

New York Hybrid Electrification Study

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Executive summary

New York State (NYS) climate policy, anchored by the 2019 Climate Leadership and Community Protection Act (CLCPA), mandates substantial reductions in economy-wide greenhouse gas (GHG) emissions while maintaining safe, reliable, and affordable energy service. Within the buildings sector, electrification of space heating has been identified as a primary long-term decarbonization strategy due to the scale of emissions associated with on-site fossil fuel combustion. In recent years, the New York State Public Service Commission (NY PSC or Commission) has advanced this strategy through a series of energy efficiency (EE) and building electrification (BE) Orders that increasingly emphasize electrification as a core program objective.

The Commission's 2023 *Order Directing Energy Efficiency and Building Electrification Portfolios* and recent 2025 Orders authorizing Non-LMI (Non Low- to Moderate-Income) and LMI (Low- to Moderate-Income) Energy Efficiency and Building Electrification portfolios (EE/BE Orders) prioritize building electrification that permanently eliminates on-site fossil fuel use and are designed to meet a building's full design heating load. The EE/BE Orders also direct that the majority of ratepayer funded program resources be allocated toward electrification and electrification readiness measures, reflecting a deliberate effort to align utility-administered programs with the state's long-term climate objectives while managing system impacts and customer costs.^{i,ii,iii}

At the same time, the Commission has pursued a separate but related policy initiative focused on long-term planning for natural gas systems. Pursuant to the Gas System Planning Order, gas utilities are required to file long-term plans that assess how they will reduce GHG emissions and continue to provide safe and reliable service under evolving policy, market, and customer adoption conditions. In response, gas utilities have developed long-term plans that evaluate a wide range of potential decarbonization measures, including EE, utility thermal energy networks, low-carbon fuels, and building electrification.^{iv}

Within these long-term plans, many gas utilities have identified Hybrid Electrification (also known as "hybrid heating") as a potential strategy to reduce end-use GHG emissions while providing other system-level benefits, including moderating winter peak electric demand impacts and managing near-term system costs. Hybrid systems pair electric heat pumps with fossil heating equipment and include a set of integrated controls that automatically switch to the fossil heating equipment below a pre-determined switchover temperature. Utilities have characterized these configurations as being potentially useful during a transitional period, particularly in colder regions and for existing buildings with physical or economic constraints.

These parallel policy developments create an important planning challenge. The EE/BE Orders currently restrict heat pump incentive eligibility to building electrification measures that can meet a customer's full design day heating requirement for many customers and explicitly preclude hybrid systems from receiving incentives. Meanwhile, gas utility long-term plans continue to advocate for Hybrid Electrification as part of their decarbonization strategies, including in

proposals for funded programs with targeted incentives. The Commission acknowledged this divergence and determined that additional analysis was needed to better understand how Hybrid Electrification compares to Full Electrification in New York, with a focus on the economics for residential customers and the system-level impacts and costs of different adoption pathways.^v

This New York Hybrid Electrification Study (HE Study) was commissioned by Department of Public Service Staff (NY DPS Staff), in consultation with New York State Energy Research and Development Authority (NYSERDA) and New York's electric and gas utilities, to provide that analysis. The HE Study evaluated Full and Hybrid Electrification pathways for residential single- and multifamily customers relative to a counterfactual in which existing heating equipment is replaced on an in-kind basis at the end of its useful life. Using a scenario-based, forward-looking analytical framework, the HE Study assessed customer economics, expected adoption trends, emissions outcomes, and electric and gas system impacts over a long-term planning horizon through 2050. The HE Study is intended to inform the Commission's consideration of future electrification programs and utility planning proposals by clarifying the customer- and system-level impacts and tradeoffs. It also quantifies the potential magnitude and distribution of system-level benefits and costs within different regions of NYS, including how these impacts align to different electric and gas utilities. Crucially, the HE Study does not prescribe or recommend a specific policy outcome or electrification pathway for NYS.

Analytical approach

The HE Study is a broad analysis that provides insight into the customer-level economics and the energy system impacts of residential building electrification in NYS under a set of modeled pathways. This analysis and the corresponding inputs and assumptions were developed with oversight and input from NY Department of Public Service Staff (NY DPS Staff), NYSERDA, and the Joint Utilities.¹

Fundamentally, the study's analytical approach is grounded in the notion that individual customers' decisions about their heating technology are driven primarily by economics and a desire to minimize home energy costs. The aggregate sum of these individual customer decisions to adopt certain technologies will influence the trajectory of the New York energy system. In this way, the study uses a "bottoms-up" approach to forecasting customer adoption of electrification measures and assessing the resulting impacts to New York State's electric and natural gas systems. These system impacts then provide the basis for the study's subsequent analyses on the cost and affordability implications of different residential building electrification pathways for utility customers.

¹ "Joint Utilities" refers to Central Hudson Gas & Electric Corporation (Central Hudson), Consolidated Edison Company of New York, Inc. (Con Edison), New York State Electric & Gas Corporation (NYSEG), Niagara Mohawk Power Corporation d/b/a National Grid (NMPC), Orange and Rockland Utilities, Inc. (O&R), National Fuel Gas Distribution Corporation (NFG), and Rochester Gas and Electric Corporation (RG&E).

The HE Study first modeled the economics of Full and Hybrid Electrification for residential customers in NYS at a highly granular level, considering a range of upfront installed costs, available incentives, and operating costs and the factors that influence them. The analysis segmented the NYS residential building stock into more than 400 unique customer archetypes that captured variation in dwelling types (e.g., single- vs. multifamily), region, fuel type, heating and cooling equipment type, construction vintage, and customer income level. Taken together, these archetypes capture a significant portion of the diversity in New York State’s residential stock that can meaningfully influence customer-level economics and decision making. Using NREL’s ResStock model, CRA developed and analyzed unique customer end-use load profiles for electricity, natural gas, and other fuels (i.e., propane or fuel oil) for different electrification and fossil fuel heating technologies, including hybrid heating systems.

The result of this analysis was a characterization of the customer-level economics of electrification for a range of different heat pump technologies, including central and mini-split air source heat pumps, air-to-water heat pumps, and packaged window heat pumps. Ground-source heat pumps (GSHP) were excluded from this study, as they were not viewed as particularly strong candidates for Hybrid Electrification because GSHP performance does not degrade at lower temperatures.

The analysis adopts the perspective of a customer’s total cost of ownership (TCO) to reflect the economics of different technologies. The TCO calculation compares the costs of heat pump electrification to the avoided costs (or benefits) in the “counterfactual” case, where a customer replaces their existing fossil fuel heating equipment in-kind. TCOs are compared across customer archetypes and scenarios by calculating the simple payback period for each electrification upgrade option, or the number of years it takes to achieve “payback” on adopting the electrification upgrade since the initial investment.

CRA then used these payback periods to inform its forecast of residential building electrification adoption in NYS, where customer archetypes with better economics saw greater adoption, while customer archetypes with poorer economics saw lower adoption. This was constructed as a “bottoms-up” forecast; it simulated individual customer adoption decisions within each customer archetype and aggregated these decisions up to create a statewide adoption forecast. CRA first simulated the number of customers eligible for heat pump adoption each year by analyzing the expected failure rate of customer heating equipment. A Bass Diffusion model (commonly known as an “s-curve”) is used to simulate the propensity of customers to adopt a technology, capturing the effects of innovators (or early adopters) and imitators (or followers) in spurring market adoption of consumer technologies. The simple payback period is used in the calculation to determine the proportion of customers that are eligible for adoption that choose a certain electrification upgrade at a given point in time. The remaining customers then revert to their counterfactual fossil fuel heating equipment.

The aggregate state-level electrification adoption forecast, combined with information on customer-level energy consumption and demand, allowed CRA to analyze the effects of different pathways on the electricity and natural gas systems in NYS. CRA forecasted the

impacts of residential building electrification on electricity usage and winter peak demand, which were then used to analyze the impacts across the electricity value chain: generation and reserve margins, wholesale electricity prices, bulk power transmission, and local utility transmission and distribution systems. CRA's analysis focused, in particular, on the level of embedded "headroom" that the New York utilities' electric systems currently have available to support additional winter peak loads caused by building electrification, and how, where, when, and to what extent that headroom could be affected in a way that leads to future system costs. CRA also used electricity and natural gas market simulation software to capture the effects of a changing system on wholesale natural gas and electricity prices in NYS. CRA then examined the potential impacts of electrification on the natural gas delivery system, including the potential impacts of electrification on natural gas utility sales volumes and customer counts over the forecast period. Finally, the analysis quantified the capital investment requirements associated with these electric and gas system changes and, combined with wholesale price effects, translated these into a forecast of indicative customer bill impacts by utility under each planning scenario.

The HE Study produced several categories of findings regarding the customer-level economics of Full versus Hybrid Electrification and the potential range of energy system impacts and affordability implications of different residential building electrification pathways for NYS. CRA's analysis and results presented in the following sections of the report support the findings described below.

Key findings: Customer economics and electrification adoption

When modeling residential building electrification at the point of equipment failure, Hybrid Electrification is typically less economic than Full Electrification in New York State, but neither electrification option is generally cost-effective for customers heating with natural gas. CRA's TCO modeling revealed that Hybrid Electrification was the most economic electrification option for fewer than 1% of customer archetypes, while Full Electrification was the most economic electrification option in the majority of cases. However, cases with favorable economics for electrification are largely concentrated in customers heating with delivered fuels (propane or fuel oil), driven by differences in operating costs.

The size of the current upfront incentive for Full Electrification, (which can be as high as \$12,000 in NYS for non-LMI and \$14,000 for LMI customers, depending on the customer type and region) has a significant influence on its economics relative to Hybrid options. This incentive addresses the incremental cost of installing and operating a heat pump to meet full design heating load, purchase a "cold climate" model, and undertake other accompanying upgrades (e.g., electric panel upgrade). While Hybrid Electrification allows customers to install a smaller heat pump, select a less expensive or standard model, and in some cases avoid electrical upgrades, they must also replace and maintain a separate fossil fuel heating system, which introduces additional costs. CRA's analysis indicated that, in the absence of any incentive for Full Electrification, Hybrid becomes comparable to Full and more attractive, in many cases, for natural gas customers.

In the Base scenario, delivered fuel customers heating with fuel oil and propane see significantly better economics for both Full and Hybrid Electrification (relative to natural gas) and make up the majority of forecasted electrification adoption. While delivered fuel customers only account for 29% of the 2026 modeled NYS housing stock, they represent 59% of the total electrification adoption in CRA's Base scenario. On the other hand, dwellings heated with natural gas make up 71% of the stock but represent only 41% of the total electrification adoption. By 2050, 65% of the dwellings heated with delivered fuels adopt electrification in the Base scenario, while only 19% of dwellings heated with natural gas today electrify.

Many of the delivered fuel customer archetypes have several viable electrification options (i.e., payback period ≤ 6 years). This is due to the relatively higher cost of delivered fuels where fuel switching to electricity (even for a portion of usage) can meaningfully reduce operating costs and therefore total cost of ownership. Natural gas space heating, on the other hand, tends to have a durable operating cost advantage over electrification today. Many single-family dwelling natural gas customer archetypes saw *no* electrification technologies that provided any economic payback over the useful life of the heat pump; these customers are the most likely to be laggards that tend to revert to their existing heating fuel and equipment at a replacement decision. Improvements to incentive levels for gas customers or a falling real cost of electricity (relative to natural gas) could spur additional adoption of heat pump technology for natural gas customers.

In most regions of the state, natural gas remains significantly less expensive than electricity such that, even with more energy-efficient heating technology, customers with natural gas heating incur increased operating costs due to both Full and Hybrid Electrification relative to the counterfactual of remaining with a fully fossil-based system.

Regional differences within New York State that affect installed costs, incentives, and operating costs can meaningfully shape economics and subsequent adoption. Generally, electrification is more economic in regions with lower total installed costs for heat pumps, higher electrification incentives, and lower-cost electricity relative to natural gas and other fuels. The spread between the price of natural gas and electricity is particularly impactful to electrification economics. All else equal, Hybrid Electrification provides more value relative to Full Electrification in colder climates (i.e., IECC Climate Zone 5 and 6 areas of Upstate NY) where the efficiency of heat pumps is reduced at cold temperatures, resulting in increased operating costs. Upstate NY, Central and Southern NY, and the Hudson Valley see the strongest electrification adoption per capita due to the combination of these factors being most supportive. Long Island also sees more adoption of Full Electrification in part due to higher natural gas costs (relative to electricity) than other parts of NYS and a more temperate climate. Western New York combines low-cost natural gas and low gas utility rates with a high penetration of natural gas service, which leads to very poor economics for electrification and hence, lower adoption of electrification. New York City sees the least heat pump adoption per capita of any region. Despite having slightly higher upfront incentives, it has the highest electricity rates in NYS and the total installed costs for heat pumps are demonstrably higher than in other regions, which worsens the electrification economics.

There are several electrification technologies that apply for both Full and Hybrid Electrification, potentially leading customers to have multiple viable options. Central ASHP systems generally offered the best economics for both Full and Hybrid Electrification, but adoption is practically limited to customers with an existing central forced air heating system (existing natural gas, fuel oil, or propane furnaces). Mini-split ASHP systems are the most versatile technology and can be used to electrify almost any residential customer in either a Full Electrification or Hybrid Electrification configuration. Air-to-water heat pump systems address the smallest market (customers with existing hot water boilers) and were frequently less economic than alternatives. Packaged window heat pump systems were particularly competitive for multifamily Full Electrification in New York City, due in large part to assumptions around modularity and ease of installation that can lead to less expensive installations.

Public policy and program design is a main driver of residential heat pump adoption in New York State today; incentive availability for Full and/or Hybrid Electrification has significant influence on economics. The addition of an equivalent upfront incentive for Hybrid Electrification in the Hybrid scenario helps to “level the playing field” and leads to significant adoption of hybrid systems. Similarly, CRA’s univariate sensitivity analysis demonstrates that, in the absence of upfront incentives for either Full or Hybrid Electrification, Hybrid Electrification is competitive in many instances and, on average, more cost-effective than Full Electrification for single-family central heat pump systems, which are a highly prevalent upgrade, particularly outside of NYC.

Key findings: Electric system impacts and winter peak dynamics

Hybrid Electrification can be an effective long-term strategy to enhance grid utilization and promote customer affordability. Starting in the 2040s, as the NY electric system approaches a winter peak transition, Hybrid Electrification has the ability to significantly reduce costs across the electricity value chain in NYS, supporting customer affordability. The Hybrid scenario leads to approximately \$5.4B in total nominal avoided bulk transmission and local T&D capital investment in NYS relative to the Base scenario, most of which is concentrated in the 2040s. These result in modeled customer bill savings.

Today, New York electric utilities’ T&D systems have meaningful “headroom” to absorb growth in winter peak demand as a result of residential building electrification. CRA’s analysis of the electric utilities’ Hosting Capacity Maps indicated varying degrees of embedded winter headroom across distribution substations and distribution feeders to support growth in winter peak loads. In many cases, adding targeted building electrification loads today could accommodate new heat pump loads and enhance distribution system utilization without requiring immediate upgrades. This can improve customer affordability (by increasing electricity sales without investment requirement). Over time, however, clustering of building electrification (including alongside other loads, like electric vehicles) could saturate the remaining winter headroom and trigger the need for significant T&D upgrades, often starting in the 2030s. Hybrid

Electrification can effectively eliminate the winter peak demand contribution from space heating electrification, which can be impactful if deployed in a targeted way.

Winter electric system reliability will need to be considered as adoption of Full Electrification accelerates; Hybrid Electrification can provide a tool to reduce investment requirements in incremental winter generation capacity. The specific timing of a transition to a winter-peaking electric system in New York is highly sensitive to the amount of residential Full Electrification, according to CRA's scenario analysis. The switch to a winter-peaking system coupled with tightening winter reserve margins under the current planned capacity mix would likely require additional capacity resources to maintain resource adequacy. In the future, Hybrid Electrification could provide flexibility by delaying the transition to a winter-peaking system by multiple years while higher levels of Full Electrification accelerate the transition to a winter-peaking system. In the Hybrid scenario, New York is effectively a dual-peaking system in the 2040s, which could improve utilization of the grid.

Key findings: Gas system impacts and customer affordability

Targeted electrification is critical to mitigating long-term gas customer bill impacts in scenarios with widespread electrification. The HE Study results underscore that broad, uncoordinated Full Electrification driven primarily by individual customer economics and natural equipment turnover can place upward pressure on remaining gas customer bills, as largely fixed gas system costs are recovered over a shrinking customer Base. In such a future, meaningful mitigation of natural gas customer bill impacts is unlikely to occur through diffuse, customer-driven electrification alone.

CRA's modeled scenarios do not assume geographically targeted adoption; as a result, customer attrition from the gas system occurs in a dispersed manner across service territories, limiting near-term opportunities to reduce underlying fixed system costs through asset retirement or system downsizing. By contrast, targeted electrification strategies that concentrate adoption in specific locations have the potential to enable more coordinated gas-electric system planning, create clearer opportunities for decommissioning or pruning portions of the gas network, and more effectively reduce fixed system costs. Such approaches may therefore play an important role in managing gas customer affordability in the future with high levels of building electrification.

Modest declines in natural gas throughputs and customer counts due to electrification are expected, but impacts are felt unevenly within New York State. The Base scenario forecasts a roughly 10% decline in *residential* natural gas throughputs due to electrification by 2050. Certain areas with more electrification adoption by natural gas customers experience more acute natural gas bill impacts. Widespread adoption of Full Electrification without targeted policy intervention may cause cost recovery and affordability challenges due to declining natural gas sales and customer counts. In a Hybrid Transition scenario, natural gas throughputs still decline by approximately 7% due to the elimination of natural gas demand for heating for these customers above certain temperatures (>30°F), while customer counts are relatively stagnant.

Key findings: Policy, program design, and planning implications

The HE Study's key findings above suggest that Hybrid Electrification is expected to see relatively little organic residential customer adoption today and in the future under current conditions in NYS. Moreover, the system-level benefits of Hybrid Electrification are most economically impactful in 15-20 years when the state's bulk power system and electric utilities shift towards a winter-peaking paradigm, not today. This creates several potential considerations for NYS policymakers, regulators, and utilities as they plan for the future of the state's energy systems, pursue CLCPA goals and targets, and continue to advance solutions to the ongoing affordability challenge.

Coordinated gas-electric system planning can co-optimize value between electric and gas network infrastructures; Hybrid Electrification may play an important role during the transition. Hybrid heating solutions that leverage the natural gas infrastructure may pose a conflict with gas system decommissioning efforts and certain planning solutions, including non-pipeline alternatives (NPAs). Simultaneously, hybrid heating solutions have the potential to provide significant future value through avoided T&D capital investment across the electric system. This includes the ability for hybrid heating to help reduce or defer electric system upgrades where electric system headroom is limited. An evolving framework for gas-electric system coordination and integrated planning should thoughtfully address the value of Hybrid Electrification and allow system planners and customers to support this solution where it makes sense to unlock system value and avoid unnecessary costs.

As a result, the value of Hybrid Electrification is likely to be highly location-specific rather than uniform across service territories. Detailed, utility-specific assessments of electric distribution system constraints, including identification of areas with limited available capacity or elevated winter peak risk, could help clarify where Hybrid Electrification provides the greatest system benefit. Such analyses could allow the NY DPS to work with New York electric utilities to consider whether program incentives or planning approaches should be more geographically targeted, supporting Hybrid Electrification where it delivers measurable system value while avoiding unnecessary costs. However, it is unlikely that Hybrid Electrification will reduce costs or provide comparable benefits for all customers or in all locations relative to other electrification pathways.

Hybrid Electrification can serve as one amongst several tools to enhance grid utilization and customer affordability. In the near-term, there may be little-to-no system costs to adding electrification due to sufficient winter headroom on the electric system. In this case, electrification can improve customer affordability by improving grid utilization. Utilities may have an opportunity to leverage hybrid heating as a targeted demand-side management or demand response strategy in the future to manage peak demand and avoid costly electric system upgrades. The value of hybrid systems will vary temporally and locationally. NY DPS Staff can build upon this effort and other efforts (e.g., Distributed System Implementation Plants),

alongside the Joint Utilities, to create a framework for assessing and valuing Hybrid Heating in the context of electric and gas utility planning.

Hybrid Electrification can reduce GHG emissions relative to a “do nothing” scenario, but equipment operation matters. Increased adoption of heat pumps decreases GHG emissions as electricity consumption offsets end-use combustion GHG emissions from natural gas and other fuels, including when accounting for increased emissions from increased electricity consumption. At a 30°F switchover temperature, operating a hybrid heating system could reduce the average customer’s annual natural gas usage by approximately half. However, a significant portion of the electric system value in Hybrid Electrification is reducing the contribution of space heating to coincident winter peak events. Due to the importance of heating equipment on health and safety, additional analysis would be needed to understand how customers and contractors would choose to operate their heating equipment in Hybrid Electrification configurations and what can be done to incentivize economically advantageous operation.

Multi-value T&D investments can help to proactively enable building electrification and reduce unforeseen or excess costs. Utilities and planners should continue to strategically prepare for electrification impacts as aging assets need to be replaced. End of life may present opportunities for “multi-value” investments that replace aging assets, address reliability, and increase load serving capacity to proactively address load growth at a lower cost. Investments must consider building electrification in context of other loads, including vehicle electrification and other load growth.

Strengthen contractor training, sizing guidance, and quality control within the NYS Clean Heat program to improve customer economics for residential electrification. CRA’s analysis of NYS Clean Heat Program data indicates that heat pump systems have historically been oversized, particularly in Full Electrification applications where equipment is designed to meet peak winter heating loads without adequate consideration of load diversity or complementary weatherization measures. Oversizing increases upfront costs and can materially worsen customer economics without providing commensurate benefits.

Expanding NYS Clean Heat Program resources devoted to contractor training, standardized sizing practices, and quality control inspections could significantly improve electrification outcomes. Properly right-sized heat pump systems, especially when paired with basic envelope weatherization, can deliver comparable comfort at substantially lower installed cost, improving payback periods for electrification. CRA’s results suggest that these factors can materially influence whether electrification is economic for many customer archetypes.

Historic incentive structures that emphasized installed capacity, such as incentives tied to heat pump Btu output, may have unintentionally encouraged oversizing in some cases. Continued refinement of program design, coupled with stronger contractor education and post-installation verification, can help ensure that future installations better reflect actual building heating needs. In addition, routine maintenance and inspection practices can serve as touchpoints to prepare

customers for future end-of-life equipment decisions and to communicate the range of viable electrification pathways before equipment failure occurs.

