2025 Central Hudson

Transmission & Distribution Marginal Cost of Service Study

Prepared for Central Hudson
By
Demand Side Analytics
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ACKNOWLEDGEMENTS

DSA Research Team

- Josh Bode
- Zhuoning Li

Central Hudson Team

- Stacy Powers
- Bradley Brandt
- Stephanie Palmer
- Pano Harpolis
- Jake Reinert
- Walter Rojowsky

ABSTRACT

The focus of the study is on quantifying the transmission and distribution marginal costs. As requested by the Commission, the study team adopted the National Economic Research Associates' method. The study only includes costs associated with growth and multi-value (growth and reliability). The study estimates location specific marginal costs for individual feeders, substations, and local transmissions. As requested by the Commission, marginal costs were then aggregated and presented at the substation level.

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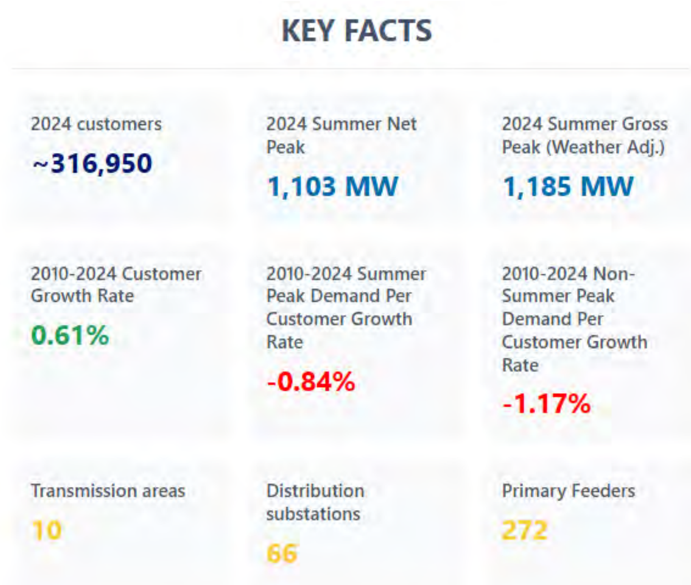
1 INTRODUCTION

Central Hudson Gas & 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 electricity and gas transmission and distribution (T&D) services to approximately 315,000 electric customers and 90,000 natural gas customers. Central Hudson territory 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 comprises approximately 9,400 miles of transmission and distribution lines.

Figure 1: Central Hudson Key Facts



Central Hudson's actual system peak in 2024 was 1,103 MW.[1] The electric peak forecast for 2030 is projected to be a summer peak of 1,087 MW. Overall, per-customer summer peak demand in Central Hudson has declined at a rate of -0.84% per year, likely due to a mixture of energy efficiency, codes and standards, and other changes in end-use loads. Per-customer winter peak demand has declined at a rate of -1.17% per year. For comparison, Central Hudson's all-time electric system peak demand of 1,295 MW was set in 2006.

On August 19, 2024, the Public Service Commission issued an Order Addressing Marginal Cost of Service studies that specify the marginal cost of service (MCOS) study methodologies for determining several components of the Value of Distributed Energy Resources (VDER) Value Stack. In 2016, 2018, 2020, and 2023, Central Hudson conducted location-specific avoided T&D cost studies that relied on probabilistic analysis and quantified the option value of reducing peak demand. This 2025 study adopts

[1] The value includes loads and net metered distribution connected solar and storage, which is used for revenue requirements. For distribution planning, the loads used also include non-net metered distribution connected solar (e.g., community solar and storage). Gross Peak (Weather Adjusted) includes net loads, net metered solar production, and community-distributed generation solar production.

the traditional National Economic Research Associates' methodology, with modifications required by the Commission to better align approaches across utilities.

In Central Hudson's MCOS study, marginal costs were estimated at three levels: local transmission, substation, and distribution feeder. For each level, all growth-related and multi-value (i.e., growth and reliability) projects in the capital investment plan were included in the analysis. To determine the total marginal cost for each location, Central Hudson aggregated the marginal costs across all three levels.

The key findings from the MCOS study are:

- Many circuits, substations, and local transmission areas are experiencing declining loads or have ample room for growth.
- Transmission and substation-level marginal costs increase over the ten-year timeframe as areas with higher marginal costs have projects with expected in-service dates in the latter half of the planning horizon.

2 CONTEXT AND BACKGROUND

One vital role of the electric utility is to ensure that the electricity supply remains reliable. By projecting future demand along with identifying reliability and/or condition-based infrastructure needs, utilities can reinforce the local transmission and distribution systems to maintain power quality and reliability of the system and ultimately avoid costly outages.

The load forecasts leveraged in the MCOS, were done using econometric forecasts for each of Central Hudson's 272 distribution feeder circuits, 66 substations, and 10 local transmission areas.[2] These forecasts incorporate substation-level growth rates, forecasted changes in household growth, and are weather-adjusted for planning conditions. Modeling was performed on an hourly basis to produce forecasts at the feeder circuit level for evolving technologies, including solar, storage, transportation electrification, and building electrification. Central Hudson produced these granular forecasts for the 10-year horizon as required in the MCOS study.

2.1 REGULATORY BACKGROUND

In its April 18, 2019, Order Regarding Value Stack Compensation in Case 15-E-0751 (Order), the Public Service Commission initiated a new proceeding to examine the Joint Utilities' marginal cost of service (MCOS) studies, which have been used for a variety of purposes, including components of the Value Stack, economic development rates, and the avoided cost benefit associated with energy efficiency load reduction programs. Following a stakeholder process, the Commission issued an order on August 19, 2024, establishing a methodology for estimating marginal costs to inform system-wide applications. The order calls for consistent MCOS study methodologies to reduce the significant variations that previously existed across the Joint Utilities.

In 2016, 2018, 2020, and 2023, Central Hudson conducted location-specific avoided T&D cost studies that relied on probabilistic analysis and quantified the option value of reducing peak demand. This 2025 study adopts the traditional National Economic Research Associates' methodology, incorporating modifications required by the Commission to better align practices across utilities. Compared to previous studies, the 2025 Marginal Cost of Service Study differs in several key areas:

- The study included all growth-related and multi-value projects planned within the 5-year corporate Capital Forecast, along with a handful of capital infrastructure investments currently identified past the 2030 timeframe. Since Central Hudson uses a five-year capital forecast, the proportion of service territory with distribution upgrade needs in years six through ten was assumed to be similar to years one through five.

[2] See 2025 Distributed System Implementation Plan (DSIP) Advanced Forecasting section for a more detailed description.

- Marginal cost estimates are developed using deterministic methods.
- Marginal costs are calculated as the actual planned investment cost net of salvage value divided by the incremental capacity provided by each project and converted into annual revenue requirements per kW of capacity. Most of the capital projects included in the MCOS are multi-value projects driven by reliability/infrastructure needs that would require investments absent any load growth. However, for various reasons, these multi-value projects also increase system capacity.

2.2 STUDY OBJECTIVES

The study focuses on quantifying the marginal costs of increasing the T&D system capacity so that it can accommodate additional loads. The study focuses on feeder, substation, and local transmission costs and was designed to meet the following objectives:

- Analyze the magnitude of expected infrastructure investments at a local level.
- Identify capital investment projects that are growth-related or multi-value.
- Calculate local marginal costs of T&D capacity for projects identified for inclusion in the study, at the local transmission, substation, and distribution feeder levels.
- Estimate the system-wide marginal costs at the local transmission, substation, and distribution feeder.
- Produce avoided T&D costs by substation.

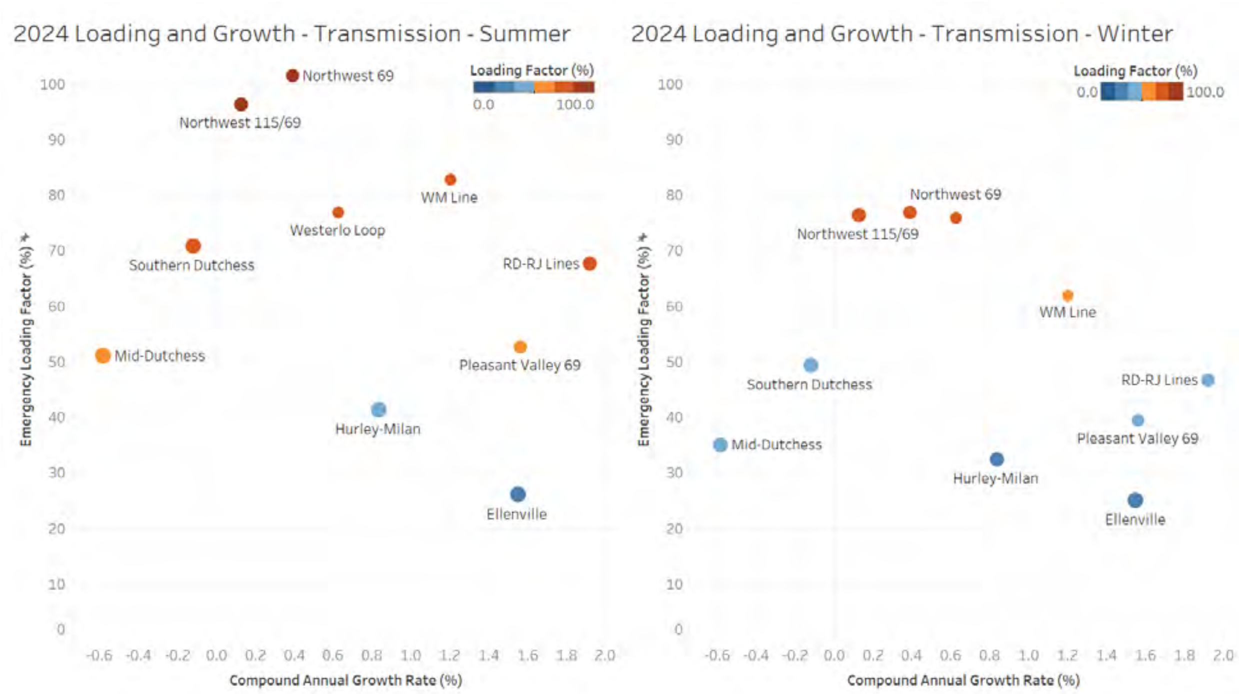
In areas with excess capacity – or areas where local, coincident peaks are declining or growing slowly – the value of capacity relief can be minimal. In areas where a large, growth-related investment is imminent, the value of capacity relief can be quite substantial, especially if it is possible to delay 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. In addition, the annual marginal cost values do not reflect whether resources are delivered at the right hours and right seasons by location.

2.3 HISTORIC LOADING FACTORS AND GROWTH RATES

Figure 2, Figure 3, and Figure 4 display the summer and winter loading factors in 2024 and the growth rates for local transmission areas, substations, and distribution feeders. The 2024 loading factor is simply the actual peak divided by the location's operating limit. 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.

Roughly 70% of the local transmission areas (load-weighted) have been experiencing growth, but approximately 25% (load-weighted) have loading factors above 85%. The two most highly loaded areas Northwest 115/69 kV and Northwest 69kV are part of non-wires alternative project that has deferred capital costs since 2015 and are scheduled for upgrades in 2029. All transmission areas in Central Hudson's territory are currently summer-peaking systems. Some are experiencing slow growth or declining loads or have ample room for growth without having to upgrade them. Several of the local transmission areas have multi-value infrastructure projects. As part of the upgrades, the transmission capacity for those locations will increase in order accommodate increasing amounts of solar, planned battery storage, and load growth.

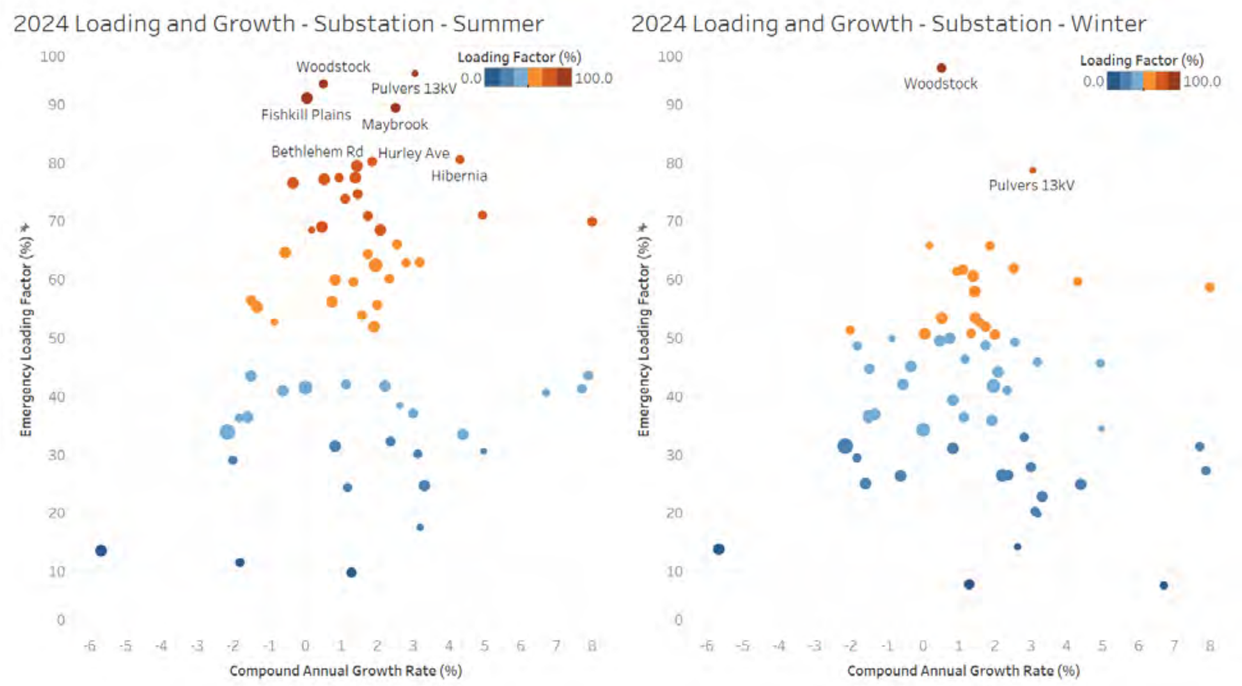
Figure 2: Growth Rates Versus Room for Growth – Local Transmission



Notes: Bubble size is proportional to the LTE rating of the site. The color reflects the 2024 loading for each site.

Figure 3 compares the annual load growth rate to the 2024 loading factor for each of Central Hudson's load serving distribution substations. Roughly 75% of the substations have been experiencing growth, most of which has been driven by growth in customers. On average, peak demand per customer has been declining across Central Hudson's service territory. A small share of the substations, less than 8%, are at 85% or more of the operating limit. Most of the substations, 87% of them, remain summer peaking. With a few exceptions, most of the substations have room to accommodate electric vehicles and building electrification loads over the next five years. One of the highly loaded substations, Fishkill Plains, is part of non-wires alternative project that has deferred capital costs since 2015 and is scheduled for upgrades in 2027.

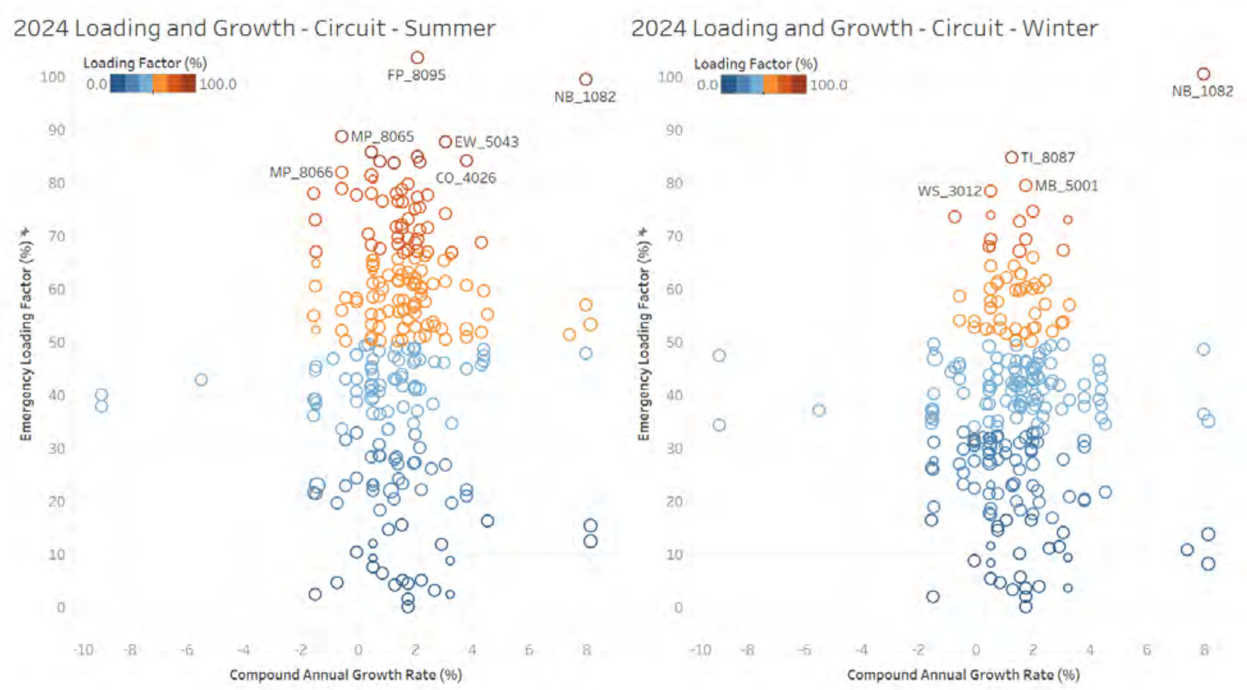
Figure 3: Growth Rates Versus Room for Growth - Substation



Notes: Bubble size is proportional to the LTE rating of the site. The color reflects the 2024 loading for each site.

Figure 4 compares the annual load growth rate to the 2024 loading factor for each of Central Hudson's distribution feeders. Central Hudson operates most of its distribution feeders so that two nearby feeders can pick accommodate peak loads in case of outages or maintenance, ensuring a high level of service reliability and operations flexibility. Generally, the feeders can accommodate more load, if needed, without exceeding the thermal limits and the main limitation for additional load is the substation transformer.

Figure 4: Growth Rates Versus Room for Growth – Distribution Feeders



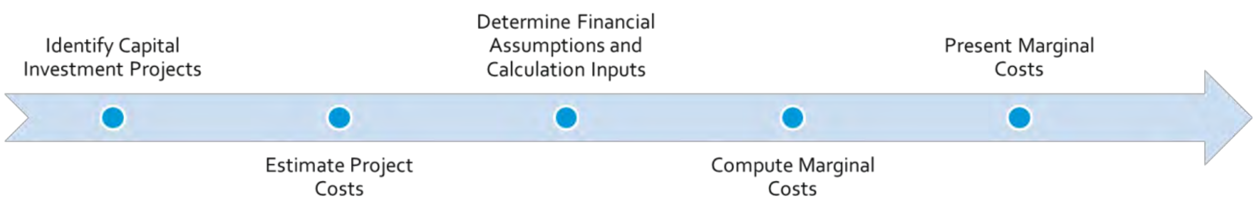
Notes: Bubble size is proportional to the emergency rating of the site. The color reflects the 2024 loading for each site.

3 METHODOLOGY

The analysis involved five (5) main steps, as shown below:

1. **Identify Capital Investment Projects.** Central Hudson included all the load growth and multi-value projects in its 5-year capital forecast and a few projects identified past the 5-year timeframe. In addition, Central Hudson included yet-to-be-identified projects in the remaining 10-year timeframe at the average cost per kW of capacity. A total of 9 specific projects were identified, with total capital expenditures of about $111M over the 2026-2035 horizon. While most of the projects are reliability/infrastructure driven, they also include a load growth component and thus were identified as a multi-value project.
2. **Estimate Project Costs.** The project costs included were consistent with the capital plan. For growth-driven projects (i.e., not multi-value), no salvage value is applied. For multi-value projects, Central Hudson assigned a salvage value of 2.5% for distribution feeder, substation, and local transmission-level investments.
3. **Determine Financial Assumptions and Calculation Inputs** for carrying charge and expense factors.
4. **Compute Marginal Costs.** The calculations simply reflect revenue requirements associated with the capital costs and are presented on $/kW-year of T&D capacity. The values are in nominal dollars and are included starting the year after the projected project in-service year. The 10-year levelized values reflect the in-service years and the time value of money.
5. **Present Marginal Costs.** The local transmission, substation, and feeder circuit value was stacked at the feeder level and aggregated to the substation level.

Figure 5: MCOS Key Analysis Steps



Additional considerations in the analysis include:

- In accordance with the Order's requirement to present costs at a granular level by including the substation serving area, Central Hudson layered marginal costs from local transmission, substation, and feeder circuit levels to the substation level. To allocate local transmission-level marginal costs, each substation within a specific local transmission area was assigned the local transmission-level marginal cost. Circuit-level marginal costs were rolled up to the substation level by weighing each circuit's marginal cost by its peak load, accounting for differences in circuit size.

- Marginal costs will vary by year depending on the projects being placed into service in that year. In addition to showing marginal costs over each of the ten years, a ten-year levelized marginal cost is presented as the net present value of the investments, factoring in the in-service year of the planned capital projects.
- In accordance with the Order, the marginal costs are shown at the local transmission, substation, and feeder level for all projects identified within the ten-year planning horizon and are representative of areas with identified projects over the study period.
- In addition, Central Hudson's study presents system-wide marginal costs, inclusive of areas with ample room for load growth. All areas were included in the study and weighed according to their share of Central Hudson's load.

4 RESULTS

Table 1 and Table 2 present the annual and 10-year levelized total marginal cost estimates by local transmission, substation and distribution feeder. Table 1 reflects the marginal costs in areas with identified projects. As indicated previously, many feeders, substations and local transmission areas in Central Hudson's territory are experiencing declining loads or have ample room for growth. As a result, the marginal costs applicable to areas with growth-related and multi-value projects are not representative of all areas of Central Hudson's system. The values also should not be stacked (i.e. added across local transmission, substation and feeder circuit), unless a specific location has upgrade projects scheduled at all three grid levels. Most locations do not have upgrades in the 10-year horizon, or, if they do, have upgrades scheduled for a specific component (e.g., transmission upgrade, but not substation, and feeder). Table 2 reflects total marginal costs on a system-wide basis, factoring in areas with no marginal costs or yet-to-be identified projects over the 10-year planning horizon. Such a value would be more appropriate for use in circumstances where a single marginal cost value is utilized regardless of where on the system a resource is located.

Table 1: Marginal Costs for Areas with Projects by Component ($ nominal)

Year	Local Transmission	Substation	Feeder Circuit
2026	$0.00	$0.00	$12.37
2027	$0.00	$0.52	$12.63
2028	$0.00	$12.65	$12.63
2029	$0.00	$12.65	$12.63
2030	$0.00	$42.84	$12.63
2031	$0.00	$99.50	$12.63
2032	$0.00	$99.50	$12.63
2033	$27.92	$127.47	$12.63
2034	$27.92	$127.47	$12.63
2035	$27.92	$127.47	$12.63
10-year levelized ($2025)	**$6.56**	**$55.51**	**$12.60**

Table 2: System-wide Marginal Costs ($ nominal)

Year	Local Transmission	Substation	Feeder Circuit	Total Marginal Costs
2026	$0.00	$0.00	$3.03	**$3.03**
2027	$0.00	$0.07	$3.10	**$3.17**
2028	$0.00	$1.80	$3.10	**$4.89**
2029	$0.00	$1.80	$3.10	**$4.89**
2030	$0.00	$6.08	$3.10	**$9.18**
2031	$0.00	$14.13	$3.10	**$17.23**
2032	$0.00	$14.13	$3.10	**$17.23**
2033	$11.62	$18.10	$3.10	**$32.81**
2034	$11.62	$18.10	$3.10	**$32.81**
2035	$11.62	$18.10	$3.10	**$32.81**
10-year levelized ($2025)	**$2.73**	**$7.88**	**$3.09**	**$13.70**

In accordance with the Order's requirement to present marginal costs at a granular level by including the substation serving area, the study team layered marginal costs from local transmission, substation, and feeder levels to the substation level. To allocate local transmission-level values, each substation within a specific transmission area was assigned the transmission-level marginal cost. Feeder-level avoided costs were rolled up to the substation level by weighting each feeder's marginal cost by its peak load, accounting for differences in feeder size.

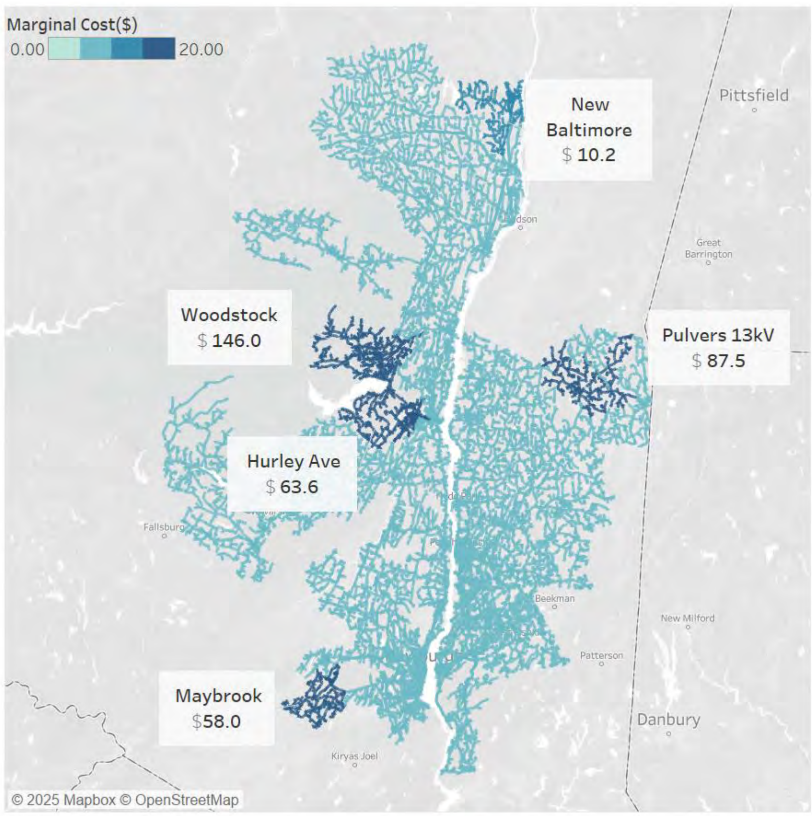
Table 3: 10-Year Levelized Marginal Cost at Substation Level

Local Transmission	Substation	Local Transmission	Substation	Feeder	Total Marginal Costs
Ellenville	Clinton Ave	$2.73	$3.37	$3.04	$9.14
Ellenville	Galeville	$2.73	$3.37	$3.06	$9.16
Ellenville	Greenfield Rd	$2.73	$3.37	$3.27	$9.37
Ellenville	Grimley Rd X1	$2.73	$3.37	$3.03	$9.13
Ellenville	Grimley Rd X2	$2.73	$3.37	$1.77	$7.86
Ellenville	High Falls	$2.73	$3.37	$3.07	$9.17
Ellenville	Honk Falls	$2.73	$3.37	$3.03	$9.13
Ellenville	Kerhonkson	$2.73	$3.37	$3.10	$9.20
Ellenville	Neversink	$2.73	$3.37	$3.05	$9.15
Hurley-Milan	East Kingston	$2.73	$3.37	$3.03	$9.13
Hurley-Milan	Lincoln Park	$2.73	$3.37	$3.10	$9.20
Hurley-Milan	Rhinebeck	$2.73	$3.37	$3.22	$9.32
Mid-Dutchess	Knapps Corners	$2.73	$3.37	$3.23	$9.33
Mid-Dutchess	Manchester	$2.73	$3.37	$3.03	$9.13
Mid-Dutchess	Sand Dock-Distribution	$2.73	$3.37	$3.03	$9.13
Mid-Dutchess	Sand Dock-Industrial	$2.73	$3.37	$3.03	$9.13
Mid-Dutchess	Spackenkill	$2.73	$3.37	$3.03	$9.13
Northwest 115/69	North Catskill	$0.00	$3.37	$3.12	$6.49

Local Transmission	Substation	Local Transmission	Substation	Feeder	Total Marginal Costs
Northwest 115/69	Woodstock	$0.00	$142.90	$3.09	$145.99
Northwest 69	Saugerties	$2.73	$3.37	$3.14	$9.24
Pleasant Valley 69	Ancram	$2.73	$3.37	$3.03	$9.13
Pleasant Valley 69	East Park	$2.73	$3.37	$3.03	$9.13
Pleasant Valley 69	Hibernia	$2.73	$3.37	$3.11	$9.21
Pleasant Valley 69	Millerton	$2.73	$3.37	$3.03	$9.13
Pleasant Valley 69	Pulvers 13kV	$2.73	$81.54	$3.28	$87.55
Pleasant Valley 69	Pulvers 34kV	$2.73	$3.37	$3.03	$9.13
Pleasant Valley 69	Smithfield	$2.73	$3.37	$3.03	$9.13
Pleasant Valley 69	Staatsburg	$2.73	$3.37	$3.04	$9.14
Pleasant Valley 69	Stanfordville	$2.73	$3.37	$3.54	$9.64
Pleasant Valley 69	Tinkertown	$2.73	$3.37	$3.05	$9.15
RD-RJ Lines	Bethlehem Rd	$0.00	$3.37	$3.25	$6.62
RD-RJ Lines	Union Ave	$0.00	$3.37	$3.23	$6.60
Southern Dutchess	Forgebrook	$2.73	$3.37	$3.55	$9.65
Southern Dutchess	Merritt Park	$2.73	$3.37	$3.20	$9.30
Southern Dutchess	Shenandoah-Distribution	$2.73	$3.37	$3.03	$9.13
Southern Dutchess	Tioronda	$2.73	$3.37	$3.15	$9.25
Southern Dutchess	Wiccopee	$2.73	$3.37	$8.66	$14.76
Stand Alone	Boulevard	$2.73	$3.37	$3.08	$9.18
Stand Alone	Coldenham	$2.73	$3.37	$3.06	$9.16
Stand Alone	East Walden	$2.73	$3.37	$3.03	$9.13
Stand Alone	Fishkill Plains	$2.73	$3.37	$3.03	$9.13
Stand Alone	Highland	$2.73	$3.37	$3.06	$9.15
Stand Alone	Hurley Ave	$2.73	$57.70	$3.17	$63.60
Stand Alone	Inwood Ave	$2.73	$3.37	$3.11	$9.21
Stand Alone	Marlboro	$2.73	$3.37	$3.10	$9.20
Stand Alone	Milan	$2.73	$3.37	$3.04	$9.14
Stand Alone	Modena	$2.73	$3.37	$3.41	$9.51
Stand Alone	Myers	$2.73	$3.37	$3.04	$9.14
Stand Alone	North Chelsea	$2.73	$3.37	$3.30	$9.40
Stand Alone	Ohioville	$2.73	$3.37	$3.05	$9.15
Stand Alone	Reynolds Hill	$2.73	$3.37	$3.09	$9.19
Stand Alone	Sturgeon Pool	$2.73	$3.37	$3.03	$9.13
Stand Alone	Todd Hill	$2.73	$3.37	$3.38	$9.48
Stand Alone	West Balmville	$2.73	$3.37	$3.11	$9.21
WM Line	Maybrook	$2.73	$52.25	$3.06	$58.03
WM Line	Montgomery	$2.73	$3.37	$3.19	$9.29
Westerlo Loop	Coxsackie	$2.73	$3.37	$3.16	$9.25
Westerlo Loop	Freehold	$2.73	$3.37	$3.21	$9.31
Westerlo Loop	Hunter	$2.73	$3.37	$3.03	$9.13
Westerlo Loop	Lawrenceville	$2.73	$3.37	$3.03	$9.13
Westerlo Loop	New Baltimore	$2.73	$4.32	$3.17	$10.22
Westerlo Loop	South Cairo	$2.73	$3.37	$3.19	$9.29
Westerlo Loop	Vinegar Hill	$2.73	$3.37	$3.03	$9.13
Westerlo Loop	Westerlo	$2.73	$3.37	$3.04	$9.14

Figure 6 shows the map of the 10-year levelized total marginal cost at the substation level, which includes cost at all levels. The total marginal costs represent the sum of marginal costs at the local transmission, substation, and feeder levels. These locations peak at different seasons and hours, with most substation being summer-peaking, while some are winter-peaking. Darker blue indicates higher marginal costs. Several substations show strong potential for DER benefits: Woodstock, Pulver 13kV, Hurley Ave, Maybrook, and New Baltimore.

Figure 6: Map of 10-Year Levelized Marginal Cost by Substation



APPENDIX A: LOCAL TRANSMISSION DETAIL

Table 4 presents the interim marginal cost calculations for local transmission level projects in the capital plan. The table shows the cost of associated with a 1 kW increase in transmission capacity, converted into revenue requirements, and annualized over the book life of the asset. The interim marginal costs calculation does not reflect the timing of the upgrades, whether resources are at the right locations, or if resources are delivered at the right hours and right seasons.

Table 4: Local Transmission Interim Marginal Cost Calculations

				Local Transmission Location-Specific		
		Local Transmission	Local Transmission Future Unidentified Projects	Northwest 115/69	RD-RJ Lines	Avg. Cost of Increasing Local Transmission Capacity
		In Service Year	2032	2035	2035	
(1)	Number of projects considered			1	1	
	Share of Central Hudson Coincident Peak Load		20.97%	12.25%	8.39%	
	Marginal investment with general plant loading:					
(2)	Investment in growth projects net of 2.5% salvage value ($)		77,240,000	68,250,000	8,990,000	77,240,000
(3)	Investment in growth projects (kW)		296,500	166,500	130,000	296,500
(4)	Investment in growth projects ($/kW)	(2)/(3)	260.51	409.91	69.15	260.51
(5)	Typical reserve margin (%)		30.00%	30.00%	30.00%	30.00%
(6)	Investment in growth projects after reserve margin ($/kW)	(4)*[1+(5)]	338.66	532.88	89.90	338.66
(7)	Portion of the system that is affected (%)		100.00%	100.00%	100.00%	100.00%
(8)	Marginal investment ($/kW)	(6)*(7)	338.66	532.88	89.90	338.66
(9)	General plant loading (%)		16.10%	16.10%	16.10%	16.10%
(10)	Marginal investment with general plant loading ($/kW)	(8)*[1+(9)]	393.18	618.68	104.37	393.18
	Annual cost before O&M and working capital:					
(11)	Annual economic carrying charge related to capital investment (%)		13.72%	13.72%	13.72%	13.72%
(12)	A&G loading (plant-related) (%)		0.00	0.00	0.00	-
(13)	Total annual carrying charge (%)	(11)+(12)	13.72%	13.72%	13.72%	13.72%
(14)	Annual cost before O&M and working capital ($/kW-year)	(10)*(13)	53.94	84.88	14.32	53.94
	Annual O&M charge:					
(15)	O&M expenses before spreading ($/kW-year)		-	-	-	-
(16)	O&M expenses after spreading ($/kW-year)	(7)*(15)	-	-	-	-
(17)	With A&G loading (non-plant-related) ($/kW-year)	(16)*0.61%	-	-	-	-
(18)	Annual O&M charge ($/kW-year)	(16)+(17)	-	-	-	-
	Annual working capital charge:					
(19)	Material and supplies ($/kW-year)	(10)*0.96%	3.77	5.94	1.00	3.77
(20)	Prepayments ($/kW-year)	(10)*1.00%	3.93	6.19	1.04	3.93
(21)	Cash working capital allowance ($/kW-year)	(18)*14.29%	-	-	-	-
(22)	Total working capital ($/kW-year)	(19)+(20)+(21)	7.71	12.13	2.05	7.71
(23)	Annual working capital charge ($/kW-year)	(22)*8.95%	0.69	1.09	0.18	0.69
(24)	Total annual cost before losses ($/kW-year)	(14)+(18)+(23)	54.63	85.97	14.50	54.63
(25)	Loss factor		1.01	1.01	1.01	1.01
(26)	**Total annual cost ($/kW-year)**	**(24)*(25)**	**55.40**	**87.17**	**14.71**	**55.40**

Table 5 show the annualized marginal cost for each project by year. The projects do not impact revenue requirement before they are in service and, thus, are shown after they local transmission projects are projected to go into service. The 10-year levelized cost accounts for the fact that most revenue requirements associated with the projects are in the future and account for the time value of money. The study also produced two aggregate metrics: (1) average marginal cost for areas with identified local transmission projects and (2) system-wide marginal cost. The system-wide marginal cost factors in areas with no marginal costs or yet-to-be identified projects over the 10-year planning horizon and is more appropriate for use in circumstances where a single marginal cost value is utilized regardless of where on the system a resource is located.

Table 5: Local Transmission Marginal Costs by Year and Project

Year	Local Transmission System-wide (Share of Central Hudson Coincident Peak Load)	Local Transmission Location-Specific Marginal Costs: Future Unidentified Projects 20.97%	Local Transmission Location-Specific Marginal Costs: Northwest 115/69 12.25%	Local Transmission Location-Specific Marginal Costs: RD-RJ Lines 8.39%	Cost of Increasing Capacity for Typical Project Areas
2026	$ -	$ -	$ -	$ -	$ -
2027	$ -	$ -	$ -	$ -	$ -
2028	$ -	$ -	$ -	$ -	$ -
2029	$ -	$ -	$ -	$ -	$ -
2030	$ -	$ -	$ -	$ -	$ -
2031	$ -	$ -	$ -	$ -	$ -
2032	$ -	$ -	$ -	$ -	$ -
2033	$ 11.62	$ 55.40	$ -	$ -	$ 27.92
2034	$ 11.62	$ 55.40	$ -	$ -	$ 27.92
2035	$ 11.62	$ 55.40	$ -	$ -	$ 27.92
2036	$ 23.53	$ 55.40	$ 87.17	$ 14.71	$ 56.55
2037	$ 23.53	$ 55.40	$ 87.17	$ 14.71	$ 56.55
2038	$ 23.53	$ 55.40	$ 87.17	$ 14.71	$ 56.55
2039	$ 23.53	$ 55.40	$ 87.17	$ 14.71	$ 56.55
2040	$ 23.53	$ 55.40	$ 87.17	$ 14.71	$ 56.55
2041	$ 23.53	$ 55.40	$ 87.17	$ 14.71	$ 56.55
2042	$ 23.53	$ 55.40	$ 87.17	$ 14.71	$ 56.55
2043	$ 23.53	$ 55.40	$ 87.17	$ 14.71	$ 56.55
2044	$ 23.53	$ 55.40	$ 87.17	$ 14.71	$ 56.55
2045	$ 23.53	$ 55.40	$ 87.17	$ 14.71	$ 56.55
Ten-year Levelized ($2025)	**$ 2.73**	**$ 13.01**	**$ -**	**$ -**	**$ 6.56**
Twenty-year Levelized ($2025)	**$ 9.84**	**$ 27.51**	**$ 30.61**	**$ 5.16**	**$ 23.66**

APPENDIX B: SUBSTATION DETAIL

Table 6 presents the interim marginal cost calculation process at substation level.

Table 6: Substation Interim Marginal Cost Calculation

				Substation Location-Specific					Avg. Cost of Increasing Substation Capacity ($/kW-Year)
		Local Transmission		WM Line	Pleasant Valley 69	Northwest 115/69	Westerlo Loop	Stand Alone	
		Substation	Future Unidentified Projects	Maybrook	Pulvers 13kV	Woodstock	New Baltimore	Hurley Ave	
		In Service Year	2030	2027	2027	2029	2026	2032	
(1)	Number of projects considered			1	1	1	1	1	
	Share of Central Hudson Coincident Peak Load		7.35%	1.69%	0.49%	1.56%	1.50%	1.62%	
	Marginal investment with general plant loading:								
(2)	Investment in growth projects net of 2.5% salvage value ($)		29,715,500	7,388,000	2,632,500	8,190,000	292,500	11,212,500	29,715,500
(3)	Investment in growth projects (kW)		61,850	24,000	7,250	6,800	13,400	10,400	61,850
(4)	Investment in growth projects ($/kW)	(2)/(3)	480.44	307.83	480.44	1,204.41	21.83	1,078.13	480.44
(5)	Typical reserve margin (%)		30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%
(6)	Investment in growth projects after reserve margin ($/kW)	(4)*[1+(5)]	624.58	400.18	624.58	1,565.74	28.38	1,401.56	624.58
(7)	Portion of the system that is affected (%)		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
(8)	Marginal investment ($/kW)	(6)*(7)	624.58	400.18	624.58	1,565.74	28.38	1,401.56	624.58
(9)	General plant loading (%)		16.10%	16.10%	16.10%	16.10%	16.10%	16.10%	16.10%
(10)	Marginal investment with general plant loading ($/kW)	(8)*[1+(9)]	725.14	464.61	725.14	1,817.82	32.95	1,627.21	725.14
	Annual cost before O&M and working capital:								
(11)	Annual economic carrying charge related to capital investment (%)		13.33%	13.33%	13.33%	13.33%	13.33%	13.33%	13.33%
(12)	A&G loading (plant-related) (%)		1.33%	1.33%	1.33%	1.33%	1.33%	1.33%	1.33%
(13)	Total annual carrying charge (%)	(11)+(12)	14.66%	14.66%	14.66%	14.66%	14.66%	14.66%	14.66%
(14)	Annual cost before O&M and working capital ($/kW-year)	(10)*(13)	106.30	68.11	106.30	266.49	4.83	238.55	106.30
	Annual O&M charge:								
(15)	O&M expenses before spreading ($/kW-year)		-	-	-	-	-	-	-
(16)	O&M expenses after spreading ($/kW-year)	(7)*(15)	-	-	-	-	-	-	-
(17)	With A&G loading (non-plant-related) ($/kW-year)	(16)*0.61%	-	-	-	-	-	-	-
(18)	Annual O&M charge ($/kW-year)	(16)+(17)	-	-	-	-	-	-	-
	Annual working capital charge:								
(19)	Material and supplies ($/kW-year)	(10)*0.96%	6.96	4.46	6.96	17.45	0.32	15.62	6.96
(20)	Prepayments ($/kW-year)	(10)*1.00%	7.25	4.65	7.25	18.18	0.33	16.27	7.25
(21)	Cash working capital allowance ($/kW-year)	(18)*14.29%	-	-	-	-	-	-	-
(22)	Total working capital ($/kW-year)	(19)+(20)+(21)	14.21	9.11	14.21	35.63	0.65	31.89	14.21
(23)	Annual working capital charge ($/kW-year)	(22)*8.95%	1.27	0.82	1.27	3.19	0.06	2.85	1.27
(24)	Total annual cost before losses ($/kW-year)	(14)+(18)+(23)	107.58	68.93	107.58	269.68	4.89	241.40	107.58
(25)	Loss factor		1.02	1.02	1.02	1.02	1.02	1.02	1.02
(26)	**Total annual cost ($/kW-year)**	(24)*(25)	**109.51**	**70.17**	**109.51**	**274.54**	**4.98**	**245.75**	**109.51**

Table 7 shows marginal costs for each year of 10-year horizon at substation level. The values are in nominal dollars. The 10-year levelized marginal cost is $55.51/kW-year for areas with projects and $7.88/kW-year system-wide.

Table 7: Substation Marginal Costs by Year and Project

Year	Substation System-wide (Share of Central Hudson Coincident Peak Load)	Substation Future Unidentified Projects	Substation Location-Specific					Cost of Increasing Capacity for Typical Project Areas
			Maybrook	Pulvers 13kV	Woodstock	New Baltimore	Hurley Ave	
		7.35%	1.69%	0.49%	1.56%	1.50%	1.62%	
2026	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ 0.07	$ -	$ -	$ -	$ -	$ 4.98	$ -	$ 0.52
2028	$ 1.80	$ -	$ 70.17	$ 109.51	$ -	$ 4.98	$ -	$ 12.65
2029	$ 1.80	$ -	$ 70.17	$ 109.51	$ -	$ 4.98	$ -	$ 12.65
2030	$ 6.08	$ -	$ 70.17	$ 109.51	$ 274.54	$ 4.98	$ -	$ 42.84
2031	$ 14.13	$ 109.51	$ 70.17	$ 109.51	$ 274.54	$ 4.98	$ -	$ 99.50
2032	$ 14.13	$ 109.51	$ 70.17	$ 109.51	$ 274.54	$ 4.98	$ -	$ 99.50
2033	$ 18.10	$ 109.51	$ 70.17	$ 109.51	$ 274.54	$ 4.98	$ 245.75	$ 127.47
2034	$ 18.10	$ 109.51	$ 70.17	$ 109.51	$ 274.54	$ 4.98	$ 245.75	$ 127.47
2035	$ 18.10	$ 109.51	$ 70.17	$ 109.51	$ 274.54	$ 4.98	$ 245.75	$ 127.47
2036	$ 18.10	$ 109.51	$ 70.17	$ 109.51	$ 274.54	$ 4.98	$ 245.75	$ 127.47
2037	$ 18.10	$ 109.51	$ 70.17	$ 109.51	$ 274.54	$ 4.98	$ 245.75	$ 127.47
2038	$ 18.10	$ 109.51	$ 70.17	$ 109.51	$ 274.54	$ 4.98	$ 245.75	$ 127.47
2039	$ 18.10	$ 109.51	$ 70.17	$ 109.51	$ 274.54	$ 4.98	$ 245.75	$ 127.47
2040	$ 18.10	$ 109.51	$ 70.17	$ 109.51	$ 274.54	$ 4.98	$ 245.75	$ 127.47
2041	$ 18.10	$ 109.51	$ 70.17	$ 109.51	$ 274.54	$ 4.98	$ 245.75	$ 127.47
2042	$ 18.10	$ 109.51	$ 70.17	$ 109.51	$ 274.54	$ 4.98	$ 245.75	$ 127.47
2043	$ 18.10	$ 109.51	$ 70.17	$ 109.51	$ 274.54	$ 4.98	$ 245.75	$ 127.47
2044	$ 18.10	$ 109.51	$ 70.17	$ 109.51	$ 274.54	$ 4.98	$ 245.75	$ 127.47
2045	$ 18.10	$ 109.51	$ 70.17	$ 109.51	$ 274.54	$ 4.98	$ 245.75	$ 127.47
Ten-year Levelized ($2025)	**$ 7.88**	**$ 45.88**	**$ 52.25**	**$ 81.54**	**$ 142.90**	**$ 4.32**	**$ 57.70**	**$ 55.51**
Twenty-year Levelized ($2025)	**$ 11.38**	**$ 67.65**	**$ 58.38**	**$ 91.11**	**$ 187.93**	**$ 4.54**	**$ 122.04**	**$ 80.13**

APPENDIX C: DISTRIBUTION FEEDER DETAIL

Table 8 presents the interim marginal cost calculation process at feeder level.

Table 8: Distribution Feeder Interim Marginal Cost Calculation

				Feeder Location-Specific	Avg. Cost of Increasing Feeder Capacity
		Local Transmission Substation		Southern Dutchess Wiccopee	
		Feeder	Feeder Future Unidentified Projects	WI_8031	
		In Service Year	2025	2026	
(1)	Number of projects considered			1	
	Share of Central Hudson Coincident Peak Load		24.14%	0.38%	
	Marginal investment with general plant loading:				
(2)	Investment in growth projects net of 2.5% salvage value ($)		725,400	750,000	1,475,400
(3)	Investment in growth projects (kW)		16,459	13,000	29,459
(4)	Investment in growth projects ($/kW)	(2)/(3)	44.07	57.69	50.08
(5)	Typical reserve margin (%)		30.00%	30.00%	30.00%
(6)	Investment in growth projects after reserve margin ($/kW)	(4)*[1+(5)]	57.30	75.00	65.11
(7)	Portion of the system that is affected (%)		100.00%	100.00%	100.00%
(8)	Marginal investment ($/kW)	(6)*(7)	57.30	75.00	65.11
(9)	General plant loading (%)		16.10%	16.10%	16.10%
(10)	Marginal investment with general plant loading ($/kW)	(8)*[1+(9)]	66.52	87.08	75.59
	Annual cost before O&M and working capital:				
(11)	Annual economic carrying charge related to capital investment (%)		17.83%	17.83%	17.83%
(12)	A&G loading (plant-related) (%)		0.00	0.00	-
(13)	Total annual carrying charge (%)	(11)+(12)	17.83%	17.83%	17.83%
(14)	Annual cost before O&M and working capital ($/kW-year)	(10)*(13)	11.86	15.53	13.48
	Annual O&M charge:				
(15)	O&M expenses before spreading ($/kW-year)		-	-	-
(16)	O&M expenses after spreading ($/kW-year)	(7)*(15)	-	-	-
(17)	With A&G loading (non-plant-related) ($/kW-year)	(16)*0.61%	-	-	-
(18)	Annual O&M charge ($/kW-year)	(16)+(17)	-	-	-
	Annual working capital charge:				
(19)	Material and supplies ($/kW-year)	(10)*0.96%	0.64	0.84	0.73
(20)	Prepayments ($/kW-year)	(10)*1.00%	0.67	0.87	0.76
(21)	Cash working capital allowance ($/kW-year)	(18)*14.29%	-	-	-
(22)	Total working capital ($/kW-year)	(19)+(20)+(21)	1.30	1.71	1.48
(23)	Annual working capital charge ($/kW-year)	(22)*8.95%	0.12	0.15	0.13
(24)	Total annual cost before losses ($/kW-year)	(14)+(18)+(23)	11.98	15.68	13.61
(25)	Loss factor		1.05	1.05	1.05
(26)	**Total annual cost ($/kW-year)**	**(24)*(25)**	**12.57**	**16.45**	**14.28**

Table 9 shows marginal costs for each year of 10-year horizon at distribution feeder level.

Table 9: Distribution Feeder Marginal Cost by Year and Project

Year	Feeder System-wide	Feeder Future Unidentified Projects	Feeder Location-Specific	Cost of Increasing Capacity for Typical Project Areas
			WI_8031	
	(Share of Central Hudson Coincident Peak Load)	24.14%	0.38%	
2026	$ 3.03	$ 12.57	$ -	$ 12.37
2027	$ 3.10	$ 12.57	$ 16.45	$ 12.63
2028	$ 3.10	$ 12.57	$ 16.45	$ 12.63
2029	$ 3.10	$ 12.57	$ 16.45	$ 12.63
2030	$ 3.10	$ 12.57	$ 16.45	$ 12.63
2031	$ 3.10	$ 12.57	$ 16.45	$ 12.63
2032	$ 3.10	$ 12.57	$ 16.45	$ 12.63
2033	$ 3.10	$ 12.57	$ 16.45	$ 12.63
2034	$ 3.10	$ 12.57	$ 16.45	$ 12.63
2035	$ 3.10	$ 12.57	$ 16.45	$ 12.63
2036	$ 3.10	$ 12.57	$ 16.45	$ 12.63
2037	$ 3.10	$ 12.57	$ 16.45	$ 12.63
2038	$ 3.10	$ 12.57	$ 16.45	$ 12.63
2039	$ 3.10	$ 12.57	$ 16.45	$ 12.63
2040	$ 3.10	$ 12.57	$ 16.45	$ 12.63
2041	$ 3.10	$ 12.57	$ 16.45	$ 12.63
2042	$ 3.10	$ 12.57	$ 16.45	$ 12.63
2043	$ 3.10	$ 12.57	$ 16.45	$ 12.63
2044	$ 3.10	$ 12.57	$ 16.45	$ 12.63
2045	$ 3.10	$ 12.57	$ 16.45	$ 12.63
Ten-year Levelized ($2025)	**$ 3.09**	**$ 12.57**	**$ 14.28**	**$ 12.60**
Twenty-year Levelized ($2025)	**$ 3.09**	**$ 12.57**	**$ 15.03**	**$ 12.61**

REPORT

2025 Central Hudson
Advanced Metering Infrastructure Benefit Cost Analysis

Prepared for Central Hudson
By Demand Side Analytics, LLC
June 2025

ACKNOWLEDGEMENTS

Principal Consultants

- Alana Lemarchand
- Josh Bode

Quantitative Analyst

- Estefania Suarez

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1 EXECUTIVE SUMMARY

Central Hudson Gas & Electric (hereafter referred to as Central Hudson) has investigated the benefits and costs of implementing an Advanced Metering Infrastructure (AMI), in accordance with the *Order Establishing the Benefit Cost Analysis Framework.*[1]

AMI was considered as a possible tool for supporting the Reforming the Energy Vision (REV) goals to empower customers through new tools and information and to effectively manage and reduce usage. The AMI deployment was evaluated through a benefit-cost analysis (BCA) framework considering the societal, utility, and ratepayer perspectives. Central Hudson will be developing an implementation plan for AMI deployment based on the BCA result indicating that AMI would be cost effective for Central Hudson customers from the societal perspective.

Central Hudson initially assessed the cost effectiveness of deploying AMI in 2016. However, the analysis from three perspectives, societal, utility, and ratepayer, and of two deployment scenarios—full and partial deployment, showed that AMI was cost-ineffective under all perspectives and scenarios investigated in 2016. Following Public Service Commission (PSC or Commission) requirements, Central Hudson transitioned its meter reading frequency from primarily bi-monthly to monthly, recognizing the enhanced customer value. Given this recent shift, the company issued a formal RFP to gather updated cost assumptions from vendors and conducted a detailed internal review of cost and avoided cost assumptions.[2] The Company developed the updated BCA for widespread AMI deployment, supported by this updated cost and avoided cost assumptions.

1.1 RESULTS

This analysis assessed a scenario for full deployment of AMI in Central Hudson's territory. Central Hudson aims to be capable of reaching all meters in the territory[3], either through radio mesh or cellular communications, including meters located in remote terrain. For purposes of the cost-effectiveness analysis the deployment was hypothetically assumed to begin in 2027, and be completed over 4 years, and be supported by a wireless mesh communication system supplemented by cellular communications.

Benefits and costs for both deployment scenarios were evaluated from the three perspectives specified in the BCA framework order:

- Societal Cost Test (SCT): Do the benefits, including externalities, exceed the costs?

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[1] CASE 14-M-0101 - 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.
[2] CASE-22-M-0645 – Order Adopting Terms of Settlement Agreement, Issued and Effective June 20, 2024.
[3] A small opt-out rate of 0.5% is expected, based on results from recent deployments

- Utility Cost Test (UCT): Is the investment or program self-funding or are additional funds needed?
- Ratepayer Impact Measure (RIM): How does the investment affect rates?

Benefits include operational utility cost savings,[4] customer fairness benefits,[5] and societal benefits.[6] Costs related to deployment of AMI include meter equipment and installation, network equipment and installation (for a wireless mesh deployment), meter data management system and other IT costs, and project management costs.

Table 1-1 summarizes the net benefits[7] and the benefit cost ratio[8] for the operational benefit cost analysis. The societal cost test for the operational benefit cost analysis shows total benefits of $182.6 million and total costs of $182.8 million, resulting in a benefit cost ratio of 1.00. The small net benefits gap is well within the uncertainty range for the analysis and benefits can be considered equal to costs. As demonstrated by these summaries, full AMI deployment is likely cost effective for Central Hudson customers from the societal perspective.

Table 1-1.Operational Benefits and Costs Summary

Benefit Cost Analysis (000s, 2025$)	Societal Cost Test	Utility Cost Test	Rate Payer Impact
Benefits	$182,560.7	$129,883.9	$137,636.2
Costs	$182,847.1	$169,448.5	$169,448.5
Net Benefits	($286.4)	($39,564.6)	($31,812.3)
B/C Ratio	**1.00**	**0.77**	**0.81**

While the AMI deployment is cost-ineffective from the utility costs test and the rate payer impact perspective, these are not the primary perspectives used in the state of New York because they don't quantify all benefits. The utility cost test has a benefit cost ratio of 0.77. The ratepayer impact test, which includes customer fairness benefits from reduced energy theft and improved meter accuracy that result in a more equitable allocation of costs across customers, has a benefit cost ratio of 0.81. This is more of a transfer between customers and comes at no incremental cost. Table 1-2 shows that time varying pricing (TVP) is cost effective from all of the test perspectives. The societal cost test for the TVP case shows net benefits of $1.9 million, since costs are assumed to be zero, indicating that there are no

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[4] Avoided meter reading costs, avoided outage management related costs, avoided field operations costs, avoided meter replacements, and avoided billing corrections
[5] Reduced energy theft and improved meter accuracy
[6] Avoided carbon emissions and avoided customer outage cost
[7] Total benefits minus total costs
[8] Total benefits divided by total costs

incremental costs due to AMI deployment and integration. The utility cost test and ratepayer test have similar results, each yielding net benefits of $1.6 million.

Table 1-2. Time-Varying Pricing Benefits and Costs Summary

Benefit Cost Analysis (000s, 2025$)	Societal Cost Test	Utility Cost Test	Rate Payer Impact
Benefits	$1,859.7	$1,566.1	$1,566.1
Costs	$0.0	$0.0	$0.0
Net Benefits	$1,859.7	$1,566.1	$1,566.1
B/C Ratio	NA	NA	NA

With AMI, Central Hudson could expand its existing TOU rate to target residential customers with the highest potential for load reduction: customers with high usage or load factors, customers with heat pumps, and customers with EVs.

Table 1-3 summarizes the net benefits and the benefit cost ratio for the operational benefit cost analysis plus AMI enabled rates and programs.

Table 1-3. Operational and Time-Varying-Pricing Benefits and Costs Summary

Benefit Cost Analysis (000s, 2025$)	Societal Cost Test	Utility Cost Test	Rate Payer Impact
Benefits	$184,420.4	$131,450.0	$139,202.3
Costs	$182,847.1	$169,448.5	$169,448.5
Net Benefits	$1,573.3	($37,998.5)	($30,246.2)
B/C Ratio	1.01	0.78	0.82

Results for the societal test show a 1.01 benefit cost ratio after benefits and costs from AMI enabled rates and programs are added to the operational benefit cost analysis. The utility cost and rate payer impact tests improve marginally by including the TVP benefits in the operational case.

1.2 WHY AMI IS NOW COST EFFECTIVE FOR CHG&E

Central Hudson initially assessed the cost effectiveness of deploying AMI in 2016. However, the analysis from three perspectives, societal, utility, and ratepayer, and of two deployment scenarios—full and partial deployment, showed that AMI was cost-ineffective under all perspectives and scenarios investigated at that time.

At that time, Central Hudson conducted meter readings on a bi-monthly basis, resulting in lower costs compared to utilities that performed monthly readings. Additionally, the approved deployment of distribution automation and management captured a substantial portion of benefits in the form of

Volt/Var Optimization (VVO) and outage location identification, limiting incremental benefits from AMI.

Several changes in key factors have improved the cost-effectiveness of AMI deployment. The reasons AMI is now cost-effective from a societal perspective are:

- Central Hudson transitioned from bi-monthly to monthly readings, which significantly reduced estimated meter readings. From March 2024, Central Hudson began conducting monthly meter readings. Variable meter reading costs roughly double from transitioning from bi-monthly to monthly readings, thus AMI can capture more benefits from meter reading savings.

- Central Hudson has deployed Distribution Automation in the past years. That deployment required investment in data concentrators and wireless radios and fiber backhaul needed to support wireless mesh communication between Distribution Automation hardware and control centers. This investment lowered the communications network investment necessary to support AMI communications, making AMI deployment more cost effective.

- The scenario studied in this analysis is full AMI deployment, aiming to reach 99.5% of all meters, compared to the 95% deployment expected to be feasible under the 2016 study. This reflects technological and cost improvements now making it possible to reach even remote meters with cell communications.

- Avoided customer outage costs, which are now included in the model, represent substantial benefits. Guidance for inclusion of this benefit was unclear in 2016, but a literature review of recent AMI business cases revealed inclusion of this benefit in multiple approved business cases.[9]

[9] Specifically, PSEG-LI, Avangrid (NY), PSEG (NJ) for which avoided customer outage costs comprised 5% to 20% of societal benefits.

2 INTRODUCTION

Central Hudson Gas & Electric (hereafter referred to as Central Hudson) has investigated the benefits and costs of implementing an Advanced Metering Infrastructure (AMI), pursuant to the *Order Adopting Distributed System Implementation Plan Guidance* and in accordance with the *Order Establishing the Benefit Cost Analysis Framework*.[10]

AMI was considered as a possible tool for supporting REV goals to empower customers through new tools and information and to effectively manage and reduce usage. The AMI deployment was evaluated through a benefit-cost analysis (BCA) framework considering the societal, utility, and ratepayer perspectives. Central Hudson will be filing a request for full AMI deployment based on the BCA indicating that AMI would be cost effective for Central Hudson customers from the societal perspective.

2.1 U.S. SMART METER OVERVIEW

According to the Energy Information Agency, by 2022 there were 119.3 million advanced meters compared to a total of 165.0 million meters, reaching a penetration rate of 72.3% in the U.S. Figure 2-1 shows that advanced meter penetration has quickly increased from 4.7% in 2007 to 72.3% in 2022.

Figure 2-1. Advanced Meter Penetration Rate in the U.S.

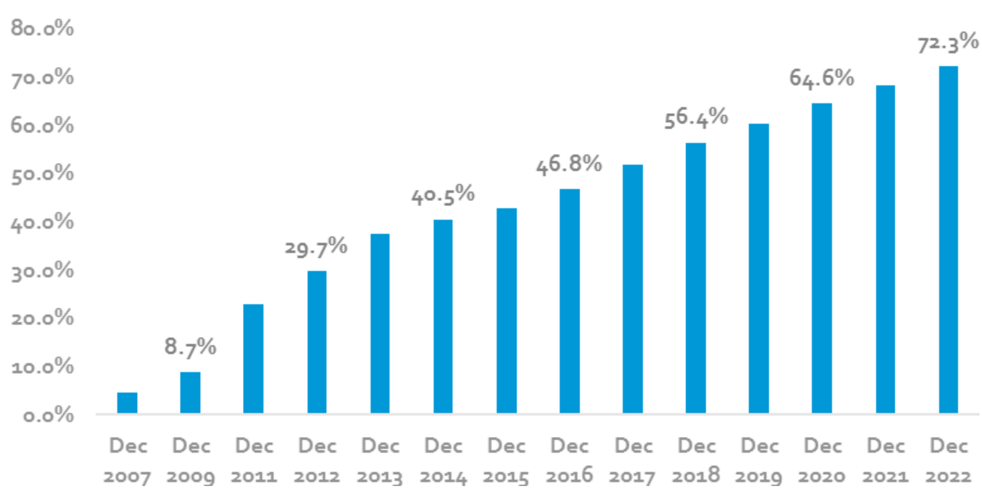
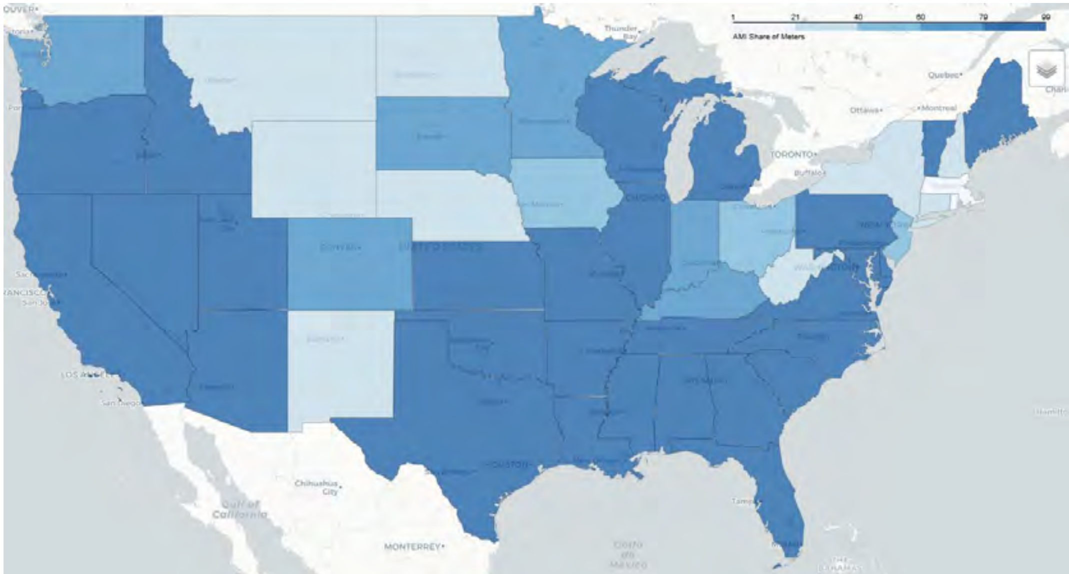


Figure 2-2 shows the AMI deployment levels across states in 2022, highlighting that AMI deployment has surpassed 80% in 29 states, 60% in another 6 states, and remains below 20% in only two states and between 20% and 40% in an addition nine states, including New York.

[10] CASE 14-M-0101 - 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.

Figure 2-2. AMI Deployment by State (2022)



2.2 AMI SYSTEM OVERVIEW (INCLUDING DEPLOYMENT)

Full-scale AMI deployment would include installation of two-way communicating meters (both electric and gas), supporting wireless mesh communications network and IT infrastructure, and software applications to process data and interact with field devices. The communications network would leverage and build upon the infrastructure already planned as part of the DA deployment. For reasons described in the following section, it would be cost-prohibitive to use the mesh network to communicate with a small portion of meters. For some of these, communication could be established using third party cellular networks; for others, no remote communication could be established without substantial additional cost.

The Meter Data Management Systems (MDMS) is assumed to be vendor hosted rather than utility hosted.

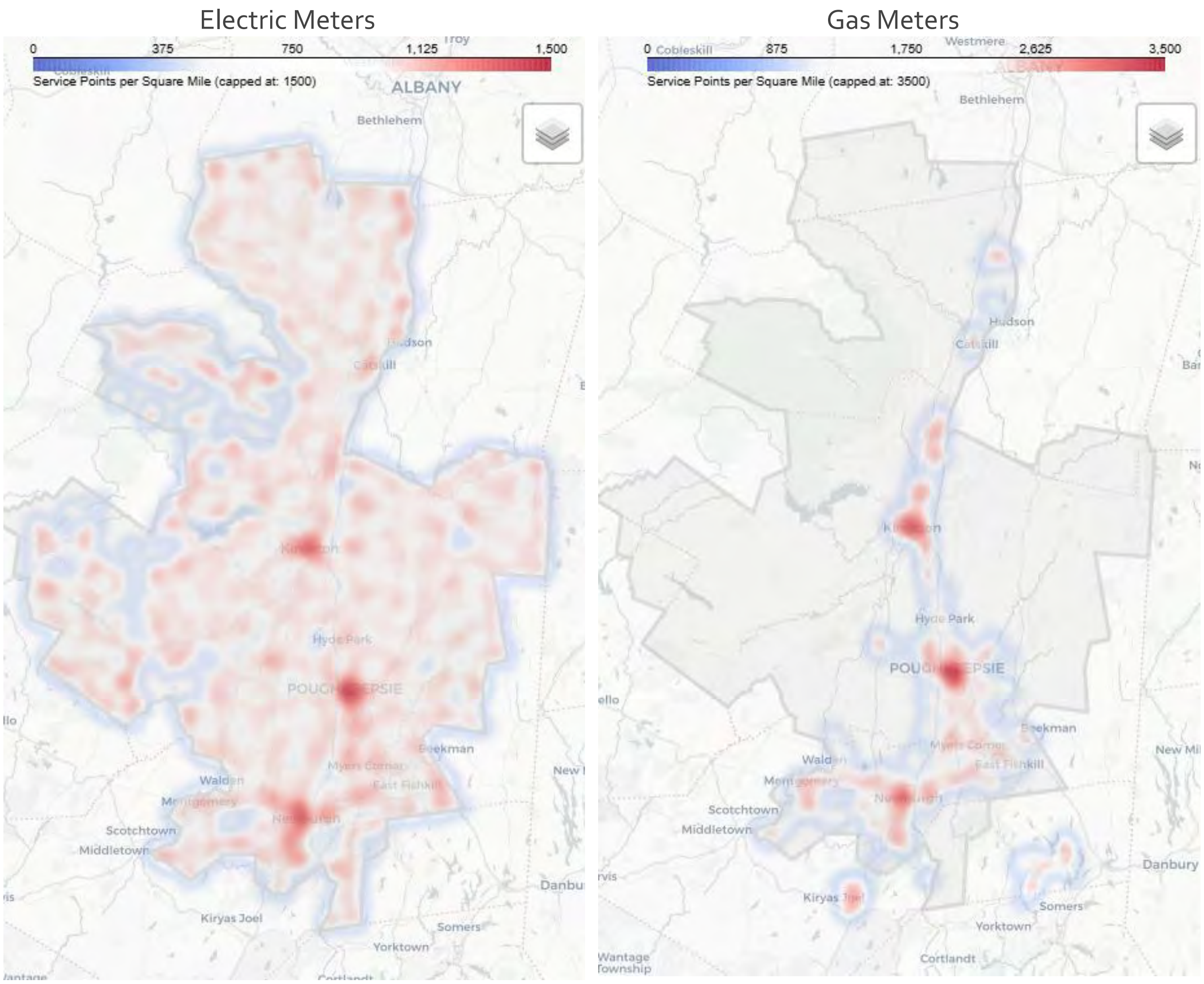
2.3 CENTRAL HUDSON CURRENT LANDSCAPE

Central Hudson serves a diverse territory with unique characteristics that influence the incremental benefits achievable, and costs incurred through AMI deployment. These include:

- Factors that reduce the potential for operational cost savings, such as reductions in meter reading costs and utility outage management costs (thereby reducing AMI benefits),
- Factors that reduce the incremental investment needed to support AMI (thereby reducing AMI costs).

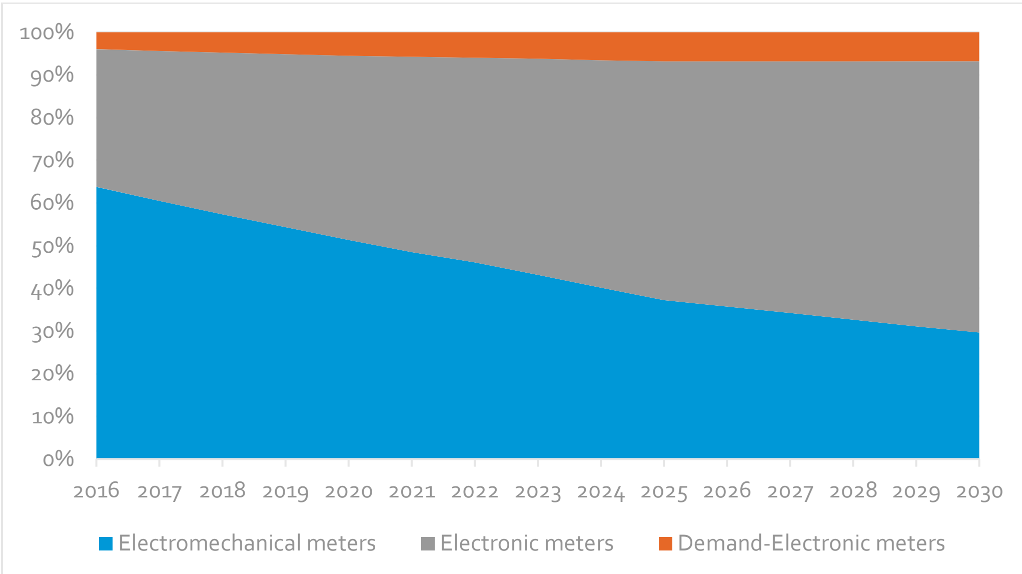
The geography of the Central Hudson territory includes some areas which are rural, remote and with mountainous terrain. Central Hudson has roughly 320 thousand electric and 89 thousand gas customer meters. The service territory covers 2,600 square miles stretching from 25 miles north of New York City to 10 miles south of Albany. The meters are dispersed throughout the territory but not evenly distributed. As seen in Figure 2-3 the concentration of electric meters varies from the large towns of Kingston, Poughkeepsie, and Newburgh where meter density ranges from about 1,125 to 1,500 meters per square mile, to more rural portions of the territory, where meter density ranges 375 meters or fewer per square mile. In contrast to the electric meter population, the gas meters are concentrated mainly on the center and southern parts of the territory and there are no meters on the east or west sides.

Figure 2-3. Central Hudson Meter Density



A primary operational benefit realized through AMI deployment is the meter reading cost savings made possible by the automated two-way communication. However, Central Hudson's pre-existing AMR deployment moderates the cost savings that could be expected through AMI relative to electromechanical meters. Figure 2-4 shows the changing meter population mix over time, demonstrating the recent pace at which Central Hudson has been replacing electromechanical meters with electronic AMR meters. Currently about 55% of meters are electronic AMR and it is expected to reach 64% by 2030, under current deployment plans.

Figure 2-4. Electric meter population in Central Hudson Territory

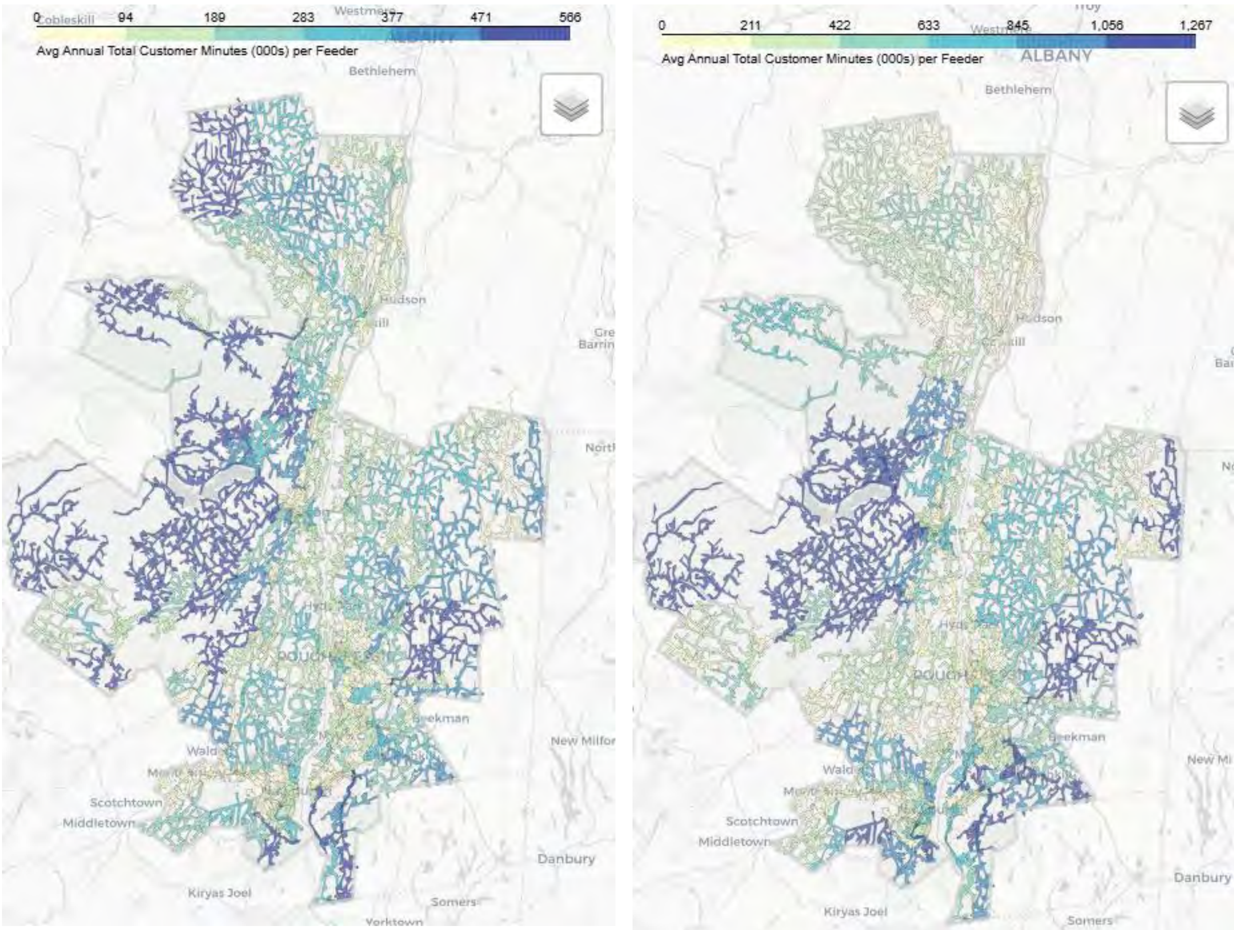


Pursuant to PSC requirements, Central Hudson agreed to implement monthly readings instead of bi-monthly. From March 2024, Central Hudson started reading most of the meters monthly, leading variable meter reading costs to roughly double. By extension, this means that the potential for reductions in variable meter reading costs is roughly double compared to what it would have been if Central Hudson maintained a bi-monthly meter reading schedule.

Another key benefit of deploying AMI is the reduction in outage-related costs for both residential and non-residential customers. As Figure 2-5 illustrates, the average annual outage duration can range from 0 to 1,267 minutes (over 20 hours) in the most affected areas during storms, and from zero to 566 minutes (more than 9 hours) for non-storm-related outages. AMI enhances outage detection and restoration capabilities, helping utilities locate issues more quickly and restore service faster, ultimately reducing both the duration of outages and the associated costs for customers.

Figure 2-5. Total customer minutes

Non-Storm Storm



2.4 REPORT STRUCTURE

The remainder of this report is organized as follows. Section 3 summarizes the BCA evaluation approach used for the operational benefit cost analysis, including defining the cost tests evaluated and enumerating and defining the benefits and costs quantified. Section 4 summarizes the benefit cost results for the full deployment scenario. Finally, section 5 summarizes the results.

3 METHODOLOGY

3.1 BCA EVALUATION APPROACH

Cost-effectiveness analysis is generally applied on a forward-looking basis to investments that typically have large upfront costs but have benefits that accrue over multiple years. It also requires a pre-specified perspective, since two different parties can view the same outcome differently. While policies and programs can lead to winners and losers, cost-effectiveness analysis focuses on the broader question of whether the overall policy is beneficial.

The BCA framework order[11] specified that benefit-cost estimates are developed based on three perspectives:

- Societal Cost Test (SCT): Do the benefits, including externalities, exceed the costs?
- Utility Cost Test (UCT): Is the investment or program self-funding or are additional funds needed?
- Ratepayer Impact Measure (RIM): How does the investment affect rates?

The societal test not only counts operational benefits to a utility, but it also includes benefits experienced by customers, reductions in resource requirements (e.g., generation capacity, energy use) and reductions in externalities such as carbon emissions. It does not treat transfers between parties as costs. On the other hand, the UCT does not include benefits experienced by customers or externalities but counts as costs things such as customer incentives, since money to fund programs and incentive payments must be collected. The RIM test focusses exclusively on rates. In some cases, resources that reduce energy consumption, such as energy efficiency and conservation voltage reduction, can lead to lower bills but higher rates, because the revenue for capital infrastructure investments is collected from fewer energy sales. Of these three perspectives, the societal test is the most important from a public policy perspective and is the primary focus in this report. When estimating the net benefits of an investment over time, the costs and benefits must be compared in present value terms since they occur at different times (with most of the costs typically incurred in the early years, while benefits often continue for many years beyond when major expenditures end). The primary focus in the following sections is the societal test. From a policy perspective, this is the most important indicator of whether or not AMI should be deployed in Central Hudson's service territory. If net benefits are positive from a societal perspective, it means that society as a whole would be better off by implementing AMI, even if some societal members might gain while others lose. However, if net benefits are negative from a

[11] CASE 14-M-0101 - Order Establishing the Benefit Cost Analysis Framework, Issued and Effective January 21, 2016

societal perspective, society as a whole would not be better off because the costs to implement AMI would outweigh the benefits derived from AMI.

All of the separate analyses summarized below are based on a common set of inputs and assumptions. Among the most important are:

- The meter and network deployment period modeled for the purposes of this benefit cost analysis consists of four years from 2027 through 2030. Meter deployment is assumed to be evenly distributed across each deployment year. This hypothetical deployment period may or may not reflect the actual deployment period which may be ultimately approved for AMI investment.

- Each AMI meter is assumed to have a 20-year life. As such, meters deployed in 2027 are assumed to produce benefits tied to meter deployment through 2047 and so on. The analysis period is 25 years and goes from 2025 through 2050, selected to fully cover the hypothetical deployment period.

- The discount rate used for present value calculations is the Weighted Average Cost of Capital (WACC) for Central Hudson. Since taxes are considered income transfers, which are excluded from the societal test, the after-tax WACC is used for the societal test (7.09%), whereas the pre-tax WACC is used for the UCT and RIM tests (8.70%). As directed by the BCA order, carbon reductions are discounted using a societal discount rate of 3%. These differences in discount rates have a very substantial impact on the net benefits and should be kept in mind when comparing the societal, UCT and RIM tests. The discount rate for 2027 was used to align with the investment start year of the hypothetical deployment period.

- All present value calculations are reported in 2025 dollars by adjusting for 2.1% annual inflation.

- The annual growth in the Central Hudson customer population is assumed to equal 0.2% for electric customers and 0.6% for gas customers.

3.2 AMI BENEFITS

The installation of AMI delivers several benefits. For this analysis the benefits were classified into four categories: operational utility cost savings, customer fairness benefits, societal benefits, and benefits from AMI enabled rates and programs.

Table 3-1 details the elements included in each benefit category and sub-category along with their applicability to each cost test evaluated.

Table 3-1. Summary of Benefit Components and Categories

Category	Subcategory	Detail	Applicability to cost tests SCT	UCT	RIM
Avoided operational costs	Avoided meter reading costs	Labor costs	X	X	X
		Vehicle costs	X	X	X
		Fuel costs	X	X	X
	Avoided outage management costs	Faster restoration time	X	X	X
		Faster location time	X	X	X
		Avoided truck rolls from false outages	X	X	X
	Avoided field operation costs	Connect/Disconnect Savings	X	X	X
		Read over savings	X	X	X
		Collection unlock savings	X	X	X
	Avoided meter replacements	Electromechanical replacements	X	X	X
		Electronic replacements	X	X	X
		Demand-Electronic replacements	X	X	X
	Avoided billing corrections	Billing corrections	X	X	X
Customer fairness benefits	Unaccounted for energy	Avoided Meter theft			X
		Improved Meter accuracy			X
	Stranded meter assets	Not included in the BCA			X
Societal benefits	Avoided carbon emissions	Avoided truck rolls from meter readings	X		
		Avoided truck rolls from restoration costs	X		
		Avoided truck rolls from outage location time	X		
		Avoided truck rolls from outages	X		
		Avoided truck rolls from field operations	X		
	Avoided customer outage costs	Avoided costs for residential and non-residential customers	X		
AMI enabled programs*	Time varying pricing	Capacity reductions	X	X	X
		Energy savings	X	X	X
		Reduced CO2 compliance cost	X		

*AMI enabled rates & programs benefits are used for sensitivity analysis and not in the core section of the BCA.

