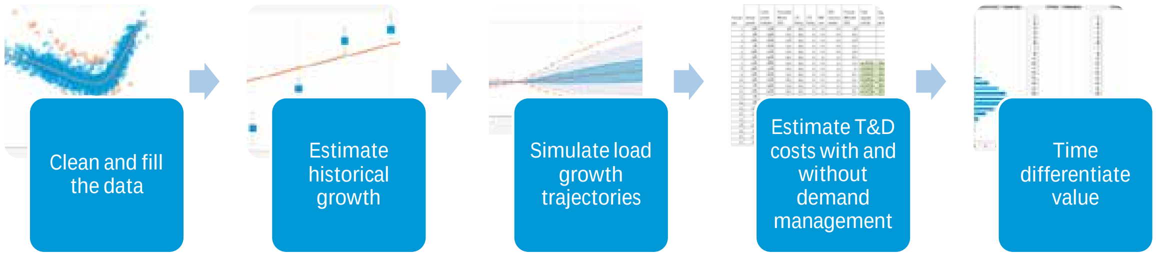
Forecasts and location specific estimates of T&D avoided costs were developed for all 10 transmission areas and 64 distribution substations[1]. For the 2023 study data gaps were filled such that 5 years of load data were prepared for all 64 substations. Given the high correlation between loads within the same load area, load patterns from substations in the same load area were used to fill in anomalous or missing data.

2.4 KEY ANALYSIS STEPS

Figure 5 describes the main steps in developing location specific avoided T&D costs using probabilistic methods. The process was implemented for substation, load areas, and transmission areas. Importantly, the 5,000 simulations of potential growth trajectories are critical to both the forecast and to estimating T&D costs with and without demand management.

[1] The report summarizes results for 60 substations. Analysis was also conducted for 4 additional substations dedicated to large industrial customers but the results are not published to ensure customer privacy.

Figure 5: Key Steps in Estimating Location Specific Avoided Costs



2.4.1 Clean and Fill the Data

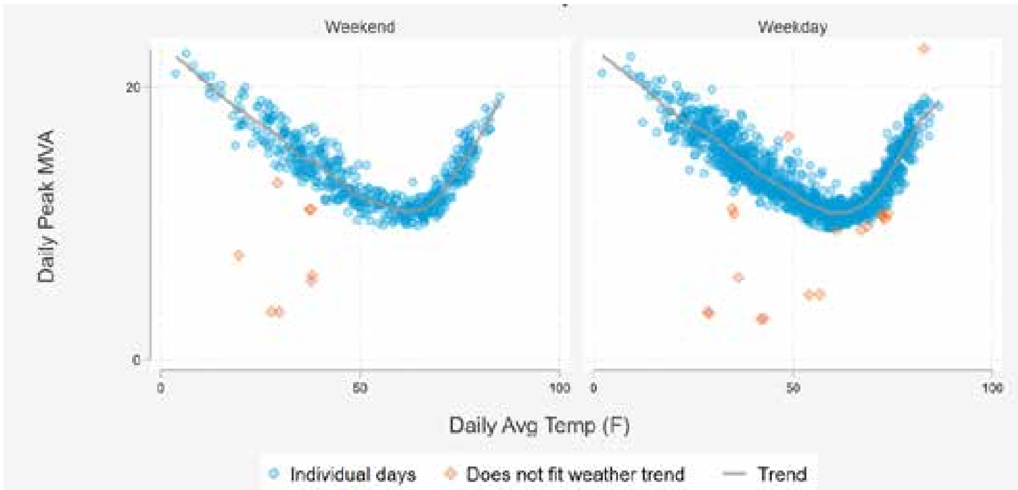
One of the key challenges in estimating load patterns and growth at granular locations is the quality of data. Not all substations and circuit feeders have usable metered data over the relevant historical period and, for those that do, it is important to identify and remove load transfers, outages, data gaps, and data recording errors. DSA used data analytics to identify loads with irregular patterns, load transfers, data gaps, and outages from substation level data. Central Hudson's engineers subsequently reviewed those loads to confirm dates where load transfers occurred.

Next, we filled the data points identified as outliers in the cleaning step with synthetic load data. To predict synthetic loads, for each location we developed regression equations relating the load at that location to the load at surrounding areas as well as day of week, month, and outdoor temperature. These equations were then used to predict the synthetic load for missing time periods. System loads were used if there was insufficient data available in the surrounding regions or if the loads were for a transmission area. For all substations and circuits without detailed interval data, we combined annual historical sales data with a normalized 8760 load shape created from neighboring substations or circuits to fill in hourly interval data.

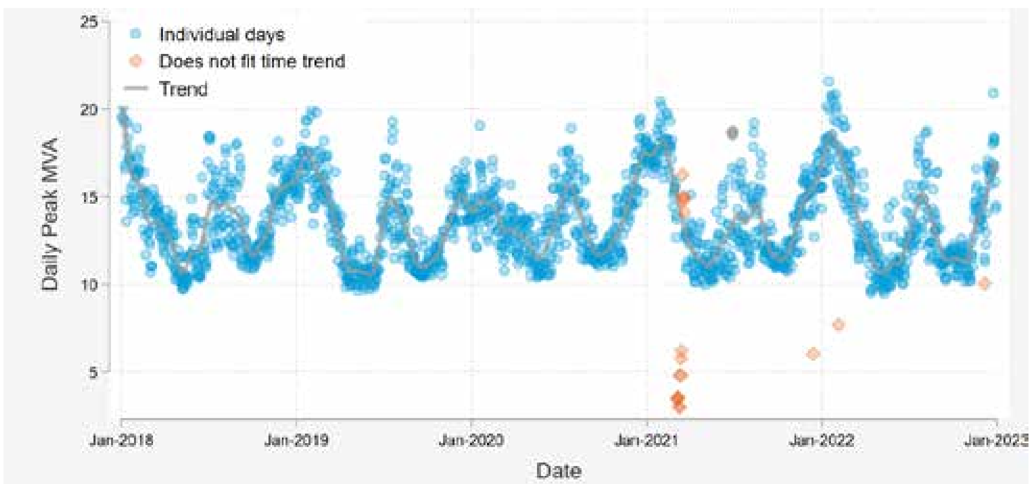
Figure 6 below illustrates the data cleaning process with an example of a location with load transfers, which, unless detected, can be mistaken for a load increase and distort the sensitivity of the area's loads to weather.

Figure 6: Example of Data Cleaning

Weather Trend: Excluded vs not Excluded



Time Trend: Excluded vs not Excluded

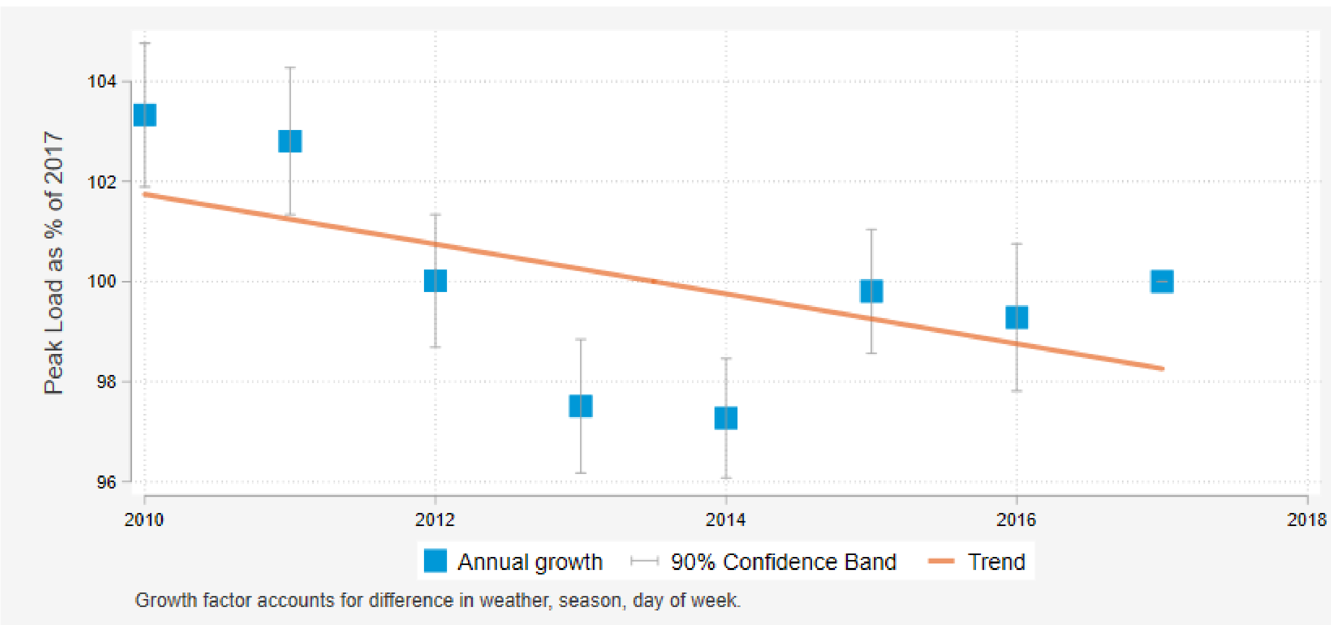


2.4.2 ESTIMATE HISTORICAL LOAD GROWTH

The objective of this step was to estimate historical load growth for each year in 2018–2022 in percentage terms. The year-to-year growth patterns were then used to assess the growth trend and the variability of load growth patterns; the degree of growth in a given year was related to growth during the prior year— technically known as auto-correlation. The econometric models were purposefully designed to both estimate historical load growth and allow us to weather normalize loads for 1-in-2 weather peaking conditions. The 2018–2022 peaks were normalized for 1-in-2 weather peak conditions based on the Central Hudson criteria for distribution and transmission design. Appendix A describes the econometric models.

Figure 7 illustrates some of the key outcomes from this analysis. First, the analysis produces year-by-year estimates of the historical growth or decline in loads after controlling for differences in weather, day of week, and season. Second, the year-by-year estimates allow us to estimate the growth trend. In the below example, loads are declining at a rate of 0.5% per year. Third, the results enabled us to estimate the variability in year-to-year growth patterns (also known as the standard error of the forecast).

Figure 7: Year-by-year Estimates of Historical Growth



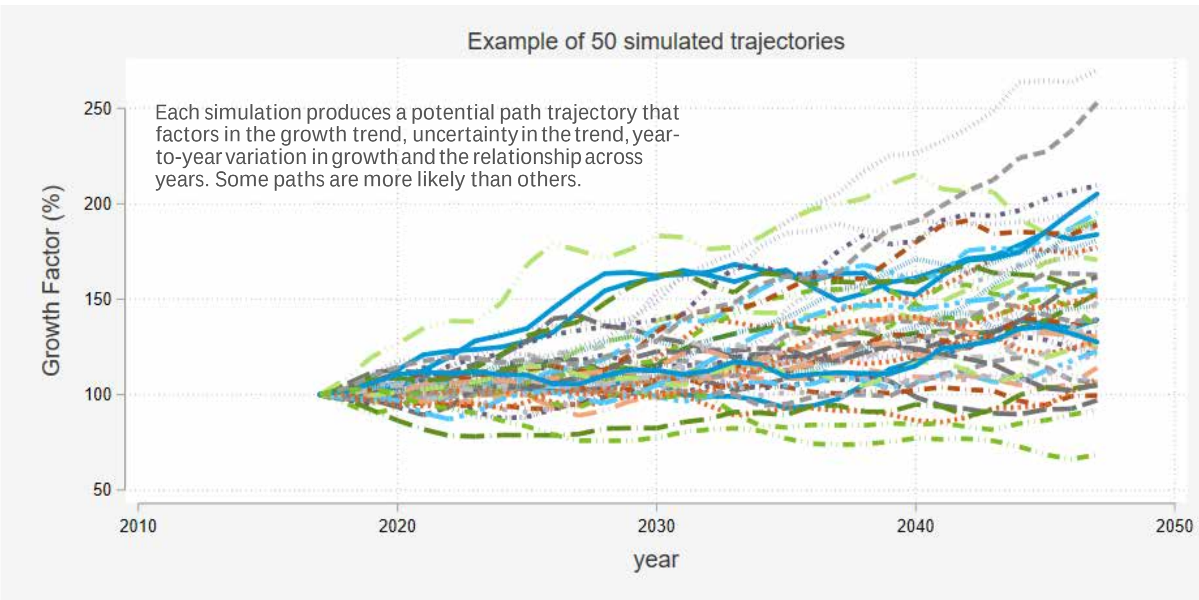
2.5 SIMULATE POTENTIAL LOAD GROWTH TRAJECTORIES

The load growth forecasts were developed using probabilistic methods—Monte Carlo simulations—that produced the range of possible load growth outcomes by year. It simulates the reality that the near-term forecast has less uncertainty than forecasts 10 years out. A total of 5,000 simulations were implemented for each substation and transmission area. Each simulation produced a distinct growth trajectory that took into account the historical trend, variability in growth patterns, and the fact that growth patterns are auto-correlated.

The simulations are based on historical growth patterns from the econometric models. Each forecast year's growth is a combination of an independent growth component and the prior year's growth trajectory.[2] The independent growth component is based on a random draw that factors in the historical trend, the uncertainty around the trend, and the year-to-year variation at the location. The forecasts are cumulative, meaning that each simulation's forecast trajectory builds on the prior year, producing a path. The process was repeated 5,000 times for each substation and for each transmission area. The result is a full picture of the possible load growth outcomes by year. Each of the 5,000 simulated growth trajectories produces specific information about if and when the design rating would be exceeded, and the amount of demand management required to maintain loads below the design ratings.

Figure 8 illustrates the critical role of probabilistic, location-specific forecasts. This type of forecasting requires estimating historical load growth patterns and simulating potential load growth trajectories thousands of times, as shown in Figure 8. Some outcomes are far more likely than others and are summarized into probabilistic bands that identify the likelihood of load growth falling within specific confidence bands, as shown in Figure 9.

Figure 8: Illustration of Location Specific Simulations and Probabilistic Forecasts



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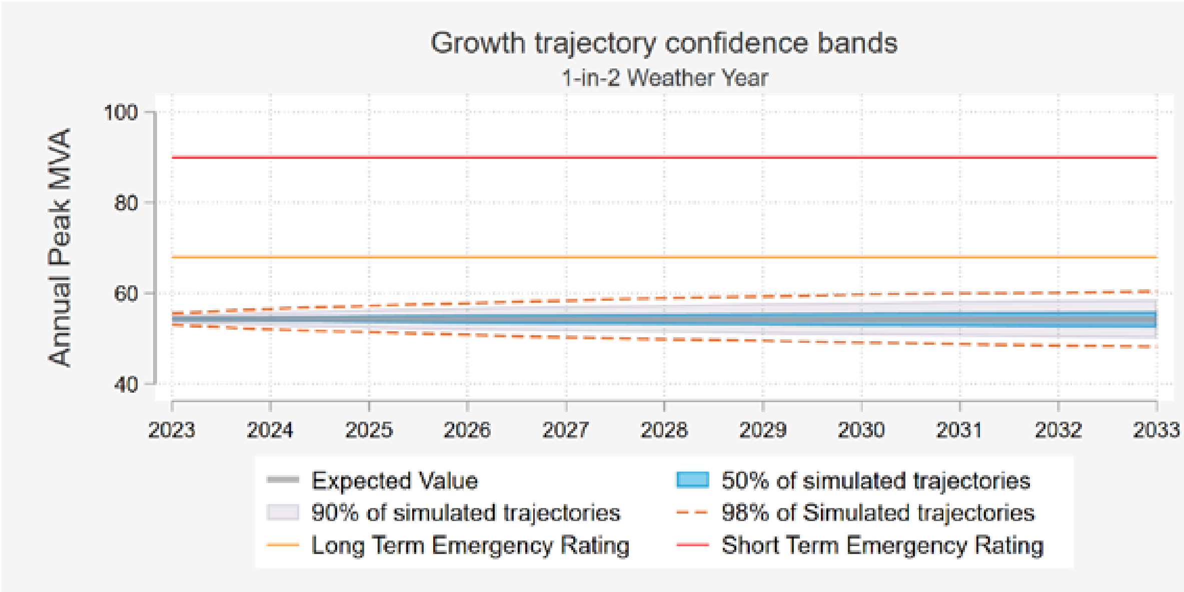
[2] *Annual growth$_t$ = Independent growth · (1 - autocorrelation) + Annual growth$_{t}$-1 · autocorrelation*

Figure 9: Annual Peak Forecast Confidence Bands



2.6 ESTIMATE COSTS WITH AND WITHOUT DEMAND MANAGEMENT

The estimates of the avoided T&D costs are based on the load growth forecast and the outcome of each simulation run. The process involved applying the below four steps to each of 5,000 simulation runs for each location:

1. Identify the timing of the infrastructure investments for each simulation run, location, and year. For each location, each simulation run produced a potential growth trajectory, which either exceeded the design rating or remained below it. As noted earlier, when forecast loads exceed design ratings, they do not automatically trigger infrastructure upgrades; forecast loads can exceed design ratings without triggering investments. Because load growth does not follow a perfect linear trajectory, forecast loads also can exceed the design ratings for a year or two, but revert to levels below the design rating in subsequent years. To reflect this complexity, the timing of infrastructure upgrades was simulated to occur the year after forecast loads exceeded design ratings for two consecutive years.

2. Identify the magnitude of demand management needed to maintain loads below the design rating. Once demand management resources were needed, we assumed they were in place for up to 5 years or until the magnitude of reductions needed exceeded 20% of peak loads, whichever came first. This reflects the reality that most projects cannot be postponed indefinitely, and the length of deferral may be shorter in areas with rapid growth.

3. Model T&D infrastructure costs with and without demand management for each simulation run, location, and year. When the design ratings were exceeded for two consecutive years, the costs of the infrastructure investments were included in the third year and allocated based on the revenue requirement of the upgrade. For example, equipment upgrade costs of $15 million with a 50-year book life would be spread or annualized over 50 years. This approach replicates how T&D costs are

incorporated into the rate base. We implemented the same cost calculations but instead assumed the investment could be deferred for up to 5 years or until 20% of the peak was managed through DERs, whichever came first.

4. Calculate the avoided costs per kW for each simulation run and location. If loads were not projected to exceed the respective design rating, no costs are avoided since a growth-related infrastructure investment would not have taken place anyhow. If the loads in a particular simulation exceeded the design rating, reducing loads to levels below the design rating would avoid or defer growth related infrastructure investment. Thus, the avoided costs are the difference between the costs with and without the reduction in loads necessary to avoid or defer the upgrade. T&D deferral value took into account when the capital costs, carrying costs, and the magnitude of the required load reduction.[3] The deferral value was levelized over the deferral years.[4]

The detailed calculations for each of the 5,000 simulations at each site were subsequently used to estimate the expected avoided costs per kW at each location for each year.[5] Because the analysis relied on probabilistic methods, the avoided cost estimates reflect the risk mitigation value of managing loads to remain below the design rating. That is, the probabilistic method assigns T&D avoided costs to location and year with, for example, a 10% likelihood of an upgrade. In contrast, a linear forecast would not assign any value to that year.

2.7 INTEGRATION OF DERS

One of the most important considerations is accurately reflecting the locational value of incremental resources. This creates a paradox: including DERs which have not yet been built and installed into forecasts lowers load forecasts and dilutes the locational value of DER resources. Similar to the 2020 study, the 2023 study isolated growth trends from the effect of solar interconnections which modify loads—this was not done for other DERs. Importantly, only existing solar resources were incorporated into the avoided T&D cost study.

Load reducing DER resources that are yet to be built (solar interconnections, energy efficiency, and battery storage) were not included because doing so would effectively dilute the estimated value of future resources.

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[3] The below equation reflects the deferral value calculations for each simulation run and location. In the equation, i reflects the inflation rate, r reflects the discount rate, and Δt reflects the deferral period. In practice, Central Hudson provided fixed charge rates (a % value) and DSA implemented the calculations. The fixed charge rates annualize the share of capital costs over the book life and include the revenue requirement adjustments.

$$Total\ Deferral\ Value\left(\frac{\$}{kW}\right) = \frac{Capital\ Cost\ (\$)\ \cdot Revenue\ Requirement\ Adjustment\ \cdot \left(1-\left(\frac{1+i}{1+r}\right)\right)^{\Delta t}}{Load\ Reduction\ Needed\ for\ Deferral\ (kW)}$$

[4] The total deferral value was annualized over the deferral period for each simulation run and location using the following equation, were r equals the discount rate, i is the inflation rate and n is the number of deferral years:

$$Annualized\ Deferral\ Value\ =\ Total\ Deferral\ Value\left(\frac{\$}{kW}\right)\cdot\frac{(r-i)}{(1+r)}\cdot\frac{(1+r)^n}{[(1+r)^n-(1+i)^n}$$

[5] The expected avoided cost is calculated by taking the average across all simulation runs (r) for each year (t) at an individual location (i).

$$Expected\ Avoided\ Cost_{i,t} = \frac{\sum_{r=1}^{5,000} \$\frac{kW}{year}_{i,t,r}}{5,000}$$

Load adding DER resources (electric vehicles, heat pumps) were added on to forecasted econometric load as these importantly flag areas where load reduction would be more beneficial due to higher loads from electrification. Table 4 and Table 5 break out the different loads that were included in the T&D avoided cost study as well as what loads were included in planning.

To isolate load growth trends from solar interconnections, production for historical interconnections was added to the cleaned load data to derive gross loads. Then the gross load data and weather data were used to estimate the relationship between load and demand on peak hours for each location, to isolate the growth rate that is unrelated to weather differences from year to year.

3 HISTORICAL LOAD GROWTH TRENDS

This section presents the data on historical peak loads, design ratings, and load growth estimates. The results are presented separately for transmission and distribution areas and for circuit feeders. A key distinction between probabilistic and straight-line forecasts is that the former approach explicitly accounts for the reality that forecasts are more uncertain further into the future.

Growth can slow down or accelerate in comparison to recent growth patterns and, in practice, actual growth trajectories are rarely linear. When a location has more room for growth, the chances it will exceed the design rating and trigger the need for infrastructure upgrades is lower. The results presented in this section focus on the growth rates, loading factors, and the standard error of the forecast.[6]

3.1 TRANSMISSION AREA LOAD GROWTH ESTIMATES

Locations with potential T&D infrastructure deferral value are areas where loads are growing but there is limited room to accommodate growth. Areas with sufficient load serving capability and areas where local, coincident peaks are declining are less likely to trigger growth related infrastructure upgrades.

Figure 9 compares the annual load growth rate to the 2022 loading factor (weather-normalized peak divided by the location's design rating including NWAs) for each of Central Hudson's ten transmission areas. Locations with a growth factor above 0% are experiencing growth and locations where the loading factor is closer to 100% have less room for growth. All other things equal, a location with a 2% annual growth rate will exceed ratings in approximately half the time as a location with a 1% growth rate. Note, however, that the chart does not factor in the uncertainty of future growth patterns.

The RD-RJ Lines transmission area is loaded above 80% in 2022 and has positive growth and both Westerlo Loop and Pleasant Valley are close to 80% loading and have positive growth rates, which causes them to become more heavily loaded later in the forecast period. All other transmission areas are experiencing slowing or declining loads or have ample room for growth without having to upgrade the transmission system. However, upgrades to transmission areas may be required due to aging equipment or grid modernization efforts not related to load growth. Specifically, electrification will increase loading in all transmission areas regardless of the current growth rate. Further, some generation capacity will be retired in the next ten years and some upgrades are currently planned for some transmission areas, which will increase the LTE and STE ratings for the Ellenville and Westerlo Loop areas and decrease the LTE and STE ratings for the Northwest 115/69 kV area. Figure 9 shows 2022 loading relative to current LTE ratings. Future changes to ratings are considered in the avoided cost estimates discussed below.

[6] The standard error of the forecast factors in both the accuracy of the historical load growth estimates and the volatility in the historical growth.

Figure 9: Transmission Area Growth Rates Versus Room for Growth

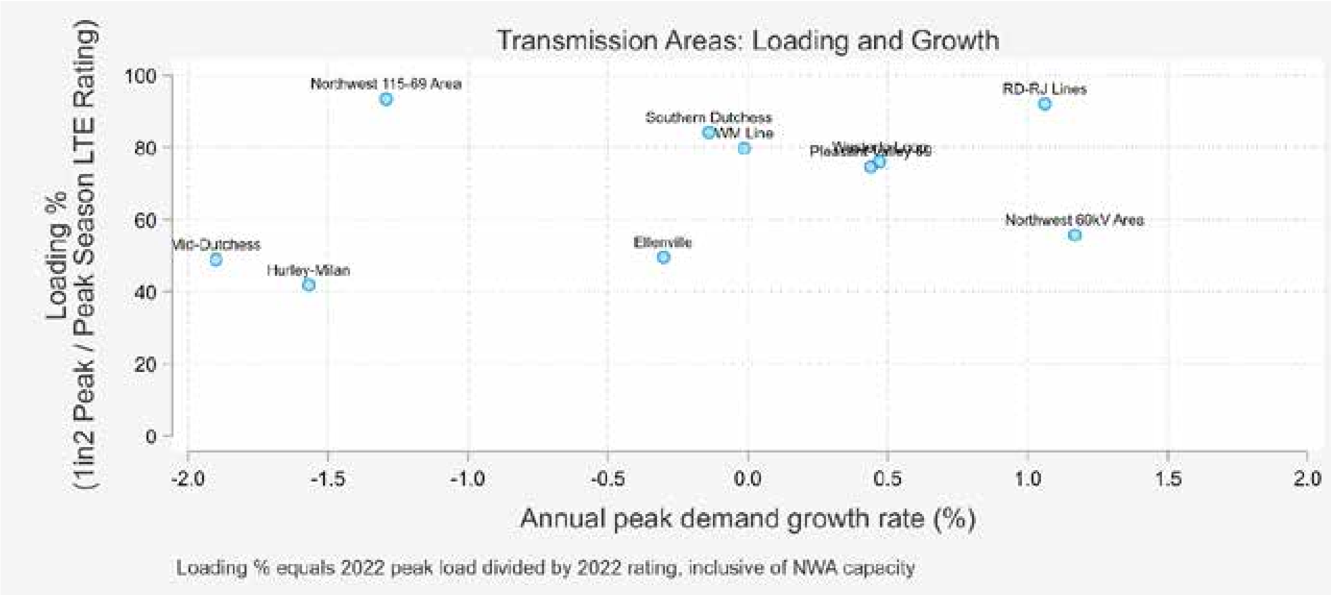


Figure 10 and Figure 11 show heat maps of the growth rate and the summer loading factor (peak / design rating) for each of Central Hudson's transmission areas for summer and winter, respectively. Darker orange colors indicate higher growth rates and higher loading factors. The RD-RJ lines are highly loaded in 2033 in the summer due to the transmission area's current loading and positive growth rate. Similarly, Westerlo Loop is highly loaded in 2033 in the winter due to its relatively high loading in 2022 and a positive growth rate. Note that this forecast includes electrification, which increases loads in addition to any additional loading from growth.

Figure 10: Heat Map of Transmission Area Growth Rates and Summer Loading Factors

Historical Growth Rates | Summer Loading Factors 2022 | Summer Loading Factors 2033

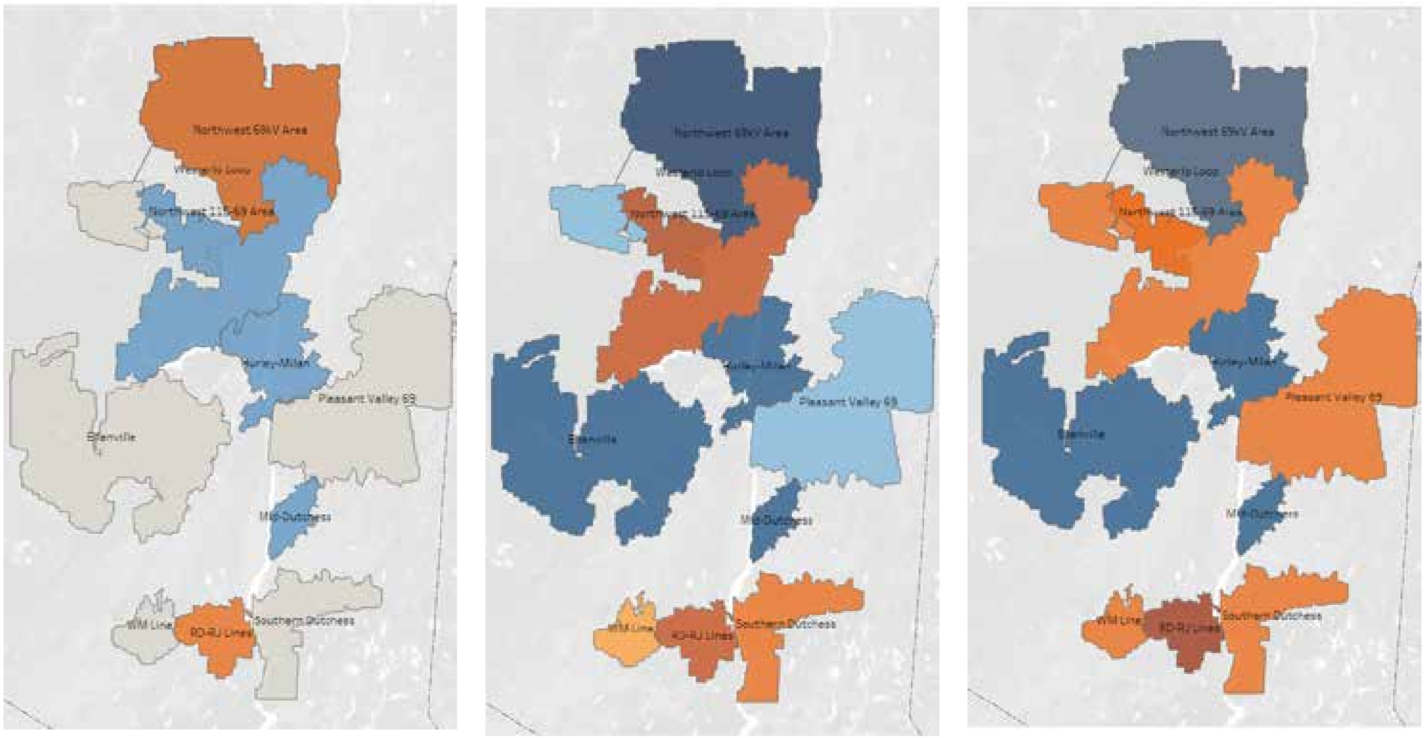


Figure 11: Heat Map of Transmission Area Growth Rates and Winter Loading Factors

Historical Growth Rates | Winter Loading Factors 2022 | Winter Loading Factors 2033

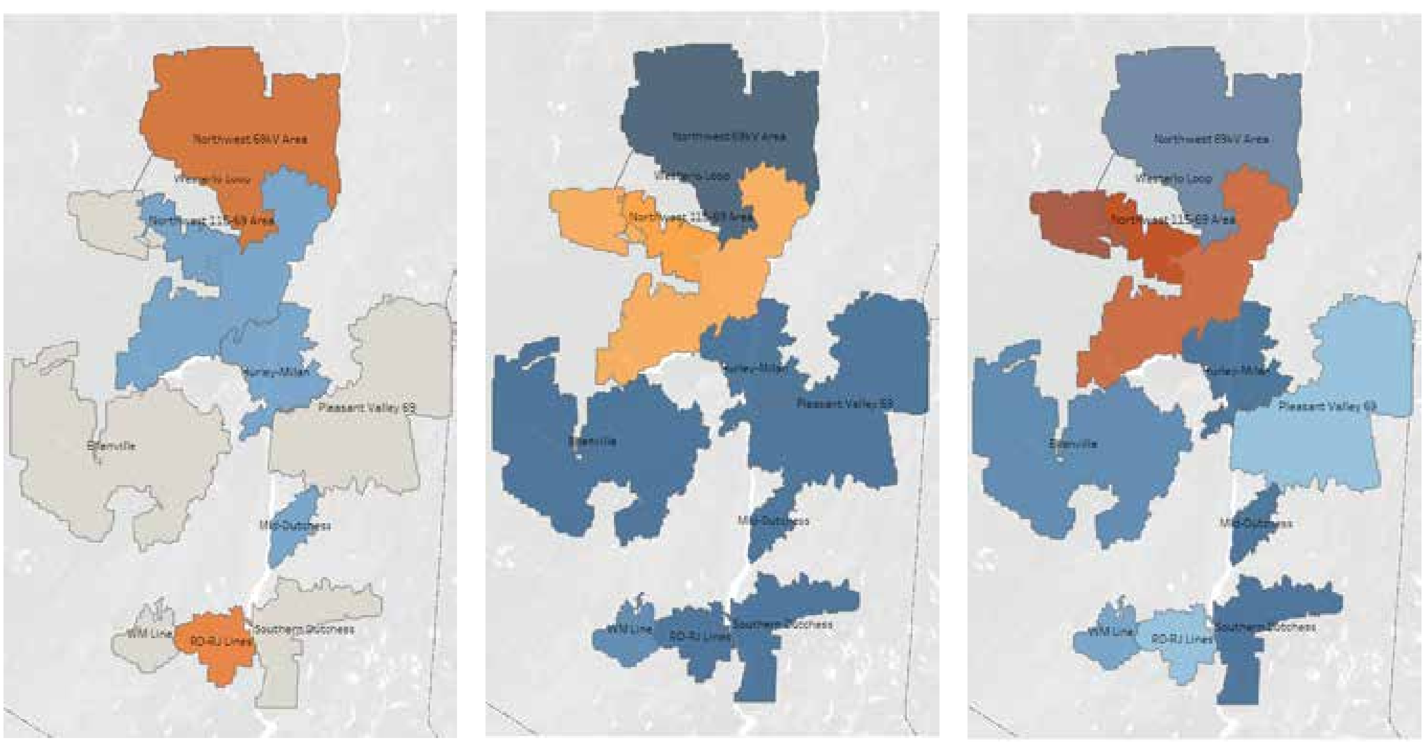


Table 3 summarizes the historical year by year growth for each transmission area, the growth trend, and the variability in the growth patterns, also known as the standard error of the forecast. The growth estimates were estimated using econometric models designed to disentangle year by year growth rates from differences in weather patterns, day of week effects, and seasonality. Historical solar production is added back to the observed historical loads to isolate load growth from growth in distributed generation which reduces net loads but does not reduce gross energy usage. For the most part, the year by year estimates of growth are relatively precise. The confidence bands around those estimates and the explanatory power of the models are summarized in Appendix A. Historical year by year growth does not follow a linear pattern and varies around the general trend line. This variation was used to develop the standard error of the forecast, which reflects how year to year growth can vary. This variability or uncertainty in the growth pattern is critical to probabilistic forecasting. Because growth and declining loads compound over time, growth patterns can deviate substantially from the straight-line forecast. An area where loads are projected to remain flat can exceed the load serving capability five to ten years out due to the uncertainty in the forecast, though the likelihood of doing so is lower than for an area that is growing.

Table 4 and Table 5 detail the elements included in developing the load forecast used for planning for summer and winter, respectively. First, the econometric forecast was developed using the load growth estimate from Table 3. This load is inclusive of all prior distributed energy resources. Next, load growth expected from vehicle and building electrification is added to the forecast. The result is the load forecast used for the avoided T&D cost study (column d) and area loading which is a key input into the identification of locations where load reduction would be beneficial. Area loading is the load as a percent of the area rating, which includes contracted Non-Wires Alternatives (NWAs). Importantly, all future load reducing distributed energy resources are not included in this load estimate, because they are not contracted and are therefore uncertain. Further, if these uncertain reductions are assumed to show up, their value is essentially removed from the load reduction valuation. The load reducing distributed energy resources (DERs) are included in the planning forecast (see Table 1 in the introduction). All peak values in the table are coincident with the transmission area's peak load for summer and winter, respectively. Therefore, the numbers will vary from the system-coincident peak forecast.

Finally, Table 6 shows the historical peaks, normalized for 1-in-2 weather conditions alongside the forecasted local peak used for the T&D avoided cost study, e.g. (column g) from Table 4. Note that in Table 3, Table 4, and Table 6 the Westerlo Loop area is nested within the NW 69 Area and the NW 69 Area is nested within the NW 115-69 Area. Not all substations are located within a transmission area. For these two reasons, the sum of the transmission areas will not equal the total system load. Finally, the ratings shown in Table 3 and Table 6 correspond to 2022 ratings, and all ratings shown include active Non-Wires Alternative project capacity. Transmission areas can peak in either the summer or the winter. In Table 3 and Table 6 transmission areas with a winter peak in 2028 (5 years into the forecast) are indicated with an asterisk (*).