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Acronyms and defined terms

Acronyms

Acronym	Definition
AAS	New York State Energy Plan's Additional Action scenario
AC	Air Conditioning
ACH50	Air Changes per Hour at 50 Pascals
ADIT	Accumulated Deferred Income Tax
AMEEP	Affordable Multifamily Energy Efficiency Program
AMI	Advanced Metering Infrastructure
AMP Up	Affordable Multifamily Program Upstate
ASHP	Air Source Heat Pump
AWHP	Air-to-Water Heat Pump
A&G	Administrative & General
BE	Building Electrification
ccASHP	Cold Climate Air Source Heat Pump
CCS	Carbon Capture and Sequestration
CECONY	Consolidated Edison Company of New York
CHG&E	Central Hudson Gas & Electric
CLCPA	Climate Leadership and Community Protection Act
CO₂e	Carbon Dioxide Equivalent
COP	Coefficient of Performance
CRA	Charles River Associates, Inc.
DAC	Disadvantaged Community
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management System

DR	Demand Response
DSIP	Distributed System Implementation Plan
EDZ	New York State Economic Development Zones
EE	Energy Efficiency
EEM	CRA's Economic Electrification Model
EIA	U.S. Energy Information Administration
EULP	End-Use Load Profile
FE	Full Electrification
FERC	Federal Energy Regulatory Commission
FF	Fossil Fuel
FOP	Fuel Oil or Propane
GHG	Greenhouse Gas Emissions
GPIS	Gross Plant in Service
GSHP	Ground-Source Heat Pump
GW	Gigawatt
GWh	Gigawatt-hour
GWP	Global Warming Potential
GWP20	20-year Global Warming Potential
HCM	Hosting Capacity Maps (or System Data Portals)
HDD	Heating Degree Days
HE	Hybrid Electrification
HEAR	Home Electrification and Appliance Rebate Program
HER	Home Efficiency Rebate Program
HVAC	Heating, Ventilation, and Cooling
IPCC	Intergovernmental Panel on Climate Change

IRA	Inflation Reduction Act
JU	New York Joint Utilities
KEDNY	KeySpan Energy Delivery New York d/b/a National Grid
KEDLI	KeySpan Energy Delivery Long Island d/b/a National Grid
kVA	Kilovolt-Ampere
kW	Kilowatt
kWh	Kilowatt-hour
LDC	Local Distribution Company
LI	Low-Income
LIPA	Long Island Power Authority
LMI	Low- to Moderate-Income
LSC	Load Serving Capacity
LTP	Long-Term Plan
MCOS	Marginal Cost of Service
MF	Multifamily
MI	Moderate-Income
MMBTU	Million British Thermal Units
MT	Metric Tons
MVA	Megavolt-Ampere
MW	Megawatt
MWh	Megawatt-hour
NENY	New Efficiency New York
NFG	National Fuel Gas Distribution Corporation
NG	Natural Gas
NMPC	Niagara Mohawk Power Corporation

NPIS	Net Plant in Service
NPV	Net Present Value
NWS	Non-Wires Solutions
NYC	New York City
NYISO	New York Independent System Operator
NY-GEO	New York Geothermal Energy Organization
NY PSC	The New York State Public Service Commission
NYSEG	New York State Electric and Gas Corporation
NYSERDA	New York State Energy Research and Development Authority
O&R	Orange & Rockland Utilities
O&M	Operation and Maintenance
PA	Program Administrator
PTHP	Packaged Terminal Heat Pump
PWHP	Packaged Window Heat Pump
RG&E	Rochester Gas & Electric Corporation
RRWP	Regional Residential Weatherization Program
SEP	New York State Energy Plan
SF	Single-Family
T&D	Transmission & Distribution
TCO	Total Cost of Ownership
TIC	Total Installed Cost
UPC	Use Per Customer
VPP	Virtual Power Plant
VRF	Variable Refrigerant Flow
WACC	Weighted Average Cost of Capital

Defined Terms

Term	Definition
CapEx	Capital Expenditures
Clean Heat	New York State Clean Heat Program
Commission	The New York State Public Service Commission
Delivered Fuels	Fuel Oil and Propane
Downstate	Includes the greater New York City metropolitan area and Long Island. Encompasses Regions 5 and 6 as defined herein for the purposes of this HE Study
Dwelling Unit	Residential home or building
EE/BE Orders	Collectively, the Order Authorizing Non-Low- to Moderate-Income Energy Efficiency and Building Electrification Portfolios for 2026–2030 and the Order Authorizing Low- to Moderate-Income Energy Efficiency and Building Electrification Portfolios for 2026–2030
HE Study	New York Hybrid Electrification Study
Gas Planning Order	Order Adopting Gas System Planning Process (Case 20-G-0131)
LMI EE/BE Order	Order Authorizing Low- to Moderate-Income Energy Efficiency and Building Electrification Portfolio for 2026–2030 (Cases 14-M-0094, 18-M-0084, and 25-M-0249)
Non-LMI EE/BE Order	Order Authorizing Non-Low- to Moderate-Income Energy Efficiency and Building Electrification Portfolios for 2026–2030 (Cases 14-M-0094, 18-M-0084, and 25-M-0248)
Order Directing EE/BE Proposals	Order Directing Energy Efficiency and Building Electrification Proposals (Cases 14-M-0094 and 18-M-0084)
Region	CRA-defined region of New York State
Rest of State	Includes all areas of New York State outside of the New York City metropolitan area. Encompasses Regions 1, 2, 3, 4, and 6 as defined herein for the purposes of this HE Study

Utilities	The Utilities include Central Hudson Gas & Electric Corporation (Central Hudson), Consolidated Edison Company of New York, Inc. (Con Edison), KeySpan Gas East Corporation d/b/a National Grid (KEDLI), The Brooklyn Union Gas Company d/b/a National Grid NY(KEDNY), National Fuel Gas Distribution Corporation (NFG), New York State Electric & Gas Corporation (NYSEG), Niagara Mohawk Power Corporation d/b/a National Grid (NMPC), Orange and Rockland Utilities, Inc. (O&R), and Rochester Gas and Electric Corporation (RG&E)
Upstate	Includes all regions of New York State outside of New York City and Long Island. Encompasses Regions 1, 2, 3, and 4 as defined herein for the purposes of this HE Study

1. Introduction and study scope

1.1 Regulatory background

Evolution of New York’s Building Electrification Policy

New York’s Climate Leadership and Community Protection Act (CLCPA), signed into law in 2019, requires greenhouse gas (GHG) emissions reduction targets (40% by 2030 and no less than 85% by 2050 from 1990 levels) be met on an economy-wide basis. The CLCPA also requires that New York State (NYS) direct resources to “achieve a goal for disadvantaged communities to receive 40% percent of overall benefits of spending on clean energy and energy efficiency programs, projects or investments.”⁶

The CLCPA has been a key factor in the evolution of New York’s energy policy since 2019. In line with its requirements, the New York Public Service Commission (NY PSC) issued the *Order Directing Energy Efficiency and Building Electrification Proposals* (Order Directing EE/BE Portfolios) in July 2023. This Order directed the major investor-owned utilities and the New York State Energy Research and Development Authority (NYSERDA) to file energy efficiency (EE) and building electrification (BE) portfolios for 2026-2030 to better align funds distributed through customer programs with NYS climate policy objectives.⁷

On May 15, 2025, the New York Public Service Commission issued two parallel Orders authorizing energy efficiency and building electrification portfolios for 2026-2030 for both the major investor-owned electric and gas utilities and NYSEDA.ⁱⁱ These Orders were issued separately for Low- to Moderate-Income (LMI) and non-LMI customers and both approve EE/BE budgets for 2026-2030 and establish a process under which the EE/BE portfolios and program implementation plans will be approved on an annual basis.^{8,9}

The Order Directing EE/BE Portfolios and the EE/BE Orders help to shape EE and BE policy in NYS. They contain significant discussion of and guidance regarding which building electrification options should be considered strategic and where there is inherent uncertainty regarding policy direction. Foundational policy language can be found early in the Non-LMI EE/BE Order:

ⁱⁱ These Orders will collectively be referred to as the “EE/BE Orders” throughout this report, and the report may specify “Non-LMI” or “LMI” to refer to one of the two Orders. The Utilities subject to the EE/BE Orders include Central Hudson Gas & Electric Corporation (Central Hudson), Consolidated Edison Company of New York, Inc. (Con Edison), KeySpan Gas East Corporation d/b/a National Grid (KEDLI), The Brooklyn Union Gas Company d/b/a National Grid NY (KEDNY), National Fuel Gas Distribution Corporation (NFG), New York State Electric & Gas Corporation (NYSEG), Niagara Mohawk Power Corporation d/b/a National Grid (NMPC), Orange and Rockland Utilities, Inc. (O&R), and Rochester Gas and Electric Corporation (RG&E).

The passage of the CLCPA in 2019 highlighted the need to eliminate on-site combustion of fossil fuels to decarbonize space and water heating needs. As we look ahead to the next era of programming, we must continue to balance achievement of the State's climate policy objectives with our primary mission of ensuring just and reasonable rates.¹⁰

Eliminating on-site combustion of fossil fuels at scale and accomplishing CLCPA goals requires significant evolution of utility EE and BE programs in a coordinated manner. Accordingly, the Commission formalized a Strategic Framework to classify which investments would be considered strategic in NYS and mandated that portfolios developed by the Utilities allocate a minimum of 85% of portfolio funds to Strategic measures, categorized as “electrification and electrification readiness (e.g., building envelope improvements).”¹¹ For LMI customers, the LMI EE/BE Order authorizes Program Administrators to allocate up to 15% of LMI program budgets to support adoption of heat pumps in LMI one- to four-family and affordable multifamily buildings. The Order also points to several LMI electrification principles that must be followed to address energy affordability and mitigate cost shifts from building owners to tenants (in multifamily buildings).¹²

While the original direction to allocate 85% of funds to Strategic measures was developed as part of the Order Directing EE/BE Portfolios, the subsequent EE/BE Orders continued to refine the types of building electrification that should be promoted by utility programs via the New York State Clean Heat Program (NYS Clean Heat). NYS Clean Heat is the primary program that utilities utilize to provide incentives for heat pump systems to facilitate building electrification for non-LMI customers in NYS. It also offers “training and qualification for contractors, inspection and oversight processes to drive quality installations, and marketing and education to attract customers.”¹³

While Clean Heat has become the primary vehicle for advancing building electrification in NYS, the recent EE/BE Orders also reflect growing Commission concern about cost, grid impacts, and appropriate sequencing of electrification at scale. At the same time, the Commission has continued to advance separate but related policy initiatives addressing long-term gas system planning, creating important intersections between building electrification policy and utility gas planning assumptions that warrant further examination.

Hybrid Electrification gas utility long-term plans

On May 12, 2022, the Commission issued an *Order Adopting Gas System Planning Process* (the Gas Planning Order) in Case 20-G-0131, creating a process whereby gas Local Distribution Companies (LDCs) file long-term natural gas system plans every third year and annual updates in non-filing years.¹⁴ These long-term plans (LTPs) provide customers, regulators, and stakeholders with relevant information on how the LDCs plan to adapt to the evolving legislative and regulatory landscape while ensuring they continue to provide safe and reliable service to their customers. They provide the Commission with the ability to evaluate and help shape the future of gas in New York.

Since 2022, all gas LDCs subject to the Gas Planning Order have filed their first LTP, a process that includes stakeholder and independent consultant review.ⁱⁱⁱ While CLCPA goals are economy-wide and therefore gas LDCs are not statutorily assigned sector-specific emissions targets, the Gas Planning Order did establish a foundational process through which the Commission can act to ensure LDCs reduce GHG emissions in accord with the CLCPA.¹⁵ Accordingly, all gas LDC LTPs provide substantial programmatic and strategic consideration of decarbonization technologies, including but not limited to system-wide hydrogen blending, renewable natural gas, EE, and building electrification.

Hybrid Electrification (HE) has been a key strategy proposed in multiple gas utility LTPs. Hybrid Electrification (to be more explicitly defined in the following section) generally refers to electrification where a central or mini-split air source heat pump system is paired with a fossil heating system, where the fossil system serves a portion of the annual heating load based on a pre-determined switchover temperature. The value proposition is that the fossil heating equipment can provide heating during colder temperatures when the heat pump system may operate less efficiently, which could lead to higher operating costs or comfort challenges. This is in contrast to Full Electrification (FE) where the heat pump system is sized to meet the building's entire design day heating demand and operates without a fossil heating system for backup.

In their LTP filings, multiple LDCs identify several *potential* system-level and customer-level benefits of hybrid heating, particularly if adopted at scale and used during winter heating events, as justification for programmatic investments. The cited benefits of Hybrid Electrification include:

- **System reliability and winter performance:** As all utilities must provide safe and reliable service, HE may improve reliability to the extent that there are extended electric outages that coincide with extremely cold temperatures.¹⁶ However, since modern thermal heating appliances typically require electricity to properly operate (e.g., for ignition, controls, and pumps), the reliability benefit largely depends on the presence of a backup generator in the home or building.¹⁷
- **Reduced electric system and infrastructure impacts:** HE configurations, as described above, do not operate a heat pump system below a defined switchover temperature, opting to switch over to a thermal heating source. This reduces or eliminates the winter peak load contribution from heat pump systems, which could provide significant benefits to the electric system in the future. Currently, most utility distribution systems are locally “summer-peaking,” meaning the annual peak demand occurs during the summer months driven largely by air conditioning loads. In these cases, the components of the distribution system (e.g., substation, feeders, transformers) are typically sized to reliably meet a summer peak load. Similarly, NYS’s bulk power system is currently summer-peaking but is projected to become a winter-peaking system sometime in the 2040s, primarily due to the electrification of space heating and transportation.¹⁸ The New York Independent System Operator’s (NYISO) 2025 “Gold Book” projects this shift to occur on a statewide basis

ⁱⁱⁱ The term “gas LDC” and “gas utility” will be used interchangeably throughout this report.

around 2042, but the exact timing depends largely on the uptake of electrification measures.¹⁹ HE can potentially avoid or defer the need for costly upgrades of transmission and distribution capacity, reduce winter generation capacity requirements, and avoid electricity consumption during expensive periods.

- **Participating customer affordability:** Because HE configurations are not designed to meet full design day heating load, they can rely on lower-capacity heat pumps and do not require cold-climate or higher-efficiency models. As a result, the upfront installation costs for HE systems may be lower, particularly when accounting for home electrical upgrades that are often required to accommodate FE. Moreover, natural gas is often lower cost than electricity on an energy-equivalent basis, and operating costs for natural gas heating appliances can be lower than heat pumps at lower temperatures, after consideration of end-use efficiencies. However, HE does require an additional appliance (furnace or boiler) to serve heating load. There may also be important equity considerations associated with HE; to the extent that it reduces costs, it may be a more attractive option for certain LMI customers. Total installation costs of HE and FE will vary and depend on a number of factors; see Section 3 of this report for further discussion.

In the LTPs, HE is often characterized by utilities as a near-to-medium-term pathway that can help to achieve partial GHG emissions reductions while still utilizing thermal heating appliances and taking advantage of the underground gas delivery infrastructure.

Various other jurisdictions in North America have conducted studies on hybrid heating and these studies and outcomes may be relevant to New York stakeholders and policymakers. Figure 1 below summarizes three key case studies based on CRA’s literature review.

Figure 1: Literature review – prior economics analyses of hybrid heating by utility regulators



1.2 Reconciling EE/BE Policy and long-term gas planning

In the 2025 EE/BE Orders, the Commission articulated a framework that distinguished among different types of electrification based on system performance, emissions outcomes, and program objectives. The EE/BE Orders defined four types of electrification for policy and program planning purposes:

- **Full Electrification:** This term refers to the installation of an electric heat pump system that is designed to meet 100 percent of the building's design day heating load. In these scenarios, an electric heat pump is sized to maintain the indoor temperature required by building codes.
- **Partial Electrification:** This term refers to the installation of an electric heat pump system that does not fully meet the building's design day heating load. In these scenarios, the electric heat pump is not sized to maintain the indoor temperature required by building codes. Partial electrification is also sometimes referred to as Part Load Electrification.
- **Phased Electrification:** This term refers to projects wherein the building electrification process is carried out over time. This staged approach aims to electrify most or all of a building's energy systems while minimizing disruptions to building operations and occupant experience. This may be a multifamily or commercial building where certain units of the building are fully converted to electric heat pumps for space heating perhaps at the time of tenant turnover, or as part of a more comprehensive phased renovation project. This may also result in instances where Full Electrification of the building may not be possible due to available electric capacity or limitations related to a customer's capital cycles.
- **Hybrid Electrification:** This term refers to a dual fuel heating system with integrated control that includes an electric heat pump that serves a portion of the building's design day heating load and relies on a fossil system to meet a portion of the load. A hybrid system relies on two separate components with integrated controls designed to operate independently, typically switching a fossil fuel system at some pre-determined lower temperature set point.²⁰

While the Commission distinguishes among Full, Partial, Phased, and Hybrid Electrification for program planning purposes, the quantitative modeling in this HE Study focuses on Full and Hybrid configurations for existing residential buildings.

The Commission's current position is that no Clean Heat incentives shall be provided for electrification not sized to meet the full design day heating load of the home, with limited exceptions for Phased Electrification in larger multifamily buildings.

Conversely, the Commission expressed concern that HE systems employed in gas LTPs often require the installation of a *new* thermal appliance, thus further locking customers into gas usage for the useful life of the equipment. Indeed, gas utility LTPs such as NYSEG and RG&E assume that customers would purchase a new gas heating appliance at the time they adopt a HE configuration.²¹ Accordingly, because HE configurations often include installation of a new

gas heating appliance and rely on heat pumps systems that are not sized to meet full design day heating load, Clean Heat incentives for HE are currently prohibited.

However, the Commission identified a need for further analytical clarity on HE pathways. In particular, how their system-level impacts compare with FE under New York-specific conditions:

... the Commission is persuaded that more information is necessary to truly assess where and how hybrid heating may be advantageous to both the customer adopting such a heating system as well as the longer-term vision of decarbonization and broader impacts on gas and electric systems. This requires analysis and modeling that takes into consideration the potential economic impacts at the participating customer-, ratepayer-, and utility- levels. As such, we direct DPS Staff, in consultation with NYSERDA and the Utilities, to conduct an analysis on various “hybrid” heating scenarios, as informed by previous and ongoing programs and pending utility proposals, that can inform future programming within the EE/BE portfolios and other relevant Commission proceedings. DPS Staff shall confer with the Utilities on this study and employ the services of an independent third-party consultant, if needed. The outcome of such analysis should include the development of an economic model that uses forecasted heat pump technology adoption rates based on inputs, such as energy price forecasts, various heat pump technology costs (both installation costs as well as maintenance and operation costs), alternate building heating system installation and maintenance costs, to evaluate ratepayer impacts and utility revenue requirement impacts. The analysis should also include a review and summary of case studies and learnings from other comparable jurisdictions. Ultimately, a report that outlines general recommendations and guidance to inform future decisions regarding the overall benefits of various hybrid heating programs and proposals versus those of Full Electrification programs shall be filed with the Commission within one year of the date of this Order.²²

This directive established the need for this New York Hybrid Electrification Study (HE Study).

1.3 Study scope and boundaries

This section provides a high-level description of the HE Study scope. The scope was developed by NY DPS Staff in conjunction with CRA. While both NYSERDA and the New York electric utilities provided input throughout the study process, this study should be viewed as independent of those entities.

This study evaluates Hybrid Electrification pathways relative to Full Electrification under New York-specific conditions. Using scenario-based modeling over a long-term planning horizon, the

analysis assesses customer-level outcomes (ownership costs, bill impacts) alongside system-level impacts on electric and gas infrastructure, peak demand, and utility revenue requirements. The HE Study is intended to inform future Commission decisions regarding electrification programming and utility planning, consistent with the directives outlined in the EE/BE Orders.

This study is also intended to be an analysis that more fulsomely addresses the merit of the purported benefits of gas utility LTP hybrid heating proposals. While some of the study's scope extends beyond natural gas customers, other scoping decisions were made explicitly to ensure gas utility LTP proposals can be analyzed by this study. For example, ground-source heat pumps (GSHPs) were excluded from the HE Study scope, as they are not necessarily candidates for Hybrid Electrification, considering the ground-source heat pump performance does not degrade at lower temperatures. It does not rely on a single forecast, consistent with Commission direction, and does not prescribe a single preferred statewide electrification pathway or policy outcome. Instead, it evaluates outcomes across a set of scenarios that reflect a range of plausible futures to capture uncertainty in technology costs and performance, energy prices, utility incentives, customer adoption behavior, etc.

The study provides an analysis of *relative* customer, electric and gas system, and utility bill impacts of residential building electrification. Specifically, the study evaluates the cost-effectiveness of FE and HE relative to a "counterfactual" case in which customers replace their existing space heating equipment in-kind, consistent with current typical equipment replacement decisions absent electrification incentives. It evaluates the impact of total installed cost, net of Clean Heat and other programmatic incentives, and operating costs associated with heat pump adoption. The HE Study does not specifically model Partial or Phased Electrification, though CRA acknowledges their potential value, especially in larger multifamily buildings.

The HE Study estimates the impact of residential building electrification on both the electric distribution system and the bulk power system and translates those system impacts into utility bill effects to support stakeholder and policymaker understanding of how different levels of HE and FE may affect customers across NYS. Specifically, the study will estimate *incremental* distribution, transmission, and electricity supply costs associated with different residential BE pathways.

This effort does not specifically analyze the issues of commercial or industrial building electrification, electric vehicle adoption, demand-side trends (other than assuming uptake of weatherization for the purposes of heat pump adoption), or electric power generation buildout necessary to meet CLCPA goals. Instead, these broader drivers are treated as exogenous background conditions (held consistent across scenarios) so that differences in results isolate the incremental impacts of residential building electrification choices.

Importantly, this study does not remove customer choice for energy options or recommend doing so. The study examines the economics of multiple Full and Hybrid Electrification technologies for a range of customer types and grounds its adoption forecasts in the notion that customers will make decisions in their economic interest.

Finally, the HE Study does not perform detailed transmission and distribution system engineering analyses or site-specific assessments to inform potential electric utility distribution system capital investment decisions. The analysis in Section 6 estimates the potential system-wide distribution headroom on each electric utility's distribution system and the need for bulk power system transmission buildout, but it does not evaluate electrification adoption impacts at a granular circuit- or neighborhood-level. Similarly, the HE Study does not perform detailed bulk power system planning or power flow analyses, nor does it assess specific NYISO transmission projects or interface upgrades. Instead, the bulk power assessment provides order-of-magnitude estimates of incremental transmission needs attributable to residential building electrification, based on high-level assumptions about winter peak growth and transfer requirements across major transmission interfaces.

Further scope boundaries can be found below:

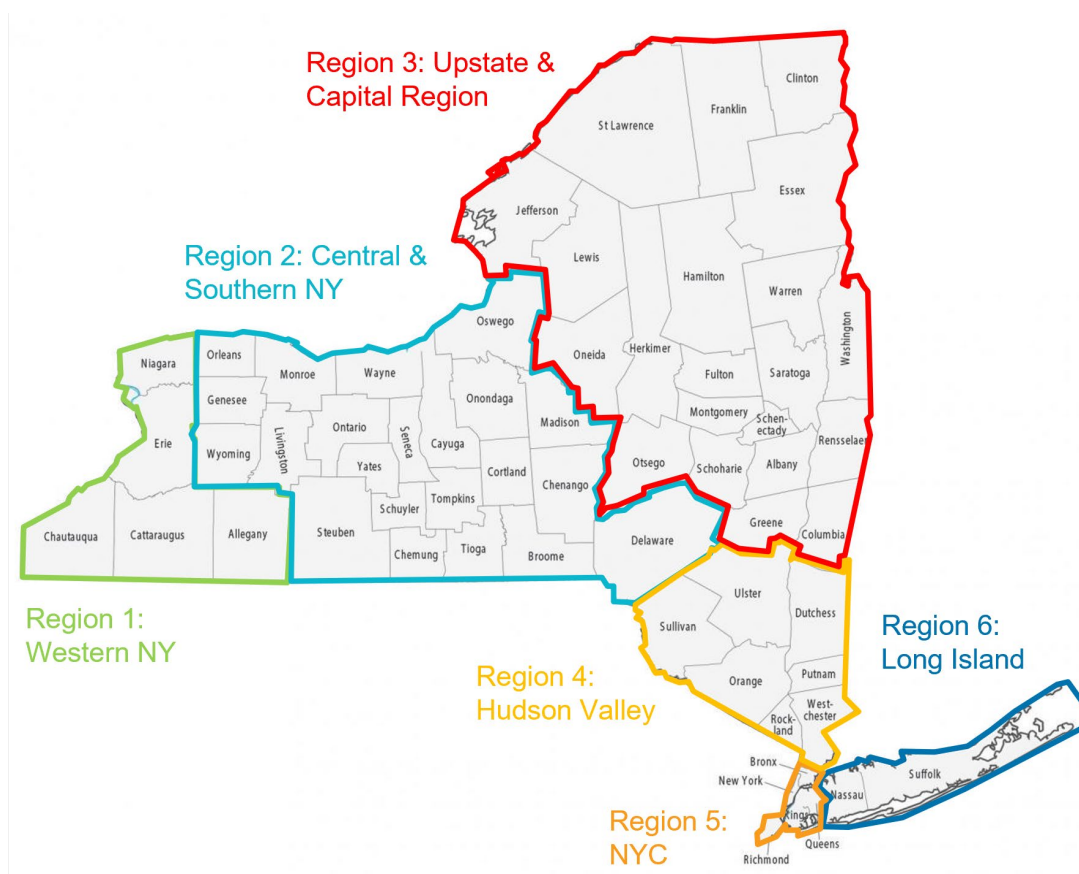
- **Customer segmentation and building types:** This study covers single- and multi-family residential buildings only, as they together represent the majority of space heating load affected by building electrification and are the primary focus of the Clean Heat Program. Commercial and industrial customers are not modeled as part of this study. Consistent with NYS legislation, the study assumes new construction will be all-electric and therefore focuses on existing building retrofits.^{iv,23}
- **Building electrification technologies:** This analysis evaluates the use of both cold climate and non-cold climate (i.e., "standard" or lower efficiency) air source heat pumps to electrify residential buildings. It does not evaluate GSHPs or district heating systems.
- **Time horizon and planning perspective:** The study evaluates various electrification pathways over a long-term planning horizon (2026-2050), consistent with the timeframe used throughout NYS for energy planning and anchored to key CLCPA milestone dates.
- **Weatherization:** The primary focus of this study is residential building electrification. However, the Commission has explicitly tied building envelope improvements to building electrification in the EE/BE Orders, setting specific incentive eligibility based on building envelope. Weatherization is a key step in improving the cost-effectiveness of heat pump adoption, as it ensures the building shell is energy-efficient and minimizes heat loss while

^{iv} The All-Electric Buildings Act, passed in 2023, was set to prohibit all new buildings seven stories or lower, except large commercial and industrial buildings, from using fossil heating appliances beginning on December 31, 2025. The same requirement was to be imposed on all other buildings by December 31, 2028. However, NYS Governor Hochul recently announced that the implementation of the All-Electric Buildings Act will be delayed. For the purposes of the HE Study, CRA assumes this Act will be implemented in the near future and therefore did not include new construction in this analysis.

the heat pump is in operation.^v It reduces the home's total energy needs and therefore allows for optimal heat pump sizing. The HE Study modeling assumes that a significant portion of residential dwellings would receive weatherization (building envelop upgrades) alongside electrification measures. The modeling properly accounts for the upfront cost, energy usage, and peak demand impacts of incorporating weatherization.

- **Geographic scope and regional representation:** To account for key factors that influence building electrification economics, including differences in climate and utility costs, CRA's segmentation of the residential building stock divided customers amongst six distinct "Regions" within NYS. These Regions are intended to balance an appropriate level of detail and granularity with a reasonable level of effort. To the extent practical, the Regions are aligned to pre-existing classifications, including New York State Economic Development Zones (EDZ), NYISO zones, and electric and gas utility service territories. Figure 2 below depicts these Regions.

Figure 2: CRA HE Study region map



^v In this report, "dwelling unit" will be used to refer to a residential home or building. Further discussion on dwelling-unit modeling can be found in Section 2.