Operational savings is the largest category of benefits from AMI implementation and includes reduced meter reading costs, meter replacement costs, reductions in storm related costs due to better visibility into outage locations and re-establishment of service, reduced field service visits associated with connections and disconnections, and avoided billing corrections.

Deployment of AMI can also address fairness issues by reducing or eliminating revenue losses from various sources that are currently socialized to all customers. AMI helps direct costs to customers who are responsible for them and reduces the socialization of energy thefts, meter inaccuracies, and stranded meter assets, resulting in more equitable distribution of revenue collection. Similarly, AMI deployment has social benefits such as CO_2 reductions from avoided truck rolls and avoided outage costs for residential and non-residential customers.

AMI can also enable rates and programs that can lead to more economically efficient use of energy which, in turn, can reduce the need for new generation, transmission and distribution capacity and lower energy use and carbon emissions associated with energy production. In addition, these programs can provide customers with information to help lower their energy bills.

Finally, other benefits that can be derived from AMI deployment are Conservation Voltage Reduction (CVR) and Volt/VAR Optimization (VVO). However, Central Hudson has already claimed those benefits in the 2014 rate case from Distribution Automation, thus those benefits CVR and VVO benefits are not included in the benefit cost analysis.

3.2.1 Operational Benefits

There are five categories of operational benefits studied, which would directly result in avoided utility costs. These are avoided meter reading costs, avoided outage management costs, avoided meter replacements, and avoided field operations costs.

Avoided Meter Reading Costs

A substantial portion but not all of the meter reading costs currently incurred by Central Hudson could be avoided by deploying AMI. As alluded to in Section 2, the limitations to these operational cost savings are:

1. About half of the meter reading is subcontracted and could be entirely avoided by a full AMI deployment. However, a portion of labor hours spent by employee meter readers is spent doing other tasks; this portion of labor hours could not be avoided.
2. A small portion of customers may opt out (around 0.5% based on other utilities' experiences and Central Hudson's AMR deployment, assuming the presence of an opt-out fee) thus there is a small portion of meter reading cost that would be incurred.

Full deployment of AMI to 99.5% of the territory would lead to the avoidance of all contract labor and a portion of employee meter reading labor. Deployment of AMI to demand meters only would result in some contract labor savings thanks to the elimination of most reader routes associated with demand meters, a small portion of total routes.

Avoided Outage Management Costs

AMI systems with two-way communications can be used to "ping" a meter to see if it is connected to the system, thereby establishing the location of an outage and to confirm whether service has been restored. Benefits from this capability fall into three categories:

1. Faster restoration times for storm related outages: Outage detection capabilities can also help reduce outage duration and restoration costs during wide scale outages by detecting whether or not power has been successfully restored everywhere while crews are still in the field, thus avoiding crew re-dispatch.
2. Faster outage location time: AMI systems can be used to identify the location of the outage, reducing patrol time to identify the source of the outage. A substantial portion of this benefit will come through distribution automation, which will allow identification of the circuit experiencing the outage. AMI systems will provide an incremental benefit of helping locate the exact customer end point of the outage.
3. Avoided truck rolls due to customer side false outage reports: when a customer calls regarding an outage it can sometimes be determined whether or not the outage is on the customer's side of the meter, thus avoiding the dispatch of field crews if it is.

Avoided Field Operations Costs

Remote connect / disconnect functionality in AMI meters will significantly reduce the need to dispatch field crews to disconnect and reconnect the power when customers move or to read meters when they are transferred from one account to another (called read overs). They can also be used as a means for restoring service more quickly to customers for whom service has been disconnected for collection related reasons. While the use of remote disconnect for collection related purposes is limited in New York State by the requirements of the Home Energy Fair Practices Act (HEFPA), the only limitation to remote connect is for gas services, and this is a result of Company practice and customer safety concerns. The ability for a customer service representative to remotely restore electric service to a customer once a collection is made would benefit customers who would otherwise need to wait for a field representative to be dispatched.

Savings for account transfer related connects, disconnects, and read overs would be avoided roughly proportionately to the number of meters deployed. However, since collection related disconnections are very uncommon among the medium sized commercial customers who are typically demand metered, this cost would not be avoided by the deployment to demand meters.

Avoided Meter Replacements (electric meters)

The expected useful life of electronic meters for planning purposes is 30 years, after which the need for meter replacements due to failures or performance issues tends to increase substantially. A substantial portion of Central Hudson electromechanical meters will reach the end of this useful life during the benefit period analyzed and would be replaced either as part of the ongoing deployment of electronic meters or due to concerns about age and performance. With AMI deployment, this replacement work will no longer be necessary.

Avoided billing corrections

AMI enables automates meter readings with higher frequency and accuracy which reduces the likelihood of billing errors caused by reading or estimation mistakes. Billing corrections are time consuming and increased with monthly readings. Automated readovers and other reading improvements will reduce the amount of manual billing corrections needed.

3.2.2 CUSTOMER FAIRNESS BENEFITS

Unaccounted for energy

In addition to the operational benefits described above, deployment of AMI can also address fairness issues by reducing or eliminating revenue losses from various sources that are currently socialized to all customers. AMI helps direct costs to customers who are responsible for those costs and reduces the socialization of certain kinds of costs from particular of customers to the overall customer population.

In this analysis these fairness issues have been addressed by quantifying how socialization of costs might be reduced through implementation of AMI, and by quantifying the extent of that socialization reduction as a rate reduction impact rather than a societal benefit. Basically, customers who today have accurate meters, who pay their bills, and who pay for all the electricity they receive will see their bills go down. Because of this, these customer fairness benefits are only applied to the ratepayer impact test and do not factor into the societal cost test. Two kinds of socialized costs that AMI can address were evaluated:

- **Theft of Service**: While it is difficult to quantify, there is undoubtedly some theft of service in the Company's service territory, and the revenue that would have been collected from individuals responsible for the theft, is effectively socialized and collected from customers who pay for the service they receive. AMI provides tamper alarms and produces granular usage data at the customer level that can be analyzed for reasonableness in order to identify unusual patterns that may reflect theft of service.
- **Meter Inaccuracy**: Not all meters are 100% accurate, and some of the existing electromechanical meters in the service territory don't measure all the electricity that is delivered to customers. Typically, electromechanical meters slow down with age and meters that are 20 years old might be under-registering usage by up to 1%. Customers with these "slow" meters do not pay for all the service they receive and the revenue shortfall from these customers is socialized to the rest of the customer base. In addition to slow electro-mechanical meters, revenue losses can occur from certain types of meter failures. For example, a three-phase meter might not measure all three phases correctly and, as a result, may under-charge a customer for the service they receive. Finally, it is well-known that new electronic meters have the ability to measure lower starting loads than electromechanical meters. As a result, customers that use proportionately more electricity at lower load levels may not be charged for all the electricity they use. Again, the extent to which this under-registration of low-load demand results in the socialization of usage costs to the rest of the customer population is uncertain but with a new population of AMI meters, the accuracy and meter malfunction problems would be reduced.

In practice it is difficult to know the extent to which theft, inaccurate meters, and malfunctioning meters result in socialization of costs from small groups of customers to the broader customer population. However, these two benefits were still quantified because empirical evidence has indicated that some amount of theft does occur on all systems and that electronic meters are more accurate than electromechanical meters. To some extent, these benefits may be observed as a reduction of the system loss factor.

Stranded assets

Stranded assets benefits arise from avoided future meter replacement costs. Essentially, when an old meter that would have eventually been replaced (e.g. due to failure) is replaced with a new meter, this avoids the future expected replacement of the old meter. However, a large proportion of Central Hudson meters will be electronic by the time AMI meters were assumed to be deployed. These relatively new electronic meters are not expected to fail for several years and avoided replacement costs due to failed meters are therefore lower than they would be if the AMI meters were to replace older electromechanical meters. This was calculated but not included in the benefit cost analysis results.

3.2.3 SOCIETAL BENEFITS

The societal benefits of the project extend beyond operational savings and ratepayer equity, encompassing broader impacts not limited to the utility and its direct customers. This benefit-cost analysis incorporates two key societal benefits: (1) avoided carbon emissions and (2) customer cost savings from reduced outages.

Avoided carbon emissions

Avoided carbon emissions were estimated based on the reduction in fuel usage from fewer truck deployments. These avoided trips stem from the elimination of in-person meter readings, reduced restoration efforts, faster outage location identification, fewer false outage reports, and decreased need for field operations such as service connections / disconnections, meter read-overs, and collection unlocks.

The monetary value of the avoided emissions was estimated using a standard gasoline emission factor[12] and the real social cost of carbon[13].

Avoided outages cost

Prolonged outages have costly impacts for customers, especially non-residential customers as they affect their regular economic operations. The customer outage cost was estimated using the ICE Calculator.[14] The 10-year average of Central Hudson's System Average Interruption Frequency Index

[12] Carbon Dioxide Emissions Coefficients: https://www.eia.gov/environment/emissions/co2_vol_mass.php
[13] Social cost of carbon: https://www.whitehouse.gov/wp-content/uploads/2021/02/tsd_2021_annual_unrounded.csv
[14] Interruption Cost Calculator: https://icecalculator.com/interruption-cost

(SAIFI) and Customer Average Interruption Duration Index (CAIDI) was used to model the interruption costs for residential and small, medium, and large commercial and industrial customers. The avoided cost was calculated by comparing current outage costs to expected outage costs under a 10% CAIDI reduction scenario.

3.2.4 AMI ENABLED PROGRAMS

In addition to the operational and customer fairness benefits described above, AMI can also enable rates and programs that would produce benefits for the utility and for society. Expansion of existing time-varying rates were evaluated as a supplementary component of the quantitative benefit cost analysis.

Time varying rates

AMI also enables the expansion of existing time varying rates to additional customers. This benefit will vary depending on the strategy (default or opt-in), customer targeting (e.g. of customers with higher usage such as those with electric vehicles or electric heating sources), the ratio of peak time rates to off-peak rates, and the magnitude of avoided T&D and generation capacity costs. To quantify this benefit, the current residential opt-in rate was assumed to be targeted to additional residential customers with high usage, including customers with electric vehicles and customers with electric heating sources. The benefits of time-varying rates for targeted residential customers have been quantified but are not included in the core operational benefit cost analysis because of uncertainty regarding how these would be implemented.

3.2.5 QUALITATIVE BENEFITS

The AMI deployment can deliver additional benefits beyond those discussed above. These benefits can be substantial; however, they are difficult to measure and monetize because they are less tangible, lack sufficient data, are more uncertain, or depend on the implementation of further technologies, programs, or marketing initiatives. As a result, while these additional benefits were considered, they are discussed only qualitatively rather than quantified. Similarly, costs that are attached to benefits that were not quantified and are not indispensable in the AMI deployment were only discussed qualitatively.

A key strength of AMI deployment is that it enables the continuous collection of granular, high-precision data at short time intervals for each premise. The availability of comprehensive data contributes to numerous benefits such as improved measurement and verification initiatives, enhanced customer experience, better targeting for programs, and improved planning.

The qualitative benefits that were discussed and included in the study are operational enhancement of existing programs, new programs and rates opportunities, better planning and deferred investments, and supporting the state's electrification goals.

Enhanced customer experience

In addition to the operational benefits outlined above, an AMI deployment will enable near real-time access to accurate, granular interval consumption data. This data will provide customers with significantly more detailed insights into their energy usage, allowing them to better understand how their bills accumulate over the course of a month. With this enhanced visibility, customers will be empowered to make informed decisions, giving them greater flexibility and control in managing their energy consumption more effectively. Furthermore, AMI data can be leveraged to deliver personalized energy-saving recommendations and send high usage alerts in response to unexpected consumption patterns, helping customers take timely action to avoid bill surprises.

Operational enhancement of existing programs

The AMI deployment has the potential to improve current program operations, targeting, and evaluation efforts. AMI's granular data would enable more extensive and more precise research. This would be beneficial for measuring demand reduction impacts associated with energy efficiency efforts such as weatherization and behavioral programs. These programs are known to provide impactful and cost-effective load reductions and AMI metering would significantly increase Central Hudson's ability to more precisely determine demand reductions associated with these efforts.

Similarly, Central Hudson has the Load Research Program used to analyze granular usage patterns for a sample of customers for the development of average load shapes. AMI would improve the Load Research Program by making granular data available for all customers to more precisely assess the customers' loads which could be used to refine participant rewards in the future.

AMI data can also contribute to better customer identification and targeting. For example, AMI would be exceptionally helpful in determining the customers with high load factors, e.g. high peak demand relative to average demand, allowing Central Hudson to identify and target the customers that have the largest demand savings potential. In this regard, the Electric Load Management program (ELM), which is currently a system wide program to promote peak load reductions, could be targeted.

New program opportunities and rates

Besides improving existing program's operations, AMI can enable new program offerings and rates. Utilities that have deployed AMI have implemented programs and rates such as demand response programs including behavioral programs, rebates for charging EVs off peak hours, Time of Use Rates (TOU) and Critical Peak Pricing (CPP).

Central Hudson currently uses AMI metering to support a demand response program called Custom Savings for customers in NWA areas. Through this program, Central Hudson installs an AMI meter and sends out notifications to customers to reduce energy usage during periods of high demand. The program is cost effective, pay-for-performance, and offers ultimate flexibility to the customer in the type of loads available for curtailment. Scaling this program beyond the NWA areas would increase system-wide demand response capacity potential.

Central Hudson also currently offers an opt-in TOU rate to residential customers, though this requires individual installation of an AMI meter (supported via cellular communications), creating friction for rate enrollment. With full AMI deployment, TOU rates could be both targeted and marketed to customers adopting technologies such as heat pumps and EVs. A programmatic approach could be used to enroll customers in a TOU rate at project completion to encourage off-peak energy use. This way, the marketing of these programs and enrollment may be relatively cost-effective with opportunities to be layered on with existing program outreach, minimizing additional recruitment costs.

Additionally, Central Hudson could also refine existing Home Energy Reports or incorporate peak demand information into reports to better inform and educate customers regarding their energy usage and peak demand, performance compared to their neighbors or similar premises, and target tips for promoting energy savings and peak load reduction. Helping customers save electricity and reduce strain on the grid would positively impact their bills and potentially increase customer satisfaction.

Enabling new programs and rates can have substantial benefits, however, it will require development of future marketing strategies and supplementary analysis of the granular usage data made available by AMI.

Improved right sizing of system planning and facilitating investment deferral

AMI provides granular real-time data on energy consumption patterns at the premise level that can be used for improving forecasting accuracy and granularity which can be incorporated into mid- and long-term planning. With AMI data Central Hudson would be able to predict peak loads and overall demand more precisely. At the same time the ability to offer energy efficiency and demand response programs that incentivize customers to decrease or shift their energy consumption during peak periods can alleviate the need to expand the infrastructure to ensure capacity. Capital expenditure can be optimized, improving Central Hudson's ability to avoid or defer capital investments. Similarly, AMI will also help improve temporal-spatial visibility on the distribution system which is currently limited to substation and feeder SCADA data and other DA system components. This can in turn facilitate more precise and granular identification and deferral of growth-related investments.

Non-wires solutions such as the Electric Load Management program could be targeted to promote more efficient use of the system by reducing peak demand thereby diminishing the need of investments.

Supporting the state's electrification goals

New York has one of the most ambitious climate laws in the country, aiming to reduce greenhouse gas emissions and achieve net-zero emissions by 2050. *The 2019 Climate Leadership and Community Protection Act (Climate Act) Scoping Plan* sets energy efficiency and end-use electrification as essential pathways to achieve New York's goals. The Scope plan estimates that 1 to 2 million efficient homes electrified with heat pumps and 3 million zero-emission vehicles will be needed by 2030[15].

Central Hudson would be supporting New York state's goals with AMI deployment, as advanced metering can be used to support the integration of beneficial electrification, such as EVs or heat pumps, by monitoring charging and usage patterns for these technologies to learn and anticipate how increased adoption of electric devices might affect peak and non-peak demand in the future. With widespread adoption of heat pumps, winter peak demand may rise significantly, potentially shifting some substations, and eventually the entire system, to winter peaking. AMI data would allow for the design of programs and rates that promote peak load shifting for the winter, similar to current summer programs.

3.3 AMI COSTS

This section discusses the costs of deploying AMI across the Central Hudson service territory. This discussion is organized into two sub-sections: AMI deployment costs and costs associated with AMI enabled rates and programs. Table 3-2 summarizes the components included in each cost category and sub-category along with their applicability to each cost test evaluated. The rest of this section describes each component, and the Itemized breakdowns of cost assumptions for each component can be found in the appendix.

Note that stranded meter assets were not included as a cost in Central Hudson's analysis, consistent with past Commission decisions. However, as Central Hudson prudently incurred expenditures for its existing meter infrastructure, the Company anticipates that it will recover the cost of the stranded meter assets.

Table 3-2. Summary of Cost Categories and Components

Category	Subcategory	Detail	Applicability to cost tests		
			SCT	UCT	RIM
AMI Deployment Costs	Meter equipment, installation costs	Mesh meters	X	X	X
		Cell meters	X	X	X
		Gas modules	X	X	X
	Network equipment, installation costs	Radio retrofit of existing concentrators	X	X	X
		Incremental concentrators w/radio	X	X	X
	Meter data management system	MDMS Hardware and Software	X	X	X
		One time IT costs (Billing system & integration)	X	X	X

[15] New York State Climate Action Council. 2022. "New York State Climate Action Council Scoping Plan." climate.ny.gov/ScopingPlan

Category	Subcategory	Detail	Applicability to cost tests		
			SCT	UCT	RIM
Operations and maintenance	Meter related maintenance	Meter maintenance	X	X	X
	Network related maintenance	Network maintenance	X	X	X
	Communications and other IT costs	Cell meter communication	X	X	X
		Meter data management	X	X	X
		MDMS Hardware and Software	X	X	X
		IT O&M Costs	X	X	X
	Unavoidable meter reading labor	Central Hudson Labor (meter shop)	X	X	X
	Project management	PMO	X	X	X
AMI enabled rates & programs*	Time-varying pricing	Variable costs	X	X	X
		Program & IT costs	X	X	X
		Lost revenue			X

*AMI enabled rates & programs costs are used for sensitivity analysis and not in the core section of the BCA.

3.3.1 AMI DEPLOYMENT COSTS

Costs related to deployment of AMI have been grouped into three categories for this analysis: meter equipment and installation, network equipment and installation (for a wireless mesh deployment), and meter data management system.

Meter Equipment, Installation Costs

Meter equipment costs include the capital cost of meters themselves as well as the various ancillary materials needed for some installations, such as panel repairs, and adapters for older panels. Cost assumptions for the meters themselves were differentiated electric versus gas, and simple versus complex and were informed by vendor RFP responses. Installation labor also includes the incremental labor necessary for these ancillary materials a fraction of the time, as well as time for testing the meters and time for processing each meter in the IT system.

Network Equipment, Installation Costs

Network costs only apply to the deployment of AMI to all meters across Central Hudson territory reachable by remote communication. These costs would essentially consist of several components to support communication with AMI meters. The first is wireless radios, which send and receive communications to and from meters in vicinity. The second is data concentrators, which are usually collocated with wireless radios acting as the hub to aggregate data from multiple smart meters and ultimately relaying that information over a backhaul network to the utility company's systems. Based on RFP vendor responses, initial propagation studies were completed specific to Central Hudson's service territory allowing to sufficiently design and reinforce the wireless mesh network. Additionally, existing fiber backhaul that has been deployed as part of Central Hudson's distribution automation deployment was planned to be utilized where available to help moderate cost and will supplement with cellular backhaul where fiber is unavailable.

Meter Data Management System and other IT Costs

The volumes of data collected from AMI meters is managed via a meter data management (MDM) system, which is connected through a meter data head end system that is in turn integrated with the utility's other systems. The MDM and head end system was assumed to be hosted and managed by a technology vendor and costs were based on RFP vendor responses. The vendor hosted system cost includes an initial setup cost.

In addition to the MDM and head end systems, an AMI deployment would require additional IT costs. Specifically, Central Hudson would need to integrate the MDMS with its billing system and integrate the head end with other internal systems such as the outage management system (OMS) and the customer information system (CIS). These costs include an upfront investment as well as an ongoing cost. These costs also include a budget allocation for a permanent position at Central Hudson for managing meter data.

3.3.2 OPERATIONS AND MAINTENANCE

Meter and Network, Operations and Maintenance

The MDM and IT costs described above have associated recurring operations and maintenance costs described in detail in the appendix under the IT cost section. There are also ongoing costs associated with maintaining the AMI meters and communications. Meter maintenance costs were analyzed using typical equipment warranties and failure rates for meters as well as cellular battery replacements. Other meter related operations and maintenance costs included a recurring annual cost for managing meter data as well as the annual cost to support communications for cellular meters. This latter cost would apply to the roughly 5% of meters that would be too remote to connect practically to the wireless mesh network but could still be reached through a cellular network.

Project management

Central Hudson would need the support of incremental staff resources during the AMI implementation period. These resources range from various engineering positions, communications and network experts, meter testers, project management, and customer service representatives to handle incoming calls and questions. These resources would be needed for roughly the duration of the deployment. The need for internal resources would be in addition to vendor services which would include network integration with wireless mesh and meter integration support.

Unavoidable meter reading labor

As noted above, some meter readers perform other duties beyond meter reading, so the labor hours associated with those tasks would not be eliminated. In addition, about 0.5% of customers are expected to opt out of AMI, meaning a residual amount of manual meter reading costs will remain.

3.3.3 COSTS FOR AMI ENABLED RATES AND PROGRAMS

AMI would enable rates and programs that could deliver substantial benefits, but these incremental benefits would come at a cost.

Time-varying pricing

Support for time varying rates could necessitate IT hardware, software license, and setup costs including interfaces between a new rate engine and various IT systems (e.g. CIS). Recurring costs would include license maintenance and cyber security testing. However, Central Hudson has determined that these costs are not incremental to AMI deployment and are rather part of their regular business case.

4 BENEFIT COST ANALYSIS

4.1 BENEFIT COST ANALYSIS RESULTS

This chapter lays out the cost benefit analysis results, both for the operational business case and then with AMI enabled rates and programs. Also included is a supplementary analysis detailing the sensitivity of results to each assumption. Detailed assumptions can be found in the appendix.

A full AMI deployment would mean installing AMI to support the electric and gas meters in Central Hudson territory that could be practically accessed via wireless mesh or cellular communications. The analysis full deployment has the following assumptions:

- The meter population at the beginning of 2025 was as follows:
  - ✓ Electromechanical: 119,452
  - ✓ Electronic: 178,842
  - ✓ Demand metered electronic: 21,830
  - ✓ Gas meters: 89,824
- The meter population is assumed to grow at 0.2% annually for electric customers and 0.6% for gas customers.
- The AMI deployment period modeled for the purposes of this business case consists of four years from 2027 through 2030. This hypothetical deployment period may or may not reflect the actual deployment period which may be ultimately approved for AMI investment.
- The conversion of electromechanical meters to electronic meters will continue until deployment begins at its current pace.
- The achievable AMI deployment rate for all meter types is 100%, meaning that wireless communication (cellular or wireless mesh) is expected to be established for all meters, even those in remote locations their remote locations.
- About 0.5% of customers are expected to opt-out of the AMI, assuming they will face an opt-out fee to avoid socializing the cost of opting out.
- Costs and benefit assumptions are given in 2025 dollars and assumed to inflate at a rate of 2.10% per year for both labor and non-labor values.
- The analysis period for determining value is the 25-year period from 2025 through 2050, selected to fully cover the hypothetical deployment period.

- To determine net present value over the analysis period, discount rates were used in accordance with Appendix A, Table A-1 of the BCA Handbook, which has been filed as an appendix to the DSIP. A discount rate of 7.09% (Central Hudson's post-tax WACC) was used for the societal cost test and a rate of 8.70% (Central Hudson's pre-tax WACC) was used for the utility cost and ratepayer impact test. For all tests, carbon was discounted at a rate of 3.00% annually. The discount rate for 2027 was used to align with the investment start year of the hypothetical deployment period.

Table 4-1 summarizes the net benefits and the benefit cost ratio for the operational business case. Note that the operational business case includes operational, customer fairness, and societal benefits but excludes AMI enabled rates.

Table 4-1. Benefits and Costs Summary

Benefit Cost Analysis (000s, 2025$)	Societal Cost Test	Utility Cost Test	Rate Payer Impact
Benefits	$182,560.7	$129,883.9	$137,636.2
Costs	$182,847.1	$169,448.5	$169,448.5
Net Benefits	($286.4)	($39,564.6)	($31,812.3)
B/C Ratio	**1.00**	**0.77**	**0.81**

The societal cost test for the operational business case shows total benefits of $182.6 million and total costs of $182.8 million, resulting in negligible net benefits gap and a benefit cost ratio of 1.00. As demonstrated by these summaries, full AMI deployment would essentially be cost effective for Central Hudson customers from the societal perspective.

AMI deployment is cost-ineffective from the utility costs test and the rate payer impact perspective. The utility cost test has a benefit cost ratio of 0.77. The ratepayer impact test, which includes customer fairness benefits from reduced energy theft and improved meter accuracy that result in a more equitable allocation of costs across customers, has a benefit cost ratio of 0.81. This is more of a transfer between customers and comes at no incremental cost. Therefore, the ratepayer benefits are $137.6 million, and the costs are $169.4 million, with a net benefit gap of $31.8 million.

Figure 4-1 shows the detailed breakdown of cost and benefit categories for the societal cost test for the operational business case. The right panel shows the breakdown of costs. The one-time and maintenance IT costs include MDM and head end costs along with other IT costs. The largest cost category is meter equipment and installation at about $92.7 million, or about half of the total cost. This is followed by ongoing IT maintenance costs, which contributes $39.0 million in costs.

The panel on the left shows the breakdown of the four operational benefit categories. The largest benefit category is avoided meter reading costs, at $73.0 million followed by avoided outage restoration costs at $33.1 million. Avoided meter replacements, avoided connect/disconnect (field operations), and avoided customer outage costs each contribute a similar magnitude of benefits, between $20 million and $28 million. However, avoided customer outage costs are included in the societal cost test but not in the utility or ratepayer impact tests. By comparison, all other avoided costs are an order of magnitude smaller.

Figure 4-1. Operational Benefit Cost Analysis Societal Benefit and Cost Details

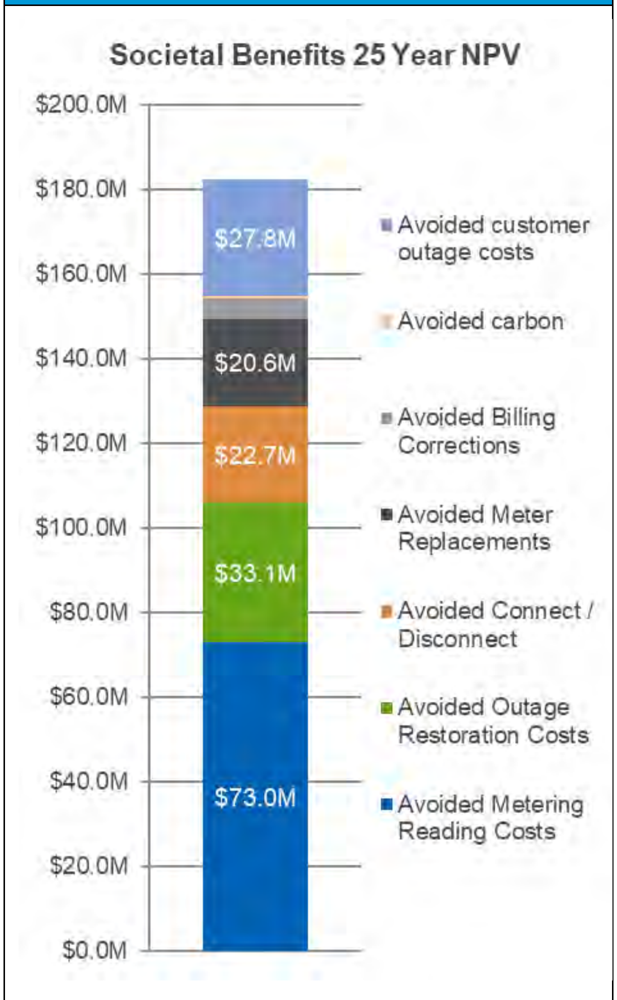
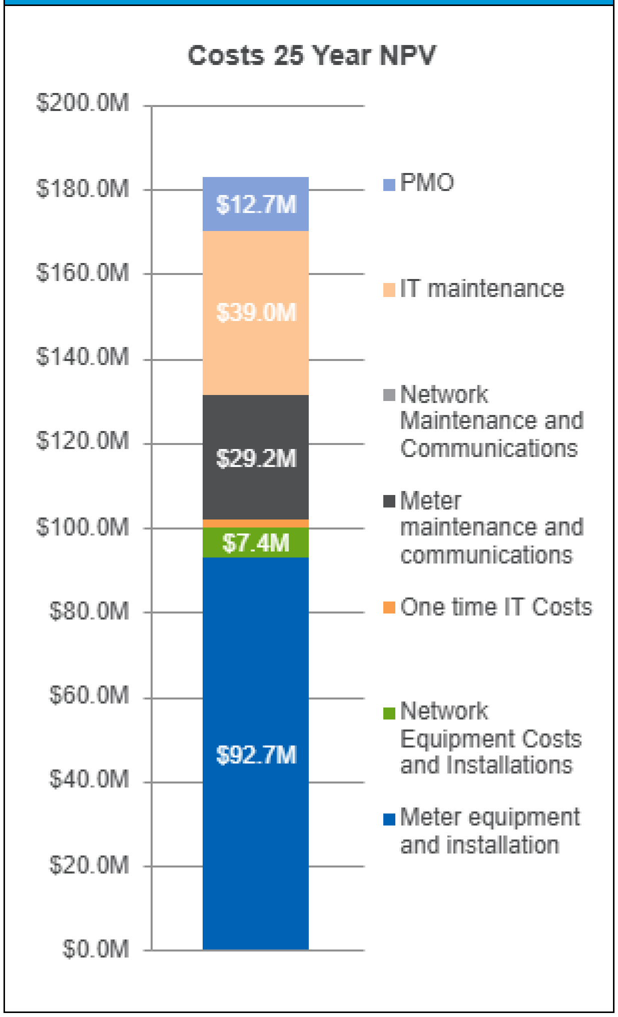
25-year NPV Benefits (2025$)	25-year NPV Costs (2025$)
	

Table 4-2. Benefits and Table 4-2 shows the benefits and costs details with their corresponding 25-year net present value.

Table 4-2. Benefits and Cost Details

Category	Subcategory	Detail	Benefit/Cost Test			25-year NPV (2025 $000)	
			SCT	UCT	RIM	25 Year NPV Post-Tax Discount Rate	25 Year NPV Pre-Tax Discount Rate
Benefits							
Avoided operational costs	Avoided meter reading costs	Labor costs	X	X	X	$50,122.8	$59,684.7
		Vehicle costs	X	X	X	$10,315.5	$12,131.7
		Fuel costs	X	X	X	$1,018.5	$1,198.1
	Avoided outage management costs	Faster restoration time	X	X	X	$2,238.4	$2,624.0
		Faster location time	X	X	X	$2,782.6	$3,284.5
		Avoided truck rolls from false reports	X	X	X	$22,982.9	$27,207.3
	Avoided field operation costs	Connect/Disconnect Savings	X	X	X	$16,162.4	$19,398.9
		Read over savings	X	X	X	$1,321.6	$1,592.5
		Collection unlock savings	X	X	X	$1,424.3	$1,716.3
	Avoided meter replacements	Electromechanical replacements	X	X	X	$0.0	$0.0
		Electronic replacements	X	X	X	$16,338.1	$19,565.3
		Demand-Electronic replacements	X	X	X	$858.1	$1,083.5
	Avoided billing corrections	Billing corrections	X	X	X	$4,024.3	$4,778.8
Customer fairness benefits	Unaccounted for energy	Avoided Meter theft			X	$4,886.3	$5,690.7
		Improved Meter accuracy			X	$2,866.1	$3,337.9
	Stranded meter assets	Not included in BCA			X	$20,948.4	$34,208.3
Societal benefits	Avoided carbon	Avoided truck rolls from meter readings	X			$337.4	$337.4
		Avoided truck rolls from restoration costs	X			$0.3	$0.3
		Avoided truck rolls from outage location time	X			$3.2	$3.2
		Avoided truck rolls from outages	X			$68.9	$68.9
		Avoided truck rolls from field operations	X			$96.0	$96.0
	Avoided customer outage costs	Avoided costs for residential and non-residential customers	X			$23,705.4	$27,789.3

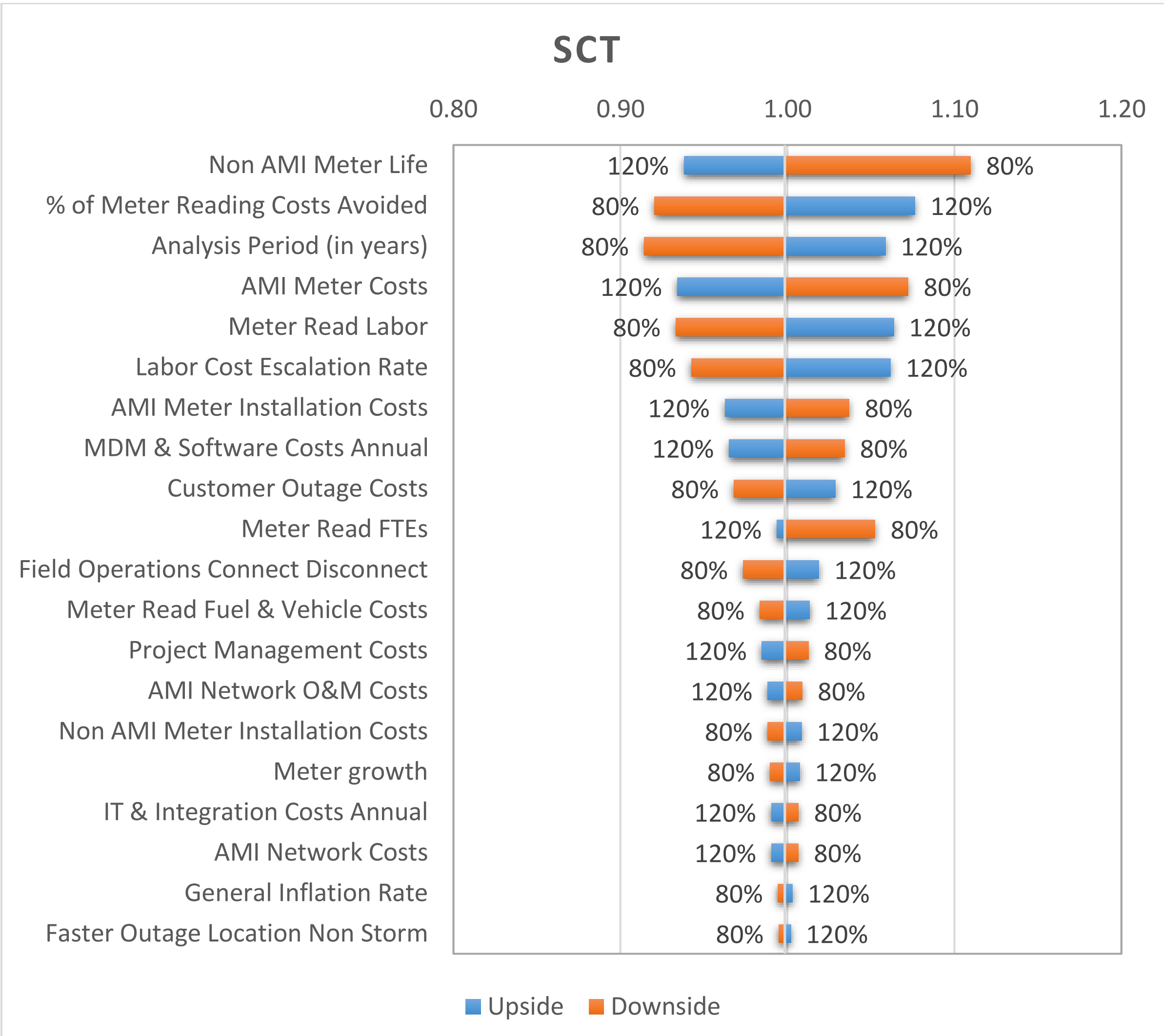
Category	Subcategory	Detail	Benefit/Cost Test SCT	UCT	RIM	25-year NPV (2025 $000) 25 Year NPV Post-Tax Discount Rate	25 Year NPV Pre-Tax Discount Rate
AMI enabled programs	Time varying pricing	Capacity reductions	X	X	X	$1,504.2	$1,789.5
		Energy savings	X	X	X	$53.5	$60.6
		Reduced CO_2 compliance cost	X			$8.5	$9.6
Costs							
AMI Deployment Costs	Meter equipment, installation costs	Mesh meters	X	X	X	$70,445.0	$72,214.2
		Cell meters	X	X	X	$3,739.7	$3,833.6
		Gas modules	X	X	X	$16,311.5	$16,663.5
	Network equipment, installation costs	Radio retrofit of existing concentrators	X	X	X	$0.0	$0.0
		Incremental concentrators w/radio	X	X	X	$7,354.8	$7,354.8
	Meter data management system	MDMS Hardware and Software	X	X	X	$896.1	$896.1
		One time IT costs (Billing system & integration)	X	X	X	$881.1	$881.1
Operations and maintenance	Meter related maintenance	Meter maintenance	X	X	X	$15,544.0	$20,193.8
	Network related maintenance	Network maintenance	X	X	X	$0.0	$0.0
	Communications and other IT costs	Cell meter communication	X	X	X	$15,279.0	$19,795.4
		Meter data management	X	X	X	$0.0	$0.0
		MDMS Hardware and Software	X	X	X	$8,059.9	$9,441.0
		IT O&M Costs	X	X	X	$0.0	$0.0
	Unavoidable meter reading labor	Central Hudson Labor (meter shop)	X	X	X	$27,515.8	$31,574.0
	Project management	PMO	X	X	X	$3,969.3	$4,554.7
AMI enabled rates & programs*	Time-varying pricing	Variable costs	X	X	X	$0.0	$0.0
		Program & IT costs	X	X	X	$0.0	$0.0
		Lost revenue			X	$150.1	$170.1

4.2 KEY COST-EFFECTIVENESS DRIVERS (SENSITIVITY ANALYSIS)

We analyzed the key drivers of cost-effectiveness through a systematic sensitivity analysis designed to identify the inputs that contribute most to net benefits. This is accomplished by varying each component by 20% while holding all other inputs constant. The goal is to identify which inputs have the greatest impact on the results and whether the results will change substantially or directionally by varying or fine tuning inputs. The key finding from the sensitivity analysis is that each individual input has only a small impact on the result.

Figure 4-2 shows the sensitivity results for the assumption inputs with the greatest impact on the societal cost test. The top 10 assumptions can be said to be the top 10 drivers of the result. The midpoint where the blue and orange lines meet is the societal test ratio, at 1.00. The orange line represents the resulting incremental net benefit downside from varying each input by 20%, while the blue line represents the resulting incremental net benefit upside. The number labels on each bar represent the alternate assumption used. Some of the top drivers are meter costs, avoided non-AMI meter replacements, and avoided meter reading costs.

Figure 4-2. Drivers of Full Deployment Societal Benefit Cost Results



The conclusion that full AMI deployment is cost-effective is supported by the sensitivity analysis.

4.3 BCA RESULTS: AMI ENABLED RATES AND PROGRAMS

AMI also enables the deployment of time varying rates, which allows different prices for different time periods and different locations. These rates enable customers to save money not only by reducing energy use, but by changing when they use power. The benefits of AMI enabled rates and programs were quantified but not included in the core operational benefit cost analysis, because of uncertainty regarding how these would be implemented.

The time-varying pricing benefit cost analysis was based on the following assumptions:

- Existing residential TOU rates would be offered to additional residential customers

- The existing rate would be targeted to the top usage quintile, and all residential customers with electric heating or EVs
- Enrollment would be on an opt-in basis rather than by default
- The enrollment level is expected to be medium for the top 20% of users, and high for electric heating and EV customers

Table 4-3 shows that the TVP is cost effective from all perspectives. The societal cost test for the TVP case shows net benefits of $1.9 million, since costs are assumed to be zero, indicating that there are no incremental costs due to AMI deployment and integration. The utility cost test and rate payer test have similar results, yielding net benefits of $1.6 million.

Table 4-3: Time Varying Pricing Benefits and Cost Summary

Benefit Cost Analysis (000s, 2025$)	Societal Cost Test	Utility Cost Test	Rate Payer Impact
Benefits	$1,859.7	$1,566.1	$1,566.1
Costs	$0.0	$0.0	$0.0
Net Benefits	$1,859.7	$1,566.1	$1,566.1
B/C Ratio	NA	NA	NA

With AMI, Central Hudson could expand marketing of its existing TOU rate to target residential customers with the highest potential for load reduction: customers with high usage or load factors, customers with electric heating sources, and customers with EVs.

4.4 BCA RESULTS: OPERATIONAL AND AMI ENABLED BENEFITS AND COSTS

Table 4-4 summarizes the net benefits and the benefit cost ratio for the operational benefit cost analysis plus AMI enabled rates and programs.

Table 4-4: Operational and Time Varying Pricing Benefits and Cost Summary

Benefit Cost Analysis (000s, 2025$)	Societal Cost Test	Utility Cost Test	Rate Payer Impact
Benefits	$184,420.4	$131,450.0	$139,202.3
Costs	$182,847.1	$169,448.5	$169,598.6
Net Benefits	$1,573.3	($37,998.5)	($30,396.3)
B/C Ratio	1.01	0.78	0.82

Results for the societal test show a 1.01 benefit cost ratio after benefits and costs from AMI enabled rates and programs are added to the operational benefit cost analysis. The societal cost test shows total benefits of $184.4 million and total costs of $182.8 million, resulting in a net benefit for utility customers of about $1.6 million.

The utility cost and rate payer impact tests improve marginally by including the TVP benefits in the operational case, but they still aren't cost-effective.

5 CONCLUSION

A potential deployment of AMI within Central Hudson territory was assessed from various perspectives (societal, utility, ratepayer) and benefit categories (operational only versus incremental AMI enabled benefits). The AMI deployment results are cost-effective from the societal perspective both from the operational and incremental AMI programs and rates benefits.

The benefit cost ratio of the operational benefit cost analysis is 1.00, compared to 1.01 for the incremental AMI-enabled programs and rates scenario. The conclusion that full AMI deployment is cost-effective is supported by the sensitivity analysis.

The largest benefits are the avoided meter reading costs, which respond to Central Hudson's transition from bi-monthly to monthly meter reading. Other substantial benefits arise from avoided outage restoration costs, avoided field operations costs, avoided customer outage costs, and avoided meter replacements. On the other hand, the largest costs are meter equipment and installation and IT maintenance. Additionally, qualitative benefits that were not factored into the BCA provide additional value and will improve customer experience and engagement.

Given that the analysis shows that full AMI deployment would be cost effective for Central Hudson customers from the societal perspective, Central Hudson will be developing an implementation plan for AMI deployment. This implementation plan will inform further refinement of the BCA.

APPENDIX A: AMI BENEFIT COST ANALYSIS ASSUMPTIONS

Category	Sub-category	Assumption

General Analysis Assumptions		• 25-year analysis time horizon from 2025 through 2049
		• 2027 discount rates used to align with the year of hypothetical deployment:
		    o WACC pre-tax 8.70%
		    o Post-tax 7.09%
		• Carbon discount rate: 3%
		• Hypothetical deployment period: 2027 through 2030
		• General inflation: 2.1%
		• Meter population growth: 0.2% electric, 0.6% gas

Benefits Assumptions	Operational Benefits	**Meter reading** • Inputs provided by CH staff • Salary included benefits for employees • Percentage of meter reading costs avoided and meters per day per reader after full deployment comes from expert judgement **Outage management** • Inputs provided by CH staff • Cost reductions allocated on a yearly basis proportionately to AMI meter population • Outage costs based on 10 years historical (2015-2024) average total costs across all districts • Percentage of costs eliminated, average time to locate the outage, reduction in outage location time comes, and share of customer truck rolls avoided from expert judgement • Annual average calls with zero customers affected, no cause code, a crew that was dispatched **Field operations (remote connect / disconnect, read over)** • Inputs provided by CH staff • Avoidance rate comes from expert judgement **Replacement of failing meters** • Inputs provided by CH staff • Meters are replaced at the end of useful life • Meter age distribution based on install date of existing stock • Only applied to metes replaced earlier due to AMI

Category	Sub-category	Assumption
		Avoided billing corrections • Inputs provided by CH staff • Avoidance rate with AMI comes from expert judgement
	Transfers and/or equity issues	**Energy theft** • Inputs provided by CH staff • Benefits are not operational, but rather transfers between ratepayers (leading to more fair allocation of costs across rates) so only apply to RIM test • Benefit is delivery charge + wholesale avoided energy charge (LBMP) for both avoided theft and improved meter accuracy • Unbilled kWh%, theft avoidance rate, and recovery improvement from meter accuracy comes from expert judgement **Meter accuracy** • Meter accuracy only applies to replaced electro-mechanical meters
	Societal benefits	**Avoided carbon emissions** • CO_2 Emission factor: 0.00889 metric ton/gal (https://www.eia.gov/environment/emissions/co2_vol_mass.php) • Social cost of carbon (https://www.whitehouse.gov/wp-content/uploads/2021/02/tsd_2021_annual_unrounded.csv) **Avoided customer outage costs** • Share of avoided customer outage minutes (CAIDI improvement)
Costs assumptions	AMI Meter cost	• Costs inputs based on Landis Gyr and Itron's RFP
	Network and software costs	• Costs inputs based on Landis Gyr and Itron's RFP • Failure rate after warranty is from expert judgment
	O&M	• Vendor costs are inputs based on Landis Gyr and Itron's RFP • Internal PMO provided by CH staff

APPENDIX B: AMI BUSINESS CASE LITERATURE REVIEW

We conducted a literature review to understand the cost and benefit categories commonly included and quantified by other utilities' AMI business cases. To identify relevant business cases, we began by reviewing the FERC AMI Assessment Reports and Form EIA-861 data files to identify the utilities that have installed the most AMI meters in the past five years with emphasis in the Northeast and the utilities with the largest percentual increase of AMI in the 5 past years in all the U.S.

We systematically analyzed, compared, and summarized the cost and benefit categories and estimation approaches used by 12 utilities, drawing from business plans, utility reports, legal documents, and Public Utility Commission (PUC) testimonies that included AMI benefit-cost analyses.

The following tables summarize the benefits and costs that were estimated and monetized in the reviewed business cases, along with a comparative breakdown of the proportional distribution of AMI costs and benefits by category for the utilities with the most comprehensive data.

Figure 5-1. Quantified benefits in AMI Business Cases

Benefit category	CHG&E 2016 Benefit Cost Analysis	PSEG Long Island (NY)	Niagara Mohawk (NY)	Con Edison (NY)	Avangrid (NY)	RECO (NY)	PECO (PA)	JCP&L (NJ)	PSEG (NJ)	Entergy (AR)	Public Service of Colorado	Consumers Energy (MI)
Meter reading labor, vehicles, and fuel	X	X	X	X	X	X	X	X	X	X	X	X
Outage management	X	X	X	X	X	X			X		X	
Field operations (remote connect/ disconnect, read over)	X	X	X	X	X	X	X		X	X	X	X
Reduced call center		X	X	X	X	X		X	X			
Replacement of failing meters	X		X	X	X	X				X	X	X
Avoided wholesale and generation / transmission / capacity costs		X	X	X	X					X	X	
GHG emission reduction		X	X	X	X			X				
Volt-VAR Optimization (VVO) / Conservation Voltage Reduction (CVR)		X	X	X		X						
Energy theft	X	X	X	X	X	X		X	X	X	X	X
Meter accuracy	X	X		X	X	X				X		X
Reduced bad write-offs		X	X	X	X	X		X	X	X	X	
Bill savings from time-varying rates		X	X	X	X			X	X			X
Avoided outage costs for costumers		X	X	X	X	X		X			X	
Improved energy usage data and potential energy/bill savings		X	X	X	X	X		X		X		X
Interval meter reading			X	X								

Figure 5-2. Quantified costs in AMI Business Cases

Cost category	CHG&E 2016 Benefit Cost Analysis	PSEG Long Island	Niagara Mohawk	Con Edison	Avangrid	RECO	PECO	JCP&L	PSEG (NJ)	Entergy (AR)	Public Service of Colorado	Consumers Energy (MI)
Meters & Installation	X	X	X	X	X	X	X	X	X	X	X	X
Communications Network (Equipment & Installation)	X	X	X	X	X	X	X	X		X	X	X
IT Platform & Ongoing Operations	X	X	X	X	X	X	X	X	X	X	X	
Program Administration / Project Management	X	X	X	X	X	X	X	X		X	X	X
Added O&M (Incremental)		X			X	X		X	X			X
DER Costs & Incentives		X			X							X
Lost Utility Revenue & Unrecovered Costs		X				X	X			X		
Pilot Deployment/Training									X	X		

Figure 5-3. Proportional Breakdown of AMI Costs and Benefits by Category

	(Million $)	Included in Cost Test?	PSEG Long Island (NY)	Niagara Mohawk (NY)	Con Edison (NY)	Avangrid (NY)	RECO (NY)	PSEG (NJ)
Benefit category	Meter reading labor, vehicles, and fuel	✓	35%	7%	23%	29%	55%	61%
	Outage management	✓	12%	6%	5%	4%	17%	0%
	Field operations (remote connect/ disconnect, read over)	✓	17%	12%	18%	13%	13%	20%
	Reduced call center and billing costs	✓	2%	0%	3%	6%	3%	7%
	Replacement of failing meters/avoided meter purchases/avoided captial	✓	0%	50%	22%	4%	10%	0%
	Avoided GT&D Costs from TVP and DSM	✓	13%	20%	8%	28%	0%	4%
	GHG emission reduction	✓	0%	0%	0%	4%	0%	0%
	Volt-VAR Optimization (VVO) / Conservation Voltage Reduction (CVR)	✓	0%	3%	20%	0%	2%	2%
	Avoided Energy theft/tamper*		0%	0%	0%	0%	0%	0%
	Improved Meter accuracy*		0%	0%	0%	0%	0%	0%
	Reduced bad debt and write-offs*		0%	0%	0%	0%	0%	0%
	Bill savings from time-varying rates*		0%	0%	0%	0%	0%	0%
	Avoided outage costs for customers	✓	20%	0%	0%	10%	0%	5%
	Improved cashflow		0%	0%	0%	0%	0%	0%
	Avoided network O&M	✓	0%	0%	0%	2%	0%	0%
	Reduction in damage claims	✓	0%	1%	0%	0%	0%	0%
Cost category	Meters & Installation	✓	54%	47%	31%	54%	49%	75%
	Communications Network (Equipment & Installation)	✓	0%	4%	18%	9%	10%	2%
	IT Platform & Ongoing Operations	✓	20%	33%	37%	17%	31%	3%
	Program Administration / Project Management	✓	11%	16%	14%	10%	10%	7%
	Added O&M (Incremental)	✓	14%	0%	0%	10%	0%	6%
	Customer Outreach & Education	✓	0%	0%	0%	0%	1%	5%
	Lost Utility Revenue & Unrecovered Costs*		0%	0%	0%	0%	0%	0%
	Training	✓	0%	0%	0%	0%	0%	1%
	Billing and system integration	✓	0%	0%	0%	0%	0%	1%

REPORT

2025 Central Hudson
Granular Load, Distributed Energy Resource, and Electrification Forecasts

Prepared for Central Hudson

By

Demand Side Analytics

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Demand Side Analytics Team

- Josh Bode
- Candace Yee
- David Pojunas

Central Hudson Team

- Stacy Powers
- Stephanie Palmer
- Pano Harpolis
- Cory Scofield
- Michael Valentino
- Ray Cotto

ABSTRACT

The focus of the study is to present the methodology and results for granular forecasting for T&D loads, distributed energy resources, and electrification technologies, both for the Central Hudson service territory and for transmission areas, substations, and circuit feeders. Specifically, the study produced 8760 profiles at the territory-wide, local transmission, substation, and feeder levels 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 program planning. The hourly 8760 historical loads and forecasts are posted on the Central Hudson website as part of the 2025 DSIP.

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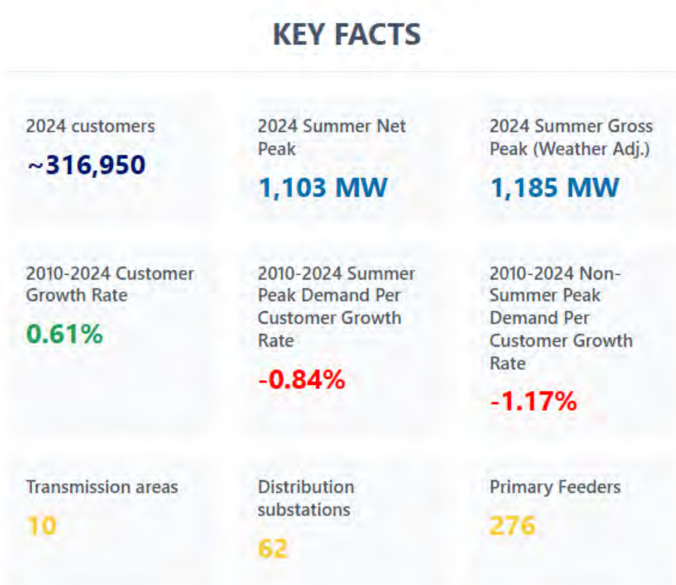
1 INTRODUCTION

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 Central Hudson forecasts and planning are done system-wide and for individual components, including 272 distribution feeder circuits, 66 substations, and 10 transmission areas. Accurate forecasts are critical since they account for planning conditions and are used to determine the sizing of the grid infrastructure needed to accommodate the loads.



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 substations 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.

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 Integrated Load Forecast (2025-2035)

Season	Year	Econometric Forecast (Gross Load)	Electric Vehicles	Heat Pumps	EE and C&S	Solar [1]	Energy Storage	Integrated Planning Loads
Summer	2025	1,121.8	19.1	-3.3	-18.8	-16.7	-5.0	1,097.2
	2026	1,121.9	25.6	-4.1	-29.5	-18.9	-6.1	1,089.0
	2027	1,122.1	34.1	-5.0	-38.0	-19.9	-10.4	1,082.8
	2028	1,123.0	44.6	-6.1	-46.1	-20.7	-11.1	1,083.7
	2029	1,124.6	57.5	-7.2	-55.4	-21.1	-12.9	1,085.6
	2030	1,126.8	72.7	-8.5	-66.4	-21.4	-15.7	1,087.4
	2031	1,128.9	89.9	-9.8	-77.9	-21.6	-19.7	1,089.8
	2032	1,131.1	109.0	-11.3	-88.6	-21.8	-24.6	1,093.8
	2033	1,132.6	129.6	-12.9	-98.9	-21.9	-30.6	1,098.0
	2034	1,133.7	151.3	-14.6	-108.5	-22.0	-37.1	1,102.8
	2035	1,134.6	173.6	-16.4	-117.4	-22.0	-43.9	1,108.5
Winter	2025	813.1	18.9	30.6	-17.0	-4.7	-4.9	835.9
	2026	813.1	25.4	37.4	-26.6	-5.3	-6.0	838.0
	2027	813.2	33.8	45.1	-34.4	-5.6	-10.3	841.9
	2028	813.9	44.3	53.4	-41.7	-5.8	-11.0	853.1
	2029	815.0	57.0	62.5	-50.1	-5.9	-12.8	865.8
	2030	816.5	72.0	72.4	-60.1	-6.0	-15.6	879.2
	2031	818.1	89.0	82.9	-70.5	-6.0	-19.5	894.0
	2032	819.7	107.9	94.2	-80.3	-6.1	-24.5	910.9

2033	820.9	128.1	106.0	-89.6	-6.1	-30.4	929.0
2034	821.8	149.4	118.5	-98.3	-6.1	-37.0	948.4
2035	771.2	157.7	146.2	-104.0	-0.7	-0.9	969.4

[1] PV includes net metered customers, Community Distributed Generation (CDG), and remote solar projects since they impact distribution planning. By comparison, system forecasts for the rate case focus on direct sales and only include net metered solar.

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 SYSTEM LEVEL 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).

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.

As much as possible, the results are grounded in empirical data but also reflect the limitations and uncertainty of what we know about changes in T&D loads and the adoption of DERs and beneficial electrification.

Due to the rapid adoption of new technology, Central Hudson has incorporated improvements to the system-level forecasting process, specifically:

- **Capability to produce system forecasts for 20 years.** Historically, the system-level forecasts focused on a five-year period and were produced for the rate case. However, due to the increased need for planning over longer T&D horizons, Central Hudson has built the capability to produce 20-year forecasts for distribution planning.
- **Forecasting outputs that align with the NYISO Gold Book format.** Specifically, the forecasts include information to understand why and how peak loads are changing and include details regarding the gross loads and load modifiers, specifically:
  - ✓ Econometric gross load forecasts
  - ✓ Electric Vehicles (+)

  - ✓ Building Electrification (+)
  - ✓ Energy Efficiency and Codes & Standards (-)
  - ✓ Solar PV (-)
  - ✓ Storage Reductions (+/-)
- **Detailed tracking of the Load Modifiers to estimate historical adoption and current penetration levels**. The data is critical for the development of the load forecasts. This is most advanced for more established technologies such as solar, storage, light-duty electric vehicles, and EE & CS. The empirical data for building electrification is at a more nascent stage, and the visibility into the heat pump market share needs to be better established.
- **Production of a Central Hudson Forecast and policy-based forecast**. The Central Forecast reflects the empirical trends, patterns, and funding levels. It reflects the best estimate of loads at Central Hudson. The policy-based forecast reflects the NY State goals and is based on the zone G NYISO forecast, scaled for Central Hudson's service territory. It includes projections of various load modifiers – energy efficiency, solar, battery storage, EVs, and building electrification – tied closely to state goals.

2.1 METHODS

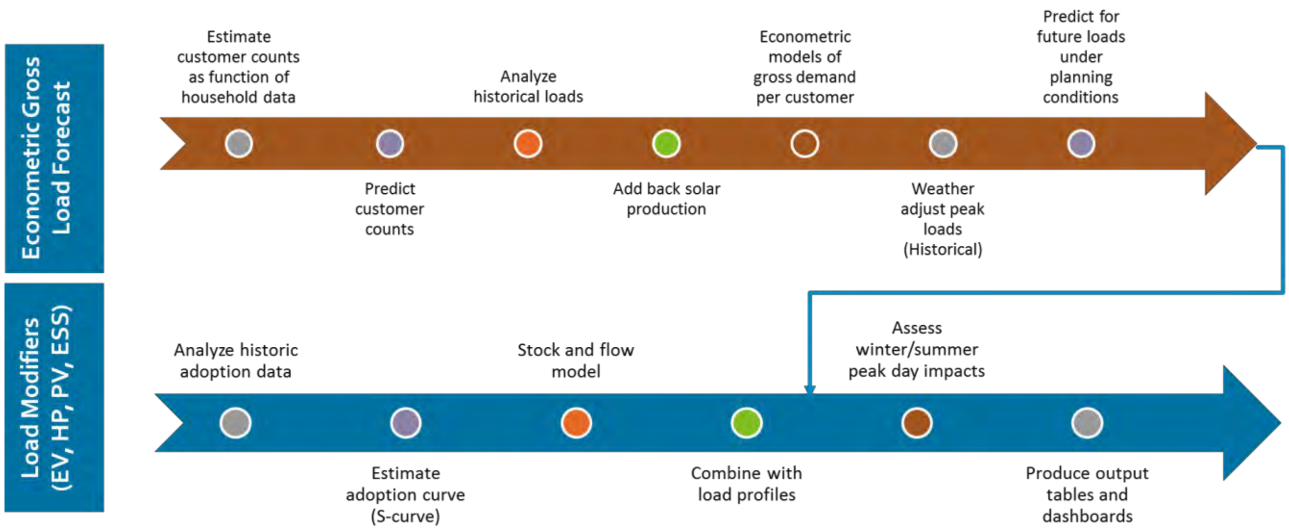
Figure 1 shows the general process for developing the forecasts. There are two main tracks: the development of the econometric gross load forecasts and the load modifier forecasts. The process for the econometric forecast develops estimates of customer counts as a function of Moody's household data for the Central Hudson area. It uses the Moody's household forecast to predict future customer counts. From 2010-2024, the number of Central Hudson customers grew at a rate of 0.61% per year. However, future household forecasts project a slowdown in household growth in the next ten years and a slight decline starting in the mid-2030s. The 2010-2024 summer and winter daily peak loads were used to develop econometric models designed to isolate per-customer demand patterns as a function of weather, time, and other day-type characteristics. Overall, per-customer summer peak demand in Central Hudson has been declining at a rate of -0.84% per year, likely due to a mixture of energy efficiency, codes and standards, and other changes in end-use loads. Winter peak demand has been declining at a rate of -1.17% per year. The difference is likely due to the increasing penetration of air conditioning in Central Hudson's territory and differences in the peak hours between summer and winter. The econometric model is then used to weather-adjust historical peaks and predict future loads under planning conditions, with and without incremental energy efficiency and codes and standards.

The process for developing the load modifier forecasts generally follows the diagram below, with a few exceptions.[1] An innovation diffusion curve is fit to the historic adoption patterns to estimate the new market share of the technology over time. Next, a stock-and-flow model is used to understand how the technology mix (e.g., vehicles) will change as old models age out and are replaced by new ones. It is

[1] The exceptions are larger, distribution connect solar and battery storage, heavy duty vehicles, and fast DC charging.

then combined with load profiles and layered onto the existing demand to understand how summer and winter peak loads will change.

Figure 1: Process for Developing Forecasts



A unique characteristic of Central Hudson is the quantity of community-distributed generation (CDG) and remote-solar projects, which are not net-metered but are distribution-connected. As of the end of 2024, Central Hudson had interconnected over 160 such projects with over 170 MW of installed solar capacity, exceeding the roughly 160 MW of net-metered solar capacity.[2]

DERs subject to net energy metering to reduce the system-wide forecast of billed sales and metered peak. In contrast, DERs subject to monetary compensation for exports, such as Community Distributed Generation (CDG), do not impact Central Hudson sales and rates. However, power system, transmission, and distribution planning must account for the impact of all distribution-connected solar and storage on planning. Central Hudson's system-level demand and sales projections for the rate case focus on billed sales. In contrast, the demand forecasts included in this report include the effect of all distribution-connected generation, including CDM and remote-metered sites.

2.2 HISTORIC LOAD PATTERNS

Table 2 shows historical peak demand data for the 2010-2024 winters and summers. Overall, the net peak demand has decreased despite increases in the total number of customers. Once solar production has been added back and demand is adjusted for weather, the overall demand is relatively flat despite a growing customer base.

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[2] Solar capacity is described in AC capacity, which is closer to the production available to customers.

Table 2: Historical Peak Demand

Season	Year	Date	Hour	Net Peak Demand	Gross Demand [1]	Gross Demand Weather-Adjusted	Gross Demand (kW) per Customer	# of Customers [2]	Peak Hour Temp [3]	Daily Avg. Temp	Daily Avg. Temp (1-in-2)
Summer	2010	7/6/2010	16	1,230	1,234	1,190	4.18	295,343	99.0	85.1	82.8
	2011	7/22/2011	17	1,225	1,229	1,187	4.15	295,985	100.0	87.9	82.8
	2012	7/17/2012	17	1,168	1,173	1,184	3.98	295,061	95.0	82.8	82.8
	2013	7/18/2013	16	1,202	1,212	1,175	4.10	295,755	95.0	84.9	82.8
	2014	7/23/2014	16	1,060	1,077	1,172	3.64	296,236	89.1	79.4	82.8
	2015	7/29/2015	17	1,059	1,078	1,167	3.62	298,030	93.9	80.3	82.8
	2016	8/13/2016	17	1,088	1,112	1,168	3.73	297,874	93.9	85.4	82.8
	2017	7/20/2017	16	1,034	1,087	1,162	3.62	300,077	90.0	77.2	82.8
	2018	7/2/2018	17	1,114	1,153	1,164	3.81	302,826	91.0	82.8	82.8
	2019	7/21/2019	17	1,109	1,141	1,167	3.74	305,051	93.9	84.3	82.8
	2020	7/27/2020	18	1,142	1,178	1,169	3.83	307,602	93.0	84.0	82.8
	2021	6/29/2021	18	1,148	1,191	1,172	3.82	311,365	93.9	86.7	82.8
	2022	7/21/2022	18	1,109	1,168	1,178	3.72	314,231	93.9	84.4	82.8
	2023	9/7/2023	17	1,046	1,153	1,182	3.64	316,462	88.0	78.3	82.8
	2024	7/10/2024	18	1,103	1,175	1,185	3.71	316,950	86.0	83.1	82.8
Winter	2010	12/14/2010	17	891	892	881	3.02	295,343	19.9	19.9	10.9
	2011	1/24/2011	18	905	905	874	3.06	295,985	5.0	2.3	10.9
	2012	1/21/2012	17	861	862	866	2.92	295,061	21.0	19.0	10.9
	2013	12/17/2013	17	900	902	855	3.05	295,755	20.0	14.0	10.9
	2014	1/7/2014	18	938	938	847	3.17	296,236	8.1	9.1	10.9
	2015	1/7/2015	18	874	875	839	2.93	298,030	10.9	16.8	10.9
	2016	2/15/2016	18	863	863	835	2.90	297,874	19.0	12.8	10.9
	2017	12/28/2017	18	885	885	826	2.95	300,077	10.0	7.8	10.9
	2018	1/6/2018	18	904	904	822	2.99	302,826	6.1	6.3	10.9
	2019	1/21/2019	17	900	900	820	2.95	305,051	10.9	8.3	10.9
	2020	12/16/2020	17	848	848	816	2.76	307,602	24.1	22.4	10.9
	2021	1/29/2021	18	841	841	813	2.70	311,365	18.0	15.6	10.9
	2022	1/22/2022	18	896	896	813	2.85	314,231	16.0	10.9	10.9
	2023	2/3/2023	18	878	878	810	2.77	316,462	8.1	17.4	10.9
	2024	12/22/2024	17	912	912	808	2.88	316,950	10.9	10.5	10.9

[1] Includes solar production addback from net-metered (NEM), CDG, and remote metered distribution-connected solar. For ratemaking purposes, only net-metered (NEM) solar is included.
[2] Count of customers based on bills sent out during the billing cycle.
[3] Mid-Dutchess Airport Weather Station
[4] Based on an analysis of 20 years of historical weather

Figure 2 shows the hourly patterns on annual peak days by season for 2010-2024. The summer system loads follow a typical pattern, peaking in the late afternoon hours, with the more recent peaks occurring later and later into the evening hours due to higher solar penetration. The winter loads have a distinctly different pattern, with both a morning and evening peak. Winter peak loads typically occur in the evening hours and are lower than summer peak loads by roughly 200-300 MW. Central Hudson expects the winter loads in the morning to grow with the increased penetration of heat pumps and electric heating.

Figure 2: Hourly Net Loads on Annual Peak Days (2010-2024)

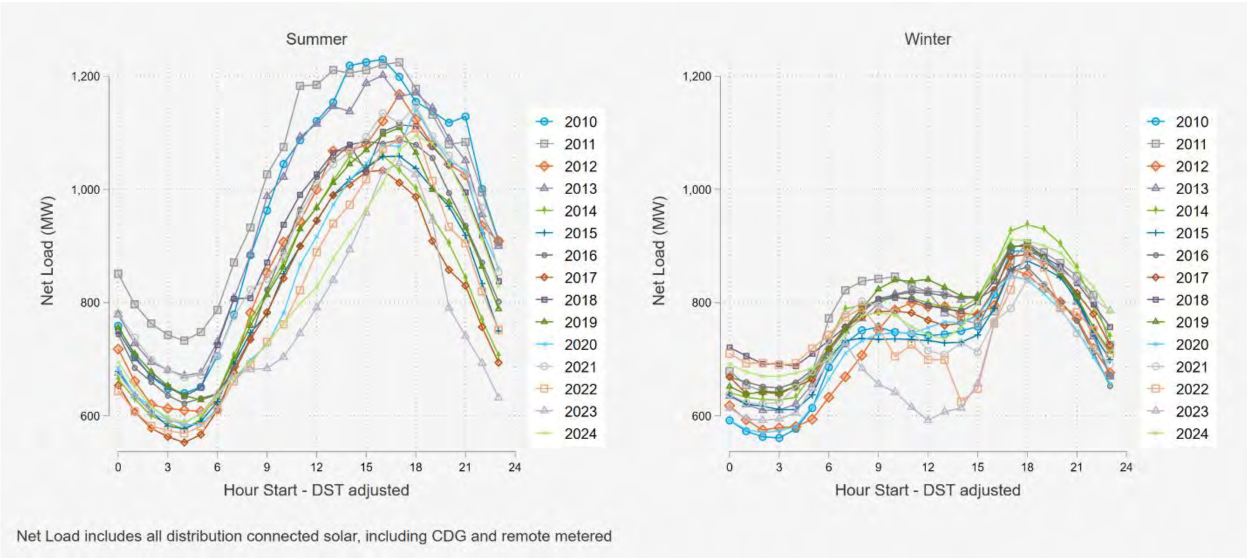


Figure 3: System Net Loads Weather Sensitivity (2022-2024)

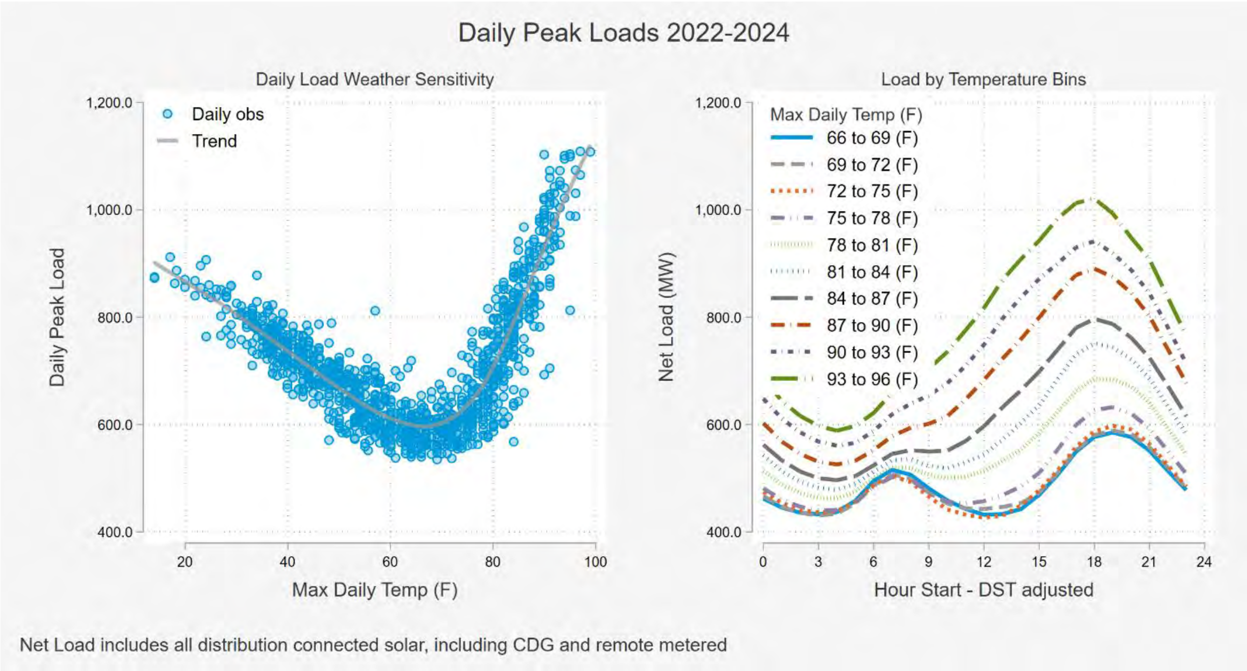


Figure 3 shows the weather sensitivity of net system loads for the most recent three years. Overall, roughly 500 MW of the summer load is weather-sensitive due to cooling and fan loads. The winter loads are lower, slightly below 900 MW, and roughly 300 MW of the winter load is weather-sensitive. While Central Hudson is summer-peaking, it has a substantial amount of winter peak loads, and pockets of the service territory are winter-peaking.

2.3 FORECASTS

Table 3 summarizes the Central Hudson system-level forecast for the DSIP. As noted earlier, it includes Community Distributed Generation (CDG) and remote-solar projects, since they impact distribution planning. Overall, Central Hudson is expecting a substantial amount of electric vehicle loads, building electrification, and additional solar storage. The additional loads shift the timing of the peak hours over time, which can also impact the effect of solar on system peak as system peak hours shift later in the afternoon and may potentially impact the season when the Central Hudson System peaks.

Table 4 shows the policy-based forecast. As noted earlier, the policy forecast is based on the NYISO Zone G forecast, adjusted for Central Hudson's share of the zone. The main difference between the policy and Central Hudson scenarios is the heat pump forecast. The policy forecast assumes a 75% saturation of heat pumps by 2050. In contrast, the Central Hudson forecast assumes a 55% saturation of heat pumps by 2050, given the adoption patterns observed. Regardless of the forecast used, Central Hudson is expected to remain a summer-peaking system through the late 2030s, although individual transmission areas, substations, and feeder circuits may become winter-peaking earlier

Table 3: DSIP Central Hudson Forecast (MW)

Season	Year	Econometric Forecast (Gross Load)	Electric Vehicles	Heat Pumps	EE and C&S	Solar [1]	Energy Storage	Integrated Planning Loads
Summer	2025	1,121.8	19.1	-3.3	-18.8	-16.7	-5.0	1,097.2
	2026	1,121.9	25.6	-4.1	-29.5	-18.9	-6.1	1,089.0
	2027	1,122.1	34.1	-5.0	-38.0	-19.9	-10.4	1,082.8
	2028	1,123.0	44.6	-6.1	-46.1	-20.7	-11.1	1,083.7
	2029	1,124.6	57.5	-7.2	-55.4	-21.1	-12.9	1,085.6
	2030	1,126.8	72.7	-8.5	-66.4	-21.4	-15.7	1,087.4
	2031	1,128.9	89.9	-9.8	-77.9	-21.6	-19.7	1,089.8
	2032	1,131.1	109.0	-11.3	-88.6	-21.8	-24.6	1,093.8
	2033	1,132.6	129.6	-12.9	-98.9	-21.9	-30.6	1,098.0
	2034	1,133.7	151.3	-14.6	-108.5	-22.0	-37.1	1,102.8
	2035	1,134.6	173.6	-16.4	-117.4	-22.0	-43.9	1,108.5
Winter	2025	813.1	18.9	30.6	-17.0	-4.7	-4.9	835.9
	2026	813.1	25.4	37.4	-26.6	-5.3	-6.0	838.0
	2027	813.2	33.8	45.1	-34.4	-5.6	-10.3	841.9
	2028	813.9	44.3	53.4	-41.7	-5.8	-11.0	853.1
	2029	815.0	57.0	62.5	-50.1	-5.9	-12.8	865.8
	2030	816.5	72.0	72.4	-60.1	-6.0	-15.6	879.2
	2031	818.1	89.0	82.9	-70.5	-6.0	-19.5	894.0
	2032	819.7	107.9	94.2	-80.3	-6.1	-24.5	910.9
	2033	820.9	128.1	106.0	-89.6	-6.1	-30.4	929.0
	2034	821.8	149.4	118.5	-98.3	-6.1	-37.0	948.4
	2035	771.2	157.7	146.2	-104.0	-0.7	-0.9	969.4

[1] PV includes net metered customers, Community Distributed Generation (CDG), and remote solar projects since they impact distribution planning. By comparison, system forecasts for the rate case focus on direct sales and only include net metered solar.

Table 4: DSIP Policy-Based Forecast

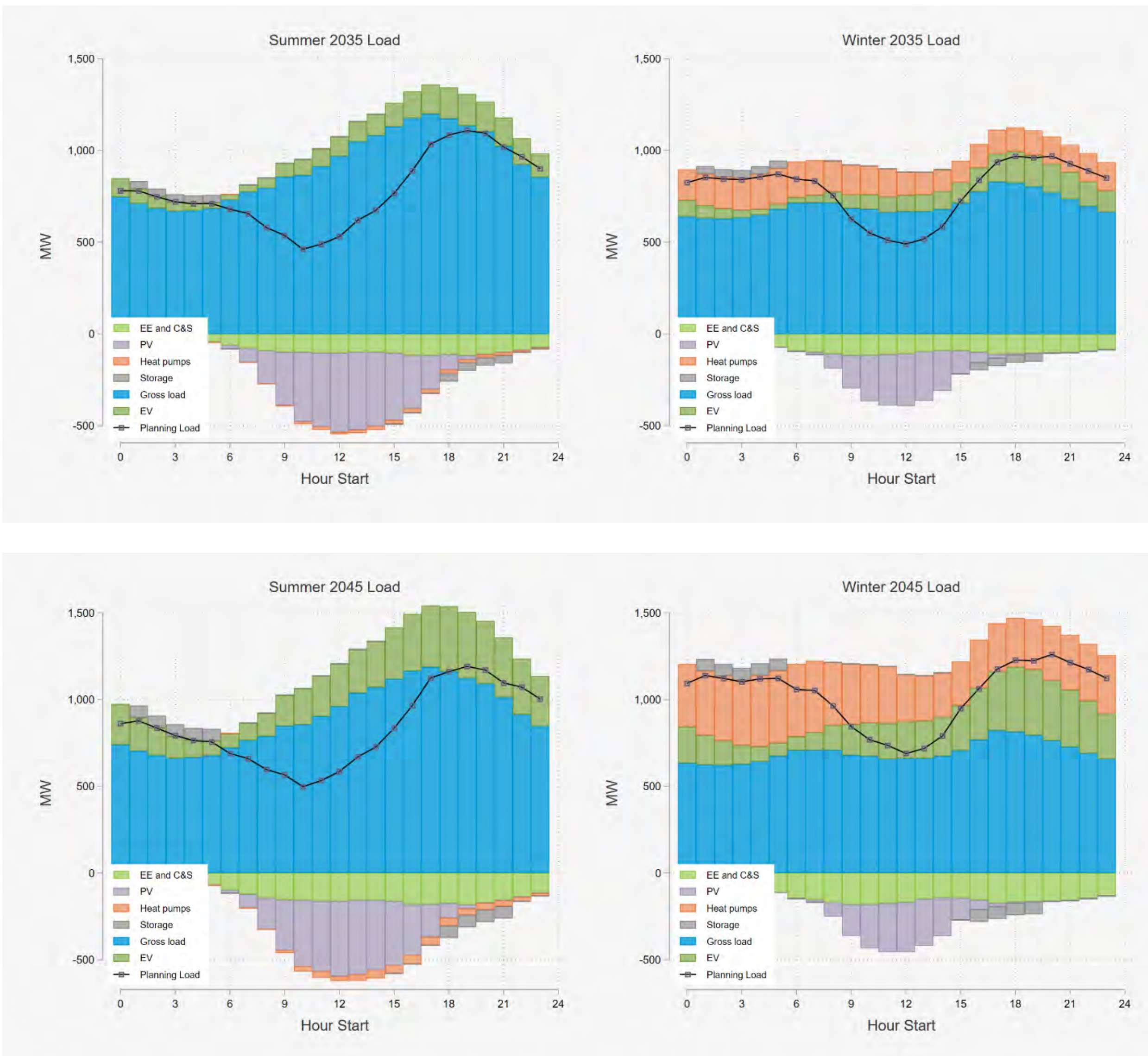
Season	Year	Econometric Forecast (Gross Load)	Electric Vehicles	Heat Pumps	EE and C&S	Solar [1]	Energy Storage	Integrated Planning Loads
Summer	2025	1,183.4	20.2	-0.7	-24.7	-68.3	-0.6	1,109.2
	2026	1,183.8	28.1	-2.2	-38.8	-77.5	-0.7	1,092.8
	2027	1,184.3	38.6	-3.7	-50.0	-86.5	-0.8	1,081.8
	2028	1,185.5	51.3	-5.6	-60.7	-94.4	-0.9	1,075.2
	2029	1,187.5	66.9	-7.6	-72.9	-101.3	-1.0	1,071.7
	2030	1,164.7	91.7	-8.9	-84.2	-48.4	-44.2	1,070.6
	2031	1,167.0	115.0	-10.9	-98.7	-50.7	-47.7	1,074.0
	2032	1,169.4	142.0	-13.1	-112.3	-52.6	-50.8	1,082.6
	2033	1,132.6	175.7	-12.5	-131.7	-14.2	-53.2	1,096.7
	2034	1,133.7	212.4	-14.8	-144.5	-14.6	-55.5	1,116.7
	2035	1,134.6	254.1	-17.3	-156.3	-14.9	-58.3	1,141.7
Winter	2025	813.1	21.9	5.1	-22.6	-2.3	-23.9	791.2
	2026	813.1	30.6	14.5	-35.5	-2.6	-28.2	791.8
	2027	813.2	41.9	24.2	-45.8	-2.9	-32.2	798.4
	2028	813.9	55.6	36.2	-55.6	-3.1	-36.5	810.6
	2029	815.0	72.5	48.6	-66.8	-3.4	-40.5	825.4
	2030	816.5	92.1	61.3	-80.1	-3.5	-43.9	842.4
	2031	767.5	109.5	82.3	-91.9	-0.4	-0.7	866.3
	2032	768.8	135.0	97.8	-104.6	-0.5	-0.7	895.7
	2033	769.8	163.7	114.5	-116.8	-0.5	-0.8	930.0
	2034	770.6	197.4	133.8	-128.1	-0.5	-0.8	972.4
	2035	771.2	235.6	154.6	-138.7	-0.5	-0.8	1,021.3

[1] Solar includes net metered customers, Community Distributed Generation (CDG), and remote solar projects since they impact distribution planning. By comparison, system forecasts for the rate case focus on direct sales and only include net metered solar.

The above tables focus on the peak hour for the integrated planning load. However, the timing, peak hours, and the peak season change over time with the increased adoption of electric vehicles, heat pumps, solar, battery storage, energy efficiency, and codes and standards. Figure 4 shows the various components of the forecast stacked, with components that increase load shown as positive and components that decrease loads are shown as negative. The black line is the integrated planning load. The amount of current and forecast distribution connected solar in Central Hudson's territory is significant, pushing the net load peaks into late evening hours over time. In addition, the expected electric vehicle loads, if not properly managed, contribute to the peaks in the summer and winter months.