Table 3: Transmission Area Historical Load Growth Estimates (2019-2022)

Transmission Area	Rating (MVA)	Historical Peak (MVA) 2019	2020	2021	2022	Loading	Annual Growth	Std. Error
Ellenville*	130.0	61.4	63.6	60.1	66.5	48.7%	-0.3%	1.5%
Hurley-Milan*	232.0	82.7	79.8	77.9	83.9	30.6%	-1.6%	1.3%
Mid-Dutchess	230.0	114.7	115.6	105.6	112.4	48.9%	-1.9%	0.9%
NW 115-69 Area*	179.8	129.0	133.6	119.8	128.9	76.0%	-1.3%	1.7%
NW 69 Area*	200.5	106.8	101.1	101.4	107.9	55.7%	1.2%	1.2%
Pleasant Valley 69	107.0	69.3	71.3	67.3	72.4	74.6%	0.4%	1.8%
RD-RJ Lines	144.0	114.4	114.8	113.1	113.6	92.0%	1.1%	3.4%
Southern Dutchess	211.0	148.5	146.5	151.3	146.1	84.1%	-0.1%	2.4%
WM Line	68.0	49.0	52.6	49.6	55.0	79.7%	0.0%	1.5%
Westerlo Loop*	83.6	62.6	61.7	59.7	60.9	76.0%	0.5%	1.7%

[1] The peak values displayed in the table above reflect the T&D avoided cost forecast and are coincident with the avoided T&D cost forecast peak for each transmission area

Table 4: Transmission Area Summer Load Forecast with and without DERs (2023-2028)

Transmission Area	Year	(a) Econometric Forecast	(b) EV Load	(c) Building Electrification	(d) Avoided T&D Cost Study Load a + b + c	(e) Rating (MVA)	(f) Avoided T&D Study Loading (%) h / i
Ellenville	2023	64.7	0.8	-0.3	65.2	130.0	50.1%
	2024	64.6	1.1	-0.6	65.2	130.0	50.1%
	2025	64.6	1.7	-0.9	65.4	165.0	39.6%
	2026	64.8	2.4	-1.2	65.9	165.0	40.0%
	2027	65.1	3.3	-1.6	66.8	165.0	40.5%
	2028	65.6	4.4	-2.1	67.9	165.0	41.2%
Hurley-Milan	2023	80.1	0.5	-0.2	80.5	193.0	41.7%
	2024	78.9	0.8	-0.4	79.3	193.0	41.1%
	2025	78.0	1.7	-0.6	79.1	193.0	41.0%
	2026	77.2	2.3	-0.8	78.7	193.0	40.8%
	2027	76.5	3.2	-1.1	78.5	193.0	40.7%
	2028	76.0	4.2	-1.5	78.8	193.0	40.8%
Mid-Dutchess	2023	111.6	0.7	-0.1	112.2	230.0	48.8%
	2024	109.7	0.9	-0.1	110.5	230.0	48.0%
	2025	107.9	1.3	-0.3	109.0	230.0	47.4%
	2026	106.3	1.9	-0.4	107.7	230.0	46.8%
	2027	104.8	2.6	-0.6	106.8	230.0	46.4%
	2028	103.5	3.5	-0.9	106.2	230.0	46.2%
Northwest 115-69 Area	2023	130.2	0.6	-0.2	130.6	146.6	89.1%
	2024	128.6	0.9	-0.3	129.1	149.8	86.2%
	2025	127.1	1.2	-0.5	127.8	136.7	93.4%
	2026	125.7	1.7	-0.7	126.6	136.7	92.6%
	2027	124.5	2.3	-1.0	125.8	136.7	92.0%
	2028	123.4	3.1	-1.3	125.2	136.7	91.6%
Northwest 69kV Area	2023	106.0	0.2	-0.1	106.1	204.7	51.8%
	2024	107.3	0.3	-0.1	107.4	207.3	51.8%
	2025	108.6	0.4	-0.2	108.9	207.3	52.5%
	2026	110.0	0.6	-0.3	110.4	207.3	53.2%
	2027	111.4	0.9	-0.3	111.9	207.3	54.0%
	2028	112.9	1.2	-0.4	113.7	207.3	54.8%
Pleasant Valley 69	2023	80.7	0.7	-0.1	81.3	107.0	76.0%
	2024	81.3	1.1	-0.2	82.2	107.0	76.8%
	2025	82.0	1.7	-0.4	83.3	107.0	77.8%
	2026	82.9	2.4	-0.7	84.6	107.0	79.1%
	2027	83.9	3.4	-1.0	86.4	107.0	80.7%
	2028	85.1	4.6	-1.3	88.4	107.0	82.6%
RD-RJ Lines	2023	133.8	0.5	-0.0	134.2	144.0	93.2%
	2024	135.4	0.7	-0.1	136.0	144.0	94.4%
	2025	137.1	1.0	-0.2	137.9	144.0	95.8%
	2026	138.8	1.4	-0.3	140.0	144.0	97.2%
	2027	140.8	2.0	-0.4	142.3	144.0	98.8%
	2028	142.9	2.7	-0.6	145.0	144.0	100.7%
Southern Dutchess	2023	177.8	0.6	-0.1	178.3	211.0	84.5%
	2024	177.8	0.9	-0.2	178.5	211.0	84.6%
	2025	177.8	1.3	-0.3	178.7	211.0	84.7%
	2026	177.8	1.8	-0.5	179.1	211.0	84.9%
	2027	178.0	2.4	-0.7	179.7	211.0	85.2%
	2028	178.3	3.2	-1.0	180.5	211.0	85.5%
WM Line	2023	54.3	0.1	-0.0	54.4	68.0	80.1%
	2024	54.4	0.2	-0.0	54.5	68.0	80.2%
	2025	54.4	0.3	-0.0	54.7	68.0	80.4%
	2026	54.5	0.4	-0.1	54.8	68.0	80.6%
	2027	54.6	0.5	-0.1	55.0	68.0	81.0%
	2028	54.8	0.7	-0.1	55.3	68.0	81.4%
Westerlo Loop	2023	63.1	0.3	-0.0	63.4	83.6	75.9%
	2024	63.6	0.6	-0.1	64.0	83.6	76.6%
	2025	64.1	0.9	-0.2	64.8	87.0	74.4%
	2026	64.7	1.3	-0.4	65.7	87.0	75.5%
	2027	65.5	2.0	-0.5	66.9	87.0	76.9%
	2028	66.3	2.7	-0.8	68.3	87.0	78.5%

Table 5: Transmission Area Winter Load Forecast with and without DERs (2023-2028)

Transmission Area	Year	(a) Econometric Forecast	(b) EV Load	(c) Building Electrification	(d) Avoided T&D Cost Study Load a + b + c	(e) Rating (MVA)	(f) Avoided T&D Study Loading (%) h / i
Ellenville	2023	65.3	0.5	1.6	67.4	130.0	51.8%
	2024	66.9	0.8	3.1	70.8	130.0	54.4%
	2025	68.9	1.1	4.9	74.9	165.0	45.4%
	2026	71.2	1.6	6.9	79.7	165.0	48.3%
	2027	73.8	2.3	9.1	85.1	165.0	51.6%
	2028	76.7	3.0	11.4	91.1	165.0	55.2%
Hurley-Milan	2023	71.9	0.6	1.0	73.5	232.0	31.7%
	2024	72.1	0.8	2.0	74.9	232.0	32.3%
	2025	72.6	1.2	3.2	77.0	232.0	33.2%
	2026	73.4	1.6	4.7	79.8	232.0	34.4%
	2027	74.6	2.2	6.4	83.2	232.0	35.9%
	2028	76.2	2.9	8.2	87.3	232.0	37.6%
Mid-Dutchess	2023	83.9	0.5	0.3	84.7	267.0	31.7%
	2024	82.9	0.7	0.7	84.3	267.0	31.6%
	2025	82.3	1.0	1.3	84.6	267.0	31.7%
	2026	82.0	1.4	2.1	85.5	267.0	32.0%
	2027	82.0	2.0	3.1	87.0	267.0	32.6%
	2028	82.3	2.7	4.2	89.2	267.0	33.4%
Northwest 115-69 Area	2023	137.0	0.4	1.0	138.4	179.8	77.0%
	2024	136.3	0.6	1.9	138.7	179.8	77.2%
	2025	135.8	0.8	2.9	139.6	156.0	89.5%
	2026	135.6	1.2	4.1	140.9	156.0	90.4%
	2027	135.8	1.6	5.5	142.9	156.0	91.6%
	2028	136.1	2.1	7.0	145.3	156.0	93.1%
Northwest 69kV Area	2023	113.1	0.2	0.5	113.7	200.5	56.7%
	2024	115.0	0.2	1.0	116.2	200.5	58.0%
	2025	117.1	0.4	1.5	119.0	200.5	59.3%
	2026	119.2	0.5	2.2	121.9	200.5	60.8%
	2027	121.5	0.8	2.9	125.1	200.5	62.4%
	2028	123.9	1.0	3.7	128.6	200.5	64.2%
Pleasant Valley 69	2023	68.5	0.5	0.5	69.5	134.0	51.8%
	2024	69.8	0.8	1.2	71.8	134.0	53.6%
	2025	71.7	1.2	2.4	75.2	134.0	56.1%
	2026	73.9	1.7	3.8	79.4	134.0	59.3%
	2027	76.6	2.3	5.5	84.4	134.0	63.0%
	2028	79.6	3.2	7.4	90.2	134.0	67.3%
RD-RJ Lines	2023	91.7	0.4	0.2	92.2	167.0	55.2%
	2024	93.1	0.5	0.4	94.0	167.0	56.3%
	2025	94.6	0.8	0.8	96.2	167.0	57.6%
	2026	96.4	1.1	1.2	98.7	167.0	59.1%
	2027	98.5	1.5	1.8	101.9	167.0	61.0%
	2028	100.8	2.1	2.5	105.5	167.0	63.2%
Southern Dutchess	2023	126.0	0.6	0.3	126.9	251.0	50.6%
	2024	126.4	0.8	0.6	127.8	251.0	50.9%
	2025	127.1	1.2	1.0	129.2	251.0	51.5%
	2026	127.9	1.7	1.5	131.0	251.0	52.2%
	2027	128.9	2.3	2.1	133.4	251.0	53.1%
	2028	130.2	3.0	2.9	136.2	251.0	54.2%
WM Line	2023	47.8	0.1	0.0	47.9	80.0	59.9%
	2024	47.9	0.2	0.1	48.1	80.0	60.2%
	2025	48.1	0.2	0.2	48.5	80.0	60.6%
	2026	48.3	0.4	0.3	49.0	80.0	61.2%
	2027	48.6	0.5	0.5	49.6	80.0	62.0%
	2028	48.9	0.7	0.7	50.3	80.0	62.9%
Westerlo Loop	2023	64.4	0.3	0.4	65.1	83.6	77.9%
	2024	65.4	0.5	1.0	66.9	83.6	80.0%
	2025	66.9	0.7	1.9	69.5	87.0	79.9%
	2026	68.8	1.1	3.0	72.9	87.0	83.8%
	2027	71.0	1.6	4.5	77.0	87.0	88.5%
	2028	73.6	2.2	6.1	81.9	87.0	94.2%

Table 6: Transmission Area Normalized Peak Load Estimates, Historical (2018-2022) and Forecast (2023-2028)

Transmission Area	Historical 1 in 2 Annual Peak (MVA)				Forecasted 1 in 2 Annual Peak (MVA)						Rating (MVA)
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	
Ellenville*	64.9	64.7	64.5	64.3	65.3	66.9	68.9	71.2	73.8	76.7	130.0
Hurley-Milan*	84.6	83.3	81.9	80.6	80.1	78.9	78.0	77.2	76.5	76.2	232.0
Mid-Dutchess	119.1	116.8	114.6	112.4	111.6	109.7	107.9	106.3	104.8	103.5	230.0
NW 115-69 Area*	142.2	140.4	138.5	136.7	137.0	136.3	135.8	135.6	135.8	136.1	179.8
NW 69 Area*	107.8	109.1	110.3	111.6	113.1	115.0	117.1	119.2	121.5	123.9	200.5
Pleasant Valley 69	78.8	79.2	79.5	79.8	80.7	81.3	82.0	82.9	83.9	85.1	107.0
RD-RJ Lines	128.6	129.9	131.1	132.5	133.8	135.4	137.1	138.8	140.8	142.9	144.0
Southern Dutchess	178.4	178.0	177.6	177.4	177.8	177.8	177.8	177.8	178.0	178.3	211.0
WM Line	54.3	54.2	54.2	54.2	54.3	54.4	54.4	54.5	54.6	54.8	68.0
Westerlo Loop*	62.7	62.9	63.2	63.5	64.4	65.4	66.9	68.8	71.0	73.6	83.6

[1] The peak values displayed in the table above reflect the T&D avoided cost forecast and are coincident with the avoided T&D cost forecast peak for each transmission area

Before presenting the overload and investment trigger results, it is important to understand how ratings change over time, whether as a result of changes to transmission area infrastructure or as a result of changes to existing NWAs. Ratings are only expected to change over time for the Northwest 69kV, Northwest 115-69kV, Ellenville, and Westerlo Loop areas, as follows:

- NWAs. The Northwest 115-69kV area currently has a 10 MW NWA that is set to expire in 2029. NWA capacity was assumed to be allocated relative to annual usage from 2018 to 2022. The NWA consists of both permanent non-dispatchable capacity (e.g., energy efficiency) and temporary dispatchable capacity (e.g., demand response) assumed to expire in 2029. This capacity was in place for the 2019 peak load season onward and was therefore reflected in the historical load data. Ratings were adjusted to reflect the NWA deployment and retirement schedule.

- Generation retirement: The Northwest 115-69kV area ratings were adjusted to reflect the generation retirement planned to be effective starting in 2025. This corresponds to a summer LTE rating decrease of 13.1 MW / 13.2 MVA beginning in 2025.

- Infrastructure upgrade: Similarly, the Ellenville area ratings were adjusted for the conversion to 115 kV planned for 2024 and the Westerlo Loop area ratings were adjusted for the increased VAr support planned for 2025. These upgrades will result in an increase of 25 MVA in Ellenville and an increase of 3.4 MVA in Westerlo Loop.

Table 7 summarizes the peak season LTE rating for all ten transmission areas over time, including NWAs. The areas highlighted in light blue are the locations where we expect the rating to change over time, based on the factors described above. The effect of these ratings changes is to reduce the risk for the Ellenville area and Westerlo Loop but increase the risk of overloading and an investment being triggered for the Northwest 115-69kV area, which was already highly loaded in 2022.

Table 7: Transmission Area LTE Ratings by Year (MVA)

Transmission Area	2028 Peak Season	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Ellenville	Winter	130	130	165	165	165	165	165	165	165	165	165
Hurley-Milan	Winter	232	232	232	232	232	232	232	232	232	232	232
Mid-Dutchess	Summer	230	230	230	230	230	230	230	230	230	230	230
Northwest 115-69 Area	Winter	180	180	156	156	156	156	156	155	155	155	155
Northwest 69kV Area	Winter	200	200	200	200	200	200	200	200	200	200	200
Pleasant Valley 69	Summer	107	107	107	107	107	107	107	107	107	107	107
RD-RJ Lines	Summer	144	144	144	144	144	144	144	144	144	144	144
Southern Dutchess	Summer	211	211	211	211	211	211	211	211	211	211	211
WM Line	Summer	68	68	68	68	68	68	68	68	68	68	68
Westerlo Loop	Winter	83.6	83.6	87	87	87	87	87	87	87	87	87

Figure 12 summarizes the mean load forecast for each transmission area from 2023 to 2033 by season, expressed as a percentage of each transmission area's LTE rating so that the design rating equals 100. The RD-RJ Lines area stands out for being the only location where the peak load exceeds the LTE rating during the summer forecast period, which is driven by a positive expected load growth rate (1.1% per year) and high loading in 2022 (84%). The Westerlo Loop is the only location where the peak load exceeds the LTE rating during the winter forecast period, which is similarly due to a positive expected growth rate, high loading in 2022, and electrification. All other areas either have no or negative growth or have ample room for growth during the forecast period.

Figure 12: Expected Loading as Percentage of Transmission Area Rating, Including NWAs

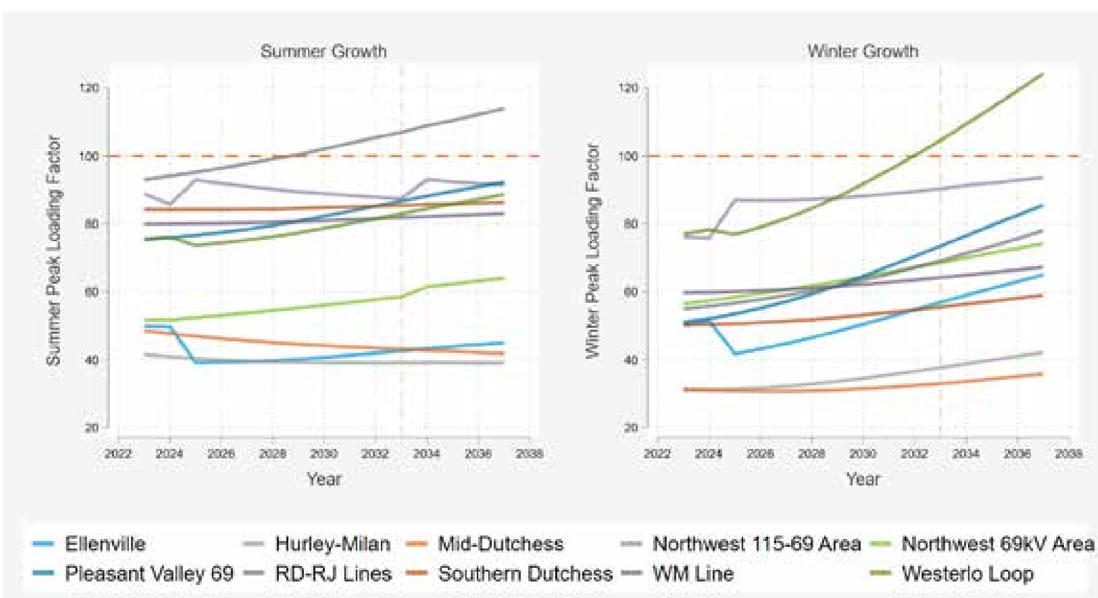


Figure 13 and Figure 14 summarize the likelihood that loads will exceed design ratings for each transmission area by year and by season. Note that only areas where the overload risk is at least 5% are triggered for deferral. Therefore, while other areas have a small overload risk there is no meaningful avoided cost except for the RD-RJ Lines and Westerlo Loop areas. Figure 15 reflects the high overload risks from the RD-RJ Lines and

Westerlo Loop areas, but is shifted back by one year, which reflects the investment criteria of two consecutive years of overloads.

Figure 13: Probability of Forecast Load Exceeding Design Ratings in Summer: Transmission Areas

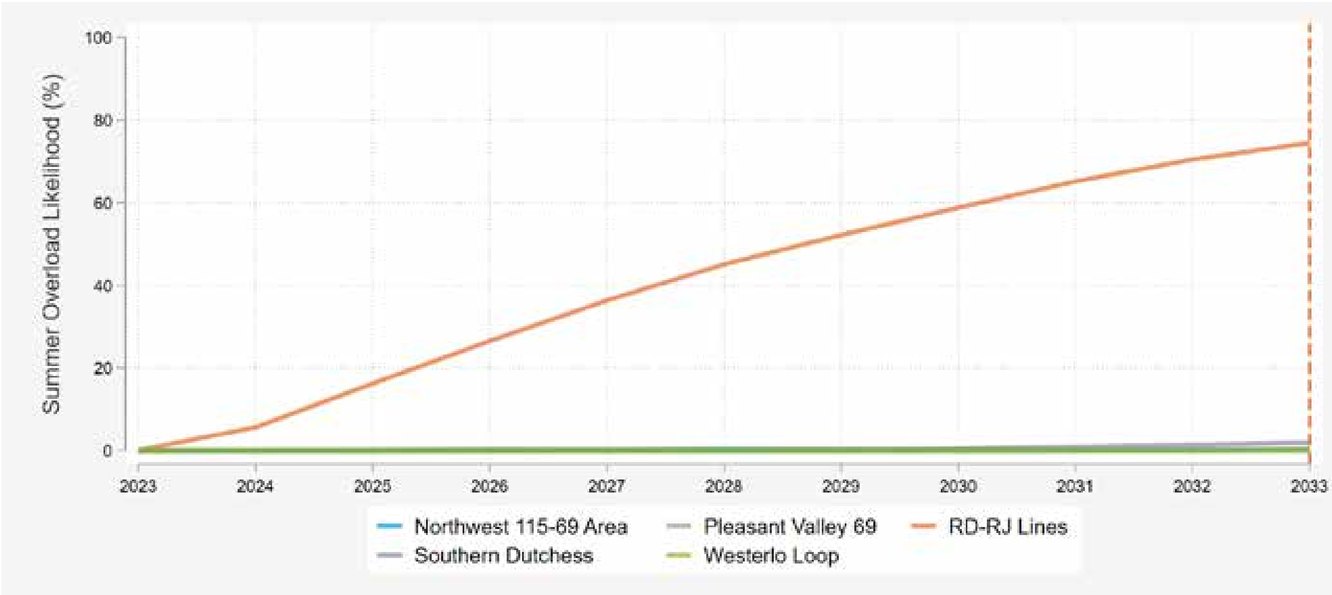


Figure 14: Probability of Forecast Load Exceeding Design Ratings in Winter: Transmission Areas

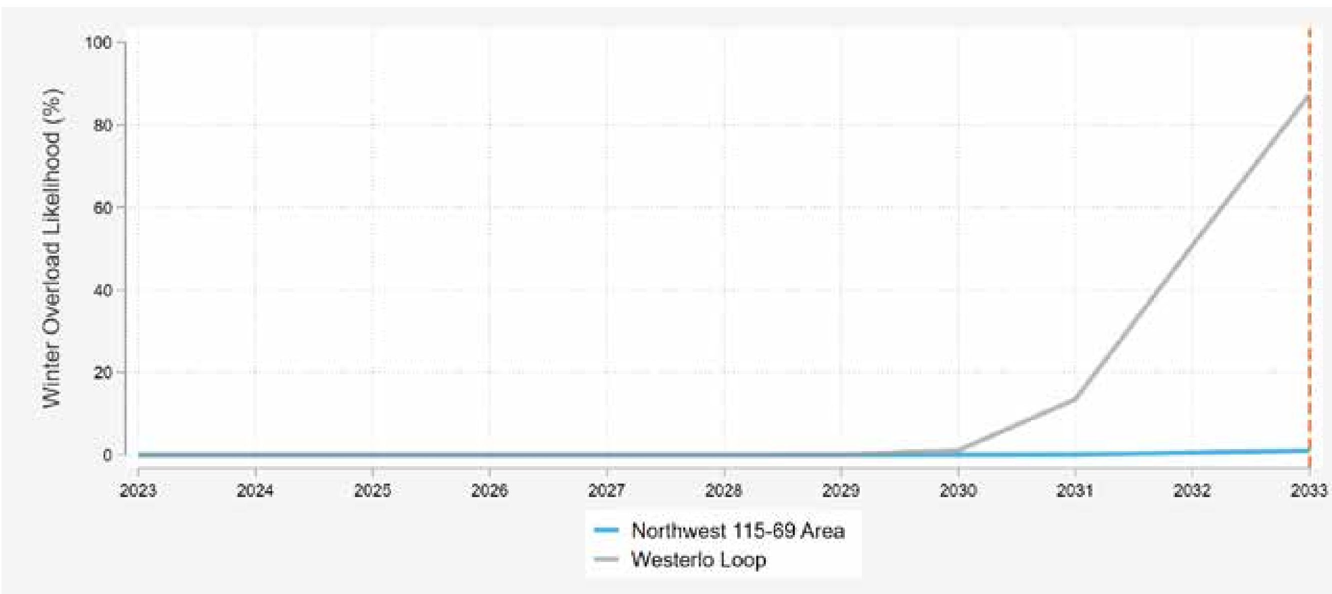
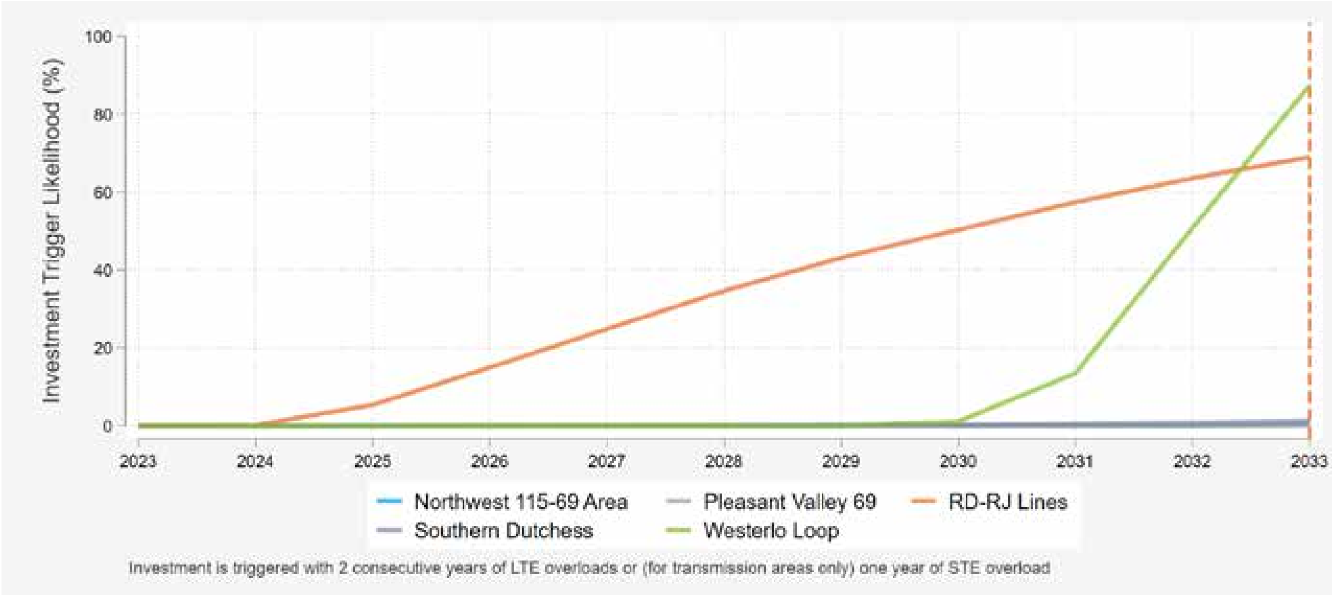
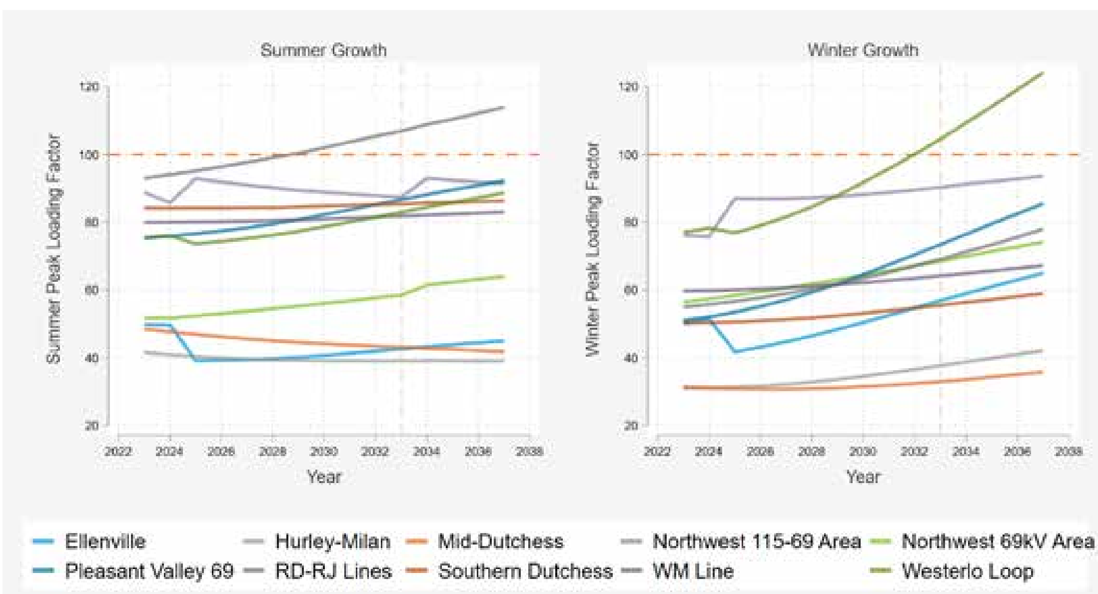


Figure 15: Probability of Growth-Related Infrastructure Upgrade: Transmission Areas



To test this finding, we conducted an additional sensitivity test. While Figure 12 shows the expected (mean) transmission area load as a percentage of the rating across 5,000 growth simulations, we also looked at forecasted growth for the top 90th percentile of growth trajectories. Figure 16 shows these growth trajectories, again normalized by the local design rating so design rating = 100 for each season. As is the case for the expected value, only the RD-RJ Lines and Westerlo Loop exceed the design ratings, with loads for other areas being flat or declining or else substantially below the design rating.

Figure 16: 90th Percentile Peak Load as Percentage of Transmission Area Rating, Including NWAs



3.2 DISTRIBUTION AREA LOAD GROWTH ESTIMATES

Figure 17 compares the annual load growth rate to the loading factor (weather-normalized peak divided by the location's design rating including NWAs) for each of Central Hudson's substations in 2022. The majority of substations are experiencing slowing growth or declining loads or have ample room for growth without having to upgrade them. Locations with a growth rate above 0% are experiencing growth, and locations where the loading factor is closer to 100% have less room for growth. However, a number of substations are highly loaded with positive growth rates, including Woodstock, Fishkill Plains, Reynolds Hill, Pulvers 13 kV, and Grimley Road. Maybrook has very high loading in 2022 but has a negative growth rate. While areas such as Fishkill Plains and Pulvers 13 kV already have planned upgrades that will take place, others such as Grimley Road and Woodstock have a high likelihood of overloading.

Figure 17: Substation Growth Rates Versus Room for Growth

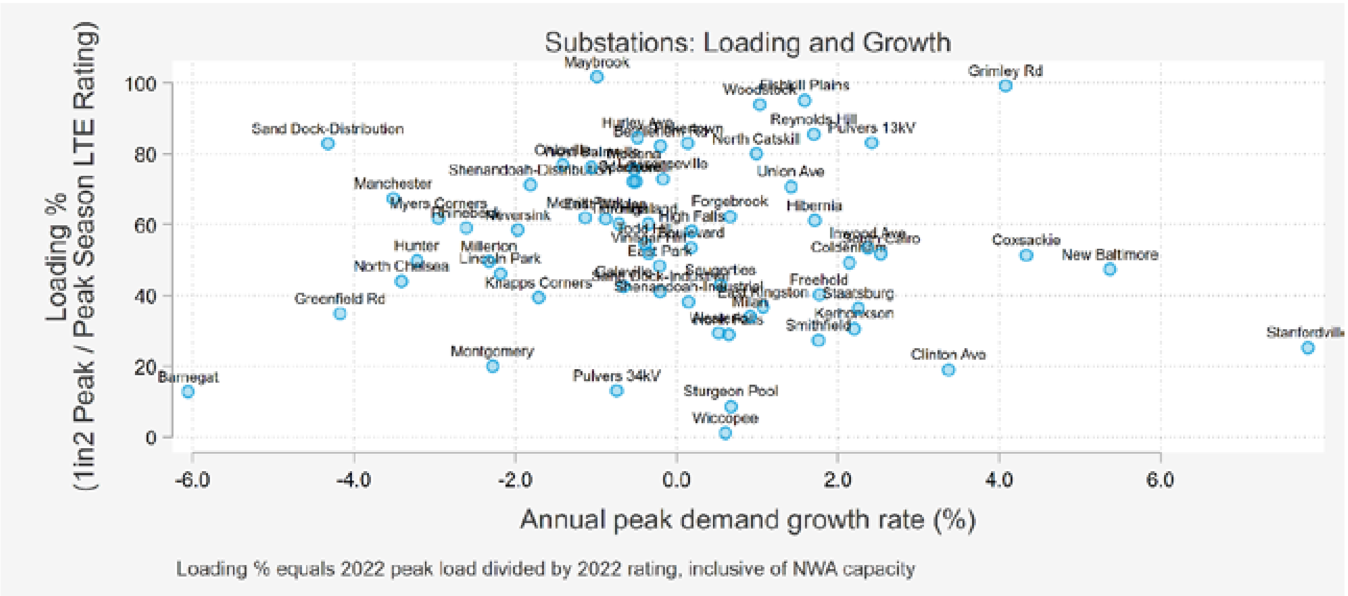
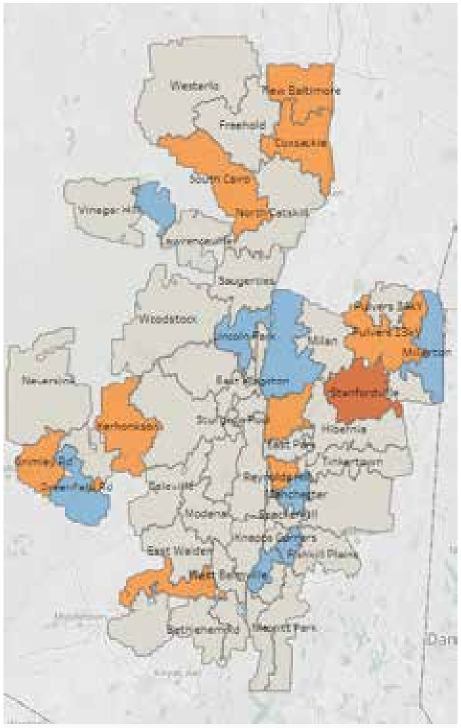


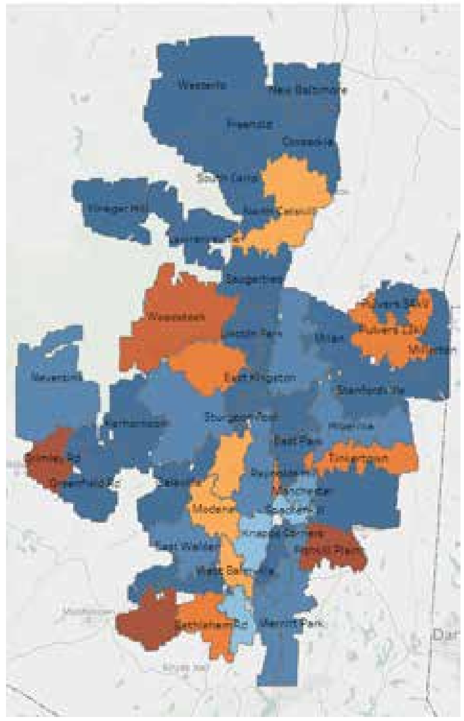
Figure 18 and Figure 19 show heat maps of the growth rate and the summer and winter loading factor (peak / design rating) for each of Central Hudson's substations. Darker orange colors indicate higher growth rates and higher loading factors. Note that this forecast includes electrification, so areas with low growth rates still can be highly loaded in 2033. Notably, Woodstock, Fishkill Plains, Grimley Road, Pulvers 13 kV, and others are highly loaded and have positive growth rates leading to overloading by 2033. Winter loading also increases substantially over the study period due to the inclusion of electrification in the forecast.

Figure 18: Heat Map of Substation Growth Rates and Loading Factors

Historical Growth Rates



Loading Factors 2022



Loading Factors 2033

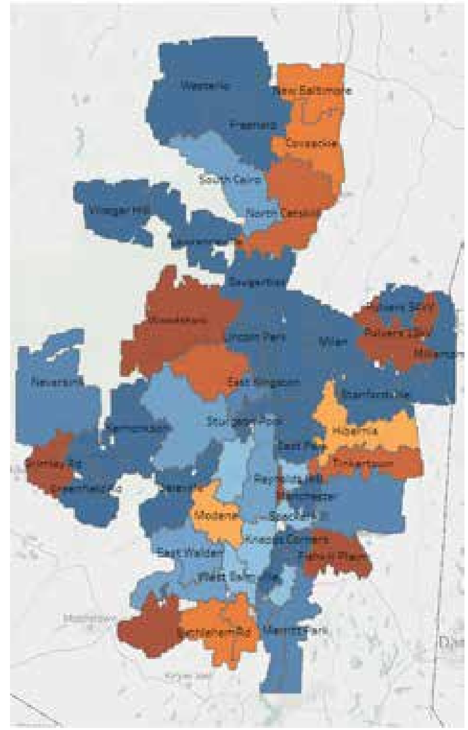
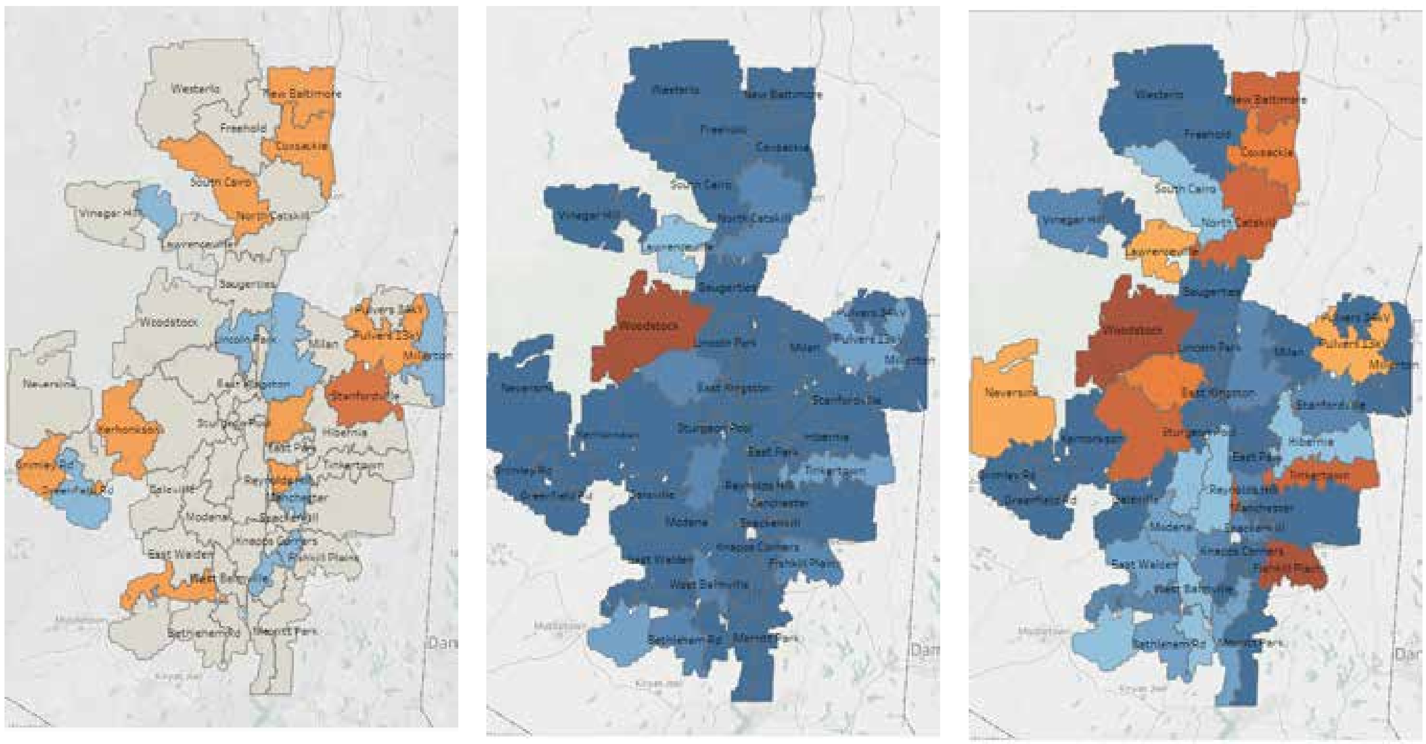


Figure 19: Heat Map of Substation Growth Rates and Winter Loading Factors

Historical Growth Rates | Winter Loading Factors 2022 | Winter Loading Factors 2030



Two substations currently have NWAs that we added to ratings. Table 8 summarizes the peak season LTE rating (in MVA) plus NWA capacity for these two substations. As was the case in the transmission area capacity, the NWAs consist of both temporary dispatchable capacity (demand response) as well as permanent non-dispatchable capacity (energy efficiency); to prevent double counting energy efficiency that would show up in the 2022 load data, we added all dispatchable capacity but only incremental non-dispatchable capacity to the substation ratings. The Fishkill Plains NWA is scheduled to sunset after 2025 and the Merritt Park NWA is scheduled to sunset after 2027, which is reflected in the reduced ratings after those years for each substation.