Table 1: NYS regions for purposes of New York Hybrid Electrification Study

Region	Name	NYS EDZs	NYISO Zones	Climate Zone (IECC)	Electric Utility(ies)	Gas Utility(ies)
1	Western NY	1	A	5	NMPC, Western NY	National Fuel Gas (NFG)
2	Central & Southern NY	2, 3, 4	B, C	5	NYSEG, RG&E	NYSEG, RG&E
3	Upstate & Capital Region	5, 6, 7	D, E, F	6	NMPC, Upstate NY	NMPC
4	Hudson Valley	8	G, H, I	5	CHG&E, O&R	CHG&E, O&R
5	New York City	9	J	4	CECONY	CECONY, KEDNY
6	Long Island	10	K	4	LIPA (PSEG LI)	KEDLI

1.4 Navigating the HE Study

The main body of this report contains an Executive Summary and ten sections:

ES Executive Summary

1. Introduction and study scope
2. Market and technology characterization
3. Costs of electrification
4. Modeling framework and scenario design
5. Customer-electrification modeling outputs: Customer-level cost and emissions impacts
6. Electric system impacts
7. Natural gas system impacts
8. Revenue requirement and bill impact analysis
9. Univariate sensitivities
10. Policy considerations and conclusion

Further detail on methodology and assumptions can be found in the appendices, which includes two Appendix sections and three Data Annexes as follows:

- CRA New York HE Study – Appendices A & B
 - Appendix A: Electrification Adoption Modeling Methodology
 - Appendix B: Revenue Requirement and Bill Impact Methodology
- CRA New York HE Study Data Annex 1: Residential Building Electrification Modeling Outputs
- CRA New York HE Study Data Annex 2: Technology and Customer Input Assumptions (Costs, Performance, Incentives, Archetypes, and End-Use Load Profiles)
- CRA New York HE Study Data Annex 3: Power & Gas Market and Revenue Requirement & Bill Impact Assumptions

2. Market and technology characterization

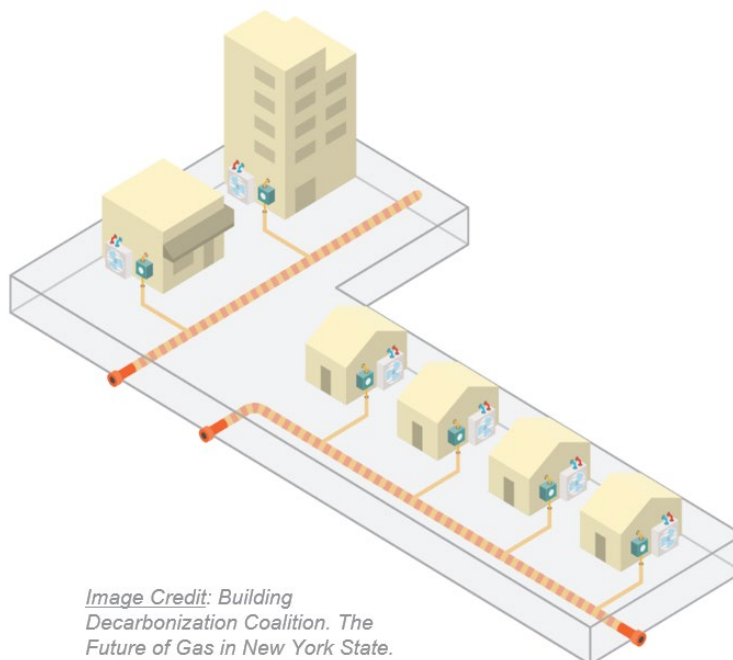
This section first analyzes the residential space heating technologies in NYS that are potentially relevant to Full and Hybrid Electrification. It describes the process for segmenting the NYS residential building stock into discrete customer archetypes, how these customer archetypes are aligned with electrification upgrade measures based on technical feasibility, the end-use load modeling of individual customer dwellings, the operating and performance characteristics of electrification measures, and the aggregation of results by customer archetype.

As described in Section 1, Hybrid Electrification in the context of the HE Study is defined as follows:

... a dual fuel heating system with integrated control that includes an electric heat pump that serves a portion of the building's design day heating load and relies on a fossil system to meet a portion of the load. A hybrid system relies on two separate components with integrated controls designed to operate independently, typically switching a fossil fuel system at some pre-determined lower temperature set point.²⁴

While this typically refers to heat pumps paired with high-efficiency natural gas furnaces or boilers for backup heating, it can also refer to heat pumps with fuel oil or propane (delivered fuel) heating systems as backup. Figure 3 below provides a graphic illustration of hybrid heating with natural gas equipment as backup.

Figure 3: Illustration of Hybrid Electrification with Natural Gas Backup



*Image Credit: Building
Decarbonization Coalition. The
Future of Gas in New York State.*

Subsection 2.1 reviews and synthesizes available data on the following types of residential heating technologies:

- “Standard” heat pumps;
- Cold climate heat pumps listed on the Northeast Energy Efficiency Partnership’s (NEEP) qualified list;
- High-efficiency natural gas furnaces, boilers, and other fossil fuel heating equipment; and
- Hybrid systems combining the technologies above.

The types of electrification CRA considered in the HE Study can be classified as either Full Electrification or Hybrid Electrification. In consultation with NY DPS Staff, NYSERDA, and Con Edison, CRA defined the relevant electrification upgrade options based on the prevalence of certain technologies in the New York market, including through the NYS Clean Heat. Partial Electrification and Phased Electrification were not explicitly considered in the HE Study.^{vi}

Subsection 2.2 details the first step of the residential stock modeling process: forming representative customer archetypes, where the statewide residential housing stock is formalized into categories for the purposes of policy application and modeling. Subsection 2.3 details the methodology behind the selection of electrification measures made available to each customer archetype. Next, Subsections 2.4 and 2.5 give an overview of the individual building level modeling of energy demands, followed by the aggregation of outputs into archetypes in Subsection 2.6. Lastly, the emissions accounting methodology is specified in the following Subsection 2.7.

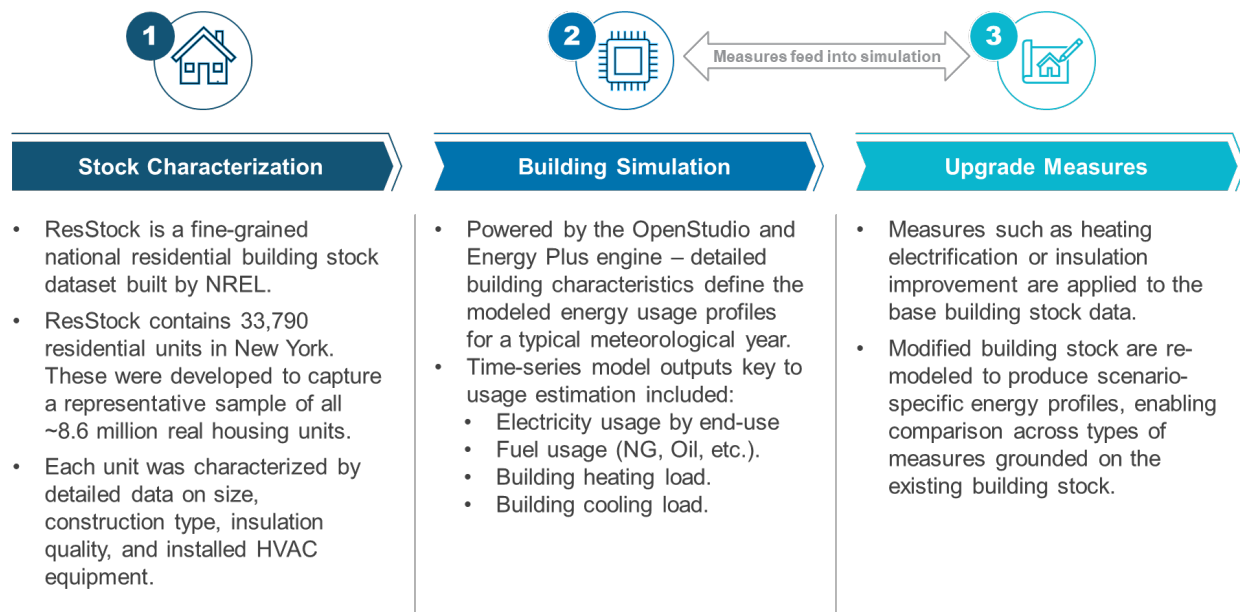
CRA used the NREL ResStock platform in two key steps of the modeling process:

1. Characterization of New York’s residential stock; and
2. Use of the corresponding Building Energy Models for detailed end-use load profiles (EULPs) for various heating equipment configurations.

Figure 4 below provides an overview on how ResStock was used to characterize and simulate the New York residential building stock; this is covered in more detail in the following subsections.

^{vi} In the EE/BE Orders, Partial Electrification is defined as the installation of an electric heat pump system that does not fully meet the building’s design-day heating load. The heat pump is not sized to maintain the required indoor temperature on its own. Phased Electrification is where electrification is carried out over time, often in larger buildings. For example, certain units or systems are converted to electric heat pumps as opportunities arise (e.g., at tenant turnover or as part of a staged renovation), with the goal of eventually electrifying the whole building. Based on alignment with NY DPS Staff, CRA’s analysis in this HE Study did not include Partial or Phased Electrification, only Full and Hybrid Electrification.

Figure 4: ResStock residential stock representation and simulation process



2.1 Overview of residential heat pump technologies

The HE Study evaluated residential customer Full and Hybrid Electrification for four different heat pump technologies:

- Central ASHP;
- Mini-split ASHP;
- Air-to-water heat pump (AWHP); and
- Packaged window heat pump (PWHP).

Central ASHP or “ducted” systems typically include a single ASHP outdoor unit that utilizes a central air handler and existing ductwork to circulate conditioned air throughout the customer premise. Central ASHP systems are highly efficient and are most suitable for single-family homes with existing forced air heating from a furnace. Hybrid systems utilizing a central ASHP rely on the ASHP unit to provide space heating at temperatures above a pre-defined switchover temperature (e.g., 30°F) and then switchover to provide heat with the fossil-based furnace. In the case of Full Electrification, additional costs may be required to expand the dwelling’s ducts to allow for the volume of air required by heat pumps, versus a furnace. However, many homes with existing forced-air heating systems can utilize existing ductwork without significant modification, depending on the condition and design of the distribution system.

Mini-split ASHP or “ductless” systems contain one or more outdoor condenser unit(s) matched to one or more indoor head(s) that provide conditioned air directly into a room or space. Mini-splits can typically be configured for and installed in almost any customer dwelling. This makes mini-splits particularly attractive for dwellings without existing ductwork. They are

also more modular than central systems and can either heat and cool a single room or zone or be expanded into multi-zone systems. Hybrid mini-split systems can be installed separately from and in addition to the HVAC system that the fossil-based system uses to provide space heating, including central forced air or hydronic distribution systems. Mini-splits can have a higher upfront installation cost, particularly for large single-family homes where space conditioning of multiple zones or levels is required. These are often more advantageous for apartments, multifamily buildings, or older single-family homes without ductwork.

AWHP systems or “hydronic” systems use a heat pump to extract thermal energy from the outdoor air to heat water that is distributed through hydronic hot water pipes to radiators or underfloor heating to provide space heating. These systems can also be used to provide hot water. AWHPs tend to have slightly lower efficiencies than ASHP systems and they cannot provide space cooling, only heating, meaning customers may miss out on the efficiency benefits and resulting bill savings of heat pumps in the summer months, when compared with central or window AC systems. AWHP systems can be appropriate and cost-effective in cases where dwellings already use hydronic hot water pipes to provide space heating. A significant portion of the older pre-1950s housing stock in NYS, particularly the NYC multifamily stock, relies on hydronic hot water systems. A hybrid AWHP system would use the same hot water distribution system as the existing fossil heating system and switchover at a defined setpoint temperature from heating with the AWHP to heating with the fossil heating system. Some stakeholders have suggested that hybrid AWHP systems could be run simultaneously at cold temperatures to leverage the combined output capabilities of both the AWHP and the fossil fuel heating system to meet heating demands, though that use case is not specifically modeled as part of the HE Study.

PWHP systems or “window heat pumps” are heat pumps that can be placed in a window, like a window air conditioning unit, use a 120V/15A wall outlet, and are self-contained with no external drainage, pipes, or plumbing. PWHP systems are emerging as a commercially viable option for space heating electrification, particularly for apartments and multifamily buildings in New York City. At least two models are commercially available: the Midea America Heat Pump and the Gradient Comfort Heat Pump. These models are being studied and tested by NYSERDA as a part of the Clean Heat for All Challenge, a \$70M joint project by New York City Housing Authority (NYCHA), New York Power Authority (NYPA), and NYSERDA to install 30,000 PWHPs in NYCHA buildings.²⁵ NYSERDA’s study also analyzed the economics of PWHPs, observing a meaningful installed cost advantage for PWHPs versus Variable Refrigerant Flow (VRF) and mini-split systems in a sample of NYC high-rise buildings, as well as advantages versus ductless and ducted systems. Hybrid PWHP systems would rely on distributed apartment window systems for space heating above a certain switchover temperature, before switching to a central furnace or boiler fossil heating system for heating below this temperature. This study only considers PWHP systems as an option for Full and Hybrid Electrification in multifamily buildings.

Other heat pump technologies, including VRF and Packaged Terminal Heat Pumps (PTHP), are also being deployed in multifamily buildings in NYS and may be a best fit in some limited instances. These technologies were not considered in the context of the HE Study modeling because their applicability is primarily limited to MF high-rise buildings and the data suggests these systems are typically higher cost than mini-split or PWHP options.

2.2 Customer archetype framework

The customer archetype framework was designed to segment and categorize the NYS residential housing stock based on key variables that influence the heating needs of the dwelling (influencing the sizing and operating expense of the heating system installed), customer energy usage, electric and gas utility rates, the upfront incentives available to the customer, and the physical limitations on the electrification measures available to the unit.

Variation in heating needs were captured through a combination of building type, region, and construction vintage. Rates and incentives were represented through a regional variable approximately delineated by utility service territories, along with the inclusion of LMI status. The physical characteristics of the unit that constrain feasible electrification measures were then modeled by the existing heating system type and its associated distribution and terminal unit systems. The full set of variables used for the archetypes are reported in detail in Data Annex 2, and an overview of the electrification measure logic is provided in the following Subsection 2.3.

Each of the 33,790 units represented in ResStock's NYS data set was initially categorized into a customer archetype. Archetypes deemed not eligible for electrification for the purposes of the HE Study (i.e., steam-based systems or units already electrified) or with low prevalence were excluded from the final archetype set. To ensure that these exclusions did not result in an underrepresentation of the overall residential housing stock, the remaining archetypes were scaled proportionally to represent the full statewide housing stock, such that the modeled archetypes continued to sum to the total number of residential dwelling units in NYS.

This process results in 141 single-family archetypes for single-family homes and 278 multifamily archetypes, or 419 total archetypes that together represent approximately 84% of the total residential housing stock in NYS. These adjustments and the general process for archetype development were shared and verified with both NYSERDA, NY DPS Staff, and Con Edison (to capture complex multifamily archetypes and electrification upgrade configurations). As an example, Table 2 below lists the ten most common archetypes for single-family customers, accounting for approximately 28% of the total SF dwellings eligible for electrification in the dataset.

Table 2: Top ten single-family archetypes (most prevalent)

Region	Vintage	Heating Fuel	Unit Type	Heating Distribution	Terminal Unit	AC Type	LMI
Region 5	Pre-1980	NG	Hot Water Boiler	Hydronic	Radiators	Window	Non-LMI
Region 5	Pre-1980	NG	Hot Water Boiler	Hydronic	Radiators	Window	Low-Income
Region 5	Pre-1980	NG	Hot Water Boiler	Hydronic	Radiators	Central	Non-LMI
Region 2	Pre-1980	NG	Furnace	Ducts	Vents	Central	Non-LMI
Region 6	Pre-1980	FOP	Furnace	Ducts	Vents	Central	Non-LMI
Region 2	Pre-1980	NG	Furnace	Ducts	Vents	Window	Non-LMI
Region 6	Pre-1980	NG	Furnace	Ducts	Vents	Central	Non-LMI
Region 6	Pre-1980	NG	Furnace	Ducts	Vents	Window	Non-LMI
Region 2	Post-1980	NG	Furnace	Ducts	Vents	Central	Non-LMI
Region 1	Pre-1980	NG	Furnace	Ducts	Vents	Central	Non-LMI

2.3 Choice of electrification measures by archetype

Each archetype was matched to a set of potential electrification measures determined by CRA in consultation with NY DPS Staff, NYSEERDA, and Con Edison. These measures were determined based on the physical characteristics of the dwelling. From the customer archetype data in ResStock, the key factors driving electrification measure selection were the customer’s existing fuel type, heating equipment (and associated distribution and terminal units), and air conditioning type.

Different electrification measures were deemed available to different archetypes in FE and HE configurations. CRA made some decisions to limit the types of electrification upgrades available to certain customer archetypes, where the upgrades would be infeasible, impractical, or not cost-effective:

- Hot water boilers with hydronic radiators were eligible for AWHPs, whereas units with a furnace in place were not.
- AWHPs were considered able to interface with hydronic systems for both FE and HE, but steam systems were considered ineligible due to the difficulty of a heat pump producing water at high enough temperatures for steam.

- Dwellings with ductwork installed solely for central air conditioning that did not utilize forced-air heating (e.g., homes with boiler-based systems) were not considered candidates for central ASHPs, as CRA assumed such duct systems were sized only for cooling loads and that electrification would therefore require substantial ductwork modification or replacement.
- Single-family dwellings were not eligible to adopt PWHPs; only multifamily dwellings.

Additionally, building envelope upgrades were applied to dwellings that do not meet an insulation integrity threshold in order to satisfy both heat pump installation incentive requirements and installation best practices.

Each customer archetype had one or more FE and one or more HE measures available to it. In most cases, customers had four total electrification measures available, such that they could adopt either central ASHP, mini-split ASHP, or AWHP, depending on the building configuration. Table 3 outlines the available FE and HE measures available to single-family customer archetypes.

Table 3: Electrification measures available for SF archetypes

Fuel Type	Heating Equipment	AC Type	Hybrid Electrification Measures	Full Electrification Measures
NG	Hot Water Boiler	Central	Mini-split ASHP; AWHP	Mini-split ccASHP; AWHP
NG	Hot Water Boiler	Window	Mini-split ASHP; AWHP	Mini-split ccASHP; AWHP
NG	Hot Water Boiler	No AC	Mini-split ASHP; AWHP	Mini-split ccASHP; AWHP
FOP	Hot Water Boiler	Central	Mini-split ASHP; AWHP	Mini-split ccASHP; AWHP
FOP	Hot Water Boiler	Window	Mini-split ASHP; AWHP	Mini-split ccASHP; AWHP
FOP	Hot Water Boiler	No AC	Mini-split ASHP; AWHP	Mini-split ccASHP; AWHP
NG	Furnace	Central	Central ASHP; Mini-split ASHP	Central ccASHP; Mini-split ccASHP
FOP	Furnace	Central	Central ASHP; Mini-split ASHP	Central ccASHP; Mini-split ccASHP
NG	Furnace	Window	Central ASHP; Mini-split ASHP	Central ccASHP; Mini-split ccASHP
FOP	Furnace	Window	Central ASHP; Mini-split ASHP	Central ccASHP; Mini-split ccASHP

NG	Furnace	No AC	Central ASHP; Mini-split ASHP	Central ccASHP; Mini-split ccASHP
FOP	Furnace	No AC	Central ASHP; Mini-split ASHP	Central ccASHP; Mini-split ccASHP

The same rules as above apply to multifamily dwellings, except that all multifamily dwellings also have the option of a PWHP for both Full and Hybrid Electrification. Table 4 below presents the electrification measures available to MF customer archetypes.

Table 4: Electrification measures available for MF archetypes

Low-Rise (both NYC and non-NYC) Multifamily Archetype and Electrification Measure Summary				
Fuel Type	Heating Equipment	AC Type	Hybrid Electrification Measures	Full Electrification Measures
Natural Gas	Steam Boiler	Window	Hybrid heating with mini-split ASHP; PWHP	Mini-split ccASHP; PWHP
Natural Gas	Steam Boiler	Central	Hybrid heating with mini-split ASHP; PWHP	Mini-split ccASHP; PWHP
Natural Gas	Steam Boiler	No AC	Hybrid heating with mini-split ASHP; PWHP	Mini-split ccASHP; PWHP
Natural Gas	Hot Water Boiler	Central	Hybrid heating with mini-split ASHP; PWHP; AWHP	Mini-split ccASHP; PWHP
Natural gas	Hot Water Boiler	Window	Hybrid heating with mini-split ASHP; PWHP; AWHP	Mini-split ccASHP; AWHP; PWHP
Natural Gas	Hot Water Boiler	No AC	Hybrid heating with mini-split ASHP; PWHP; AWHP	Mini-split ccASHP; AWHP; PWHP
FOP	Hot Water Boiler	Window	Hybrid heating with mini-split ASHP; PWHP; AWHP	Mini-split ccASHP; AWHP; PWHP
FOP	Hot Water Boiler	No AC	Hybrid heating with mini-split ASHP; PWHP; AWHP	Mini-split ccASHP; AWHP; PWHP
FOP	Hot Water Boiler	Central	Hybrid heating with mini-split ASHP; PWHP; AWHP	Mini-split ccASHP; AWHP; PWHP
FOP	Steam Boiler	Window	Hybrid heating with mini-split ASHP; PWHP	Mini-split ccASHP; PWHP

FOP	Steam Boiler	No AC	Hybrid heating with mini-split ASHP; PWHP	Mini-split ccASHP; PWHP
FOP	Steam Boiler	Central	Hybrid heating with mini-split ASHP; PWHP	Mini-split ccASHP; PWHP
Natural gas	Furnace	Central	Hybrid heating with central OR Mini-splits; PWHP	Central ccASHP; mini-split ccASHP; PWHP
Natural Gas	Furnace	Window	Hybrid heating with central OR Mini-splits; PWHP	Central ccASHP; mini-split ccASHP; PWHP
Natural gas	Furnace	No AC	Hybrid heating with central OR Mini-splits; PWHP	Central ccASHP; mini-split ccASHP; PWHP

NYC Mid-Rise Multifamily Archetype and Electrification Measure Summary

Fuel Type	Heating Equipment	AC Type	Hybrid Electrification Measures	Full Electrification Measures
Natural Gas	Steam Boiler	Window	Hybrid heating with mini-split ASHP; PWHP	Mini-split ccASHP; PWHP
Natural Gas	Steam Boiler	Central	Hybrid heating with mini-split ASHP; PWHP	Mini-split ccASHP; PWHP
Natural Gas	Steam Boiler	No AC	Hybrid heating with mini-split ASHP; PWHP	Mini-split ccASHP; PWHP
Natural Gas	Hot Water Boiler	Window	Hybrid heating with mini-split ASHP; PWHP; AWHP	Mini-split ccASHP; AWHP
Natural Gas	Hot Water Boiler	Central	Hybrid heating with mini-split ASHP; PWHP; AWHP	Mini-split ccASHP; AWHP
Natural Gas	Hot Water Boiler	No AC	Hybrid heating with mini-split ASHP; PWHP; AWHP	Mini-split ccASHP; AWHP
FOP	Hot Water Boiler	Central	Hybrid heating with mini-split ASHP; PWHP; AWHP	Mini-split ccASHP; AWHP
FOP	Hot Water Boiler	Window	Hybrid heating with mini-split ASHP; PWHP; AWHP	Mini-split ccASHP; AWHP
FOP	Hot Water Boiler	No AC	Hybrid heating with mini-split ASHP; PWHP; AWHP	Mini-split ccASHP; AWHP
FOP	Steam Boiler	Window	Hybrid heating with mini-split ASHP; PWHP	Mini-split ccASHP; PWHP

FOP	Steam Boiler	Central	Hybrid heating with mini-split ASHP; PWHP	Mini-split ccASHP; PWHP
FOP	Steam Boiler	No AC	Hybrid heating with mini-split ASHP; PWHP	Mini-split ccASHP; PWHP
NYC High-Rise Multifamily Archetype and Electrification Measure Summary				
Fuel Type	Heating Equipment	AC Type	Hybrid Electrification Measures	Full Electrification Measures
Natural Gas	Steam Boiler	Window	Hybrid heating with mini-split ASHP; PWHP	Mini-split ccASHP; PWHP
Natural Gas	Steam Boiler	Central	Hybrid heating with mini-split ASHP; PWHP	Mini-split ccASHP; PWHP
Natural Gas	Steam Boiler	No AC	Hybrid heating with mini-split ASHP; PWHP	Mini-split ccASHP; PWHP
Natural Gas	Hot Water Boiler	Window	Hybrid heating with mini-split ASHP; PWHP; AWHP	Mini-split ccASHP; AWHP; PWHP
Natural Gas	Hot Water Boiler	Central	Hybrid heating with mini-split ASHP; PWHP; AWHP	Mini-split ccASHP; AWHP; PWHP
Natural Gas	Hot Water Boiler	No AC	Hybrid heating with mini-split ASHP; PWHP; AWHP	Mini-split ccASHP; AWHP; PWHP
FOP	Hot Water Boiler	Central	Hybrid heating with mini-split ASHP; PWHP; AWHP	Mini-split ccASHP; AWHP; PWHP
FOP	Hot Water Boiler	Window	Hybrid heating with mini-split ASHP; PWHP; AWHP	Mini-split ccASHP; AWHP; PWHP
FOP	Hot Water Boiler	No AC	Hybrid heating with mini-split ASHP; PWHP; AWHP	Mini-split ccASHP; AWHP; PWHP
FOP	Steam Boiler	Central	Hybrid heating with mini-split ASHP; PWHP	Mini-split ccASHP; PWHP
FOP	Steam Boiler	Window	Hybrid heating with mini-split ASHP; PWHP	Mini-split ccASHP; PWHP
FOP	Steam Boiler	No AC	Hybrid heating with mini-split ASHP; PWHP	Mini-split ccASHP; PWHP

2.4 End-use load modeling

CRA develop detailed EULPs for all customer archetypes for each applicable electrification upgrade. These are detailed physics simulations created using the National Renewable Energy Laboratory's (NREL) ResStock model that produce an hourly (8760) load shape with detailed electricity, natural gas, and other fuel consumption. The first step is to determine the appropriate size of the heat pump for the electrification upgrade. Accurately sizing the HVAC system for a home is essential to properly optimizing the installed and operational costs of a heat pump. The sizing methodologies used were distinct between the counterfactual, HE, and FE configurations, following three primary steps:

1. Develop estimated hourly heating load of the home, typically done through the Manual J calculation, but approximated for this study using hourly modeled heat load outputs from ResStock.^{vii}
2. Determined design temperature for the region (99.6% coldest condition) and corresponding design load at that temperature.
3. Matching a system to meet the load requirements.

CRA used the guidelines outlined by The American Society of Heating, Refrigerating and Air-Conditioning Engineers, simplified by the direct simulated heating load data provided from the ResStock building energy model. The maximum heating need that systems were sized to was determined by the *design temperature* from the *Design Day Conditions* (DDY) by region, representing 99.6% of design day heating load.^{viii} Under the FE configuration, the heat pump system was sized to meet the full heating load up to the heating load design temperature. Under the HE configuration, the heat pump system was sized to meet the heating load up to the *switchover temperature* of 30°F, and the fossil unit was sized to cover the gap between the heating load at switchover and design temperature. The counterfactual configuration (i.e., the previous system replaced like-for-like with a high-efficiency furnace or boiler) was sized to meet the design load.