A key planning issue will be identifying ways to manage or incentivize electric vehicles to charge during off-peak periods. Electric vehicle loads are large, adding between 3,000 to 5,000 kWh per vehicle depending on miles driven. However, they are much more diverse and shiftable than heating and cooling, since not all homes need to charge on the same day or at the same time. The contribution of heat pumps to peak loads is primarily in the winter. In general, heat pumps contribute a substantial amount of load throughout the day but peak in the morning, when temperatures are colder and home occupancy is high. However, when combined with existing load and other load modifiers (e.g., EVs), Central Hudson still expects winter loads to peak in the evening hours.

Figure 4: 2035 and 2045 Summer and Winter Peak Day Load Changes Central Hudson Forecast



3 LOCATION SPECIFIC FORECASTS

The expected growth in electric vehicles, building electrification, solar, and battery storage requires significant changes to how distribution planning takes place and how it is coordinated with system forecasts. The most immediate impact of the adoption of technologies such as electric vehicles, heat pumps, solar, and storage is observed in distribution planning. Newer technology adoption is often concentrated in specific pockets of Central Hudson's service territory. While a system-level forecast provides a broad view of load growth and adoption of EVs, heat pumps, solar, and storage, a granular circuit-level forecast is essential for grid planning and reliability. The core questions are: when and where will new electrification and DER technology appear? And how will they impact hourly demand on peak days?

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 include loads, new electrification, and DER technologies.

A key barrier, however, was that not all feeders and substations had meters collecting hourly or sub-hourly data. For Central Hudson, this barrier was effectively eliminated through ongoing infrastructure replacement programs, installing hourly metering data for nearly all of its substations and feeders, achieving a goal in the 2020 DSIP. However, once meters are installed, several years of data must be collected to accurately estimate local annual and especially hourly load growth trends.

3.1 METHODS OVERVIEW

Figure 5 summarizes the process used for transmission area, substation, and feeder circuit forecasts. The bottom-up granular forecasts have been designed to isolate the key drivers of change in loads. Specifically, the approach aims to isolate load growth trends from solar interconnections; historical solar production is added to the observed historical loads. The objective is to quantify the growth in gross loads separately from the changes in electric vehicles, heat pumps, solar, battery storage, and other load modifiers. 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 granular forecasts are all calibrated to territory-wide forecasts, thus ensuring consistency in outputs.

Figure 5: Process for Granular Distribution Forecasts

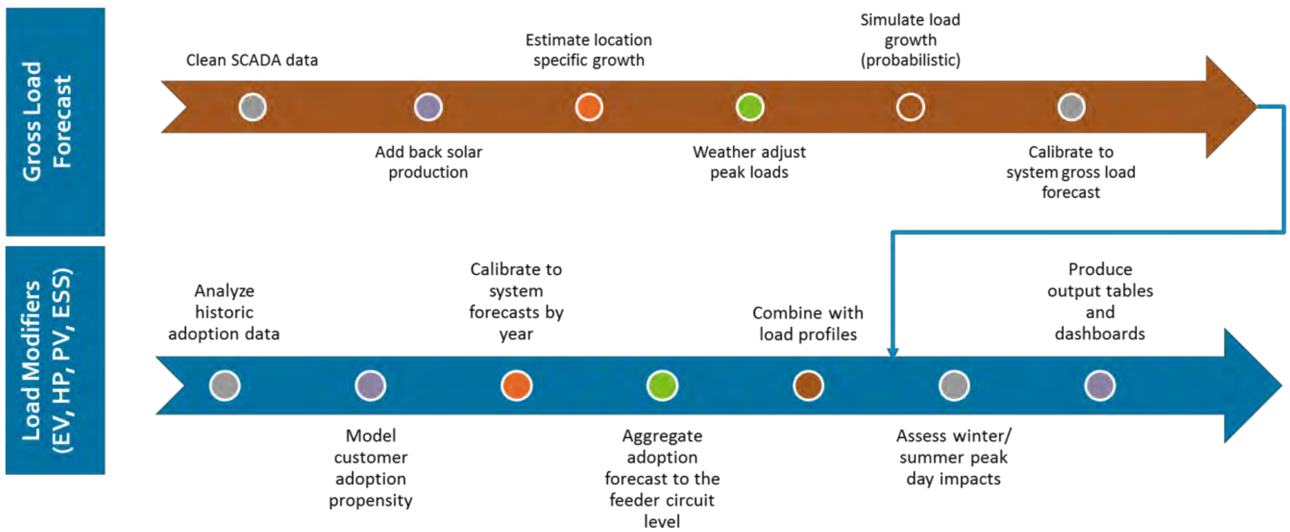


Figure 6 provides a more detailed view of the process for the granular forecasting of load modifiers and includes inputs and key outputs. The process allows Central Hudson to identify potential constraints, prioritize infrastructure investments, and ensure reliable service delivery as EV, heat pumps, solar, and storage adoption increases across different neighborhoods. By understanding when and where these loads will materialize at various levels – pole top/pad mount transformers, feeders, substation transformers, banks, substations, and transmission load pockets – Central Hudson can better prepare for and manage the impacts of DERs and electrification.

Figure 6: Process for Heat Pumps, Electric Vehicles, Solar, Battery storage, and Energy Efficiency

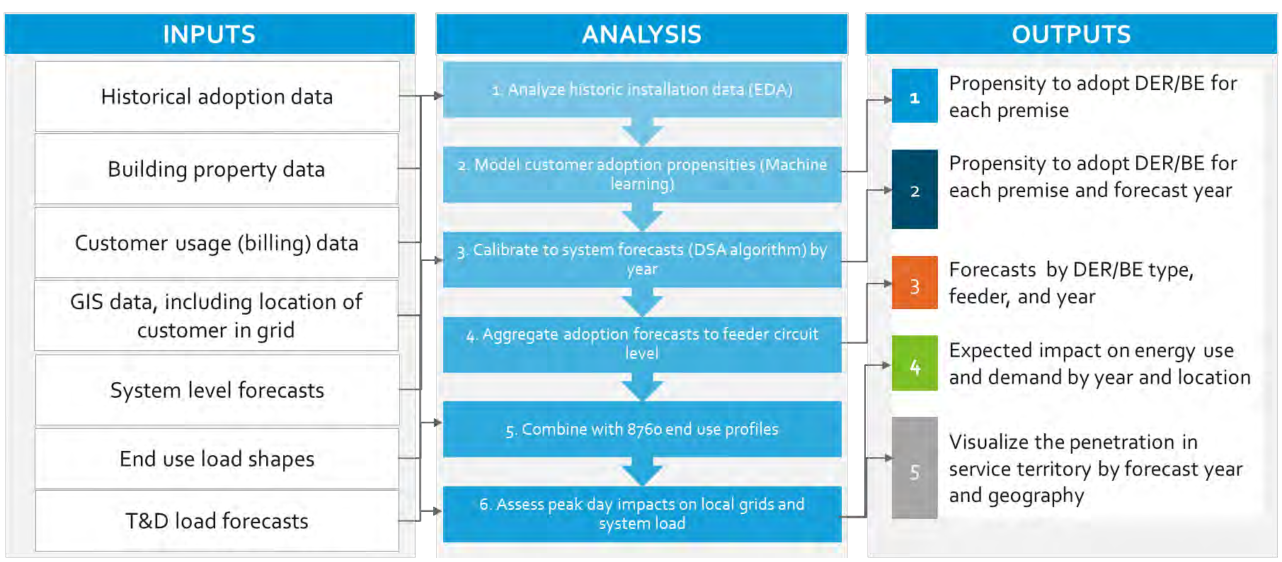


Table 5 illustrates the components of the bottom-up load forecasts for a specific, illustrative substation. The granular forecasts can be summarized for the coincident (territory-wide) or non-coincident (local) summer and winter peak at different levels of geographic granularity – system, transmission area, substation, and feeder circuit. They also can be shown for the single peak hour, for peak days, or for the full 8,760 hours per year and at each level of geographic granularity. As described above, the bottom-up, location-specific forecasts are reconciled with the system-wide forecasts.

Table 5: Example Granular Forecast for a Substation

Season	Forecast year	Econometric Forecast (Gross Load)	Electric Vehicles	Heat Pumps	EE and C&S	Solar [1]	Energy Storage	Integrated Planning Loads
Summer	2025	44.0	1.3	-0.1	-1.1	-1.4	-0.1	**42.6**
	2026	43.4	1.7	-0.1	-1.7	-1.5	-0.1	**41.7**
	2027	42.7	2.3	-0.1	-2.1	-1.6	-0.1	**41.1**
	2028	42.2	3.0	-0.2	-2.5	-1.6	-0.1	**40.7**
	2029	41.8	3.8	-0.2	-3.0	-1.7	-0.1	**40.6**
	2030	41.6	4.8	-0.3	-3.5	-1.8	-0.2	**40.7**
	2031	41.2	5.9	-0.3	-4.0	-1.8	-0.2	**40.7**
	2032	40.8	7.1	-0.4	-4.5	-1.9	-0.3	**40.9**
	2033	40.6	8.4	-0.4	-5.0	-1.9	-0.4	**41.3**
	2034	38.4	9.6	-0.6	-5.0	-0.1	-0.5	**41.8**
	2035	38.4	10.9	-0.6	-5.4	-0.1	-0.6	**42.5**
Winter	2025	24.6	1.2	0.4	-0.9	-0.1	-0.1	**25.1**
	2026	24.2	1.6	0.5	-1.4	-0.1	-0.1	**24.8**
	2027	23.5	2.6	0.7	-1.7	-0.1	-0.1	**24.9**
	2028	23.2	3.4	0.9	-2.0	-0.2	-0.1	**25.2**
	2029	23.0	4.4	1.0	-2.3	-0.2	-0.1	**25.8**
	2030	22.8	5.5	1.3	-2.7	-0.2	-0.2	**26.5**
	2031	22.6	6.7	1.5	-3.1	-0.2	-0.2	**27.3**
	2032	22.4	8.1	1.7	-3.5	-0.2	-0.3	**28.3**
	2033	22.3	9.5	2.0	-3.8	-0.2	-0.4	**29.4**
	2034	22.2	11.0	2.3	-4.1	-0.2	-0.5	**30.7**
	2035	22.2	12.4	2.6	-4.4	-0.2	-0.6	**32.1**

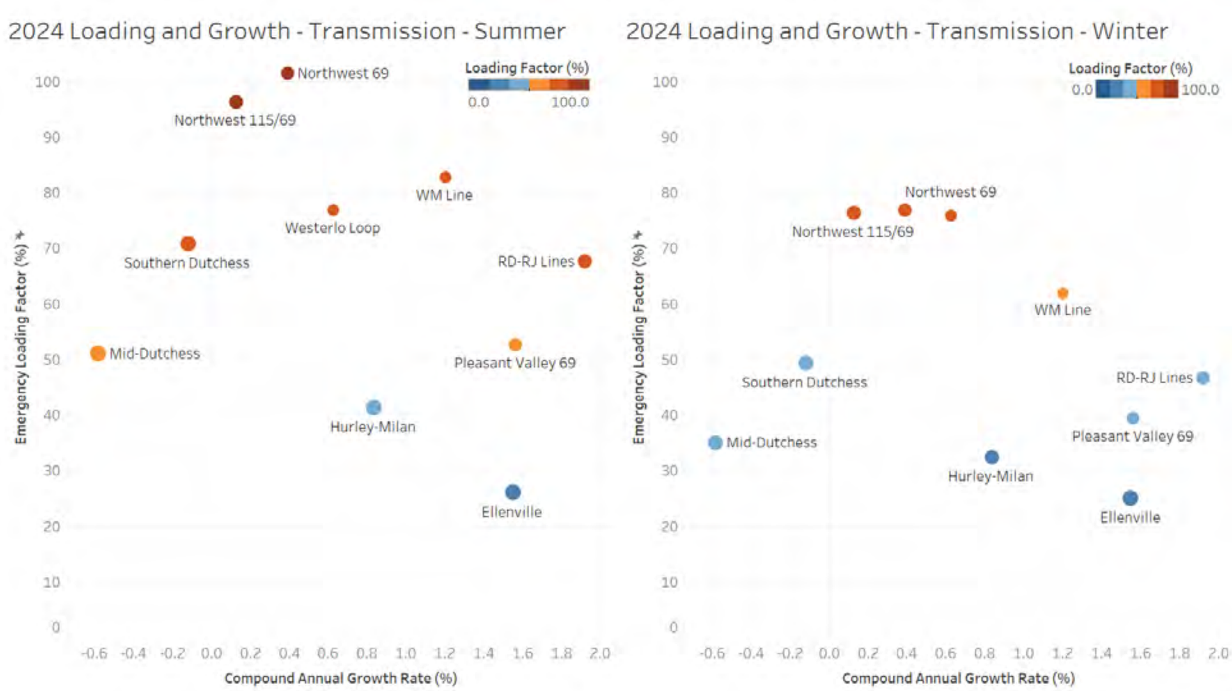
[1] Solar includes net-metered customers, Community Distributed Generation (CDG), and remote solar projects, since they impact distribution planning.

3.2 TRANSMISSION AREA FORECASTS

Central Hudson has ten local transmission areas. Figure 7 compares the annual load growth rate over the past ten years to the 2024 loading factor (actual peak divided by the location's operating limit) 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. Roughly 70% of the local transmission areas (load-weighted) have been experiencing growth, but approximately 25% (load-weighted) have loading factors above 85%. The two most highly loaded areas Northwest 115/69 kV and Northwest 69kV are part of non-wires alternative project that has deferred capital costs since 2015 and are scheduled for upgrades in 2029.

All transmission areas in Central Hudson's territory are currently summer-peaking systems. Some are experiencing slow growth or declining loads or have ample room for growth without having to upgrade them. Several of the local transmission areas have multi-value infrastructure projects. As part of the upgrades, the transmission capacity for those locations will increase in order accommodate increasing amounts of solar, planned battery storage, and load growth.

Figure 7: Local Transmission Historical Growth Rates and Loading Factors



Notes: Bubble size is proportional to the LTE rating of the site. The color reflects the 2024 loading for each site.

Table 6 summarizes the forecasts for each local transmission area for winter and summer annual peak loads. The forecasts incorporate the historic growth trends, projected changes in household growth, and the forecasts for electric vehicles, building electrification, solar, battery storage, energy efficiency and codes and standards. They are implemented at an hourly level, so the changes in the peak hour and season can be identified.

Table 6: Local Transmission 2025-2035 Integrated Load Forecast

	Substation	Actual 2024 Loading (%)	Historical growth rate[1]	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Summer	Ellenville	26.1%	1.5%	78.8	77.8	78.4	79.0	79.8	80.4	81.0	81.2	81.4	81.3
	Hurley-Milan	41.2%	0.8%	94.9	94.9	95.3	95.7	96.0	97.0	97.7	98.6	99.1	99.7
	Mid-Dutchess	51.0%	-0.6%	139.7	137.4	135.8	134.2	132.5	131.6	130.7	130.8	130.8	130.9
	Northwest 115/69	96.2%	0.1%	168.5	166.9	166.0	164.7	164.1	163.7	163.3	163.3	163.3	163.7
	Northwest 69	101.4%	0.4%	137.9	137.3	137.4	137.8	137.6	137.6	137.9	138.1	138.1	138.2
	Pleasant Valley 69	52.5%	1.6%	68.9	69.5	70.4	71.6	72.7	73.7	74.9	75.7	76.4	77.2
	RD-RJ Lines	67.5%	1.9%	120.0	121.6	123.1	125.1	127.2	128.7	130.4	131.2	132.2	133.1
	Southern Dutchess	70.7%	-0.1%	182.0	180.7	179.4	178.6	177.7	177.1	177.1	177.1	178.0	178.8
	WM Line	82.6%	1.2%	70.4	71.1	71.8	72.3	73.1	73.5	73.8	74.4	74.7	75.0
	Westerlo Loop	76.8%	0.6%	75.5	75.3	75.3	75.5	75.6	75.5	75.1	74.8	74.5	74.2
Winter	Ellenville	25.0%	1.5%	66.5	67.2	69.2	71.5	74.0	76.5	79.3	82.0	84.7	87.3
	Hurley-Milan	32.3%	0.8%	69.7	70.6	71.7	73.0	74.2	76.0	77.7	79.6	81.3	83.1
	Mid-Dutchess	35.0%	-0.6%	84.4	83.6	83.3	83.2	83.0	83.3	83.9	85.0	86.3	87.7
	Northwest 115/69	76.3%	0.1%	142.4	142.0	142.7	142.8	143.4	144.3	145.3	146.6	148.0	149.7
	Northwest 69	76.9%	0.4%	121.4	121.3	121.9	122.8	123.2	123.8	124.7	125.5	126.3	127.1
	Pleasant Valley 69	39.3%	1.6%	48.0	49.1	50.5	52.3	54.0	55.8	57.9	59.8	61.8	63.8
	RD-RJ Lines	46.6%	1.9%	74.5	76.0	77.3	79.1	81.0	82.6	84.4	85.8	87.4	89.0
	Southern Dutchess	49.2%	-0.1%	112.7	112.6	112.6	113.0	113.4	114.1	115.2	116.5	118.4	120.3
	WM Line	61.9%	1.2%	45.9	46.5	47.1	47.5	48.2	48.7	49.1	49.7	50.2	50.7
	Westerlo Loop	75.7%	0.6%	70.3	70.8	71.6	72.6	73.9	75.7	77.7	80.1	82.6	85.3

Table 7 and Table 8 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). 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.

Table 7: Transmission Area Summer Integrated Load Forecast by Component (2025-2030)

Transmission Area	Year	(a) Econometric Forecast (Gross Load)	(b) EV Load	(c) Building Electrification	(d) EE & CS	(e) Solar PV	(f) Storage Net Load	(g) Planning Load (a) + (b) + (c) + (d) + (e) + (f)
Ellenville	2025	81.3	1.4	-0.5	-1.7	-1.8	-0.1	78.6
	2026	82.2	1.9	-0.6	-2.6	-1.9	-0.1	78.9
	2027	83.2	2.5	-0.7	-3.4	-1.9	-0.1	79.5
	2028	84.0	3.3	-0.8	-4.1	-2.1	-0.1	80.1
	2029	84.8	4.3	-1.0	-5.0	-2.2	-0.3	80.7
	2030	86.0	5.4	-1.1	-5.9	-2.3	-0.6	81.6
Hurley-Milan	2025	100.2	1.6	-0.4	-1.5	-4.3	-0.1	95.5
	2026	100.5	2.1	-0.5	-2.3	-4.4	-0.1	95.2
	2027	100.7	2.7	-0.6	-3.0	-4.7	-0.1	95.1
	2028	97.7	3.5	-0.6	-3.8	-1.3	-0.2	95.4
	2029	98.1	4.5	-0.7	-4.5	-1.3	-0.3	95.8
	2030	98.4	5.6	-0.8	-5.3	-1.4	-0.4	96.0
Mid-Dutchess	2025	147.7	1.3	-0.2	-1.5	-4.7	0.0	142.6
	2026	145.8	1.7	-0.3	-2.2	-5.0	0.0	140.0
	2027	143.9	2.2	-0.3	-2.8	-5.3	0.0	137.7
	2028	142.4	2.9	-0.4	-3.4	-5.5	0.0	135.9
	2029	141.0	3.7	-0.5	-4.1	-5.8	0.0	134.3
	2030	139.3	4.6	-0.6	-4.9	-6.0	-0.1	132.5
Northwest 115/69	2025	172.1	1.2	-0.4	-1.2	-2.0	-0.1	169.6
	2026	171.6	1.6	-0.5	-1.9	-2.1	-0.1	168.7
	2027	170.2	2.2	-0.6	-2.5	-2.3	-0.1	167.0
	2028	169.9	2.9	-0.7	-3.0	-2.9	-0.1	166.1
	2029	168.6	3.7	-0.8	-3.6	-3.1	-0.2	164.6
	2030	168.0	4.7	-0.9	-4.3	-3.3	-0.2	163.9
Northwest 69	2025	140.6	0.5	-0.2	-0.7	-1.9	0.0	138.2
	2026	141.0	0.7	-0.3	-1.0	-2.0	0.0	138.4
	2027	141.7	0.9	-0.3	-1.3	-2.1	-0.8	138.0
	2028	141.8	1.2	-0.4	-1.6	-2.4	-0.8	137.8
	2029	142.4	1.5	-0.4	-1.9	-2.5	-1.0	138.1
	2030	142.4	2.0	-0.5	-2.2	-2.7	-1.1	137.8
Pleasant Valley 69	2025	70.9	1.6	-0.2	-1.5	-1.6	-0.1	69.0
	2026	71.6	2.2	-0.3	-2.5	-1.7	-0.1	69.2
	2027	72.3	2.9	-0.4	-3.3	-1.8	-0.1	69.6
	2028	73.1	3.8	-0.5	-4.0	-1.9	-0.1	70.4
	2029	72.4	4.8	-0.6	-4.6	-0.1	-0.1	71.6

Transmission Area	Year	(a) Econometric Forecast (Gross Load)	(b) EV Load	(c) Building Electrification	(d) EE & CS	(e) Solar PV	(f) Storage Net Load	(g) Planning Load (a) + (b) + (c) + (d) + (e) + (f)
	2030	73.4	6.0	-0.7	-5.6	-0.1	-0.2	72.7
RD-RJ Lines	2025	120.0	1.4	-0.1	-1.2	-1.3	-0.1	118.8
	2026	121.6	1.9	-0.2	-1.9	-1.4	-0.1	120.1
	2027	123.3	2.6	-0.2	-2.5	-1.4	-0.1	121.7
	2028	125.0	3.4	-0.2	-3.0	-1.5	-0.4	123.2
	2029	126.9	4.4	-0.3	-3.7	-1.5	-0.5	125.2
	2030	129.0	5.5	-0.4	-4.5	-1.6	-0.8	127.4
Southern Dutchess	2025	189.5	1.8	-0.2	-1.6	-4.8	-0.1	184.6
	2026	188.0	2.4	-0.3	-2.5	-5.1	-0.1	182.3
	2027	187.0	3.1	-0.4	-3.2	-5.4	-0.1	181.0
	2028	185.8	3.9	-0.5	-3.9	-5.7	-0.1	179.6
	2029	185.0	4.9	-0.5	-4.7	-5.9	-0.1	178.7
	2030	184.1	6.1	-0.7	-5.5	-6.1	-0.1	177.8
WM Line	2025	73.0	0.3	0.0	-0.3	-2.7	0.0	70.3
	2026	71.5	0.5	0.0	-0.5	-0.9	0.0	70.6
	2027	72.3	0.6	-0.1	-0.7	-0.9	0.0	71.3
	2028	72.9	0.8	-0.1	-0.8	-0.9	0.0	71.9
	2029	73.4	1.0	-0.1	-1.0	-0.9	-0.1	72.4
	2030	74.2	1.3	-0.1	-1.2	-0.9	-0.1	73.3
Westerlo Loop	2025	77.6	1.1	-0.2	-1.2	-0.2	0.0	77.1
	2026	77.4	1.6	-0.2	-2.0	-0.2	-1.2	75.4
	2027	77.3	2.2	-0.3	-2.6	-0.2	-1.2	75.2
	2028	77.2	3.0	-0.4	-3.2	-0.2	-1.2	75.1
	2029	77.6	4.0	-0.5	-3.9	-0.2	-1.5	75.4
	2030	78.1	5.1	-0.6	-4.8	-0.2	-2.0	75.7

Table 8: Transmission Area Winter Load Forecast with and without DERs (2025-2030)

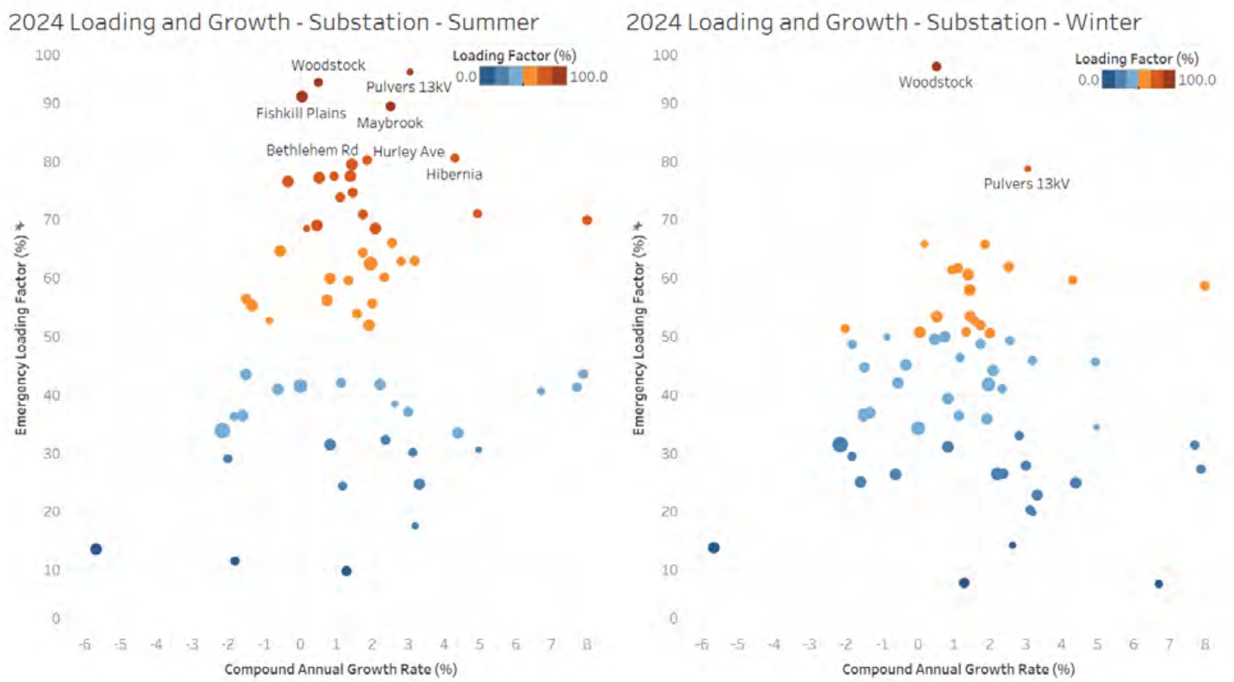
Transmission Area	Year	(a) Econometric Forecast (Gross Load)	(b) EV Load	(c) Building Electrification	(d) EE & CS	(e) Solar PV	(f) Storage Net Load	(g) Planning Load (a) + (b) + (c) + (d) + (e) + (f)
Ellenville	2025	60.7	1.5	5.1	-1.6	-0.4	-0.1	65.2
	2026	61.4	2.1	6.1	-2.5	-0.5	-0.1	66.6
	2027	61.5	2.8	7.4	-3.1	-0.1	-0.1	68.4
	2028	62.1	3.7	8.6	-3.8	-0.1	-0.1	70.3
	2029	62.7	4.7	9.8	-4.5	-0.1	-0.2	72.4
	2030	63.6	6.0	11.1	-5.4	-0.1	-0.5	74.7
Hurley-Milan	2025	67.0	1.4	3.3	-1.5	-0.8	0.0	69.3
	2026	66.3	1.9	4.0	-2.2	-0.3	-0.1	69.7
	2027	66.5	2.5	4.8	-2.8	-0.3	-0.1	70.6
	2028	66.9	3.2	5.6	-3.4	-0.3	-0.2	71.7
	2029	67.1	4.1	6.4	-4.0	-0.3	-0.3	73.0
	2030	67.3	5.1	7.4	-4.8	-0.3	-0.4	74.3
Mid-Dutchess	2025	84.6	1.2	1.4	-1.2	-0.4	0.0	85.5
	2026	83.5	1.6	1.7	-1.9	-0.4	0.0	84.4
	2027	82.4	2.1	2.1	-2.5	-0.5	0.0	83.7
	2028	81.5	2.7	2.6	-3.0	-0.5	0.0	83.4
	2029	80.7	3.5	3.2	-3.6	-0.5	0.0	83.2
	2030	79.8	4.3	3.8	-4.3	-0.5	0.0	83.0
Northwest 115/69	2025	139.1	1.3	3.3	-1.3	-0.1	0.0	142.3
	2026	138.8	1.8	3.9	-1.9	-0.1	0.0	142.4
	2027	137.6	2.4	4.7	-2.5	-0.1	0.0	142.0
	2028	137.4	3.1	5.5	-3.0	-0.2	0.0	142.8
	2029	136.3	4.0	6.3	-3.5	-0.2	-0.1	142.8
	2030	135.8	5.1	7.2	-4.2	-0.2	-0.2	143.5
Northwest 69	2025	119.2	0.5	1.8	-0.6	-0.1	0.0	120.8
	2026	119.6	0.7	2.1	-0.9	-0.1	0.0	121.4
	2027	120.1	1.0	2.5	-1.2	-0.1	-0.8	121.5
	2028	120.3	1.3	2.9	-1.4	-0.2	-0.8	122.1
	2029	120.8	1.7	3.3	-1.7	-0.2	-1.0	123.0
	2030	120.7	2.2	3.8	-2.0	-0.2	-1.1	123.4
Pleasant Valley 69	2025	45.4	1.4	2.6	-1.6	-0.4	-0.1	47.4
	2026	45.8	2.0	3.3	-2.5	-0.4	-0.1	48.1
	2027	46.3	2.7	4.0	-3.3	-0.5	-0.1	49.1
	2028	46.8	3.5	4.9	-4.0	-0.5	-0.1	50.6
	2029	47.5	4.5	5.8	-4.8	-0.5	-0.2	52.4

Transmission Area	Year	(a) Econometric Forecast (Gross Load)	(b) EV Load	(c) Building Electrification	(d) EE & CS	(e) Solar PV	(f) Storage Net Load	(g) Planning Load (a) + (b) + (c) + (d) + (e) + (f)
	2030	48.2	5.7	6.7	-5.8	-0.5	-0.2	54.1
RD-RJ Lines	2025	72.4	1.3	1.2	-1.0	-0.3	-0.1	73.5
	2026	73.3	1.8	1.5	-1.7	-0.3	-0.1	74.6
	2027	74.4	2.4	1.9	-2.2	-0.3	-0.1	76.0
	2028	75.4	3.1	2.4	-2.7	-0.4	-0.4	77.3
	2029	76.5	4.0	2.9	-3.3	-0.4	-0.5	79.2
	2030	77.8	5.1	3.4	-4.1	-0.4	-0.8	81.1
Southern Dutchess	2025	111.8	1.8	1.7	-1.5	-0.1	-0.1	113.5
	2026	110.9	2.3	2.1	-2.4	-0.2	-0.1	112.7
	2027	110.3	3.0	2.6	-3.0	-0.2	-0.1	112.6
	2028	109.6	3.9	3.1	-3.6	-0.2	-0.1	112.6
	2029	109.1	4.8	3.7	-4.3	-0.2	-0.1	113.0
	2030	108.6	6.0	4.4	-5.2	-0.2	-0.2	113.5
WM Line	2025	45.4	0.3	0.3	-0.3	-0.2	0.0	45.5
	2026	45.8	0.4	0.4	-0.5	-0.2	0.0	45.9
	2027	46.3	0.5	0.5	-0.6	-0.2	0.0	46.5
	2028	46.7	0.7	0.6	-0.7	-0.2	0.0	47.1
	2029	47.0	0.9	0.8	-0.9	-0.2	-0.1	47.6
	2030	47.5	1.2	0.9	-1.0	-0.2	-0.1	48.3
Westerlo Loop	2025	70.2	1.3	2.0	-1.4	-0.6	0.0	71.4
	2026	69.9	1.8	2.5	-2.2	-0.7	-1.2	70.2
	2027	69.9	2.5	3.1	-2.9	-0.7	-1.2	70.7
	2028	69.8	3.3	3.8	-3.6	-0.7	-1.2	71.4
	2029	70.1	4.4	4.6	-4.3	-0.8	-1.5	72.6
	2030	68.0	5.1	5.9	-5.0	-0.1	0.0	73.9

3.3 SUBSTATION FORECASTS

Figure 8 compares the annual load growth rates to the 2024 loading factors for each of Central Hudson's load serving distribution substations. Roughly 75% of the substations have been experiencing growth, most of which has been driven by growth in customers. On average, peak demand per customer has been declining across Central Hudson's service territory. A small share of the substations, less than 8%, are at 85% or more of the operating limit. Most of the substations, 87% of them, remain summer peaking. With a few exceptions, most of the substations have room to accommodate electric vehicles and building electrification loads over the next five years. One of the highly loaded substations, Fishkill Plains, is part of non-wires alternative project that has deferred capital costs since 2015 and is scheduled for upgrades in 2027.

Figure 8: Substation Historical Growth Rates and Loading Factors



*Note: Bubble size is proportional to the LTE rating of the site. The color reflects the 2024 loading for each site.

Table 9 shows the 2025-2035 summer peak forecast (MW) for each load serving substation. The forecasts are calibrated to the territory-wide load forecasts and incorporate forecasted changes in household growth. They include existing loads and all load modifiers - solar, battery storage, EVs, heat pumps, and incremental EE and codes and standards. For each year, the peak is shown after accounting for changes in the peak hours due to the forecasted increase in solar, electric vehicles, and other load modifiers. Table 10 shows a similar forecast, but for winter annual peaks.

Table 9: Substation Summer 2025-2035 Integrated Load Forecast (MW)

Substation	Actual 2024 Loading (%)	Historical growth rate[1]	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Barnegat	13.5%	-5.7%	4.9	4.6	4.2	3.9	3.7	3.4	3.2	3.1	2.9	2.9	2.8
Bethlehem Rd	79.4%	1.4%	40.4	40.5	40.5	40.4	40.5	40.4	40.5	40.4	40.2	40.0	39.6
Boulevard	56.3%	-1.5%	17.4	16.7	15.9	15.4	15.1	14.9	14.8	14.8	14.9	15.2	15.4
Clinton Ave	17.5%	3.2%	4.4	4.5	4.5	4.6	4.7	4.7	4.8	4.9	4.9	5.0	5.0
Coldenham	55.2%	-1.3%	25.3	24.8	24.3	23.8	23.3	22.8	22.2	21.9	21.7	21.6	21.6
Coxsackie	31.4%	0.8%	22.7	22.5	22.2	22.1	22.1	22.2	22.1	22.3	22.4	22.5	22.7
East Kingston	33.5%	4.4%	16.0	16.3	16.7	17.2	17.7	18.3	18.7	19.2	19.5	19.8	20.0
East Park	60.1%	2.3%	14.2	14.3	14.4	14.6	14.9	15.1	15.3	15.5	15.7	15.9	16.0
East Walden	62.9%	3.2%	16.0	16.3	16.0	16.4	16.7	17.1	17.3	17.5	17.6	17.6	17.7
Fishkill Plains	91.1%	0.0%	43.1	42.0	41.1	40.6	40.3	40.1	39.8	39.7	39.7	39.9	40.2

Substation	Actual 2024 Loading (%)	Historical growth rate[1]	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Forgebrook	59.8%	0.8%	30.1	29.9	29.8	29.7	29.7	29.6	29.7	29.7	29.9	30.2	30.5
Freehold	62.8%	2.8%	7.9	7.0	7.0	7.2	7.3	7.4	7.5	7.6	7.6	7.6	7.7
Galeville	42.0%	1.1%	11.5	11.2	11.1	11.1	11.0	10.9	10.8	10.6	10.4	10.2	9.9
Grimley Rd X1	38.4%	2.6%	3.8	3.6	3.6	3.7	3.7	3.7	3.8	3.9	3.9	3.9	3.9
Grimley Rd X2	40.6%	6.7%	10.9	11.6	12.4	13.3	14.4	15.6	16.7	17.6	18.3	18.7	18.9
Hibernia	80.5%	4.3%	14.1	14.4	14.7	15.1	15.6	16.2	16.6	17.1	17.6	18.0	18.2
High Falls	55.6%	2.0%	19.7	19.6	19.6	19.8	19.9	20.1	20.2	20.4	20.7	20.8	21.0
Highland	64.2%	1.7%	20.7	20.7	20.8	21.0	21.2	21.4	21.6	21.7	21.8	22.0	22.2
Honk Falls	36.2%	-1.8%	7.2	7.0	5.7	5.5	5.3	5.1	5.2	5.2	5.3	5.5	5.7
Hunter	11.5%	-1.8%	2.1	2.0	1.9	1.9	1.9	1.8	1.8	1.8	1.9	1.9	2.0
Hurley Ave	80.1%	1.9%	17.8	17.7	17.9	18.0	18.2	18.4	18.5	18.7	18.8	18.9	19.0
Inwood Ave	68.5%	2.1%	27.9	27.6	27.6	27.9	28.5	28.8	29.2	29.5	29.7	30.0	30.1
Kerhonkson	24.6%	3.3%	10.8	10.9	10.5	10.7	11.0	11.2	11.3	11.3	11.3	11.3	11.2
Knapps Corners	36.3%	-1.6%	18.0	17.4	16.8	16.3	15.9	15.3	14.9	14.5	14.3	14.2	14.3
Lawrenceville	29.0%	-2.0%	5.7	5.5	5.3	5.2	5.1	5.0	4.9	4.8	4.8	4.8	4.8
Lincoln Park	41.5%	0.0%	38.6	37.7	37.2	36.6	36.1	35.6	35.1	34.6	34.3	34.0	33.9
Manchester	76.5%	-0.3%	34.9	34.2	33.3	32.7	32.1	31.6	31.2	30.9	30.7	30.7	31.0
Marlboro	70.9%	1.8%	21.7	21.8	21.0	21.1	21.4	21.4	21.4	21.5	21.6	21.9	22.1
Maybrook	89.3%	2.5%	21.8	22.1	22.4	22.8	23.3	23.6	23.9	24.2	24.4	24.6	24.8
Merritt Park	64.5%	-0.6%	33.9	33.0	32.3	31.6	30.9	30.3	29.6	29.2	28.8	28.5	28.5
Milan	41.2%	7.7%	9.6	10.2	10.8	11.6	12.4	13.3	14.2	15.0	15.7	16.1	16.4
Millerton	52.7%	-0.9%	4.5	4.4	4.3	4.2	4.2	4.1	4.1	4.1	4.2	4.3	4.4
Modena	53.8%	1.6%	14.7	14.5	14.5	14.5	14.6	14.6	14.7	14.9	15.0	15.2	15.3
Montgomery	43.5%	7.9%	10.7	11.3	12.0	12.8	13.7	14.6	15.6	16.4	17.1	17.6	17.8
Myers	56.4%	-1.5%	19.2	18.0	17.5	17.0	16.5	16.0	15.6	15.3	15.2	15.1	15.2
New Baltimore	69.8%	8.0%	18.3	19.6	21.0	21.5	23.0	24.9	26.9	28.5	29.9	30.8	31.4
North Catskill	74.6%	1.5%	26.5	26.4	26.3	25.9	26.1	26.2	26.2	26.2	26.2	26.4	26.6
North Chelsea	40.9%	-0.6%	18.2	17.8	17.3	16.9	16.6	16.1	15.7	15.3	14.9	14.7	14.8
Ohioville	73.8%	1.1%	22.8	22.0	22.1	22.1	22.1	22.0	21.9	21.8	21.6	21.4	21.5
Pulvers 13kV	95.2%	3.1%	5.9	5.9	6.0	6.1	6.3	6.4	6.6	6.8	6.9	7.1	7.2
Reynolds Hill	77.4%	1.4%	41.1	40.8	40.6	40.6	40.6	40.8	40.9	41.2	41.4	41.7	42.1
Rhinebeck	56.1%	0.8%	27.9	27.6	27.4	27.5	27.6	27.6	27.7	27.9	28.2	28.5	28.9
Sand Dock-Distribution	68.5%	0.2%	5.0	5.0	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
Sand Dock-Industrial							Confidential						
Saugerties	41.8%	2.2%	23.2	23.2	22.3	22.7	22.8	23.0	23.2	23.2	23.4	23.4	23.5
Shenandoah-Distribution	71.0%	4.9%	14.7	15.2	15.7	16.4	17.1	17.8	18.4	19.0	19.6	19.9	20.2
Shenandoah-Industrial							Confidential						
Smithfield	30.6%	5.0%	2.8	2.9	3.0	3.1	3.2	3.3	3.4	3.5	3.6	3.7	3.7
South Cairo	65.9%	2.6%	12.2	12.2	12.4	12.6	12.7	12.8	12.8	12.6	12.4	12.5	13.1
Spackenkill	69.0%	0.5%	33.3	32.9	32.7	32.4	32.2	32.0	31.8	31.7	31.7	31.8	32.1
Staatsburg	37.1%	3.0%	9.8	9.8	10.0	10.1	10.3	10.5	10.6	10.8	10.8	10.9	10.9
Stanfordville	30.1%	3.1%	5.8	5.9	6.0	6.1	6.2	6.4	6.5	6.7	6.8	6.9	7.0
Sturgeon Pool	9.7%	1.3%	3.1	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.1	3.1
Tinkertown	77.4%	0.9%	14.4	14.3	14.2	14.2	14.2	14.2	14.2	14.3	14.4	14.6	14.7
Tioronda	59.6%	1.3%	16.2	16.2	16.4	16.4	16.5	16.6	16.8	17.0	17.2	17.4	17.7
Todd Hill	51.9%	1.9%	24.9	24.9	25.1	25.3	25.5	25.7	26.0	26.2	26.4	26.6	26.7
Union Ave	62.5%	2.0%	59.9	60.2	60.8	61.4	61.5	62.3	63.0	63.9	64.8	65.6	66.3
Vinegar Hill	24.4%	1.2%	4.9	4.9	4.8	4.9	4.9	4.9	5.0	5.0	5.1	5.1	5.2
West Balmville	77.1%	0.5%	36.8	36.0	35.8	35.4	35.0	34.6	34.4	34.4	34.5	34.7	35.0
Westerlo	32.2%	2.4%	8.7	8.7	8.8	8.9	9.0	8.9	8.8	8.6	8.3	8.4	9.1
Wiccopee	4.6%	0.8%	1.2	1.2	1.2	1.2	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Woodstock	93.4%	0.5%	18.2	17.8	17.6	17.5	17.5	17.5	17.5	17.6	17.8	18.0	18.2

[1] Forecast are calibrated to the territory wide load forecasts and incorporate forecasted changes in household growth. They include loads and all load modifiers - solar, battery storage, EVs, heat pumps, and incremental EE and codes and standards.

Table 10: Substation Winter 2025-2035 Integrated Load Forecast (MW)

Substation	Actual 2024 Loading (%)	Historical growth rate[1]	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Barnegat	13.8%	-5.7%	4.0	3.8	3.5	3.3	3.0	2.8	2.6	2.5	2.4	2.4	2.3
Bethlehem Rd	57.9%	1.4%	26.3	26.5	26.6	26.6	26.8	26.9	27.3	27.9	28.4	29.0	29.6
Boulevard	44.7%	-1.5%	16.4	16.2	16.1	16.0	16.0	16.1	16.3	16.5	17.0	17.5	18.1
Clinton Ave	19.8%	3.2%	4.6	4.7	4.8	4.9	5.0	5.1	5.2	5.3	5.3	5.4	5.4
Coldenham	37.0%	-1.3%	17.6	17.3	17.0	16.8	16.5	16.2	15.9	15.8	15.8	15.8	15.9
Coxsackie	30.9%	0.8%	39.7	39.5	39.1	39.0	39.1	39.2	39.2	39.5	39.5	39.7	40.1
East Kingston	24.8%	4.4%	12.0	12.4	12.8	13.4	14.0	14.7	15.3	15.9	16.5	17.0	17.6
East Park	40.9%	2.3%	10.2	10.4	10.7	11.0	11.3	11.6	12.0	12.4	12.7	13.1	13.5
East Walden	45.8%	3.2%	12.0	12.3	12.1	12.6	12.9	13.4	13.7	14.2	14.7	15.2	15.7
Fishkill Plains	50.7%	0.0%	24.4	24.1	24.0	24.1	24.4	24.8	25.2	25.8	26.5	27.3	28.3
Forgebrook	39.3%	0.8%	19.3	19.3	19.5	19.7	20.0	20.3	20.7	21.2	21.7	22.4	23.1
Freehold	32.9%	2.8%	7.0	6.7	6.8	7.0	7.2	7.5	7.8	8.0	8.3	8.6	8.9
Galeville	36.4%	1.1%	10.2	10.3	10.5	10.7	10.9	11.2	11.6	11.9	12.3	12.7	13.1
Grimley Rd X1	14.2%	2.6%	1.5	1.4	1.5	1.5	1.5	1.5	1.6	1.6	1.7	1.7	1.8
Grimley Rd X2	7.5%	6.7%	0.9	0.9	0.9	0.9	1.0	1.0	1.1	1.1	1.2	1.3	1.3
Hibernia	59.6%	4.3%	11.0	11.3	11.7	12.1	12.6	13.2	13.7	14.2	14.7	15.3	15.7
High Falls	50.5%	2.0%	18.2	18.6	19.2	19.9	20.6	21.4	22.2	23.0	23.9	24.7	25.7
Highland	48.7%	1.7%	16.6	16.9	17.2	17.7	18.2	18.7	19.2	19.7	20.2	20.7	21.3
Honk Falls	29.4%	-1.8%	5.2	5.1	5.6	5.5	5.5	5.4	5.5	5.7	5.8	6.1	6.4
Hunter	48.6%	-1.8%	9.1	8.9	8.7	8.4	8.2	8.0	7.9	7.8	7.8	7.8	7.8
Hurley Ave	65.8%	1.9%	15.4	15.6	16.1	16.5	17.1	17.6	18.1	18.7	19.2	19.8	20.3
Inwood Ave	44.1%	2.1%	20.2	20.3	20.5	20.8	21.3	21.6	22.0	22.4	22.8	23.3	23.7
Kerhonkson	22.8%	3.3%	10.3	10.7	11.0	11.5	12.1	12.7	13.3	13.8	14.4	15.0	15.6
Knapps Corners	25.0%	-1.6%	11.2	11.0	10.7	10.5	10.4	10.2	10.1	10.1	10.2	10.5	10.8
Lawrenceville	51.3%	-2.0%	13.8	13.4	13.0	12.8	12.5	12.3	12.1	11.9	11.9	12.0	12.1
Lincoln Park	34.3%	0.0%	27.8	27.5	27.6	27.4	27.5	27.6	27.7	27.8	28.1	28.5	29.2
Manchester	45.1%	-0.3%	21.3	21.0	20.7	20.6	20.5	20.6	20.7	20.9	21.2	21.7	22.3
Marlboro	51.9%	1.8%	16.1	16.2	15.4	15.7	15.9	16.0	16.3	16.6	17.1	18.0	18.9
Maybrook	61.9%	2.5%	15.5	15.8	16.0	16.4	16.8	17.2	17.5	17.8	18.0	18.4	18.6
Merritt Park	41.9%	-0.6%	20.6	20.2	19.9	19.8	19.6	19.4	19.3	19.3	19.4	19.6	19.9
Milan	31.4%	7.7%	9.2	9.9	10.6	11.5	12.4	13.4	14.5	15.5	16.3	17.0	17.6
Millerton	49.9%	-0.9%	4.2	4.1	4.1	4.1	4.1	4.2	4.2	4.4	4.5	4.7	4.9
Modena	52.5%	1.6%	11.1	11.3	11.5	11.7	12.1	12.4	12.8	13.2	13.7	14.1	14.6
Montgomery	27.3%	7.9%	6.4	6.8	7.3	7.8	8.3	8.9	9.5	10.0	10.5	10.8	11.1
Myers	36.2%	-1.5%	12.4	12.1	11.9	11.8	11.7	11.6	11.6	11.8	12.0	12.4	12.8
New Baltimore	58.6%	8.0%	17.2	18.3	19.5	20.7	22.0	23.5	25.1	26.3	27.3	28.0	28.3
North Catskill	53.4%	1.5%	20.4	20.5	20.7	20.8	21.2	21.5	21.9	22.2	22.6	23.2	23.8
North Chelsea	26.3%	-0.6%	10.5	10.3	10.1	10.0	9.9	9.7	9.5	9.5	9.7	10.0	10.4
Ohioville	61.6%	1.1%	19.3	19.4	19.7	20.1	20.4	20.6	20.8	21.0	21.3	21.8	22.4
Pulvers 13kV	78.7%	3.1%	4.9	5.0	5.2	5.3	5.6	5.8	6.0	6.2	6.5	6.7	7.0
Reynolds Hill	60.5%	1.4%	26.2	26.2	26.2	26.3	26.4	26.6	26.8	27.2	27.6	28.0	28.5
Rhinebeck	49.8%	0.8%	23.3	23.4	23.7	24.1	24.6	25.0	25.7	26.3	27.1	27.9	28.8
Sand Dock-Distribution	65.8%	0.2%	3.0	3.0	3.0	3.0	3.1	3.1	3.1	3.2	3.2	3.3	3.4
Sand Dock-Industrial							Confidential						
Saugerties	26.4%	2.2%	19.1	19.5	19.4	20.1	20.9	21.7	22.6	23.4	24.4	25.4	26.4
Shenandoah-Distribution	45.5%	4.9%	9.7	10.1	10.6	11.1	11.7	12.2	12.8	13.3	13.9	14.3	14.6
Shenandoah-Industrial							Confidential						
Smithfield	34.5%	5.0%	3.0	3.1	3.2	3.3	3.4	3.5	3.6	3.7	3.8	3.9	3.9
South Cairo	49.2%	2.6%	11.8	12.0	12.3	12.6	12.8	13.1	13.5	13.9	14.4	14.9	15.7
Spackenkill	49.4%	0.5%	20.2	20.2	20.3	20.4	20.6	20.9	21.2	21.6	22.0	22.6	23.3

Staatsburg	27.8%	3.0%	8.0	8.2	8.4	8.6	8.9	9.1	9.4	9.7	9.9	10.1	10.4
Stanfordville	20.2%	3.1%	5.2	5.3	5.5	5.7	6.0	6.2	6.5	6.8	7.1	7.4	7.7
Sturgeon Pool	7.8%	1.3%	2.6	2.6	2.6	2.7	2.8	2.8	2.9	3.0	3.1	3.2	3.3
Tinkertown	61.4%	0.9%	11.5	11.5	11.6	11.7	11.9	12.0	12.2	12.5	12.9	13.2	13.7
Tioronda	50.7%	1.3%	12.7	12.8	13.1	13.3	13.6	13.9	14.3	14.7	15.2	15.7	16.2
Todd Hill	35.8%	1.9%	17.1	17.3	17.6	17.9	18.3	18.7	19.2	19.7	20.2	20.8	21.3
Union Ave	41.7%	2.0%	38.8	39.2	39.9	40.6	41.2	42.1	43.1	44.3	45.6	46.9	48.3
Vinegar Hill	46.3%	1.2%	9.7	9.7	9.8	9.8	9.9	10.1	10.2	10.3	10.5	10.6	10.9
West Balmville	53.4%	0.5%	25.2	24.9	25.0	25.0	25.0	25.0	25.2	25.6	26.0	26.6	27.3
Westerlo	26.5%	2.4%	8.2	8.3	8.5	8.7	8.8	8.9	9.1	9.6	10.2	11.0	11.8
Wiccopee	3.9%	0.8%	0.9	0.9	0.9	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Woodstock	96.2%	0.5%	21.0	21.3	21.7	22.4	23.1	23.8	24.7	25.5	26.5	27.5	28.6

[1] Forecast are calibrated to the territory wide load forecasts and incorporate forecasted changes in household growth. They include loads and all load modifiers - solar, battery storage, EVs, heat pumps, and incremental EE and codes and standards. The implication is that the future differs from the past.

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 11 shows the 2030 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 11: 2030 Substation Summer Peak Load Forecast by Component

Load Area	Substation	(a) Econometrics Forecast (Gross Load)	(b) EV Load	(c) Building Electrification	(d) EE & CS	(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	-0.2	0.0	1.6
	Grimley Rd X1	2.7	0.1	0.0	-0.1	0.0	0.0	2.6
	Grimley Rd X2	21.6	0.0	0.0	-0.2	-3.7	0.0	17.7
	High Falls	23.5	2.0	-0.4	-2.1	-0.6	-0.1	22.2
	Honk Falls	5.0	0.2	0.0	-0.3	0.0	-0.1	4.8
	Kerhonkson	14.9	1.0	-0.2	-1.1	-0.4	-0.1	14.0
	Sturgeon Pool	3.0	0.3	-0.1	-0.2	0.0	0.0	2.9
Fishkill-D	Fishkill Plains	41.1	3.4	-0.3	-3.5	-0.9	-0.1	39.7
	Forgebrook	32.9	2.2	-0.2	-1.8	-1.6	0.0	31.4
	Knapps Corners	14.8	0.7	-0.1	-0.7	-0.8	0.0	13.9
	Merritt Park	31.8	1.0	-0.2	-1.3	-2.1	0.0	29.3
	Myers	15.8	1.2	-0.1	-1.3	-0.8	0.0	14.8
	North Chelsea	15.8	1.0	-0.1	-1.1	0.0	-0.3	15.4
	Sand Dock-Distribution	4.6	0.5	-0.1	-0.2	-0.1	0.0	4.6
	Shenandoah-Industrial	Confidential						
	Tioronda	17.4	1.7	-0.1	-1.2	-0.2	0.0	17.6
Fishkill-I	Shenandoah-Industrial	Confidential						
	Wiccopee	3.8	0.0	0.0	0.0	0.0	0.0	3.8
	Boulevard	10.7	0.6	-0.1	-0.6	0.0	2.9	13.6

Load Area	Substation	(a) Econometrics Forecast (Gross Load)	(b) EV Load	(c) Building Electrification	(d) EE & CS	(e) Solar PV	(f) Storage Net Load	(g) Planning Load (a) + (b) + (c) + (d) + (e) + (f)
Kingston-Saugerties	East Kingston	25.4	1.0	-0.3	-1.6	-1.5	0.0	22.9
	Hurley Ave	21.8	1.4	-0.3	-1.5	-0.5	-0.1	20.8
	Lincoln Park	37.3	1.8	-0.3	-1.9	-0.8	-0.3	35.9
	Saugerties	28.7	2.0	-0.4	-2.3	-0.7	-1.1	26.1
	Woodstock	18.8	2.8	-0.5	-2.6	-0.4	-0.1	18.0
Modena	Galeville	11.5	1.0	-0.2	-1.0	0.0	-0.2	11.1
	Highland	24.4	1.9	-0.3	-1.5	-0.6	-0.3	23.6
	Modena	16.2	1.2	-0.2	-1.1	-0.4	-0.1	15.6
	Ohioville	23.8	1.8	-0.3	-1.2	-0.4	-0.2	23.6
Newburgh	Bethlehem Rd	44.2	1.6	-0.1	-1.2	-0.1	-0.7	43.8
	Coldenham	d21.6	1.0	-0.1	-0.8	-0.1	-0.1	21.5
	East Walden	20.9	1.1	-0.1	-1.0	0.0	-0.7	20.2
	Marlboro	27.7	1.1	-0.1	-1.1	-3.7	0.0	23.9
	Maybrook	27.0	0.8	-0.1	-0.6	-0.1	-0.1	27.0
	Montgomery	22.9	0.4	-0.1	-0.5	-1.0	0.0	21.8
	Union Ave	70.9	3.9	-0.3	-3.1	-2.4	-0.1	68.9
	West Balmville	36.4	1.8	-0.2	-1.7	-1.2	0.0	35.0
Northeastern Dutchess	East Park	16.8	1.2	-0.1	-0.9	-0.3	-0.1	16.6
	Hibernia	20.9	1.1	-0.2	-1.1	-1.0	0.0	19.6
	Milan	19.5	1.2	-0.1	-1.0	-0.3	0.0	19.2
	Millerton	3.8	0.6	-0.1	-0.4	-0.1	0.0	3.9
	Pulvers 13kV	7.3	0.6	-0.1	-0.4	-0.4	0.0	7.1
	Rhinebeck	28.6	2.6	-0.3	-1.9	-0.4	0.0	28.6
	Smithfield	2.8	0.1	0.0	-0.1	-0.1	0.0	2.7
	Staatsburg	12.6	0.8	-0.1	-0.8	-0.3	-0.1	12.1
	Stanfordville	7.1	0.6	-0.1	-0.6	0.0	0.0	7.0
	Tinkertown	14.9	1.2	-0.1	-1.0	-0.3	0.0	14.6
Northwest	Coxsackie	10.9	1.3	-0.1	-0.7	-0.1	0.0	11.4
	Freehold	9.3	0.7	-0.1	-0.7	0.0	-1.2	7.9
	Hunter	1.5	0.3	0.0	-0.2	0.0	0.0	1.5
	Lawrenceville	4.3	0.5	-0.1	-0.3	0.0	0.0	4.3
	New Baltimore	41.5	0.8	-0.1	-0.7	-3.8	0.0	37.7
	North Catskill	30.1	1.9	-0.3	-1.8	-1.8	-0.1	28.1
	South Cairo	15.5	1.0	-0.1	-1.0	-0.4	-0.3	14.7
	Vinegar Hill	4.9	0.3	-0.1	-0.3	0.0	0.0	4.9
	Westerlo	10.0	0.8	-0.1	-0.7	-0.1	-0.3	9.6
Poughkeepsie-D	Inwood Ave	35.6	1.1	-0.1	-0.9	-1.4	-1.5	32.8
	Manchester	33.2	1.7	-0.2	-1.9	-2.0	0.0	30.8
	Reynolds Hill	44.8	1.2	-0.1	-1.1	-1.0	0.0	43.8
	Spackenkill	34.8	2.0	-0.2	-1.9	-1.3	0.0	33.3
	Todd Hill	28.8	1.9	-0.2	-1.9	-0.5	-0.1	28.1
Poughkeepsie-I	Barnegat	2.5	0.0	0.0	0.0	0.0	0.0	2.5

3.4 DISTRIBUTION FEEDER FORECASTS

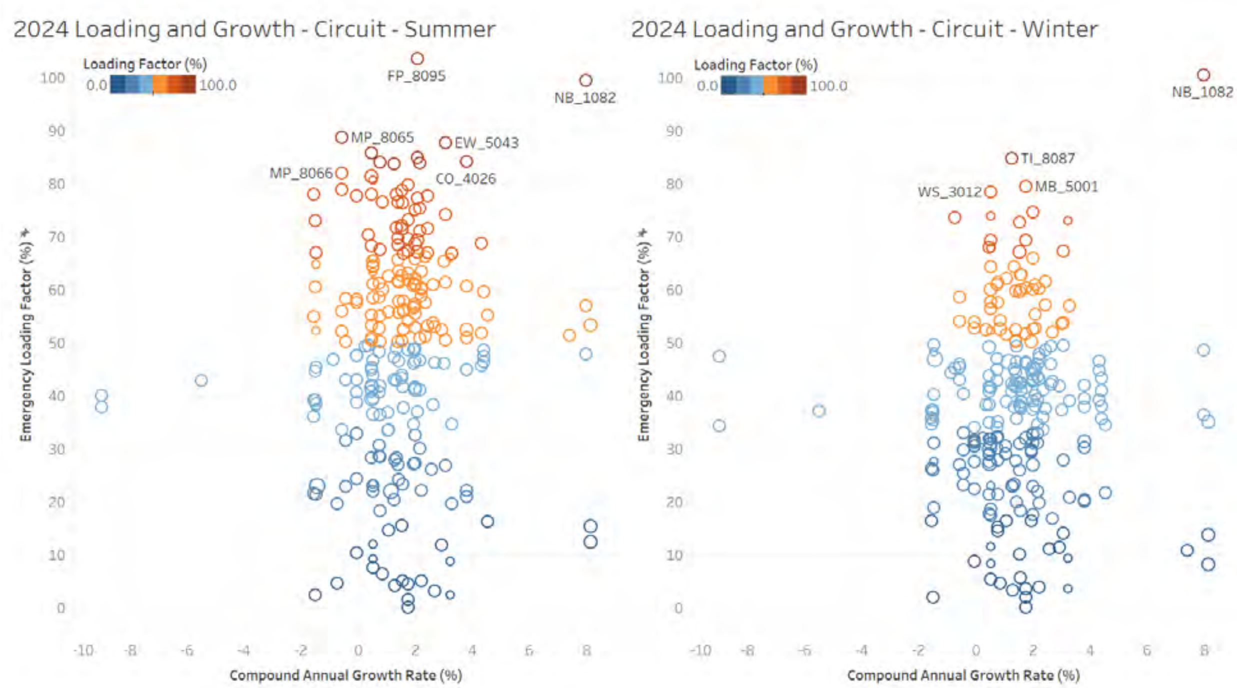
Figure 9 compares the annual load growth rate to the 2024 loading factor for each of Central Hudson's load serving distribution circuits. Unlike substation and transmission areas, circuits utilize design criteria, which includes a normal and emergency design rating, but do not have an LTE rating. The 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, each circuit's corresponding substation was used to determine the growth rate for the circuit.

Figure 9: Distribution Feeder Historic Growth Rates and Loading Factors



*Note: Bubble size is proportional to the LTE rating of the site. The color reflects the 2024 loading for each site.

Table 12 provides a high level summary of the actual (i.e., not weather normalized) loading factors by season. With a few exceptions, most of the distribution feeders have room to accommodate electric vehicles and building electrification loads in the near term. The main drivers for feeder upgrades are either reliability, aging equipment, grid modernization efforts, or large lump loads. Table 13 provides the same summary for circuit-level forecasted loading factors for 2030.

Table 12: Summary of Loading Factors for Distribution Feeders

2024 Loading Factor	# of Circuits (Summer)	# of Circuits (Winter)
Less than 50%	129	203
50% to 60%	50	28
60% to 70%	46	21
70% to 80%	23	7
80% to 90%	11	1
90% to 100%	1	0
100% or higher	1	1

Table 13: Summary of Forecasted 2030 Loading Factors for Distribution Feeders

2030 Loading Factor (Weather-normalized)	# of Circuits (Summer)	# of Circuits (Winter)
Less than 50%	175	205
50% to 60%	53	39
60% to 70%	22	10
70% to 80%	7	5
90% to 100%	1	0
100% or higher	4	3

4 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) and L2 ports.

4.1 METHODOLOGY OVERVIEW

Forecasts for LDVs, MHDVs, buses, DCFC, and L2 were produced using the methodology described in Figure 10 and Figure 11. Figure 10 provides a high-level overview and Figure 11 provides additional detail for each step.

Figure 10: Electric Vehicles Forecast Process Overview

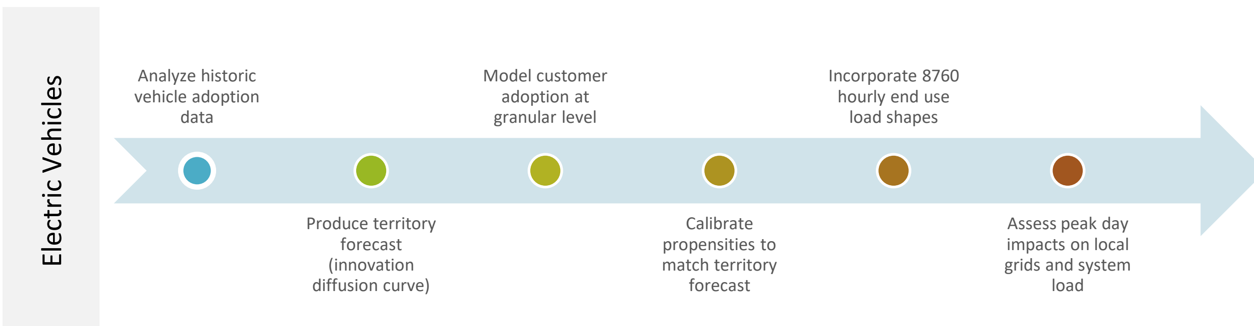


Figure 11: Electric Vehicles Forecast Process Detail

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

4.2 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) has changed over time.

Table 14 shows the registered vehicle counts by class as of March 2025. Figure 12 shows the vehicle stock by model year and the share of electric LDVs that are plugin-hybrid by model year.

Table 14: Counts of vehicles by vehicle class and fuel source as of March 2025

Vehicle Class	Gas	Diesel	Hybrid	Electric	PHEV	Other	Total
LDV	522,706	8,722	20,131	8,073	5,154	2	565,317
MHDV	12,460	18,578	474	227	24	4	32,799
Other	3,455	291	0	29	0	0	3,820
School Bus	174	848	0	1	0	0	1,165
Transit Bus	29	771	0	0	0	2	803
Total	538,824	29,210	20,605	8,330	5,178	8	603,904

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, supply chain problems, and the reality that not all of 2024 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 12: Central Hudson Vehicle Stock and Electric Vehicle Share by Model Year

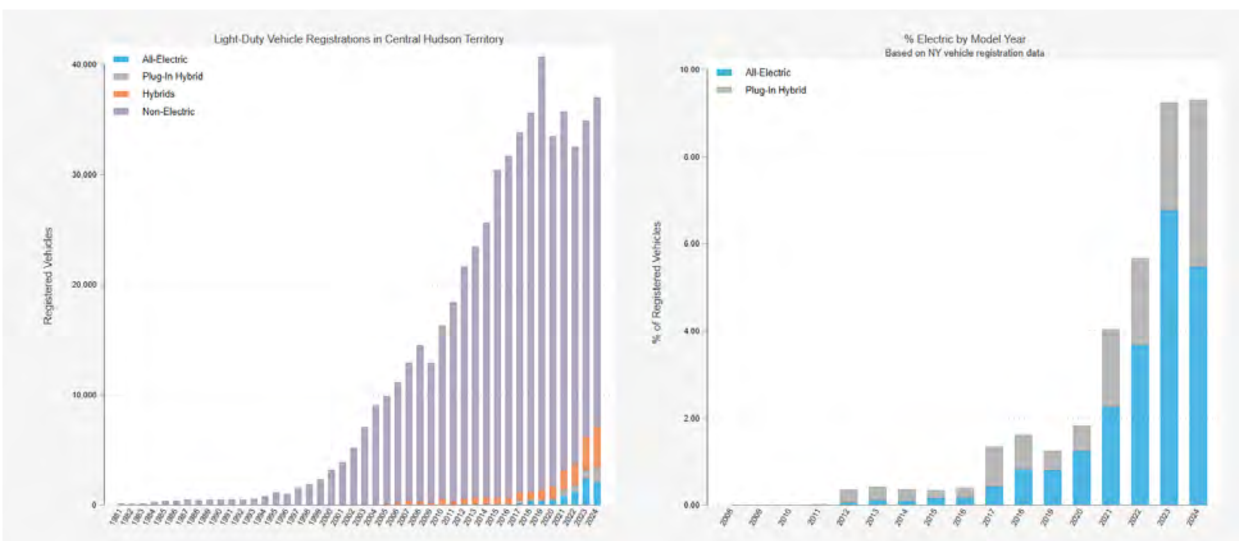
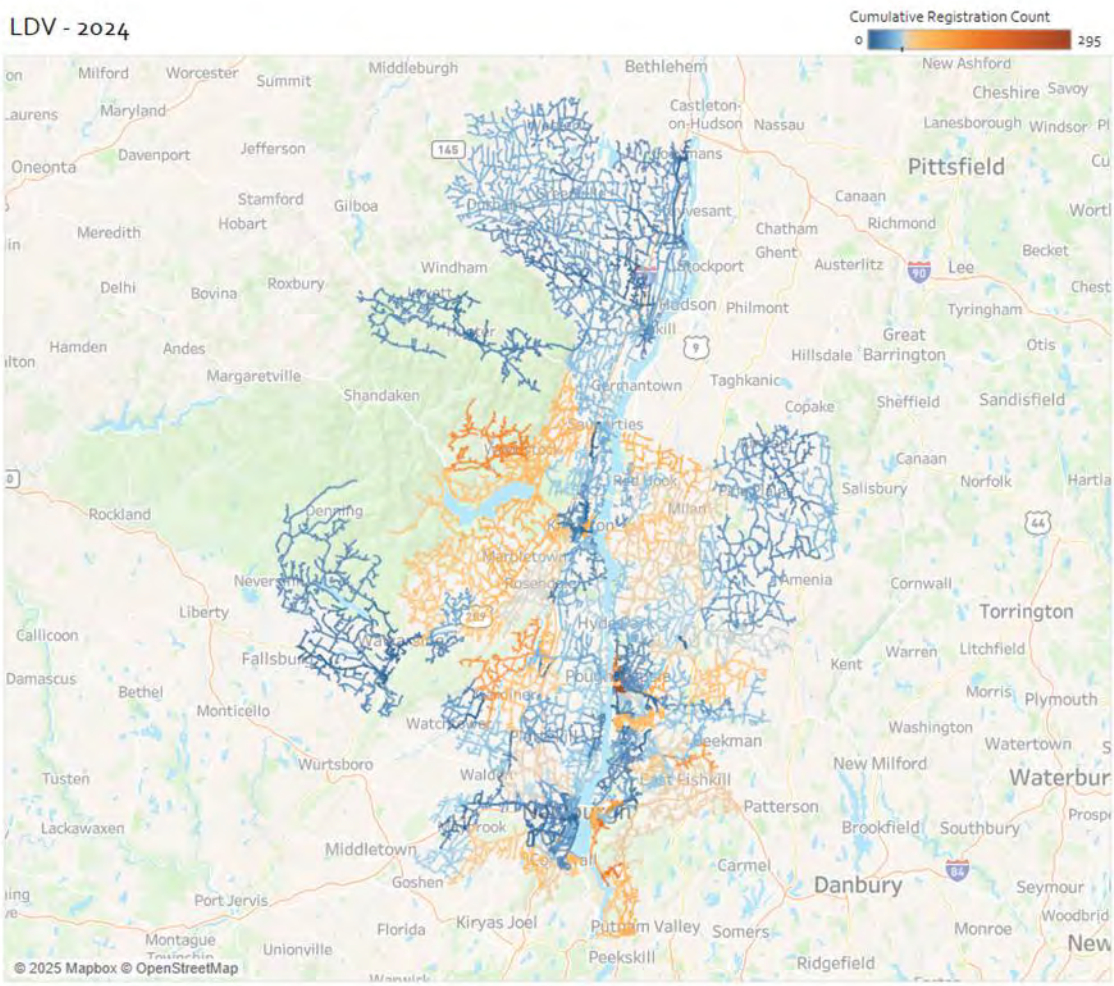


Figure 13 shows the historic geographic penetration of electric vehicles in Central Hudson's service territory. The map was produced by associating the NYSERDA electric vehicle rebate with Central Hudson accounts via spatial matching and circuit feeders. While it does not reflect the full electric vehicle population, it indicates that adoption is higher in specific pockets of Central Hudson territory.

Figure 13: 2024 Penetration of Electric Vehicles by Circuit Feeder



4.3 FORECAST RESULTS

Table 15 shows the electric vehicle forecasts for 2025 to 2035 and provides details about vehicle counts and annual MWh. Overall, 85% of energy consumption for light duty vehicles is assumed to occur via home charging, and 15% 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. The top-down forecasts for EV buses was derived from using the "low" scenario in NYISO's EV bus forecast.

Table 15: Electric Vehicle Forecast

		Vehicles			Annual MWh				
Scenario	Year	EV Light Duty	EV Medium Heavy Duty	EV Bus	EV Light Duty	EV Medium Heavy Duty	EV Bus	LDV Public Chaging (DCFC/L2)	Total MWh
Central Hudson	2025	19,475	164	7	55,069	5,850	196	9,718	70,834
	2026	26,043	210	34	74,108	7,488	693	13,078	95,366
	2027	34,474	269	61	98,672	9,611	1,192	17,413	126,888
	2028	44,988	345	87	129,456	12,346	1,694	22,845	166,342
	2029	57,687	442	114	166,807	15,841	2,210	29,437	214,296
	2030	72,510	565	142	210,596	20,268	2,740	37,164	270,768
	2031	89,229	719	172	260,186	25,816	3,316	45,915	335,233
	2032	107,476	910	205	314,521	32,679	3,925	55,504	406,629
	2033	126,804	1,141	239	372,290	41,046	4,566	65,698	483,601
	2034	146,753	1,419	276	432,128	51,075	5,258	76,258	564,718
	2035	166,897	1,745	315	492,765	62,868	5,988	86,959	648,579

Figure 14 and Figure 15 shows the hourly EV loads for Central Hudson territory from 2025 through 2035 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 14: EV Loads Coincident with Central Hudson Summer Peak Day for years 2025 through 2035

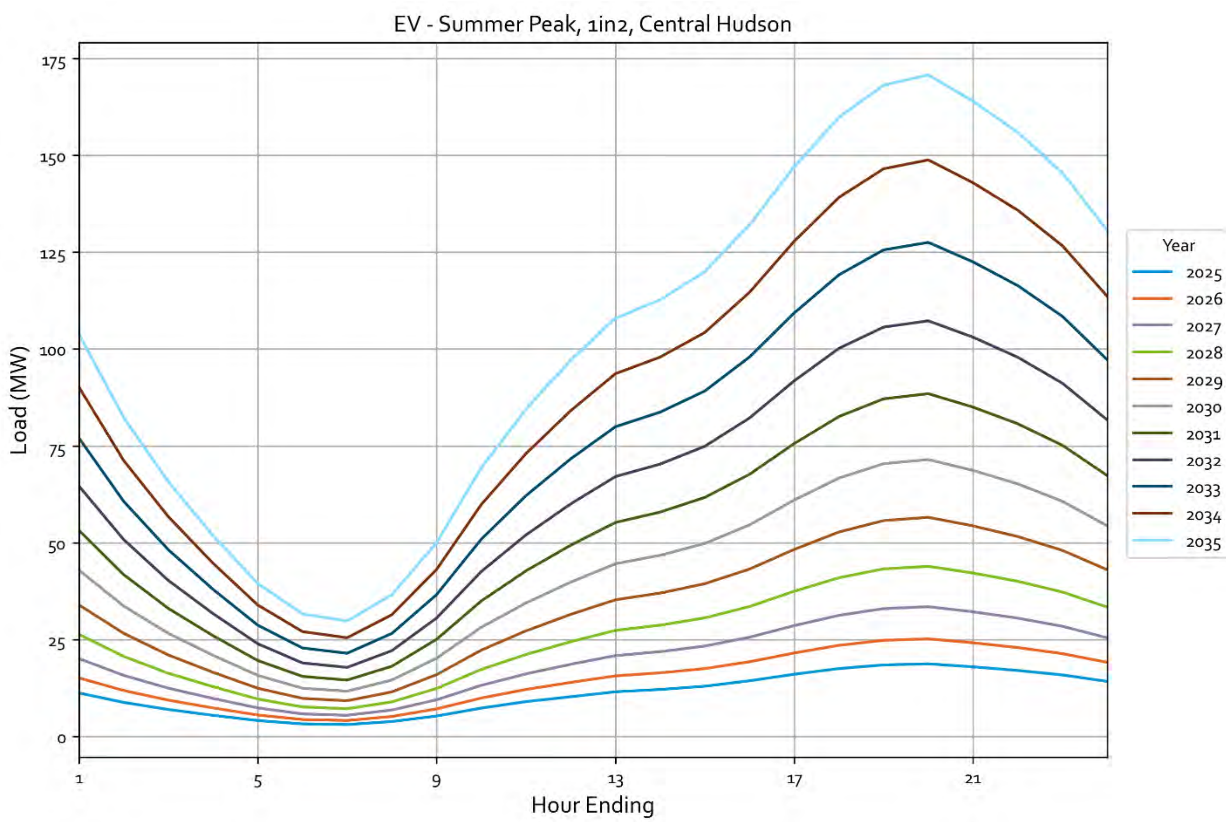


Figure 15: EV Loads Coincident with Central Hudson Winter Peak Day for years 2025 through 2035

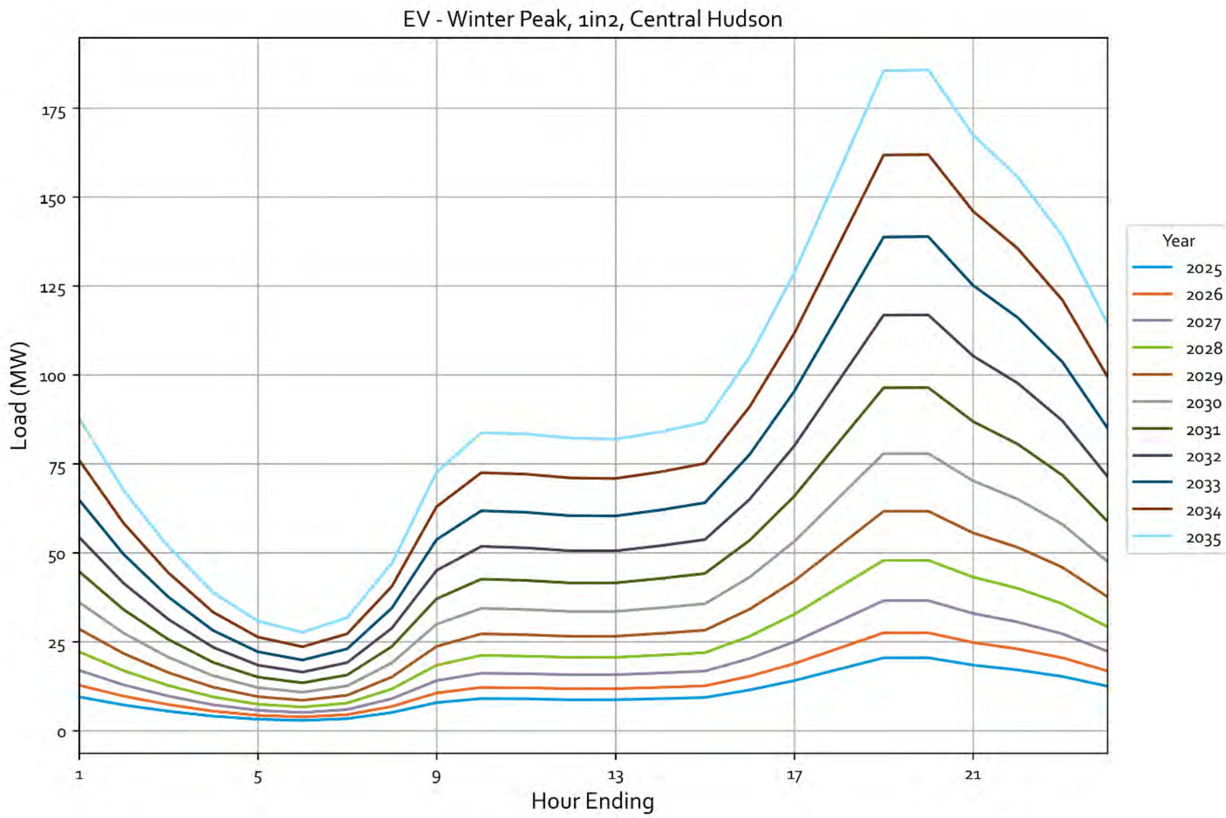
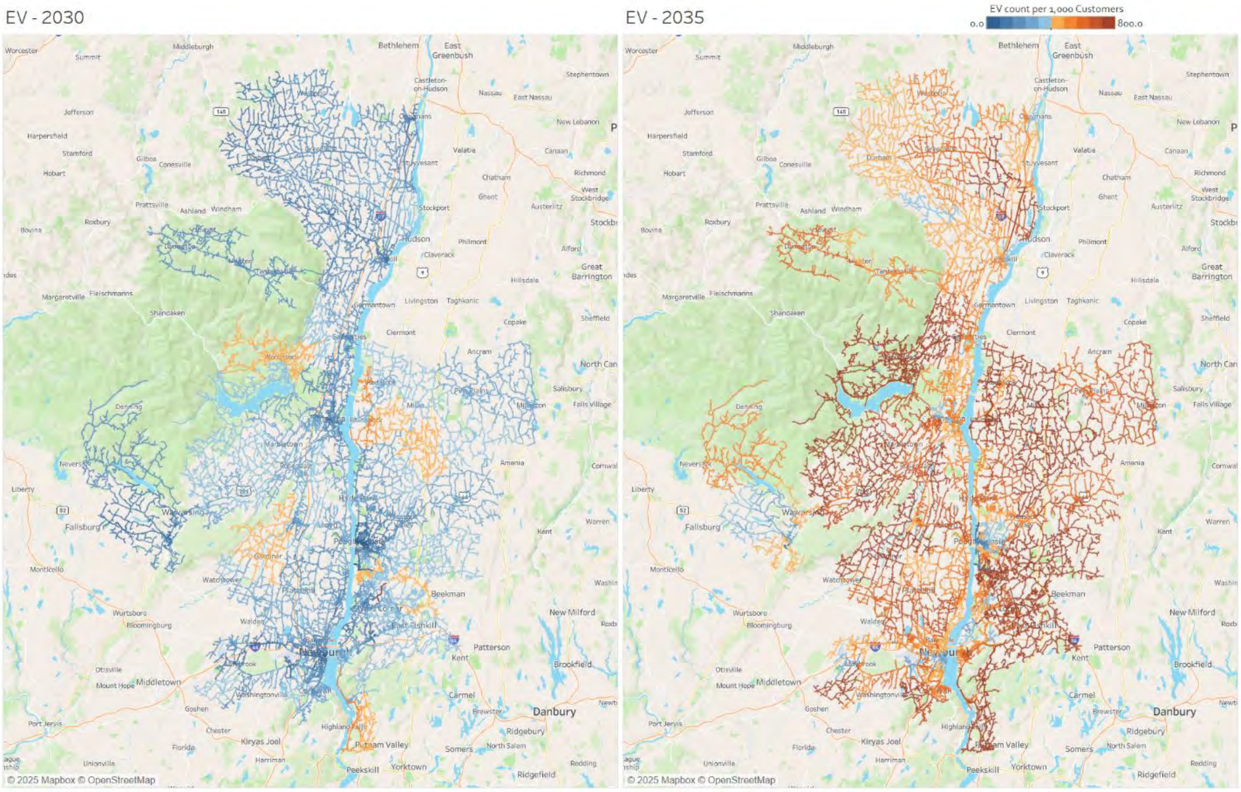


Figure 16 shows the electric vehicle coincident peak contribution forecasts by substation for 2025 and 2035. Overall, the penetration is currently low and concentrated but electric vehicles are expected to be more widespread within 10 years.

Figure 16: Electric Vehicles Feeder-level Penetration: 2030 and 2035



5 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.

5.1 METHODOLOGY OVERVIEW

Figure 17 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 17: Building Electrification Forecast Process Overview

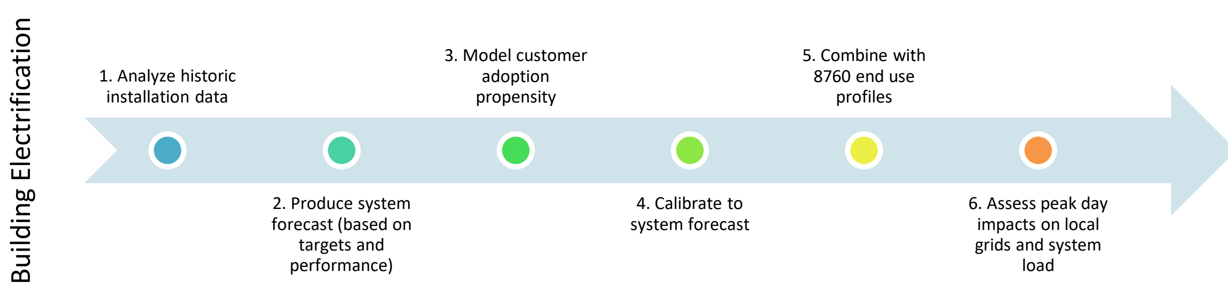


Figure 18 provides more detail on each step in the analysis. Methods are further discussed in Appendix B – Building Electrification.