Table 8: Substation Ratings by Year (MVA)[a]

Substation	Peak Season	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Fishkill Plains	Summer	50.3	51.2	51.2	48.2	48.2	48.2	48.2	48.2	48.2	48.2	48.2
Merritt Park	Summer	52.1	52.2	52.2	52.2	52.2	51.2	51.2	51.2	51.2	51.2	51.2

[a] The 5 MW Fishkill NWA sunsets at the end of 2025. The 1 MW Merritt Park NWA sunsets at the end of 2027.

Figure 20 and Figure 21 summarize the likelihood that loads will exceed long term design ratings by year and by season for twelve substations. Figure 22 summarizes the likelihood of triggering an infrastructure upgrade due to load growth, assuming two consecutive years where the long-term rating is exceeded, assuming 1-in-2 weather conditions. Based on the trajectory and variability in load growth, a total of seven substations (Fishkill Plains, Woodstock, Grimley Road, Reynolds Hill, New Baltimore, Maybrook, and Pulvers 13kV) exhibit more than a 5% probability of triggering a growth-related upgrade over the next 10 years, with the remaining substations having less than a 5% probability of triggering a growth-related upgrade.

Among the locations with greater than a 5% probability of loads exceeding ratings, potential overloads can be easily addressed through existing infrastructure projects that are already planned for the substation (Fishkill Plains, New Baltimore, Maybrook, and Pulvers 13kV). However, for three substations there are limited possibilities of load transfer and there are no current infrastructure upgrades planned in the next two years. Therefore, these three substations (Woodstock, Grimley Road, and Reynolds Hill) all are considered for deferral.

Figure 20: Probability of Forecast Loads Exceeding Design Ratings in Summer

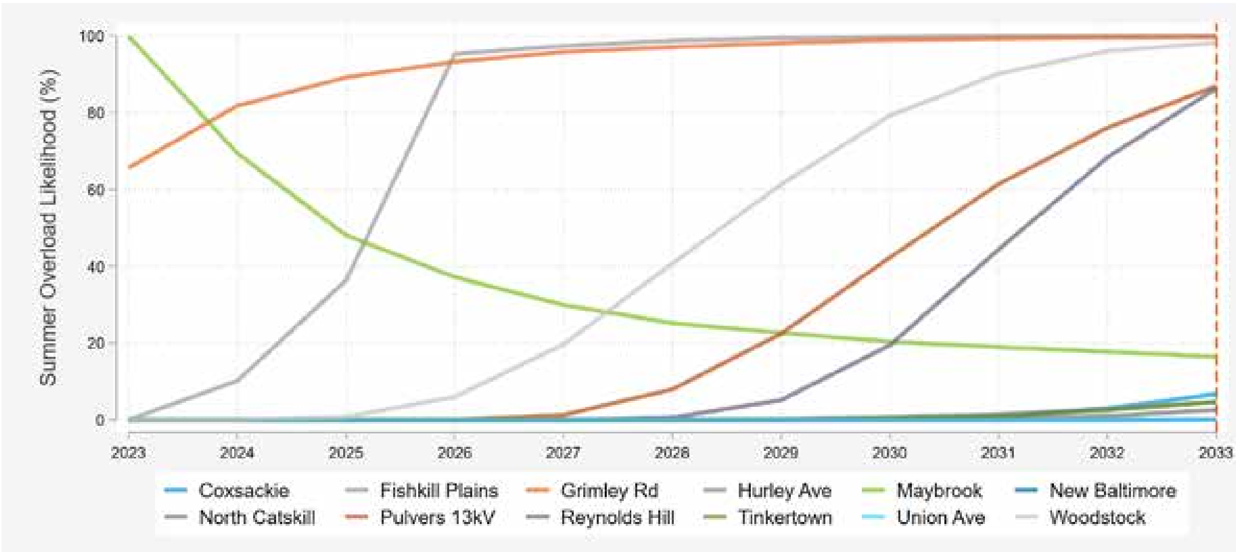


Figure 21: Probability of Forecast Loads Exceeding Design Ratings in Winter

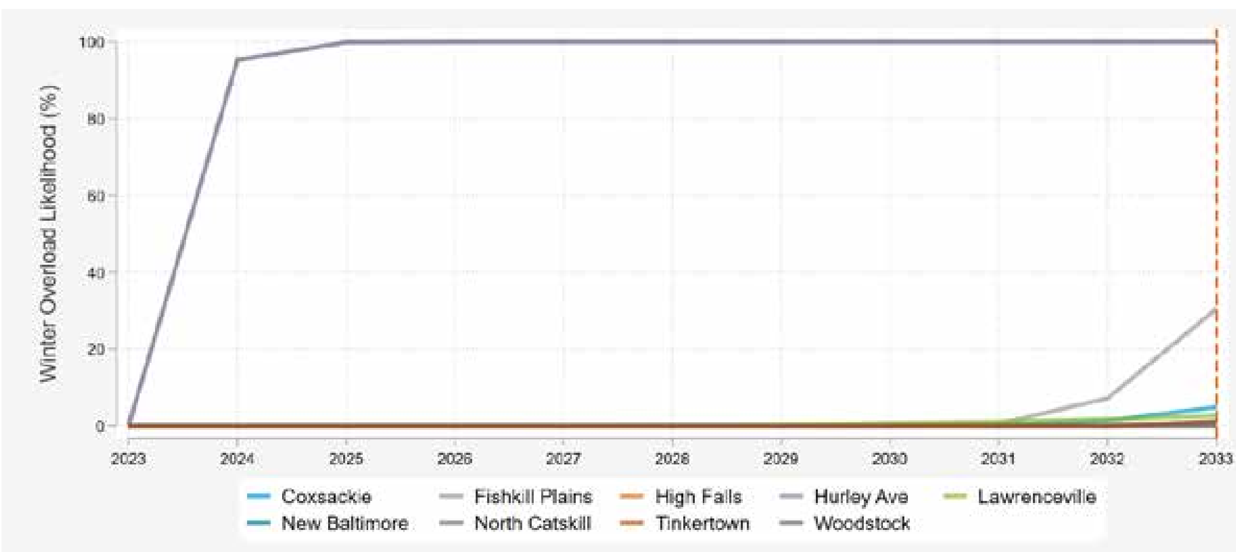


Figure 22: Probability of Growth-Related Infrastructure Upgrade

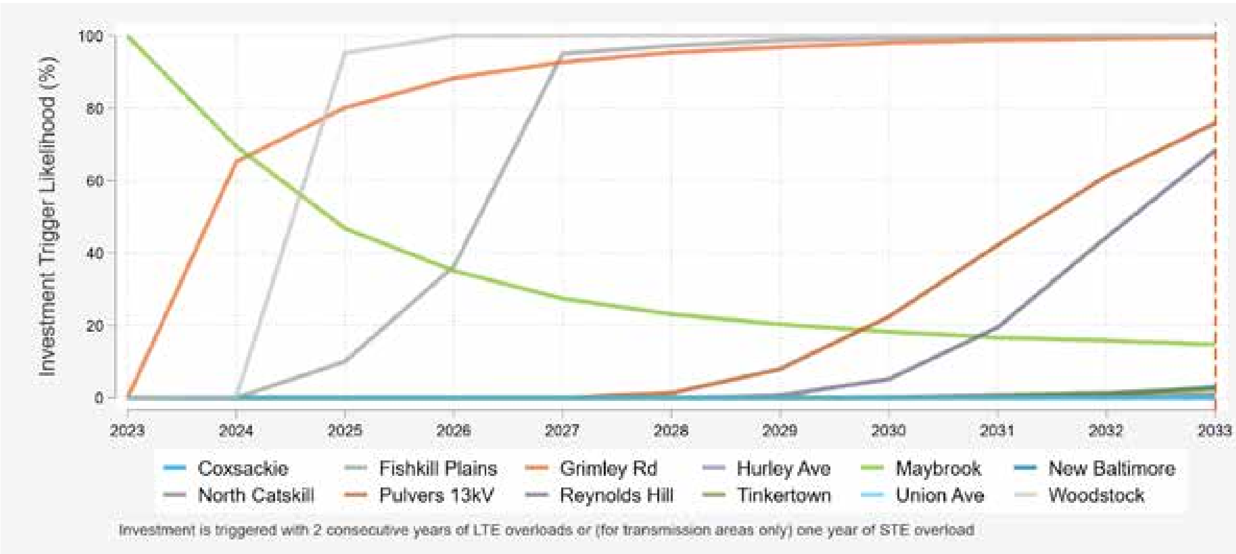


Table 9 through Table 16 summarize the results of the historical load growth analysis for each of the distribution load serving substations with at least three years of hourly data, grouped by load area.[7] Similar to the transmission areas, most of the substations have ample room to accommodate additional load growth. Substations can peak in either the winter or summer, or the peak can change over time. Substations with a winter peak in 2028 are indicated with an asterisk (*).

Table 17 shows historical and forecasted peak loads for all substations, normalized to 1 in 2 weather conditions. Substations with a winter peak in 2028 are indicated with an asterisk (*). The five substations for which we used historic sales data rather than metered data are indicated with two asterisks (**). Just as with the transmission areas, this T&D avoided cost study forecast was developed by adding the end use load forecast based on historical growth trends to load growth expected from vehicle and building electrification is added to the forecast. Area loading is the load as a percent of the area rating, which includes contracted Non-Wires Alternatives (NWAs). Importantly, load reducing distributed energy resources (DERs) are not subtracted from this load estimate, because they are not contracted and are therefore uncertain. Further, if these uncertain reductions are assumed to show up, their value is essentially removed from the load reduction valuation. Please see the tables in Appendix B

[7] Central Hudson groups most substations in 10 distinct planning load areas. Load areas represent adjacent geographic regions, but, more importantly, nearly all load transfers between substations occur within planning load areas.

and Appendix C for a detailed breakout of which loads were included in the avoided cost forecast for substations.

Table 9: Ellenville Area – Historical Load Growth Estimates (2019-2022)

Substation	Rating (MVA)	Historical Peak (MVA) 2019	2020	2021	2022	Loading	Annual Growth	Std. Error
Clinton Ave*	11.6	1.7	1.4	1.5	1.6	15.6%	3.4%	3.9%
Greenfield Rd*	23.3	7.2	7.7	7.4	6.6	28.7%	-4.2%	2.2%
Grimley Rd	7.2	5.4	7.0	6.5	7.0	99.2%	4.1%	4.8%
High Falls*	34.5	20.0	19.5	19.2	19.4	56.1%	0.2%	1.6%
Honk Falls	21.1	5.8	5.8	6.2	5.5	28.9%	0.6%	1.9%
Kerhonkson*	47.3	10.6	9.9	10.3	10.8	22.3%	2.2%	1.9%
Neversink*	7.4	3.7	4.2	3.9	3.5	48.1%	-2.0%	2.3%
Sturgeon Pool*	40.3	2.9	2.9	2.7	2.7	6.6%	0.7%	2.1%
Overall	N/A	**45.1**	**43.1**	**44.2**	**44.4**	.	**1.1%**	**1.4%**

[1] The peak values displayed in the table above reflect the T&D avoided cost forecast and are coincident with substation peak

Table 10: Fishkill Area – Historical Load Growth Estimates (2019-2022)

Substation	Rating (MVA)	Historical Peak (MVA) 2019	2020	2021	2022	Loading	Annual Growth	Std. Error
Fishkill Plains	50.4	45.0	44.8	49.0	43.0	95.1%	1.6%	2.4%
Forgebrook	47.4	28.3	27.3	28.8	29.4	62.3%	0.7%	1.2%
Knapps Corners	47.8	18.5	17.3	17.6	18.0	39.4%	-1.7%	1.3%
Merritt Park	52.2	30.7	31.9	31.4	30.5	62.2%	-1.1%	1.3%
Myers Corners	35.1	20.4	19.3	20.2	19.9	61.7%	-3.0%	1.6%
North Chelsea	48.3	19.9	20.1	19.2	18.6	44.0%	-3.4%	1.6%
Sand Dock-D	6.0	4.9	4.7	4.7	4.6	82.9%	-4.3%	1.7%
Shenandoah-D	18.9	13.7	13.0	12.6	12.7	71.2%	-1.8%	1.6%
Tioronda	28.7	18.1	16.6	15.2	15.7	60.2%	-0.7%	1.7%
Overall	N/A	**196.5**	**190.9**	**194.7**	**186.5**	.	-1.0%	1.3%

[1] The peak values displayed in the table above reflect the T&D avoided cost forecast and are coincident with substation peak

Table 11: Kingston-Saugerties Area – Historical Load Growth Estimates (2019-2022)

Substation	Rating (MVA)	Historical Peak (MVA) 2019	2020	2021	2022	Loading	Annual Growth	Std. Error
Boulevard*	44.8	17.7	15.5	19.6	19.0	37.2%	0.2%	2.3%
East Kingston	48.0	15.9	16.3	16.1	16.9	36.7%	1.1%	1.4%
Hurley Ave*	28.4	19.7	18.7	18.6	18.8	60.1%	-0.5%	2.2%
Lincoln Park	84.0	38.8	38.3	38.4	38.6	46.2%	-2.2%	1.1%
Saugerties*	70.5	22.0	23.5	22.1	22.6	28.8%	0.5%	1.7%
Woodstock*	23.9	21.3	19.5	20.4	21.6	93.8%	1.0%	1.6%
Overall	N/A	129.2	126.3	130.6	132.4	.	-0.7%	1.2%

[1] The peak values displayed in the table above reflect the T&D avoided cost forecast & are coincident with substation peak

Table 12: Modena Area – Historical Load Growth Estimates (2019-2022)

Substation	Rating (MVA)	Historical Peak (MVA)				Loading	Annual Growth	Std. Error
		2019	2020	2021	2022			
Galeville*	28.7	11.3	11.6	11.5	12.4	37.4%	-0.7%	1.5%
Highland*	37.3	20.0	19.5	19.6	19.4	50.4%	-0.4%	1.4%
Modena	21.1	14.6	14.9	14.3	14.8	75.7%	-0.5%	1.5%
Ohioville*	34.2	21.9	21.2	23.2	22.2	56.4%	-1.4%	1.3%
Overall	N/A	**66.6**	**66.4**	**65.0**	**66.9**	.	-1.2%	1.1%

[1] The peak values displayed in the table above reflect the T&D avoided cost forecast & are coincident with substation peak

Table 13: Newburgh Area – Historical Load Growth Estimates (2019-2022)

Substation	Rating (MVA)	Historical Peak (MVA)				Loading	Annual Growth	Std. Error
		2019	2020	2021	2022			
Bethlehem Rd	47.8	35.9	36.1	36.0	35.7	82.2%	-0.2%	1.5%
Coldenham	47.8	20.2	24.3	26.0	22.2	49.3%	2.1%	1.6%
East Walden	26.2	16.0	14.5	15.5	16.1	61.6%	-0.9%	1.5%
Marlboro	30.9	21.1	20.7	21.1	21.2	72.1%	-0.5%	1.6%
Maybrook	20.9	19.1	21.7	20.2	20.5	101.7%	-1.0%	1.4%
Montgomery	24.0	4.8	5.1	5.2	4.7	20.0%	-2.3%	1.5%
Union Ave	94.5	63.0	59.9	67.6	65.7	70.7%	1.4%	1.5%
West Balmville	47.8	37.7	35.1	35.0	35.4	76.2%	-1.1%	1.3%
Overall	N/A	202.8	213.7	218.1	220.3	.	-0.2%	1.1%

[1] The peak values displayed in the table above reflect the T&D avoided cost forecast & are coincident with substation peak

Table 14: Northeastern Dutchess Area – Historical Load Growth Estimates (2019-2022)

Substation	Rating (MVA)	Historical Peak (MVA)				Loading	Annual Growth	Std. Error
		2019	2020	2021	2022			
East Park	30.4	13.7	14.0	14.1	13.2	48.3%	-0.2%	1.7%
Hibernia	23.7	13.3	13.6	14.1	13.6	61.1%	1.7%	2.0%
Milan*	38.2	10.7	10.9	12.1	11.1	29.4%	0.9%	2.2%
Millerton*	13.0	5.4	5.1	5.2	5.9	41.8%	-2.3%	1.7%
Pulvers 13	7.2	5.3	5.4	5.6	5.6	83.1%	2.4%	1.8%
Pulvers 34*	26.7	2.8	2.8	3.0	3.2	11.2%	-0.7%	1.4%
Rhinebeck*	47.8	29.9	28.2	27.7	27.3	53.8%	-2.6%	1.5%
Smithfield*	8.7	1.8	1.8	2.0	2.0	22.5%	1.8%	1.0%
Staatsburg	28.9	9.1	9.3	9.5	10.6	36.4%	2.3%	1.6%
Stanfordville*	24.5	4.5	4.3	4.4	5.6	20.8%	7.8%	3.2%
Tinkertown	19.1	15.0	15.5	14.2	17.4	83.0%	0.1%	1.9%
Overall	N/A	108.0	106.2	104.7	109.0	.	-0.1%	1.2%

[1] The peak values displayed in the table above reflect the T&D avoided cost forecast & are coincident with substation peak

Table 15: Northwest Area – Historical Load Growth Estimates (2019-2022)

Substation	Rating (MVA)	Historical Peak (MVA)				Loading	Annual Growth	Std. Error
		2019	2020	2021	2022			
Coxsackie*	24.8	6.7	12.1	11.2	9.8	42.3%	4.3%	5.0%
Freehold*	25.0	7.4	7.3	8.1	8.1	31.9%	1.8%	2.9%
Hunter*	21.2	10.7	12.3	10.7	11.0	49.8%	-3.2%	5.6%
Lawrenceville*	19.3	12.1	15.2	12.7	12.8	72.9%	-0.2%	4.3%
New Baltimore	28.7	11.4	13.4	12.7	12.9	47.3%	5.4%	1.7%
North Catskill	35.1	24.8	25.9	26.1	27.0	80.0%	1.0%	1.7%
South Cairo*	29.4	12.1	11.8	13.1	14.0	45.0%	2.5%	1.4%
Vinegar Hill*	21.3	10.4	9.2	9.9	10.8	52.0%	-0.3%	3.1%
Westerlo*	35.0	8.7	8.3	8.2	8.5	24.1%	0.5%	2.0%
Overall	N/A	88.0	94.6	93.4	98.1	.	3.1%	1.4%

[1] The peak values displayed in the table above reflect the T&D avoided cost forecast & are coincident with substation peak

Table 16: Poughkeepsie Area – Historical Load Growth Estimates (2019-2022)

Substation	Rating (MVA)	Historical Peak (MVA)				Loading	Annual Growth	Std. Error
		2019	2020	2021	2022			
Inwood Ave	51.2	24.4	25.6	23.5	31.0	53.3%	2.4%	2.2%
Manchester	47.8	32.1	32.6	30.9	30.2	67.4%	-3.5%	1.3%
Reynolds Hill	47.8	36.0	41.4	40.5	41.9	85.5%	1.7%	1.1%
Spackenkill	47.8	33.5	33.4	33.1	32.8	72.1%	-0.5%	1.4%
Todd Hill	47.8	26.7	25.9	25.4	24.6	54.5%	-0.4%	1.6%
Overall	N/A	148.5	154.0	146.7	155.7	.	-0.1%	1.1%

[1] The peak values displayed in the table above reflect the T&D avoided cost forecast & are coincident with substation peak

Table 17: Substation Normalized Peak Load Estimates, Historical (2019-2022) and Forecast (2023-2028)

Load Area	Substation	Historical 1 in 2 Annual Peak (MVA)				Forecasted 1 in 2 Annual Peak (MVA)						Rating (MVA)
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	
Ellenville	Clinton Ave*	1.6	1.7	1.8	1.8	1.9	1.9	2.0	2.1	2.2	2.3	11.6
	Greenfield Rd*,**	7.6	7.3	7.0	6.7	6.7	6.5	6.5	6.6	6.6	6.8	23.3
	Grimley Rd	6.3	6.6	6.8	7.1	7.2	7.5	7.8	8.1	8.5	8.8	7.2
	High Falls*	20.0	20.0	20.0	20.0	20.3	21.0	21.8	22.7	23.8	24.9	34.5
	Honk Falls	6.0	6.0	6.1	6.1	6.1	6.2	6.2	6.3	6.3	6.4	21.1
	Kerhonkson*	10.2	10.4	10.6	10.9	11.0	11.6	12.2	12.9	13.7	14.5	47.3
	Neversink*,**	3.8	3.7	3.7	3.6	3.6	3.7	3.8	3.9	4.1	4.4	7.4
	Sturgeon Pool*	2.8	2.8	2.9	2.9	2.9	2.9	3.1	3.2	3.3	3.5	40.3
	Total	44.4	44.9	45.4	45.8	46.2	46.8	47.4	49.2	52.0	55.1	N/A
Fishkill	Fishkill Plains	45.8	46.5	47.2	48.0	48.6	49.6	50.6	51.7	52.9	54.2	50.4
	Forgebrook	29.0	29.2	29.3	29.5	29.8	30.1	30.4	30.8	31.2	31.6	47.4
	Knapps Corners	19.8	19.5	19.2	18.8	18.8	18.5	18.2	18.0	17.8	17.6	47.8
	Merritt Park	33.6	33.2	32.8	32.5	32.5	32.1	31.9	31.7	31.5	31.4	52.2
	Myers Corners	23.7	23.0	22.3	21.7	21.6	21.0	20.4	19.9	19.5	19.1	35.1
	North Chelsea	23.6	22.8	22.0	21.2	21.1	20.4	19.8	19.2	18.7	18.3	48.3
	Sand Dock-D	5.7	5.4	5.2	5.0	4.9	4.7	4.6	4.4	4.2	4.1	6.0
	Shenandoah-D	14.2	14.0	13.7	13.5	13.5	13.4	13.2	13.1	13.0	12.9	18.9
	Tioronda	17.7	17.5	17.4	17.3	17.4	17.3	17.3	17.2	17.2	17.3	28.7
	Total	208.3	206.1	204.0	201.9	203.0	201.5	200.2	199.2	198.4	198.0	N/A
Kingston-Saugerties	Boulevard*	18.6	18.7	18.7	18.7	18.9	19.0	19.1	19.2	19.4	20.0	44.8
	East Kingston	17.0	17.2	17.4	17.6	17.7	17.9	18.1	18.3	18.5	18.8	48.0
	Hurley Ave*	19.9	19.7	19.6	19.5	19.7	19.6	19.6	19.6	19.6	20.1	28.4
	Lincoln Park	41.4	40.5	39.7	38.8	38.5	37.7	36.8	36.0	35.3	34.6	84.0
	Saugerties*	22.9	23.0	23.1	23.2	23.4	23.6	23.8	24.0	24.5	25.6	70.5
	Woodstock*	21.8	22.0	22.2	22.4	23.6	24.5	25.7	26.9	28.3	29.8	23.9
	Total	133.9	133.0	132.0	131.0	131.3	130.5	129.7	128.9	130.0	133.5	N/A
Modena	Galeville*	12.4	12.4	12.3	12.2	12.3	12.2	12.2	12.2	12.5	12.9	28.7
	Highland*	20.1	20.0	19.9	19.8	19.9	19.9	20.0	20.5	21.2	21.9	37.3
	Modena	16.2	16.1	16.0	16.0	16.0	15.9	15.9	15.9	15.9	15.9	21.1
	Ohioville*	23.8	23.5	23.1	22.8	22.8	22.4	22.1	21.9	21.6	22.0	34.2
	Total	71.1	70.3	69.4	68.6	68.9	68.1	67.5	66.9	68.2	70.2	N/A
Newburgh	Bethlehem Rd	39.5	39.5	39.4	39.3	39.4	39.4	39.4	39.5	39.6	39.7	47.8
	Coldenham	22.1	22.6	23.1	23.5	23.8	24.4	25.0	25.6	26.3	27.0	47.8
	East Walden	16.6	16.4	16.3	16.1	16.2	16.1	16.0	16.0	16.0	16.0	26.2
	Marlboro	22.7	22.5	22.4	22.3	22.4	22.3	22.2	22.2	22.2	22.3	30.9
	Maybrook	21.9	21.7	21.5	21.2	21.2	21.1	20.9	20.7	20.6	20.5	20.9
	Montgomery**	5.2	5.0	4.9	4.8	4.8	4.7	4.5	4.4	4.3	4.2	24.0
	Union Ave	64.0	64.9	65.8	66.8	67.2	68.2	69.2	70.3	71.4	72.5	94.5
	West Balmville	37.6	37.2	36.8	36.4	36.4	36.1	35.7	35.4	35.2	34.9	47.8
	Total	225.1	224.7	224.2	223.8	224.4	224.2	224.2	224.4	224.8	225.3	N/A
Northeastern Dutchess	East Park	14.8	14.7	14.7	14.7	14.7	14.7	14.8	14.8	14.8	14.9	30.4
	Hibernia	13.8	14.0	14.3	14.5	14.7	14.9	15.2	15.6	15.9	16.3	23.7
	Milan*	11.0	11.1	11.1	11.2	11.5	11.8	12.1	12.4	12.8	13.3	38.2
	Millerton*	5.9	5.8	5.6	5.5	5.5	5.4	5.4	5.4	5.5	5.6	13.0
	Pulvers 13	5.6	5.7	5.8	6.0	6.0	6.2	6.3	6.5	6.6	6.8	7.2
	Pulvers 34*	3.0	3.0	3.0	3.0	3.1	3.2	3.3	3.6	3.8	4.2	26.7
	Rhinebeck*	30.6	29.8	29.0	28.3	28.2	27.5	26.9	26.3	26.1	26.5	47.8
	Smithfield*	1.9	1.9	1.9	2.0	2.0	2.0	2.1	2.1	2.2	2.3	8.7
	Staatsburg	9.8	10.1	10.3	10.5	10.7	11.0	11.2	11.5	11.9	12.2	28.9
	Stanfordville*	4.1	4.4	4.7	5.1	5.4	5.9	6.5	7.2	8.0	8.8	24.5
	Tinkertown	15.8	15.8	15.8	15.9	16.0	16.0	16.1	16.2	16.3	16.4	19.1
	Total	109.8	109.6	109.5	109.3	109.7	109.7	109.7	109.8	112.3	115.8	N/A

Load Area	Substation	Historical 1 in 2 Annual Peak (MVA)				Forecasted 1 in 2 Annual Peak (MVA)						Rating (MVA)
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	
Northwest	Coxsackie*,**	9.3	9.7	10.1	10.5	10.8	11.4	12.1	12.8	13.7	14.6	24.8
	Freehold*	8.1	8.2	8.4	8.5	8.6	8.8	9.0	9.2	9.6	10.1	25.0
	Hunter*	11.7	11.3	10.9	10.6	10.4	10.1	9.9	9.6	9.4	9.3	21.2
	Lawrenceville*	14.1	14.1	14.1	14.0	14.1	14.1	14.2	14.2	14.4	14.5	19.3
	New Baltimore	11.6	12.2	12.9	13.6	13.9	14.7	15.5	16.3	17.3	18.3	28.7
	North Catskill	27.3	27.6	27.8	28.1	28.3	28.6	28.9	29.2	29.5	29.9	35.1
	South Cairo*	12.3	12.6	12.9	13.2	13.5	14.0	14.6	15.2	16.0	16.8	29.4
	Vinegar Hill*	11.2	11.2	11.1	11.1	11.1	11.1	11.2	11.3	11.4	11.5	21.3
	Westerlo*	8.3	8.4	8.4	8.4	8.6	8.7	9.0	9.3	9.7	10.2	35.0
	Total	95.6	98.5	101.5	104.6	105.7	109.7	114.2	119.1	124.5	130.4	N/A
Poughkeepsie	Inwood Ave	25.5	26.1	26.7	27.3	27.7	28.4	29.1	29.9	30.8	31.7	51.2
	Manchester	35.8	34.6	33.4	32.2	31.9	30.8	29.8	28.8	28.0	27.3	47.8
	Reynolds Hill	38.8	39.5	40.2	40.8	41.1	41.9	42.6	43.3	44.1	44.9	47.8
	Spackenkill	35.0	34.8	34.6	34.5	34.6	34.5	34.4	34.3	34.3	34.3	47.8
	Todd Hill	26.4	26.3	26.2	26.1	26.2	26.1	26.1	26.1	26.2	26.3	47.8
	Total	155.3	155.2	155.1	155.0	155.3	155.3	155.3	155.5	155.7	155.9	N/A

[1] The peak values displayed in the table above reflect the T&D avoided cost forecast and are coincident with substation peak

Central Hudson is progressing with its implementation of its Distribution Grid Modernization program. Once the Distribution Management System (DMS) is fully integrated, the ability to increase the utilization of our power transformers in our distribution substations becomes possible. Currently two transformer substations are designed to operate with an auto scheme that allows for all the substation load to be supplied by one transformer for the loss of either a bus or transformer making for a "firm" rating. With additional Intelligent Electronic Devices (IEDs) and a DMS to manage the load on a 24-hour basis the potential for additional automated load transfer during contingencies on the distribution system will allow for the increased utilization for both summer and winter periods at our substations while maintaining system reliability.

3.3 CIRCUIT LOAD GROWTH ESTIMATES

As a continued advancement of the methodologies utilized in this study, forecasts were completed at the more granular circuit level for the first time. Unlike substation and transmission areas, circuits utilize design criteria, which includes a normal and emergency design rating, but do not have a long-term emergency (LTE) rating. The design criteria are tied to operational requirements to maintain flexibility at the substation level and are more conservative than the actual thermal rating of the distribution assets on the feeder. Central Hudson utilizes several standard design ratings for circuits (i.e., 6/9 MVA or 9/12 MVA high capacity for 13.8kV circuits). This circuit design rating does not represent the thermal capability for the circuit which is typically higher and provides for local operating flexibility. Therefore, for this initial analysis the circuit's normal design criteria rating + 1 MVA was used to determine the circuit's capability.

Circuit overloads are treated differently from substation and transmission areas, with some circuits operating above their design criteria but never exceeding their thermal rating. This is due to the following:

- The distribution system is more dynamic;

- Central Hudson can transfer loads more easily between circuits to maintain load balancing amongst area circuits in addition to addressing reliability;
- There is a potentially shorter timeframe required to complete upgrades; and
- Central Hudson often has the option to connect large new loads to one of multiple circuit feeders.

The plans for determining criteria for triggering an upgrade and providing deferral value are discussed in greater detail later in this section.

Central Hudson's design criteria are a combination of thermal, economic, and reliability considerations, as well as engineering judgment, to provide a guiding foundation in developing or altering circuit configurations. Central Hudson is a summer peaking utility and since summer ratings are limiting, the design ratings were established utilizing summer ratings because they are most limiting. With electrification and the potential shift to a winter peak, Central Hudson will need to establish winter ratings for its distribution facilities at the feeder level in the future which will vary by station. These ratings will likely allow for more load serving capabilities on the distribution facilities during the winter period.

Figure 23 compares the annual load growth rate to the loading factor (weather-normalized peak divided by the location's circuit design criteria: Normal Design Criteria Rating + 1 MVA) for each of Central Hudson's circuits. Due to the noise in the circuit data, the circuit's corresponding substation was used to determine the growth rate for the circuit. For example, any circuits connected to New Baltimore substation will have the same growth rate (5.4%). Many circuits exceed their design criteria rating in 2022 as they are able to operate above their design criteria and remain under their thermal limits.

Figure 23: Circuit Growth Rates Versus Room for Growth

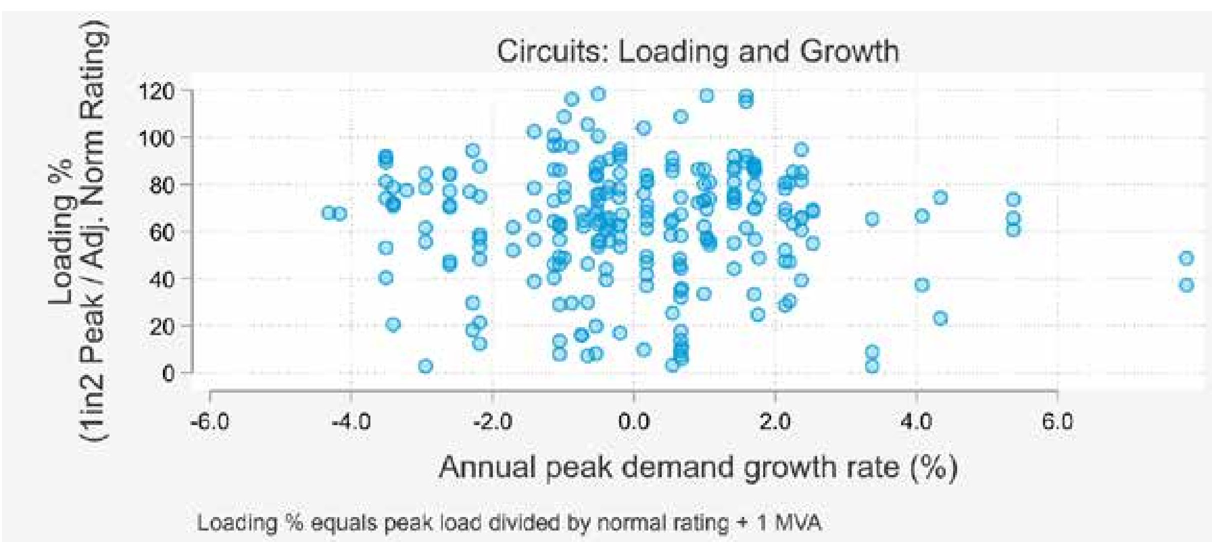


Figure 24 and Figure 25 show heat maps of the growth rate and the summer and winter loading factor (peak / design rating) for each of Central Hudson's circuits. Darker orange colors indicate higher growth rates and higher loading factors. As seen in the previous figure, there are many highly loaded circuits in 2022, with some circuits operating above their design rating. Summer loading does not change dramatically between 2023 and 2033 while winter loading increases due to the addition of electrification. For a detailed breakout of the circuit load forecasts, please see Appendix B and Appendix C of this report.

Figure 24: Heat Map of Substation Growth Rates and Summer Loading Factors

Historical Growth Rates | Summer Loading Factors 2022 | Summer Loading Factors 2033

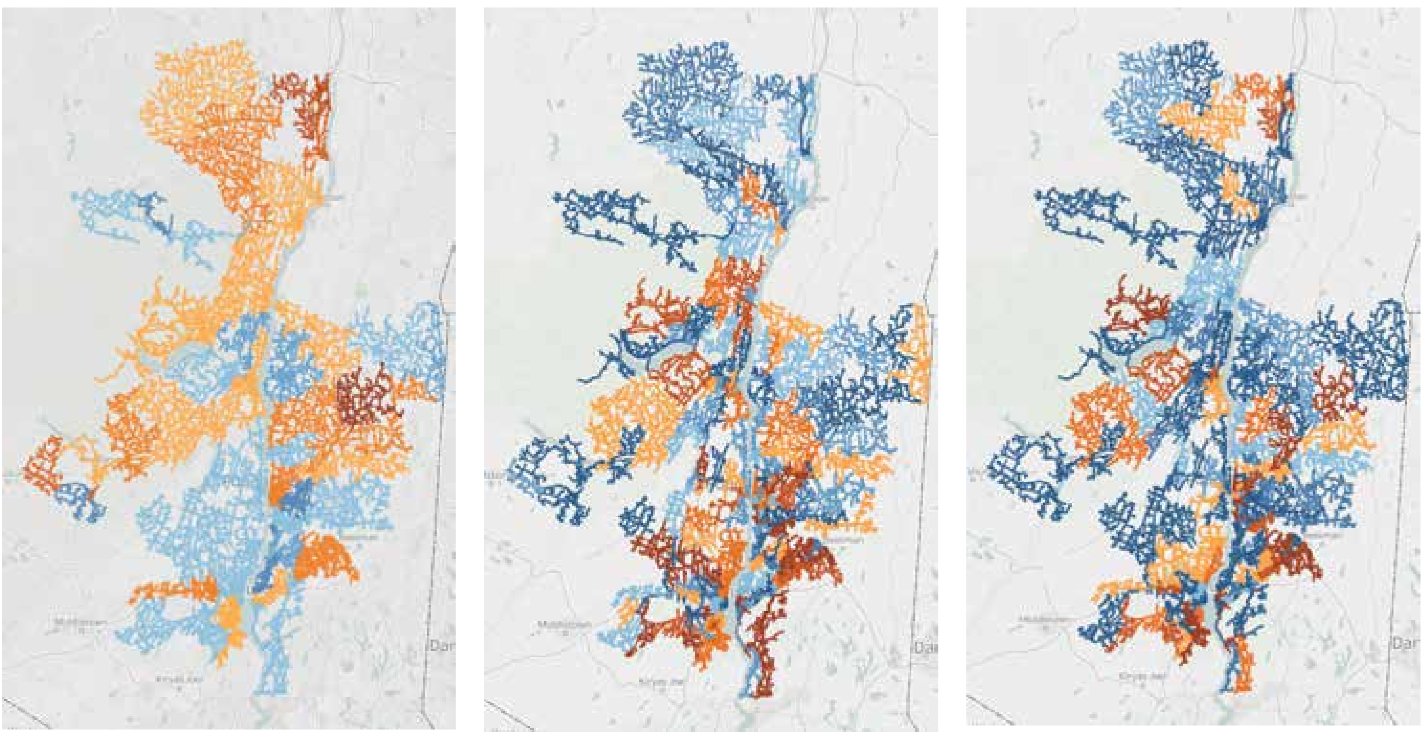
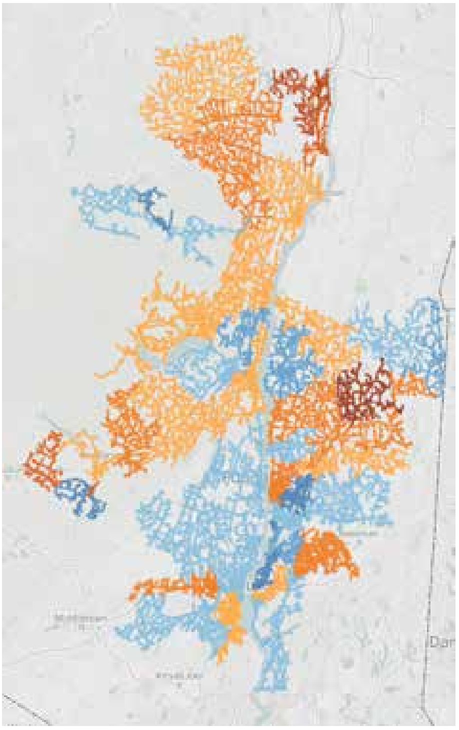
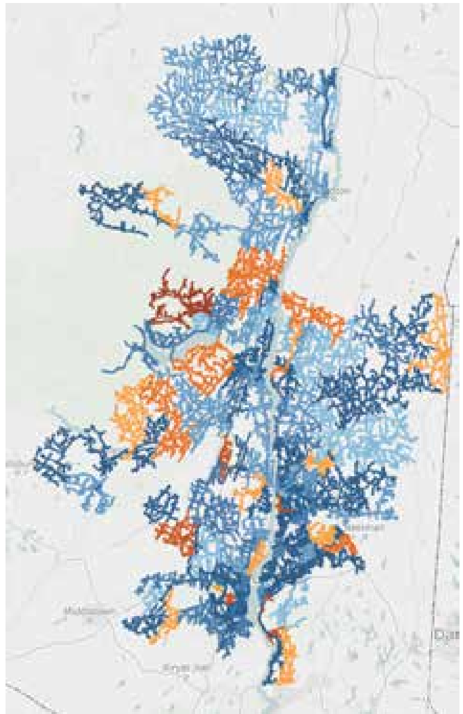


Figure 25: Heat Map of Substation Growth Rates and Winter Loading Factors

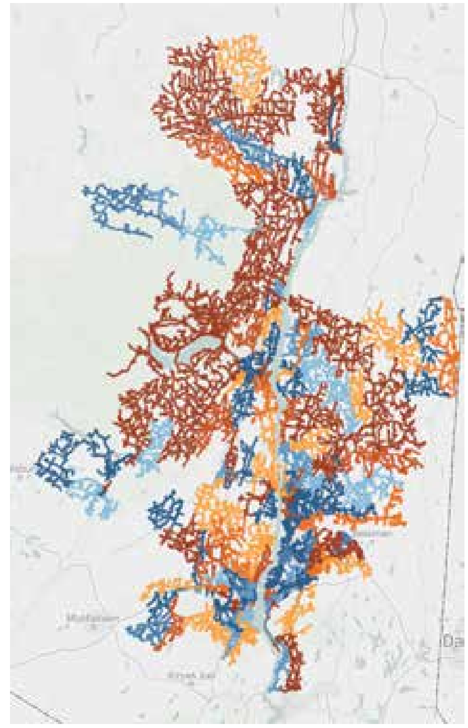
Historical Growth Rates



Winter Loading Factors 2022



Winter Loading Factors 2033



As discussed above, the circuit ratings were adjusted to account for the fact that it is not unusual for a circuit to exceed its normal design rating. The table below depicts the unadjusted and adjusted ratings for the different circuit ratings. Most circuits have a normal design rating of 6 MVA, or an adjusted rating of 7 MVA.