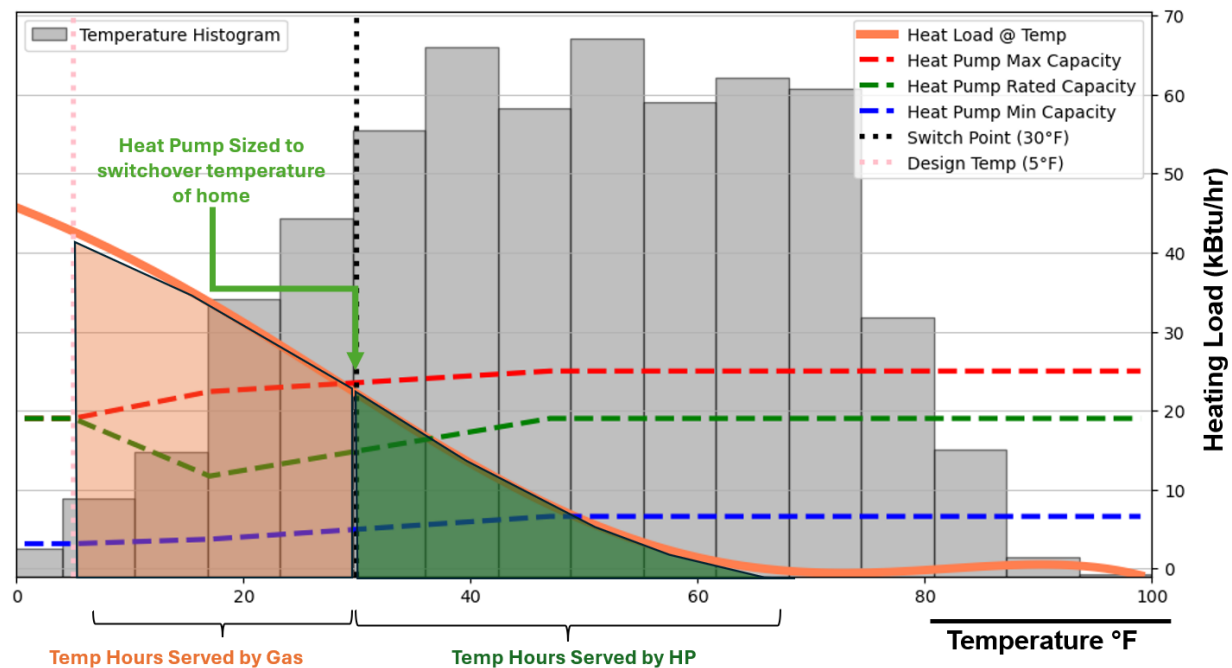
An example of the sizing process is depicted in Figure 5, showing a sample archetype under a Hybrid Electrification configuration. The orange line represents the heat load (output of heating system per hour in kBtu required to maintain the indoor setpoint temperature) across the range of outdoor temperatures. At outdoor temperatures greater than 60°F, heating load is at or near zero, and increases as temperatures grow colder. The grey histogram in the background depicts the frequency of each temperature in a typical year (most hours are between 20°F and 80°F).

^{vii} Manual J 8th Edition is the national ANSI-recognized standard for producing HVAC equipment sizing loads for residential buildings. Manual J is required by national building codes and most state and local jurisdictions.

^{viii} Annual design conditions for heating correspond to the 99.6% and 99% cumulative frequency of occurrence as defined in the ASHRAE Standard 169-2021. For the purposes of load calculation, the 99.6% design day conditions were used by CRA from the NREL Energy Plus data library. Individual gas utilities utilize different definitions of design day conditions from each other and from NREL or ASHRAE for planning purposes.

The dashed lines detail a heat pump's output capability range across outdoor conditions. Finally, the vertical lines are examples of a defined switchover temperature (30°F) and a design temperature (5°F). Since this is a *HE* configuration, the heat pump system is sized such that the heating load just barely exceeds the heating need at the switchover temperature. Under an *FE* configuration, the heat pump system would be sized to meet the 5°F design load, and there would be no gas system present.

Figure 5: Heat pump sizing and annual heating split



The heat pump data used for sizing is reflective of real-world Coefficients of Performance (COP) at rated temperatures across cold climate and non-cold climate models to accurately capture capacity degradation, detailed in subsection Heat Pump Technology Operating Characteristics & Performance2.5. Under both *FE* and *HE* configurations, the heating load is the determining factor in system unit sizing, and electric load from space cooling is determined by derating the air conditioning unit capacity based on the size of the system installed for heating.

Under the *FE* configuration, water heating profiles previously fueled by NG or FOP were converted to electric profiles with an improved efficiency accounting for electric and air source heat pump water heating. All other end-use loads consuming fuel (cooking appliances, dryers, etc.) were converted into electric usage on an equivalent kW basis. For the *HE* configuration, the fuel-based EULPs other than space heating (i.e., water heating, cooking appliances, etc.) were left unchanged.

The average resulting EULP by configuration is shown in Figure 6. In alignment with the modeling logic, the *CF* configuration has the highest monthly consumption of fuels, while the *FE*

configuration has no consumption whatsoever. The impact of the HE configurations is seen most in the winter, when the heat pump displaces energy used towards space heating, as opposed to other end uses that it cannot serve. For electric load the FE configuration dominates as all fuel-based heating is shifted to the heat pump. In the summer months FE and HE configurations are at similar or lower levels to the CF as higher efficiency heat pumps and envelope upgrades were applied.

Figure 6: Average monthly fuel use by scenario across archetypes

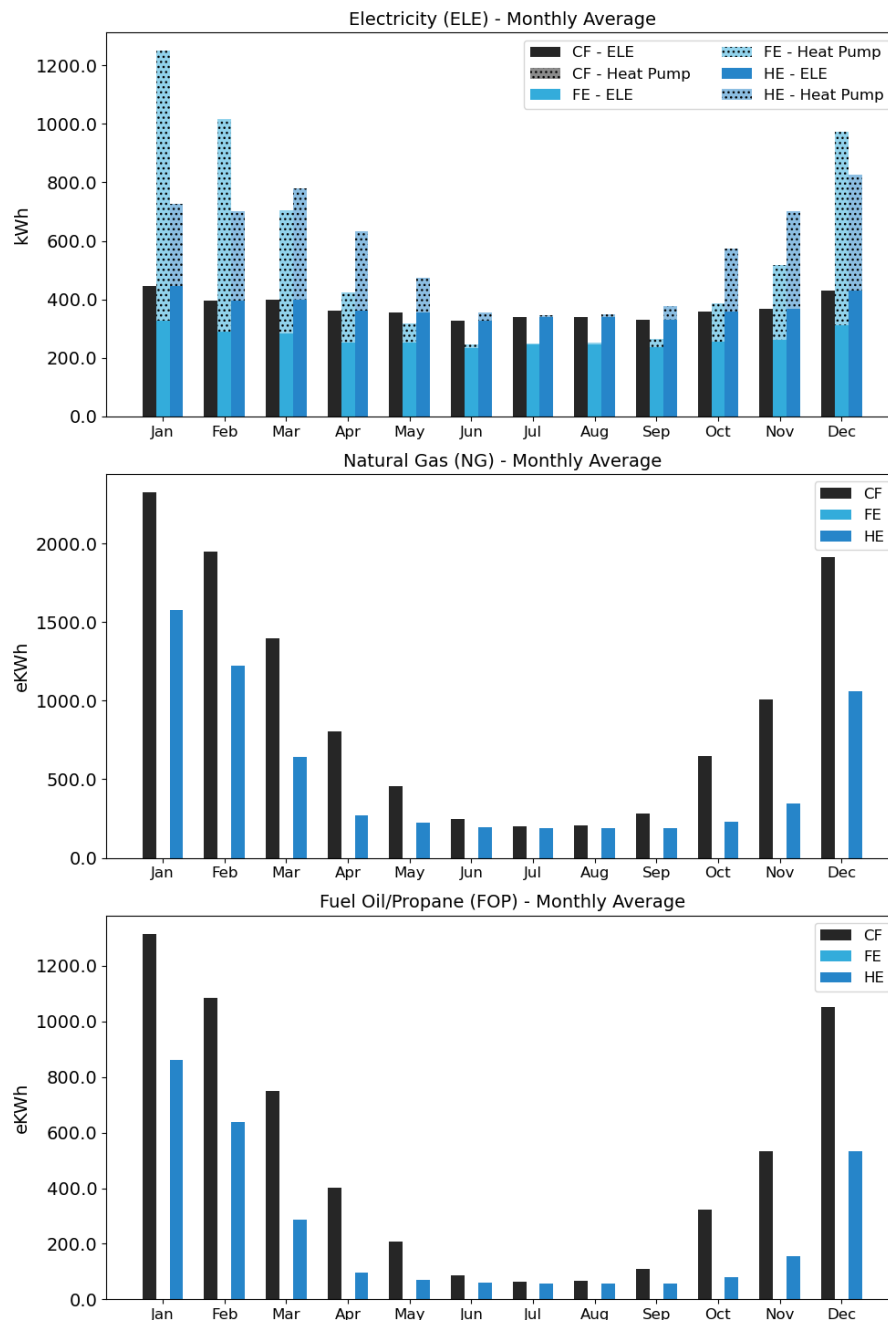


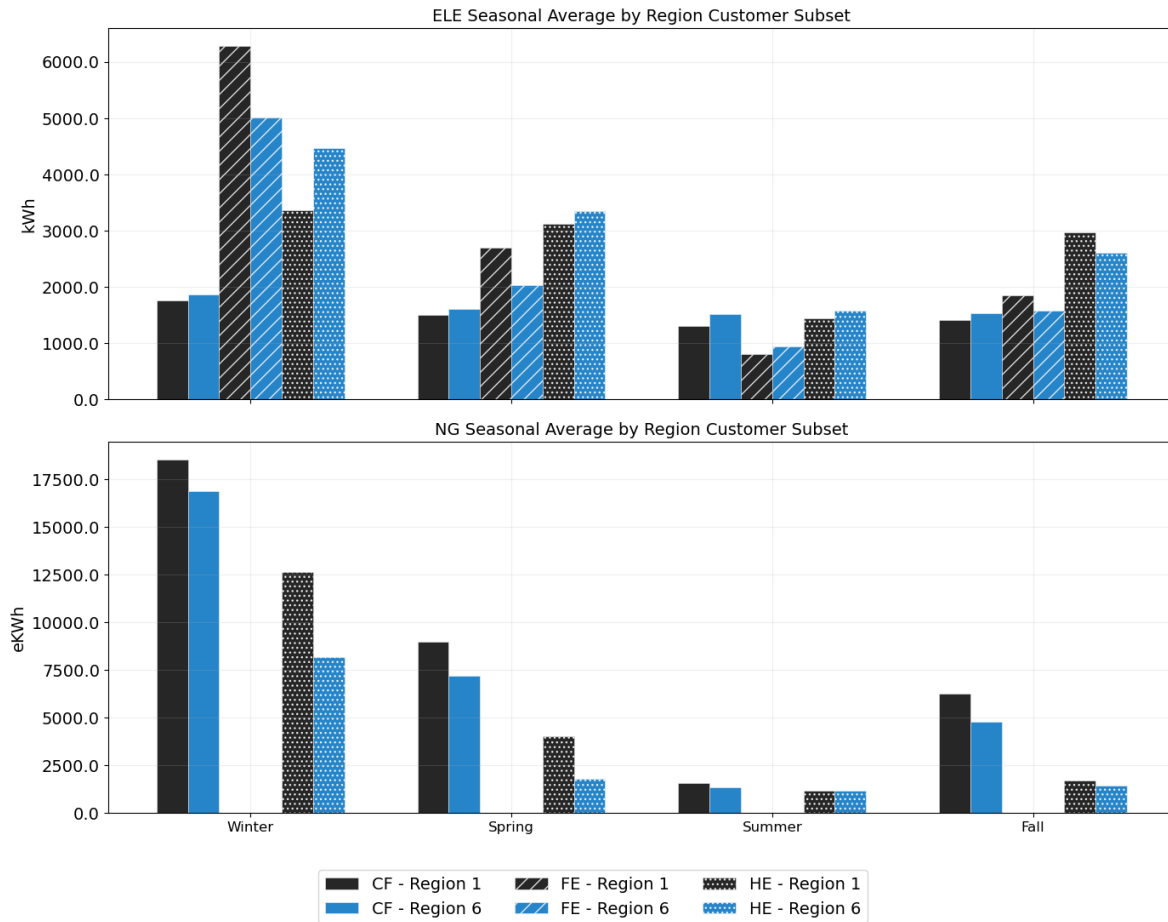
Figure 7 illustrates seasonal differences in EULPs for single-family natural gas customer archetypes between two different weather regions: Region 1 (Western NY) and Region 6 (Long Island) under the CF, FE and HE configurations.

Natural gas consumption follows expected climate patterns: Region 1, with the colder winters, exhibits the highest gas consumption in the heating season, while Region 6, with the milder climate, shows the lowest. For both regions summer gas consumption converges as space heating demand drops and load is driven primarily by non-heating end uses such as water heating and cooking.

The electric load profiles reveal a more nuanced dynamic. Under FE configurations, winter electric load is higher in Region 1, consistent with the greater heating demand in colder climates. Under HE configurations, however, this relationship is conditional on the climate. The difference stems from the distribution of temperatures relative to the switchover temperature. In Region 1, a substantial share of winter hours falls below the switchover temperature, shifting a meaningful portion of heating load back to the natural gas system and materially reducing total electric demand. In Region 5, winter temperatures are largely concentrated above the switchover threshold, such that HE and FE configurations produce similar winter electric load profiles. In terms of annual accounting, 10% of total hours in Region 5 fall below 30°F, meaning 90% of hours are above or equal to 30°F. Region 1 has a slightly higher share of hours below 30°F, at 18%, resulting in 82% of hours being above or equal to 30°F. This interaction between regional climate and switchover temperature results in Region 5 having the greater winter electric load under the HE configuration.

The electric usage differences between FE and HE configurations in the summer and shoulder seasons reveals the efficiency differences between the heat pump systems. FE configurations were sized to serve the full heating load and are therefore larger than the HE systems. The efficiency gains from a larger system utilizing a lower range of its full output are the primary driver of FE systems consuming less electricity than HE systems, especially clear in seasons when the majority of the temperature range is above the switchover temperature. To a lesser extent, the FE systems being cold climate heat pumps with better performance characteristics than the HE systems is a contributing factor to this observation.

Figure 7: Comparison of EULPs across archetypes in Region 1 and Region 6



2.5 Heat pump technology operating characteristics & performance

The modeling of the performance characteristics of heat pumps across outdoor conditions is a key component of the HE Study. For each configuration and measure type, manufacturer specifications of real-world heat pump ratings were used to develop the performance profile. The COP of a heat pump at a given moment is based on two conditions: the outdoor temperature, and the heating output of the system relative to its minimum and maximum rated capability. By way of example, Table 5 below details the performance specifications for one of the cold climate mini-split systems modeled. At each outdoor temperature, there is an associated heating minimum, rated, and maximum output capability for the unit, with matching set of COP values at each output level.

Table 5: Heat pump specifications for Mitsubishi M-Series Mini-split Heat Pump, AHRI 211289244

Outdoor Temp	Heat Max	Cool Max	Heat Rated	Cool Rated	Heat Min	Cool Min	COP Min	COP Rated	COP Max
-4	4,500	-	-	-	1,400	-	4.10	-	3.07
5	5,600	-	-	-	1,800	-	3.77	-	3.04
17	6,900	-	6,900	-	2,400	-	4.14	2.50	2.50
47	12,000	-	11,000	-	4,010	-	5.11	3.98	3.74
82	-	9,100	-	-	-	4,200	8.79	-	4.85
95	-	9,000	-	9,000	-	3,600	6.21	3.94	3.94

Heat pump systems generally exhibit higher COPs during part-load operation and lower COPs as operation approaches the system’s maximum heating capacity. At temperatures near freezing, COP typically exhibits a temporary dip due to frost accumulation on the outdoor heat exchanger and the associated need for periodic defrost cycles, after which performance often stabilizes or modestly improves as air temperatures continue to decline and frost formation becomes less prevalent. Figure 8 displays these characteristics for the same mini-split heat pump – the COP at the minimum capacity rating is above the values at the maximum rated output, and as temperature and heating output vary, the COP declines as well. The combination of these two variances form a 3-dimensional plane describing the COP given the outdoor and heat pump output conditions shown in Figure 9.

Figure 8: Heat pump performance across temperature and capacity

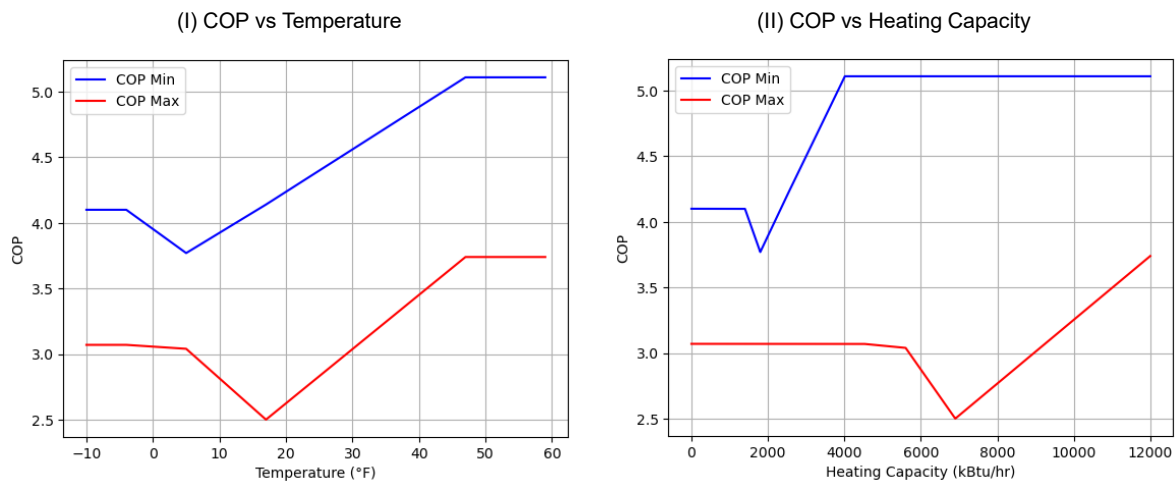
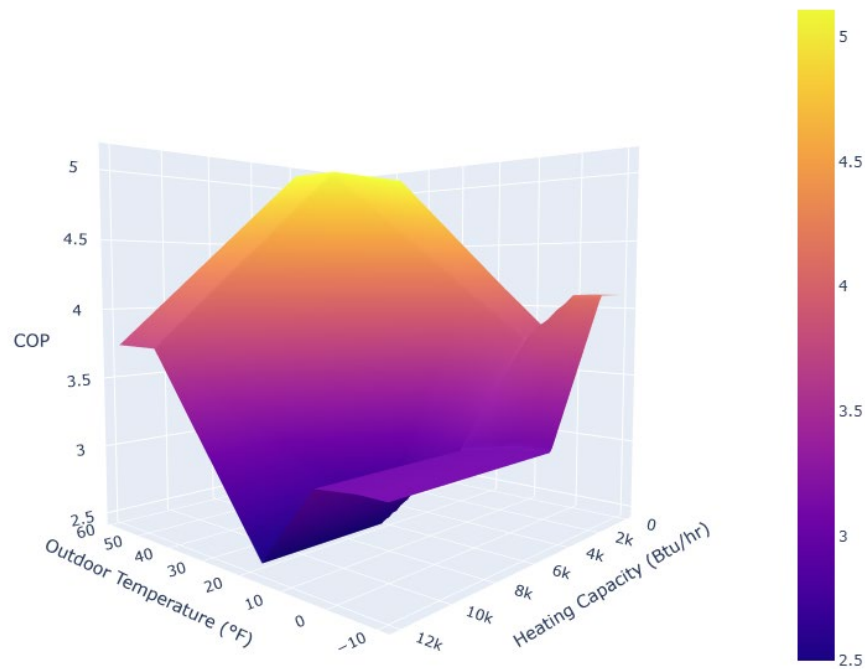


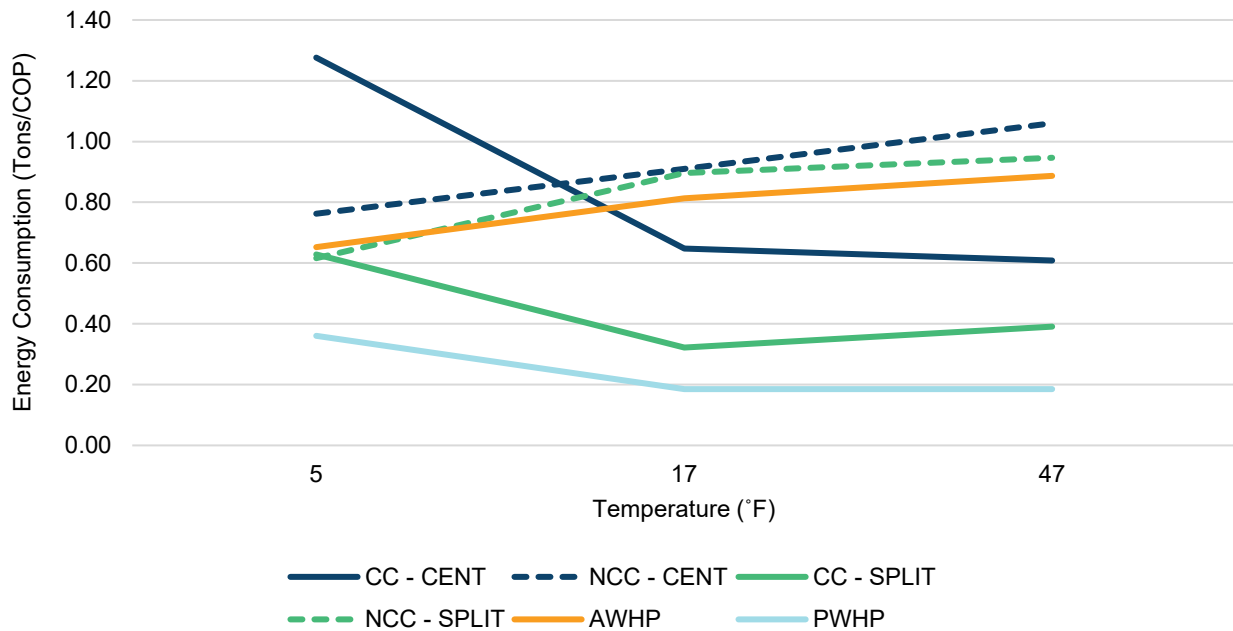
Figure 9: Heat pump performance profile across temperature and heating capacity



The heat pump performance profile was adjusted according to the unit(s) installed to meet the design load of the system. Therefore, at each hour modeled for an individual dwelling unit, the outdoor temperature and the heating capacity needed to maintain setpoint temperature (as defined by the heat load line) produced a specific COP value of the system in that hour. The COP value was then used to determine the electric consumption of the heat pump system on an hourly basis.

CRA modeled cold climate heat pump models for the FE configurations, and non-cold climate (or standard) heat pumps for the HE configurations, except for the Air-to-Water heat pumps and PWHPs, which were the same between configurations. For each type of heat pump, the COP characteristics were recorded at various sizes permitting data availability to accurately characterize performance gains by larger systems determined by the sizing process. In total CRA modeled 21 types of heat pump models; Figure 10 displays an approximate heuristic of average energy consumption by heat pump type. The *rated* tonnage of the system is divided by the COP at the rated output, where higher values indicate higher levels of energy consumption at that temperature. Cold climate heat pumps are more efficient across the temperature ranges for both central and mini-split ASHP systems. The efficiency of the AWHP model lies between the cold climate and non-cold climate systems, accurately capturing the performance tradeoff of AWHP systems. While PWHP has the lowest energy consumption in this plot, an important consideration is the overall *size* of the systems. The operational efficiency characteristics are a part of the financial outlook which includes the capital cost of installing multiple heating units, where smaller unit systems lose ground in the aggregate.

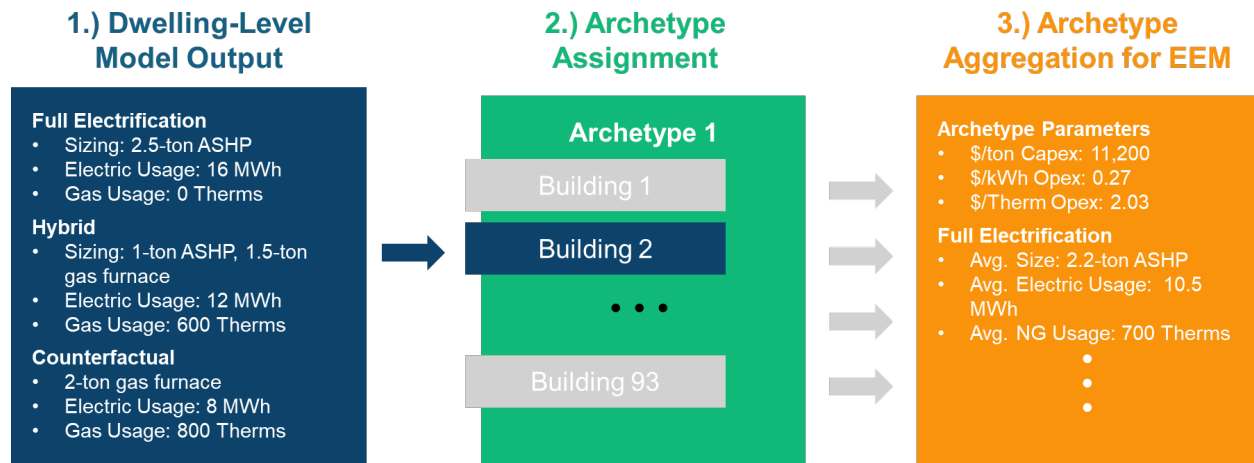
Figure 10: Heat pump tonnage normalized by COP



2.6 Results aggregation by archetype

Following the calculation of EULPs for individual units, the profiles were aggregated into their respective customer archetypes. The overarching process is visualized in Figure 11. For each archetype and measure applied to that archetype, the resulting EULPs were aggregated to form an average profile. In this methodology, the important distinction is that homes were modeled individually for the most accurate sizing and resulting usage profiles, followed by the averaging of the building energy model outputs. The archetype-level sizing parameters and usage estimates informed the payback curves calculated in CRA's Economic Electrification Model (EEM).