Figure 18: 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

5.2 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 (CHP) 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.

In mid-2022, Central Hudson shifted incentives away from mini-split units and instead only offered incentives for whole-home heat pumps. In addition, budgets for marketing the Clean Heat Program and incentives were throttled beginning in 2022, leading to fewer installations occurring through the CHP. As a result, total installations fell in 2023 relative to 2022, and once again in 2024 relative to 2023. Because heat pump installations are heavily dependent on the budgetary constraints of the Clean Heat Program, and no longer includes mini splits, which are the majority type of heat pump installed, adoption curves corresponding to NYISO's "low" building electrification adoption scenario in their 2025 forecast were used to predict heat pump market share going forward.

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 57.8% of installations have replaced oil heating, 12.6% have replaced propane heating, and 15.1% 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 13.8% of heat pump installation have replace existing, but less efficient, electric resistance heating units, leading to a decrease in demand.

Table 16: Historical Installation of Heat Pump Units via Central Hudson Programs

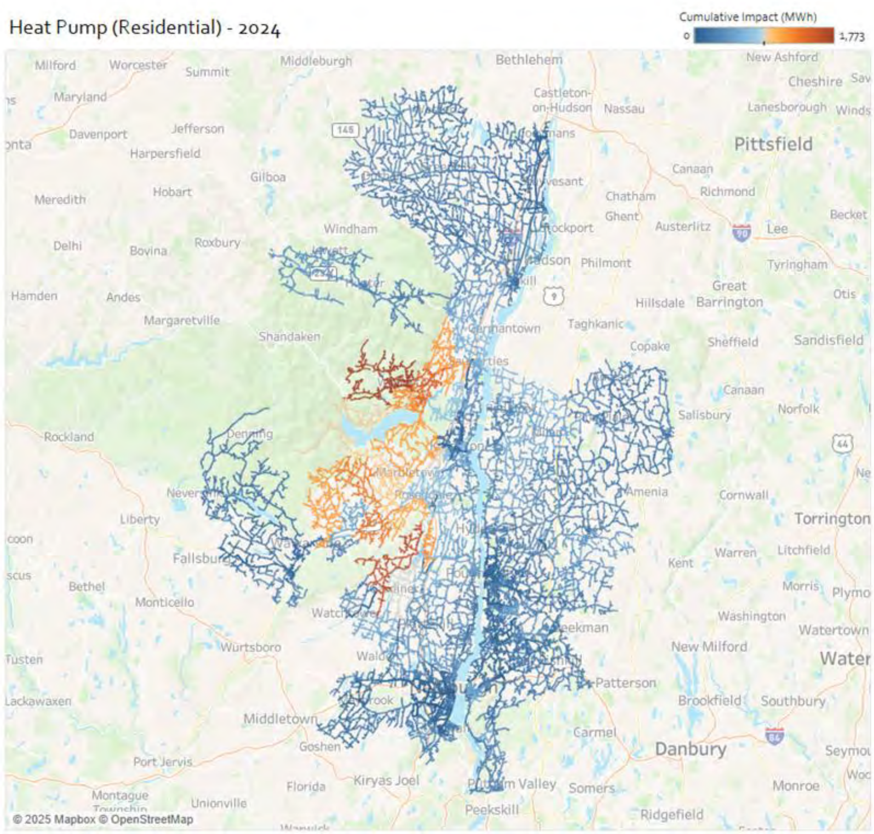
	Devices Installed				Premises	
Year	Air Source	Ground Source	HPWH	Total	Heat Pump	HPWH
2017	951	0	0	951	625	0
2018	1,319	0	0	1,319	770	0
2019	1,826	0	1	1,827	1,013	1
2020	2,748	65	278	3,091	1,238	227
2021	5,772	96	573	6,441	2,415	430
2022	4,612	123	603	5,338	1,682	442
2023	4,048	132	820	5,000	1,409	632
2024	2,464	107	515	3,086	834	386
Total	23,740	523	2,790	27,053	9,986	2,118

Table 17: Clean Heat Historical Impact of Energy of Heat Pump Installations per Projects[3]

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
Air Source	-422.43	6,326.86	5,904.16	-0.38	3.07
Ground Source	-622.18	7,689.86	7,011.79	-0.21	2.39
HPWH	-	-	-309.50	-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 2024, 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 4%.

Figure 19: 2024 Penetration of Heat Pumps by Feeder



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[3] 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).

5.3 FORECAST RESULTS

To develop the territory-wide forecast, we used the "low" scenario in the NYISO building electrification forecast to estimate heat pump market share over time, and used heat pump installation data to estimate the average turnover of heating and water heating equipment. Table 18 shows the heat pump forecasts for 2025 to 2035 and provides details about participants and net annual MWh.

Figure 20 shows the summer system peak day impacts due to cumulative building electrification activity for 2025 to 2035. Since heat pumps are expected to replace less efficient air conditioning, it leads to a net reduction in energy demand during summer months. Figure 21 shows the winter system peak day impacts due to cumulative building electrification activity for 2025 to 2035. Heat pumps are expected to replace fossil fuel burning units and add just over 200 MW to winter electric peaks loads by 2035, as shown in Figure 21. 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 18: Heat Pump Forecast by Equipment Type

		Premises				Annual MWh				
Scenario	Year	Residential Heat Pump	Non-Residential Heat Pump	Residential HPWH	Non-Residential HPWH	Residential Heat Pump	Non-Residential Heat Pump	Residential HPWH	Non-Residential HPWH	Total Net MWh
Central Hudson	2025	12,422	1,432	3,159	288	73,815	8,508	-978	-89	81,256
	2026	15,557	1,503	4,737	304	92,440	8,930	-1,466	-94	99,810
	2027	19,035	1,589	6,736	327	113,106	9,444	-2,085	-101	120,364
	2028	22,861	1,692	9,224	357	135,841	10,054	-2,855	-110	142,930
	2029	27,036	1,811	12,270	396	160,647	10,763	-3,798	-122	167,490
	2030	31,555	1,947	15,938	444	187,500	11,569	-4,933	-137	193,999
	2031	36,410	2,098	20,285	501	216,349	12,469	-6,278	-155	222,384
	2032	41,588	2,264	25,359	569	247,119	13,455	-7,848	-176	252,550
	2033	47,074	2,443	31,193	646	279,717	14,519	-9,654	-200	284,382
	2034	52,848	2,634	37,806	731	314,029	15,650	-11,701	-226	317,751
	2035	58,890	2,834	45,202	824	349,928	16,838	-13,990	-255	352,521

Figure 20: Forecasted Building Electrification Impacts on Summer Peak Day: 2025-2035

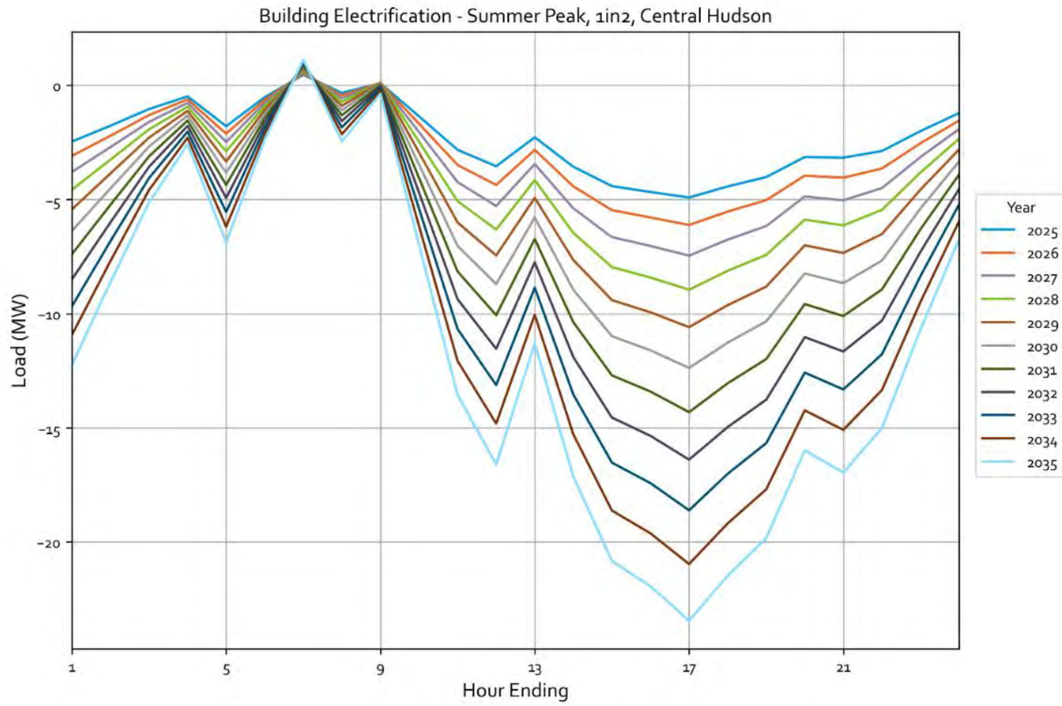
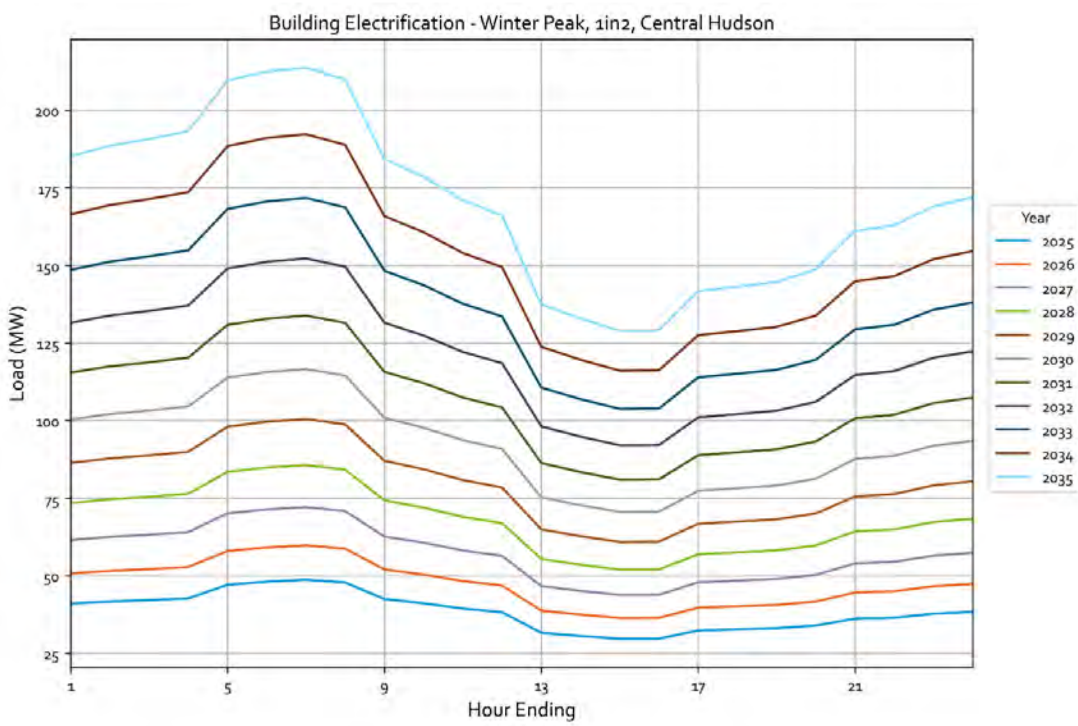


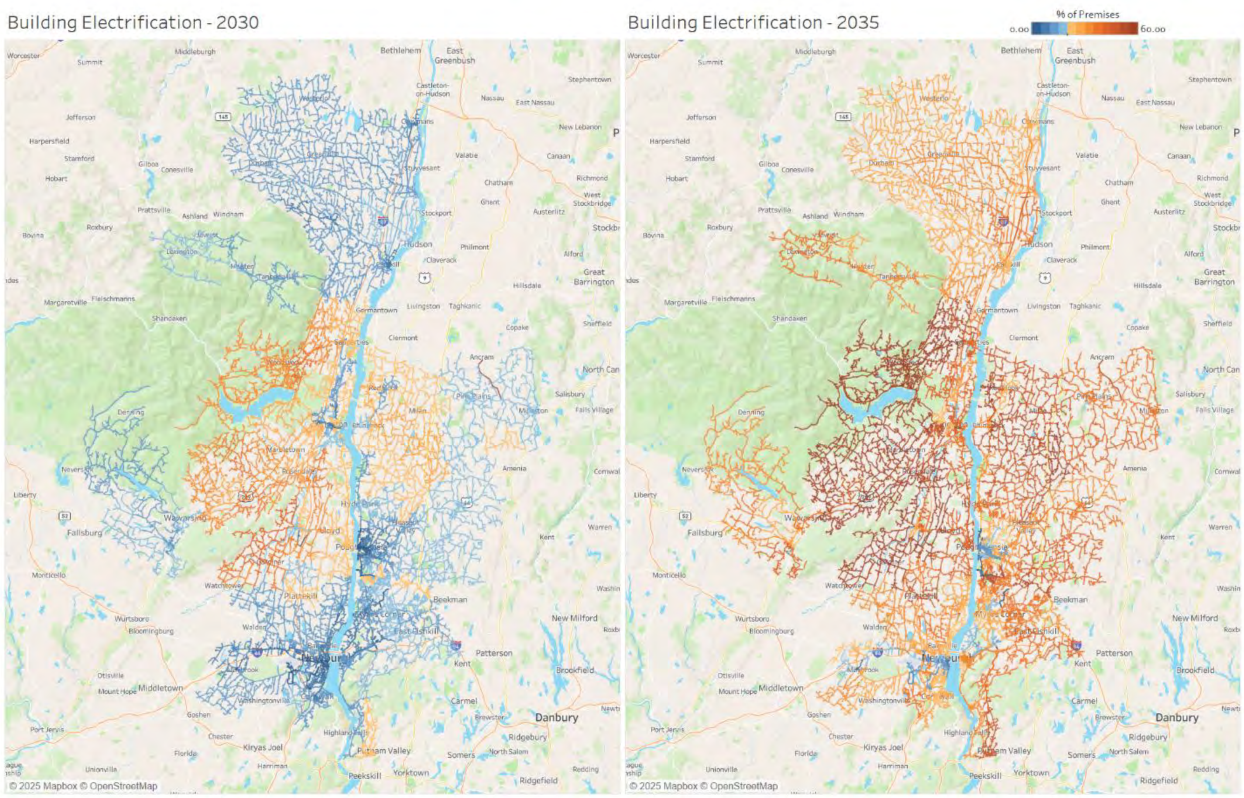
Figure 21: Forecasted Building Electrification Impacts on Winter Peak Day: 2025-2035



In addition to system-wide electric impacts, we calculated the feeder level adoption rates of heat pumps by year. Figure 22 shows the percent penetration of heat pumps and heat pump water heaters in

2030 and 2035 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 2035.

Figure 22: Heat Pump and HPWH Feeder-level Penetration: 2030 and 2035



6 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 7.4% of customers who installed rooftop solar in 2024 also installed battery storage.

6.1 METHODOLOGY OVERVIEW

Figure 23 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 24 provides more detail on each step.

Figure 23: BTM Solar and Storage Forecast Process Overview

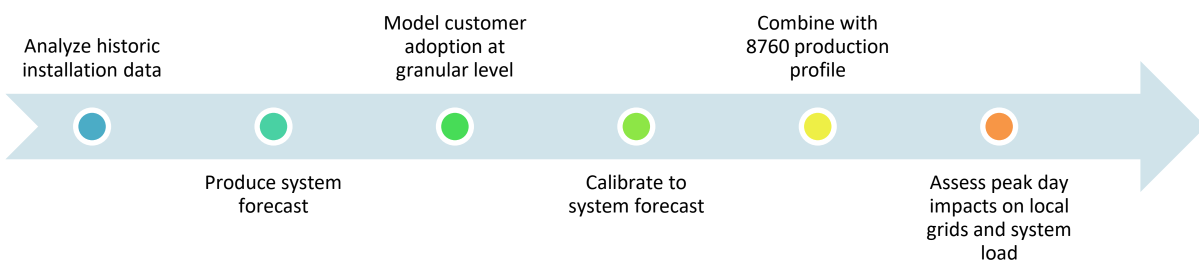


Figure 24: BTM Solar and Storage Forecast Process Detail

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

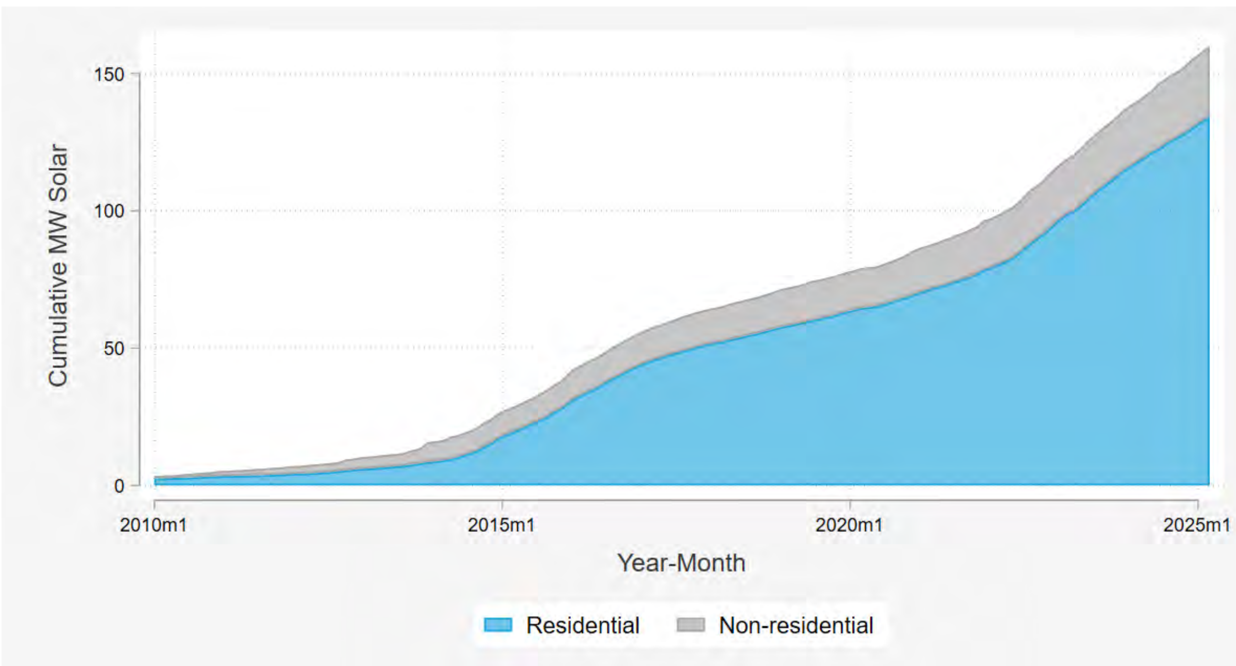
- Identify the local winter and summer peak days for feeder, substations, and transmission areas using historical hourly interval data
- Combine loads with forecasted T&D loads on peak days for each location (feeder, substation, and transmission area) and forecast year

6.2 HISTORIC ADOPTION PATTERNS IN CENTRAL HUDSON TERRITORY

As of December 2024, there were 16,342 total residential solar installations in Central Hudson territory with 135 MW of installed capacity (AC). An additional 605 non-residential sites installed rooftop solar with 26 MW (AC) 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.

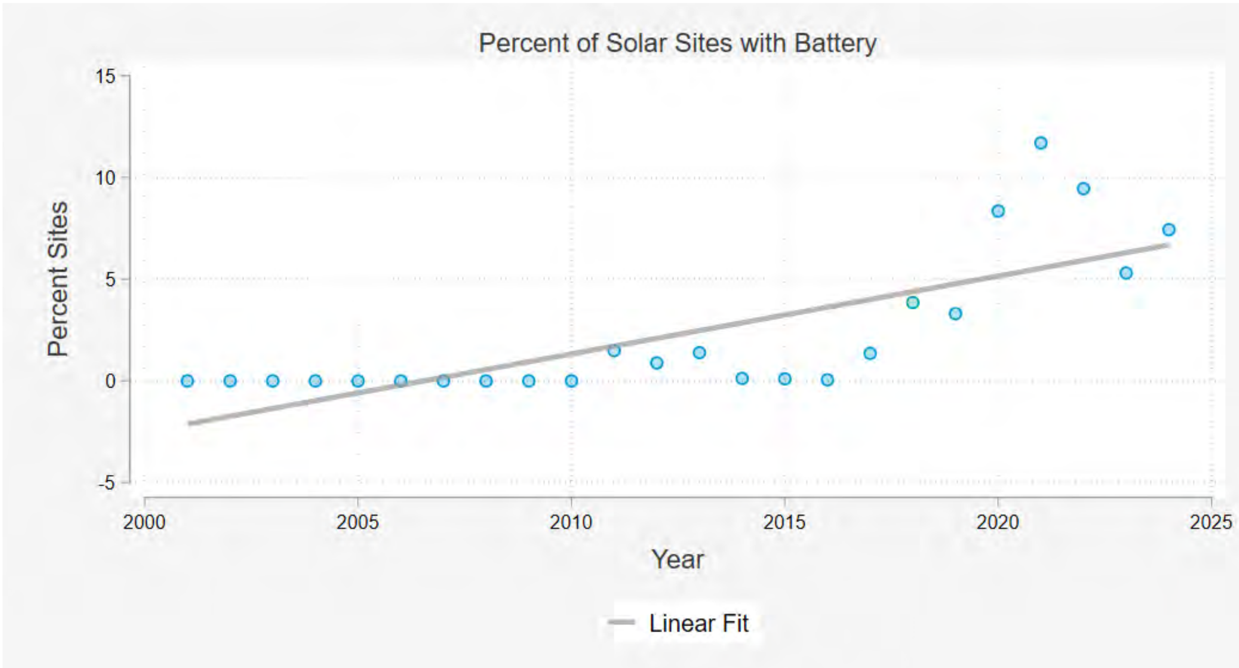
Rooftop solar technology has been available for over 30 years, but the scale of adoption grew around 2014 when the cost per watt of installed capacity declined and new financial models allowed customer to lease solar, enter into power purchase agreements, or purchase solar with zero down payment. Most rooftop, or net metered, solar installations have been on residential sites. Rooftop solar installations have grown over time and exceeded 160 MW (AC) at the end of 2024.

Figure 25: Historical Net Metered Solar Installed Capacity (MW)



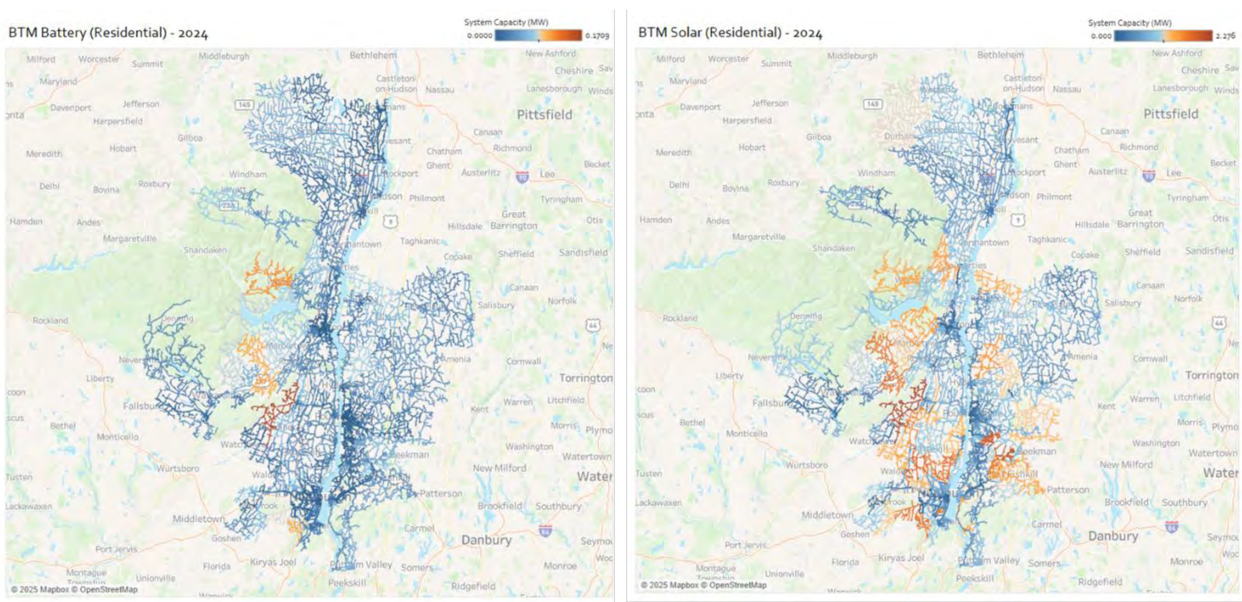
A more recent phenomenon is the installation of battery storage, which is nearly always paired with solar for net metered sites and mostly at residential sites. Figure 26 shows the share of solar installation paired with battery storage by year. In 2024, 7.4% of residential solar installations were paired with battery storage.

Figure 26: 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 27: 2024 Penetration of Net Metered Solar and Battery Storage by Circuit



6.3 FORECAST RESULTS

To develop the territory-wide forecast, Central Hudson used the historical adoption trends to estimate incremental net metered solar adoption. Table 19 shows the solar net metered forecasts for 2025 to 2035 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 15% by 2035.

Table 19: Net Metered Solar and Battery Storage Forecast (Installed MW DC)

		Installations				Capacity Installed (MW)				
Scenario	Year	Residential Solar	Non-Residential	Residential Battery	Non-Residential	Residential Solar	Non-Residential	Residential Battery	Non-Residential Battery	Total MW
Central Hudson	2025	18,085	660	808	16	146.4	30.6	7.2	0.5	185
	2026	19,351	696	925	20	156.7	32.3	8.2	0.6	198
	2027	20,454	728	1,033	23	165.6	33.8	9.3	0.8	210
	2028	21,393	755	1,130	26	173.3	35.1	10.2	1.0	220
	2029	22,176	779	1,215	28	179.7	36.2	11.0	1.1	228
	2030	22,817	798	1,288	30	184.9	37.1	11.8	1.2	235
	2031	23,336	814	1,349	32	189.1	37.8	12.4	1.3	241
	2032	23,750	828	1,401	34	192.5	38.4	12.9	1.4	245
	2033	24,079	839	1,443	35	195.1	38.9	13.3	1.5	249
	2034	24,337	848	1,478	37	197.2	39.4	13.7	1.6	252
	2035	24,538	855	1,506	38	198.9	39.7	14.0	1.7	254

Figure 28 and Figure 29 show the hourly loads of net metered solar and battery units, combined for Central Hudson summer and winter 1-in-2 peak days from 2025 to 2035. 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 28: Forecasted BTM Battery and Solar - Summer 1-in-2 Peak Day: 2025-2035

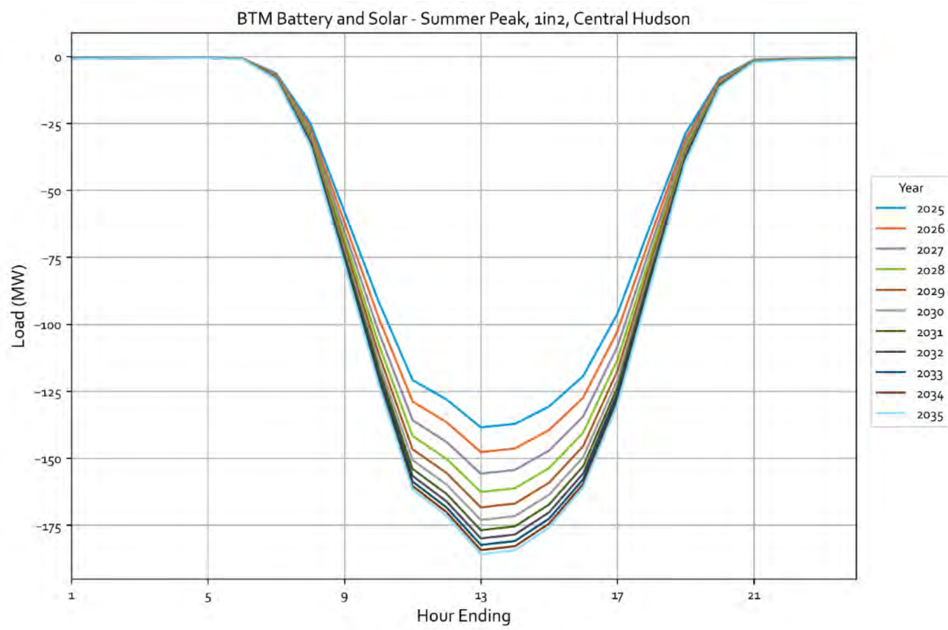
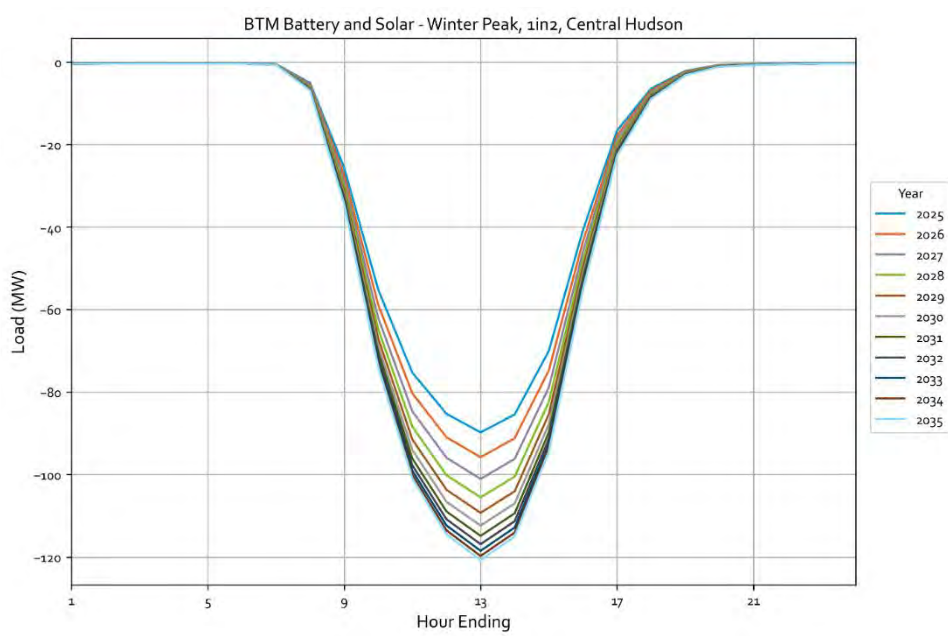
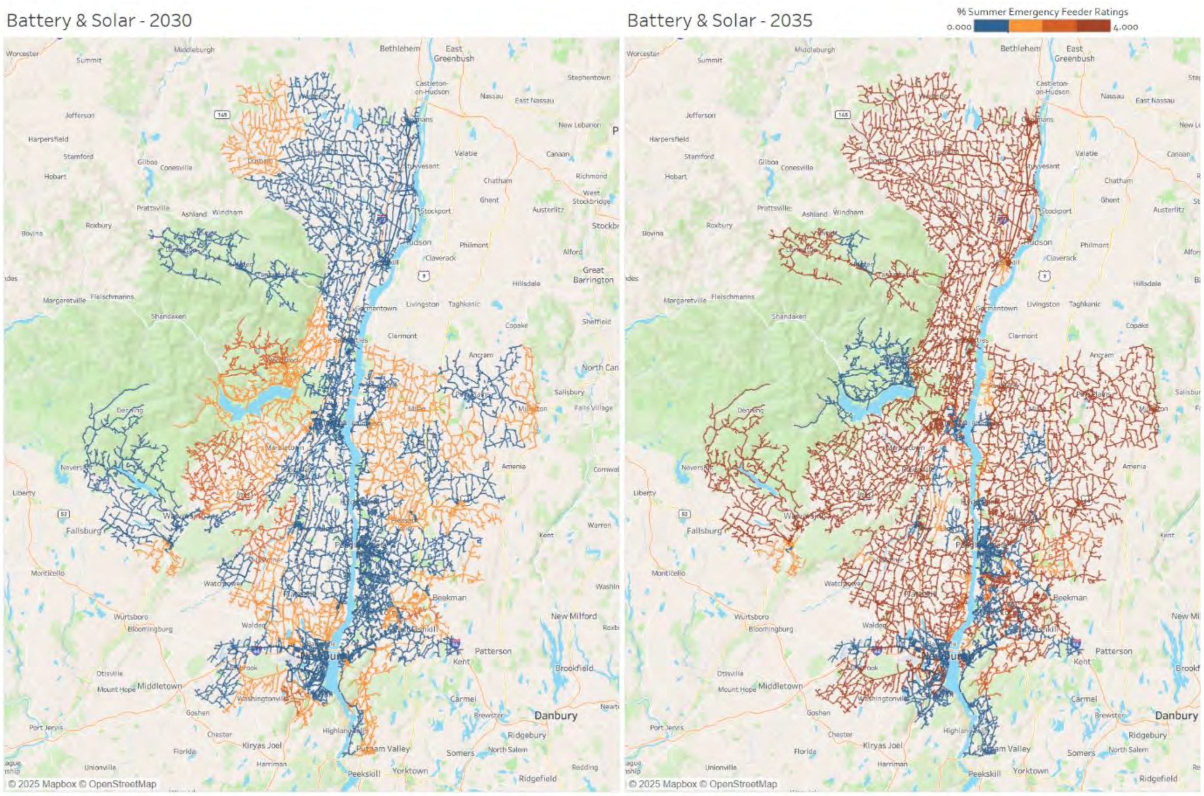


Figure 29: Forecasted BTM Battery and Solar - Winter 1-in-2 Peak Day: 2025-2035



In addition to load forecasts, we calculated the feeder-level penetration of behind the meter battery and solar for each year. Figure 30 shows the feeder-level penetration forecasted in Central Hudson territory in 2030 and 2035.

Figure 30: BTM Solar and Battery Feeder-level Penetration: 2030 and 2035



7 COMMUNITY AND REMOTE METERED SOLAR AND BATTERY STORAGE

Community distributed generation (CDG) and remote-metered (RM) solar. CDG, often called community solar, allows individuals and businesses to subscribe to and receive credits for electricity generated by larger off-site solar projects. It enables access to renewable energy for homes and businesses who might not otherwise be able to install solar panels on their property, such as renters or those with limited roof space. Remote-metered solar is a similar concept. It allows businesses and farms to install solar panels on one property and then credit the excess energy generated to other properties under the same ownership, allowing businesses to offset their energy bills.

CDG and RM solar projects are larger, typically submitted by developers, 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 many applications for community solar and battery storage, but 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.

7.1 METHODOLOGY

Figure 31 provides a high-level overview of the forecasting process for both CDG and RM 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 32 provides more detail on each step.

Figure 31: Community/Remote Solar and Storage Forecast Process Overview

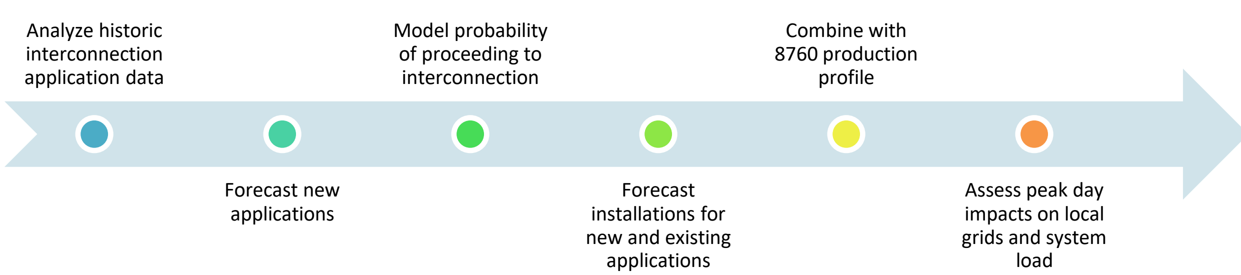


Figure 32: Community/Remote Solar and Storage Forecast Process Detail

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 (75% Res / 80% Non-Res / 96% 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

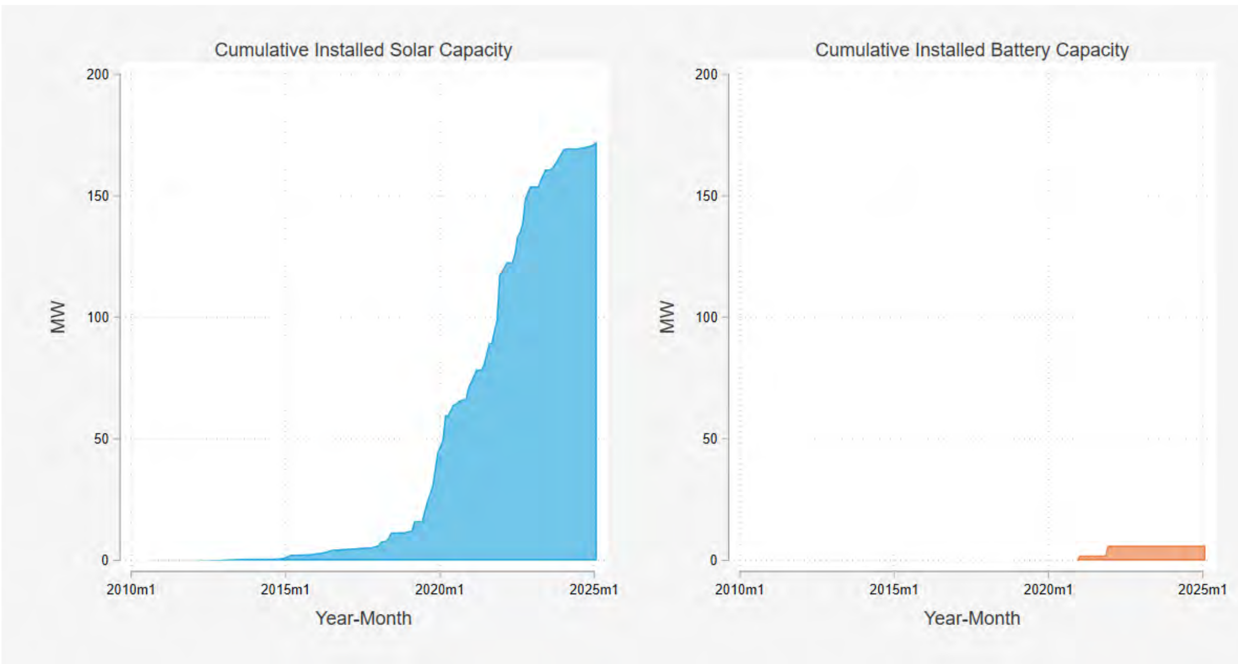
7.2 HISTORIC INSTALLATION PATTERNS IN CENTRAL HUDSON

The penetration of remote and net-metered solar in Central Hudson is substantial. As of the end of 2024, Central Hudson had 59 community solar projects with 138 MW (AC) of installed capacity and 88 remote net metering projects with 34 MW (AC) of capacity. To place in context, the solar capacity from CDG and RM exceeds the solar capacity from the over 17,000 sites with net metered solar.

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 2024, there were two community battery installations with 6 MW (AC) of installed capacity.

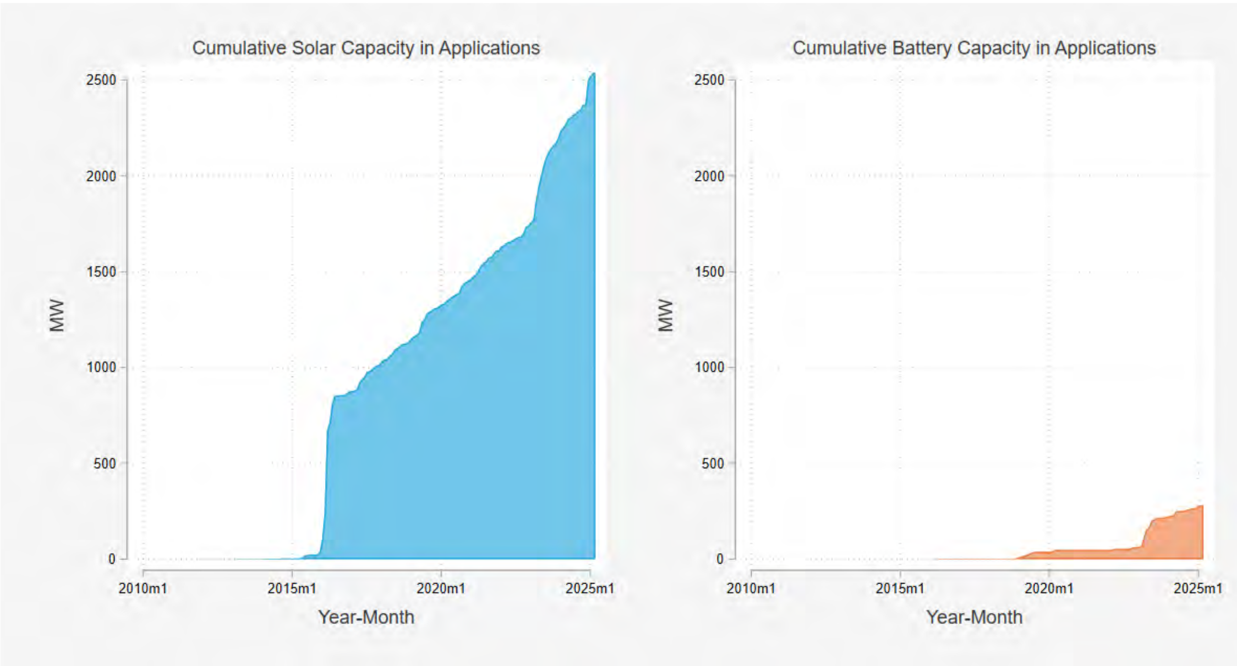
Figure 33 shows the historic cumulative installed capacity of community and remote solar and battery storage projects. Figure 34 shows the historical applications. Community solar installations in Central Hudson surpassed 170 MW by the end of 2024, which is substantial when compared to Central Hudson's peak demand of approximately 1,100 MW. However, Central Hudson has received application for over 2,500 MW of community solar, nearly three times the overall territory peak demand and more than 10X the amount to installed solar capacity. The ratio of applications to installed capacity is similar for battery storage.

Figure 33: Historical Community/Remote Solar and Battery Installed Capacity (Nameplate MW)



There is a multi-step process to connect larger installation, with agreed up response time frames at each step, and a (Coordinated Electric System Interconnection Review) engineering analysis to determine the impact of a proposed distributed energy resource (DER) project on the electric grid and to identify any necessary upgrades or construction. Central Hudson meets nearly all regulatory timelines, as well as provide flexibility to developers/applicants where possible, to support the integration of CDG, RM, and other DERs. However, the developers can withdraw from the process at any point and, historically, a large of number of applications have been withdrawn prior to construction and interconnection.

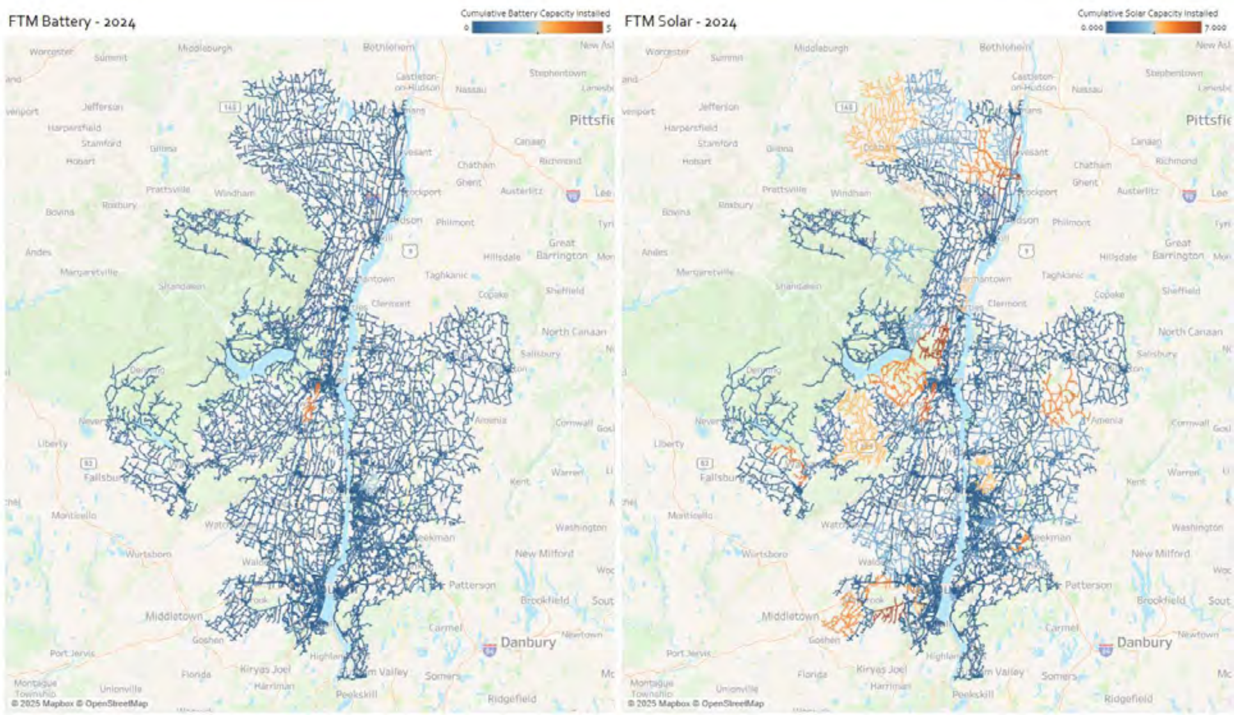
Figure 34: Historical Community and Remote Solar and Battery Applications (Nameplate MW)



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. 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 applications, and the probability that an application will proceed through each stage of application process (a probability transition matrix).

Figure 35 shows the geographic footprint of the projects that have been interconnected as of 2024, and displays the installed capacity by feeder. 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 35: 2024 Community/Remote Solar and Battery Penetration



7.3 FORECAST RESULTS

Figure 36 and Figure 37 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 2035 there will be approximately 340 MW (AC) of community solar and 57 MW (AC) of community battery storage (Table 20). Both estimates are of AC nameplate capacity.

Table 20: Forecasted Community/Remote Solar and Battery Interconnections

		Installations		Capacity Installed (MW)		
Scenario	Year	FTM Solar	FTM Battery	FTM Solar	FTM Battery	Total MW
Central Hudson	2025	109	2	217.3	6.0	223
	2026	118	3	242.8	7.7	250
	2027	123	4	257.1	11.5	269
	2028	131	4	275.8	12.3	288
	2029	137	4	291.1	14.3	305
	2030	143	5	304.9	17.5	322
	2031	148	6	315.9	22.0	338
	2032	151	8	324.3	28.1	352
	2033	154	10	330.5	35.9	366
	2034	156	13	334.9	45.7	381
	2035	157	16	338.1	57.0	395

Figure 36: Solar Storage Capacity Forecast

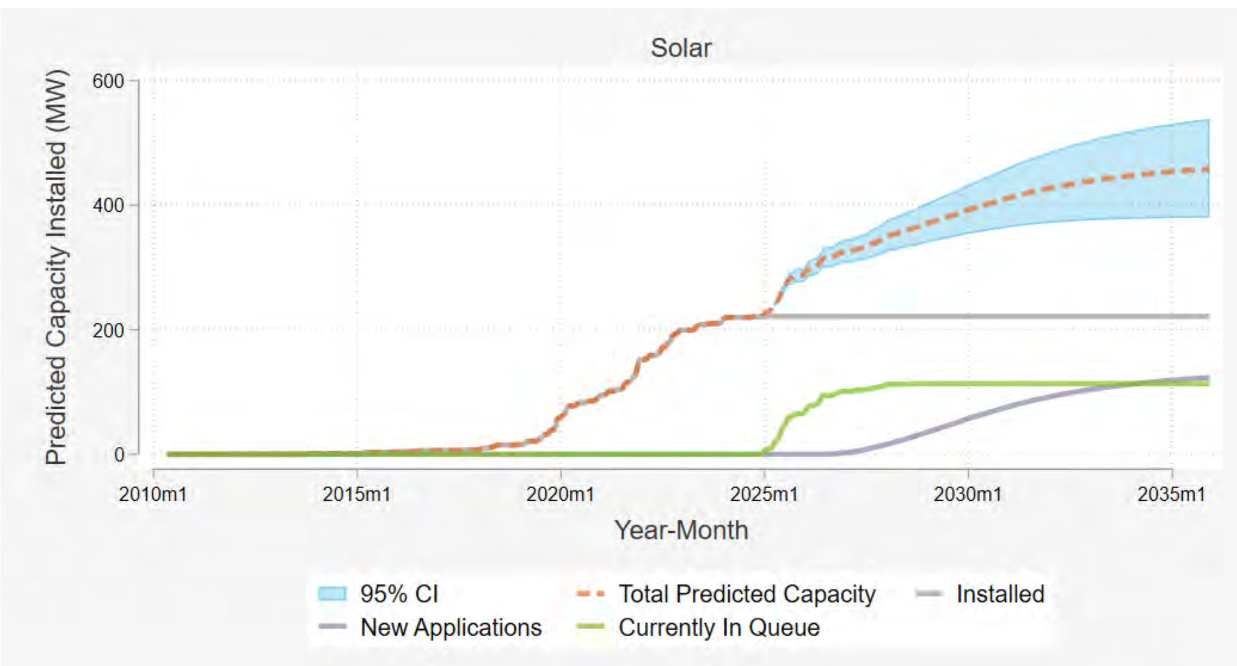
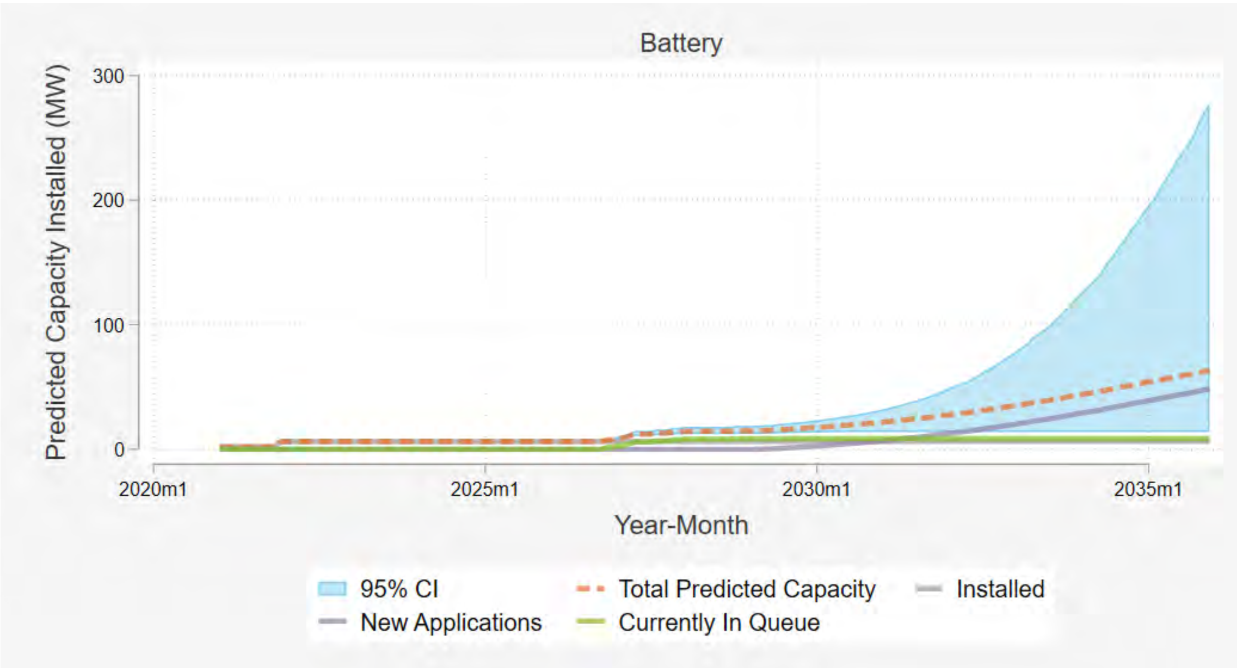


Figure 37: Battery Storage Capacity Forecast



Because there are only two community battery installations in the territory, and few applications for community battery, the uncertainty for predicted battery capacity is higher than the uncertainty for solar, which is reflected in Figure 37.

Figure 38 and Figure 39 show the cumulative forecast of community and remote net metered solar and battery production on the Central Hudson summer and winter 1-in-2 peak days from 2025 to 2035. The graphs show the year-by-year change in 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 38: Forecasted community Battery and Solar - Summer 1-in-2 Peak Day: 2025-2035

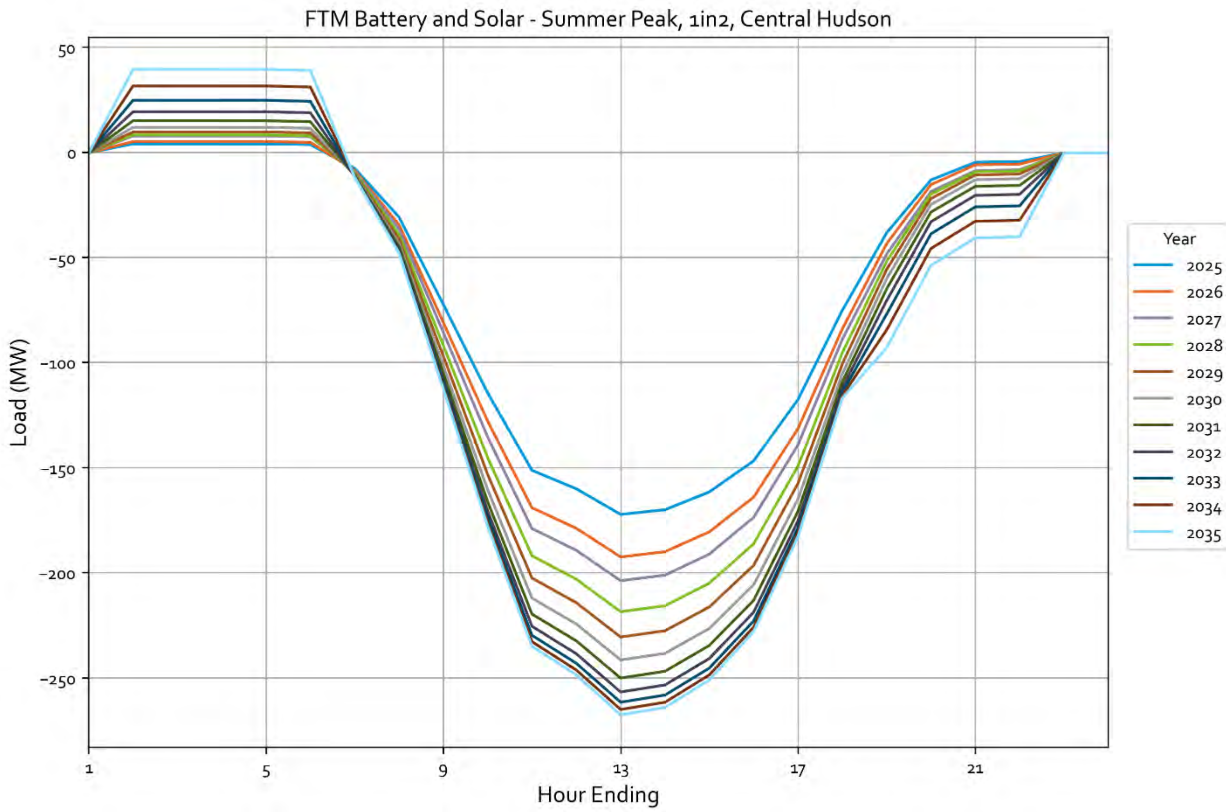
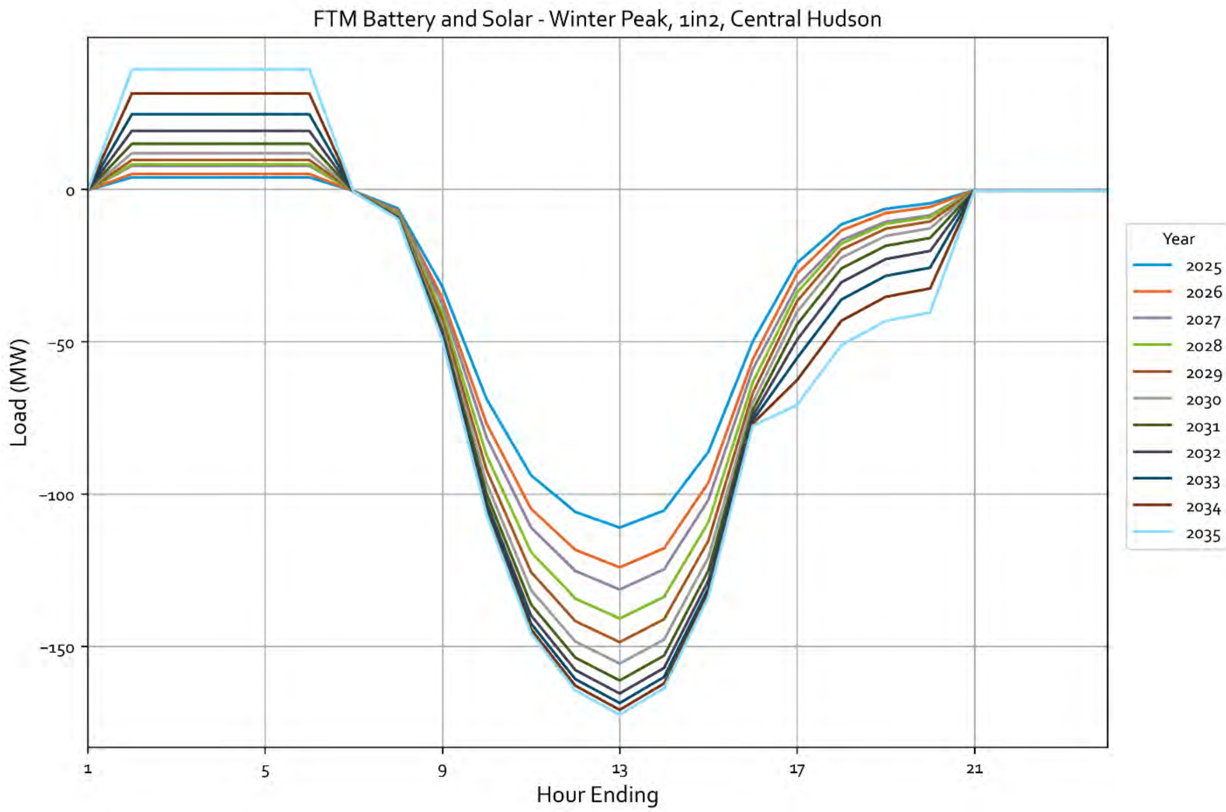
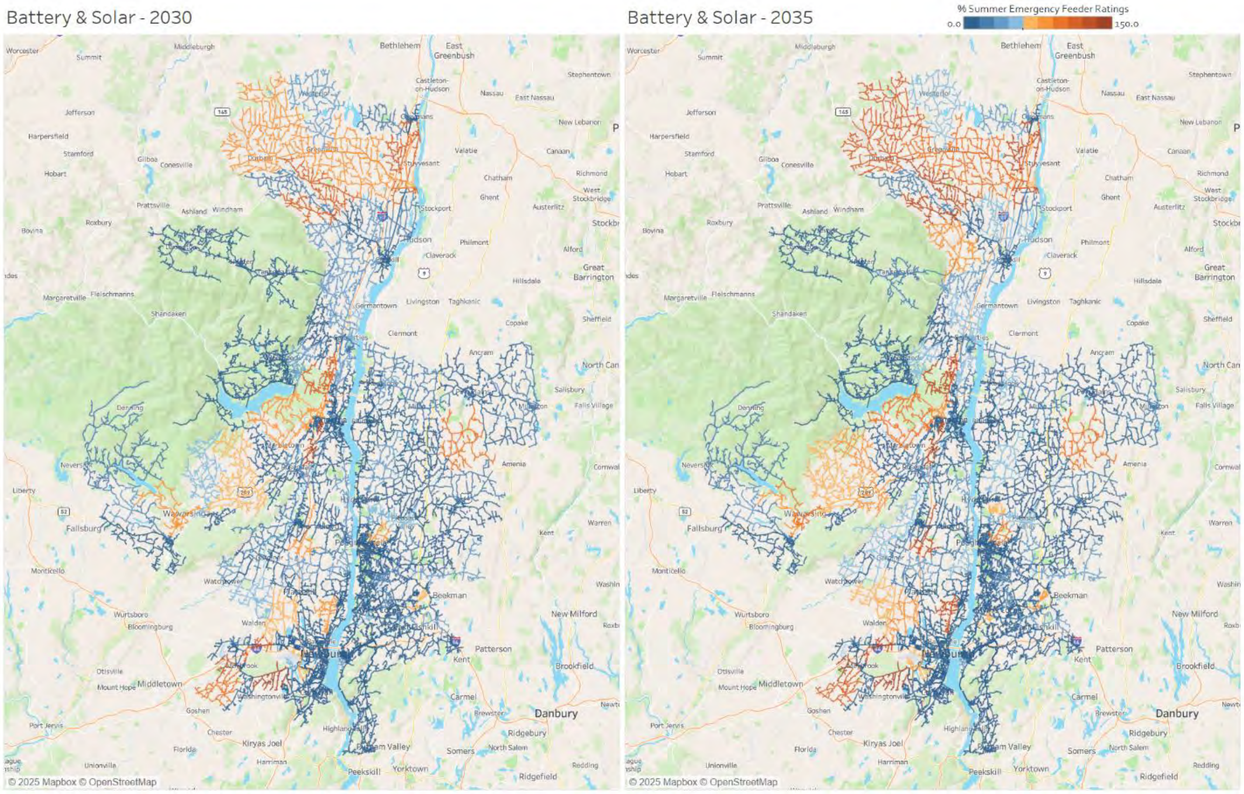


Figure 39: Forecasted community Battery and Solar - Winter 1-in-2 Peak Day: 2025-2035



In addition to load forecasts, we calculated the feeder-level penetration of community solar and battery for each year. Figure 40 shows the feeder-level penetration forecasted in Central Hudson territory in 2030 and 2035.

Figure 40: Community and Remote Solar and Battery Feeder-level Penetration: 2030 and 2035



8 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.

8.1 METHODOLOGY OVERVIEW

Figure 41 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 42 provides more detail on each step in the analysis.

Figure 41: Energy Efficiency Forecast Process Overview

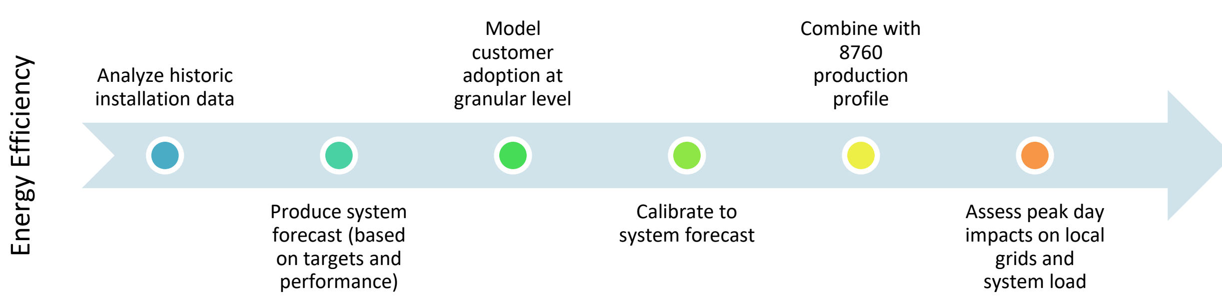


Figure 42: Energy Efficiency Forecast Process Detail

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

8.2 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

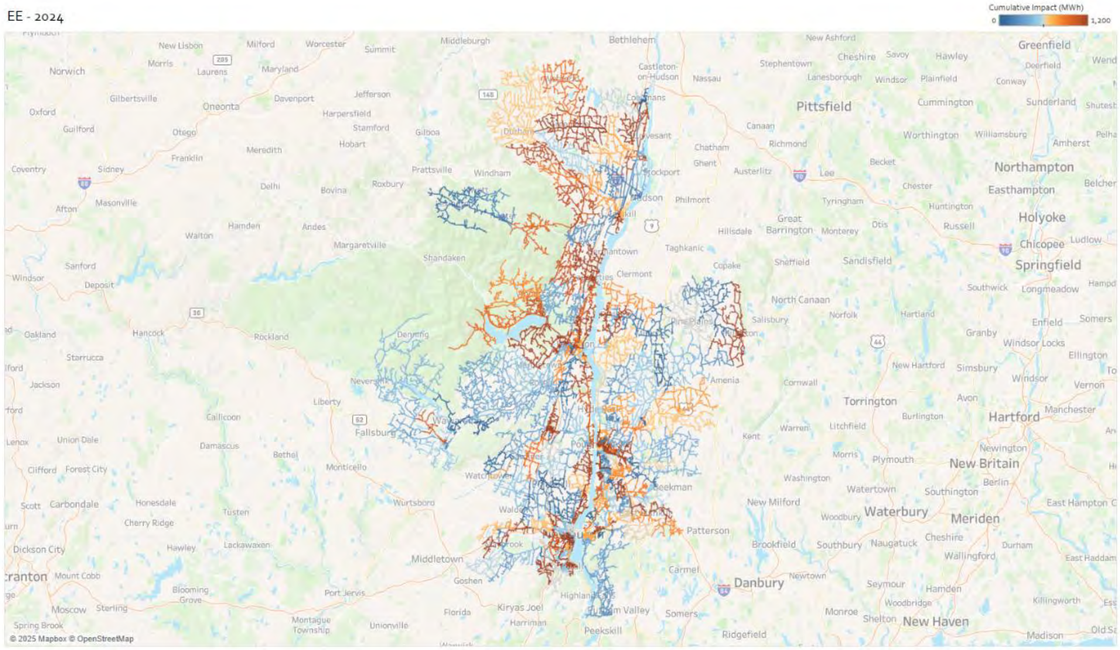
MWh savings attained. Table 21 shows the historical impact of energy efficiency as part of Central Hudson's programs.

Table 21: Historical Impact of Energy Efficiency via Central Hudson Programs

Year	HVAC	Lighting	Other
2012	0	6,540,934	0
2013	0	9,513,429	0
2014	0	10,988,749	0
2015	14,483	19,421,687	0
2016	523,272	8,983,949	0
2017	761,698	9,451,934	176,056
2018	870,318	18,244,314	220,094
2019	734,569	18,077,687	1,098,167
2020	639,789	13,725,214	877,813
2021	487,914	14,270,639	113,967
2022	920,637	20,681,240	1,698,710
2023	215,750	13,486,614	127,419
2024	138,711	18,882,588	300,918
Total	5,307,142	182,268,978	4,613,143

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 have accumulated over 1 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 43: 2024 MWh Impacts of Energy Efficiency by Feeder



8.3 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 2035, 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.

The 2010-2024 summer and winter daily peak loads were used to develop econometric models designed to isolate per-customer demand patterns as a function of weather, time, and other day-type characteristics. Overall, per-customer summer peak demand in Central Hudson has been declining at a rate of -0.84% per year, likely due to a mixture of energy efficiency, codes and standards, and other changes in end-use loads. Winter peak demand has been declining at a rate of -1.17% per year. The difference is likely due to the increasing penetration of air conditioning in Central Hudson's territory and differences in the peak hours between summer and winter. While Central Hudson's per customer peak loads and consumption have decreased over time, the service territory has experienced a 0.61% annual growth rate in the number of customers over the 2010-2024 period, offsetting some but not all of the per customer reductions. The patterns suggest that energy efficiency and codes and standards have had a substantial effect on mitigating summer and winter peak loads.

Table 22 shows the forecasted aggregate energy efficiency savings in MWh. Figure 44 and Figure 45 shows the forecasted summer and winter system peak day reduction due to cumulative energy efficiency activity for 2025 to 2035, respectively.

Table 22: Energy Efficiency and Codes and Standards Forecast (Annual MWh)

		Premises			Annual MWh			
Scenario	Year	HVAC	Lighting	Other	HVAC	Lighting	Other	Total MWh
Central Hudson	2025	12,165	21,897	19,464	19,680	84,341	59,039	163,060
	2026	19,083	34,349	30,532	30,870	132,300	92,610	255,780
	2027	24,649	44,367	39,438	39,874	170,888	119,621	330,383
	2028	29,896	53,813	47,834	48,363	207,270	145,089	400,722
	2029	35,939	64,691	57,503	58,139	249,165	174,416	481,719
	2030	43,135	77,643	69,016	69,779	299,053	209,337	578,169
	2031	50,609	91,096	80,974	81,870	350,871	245,609	678,350
	2032	57,606	103,691	92,170	93,189	399,381	279,566	772,136
	2033	64,285	115,713	102,856	103,993	445,686	311,980	861,659
	2034	70,527	126,948	112,843	114,090	488,959	342,271	945,320
	2035	76,331	137,396	122,130	123,480	529,200	370,440	1,023,120

Figure 44: Aggregate Forecasted Energy Efficiency Savings Summer Peak Day: 2025-2035

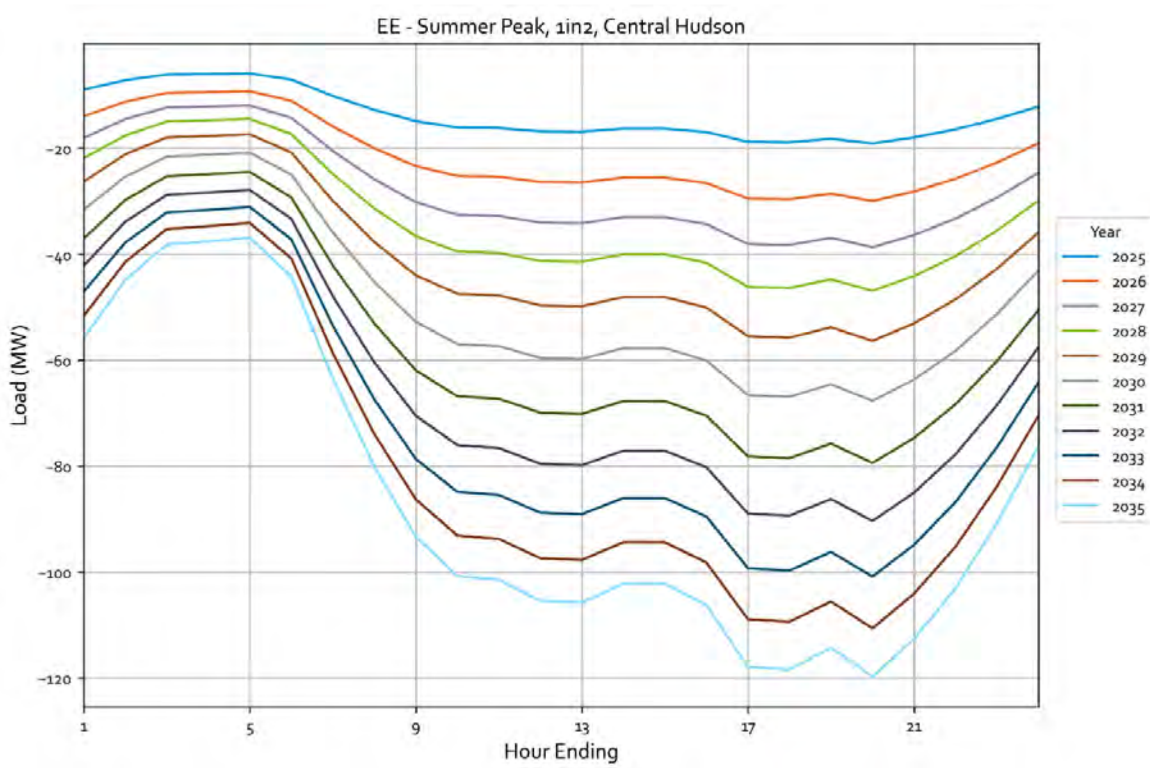


Figure 45: Aggregate Forecasted Energy Efficiency Savings Winter Peak Day: 2025-2035

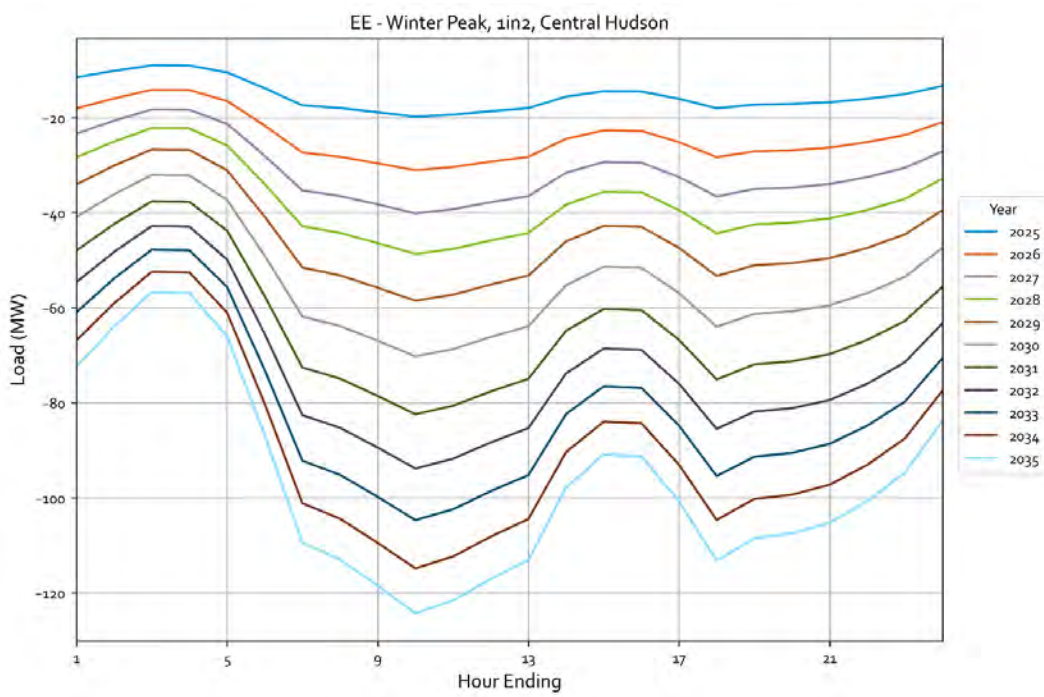
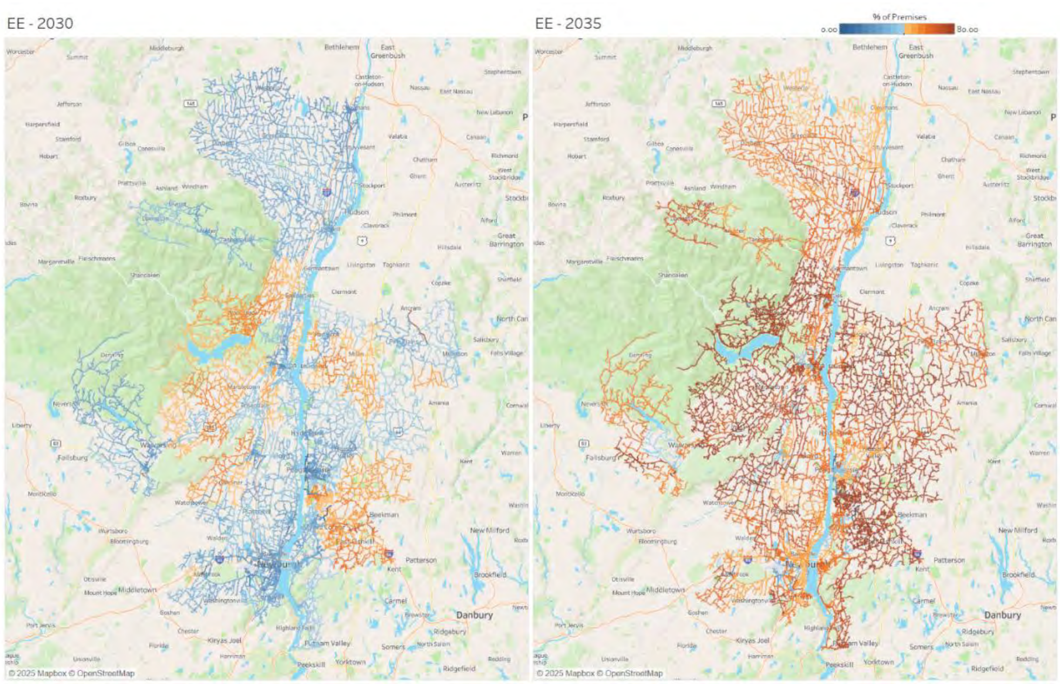


Figure 46 shows the energy efficiency measure adoption rates by circuit feeder, expressed as a percentage of each substation's total premise count in order to normalize for substation size.

Figure 46: Energy Efficiency Feeder-level Penetration: 2030 and 2035



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.

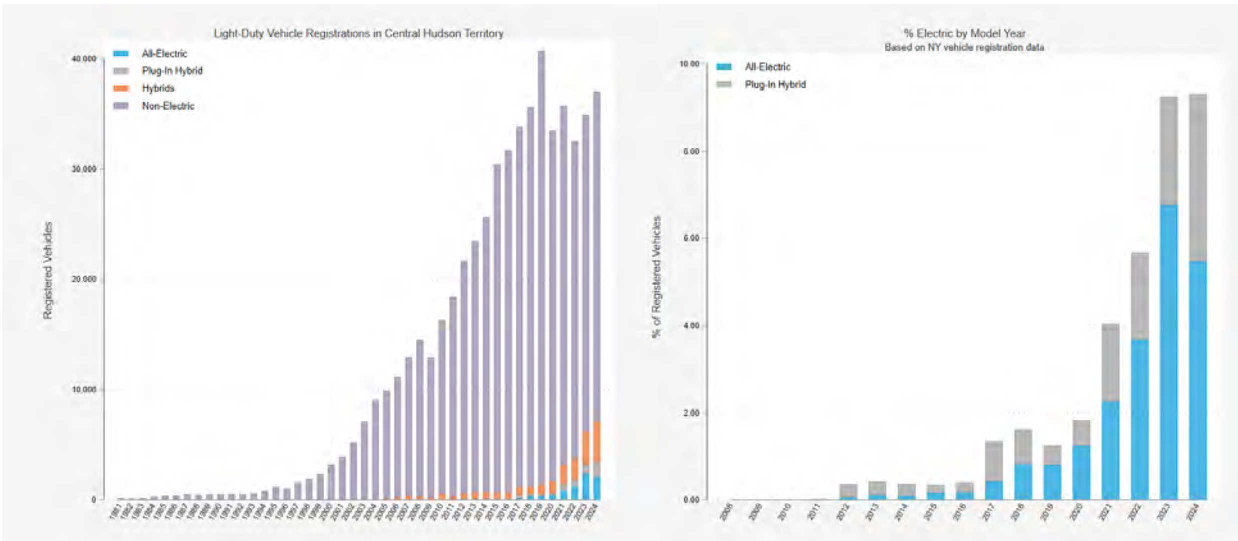
ANALYZE HISTORICAL VEHICLE ADOPTION

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).

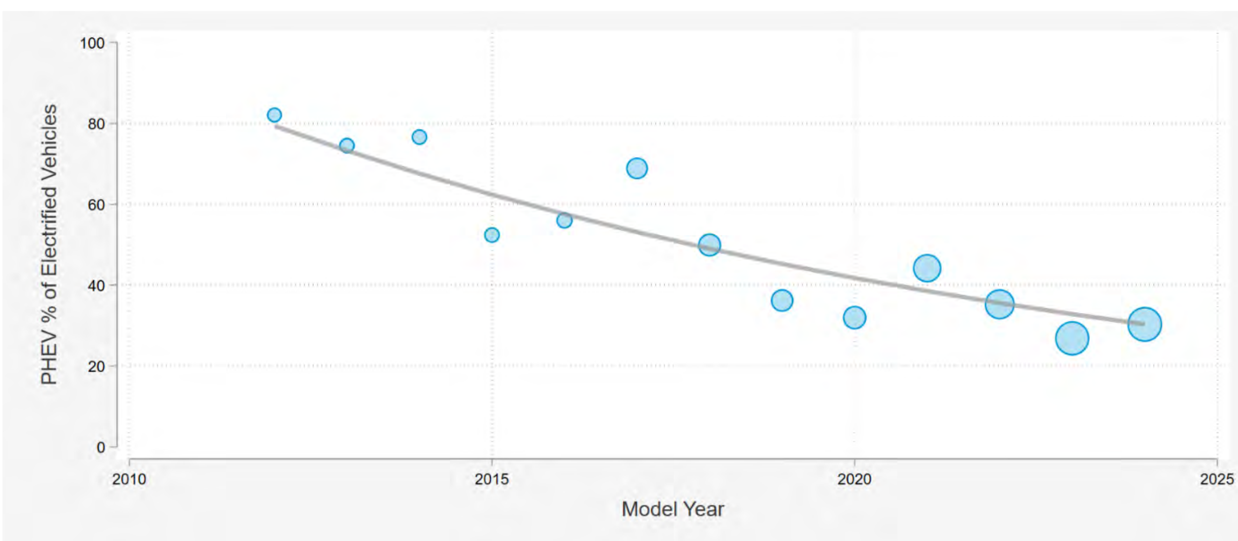
Figure 47 shows the Vehicle stock in Central Hudson territory as March 2025 by model year. Based on the vehicle registration data, there are approximately 565,300 Light Duty Vehicles (LDV), 32,800 Medium and Heavy-Duty Vehicles, and 1,970 Buses in Central Hudson's service territory. Approximately, 43,000 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 newest 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 47: Central Hudson Vehicle Stock and Electric Vehicle Share by Model Year



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 48: PHEV Share of Electric Vehicles by Model Year



PRODUCE THE SERVICE TERRITORY (TOP-DOWN) 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:
   - ✓ Vehicle miles traveled per year: 11,712
   - ✓ kWh per mile: 0.31
   - ✓ PHEV share of miles on electric: 75%

Figure 49 shows 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 49: Historical and Forecasted Electric Vehicle Market Share by Model Year

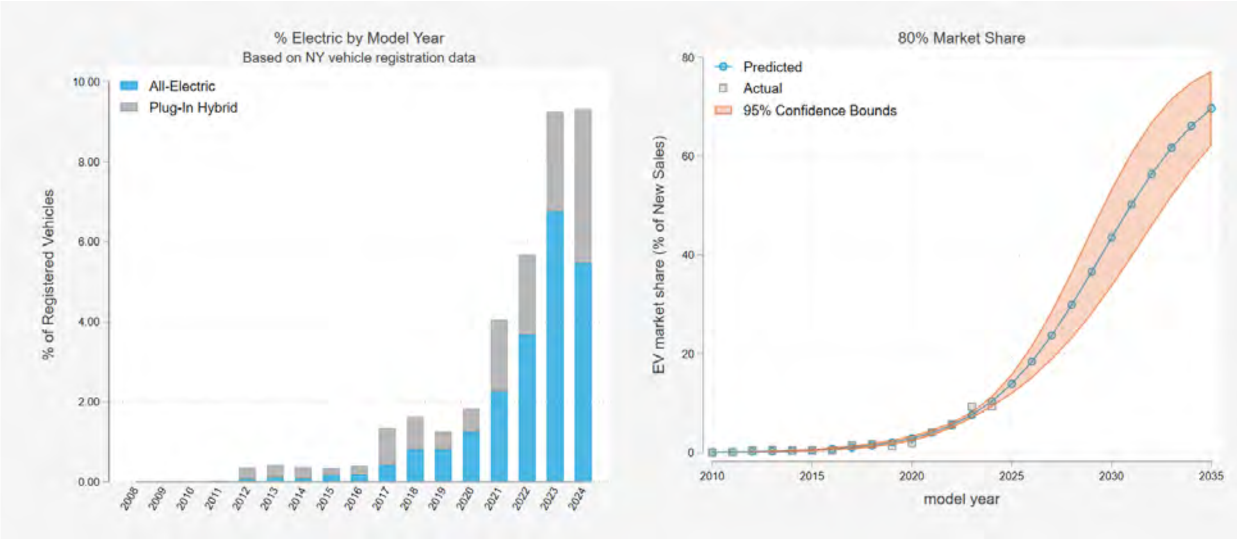


Table 23 shows the system level forecasts for LDVs, MHDVs, and buses. While the LDV and MHDV forecasts were developed based on the historical data, there is limited data on the rate or overall energy use of buses. Thus, we relied on detailed assumptions about the forecasted new vehicle market share of electric school and transit buses presented by NYISO.[4]

Table 23: Service territory forecast for LDV, MHDV, and buses.