Table 18: Circuit Normal Design Rating Adjustments (MVA)

Number of Circuits	Unadjusted Circuit Rating	Adjusted Circuit Rating
15	1.5 MVA	2.5 MVA
257	6 MVA	7 MVA
18	9 MVA	10 MVA
1	17.2 MVA	18.2 MVA
1	18.8 MVA	18.8 MVA
1	19.3 MVA	20.3 MVA

Our initial analysis of circuits exceeding their design criteria used the same criteria as for substations, where a circuit feeder triggers a deferral if it has a greater than 5% likelihood of exceeding its design rating for more than two years in a row. This initial analysis at the more granular level identified a total of 80 circuits that have a greater than 5% likelihood of exceeding their design criteria in the summer and 75 circuits that have a greater than 5% likelihood of exceeding their design criteria in the winter. Utilizing these criteria, a total of 69 circuits would trigger a deferral by 2033.

As indicated, this is the first time the methodologies outlined in this report were utilized to analyze loading at the more granular distribution circuit level. The criteria utilized in this initial study were very conservative. The Company is utilizing the data from this initial analysis in conjunction with localized planning knowledge to further refine the methodology for estimating circuit deferral value. Preliminary review identified that a number of the circuits that the analysis determined had a greater than 5% likelihood of exceeding their rating 2 years in a row have firm plans for upgrades. In most cases, the upgrades are being driven by other factors (i.e., operating flexibility, infrastructure issues, reliability/resiliency improvements, grid modernization, emergent large spot loads). An additional subset of circuits identified had known historic load transfers due to switching orders that may have impacted the forecasted loads. Finally, in a number of cases, low cost switching options that could permanently transfer load to neighboring circuitry are available to address the identified design criteria violations, alleviating the need to complete upgrades.

As this was the first time this analysis was performed at the circuit level, the Company plans on refining the criteria utilized within the analysis prior to estimating deferral value. As discussed earlier, Central Hudson will need to establish winter ratings for its distribution facilities at the feeder level in the future. The winter criteria update will allow Central Hudson e to estimate deferral value at circuit feeder level in future studies.

4 AVOIDED T&D COST AND LOAD RELIEF NEEDS

Until recently, avoided T&D cost studies have not produced location specific estimates and have not relied on probabilistic methods, which quantify the risk mitigation value of managing demand. The estimates produced here are based on 5,000 simulations of potential load growth patterns for each substation and transmission area, respectively. For each simulation, we are thus able to assess if the relevant design rating is exceeded, identify the timing of infrastructure upgrade, quantify the magnitude of demand reductions needed to avoid the infrastructure upgrade, and calculate what the avoided costs associated with deferral of infrastructure upgrades would be if demand reductions were in place. The detailed calculations from each of the simulations at each location are used to estimate the expected avoided costs per kW. That is, the probabilistic method assigns T&D avoided costs when, for example, only 5% of potential growth trajectories leads to infrastructure upgrades.

This approach quantifies the risk mitigation value provided by resources that reduce demand at the right times at each location. The purpose of producing avoided T&D costs estimates is not necessarily to establish payments or incentives for DERs. The objective is to allow distributed energy resources to compete against each other and against traditional engineering solutions – wires, transformers, etc. – and thus increase competition and improve efficiency. The avoided cost estimates signal to DER providers not only where DERs are most beneficial but where they are most likely to be monetized. They also provide a reference point and allow comparison of DER costs to traditional engineering solutions. To deliver value, however, DERs needs to ramp up at the right time and the right place, for the right hours, with the right amount of availability, and the right level of certainty.

Avoided costs are tied to deferral of actual investments. Once sufficient NWA capacity has been contracted to defer a likely investment for a 10-year period, no value remains. As such, deferral value, though often expressed in dollars per kVA, really corresponds to deferral of a specific capacity magnitude for a specified length of time. Further, avoided T&D costs are classified into three mutually exclusive categories:

- Non-Wire Alternative (NWA) projects which provide contractual resources;
- Location Specific Relief Value (LSRV) which can be used to incentivize non-contracted resources in a specific location (in this study, locations with greater than 25% likelihood of deferral in the next ten years);
- System-wide value which can be used to incentivize non-contracted resources and which incorporates the random chance that resources will be located where they will actually provide load relief; and

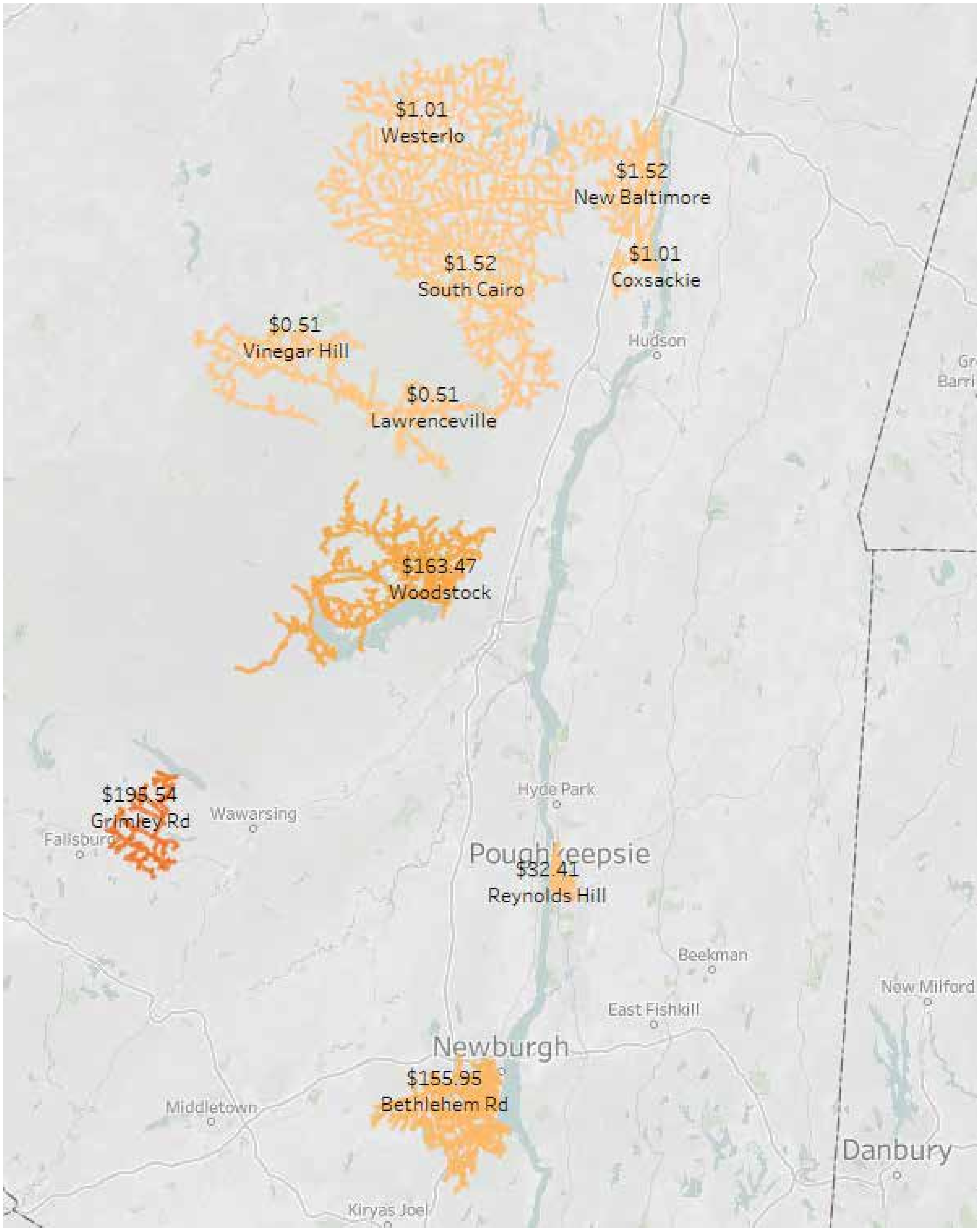
- The Demand Reduction Value (DRV), which is the delta between the system value and the locations with high value (in this study, locations with between 5% and 25% likelihood of an upgrade over the next ten years).

In general system-wide untargeted values take into account the likelihood reductions would be in the location with value due to random chance. Without targeting, the likelihood that reductions will be at a location where it might help defer or delay substation upgrades is relatively low, diluting any “system” avoided cost.

Figure 26 summarizes the 10-year NPV of the total LSRV (transmission + distribution) for all beneficial locations in Central Hudson territory. Note that while substations are labeled, the value includes both value from transmission deferral and substation deferral combined for each location. In areas where there is value from upgrading both substation and transmission areas, the value is added together. Specifically, there is a higher value in areas where Westerlo Loop transmission area and Woodstock substation are both located.

As a part of the analysis load forecasts were produced at the granular circuit level. This is the first time the methodologies outlined in this report were utilized to analyze loading at the more granular distribution circuit level. The Company is utilizing the data from this initial analysis in conjunction with localized planning knowledge to further refine the methodology for estimating circuit deferral value. Therefore, no deferral values were produced for circuits as a part of this study.

Figure 26: 10-Year NPV of Total LSRV (Transmission & Distribution) All Locations with Deferral Benefit



4.1 AVOIDED TRANSMISSION COSTS

Table 19 shows the 10-year levelized avoided cost estimates by transmission area. A total of two transmission areas have potential avoided costs – RD-RJ Lines and Westerlo Loop. The RD-RJ Lines peak in the summer and Westerlo Loop peaks in the winter. Both locations would require infrastructure upgrades to meet the higher loading predicted in the forecast.

Avoided T&D costs are location specific. In order to delay upgrades, it is necessary to have the right level of reductions at the right location at the right time and right season. We break out the avoided costs into three separate areas: Locational System Relief Value (LSRV); Demand Reduction Value (DRV); and system-wide. The LSRV is by design location-specific. The DRV is the delta between the system value and the locations with high value (greater than 25% likelihood of deferral in the next ten years), which is applied to the remainder of the territory. This value is derived from locations with between 5% and 25% likelihood of an upgrade over the next ten years. The system-wide value is substantially lower than the location-specific values because it is taking into account the likelihood reductions would be in locations with value due to random chance. In this case, both transmission areas have a greater than 25% likelihood of deferral during the study period which comprises the LSRV value. There are no areas with DRV value, as no areas had between 5% and 25% likelihood of deferral. The diluted "system" 10-year levelized avoided cost is $2.10 /kW- year. We emphasize that system wide value is a weighted average of a few beneficial locations with numerous locations where reductions do not lead to avoided T&D costs.

Because there is deferral value for both summer peaking and winter peaking transmission areas, there is value for both summer and winter resources.

Table 19: Avoided Transmission Cost Estimates ($/kVA-Year) – 10 Year Levelized Value

Year	LSRV Value		DRV Value	System Value
	RD RJ Lines	Westerlo Loop		
2024	$0.10	$0.00	$0.00	$0.01
2025	$4.20	$0.00	$0.00	$0.45
2026	$12.59	$0.00	$0.00	$1.34
2027	$20.83	$0.00	$0.00	$2.21
2028	$27.82	$0.00	$0.00	$2.96
2029	$33.72	$0.00	$0.00	$3.58
2030	$34.76	$0.06	$0.00	$3.70
2031	$31.39	$0.67	$0.00	$3.38
2032	$28.62	$2.43	$0.00	$3.19
2033	$24.98	$4.12	$0.00	$2.91
10-year NPV	$19.49	$0.51	$0.00	$2.10

4.2 AVOIDED DISTRIBUTION SUBSTATION COST ESTIMATES

Table 20 shows the 10-year levelized avoided cost estimates by substation and for the entire system. A total of three substations have potential avoided costs – Grimley Road, Reynolds Hill, and Woodstock. Grimley Road and Reynolds Hill both peak in the summer, with their entire value occurring in the summer for both substations. Woodstock primarily peaks in the winter but there is also some value from reducing load in the summer for Woodstock.

Avoided T&D costs are location specific. In order to delay upgrades, it is necessary to have the right level of reductions at the right location at the right time and right season. We breakout the avoided costs into three separate areas: Locational System Relief Value (LSRV), Demand Reduction Value (DRV), and system-wide. The LSRV is by design location-specific. The DRV is the delta between the system value and the locations with high value (greater than 25% likelihood of deferral in the next ten years), which is applied to the remainder of the territory. This value is derived from locations with between 5% and 25% likelihood of an upgrade over the next ten years. The system-wide value is substantially lower than the location-specific values because it is taking into account the likelihood reductions would be in locations with value due to random chance. In this case, all three substations have a greater than 25% likelihood of deferral during the study period which comprises the LSRV value. There are no areas with DRV value, as no areas had between 5% and 25% likelihood of deferral. The diluted "system" 10-year levelized avoided cost is $1.68 /kW- year. We emphasize that system wide value is a weighted average of a few beneficial locations with numerous locations where reductions do not lead to avoided T&D costs.

Because there is deferral value for both summer peaking and winter peaking transmission areas, there is value for both summer and winter resources.

Table 20: Avoided Substation Cost Estimates ($/kVA-Year) – 10 Year Levelized Value

Year	LSRV Value			DRV Value	System
	Grimley Rd	Reynolds Hill	Woodstock		
2024	$156.71	$0.00	$0.30	$0.00	$0.81
2025	$187.91	$0.00	$109.16	$0.00	$2.86
2026	$191.73	$0.00	$114.46	$0.00	$2.97
2027	$173.80	$0.00	$112.79	$0.00	$2.85
2028	$151.56	$0.00	$61.73	$0.00	$1.85
2029	$48.32	$0.41	$5.10	$0.00	$0.36
2030	$26.28	$3.44	$0.02	$0.00	$0.29
2031	$13.47	$12.45	$0.00	$0.00	$0.62
2032	$6.96	$28.15	$0.00	$0.00	$1.29
2033	$4.09	$43.54	$0.00	$0.00	$1.96
10-year NPV	$97.77	$5.40	$40.87	$0.00	$1.68

4.3 2023 VERSUS 2020 AVOIDED T&D COST STUDIES

In comparison to the 2020 study, the 2023 T&D avoided cost results differ along the following dimensions:

- The two locations with value in the 2020 study (Northwest 115-69 kV transmission area and Shenandoah-Distribution substation) no longer trigger upgrades, due to load declines in the past two years and forecasted negative load growth
- The five locations with value in the 2022 study (RD-RJ Lines and Westerlo Loop transmission areas and Grimley Rd, Reynolds Hill, and Woodstock substations) are all relatively highly loaded, have positive growth rates, and are expected to see increases in load due to electrification
- While avoided costs were not included in the 2020 study because the identified beneficial locations already had NWAs in place, there are avoided costs for all five of the locations studied in 2023. Overall, the systemwide 10-year levelized avoided cost is $2.10 /kW-year for transmission and the systemwide 10-year levelized avoided cost is $1.68 /kW-year for distribution.

5 BENEFICIAL LOCATIONS FOR DER

Locations were identified as potentially benefitting from DERs when there was a 5% or greater likelihood of triggering an infrastructure investment by 2033 (10 years). In total, this includes two transmission areas and seven substations. While the locations can benefit from DERs, in some instances Central Hudson already has planned infrastructure upgrades in the short term to alleviate overloading. This is specifically the case for four of the substations: Fishkill Plains; New Baltimore; Maybrook; and Pulvers 13kV.

For areas that do not have planned infrastructure upgrades, the right type of DERs with the right availability may allow for deferral of infrastructure investment. This is the case for the two transmission areas and the three remaining substations. The areas vary in terms of their seasonal peak, meaning that they will need load management programs for both the summer and the winter. Additional detail on each of the locations is covered in the remainder of this section.

Figure 27: Map of Beneficial Transmission Locations for DERs

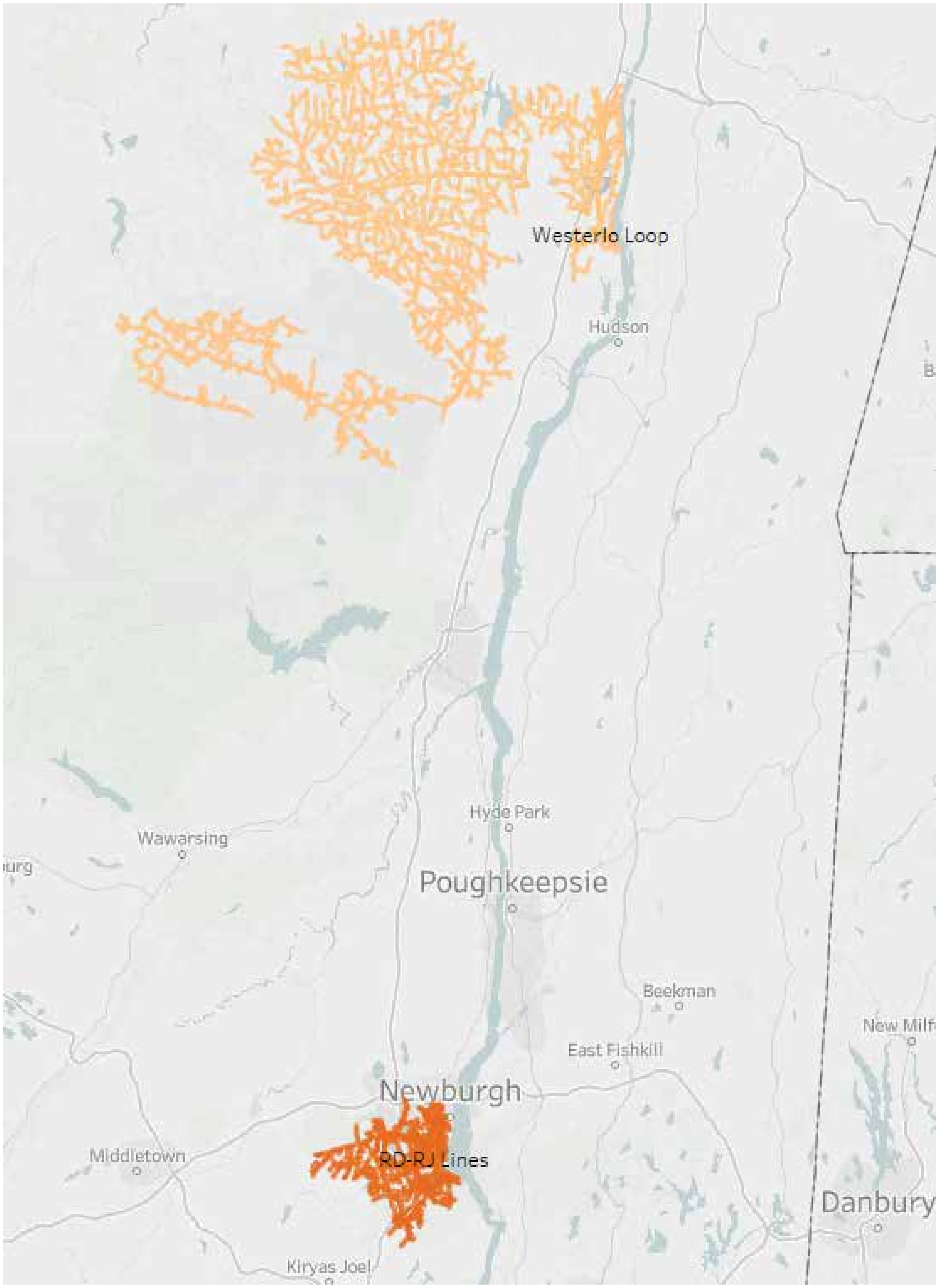
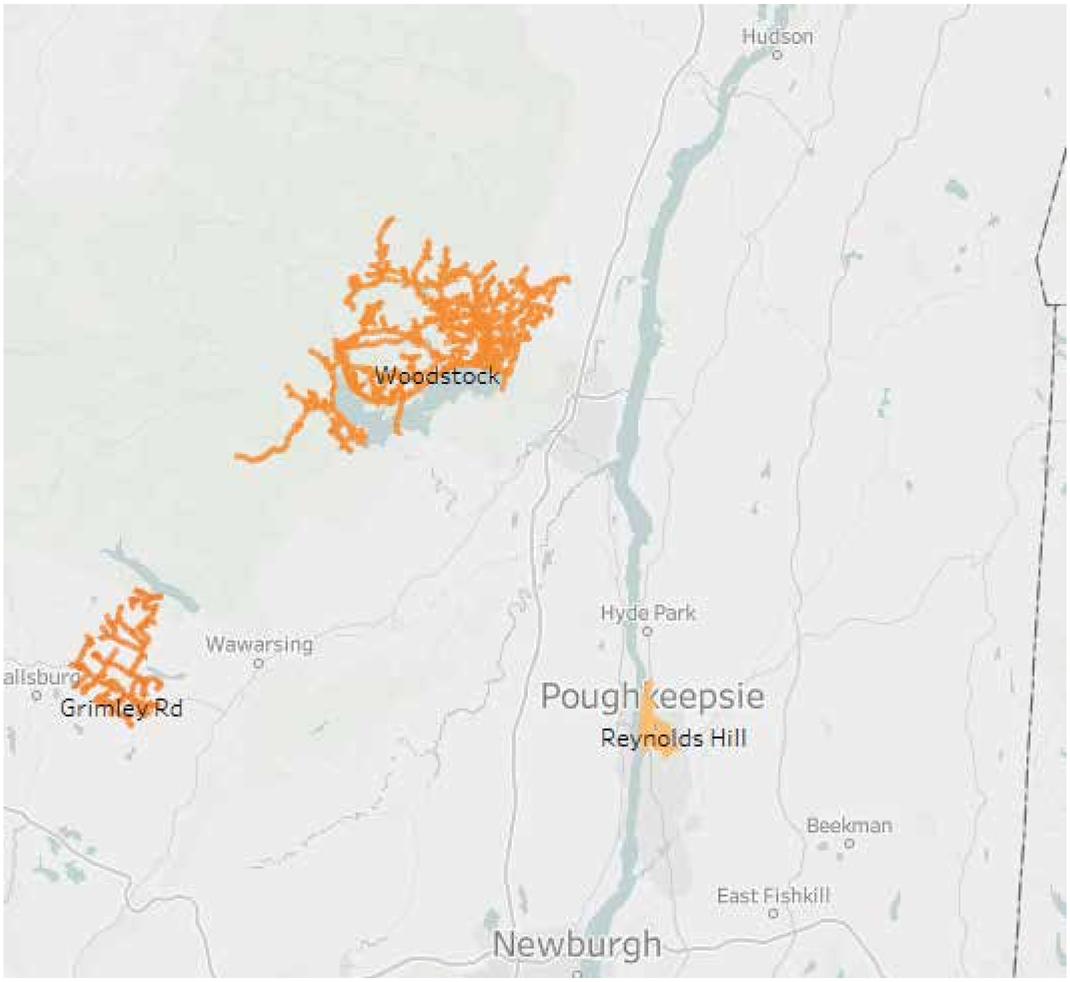


Figure 28: Map of Beneficial Substation Locations for DERs



5.1 TRANSMISSION AREAS

5.1.1 RD-RJ LINES

The RD-RJ Lines transmission area is located at the southernmost part of the Central Hudson electric service territory. It currently has a summer long term emergency rating (LTE) of 144 MVA and a short-term emergency (STE) rating of 155 MVA. In the winter, when cooler temperatures allow for higher loads, the LTE rating is higher, 167 MVA and a STE rating of 176 MVA.

Figure 29 shows the division of active accounts and electricity consumption in 2022 for RD-RJ Lines between residential and non-residential customers. Roughly 85% of the accounts belonged to the residential customer class, and together they comprised 47% of total usage in 2022.

Figure 29: RD-RJ Lines Accounts and Consumption

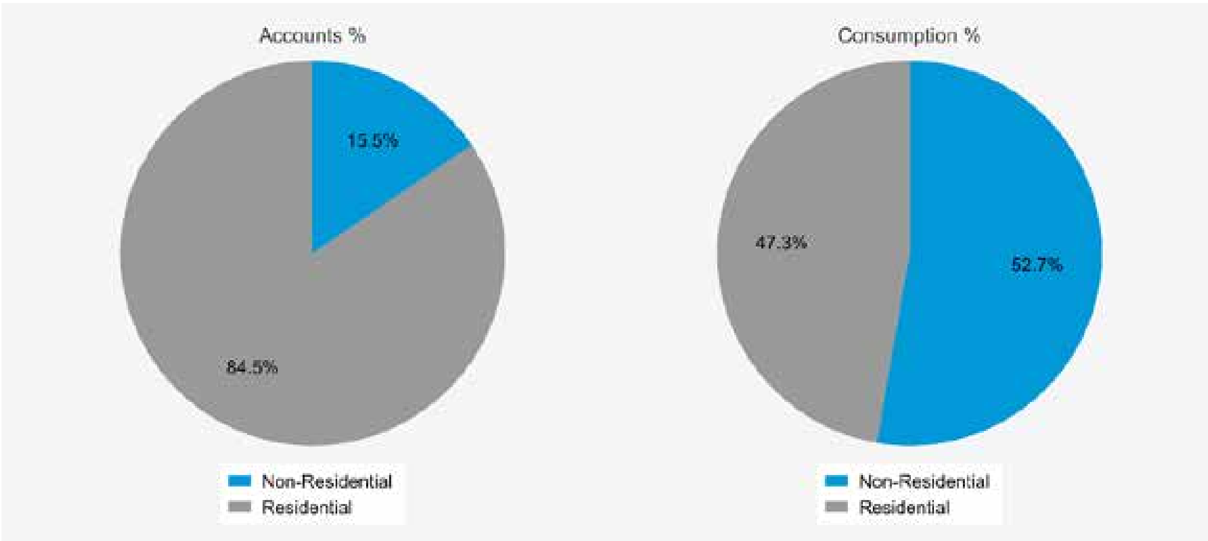
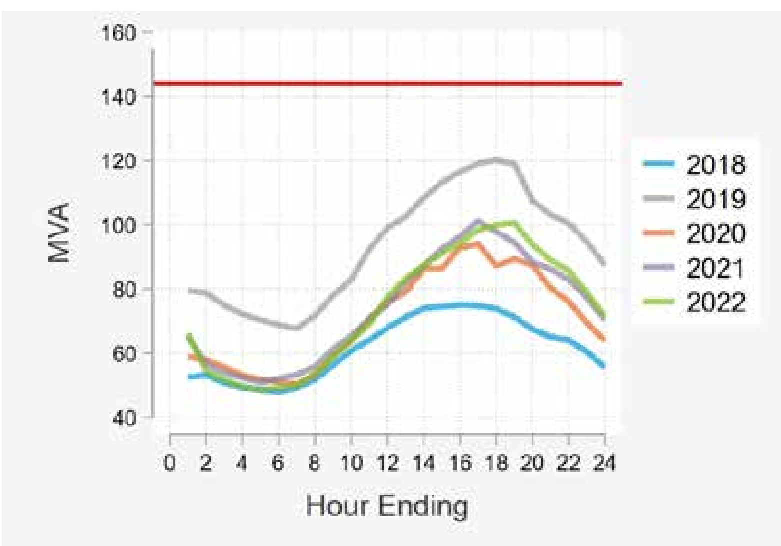


Figure 30 summarizes the peak day load for each year from 2018 to 2022 and includes details about the timing of the peak. Figure 31 summarizes the multi-year load duration curve over the same time frame and shows that peak demand is concentrated on a small share of hours. The weather sensitivity of load is illustrated in Figure 32, which shows the daily peak load as a function of different temperature ranges. RD-RJ Lines are summer-peaking and are fairly weather-sensitive, with loads increasing as temperatures increase.

Figure 30: RD-RJ Lines Transmission Area Historical Annual Peak Day Load Shapes



Date	Year	Hour	Load (MVA)	Day of Week
Aug-07-2018	2018	19	71.3	Tuesday
Jul-21-2019	2019	20	107.4	Sunday
Jul-22-2020	2020	18	87.3	Wednesday
Aug-12-2021	2021	19	94.5	Thursday
Aug-04-2022	2022	20	93.8	Thursday

Figure 31: RD-RJ Lines Multi-year Normalized Load Duration Curve, 2018-2022

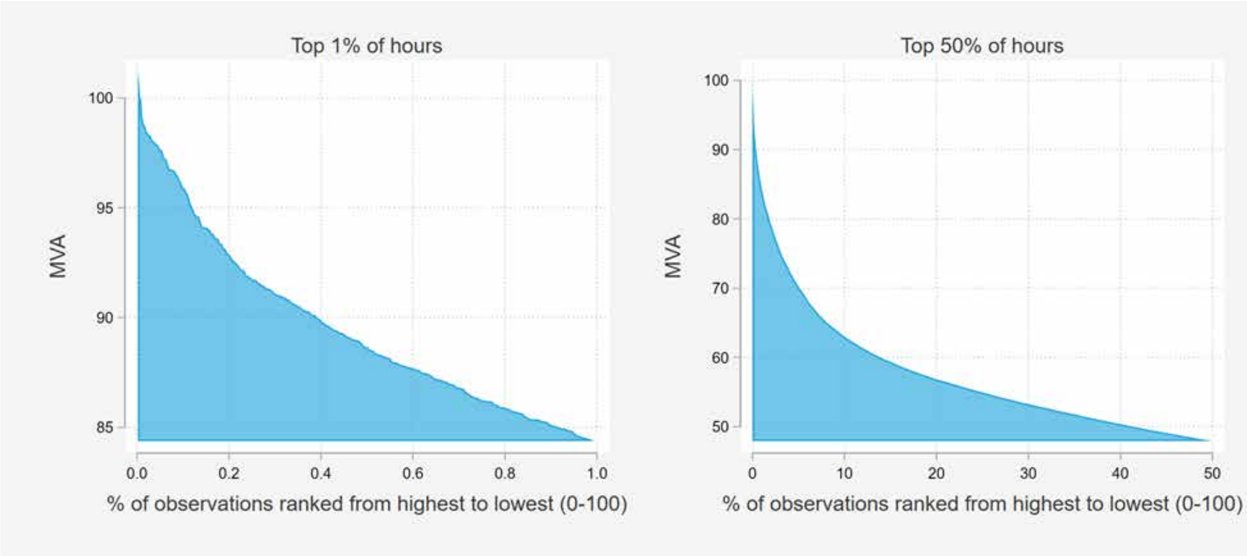


Figure 32: RD-RJ Lines Daily Peak Load Weather Pattern by Year

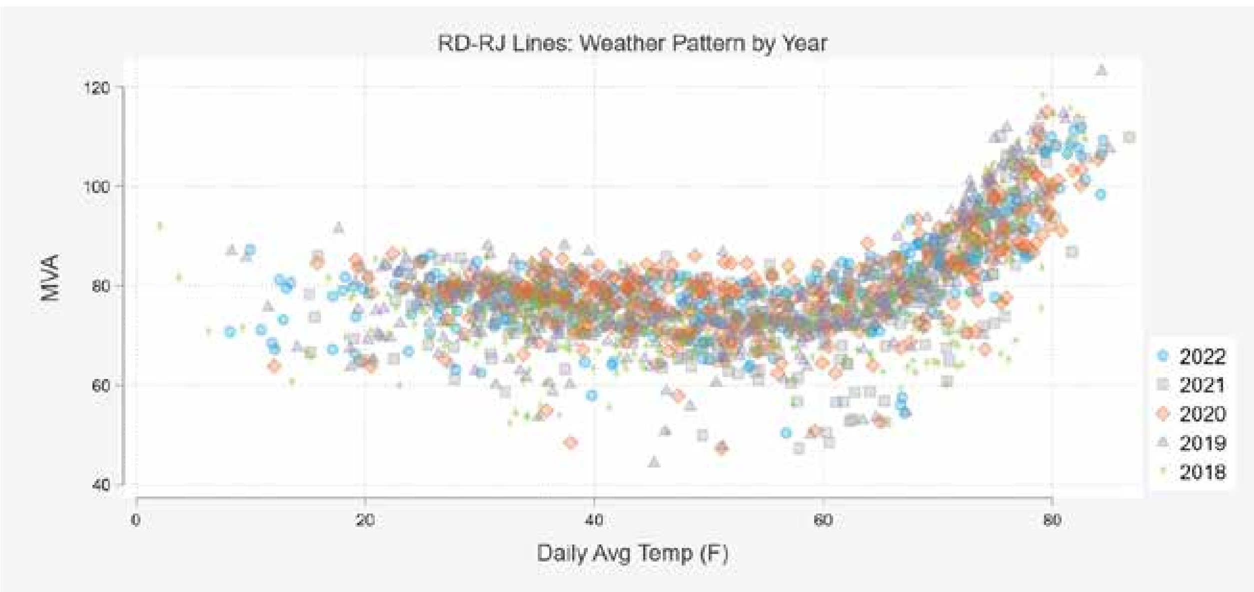
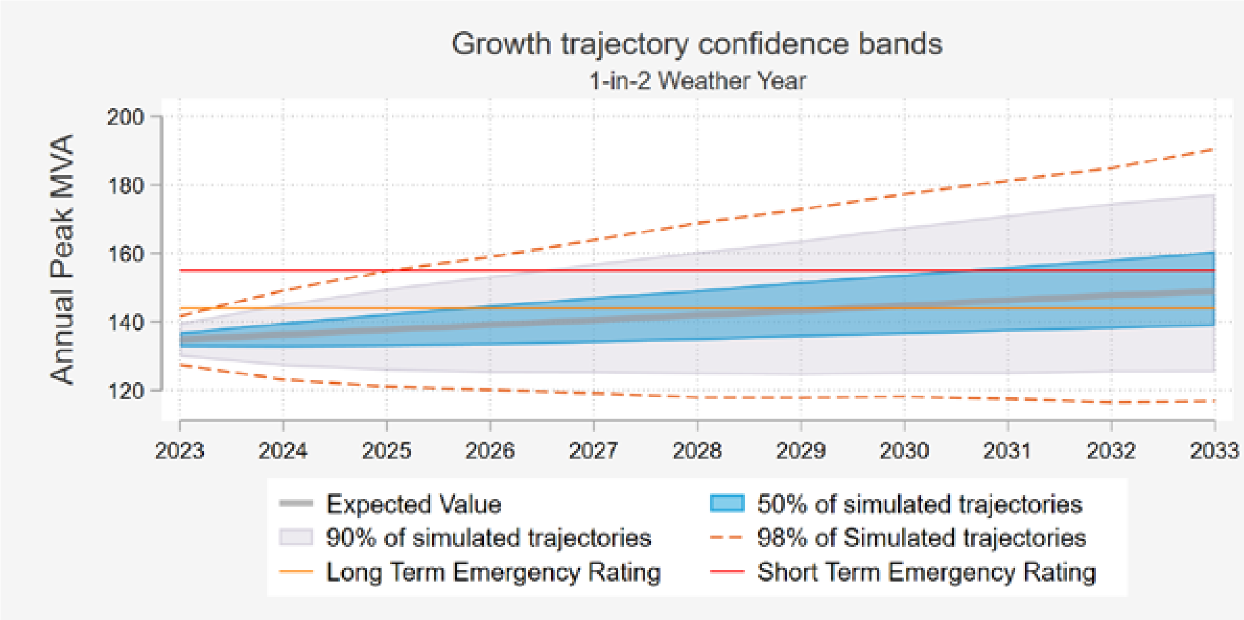


Figure 33 shows the load growth forecast, assuming 1-in-2 weather year conditions. Load growth was modeled using probabilistic methods rather than straight-line forecasts. There is substantial uncertainty in the forecast, but there is a greater than 25% probability that loads will exceed the LTE rating by 2026. Note that this graph does not include the additional load from electrification.