Figure 11: Archetype and EULP model workflow



2.7 Greenhouse Gas Emissions

Residential building electrification affects GHG emissions in two primary ways. First, electrification reduces or eliminates on-site combustion of fossil fuels used for space and water heating, thereby lowering direct emissions from residential buildings. Second, electrification shifts energy consumption from fossil fuels to electricity, making realized emissions outcomes dependent on the emissions intensity of the electric grid supplying that load over time. This is considered net of the effects of any weatherization or building envelope upgrades, which can reduce the annual and peak electricity consumption due to heating. As NYS’s electric grid decarbonizes, the emissions associated with electric heating decline, increasing the long-term emissions benefits of electrification.

The magnitude and timing of emissions reductions resulting from electrification therefore depend on several interacting factors, including the rate of heat pump adoption, the share of heating load served by electric versus fossil equipment in hybrid configurations, and the trajectory of grid decarbonization. This study’s emissions accounting framework is designed to capture these dynamics consistently across scenarios, enabling a comparison of emissions outcomes under the HE and FE configurations, and the counterfactual case in which existing fossil heating equipment is replaced on an in-kind basis.

The emissions attributed to the residential stock modeled change throughout the forecast period due to two dynamic factors: (1) the state of electrification adoption in that year, and (2) the emission intensity of the electric grid in that year. For the first component, an average fuel and electric usage profile was calculated for each archetype and measure combination. Every year, the stock of archetypes at each state of electrification were multiplied by their average energy profiles to produce the total stock-level electric, gas, and delivered fuel usage.

The annual usage levels were then multiplied by their corresponding emission factors featured in Table 6. Emissions related to electric demand were accounted for using annual emission factors produced from the CRA Aurora Market Model (see Data Annex 3).

Table 6: Residential fuel emissions (Metric Ton/MMBtu)²⁶

Sector	Fuel	CO ₂	CH ₄	N ₂ O
Residential	Natural Gas	6.50E-02	3.62E-04	2.46E-07
Residential	Heating Oil - Fossil	8.93E-02	1.32E-04	8.94E-07

Total CO₂ equivalents GHG emissions are calculated using IPCC GWP20 values.

Table 7: Global warming potential (20 year) factors

Emission Type	Factor
CO ₂	1
CH ₄	84
N ₂ O	264

3. Costs of electrification

This section synthesizes CRA's findings on the trends, ranges, and representative values for capital costs, installation costs, incentives, and operating costs for residential heating technologies. This includes the costs and incentives for installing heat pumps, costs and incentives for weatherization upgrades, costs for fossil fuel equipment replacement (in the case of Hybrid Electrification), and other ancillary costs required to enable the solution. These values were subsequently used to establish baseline assumptions to inform CRA's modeling of customer economics and inform its modeling of customer adoption over the forecast period.

Upfront equipment, labor, and installation costs are highly influential on the customer economics of Full and Hybrid Electrification at the point of equipment replacement. The relative weight of installed costs (net of incentives) versus operating costs in overall heat pump economics (i.e., total cost of ownership) depends on a wide range of factors, including the type of heat pump, climate, electric and gas utility rates, insulation/weatherization, and more. The following subsections examine the total installed costs, available incentives, and operating characteristics for central ASHP, mini-split ASHP, AWHP, and PWHP technologies.

3.1 Electrification total installed costs

In this context, total installed cost refers to all of the upfront costs required to install a heat pump, including but not limited to: heat pump unit, air handlers, associated plumbing or piping, electric panel upgrades, distribution or ventilation systems, and the labor, installation, and overhead costs associated with contractor installation. These upfront costs are highly influential on the customer economics of Full and Hybrid Electrification and can vary considerably between regions (e.g., New York City versus Rest of State) and individual customer installations. A key task of the HE Study was to establish informed estimates for the total installed costs of residential heat pumps for use in CRA's economically-driven heat pump adoption modeling.

Analysis of clean heat program data

CRA relied primarily on data from NYS Clean Heat to develop its estimates for the total installed cost of residential heat pump systems, for use in this analysis. Clean Heat is jointly administered by NYSEERDA and the Utilities to provide rebates and financing opportunities to customers using natural gas, propane, oil, or electric resistance heating to switch to a heat pump. It was launched on April 1, 2020 and—through 2024—has supported more than 100,000 heat pump installations, achieved over 5,936,000 MMBtu of energy savings, spent over \$1B towards customer upgrades, and has more than 1,500 enrolled contractors.²⁷ CRA leveraged cost and sizing data from more than 20,000 individual heat pump installations across NYS between 2023-2025 that are representative of residential Full Electrification, specifically NYS Clean Heat Categories 2, 2a, and 2b, defined in more detail below.^{ix}

^{ix} CRA focused on data from 2023-2025 due to differences in project incentive amounts pre-2023 and to align to the period for which each utility had available program data.

- **Category 2 – ccASHP: Residential full load heating:** Projects in Category 2 must install full load cold climate ASHP systems (both mini-split and central) listed on, or that meet the criteria of, the NEEP Cold Climate Products List. May also include AWHP systems listed on the NYS Clean Heat AWHP Eligible Products List.
- **Category 2a – ccASHP: Residential full load heating with integrated controls:** Projects in Category 2a install full load air source heat pump systems with integrated controls to manage the heat pumps and legacy fossil systems in concert. Integrated controls units must be attached to existing heating units and operated such that the heat pump serves as the primary source of heat from the combined heat pump and legacy system.
- **Category 2b – ccASHP: Residential full load heating with decommissioning:** Projects in Category 2b install eligible heat pumps and decommission their legacy fossil fuel heating system such that the heat pump system is the only system providing space heating over the scope of the project. Inclusion of new fossil fuel equipment is prohibited. These customers may still utilize fossil fuels for other end-uses such as cooking or clothes drying.

Other NYS Clean Heat categories were not pertinent to this analysis. Where applicable, costs were differentiated by customer type (e.g., single-family, multifamily) and by region (e.g., New York City, non-New York City) to most accurately represent actual total installed costs for different technologies.

After removing the top and bottom 20% of installations to reduce the influence of outlier projects, CRA used the reported project cost data and the design heating specifications (in Btu/hr) to develop estimates for total installed costs expressed on a dollar per ton basis. These were used in conjunction with heat pump sizing analysis to develop estimates for the total installed costs of heat pump retrofits for Full and Hybrid Electrification based on how a customer would actually size a heat pump to meet its design heating load. CRA developed total installed cost estimates for each of the electrification upgrades for both New York City and non-NYC single-family, multifamily low-rise, and multifamily high-rise dwellings. Where NYS Clean Heat data was unavailable or insufficient, CRA either (a) supplemented with data from other reputable sources or studies or (b) imputed a cost value based on the establishment of a relationship between other variables (e.g., converting costs from Downstate-to-Upstate, or from Full-to-Hybrid).

The following table summarizes the underlying NYS Clean Heat data CRA used to develop its cost estimates for Full Electrification central and mini-split ASHP technologies, including more than 15,000 individual installations. Notably, the average total project cost outside of NYC was larger than projects within NYC for both single- and multifamily projects. However, the heating design load (in tons) was typically much smaller for NYC projects. The average single-family ASHP installation outside of NYC had more than three times the heating capacity of the average NYC single-family project; the average multifamily project had more than four times the average capacity. This is likely reflective of the combination of colder climates and larger dwellings in the

Rest of State Regions compared to NYC. The result is that the cost per ton of installed heat pump capacity in NYC is more than twice that of the Rest of State. Table 8 below provides the number of projects, average heating design load, average project cost, average project incentive, and average installed cost per ton for Category 2b NYS Clean Heat projects used by CRA to develop the cost estimates for Full Electrification.

Table 8: Summary of Category 2b NYS Clean Heat Project reporting data

Metric	Single-Family			Multifamily Low-Rise		
	NY Total	NYC	Non-NYC	NY Total	NYC	Non-NYC
Number of Projects (#)	15,603	11,647	3,956	3,830	3,574	256
ASHP Mini-split	14,987	11,356	3,631	3,780	3,543	237
ASHP Central	616	291	325	50	31	19
Heating Design Load (Tons)	2.24	1.37	4.82	1.19	0.98	4.14
ASHP Mini-split	2.20	1.36	4.82	1.18	0.98	4.15
ASHP Central	3.24	1.48	4.81	2.21	1.11	4.00
Project Cost (\$0s)	\$25,447	\$23,394	\$29,864	\$19,107	\$15,688	\$24,129
ASHP Mini-split	\$24,093	\$22,434	\$29,281	\$16,211	\$15,687	\$24,051
ASHP Central	\$25,914	\$23,334	\$28,224	\$19,343	\$15,814	\$25,099
Project Incentive (\$0s)	\$7,413	\$7,654	\$6,704	\$5,576	\$5,531	\$6,207
ASHP Mini-split	\$7,406	\$7,643	\$6,664	\$5,578	\$5,538	\$6,169
ASHP Central	\$7,599	\$8,089	\$7,161	\$5,461	\$4,710	\$6,688
Cost Net of Incentive (\$0s)	\$18,034	\$15,740	\$23,159	\$13,531	\$10,157	\$17,922
ASHP Mini-split	\$16,687	\$14,791	\$22,617	\$10,633	\$10,149	\$17,882
ASHP Central	\$18,315	\$15,246	\$21,064	\$13,881	\$11,105	\$18,411
Installed Cost per Ton (\$/Ton)	\$13,807	\$16,434	\$6,072	\$15,346	\$16,019	\$5,947
ASHP Mini-split	\$13,941	\$16,451	\$6,091	\$15,402	\$16,036	\$5,913
ASHP Central	\$10,543	\$15,767	\$5,865	\$11,147	\$14,073	\$6,372

Far fewer Category 2a (Full Load Electrification with Integrated Controls) projects were reported in the NYS Clean Heat dataset in the last three program years. CRA used cost estimates from these projects as the basis for developing its cost estimates for Hybrid Electrification. This is discussed in more detail later in this section. Table 9 below contains project cost, size, and incentive data for NYS Clean Heat Category 2a projects.

Table 9: Summary of Category 2a NYS Clean Heat Project reporting data

Metric	Single-Family			Multifamily Low-Rise		
	NY Total	NYC	Non-NYC	NY Total	NYC	Non-NYC
Number of Projects (#)	325	57	268	7	4	3
ASHP Mini-split	155	33	122	6	4	2
ASHP Central	170	24	146	1	0	1
Heating Design Load (Tons)	3.76	1.46	4.25	3.08	1.18	5.60
ASHP Mini-split	4.00	1.54	4.67	2.95	1.18	6.48
ASHP Central	3.54	1.36	3.90	3.83	N/A	3.83
Project Cost (\$0s)	\$26,947	\$30,043	\$26,670	\$13,055	\$23,555	\$44,666
ASHP Mini-split	\$30,939	\$31,818	\$30,702	\$35,654	\$23,555	\$59,853
ASHP Central	\$22,070	\$22,818	\$21,947	\$14,294	N/A	\$14,294
Project Incentive (\$0s)	\$4,815	\$2,675	\$5,270	\$4,644	\$1,500	\$8,835
ASHP Mini-split	\$5,080	\$2,682	\$5,729	\$4,344	\$1,500	\$10,033
ASHP Central	\$4,574	\$2,667	\$4,887	\$6,440	N/A	\$6,440
Cost Net of Incentive (\$0s)	\$22,132	\$27,367	\$21,400	\$8,411	\$22,055	\$35,831
ASHP Mini-split	\$25,859	\$29,136	\$24,972	\$31,310	\$22,055	\$49,820
ASHP Central	\$17,496	\$20,151	\$17,060	\$7,854	N/A	\$7,854
Installed Cost per Ton (\$/Ton)	\$8,383	\$19,245	\$6,073	\$14,554	\$19,941	\$7,371
ASHP Mini-split	\$9,608	\$20,710	\$6,605	\$16,358	\$19,941	\$9,192
ASHP Central	\$7,267	\$17,230	\$5,629	\$3,729	N/A	\$3,729

Discount to Hybrid Electrification costs

To develop per-ton costs for Hybrid Electrification, CRA analyzed NYS Clean Heat Category 2a data. Because Category 2a entails full load electrification with integrated controls and fossil-based heating system backup, the heat pump is necessarily sized to meet a higher portion of load than would otherwise be necessary if only the fossil heating system was relied upon for heating during cold temperatures. For example, many utility hybrid heating programs suggest a switchover temperature of 30°F, at which point the fossil fuel equipment takes over as the primary heat source. Sizing a heat pump to meet a dwelling's full design heating load, versus a prescribed switchover temperature, typically incurs additional costs, potentially including but not limited to: home distribution system upgrades, electric panel upgrades, or premiums for a cold climate-rated ASHP model. CRA applied a discount of approximately **35%** to all Category 2a project costs to adjust NYS Clean Heat data for costs of Hybrid Electrification. This was based on CRA's independent analysis of ASHP installation cost data in Massachusetts, which compared total installed costs for "whole-home" electrification against costs for Hybrid Electrification, where customers chose to retain their fuel backup heating systems but did not size their heat pumps to meet the entire design heating load.^{28, x} This analysis indicated that the average total installed cost for a Hybrid Electrification project was 35 percent less than a whole-home electrification project.^{xi} CRA and NY DPS Staff aligned on this assumption as a de-rate to determine appropriate costs for Hybrid Electrification.

Costs for potential hazard remediation

While hazard or asbestos remediation may be required in certain older homes, such remediation is not inherently triggered by electrification and may also occur under the counterfactual scenario, particularly where heating equipment replacement or other mechanical work is required. As a result, remediation risk is driven primarily by building age, specific construction characteristics, and the scope of equipment replacement rather than by the electrification pathway itself.

Consistent with this, CRA did not model separate hazard remediation costs as an explicit incremental cost for any scenario. Instead, the analysis relies on statewide average installed cost data derived from real-world program and project experience, which reflect the all-in costs of electrification measures across a wide range of building types and installation conditions. These observed costs inherently capture, on average, the effects of site-specific factors such as panel upgrades, limited electrical capacity, and other installation complexities that arise in practice. Importantly, any boiler/furnace replacement may also involve disturbance of existing piping, mechanical equipment, or building materials and therefore may require hazard

^x CRA further eliminated all single-zone ASHP installations where only one mini-split unit was included in the upgrade from the Massachusetts dataset, to ensure the bulk of estimates included sufficient ASHP capacity to qualify.

^{xi} CRA analyzed data for 158 projects in Massachusetts Clean Energy Center's (MassCEC) Whole-Home Heat Pump Pilot, which ran from May 2019 to June 2021, intended to represent Full Electrification. These costs were compared to select projects from MassCEC's Residential Air-Source Heat Pump Program, which ran from November 2014 to March 2019, intended to represent Hybrid Electrification. Costs were adjusted for historical inflation for purposes of comparison.

remediation in some specific cases. Because these remediation requirements can arise across all modeled pathways and vary substantially at the individual building level, they are not treated as systematically incremental to either Full or Hybrid Electrification pathways in the comparative analysis and are instead captured in the average installation costs.

The following subsections present the total installed cost estimates for central ASHP, mini-split ASHP, AWHP, and PWHP systems.

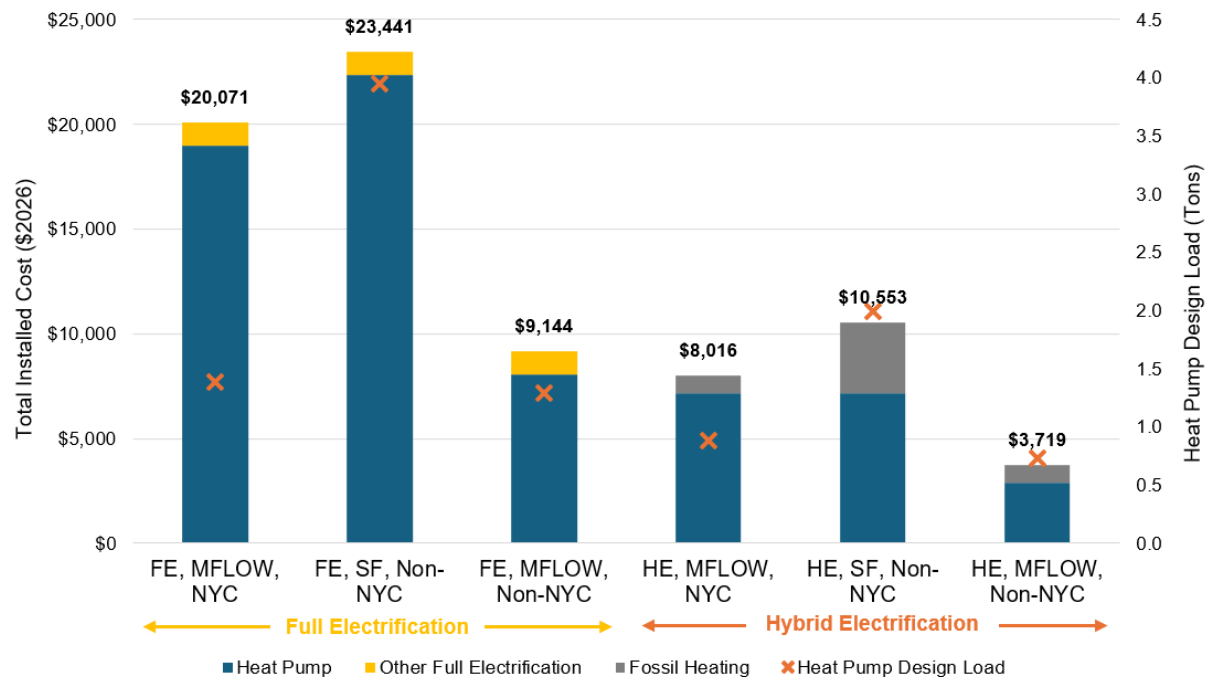
3.1.1 Central Air Source Heat Pumps

Per-ton costs for Full Electrification central ASHP installations were primarily determined based on analysis of NYS Clean Heat data for Category 2b installations between 2023-2025. Table 10 presents the total installed cost on a per-ton basis for central ASHP systems and Figure 12 shows the average total installed cost and design heating load (in tons).

Table 10: Central ASHP, total installed cost per ton (\$2026/Ton)

Customer Type	Full Electrification		Hybrid Electrification	
	Rest of State	NYC	Rest of State	NYC
Single-Family	\$5,660	\$15,601	\$3,594	\$9,188
Multifamily Low-Rise	\$6,230	\$13,754	\$3,956	\$8,100
Multifamily High-Rise	N/A	N/A	N/A	N/A

Figure 12: Central ASHP Electrification, average total installed costs (\$2026)



The costs above were to determine the total installed costs for Full and Hybrid Electrification upgrades based on the design heating capacity (in tons) for a given customer archetype, which can vary based on the attributes of that archetype. Full Electrification upgrades also include an average level of other home upgrades required to accommodate electrification (e.g., electrical panel upgrades, home distribution system upgrades). For Hybrid Electrification upgrades include costs to replace the counterfactual fossil fuel equipment (e.g., high-efficiency natural gas furnace). Note that the costs above do not include the impact of incentives for Full Electrification.

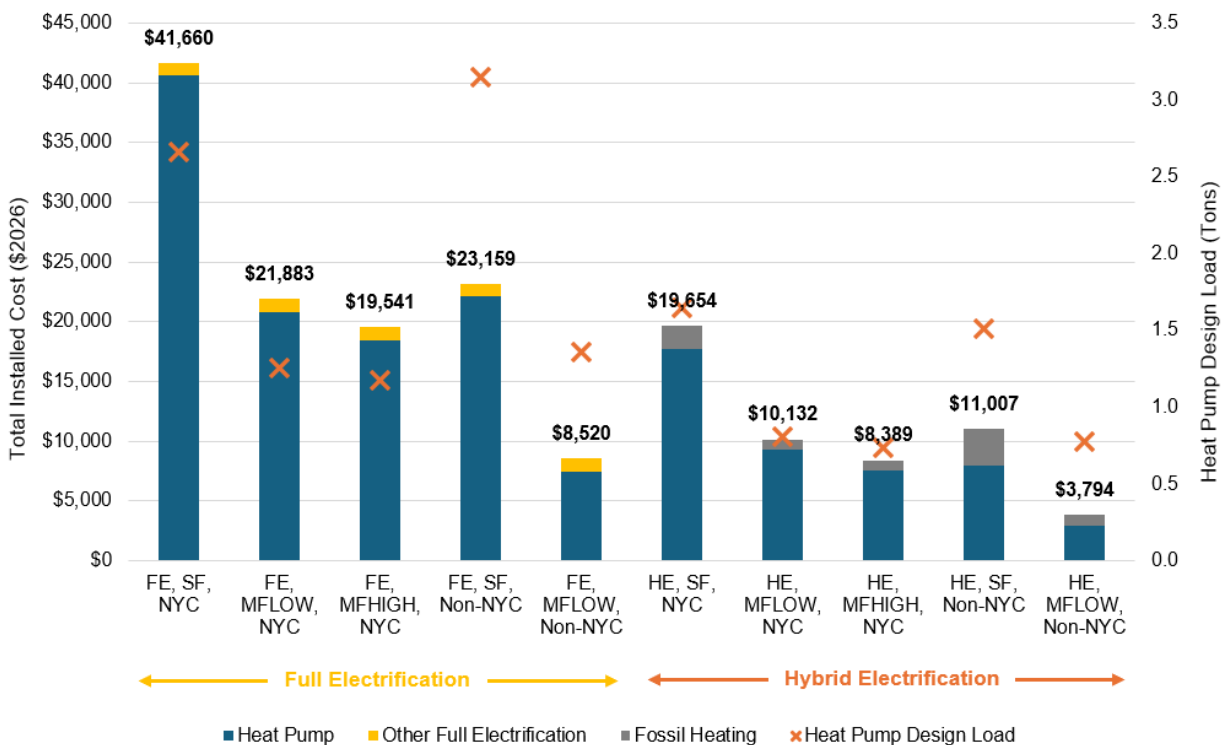
3.1.2 Mini-split Air Source Heat Pumps

Costs for Full and Hybrid Electrification mini-split ASHP installations were determined using the same methodology as central ASHP systems above. Mini-splits are assumed to be available for MF high-rise buildings; CRA used data from CECONY’s CHP to develop estimates for average per-ton cost of these installations. Table 11 presents the total installed cost per ton for mini-split ASHP systems and Figure 13 shows the average total installed cost and design heating load (in tons).

Table 11: Mini-split ASHP Electrification, total installed cost per ton (\$2026/Ton)

Customer Type	Full Electrification		Hybrid Electrification	
	Rest of State	NYC	Rest of State	NYC
Single-Family	\$5,911	\$15,236	\$4,162	\$10,756
Multifamily Low-Rise	\$5,740	\$15,781	\$4,041	\$11,141
Multifamily High-Rise	N/A	\$14,444	N/A	\$9,389

Figure 13: Mini-split ASHP Electrification, average total installed costs (\$2026)



3.1.3 Air-to-Water Heat Pumps (AWHP)

The NYS Clean Heat dataset only contained cost data for five AWHP installations over the historical period examined for the HE Study. All were Upstate Full Electrification single-family AWHP installations; there was no information on AWHP installations Downstate or for Hybrid Electrification. The NYS Clean Heat data did not contain any multifamily AWHP installations. CRA leveraged data and estimates published by the American Council for an Energy-Efficient Economy (“ACEEE”) in its 2025 study, *Decarbonizing Space Heating in Existing Multifamily*

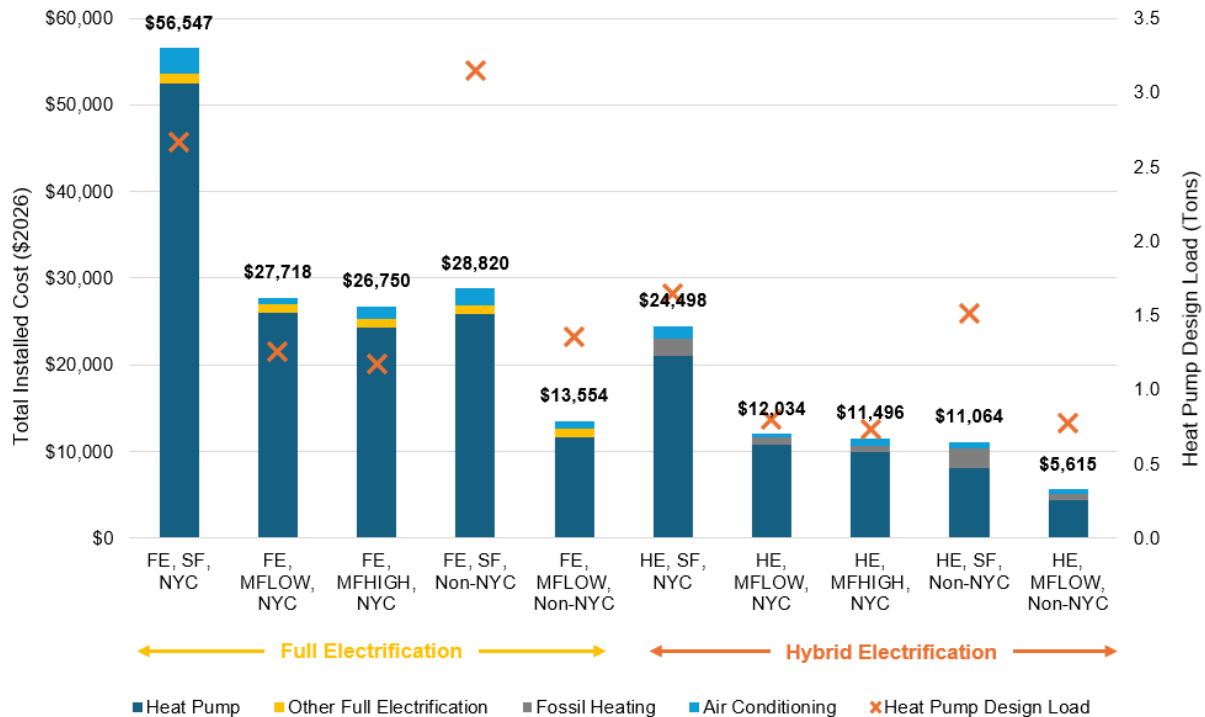
*Buildings.*²⁹ ACEEE estimated the costs for multifamily *hybrid* AWHP installations combined with a backup natural gas boiler and propane boiler at \$14,568/ton and \$15,016/ton, respectively. CRA adjusted these figures for inflation and removed the costs for supplemental air conditioning (~\$1,300/ton) and replaced fossil fuel equipment (~\$1,000/ton) to arrive at an estimate for AWHP total installed cost without other HVAC equipment. The resulting average cost was \$13,441/ton. This Downstate Hybrid Electrification figure was derated to create a comparable Upstate figure and uprated (+35%) to create a comparable Downstate Full Electrification for AWHP. Costs for multifamily low- and high-rise AWHP installations are assumed to be equivalent. Table 12 below presents the total installed cost per ton for AWHP technologies.