	Light Duty		Medium-Heavy Duty		School and Transit Bus		Total	
Year	Vehicles	GWh	Vehicles	GWh	Vehicles	GWh	Vehicles	GWh
2025	19,475	65	164	6	7	0	19,645	71
2026	26,043	87	210	7	34	1	26,287	95
2027	34,474	116	269	10	61	1	34,803	127
2028	44,988	152	345	12	87	2	45,420	166
2029	57,687	196	442	16	114	2	58,243	214
2030	72,510	248	565	20	142	3	73,217	271
2031	89,229	306	719	26	172	3	90,120	335
2032	107,476	370	910	33	205	4	108,590	407
2033	126,804	438	1,141	41	239	5	128,185	484
2034	146,753	508	1,419	51	276	5	148,448	565
2035	166,897	580	1,745	63	315	6	168,957	649
2036	186,882	651	2,121	76	357	7	189,360	734
2037	206,432	720	2,543	92	401	8	209,377	820

[4] NYISO (2025). Electric Vehicle Forecast. Available at: https://www.nyiso.com/documents/20142/50093939/08_2025_EV_Forecast_V2.pdf/ea56b2e1-db54-508d-8cc1-2b0b5290b722

	Light Duty		Medium-Heavy Duty		School and Transit Bus		Total	
Year	Vehicles	GWh	Vehicles	GWh	Vehicles	GWh	Vehicles	GWh
2038	225,348	788	3,009	109	448	8	228,805	905
2039	243,495	853	3,511	127	498	9	247,504	989
2040	260,791	915	4,041	146	550	10	265,383	1,072
2041	277,196	975	4,590	166	606	11	282,393	1,152
2042	292,696	1,031	5,149	186	665	12	298,510	1,230
2043	307,300	1,084	5,710	207	726	14	313,736	1,304
2044	321,030	1,134	6,265	227	787	15	328,082	1,376
2045	333,917	1,181	6,808	247	848	16	341,573	1,444

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 24: Electric Vehicle Charging Port Forecast

				Ports			
Year	BEV	PHEV	PHEV (%)	Single-Family	Multi-Family	L2	DCFC
2025	12,966	6,504	33%	15,338	716	723	62
2026	17,936	8,104	31%	20,515	959	965	86
2027	24,481	9,989	29%	27,153	1,267	1,274	114
2028	32,838	12,146	27%	33,909	1,445	1,432	119
2029	43,154	14,530	25%	43,476	1,845	1,832	156
2030	55,439	17,068	24%	52,780	2,109	2,127	169
2031	69,557	19,669	22%	64,949	2,585	2,615	215
2032	85,240	22,234	21%	76,691	3,146	3,145	263
2033	102,130	24,672	19%	90,484	3,704	3,703	316
2034	119,842	26,908	18%	104,719	4,278	4,272	374
2035	138,003	28,892	17%	119,090	4,861	4,846	431

MODEL CUSTOMER ADOPTION PROPENSITY

The methodology for determining propensity scores for EV adoption at the premise level varies between EV types. For light-duty vehicles, MHDV 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 50 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 and buses were developed at the feeder level instead of the premise level. Vehicle registration data provided counts of 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 buses in each zip code. The electricity usage of a bus for each circuit was calculated by dividing this product by the total count of buses registered in the zip code. Electricity usage per bus was summed across circuits to the feeder level, which was subsequently used as the propensity scores for bus DERs.

Figure 50: Development of Adoption Propensity Scores

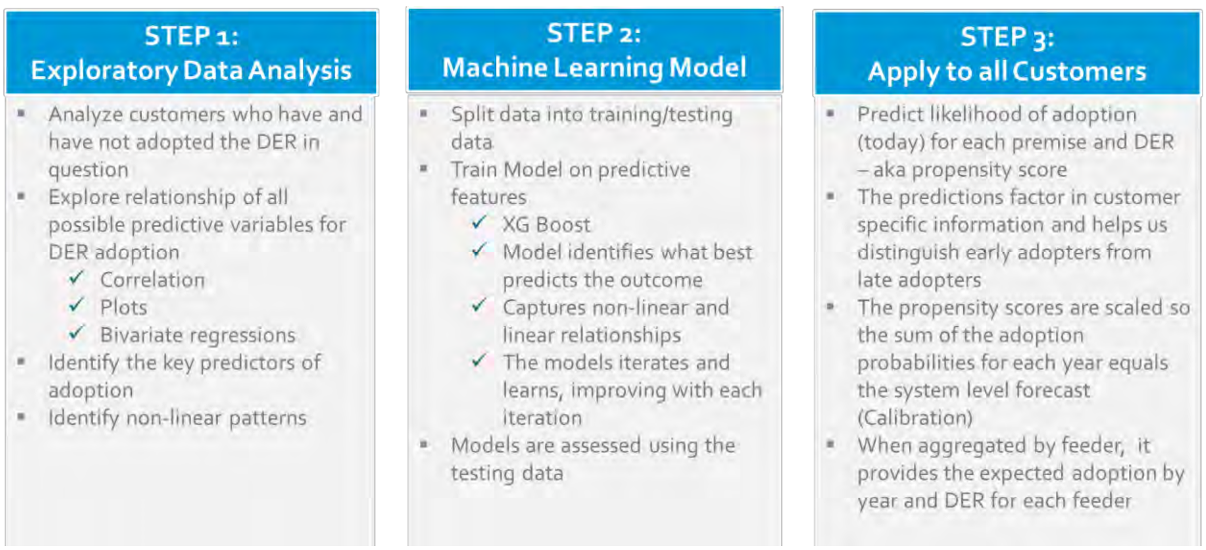
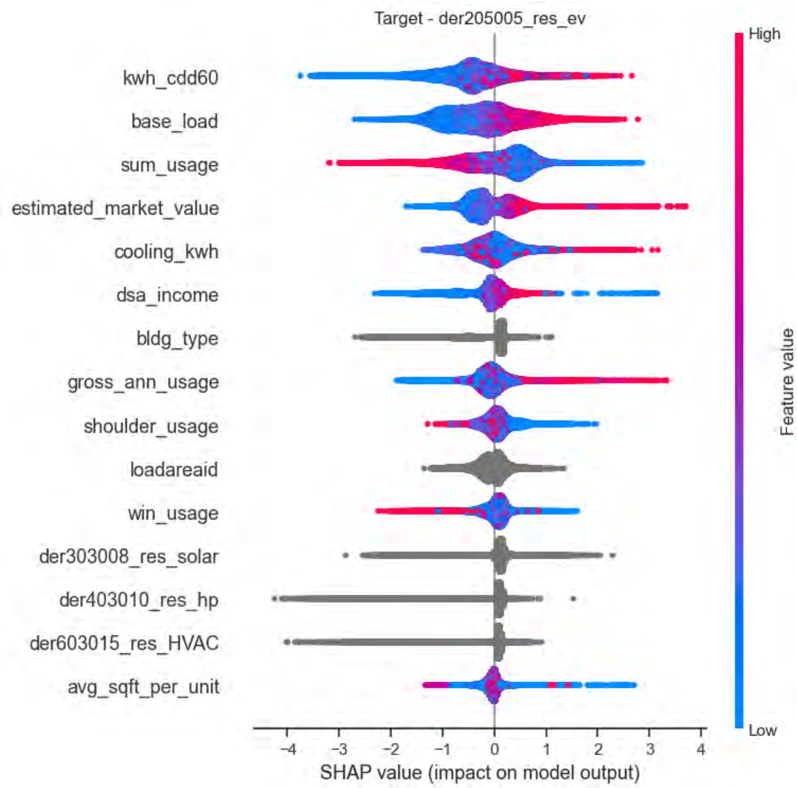


Figure 51 illustrates the relationships between some of the predictors and adoption likelihood. Overall, higher gross annual usage prior to the EV adoption, higher home square, and higher estimated income were predictive a higher probability of electric vehicle adoption. Utility customers in newer homes, 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 52 shows the feature importance for the final model.

Figure 51: Predictors of Electric Vehicle Adoption Propensity

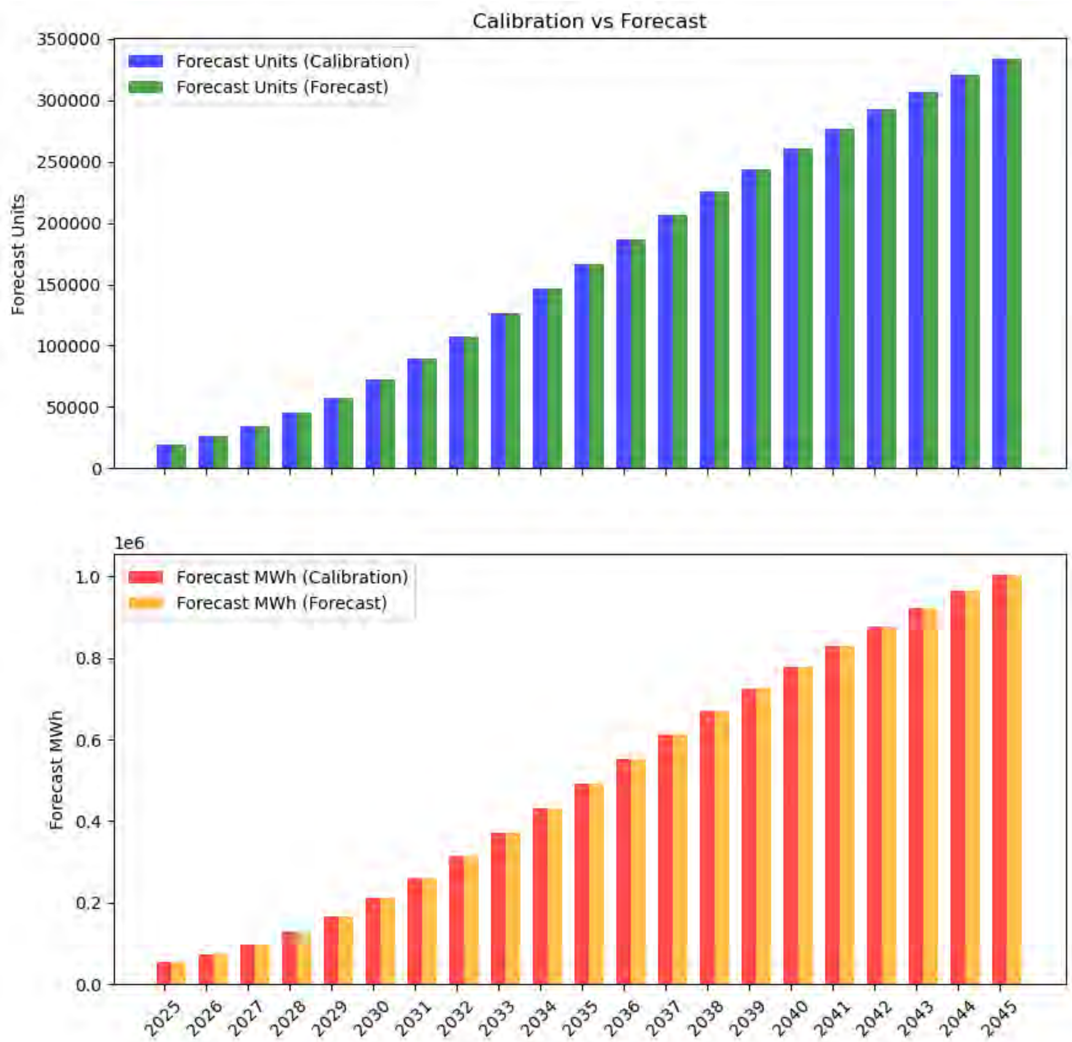
Figure 52: LDV Electric Vehicle Propensity Model SHAP Feature Importance



CALIBRATE TO SYSTEM 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 2025 through 2045 and for two scenarios, Central Hudson forecast and NYISO consistent forecast. Figure 53 compares the calibrated forecast and system level forecast for light-duty vehicles.

Figure 53. Calibrated Feeder Level Forecast vs. System Level Forecasts, LDV



COMBINE WITH 8760 PRODUCTION PROFILE

A key component for the electric vehicle granular forecast 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, providing 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 2025 through 2045, 1-in-2 and 1-in-10 weather years, and Central Hudson and NYISO forecast scenarios. The granular data was then combined 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

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.

ANALYZE HISTORICAL HEAT PUMP ADOPTION

The primary data sources used in the building electrification analysis are listed below:

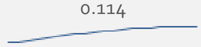
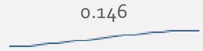
- Clean Heat Program measure and project level participation data and incentive levels,
- Central Hudson electric and gas usage and rate data for all customers
- Property data including square footage, year built, and type of home
- NREL residential and non-residential load shapes for Central Hudson 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 THE SERVICE TERRITORY (TOP-DOWN) FORECAST

Because heat pump and HPWH adoption trends in the territory are heavily influenced by incentive levels and the marketing of the Clean Heat Program, we modeled the innovation diffusion curve to match the baseline scenario of heat pump adoption outlined in NYISO's 2025 Gold Book forecast. The approach was adopted primarily because Central Hudson lost visibility into partial-home and non-cold climate heat pump adoption when the Clean Heat program began to only incentivize who-home, cold-climate heat pumps in mid-2022. For residential heat pumps and HPWHs, NYISO projects that 55% of new market sales will be heat pumps. For commercial heat pumps and HPWHs, we estimated the market cap in 2050 to be 20% and 10%, which reflects the reality that the non-residential sector consistently has much lower penetration of heat pumps than the residential sector.

Figure 54: S-curve assumptions for heat pumps and HPWH

Assumed Market Share S-Curves		Residential Heat Pump	Residential HPWH	Commercial Heat Pump	Commercial HPWH
	Start year	2025			
	Start year market share	20%	5%	5%	1%
	Target year	2050	2050	2045	2045
	Target year market cap %	55%	55%	20%	10%
	S-curve parameter	0.114	0.146	0.182	0.216
	Curve				
Year Index	**Year**	**Residential Heat Pump**	**Residential HPWH**	**Commercial Heat Pump**	**Commercial HPWH**
0	2025	20.00%	5.00%	5.00%	1.00%
1	2026	22.39%	6.44%	6.23%	1.43%
2	2027	24.84%	8.16%	7.57%	1.98%
3	2028	27.33%	10.16%	8.98%	2.63%
4	2029	29.82%	12.43%	10.43%	3.39%
5	2030	32.28%	14.97%	11.87%	4.21%
6	2031	34.68%	17.74%	13.25%	5.07%
7	2032	36.99%	20.71%	14.52%	5.92%
8	2033	39.18%	23.81%	15.67%	6.73%
9	2034	41.25%	26.99%	16.66%	7.47%
10	2035	43.15%	30.19%	17.49%	8.11%
11	2036	44.90%	33.32%	18.17%	8.64%
12	2037	46.48%	36.34%	18.70%	9.06%
13	2038	47.88%	39.18%	19.10%	9.37%
14	2039	49.11%	41.79%	19.39%	9.60%
15	2040	50.19%	44.16%	19.61%	9.75%
16	2041	51.11%	46.24%	19.75%	9.85%
17	2042	51.88%	48.05%	19.85%	9.92%
18	2043	52.53%	49.57%	19.91%	9.96%
19	2044	53.07%	50.84%	19.95%	9.98%
20	2045	53.51%	51.87%	19.97%	9.99%
21	2046	53.86%	52.68%	19.98%	9.99%
22	2047	54.14%	53.32%	19.99%	10.00%
23	2048	54.35%	53.80%	19.99%	10.00%
24	2049	54.52%	54.16%	19.99%	10.00%
25	2050	54.65%	54.43%	19.99%	10.00%

MODEL CUSTOMER ADOPTION PROPENSITY

For heat pumps 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 55 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 weak relationship with heat pump adoption.

Figure 55: Predictors of Residential Heat Pump Adoption

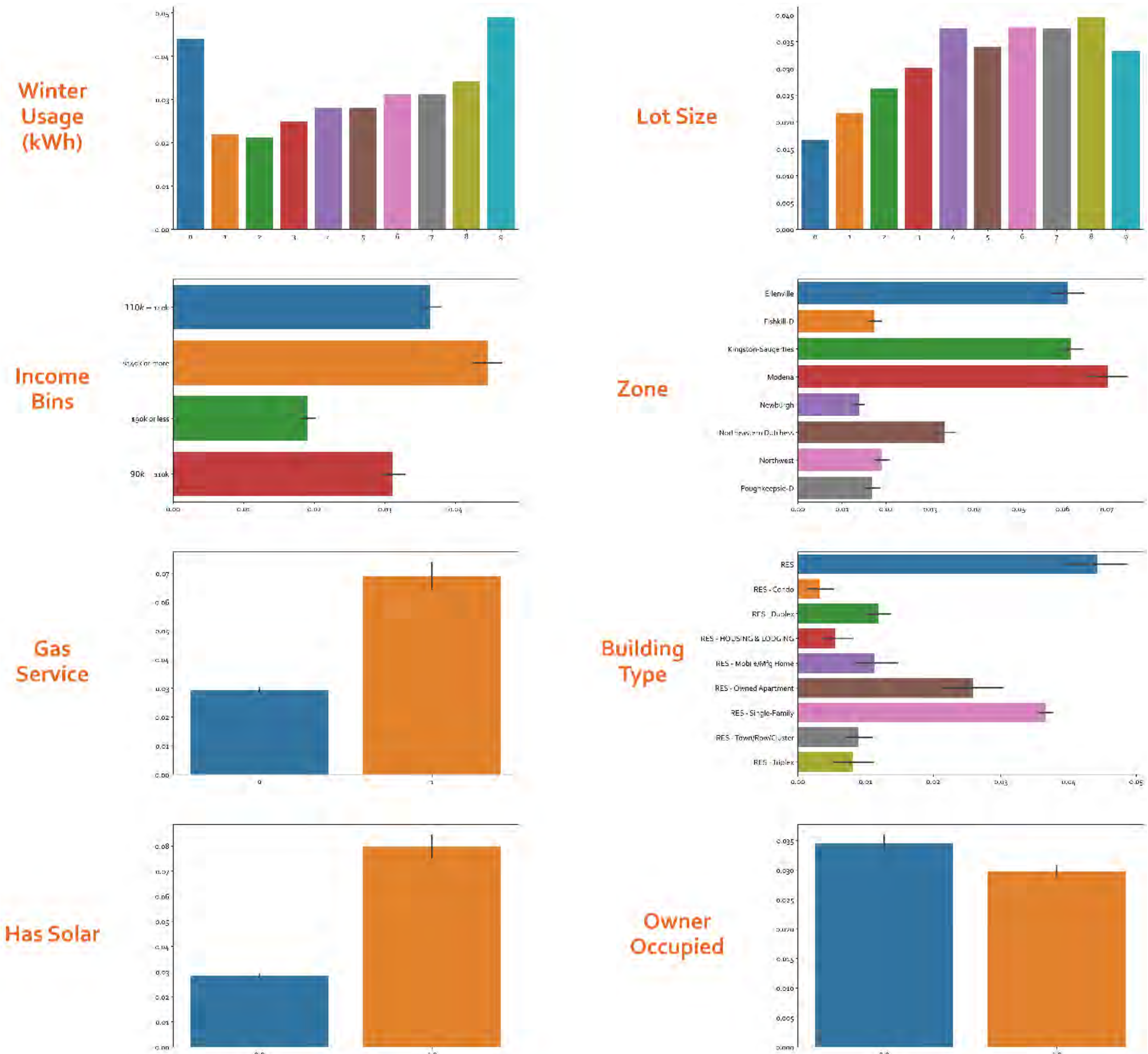
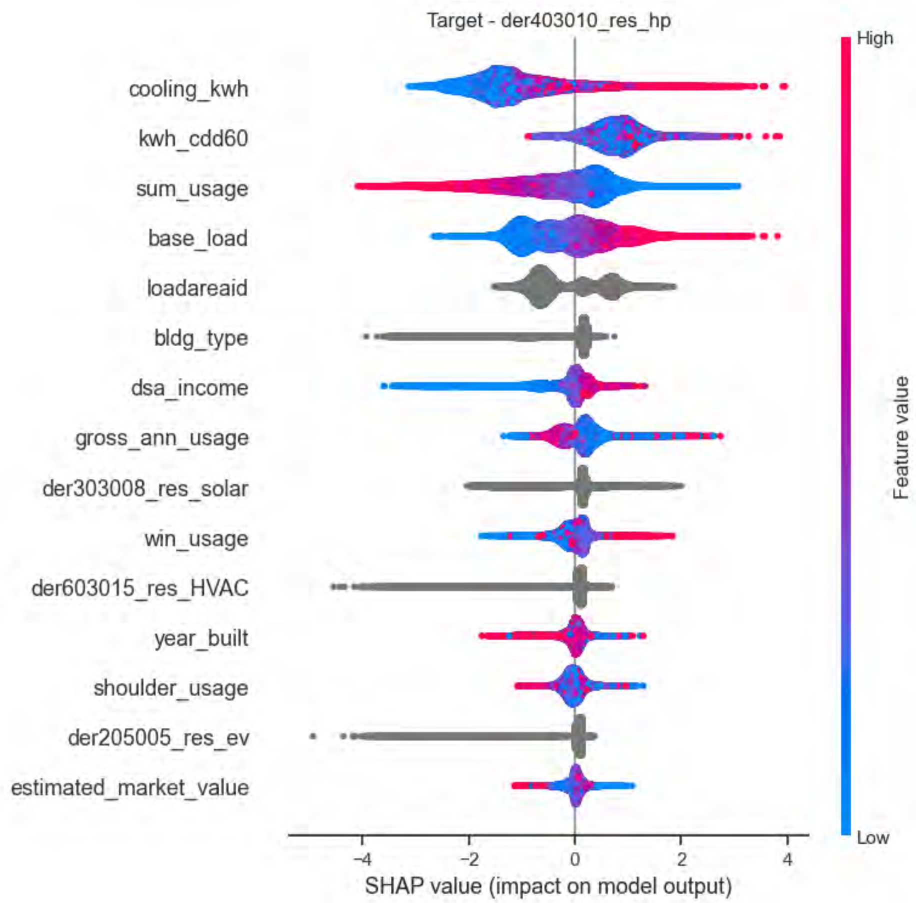


Figure 56 below shows SHAP value importances with the effects of each feature tested. The higher the feature importance (ranked from highest to lowest), the more useful it is for predicting propensities. The x-axis shows the impact (-/+) the feature contributed to predicting der adoption, and the color shows the magnitude of the feature. For example, annual cooling kWh had the highest score showing that higher usage is likely to prediction higher adoption propensities. This is the customers annual cooling kWh before any DER intervention. Additionally, the customer's Zone (loadareaid), 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.

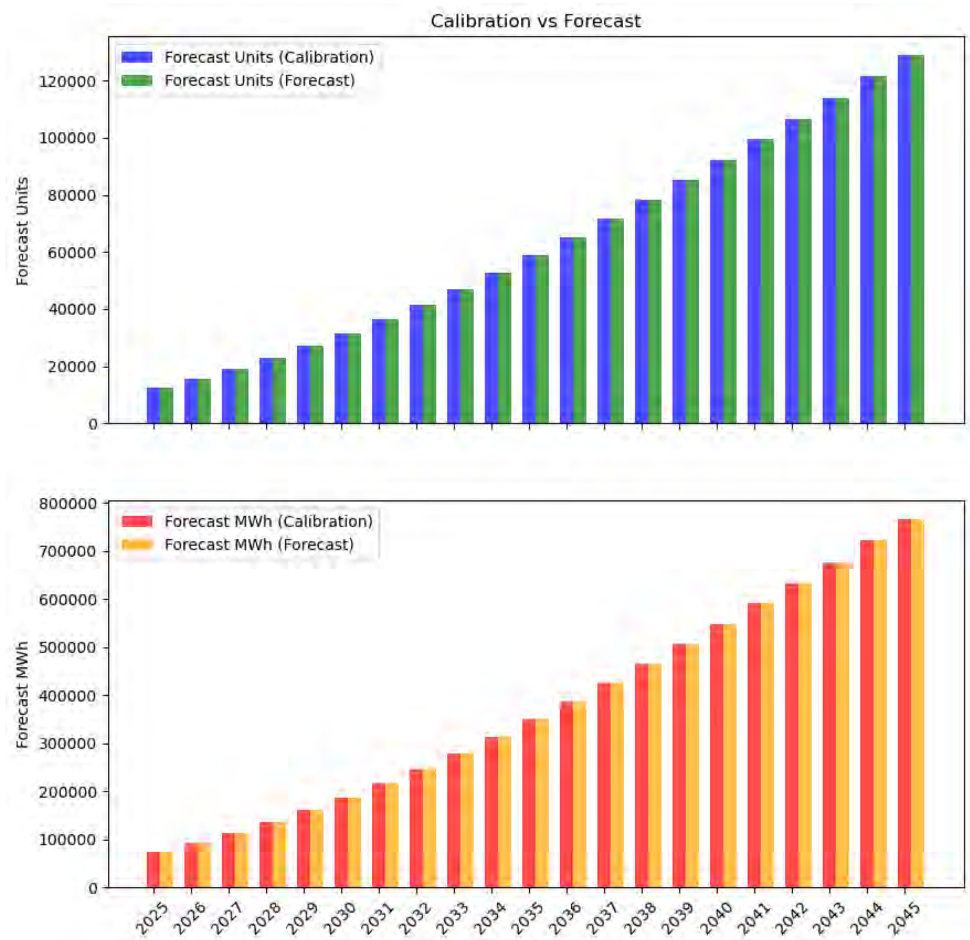
Figure 56: Building Electrification Propensity Modeling Feature Importance, Residential Heat Pump



CALIBRATE TO SYSTEM FORECAST

The premise-level propensities were then scaled so that the total for each year equals the system level forecasts for that year. Two forecasts were generated for this evaluation, a Central Hudson forecast that was fitted to their goals, and a NYISO forecast that was fitted to the goals established by the CLCPA. 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 57 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. Commercial Heat Pumps and Residential HPWHs were calibrated in the same way.

Figure 57: Calibrated Feeder Level Forecast vs. System Level Forecasts, Residential Heat Pumps



COMBINE WITH 8760 PRODUCTION PROFILE

NREL residential and non-residential end use load profiles for heating and cooling were pulled and weather-normalized to predict heat pump and HPWH loads under 1-in-2 and 1-in-10 weather conditions. Hourly loads were then normalized to the total annual usage to obtain a normalized, 8760 load shape. These load shapes were used to scale the forecasted annual usage from building electrification adoption, expanding the annual, calibrated forecast to an hourly demand forecast at each feeder for 20 forecast years.

ASSESS PEAK DAY IMPACTS

To assess the impacts of heat pump and HPWH adoption on the peak days, the local winter and summer peak days were first 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, the building electrification contribution to forecasted load was estimated.

APPENDIX C – ENERGY EFFICIENCY METHODOLOGY

The granular energy efficiency forecasts were produced using the following six step process:

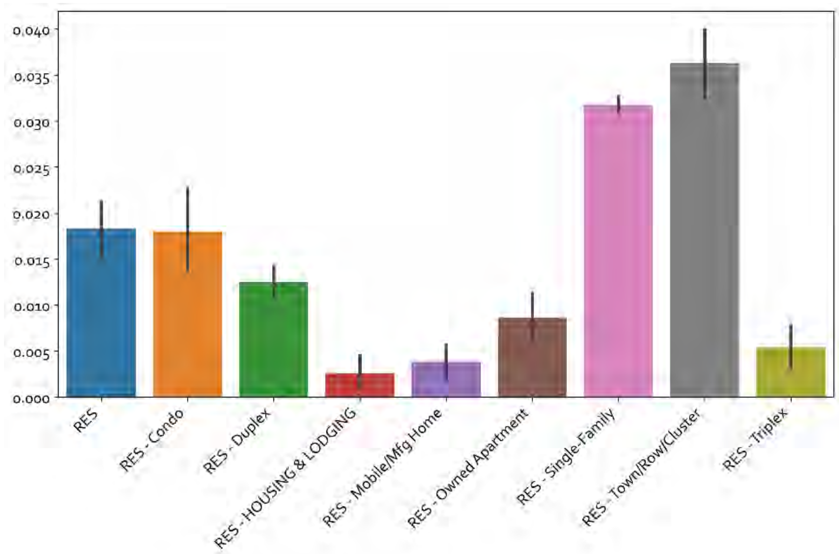
1. Analyze historic vehicle adoption data
2. Produce territory forecast
3. Model customer adoption propensity at granular level
4. Calibrate propensities to match territory forecast
5. Incorporate 8760 hourly end use load shapes
6. Assess peak day impacts on local grids and system load

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.

ANALYZE HISTORICAL ENERGY EFFICIENCY ADOPTION

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 58 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.

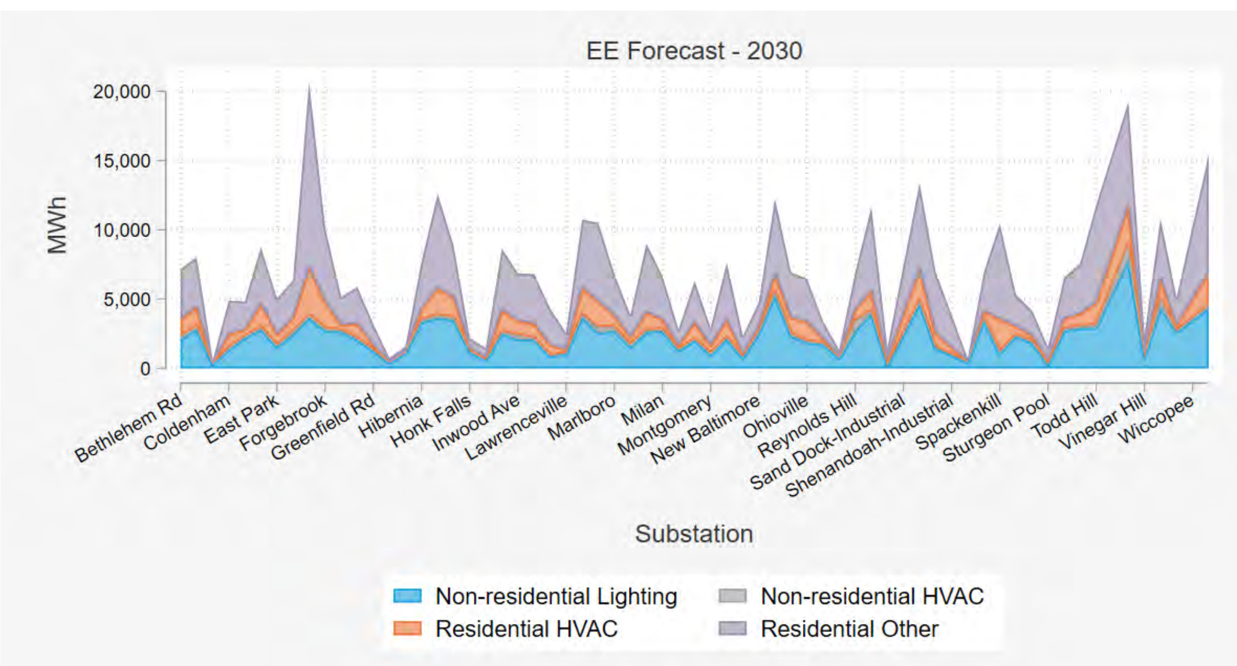
Figure 58: Residential HVAC Adoption Rates by Building Type



PRODUCE THE SERVICE TERRITORY (TOP-DOWN) FORECAST

To develop an energy efficiency forecast, the 2025 Gold Book 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 59 shows the resulting forecasted annual MWh usage for each substation by sector, residential or commercial, and energy efficiency category.

Figure 59: Forecasted Energy Efficiency Savings

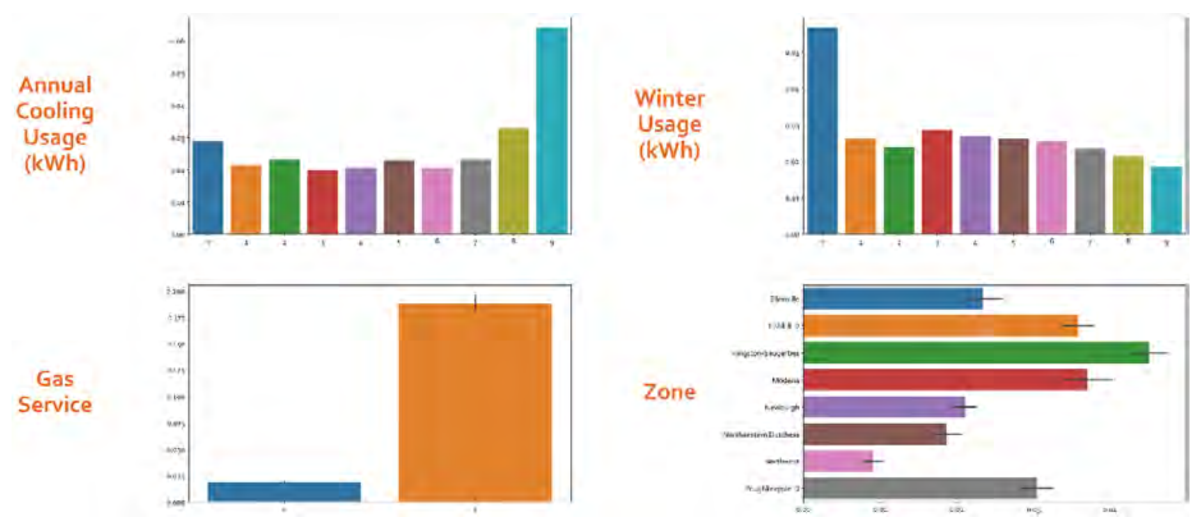


MODEL CUSTOMER ADOPTION PROPENSITY

After forecasting system-level energy efficiency, developed adoption propensity scores were developed 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 60 illustrates the relationships between some of the predictors and adoption likelihood.

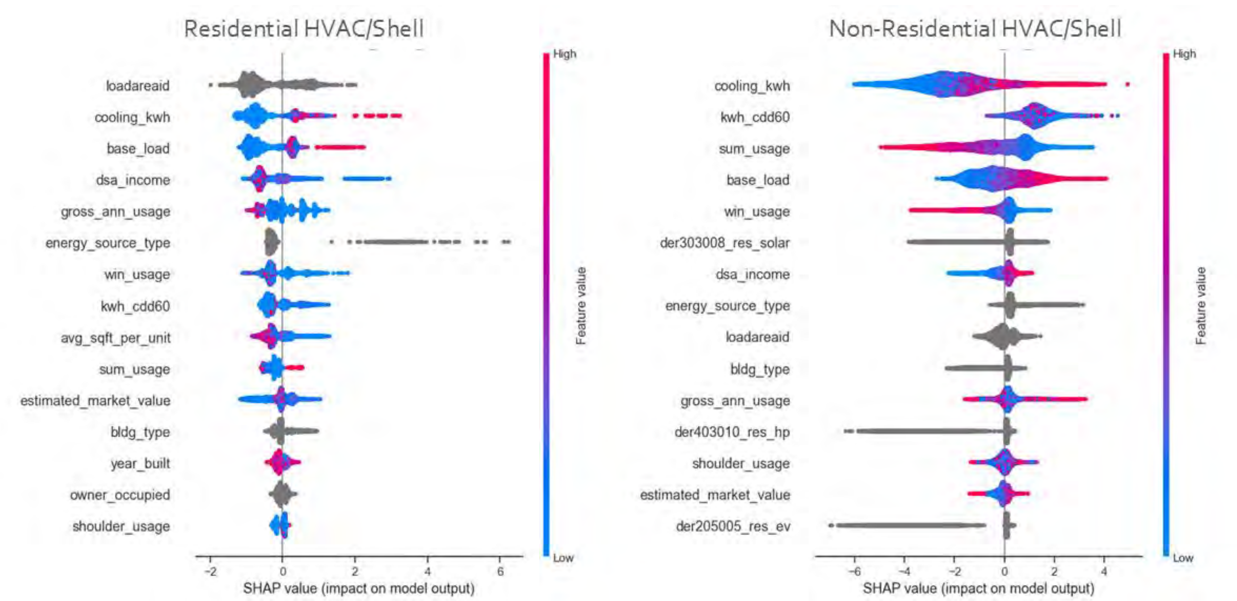
Figure 60: Exploratory Analysis of Residential HVAC/Shell Energy Efficiency



We then 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 61 shows the SHAP value importances with the effects of each feature tested. The higher the feature importance (ranked from highest to lowest), the more useful it is for predicting propensities. The x-axis shows the impact (-/+) the feature contributed to predicting der adoption, and the color shows the magnitude of the feature. For example, the top three features for the residential model were 1) Zone (loadareaid), 2) what the participants annual cooling kWh was, and 3) their base load. Additionally, the customer's income and gross annual usage (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.

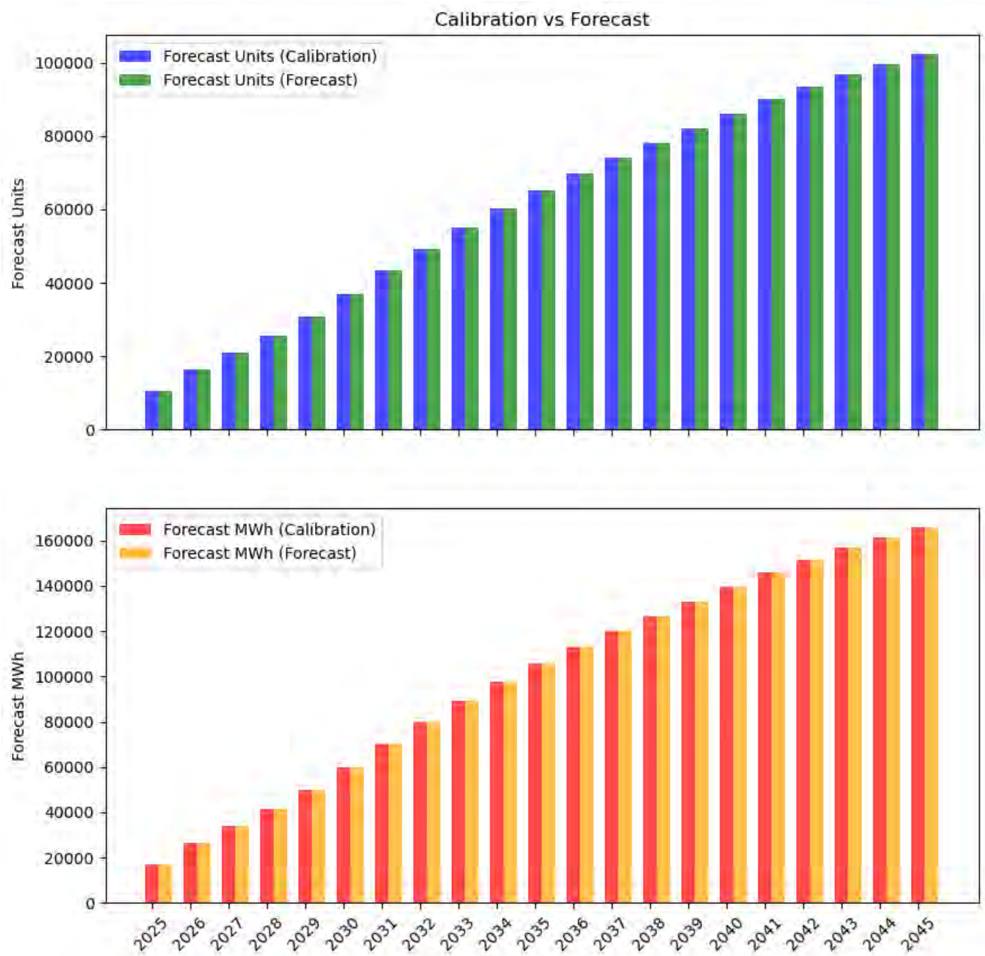
Figure 61: Energy Efficiency Models Feature Importance



CALIBRATE TO SYSTEM FORECAST

The premise level propensities were calibrated to the system-level, top-down forecast. Two forecasts were generated for this analysis, a Central Hudson forecast that was fitted to their goals, and a NYISO forecast that was calibrated to the forecast released by NYISO annually in their Gold Book. The scaled results were then aggregated to the circuit level. Figure 62 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. All energy efficiency types (i.e., HVAC, lighting, appliances) were calibrated in the same manner.

Figure 62: Calibrated Feeder Level Forecast vs. System Level Forecasts, Residential HVAC



COMBINE WITH 8760 PRODUCTION PROFILE

NREL residential and non-residential end use load profiles were normalized to the total annual usage. These load shapes were used to scale the forecasted annual usage from energy efficiency and codes and standards to produce the hourly (8760) demand forecasts at the feeder level for 20 forecast years.

ASSESS PEAK DAY IMPACTS

To assess the impacts of energy efficiency on the peak days, the local winter and summer peak days were first identified by feeder, substations, and transmission areas using historical hourly interval data. Energy efficiency loads were then combined with forecasted T&D loads on peak days for each location (feeder, substation, and transmission area) and each forecast year. From this, the energy efficiency contribution to forecasted load was estimated.

Central Hudson Gas & Electric

Benefit-Cost Analysis (BCA) Handbook

Version 5.0

June 30, 2025

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
V4.5	Central Hudson BCA Handbook – v5.0	6/30/25	Central Hudson	Fifth 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 2025 Standard BCA Template 5.0 is the latest update to the Handbook.

The 2025 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 2025 BCA Handbooks are to be filed on June 30, 2025 with each utility's 2025 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 2025 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 2025 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: 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]
Emission Rates for Electric Generation	NYSERDA

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 2024 ICAP Spreadsheet Model (filed October 3, 2024) 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	Joint Proposal dated May 13, 2025, pending before the Commission in Cases 24-E-0461 and 24-G-0462.
Losses	2019 Central Hudson Gas & Electric Corporation Analysis of System Losses
Marginal Avoided Transmission & Distribution Costs	DPS: 2023 Electric Service Reliability Report
Reliability Statistics	DPS: 2023 Electric Service Reliability Reports[14]

The New York general and utility-specific assumptions that are included in the 2025 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 2025 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.

14 The Annual Electric Service Reliability Reports are available at: https://dps.ny.gov/electric-service-reliability-reports

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 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.

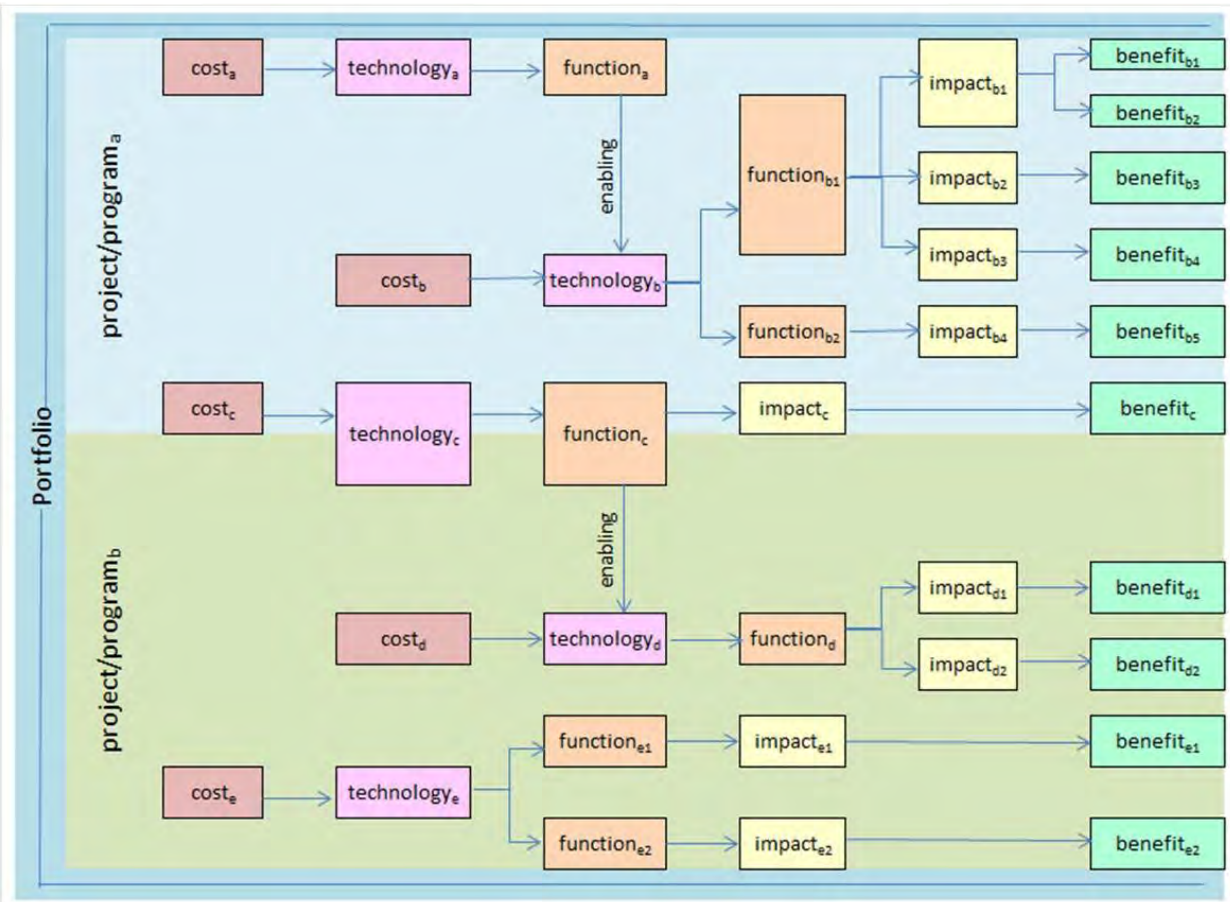
Sections 2.1.1 and 2.1.2 discuss these considerations in more detail.

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 Losses and Avoided Distribution Losses benefits.

[15] *BCA Order*, Appendix C pg. 18

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.

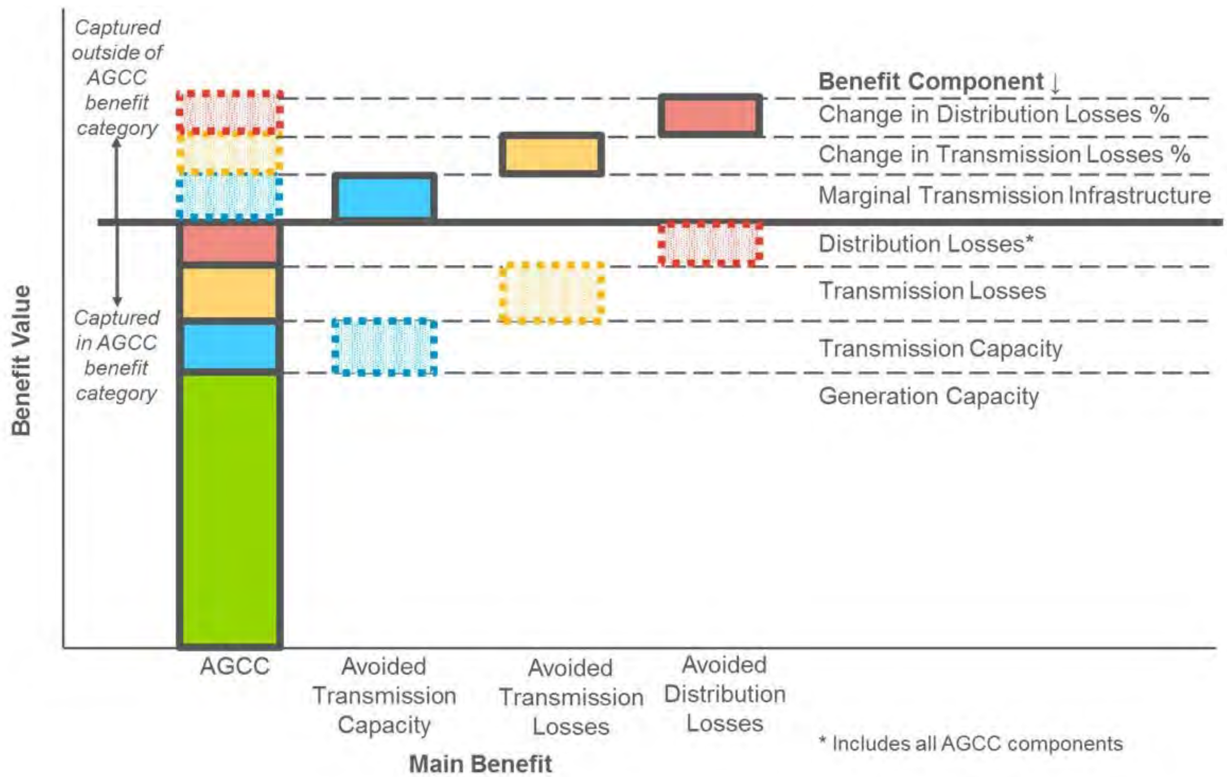
Table 2-1. Benefits with Potential Overlaps

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.

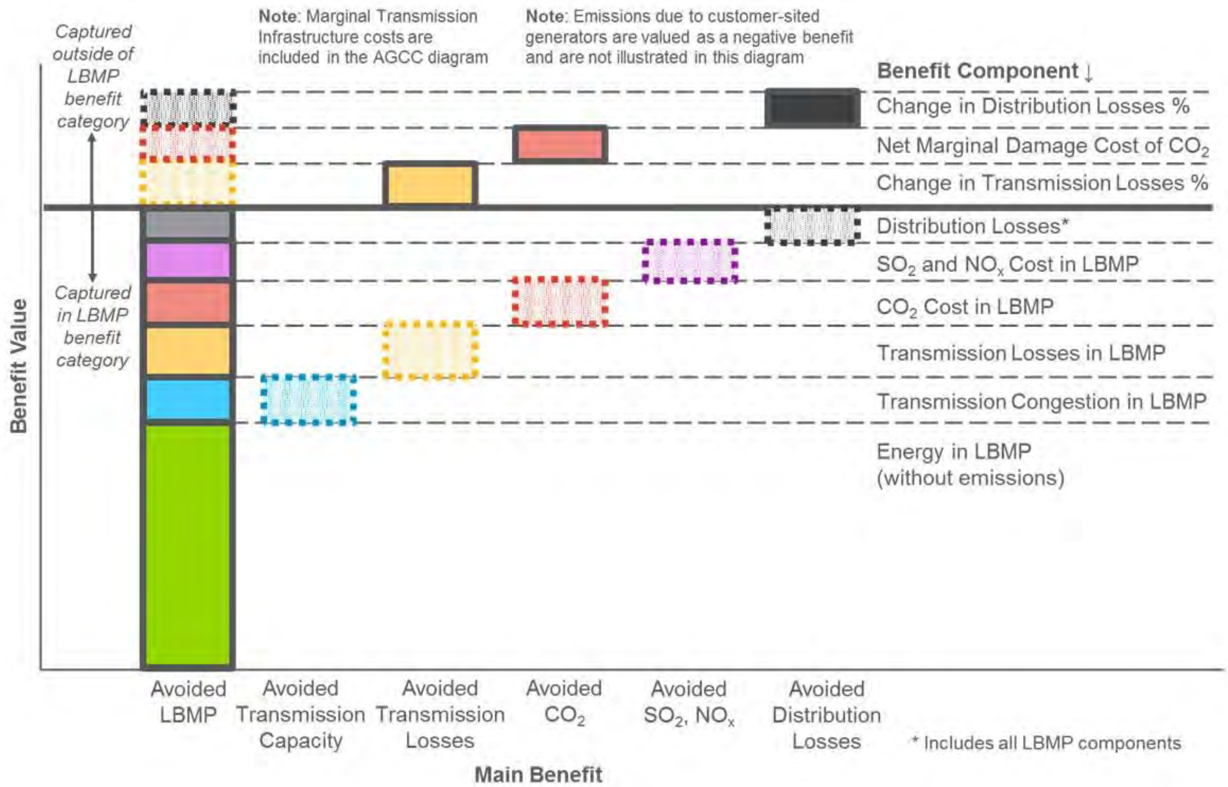
If a project changes the electrical topology and, therefore, the transmission loss percent, the incremental changes in transmission losses would be allocated to the Avoided Transmission Losses benefit. Similarly, any incremental changes to distribution loss percent as a result of the project would be 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 $\mathrm{Loss\%}_{b\rightarrow r}$ would represent the loss percent between the bulk system ("b") and the retail delivery or connection point ("r"). In this example, the loss percent would be the sum of the distribution secondary, distribution primary and transmission loss percentages. If a large commercial customer is connected to primary distribution the appropriate loss percent would be the sum of distribution primary and transmission loss percentages.

[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 Questions 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)
UTC	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†	✓	✓	✓
4.1.2	Avoided LBMP‡	✓	✓	✓
4.1.3	Avoided Transmission Capacity Infrastructure†‡	✓	✓	✓
4.1.4	Avoided Transmission Losses†‡	✓	✓	✓
4.1.5	Avoided Ancillary Services*		✓	✓
4.1.6	Wholesale Market Price Impacts**		✓	✓
4.2.1	Avoided Distribution Capacity Infrastructure	✓	✓	✓
4.2.2	Avoided O&M	✓	✓	✓
4.2.3	Avoided Distribution Losses†‡	✓	✓	✓
4.3.1	Net Avoided Restoration Costs	✓	✓	✓
4.3.2	Net Avoided Outage Costs	✓		
4.4.1	Net Avoided CO_2‡	✓		
4.4.2	Net Avoided SO_2 and NO_x‡	✓		
4.4.3	Avoided Water Impacts	✓		
4.4.4	Avoided Land Impacts	✓		
4.4.5	Net Non-Energy Benefits***	✓	✓	✓
Cost				
4.5.1	Program Administration Costs	✓	✓	✓
4.5.2	Added Ancillary Service Costs*		✓	✓
4.5.3	Incremental T&D and DSP Costs	✓	✓	✓
4.5.4	Participant DER Cost	✓		
4.5.5	Lost Utility Revenue			✓
4.5.6	Shareholder Incentives		✓	✓
4.5.7	Net Non-Energy Costs**	✓	✓	✓

† See Section 2 for discussion of potential overlaps in accounting for these benefits.
‡ See Section 2.1.2.1 for discussion of potential overlaps in accounting for these benefits.
** The amount of DER is not 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 Questions 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)

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 Questions Answered	Calculation Approach
UTC	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 Questions Answered	Calculation Approach
RIM	Ratepayer	How will utility rates be affected?	Compares utility costs and utility bill reductions with avoided electricity and other supply-side resource costs

The RIM test can address rate impacts to non-participants. External benefits such as Avoided CO2, Avoided SO2 and NOX, 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 2025 BCA Handbook 5.0 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 2025, the AGCC benefit would not be realized until 2026.

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

$$\text{Benefit}_{Y+1} = \sum_{Z} \frac{\Delta\text{PeakLoad}_{Z,Y,r}}{1\text{-Loss\%}_{Z,Y,b\rightarrow r}} * \text{SystemCoincidenceFactor}_{Z,Y} * \text{DeratingFactor}_{Z,Y} * \text{AGCC}_{Z,Y,b}$$

The indices of the parameters in Equation 4-1 include:

- Z = NYISO zone (A → K)
- Y = Year
- b = Bulk System
- r = Retail Delivery or Connection Point

$\Delta\text{PeakLoad}_{Z,Y,r}$ (ΔMW) is the project's expected maximum demand reduction capability, or "nameplate" impact at the retail delivery or connection point ("r"), by zone if applicable. This input is project or program specific. A positive value represents a reduction in peak load.

$\text{Loss\%}_{Z,b\rightarrow r}$ **(%)** is the variable loss percent between bulk system ("b") and the retail delivery or connection point ("r"). The loss percentages by system level are found in Table A-2.

$\text{SystemCoincidenceFactor}_{Z,Y}$ **(dimensionless)** captures a project's or program's contribution to reducing bulk system peak demand relative to its expected maximum demand reduction capability. For example, a nameplate demand reduction capacity of 100 kW with a system coincidence factor of 0.8 would reduce the bulk system peak demand by 80 kW. This input is project specific.

$\text{DeratingFactor}_{Z,Y}$ **(dimensionless)** is presented here as a factor to de-rate the coincident peak load reduction based on the availability of a resource during system peak hours. For example, a demand response program may only be allowed to dispatch a maximum of 10 events per year, which could limit the availability of the resource during peak hours. Another example is the variability and intermittence (e.g., due to clouds) of a solar array which could limit its contribution to system peak load reduction. This input is project specific.

$\text{AGCC}_{Z,Y,b}$ ($/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 a

[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

$$\text{Benefit}_Y = \sum_Z \sum_P \frac{\Delta \text{Energy}_{Z,P,Y,r}}{1 - \text{Loss\%}_{Z,b \to r}} * \text{LBMP}_{Z,P,Y,b}$$

The indices of the parameters in Equation 4-2 include:

- Z = zone (A → K)
- P = period (e.g., year, season, month, and hour)
- Y = Year
- b = Bulk System
- r = Retail Delivery or Connection Point

$\Delta \text{Energy}_{Z,P,Y,r}$ (ΔMWh) is the difference in energy purchased at the retail delivery or connection point ("r") as the result of project implementation, by NYISO zone and by year with by time-differentiated periods, for example, annual, seasonal, monthly, or hourly as appropriate. This parameter represents the energy impact at the project location and is **not** yet grossed up to the LBMP location based on the losses between those two points on the system. This adjustment is performed based on the $\text{Loss\%}_{Z,b \to r}$ parameter. This input is project- or program-specific. A positive value represents a reduction in energy.

$\text{Loss\%}_{Z,b \to r}$ **(%)** 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.

$\text{LBMP}_{Z,P,Y,b}$ ($/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

$$\text{Benefit}_{Y+1} = \sum_{C} \frac{\Delta \text{PeakLoad}_{Y,r}}{1 - \text{Loss\%}_{Y,b\rightarrow r}} * \text{TransCoincidentFactor}_{C,Y} * \text{DeratingFactor}_{Y} * \text{MarginalTransCost}_{C,Y,b}$$

The 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

$$\mathrm{Benefit}_{Y+1} = \sum_{Z} \mathrm{SystemEnergy}_{Z,Y+1,b} * \mathrm{LBMP}_{Z,Y+1,b} * \Delta\mathrm{Loss\%}_{Z,Y+1,b\rightarrow i} + \mathrm{SystemDemand}_{Z,Y,b} * \mathrm{AGCC}_{Z,Y,b} * \Delta\mathrm{Loss\%}_{Z,Y,b\rightarrow i}$$

Where,

$$\Delta\mathrm{Loss\%}_{Z,Y,b\rightarrow i} = \mathrm{Loss\%}_{Z,Y,b\rightarrow i,\mathrm{baseline}} - \mathrm{Loss\%}_{Z,Y,b\rightarrow i,\mathrm{post}}$$

The indices[31] of the parameters in Equation 4-4 include:

- Z = NYISO zone (for LBMP: A → K; for AGCC: NYC, LHV, LI, ROS[32])
- Y = Year
- b = Bulk System
- i = Interface of the transmission and distribution systems

$\mathbf{SystemEnergy_{Z,Y+1,b}}$ **(MWh)** is the annual energy forecast by NYISO in the Load & Capacity Report at the bulk system ("b", ")includes both transmission and distribution losses. Total system energy is used for this input, rather than the project-specific energy, because this benefit is only included in the BCA when a change in system topology produces a change in the transmission loss percent, which affects all load in the relevant area.

$\mathbf{LBMP_{Z,Y+1,b}}$ **($/MWh)** is the LBMP, which is the sum of energy, congestion, and losses components by NYISO zone at the bulk system level ("b"). To determine time-differentiated LBMPs, for example, annual, seasonal, monthly, or hourly, leverage NYISO's hourly LBMP forecast by zone rather than developing an alternative forecast of time-differentiated LBMPs based on shaping annual averages by zone from historical data. The NYISO hourly LBMP forecast is a direct output from the CARIS Phase 2 modeling. To extend the LBMP forecast beyond the CARIS planning period, if necessary, assume that the last year of the LBMPs stay constant in real (inflation adjusted) $/MWh.

$\mathbf{SystemDemand_{Z,Y,b}}$ **(MW)** is the system peak demand forecast by NYISO at the bulk system level ("b"), which includes transmission and distribution losses by zone. System demand is used in this evaluation, rather than the project-specific demand, because this benefit is only quantified 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.

$\mathbf{AGCC_{Z,Y,b}}$ **($/MW-yr)** represents the annual AGCCs based on the 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.

$\mathbf{\Delta Loss\%_{Z,Y,b\rightarrow i}}$ **(Δ%)** is the change in fixed and variable loss percent between the bulk system ("b") and the interface of the transmission and distribution systems ("i") resulting from a project that changes the topology of the transmission system. This value would typically be determined in a project-specific engineering study. Two parameters are provided in the equations above: one with a "Y" subscript to represent the current year, and one with a "Y+1" subscript to represent the following year.

[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").

$\text{Loss\%}_{Z,Y,b\rightarrow i,baseline}$ **(%)** 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.

$\text{Loss\%}_{Z,Y,b\rightarrow i,post}$ **(%)** 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

$$\mathrm{Benefit}_Y = \mathrm{Capacity}_Y * n * (\mathrm{CapPrice}_Y + \mathrm{MovePrice}_Y * \mathrm{RMM}_Y)$$

The indices of the parameters in Equation 4-5 include:

- Y = Year

$\mathrm{Capacity}_Y$ **(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.

$\mathrm{CapPrice}_Y$ **($/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.

$\mathrm{MovePrice}_Y$ **($/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

$$\mathrm{Benefit}_Y = \mathrm{Capacity}_Y * n * \mathrm{CapPrice}_Y$$

The indices of the parameters in Equation 4-6 include:

- Y = Year

$\mathrm{Capacity}_Y$ **(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.

$\mathrm{CapPrice}_Y$ **($/MW·hr)** is the average hourly spinning reserve capacity price. The default value uses the two- year historical average spinning reserve pricing by region.

4.1.5.2 General Considerations

There are no reductions in annual average frequency regulation, and spinning reserve, because those are set by the NYISO independent of load levels and DER penetration.

The average hourly prices for frequency regulation capacity, frequency regulation movement, and spinning reserve capacity can be calculated from historical pricing data posted by NYISO. The recommended basis is a historical average of interval pricing over the prior two-year period.

The NYISO Ancillary Services Manual indicates that the day-ahead market is the predominant market for regulation capacity and spinning reserves; regulation movement is only available in real-time.
The RMM is fixed by NYISO at a value of 13 ΔMW/MW per hour. While NYISO does not publish historical interval volume data to calculate actual movement, this value can be considered a reasonable proxy for actual movement.

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 → 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

$$\mathrm{Benefit}_{\mathrm{Y}} = \sum_{V}\sum_{\mathrm{C}} \frac{\Delta \mathrm{PeakLoad}_{\mathrm{Y,r}}}{1 - \mathrm{Loss\%}_{\mathrm{Y,b \rightarrow r}}} * \mathrm{DistCoincidentFactor}_{\mathrm{C,Y}} * \mathrm{DeratingFactor}_{\mathrm{Y}} * \mathrm{MarginalDistCost}_{\mathrm{C,V,Y,b}}$$

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

$\Delta \mathrm{PeakLoad}_{\mathrm{Y,r}}$ (∆MW) is the nameplate demand reduction of the project at the retail delivery or connection point (“r”). This input is project specific. A positive value represents a reduction in peak looa.

[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

$$\mathrm{Benefit}_{Y+1} = \sum_{Z} \mathrm{SystemEnergy}_{Z,Y+1,b} * \mathrm{LBMP}_{Z,Y+1,b} * \Delta\mathrm{Loss\%}_{Z,Y+1,b\rightarrow i} + \mathrm{SystemDemand}_{Z,Y,b} * \mathrm{AGCC}_{Z,Y,b} * \Delta\mathrm{Loss\%}_{Z,Y,b\rightarrow i}$$

Where,

$$\Delta\mathrm{Loss\%}_{Z,Y,i\rightarrow r} = \mathrm{Loss\%}_{Z,Y,i\rightarrow r,\mathrm{baseline}} - \mathrm{Loss\%}_{Z,Y,i\rightarrow r,\mathrm{post}}$$

The indices[39] of the parameters in Equation 4-10 include:

- Z = NYISO zone (for LBMP: A → 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

$\mathrm{SystemEnergy}_{Z,Y,b}$ (MWh) is the system energy purchased in the relevant area of the distribution system (i.e., the portion of the system where losses were impacted by the project) at the retail location by zone. Note that the system energy is used here, rather than the project-specific energy, because this benefit is only quantified when the distribution loss percent value has changed, an event which affects all load in the relevant part of the distribution system.

$\mathrm{LBMP}_{Z,Y,b}$ ($/MWh) is the LBMP, which is the sum of energy, congestion, and losses components by NYISO zone at the bulk system level ("b"). To determine time-differentiated LBMPs, for example, annual, seasonal, monthly, or hourly, leverage NYISO's hourly LBMP forecast by zone rather than developing an alternative forecast of time-differentiated LBMPs based on using historical data to shape annual zonal averages by zone. The NYISO hourly LBMP forecast is a direct output from the CARIS Phase 2

[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.

$\Delta CrewTime_Y$ **(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.

$CrewCost_Y$ **($/hr)** is the average hourly outage restoration crew cost for activities associated with the project under consideration as provided in Table A-4.

$\Delta Expenses_Y$ **(Δ$)** are the average expenses (e.g. equipment replacement) associated with outage restoration.

$\#Interruptions_{base,Y}$ **(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.

$CAIDI_{base,Y}$ **(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.

$CAIDI_{post,Y}$ **(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.

$\%ChangeSAIFI_Y$ **(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.

$SAIFI_{base,Y}$ **(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.

$SAIFI_{post,Y}$ **(int/cust/yr)** is the post-project System Average Interruption Frequency Index. It represents the average number of times that a customer experiences an outage per year in the post-project scenario. Determining this parameter would require development of a distribution level model and a respective engineering study to quantify appropriately.

Equation 4-12. Net Avoided Restoration Costs

$$\text{Benefit}_{Y} = \text{MarginalDistCost}_{R,Y}$$

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

$\text{MarginalDistCost}_{R,Y}$ ($/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.

$\Delta\text{SAIDI}_{\text{Y}}$ **(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.

$\text{SAIFI}_{\text{post,Y}}$ **(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.

$\text{CAIDI}_{\text{post,Y}}$ **(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 CO_2

Net Avoided CO_2 accounts for avoided CO_2 due to a reduction in system load levels[42] or the increase of CO_2 from onsite generation. To value the benefits associated with avoided CO_2 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:

$$\text{Benefit}_{\text{Y}} = \text{CESCost} * \left(\frac{\Delta\text{Energy}_{\text{Y,r}}}{1 - \text{Loss\%}_{\text{Y,b}\rightarrow\text{r}}} + \Delta\text{Energy}_{\text{TransLosses,Y}} + \Delta\text{Energy}_{\text{DistLosses,Y}}\right)$$

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

$\text{C02Cost}\Delta\text{LBMP}_Y$ **($)** 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.

$\text{C02Cost}\Delta\text{0nsiteEmissions}_Y$ **($)** 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 interface of the 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.

$\Delta\text{0nsite}\textbf{Energy}_{\text{Y}}$ **(ΔMWh)** is the energy produced by customer-sited carbon-emitting generation.

$\textbf{CO2Intensity}_{\textbf{Y}}$ **(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., $\text{NetMarginalDamageCost}_Y$ parameter above) to be provided by Staff, and (2) customer-sited carbon emissions from onsite generation (e.g., such as combined heat and power [CHP]), 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

$$\text{Cost}_{Y} = \sum_{M} \Delta\text{ProgramAdminCost}_{M,Y_{p,Y}}$$

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

[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.

Fixed Operating Cost ($/kW)	**15**

Note: These costs would change as DER project-specific data is considered.

1. **Capital and Installation Cost:** Based on E3's estimate 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 ($/kW)	3,000
Fixed Operating Cost ($/kW)	**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 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/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	**∆Energy (time-differentiated)**
3	Avoided Transmission Capacity Infrastructure	**TransCoincidenceFactor**
4	Avoided Transmission Losses	Limited or no applicability
5	Avoided Ancillary Services	Limited or no applicability
6	Wholesale Market Price Impacts	**∆Energy (annual)** **∆AGCC**
7	Avoided Distribution Capacity Infrastructure	**DistCoincidenceFactor**
8	Avoided O&M	Limited or no applicability
9	Avoided Distribution Losses	Limited or no applicability
10	Net Avoided Restoration Costs	Limited or no applicability
11	Net Avoided Outage Costs	Limited or no applicability[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.
CO2 Intensity	CO_2 intensity is required to calculate the Net Avoided CO_2 benefit. This parameter is dependent on the type of DER being evaluated – emission-free or emission-generating. It is the average CO_2 emission rate of customer- sited pollutant-emitting generation. This is a project-specific input based on the type of onsite generation.
Pollutant Intensity	Pollutant intensity is required to calculate the Net Avoided SO_2 and NO_X benefit. This parameter is dependent on the type of DER being evaluated – emission-free or emission-generating. It is the average SO_2 and/or NO_X emission rate of customer-sited pollutant-emitting generation. This is a project-specific input based on the type of onsite generation.
Δ Energy (time-differentiated)	This parameter measures the change in bulk system energy consumed as a result of specific DER project implementation. This value is reliant on project-specific details including location. The ΔEnergy is dependent on the type of DER (e.g., intermittent vs. baseload), and how the DER would be operated (e.g., load reduction vs. energy conservation vs. backup generation). Thus, the Δ Energy is time-differentiated. It may be appropriate to use an annual average value for some DER, while for others it may be more appropriate to use an average on-peak hours of operation, or even hourly operation. In each case the corresponding LBMP data would be required to value the benefit. The examples provided herein discuss potential approaches to consider time-differentiation by DER

[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.

type.[55]

[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

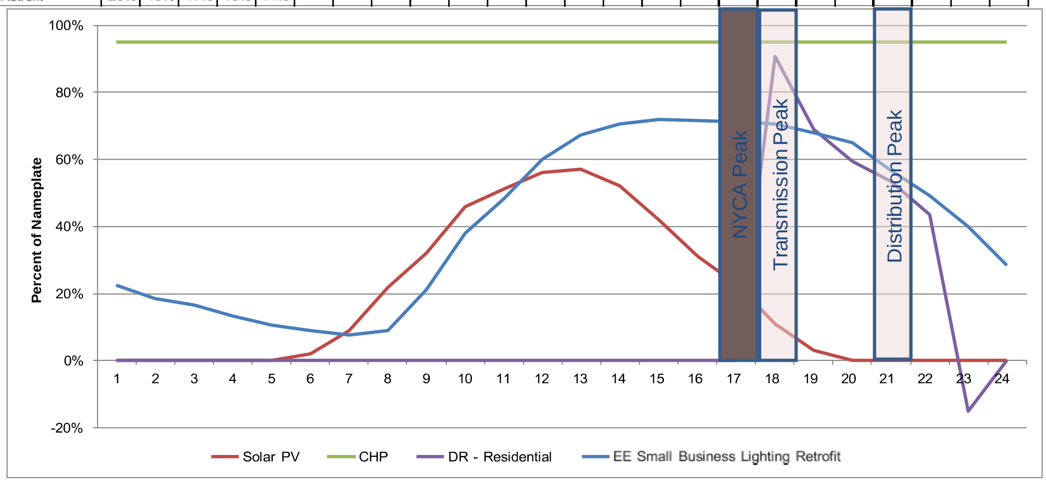
There are multiple approaches for estimating coincidence factors that apply different levels of rigor. Rigorous approaches could be defined and applied across a range of DERs; however, such an approach is likely to require a significant amount of granular information (e.g., 8760 hour load shapes for 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
∆Energy (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. **∆Energy (time-differentiated):** As discussed above, solar output would be higher during daylight hours and summer months. As hourly solar profiles are available from SAM, it would be appropriate to compare the projected energy output with hourly LBMPs.

5.4 Combined Heat and Power Example

CHP is an example of a baseload DER which typically operates during system, transmission, and distribution peaks.

5.4.1 Example System Description

CHP depicts a baseload DER where the electricity is generated at all hours, except during maintenance. The CHP system used in this example is a 100 kW capacity natural gas-fired engine unit sized for commercial thermal load following applications. In this simplified example, the 100 kW system is assumed to be small relative to the commercial building's overall electric load and thus the system operates at full electrical generating capacity at all times, except when it is down for maintenance. The example is described in EPA's Catalog of CHP Technologies (EPA CHP Report).[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 provide 95% power output at all hours, assuming it is down for maintenance 5% of the year.[61]

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[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/chp-technologies.
[61] EPA CHP Report. pg. 2-20.

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
∆Energy (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).[63]
9. **Pollutant Intensity:** 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. **∆Energy (time-differentiated):** Assuming the CHP is used as a baseload resource, with the exception of downtime for maintenance, capacity factor is 95%. Because it is not possible to predict when the downtime may occur, using annual average LBMP would be appropriate.

5.5 Demand Response Example

DR depicts an example of a **dispatchable** DER where the resource can be called upon to respond to peak demand.

[62] EPA CHP Emissions Calculator https://www.epa.gov/chp/chp-emissions-calculator.
[63] Alternative sources to EPA's calculator may be available.

5.5.1 Example System Description

The system dispatchable DR technology described herein is a programmable and controllable thermostat in a residence with central air conditioning that is participating in a direct load control program.

DR is a dispatchable DER because it reduces demand on request from the system operator or utility.[64] 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.[65] 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.[66]

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.

[64] Some DR programs may be “dispatched” or scheduled by third-party aggregators.
[65] Note, the controllable load may not be operating at the time of peak.
[66] 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
∆Energy (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.[67] 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. **∆Energy (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.[68]

[67] 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

[68] 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.[69] 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
ΔEnergy (time-differentiated)	~7 am to ~7 pm weekdays

Note: These are illustrative estimates and would change as specific projects and locations are considered.

1. **SystemCoincidenceFactor:** The system coincidence factor is 1.0 under the assumption that the system peak occurs while standard office lighting systems are operating.
2. **TransCoincidenceFactor:** The transmission coincidence factor is 1.0 under the assumption that the transmission system peak occurs while standard office lighting system are operating.
3. **DistCoincidenceFactor:** The distribution coincidence factor is 1.0 under the assumption that the distribution system peak occurs while standard office lighting systems are operating.
4. **ΔEnergy (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.

[69] 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)[70]	Customer Scale (Behind the Meter)
Storage Type	Lithium Ion Battery	Lithium Ion Battery
Size (capacity/energy)[71]	1MW/5MWh	5kW/13.5kWh
Cycle Life	4,500 cycles (to 80% of rated energy)	2,800 cycles[72]
Efficiency	90%	90%[73]
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[74] 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[75]	
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

[70] 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

[71] 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.

[72] 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

[73] Based on Tesla Powerwall datasheet https://www.tesla.com/sites/default/files/pdfs/powerwall/Powerwall%202_AC_Datasheet_en_northamerica.pdf

[74] 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.

[75] 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
∆Energy (time-differentiated)	Hourly
∆Capacity$_{y/}$(∆MW); n (hr)	Modeled from hourly dispatch analysis

Note: These are illustrative estimates and would change as specific projects and locations are considered.

1. **SystemCoincidenceFactor:** Without specifically targeting the overall system peak, the coincidence factor is assumed to be 0.8, 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.[76] Location- and program-specific distribution coincidence factors could be calculated using hourly load data per the methodology described above.

3. **DistCoincidenceFactor:** In this example, the storage is used as a non-wires alternative and the top priority of dispatch operation is to reduce location-specific distribution peak capacity. Therefore, the distribution coincidence factor is 100%.

4. **∆Energy (time-differentiated):** The value of reduced energy use attributable to the storage project can be calculated using the hourly LBMP compared to the hourly charge and discharge

[76] 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. **∆Capacity$_{y/}$(∆MW); n (hr):** In this example, distribution capacity and system capacity take precedence over ancillary services in the storage dispatch operation. This dispatch schedule would need to be modeled on an hourly basis to determine the remaining capacity and hours (n) 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
∆Energy (time-differentiated)	Hourly
ValueOfService$_{C,Y,r}$ ($/kWh); ΔSAIDI$_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. **∆Energy (time-differentiated**): The value of reduced energy use attributable to the storage project can be calculated using the hourly LBMP compared to the hourly charge and discharge cycles of the storage project. Energy impacts should be adjusted for round-trip efficiency (battery losses).

5. **ValueOfService$_{C,Y,r}$ ($/kWh); ΔSAIDI$_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.

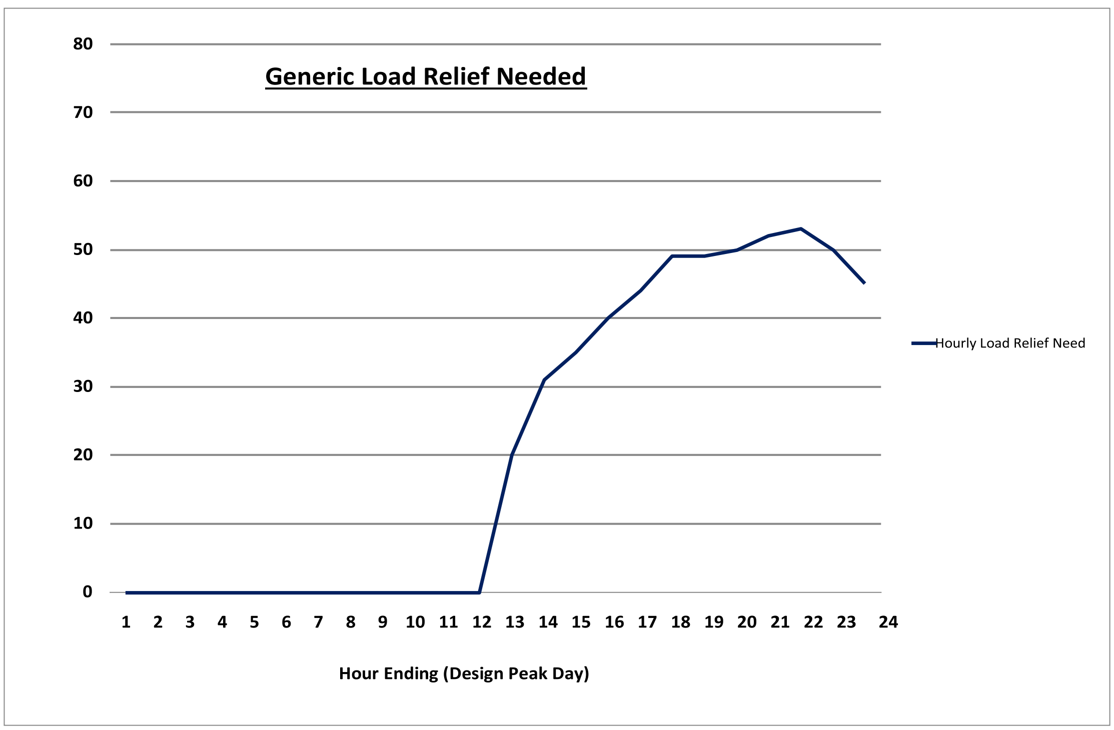
5.8 Portfolio Example

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.