Figure 33: RD-RJ Lines Transmission Area Annual Peak Load Forecast with Uncertainty



5.1.2 Westerlo Loop

The Westerlo Loop transmission area is located at the northernmost part of the Central Hudson electric service territory. It currently has a long-term emergency rating (LTE) of 83.6 MVA and a short-term emergency (STE) rating of 83.6 MVA in both summer and winter; these limits are based on acceptable post-contingency voltages.

Figure 34 shows the division of active accounts and electricity consumption in 2022 for Westerlo Loop between residential and non-residential customers. Roughly 87% of the accounts belonged to the residential customer class, and together they comprised 60% of total usage in 2022.

Figure 34: Westerlo Loop Transmission Area Accounts and Consumption

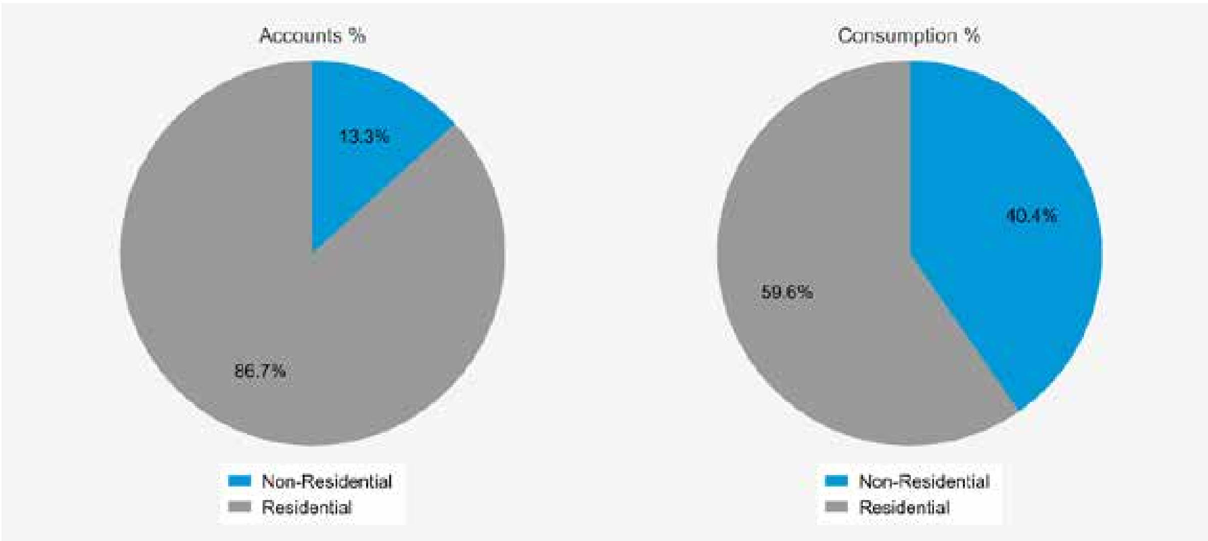
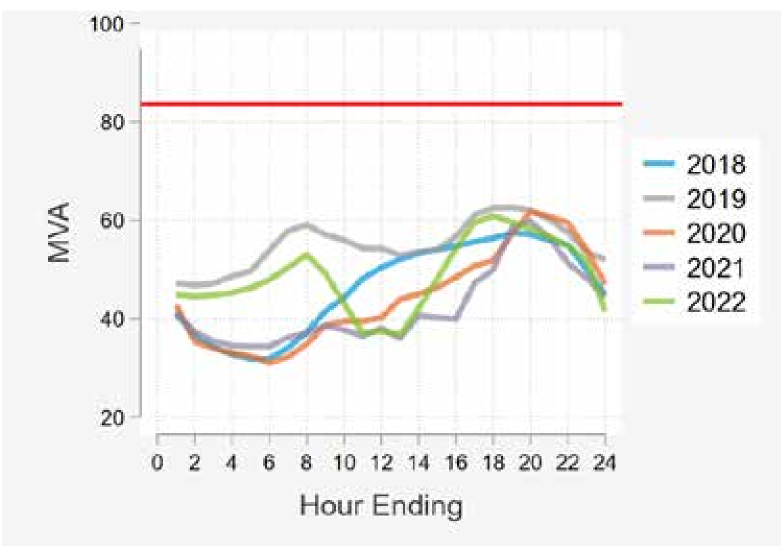


Figure 35 summarizes the peak day load for each year from 2018 to 2022 and includes details about the timing of the peak. Figure 36 summarizes the multi-year load duration curve over the same time frame and shows that peak demand is concentrated on a small share of hours. The weather sensitivity of load is illustrated in Figure 37, which shows the daily peak load as a function of different temperature ranges. Westerlo Loop has historically peaked in both the summer and winter and is very weather-sensitive.

Figure 35: Westerlo Loop Historical Annual Peak Day Load Shapes



Date	Year	Hour	Load (MVA)	Day of Week
Jul-02-2018	2018	19	57.4	Monday
Dec-19-2019	2019	19	62.6	Thursday
Jul-27-2020	2020	20	61.7	Monday
Aug-13-2021	2021	20	59.7	Friday
Jan-15-2022	2022	18	60.9	Saturday

Figure 36: Westerlo Loop Multi-year Normalized Load Duration Curve, 2018-2022

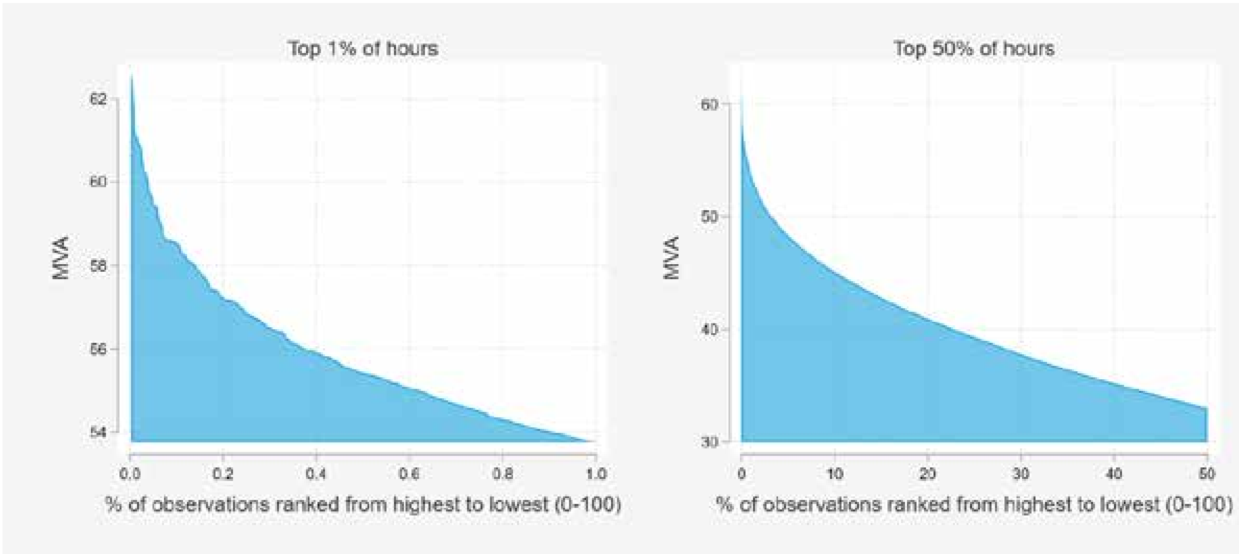


Figure 37: Westerlo Loop Daily Peak Load Weather Pattern by Year

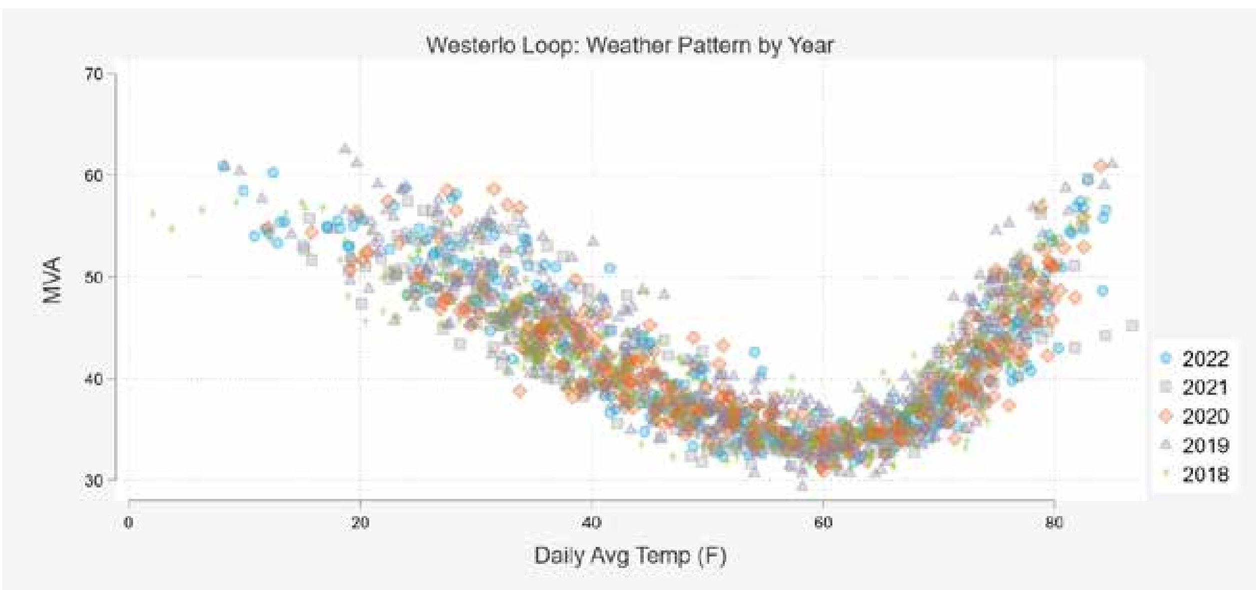
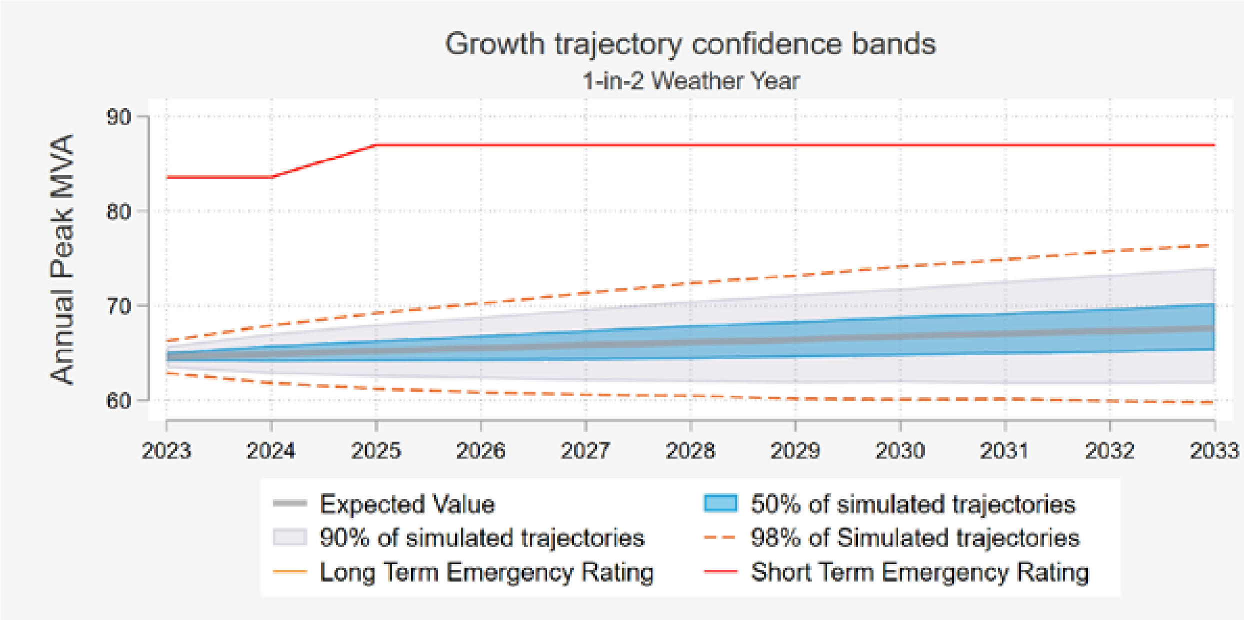


Figure 38 shows the load growth forecast, assuming 1-in-2 weather year conditions. Note that this graph does not include the additional load from electrification. Load growth was modeled using probabilistic methods rather than straight-line forecasts. Absent electrification, there is zero likelihood of the native load exceeding the LTE rating (which is the same as the STE in this graph). Once electrification is added the likelihood increases to 85% by 2033.

Figure 38: Westerlo Loop Load Forecast with Uncertainty



5.2 DISTRIBUTION AREAS

5.2.1 Grimley Road

The Grimley Road substation is located in the southwestern part of the Central Hudson electric service territory. It is a summer peaking substation with a summer long term emergency rating (LTE) of 7.2 MVA and a short-term emergency (STE) rating of 9.4 MVA. In the winter the cooler temperatures allow for a higher LTE of 8.72 MVA and an STE of 9.4 MVA.

Figure 39 shows the division of active accounts and electricity consumption in 2022 for Grimley Road between residential and non-residential customers. Roughly 78% of the accounts belonged to the residential customer class, and together they comprised 50% of total electricity consumption in 2022.

Figure 39: Grimley Road Substation Accounts and Consumption

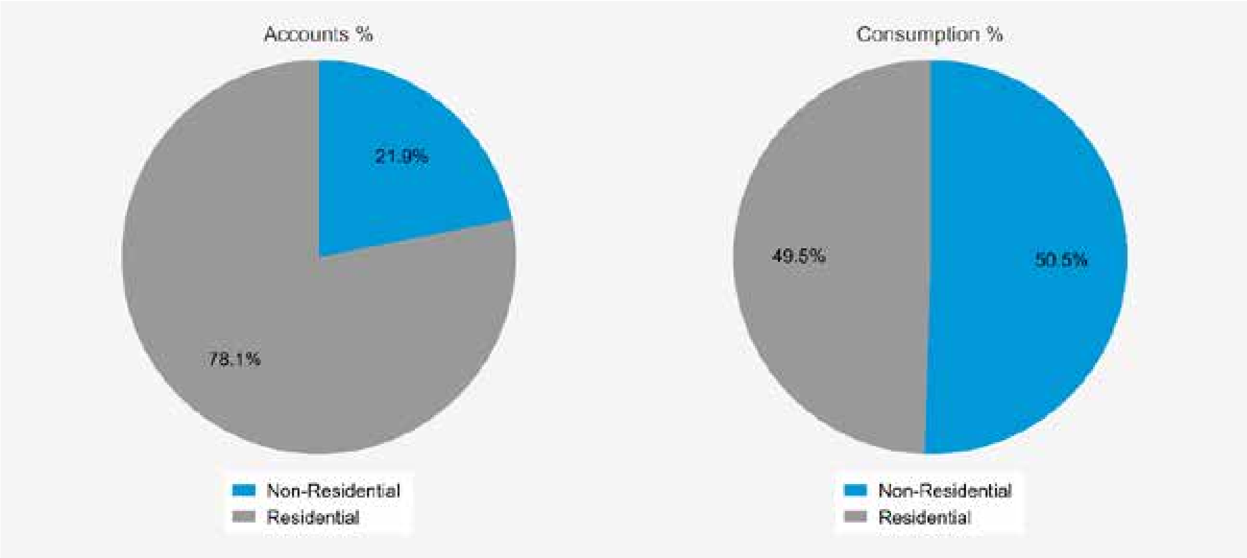
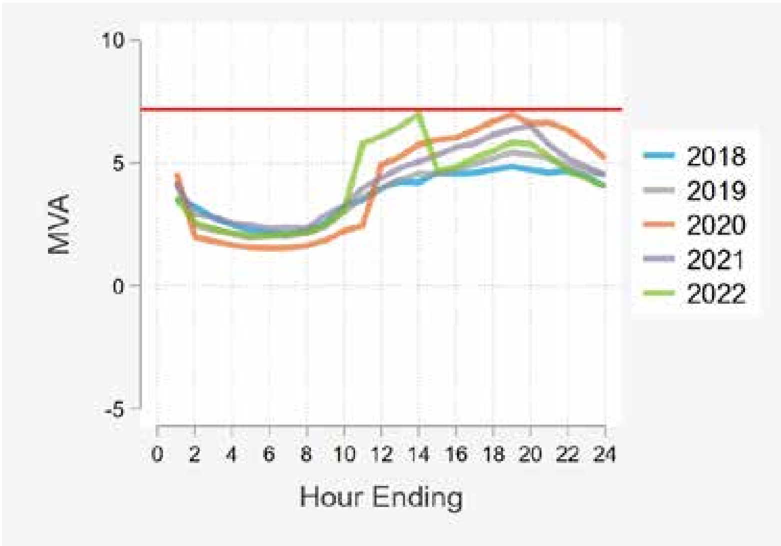


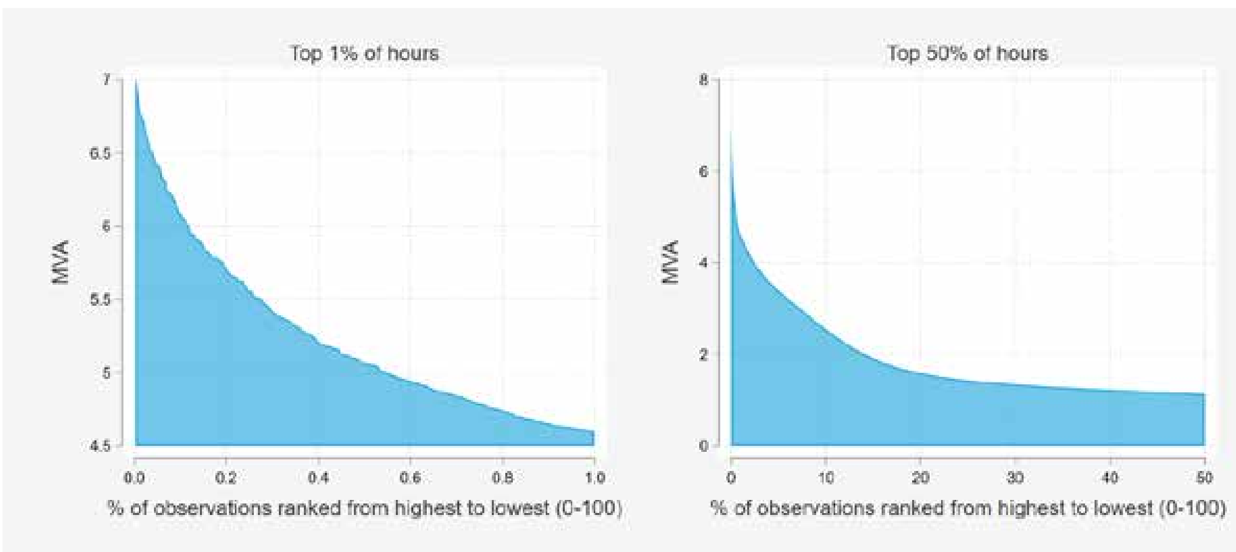
Figure 40 summarizes the peak day load for each year from 2018 to 2022 and includes details about the timing of the peak. Figure 41 summarizes the multi-year load duration curve over the same time frame and shows that peak demand is concentrated on a small share of hours. The weather sensitivity of Grimley Road substation load is illustrated in Figure 42, which shows the daily peak load as a function of different temperature ranges. Grimley Road is a resort area, with substantially higher seasonal loads for portions of the summer each year regardless of the temperature.

Figure 40: Grimley Road Substation Historical Annual Peak Day Load Shapes[8]



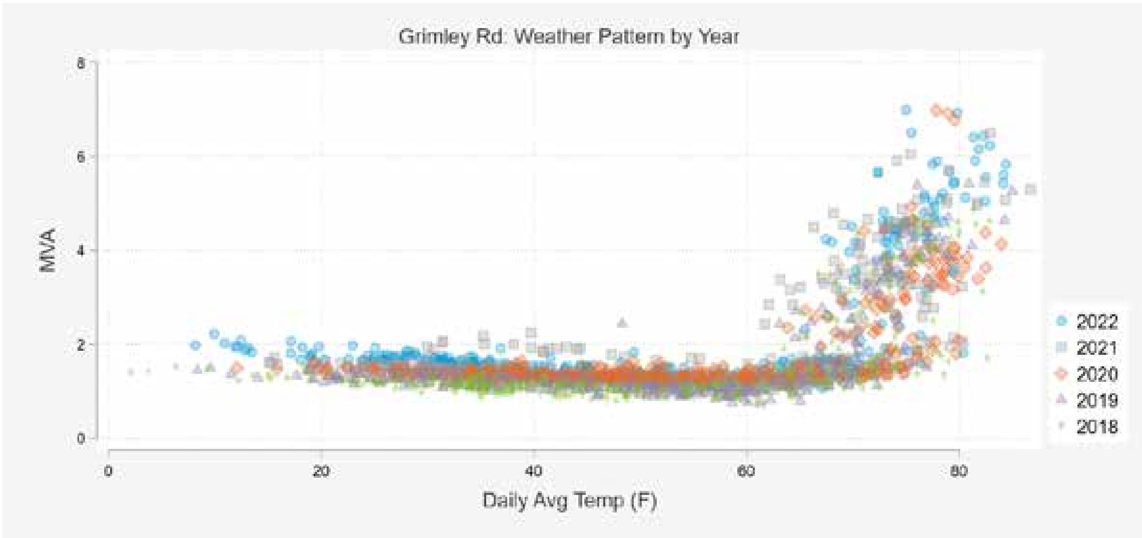
Date	Year	Hour	Load (MVA)	Day of Week
Jul-01-2018	2018	19	4.9	Sunday
Jul-19-2019	2019	19	5.4	Friday
Jul-21-2020	2020	19	7.0	Tuesday
Aug-13-2021	2021	20	6.5	Friday
Jul-08-2022	2022	14	7.0	Friday

Figure 41: Grimley Road Multi-year Normalized Load Duration Curve, 2014-2019



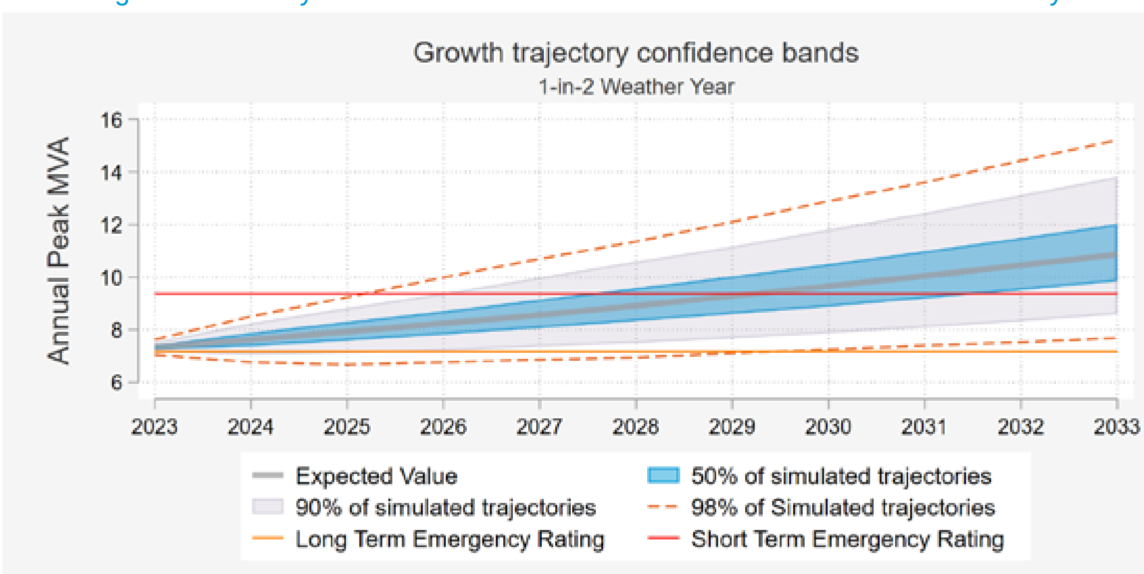
[8] The 2018 and 2019 historical peak day load shapes were adjusted upwards during event hours to account for a non-wires alternative events.

Figure 42: Grimley Road Substation Daily Peak Load Weather Pattern by Year



Load growth and decline were modeled using probabilistic methods rather than straight-line forecasts. Figure 43 shows the load growth forecast, assuming 1-in-2 weather year conditions used for distribution planning. There is a relatively high likelihood of the peak load exceeding the LTE rating in 2024 (the overload risk is roughly 80% in 2024), and then load growth causes it to increase to over 98% by 2030.

Figure 43: Grimley Road Substation Annual Peak Load Forecast with Uncertainty



5.2.2 Reynolds Hill

The Reynolds Hill substation is centrally located in Central Hudson electric service territory. It is a summer peaking substation with a summer long term emergency rating (LTE) of 47.8 MVA and a short-term emergency (STE) rating of 47.8 MVA.

Figure 44 shows the division of active accounts and electricity consumption in 2022 for Reynolds Hill between residential and non-residential customers. Roughly 81% of the accounts belonged to the residential customer class, but they comprised only 26% of total electricity consumption in 2022.

Figure 44: Reynolds Hill Substation Accounts and Consumption

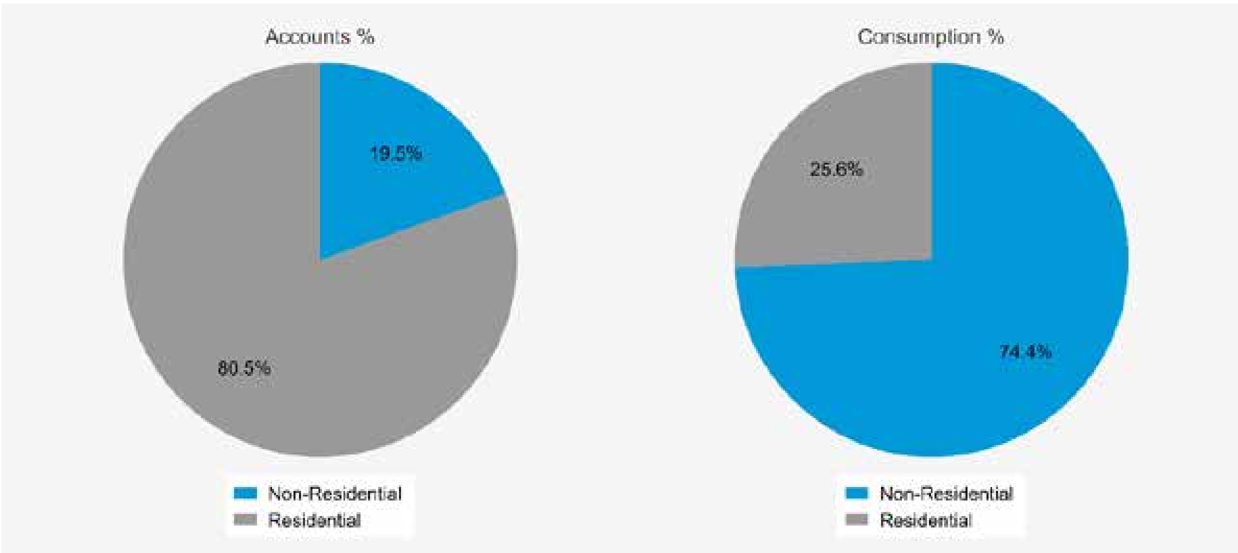
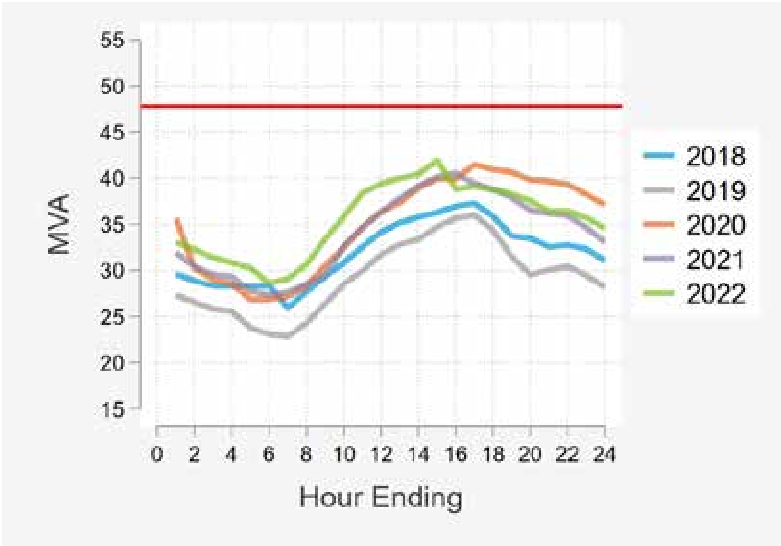


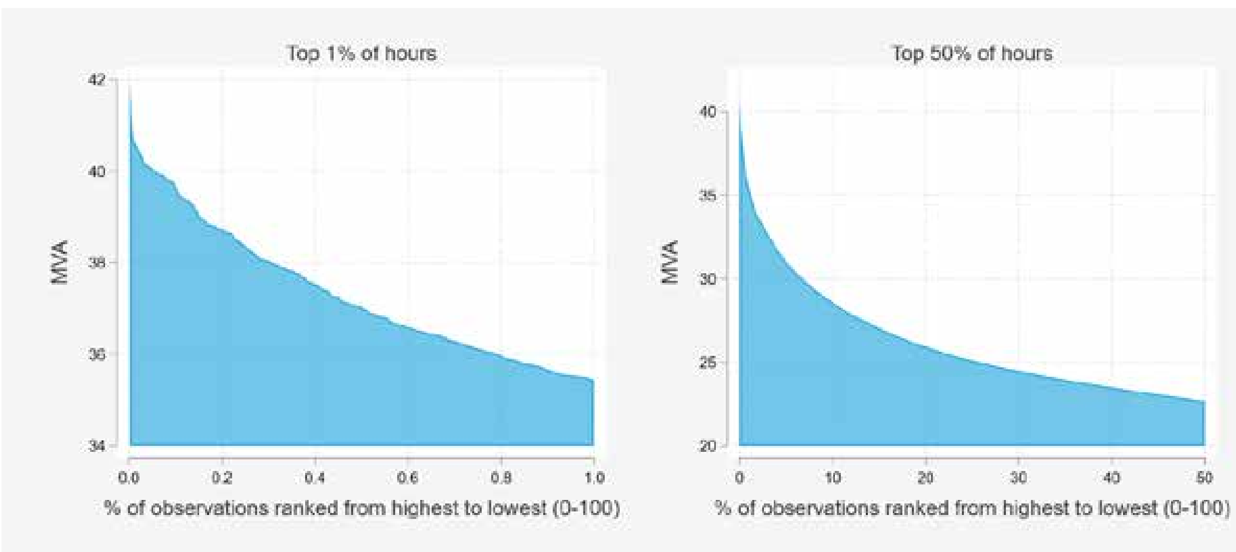
Figure 45 summarizes the peak day load for each year from 2018 to 2022 and includes details about the timing of the peak. Figure 46 summarizes the multi-year load duration curve over the same time frame and shows that peak demand is concentrated on a small share of hours. The weather sensitivity of Reynolds Hill substation load is illustrated in Figure 47, which shows the daily peak load as a function of different temperature ranges.

Figure 45: Reynolds Hill Substation Historical Annual Peak Day Load Shapes[9]



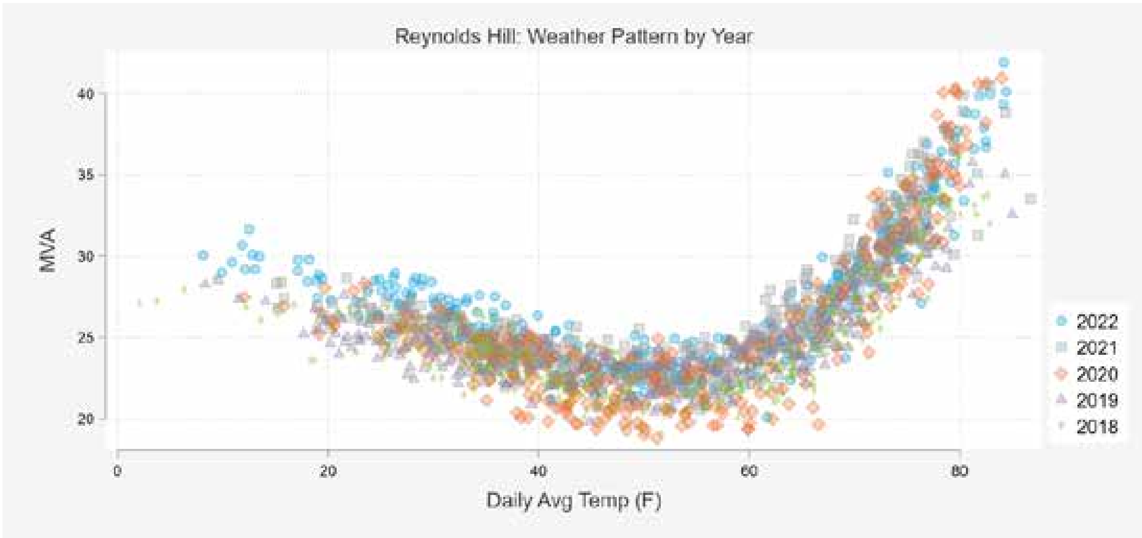
Date	Year	Hour	Load (MVA)	Day of Week
Jul-03-2018	2018	17	37.3	Tuesday
Jul-29-2019	2019	17	36.0	Monday
Jul-27-2020	2020	17	41.4	Monday
Aug-12-2021	2021	16	40.5	Thursday
Jul-20-2022	2022	15	41.9	Wednesday

Figure 46: Reynolds Hill Substation Multi-Year Normalized Load Duration Curve, 2018-2022



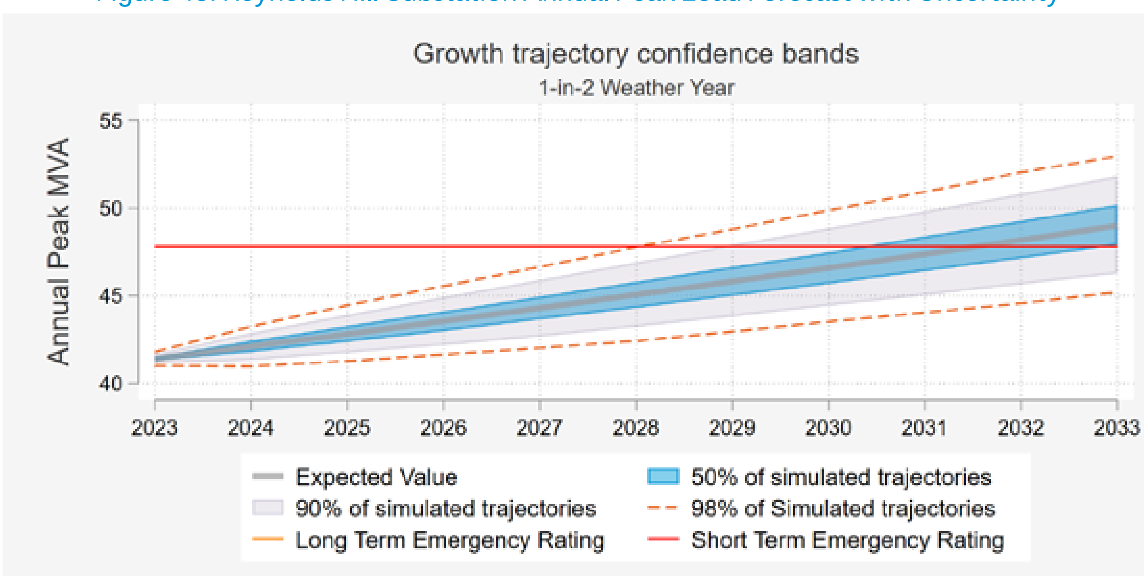
[9] The 2018 and 2019 historical peak day load shapes were adjusted upwards during event hours to account for a non-wires alternative events.

Figure 47: Reynolds Hill Substation Daily Peak Load Weather Pattern by Year



Load growth and decline were modeled using probabilistic methods rather than straight-line forecasts. Figure 48 shows the load growth forecast, assuming 1-in-2 weather year conditions used for distribution planning. There is a relatively low but nonzero likelihood of the peak load exceeding the LTE rating starting in 2028, and by 2033 there is an approximately 80% chance of overloading at the location.

Figure 48: Reynolds Hill Substation Annual Peak Load Forecast with Uncertainty



5.2.3 WOODSTOCK

The Woodstock substation is located in the western part of the Central Hudson electric service territory. It is a winter peaking substation with a summer long term emergency rating (LTE) of 21.6 MVA and a winter LTE of 23.9 MVA. It has a short-term emergency (STE) rating of 23.9 MVA for both seasons.

Figure 49 shows the division of active accounts and electricity consumption in 2022 for Woodstock between residential and non-residential customers. Roughly 87% of the accounts belonged to the residential customer class, and together they comprised 79% of total electricity consumption in 2022.