Table 12: Air-to-Water Heat Pump Electrification – total installed cost estimates (\$2026/Ton)

Customer Type	Full Electrification		Hybrid Electrification	
	Rest of State	NYC	Rest of State	NYC
Single-Family	\$8,195	\$19,714	\$5,327	\$12,814
Multifamily Low-Rise	\$8,596	\$20,679	\$5,587	\$13,441
Multifamily High-Rise	N/A	\$20,679	N/A	\$13,441

AWHP systems may require additional upfront costs for an air conditioning system and hybrid systems require fossil fuel heating equipment. Figure 14 below presents the average total installed cost for AWHP alongside the average heating design load (in tons).

Figure 14: Air-to-Water Heat Pump Electrification, average total installed costs (\$2026)



3.1.4 Packaged Window Heat Pumps (PWHP)

The NYS Clean Heat dataset did not contain any PWHP installations. To develop cost estimates for PWHP, CRA relied on data available in NYSERDA’s aforementioned PWHP demonstration pilot and ACEEE’s aforementioned multifamily electrification study. These studies both found similar cost advantages for PWHPs in multifamily buildings. The ACEEE study found that PWHPs “generally have the lowest lifecycle capital and energy costs” and estimated the median installed costs at \$9,300/dwelling (for an approximately one-ton design heating load apartment in New York City). This figure includes the equipment costs for three \$3,000 PWHP units and approximately \$100 in labor and installation costs associated with each. However, this may understate the total installation cost, as it takes a very conservative view of contractor labor costs. To address this, CRA adjusted this figure to include a higher cost for labor and installation and took the midpoint of the advertised retail cost of the two prominent PWHP vendors, Midea and Gradient, instead of the lower value. More information on the assumptions is available in Data Annex 2: Technology Cost and Performance Assumptions.

CRA assumed these values were applicable to Full Electrification in NYC and made downward adjustments to the labor and installation portion of the total installed cost to develop estimates for non-NYC. CRA further assumed these costs would be the same across all multifamily customer types, given the modularity of the installation and lack of data to suggest differentiation in cost between multifamily construction types. Costs for PWHPs in single-family homes were not considered in the context of the HE Study. Table 13 below summarizes the *per-dwelling* total installed cost estimates for PWHP technologies used in CRA’s modeling. Note that

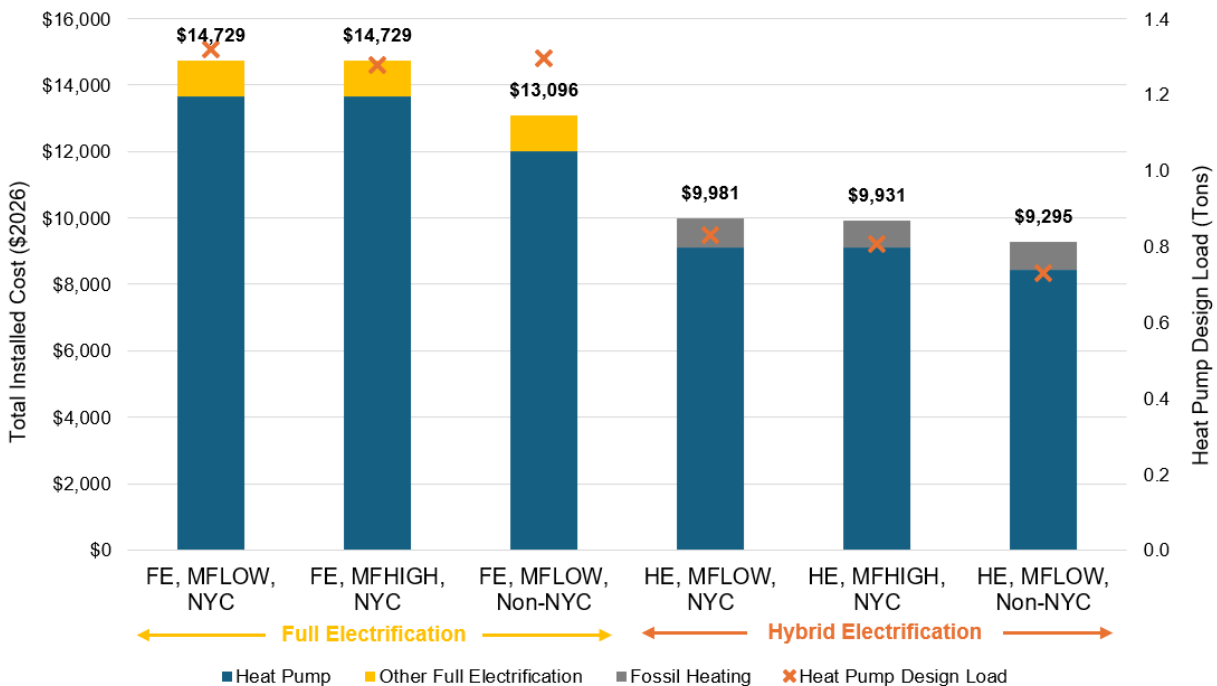
these costs are not formulated on a per-ton basis like other technologies; CRA assumes that each multifamily unit requires, on average, three PWHP units for Full Electrification installations and two PWHP units for Hybrid Electrification installations.

Table 13: Packaged Window Heat Pump, total installed cost per dwelling (\$2026/Dwelling)

Customer Type	Full Electrification		Hybrid Electrification	
	Rest of State	NYC	Rest of State	NYC
Single-Family	N/A	N/A	N/A	N/A
Multifamily Low-Rise	\$12,021	\$13,653	\$8,450	\$9,102
Multifamily High-Rise	\$12,021	\$13,653	\$8,450	\$9,102

Figure 15 below compares the average total installed cost of PWHPs across customer archetypes, including the average design heating load (in tons), inclusive of additional costs for Full Electrification and replacement cost for natural gas equipment in Hybrid Electrification.

Figure 15: Packaged Window Heat Pump, average total installed costs (\$2026)



3.2 Electrification incentives

This section presents the incentive amounts offered for Full Electrification. NYS offers incentives for ASHP and AWHP adoption for Full Electrification that significantly influences the economics on a per-dwelling-unit basis. These incentives can vary considerably by customer type, utility and region, and income level. Today, New York State does not offer incentives for Hybrid Electrification.

In all cases presented below, utility Program Administrators (PAs) through NYS Clean Heat, NYSEDA through the EmPower+, and other electric utility programs do not offer incentives for Partial or Hybrid Electrification without sizing the heat pump to meet the full heating load with integrated controls (i.e., Category 2a). CRA further assumes that the incentives are available unilaterally for each mini-split, central, AWHP, and PWHP technologies.

3.2.1 Single-family electrification incentives

For market-rate single-family customers, each of the Joint Utilities (other than NFG as a gas-only utility) offers incentive through Clean Heat for residential electrification in single-family or small multifamily attached buildings. The PAs tend to differentiate incentives by whether a customer dwelling is located in a DAC or if it is a single-family home or an apartment that is more/less than 1,000 square feet. Because CRA’s customer segmentation does not identify whether an archetypal customer is in a DAC and floor area varies within a specific archetype, CRA calculated and applied a uniform incentive for non-LMI customers based on the average amount of DACs and floor area in each Region derived using ResStock data. These percentage splits are presented in Table 14.

Table 14: Share of Disadvantaged Communities (DAC) and dwellings above/below 1,000 Sq Ft by region

Region	Name	Electric Utility(ies)	Share of Census Tracts in DAC vs. Non-DAC		Share of Dwellings Above or Below 1,000 sq ft Area	
			% Dwellings DAC	% Dwellings Non-DAC	% Dwellings <1,000 sq. ft.	% Dwellings >1,000 sq. ft.
1	Western NY	NMPC, Western NY	28%	72%	31%	69%
2	Central & Southern NY	NYSEG, RG&E	27%	73%	29%	71%
3	Upstate & Capital Region	NMPC, Upstate NY	19%	81%	32%	68%
4	Hudson Valley	CHG&E, O&R	43%	57%	29%	71%

5	New York City	CECONY	47%	53%	56%	44%
6	Long Island	LIPA (PSEG LI)	15%	85%	17%	83%

The weights above are used to create a composite weighted average Full Electrification incentive for SF non-LMI customers based on the share of customers that are DAC/Non-DAC and with above/below 1,000 sq ft incentive levels available through NYS Clean Heat. This is intended to reflect the average incentive received by customers of a certain archetype in that Region. Table 15 below presents the weighted incentives for each Region for Category 2b (Full Electrification with Gas Decommissioning), as well as the composite average using the percentages above.

Table 15: Single-family market-rate Full Electrification incentives

Region	Name	Electric Utility(ies)	Incentive Levels (Per Dwelling Unit) (\$2026)				Composite Average
			SF / Non-DAC	SF / DAC	Apt. <1,000 sf / Non-DAC	Apt. <1,000 sf / DAC	
1	Western NY	NMPC, Western NY	\$10,000	\$12,000	\$5,000	\$7,000	\$9,018
2	Central & Southern NY	NYSEG, RG&E	\$10,000	\$11,000	\$5,000	\$6,000	\$8,813
3	Upstate & Capital Region	NMPC, Upstate NY	\$10,000	\$12,000	\$5,000	\$7,000	\$8,771
4	Hudson Valley	CHG&E, O&R	\$8,500	\$9,000	\$5,250	\$5,750	\$7,773
5	New York City	CECONY	\$8,000	\$10,000	\$4,000	\$5,000	\$6,433
6	Long Island	LIPA (PSEG LI)	\$4,000	\$5,000	\$4,000	\$5,000	\$4,151

For LMI customers, single-family (and small 1-4 multifamily) customers that qualify as low- or moderate-income are eligible for incentives under NYSERDA's EmPower+ program. There are certain rules and restrictions that apply to these incentives, notably:

- Projects cannot receive both EmPower+ and Clean Heat funding for the same project;
- Homes must meet certain envelope standards, which are either a precursor or can be completed in the course of the project;
- The existing primary HVAC systems must be more than five years old;
- Heat pumps must follow NEEP cold climate guidelines, and the proposed system must be designed to meet between 100-110% of heating load. It may include the use of a supplemental heating source to reach 100% of building heating load; and
- The existing whole house fossil fuel heating system must be decommissioned.

New York City (Region 5) low-income customers can receive \$14,000 per dwelling, up to 100% of eligible projects costs, and moderate-income customers can receive \$7,000 per dwelling, capped at 50% of eligible project costs. Upstate (Regions 1-4) low-income customers can receive \$12,000 per dwelling, up to 100% of eligible projects costs and moderate-income customers can receive \$6,000 per dwelling, capped at 50% of eligible project costs. EmPower+ incentives for Long Island (Region 6) SF LMI customers are not yet finalized. On Long Island, where PSEG LI administers incentives, LMI customers can receive a slightly higher incentive. The low-income customers incentives are capped at \$10,500 per dwelling and moderate-income customers are capped at \$5,625 per dwelling. In some cases, customers could have 100% of their project costs covered by the incentive (e.g., certain small low-income customer ASHP installations). CRA assumes that LMI customers will choose the more lucrative incentive if multiple incentives are available.

3.2.2 Multifamily electrification incentives

For market-rate incentives, utility PAs set the recommended incentive levels for market-rate MF customers through two respective programs. The market-rate programs are being revamped in 2026, but no programs have released incentive amounts as of April 2026. The existing Con Edison Downstate multifamily program provided \$5,000/dwelling for non-LMI or market-rate customers. In the absence of concrete incentive amounts, CRA assumed that market-rate MF incentives would be \$5,000 per dwelling for customers in all Regions.

For LMI customers, the Downstate utilities, Con Edison and National Grid Downstate, administer the Affordable Multifamily Energy Efficiency Program (AMEEP) while the Upstate utilities, Avangrid, National Grid Upstate, Central Hudson, and more, administer the Affordable Multifamily Program Upstate (AMP Up). Each of these programs provide incentives for EE and electrification measures, including ASHP electrification. The AMP Up incentives for heat pumps are proposed at \$5,750 per dwelling.³⁰ LMI incentives for multifamily Downstate are assumed to be the same as AMP Up without any additional information on the forthcoming AMEEP incentive amounts.

3.2.3 Additional electrification rebates and incentives – Long Island

PSEG LI incentive programs for both SF and MF dwelling units are developed and offered separately from the NYS Clean Heat Program incentives. PSEG LI offers a tiered rebate per ton of heat pump capacity (up to 5 tons), in addition to a \$500/project incentive, as well as a \$250/project “bonus” incentive for gas decommissioning. The rebates are subject to the lower of a percentage of cost cap and a dollar cost cap. The incentive structure is the same, but the per-ton rebate amounts and caps differ for market-rate, moderate-income or market-rate DAC, and low-income customers. PSEG LI offers distinct incentives for in-unit multifamily heat pumps (i.e., mini-split or AWHP) use a per dwelling rebate structure while “common area” projects (i.e., central or AWHP) use a per ton rebate structure. Projects are also subject to an incentive cap.

3.2.4 Additional federal incentives – Inflation Reduction Act funding

At the federal level, the 2022 Inflation Reduction Act (IRA) established funding targeting residential and commercial EE and electrification for states through two main programs: Home Electrification and Appliance Rebate (HEAR) program, which supports high-efficiency electric appliances and other home energy upgrades, and the Home Efficiency Rebates (HER) program, which supports whole-home EE improvements. New York was allocated approximately \$317.7M in total funding through these programs, including \$158.4M in HEAR program funding and \$159.3M in HER program funding. New York was the first state to launch its IRA-funded programs in May 2024, administered via EmPower+. The IRA incentives of up to \$14,000 are offered on top of the non-Clean Heat incentives including \$8,000 for heat pumps, \$1,750 for HPWH, \$4,000 for panel boxes, \$2,000 for electric wiring upgrades and \$1,600 for insulation, air sealing, and ventilation. CRA did not consider HEAR/HER incentives in its economic modeling for either electrification or weatherization. This is because the incentives are already being deployed in the near-term through EmPower+ and their renewal is uncertain due to ongoing political risk at the federal level.

3.2.5 Analysis of total installed cost of electrification, net of incentives

It is important to consider the total installed cost of electrification net of incentives, since this is what drives the customer’s upfront cost. Today, as discussed above, NYS only offers incentives for Full Electrification. Table 16 below compares the *average* total installed costs of Full and Hybrid Electrification (previously shown in Section 3.1 above) used in the HE Study after considering the average incentive for Full Electrification. Note that the total installed cost figures include additional costs required for other equipment (e.g., backup fossil heating equipment for hybrid systems), not just the heat pump system.

Table 16: Average total installed cost of electrification, net of incentive (Non-LMI only)

Customer Type	Region	Technology	Total Installed Cost, Full Electrification	Average Incentive	Total Installed Cost, Full Electrification, Net of Incentive	Total Installed Cost, Hybrid Electrification
MFLOW	NYC	Central ASHP	\$20,071	(\$5,000)	\$15,071	\$8,016
SF	Non-NYC	Central ASHP	\$23,441	(\$8,538)	\$14,903	\$10,553
MF	Non-NYC	Central ASHP	\$9,144	(\$5,143)	\$4,001	\$3,719
SF	NYC	Mini-split ASHP	\$41,660	(\$6,433)	\$35,227	\$19,654
MFLOW	NYC	Mini-split ASHP	\$21,883	(\$5,000)	\$16,883	\$10,132
MFHIGH	NYC	Mini-split ASHP	\$19,541	(\$5,000)	\$14,541	\$8,389
SF	Non-NYC	Mini-split ASHP	\$23,159	(\$8,513)	\$14,647	\$11,007
MF	Non-NYC	Mini-split ASHP	\$8,520	(\$5,160)	\$3,360	\$3,794
SF	NYC	AWHP	\$56,547	(\$6,433)	\$50,114	\$24,498
MFLOW	NYC	AWHP	\$27,718	(\$5,000)	\$22,718	\$12,034
MFHIGH	NYC	AWHP	\$26,750	(\$5,000)	\$21,750	\$11,496
SF	Non-NYC	AWHP	\$28,820	(\$8,443)	\$20,377	\$11,064
MF	Non-NYC	AWHP	\$13,554	(\$5,500)	\$8,054	\$5,615
MFLOW	NYC	PWHP	\$14,729	(\$5,000)	\$9,729	\$9,981
MFHIGH	NYC	PWHP	\$14,729	(\$5,000)	\$9,729	\$9,931
MF	Non-NYC	PWHP	\$13,096	(\$5,160)	\$7,936	\$9,295

3.3 Weatherization costs and incentives

Improvements to the building envelope in conjunction with electrification may be necessary for effective heat pump performance and to qualify for NY Clean Heat Program incentives. Beginning in 2026, utilities must vary NYS Clean Heat incentive levels based on building envelope, providing a higher incentive for homes with well-insulated envelopes. By 2028, dwelling units must meet a minimum building envelope requirement to receive any NYS Clean Heat incentive.³¹ Weatherization total installed cost assumptions are detailed in Data Annex 2.

NREL's ResStock provides EULP outputs for a building envelope improvement measure that is used for modeling heat load and usage estimated under cases where an envelope improvement is needed. CRA has adopted the same building envelope improvement logic as NREL: dwelling units that have an ACH50 score greater than 10 will have their air sealing improved by 30%, and if the unit contains an attic, the insulation value will be increased to IECC climate zone standards. The functional implication of this method is that the weatherization upgrade is only applied to homes with inefficient envelopes that require improvement. Weatherization is assumed to occur alongside or just prior to heat pump adoption such that the heat pump adoption reflects higher-performance envelopes for dwelling units that require weatherization. This approach is intended to reasonably capture and apply the necessary weatherization upgrades to the subsets of dwelling units within CRA's modeling archetypes. For example, under this approach, approximately 91% of single-family homes pre-1980 would require weatherization, compared to only 72% of post-1980 homes.

3.3.1 Weatherization total installed costs

CRA developed total installed costs estimates for weatherization based on a dollar-per-square foot. These estimates were applied to each archetype using its average square footage, reflecting the fact that weatherization costs vary significantly based on dwelling size. To capture regional and customer differences, CRA developed separate installed cost estimates (net of incentives) for NYC separately from Rest of State.^{xii} The per-square foot cost estimates will be applied to each archetype using its average square footage, reflecting the fact that weatherization costs vary significantly based on housing size. Table 17 below contains the weatherization cost assumptions used in CRA's modeling.^{xiii}

^{xii} Single-Family weatherization costs of \$5,682 in \$2025, inflated to \$2026, were sourced directly from NYSERDA based on actual project cost data from the NYSERDA Comfort Home program "Good" package, which is in line with CRA's assumed envelope upgrade. CRA then applied a cost premium of 49% for NYC based on NYSERDA Comfort Home project data as filed in NY PSC Case 25-M-0248 on November 10, 2025.

^{xiii} Multi-Family weatherization costs were developed based on Con Edison's November 2023 NE:NY Program Update filing in Case 18-M-0084. While the scope of the weatherization project contemplated in that filing varies slightly from the CRA air-sealing-only scope for multi-family buildings, CRA determined it to be the most reasonable estimate available on a per-dwelling-unit basis for multi-family projects in NYC. 81% of all of CRA's multi-family archetypes are located within NYC.

Table 17: Weatherization (basic air sealing) cost per dwelling and per-square foot

Customer Type	Cost Per Dwelling (\$2026)		Normalized Cost (\$/sf)	
	NYC	Rest of State	NYC	Rest of State
Single-Family	\$8,734	\$5,848	\$5.04	\$3.38
Multifamily	\$2,789	\$1,867	\$3.02	\$2.02

3.3.2 Weatherization incentives

Distinct levels of incentive for weatherization are available through different vehicles, to different customer types, in different regions of NYS. CRA's economic modeling of electrification includes weatherization incentives for customers (subject to an incentive cap) based on whether a dwelling is single- or multifamily, its income level, and whether it is located in NYC or Rest of State.

Single-family LMI weatherization incentives are primarily administered through NYSEDA's EmPower+ program. Incentives are structured on a per-dwelling-unit basis; new incentives took effect in early 2026. Importantly, moderate-income customer incentives are capped at 50% of weatherization project costs. There is no cap for low-income customers; they can receive weatherization incentives up to 100% of project costs.

Single-family non-LMI weatherization incentives are offered through the Regional Weatherization Program. As of Q2 2026, 2027 incentive levels for the RWP are still being finalized. The Non-LMI EE/BE Order specifies that incentives offered through these programs must not be greater than those offered to LMI customers for similar measures.³² At the direction of NY DPS Staff, CRA assumed a slight derate from the EmPower+ incentive levels and caps for Upstate and Downstate customers: a \$5,500 incentive for Downstate non-LMI and \$5,000 for Upstate non-LMI. All non-LMI weatherization incentives are subject to an incentive cap at 40% of project costs, a slight derate of the 50% cap offered by EmPower+ for Moderate-income customers.

Multifamily LMI weatherization incentives for Downstate customers are administered through Con Edison's AMEEP while Upstate customers receive incentives through the AMP Up program, set to launch in Q1 2026. CRA assumes Downstate LMI customers receive up to \$1,500 per project and Upstate LMI MF customers can receive up to \$2,500 per project, each subject to a 50% project cost cap.

Multifamily non-LMI incentives for Downstate customers will be administered through the forthcoming Downstate Regional Weatherization Program.³³ Because these incentive levels have not been published yet, CRA assumes that, consistent with Commission guidance, non-LMI incentives must not be higher than the equivalent LMI incentive. Upstate non-LMI

multifamily building incentives will continue to be distributed through utility-specific market-rate programs. The depth of public information provided by each utility and the status of each program varies. CRA assumes that both Upstate and Downstate non-LMI customers can receive up to \$1,250 per project, subject to a 40% cap.

Table 18 summarizes the applicable weatherization incentive amounts and caps by customer type, income level, and region.

Table 18: Weatherization incentive amounts per dwelling and incentive cap as share of project costs

Customer Type	Non-LMI		Moderate-Income		Low-Income	
	Downstate	Upstate	Downstate	Upstate	Downstate	Upstate
Single-Family	\$5,500 (40%)	\$5,000 (40%)	\$7,000 (50%)	\$6,000 (50%)	\$14,000 (100%)	\$12,000 (100%)
Multifamily	\$1,250 (40%)	\$1,250 (40%)	\$1,500 (50%)	\$2,500 (50%)	\$1,500 (50%)	\$2,500 (50%)

3.4 Fossil fuel space heating technologies

To establish baseline costs and performance for common fossil fuel heating technologies, CRA relied on data from the EIA’s 2023 report *“Technology Forecast Updates – Residential and Commercial Building Technologies – Reference Case.”* This includes costs for natural gas high-efficiency furnaces and boilers and fuel oil or propane high-efficiency furnaces and boilers, for both single- and multifamily customers. When evaluating the economics of electrification, CRA is comparing all electrification options against a counterfactual where customers revert to or replace their fossil space heating equipment like-for-like with a high-efficiency version. When evaluating Hybrid Electrification, CRA assumes that customers would similarly replace their fossil space heating equipment with a high-efficiency version.

CRA selected the equipment and labor and installation cost information associated with the equipment most reflective of a high-efficiency or ENERGY STAR standard model, as of the most recent non-forecast year in the EIA dataset (2023). EIA provides total installed cost data for each equipment type. CRA inflated these costs to 2026 dollars (from 2022 dollars) and divided the listed total installed cost by the listed system design capacity to create a per-ton cost estimate. See Table 19 below.

Table 19: Total installed costs for fossil fuel space heating technologies (\$2026/Ton)

Customer Type	Natural Gas		Delivered Fuels	
	Furnace	Boiler	Furnace	Boiler
Single-Family and Multifamily Low-Rise	\$776	\$888	\$1,086	\$653
Multifamily Mid-Rise and High-Rise	\$181	\$801	\$541	\$820

CRA adjusted the capacity of fossil fuel heating equipment from BTU/hr to tons for comparison to the costs of heat pump equipment, as shown above. There are no incentives available for replacement of fossil fuel space heating equipment in NYS.

4. Modeling framework and scenario design

This section describes the modeling and scenario analysis framework of the HE Study, including (i) the overarching system context shared across all scenarios, (ii) the rationale for holding certain variables constant while adjusting others, and (iii) the scenario definitions. The goal of modeling multiple scenarios is to explore alternative futures for residential Hybrid and Full Electrification adoption in NYS and the corresponding electric and gas system, societal (e.g., GHG emission), and ratepayer impacts over a 25-year forecast period (through 2050). Its intent is to isolate the most significant economic drivers of residential heat pump adoption and clearly attribute differences in outcomes to those drivers.