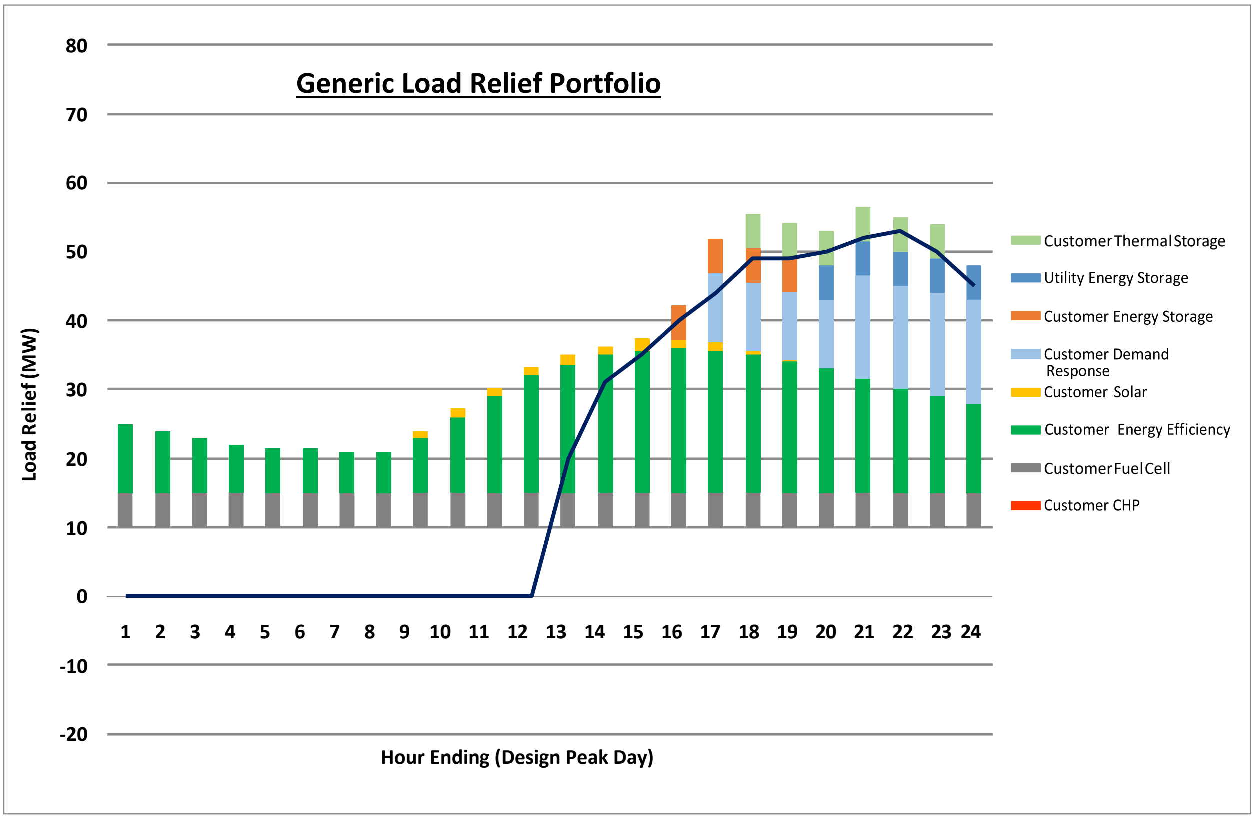
Figure 5.2. Location Load Relief Requirement



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[77]

Year	For Use in SCT	For Use in UCT, RIM
2025	6.92%	8.53%
2026	6.97%	8.59%
2027	7.09%	8.70%

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[78]

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%

[77] 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.
[78] 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[79]

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

Operation and Maintenance Costs
Restoration Costs will be determined for each specific project as applicable

Source: Project Specific

[79] 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.

REPORT

2025 Central Hudson Beneficial Locations

Prepared for Central Hudson

By

Demand Side Analytics

June 2025

ACKNOWLEDGEMENTS

Demand Side Analytics Team

- Josh Bode
- Candace Yee

Central Hudson Team

- Stephanie Palmer
- Pano Harpolis

ABSTRACT

Locations were identified as potentially benefiting from a Non-Wire Alternative (NWA) when there is a 10% or greater likelihood of exceeding the location's operating limit by 2035 (10 years), and when there is no infrastructure upgrade planned in Central Hudson's 5-year capital plan. In total, this includes 1 transmission area and 4 substations. This report summarizes the historical weather, hourly demand, and customer mix, as well as the forecasted load growth for each of these identified areas.

TABLE OF CONTENTS

1 INTRODUCTION

As part of granular forecasting efforts to support the Distributed System Implementation Plan (DSIP) filing, ten years of historical interval data was analyzed at the transmission area, substation, and distribution feeder level to assess historical loading factors for summer and winter as well as growth rates.

Historical data was used to develop probabilistic, 20-year forecasts of the gross load (i.e., load without load modifiers). Based on the location-specific historical growth rates, 200 simulations of potential load growth patterns were produced for each area and forecast year. The probabilistic forecasted gross loads were then combined with the distributed energy resource (DER) and electrification forecasts.[1]

The probabilistic method used to produce the gross and planning loads allows us to quantify the uncertainty associated with weather and load growth and estimate the risk of exceeding the rating for each area. In some cases, only a few simulations out of 200 exceeded the summer or winter operating limit. In other cases, close to 100% of the simulated growth patterns exceeded the operating limits. An overload is defined as exceeding the operating limit for two consecutive years.

Figure 1 shows the summer overload risk for substations where the overload risk was estimated to be at or greater than 10% by 2035. Figure 2 shows the overload risk for transmission areas. This overload risk analysis helps inform Central Hudson on which areas to identify potential candidates for Non-Wire Alternative (NWA) implementation. These locations are referred to as beneficial locations. Once a beneficial location is identified, it undergoes a more detailed engineering analysis and an NWA feasibility assessment.

[1] See 2025 Distributed System Implementation Plan Appendix C: Granular Load, Distributed Energy Resources, and Electrification Forecast.

Figure 1: Summer Overload Risk for Substations

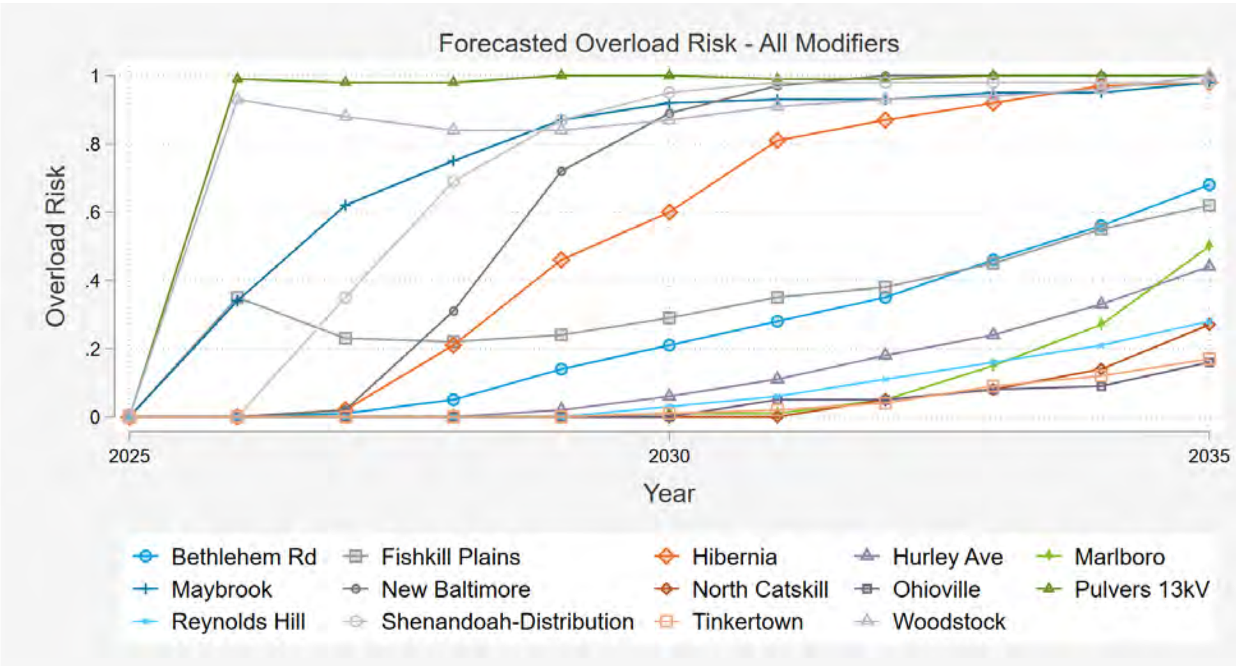
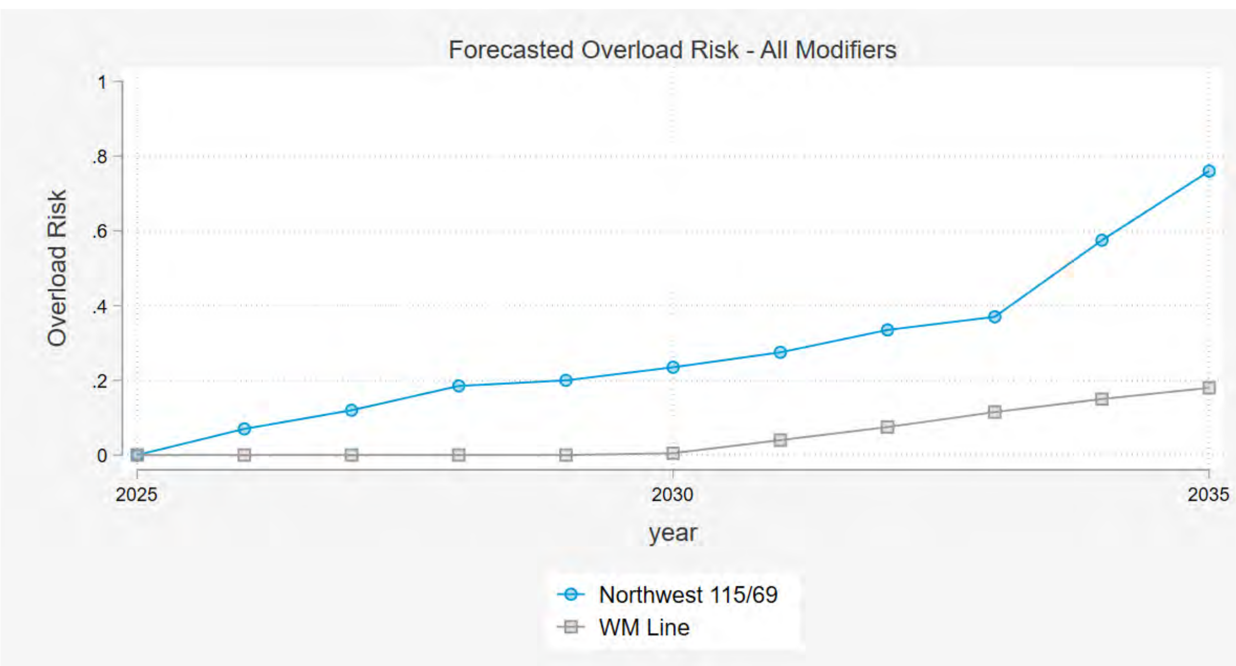


Figure 2: Summer Overload Risk for Transmission Areas



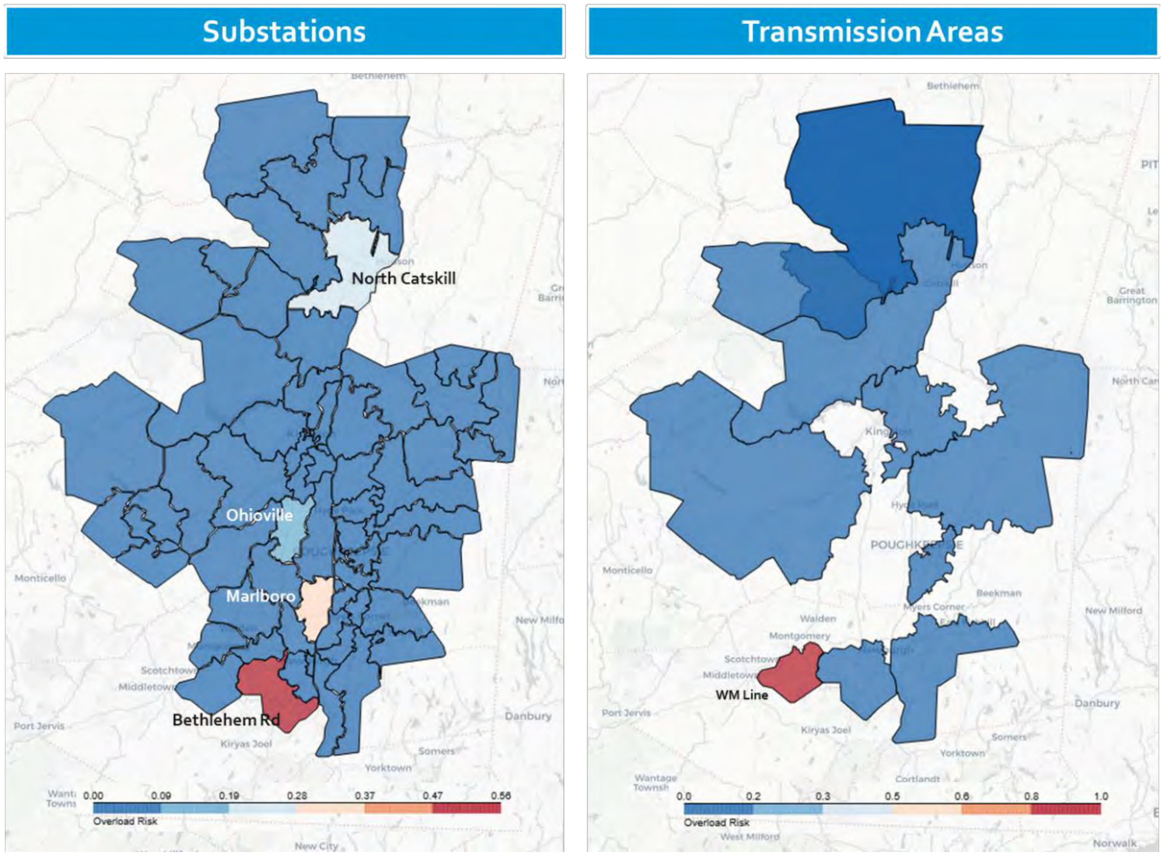
Beneficial locations are typically areas where loads are growing, but there is limited room to accommodate this growth. For this analysis, substations and transmission areas with an overload risk greater than 10% by 2035 (ten years from now) were selected. Any substations or transmission areas with scheduled upgrades, due to reliability upgrades or aging equipment, were removed from consideration for an NWA. In addition, any areas with an overload risk greater than 50% within the next 3 years were removed from consideration, as NWAs typically take several years to ramp up. Lastly, any areas that currently have an NWA implemented were also removed. Table 1 shows the substations and transmission areas that fall within each category.

Table 1: Categorization of Areas with High Risk of Overload

Component Type	Component Name	Planned Upgrade	NWA in Place	Beneficial Location
Substation	Bethlehem Rd			✓
	Fishkill Plains	✓	✓	
	Hibernia	✓		
	Hurley Ave	✓		
	Marlboro			✓
	Maybrook	✓		
	New Baltimore	✓		
	North Catskill			✓
	Ohioville			✓
	Pulvers 13kV	✓		
	Reynolds Hill	✓		
	Shenandoah-Distribution	✓	✓	
	Tinkertown	✓		
	Woodstock	✓		
Transmission Area	Northwest 115/69	✓	✓	
	WM Line			✓

The remaining substations identified as beneficial locations are Bethlehem Rd, Marlboro, Ohioville, and North Catskill, and the only remaining transmission area is WM Line. These areas are mapped in Figure 3. The beneficial locations are colored according to their summer overload risk in 2035, where red indicates higher risk and blue indicates lower risk.

Figure 3: Beneficial Locations



Section 2 provides a detailed look at the accounts, consumption, and historical load patterns of the each of the aforementioned transmission area, while Section 3 does the same for the identified substations. Details on these beneficial locations include:

- Accounts and consumption
- Historical peak day load shapes
- Multi-year load duration curves
- Weather patterns
- Forecasted load growth with uncertainty

This information helps answer key questions for NWA consideration, including:

- What sector (residential or non-residential) is responsible for the majority of the area's consumption? Who should be or can be targeted for load management?
- What should the timing of the NWA be? Will a solution need to be implemented in the near-term, or does the overload risk only become salient 10 years out?
- What are the hours to target for load shaving on peak days?
- Is peak demand spread across many hours or concentrated on a small share?

2 TRANSMISSION AREAS

2.1 WM LINE

The WM Line Transmission Area is located in the southern part of the Central Hudson electric service territory. The WM Line has a 68 MW long term emergency rating (LTE) and a 90 MW short term emergency (STE) rating.

Figure 4 shows the division of active accounts and electricity consumption in 2024 for WM Line between residential and non-residential customers. Roughly 86% of the 6,558 total accounts belong to the residential customer class, and together the residential customers accounted for 46% of the total usage in 2024.

Figure 4: WM Line Transmission Area Accounts and Consumption

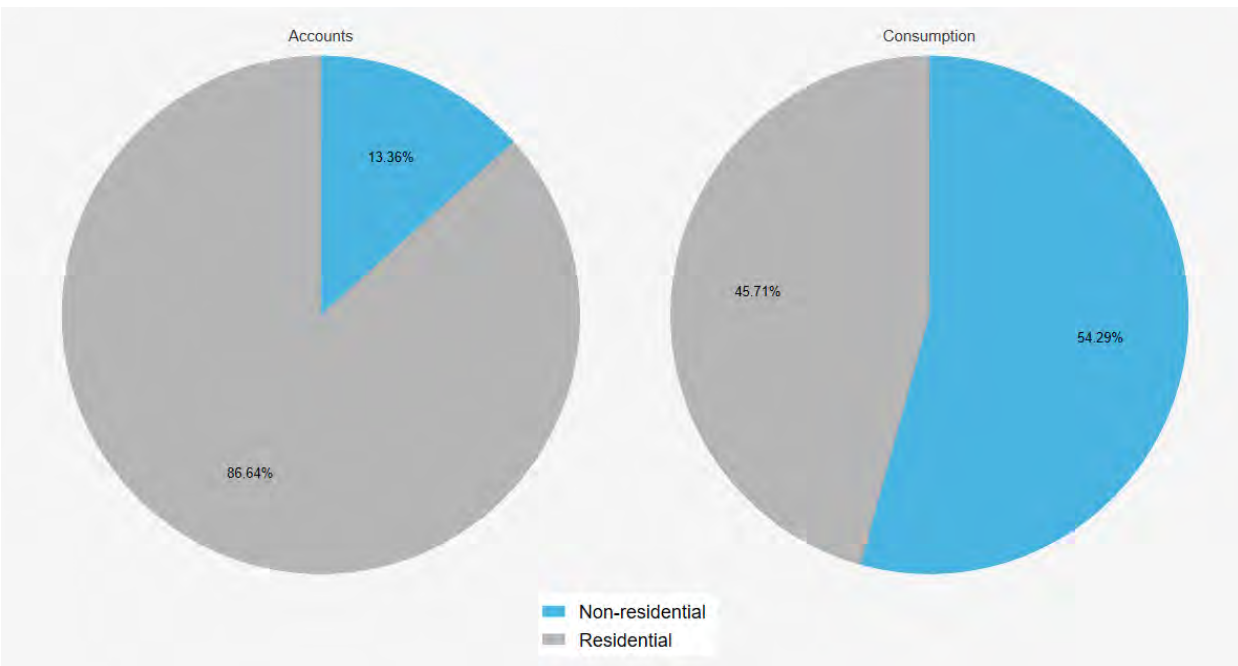


Figure 5 summarizes the peak day load for each year from 2014 to 2024 and includes details about the timing of the peak. Figure 6 summarizes the multi-year load duration curve over the same time frame and shows that the peak demand is concentrated on a small share of hours. The weather sensitivity load is illustrated in Figure 7, which shows the daily peak load as a function of different temperature ranges.

Figure 5: WM Line Historical Annual Peak Day Load Shapes

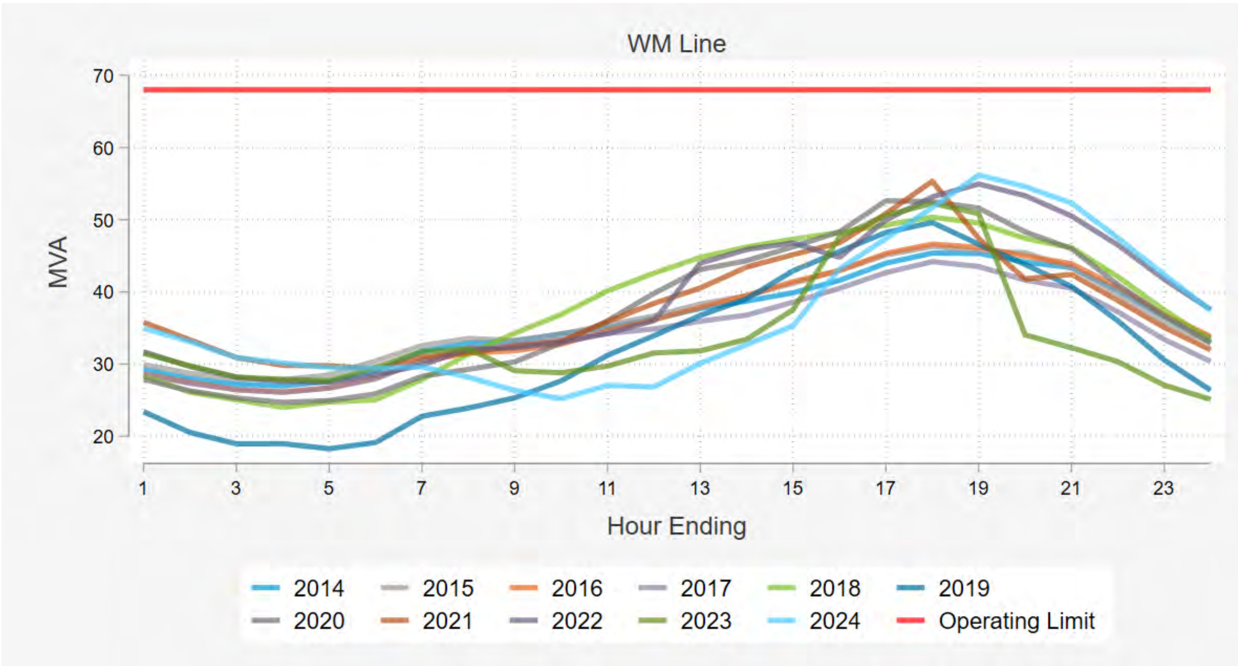


Figure 6: WM Line Multi-Year Load Duration Curves

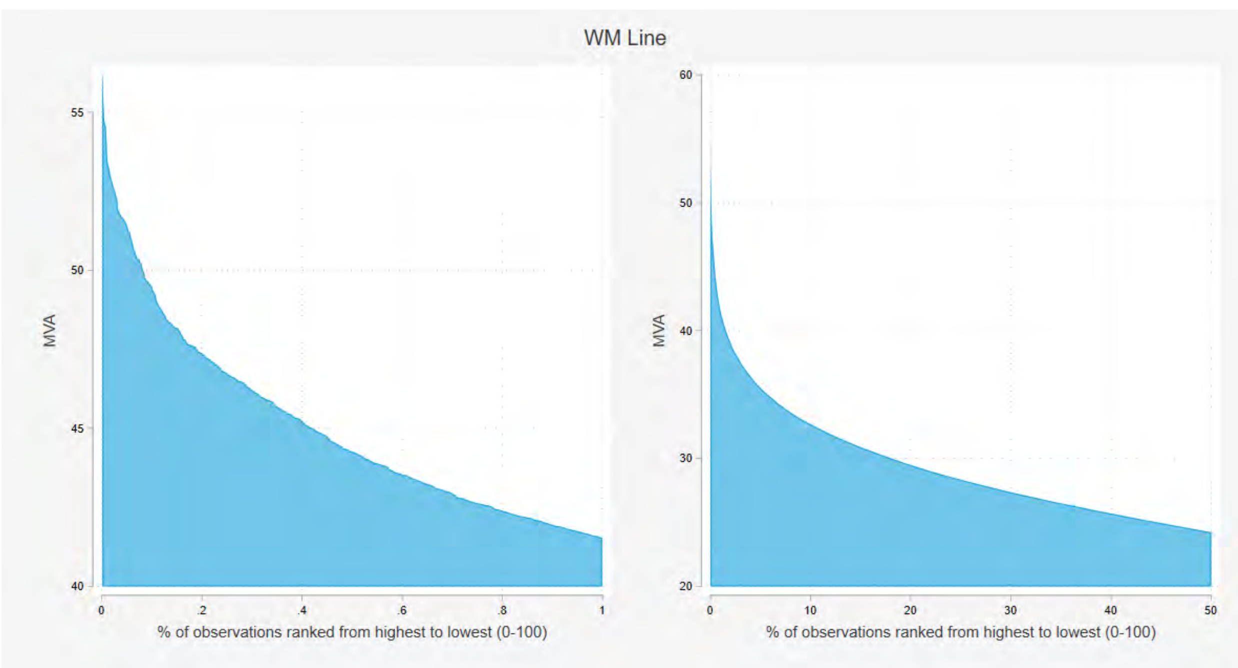
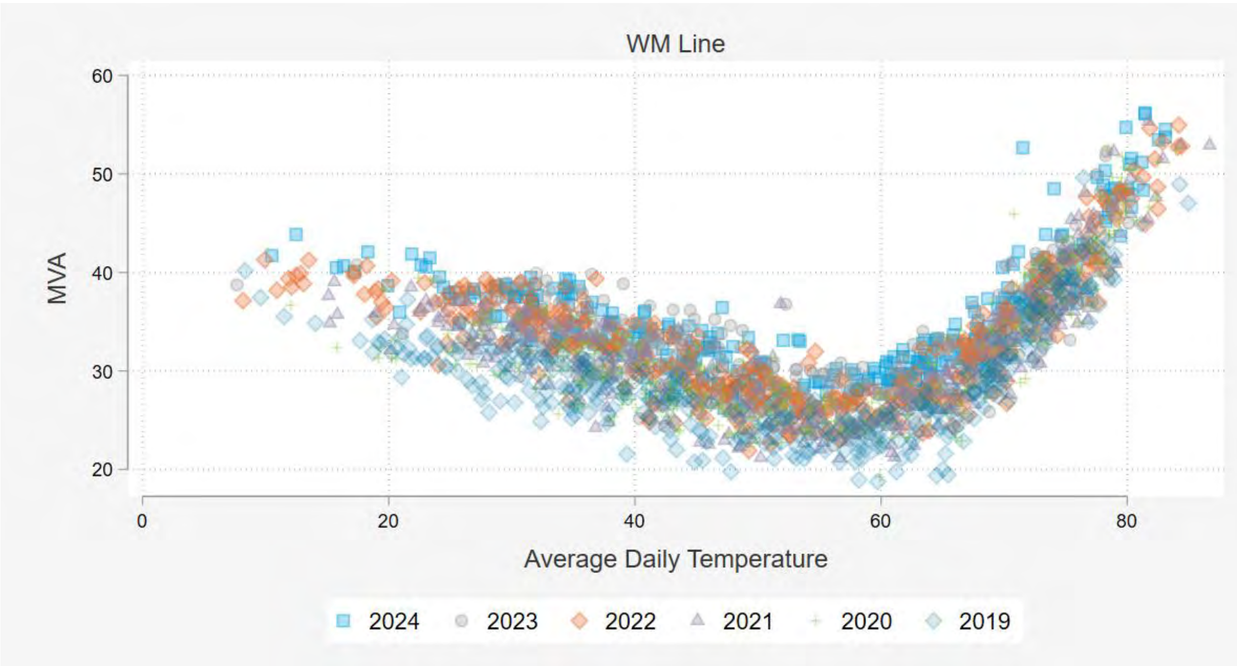
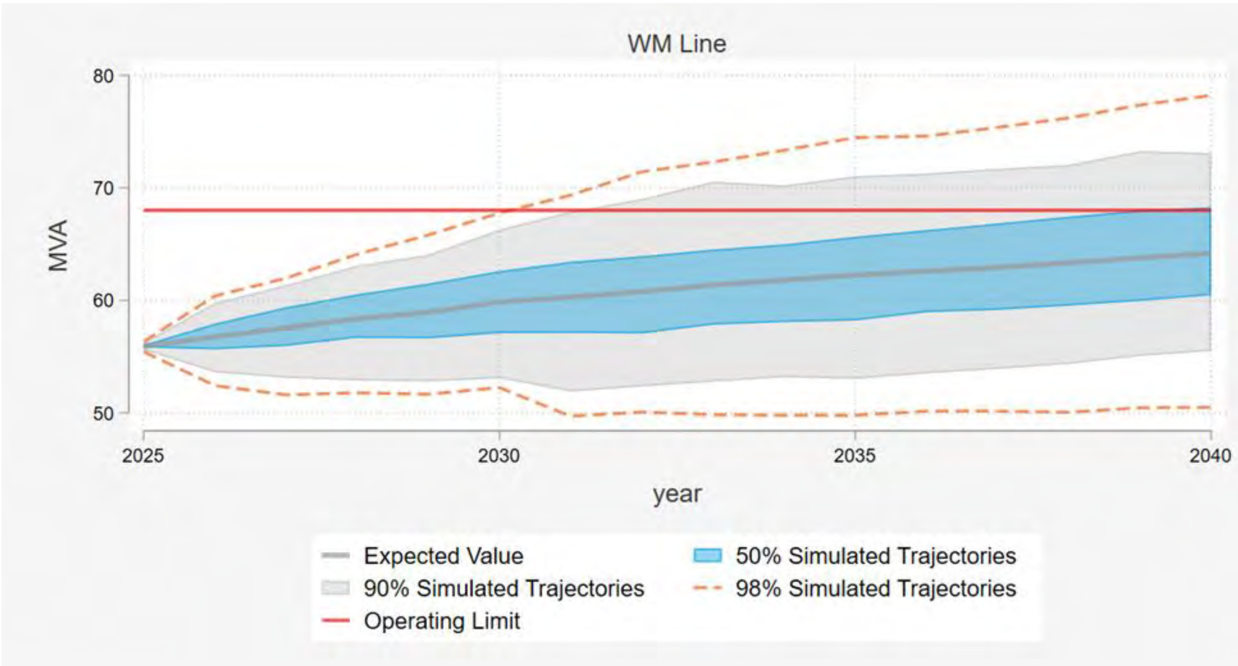


Figure 7: WM Line Daily Peak Load Weather Pattern by Year



Peak demand in the WM Line area has been growing at a rate of 1.2% per year since 2014. Load growth was evaluated using probabilistic methods rather than straight-line forecasts, and is calibrated to match the territory-wide growth rate after 5 years. Figure 8 shows the load growth forecast for summer, assuming 1-in-2 weather year conditions. There is substantial uncertainty in the forecast, but there is a greater than 18.2% of an overload risk by 2035.

Figure 8: WM Line Load Forecast with Uncertainty



3 SUBSTATIONS

3.1 BETHLEHEM ROAD

The Bethlehem Rd substation is located in the southern part of the Central Hudson electric service territory. The Bethlehem Road circuitry supplies a predominately rural residential area with 3 feeders supporting the commercial load along Route 300, the airport, and the light industrial load near the airport. The substation has a 48 MW long term emergency rating (LTE) and a 48 MW short term emergency (STE) rating.

Figure 9 shows the division of active accounts and electricity consumption in 2024 for Bethlehem Rd between residential and non-residential customers. Roughly 88% of the 7,275 total accounts belong to the residential customer class, and together the residential customers accounted for 32% of the total usage in 2024.

Figure 9: Bethlehem Rd Substation Accounts and Consumption

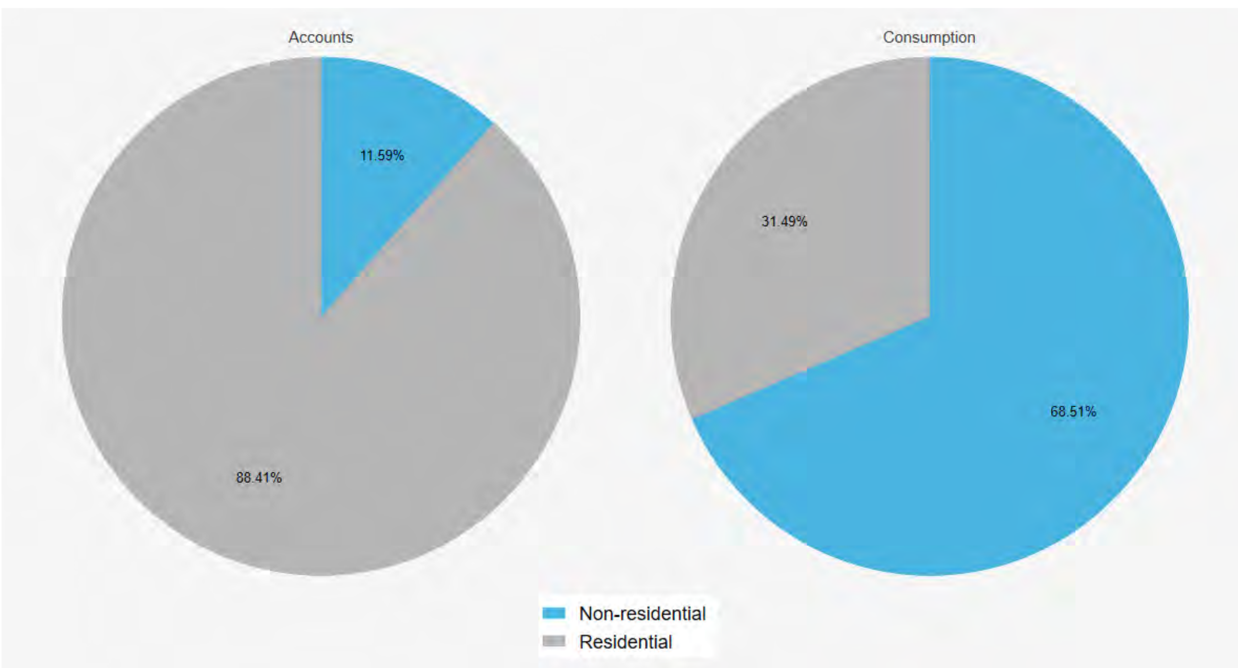


Figure 10 summarizes the peak day load for each year from 2014 to 2024 and includes details about the timing of the peak. Figure 11 summarizes the multi-year load duration curve over the same time frame and shows that the peak demand is concentrated on a small share of hours. The weather sensitivity load is illustrated in Figure 12, which shows the daily peak load as a function of different temperature ranges.

Figure 10: Bethlehem Rd Historical Annual Peak Day Load Shapes

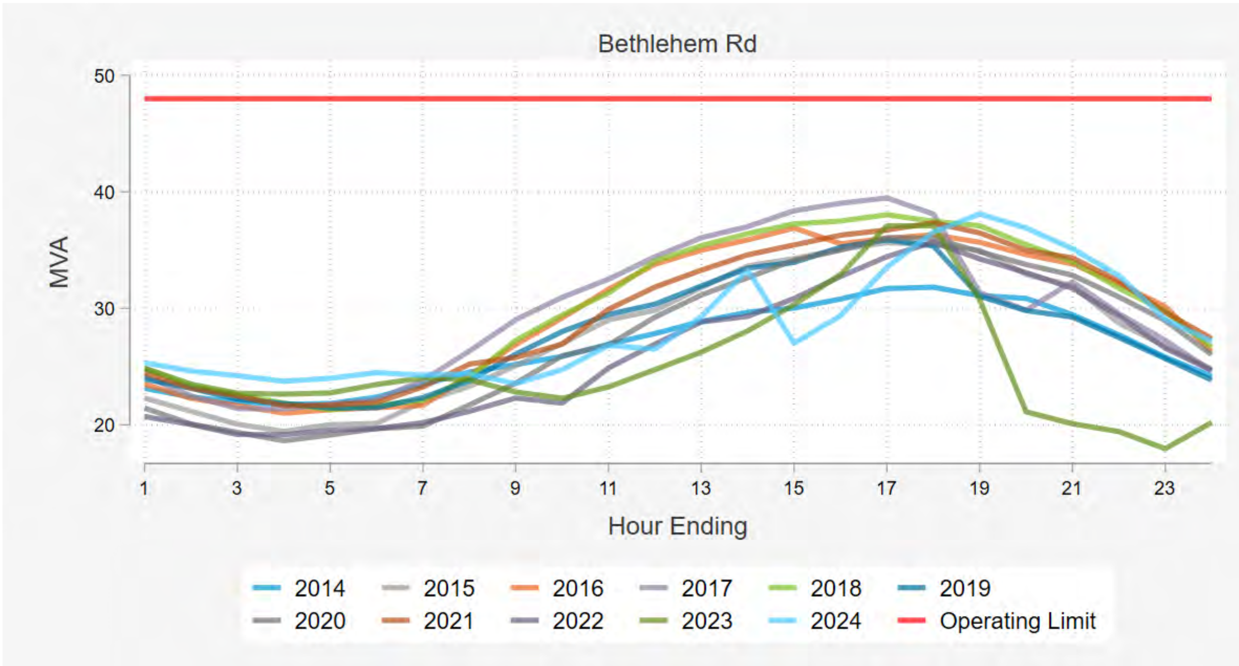


Figure 11: Bethlehem Rd Multi-Year Load Duration Curves

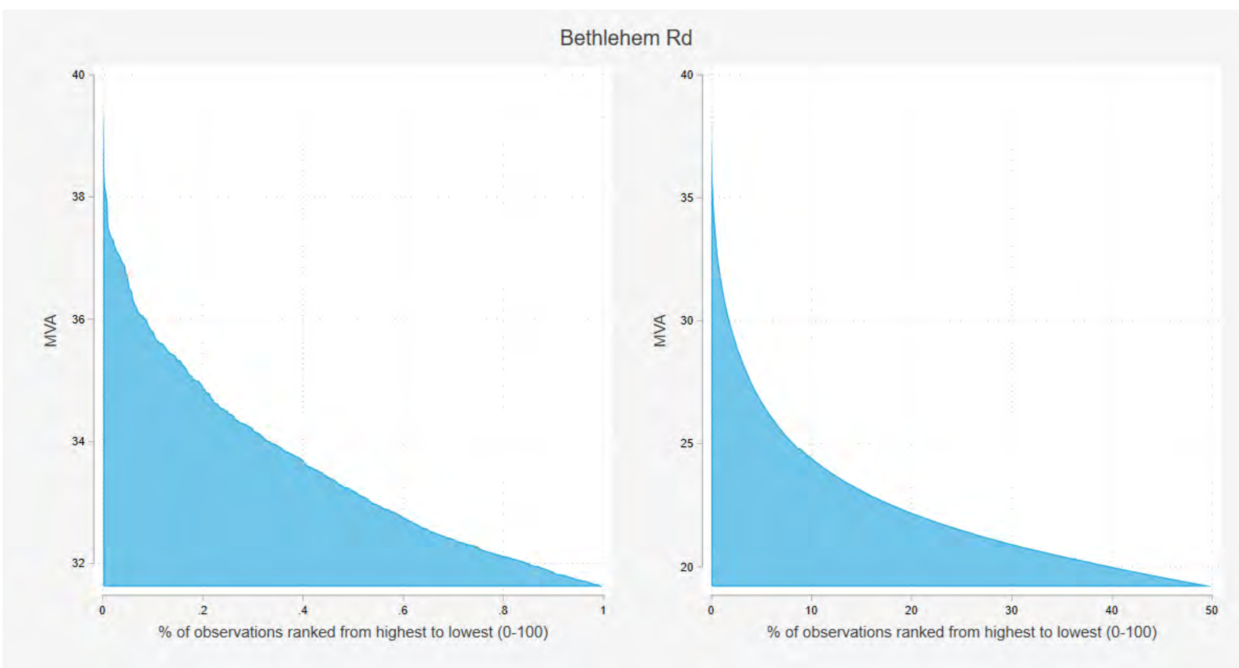
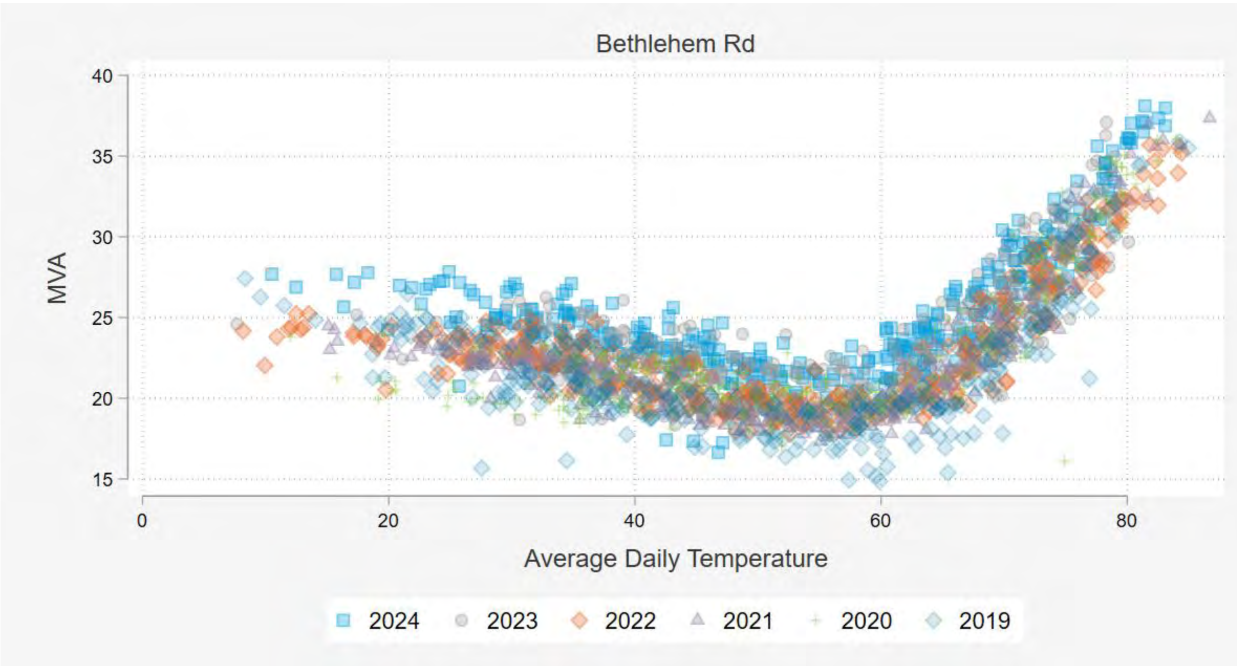
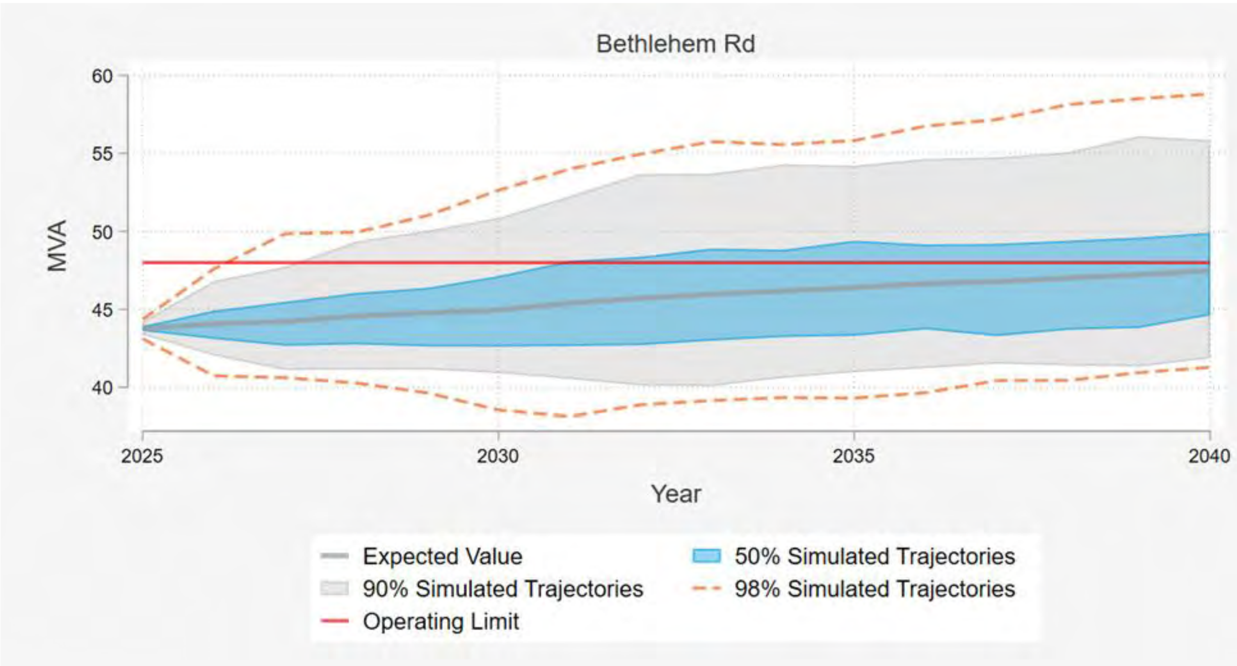


Figure 12: Bethlehem Rd Daily Peak Load Weather Pattern by Year



Peak demand in the Bethlehem Rd area has been growing at a rate of 1.44% per year since 2014. Load growth was evaluated using probabilistic methods rather than straight-line forecasts, and is calibrated to match the territory-wide peak demand forecast by season after 5 years. Figure 13 shows the load growth forecast for summer, assuming 1-in-2 weather year conditions. There is substantial uncertainty in the forecast, but there is a greater than 18% of an overload by 2030, and a greater than 56% of an overload risk by 2035.

Figure 13: Bethlehem Rd Load Forecast with Uncertainty



3.2 MARLBORO

The Marlboro Substation is located in the central part of the Central Hudson electric service territory, alongside the Hudson River. The Marlboro circuit supplies the rural residential load which has many commercial farms and vineyards. The Route 9W corridor, the Village of Marlboro and the Hamlet of Milton have some light commercial and light industrial load. Marlboro has a 31 MW long term emergency rating (LTE) and a 45 MW short term emergency (STE) rating.

Figure 14 shows the division of active accounts and electricity consumption in 2024 for Marlboro between residential and non-residential customers. Roughly 88% of the 6,386 total accounts belong to the residential customer class, and together the residential customers accounted for 46% of the total usage in 2024.

Figure 14: Marlboro Substation Accounts and Consumption

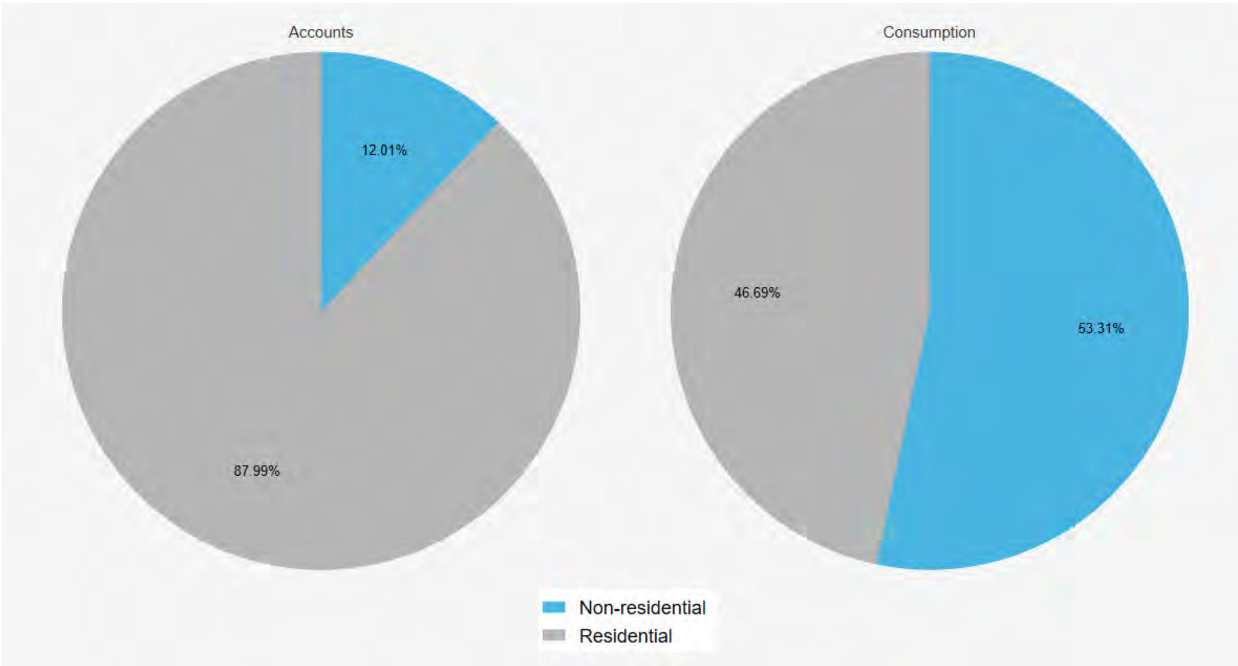


Figure 15 summarizes the peak day load for each year from 2014 to 2024 and includes details about the timing of the peak. Figure 16 summarizes the multi-year load duration curve over the same time frame and shows that the peak demand is concentrated on a small share of hours. The weather sensitivity load is illustrated in Figure 17, which shows the daily peak load as a function of different temperature ranges.

Figure 15: Marlboro Historical Annual Peak Day Load Shapes

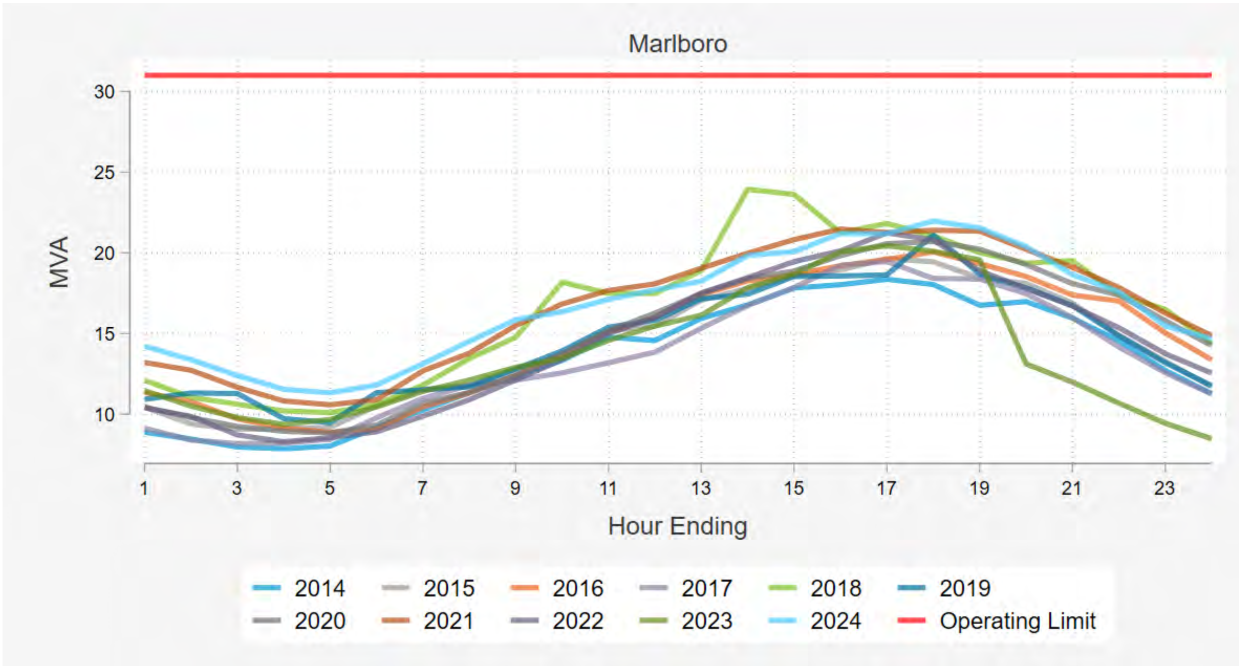


Figure 16: Marlboro Multi-Year Load Duration Curves

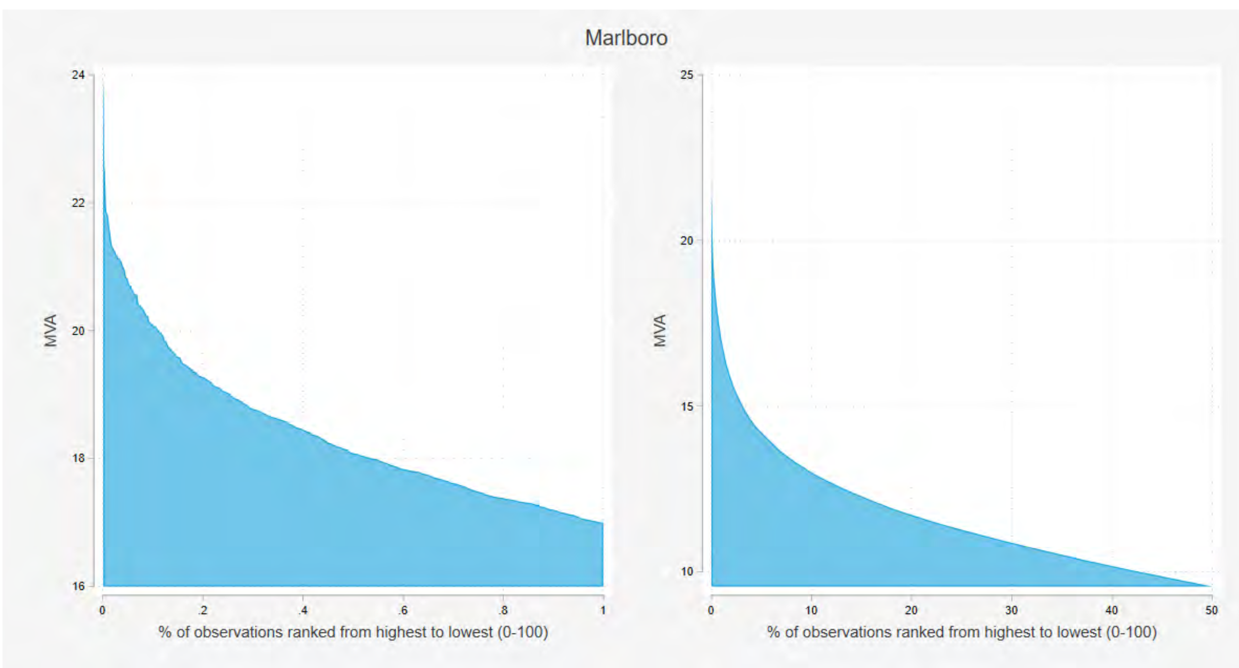
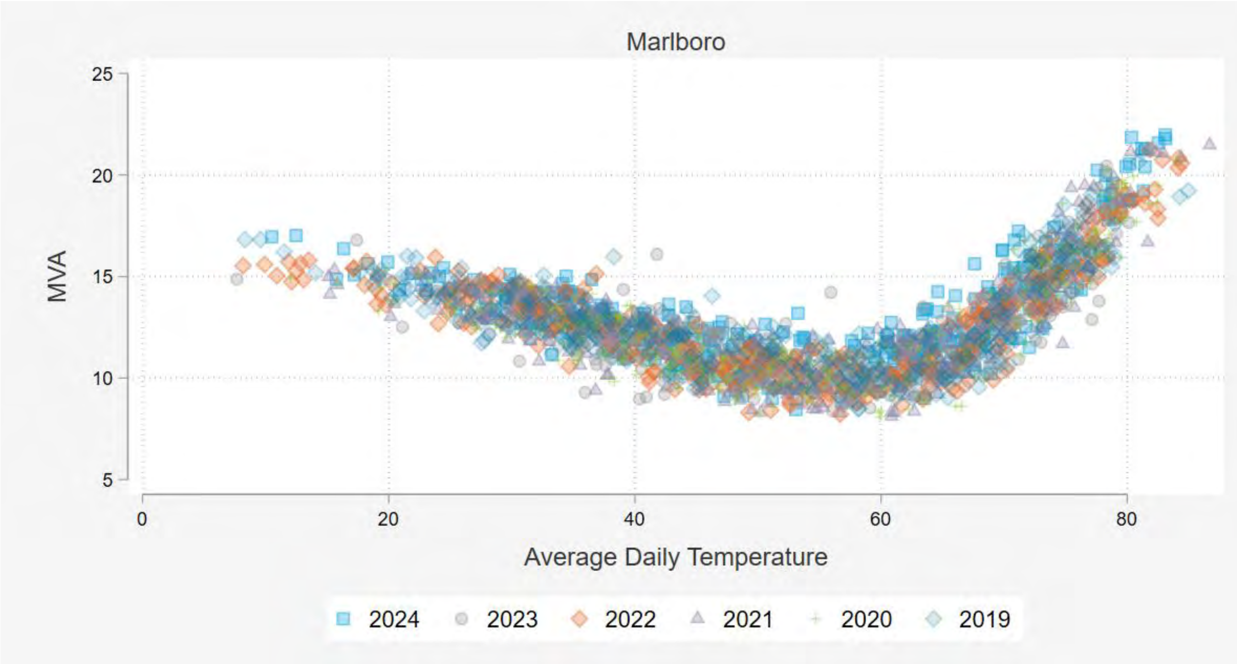
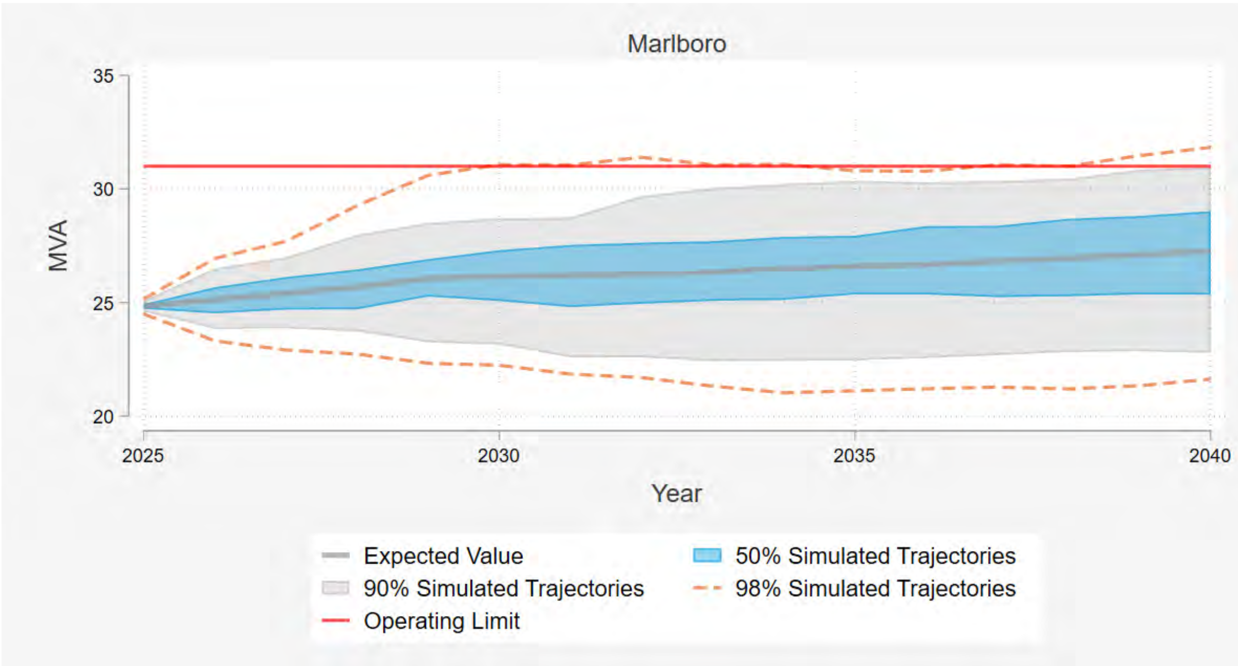


Figure 17: Marlboro Daily Peak Load Weather Pattern by Year



Peak demand in the Marlboro area has been growing at a rate of 1.75% per year since 2014. Load growth was evaluated using probabilistic methods rather than straight-line forecasts, and is calibrated to match the territory-wide peak demand forecast by season after 5 years. Figure 18 shows the load growth forecast for summer, assuming 1-in-2 weather year conditions. There is substantial uncertainty in the forecast, but there 33% of an overload risk by 2035.

Figure 18: Marlboro Load Forecast with Uncertainty



3.3 NORTH CATSKILL

The North Catskill substation is located at the southern portion of the Catskill District within the Central Hudson electric service territory. This substation also supplies a majority of rural residential load with a mix of commercial businesses along the Route 9W corridor and the Village of Catskill. North Catskill has a 35 MW long term emergency rating (LTE) and a 45 MW short term emergency (STE) rating.

Figure 19 shows the division of active accounts and electricity consumption in 2024 for North Catskill between residential and non-residential customers. Roughly 84% of the 10,060 total accounts belong to the residential customer class, and together the residential customers accounted for 56% of the total usage in 2024.

Figure 19: North Catskill Substation Accounts and Consumption

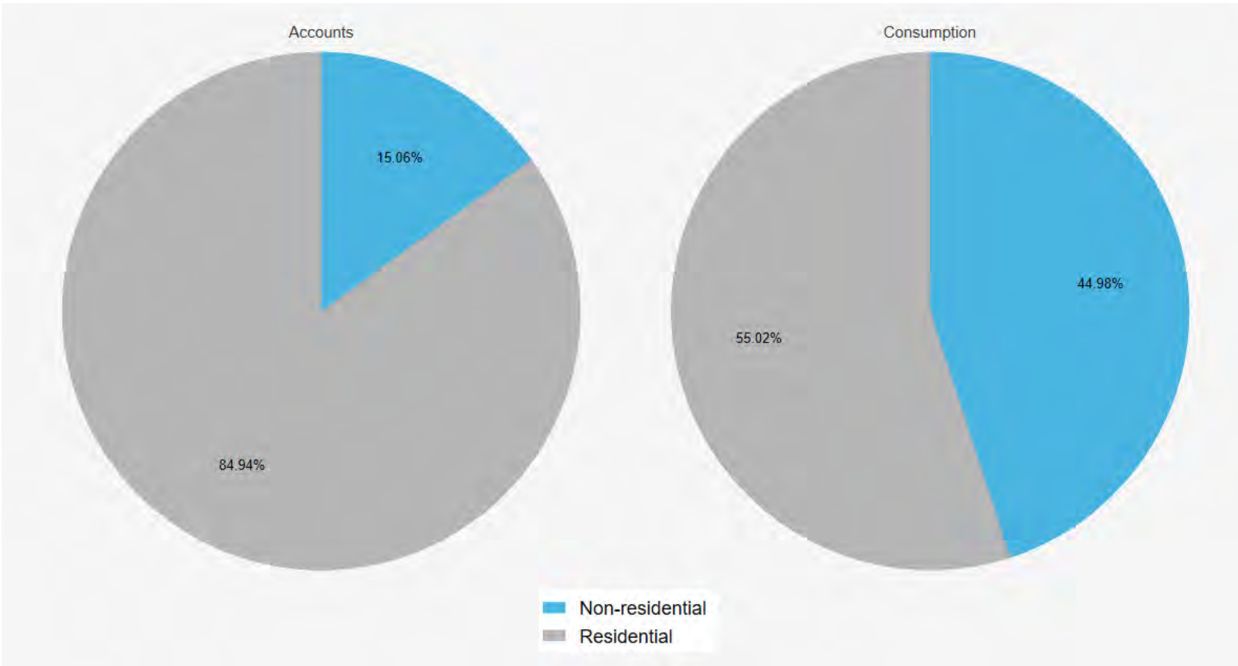


Figure 20 summarizes the peak day load for each year from 2014 to 2024 and includes details about the timing of the peak. Figure 21 summarizes the multi-year load duration curve over the same time frame and shows that the peak demand is concentrated on a small share of hours. The weather sensitivity load is illustrated in Figure 22, which shows the daily peak load as a function of different temperature ranges.

Figure 20: North Catskill Historical Annual Peak Day Load Shapes

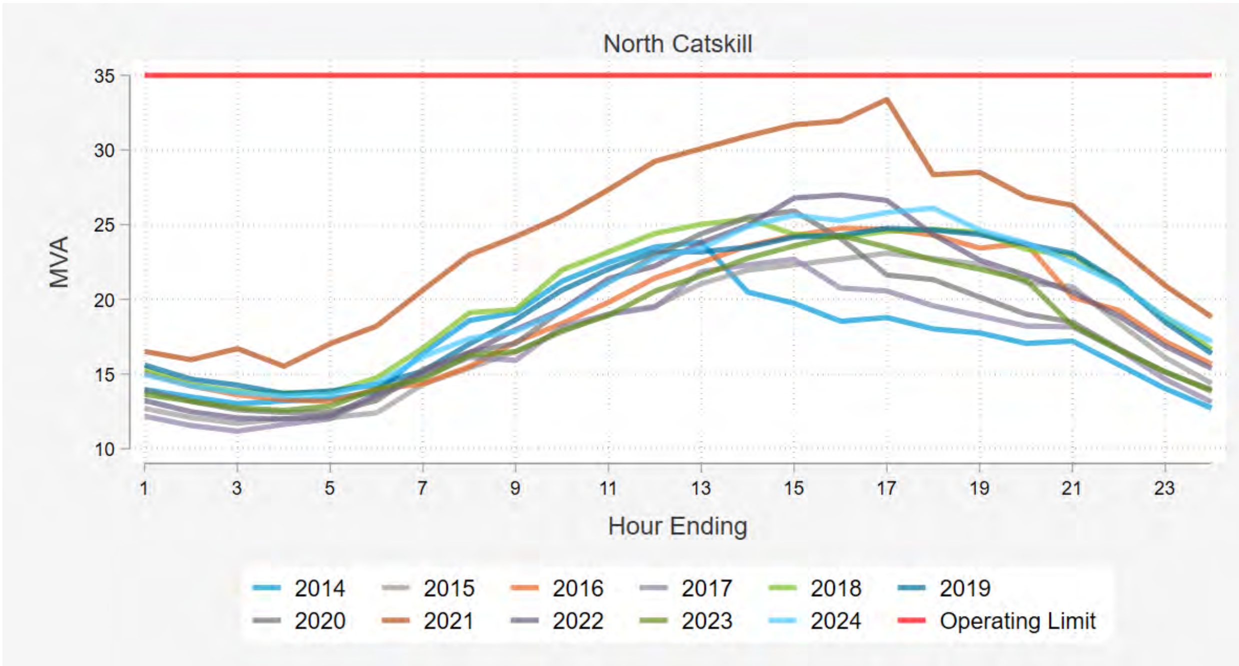


Figure 21: North Catskill Multi-Year Load Duration Curves

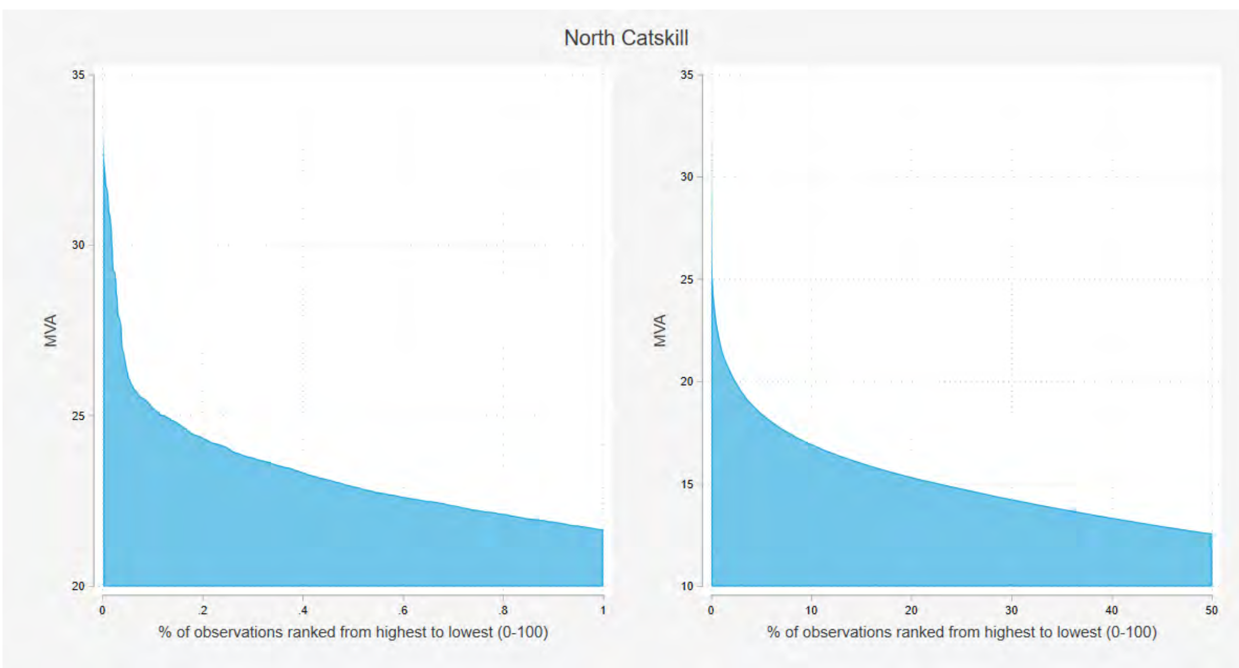
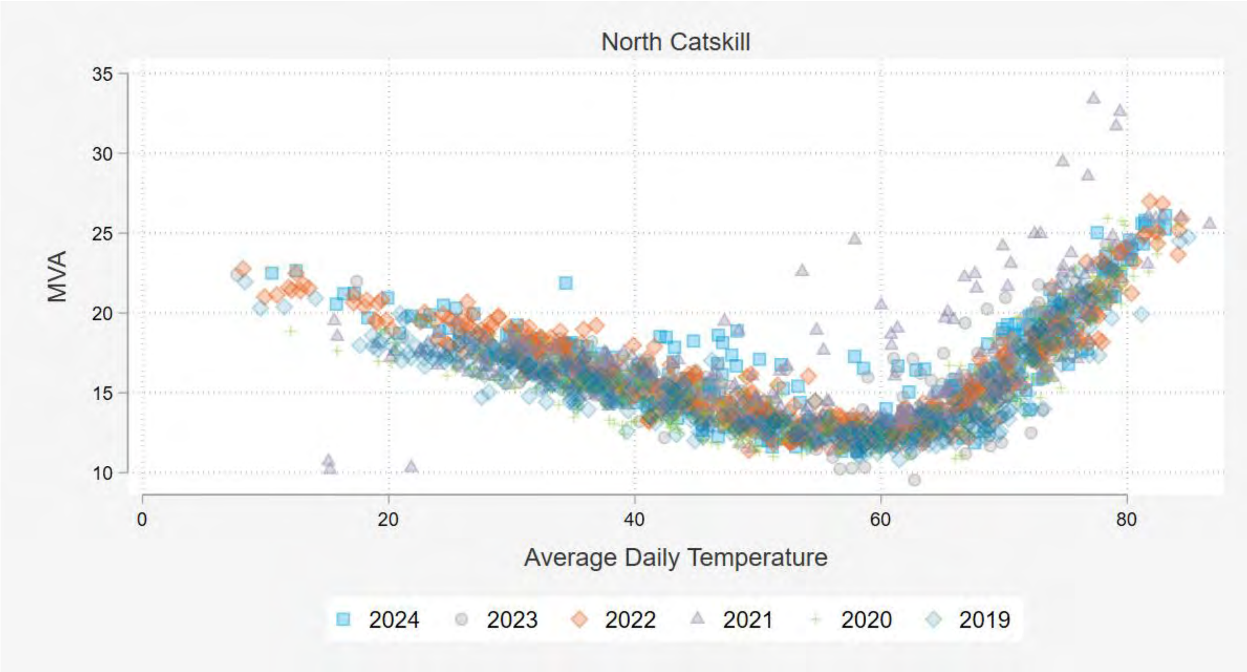
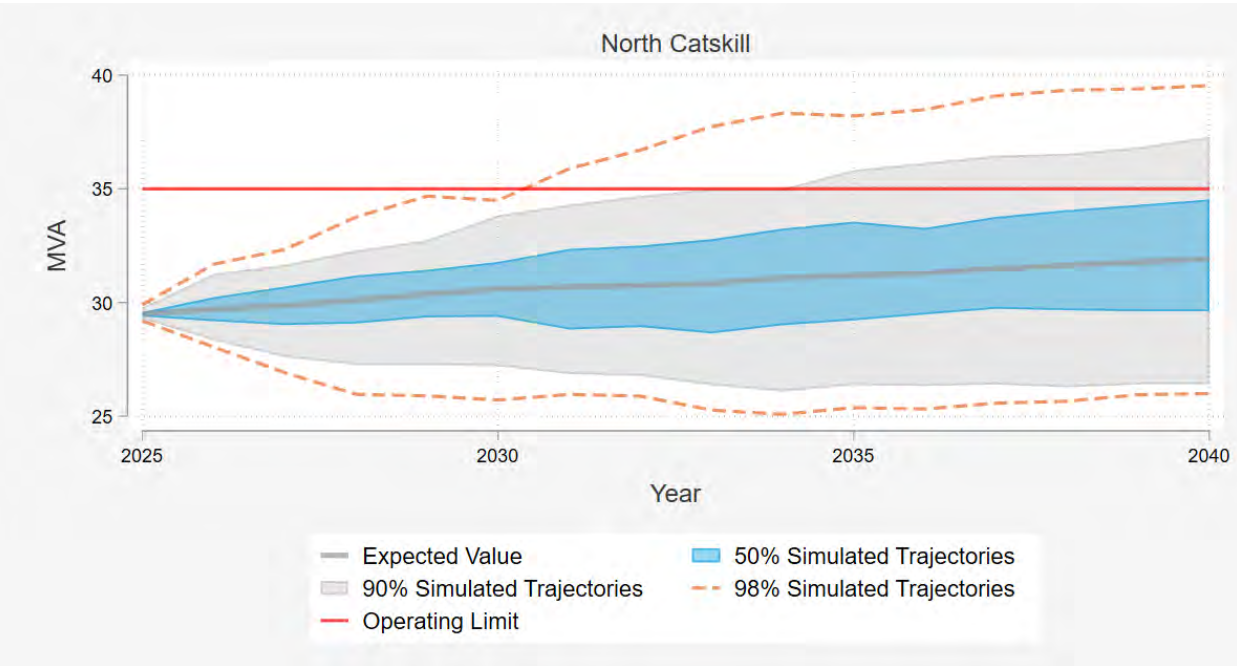


Figure 22: North Catskill Daily Peak Load Weather Pattern by Year



Peak demand in the North Catskill area has been growing at a rate of 1.46% per year since 2014. Load growth was evaluated using probabilistic methods rather than straight-line forecasts, and is calibrated to match the territory-wide peak demand forecast by season after 5 years. Figure 23 shows the load growth forecast for summer, assuming 1-in-2 weather year conditions. There is substantial uncertainty in the forecast, but there is a greater than 20% of an overload risk by 2035.

Figure 23: North Catskill Load Forecast with Uncertainty



3.4 OHIOVILLE

The Ohioville substation is located in the central part of the Central Hudson electric service territory. The Ohioville feeders supply a rural residential area with mixed commercial along the Route 299 corridor into the Village of New Paltz where SUNY New Paltz is located. The western portion of the circuits touch up against the Minnewaska State Park. Ohioville is a substation with a 30 MW long term emergency rating (LTE) and a 40 MW short term emergency (STE) rating.

Figure 24 shows the division of active accounts and electricity consumption in 2024 for Ohioville between residential and non-residential customers. Roughly 84% of the 7,123 total accounts belong to the residential customer class, and together the residential customers accounted for 40% of the total usage in 2024.

Figure 24: Ohioville Substation Accounts and Consumption

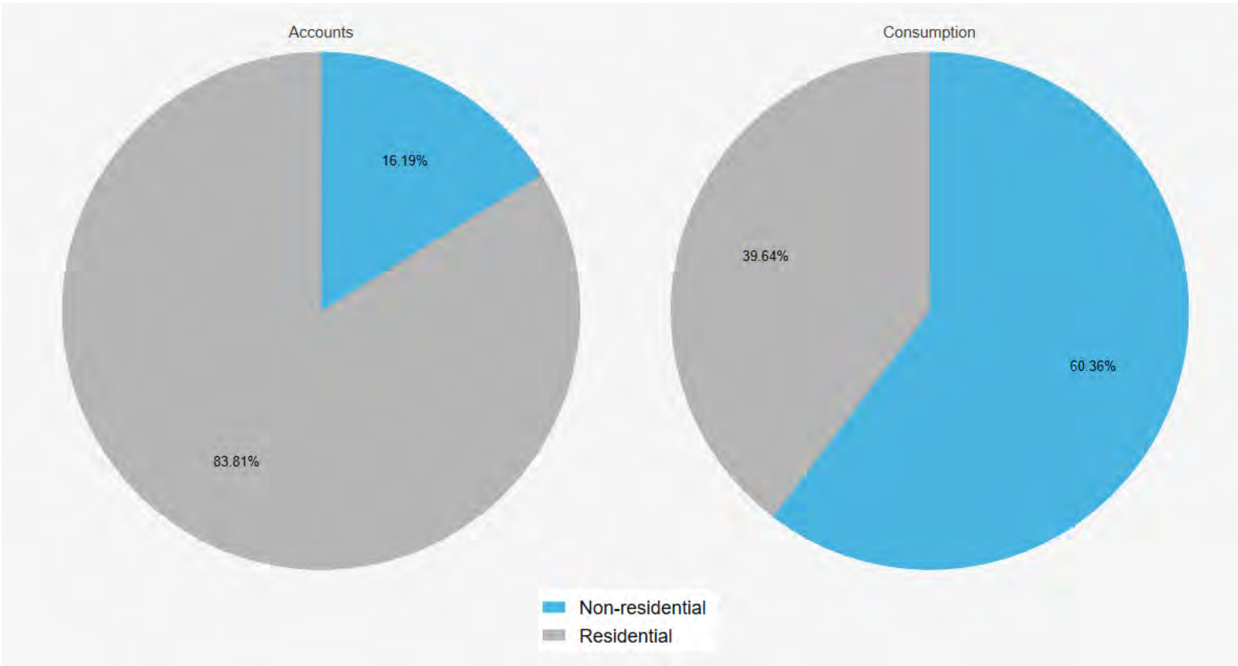


Figure 25 summarizes the peak day load for each year from consumption in 2014 to 2024 and includes details about the timing of the peak. Figure 26 summarizes the multi-year load duration curve over the same time frame and shows that the peak demand is concentrated on a small share of hours. The weather sensitivity load is illustrated in Figure 27, which shows the daily peak load as a function of different temperature ranges.

Figure 25: Ohioville Historical Annual Peak Day Load Shapes

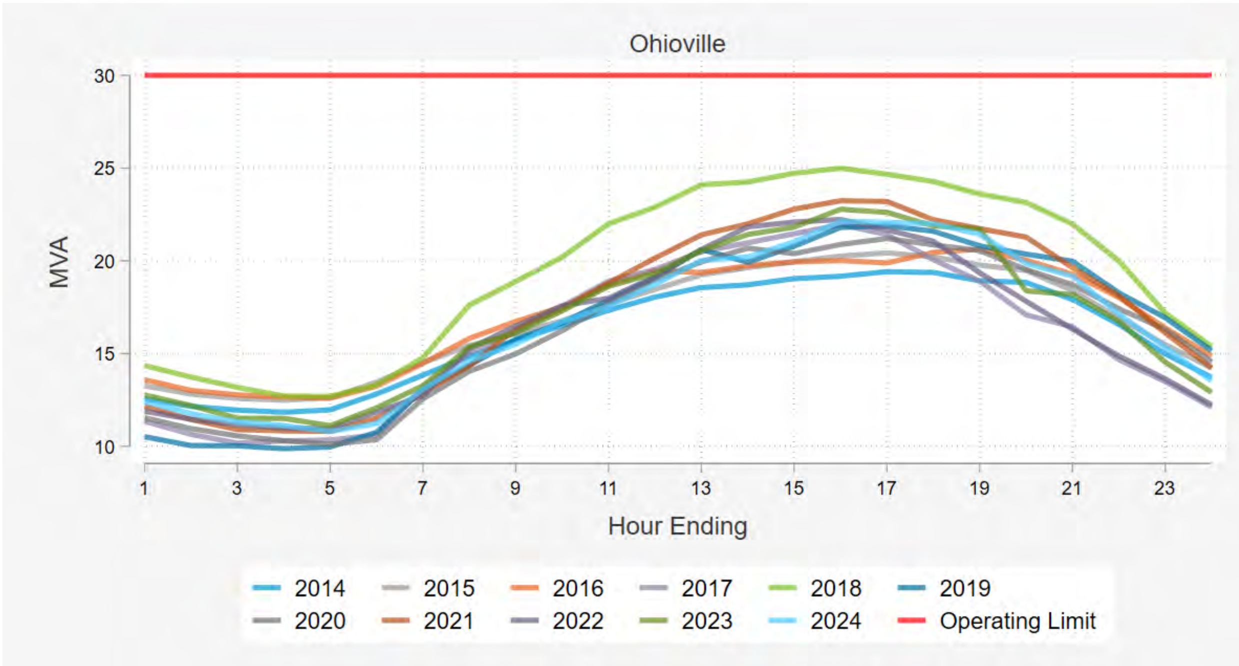


Figure 26: Ohioville Multi-Year Load Duration Curves

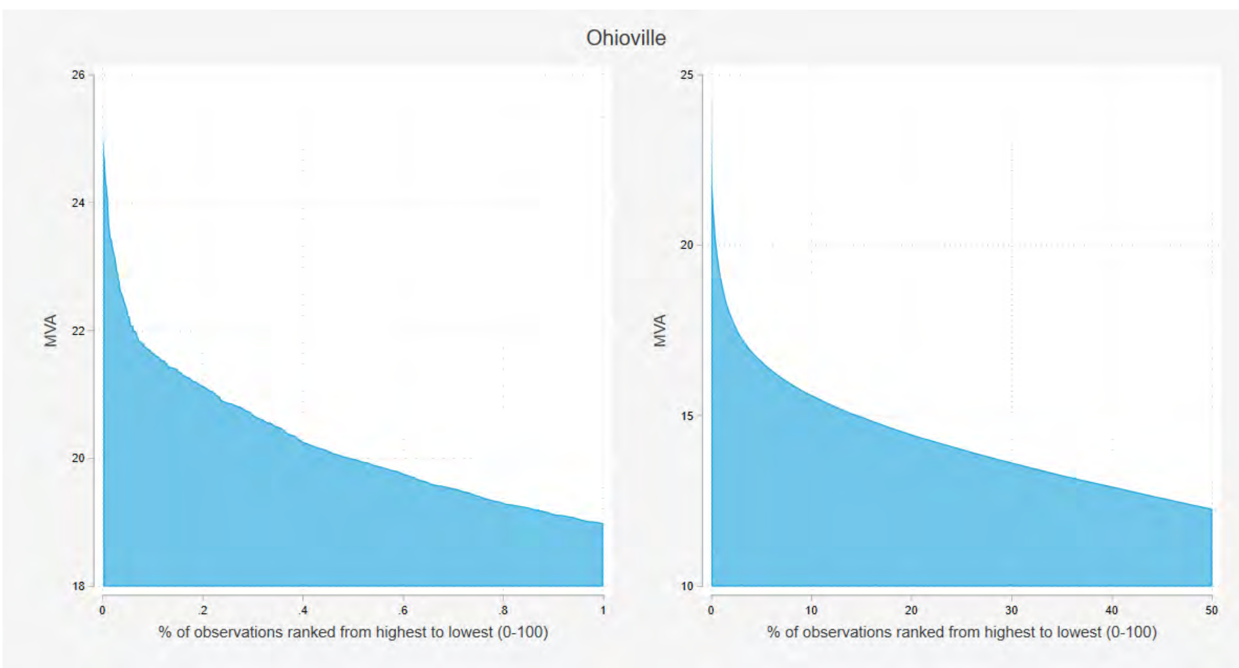
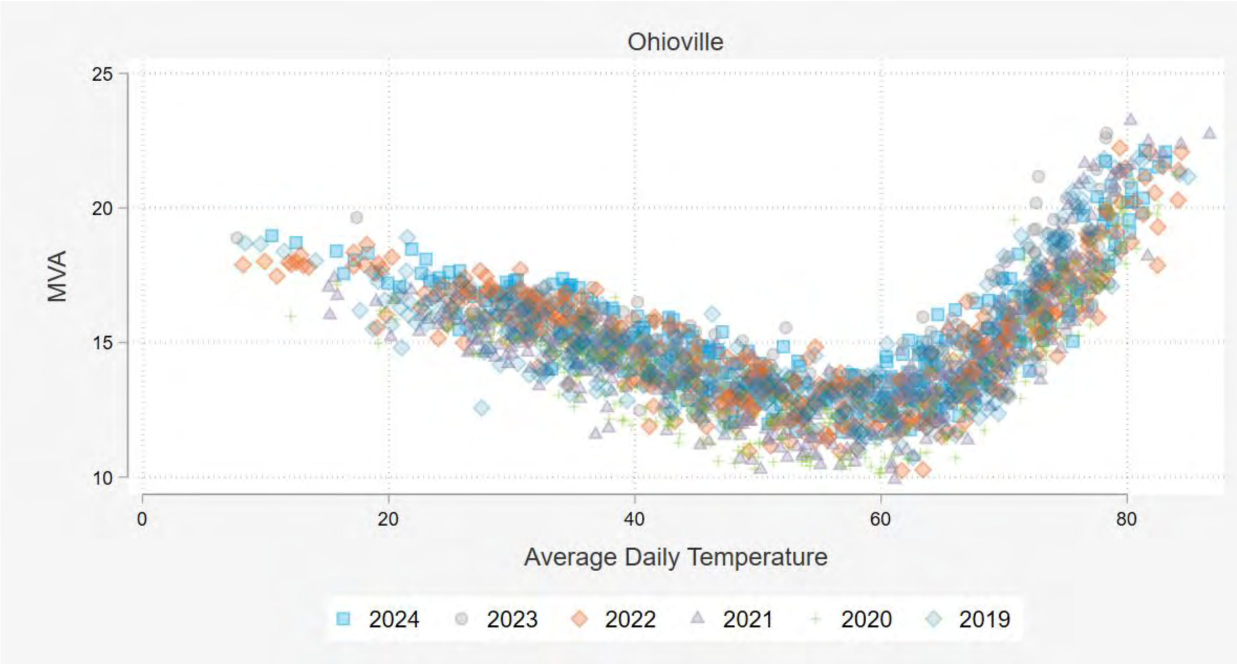
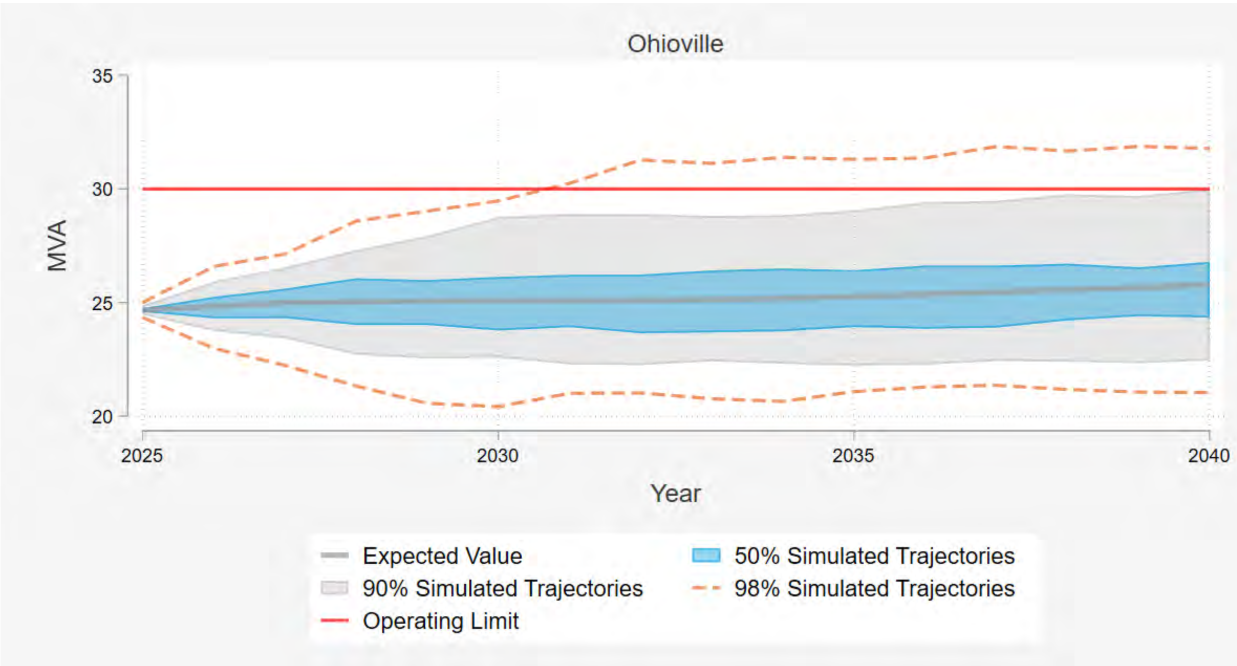


Figure 27: Ohioville Daily Peak Load Weather Pattern by Year



Peak demand in the Ohioville area has been growing at a rate of 1.12% per year since 2014. Load growth was evaluated using probabilistic methods rather than straight-line forecasts, and is calibrated to match the territory-wide peak demand forecast by season after 5 years. Figure 28 shows the load growth forecast for summer, assuming 1-in-2 weather year conditions. There is substantial uncertainty in the forecast, but there is a greater than 10% of an overload risk by 2035.