Figure 49: Woodstock Substation Accounts and Consumption

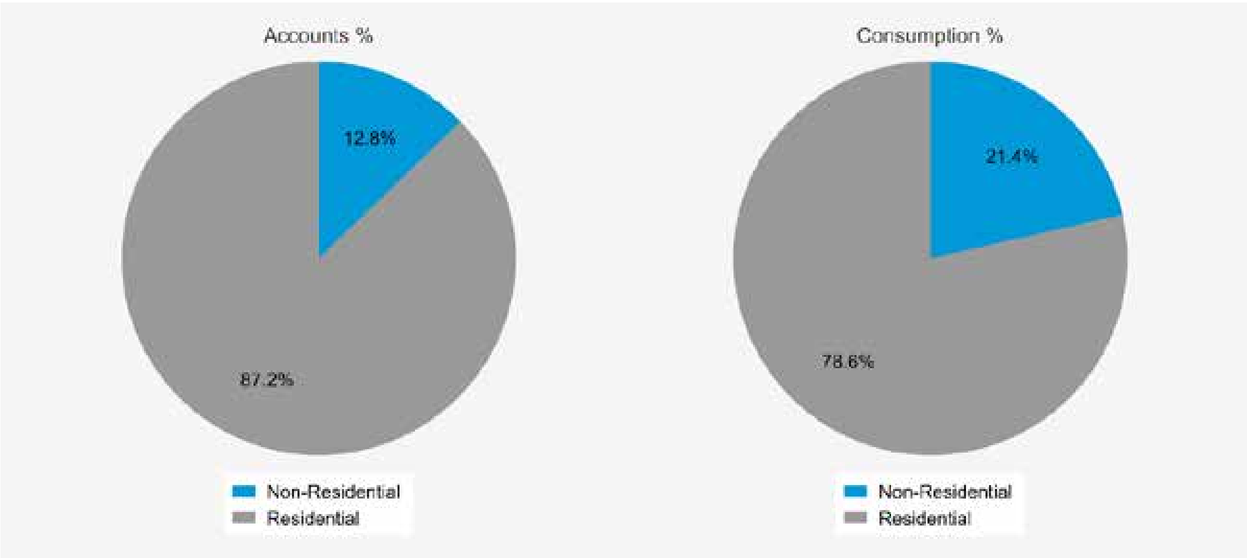
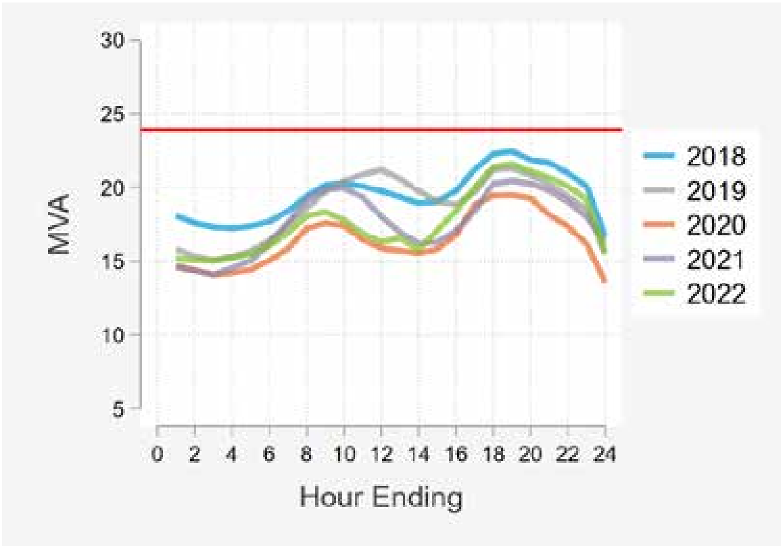


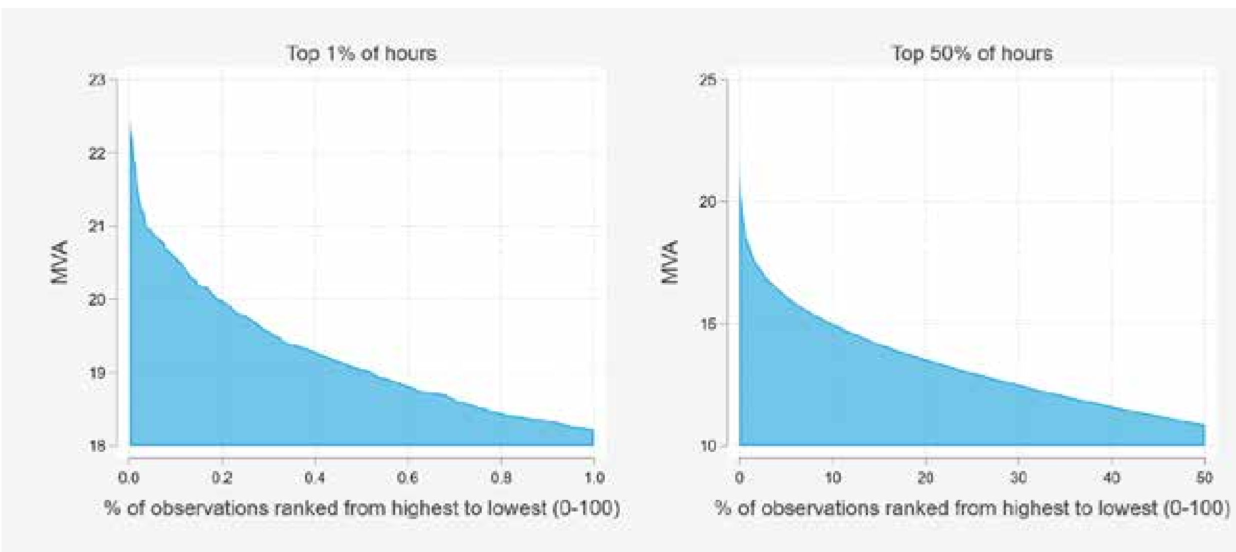
Figure 50 summarizes the peak day load for each year from 2018 to 2022 and includes details about the timing of the peak. Figure 51 summarizes the multi-year load duration curve over the same time frame and shows that peak demand is concentrated on a small share of hours. The weather sensitivity of Woodstock substation load is illustrated in Figure 52, which shows the daily peak load as a function of different temperature ranges.

Figure 50: Woodstock Substation Historical Annual Peak Day Load Shapes[10]



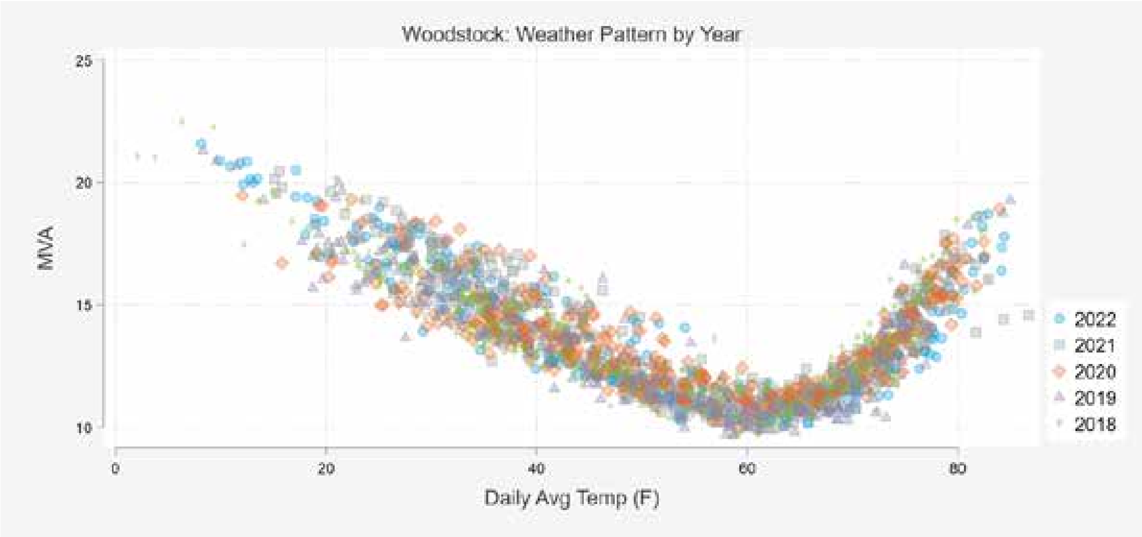
Date	Year	Hour	Load (MVA)	Day of Week
Jan-06-2018	2018	19	22.5	Saturday
Jan-21-2019	2019	19	21.3	Monday
Dec-19-2020	2020	19	19.5	Saturday
Jan-29-2021	2021	19	20.4	Friday
Jan-15-2022	2022	19	21.6	Saturday

Figure 51: Woodstock Substation Multi-Year Normalized Load Duration Curve, 2018-2022



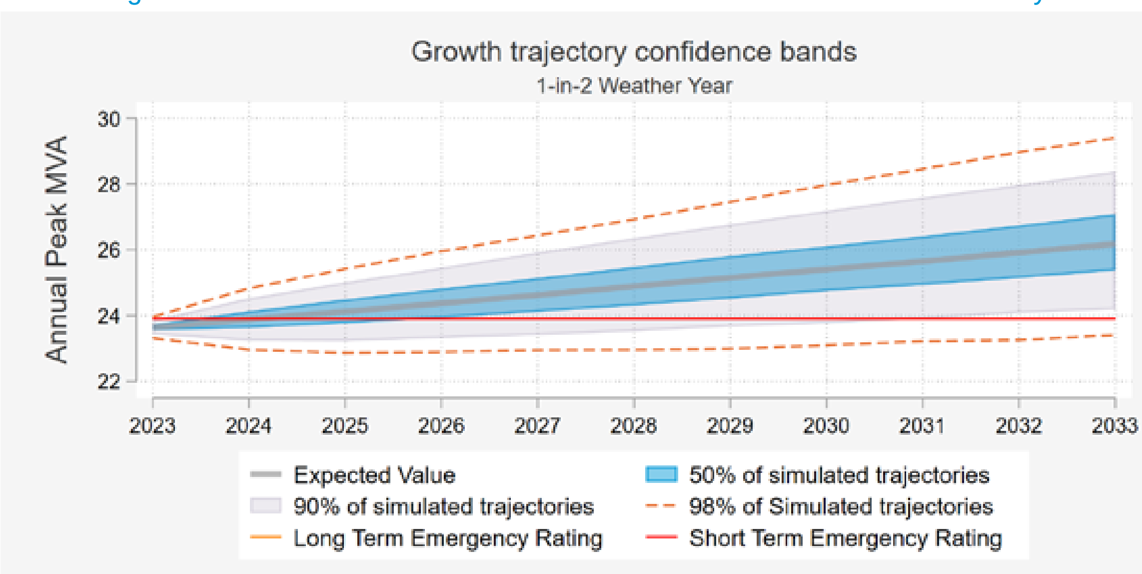
10 The 2018 and 2019 historical peak day load shapes were adjusted upwards during event hours to account for a non-wires alternative events.

Figure 52: Woodstock Substation Daily Peak Load Weather Pattern by Year



Load growth and decline were modeled using probabilistic methods rather than straight-line forecasts. Figure 53 shows the load growth forecast, assuming 1-in-2 weather year conditions used for distribution planning. There is a high likelihood of overload as early as 2023, which increases to a likelihood of overload that is greater than 90% by 2031. Because Woodstock is a winter-peaking substation the winter LTE is depicted in the figure below. Note that this forecast does not include electrification.

Figure 53: Woodstock Substation Annual Peak Load Forecast with Uncertainty



6 KEY FINDINGS AND CONCLUSIONS

The key findings from the analysis are:

- The five locations that require deferral value are both summer peaking and winter peaking. As a result, both summer and winter resources will provide value.
- Winter loading is expected to increase for all locations due to the inclusion of electrification in the study forecast.
- The expected avoided costs vary by location, year, season, and hour and are highly concentrated. Avoided costs are realized if additional resources are placed in the right locations and can deliver load relief at the right times. Without targeting, the value of distributed resources is diluted.
- For many distribution substations and transmission areas that have expected growth, the potential for avoided upgrades through DER resources is minimal because in some cases there are upgrades in the capital plan that will increase the area capacity or because there is sufficient latent capacity in the area to meet this load growth through the study period without exceeding ratings.
- In practice, all avoided T&D costs are location specific. For system-wide untargeted values, the estimates take into account the likelihood that reductions would be in locations with value due to random chance. Without precise targeting, the likelihood that reductions will defer or delay transmission upgrades is relatively low.
- Avoided T&D costs are classified into three mutually exclusive categories: projects for non-wire solutions which provide contractual resources; Location Specific Relief Value (LSRV) which can be used to incentivize non-contracted resources in a specific location; and Demand Reduction Value (DRV) which can be used to incentivize non-contracted resources and which incorporates the random chance that resources will be located where they will actually provide load relief. The LSRV T&D value derives from the five locations with the potential for deferral. Because all other projects had a very low deferral likelihood (less than 5%), the DRV T&D value is zero.
- Central Hudson has utilized the results of this study to identify beneficial areas with locational specific avoided T&D value. These locational specific values will be leveraged to develop an overall system wide Demand Reduction Value (DRV) or remain location specific for the identified beneficial areas.

The study demonstrates the value of developing T&D avoided cost estimates at a local level using probabilistic methods. Because the methodology is relatively novel, it may require future refinements and improvements. Future studies can be further bolstered by conducting sensitivity analyses and refinement of engineering rules, which trigger T&D infrastructure upgrades.

APPENDIX A: ECONOMETRIC MODELS USED TO ESTIMATE HISTORICAL GROWTH

The econometric models were purposefully designed to both estimate historical load growth in percentage terms and allow us to weather normalize loads for 1-in-2 weather peaking conditions.

The key to this process was to model the natural log of the daily peak loads as the dependent variable and include year-specific coefficients to estimate the percent change in loads, after controlling for other factors. By using the natural log as the dependent variable, all of the explanatory variables reflect the percent change in load associated with a unit change in the independent variable.

The regressions were estimated on the highest 150 local peak days for each year in the 2018 to 2022 timeframe for a total of up to 900 observations per location.[11] The goal was to include a sufficient number of days that reflected peaking conditions for each year. The number of observations by location varies slightly because of differences in the amount of data available and because peaks occurring on weekends or holidays were excluded. The model estimated daily peaks as a function of weather interacted with day of week, month, and historical year. Weather was included using a process that avoids assumptions about the type of relationship between weather and load. Rather than assume a constant linear relationship, the weather data is split into equally sized bins and a separate relationship is estimated for different temperature ranges—also known as a spline regression. All models were estimated using time series methods to take into account auto-correlation.[12]

Figure A-1 illustrates the model output for one location. A separate model was estimated for each substation and transmission area. The model explained 98.9% of the variation and, more importantly, produced estimates of the percent change in loads—the load growth—relative to 2022, after controlling for weather, day of week, and other factors. The coefficient on the year term represents annualized percent growth (in this case of 1.2%). The growth trend and the amount of year-to-year variation differ by location and are central to developing the probabilistic load forecasts. In addition, the confidence bands for the historical growth estimates are linked to the explanatory power of the models. When explanatory power is high, confidence bands are tight. When explanatory power is lower, confidence bands are broader.

[11] For the Grimley Road, Hunter, and Lawrenceville substations, which have unique seasonal peaking behavior attributable to ski resort and summer camp loads, we added an additional minimum load requirement to include only seasonal driven peak loads.
[12] We relied on an iterative feasible GLS model with first order auto-correlation. Other time series options—such as ARIMA and the Newey-West model—do not handle gaps in the time series as easily. All options, however, produce consistent estimates.

The estimates of year-to-year historical load growth also were used to assess the degree to which growth patterns are related to each other—that is, the degree to which growth in the prior year predicts growth in the following year, technically known as auto-correlation. Each individual site had a limited number of individual year growth estimates—five years at most—so the estimate of auto-correlation was developed across all sites.

Figure A-1: Example Load Growth Econometric Model

```
Prais-Winsten AR(1) regression -- twostep estimates

Linear regression                               Number of obs     =        241
                                                F(12, 228)        =      73.58
                                                Prob > F          =     0.0000
                                                R-squared         =     0.9893
                                                Root MSE          =     .05178
```

lnload_gross	Coef.	Semirobust Std. Err.	t	P>|t|	[95% Conf.	Interval]
year	.0120939	.0025595	4.73	0.000	.0070506	.0171372
month						
7	.0543057	.0127421	4.26	0.000	.0291984	.079413
8	.0446781	.0127242	3.51	0.001	.0196061	.0697501
9	.0239124	.0173762	1.38	0.170	-.010326	.0581508
dow						
2	-.0095471	.0092772	-1.03	0.305	-.0278271	.0087329
3	-.0049196	.0114402	-0.43	0.668	-.0274617	.0176226
4	.0036314	.0114539	0.32	0.751	-.0189376	.0262005
5	-.0017852	.0116135	-0.15	0.878	-.0246687	.0210983
cdh60	.0042249	.0014206	2.97	0.003	.0014258	.007024
hdh60	0	(omitted)				
3.bins_cdd	-.1768186	.05521	-3.20	0.002	-.2856056	-.0680316
cdd60	.006798	.0048242	1.41	0.160	-.0027078	.0163038
bins_cdd#c.cdd60						
3	.0143631	.0048034	2.99	0.003	.0048985	.0238278
0.bins_hdd	0	(omitted)				
hdd60	0	(omitted)				
bins_hdd#c.hdd60						
0	0	(omitted)				
_cons	-20.02559	5.156308	-3.88	0.000	-30.1857	-9.865478
rho	.2534914					

```
Durbin-Watson statistic (original)    0.879187
Durbin-Watson statistic (transformed) 1.155407
```

APPENDIX B: DETAILED PLANNING LOAD TABLES

APPENDIX C: DETAILED HOURLY PLANNING TABLES

E. Benefit Cost Analysis (BCA) Handbook

Central Hudson Gas & Electric

Benefit-Cost Analysis (BCA) Handbook

Version 4.0

June 30, 2023

Version History

Version	File Name	Last Updated	Document Owner	Updates since Previous Version
V1.0	Central Hudson BCA Handbook – v1.0	06/30/16	Central Hudson	First Issue
V1.1	Central Hudson BCA Handbook – v1.1	08/30/16	Central Hudson	Correction to Equation 4-3 and Equation 4-7
V2.0	Central Hudson BCA Handbook – v2.0	7/31/18	Central Hudson	Second Issue
V3.0	Central Hudson BCA Handbook – v3.0	6/30/20	Central Hudson	Third Issue
V4.0	Central Hudson BCA Handbook – v4.0	6/30/23	Central Hudson	Fourth Issue

BACKGROUND

New York's Joint Utilities collaboratively developed a Standard BCA Handbook Template 2.0 in 2018 and have collaboratively worked to develop a revised 2023 Standard BCA Handbook Template 4.0 which reflects revisions to the 2018 filing. The purpose of the BCA Handbook Template 4.0 is to provide interested parties a consistent and transparent methodology to calculate the benefits and costs of potential projects and investments. The 2023 Standard BCA Template 4.0 serves as the common basis for each utility's individual BCA Handbook.

The 2023 BCA Handbooks include the key assumptions, scope, and approach for a BCA. They 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 BCA Order. The BCA Handbooks also presents 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.

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
CO_2	Carbon Dioxide
DC	Direct Current
DER	Distributed Energy Resources
DR	Demand Response
DSIP	Distributed System Implementation Plan
DSIP Guidance Order	Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Adopting Distributed System Implementation Plan Guidance (issued April 20, 2016)
DSP	Distributed System Platform
EPA	Environmental Protection Agency
GHG	Greenhouse Gas
ICAP	Installed Capacity
JU or Joint Utilities	(Consolidated Edison Company of New York, Inc., Orange and Rockland Utilities, Inc., Central Hudson Gas & Electric Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, New York State Electric and Gas Corporation, and Rochester Gas & Electric Corporation)
kV	Kilovolt
LBMP	Locational Based Marginal Prices
LCR	Locational Capacity Requirements
LHV	Lower Hudson Valley
LI	Long Island
MW	Megawatt
MWh	Megawatt Hour
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) 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)*.[1] 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.[2] The 2023 BCA Handbooks are to be filed on June 30, 2023 with each utility's 2023 DSIP.

The purpose of the BCA Handbook is to provide a common methodology for calculating benefits and costs of projects and investments. The *BCA Order* requires that a benefit-cost analysis be applied to the following four categories of utility expenditure.[3]

1. Investments in distributed system platform (DSP) capabilities
2. Procurement of distributed energy resources (DER) through competitive selection[4]
3. Procurement of DER through tariffs[5]
4. Energy efficiency programs

The BCA Handbook provides methods and assumptions that may be used to inform BCA for each of these four types of expenditure.

The *BCA Order* also includes key principles for the BCA Framework that are reflected in this 2023 BCA Handbook. Specifically, the Commission determined that the BCA framework should[6]:

1. Be based on transparent assumptions and methodologies; list all benefits and costs including those that are localized and more granular.
2. Avoid combining or conflating different benefits and costs.
3. Assess portfolios rather than individual measures or investments (allowing for consideration of potential synergies and economies among measures).
4. Address the full lifetime of the investment while reflecting sensitivities on key assumptions.
5. Compare benefits and costs to traditional alternatives instead of valuing them in isolation.

1.1 Application of the BCA Handbook

The BCA Handbook provides a common methodology to be applied across investment projects and portfolios. The 2023 version of the BCA Handbook is meant to inform investments in DSP capabilities, the procurement of DERs through tariffs, the procurement of DERs through competitive solicitations (i.e. non-wire alternatives) and the procurement of energy efficiency programs. Common input assumptions and

[1] *BCA Order*: Case 14-M-0101, Order Establishing the Benefit Cost Analysis Framework (issued January 21, 2016).
[2] DSIP Guidance Order, pg. 64: "shall file subsequent Distributed System Implementation Plans on a biennial basis beginning June 30, 2018."
[3] *BCA Order*, pg. 1-2.
[4] Also known as non-wires alternatives (NWA).
[5] These may include, for example, demand response tariffs or successor tariffs to net energy metering (NEM).
[6] *BCA Order*, pg. 2.

sources that are applicable on a statewide basis (e.g., information publicly provided by the New York Independent System Operator (NYISO) or by Department of Public Service (DPS) Staff as required in the *BCA Order*) and utility-specific inputs (e.g., marginal costs) that may be commonly applicable to a variety of project-specific BCAs are provided within. Individual BCAs for specific projects or portfolios are likely to require additional, project-specific information and inputs.

Table 1-1 lists the statewide values and respective sources to be used for BCA and referenced in this Handbook.

Table 1-1. New York Assumptions

New York Assumptions	Source
Energy and Demand Forecast	NYISO: Load & Capacity Data[7]
Avoided Generation Capacity Cost (AGCC)	DPS Staff: 2022 ICAP Spreadsheet Model[8]
Locational Based Marginal Prices (LBMP)	NYISO: Congestion Assessment and Resource Integration Study Phase 2 (CARIS Phase 2)[9]
Historical Ancillary Service Costs	NYISO: Markets & Operations Reports [10]
Wholesale Energy Market Price Impacts	DPS Staff: To be provided[11]
Allowance Prices (SO_2, and NO_X)	NYISO: CARIS Phase 1[12]
Net Marginal Damage Cost of Carbon	DPS Staff: To be provided[13]

[7] The 2023 Load & Capacity Data report is available at: https://www.nyiso.com/documents/20142/2226333/2023-Gold-Book-Public.pdf/. Supporting data can be found on the NYISO website in the Load & Capacity Data Report folder in the Planning Reports library section: https://www.nyiso.com/library.
[8] The 2022 ICAP Spreadsheet Model (filed October 3, 2022) is to be used, to be superseded by more recent forecasts filed by DPS Staff if accompanied by cover letter stating "The attached forecast should be used, going forward, in evaluating avoided ICAP costs as part of the Benefit Cost Analysis Framework". All ICAP Spreadsheet Models are found under Case 14-M-0101 at the Commission's website: http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=14-m-0101 (search term "Capacity Price Forecast")
[9] The finalized annual and hourly zonal LBMPs from 2020 CARIS Phase 2 was filed in December 2020 and is available on the NYISO website in the CARIS Study Outputs folder within the Economic Planning Studies folder, also available at https://www.nyiso.com/documents/20142/1407490/2020-CARIS-Phase-2-Hourly-Zonal-LBMP.xlsx/e6535916-7af4-2189-c17b-0c6edfb97e7f
[10] Historical ancillary service costs are available at: http://mis.nyiso.com/public/P-6Blist.htm. The values to apply are described in Section 4.1.5.
[11] DPS Staff will perform the modeling and file the results with the Secretary to the Commission on or before July 1 of each year.
[12] Allowance price assumptions are to use the 2019 CARIS Phase 1, searchable at https://www.nyiso.com/planning or available at https://www.nyiso.com/documents/20142/7239276/03c+2019_CARIS_EmissionsForecastInformatio.pdf.
[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 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	Order Approving Rate Plan issued and effective November 18, 2021, in Cases 20-E-0428 and 20-G-0429
Losses	2019 Central Hudson Gas & Electric Corporation Analysis of System Losses
Marginal Avoided Transmission & Distribution Costs	Location Specific Avoided Transmission and Distribution Avoided Costs Using Probabilistic Forecasting and Planning Methods, 2016
Reliability Statistics	DPS: 2021 Electric Service Reliability Reports[14]

[14] The Annual Electric Service Reliability Reports are available at: https://dps.ny.gov/electric-service-reliability-reports

The New York general and utility-specific assumptions that are included in the 2023 BCA Handbook (as listed in Table 1-1 and Table 1-2) are typically values by zone or utility system averages.

The BCA methodology underlying the BCA Handbook is technology-agnostic and should be broadly applicable to all anticipated project and portfolio types with some adjustments as necessary. BCA development will require the standard inputs provided in the BCA Handbook as well as project-specific information that captures locational and temporal aspects of the investment under analysis.

1.2 BCA Handbook Version

This 2023 BCA Handbook provides techniques for quantifying the benefits and costs identified in the *BCA Order*. Interim revisions will be limited to material changes to input assumptions and/or new guidance or orders.

1.3 Structure of the Handbook

The four 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 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.

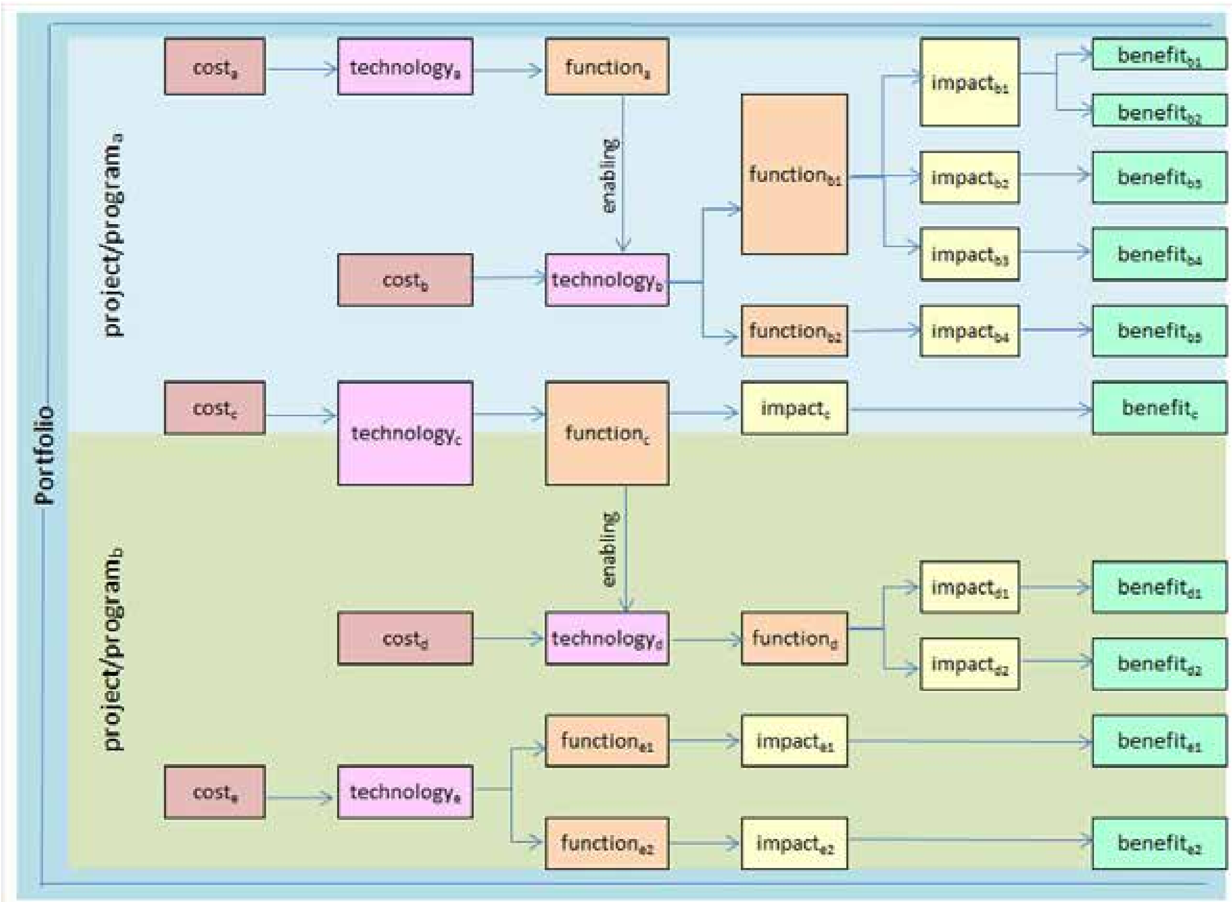
Sections 2.1.1 and 2.1.2 discuss these considerations in more detail.

2.1.1 Accounting Across Multiple Value Streams of Benefits and Costs

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. Over time, investments made as part of previous projects or portfolios may also enable or enhance new projects. The *BCA Order* states that utility BCA shall consider incremental T&D costs "to the extent that the characteristics of a project cause additional costs to be incurred."[15]

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 address situations where costs are incurred for a technology with a core function that benefits two programs as well as situations where costs are incurred for a technology with more than one core function, each potentially benefitting different programs.

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

[15] *BCA Order*, Appendix C pg. 18

Losses and Avoided Distribution Losses benefits. Sections 2.1.1.1 and 2.1.1.2 also provide differentiation between the transmission capacity values embedded as components of the AGCC and Avoided LBMP values, as well as differentiation between the CO_2, SO_2, and NO_x values embedded in Avoided LBMP values and those values that must be applied separately in the Net Avoided CO_2 and Net Avoided SO_2, and NO_x benefits calculations.

Table 2-1 provides a list of potentially overlapping AGCC, and Avoided LBMP benefits.

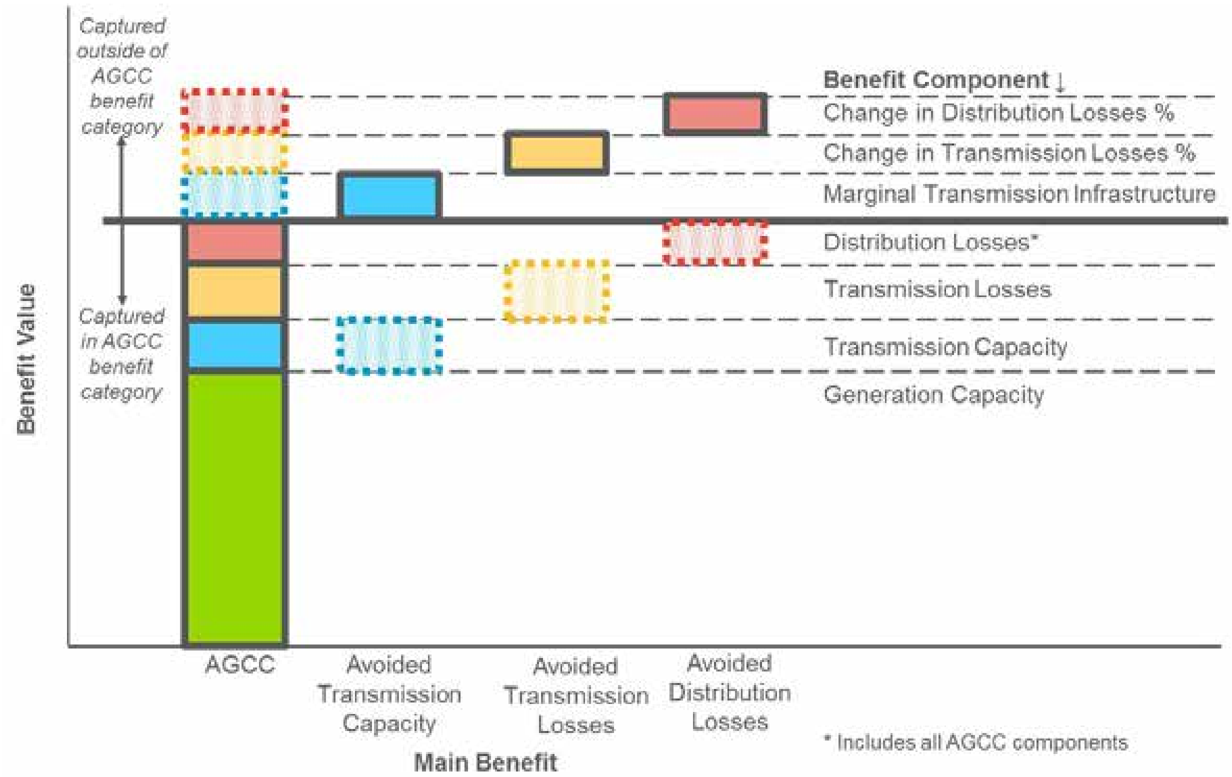
Table 2-1. Benefits with Potential Overlaps

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.[16] Additionally, a project's location on the system can affect distribution losses and the calculation of AGCC.[17] The AGCC calculation accounts for these distribution losses.

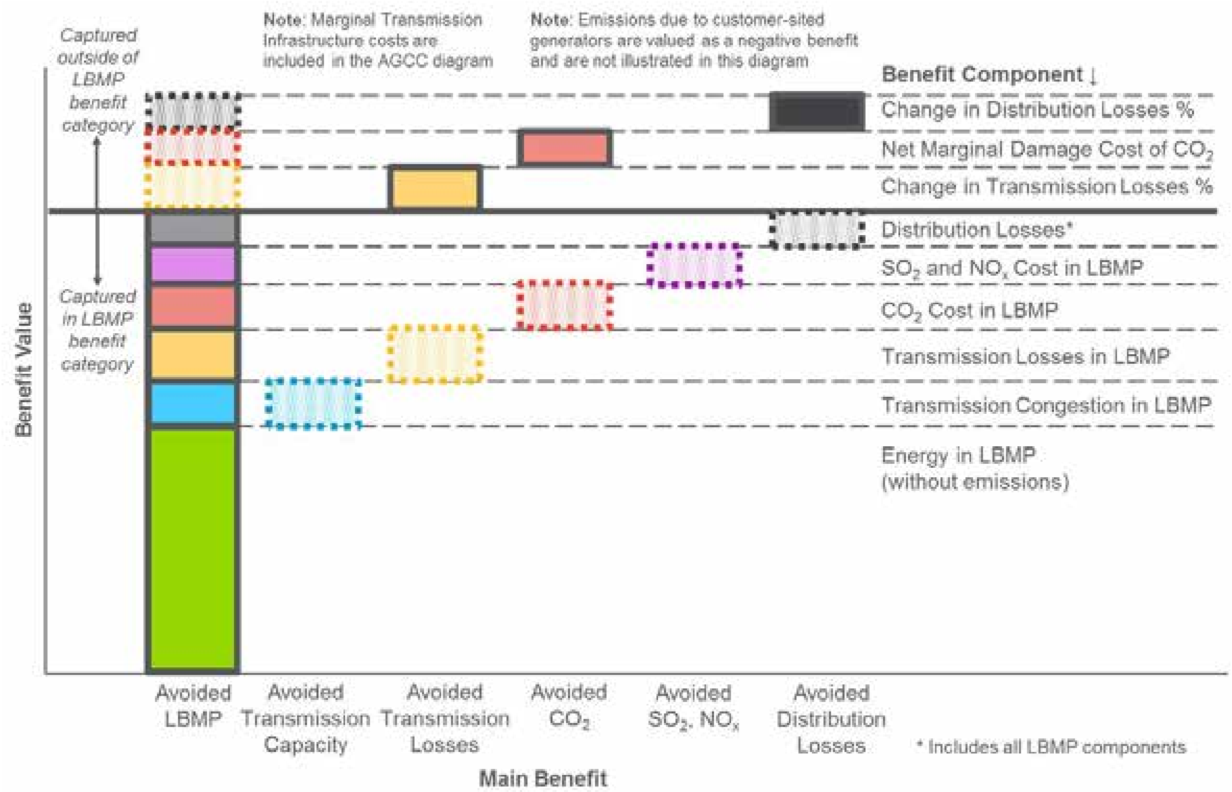
If a project changes the electrical topology and, therefore, the transmission loss percent, the incremental changes in transmission losses would be allocated to the Avoided Transmission Losses benefit. Similarly, any incremental changes to distribution loss percent as a result of the project would be included in the Avoided Distribution Losses benefit. These benefits are calculated separately from the AGCC benefit.

[16] The AGCC includes a portion of avoided transmission capacity infrastructure costs as zonal differences in the ICAP clearing price.
[17] 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.

2.1.2.2 Benefits Overlapping with Avoided LBMP

Figure 2-3 graphically illustrates potential overlaps of benefits pertaining to Avoided LBMP.

Figure 2-3. Benefits Potentially Overlapping with Avoided LBMP Benefit (Illustrative)



In this stacked column chart, the boxes with solid borders represent impacts and embedded values included in the calculation of the main benefit, while boxes with dotted borders represent impacts excluded from the main benefit, but included in calculation of a separate benefit. As seen in the figure, the stacked solid boxes in the Avoided LBMP benefit include costs for factors beyond just the energy cost per megawatt-hour (MWh) of the electricity traded in the wholesale energy market. The following are included in the Avoided LBMP benefit:

- 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.[18] To the extent a project changes the electrical topology and changes the distribution loss percent itself, the incremental changes in distribution losses would be allocated to the Avoided Distribution Losses benefit. Similarly, there may be projects that would specifically impact Avoided Transmission Capacity or change the transmission loss percent. In these instances, the impacts would be captured outside of the Avoided LBMP benefit.

2.2 Incorporating Losses into Benefits

Many of the benefit equations provided in Section 4 include a parameter to account for losses. In calculating a benefit or cost resulting from load impacts, losses occurring upstream from the load impact must be accounted for to arrive at the total energy or demand impact. Losses can be accounted for either by adjusting the impact parameter or the valuation parameter. For consistency, all equations in Section 4 are shown with a loss adjustment to the impact parameter.