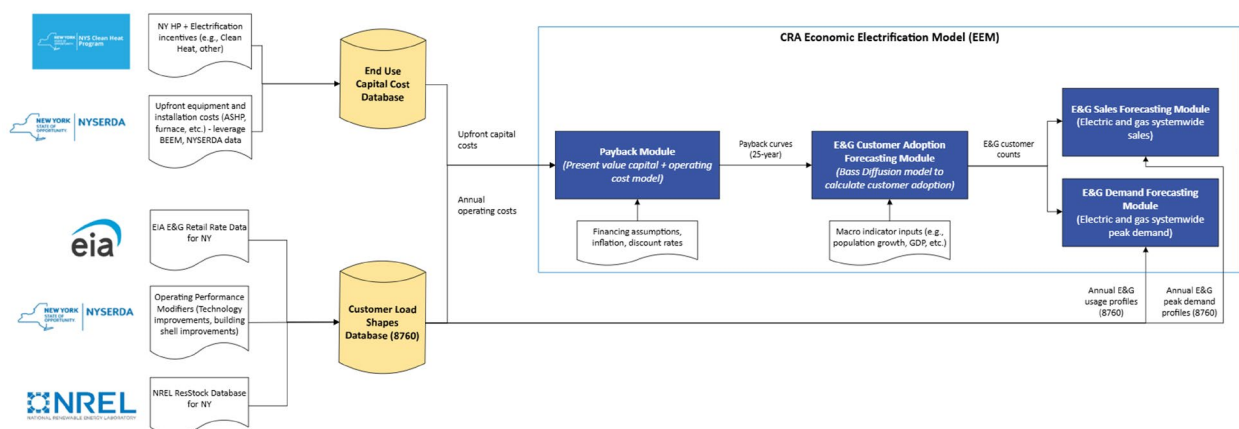
4.1.1 Modeling framework

CRA's modeling consisted of three main steps: 1) forecasting electrification adoption within the residential building stock, 2) translating customer adoption into electric and gas system impacts (including: sales, demand, and customer counts), and 3) translating electric and gas system impacts into utility investment requirements and wholesale price impacts, which are used to analyze customer bill impacts. The following subsections discuss these steps in more detail.

4.1.2 Forecasting electrification adoption

A core element of the HE Study is modeling forecasted adoption of Full and Hybrid Electrification for different customer archetypes, in different geographies, and under different scenarios or planning conditions. CRA leveraged its Economic Electrification Model, which simulates stock turnover and customer adoption based on the economics of different electrification options. The economics for individual customers archetypes are represented by the simple payback period (measured in years); this is discussed in more detail in Section 5.1. The modeled adoption results in different amounts of forecasted electricity and natural gas customer counts, energy sales, and system peak demand. This created different system-level outcomes based on the amount of Full and Hybrid Electrification, where, and by whom these measures are adopted. Figure 16 below presents a high-level overview of the EEM model's structure.

Figure 16: Model schematic for CRA's Economic Electrification Model

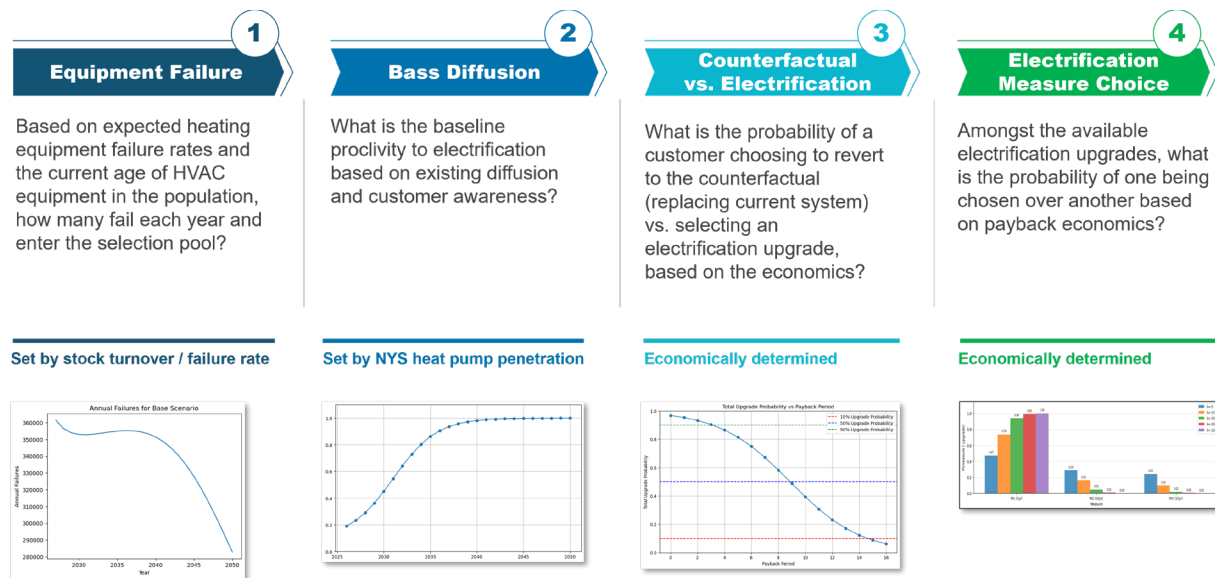


The process for determining a customer adoption decision consists of four main steps, including:

- **Equipment failure:** CRA simulates turnover of fossil fuel space heating equipment in the residential stock to determine the number of customers within each archetype that are eligible for electrification in a given year.
- **Bass Diffusion:** A Bass Diffusion curve is used to calibrate adoption based on customer propensity to adopt. The Bass Diffusion curve presents a scaler value between 0 and 1 and resembles an “S-curve”, with a starting value of approximately 0.20 based on the amount of electrification adoption that has occurred to-date in NYS.
- **Counterfactual vs. electrification decision:** The probability of a customer choosing to adopt an electrification measure versus reverting to the counterfactual heating equipment is based on the payback periods for the electrification options.
- **Electrification measure choice:** Customers within a given archetype are allocated amongst the available electrification upgrades based on the payback periods.

These four steps are combined to determine the number of customers within a given archetype that adopt Full or Hybrid Electrification in a given year. The detailed assumptions and methodology for these steps are discussed further in Appendix A. Figure 17 summarizes the four steps.

Figure 17: Four steps in electrification adoption decision



4.1.3 Forecasting electric and gas system impacts

CRA’s EEM produced a highly granular forecast for residential building counts by technology for the period 2026-2050, including so-called “counterfactual” technologies (natural gas, propane, and fuel oil furnaces and boilers) and electrification technologies (central and mini-split ASHP, AWHP, and PWHP). Adoption forecasts by technology and customer archetype were then combined with the EULPs to determine annual electricity usage impacts, annual natural gas or

fuel usage impacts, and summer and winter electricity peak demands. These impacts were then aggregated up across all customer archetypes to create a forecast for electricity sales, natural gas sales, electricity peak demand (both summer and winter), and natural gas customer counts.

4.1.4 Forecasting system costs and customer bill impacts

Forecasts for electricity sales, natural gas sales, electricity peak demand (both summer and winter), and natural gas customer counts were used to analyze how the costs to electricity and natural gas customers might change. The following analyses, detailed in later sections of this report, were built upon and leveraged the electric and gas system-level forecasts:

- **Reserve Margins:** Forecasts for electricity summer and winter peak demand were used to analyze the impacts on reserve margins by comparing demand against the generation capacity built in the *2025 New York State Energy Plan's* (SEP) Additional Action scenario. Section 6.2 provides more detail and key findings.
- **Wholesale prices:** Forecasts for electricity sales and electricity peak demand were used in a production cost model simulation to analyze wholesale electricity price impacts in NYISO. Natural gas sales forecasts were used to analyze wholesale natural gas price impacts in NYS, using the Gas Pipeline Competition Model. Section 6.3 provides more detail and key findings.
- **Bulk power system transmission investment:** Coincident peak demand forecasts, aggregated by NYISO zone, were used to analyze future transmission constraints and corresponding capital investment requirements. Section 6.4.5 provides more detail and key findings.
- **Local utility transmission & distribution investment:** Winter peak demand forecasts were used in combination with data from the Utilities' Hosting Capacity Maps to analyze the impacts on utility T&D "headroom" and corresponding investment requirements as winter peak loads from building electrification grow. Section 6.4 provides more detail and key findings.
- **Natural gas system impacts:** Changes in natural gas sales and customer counts are analyzed and discussed in Section 7 for their relevance to the New York LDCs.
- **Electric and gas customer bill impacts:** The potential impacts to electric and gas customer bills solely due to incremental or decremental residential building electrification can be found in Section 8.

4.2 Scenario design & system context

The intent of including forward-looking scenarios in the HE Study is to analyze the system-level impacts of various electrification futures. The scenarios used in this study are designed to both:

- a) operate within a consistent underlying macro system context, and

- b) provide electrification outcomes that enable comparison of hybrid heating relative to Full Electrification and counterfactual heating equipment decisions.^{xiv}

Regarding the macro system context, each HE Study scenario aligns assumptions other than residential building electrification with the SEP's *Additional Action* scenario, to the extent practicable, which reflects:

- Continuation of existing policies and programs with incremental policy strengthening over time, and
- Further acceleration of adoption of clean energy technologies without assuming a fully transformational pathway to net-zero emissions by 2050.

SEP includes multiple scenarios designed in the context of that study effort to explore different energy pathways for NYS.³⁴ The SEP's *Additional Action* scenario was selected as the common source of non-residential-building-electrification assumptions across all three HE Study scenarios.

Importantly, use of the SEP *Additional Action* scenario is not intended as a policy recommendation or as a statement regarding long-term statutory compliance outcomes. Rather, it provides a coherent and internally consistent analytical foundation for modeling power generation, fuel supply, and other ancillary system and technology adoption assumptions (including commercial and industrial electrification), allowing the HE Study to focus specifically on the relative economics and adoption dynamics of hybrid versus fully electric residential heating technologies for residential customers.

By anchoring all scenarios to the SEP *Additional Action* framework, the analysis ensures that differences in results between scenarios reflect differences in electrification economics and adoption behavior, rather than broader system transformations.

4.3 Scenario variables

4.3.1 Assumptions held constant across scenarios

To enable clean comparisons across scenarios, a number of key assumptions are held constant across all three scenarios, including:

- Electric vehicle adoption and other non-building electrification assumptions,
- Distributed energy resource (DER) assumptions,
- Non-residential (Commercial, Industrial) electrification trajectories,
- Treatment of energy efficiency and weatherization, and

^{xiv} Consistent with the definition provided in Section 1, "counterfactual" in this context refers to a dwelling unit purchasing a new fossil heating equipment system consistent with their existing equipment and fuel type at the point of assumed failure, rather than either fully electrifying or adopting a hybrid heating system.

- Generation fleet build-out and other supply-side assumptions.

Holding these elements constant avoids mixing signals in the results and ensures that observed differences in adoption, system impacts, and emissions can be directly attributed to differences in heat pump economics and the resulting changes in customer technology adoption, rather than unrelated assumptions such as electric vehicle growth or generation mix.

4.3.2 Assumptions adjusted across scenarios

Scenarios differ only with respect to parameters that directly influence the economics and adoption of residential heat pumps. The following variables are material to economically-driven heat pump adoption and can be reasonably varied based on qualified expectations about how these might change in the future, including:

- Electrification incentive levels in NYS,
- Heat pump efficiency trajectories and capital cost trajectories,
- Electric and natural gas retail rate and delivered fuel price assumptions used in customer total cost of ownership calculations.

The HE Study calculates payback periods for different electrification measures based on both upfront and operating costs over time. Importantly, the study approach to forecasting electrification anchors to the consumer economics that drive adoption and consumer behavior. Please see Section 5 for further information.

4.4 Scenario definitions and detailed Assumptions

CRA modeled three distinct scenarios:

1. **Scenario 1: Market-driven advancement (or “Base” scenario)**
2. **Scenario 2: Hybrid transition (or “Hybrid” scenario)**
3. **Scenario 3: Accelerated full building electrification (or “Full Electrification” scenario)**

The Base scenario represents a market-driven outcome reflecting current trends in technology, policy, and customer decision-making. Under this scenario, the relative shares of hybrid and fully electric heat pump adoption reflect a Base view of market conditions and customer economics over the study horizon.

The Hybrid scenario represents a future in which a confluence of economic variables supports adoption of hybrid heating systems relative to Full Electrification for a larger share of customers. The broader system context remains unchanged, but the economics tilt toward hybrid adoption.

The Full Electrification scenario represents a future in which Full Electrification becomes increasingly economically attractive, leading to higher adoption of fully electric heat pump

systems. This scenario does not assume a net-zero system transformation, but rather accelerated market progress within the same underlying system context.

Importantly, the levels of adoption for specific technologies, customer types, and geographies are not pre-fixed but remain dictated by the fundamental economic modeling.

See Table 20 for a brief overview of the HE Study scenarios. This matrix provides a reference point for all variable scenario adjustments.

Table 20: CRA scenario matrix

Scenario	Market-Driven Advancement (Base scenario)	Hybrid Transition (Hybrid scenario)	Accelerated Full Electrification (Full Electrification scenario)
Electrification Incentives	Current incentives in place through 2050 in real dollars	<ul style="list-style-type: none"> <i>All Electrification:</i> Current incentives in place through 2030 in real dollars <i>Hybrid Electrification:</i> Beginning in 2031, introduce incentives for hybrid heating consistent with Full Electrification incentives on a project cost coverage basis through 2050 <i>Full Electrification:</i> Current incentives in place through 2050 in real dollars 	<ul style="list-style-type: none"> <i>All Electrification:</i> Current incentives in place through 2030 in real dollars <i>Hybrid Electrification:</i> No incentives, consistent with current Commission policy <i>Full Electrification:</i> Beginning in 2031, increase incentives for Full Electrification by 15%
Heat Pump Efficiency (COP)	Gradual improvements compared to 2026 through 2040, then flat	Flat	Gradual improvements compared to 2026 through 2040, then flat
Heat Pump Installed Cost	Flat in real dollars	Flat in real dollars	Gradual decline reflecting both contractor learnings and manufacturer efficiencies
Electricity and Natural Gas Rates	Current electric and natural gas rates and oil/propane prices grow together with inflation and remain stable relative to one another (i.e., reflects current rate differentials)	<i>Rate/price trends favor gas and hybrid:</i> The energy-equivalent rate differential between electricity and natural gas grows from 4.28x (current level) by +15% to 4.92x over 10 years (by 2036), then remains constant over the remainder of the forecast period.	<i>Rate/price trends favor Full Electrification:</i> The energy-equivalent rate differential between electricity and natural gas falls from 4.28x (current level) by -15% to 3.63x over 10 years (by 2036), then remains constant over the remainder of the forecast period.

The remainder of this section will describe the four variables that are adjusted within each scenario in more detail.

4.4.1 Electrification incentives

Role in heat pump economics

Upfront cost remains one of the most significant barriers to residential heat pump adoption, particularly for Full Electrification and retrofits in existing buildings. Electrification incentives directly affect customer payback periods by reducing initial capital costs, thereby improving adoption economics at the point of equipment replacement, all else equal. While operating cost savings can drive positive payback, customers often make decisions based on upfront costs.

In evaluating and modeling incentive impacts, three elements are important to consider:

1. Incentive dollar levels, which determine the magnitude of upfront cost reductions available to customers;
2. Total program budget, which determines whether incentives remain available at scale given levels of customer adoption; and
3. Incentive availability and timeline – i.e., how many years the incentives are in place within the modeling framework.

Together, these factors shape both near-term adoption and longer-term market transformation. Within the context of the HE Study, only the incentive dollar levels were adjusted by scenario.

Scenario assumptions

Consistent with other large-scale electrification studies, such as NYSERDA's *Assessment of Energy Efficiency and Electrification Potential in New York State Residential and Commercial Buildings*, scenarios do not explicitly model specific incentive program sunsets or budget constraints.³⁵ The HE Study assumes incentives persist throughout the modeling horizon and that program budgets are sufficient to support continued availability. This simplifying assumption avoids introducing uncertainty related to future program funding decisions and allows the analysis to focus on relative technology economics rather than program design constraints.

Under this approach, incentive values are applied consistently across customers and time, and total incentive expenditures are tracked endogenously as adoption evolves.

The Base scenario assumes that current incentive levels persist throughout the modeling horizon.

In the Hybrid and Full Electrification scenarios, incentive levels are adjusted relative to the Base scenario beginning in 2031, reflecting the fact that current Clean Heat Program incentives are scheduled to sunset or be reevaluated in 2030. Adjustments to incentive levels are implemented

beginning in 2031 to avoid introducing abrupt near-term changes while remaining consistent with policy planning horizons.

The Hybrid scenario keeps incentives constant for Full Electrification in all future years, while the Full Electrification scenario increases incentives for Full Electrification by 15% starting in 2031.

The Hybrid scenario introduces incentives for Hybrid Electrification at a level consistent with Full Electrification on a total project cost coverage basis starting in 2031, while the Full Electrification scenario does not introduce any incentives for Hybrid Electrification.

Incentive adjustments for Full Electrification were implemented as $\pm 15\%$ changes relative to Base scenario levels, intended to represent a moderate, policy-relevant change in customer economics rather than a significant infusion of funding to completely close the gap between Full and Hybrid Electrification.

The use of a $\pm 15\%$ adjustment is consistent with empirical findings across clean energy technologies that adoption responds meaningfully to incentive changes. A review of existing literature on heat-pump-specific elasticity yielded relatively limited results. One study conducted in North Carolina yielded a 13% increase in heat pump adoption with incentives in place for approximately 5% of total upfront cost, but was unable to specifically determine elasticity values.³⁶ Incentive levels in NYS provide a meaningful rebate compared to total project cost (amount varies by utility and specific project type), and 15% adjustment to the existing incentive levels was deemed reasonable based on review of heat pump and other clean energy technology elasticity literature.

4.4.2 Heat pump operating efficiency

Role in heat pump economics

Heat pump efficiency directly affects operating costs by determining the amount of electricity required to deliver a unit of usable heat energy. Heat pump efficiency varies by heat pump model and under different temperature and loading conditions. Improvements in efficiency therefore reduce lifetime energy costs, improve customer payback, and enhance the competitiveness of heat pump systems relative to the counterfactual fossil-based alternatives, all else equal. In New York, climate plays a significant role in heat pump economics, as heat pump models generally are less efficient at colder temperatures. The specific model of heat pump will impact performance, as cold climate-rated models typically perform better at lower temperatures.

While efficiency improvements would apply to hybrid systems as well, the economics of hybrid systems would see a more limited benefit from improvements in efficiency because the majority of the energy needs for heating are met by the hybrid system during cold weather periods when the efficiency degrades.

Scenario assumptions

In the Base and Full Electrification scenarios, heat pump efficiency is assumed to improve gradually over time, with a cumulative improvement of approximately 22% by 2040 compared to 2026 levels. Efficiency is kept flat between 2040 and 2050. This trajectory is consistent with the 2025 NY SEP assumptions, which were derived from the NREL *Electrification Futures Study* Moderate Advancement scenario. The Base and Full Electrification scenarios adjusted the overall COP plane, which already accounts for the capacity degradation at colder temperatures.

Applying this efficiency trajectory in both scenarios reflects continued technological progress in heat pump performance for newer models without assuming breakthrough innovation beyond historically observed learning trends.

In the Hybrid scenario, heat pump efficiency is held constant over time at current levels. This assumption reflects a world view in which efficiency improvements are slower to materialize, thereby favoring hybrid systems that rely more heavily on fossil backup during peak heating conditions.

4.4.3 Heat pump installed costs

Role in heat pump economics

Upfront equipment, labor, and installation costs significantly influence customer economics. The relative weight of installed costs (net of incentives) versus operating costs in overall heat pump economics depends on a wide range of factors, including the type of heat pump, climate, insulation/weatherization, and more. Heat pump installation costs in the study's analysis reflect the upfront cost of heat pump equipment, the "soft costs" (i.e., costs for installation and contractor labor), and other "hard costs" (i.e., electric panel upgrades, home distribution system upgrades, etc.). The total installed cost estimates and incentive levels assumed for different technologies were presented in Section 2 and are further detailed in Data Annex 2.

This section focuses on the influential role of changes to installation costs *over time* in the context of scenario design. Declining installed costs over time improve adoption economics for both hybrid and fully electric systems, with a particularly strong effect on Full Electrification pathways. There is no clear industry consensus around whether heat pump costs will reduce over time, what types of costs are most likely to decline in real terms, and what the key drivers of such declines would be. This could be a combination of technological innovation, economies of scale from heat pump manufacturers, and contractor learnings as they gain experience installing heat pump systems.

The NREL *Electrification Futures Study* is the most commonly cited study that projects specific learning rates for heat pump project costs (and efficiency) over an extended time horizon. It presents three alternative cases for heat pump cost improvements: Slow, Moderate, and Rapid Advancement. While this study is approximately a decade old, many derivative studies rely on these assumptions, including the SEP. NREL's "Slow Advancement" scenario, which represents

a more conservative trajectory of heat pump efficiency, assumes a slight reduction in real costs over time.³⁷ The 2025 NY SEP's *Data Annex* shows an assumption of flat (in real dollars) installed costs over time. Finally, the EIA's *Updated Buildings Sector Appliance and Equipment Costs and Efficiencies* shows a 6% increase in Typical Air Source Heat Pump costs between 2030=2050.³⁸

Scenario assumptions

Based on its review of industry literature, select Clean Heat project cost data reflecting recent market activity, and after consideration of current federal policy, CRA assumed that heat pump installed costs remain flat over time (in real dollars) in the Base and Hybrid scenarios. This is the same as the assumptions underlying the SEP's Additional Action scenario. To forecast nominal heat pump costs through time, a universal 2.10% annual general inflation rate is applied in all scenarios.

In the Full Electrification scenario, real heat pump installation costs gradually decrease over time consistent with NREL's *Electrification Futures Study* Moderate Advancement scenario. The reductions are applied uniformly across customer segments and heat pump technologies and are phased in gradually to avoid unrealistic step changes.

4.4.4 Gas-electric retail rate differential

Role in heat pump economics

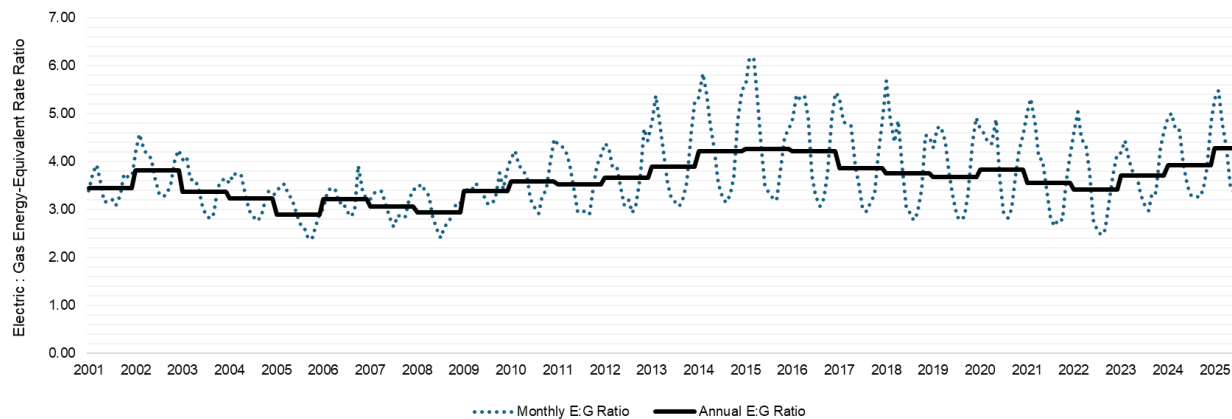
As briefly discussed in earlier sections, the study's analysis compares the TCO of different electrification measures to the counterfactual. Utility retail gas and electric rates are the main drivers of operating costs, as well as the costs for delivered fuels. The rates for utility electricity and gas can vary significantly in NYS between utilities and regions. There are a wide range of potential drivers that could cause the retail rates customers pay for electricity, gas, and other fuels to converge or diverge over such a long-time horizon.

In this study, CRA adjusted the all-in energy-equivalent *differential* between the retail electricity and gas rates over time to reflect potential future changes in the relative expensiveness of gas and electricity. The analysis did not take specific forward views on the underlying components of electric and gas utility rates over the forecast period (2026-2050). Instead, it selected multiple futures for the differential between the electric and natural gas rates—one in which the differential continues to widen over time (i.e., electricity becomes more expensive relative to gas and fuels, as compared to current levels) and one in which the differential closes over time (i.e., gas and fuels become more expensive relative to electricity, as compared to current levels)The present-day energy-equivalent rate differential based on EIA data for New York was calculated to be approximately 4.28 (i.e., the 2025 retail electric rate in New York is 4.28 times the 2025 average retail gas rate if both rates were priced in cents per kWh).^{xv} This is high relative to

^{xv} Based on EIA Residential Retail Rate data for New York through November 2025.

historical levels; the average electric to gas energy-equivalent rate differential for the last 20 years was 3.64 times, or approximately 15% lower than current levels and has tended to settle between 3 and 4 times, depending on the year. This ratio can fluctuate much more significantly on a monthly basis, due primarily to seasonal changes in natural gas prices. Figure 18 below charts this differential in NYS for each year since 2001 on both a monthly and annual basis, based on EIA data.

Figure 18: New York Electric-Gas Energy-Equivalent Rate Differential (EERD) (data from EIA)



Scenario assumptions

In the HE Study, the electric-gas EERD is held constant in the Base scenario and varied in the Hybrid Full Electrification scenarios. This adjustment is also applied to the price of delivered fuels to reflect more or less favorable economics for electricity relative to gas and fuels. Adjustments are applied gradually over time and reflect alternative futures in which:

- **Hybrid scenario:** Natural gas and delivered fuels become marginally more cost-competitive relative to electricity, favoring Hybrid Electrification and the counterfactual. The electric-gas EERD is adjusted *upward* by 15% in the next decade (+1.5% per year), reaching an average of 4.92 times by 2036, and is then held constant over the remainder of the forecast period (2035-2050).
- **Full Electrification scenario:** Electricity becomes more cost-competitive relative to gas and delivered fuels, favoring Full Electrification. The electric-gas EERD is adjusted *downward* by 15% in the next decade (-1.5% per year), reaching an average of 3.63 times in 2036, and is then held constant over the remainder of the forecast period (2035-2050).