Figure 28: Ohioville Load Forecast with Uncertainty



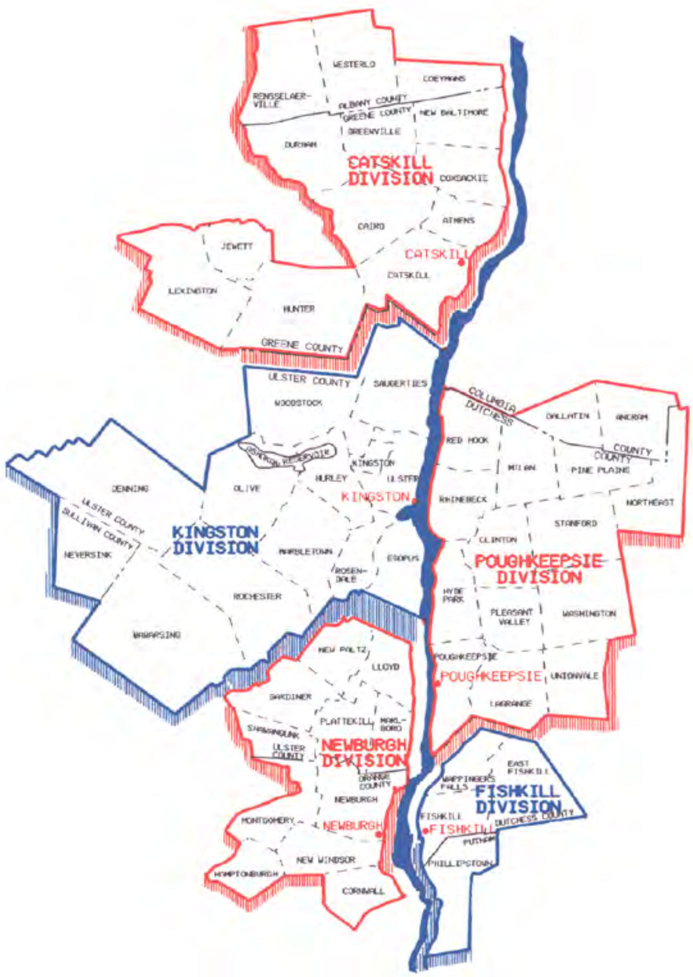
Central Hudson Gas & Electric

Long Range Electric System Plan

June 2024

1. Introduction

Central Hudson Gas & Electric Corporation is a regulated transmission and distribution utility serving approximately 321,000 electric customers and 90,000 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 7,148 pole miles of overhead lines and 1,728 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 working to achieve 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 PSC targets for non-storm SAIFI and non-storm CAIDI were reduced to 1.30 and 2.5, respectively through 2024. In order to drive continuous improvement, the Company establishes its own internal targets that are more stringent. For 2024, these internal targets for SAIFI and CAIDI are 1.26 and 2.40, respectively (see the table below). While the Company is in the process of a Litigated Rate Settlement, 2025 SAIFI and CAIDI targets are expected to remain at those same levels.

Performance Indicator (Non-Storm)	2022 Actual	2023 PSC Actual	2024 PSC Target	2024 Internal Target	2025 PSC Target
SAIFI – System	1.27	1.08	≤ 1.30	≤ 1.26	≤ 1.30
CAIDI – System	2.25	2.31	≤ 2.50	≤ 2.40	≤ 2.50

To achieve a balance between reliability and affordability, the Five-Year 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 department 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 Distributed Energy Resources (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

In 2020, 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:

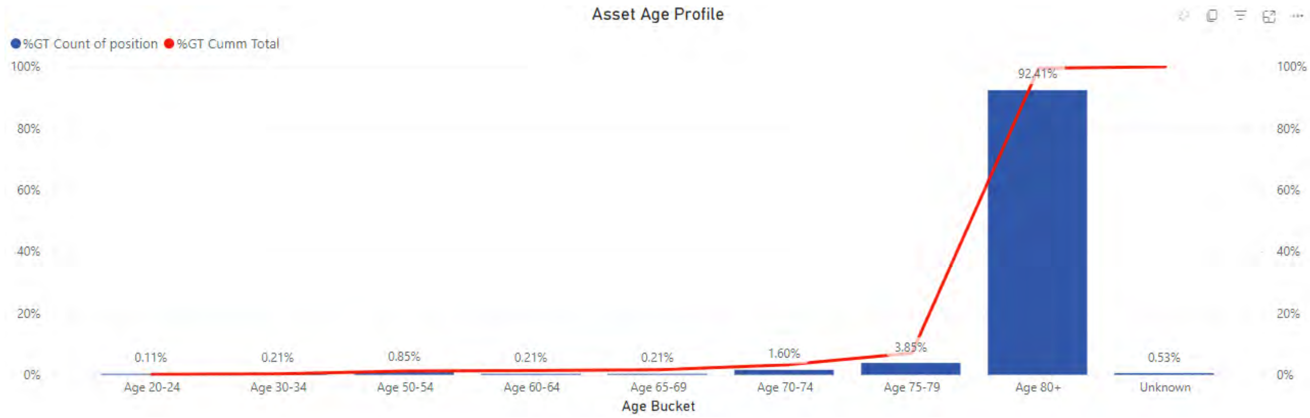
<table>
<tr><th>Operating Voltage</th><th>Design Voltage</th><th>Overhead Circuit Miles</th><th>Pipe-Type Cable Circuit Miles</th><th>Total Circuit Miles</th></tr>
<tr><td>345 kV</td><td>345 kV</td><td>76.3</td><td>0</td><td>76.3</td></tr>
<tr><td>115 kV</td><td>115 kV</td><td>224.4</td><td>4.1</td><td>228.5</td></tr>
<tr><td rowspan="2">69 kV</td><td>69 kV</td><td>248</td><td rowspan="2">0</td><td rowspan="2">274.6</td></tr>
<tr><td>115 kV</td><td>26.6</td></tr>
<tr><td colspan="2">Total</td><td>575.3</td><td>4.1</td><td>579.4</td></tr>
</table>

3.2.2.1. Lattice Towers

Inventory
Central Hudson's transmission lines include 936 lattice towers.

Age and Condition
Central Hudson's lattice tower population age is shown in the histogram below. A subset of these towers (i.e., 1920's vintage 69 kV "E" Line) were analyzed in detail[1] in 2004 as part of a reconductor project on that line which indicated a significant anticipated remaining life for those towers.

[1] EDM International, Inc. "Latticed Steel Tower Assessment for 'E' Line Reconductoring Project." December 2004.



Plans

While the 2004 analysis did not indicate significant issues, the average age of the Company's lattice tower structures is 99 years with over ninety percent beyond their expected life. There are several lines that have been identified through inspections as having over 50% of the existing towers requiring significant maintenance or replacement. Based on fleet age and condition, the remaining lines will eventually require the same level of actions if the condition of the towers are allowed to degrade without mediation. To control the potential degradation caused by corrosion and to extend the current life of the remaining tower population, the Company plans to employ the use of a targeted Structure Coating Program. The coating program will target and prioritize structures and lines that are not currently being considered in any long-term replacement plans or programs. Other system planning factors and/or infrastructure conditions may precipitate additional actions and will be addressed on individual lattice towers or lattice tower lines at the time they are identified or require attention. Central Hudson plans on completing a new assessment on a subset of the remaining tower assets in the two-year time frame.

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 for replacement.

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 and 11.4 mile SB Line, these majority lattice tower lines will be rebuilt using steel poles and 795 ACSR conductor. The SB Line project will be completed by mid-2024 with the H Line being completed by mid-2026.

SD & SJ Lines

The 11.4 mile SD/SJ Common Tower Line was built in the 1920's. The line is in poor condition, however major repairs are not planned at this time since a project to retire this lattice tower line is included as part of the 5-year capital plan. There are currently discussions on-going with third parties regarding the use of the ROWs/re-purposing of the corridors associated with these lines.

5 Line

The rebuild of Central Hudson's 2.87-mile portion the 5 Line is intended to address significant infrastructure issues identified on the line as part of the company's routine inspection cycle. The line was originally constructed in the 1910's and runs from the Company's North Catskill Substation to an interconnection with the National Grid owned section of the line. Inspection results have shown that 57% of the structures on the line are in need of replacement with an additional 36% requiring some level of repair. A planning memo is in-progress to determine final conductor and static wire size.

3.2.2.2. Wood Poles

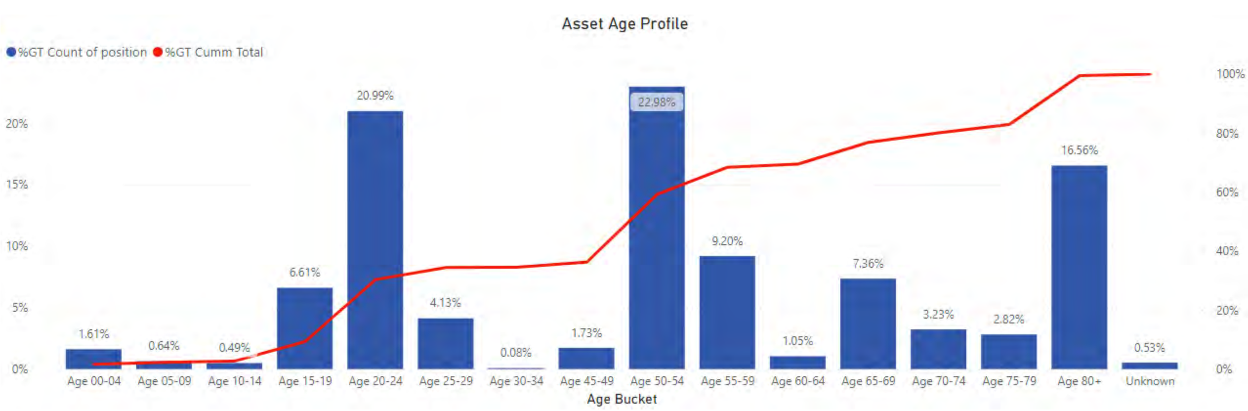
Inventory

Central Hudson's transmission system includes 2,663 wood poles.

Age and Condition

General

These wood poles vary in ages as shown in the following histogram. Wood poles are relatively short-lived and often times require replacement prematurely due to damage from lightning, woodpeckers, insects, rot, 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.

<u>HG Line</u>
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.

<u>TR Line</u>
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.

<u>Q Line</u>
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.

<u>SK Line</u>
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

<u>General</u>
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.

<u>KM Line</u>
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 is being rebuilt. The new line is employing the use of 795 ACSR

conductor and an OPGW static wire. The KM line rebuild is scheduled to be completed by mid-2024.

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 2028.

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
While there have been various maintenance projects on the Q line over the years, most of the line remains original vintage. Due to the advanced age and condition of the line, a more comprehensive approach to mitigation is being recommended that includes evaluation of a rebuild to accommodate future 115kV operation. A planning memo is currently underway to evaluate the details related to the rebuild of the line.

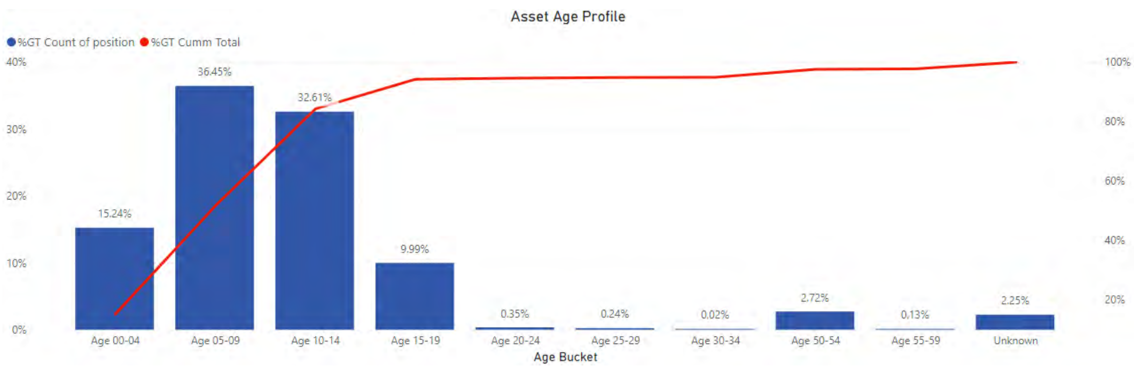
SK Line
To address the various structure condition findings on the line as well as R.O.W. deficiencies as identified as part of Central Hudson's Deficiency Program, it is recommended that the line be rebuilt and centered within the existing R.O.W. The Line will be rebuilt utilizing 1033.5 ACSR conductor and an OPGW Static. The SK Line is scheduled to be rebuilt in 2029.

3.2.2.3. Steel Poles

Inventory
Central Hudson's transmission system includes 4,625 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 15 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 increase the resiliency of 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 continues to evaluate the future 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. The Company 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

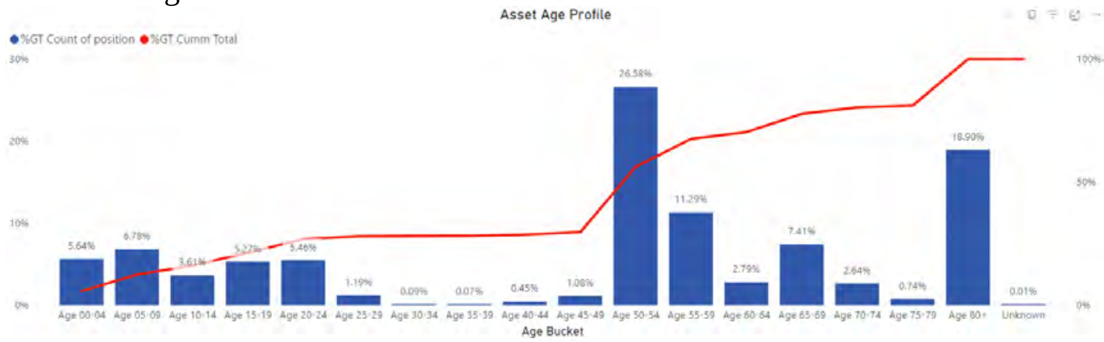
Inventory

Phase conductors on the Central Hudson transmission system are of the type as follows:

Conductor Type	Percentage of System
Aluminum	10.7
ACSR	77.9
Copper	8.6

Age and Condition

These conductors were installed in the years shown in the following histogram.



For ACSR[2] conductor, issues have been identified in the past after several failures. Samples were subsequently taken and sent to NEETRAC[3] (at the Georgia Institute of Technology) for testing. Following the evaluation, an ACSR testing program was implemented to ascertain the general condition of ACSR conductor. Based on these test results, a targeted program was developed to replace ACSR conductor that had poor test results. This is an ongoing program with conductor already having been replaced on several lines and the remainder prioritized based upon test results and other considerations (i.e. other planned work, conductor size, vintage). No issues with other types of conductors (e.g., copper) have been identified. Central Hudson is planning to utilize testing facilities available through EPRI to perform a new round of evaluations on conductor samples taken from various transmission lines throughout the territory in continuation of this program.

Plans

<u>FV Line</u>
NEETRAC conductor testing on Central Hudson'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
Central Hudson's transmission system includes approximately 27,600 insulator units / strings.

Age and Condition

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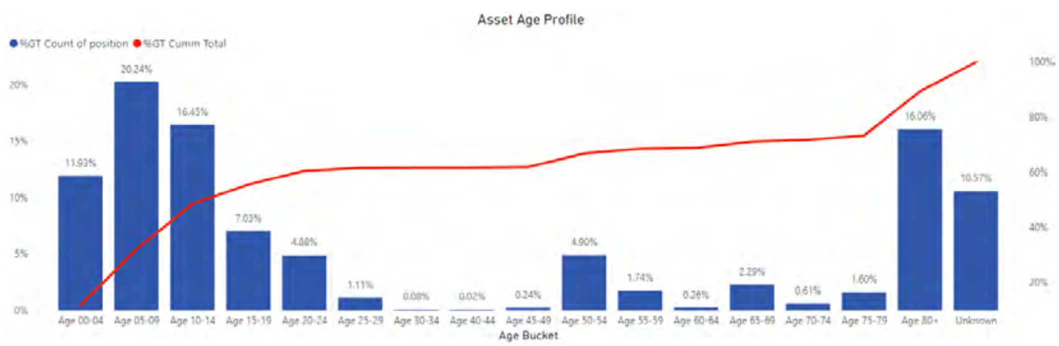
[2] Aluminum Conductor Steel Reinforced
[3] National Electric Energy Testing, Research & Applications Center

These insulators were installed in the years shown in the following histogram and represent a range of material types (ceramic disc, polymer, toughened glass disc, etc.). Central Hudson has experienced very few insulator failures. Most have been a result of external causes (e.g., lightning, gunshot, etc.) or end of life. Some recent findings have uncovered degradation in a subset of suspension polymer insulators that are still under investigation.



Plans

While the overall performance to-date of Central Hudson's insulator population is acceptable, and no specific replacement plans have been identified, there have been several work practice adjustments made in response to recent findings. Central Hudson monitors industry experience and best practice via participation in EPRI's insulator task forces as well as other groups. Based on recent findings and continued feedback from these industry groups, Central Hudson will now replace both ceramic as well as polymer insulators in a tangent (vertical suspension) configuration with toughened glass equivalents as a typical practice. Toughened Glass will continue to be used in all dead-end or heavy angle applications where insulator strings are subject to higher tensile loading. Polymer insulators will only be utilized for tangent applications in either a post or braced-post configuration moving forward.

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 Designation	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 will be completed in 2024 and will be reviewed 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 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 currently in the design process with replacements to be completed in 2025.

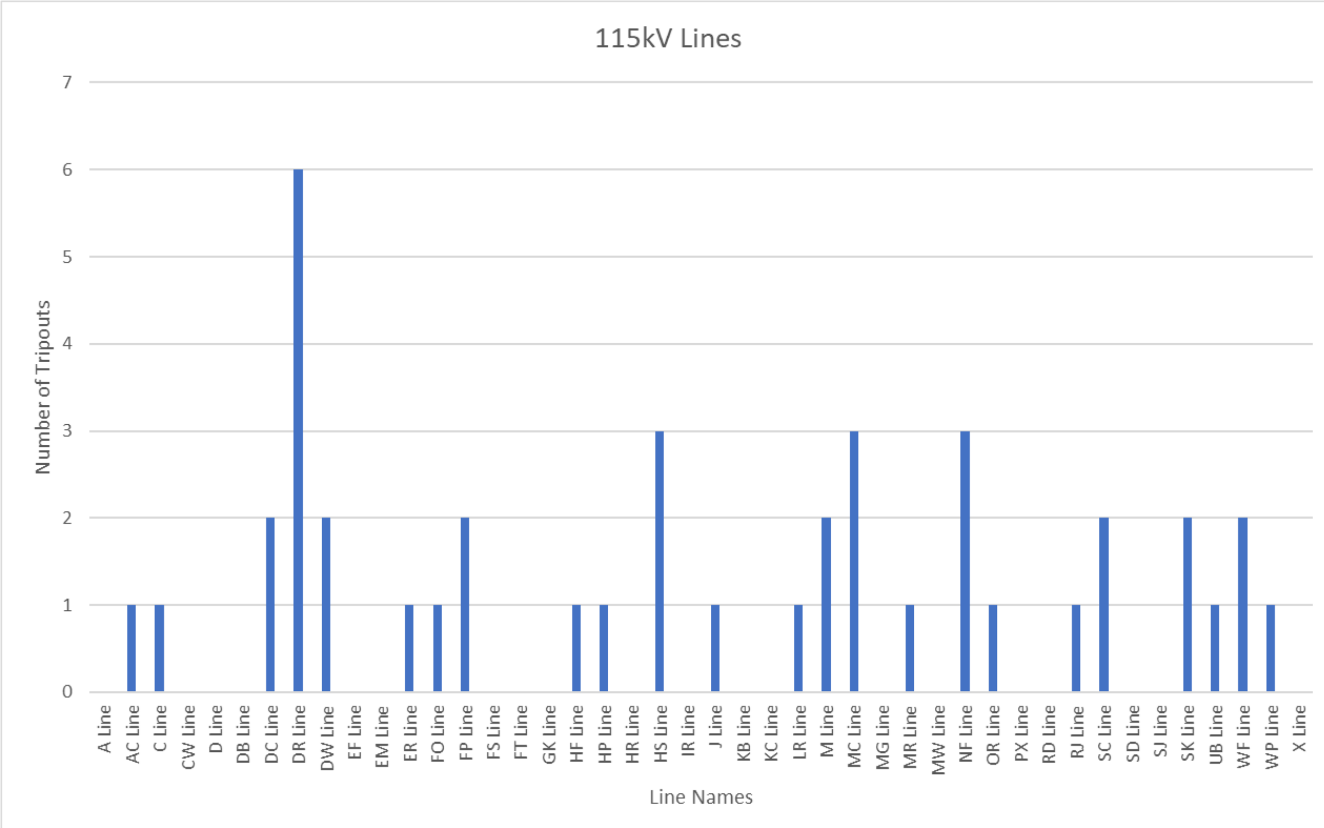
3.2.3. Reliability Performance Data

The System Operation's outage database in TOA was used for this analysis. Transmission trips from 2019 through 2023 were reviewed for the purpose of identifying lines with high failure rates; substation equipment was not included. Below are the results.

<u>345 kV</u>
Central Hudson owns three 345 kV lines. From 2019 through 2023, there was one tripout on the 303 line, and one on the 301 line. There were no tripouts on the 311 line during this time frame.

No systemic issues can be discerned from the data.

<u>115 kV</u>
The chart below illustrates the number of tripouts on our 115kV transmission lines from 2019 through 2023. This data helps identify potential negative reliability trends and areas for further study.



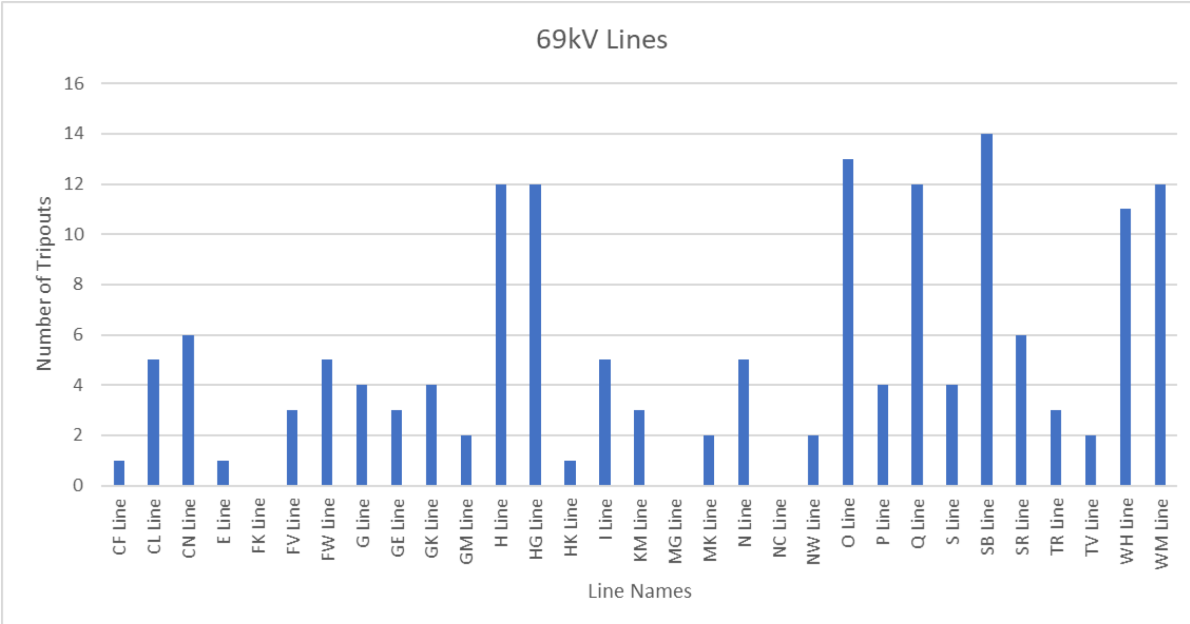
Due to the high number of DR line tripouts, these events were examined in greater detail and are summarized in the following table.

Cause	DR Line
Equipment	1
Tree	-
Lightning	-
Unknown	5
Total	6

The equipment-related outage on the DR Line was 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.

69 kV

The chart below depicts the number of tripouts on our 69kV transmission lines for the period of 2019 through 2023. This data helps identify potential negative reliability trends and areas for further study.



Tripouts for the H, HG, Q, and SB lines were not examined further due to plans to rebuild these lines.

Due to the high number of O, WH, and WM line tripouts, these events were examined in greater detail and are summarized in the following table.

Cause	O Line	WH Line	WM Line
Obstruction (mylar balloons)	-	-	2
Equipment	2	-	-
Storm	-	-	1
Tree	9	3	4
Lightning	-	-	-
Unknown	2	8	5
Total	13	11	12

Nine out of the thirteen O Line outages were due to trees with two of unknown cause. Transmission Design will work with the Vegetation Management to identify targeted areas for enhanced trimming to improve reliability of this line. In addition, obtaining additional easements for the right-of-way (ROW) will be explored in the three most condensed section of the line.

Seven out of the twelve WM Line outages occurred in the span between Rock Tavern and Montgomery. No systemic issues can be discerned from the data on the line tripouts. The line will continue to be monitored to track reliability trends and identify potential corrective actions if necessary.

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	Honk Falls to NYSEG	Neversink Tap	NYSEG to West Woodbourne
Wires Down			1
Equipment			
Storm			
Tree	1	3	
Lightning		1	
Unknown		2	2
Insulator			1
Total	1	6	4

**** Note – One additional tripout with unknown location and cause which is not tallied in the chart.***

The rebuilt section (Honk Falls to NYSEG) had one tripout in this timeframe. While the section from the Neversink Tap to Neversink had six tripouts, no systemic issues can be discerned from the data. 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.

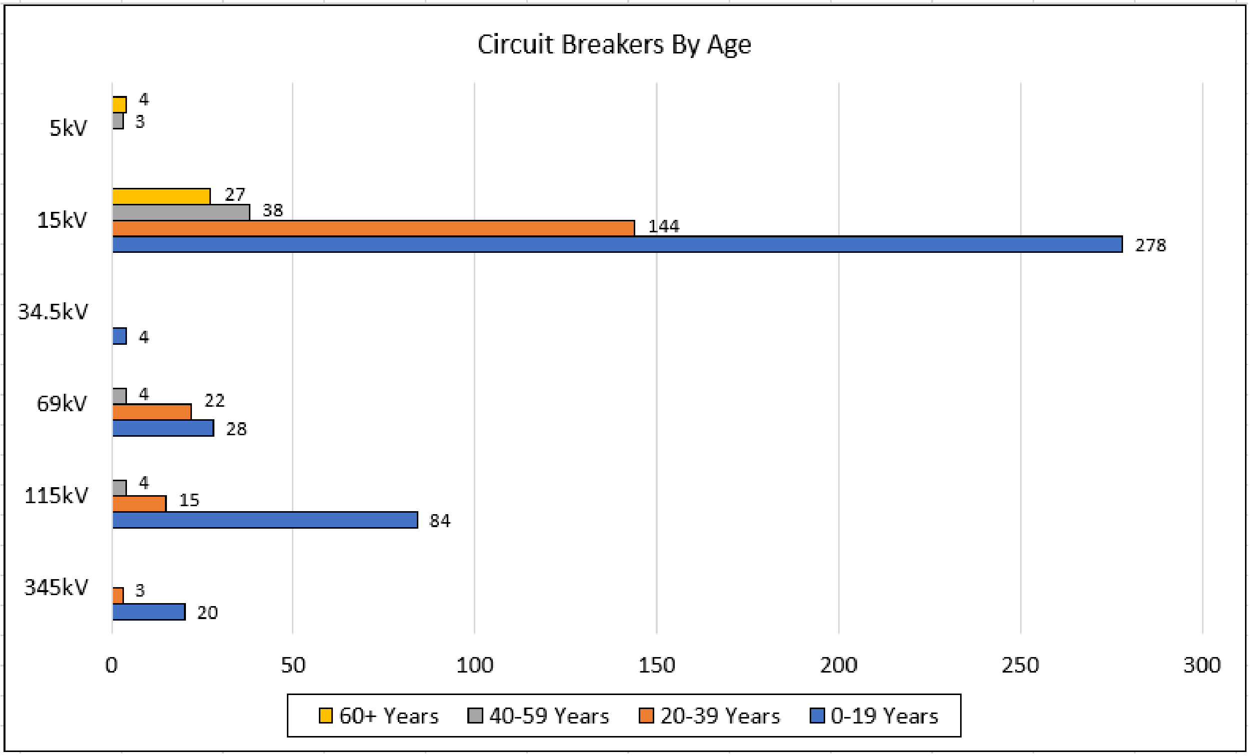
Inventory
The following chart depicts the current inventory of circuit breakers on our system (the chart does not include circuit breakers listed as retired, junked, EC spare, spare, deleted, or undated).

Operating Voltage	Number
345 kV	23
115 kV	103
69 kV	54

34.5 kV	4
15 kV	487
5 kV	7
Total	678

Age and Condition

The following chart depicts the number versus age of circuit breakers:



The condition of the circuit breakers varies and the ability to maintain them is closely tied to their age. Overall, 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 (1)

15kV- General Electric Type AM (12)
General Electric Type FK (9)
Westinghouse Type 150-DH (13)
Westinghouse Type 150-DHP (37)

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 104 circuit breakers.

Circuit Breaker Replacement Plan (# of breakers)				
Year	345kV	115kV	69kV	15kV
2024	1	4	0	8
2025	0	0	0	4
2026	0	2	1	14
2027	0	0	0	19
2028	0	0	0	19
2029	0	0	1	31
Total	1	6	2	95

Based on the field condition and the above breaker replacement prioritization, it is planned to complete the breaker replacement program by 2029.

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	152
115 kV	360
69 kV	255
34.5 kV	20
13.8 kV	264
7.5 kV	16
4.16 kV	6
Total	1,073

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	(12)
	Memco	Type VR2	(10)

Plans
Central Hudson has developed a multi-year 345kV switch replacement program. The 345kV switch replacement program will replace fifteen 345kV switches in the next five years. The breakdown of the program is as follows:

345kV Switch Replacement Plan (# of switches)

Year	345kV
2024	3
2025	3
2026	3
2027	3
2028	3
2029	3
Total	18
Future	5

The program will continue addressing the remaining ~5 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 2029.

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	42
34.5 kV	5
13.8 kV	8
Total	148
* Single Phase Transformers are counted individually	

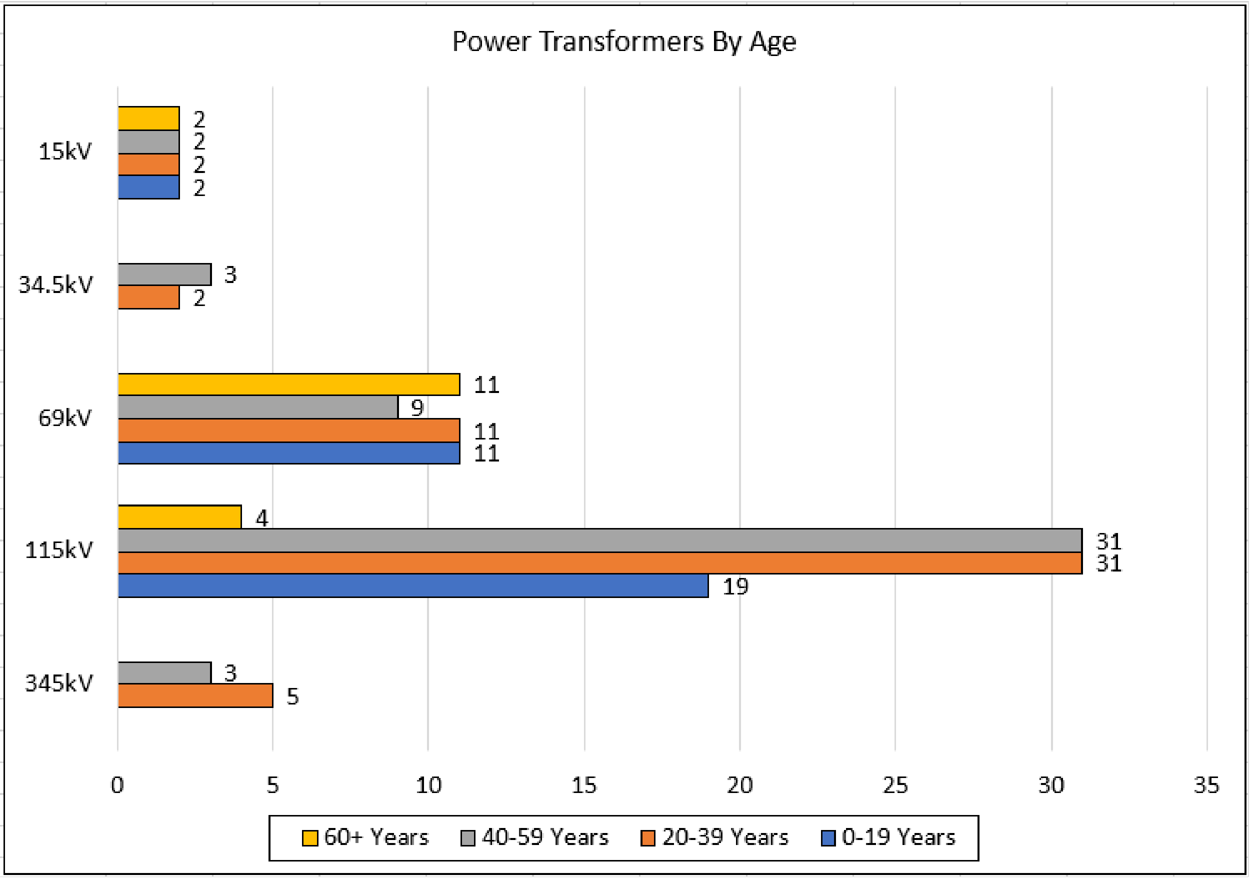
Age and Condition
The condition of the power transformers varies and the ability to maintain them is closely tied to their age. The overall condition of this equipment, based on our ongoing assessment program, is considered good. During our ongoing assessment process, however, the following issues were 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.

The following chart depicts the number versus age of power transformers:



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:

- 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 scrapped);
- Converse Street Substation Transformers #1, #2 (replace with new 14.4-4.16 kV transformers).
- Pulvers Corners Substation Transformer #1 (replace with new 67-13.8 kV 11.2MVA unit);
- Ancram Substation Transformer #1, Phases #1, #2, #3 (replace with new 34.5-13.8 kV 8.4MVA unit)
- Tinkertown Substation Transformers #1 and #2 (replace with new 69-13.8kV 13.4MVA units)
- Woodstock Substation Transformers #1 and #2 (replace with new 69-13.8kV 13.4 MVA units)

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 (CT) at these locations and a new 12MVA 115x69-13.2kV 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
13.8 kV	13
Total	24

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. New 69 kV capacitor banks will be installed at the South Cairo and New Baltimore Substations based on the planned retirements of the Combustion Turbines at South Cairo and Coxsackie Substations.

3.3.2.1.8. Substation Batteries/Battery Chargers

Inventory
Central Hudson currently has 85 substation batteries and 85 substation battery chargers.

Age and Condition
Most equipment is age 20 years or less. Generally, ages and conditions vary. There are currently 41 batteries under 10 years old, 39 batteries under 20 years old, and 5 batteries over 20 years old. 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 45 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.

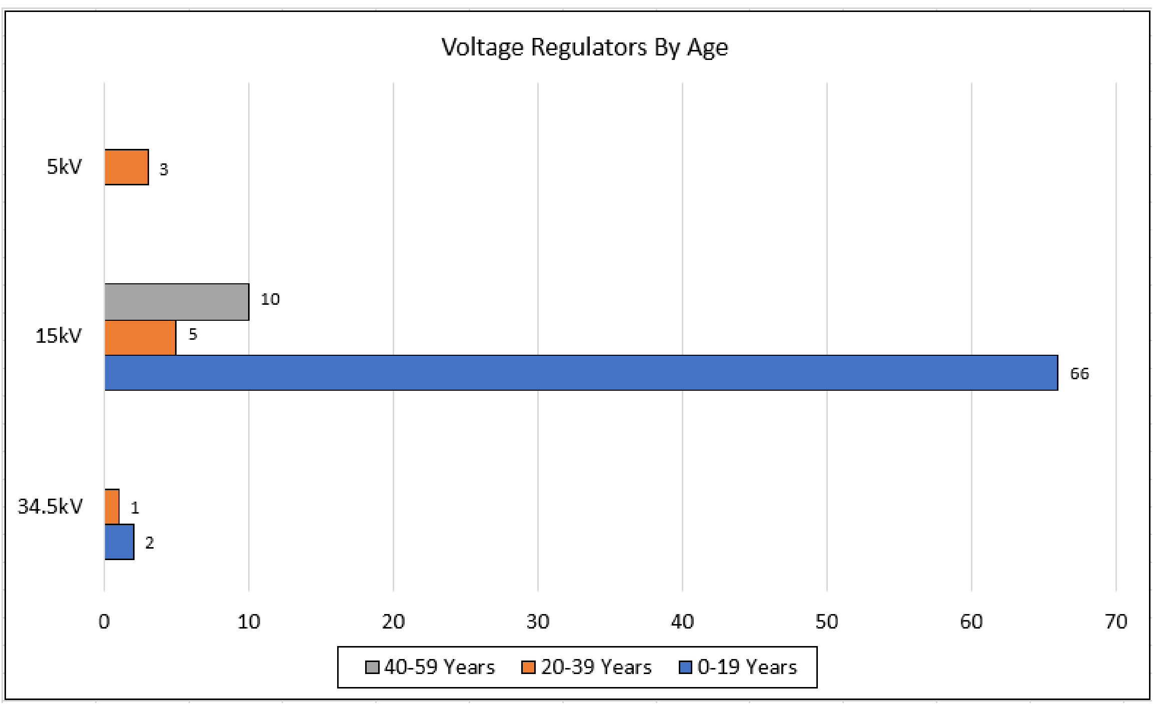
3.3.2.1.9. Voltage Regulators

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	81
4.16 kV	3
Total	87

Age and Condition
Generally, ages and conditions vary. The general condition of this equipment is considered good.

The following chart depicts the number versus age of voltage regulators:



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.

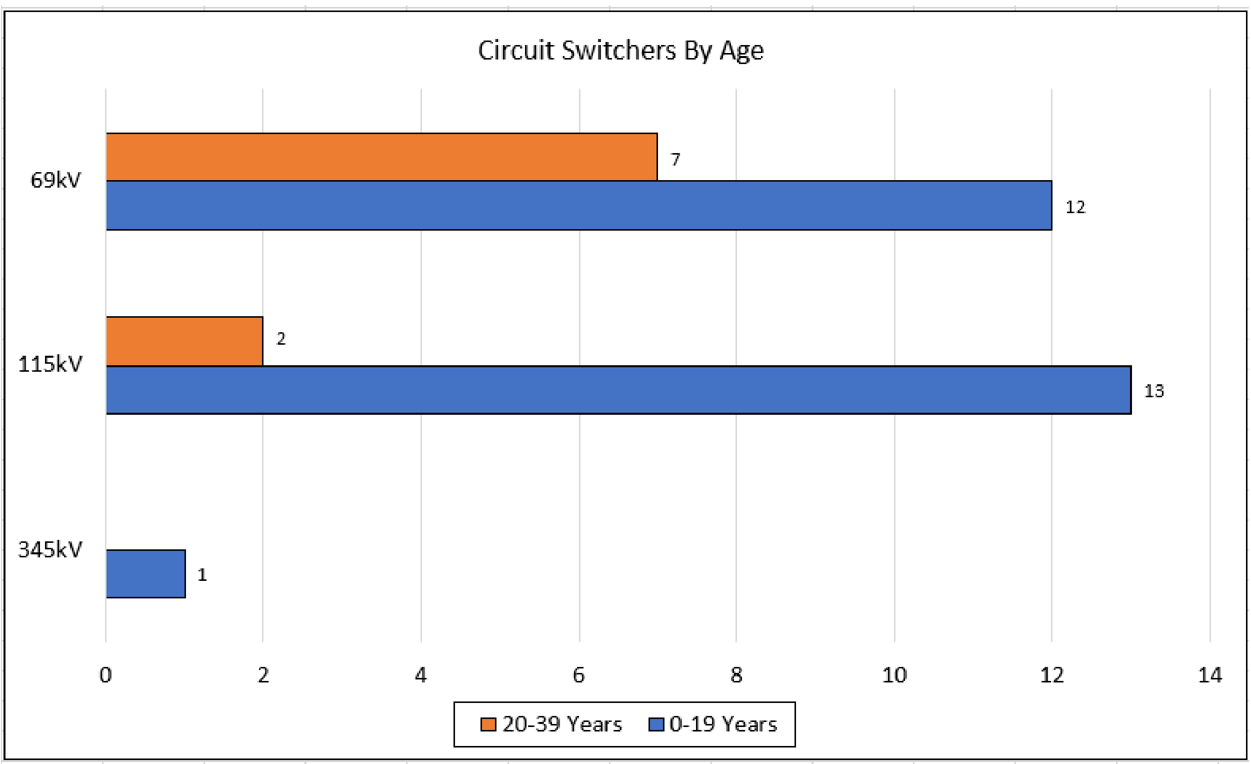
3.3.2.1.10. Circuit Switchers

Inventory
The following chart depicts the inventory of the Circuit Switchers on our system:

Circuit Switchers	
Operating Voltage	Quantity
345 kV	1
115 kV	15
69 kV	19
Total	35

Age and Condition
Generally, ages and conditions vary. The general condition of this equipment is considered good.

The following chart depicts the number versus age of circuit switchers:



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	10
Total	10

Age and Condition
Generally, ages and conditions vary. There are currently 4 substation reclosers under 30 years old and 6 substation reclosers under 40 years old. The general condition of this equipment is considered good.

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 62 control houses and 62 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 Converse Street, Woodstock Substation, Myers Corners Substation, Montgomery Street, Hurley Avenue, and Tioronda Substation switchgears were evaluated and identified for replacement in five-year capital plan.

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 30 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.

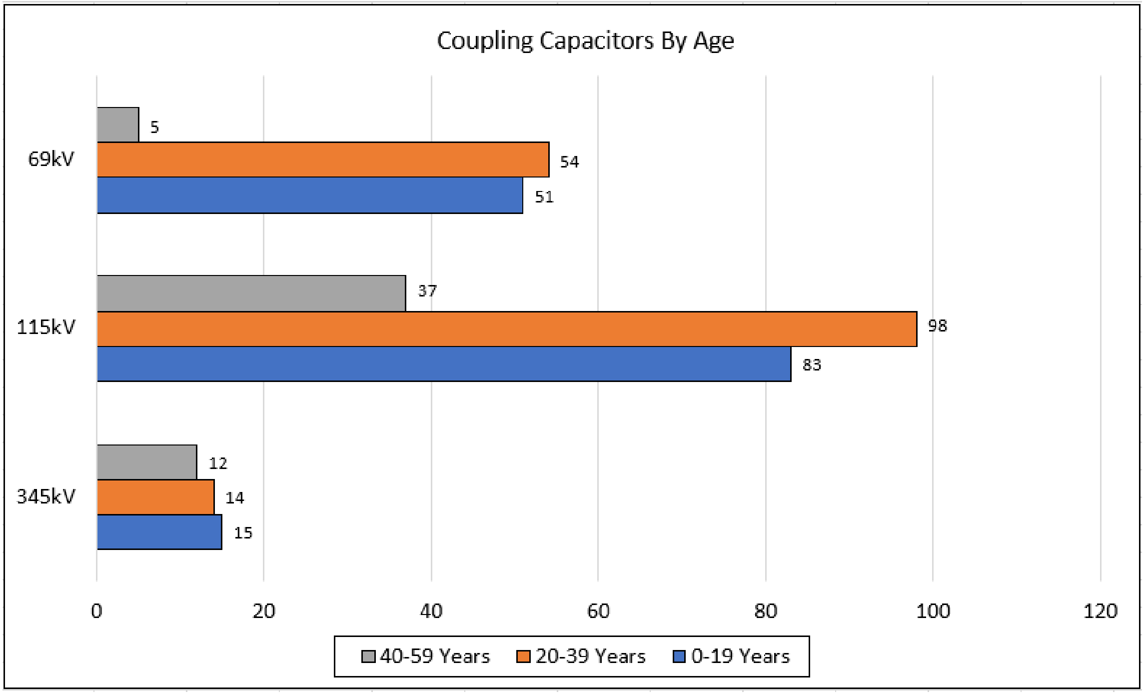
3.3.2.1.14. Coupling Capacitors

Inventory
The following chart depicts the inventory of Coupling Capacitors on our system:

Coupling Capacitors	
Operating Voltage	Quantity
345 kV	41
115 kV	218
69 kV	110
Total	369

Age and Condition
Generally, ages and conditions vary. The general condition of this equipment is considered good.

The following chart depicts the number versus age of coupling capacitors:



Plans
No specific rebuild/refurbish/replacement programs identified.

3.3.2.1.15. Arresters

Inventory
The following chart depicts the inventory of Arresters on our system:

Arresters	
Operating Voltage	Quantity
345 kV	6
115 kV	27
69 kV	38
15 kV	25
Total	96

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
<u>Substation Fences</u>
Central Hudson currently has 87 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 4,100 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	1,378	34%
Electromechanical (Non Digital) Relays[4]	708	17%
Lockout Relays	785	19%
Auxiliary Relays	315	8%
Tele-protection Units	132	3%
Transformer/Regulator Relays & Controls	505	12%
Network Devices	296	7%
Total	4,119	100%

Age and Condition
The ages and conditions generally vary. Older equipment is electromechanical, and newer equipment is microprocessor-based.

[4] This number represents relay systems. Electromechanical relay systems typically include three phase and one ground relay.

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 two Alternate #2 345kV Line packages 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 66% 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 Grid Modernization, electromechanical relays replacements are being added to scope where appropriate.

3.3.2.3. Substation Meter Devices

Inventory

Central Hudson currently meters distribution feeders, buses, transformers and transmission lines. Almost all metering is performed in microprocessor relays or by MV-90 metering devices. There are currently three substations with chart meters that will be retired or replaced within the 5 year plan.

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 2024.

3.3.2.5. Remote Terminal Units (RTU)

Inventory

Central Hudson currently has 108 Remote Terminal Units (75 main RTU's and 36 sub RTU's) in its electric substations. 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	69
Outdated	3
NONE	3

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 Grid Modernization, 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. The four Telvent 2100's and one Telvent Micro1C 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 three 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, and 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 through 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 fireproofing, 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 1,728 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 cable defects, which would provide the capability to target repairs on assets that require it. Cable sections that exhibit no partial discharge can be recertified as new and are guaranteed for 25 more years. Central Hudson's plans for using this technology are outlined in Section 3.4.4.4 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. The oldest portions of the primary feeders range in age from 20 to 90 years old (see Table 3.4.2). Most of the older portions of these feeders are comprised of paper-insulated-lead-covered (PILC) conductors. The underground infrastructure for both the primary and secondary network cables is in some cases older than the associated cables.

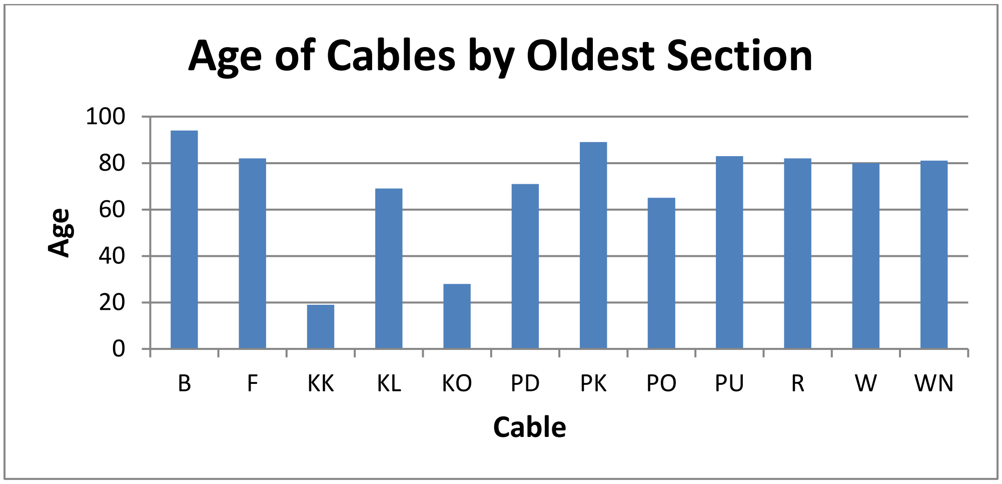


Table 3.4.2 – Age of Cables by Oldest Section (2024)

Due to an increase in failure rates of the PILC cables and failing underground infrastructure, targeted replacement programs were developed 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.

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 external 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. In 2014, it was determined that installing communicating relays in the network protectors would provide improved network monitoring capabilities, as well as additional transformer health monitoring capabilities. Access of relay data is currently through a Sensus CDMA cellular communications system, with the final goal being cutover to our internal Network Strategy communication system. A project to link the relays to the Network Strategy communications network is expected to begin returning data by the end of 2024. As of the first quarter of 2024, there are 21 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 2025.

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 retrofits by 2025, with the remaining 13 retrofits in Kingston and Newburgh network following shortly after.

3.4.2.4. Manholes and Pull Boxes

Central Hudson currently has 608 manholes and 744 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.

Kingston – There are three sub-transmission cables in Kingston. The KK cable feeds the South Wall Street and Converse Street low voltage substations. The Converse Street Substation feeds the Kingston secondary network. The KL and

KO cables are the primary and backup feeds, respectively, to the Jansen Ave Substation. Plans to replace the remaining PILC cable in Kingston are discussed in Section 3.4.4.3.

Newburgh – 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 3.4.4.3.

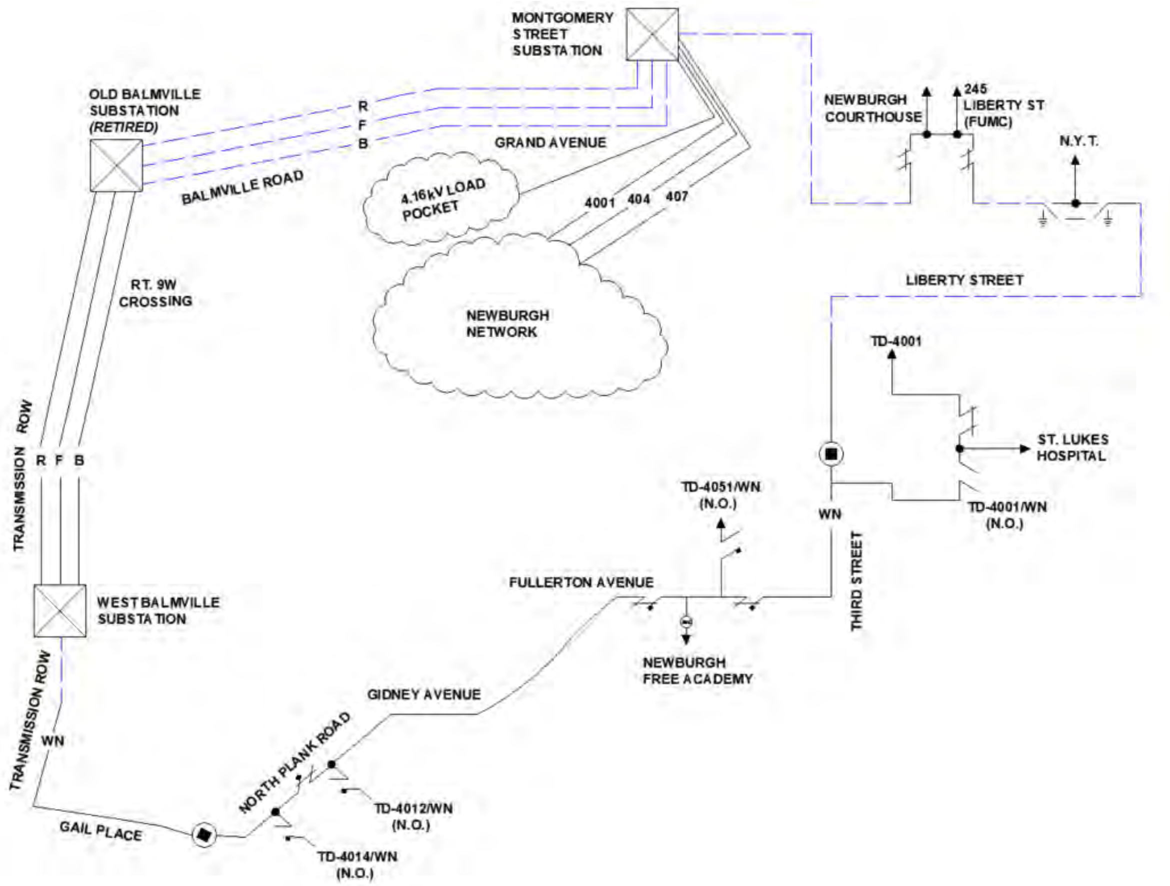


Figure 3.4.3-1: Newburgh 14.4 kV System

Poughkeepsie – As of 2020, the Poughkeepsie District has five 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 3.4.4.2.

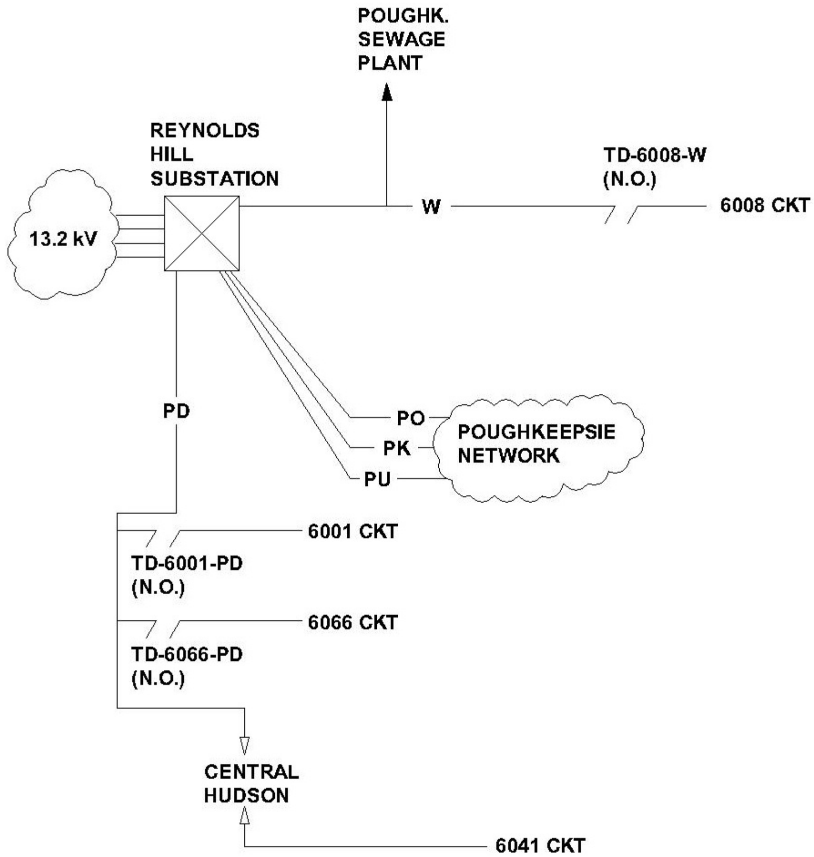


Figure 3.4.3-2 - Poughkeepsie 14.4kV System

As noted, there are three secondary networks in our system located in the cities of Kingston, Newburgh, and Poughkeepsie. Each secondary network has three 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 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 nine network feeders serving the three networks that serve less than 1% of our customers. All three networks experienced nine 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 of 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 remained energized. 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.

Cable Failure Outages

An outage occurred on the Kingston Network in 2022 when a secondary connector within a pull box overheated and caught fire. Conditions necessitated the network feeder circuits to be opened temporarily to make the location safe for repairs. 376 network customers experienced a 53 minute outage. Plans are currently in development to replace similar connectors in the Kingston network that may be subject to this type of failure.

Despite the nine 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

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. The five-phase plan to address this failing infrastructure was completed by the end of 2020 for a total capital investment of approximately $1.74 million. With the infrastructure portion completed, plans are now in development to install new secondary cable on Market Street in Poughkeepsie.

In addition to the Poughkeepsie secondary cable replacements, other upgrades in the Kingston and Newburgh networks have been identified in the 2025-2029 capital plan. The northeastern section of Broadway and the secondary cable crossings between the north side and south side of Broadway in Newburgh have been evaluated for possible infrastructure and cable replacement. Reliability of the Newburgh network and risk of a network outage is being considered before plans for new infrastructure are finalized. Budgeted dollars were determined based on the average cost for secondary network repairs in the prior five years. The largest section of the Kingston network identified for upgrades is along North Front St. Upgrades along this portion of the network will replace collapsed tile ducts and expand small structures that are impractical to safely work in. Additionally, these plans include replacements of secondary cables in poor condition and the previously mentioned secondary connectors from the 2022 outage that are not adequate for this network application.

3.4.4.2. Poughkeepsie Network Primary Feeder PILC Cable Replacement

Following completion of a multi-phase replacement program, there are three lateral branches, or 7,250 feet, remaining of PILC cable on the primary feeders and infrastructure to the Poughkeepsie Secondary Network. As mentioned above, the infrastructure work along Market Street was completed in 2020, and 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 as well. In 2022, work began to replace the 3,300 feet of PILC on these lateral branches with rubber insulated cable. The 2022 and 2023 total capital invest thus far has been $480,000, and the last portion (100 feet) of the Market Street branches under construction are scheduled to be completed by the end of 2024, with a remaining estimated cost of $20,000.

Portions of the PK and PO cables (approximately 1,200 feet) PILC will be replaced in 2027 as part of a larger plan to replace collapsing infrastructure and old secondary cable on Cannon Street. Once the work on Cannon Street is completed approximately 2,650 feet of the PK will still be PILC. Replacement of this portion will be prioritized based on the level of risk. Currently there is the ability to isolate this section should a fault occur, allowing operating flexibility.

3.4.4.3. 14.4 kV Cable System Replacement

Between 2009 and 2022, the KK and KO cables (approximately 9 miles) were reconductored from PILC to a combination of spacer cable, and EPR rubber. The KL cable emanates from the Boulevard Substation and is the primary feed to the Jansen Avenue substation. It is the last of the PILC sub-transmission cable in Kingston (approximately 3 miles). Replacement will be prioritized based on failure rate and risk.

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 retirements identified in the Poughkeepsie 14.4 kV Area Study have been completed for the Poughkeepsie 14.4 kV non-network PILC cables. 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 can be retired and replaced with a single overhead high-capacity circuit. This new overhead circuit will work with the WN cable to feed the Montgomery Street Substation and the Newburgh Network, provided that the WN is reconductored to match the capacity of the new circuit.

The project to build the new circuit and replace the B, F and R cables was divided into five phases. The majority of the new 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. The phases are not being completed in sequential order. New underground infrastructure (Phase 5) 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 as the upgrades to the WN PILC cable that currently runs under the

Newburgh Free Library. Portions of the overhead phases were completed for a capital investment of approximately $196,000 in 2021, $42,000 in 2022, and $1.221 million in 2023. Phase 1 of the new circuit build involving the West Balmville Substation circuit exit will be completed in the first half of 2024. The remaining phases of this project to continue the new circuit construction to the Montgomery St Substation and reconductor the WN circuit have been included in the capital budget for 2025 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 based on failure rates, Central Hudson is reviewing the ability to utilize IMCORP's services 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 five 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.

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 are sections that focus 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 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
	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

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

The table below contains a five year summary of conditions resulting from the inspection process:

Year	Priority Level / Repair Expected		Deficiencies Found (Total)
2019	I	Within 1 week	7
	II	Within 1 year	192
	III	Within 3 years	6,021
	IV	N/A	6,978
2020	I	Within 1 week	3
	II	Within 1 year	169
	III	Within 3 years	5,148
	IV	N/A	7,309
2021	I	Within 1 week	1
	II	Within 1 year	325
	III	Within 3 years	2,780
	IV	N/A	8,114
2022	I	Within 1 week	3
	II	Within 1 year	181
	III	Within 3 years	3,565
	IV	N/A	5,012
2023	I	Within 1 week	22
	II	Within 1 year	281
	III	Within 3 years	9,614
	IV	N/A	7,217

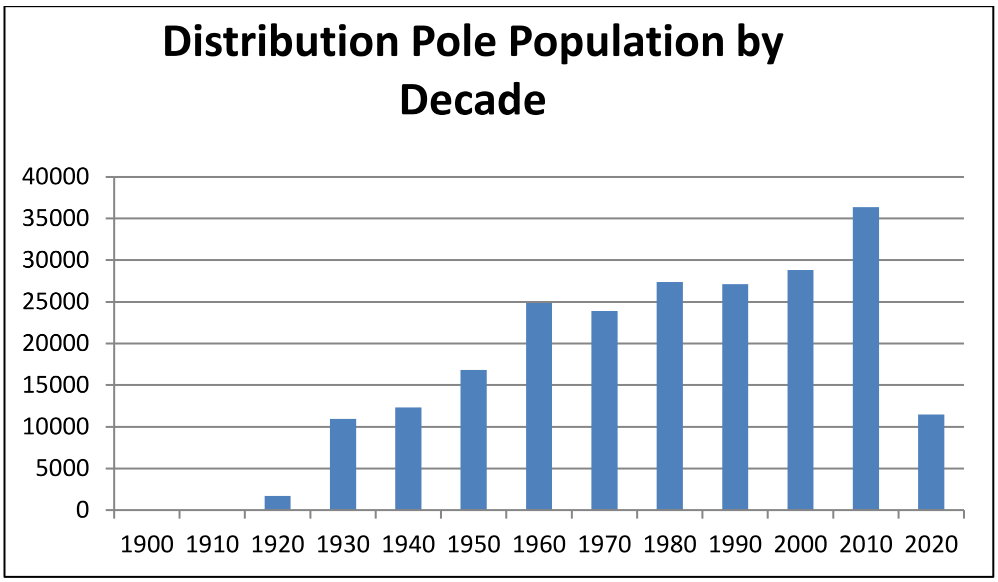
In addition, comprehensive thermal inspections of the three-phase distribution system are completed annually during the summer peak season. Beginning with the 2018/2019 winter season, thermal scanning was expanded to include winter-peaking circuits and spur lines with large numbers of customers. The 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 221,679 distribution poles. With a few exceptions, theses 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 five-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 requiring immediate attention. As a result of this assessment program, Central Hudson replaced 1,336 poles in 2023, and approximately 5,200 poles are scheduled for replacement in 2024. 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 43,727 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 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 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 less.

Porcelain insulator failures averaged approximately 0.67% of total non-storm System SAIFI between 2019 and 2023, compared to 0.81% for porcelain cutout failures over the same period. Central Hudson will continue to inspect these devices as part of the annual inspections 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)

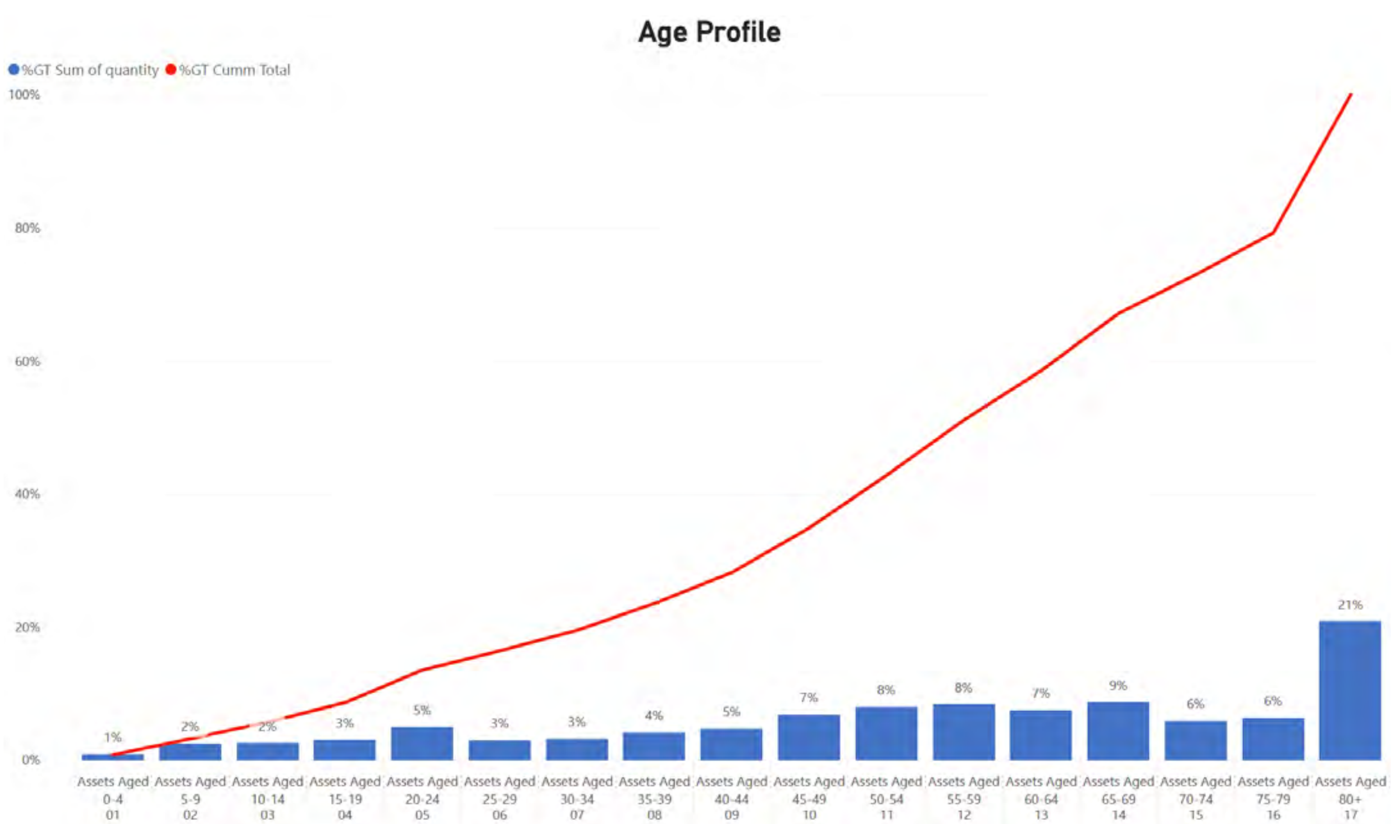
Inventory

The following chart depicts the inventory of wire by voltage class:

Conductor	Pole Miles of Line
34.5 kV Overhead	210
13.2 kV Single Phase	4,523
13.2 kV Multi Phase	2,395
5 kV and Under	20

Age and Condition

Approximately 32% of Central Hudson's distribution overhead conductor is at or beyond its expected life. Over the next ten years it is estimated that



a total of 48% of distribution overhead conductor will be beyond its expected life.

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. These conductors are not only antiquated and prone to failure, but they are frequently undersized for modern operational needs, such as FLISR and CVR. They are also susceptible to burndown during reclosing operations. 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 long 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 anywhere it exists is a sign 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.

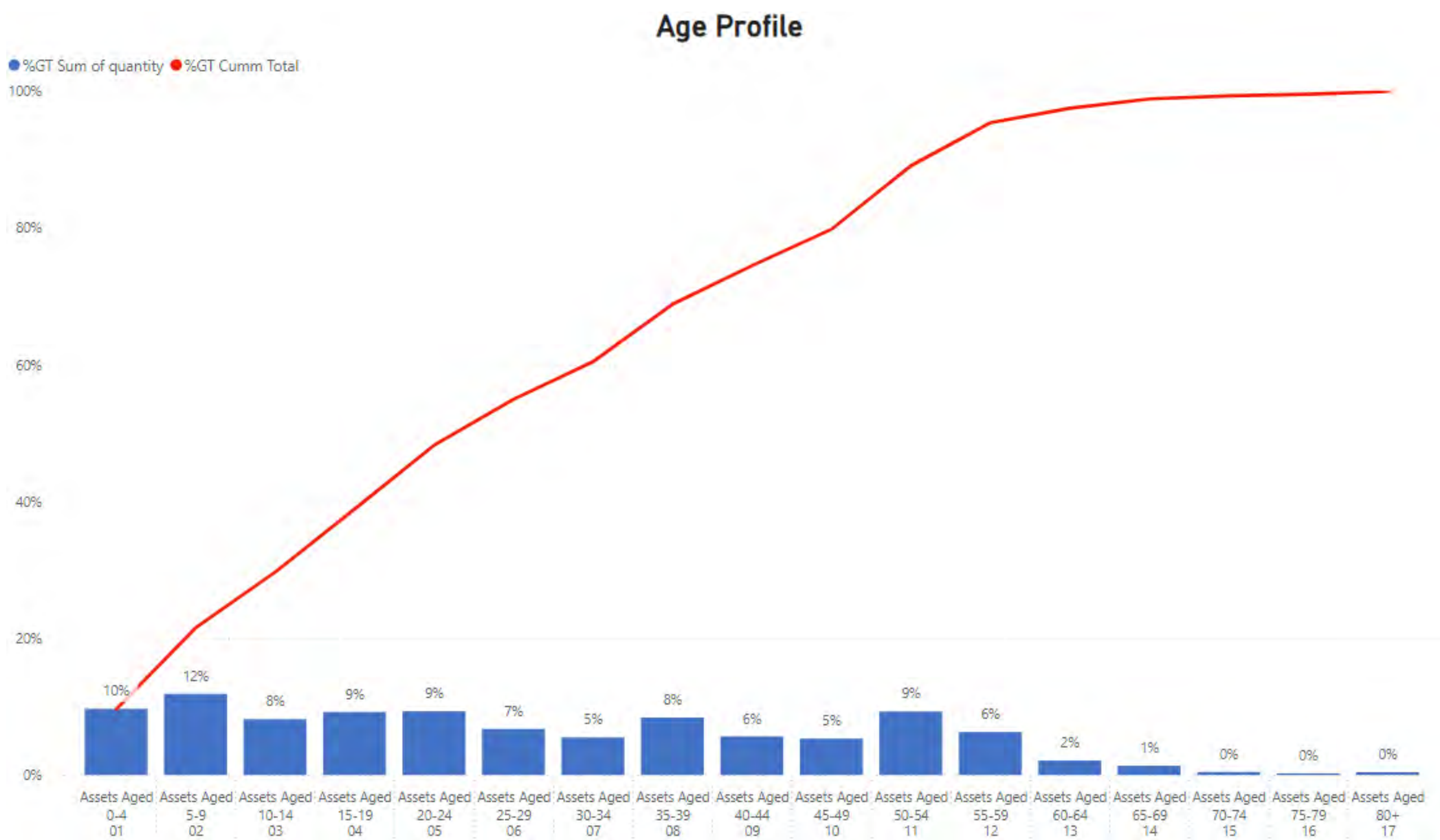
A 5 kV aerial replacement program was created to mitigate the reliability, loading, environmental, and safety concerns associated with this cable. When this type of cable is replaced, the typical practice is to convert the customers over to 13.2 kV voltage class circuitry. This aids in Central Hudson's goal to move away from 5 kV operation to flatten the voltage profile, better enabling Conservation Voltage Reduction (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 85,948 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 regular inspection cycle utilized to assess the condition of our distribution facilities.

3.5.2.6. Voltage Regulators

Inventory
Central Hudson currently has 626 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 DERs.

3.5.2.7. Capacitors (Fixed and Switched)

Inventory
Central Hudson currently has approximately 2,485 distribution class overhead capacitor units installed at 801 locations.

Age and Condition
The current average age of these facilities is approximately 23 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. 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 50,921 distribution cutouts on the primary distribution system.

Age and Condition
The age of the cutouts is not readily available. Porcelain style cutouts are more prone to failure compared to polymer. A program was completed to replace three-phase locations that would impact 500 customers or more in the event of a cutout failure.

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 45,549 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 2,144 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 average age of hydraulic reclosers on the system is 17 years. The average age of electronic reclosers on the system is 6 years. The overall condition of hydraulic reclosers is considered fair, and the condition of electronic reclosers is considered 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 88 individual ScadaMate Switches that operate as 39 teams and 3 sectionalizers. Also, Central Hudson has 6 padmount ALTs. In addition, Central Hudson has configured 152 additional Electronic Reclosers into 73 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 40,947 customers per year from outages over the past five years.

Age and Condition
The maximum age of the ScadaMate switches is approximately 22 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 6 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:

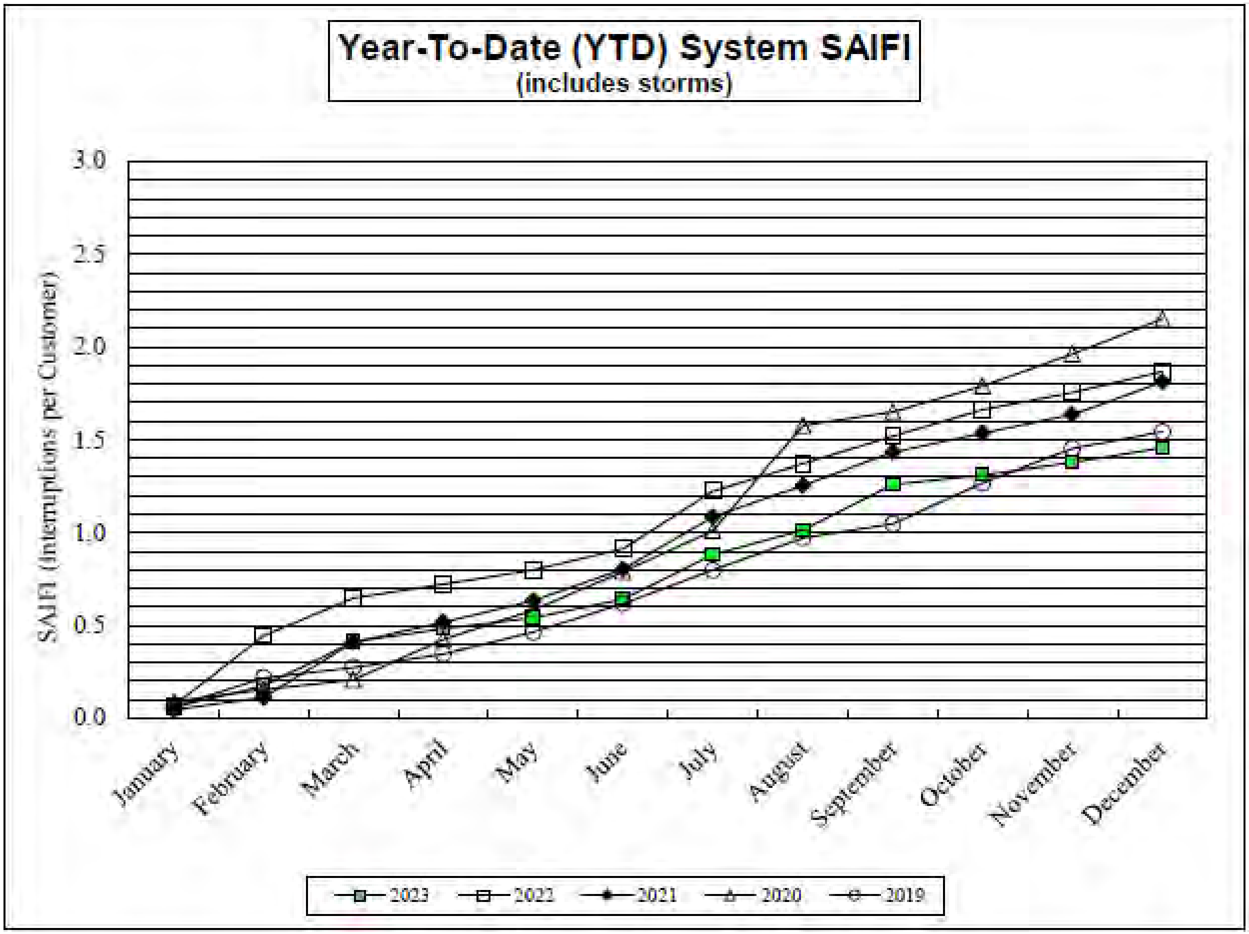
SAIFI = System Average Interruption Frequency Index =

$$\frac{\textit{Total \# of Customers Interrupted}}{\textit{Total \# of Customers Served}}$$

CAIDI = Customer Average Interruption Duration Index =

$$\frac{\textit{Sum of Customer Interruption Duration}}{\textit{Total \# of Customers Interrupted}}$$

The Public Service Commission monitors these indices and can levy fines if SAIFI or CAIDI exceed predetermined thresholds (for 2023, the non-storm PSC SAIFI target was 1.30 and the CAIDI non-storm PSC target was 2.50).



Non-storm system SAIFI averaged 1.263 over the five-year period from 2019 through 2023. The highest SAIFI over this period occurred in 2021 (1.418) and the lowest occurred in 2023 at 1.084. This SAIFI value was 14% below 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 Programs

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 programs are carefully designed to reduce the incidents of power outages due to tree damage while also protecting the natural beauty of the Hudson Valley.

After experiencing significant improvement in tree-related SAIFI as a result of the Routine Trimming Program, which began in its current form in 2011, 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 collecting and reviewing 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 hazard trees.