The following losses-related nomenclature is used in the BCA Handbook:

- **Losses (MWh or MW)** are the difference between the total electricity send-out and the total output as measured by revenue meters. This difference includes technical and non-technical losses. Technical losses are the losses associated with the delivery of electricity 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[19] 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[20]
- “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 $\mathrm{Loss\%}_{b \to r}$ 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.

[18] 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.
[19] 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.
[20] Transmission in this context refers to the distribution utility’s sub-transmission and internal transmission.

2.3 Establishing Credible Baselines

One of the most significant challenges associated with evaluating the benefit of a grid or DER project or program is establishing baseline data that illustrates the performance of the system without the project or program. The utility may derive baseline estimates from recent historical data, forecasts, statistical or model-based projections, or comparison/control groups (e.g., similar feeders and households) during the course of the project.

Sound baseline data is crucial in measuring the incremental impact of the technology deployment. The benefits of grid modernization projects accrue over many years; thus, baselines must be valid across the same time horizon. This introduces the following considerations:

- **Forecasting market conditions**: Project impacts as well as benefit and cost values are affected by market conditions. For example, the Commission has directed that Avoided LBMP should be calculated based on NYISO's CARIS Phase 2 economic planning process base case LBMP forecast. However, the observed benefit of a project will be different if the wholesale energy market behaves differently from the forecasted trends.
- **Forecasting operational conditions**: Many impacts and benefits are tied to how the generation, transmission, and distribution infrastructure are operated. In this example, the Commission indicated that benefits associated with avoided CO_2 emissions shall be based on the change in the tons of CO_2 produced by the bulk system when system load levels are reduced by 1%. It is important to note that this impact calculation is an approximation and it is still very difficult to determine the actual CO_2 reductions at the bulk system level from the impacts of projects implemented at the distribution system level. Project-specific reductions are tied to dispatch protocols based on the optimized operation of the bulk system given a set of preventive post-contingency settings. In addition, the carbon intensity of the generation mix will inevitably change over time independent of any investment at the distribution level.
- **Predicting asset management activities**: Some impacts and benefits, such as Avoided Distribution Capacity Infrastructure, are affected by distribution-level capital investments that may be made independent of the projects being evaluated. In this example, the amount of available excess capacity may change if key distribution assets are replaced and uprated.
- **Normalizing baseline results**: Baseline data should be normalized to reflect average conditions over the course of a year. This is likely to involve adjustments for weather and average operational characteristics.

There are significant uncertainties surrounding the benefits and costs. Regulatory approvals, technological advances, operational budgets, and other business conditions all affect the cost of deployment and/or expected system performance. As such, the utility may re-evaluate and revise its baseline data as significant events or developments alter the assumed or implied conditions of the current baseline.

2.4 Establishing Appropriate Analysis Time Horizon

The duration over which the impact and benefits of new grid and DER investments accrue varies significantly. The time horizon for the analysis must consider several factors, including differences among the lengths of expected useful life of various hardware and software across multiple projects and how to reconcile the differences in these lengths of expected useful lives. The analysis timeframe should be based on the longest asset life included in the portfolio/solution under consideration.[21]

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 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.[22] 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.

For example, 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.[23]

[21] *BCA Order*, pg. 2
[22] *BCA Order*, Appendix C, pg. 31.
[23] *BCA Order*, pg. 25 ("The evaluation would then be conducted showing separately the impacts both with and without the wholesale market price effect.")

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 ratepayer 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 ratepayers. 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”.[24]

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.

[24] *BCA Order*, pg. 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†	ü	ü	ü
4.1.2	Avoided LBMP‡	ü	ü	ü
4.1.3	Avoided Transmission Capacity Infrastructure†‡	ü	ü	ü
4.1.4	Avoided Transmission Losses†‡	ü	ü	ü
4.1.5	Avoided Ancillary Services*		ü	ü
4.1.6	Wholesale Market Price Impacts**		ü	ü
4.2.1	Avoided Distribution Capacity Infrastructure	ü	ü	ü
4.2.2	Avoided O&M	ü	ü	ü
4.2.3	Avoided Distribution Losses†‡	ü	ü	ü
4.3.1	Net Avoided Restoration Costs	ü	ü	ü
4.3.2	Net Avoided Outage Costs	ü		
4.4.1	Net Avoided CO_2‡	ü		
4.4.2	Net Avoided SO_2 and NO_x‡	ü		
4.4.3	Avoided Water Impacts	ü		
4.4.4	Avoided Land Impacts	ü		
4.4.5	Net Non-Energy Benefits***	ü	ü	ü
Cost				
4.5.1	Program Administration Costs	ü	ü	ü
4.5.2	Added Ancillary Service Costs*		ü	ü
4.5.3	Incremental T&D and DSP Costs	ü	ü	ü
4.5.4	Participant DER Cost	ü		
4.5.5	Lost Utility Revenue			ü
4.5.6	Shareholder Incentives		ü	ü
4.5.7	Net Non-Energy Costs**	ü	ü	ü

† 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 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.*
*** 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.

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 to 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 ratepayers as Lost Utility Revenue because of revenue decoupling or other means that transfer costs from participants to non-participants.

4 BENEFITS AND COSTS METHODOLOGY

Each subsection below aligns with a benefit or cost listed in the *BCA Order*. Each benefit and cost includes a definition, equation, and a discussion of general considerations.

Four types of benefits are addressed in the subsections below:

- Bulk System: Larger system responsible for the generation, transmission and control of electricity that is passed on to the local distribution system.
- Distribution System: System responsible for the local distribution of electricity to end use consumers.
- Reliability/Resiliency: Efforts made to reduce duration and frequency of outages.
- External: Consideration of social values for incorporation in the SCT.

There are also four types of costs considered in the BCA Framework and addressed in the subsections below. They are:

- Program Administration: Includes the cost of state incentives, measurement and verification, and other program administration costs to start, and maintain a specific program
- Utility-related: Those incurred by the utility such as incremental T&D, DSP, lost revenues and shareholder incentives
- Participant-related: Those incurred to achieve project or program objectives
- Societal: External costs for incorporation in the SCT

The 2023 BCA Handbook 4.0 assumes that all energy, operational, and reliability-related benefits and cost,[25] occur in the same year. Thus, there is no time delay between benefit/cost impacts. However, for capacity and infrastructure benefits and costs,[26] it is assumed that impacts generate benefits/costs in the following year of the impact. For example, if a project reduces system peak load in 2023, the AGCC benefit would not be realized until 2021.

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

[25] Energy, operational, and reliability-related benefits and costs include: Avoided LBMP, the energy component of Avoided Transmission Losses, Avoided Ancillary Services, the energy portion of Wholesale Market Price Impact, Avoided O&M, Avoided Distribution Capacity Infrastructure, Net Avoided Restoration Costs, Net Avoided Outage Costs, the energy component of Distribution Losses, Net Avoided CO2, Net Avoided SO2 and NOx, Avoided Water Impact, Avoided Land Impact, Net Non-Energy Benefits Related to Utility or Grid Operations, Program Administration Costs, Participant DER Cost, Lost Utility Revenue, Shareholder Incentives, and Net Non-Energy Costs.

[26] 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.

is calculated by NYISO zone, which is the most granular level for which AGCC are currently available.[27] 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

$$\text{Benefit}_{Y+1} = \sum_{Z} \frac{\Delta\text{PeakLoad}_{Z,Y,r}}{1\text{-Loss\%}_{Z,Y,b\to r}} * \text{SystemCoincidenceFactor}_{Z,Y} * \text{DeratingFactor}_{Z,Y} * \text{AGCC}_{Z,Y,b}$$

The indices of the parameters in Equation 4-1 include:

- Z = NYISO zone (A à K)
- Y = Year
- b = Bulk System
- r = Retail Delivery or Connection Point

$\Delta\text{PeakLoad}_{Z,Y,r}$ **(ΔMW)** is the project’s expected maximum demand reduction capability, or “nameplate” impact at the retail delivery or connection point (“r”), by zone if applicable. This input is project or program specific. A positive value represents a reduction in peak load.

$\text{Loss\%}_{Z,b\to r}$ **(%)** is the variable loss percent between bulk system (“b”) and the retail delivery or connection point (“r”). The loss percentages by system level are found in Table A-2.

$\text{SystemCoincidenceFactor}_{Z,Y}$ **(dimensionless)** captures a project’s or program’s contribution to reducing bulk system peak demand relative to its expected maximum demand reduction capability. For example, a nameplate demand reduction capacity of 100 kW with a system coincidence factor of 0.8 would reduce the bulk system peak demand by 80 kW. This input is project specific.

$\text{DeratingFactor}_{Z,Y}$ **(dimensionless)** is presented here as a factor to de-rate the coincident peak load reduction based on the availability of a resource during system peak hours. For example, a demand response program may only be allowed to dispatch a maximum of 10 events per year, which could limit the availability of the resource during peak hours. Another example is the variability and intermittence (e.g., due to clouds) of a solar array which could limit its contribution to system peak load reduction. This input is project specific.

$\text{AGCC}_{Z,Y,b}$ **($/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

[27] 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.

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. 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[28] 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. $\Delta \mathrm{PeakLoad}_{z,Y,r}$) should also be multiplied by a coincidence factor and derating factor to properly match the planning impact to the system peak. The coincident factor quantifies a project's contribution to system peak relative to its nameplate impact.

It is also important to consider the persistence of impacts in future years after a project's implementation. For example, participation in a demand response program may change over time. Also, a peak load reduction impact will not be realized as a monetized AGCC benefit until the year following the peak load reduction, as capacity requirements are set by annual peak demand and paid for in the following year.

The AGCC values provided in Staff's ICAP Spreadsheet Model account for the value of transmission losses and infrastructure upgrades. In instances where projects change the transmission topology, incremental infrastructure and loss benefits not captured in the AGCC values should be modeled and quantified in the Avoided T&D Losses and Avoided T&D Infrastructure benefits, below.

4.1.2 Avoided LBMPs

Avoided LBMP is avoided energy purchased at the Locational Based Marginal Price (LBMP). The three components of the LBMP (i.e., energy, congestion, and losses) are all included in this benefit. See 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:

[28] The NYISO Installed Capacity Manual is available at: https://www.nyiso.com/documents/20142/2923301/icap_mnl.pdf/234db95c-9a91-66fe-7306-2900ef905338.

Equation 4-2. Avoided LBMP

$$\text{Benefit}_{Y} = \sum_{Z}\sum_{P}\frac{\Delta \text{Energy}_{Z,P,Y,r}}{1 - \text{Loss\%}_{Z,b\rightarrow r}} * \text{LBMP}_{Z,P,Y,b}$$

The indices of the parameters in Equation 4-2 include:

- Z = zone (A à K)
- P = period (e.g., year, season, month, and hour)
- Y = Year
- b = Bulk System
- r = Retail Delivery or Connection Point

$\Delta \text{Energy}_{Z,P,Y,r}$ (ΔMWh) is the difference in energy purchased at the retail delivery or connection point ("r") as the result of project implementation, by NYISO zone and by year with by time-differentiated periods, for example, annual, seasonal, monthly, or hourly as appropriate. This parameter represents the energy impact at the project location and is **not** yet grossed up to the LBMP location based on the losses between those two points on the system. This adjustment is performed based on the $\text{Loss\%}_{Z,b\rightarrow r}$ parameter. This input is project- or program-specific. A positive value represents a reduction in energy.

$\text{Loss\%}_{Z,b\rightarrow r}$ **(%)** is the variable loss percent between bulk system ("b") and the retail delivery or connection point ("r"). The loss percentages by system level are found in Table A-2.

$\text{LBMP}_{Z,P,Y,b}$ ($/MWh) is the Locational Based Marginal Price, which is the sum of energy, congestion, and losses components by NYISO zone at the bulk system level ("b"). NYISO forecasts 20-year annual and hourly LBMPs by zone. To determine time-differentiated LBMPs, for example, annual, seasonal, monthly, or hourly, leverage NYISO's hourly LBMP forecast by zone rather than developing an alternative forecast of time-differentiated LBMPs based on shaping annual averages by zone from historical data. The NYISO hourly LBMP forecast is a direct output from the CARIS Phase 2 modeling. To extend the LBMP forecast beyond the CARIS planning period, if necessary, assume that the last year of the LBMPs stay constant in real (inflation adjusted) $/MWh.

4.1.2.2 General Considerations

Avoided LBMP benefits are calculated using a static forecast of LBMP. Any wholesale market price changes as a result of the project or program are not accounted for in this benefit, and are instead captured in Wholesale Market Price Impacts, described in Section 4.1.6.

The time differential for subscript P (period) will depend on the type of project, and could be season, month, day, hour, or any other interval. The user must ensure that the time-differentiation is appropriate for the project being analyzed. For example, it may be appropriate to use an annual average price and impact for a DER that has a consistent load reduction at all hours of the year. However, using the annual average may not be appropriate for energy storage which may be charging during non-peak hours and discharging during peak hours. In that case, it may be appropriate to multiply an average on-peak (or super-peak) and off-peak LBMP by the on-peak (or super-peak) and off-peak energy impacts, respectively.

It is important to consider the trend (i.e., system degradation) of impacts in future years after a project's implementation. For example, a PV system's output may decline over time. It is assumed that the benefit is realized in the year of the energy impact.

4.1.3 Avoided Transmission Capacity Infrastructure and Related O&M

Avoided Transmission Capacity Infrastructure and Related O&M benefits result from location-specific load reduction that are 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

$$\mathrm{Benefit}_{Y+1} = \sum_{C} \frac{\Delta \mathrm{PeakLoad}_{Y,r}}{1 - \mathrm{Loss\%}_{Y,b\rightarrow r}} * \mathrm{TransCoincidentFactor}_{C,Y} * \mathrm{DeratingFactor}_{Y} * \mathrm{MarginalTransCost}_{C,Y,b}$$

The indices[29] of the parameters in Equation 4-3 include:

- C = constraint on an element of transmission system[30]
- Y = Year
- b = Bulk System
- r = Retail Delivery or Connection Point

[29] In future versions of the Handbook, additional indices such as time period and voltage level can be included as this data becomes available.
[30] If system-wide marginal costs are used, this is not an applicable subscript.

$\Delta PeakLoad_{Y,r}$ **(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.

$Loss\%_{Y,b\rightarrow r}$ **(%)** 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.

4.1.3.2 General Considerations

In order to find the impact of the measure, project, or portfolio on the transmission system peak load, the "nameplate" capability or load impact must be multiplied by the transmission system coincidence factor and derating factor. Coincidence factors and derating factors would need to be determined by a project-specific engineering study.

Some transmission capacity costs are already embedded in both LBMP and AGCC. Both the AGCC and transmission congestion charges could be decreased in the event that additional transmission assets are built or load is reduced. To the extent that deferred or avoided transmission upgrades are incremental to the value captured in LBMP and AGCC and can be modeled or calculated, these benefits would be reported in this benefit. This value would need to be project-specific based on the specific deferral and/or change to the system topology rather than through generic utility marginal cost of service studies. Using system average marginal costs to estimate avoided transmission and infrastructure need may result in

A significant over- or under-valuation of the benefits and/or costs and may result in no savings for customers.

The use of project-specific values helps ensure that the calculated impact is applicable to the specific impact of the project both on a temporal and locational basis, adjusting for losses (i.e., locational alignment) and coincidence with the transmission peak (i.e., temporal alignment). In other words, the load reduction ultimately used to value this benefit must be coincident with the load on the relieved equipment. It is important to distinguish between system and local constraints in order to match the impact with the avoided cost. It is assumed that the marginal cost of service is based on the load at the bulk system. If the available marginal cost of service value is based on a different location in the system (e.g., interface between transmission and distribution), then this parameter must first be converted to represent load at the bulk system prior to using in the equation above.

Avoided transmission infrastructure cost benefits are realized only if the project improves load profiles that would otherwise create a need for incremental infrastructure. Benefits are only accrued when a transmission constraint is relieved due to coincident peak load reduction from DER. Under constrained conditions, it is assumed that a peak load reduction impact will produce benefits in the following year as the impact. Once the peak load reduction is less than that necessary to avoid or defer the transmission investment and infrastructure must be built, or the constraint is relieved, this benefit would not be realized from that point forward.

The marginal cost of transmission capacity values provided in Table A-3 include both capital and O&M, which cannot be split into two discrete benefits. Therefore, care should be taken to avoid double counting of any O&M values included in this benefit as part of the Avoided O&M benefit described in Section 4.2.2.

4.1.4 Avoided Transmission Losses

Avoided Transmission Losses are the benefits that are realized when a project changes the topology of the transmission system that results in a change to the transmission system loss percent. Reductions in end use consumption and demand that result in reduced losses are included in Avoided LBMP and Avoided Generation Capacity benefits as described above in Sections 4.1.2 and 4.1.1. While both the LBMP and AGCC will adjust to a change in system losses in future years, the static forecast used in this methodology does not capture these effects.

4.1.4.1 Benefit Equation, Variables, and Subscripts

Equation 4-4 presents the benefit equation for Avoided Transmission Losses:

Equation 4-4. Avoided Transmission Losses

$$\text{Benefit}_{Y+1} = \sum_{Z} \text{SystemEnergy}_{Z,Y+1,b} * \text{LBMP}_{Z,Y+1,b} * \Delta\text{Loss\%}_{Z,Y+1,b\rightarrow i} + \text{SystemDemand}_{Z,Y,b} * \text{AGCC}_{Z,Y,b} * \Delta\text{Loss\%}_{Z,Y,b\rightarrow i}$$

Where,

$$\Delta\text{Loss\%}_{Z,Y,b\rightarrow i} = \text{Loss\%}_{Z,Y,b\rightarrow i,\text{baseline}} - \text{Loss\%}_{Z,Y,b\rightarrow i,\text{post}}$$

The indices[31] of the parameters in Equation 4-4 include:

- Z = NYISO zone (for LBMP: A à K; for AGCC: NYC, LHV, LI, ROS[32])
- Y = Year
- b = Bulk System
- i = Interface of the transmission and distribution systems

$SystemEnergy_{Z,Y+1,b}$ (MWh) is the annual energy forecast by NYISO in the Load & Capacity Report at the bulk system ("b", ")includes both transmission and distribution losses. Total system energy is used for this input, rather than the project-specific energy, because this benefit is only included in the BCA when a change in system topology produces a change in the transmission loss percent, which affects all load in the relevant area.

$LBMP_{Z,Y+1,b}$ (\$/MWh) is the LBMP, which is the sum of energy, congestion, and losses components by NYISO zone at the bulk system level ("b"). To determine time-differentiated LBMPs, for example, annual, seasonal, monthly, or hourly, leverage NYISO's hourly LBMP forecast by zone rather than developing an alternative forecast of time-differentiated LBMPs based on shaping annual averages by zone from historical data. The NYISO hourly LBMP forecast is a direct output from the CARIS Phase 2 modeling. To extend the LBMP forecast beyond the CARIS planning period, if necessary, assume that the last year of the LBMPs stay constant in real (inflation adjusted) $/MWh.

$SystemDemand_{Z,Y,b}$ (MW) is the system peak demand forecast by NYISO at the bulk system level ("b"), which includes transmission and distribution losses by zone. System demand is used in this evaluation, rather than the project-specific demand, because this benefit is only quantified a change in the system topology is changed resulting in a change in the transmission losses percent, which affects all load in the relevant zone.

$AGCC_{Z,Y,b}$ (\$/MW-yr) represents the annual AGCCs based on forecast of capacity prices for the wholesale market provided by Staff. This data is posted on DMM in Case 14-M-0101 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"[33] 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.

$\Delta Loss\%_{Z,Y,b \to i}$ (Δ%) is the change in fixed and variable loss percent between the bulk system ("b") and the interface of the transmission and distribution systems ("i") resulting from a project that changes the topology of the transmission system. This value would typically be determined in a project-specific engineering study. Two parameters are provided in the equations above: one with a "Y" subscript to represent the current year, and one with a "Y+1" subscript to represent the following year.

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[31] In future versions of the Handbook, additional indices such as time period and voltage level can be included as this data becomes available.
[32] Mapping NYISO localities to NYISO zones: ROS = A-F, LHV = G-I, NYC = J, LI = K
[33] "Transmission level" represents the bulk system level ("b").

$\text{Loss\%}_{Z,Y,b\rightarrow i,\text{baseline}}$ **(%)** is the baseline fixed and variable loss percent between bulk system ("b") and the interface of the transmission and distribution systems ("i"). Thus, this reflects the sub-transmission and internal transmission losses pre-project, which is found in Table A-2.

$\text{Loss\%}_{Z,Y,b\rightarrow i,\text{post}}$ **(%)** is the post-project fixed and variable loss percent between bulk system ("b") and the interface of the transmission and distribution systems ("i"). Thus, this reflects the sub-transmission and internal transmission losses post-project.

4.1.4.2 General Considerations

Transmission losses are already embedded in the LBMP. This benefit is incremental to what is included in LBMP and is only quantified when the transmission loss percent is changed (e.g., from 3% to 2.9%). For most projects, this benefit will be zero unless an engineering study determines otherwise.

The energy and demand impacts are based on system-wide energy and demand, rather than project-specific, because this benefit is only quantified when the losses percentage is changed which affects all customers in the affected area. Transmission losses will not affect downstream distribution losses.

It is assumed that the LBMP component of the avoided losses benefit is accrued in the same year as the impact, and the AGCC component of the benefit is accrued in the following year of the benefit. This is reflected in the equation above with "Y" and "Y+1" subscripts to indicate the timing of the benefits relative to the impacts.

4.1.5 Avoided Ancillary Services (Spinning Reserves, and Frequency Regulation)

Avoided Ancillary Services benefits may accrue to select 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.

DER causes a reduction in load but 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 the 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

$$Benefit_Y = Capacity_Y * n * (CapPrice_Y + MovePrice_Y * RMM_Y)$$

The indices of the parameters in Equation 4-5 include:

- Y = Year

$Capacity_Y$ **(MW)** is the amount of annual average frequency regulation capacity when provided to NYISO by the project.

n (hr) is the number of hours in a year that the resource is expected to provide the service.

$CapPrice_Y$ **($/MW·hr)** is the average hourly frequency regulation capacity price. The default value is the two-year historical average for day-ahead regulation capacity prices from NYISO.

$MovePrice_Y$ **($/ΔMW)**: is the average hourly frequency regulation movement price. The default value is the two-year historical average for real-time dispatch of regulation movement prices from NYISO.

RMM_Y **(ΔMW/MW·hr)**: is the Regulation Movement Multiplier (RMM) used for regulation bids and accounts for the ratio between movement and capacity. It is assumed to be 13 ΔMW/MW-hr.

Spinning Reserves

Equation 4-6 presents the benefit equation for spinning reserves:

Equation 4-6. Spinning Reserves

$$Benefit_Y = Capacity_Y * n * CapPrice_Y$$

The indices of the parameters in Equation 4-6 include:

- Y = Year

$Capacity_Y$ **(MW)** is the change in the amount of annual average spinning reserve capacity when provided to the NYISO by the project.

n (hr): is the number of hours in a year that the resource is expected to provide the service.

$CapPrice_Y$ **($/MW·hr)** is the average hourly spinning reserve capacity price. The default value uses the two- year historical average spinning reserve pricing by region.

4.1.5.2 General Considerations

There are no reductions in annual average frequency regulation, and spinning reserve, because those are set by the NYISO independent of load levels and DER penetration.

The average hourly prices for frequency regulation capacity, frequency regulation movement, and spinning reserve capacity can be calculated from historical pricing data posted by NYISO. The recommended basis is a historical average of interval pricing over the prior two-year period.

The NYISO Ancillary Services Manual indicates that the day-ahead market is the predominant market for regulation capacity and spinning reserves; regulation movement is only available in real-time.
The RMM is fixed by NYISO at a value of 13 ∆MW/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.

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 database to calculate the static impact on wholesale LBMP of a 1% change in the level of load that must be met.[34] LBMP impacts will be calculated for each NYISO zone. AGCC price impacts are developed using Staff's ICAP Spreadsheet Model.

4.1.6.1 Benefit Equation, Variables, and Subscripts

Equation 4-7 presents the benefit equation for Wholesale Market Price Impact:

Equation 4-7. Wholesale Market Price Impact

$$\text{Benefit}_{Y+1} = \sum_{Z} (1 - \text{Hedging\%}) * (\Delta\text{LBMPImpact}_{Z,Y+1,b} * \text{WholesaleEnergy}_{Z,Y+1,b} + \Delta\text{AGCC}_{Z,Y,b} * \text{ProjectedAvailableCapacity}_{Z,Y,b})$$

[34] *BCA Order*, Appendix C, pg. 8.

The indices of the parameters in Equation 4-7 include:

- Z = NYISO zone (A à K[35])
- Y = Year
- b = Bulk System

Hedging% **(%)** is the fraction of energy or capacity hedged via fixed price or multi-year agreements or other mechanisms in each year. Price hedging via long term purchase contracts should be considered when assessing wholesale market price impacts. The JU 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); requires wholesale market modeling to determine impact. 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.[36] 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 the capacity portion of 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.[37] As noted previously, it is assumed that the capacity portion of Wholesale Market Price Impacts will produce benefits in the year following the impact.

[35] Mapping NYISO localities to NYISO zones: ROS = A-F, LHV = G-I, NYC = J, LI = K
[36] As in the AGCC benefit equation, System Coincidence Factors and Derating Factors adjust the maximum load reduction of the project.
[37] The one year assumption is based on an overview of price suppression provided in the New England Regional Avoided Cost Study 2015.

4.2 Distribution System Benefits

4.2.1 Avoided Distribution Capacity Infrastructure

Avoided Distribution Capacity Infrastructure benefit results from location-specific distribution load reductions that are valued at the marginal cost of distribution system infrastructure that is avoided or deferred by a DER project or program. The load reduction impact must be coincident with the distribution equipment peak or otherwise defer or avoid the need for incremental distribution infrastructure based on the characteristics of the specific load and the design criteria of the specific equipment that serves it.

4.2.1.1 Benefit Equation, Variables, and Subscripts

Equation 4-8 presents the benefit equation for Avoided Distribution Capacity Infrastructure:

Equation 4-8. Avoided Distribution Capacity Infrastructure

$$\text{Benefit}_{Y} = \sum_{V}\sum_{C}\frac{\Delta\text{PeakLoad}_{Y,r}}{1-\text{Loss\%}_{Y,b\rightarrow r}} * \text{DistCoincidentFactor}_{C,Y} * \text{DeratingFactor}_{Y} * \text{MarginalDistCost}_{C,V,Y,b}$$

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[38]
- V = Voltage level (e.g., primary, and secondary)
- Y = Year
- b = Bulk System
- r = Retail Delivery or Connection Point

$\Delta\text{PeakLoad}_{Y,r}$ (ΔMW) is the nameplate demand reduction of the project at the retail delivery or connection point (“r”). This input is project specific. A positive value represents a reduction in peak load.

[38] In limited cases where use of system-wide marginal cost values is required, this subscript is not applicable.

$\mathrm{Loss\%}_{Y,b\rightarrow r}$ **(%)** 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.

$\mathbf{DistCoincidentFactor}_{C,V,Y}$ **(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.

$\mathrm{DeratingFactor}_{Y}$ **(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.

$\mathbf{MarginalDistCost}_{C,V,Y,b}$ **($/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. System average marginal cost of service values are provided in Table A-3.

4.2.1.2 General Considerations

Project- and location- specific avoided distribution costs and deferral values should be used wherever 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

$$\text{Benefit}_{Y+1} = \sum_{AT} \Delta\text{Expenses}_{AT,Y}$$

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

$\Delta\text{Expenses}_{AT,Y}$ (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

$$\text{Benefit}_{\text{Y+1}} = \sum_{\text{Z}} \text{SystemEnergy}_{\text{Z,Y+1,b}} * \text{LBMP}_{\text{Z,Y+1,b}} * \Delta\text{Loss\%}_{\text{Z,Y+1,b}\rightarrow\text{i}} + \text{SystemDemand}_{\text{Z,Y,b}} * \text{AGCC}_{\text{Z,Y,b}} * \Delta\text{Loss\%}_{\text{Z,Y,b}\rightarrow\text{i}}$$

Where,

$$\Delta\text{Loss\%}_{\text{Z,Y,i}\rightarrow\text{r}} = \text{Loss\%}_{\text{Z,Y,i}\rightarrow\text{r,baseline}} - \text{Loss\%}_{\text{Z,Y,i}\rightarrow\text{r,post}}$$

The indices[39] of the parameters in Equation 4-10 include:

- Z = NYISO zone (for LBMP: A à K; for AGCC: NYC, LHV, LI, ROS[40])
- Y = Year
- i = Interface Between Transmission and Distribution Systems
- b = Bulk System
- r = Retail Delivery or Connection Point

$\text{SystemEnergy}_{\text{Z,Y,b}}$ (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.

$\text{LBMP}_{\text{Z,Y,b}}$ ($/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

[39] In future versions of the Handbook, additional indices such as time period and voltage level can be included as this data becomes available.
[40] Mapping NYISO localities to NYISO zones: ROS = A-F, LHV = G-I, NYC = J, LI = K.

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 $\mathrm{Loss\%}_{Z,b\rightarrow r}$ parameter. Note that the system demand is used in this evaluation, rather than the project-specific demand, because this benefit is only quantified when the system topology is changed resulting in a change in distribution loss percent has changed, an event which affects all load in the relevant part of the distribution system.

$\mathbf{AGCC_{Z,Y,b}}$ **($/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 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.

$\mathrm{Loss\%}_{Z,Y,i\rightarrow r,baseline}$ **(%)** is the baseline fixed and variable loss percent between the interface of the transmission and distribution systems ("i") and the retail delivery point ("r"). Thus, this reflects the distribution loss percent pre-project, which is found in Table A-2.

$\mathrm{Loss\%}_{Z,Y,i\rightarrow r,post}$ **(%)** is the post-project fixed and variable loss percent between the interface of the transmission and distribution systems ("i") and the retail delivery point ("r").

4.2.3.2 General Considerations

Distribution losses are already accounted for in the LBMP and AGCC when grossing impacts at the project location to the price locations. Because static forecasts of LBMPs and AGCC are used, this benefit will be quantified only in cases where a measure, project, or portfolio alters the distribution system losses percentage (e.g., from 3% to 2.9%). For most projects, this benefit will be zero unless an engineering study determines otherwise.

The energy and demand impacts are grossed up from retail impacts to transmission system impacts based on losses from the equations above. Impacts are based on system-wide energy and demand, not project-specific, because this benefit is only quantified when the loss percentage is changed which affects all load in the affected area. Note that distribution losses also affect upstream transmission losses.

Because losses data is usually available on an annual average basis, the energy and demand impacts should be on an annual average basis as well.

It is assumed that the LBMP component of the avoided losses benefit is accrued in the same year as the impact, and the AGCC component of the benefit is accrued in the following year of the benefit. This is reflected in the equation above with "Y" and "Y+1" subscripts to indicate the time delay of benefits relative to the impacts.

4.3 Reliability/Resiliency Benefits

4.3.1 Net Avoided Restoration Costs

Avoided Restoration Costs accounts for avoided costs of restoring power during outages. For most DER investments, this benefit will not be quantified, since utilities are required to fix 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. 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 invesments:

Equation 4-11. Net Avoided Restoration Costs

$$\text{Benefit}_Y = -\Delta\text{CrewTime}_Y * \text{CrewCost}_Y + \Delta\text{Expenses}_Y$$

Where,

$$\Delta\text{CrewTime}_Y = \#\text{Interruptions}_{base,Y} * (\text{CAIDI}_{base,Y} - \text{CAIDI}_{post,Y} * (1 - \%\text{ChangeSAIFI}_Y))$$

$$\%\text{ChangeSAIFI}_Y = \frac{\text{SAIFI}_{base,Y} - \text{SAIFI}_{post,Y}}{\text{SAIFI}_{base,Y}}$$

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 & granular data should be utilized for localized and geographic specific projects that exhibit more localized impacts. Other reliability metrics will need to be developed to more suitably quantify reliability or resiliency benefits and costs associated with localized projects or programs. Once developed, the localized restoration cost metric will be applied and included in this handbook.

There is no subscript to represent the type of outage in Equation 4-11 because it assumes an average restoration crew cost that does not change based on the type of outage. The ability to reduce outages would be dependent on the outage type.

$\Delta \mathrm{CrewTime}_{Y}$ **(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.

$\mathrm{CrewCost}_{Y}$ **($/hr)** is the average hourly outage restoration crew cost for activities associated with the project under consideration as provided in Table A-4.

$\Delta \mathrm{Expenses}_{Y}$ **(Δ$)** are the average expenses (e.g. equipment replacement) associated with outage restoration.

$\#\mathrm{Interruptions}_{base,Y}$ **(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.

$\mathrm{CAIDI}_{base,Y}$ **(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. However, in localized project/program specific cases, it should be representative of the relevant area of the system that the measure, project, or portfolio affects.

$\mathrm{CAIDI}_{post,Y}$ **(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.

$\%\mathrm{ChangeSAIFI}_{Y}$ **(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.

$\mathrm{SAIFI}_{base,Y}$ **(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. It 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.

$\mathrm{SAIFI}_{post,Y}$ **(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

$$Benefit_{Y} = MarginalDistCost_{R,Y}$$

The indices of the parameters in Equation 4-12 are applicable to DER installations and include:

- R = Reliability constraint on an element (e.g., pole-mounted transformer, distribution line, etc.) of T&D system
- Y = Year

$MarginalDistCost_{R,Y}$ ($/yr): Marginal cost of the reliability investment. Because this value is project and location specific, a system average value is not applicable.

This benefit only applies for an individual project or portfolio of DER which is able to provide functionally equivalent reliability as compared to the traditional distribution reliability investment that would have otherwise been installed/built; 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. However, as measurement capabilities and DER experience evolve, utilities may be able to develop comparative evaluations of the reliability benefits of DER and traditional utility investments. Application of this benefit would be considered only for investments with validated reliability results.

4.3.2 Net Avoided Outage Costs

Avoided Outage Costs accounts for customer outage costs due to a reduction in frequency and duration of outages, then multiplying that expected change by an estimated outage cost. The quantification of this benefit is highly dependent on the type and size of affected customers.

4.3.2.1 Benefit Equation, Variables, and Subscripts

Equation 4-13 presents the benefit equation for Net Avoided Outage Costs:

Equation 4-13. Net Avoided Outage Costs

$$\text{Benefit}_{\text{Y}} = \sum_{\text{C}} \text{ValueofService}_{C,Y,r} * \text{AverageDemand}_{C,Y,r} * \Delta\text{SAIDI}_{\text{Y}}$$

Where,

$$\Delta\text{SAIDI}_{\text{Y}} = \text{SAIFI}_{\text{base,Y}} * \text{CAIDI}_{\text{base,Y}} - \text{SAIFI}_{\text{post,Y}} * \text{CAIDI}_{\text{post,Y}}$$

The indices of the parameters in Equation 4-13 include:

- C = Customer class (e.g., residential, small C&I, large C&I) – BCA should use customer-specific values if available.
- Y = Year
- r = Retail Delivery or Connection Point

$\mathbf{ValueOfService_{C,Y,r}}$ ($/kWh) is the value of electricity service to customers, by customer class, in dollars per unserved kWh at the retail delivery point. The value(s) should be determined based on the customers' willingness to pay for reliability. If location-, customer class- or customer-specific values are not available, these values should default to the retail rate of electricity by customer class.

$\mathbf{AvgDemand_{C,Y,r}}$ (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.

$\Delta SAIDI_{Y}$ **(Δhr/cust/yr):** is the change in System Average Interruption Duration Index due to the project. The impact on SAIDI can be determined based on the impact on CAIDI and SAIFI.[41] Baseline system average reliability metrics can be found in Table A-4. A positive value represents a reduction in SAIDI.

$SAIFI_{post,Y}$ **(int/cust/yr)** is the post-project System Average Interruption Frequency Index; represents the average number of times that a customer experiences an outage per year in the post-project case. Determining this parameter requires development of a distribution level model and a respective engineering study to quantify appropriately.

$CAIDI_{post,Y}$ **(hr/int)** is the post-project Customer Average Interruption Duration Index; represents the impact of a project on the average time to restore service in the post-project case. Determining this parameter requires the development of a distribution level model and a respective engineering study to quantify appropriately.

[41] SAIDI = SAIFI * CAIDI

$SAIFI_{base,Y}$ **(int/cust/yr)** is the baseline (i.e., pre-project) System Average Interruption Frequency Index. It represents the average number of times that a customer experiences an outage per year, excluding major storms. The baseline system-wide value is a five-year average that is available from the annual Electric Service Reliability Reports. This parameter is not necessarily a system-wide value. Rather, it should be representative of the relevant area of the system that the measure, project, or portfolio affects.

$CAIDI_{base,Y}$ **(hr/int)** is the baseline (i.e., pre-project) Customer Average Interruption Duration Index. It represents the impact of a project on the average time to restore service, excluding major storms. The baseline system-wide is a five-year average that is available from the annual Electric Service Reliability Reports. This parameter is not necessarily a system-wide value. Rather, it should be representative of the relevant area of the system that the measure, project, or portfolio affects.

4.3.2.2 General Considerations

The value of the avoided outage cost benefit is customer-specific; the customer class should match or be consolidated properly between the utility and the study area to ensure that the value of reliability matches, what the customer would be willing to pay.

For this version of the BCA Handbook, the outage cost can be estimated by assuming that the customer would be willing to pay the same retail rate they pay for electricity, to avoid an outage. The full retail rate value can be found in the utility's latest tariff by customer class.

Currently, the Standard Interconnection Requirements 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 CO2

Net Avoided CO_2 accounts for avoided CO2 due to a reduction in system load levels[42] or the increase of CO2 from onsite generation. To value the benefits associated with avoided CO2 emissions, utilities shall rely on the costs to comply with New York's Clean Energy Standard (CES),[43] valued as the resulting price per MWh of a Renewable Energy Certificate (REC) from the most recently completed NYSERDA RECs solicitation.

The net marginal damage cost of CO_2 may also be used to value CO_2 as a sensitivity to the BCA. 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

[42] The Avoided CO2 benefit considers the change in energy as a result of the project by including the change in energy identified in the Avoided LBMP, Avoided Transmission Losses, and Avoided Distribution Losses benefits.
[43] Clean Energy Standard.