Distribution Engineering works in conjunction with Line Clearance to identify the worst performing circuits that should be targeted for hazard tree removal. To the extent practical, hazard tree removals are aligned with routine trimming activities such that the greatest number of customers can be prevented from experiencing outages while minimizing setup, travel, and other costs. As of the end of 2023, hazard tree removals have been performed on approximately 175 circuits. On the circuits where hazard trees were removed between the program's inception in 2018 and the end of 2023, analysis indicates a 20% non-storm SAIFI reduction for tree contact outages, on average, compared to three-year historical averages for those circuits.

Engineering analysis will continue to guide the line clearance work in 2024 as Central Hudson executes on its planned trimming cycle, while also accounting for trimming restrictions due to protected bat species.

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 Operations 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.

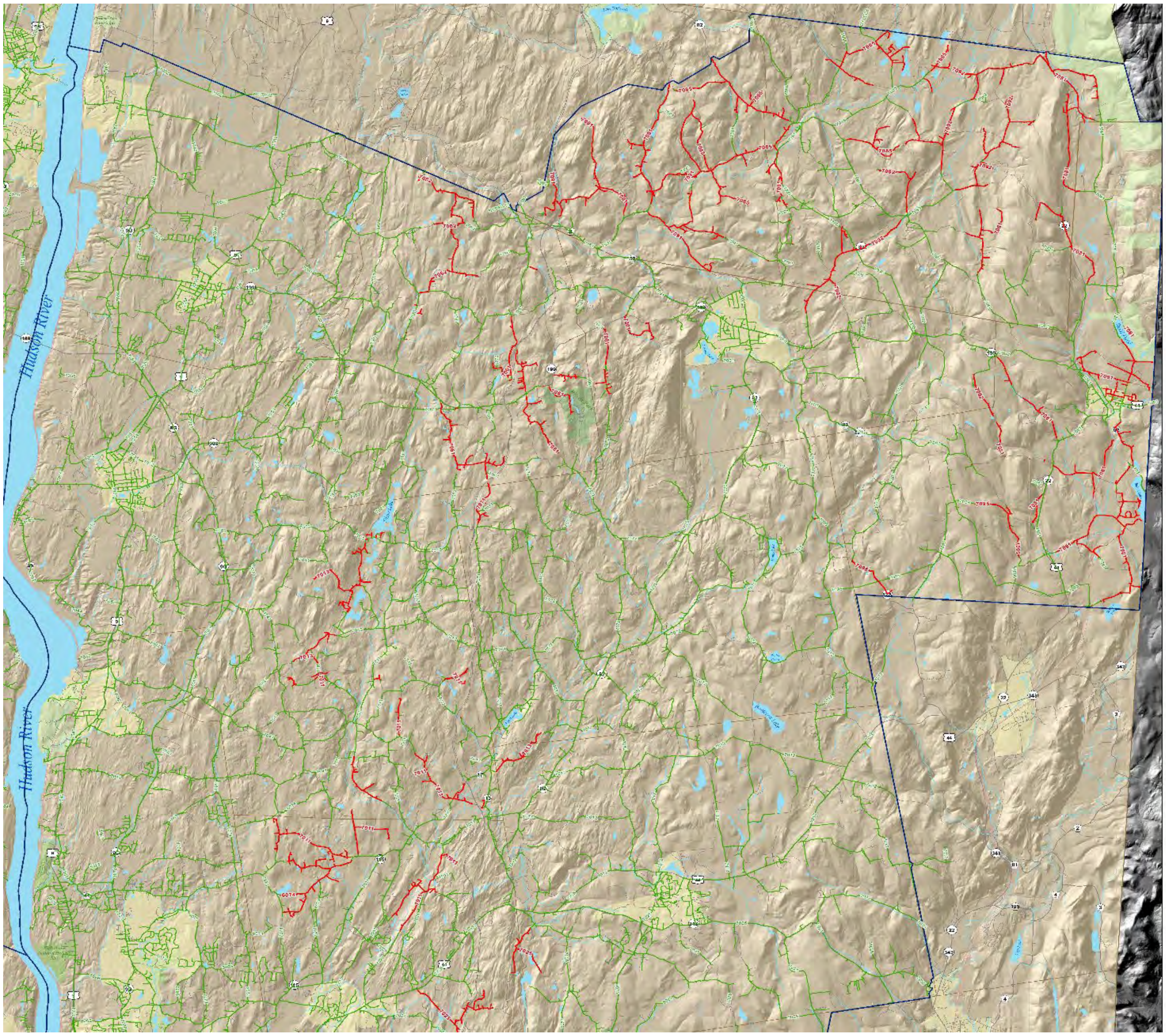
In addition to the 3X Report, the 10X Report was developed in 2008 as a way to identify customers on Central Hudson's system that experience 10 or more outages within a calendar year. The 10X Report provides Central Hudson with an opportunity to address areas that normally would not justify Capital Budget 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

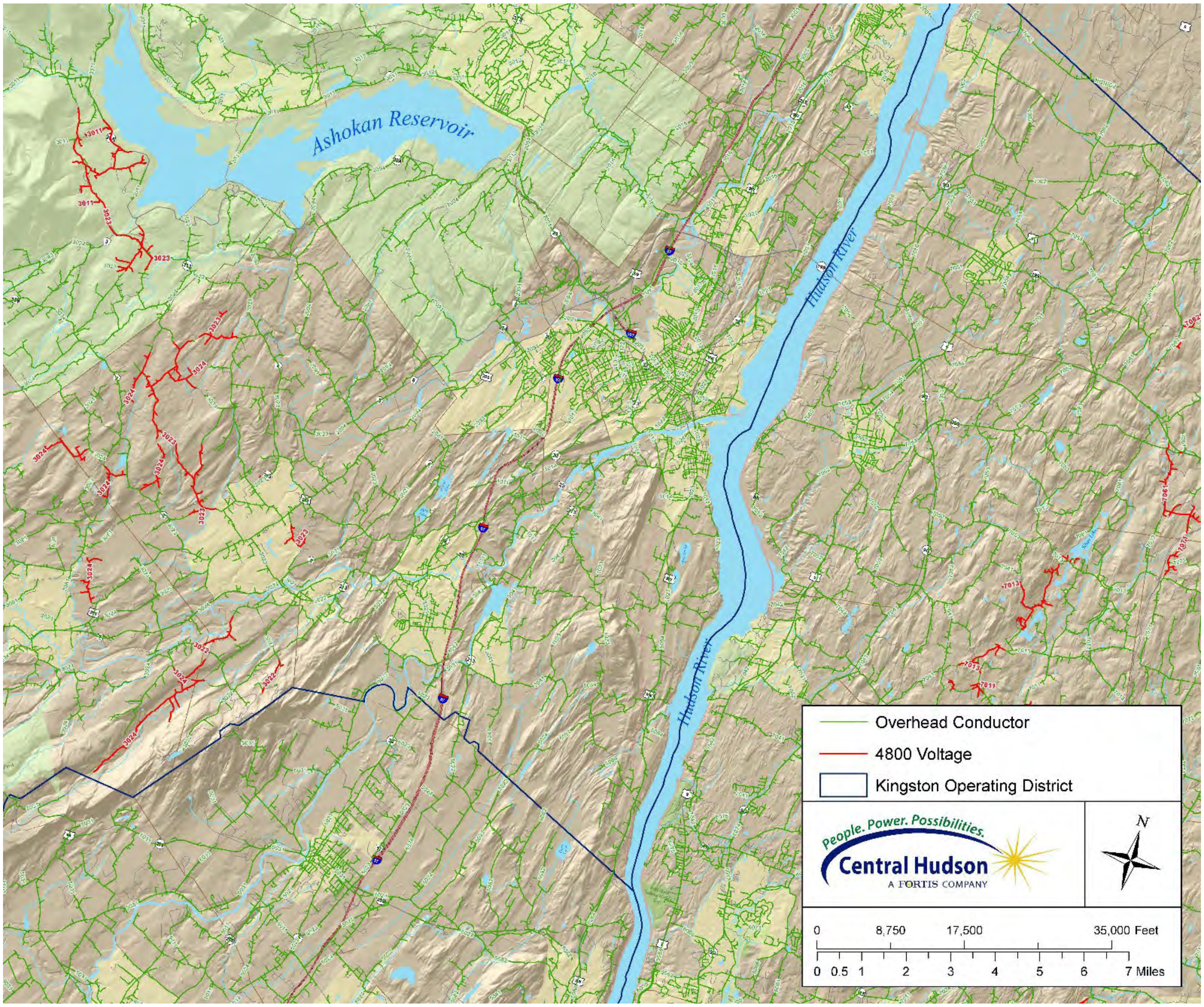
Central Hudson has approximately 230 miles of 4800V delta circuitry remaining on its distribution system. The Company abandoned the practice of installing 4800V circuitry in the 1940s, so much of the infrastructure is aged. In addition, capacity and operational flexibility is limited by the low voltage 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:

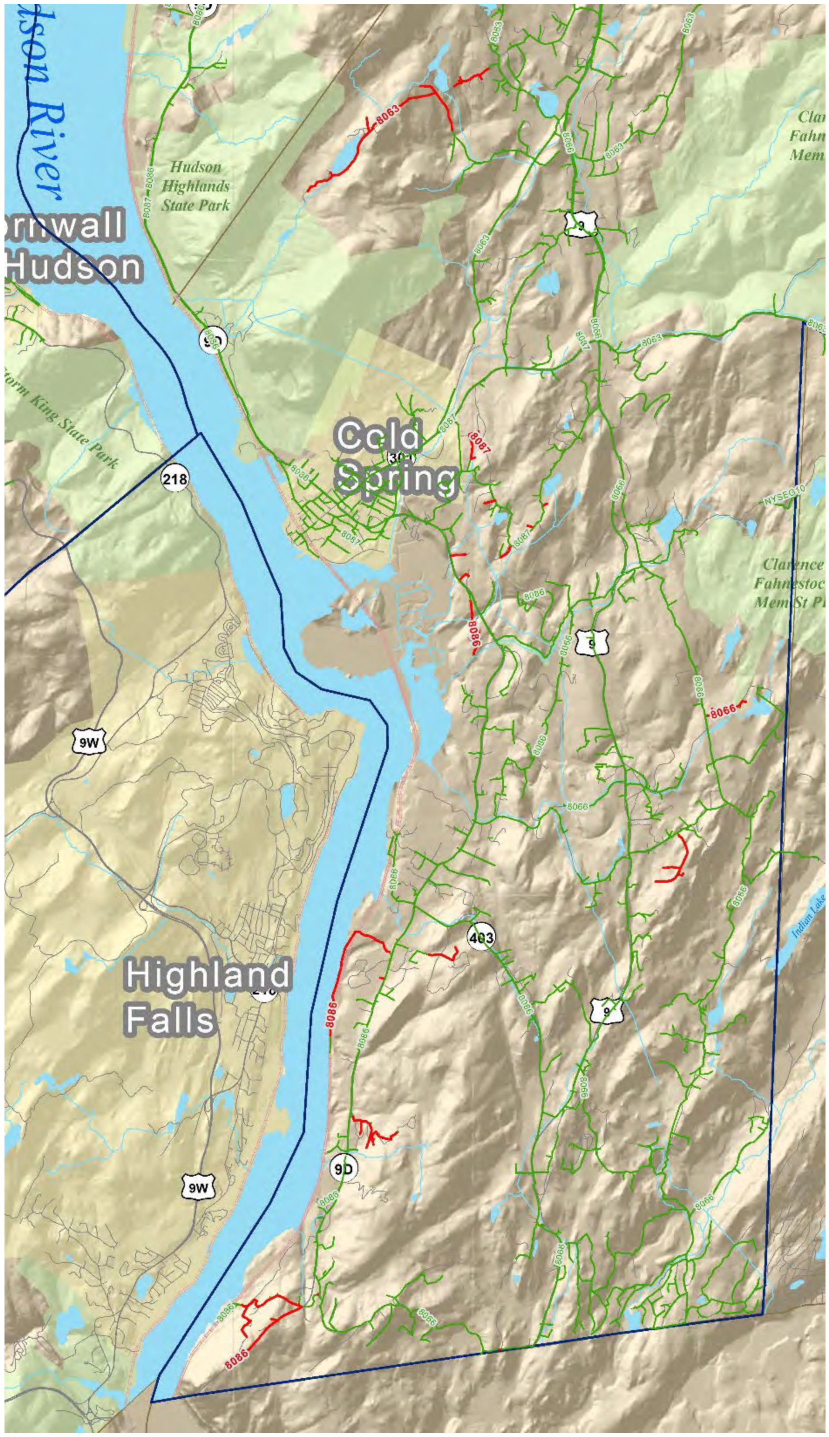
Northern Poughkeepsie District:



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 five-year weighted average SAIFI, and the worst 5% of circuits based on five-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. Resiliency and Storm Hardening

While Central Hudson has historically maintained a core focus on customer reliability, 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. In 2019, in response to the New York State Public Service Commission's Order Instituting Proceeding and to Show Cause issued April 18, 2019 in Case 19-E-0109 ("Storm Order"), Central Hudson filed the Central Hudson Gas & Electric Corporation's Storm Investigation Implementation Plan ("Implementation Plan") addressing 94 recommendations within the Storm Order and subsequently submitted an action plan on July 1, 2019 to address Recommendation 88 detailing future storm hardening measures. This Storm Hardening Plan consisted of both a Vegetation Management component and a Capital Investment component, including storm hardening.

While this plan was not approved, Central Hudson completed a pilot project in 2020 to improve the resiliency (i.e., storm harden) of the Woodstock 3012 circuit against 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 2021 rate agreement, capital funds were included for the storm hardening program. As with the pilot, circuit hardening programs focus on rebuilding the mainline zones of protection that impact large numbers of customers on those circuits that have shown poor historical reliability performance, including Code 1 (major storm) reliability data. To date, storm hardening projects have been completed on nine circuits. For circuits on which storm hardening projects were completed and for which sufficient time has passed to evaluate their effectiveness, there has been an overall 52% reduction in customers interrupted and a 70% reduction in number of outages originating in the respective project areas. Time will be needed following the completion of additional projects to fully realize the resiliency and reliability impacts of this program. The storm hardening program in the five-year capital plan is a continuation of the Company's plan included within the previous rate filing, and includes funding to address five additional circuits, with projects developed to bring the circuit mainlines up to current design and construction standards and to complete any danger tree removal work that is required. In addition, as part of the storm hardening program, a strategic undergrounding project is included in the forecast. This project will complete the undergrounding of approximately 1.5 miles of mainline that is currently off-road, cross-lot circuitry prone to outages where traditional solutions such as overhead line relocations are not viable.

In addition to this program, in response to Assembly Bill A8763, Central Hudson completed a Climate Change Vulnerability Study (CCVS) in September 2023 to evaluate future climate projections and evaluate the Company's physical infrastructure, design specifications, and operating procedures based on those projections to determine the areas of greatest vulnerability. Results indicated that flooding/extreme precipitation, extreme wind, and extreme heat pose the greatest risks to the Company. Central Hudson also completed a Climate Change Resilience Plan (CCRP) in November 2023 to identify and recommend strategies to mitigate the vulnerabilities identified in the CCVS. The CCRP proposed several projects and programs as well as process-based measures at the distribution, substation, and transmission levels to mitigate climate risks. The CCRP is currently undergoing review by the PSC for modifications or approval.

In addition to the new initiatives above, Central Hudson has ongoing programs that fall under the category of storm hardening. The following 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) Maintenance
(4) Emergency Response & Repair
(5) 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 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.

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 types of 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:

- **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 112 ALT teams and has seen a cumulative non-storm SAIFI improvement of 1.807 and a SAIFI improvement of 2.287 including storms through December 2023. 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 Operations 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 61 times during major and minor storms, beginning with the Twin Peaks storm in February 2010.

Central Hudson completed construction of a natural gas-fired turbine along with battery storage in 2023. The Four Corners Microgrid project was 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 included the installation of a microgrid to enhance reliability in the Four Corners Area of the Central Hudson service territory. The 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 microgrid includes optionality to use the BESS for other services (i.e., demand reduction, frequency regulation) during parallel operation.

Central Hudson has proposed four additional microgrid locations as part of its Climate Change Resilience Plan filing, which is currently undergoing review by the Public Service Commission as described above. If funding is granted, two locations (Cragsmoor and Spring Glen) would have planned in-service dates between 2030 and 2034 and the remaining two (Lanesville and Millerton) would have planned in-service dates between 2035 and 2044.

3.6.3. 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. In addition, Central Hudson maintains a hazard tree removal program with circuits prioritized by historical SAIFI per mile.

3.6.4. 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.

3.6.5. Weather Prediction Tools

Central Hudson monitors and maintains 24 weather stations to provide detailed weather information across the service territory. Data from the weather stations is collected by Central Hudson and is displayed on a vendor's proprietary website. The same weather service vendor produces a twice-daily forecast that correlates predicted weather conditions with their potential impact on Central Hudson's service territory. To enhance our outage prediction capabilities, Central Hudson remains a committed partner with academia. Working with the University of Albany, in 2017 an outage prediction model was developed based on continuously updated inputs from the National Weather Service. Central Hudson continues to work with the University of Albany on multiple weather-related projects, including one that will include an updated outage prediction model.

3.6.6. Future Plans

Based on recommendations from a recently completed vegetation management consultant study, adaptations have been made to the circuit prioritization of Central Hudson's routine trimming program and hazard tree program to maximize SAIFI reduction. Engineering and Line Clearance have prioritized the routine trimming scheduled for 2024 to shift resources to the most impactful areas on SAIFI to the beginning of the year. They have also identified circuits for hazard tree removals in 2024 and prioritized them under the new methodology. In addition, Central Hudson is participating in a thermographic satellite imagery pilot project through EPRI to evaluate use of this technology to more efficiently characterize tree health and determine proximity of trees to distribution lines. This pilot project is a long-term initiative that is in the R&D phase; it will continue to be evaluated to determine its effectiveness.

Central Hudson has set a goal to configure at least 10 additional automatic load transfer teams in 2024 utilizing existing installed equipment ("Sensus ALTs"), bringing the total such teams to 49 which protect over 28,000 customers from outages.

As previously described, Central Hudson completed a Climate Change Vulnerability Study and a Climate Change Resilience Plan in 2023 pursuant to New York State Public Service Law §66(29) and Public Service Commission Case 22-E-0222. The Resilience Plan is currently undergoing review by DPS Staff and Central Hudson will begin to implement any approved mitigation measures beginning in 2025.

3.6.7. 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 and climate change. 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 has been implementing this centralized Grid Modernization Program over the past nine 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 DERs. Approximately 1,600 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-A Integrated Planning, and III-C Grid Operations, filed on June 30, 2023 for additional information.

4.2. Current Status (2024-2029)

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 have been completed in the Poughkeepsie area (Phase I and II).
- A portion of the Catskill DA devices have already been installed in 2022 and 2023. The remainder will be installed in 2024.
- A portion of the Kingston DA devices have already been installed in 2022 and 2023 (Phase I and II). The remainder will be installed in 2024 (Phase I and II).

Distribution Management System

- The DMS Factory Acceptance Testing was completed in Q2 2021.
- The DMS Site Acceptance Testing was completed in Q4 2021.
- The DMS 'Go-Live' milestone will be reached in Q3 2024.
- The final commissioning of the DMS system is complete for the Fishkill and Poughkeepsie Operating Districts. Substantial completion of the Newburgh, Catskill, and Kingston districts are slated for 2024, 2025, and 2026 respectively.
- Construction of the Distribution System Operations Control Center is on schedule to be completed in 2024.

Network Communications Strategy

- The Tier 2 network has been completed in the Fishkill district, but future additions may include service for new automation devices or gateways for improved performance.
- A majority of the Tier 2 network has been completed in the Newburgh district except for installing TropOS 1420 radios and MicrOS411 radios at Distribution Automation Devices.

- A majority of the Poughkeepsie Tier 2 network was completed in 2022, but gateways or radios at new automation devices must be added.
- 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 2025. The scheduled in-service date is 2026.
- Construction for the new Primary Control Center for Transmission and Distribution System Operations started in 2022. Once complete, the Distribution System Operations organization is expected to be fully staffed. The facility is planned to be fully operational in Q1 2025.

DMS

- The Distribution Management System is scheduled to "go-live" on the east side of the river (Poughkeepsie and Fishkill Districts) in July 2024. Distribution System Operations Plans have been finalized to fully transfer operating authority to Distribution Operators at this time. For the west side of the river, all DA devices in Newburgh have been installed with installation of the remaining Catskill and Kingston DA devices expected to be completed by the end of 2024. West side "go-live" is expected to follow in 2025.

5. Long Term System Load Forecast[5]

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 utilizes 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

[5] Load forecasts within this section are based on analysis completed in 2023. Forecasts are currently completed to coincide with the development of Central Hudson's DSIP filing and a new Avoided T&D Cost Study. The updated analysis was completed in accordance with Central Hudson's filing of the most recent DSIP in June 2023.

forecast of Central Hudson's distribution substations using hourly load data from 2018 through 2022.

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
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 2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Northwest Load Group																				
Coxsackie	13.2 kV	16.40		4.30%	12.0	12.5	13.1	13.6	14.2	14.8	15.4	16.1	16.8	17.5	18.3	19.1	19.9	20.7	21.6	22.6
Freehold	13.2 kV	15.78		1.80%	10.0	10.2	10.4	10.6	10.8	11.0	11.2	11.4	11.6	11.8	12.0	12.2	12.4	12.7	12.9	13.1
Hunter	13.2 kV	15.90	F	-3.20%	6.0	5.8	5.6	5.4	5.3	5.1	4.9	4.8	4.6	4.5	4.3	4.2	4.1	3.9	3.8	3.7
Hunter #2	13.2 kV	15.90		-3.20%	4.7	4.5	4.4	4.3	4.1	4.0	3.9	3.7	3.6	3.5	3.4	3.3	3.2	3.1	3.0	2.9
Lawrenceville	34.5 kV	15.86		-0.20%	11.3	11.3	11.2	11.2	11.2	11.2	11.1	11.1	11.1	11.1	11.1	11.0	11.0	11.0	11.0	10.9
New Baltimore	13.2 kV	25.80		5.40%	15.2	16.1	16.9	17.8	18.8	19.8	20.9	22.0	23.2	24.4	25.8	27.2	28.6	30.2	31.8	33.5
North Catskill	13.2 kV	35.12	F	1.00%	24.3	24.5	24.8	25.0	25.3	25.5	25.8	26.0	26.3	26.6	26.8	27.1	27.4	27.6	27.9	28.2
South Cairo	13.2 kV	19.90		2.50%	12.3	12.6	12.9	13.3	13.6	13.9	14.3	14.6	15.0	15.4	15.8	16.1	16.6	17.0	17.4	17.8
Vinegar Hill	34.5 kV	18.80		-0.30%	9.7	9.7	9.7	9.6	9.6	9.6	9.6	9.5	9.5	9.5	9.4	9.4	9.4	9.4	9.3	9.3
Westerlo	13.2kV	32.16		0.50%	8.5	8.5	8.6	8.6	8.7	8.7	8.7	8.8	8.8	8.9	8.9	9.0	9.0	9.1	9.1	9.1
Kingston-Saugerties Load Group																				
Boulevard	14.4 kV	35.00	F	0.20%	18.0	18.0	18.1	18.1	18.1	18.2	18.2	18.2	18.3	18.3	18.4	18.4	18.4	18.5	18.5	18.5
Converse Street	4 kV	7.07	F	0.20%	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
East Kingston	13.2 kV	47.97	F	1.10%	15.5	15.7	15.8	16.0	16.2	16.4	16.6	16.7	16.9	17.1	17.3	17.5	17.7	17.9	18.1	18.3
Hurley Avenue	13.2 kV	23.10	F	-0.50%	17.3	17.2	17.1	17.0	16.9	16.9	16.8	16.7	16.6	16.5	16.4	16.4	16.3	16.2	16.1	16.0
Jansen Avenue	13.2 kV	11.00	F	-2.20%	4.6	4.5	4.4	4.3	4.2	4.1	4.0	3.9	3.9	3.8	3.7	3.6	3.5	3.4	3.4	3.3
Lincoln Park	14.4 kV	84.00	F	-2.20%	34.8	34.0	33.3	32.6	31.8	31.1	30.5	29.8	29.1	28.5	27.9	27.2	26.6	26.1	25.5	24.9
Saugerties	13.2 kV	54.11	F	0.50%	20.8	20.9	21.0	21.1	21.2	21.3	21.4	21.5	21.6	21.8	21.9	22.0	22.1	22.2	22.3	22.4
South Wall Street	4 kV	5.77		0.20%	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.1	2.1	2.1
Woodstock	13.2 kV	23.90	F	1.00%	18.4	18.6	18.8	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
Ellenville Load Group																				
Clinton Avenue	4 kV	7.69		3.40%	1.6	1.6	1.7	1.7	1.8	1.9	1.9	2.0	2.1	2.1	2.2	2.3	2.3	2.4	2.5	2.6
Greenfield Road	13.2 kV	15.38		-4.20%	8.3	7.9	7.6	7.3	6.9	6.7	6.4	6.1	5.9	5.6	5.4	5.1	4.9	4.7	4.5	4.3
Grimley Road	13.2 kV	5.80	F	4.10%	2.4	2.5	2.6	2.7	2.8	2.9	3.1	3.2	3.3	3.4	3.6	3.7	3.9	4.0	4.2	4.4
Grimley Road #2		6.50		4.10%	4.3	4.5	4.7	4.9	5.0	5.3	5.5	5.7	5.9	6.2	6.4	6.7	7.0	7.2	7.5	7.9
High Falls	13.2 kV	34.50	F	0.20%	17.8	17.9	17.9	18.0	18.0	18.0	18.1	18.1	18.1	18.2	18.2	18.2	18.3	18.3	18.4	18.4
Honk Falls	13.2 kV	18.20		0.60%	6.7	6.7	6.8	6.8	6.9	6.9	6.9	7.0	7.0	7.1	7.1	7.2	7.2	7.2	7.3	7.3
Kerhonkson	13.2 kV	35.55	F	2.20%	10.7	11.0	11.2	11.5	11.7	12.0	12.2	12.5	12.8	13.1	13.4	13.6	13.9	14.3	14.6	14.9
Neversink	13.2 kV	4.92		-2.00%	3.9	3.8	3.7	3.6	3.6	3.5	3.4	3.3	3.3	3.2	3.1	3.1	3.0	3.0	2.9	2.8
Neversink	4 kV	2.46		-2.00%	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Sturgeon Pool	13.2 kV	29.70		0.70%	2.5	2.6	2.6	2.6	2.6	2.6	2.6	2.7	2.7	2.7	2.7	2.7	2.8	2.8	2.8	2.8
Modena Load Group																				
Galeville	13.2 kV	28.70	F	-0.70%	11.3	11.2	11.1	11.0	10.9	10.9	10.8	10.7	10.6	10.6	10.5	10.4	10.3	10.3	10.2	10.1
Highland	13.2 kV	32.93	F	-0.40%	19.1	19.1	19.0	18.9	18.8	18.8	18.7	18.6	18.5	18.5	18.4	18.3	18.2	18.2	18.1	18.0
Modena	13.2 kV	21.10	F	-0.50%	14.6	14.6	14.5	14.4	14.3	14.3	14.2	14.1	14.1	14.0	13.9	13.8	13.8	13.7	13.6	13.6
Ohioville	13.2 kV	29.68	F	-1.40%	22.8	22.5	22.2	21.8	21.5	21.2	20.9	20.6	20.4	20.1	19.8	19.5	19.2	19.0	18.7	18.4
Newburgh Load Group																				
Bethlehem Road	13.2 kV	47.80	F	-0.20%	37.1	37.0	36.9	36.9	36.8	36.7	36.6	36.6	36.5	36.4	36.4	36.3	36.2	36.1	36.1	36.0
Coldenham	13.2 kV	47.80	F	2.10%	22.9	23.4	23.9	24.4	24.9	25.4	26.0	26.5	27.1	27.6	28.2	28.8	29.4	30.0	30.7	31.3
East Walden	13.2 kV	26.17		-0.90%	14.8	14.7	14.5	14.4	14.3	14.1	14.0	13.9	13.8	13.6	13.5	13.4	13.3	13.2	13.0	12.9
Marlboro	13.2 kV	30.91	F	-0.50%	20.4	20.3	20.2	20.1	20.0	19.9	19.8	19.7	19.6	19.5	19.4	19.3	19.2	19.2	19.1	19.0
Maybrook	13.2 kV	20.90	F	-1.00%	19.6	19.4	19.2	19.0	18.9	18.7	18.5	18.3	18.1	17.9	17.8	17.6	17.4	17.2	17.1	16.9
Montgomery	13.2 kV	24.00	F	-2.30%	9.8	9.5	9.3	9.1	8.9	8.7	8.5	8.3	8.1	7.9	7.7	7.6	7.4	7.2	7.1	6.9
Montgomery Street	13.2 kV	15.40	F	-1.10%	4.3	4.3	4.2	4.2	4.1	4.1	4.0	4.0	3.9	3.9	3.9	3.8	3.8	3.7	3.7	3.7
Montgomery Street	4 kV	9.06	F	-1.10%	4.7	4.7	4.6	4.6	4.5	4.5	4.4	4.4	4.3	4.3	4.2	4.2	4.2	4.1	4.1	4.0
Union Avenue	13.2 kV	94.48	F	1.40%	56.3	57.1	57.9	58.7	59.5	60.3	61.2	62.0	62.9	63.8	64.7	65.6	66.5	67.4	68.4	69.3
West Balmville	14.4 kV	47.80	F	-1.10%	34.3	34.0	33.6	33.2	32.8	32.5	32.1	31.8	31.4	31.1	30.7	30.4	30.1	29.7	29.4	29.1

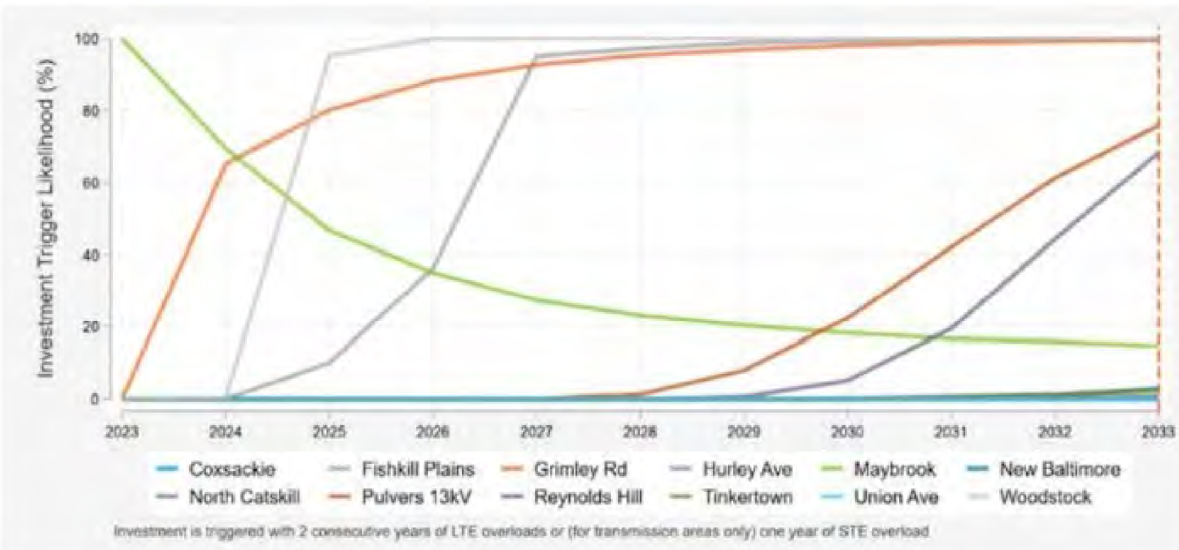
Substation	Type	MVA Rating		Growth Rate	MVA 2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Northeastern Dutchess Load																				
Ancram	13.2 kV	4.65		-0.70%	1.5	1.5	1.5	1.5	1.5	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.3
East Park	13.2 kV	24.20		-0.20%	12.6	12.5	12.5	12.5	12.5	12.4	12.4	12.4	12.4	12.4	12.3	12.3	12.3	12.3	12.2	12.2
Hibernia	13.2 kV	17.84		1.70%	13.0	13.2	13.5	13.7	13.9	14.2	14.4	14.6	14.9	15.1	15.4	15.7	15.9	16.2	16.5	16.8
Milan	13.2 kV	25.86		0.90%	10.3	10.3	10.4	10.5	10.6	10.7	10.8	10.9	11.0	11.1	11.2	11.3	11.4	11.5	11.6	11.7
Millerton	13.2 kV	8.30		-2.30%	4.7	4.6	4.5	4.4	4.3	4.2	4.1	4.0	3.9	3.8	3.7	3.7	3.6	3.5	3.4	3.3
Pulvers Corners	13.2 kV	5.77		2.40%	5.3	5.4	5.6	5.7	5.8	5.9	6.1	6.2	6.4	6.5	6.7	6.8	7.0	7.2	7.4	7.5
Pulvers Corners	34.5 kV	17.21		-0.70%	2.8	2.8	2.7	2.7	2.7	2.7	2.7	2.6	2.6	2.6	2.6	2.6	2.5	2.5	2.5	2.5
Rhinebeck	13.2 kV	47.80	F	-2.60%	26.5	25.8	25.1	24.5	23.8	23.2	22.6	22.0	21.4	20.9	20.3	19.8	19.3	18.8	18.3	17.8
Smithfield	13.2 kV	7.08		1.80%	2.2	2.2	2.3	2.3	2.4	2.4	2.5	2.5	2.5	2.6	2.6	2.7	2.7	2.8	2.8	2.9
Staatsburgh	13.2 kV	26.50		2.30%	8.6	8.8	9.0	9.2	9.4	9.6	9.8	10.0	10.3	10.5	10.7	11.0	11.2	11.5	11.8	12.0
Stanfordville	13.2 kV	17.92		7.80%	5.0	5.4	5.9	6.3	6.8	7.3	7.9	8.5	9.2	9.9	10.7	11.5	12.4	13.4	14.4	15.6
Tinkertown	13.2 kV	19.13	F	0.10%	13.3	13.3	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.5	13.5	13.5	13.5	13.5	13.5
Poughkeepsie Load Area																				
Inwood Avenue	13.2 kV	47.80	F	2.40%	27.6	28.3	29.0	29.7	30.4	31.1	31.8	32.6	33.4	34.2	35.0	35.8	36.7	37.6	38.5	39.4
Manchester	14.4 kV	47.80	F	-3.50%	32.6	31.5	30.4	29.3	28.3	27.3	26.3	25.4	24.5	23.7	22.8	22.0	21.3	20.5	19.8	19.1
Reynolds Hill	14.4 kV	47.80	F	1.70%	39.1	39.8	40.5	41.2	41.9	42.6	43.3	44.0	44.8	45.5	46.3	47.1	47.9	48.7	49.5	50.4
Spackenkill	13.2 kV	47.80	F	-0.50%	29.6	29.4	29.3	29.1	29.0	28.8	28.7	28.5	28.4	28.3	28.1	28.0	27.8	27.7	27.6	27.4
Todd Hill	13.2 kV	47.80	F	-0.40%	23.0	22.9	22.9	22.8	22.7	22.6	22.5	22.4	22.3	22.2	22.1	22.0	22.0	21.9	21.8	21.7
Fishkill Load Group																				
Fishkill Plains	13.2 kV	47.80	F	1.60%	38.6	39.2	39.9	40.5	41.1	41.8	42.5	43.1	43.8	44.5	45.2	46.0	46.7	47.5	48.2	49.0
Forgebrook	14.4 kV	47.43	F	0.70%	26.5	26.7	26.8	27.0	27.2	27.4	27.6	27.8	28.0	28.2	28.4	28.6	28.8	29.0	29.2	29.4
Knapps Corners	14.4 kV	47.80	F	-1.70%	17.9	17.6	17.3	17.0	16.8	16.5	16.2	15.9	15.6	15.4	15.1	14.9	14.6	14.4	14.1	13.9
Merritt Park	13.2 kV	51.15	F	-1.10%	29.7	29.4	29.1	28.8	28.4	28.1	27.8	27.5	27.2	26.9	26.6	26.3	26.0	25.7	25.5	25.2
Myers Corners	13.2 kV	35.12	F	-3.00%	18.0	17.5	16.9	16.4	15.9	15.5	15.0	14.6	14.1	13.7	13.3	12.9	12.5	12.1	11.8	11.4
North Chelsea	13.2 kV	48.27	F	-3.40%	16.5	15.9	15.4	14.9	14.3	13.9	13.4	12.9	12.5	12.1	11.7	11.3	10.9	10.5	10.2	9.8
Sand Dock	13.2 kV	8.00		-4.30%	5.8	5.5	5.3	5.1	4.9	4.6	4.4	4.3	4.1	3.9	3.7	3.6	3.4	3.3	3.1	3.0
Shenandoah	13.2 kV	18.00		-1.80%	12.0	11.8	11.5	11.3	11.1	10.9	10.7	10.5	10.4	10.2	10.0	9.8	9.6	9.5	9.3	9.1
Tioronda	13.2 kV	25.74		-0.70%	13.9	13.8	13.7	13.6	13.5	13.4	13.3	13.2	13.1	13.0	13.0	12.9	12.8	12.7	12.6	12.5
		TOTAL:			1026.5															

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 of the *2023 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 three substations (Woodstock, Reynolds Hill, and Grimley Road) to require an upgrade due to load growth at the end of the 10-year planning horizon.

Probability of Growth Related Substation Infrastructure Upgrade



The Woodstock Substation has been slated for a rebuild due to infrastructure needs and the Reynolds Hill area is currently being reviewed and load will likely be balanced utilizing available capacity at Inwood Avenue Substation. Grimley Road was identified in the Avoided T&D Cost Study as an area of concern however, further review determined the ability to apply a higher station rating based on existing configuration and the non-automatic bus tie upon loss of a transformer, thus eliminating the need for infrastructure upgrades. Central Hudson has infrastructure related upgrades in the Fishkill Plains, Maybrook and Pulvers Corners 13 kV Substations, that will increase load serving capability as part of these capital projects.

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 with a version of the Demand Side Analytics' probabilistic forecasting tool that is using static data and is developing an on-line version of the tool with live feeds that is expected to be completed in September 2024 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 A Integrated Planning and Advanced Forecasting, filed on June 30, 2023 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

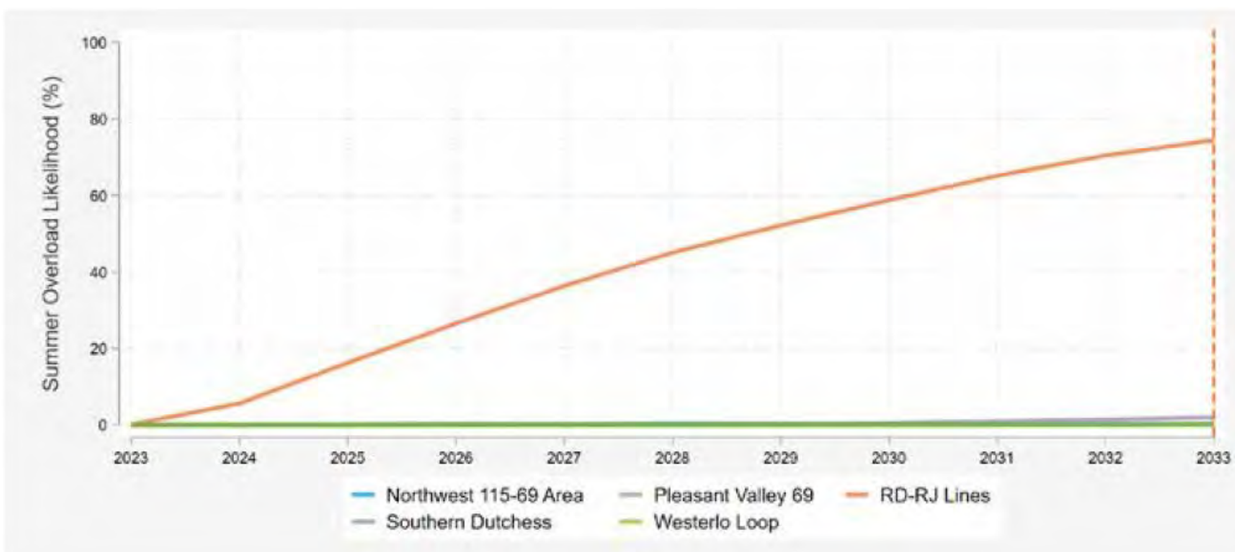
During 2023, Central Hudson's consultant, Demand Side Analytics, performed a probabilistic forecast of Central Hudson's transmission areas using hourly load data from 2018 through 2022. Updated analyses typically are completed every two years to coincide with the development of Central Hudson's DSIP filing and new Avoided T & D Cost Study. The updated analysis was originally planned for completion by June of 2022. Due the deferral of the DSIP filing, the updated analysis and new Avoided T & D Cost Study was completed by June 2023. 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 charts, these analyses determined a potential need for two transmission areas: RD-RJ Lines and Westerlo Loop.

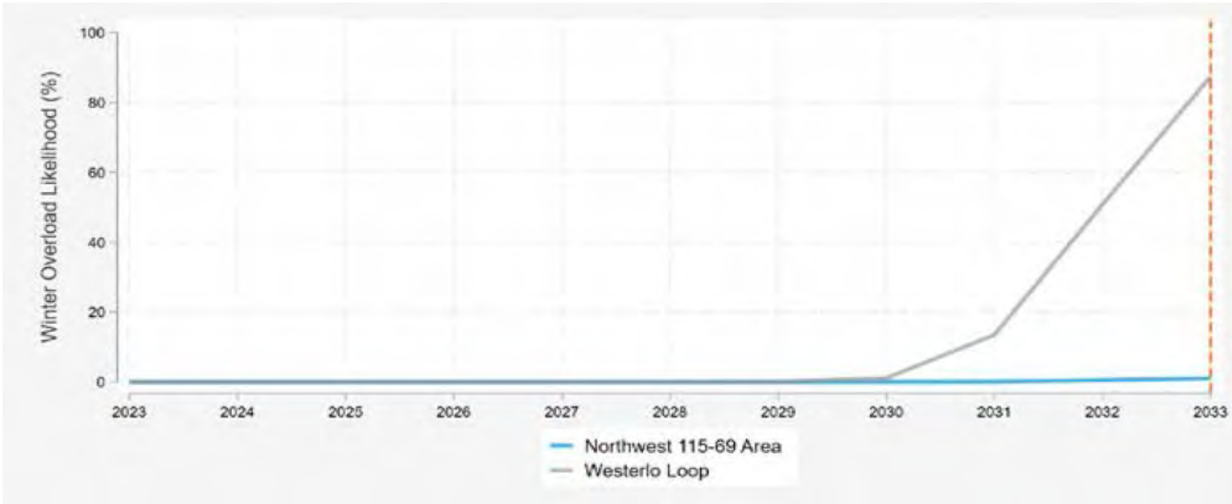
The Electric Transmission Planning group is further evaluating the need for RD-RJ infrastructure upgrades, based on an adjustment to weather normalization values identified after the 2023 DSIP filing.

The Westerlo Loop is not anticipated to exceed its winter rating until after 2030. Central Hudson currently has an active demand response program within the 115kV-69kV Northwest Area. It is recommended for this program to continue as new resources sited within this area have the potential to support load reductions. The area will be re-evaluated periodically in the future.

<u>Probability of Growth Related Transmission Area Infrastructure Upgrade: Summer</u>



<u>Probability of Growth Related Transmission Area Infrastructure Upgrade: Winter</u>



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.

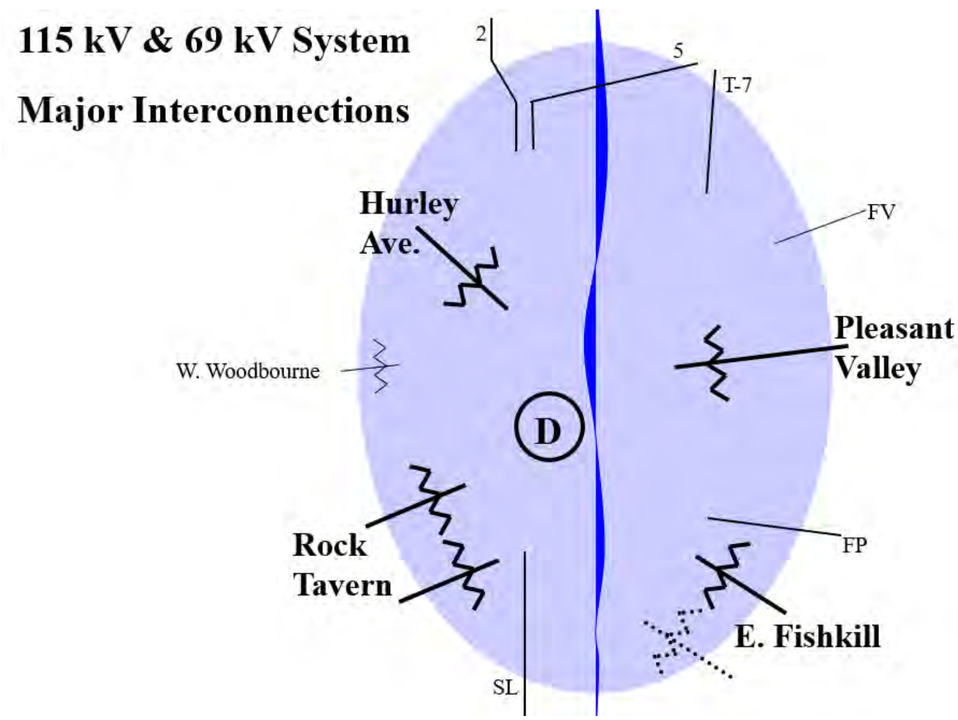
6.3.1. 115/69 kV Transmission Network

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:



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
2023	September 7 @ 1800	1046
2022	July 21 @1900	1109
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

The existing system zero Danskammer LSC (i.e., the LSC with no Danskammer generation) is limited by the 115 kV HF line conductor following the loss of the 115 kV EF line at a system load of approximately 1495 MW.

6.3.1.2. Summary of Recommendations

No upgrades are necessary at this time.

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 (the jointly owned ‘2’ line[6] and ‘5’ line[7]) 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, proposing to interconnect to the ‘2’ and ‘8’ lines, has the potential to increase ‘2’ line flows; 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 has also reconfigured the North Catskill T-7 line terminal to be designated the ‘5’ line and rerouted to the new NY Transco Churchtown Substation; the T-7 is now National Grid’s Blue Stores to Milan with the ‘4’ line connecting Blue Stores to Churchtown.

  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 station is located to the north of the eastern rim of the Ashokan Reservoir serving customers within the western boarder of Central Hudson’s service territory in the Kingston District. The only transmission supply to the Woodstock area is the 69 kV ‘SR’ line. Due to the amount of load served from Woodstock (2023 coincident peak = 15.6 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

[6] National Grid Feura Bush – North Catskill is jointly owned by National Grid and Central Hudson.
[7] NY Transco Churchtown – North Catskill is jointly owned by National Grid, Central Hudson, and NY Transco.

significant additional Northwest 115/69 kV area load. An Article VII filing was submitted to the PSC in 2017 for the rebuild of the lines. The line rebuilds commenced in 2023 and are scheduled to be completed in June 2026.

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 generator[8].

[8] Due to the DEC Peaker Rule (contained in DEC 227-3) the South Cairo Combustion Turbine (CT) was retired during March 2024 and the Coxsackie CT is scheduled for retirement during December 2025.

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
2023	July 28 @ 2000	56.4	-10.5	57.3
2022	August 8 @ 1900	58.9	-8.1	59.5
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

Year	Date of Winter Peak	MW	MVAr	MVA
2023-24	February 3 @ 1900	61.8	-9.3	62.5
2022-23	January 15 @1800	60.4	-7.6	60.9
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

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 the Coxsackie generator will start, post-contingency.

  The area is voltage limited to 83.6 MW (summer and winter) for loss of CL line.

The Coxsackie generator's annual run-time (starting in May), however, is restricted by environmental/emissions limitations to 826 hours if the fuel was natural gas only and 430 hours if using oil.

Various large industrial customers have proposed to interconnect in this area.

Proposed Solar & Battery Energy Storage System Interconnection Projects
For lines and substations supplied by the CL & NC lines, there are currently 230 MW of projects that went through the NYISO Interconnection Process prior to the 2024 Interconnection Reform. 30 MW of these are in construction with an additional 20 MW in the current NYISO Class Year. It is not clear if the remaining 180 MW will enter the NYISO's revised Interconnection Process[9]. Additionally, there are approximately 50 MW in service and 58 MW in queue in the New York State SIR process as of June 2024. The 77 MVA rated NC line cannot support this level of solar generation.

Several significant industrial loads have been proposed for the area, however, none are firm at this time.

6.4.2.2. Summary of Recommendations

DEC Peaker Rule
To maintain Westerlo Loop reliability following the retirement of the Coxsackie and 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 were recommended. Subsequent analysis determined that the voltage support devices be installed at New Baltimore in-place of Freehold.

CLCPA[10] Area of Concern
As part of CLCPA 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. The NC Line project

[9] Revised as ordered in FERC Order 2023.
[10] Climate Leadership and Community Protection Act

was approved by the Commission in February 2023 with costs covered through load ratio share methodology.

Due to the significant industrial load proposals, Central Hudson has undertaken a study to determine how to reinforce the Westerlo Loop, as well as the Northwest 115/69 kV area.

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.

Year	Date of Peak	MW	MVAr	MVA
2023	August 8 @1800	83.5	8.6	83.9
2022	July 20 @1600	78.9	-10.7	79.7
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

6.4.3.1. Summary of Issues

Following loss of the HP line this area is voltage limited at approximately 170 MW at unity power factor. Should a large (e.g., 25-35 MW) industrial load come in at Lincoln Park / Tech City, the voltage based load serving capability may decrease.

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 transmission inputs (69 kV P line, 115 kV 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 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
Early in 2024, the sag limited sections of the Galeville-Kerhonkson GK line were improved to provide additional capability. While some clearance issues through Minnewaska Park still remain, the work performed will provide for approximately 50% load growth after the large Schrade customer goes in service. During Q2 2024, the Modena 115/69 kV transformer was retired. The Modena-Galeville MG Line and the GK line were converted to 115 kV operation. Additionally, the 115/69 kV Kerhonkson Tr.4 was placed in service. Kerhonkson currently is half at 115 kV and half at 69 kV.

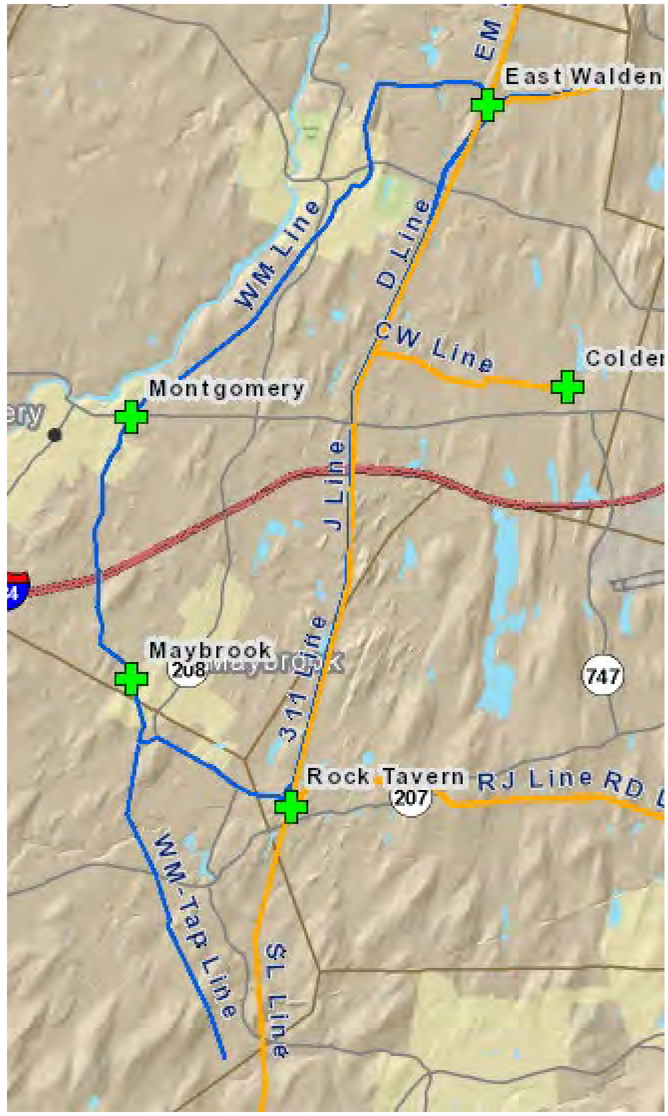
The remainder of the area conversion to 115 kV operation is scheduled for 2025.

GM Line Tap: Rebuild
The GM line from the tap to Greenfield Road to Clinton Avenue had previously been planned to be retired due to its condition. In order to accommodate the proposed large industrial load at the former Schrade site, a 0.35-mile section of the 69kV GM Line would need to be rebuilt. Following the rebuild of the Greenfield Road Substation and retirement of the Clinton Avenue Substation, a determination will be made whether to retire the GM Line Tap or rebuild pending the status of proposed industrial customer.

HG Line
The HG Line is scheduled to be rebuilt with 397.5 ACSR Ibis and OPGW static wire by June 2028. 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**
2023	September 7 @ 1800	51.5	8.64	52.3
2022	August 4 @1800	53.2	12.5	54.6
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

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

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
2023	September 7 @ 1800	93.2	1.8	93.2
2022	August 4 @ 1800	100.3	8.7	100.6
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

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

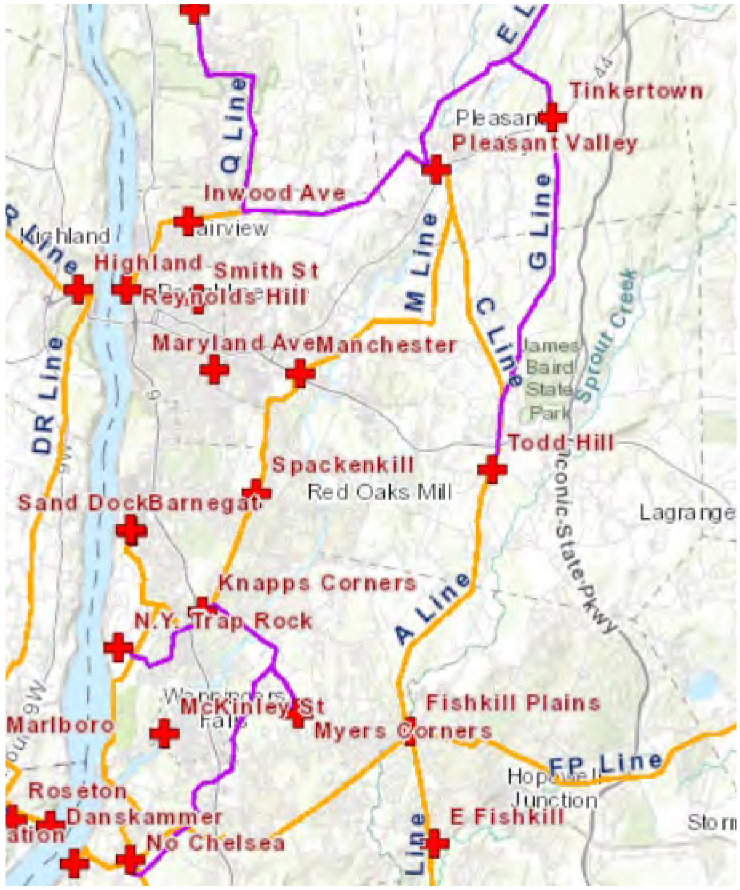
The area has sufficient LSC to provide for future load growth in the near-term. A potential long-term reinforcement option is to reconductor/rebuild the RD line using a larger conductor (potentially 795 MCM ACSR to match the RJ line).

6.4.6.2. Summary of Recommendations

There are no recommendations for this area at this time. The Electric Transmission Planning group is further evaluating the need for RD-RJ infrastructure upgrades, based on an adjustment to weather normalization values identified after the 2023 DSIP filing.

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
2023	September 7 @ 1600	120.5	14.2	121.4
2022	August 4 @1700	123.2	25.5	125.8
2021	June 29 @ 1900	116.1	12.6	116.8
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

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 2029.

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

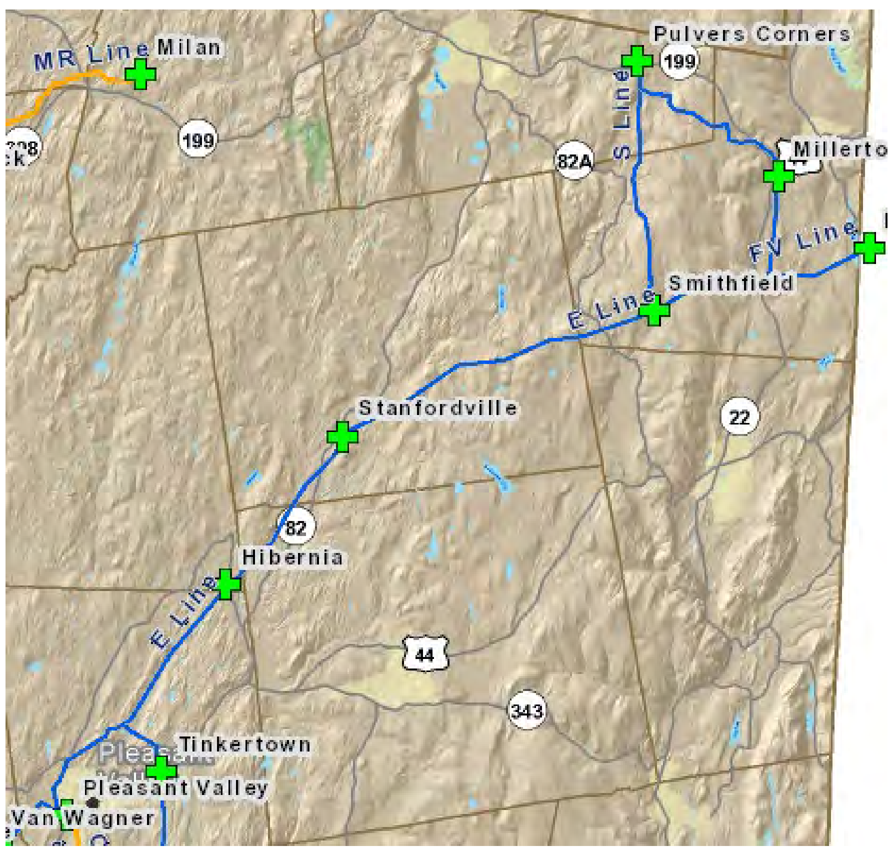
As described in Section 3.2.2.2, inspection reports for the 20.5 mile Q Line show that approximately 65% of the wood poles require replacement or repair.

6.4.8.2. Summary of Recommendations

It has been recommended to rebuild this line using 795 MCA ACSR or equivalent ACSS conductor. Rebuild is scheduled for completion in 2030.

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
2023	July 28 @ 1800	31.7	-	-
2022	July 24 @ 1900	33.2	-	-
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	-	-

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 Eversource's 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 Eversource 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 and Olivet University) suggest that NYSEG may not be able to supply the reserve on peak.

A FV line inspection had shown damage to the section of wire spanning Indian Lake that requires a conductor replacement. The small section of damaged conductor was replaced in Fall 2023.

There have been several NYISO small generator preapplications for the Northeast Dutchess Country 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

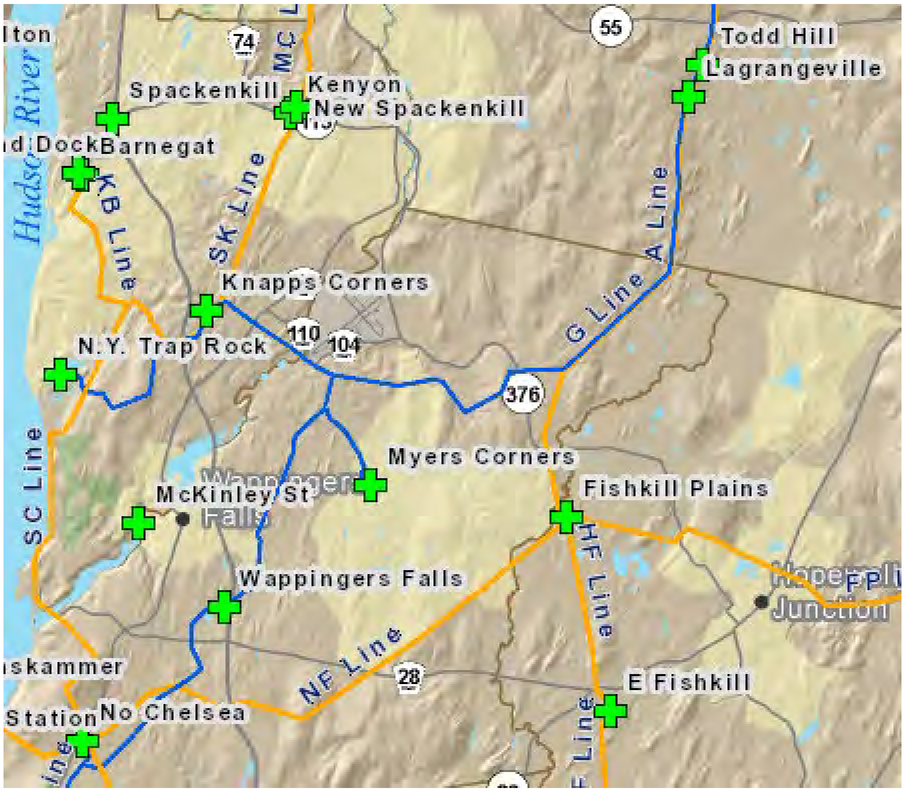
The G line provides the capability to reserve the E line for a Pleasant Valley Transformer #10 fault, 69 kV bus fault or an E/G common tower failure. This improves the ability to reserve E line loads but does not provide for reserve for all conditions. This area will be studied in the future. After recent 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
2023	July 5 @ 1800	20.0	0.9	20.4
2022	August 4 @ 1700	22.3	2.8	22.4
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

6.4.10.1. Summary of Issues

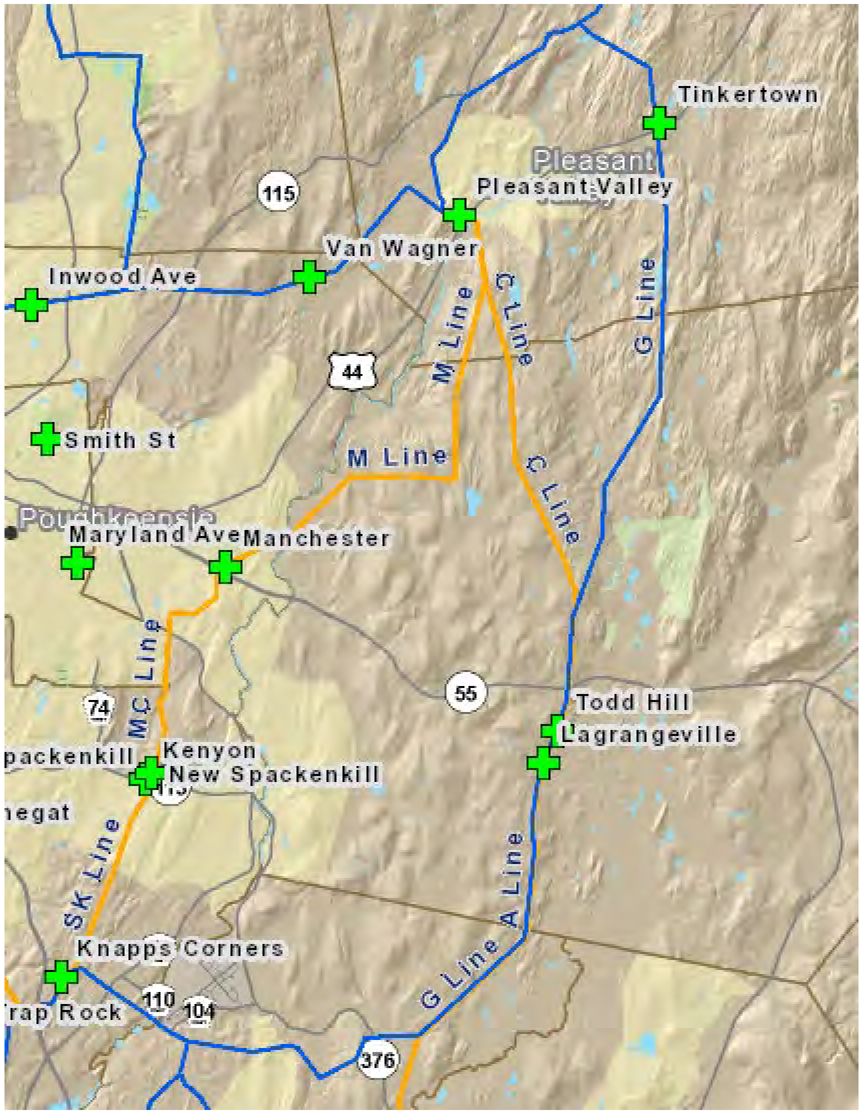
Condition assessments on the KM line have shown sufficient structural issues to warrant a rebuild.

6.4.10.2. Summary of Recommendations

The KM line will be rebuilt with 795 ACSR. This project is scheduled to be completed in June 2024. 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.

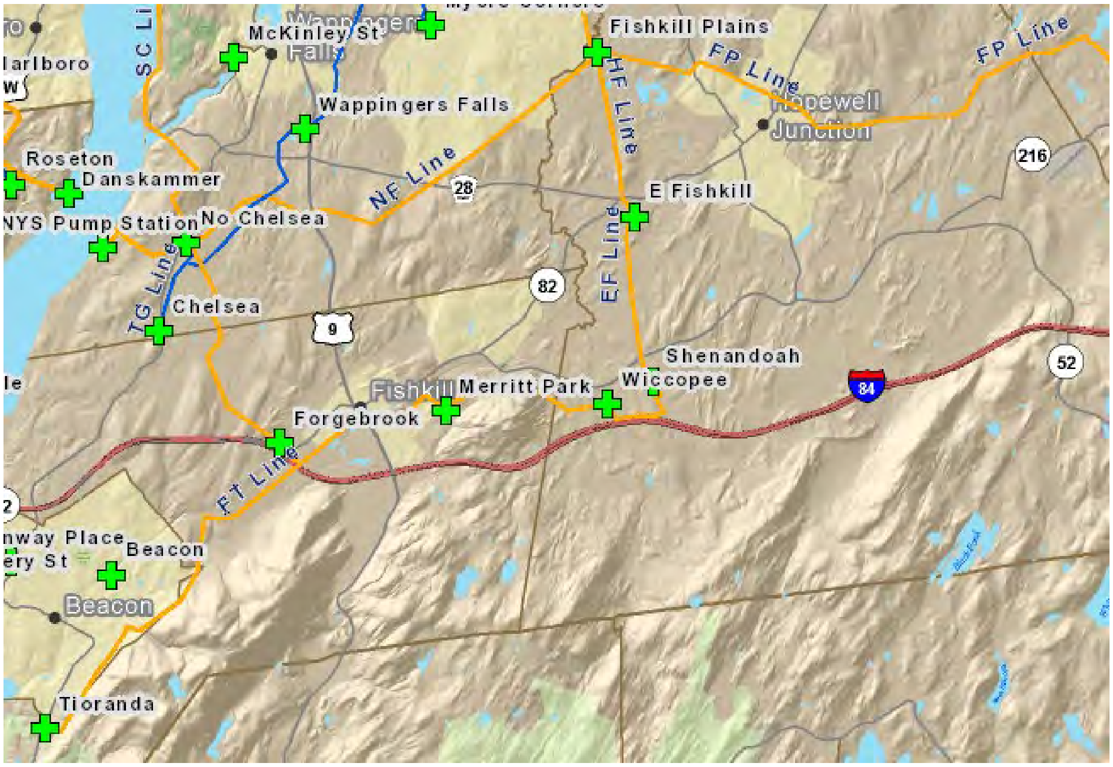
Year	Date of Peak	MW	MVAr	MVA
2023	September 6 @ 1800	13.3	-0.03	13.3
2022	August 8 @ 1700	17.2	2.3	17.4
2021	June 29 @ 1900	14.6	0.8	14.7
2020	July 27 @1900	14.5	1.6	14.6
2019	July 20 @ 1800	14.4	1.9	14.5
2018	July 2 @ 1800	14.4	0.6	14.4
2017	July 20 @ 1700	13.1	0.8	13.1
2016	August 13 @ 1800	15.4	1.1	15.4
2015	July 29 @ 1800	13.0	0.8	13.1
2014	July 23 @ 1500	13.0	2.0	13.1

6.4.11.1. Summary of Issues and Recommendations

No transmission reinforcement is needed at this time.

6.4.12. Southern-Dutchess Area (SDA)

This area comprises the 115 kV substations between North Chelsea and East Fishkill in Southern Dutchess County. It includes the Onsemi 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
2023	September 7 @ 1600	140.2	7.7	140.5
2022	July 21 @ 1700	145.3	14.5	146.1
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

This area's all-time high coincident peak load was 213.7 MVA on August 2, 2006 (HE 1700). Subsequent coincident peaks have been lower largely due to decreased Global Foundries/Onsemi 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 forecasted 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, however, at this time only an Amazon warehouse has emerged.

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)	2023 Peak Load (MVA)
Coxsackie	16.4	12.0 est.
New Baltimore	25.8	15.20

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 Coxsackie CT 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 over 41MW 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 DEC emissions rule "Peaker Rule" and the unit is now planned for retirement by the end of 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 New Baltimore Substations are being constructed for voltage support during contingencies. Final project scoping has been completed and construction has begun.

- To address the aging infrastructure concerns at Coxsackie, a new switchgear installation at the Coxsackie substation and replacement of the Coxsackie transformer were completed in Q2 2024. Based on area loading levels, the transformer was originally planned to be replaced with a 13.4MVA transformer. With over 31MW of potential DER proposed onto the substation bus, a 22MVA transformer was ordered and installed with the incremental cost for the larger transformer paid for by a PV developer. A second transformer is expected to be installed in Q2 of 2025 to address reserve capability in the area as a result of the Coxsackie CT retirement.

- 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 Q2 2025 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 existing circuits 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, 15kV breakers, and D-VAR units for voltage support during contingency will 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 was home to the South Cairo CT which was used as a backup for a transformer failure and to provide voltage support to the local transmission area. Due to DEC emission restrictions, the CT was retired March 31, 2024.

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 New Baltimore to provide voltage support for the transmission loop have been recommended. These projects are scheduled to be in service by March 2025.

7.3. Load Group 2 - Kingston

7.3.1. Woodstock

- Reference: K-2019-05 - Woodstock Substation Circuit Exits
- Reference: EP 2024-003: Woodstock Switchgear Replacement/Area Review

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 interruptions 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, due to space constraints and 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 Winter LTE at 23.9 MVA. The peak load at the substation was 18.4 MVA in the winter of 2023 (taking into account the Ashokan hydro generation). The Ashokan hydro generator, located on the 3011 distribution circuit, has a nameplate rating of 4.6 MW at 0.9 power factor, but has only generated a peak of 2.5 MW, and is not necessarily available for deployment on a peak day. The Ashokan hydro facility was generating 2.3 MVA at the time of the 2023 winter peak. Without the generation of the Ashokan hydro the substation could exceed its 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.

The Woodstock Switchgear replacement has been budgeted for an in-service date of December 2028. A Study has been written and which has recommended that the Woodstock switchgear is installed to support six distribution feeders and to establish a firm 30 MVA substation to support future electrification. The plan recommends two 69-13.8kV, 13.4/17.1/22.4 transformers with LTC to support improved reliability and electrification needs. 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.

7.3.2. 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

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 Q4 2027. In addition to the transformer replacement, replacement of the Converse Street breakers and switchgear will also be completed in Q4 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
- Reference: EP 2023-003: South Wall Street Substation Outdoor Switchgear Retirement

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

The 2023 planning study recommended to retire the South Wall Street Substation and convert portions of the distribution facilities from 4.16 kV to 13.2 kV and supply from the Boulevard 1013 circuit. The distribution conversion is planned for 2028 with the substation retirement planned for completion following the conversion work.

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, the 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 reliability and operational flexibility. Recommendations will incorporate cost-benefit analysis to determine the most appropriate solution.

7.4.2. Greenfield Road/Clinton Avenue

- Reference: EP 2016-012 Spare 10/12MVA Transformer Relocations
- Reference: EP 2019-006 Greenfield Road/Clinton Ave. Area Study
- Reference: EP 2022-09: Greenfield Road/Clinton Avenue Integration Study

7.4.2.1. Summary of Issues

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 was completed and identified the appropriate circuit paths and conversion work required.

Once the Greenfield Road Substation rebuild is complete, currently scheduled for 2025, the Clinton Avenue 4kV circuitry will be converted and supplied by the Greenfield Road 13.2kV circuitry. The Clinton Avenue substation can then be retired.

7.5. Load Group 4 – Southern Ulster

There are currently no areas identified as deficient in the Southern Ulster Load Group.

7.6. Load Group 5 - Orange

7.6.1. Maybrook/Montgomery

3.0 Reference: EP2011-012 Montgomery/Maybrook Area Study
4.0 Reference: EP2018-008 Montgomery Substation Integration Study
5.0 Reference: EP2022-007 Maybrook-Montgomery Spot Load Review

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 existing 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 thereby addressing some of the area loading and infrastructure issues. 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

As part of the 2022 Maybrook-Montgomery Substation Spot Load Review, the following items have been recommended for the area:

- Complete load transfers to move 4.1 MW from the Maybrook/Montgomery circuitry to Coldenham.
- Replace existing Maybrook transformers with 22.4/29.8/37.4 MVA transformers including the high side circuit switchers, bus work, and connections in 2025.
- Obtain property adjacent to the Maybrook Substation to allow for future expansion of additional circuits which may require a Power Control Center (PCC) if loading on the Maybrook Substation surpasses 30MVA.

7.6.2. Newburgh Area

- Reference: EP2011-001 Newburgh 14.4kV Area Study
- Reference: EP2013-016 Montgomery Street Transformer Replacement
- Reference: ECS 23-006 West Balmville to Montgomery Street Substation – WN and B Circuit Upgrades

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 other alternatives.

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

The following is recommended for the West Balmville – Montgomery Street 14.4kV Loop:

- Construct a new high-capacity overhead circuit to replace the B, F and R cables. The new circuit will be called the “B” cable and will utilize the same breakers at the West Balmville and Montgomery

Street substations. This work commenced in 2018 and will be completed in 2025.
  - Reconductor WN cable to match the high capacity of the new "B" cable. Install switched capacitors on the WN cable to maintain acceptable voltage levels, as well as replace an existing 600A SF6 switch with a new 900A PM-9 switch. This work will commence in 2025 and is expected to be completed in 2026.
  - Retire the old PILC underground B, F and R cables once both new high-capacity feeders are in service.

The Montgomery Street 14.4kV Switchgear is scheduled for replacement upon completion of the cable projects and is currently planned for 2028.

7.7. Load Group 6 – Northeast Dutchess

7.7.1. Pulvers/Ancram Area

- 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
- Reference: EP2022-013: Pulvers/Ancram Area Review

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, and concerns regarding aging distribution infrastructure.

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. 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. Portions of the line are over 70 years old and the circuit has experienced two conductor failures in 2017 and 2020, however the bulk of the outages have been tree related.

Pulvers Transformer #1 has shown a trend of overheating of the oil and tested high for furans which indicates a degradation of the insulating paper, thus has been recommended for replacement by Substation Operations. Ancram consists of three single phase transformers, which are 54 years old and recently had some undesirable dissolved gas analysis. A recent study has recommended that both the Pulvers Corners 69-13.8 kV transformer as well as the Ancram transformers be replaced as mentioned below. These recommendations will address both the loading concerns at Pulvers Corners as well as the reliability in the area.

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.
- Transfer load from the Pulvers Corners Substation to Ancram Substation in the near term.
- Polyphase and reconductor to three-phase, 13.2kV of the 7085 and 7091 circuits shifting additional load to Ancram in 2026.
- Replace the Pulvers Corners Transformer #1 with a new 69-13.8 kV, 11.2/14 MVA transformer in 2027.
- Replace the Ancram 54-year-old transformers with a new 34.5-13.8 kV, 7300/9375 kVA transformer. Add a low side free standing breaker for the 7085 circuit in 2028.
- Monitor the reliability of the 7395 for conductor failure and develop a plan to reconductor the line as needed.

7.7.2. Tinkertown Substation

- Reference: EP2023-02: Tinkertown Transformer Condition Replacement Study

7.7.2.1. Summary of Issues

The substation transformers at the Tinkertown Substation are approaching the end of their useful life. The 10/12.5 MVA, 69 to 13.8 kV Transformer

#1 and Transformer #2 were manufactured in 1958 and 1957, respectively, and have experienced unsatisfactory power factor tests. Based on the transformer assessments, these transformers are being recommended for replacement.

7.7.2.2. Summary of recommendations

Replace the Tinkertown Transformers #1 and #2 with new 69-13.8 kV wye-wye, 13.4/17.1/22.4 MVA transformers with low side LTC, high side circuit switchers and necessary cabling to accommodate the upgraded substation ratings scheduled for completion in Q4 2029.

7.8. Load Group 7 – Mid-Dutchess (North)

7.8.1. Poughkeepsie 14.4 kV System

- Reference: EP2010-002 Poughkeepsie 14.4kV Area Study
- Reference: EP2012-017 Reynolds Hill Transformer Study

7.8.1.1. Summary of Issues

The Reynolds Hill Substation is composed of two 115-13.8 kV transformers that were installed in 2018, and in addition to distribution circuits, serves 14.4 kV feeders that supply the secondary network transformers and load in the City of Poughkeepsie.

There are four lateral branches remaining of aging PILC cable on the Poughkeepsie 14.4kV system which supply the network.

The City of Poughkeepsie has seen an influx of new load comprising of the Vassar Hospital expansion, residential apartments, retail and a hotel along the Route 9 corridor expanding north towards St. Andrews Rd. in Hyde Park. This area is supplied by the Reynolds Hill, Inwood Ave and Spackenkill Substations.

The Town of Poughkeepsie has also experienced load growth in the form of retail, apartments, a hotel and housing for Vassar College along the Raymond Ave. corridor. This area is supplied by the Manchester Substation.

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 and are planned for completion in 2024.

A study is planned to review the loading in the Poughkeepsie area. This study will look at the existing and planned loading in the area with the intent to first utilize any existing capacity via load transfers or existing spare circuit positions in substations within the Poughkeepsie area.

7.8.1.3. Anticipated Date of Study

- Reynolds Hill Avoided T&D Cost Study Review – Q4 2024

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. An automatic load transfer team was installed at the former Beacon Substation location.

7.9.1.2. Summary of Recommendations

Based on the retirement of the 4kV Beacon and Conway Place Substations, the following project is expected to be completed within the upcoming years to improve reliability:

- 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 2028.

7.9.2. Myers Corners

- Reference: EP2021-014 Change to Bus Tie Configuration at Myers Corners Road Substation

7.9.2.1. 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 Distribution Automation 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.

7.9.2.2. 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 Q4 2026.

7.9.3. Shenandoah/Fishkill Plains – East Fishkill Area

- Reference: EP2022-015: East Fishkill Area Review

7.9.3.1. Summary of Issues

The East Fishkill area has recently seen an increase in commercial load stemming from new warehouses such as Amazon and Frito-Lay. 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.

7.9.3.2. Summary of Recommendations

It is recommended to re-configure the Wiccopee Substation to operate as a standard highside half-breaker /two transformer substation (normally open 13.8kV bus tie with the ability to automatically transfer load for loss of a transformer), scheduled for completion in Q4 2026.

Extend and integrate the 8032 and 8033 circuit from the breaker to Rt. 52 as high-capacity feeders in 2026. Circuits should be designed with a 9/14 MVA rating.

8. Summary of Projects

To optimize the expenditure of ratepayer contributions and plan for the future, the Electric Capital Plan 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 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 "2025-2029 Corporate Capital Forecast July 1st 2024".

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 and subsequent Climate Leadership and Community Protection Act (CLCPA) and the Accelerated Renewable Energy Growth and Community Benefit Act (Renewables Act). In addition, a new PSC proceeding entitled "Grid of the Future" initiated in April 2024 and will further inform and shape the way Central Hudson meets the needs of its customers.

DERs continue to grow at a rapid rate as the State presses to meet its ambitious climate goals. These resources which include standalone Photo-voltaic (PV systems), standalone Battery Energy Storage

Systems (BESS), PV paired with BESS and Demand Response, coupled with other emerging technologies such as Electric Vehicles (EVs), Clean Heat technologies and Energy Efficiency continue to change the grid. Central Hudson has begun incorporating DER into our planning processes as these resources impact our system. Please note that Central Hudson's DSIP (most recently filed in July 2023) contains greater detail including the current status and long-range plans for these emerging technologies.

PSC 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 Renewables Act. Among other topics, these documents present global and 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, NYSEG/RG&E and O&R) in a number of forums to help facilitate the achievement of the goals outlined in these documents. This includes the Coordinated Grid Planning Process (CGPP) which kicked off in August 2023. The CGPP is designed to assess NY State's electric grid using a 20-year planning horizon, to identify electric grid expansions that can aid in unlocking renewable generation capacity and provide energy headroom for the purpose of meeting NY State's clean energy goals while providing value to customers. The CGPP is currently in the midst of Stages 1 and 2 of a six-stage process, with the CGPP cycle anticipated to conclude by December 2025. Additionally, Central Hudson is engaged in a number of other proceedings including proactive planning related to electric vehicles[11] as well as the Grid of the Future[12] initiative. 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 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 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.

[11] Case 23-E-0070, Proceeding on Motion of the Commission to Address Barriers to Medium-and Heavy-Duty Electric Vehicle Charging Infrastructure, April 20, 2023.
[12] Case 24-E-0165, Proceeding on the Motion of the Commission Regarding the Grid of the Future, April 1, 2024.

G. Capital Investment Plan

Included below is a link to the Joint Utilities' website, which contains Central Hudson's comprehensive Capital Expenditure Plan (Capital Plan) for the Electric, Gas, and Common Program areas of Central Hudson Gas & Electric Corporation for the forecast period 2025 through 2029.

Central Hudson Capital Investment Plan

https://jointutilitiesofny.org/utility-specific-pages/system-data/capital-investment-plans

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 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 (22-M-0429)
- Customer Information System Investigations (22-00666, 22-E-0121, 22-M-0645)
- Petition of Interconnection Policy Working Group Seeking a Cost-Sharing Amendment to the New York State Standardized Interconnection Requirements (Case 20-E-0543)