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

Using the cost to comply with New York's CES:

$$\mathrm{Benefit_Y} = \mathrm{CESCost} * \left(\frac{\Delta \mathrm{Energy_{Y,r}}}{1 - \mathrm{Loss\%_{Y,b \to r}}} + \Delta \mathrm{Energy_{TransLosses,Y}} + \Delta \mathrm{Energy_{DistLosses,Y}} \right)$$

Using the net marginal damage cost:

$$\text{Benefit}_Y = \text{CO2Cost}\Delta\text{LBMP}_Y - \text{CO2Cost}\Delta\text{OnsiteEmissions}_Y$$

Where,

$$\text{CO2Cost}\Delta\text{LBMP}_Y = \left(\frac{\Delta\text{Energy}_{Y,r}}{1-\text{Loss\%}_{Y,b\rightarrow r}} + \Delta\text{Energy}_{\text{TransLosses},Y} + \Delta\text{Energy}_{\text{DistLosses},Y}\right) * \text{NetMarginalDamageCost}_Y$$

$$\Delta\text{Energy}_{\text{TransLosses},Y} = \text{SystemEnergy}_{Y,b} * \Delta\text{Loss\%}_{Y,b\rightarrow i}$$

$$\Delta\text{Energy}_{\text{DistLosses},Y} = \text{SystemEnergy}_{Y,b} * \Delta\text{Loss\%}_{Y,i\rightarrow r}$$

$$\Delta\text{Loss\%}_{Z,Y,b\rightarrow i} = \text{Loss\%}_{Z,Y,b\rightarrow i,\text{baseline}} - \text{Loss\%}_{Z,Y,b\rightarrow i,\text{post}}$$

$$\Delta\text{Loss\%}_{Z,Y,i\rightarrow r} = \text{Loss\%}_{Z,Y,i\rightarrow r,\text{baseline}} - \text{Loss\%}_{Z,Y,i\rightarrow r,\text{post}}$$

$$\text{CO2Cost}\Delta\text{OnsiteEmissions}_Y = \Delta\text{OnsiteEnergy}_Y * \text{CO2Intensity}_Y * \text{SocialCostCO2}_Y$$

The indices of the parameters in Equation 4-14 include:

- Y = Year
- b = Bulk System
- i = Interface of the Transmission and Distribution Systems
- r = Retail Delivery or Connection Point

$\text{CO2Cost}\Delta\text{LBMP}_Y$ **($)** 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.

$\text{CO2Cost}\Delta\text{OnsiteEmissions}_Y$ **($)** 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.

$\Delta\text{Energy}_{Y,r}$ **(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 $\text{Loss\%}_{b\rightarrow r}$ parameter. A positive value represents a reduction in energy.

$\text{Loss\%}_{Y,b\rightarrow r}$ **(%)** 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.

$\Delta\text{Energy}_{\text{TransLosses},Y}$ **(ΔMWh)** represents the change in electricity lost on the transmission system due to the Avoided Transmission Losses benefit. Refer to Section 4.1.4 for more details. In most cases, unless the transmission system loss percent is altered due to a project or portfolio, this parameter will be zero. A positive value represents a reduction in energy lost in transmission system losses.

$\Delta\text{Energy}_{\text{DistLosses,Y}}$ **(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.

$\text{NetMarginalDamageCost}_{\text{Y}}$ **($/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 Phase 2. The LBMP forecast from CARIS Phase 2 includes the cost of carbon based on the RGGI, fully reflect the SCC.

$\boldsymbol{\Delta\text{Loss}\%_{\text{Z,Y,b}\rightarrow\text{i}}}$ **(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.

$\text{Loss}\%_{\text{Z,Y,b}\rightarrow\text{i,baseline}}$ **(%)** is the baseline fixed and variable loss percent between the interface between the bulk system ("b") and the interfaceofthe transmission and distribution systems ("i"). Thus, this reflects the transmission loss percent pre-project, which is found in Table A-2.

$\text{Loss}\%_{\text{Z,Y,b}\rightarrow\text{i,post}}$ **(%)** 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.

$\boldsymbol{\Delta\text{Loss}\%_{\text{Z,Y,i}\rightarrow\text{r}}}$ **(Δ%)** is the change in fixed and variable loss percent between the interface of the transmission and distribution systems ("i") and the retail delivery point ("r") resulting from a project that changes the topology of the distribution system. This represents the change in the distribution system loss factor. This value would typically be determined in a project-specific engineering study.

$\text{Loss}\%_{\text{Z,Y,i}\rightarrow\text{r,baseline}}$ **(%)** is the baseline fixed and variable loss percent of 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.

$\text{Loss}\%_{\text{Z,Y,i}\rightarrow\text{r,post}}$ **(%)** is the post-project fixed and variable loss percent of 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.

$\Delta\text{0nsite}\mathbf{Energy}_{\text{Y}}$ **(ΔMWh)** 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.

$\text{SocialCostC02}_{\text{Y}}$ **($ / 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]), 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.”[44]

4.4.2 Net Avoided SO2 and NOx

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

$$\text{Benefit}_Y = \sum_P \text{OnsiteEmissionsFlag}_{C,Y,r} * \text{OnsiteEnergy}_{Y,r} * \text{PollutantIntensity}_{p,Y} * \text{SocialCostPollutant}_{p,Y}$$

The indices of the parameters in Equation 4-15 include:

- p = Pollutant (SO_2, NO_x)
- Y = Year
- r = Retail Delivery or Connection Point

$\text{OnsiteEmissionsFlag}_Y$ 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.

$\text{Onsite}\mathbf{Energy}_{Y,r}$ **(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.

[44] *BCA Order*, Appendix C, 16.

$SocialCostPollutant_{p,Y}$ ($/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

$$\mathrm{Cost}_{\mathrm{Y}} = \sum_{\mathrm{M}} \Delta\mathrm{ProgramAdminCost}_{\mathrm{M,Y}_{\mathrm{p,Y}}}$$

The indices of the parameters in Equation 4-16 include:

- M = Measure
- Y = Year

$\mathbf{\Delta ProgramAdminCost_{M,Y}}$ 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 in advance 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.

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) – reciprocating 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 the 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."[45]

Thus, the acquisition of most DER in the near term will be through competitive solicitations rather and standing tariffs. The BCA Order requires a fact specific basis for quantifying costs that are considered in any SCT evaluation.[46] Company competitive solicitations for DER 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 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").[47] 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. 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$/kW-AC)[48]	4,430
Fixed Operating Cost ($/kW)	**15**

Note: These costs would change as DER project-specific data is considered.

[45] Order Adopting Regulatory Policy Framework and Implementation Plan, Case 14-M-0101, pg. 33.
[46] *BCA Order*, Appendix C pg. 18.
[47] 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.
[48] 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.

1. **Capital and Installation Cost:** Based on E3's estimate for NYSERDA 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 for NYSERDA of O&M for a residential PV panel in 2015. This estimate is applied to all New York electric utilities in the NYSERDA paper.

4.5.4.2 CHP Example

The CHP system used in this example is a 100 kW capacity natural gas-fired engine unit sized for commercial thermal load following applications. For this illustration, cost parameter values were obtained from the EPA's Catalog of CHP Technologies[49] 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 of 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.[50]
2. **Variable:** EPA's estimate of a 100 kW reciprocating engine CHP system's non-fuel O&M costs.[51]

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 DR technology benchmarks will evolve as the company gains experience with development and implementation of a DR program portfolio.

[49] EPA CHP Report available at: https://www.epa.gov/chp/catalog-chp-technologies
[50] EPA CHP Report. pg. 2-15.
[51] EPA CHP Report. pg. 2-17.

Table 4-3. DR Example Cost Parameters

Parameter	Cost
Capital Cost ($/Unit)	**$233**
Installation Cost ($/Unit)	**$140**

Note: This illustration would change as projects and locations are considered.

3. **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.
4. **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 a LED lighting fixture in a commercial office setting. The Company would need to incorporate its service territory specific information when developing its DR technology benchmarks.

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.

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 “losses” 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 ratepayers.

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 ratepayers of utility shareholder incentives that are tied to the projects or programs being evaluated.

Shareholder incentives should be project or program specific and should be evaluated as such.

4.5.7 Net Non-Energy Costs

A wide array of potential non-energy costs may be considered depending on the project type. As such, determination of suggested methodology to address a comprehensive listing of applicable elements is complex and will not be established in the Handbook.

However, methodology for one item; Suitable, Unused and Undedicated Land, has been addressed in this version of the Handbook. Suitable, Unused and Undedicated Land is defined as utility-owned property in reasonable proximity and electrically connected for possible use by non-wires opportunities projects providing load relief solutions. The formal appraised value of said land will be used in the BCA, should the bidder elect to proceed with lease or sale of the property along with costs incurred by the utility associated with securing property appraisals, environmental studies, and any other necessary documentation to support the sale or lease of Suitable, Unused and Undedicated Land.

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 that have been 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
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, 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	**DEnergy (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	**DEnergy (annual)** **DAGCC**
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[52]
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.

[52] 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.[53] 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[54]	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.
DEnergy (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 DEnergy 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 DEnergy 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.[55]

[53] This parameter is also used to calculate the Wholesale Market Price Impact Benefit.
[54] 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.
[55] 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 peaks generally occur 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, obtained from the 2023 Load and Capacity Data report.

Table 5-6. NYCA Peak Dates and Times

Year	Date of Peak	Time of Peak
2015	7/29/2015	Hour Ending 5 PM
2016	8/11/2016	Hour Ending 5 PM
2017	7/19/2017	Hour Ending 6 PM
2018	8/29/2018	Hour Ending 5 PM
2019	7/20/2019	Hour Ending 5 PM

5.1.2 Transmission

The transmission peak as defined for the BCA may occur on a different day or hour than that of the NYCA peak. The peak is dependent on the location of specific transmission constraints where utility capital investment may be needed. If applicable, use the hour that the constrained element on the transmission system experiences its peak load. In general, the benefits of a reduced transmission peak would be captured through the Avoided LBMP and AGCC benefits.

5.1.3 Distribution

The distribution peaks 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 coincide with the NYCA system peak and 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 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 low or zero if no constrained element is relieved (e.g., no distribution investment is otherwise required in capacity in that location, thus there is no distribution investment to be deferred even with highly coincident DER behavior).

5.2 Estimating Coincidence Factors

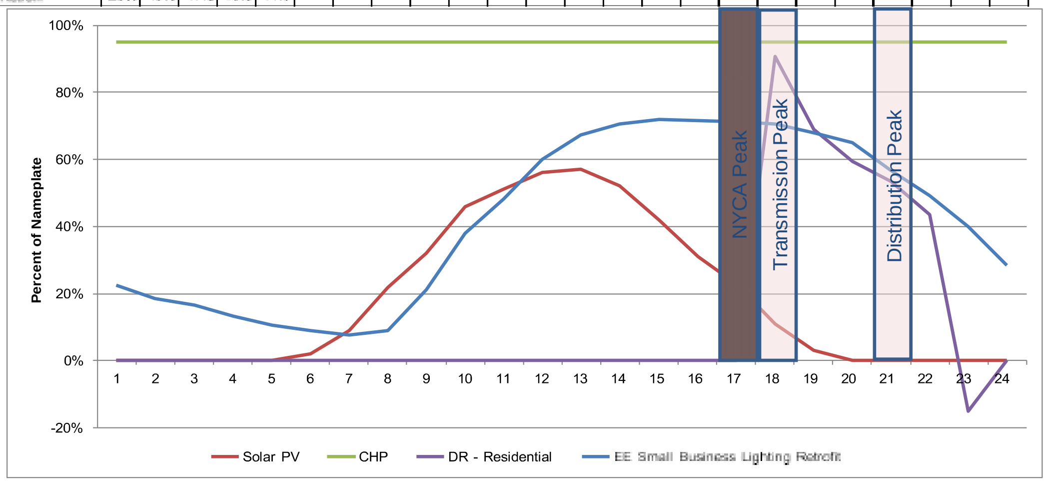
There are multiple approaches for estimating coincidence factors that apply different levels of rigor. Rigorous approaches could be defined and applied across a range of DERs; however, such an approach is likely to require a significant amount of granular information (e.g., 8760 hour load shapes for the DER projects and network information for specific locations) and time to analyze. Other approaches that require less granular information may be suitable in some cases and thus may be preferable in some situations.

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 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 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

The individual DER example technologies that have been selected are discussed below.[56]

The values for the DER 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")[57] based on a simulation of a large number of solar systems across New York.

An area for further investigation will be to assess and develop a common approach and methodology for determining the values for DER-specific parameters for each type of DER.

5.3 Solar PV Example

Solar PV is selected to depict an **intermittent** DER, where the electricity generation is dependent on the resource availability, in this case solar irradiance. The parameter assumptions and methodology used to develop those assumptions, were obtained from the E3 Report.

[56] 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 was not included.

[57] 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.

The following examples include illustrative coincidence factors for several technologies. Actual locational estimates of coincidence with specific DER technologies are included in Appendix N of the DSIP.

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 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 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	0.36
TransCoincidenceFactor	0.08
DistCoincidenceFactor	0.07
DEnergy (time-differentiated)	Hourly

Note: These are illustrative estimates and 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%-40% depending on system azimuth and tilt angle.[58] 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.[59] 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. **DEnergy (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).[60]

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 down time for maintenance. Since it is not always possible to schedule downtimes, the CHP unit is assumed to

[58] NYISO Installed Capacity Manual Version 6.47, page 55. Available at: https://www.nyiso.com/documents/20142/2923301/icap_mnl.pdf/234db95c-9a91-66fe-7306-2900ef905338.
[59] 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.
[60] The Catalog on CHP Technologies is available here: https://www.epa.gov/chp/catalog-chp-technologies.

provide 95% power output at all hours, assuming it is down for maintenance 5% of the year.[61]
The carbon and criteria pollutant intensity can be estimated using the EPA's publically-available CHP Emissions Calculator.[62] "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
DEnergy (time-differentiated)	Annual average

Note: These are illustrative estimates and would change as specific projects and locations are considered.

5. **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.
6. **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.
7. **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.
8. **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).
9. **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.
10. **DEnergy (time-differentiated):** Assuming the CHP is used as a baseload resource, with the exception of downtime for maintenance, capacity factor is 95%. Because it is not possible to predict when the downtime may occur, using annual average LBMP would be appropriate.

5.5 Demand Response Example

DR depicts an example of a **dispatchable** DER where the resource can be called upon to respond to peak demand.

[61] EPA CHP Report. pg. 2-20.
[62] EPA CHP Emissions Calculator https://www.epa.gov/chp/chp-emissions-calculator.

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.[63] 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). 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 do not account for load or device availability. Load availability is defined as the percentage of total potential capacity that can be shed from the load connected to the DR system at the time the DR event is called. Device availability is defined as the ability the DR system to accurately receive the DR signal and control the load. These factors, multiplied by the total potential capacity of the DR asset, would produce the average demand reduction for the asset. Average demand reduction multiplied by the coincidence factor is then defined as the average peak coincidence demand. These values are not presented here but are project- and technology-specific and will differ substantially among DR technologies and loads. As such, project-specific analyses would need to consider the load and system availability, as well as response rate (as described above) to accurately determine the appropriate coincidence factors.

This DR example is designed to reduce system peak (consistent with most existing DR programs), thus the system coincidence factor is 1.0 such that the DR resource is called to reduce the system peak load.[64] Given the small number of calls annually, the coincidence factor with the system peak is assumed to be 1, while the coincidence factors for the transmission and distribution peaks is assumed to be 0.5 which is consistent with the assumption that this particular DR example is not targeted to be coincident with those peaks.[65]

As an alternative approach, to calculate the coincidence factors for a specific DR resource, comparative analysis should be performed on the most recent annual data comparing the peak demand of the targeted system with the peak demand of the other systems. Comparing the coincidence of the top 50 hours of total system load and top 50 hours of each feeder's load would produce the distribution coincidence factor for a DR project that targets system peak. Analysis should be based on data from the Day-Ahead Market or Real-Time Market depending on the design of the DR program. Coincidence factors for DR projects should use the most recently available data.

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.

[63] Some DR programs may be "dispatched" or scheduled by third-party aggregators.
[64] Note, the controllable load may not be operating at the time of peak.
[65] Specifically from the July 15 – 19, 2013 heat wave.

5.5.2 Benefit Parameters

The benefit parameters described here are assumed based on the example and considerations described above.

Table 5-9. DR Example Benefit Parameters

Parameter	Value
SystemCoincidenceFactor	1.0
TransCoincidenceFactor	0.5
DistCoincidenceFactor	0.5
DEnergy (time-differentiated)	Average of highest 100 hours

Note: These are illustrative estimates and would change as specific projects and locations are considered.

1. **SystemCoincidenceFactor:** The system coincidence factor is assumed to be 1.0, based on the assumption that the DR system is called upon at the time of system peak.
2. **TransCoincidenceFactor:** Without targeting portions of the transmission system, the coincidence factor is assumed to be 0.5 but would be greater if the DR is dispatched to target the transmission peak.[66] Location- and program-specific distribution coincidence factors could be calculated using hourly load data per the methodology described above.
3. **DistCoincidenceFactor:** Without targeting portions of the transmission system, the coincidence factor is assumed to be 0.5 but would be greater if the DR is dispatched to target the transmission peak. Location- and program-specific distribution coincidence factors could be calculated using hourly load data per the methodology described above. If instead the DR asset were used to defer distribution capacity, the coincidence factor could be as high as 1 (though the system coincident factor could then be as low as zero, since if the peak periods were to occur at the same time, the project could only be dispatched for one program).
4. **DEnergy (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. The parameter assumptions, and methodology used to develop those assumptions, developed using the NY TRM.[67]

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[66] Con Edison Callable Load Study, Page 78, Submitted May 2008. https://uploads-ssl.webflow.com/5a08c6434056cc00011fd6f8/5a27177a5f89cb0001ea0c03_Schare%20Welch%20Edison%20Callable%20Load%20Study_Final%20Report_5-15-08.pdf

[67] New York State Technical Resource Manual (TRM): New York Standard Approach for Estimating Energy Savings from Energy Efficiency Programs – Version 7, Issue on April 15, 2019 and effective on January 1, 2020.– Lighting operating hour data is sourced from the 2008 California DEER Update study.

5.6.1 Example System Description

The energy efficient lighting used in this example is indoor installation of linear fluorescent lighting in a commercial office setting with an estimated utilization of 3,013 hours/year.[68] The peak period for this example is assumed to occur in the summer during afternoon hours.

EE, including lighting, is a load reducing because it decreases the customers' energy consumption and load shape, which in turn, reduces the system, transmission and distribution peak. This example of an indoor, office-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.

5.6.2 Benefit Parameters

The benefit parameters described here were developed using guidance from the NY TRM.

Table 5-10. EE Example Benefits Parameters

Parameter	Value
SystemCoincidenceFactor	1.0
TransCoincidenceFactor	1.0
DistCoincidenceFactor	1.0
DEnergy (time-differentiated)	~7 am to ~7 pm weekdays

Note: These are illustrative estimates and would change as specific projects and locations are considered.

5. **SystemCoincidenceFactor:** The system coincidence factor is 1.0 under the assumption that the system peak occurs while standard office lighting systems are operating.
6. **TransCoincidenceFactor:** The transmission coincidence factor is 1.0 under the assumption that the transmission system peak occurs while standard office lighting system are operating.
7. **DistCoincidenceFactor:** The distribution coincidence factor is 1.0 under the assumption that the distribution system peak occurs while standard office lighting systems are operating.
8. **DEnergy (time-differentiated):** This value is calculated using the lighting hours per year (3,013) as provided for General Office types in the NY TRM, divided by the total hours in a year (8,760). This time period is subject to building operation, which is roughly between 7 am and 7 pm, 5 days a week, 52 weeks a year. This would define the corresponding period for determining an average LBMP that would be used to calculate the benefit.

[68] Ibid.

5.7 Energy Storage Example

ES depicts an example of a dispatchable DER where the resource can be called upon to respond to peak demand. Furthermore, the storage will add load to the system during times of charge. This is the most flexible technology, with a wide variety of use cases.

5.7.1 Example Description

An exhaustive discussion of the types of storage configurations and potential use cases is beyond the scope of this handbook. ES requires understanding the specifics of how the project will be designed and operated to provide benefits to the system and/or customer. In this section, several of the most common considerations and examples are discussed, but this flexible resource must be considered on a case-by-case basis. Key system design parameters to consider include:

1. **Storage type:** There are many physical methods for storing energy such as thermal, chemical (electric battery), pumped hydro, compressed air, hydrogen, etc. All of these have their own benefits and constraints. In general, it is best to consider how the technical characteristics of the storage type may inhibit or facilitate electric load reduction or addition to the grid. For simplicity, the following examples consider electrochemical lithium ion battery storage only as this technology currently delivers desired services from ES at the least cost.
2. **Storage size:** Size is measured in both energy (kWh) and capacity (kW). The determination of energy and power are driven by the use case and what is needed to deliver services most cost-effectively.
3. **Ownership and Operation:** A wide variety of business models for storage ownership and operation exist today. Broadly, these can be characterized into two categories of utility and customer ownership. The ownership has implications for storage size, dispatch schedule, and location, which is why two different ownership scenarios are present in this example. For simplicity, we assume that the owner controls the storage dispatch and operates it to their benefit.
4. **Location:** ES may connect to the grid in front of the meter or behind the meter. The system configuration and isolation scheme determine whether the ES can be used to provide backup power during planned or unplanned outages. If multiple batteries are aggregated and dispatched simultaneously using a single control scheme, whether those batteries are all located on different parts of the system needs to be considered when calculating transmission and distribution deferral benefits.
5. **Dispatch Operation:** ES may be operated in a variety of ways, from completely automatic and optimized operation, to manual, to “standby” operation in which the storage stays charged until needed for backup power. Generally, it is presumed that storage is operated according to a set of priorities that establishes the primary reason for the storage investment as the top operational priority, then uses the remaining capacity and energy to capture the most economic value.
6. The two examples outlined below illustrate the interplay between these various system design parameters

Table 5-11. ES Example Characteristics for Utility and Customer Scale Systems

Storage Owner/Operator (Location)	Utility Scale (In Front of the Meter)[69]	Customer Scale (Behind the Meter)
Storage Type	Lithium Ion Battery	Lithium Ion Battery
Size (capacity/energy)[70]	1MW/5MWh	5kW/13.5kWh
Cycle Life	4,500 cycles (to 80% of rated energy)	2,800 cycles[71]
Efficiency	90%	90%[72]
Dispatch Operation Examples	Prioritized based on 1) distribution capacity 2) bulk system capacity, 3) ancillary service provision and 4) LBMP arbitrage	Prioritized based on 1) minimizing demand charges[73] 2) TOU rate arbitrage and 3) outage backup
Capital cost	Based on energy and capacity, decreasing annually at 8%/yr through 2022, then 4%/yr afterward[74]	
Fixed O&M	3% of capex per year, inflated annually	negligible
Variable O&M	$2/MWh	negligible
Degradation/ Augmentation Costs	Annual degradation should be calculated based upon number of cycles each year and degradation per cycle. For large batteries, augmentation can be conducted to counteract degradation each year. For smaller batteries, the battery will need to be replaced at the end of its useful life, which is typically determined in dispatch cycles rather than years.	

The use case of the battery determines the dispatch schedule and system design (size, location), which in turn determines the coincidence factors and hourly load/savings shape of storage. The battery needs to have a high enough duration (or be paired with other resources in a portfolio) to properly address the distribution peak period. There are numerous use cases, so the load impacts of each storage project need to be considered on an hourly basis. It is also possible that a customer may own a battery but provide the utility some control of the battery during certain times, in which case the storage operation would be similar to a DR event.

To calculate the coincidence factors for a specific storage resource, comparative analysis should be performed on the most recent annual data comparing the peak demand of the targeted system (e.g., distribution) with the peak demand of the other systems (e.g., transmission). Comparing the coincidence of the top X hours of each feeder's load and top X hours of system load (where X is the storage duration at

[69] Unless otherwise noted, technical assumptions are sourced from a recent utility-scale storage for NWA analysis: Puget Sound Energy (PSE) Bainbridge Island Non-Wires Alternative Analysis, Appendix C: Energy Storage Analysis. July 9, 2019. https://oohpsebainbridgefall2019.blob.core.windows.net/media/Default/documents/Appendix%20D_Bainbridge%20Island%20Non-Wires%20Alternative%20Analysis_Navigant%20Consulting_July_9_2019.pdf

[70] These examples use round numbers for simplicity. If energy is 5 times the capacity, the battery is said to have 5 hours of dispatch duration.

[71] Based on Tesla Powerwall warranty which includes 37.8 MWh of aggregate throughput. At 13.5kWh per discharge, this equates to 2800 cycles. https://www.tesla.com/sites/default/files/pdfs/powerwall/powerwall_2_ac_warranty_us_1-4.pdf

[72] Based on Tesla Powerwall datasheet https://www.tesla.com/sites/default/files/pdfs/powerwall/Powerwall%202_AC_Datasheet_en_northamerica.pdf

[73] Demand charges in New York would only apply to customers on commercial rates. In other parts of the US (Arizona for instance) residential customers are subject to demand charges.

[74] These costs reflect front-of-meter installed cost including a rough estimate of land lease costs for a large bulk system as well as interconnection. It is important to note that costs are changing in the energy storage industry and although there is a trend toward cost declines there is uncertainty about future costs. These cost declines may not apply to widely available consumer products. From PSE Ibid.

maximum discharge) would produce the system coincidence factor for a storage project that targets distribution peak. Analysis should be based on data from the Day-Ahead Market or Real-Time Market depending on the design of the storage dispatch plan. Coincidence factors for storage projects should use the most recently available data.

Because storage projects often take advantage of the "value stack" of multiple benefits, it is important to avoid double counting of benefits. For example, the battery must be charged and ready to dispatch during distribution peak, thus may not be eligible for energy arbitrage or ancillary services benefits in the hours leading up to and following the distribution peak hours.

5.7.2 Benefit Parameters

The benefit parameters described here are assumed based on the example and considerations described above.

Table 5-12. ES Example Benefits Parameters – Utility Scale

Parameter	Value
SystemCoincidenceFactor	0.8
TransCoincidenceFactor	0.8
DistCoincidenceFactor	1.0
DEnergy (time-differentiated)	Hourly
ΔCapacity$_Y$ (ΔMW); n (hr)	Modeled from hourly dispatch analysis

Note: These are illustrative estimates and would change as specific projects and locations are considered.

1. **SystemCoincidenceFactor:** Without specifically targeting the overall system peak, the coincidence factor is assumed to be 0.8, based on the assumption that the distribution system peak load is likely coincident with overall system peak load. However, this is not always the case. Location- and program-specific distribution coincidence factors should be calculated using hourly load data per the methodology described above.

2. **TransCoincidenceFactor:** Without targeting portions of the transmission system, the coincidence factor is assumed to be 0.5 but, similar to DR, would be greater if the storage is dispatched to target the transmission peak.[75] Location- and program-specific distribution coincidence factors could be calculated using hourly load data per the methodology described above.

3. **DistCoincidenceFactor:** In this example, the storage is used as a non-wires alternative and the top priority of dispatch operation is to reduce location-specific distribution peak capacity. Therefore, the distribution coincidence factor is 100%.

4. **DEnergy (time-differentiated):** The value of reduced energy use attributable to the storage project can be calculated using the hourly LBMP compared to the hourly charge and discharge

[75] Con Edison Callable Load Study, Page 78, Submitted May 2008. https://uploads-ssl.webflow.com/5a08c6434056cc00011fd6f8/5a27177a5f89cb0001ea0c03_Schare%20Welch%20Edison%20Callable%20Load%20Study_Final%20Report_5-15-08.pdf.

cycles of the storage project. Energy impacts should be adjusted for round-trip efficiency (battery losses).

5. **ΔCapacity$_Y$ (ΔMW); n (hr):** In this example, distribution capacity and system capacity take precedence over ancillary services in the storage dispatch operation. This dispatch schedule would need to be modeled on an hourly basis to determine the remaining capacity and hours (n) that the storage would be available for providing spinning reserves to NYISO. This could be a significant benefit if hours when spinning reserves are needed by NYISO are not coincident with distribution or system peak capacity needs.

Table 5-13. ES Example Benefits Parameters – Customer Scale

Parameter	Value
SystemCoincidenceFactor	1.0
TransCoincidenceFactor	1.0
DistCoincidenceFactor	0.5
DEnergy (time-differentiated)	Hourly
ValueOfService$_{C,Y,r}$ ($/kWh) ; **$\Delta$SAIDI$_Y$ (Δhr/cust/yr)**	Retail rate of electricity (minimum) ; average energy stored compared to customer load

Note: These are illustrative estimates and would change as specific projects and locations are considered.

1. **SystemCoincidenceFactor:** Assuming that customer TOU rates and demand charges align financial incentives toward peak load reduction, if the customer operates the battery to reduce energy costs the storage will have 100% coincidence with system peak.

2. **TransCoincidenceFactor:** Without targeting portions of the transmission system, the coincidence factor is assumed to be 0.5. Location- and program-specific distribution coincidence factors could be calculated using hourly load data per the methodology described above.

3. **DistCoincidenceFactor:** Without targeting portions of the distribution system, the coincidence factor is assumed to be 0.5. Location- and program-specific distribution coincidence factors could be calculated using hourly load data per the methodology described above.

4. **DEnergy (time-differentiated**): The value of reduced energy use attributable to the storage project can be calculated using the hourly LBMP compared to the hourly charge and discharge cycles of the storage project. Energy impacts should be adjusted for round-trip efficiency (battery losses).

5. **ValueOfService$_{C,Y,r}$ ($/kWh)** ; **$\Delta$SAIDI$_Y$ (Δhr/cust/yr):** To determine Net Avoided Outage costs, the storage project needs to carry customer loads through an outage. The value of carrying a load through an outage should be at least the retail rate of electricity that would be used during that outage time. The change in SAIDI at the customer level can be calculated based on the average state of charge of the battery compared to the customer load to determine how long the battery could carry the load through an outage. For example, if the maximum energy in the battery is 10 kWh, and the annual average state of charge is 50%, then during a typical outage there will be 5 kWh available to carry the customer's load through the outage. If the customer uses 2 kW per hour on average, the storage can reduce the customer-level SAIDI by 2.5 hours on average.

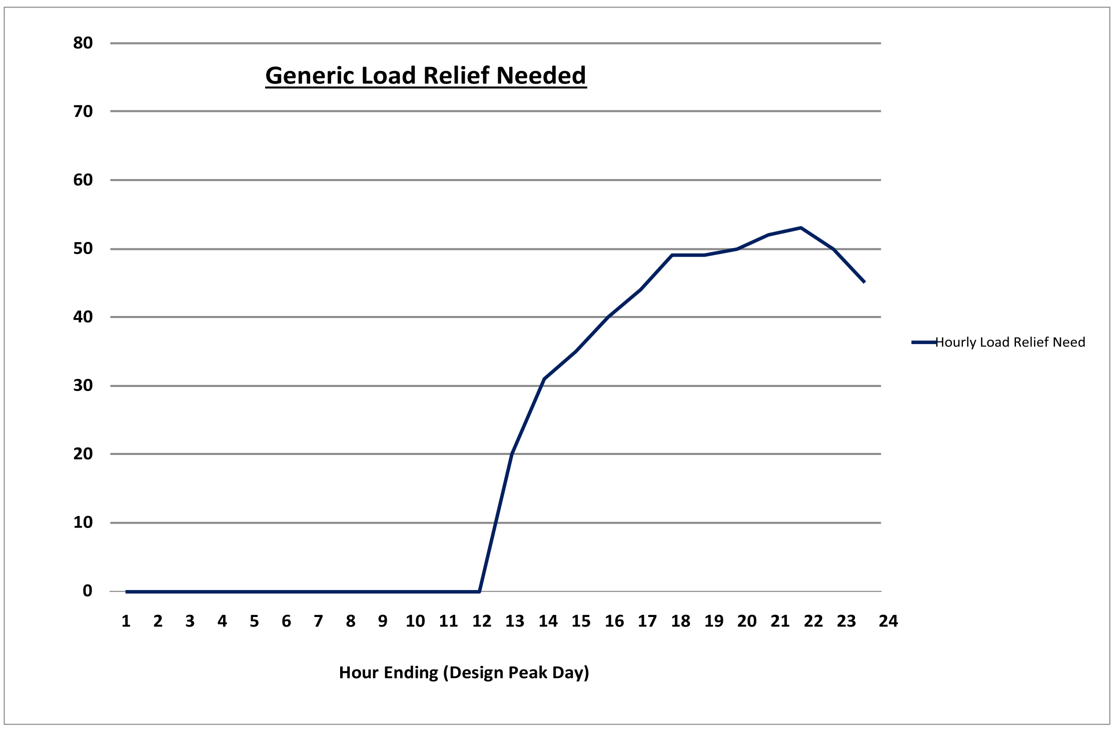
5.8 Portfolio Example

This example assumes that a segment of the distribution system needs locational load relief, illustrates how that relief might be provided through a portfolio approach, and examines some of the qualitative considerations impacting the development of the portfolio solution.

5.8.1 Example Description

The hourly locational load relief need is defined in Figure 5.2. This example is most likely representative of a locational need in a densely populated urban area and captures many of the considerations that go into the development of a portfolio of resources to provide a non-wires solution to the locational need.

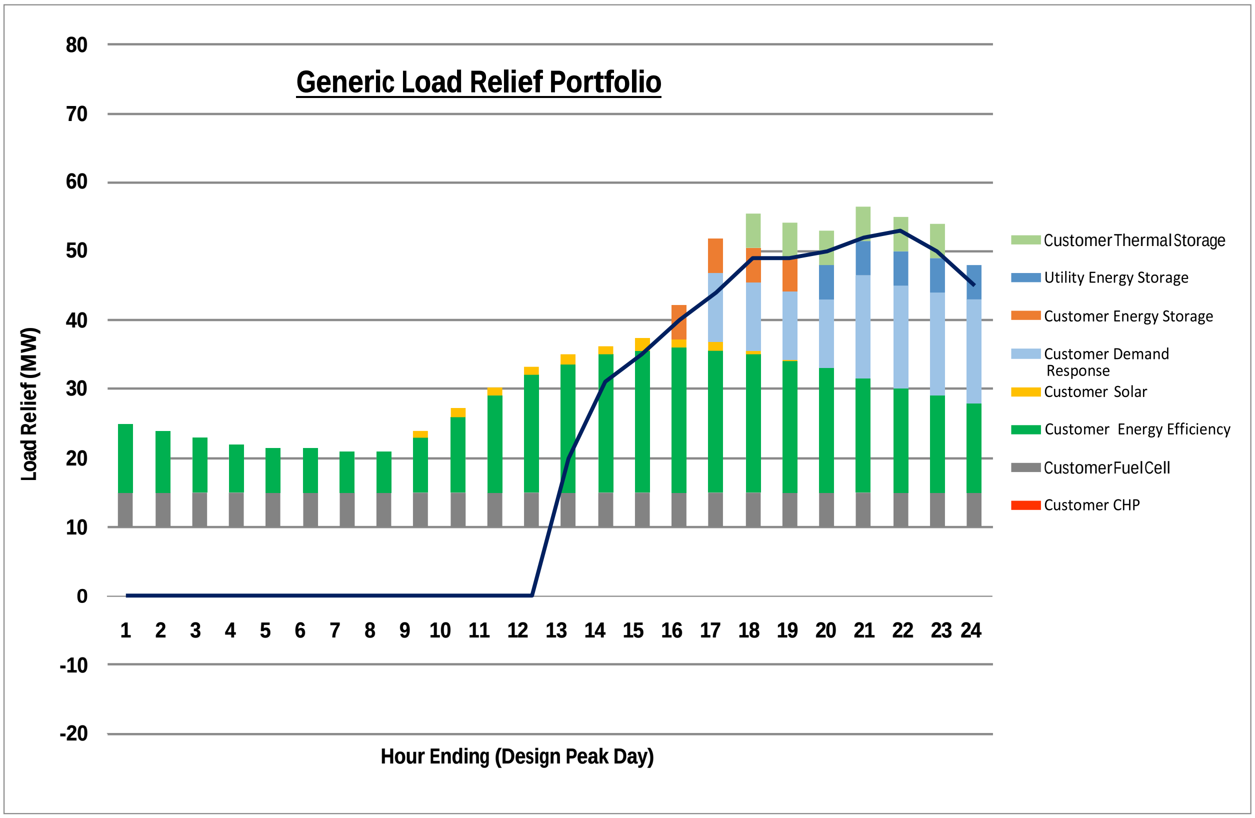
Figure 5.2. Location Load Relief Requirement



5.7.1 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[76]

Year	For Use in SCT	For Use in UCT, RIM
2022	6.48%	8.07%
2023	6.40%	7.96%
2024	6.33%	7.86%

System loss values may be affected by certain projects which alter the topography of the transmission and/or distribution systems. Central Hudson does not currently have disaggregated fixed and variable loss information available. Where loss values are applicable to calculations within the handbook, system average values should be used. System annual average loss data is shown in Table A-2.

Table A-2. Utility Loss Data[77]

System	Average Loss Percent (MWh)	Average Loss Percent (MW)
Transmission	1.87%	2.01%
Primary Substation	0.45%	0.46%
Primary Distribution	1.22%	2.26%
Secondary Distribution	1.84%	1.56%
Total System	5.39%	6.29%

[76] Source: Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plan, issued and effective November 11, 2021, in Cases 20-E-0428 and 20-G-0429. The 2024 values can be used for future years until superseded.
[77] Source: 2019 Central Hudson Gas & Electric Corporation Analysis of System Losses Appendix B Exhibit 1, produced by Management Applications Consulting, Inc. for Central Hudson.

Utility-specific system average marginal costs of service are found in Table A-3.

Table A-3. 10-Year Average Utility System Marginal Avoided T&D Costs[78]

Component	10 year Levelized Avoided Costs ($kW-year)
Distribution	$0.225
Transmission	$14.325
10-Year Levelized	$14.550

Note: The 2016 values are used based on guidance by the Department of Public Service to Central Hudson.

Average restoration costs are found in Table A-4.

Table A-4. Average Hourly Restoration Costs

Average Hourly Restoration Costs
Restoration Costs will be determined for each specific project as applicable
Source: Project Specific

Table A-5. Operation & Maintenance Costs

Average Hourly Restoration Costs
O&M Costs will be determined for each specific project as applicable
Source: Project Specific

[78] Source: Location Specific Transmission and Distribution Avoided Costs Utilizing Probabilistic Forecasting and Planning Methods report, 2016, produced by Nexant for Central Hudson. Central Hudson may update the avoided T&D costs to reflect the 2020 study results, upon approval by the Department of Public Service.