In the analysis, the EERD varies by region of NYS, depending on the current retail electric and gas rate levels for each of the electric and gas utilities. By adjusting the differential rather than individual rate components, the analysis captures a realistic and reasonable range of potential electric, gas, and delivered fuel price futures grounded in historical data on retail rates in NYS, which could be driven by a confluence of market, technological, regulatory, and other factors beyond the scope of this analysis.

5. Customer-electrification modeling outputs: Customer-level cost and emissions impacts

This section first presents findings on the economics of Full and Hybrid Electrification for various residential customer types in NYS, exploring the impact of different attributes on economics. It then presents CRA's forecast for electrification technology adoption over the forecast period (2026-2050) under each of the three planning scenarios. Lastly, this section presents sales, peak demand, and GHG emission outputs for each scenario and discusses distributional impacts.

CRA calculated payback periods for all customer archetypes for all applicable electrification upgrade measures. This provides insights into where Full and Hybrid Electrification are more advantageous and most likely to be adopted by customers. Ultimately, these payback periods guide CRA's model simulation of electrification technology adoption under each of the three planning scenarios.

5.1 Electrification total cost of ownership and payback period analysis

5.1.1 Methodology

In this context, a residential consumer whose space heating equipment fails may have the option to either (a) replace their space heating equipment like-for-like, (b) invest in a new type of heating equipment, or (c) take no action. In reality, in a cold climate like NYS, continued access to space heating is essential for health and safety, making inaction infeasible. The decision to adopt a heat pump requires consideration of all of the lifetime costs that a customer may incur to purchase, install, own, and operate a heat pump system. The "total cost of ownership" (TCO) provides a useful framework for comparing the relative merits of multiple options or pathways for a prospective consumer.

The HE Study relies on the simple payback periods to capture the customer economics of heat pump adoption versus the counterfactual (i.e., like-for-like replacement). The simple payback period is defined as the number of years required for the net present value (NPV) of the TCO of a heat pump to become permanently less than that for the counterfactual heating technology, for a given customer archetype, in a given year. The NPV of the cumulative costs to electrify are compared annually against the cumulative avoided costs in the counterfactual. If the cumulative avoided costs of the counterfactual are more than the electrification upgrade, then the year of the crossover is the simple payback period. If no crossover exists, payback period is capped at 16 years, based on expected useful life of a typical heat pump system. In this way, the payback period measures a customer's forward-looking expectation about the NPV of multiple options for an investment in new heating equipment, when faced with a driving decision point (e.g., failure of existing HVAC equipment) or "opportunistic" consumer adoption that is unrelated to equipment failure. The calculation of the simple payback period includes the following types of costs shown in Table 21 below. Specifically, the costs for the electrification upgrade are

formulated as realized costs, while the costs for the counterfactual are formulated as avoided costs or benefits.

Table 21: Costs included in calculation of simple payback period for electrification upgrades

Type	Cost Category	Full Electrification	Hybrid Electrification	Counterfactual
One-Time (Year 0)	Total Installed Costs	<ul style="list-style-type: none"> Heat pump Total Installed Cost (TIC) Weatherization TIC Other electrification costs (panel upgrade, distribution upgrade, etc.) 	<ul style="list-style-type: none"> Heat pump TIC Fossil Fuel equipment TIC 	<ul style="list-style-type: none"> Fossil Fuel equipment TIC
	Upfront Incentives	<ul style="list-style-type: none"> Electrification incentive Weatherization incentive 	<ul style="list-style-type: none"> Weatherization incentive 	<ul style="list-style-type: none"> N/A
Annual (Years 1 to 16)	Owner's & Maintenance Costs	<ul style="list-style-type: none"> Heat pump O&M 	<ul style="list-style-type: none"> Heat pump O&M FF Equipment O&M 	<ul style="list-style-type: none"> FF Equipment O&M
	Operating Costs	<ul style="list-style-type: none"> Electricity costs (heating, cooling) 	<ul style="list-style-type: none"> Electricity costs (heating, cooling) Fuel costs 	<ul style="list-style-type: none"> Electricity costs (cooling) Fuel costs

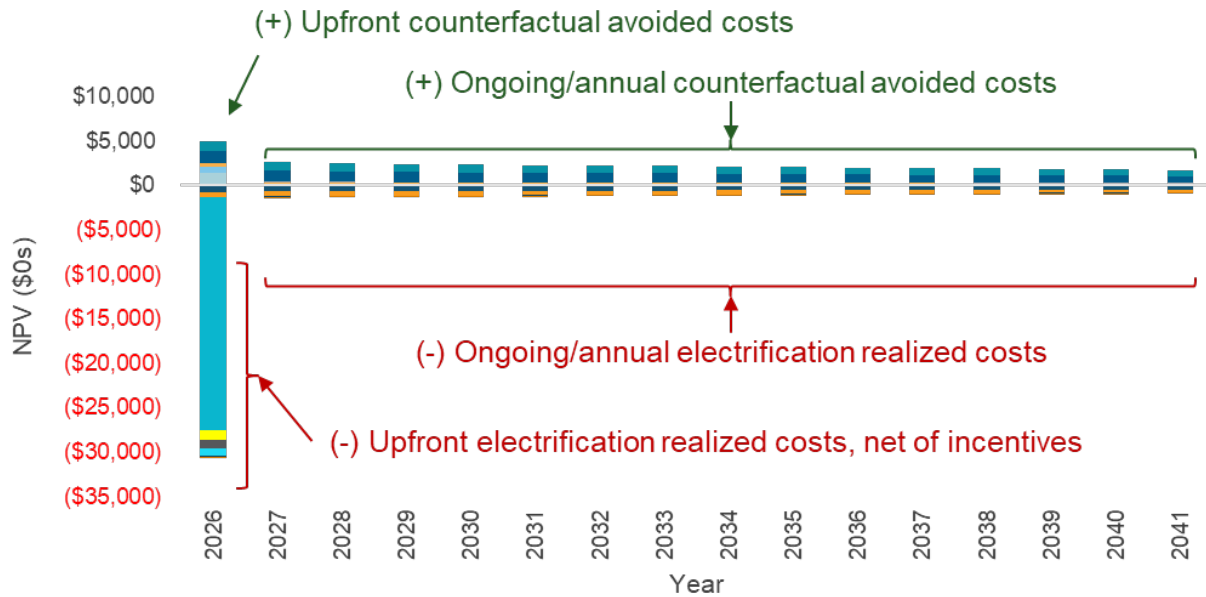
The formula for the calculation of the cumulative NPV of TCO in year “t” for both the counterfactual and the upgrade scenario is presented below.

$$TCO_t = (Equipment\ Cost + Installation/Labor\ Costs + Other\ Hard\ Cost - Incentives)_{t=0} + \sum_{t=0}^{UL} \frac{Electricity\ Cost_t + Fuel\ Cost_t + Owner's\ \&\ Maintenance\ Cost_t}{(1 + DR)^t}$$

Where: DR = Discount Rate; UL = Useful Life of Equipment

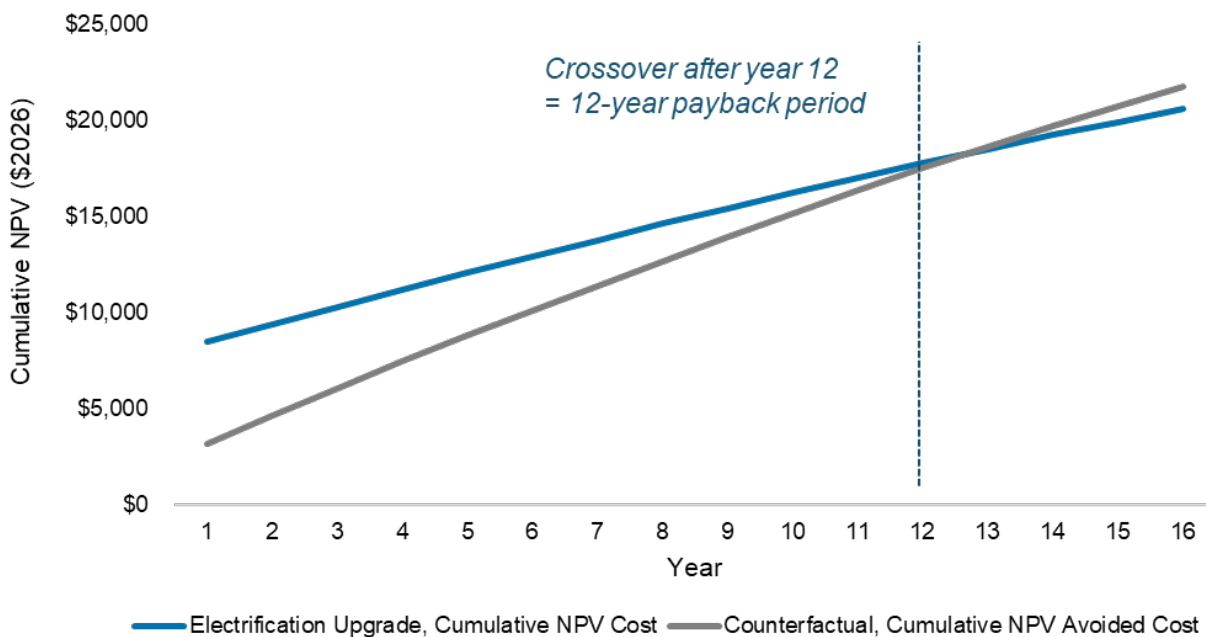
Figure 19 below illustrates the components of the payback calculation for a sample archetype in CRA’s model, over a 16-year period.

Figure 19: Example of simple payback calculation (annual NPV)



For the sample archetype above, the cumulative NPV of the avoided costs (from the counterfactual) exceeds the realized costs (from the electrification upgrade) in year 12, equating to a simple payback period of 12 years. Figure 20 below illustrates this crossover point that determines the payback period.

Figure 20: Example of simple payback period calculation (cumulative NPV)



For a given customer archetype, the “payback curve” is the simple payback period calculated for each year of the HE Study forecast period.

CRA calculated the simple payback period for all 419 customer archetypes, for up to eight unique Full and Hybrid Electrification technology measures, for all years in the forecast period (2026-2050), under each of the three planning scenarios. This led to 141,450 unique simple payback periods that are used to guide customer adoption of electrification measures. The next section analyzes the payback periods by exploring different variables that can influence heat pump and electrification economics, including: customer type, heat pump technology, region of NYS, construction vintage, and income level.

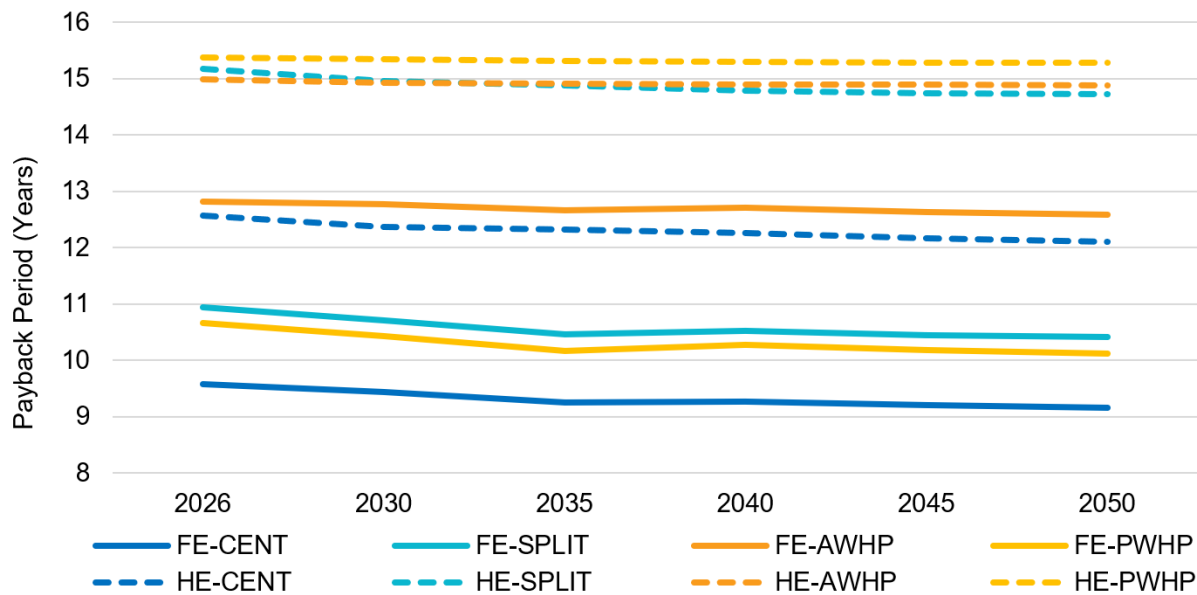
5.2 Economics of electrification within New York’s residential stock

5.2.1 Base scenario

Today and in the future in the Base scenario, Full Electrification is generally more economic than Hybrid Electrification. A core driver of this outcome is the relatively large incentives offered by electric utilities in NYS for Full Electrification. Central ASHP systems have the lowest (i.e., best) average payback period across all customer archetypes—between 9 and 10 years—though central systems are available to fewer customer archetypes (i.e., only those with central forced air fossil fuel heating systems). PWHP has the next best average payback—between 10 and 11 years—but are only assumed to be available to MF customers. Mini-split ASHPs, which are the most widely available technology, also have an average payback of between 10 and 11 years for Full Electrification. AWHP systems have an average payback between 12 and 13 years.

Central ASHP systems have the best overall economics for Hybrid Electrification, with an average payback period between 12 and 13 years. Other technologies for Hybrid Electrification have average payback periods between 14 and 16 years, indicating that most customer archetypes would see poor economics relative to the counterfactual and many more would revert to their counterfactual heating equipment rather than adopt. Figure 21 presents the weighted average payback by electrification technology over the forecast period in the Base scenario.

Figure 21: Weighted average payback period by technology and electrification type, Base scenario



CRA calculated the simple payback periods by technology for all 141 single-family customer archetypes and 278 multifamily customer archetypes. Most archetypes have between 3 and 4 viable electrification upgrade options (which are all compared against the counterfactual).

According to NYSERDA, a payback period of between 9-10 years is equivalent to an internal rate of return (IRR) of approximately 10%, while a six-year payback period corresponds to an IRR of roughly 16%. NYSERDA has targeted a six-year payback period when sizing incentive levels for certain technologies:³⁹

Specifically, the incentive is set such that subsidized affordable multifamily buildings, public sector buildings, and certain large commercial building types achieve an internal rate of return (IRR) of 10% (corresponding to a project payback period of nine to ten years) and other residential or commercial customers see an internal rate of return of 16% (corresponding to roughly a six-year payback period).

For electrification and EE measures, this can be used as a barometer for when an option becomes economically attractive. A payback period of 6 years or below indicates a measure is likely to be economically attractive. A payback period between 6 and 15 years indicates that a measure is potentially economic, but not necessarily attractive to the majority of customers. Payback periods of 16 years (or higher) are economically non-viable and would produce a negative real IRR (or negative TCO) for customers over the useful life of the equipment.

Looking at the Base scenario in the present-day (2026), the following observations can be made:

- Some customer archetypes have no economically attractive electrification options (i.e., simple payback is 16 years for all available upgrades, at the enforced cap);
- Some customer archetypes have multiple economically attractive electrification options, where more than one electrification type or technology has a payback period below 6 years; and
- The best electrification technology (central, mini-split) can vary by customer archetype depending on the variables that affect the total installed cost (e.g., heating design load) and the operating costs (e.g., income level, location in NYS).

Figure 22 plots the simple payback period in 2026 for all 141 SF customer archetypes (#1-141) and Figure 23 plots the payback for all 278 MF customer archetypes (#142-419). Each tick mark represents a different, unique customer archetype. Note that lower numbered archetypes represent customers with a greater prevalence in the NYS building stock. As the archetype ID increases (from 1 to 141), the representation of that customer in the NYS residential housing stock declines.

Figure 22: Simple payback period by technology, single-family customer archetypes

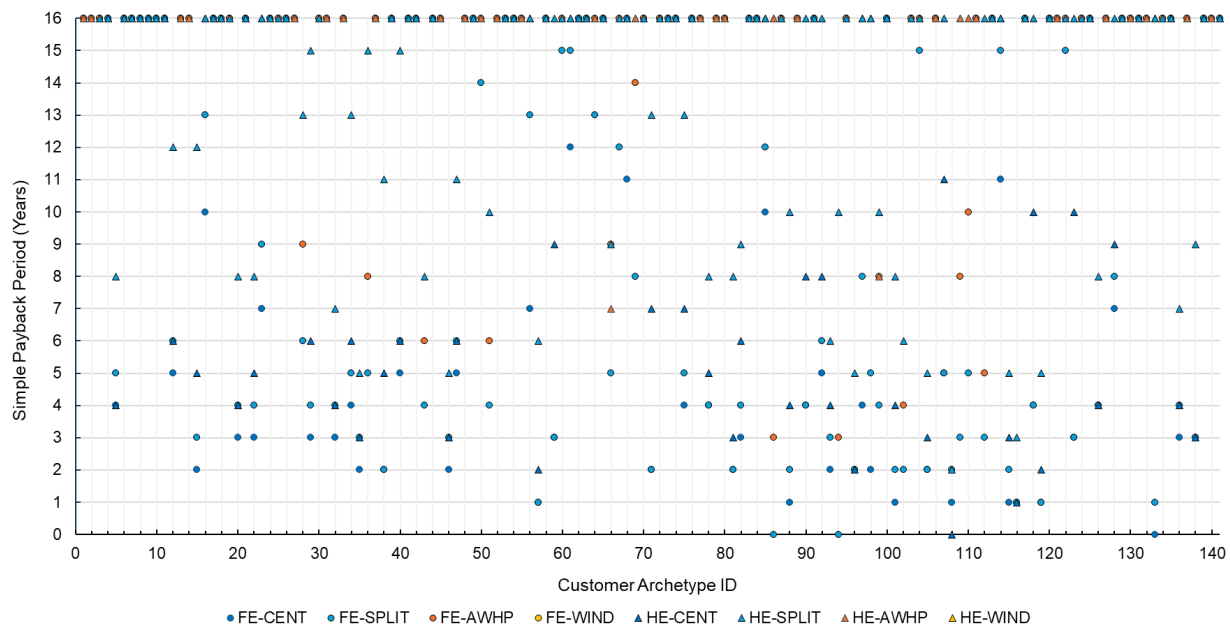
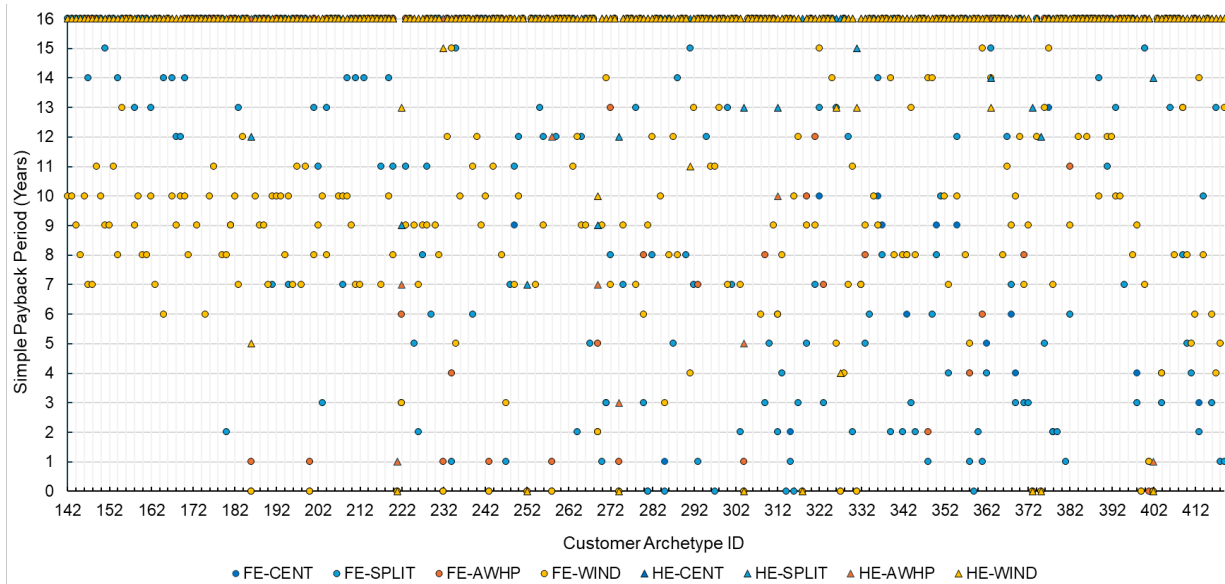


Figure 23: Simple payback period by electrification type and technology, multifamily archetypes



Payback analysis by heat pump technology type

This subsection analyzes the relative economics of the electrification technologies using the weighted average payback period, which represents the average payback period over the forecast period for all customer archetypes with certain attributes, weighted towards archetypes with higher prevalence in the NYS residential stock. CRA examined the weighted average payback period for Full Electrification by customer type (i.e., SF, MF) for the following customer attributes: Region, construction vintage, counterfactual fuel type and heating equipment, and income level.

In the Base scenario, FE generally sees better economics than HE. Single-family customers adopting hybrid systems see the best paybacks with central and mini-split ASHPs, on average, but the economics are slightly worse than FE options. Table 22 below includes the weighted average payback period by technology and electrification type in the Base scenario.

Table 22: Weighted average payback period by technology, Base scenario

Technology	Full Electrification				Hybrid Electrification			
	SF	MFLOW	MF MID	MF HIGH	SF	MFLOW	MF MID	MF HIGH
Central ASHP	10.1	8.9	N/A	N/A	11.4	16.0	N/A	N/A
Mini-split ASHP	11.8	11.1	14.0	15.3	13.7	15.6	16.0	16.0
AWHP	14.6	9.8	15.8	15.9	15.7	14.0	16.0	16.0
PWHP	N/A	9.9	9.0	10.3	N/A	15.3	16.0	15.9

Payback analysis by region

CRA also analyzed average payback periods by Region. This explores whether the differences in upfront costs, incentive amounts, and operating costs (i.e., due to different utility rates for electricity and natural gas) lead customers to make different economic choices regarding electrification. The results indicate meaningful variation between the Regions. Notably, Region 1 has relatively poor economics for both FE and HE, due primarily to its lower-cost natural gas service. This makes the economics of reversion to the counterfactual much more attractive for existing gas customers than either FE or HE options. Regions 4 and 6 see the best economics. These areas have higher natural gas rates while electricity remains relatively affordable (relative to other areas). Region 4, in particular, also benefits from higher upfront incentives for electrification. Archetypes in Region 5 (NYC) have the worst average payback periods, due to both the higher total installed costs for electrification NYC (which are rooted in real-life Clean Heat project data) without a commensurate increase in the electrification incentive. Simultaneously, electricity rates for CECONY are the highest in the state, which increase operating costs for both FE and HE options relative to counterfactuals. HE, in particular, is very challenged within NYC (average payback periods hit the enforced cap of 16 years for all customer types) and is unlikely to see much natural adoption in the Base scenario. Table 23 includes the weighted average payback periods by Region and customer type in the Base scenario.

Table 23: Weighted average payback period by region, Base scenario

Region	Full Electrification				Hybrid Electrification			
	SF	MFLOW	MF MID	MF HIGH	SF	MFLOW	MF MID	MF HIGH
Region 1 (Western)	14.6	9.0	N/A	N/A	15.0	16.0	N/A	N/A
Region 2 (Central)	12.1	7.4	N/A	N/A	13.2	15.0	N/A	N/A
Region 3 (Upstate)	9.8	7.1	N/A	N/A	11.2	14.1	N/A	N/A
Region 4 (Hudson)	7.3	7.2	N/A	N/A	11.6	14.1	N/A	N/A
Region 5 (NYC)	15.8	12.6	12.2	12.9	16.0	16.0	16.0	16.0
Region 6 (Long Island)	9.2	4.8	N/A	N/A	11.2	14.1	N/A	N/A

Payback analysis by construction vintage

CRA segmented the residential building stock by construction vintage. Older vintages tend to have less energy-efficient shells. This leads to increased energy usage in the counterfactual but may also require meaningful weatherization (basic shell) upgrades paired with electrification, to help reduce energy usage and improve the economics. New construction vintages tend to see

better economics than older vintages. Single-family customers saw a roughly 2-year improvement in average payback for homes constructed after 1980 versus those constructed before 1980. For Full Electrification, the difference in average payback between a post-2010 (new build) multifamily building and a pre-1940 building is approximately 4-5 years, or 40%. The differences in the economics for Hybrid Electrification were less pronounced.

Table 24: Weighted average payback period by construction vintage, Base scenario

Construction Vintage	Full Electrification				Hybrid Electrification			
	SF	MFLOW	MF MID	MF HIGH	SF	MFLOW	MF MID	MF HIGH
Pre-1940 (MF)	N/A	13.1	13.4	13.3	N/A	15.6	15.6	15.6
1940-1980 (MF)	N/A	11.6	13.4	13.9	N/A	15.1	16.0	15.9
Pre-1980 (SF)	12.8	N/A	N/A	N/A	12.3	N/A	N/A	N/A
Post-1980 (SF)	10.9	N/A	N/A	N/A	11.8	N/A	N/A	N/A
1980-2010 (MF)	N/A	9.0	11.2	11.7	N/A	15.3	16.0	15.9
Post-2010 (MF)	N/A	7.8	8.0	N/A	N/A	15.7	16.0	N/A

Payback analysis by fuel type & counterfactual heating equipment

CRA also examined the differences in payback by fuel type and fossil fuel heating equipment. Broadly, the economics of electrification were more favorable for delivered fuel customers (versus natural gas). Crucially, single-family natural gas furnaces, which make up the largest share of the heating stock, see extremely poor economics for both Full Electrification (14.9 years) and Hybrid Electrification (16.0 years). This indicates that a frequently proposed use case for Hybrid Electrification – single-family homes with natural gas furnaces – are unlikely to hybridize when their heating equipment fails without intervention to improve economics (e.g., a change in the incentive or rebate structure). It also indicates that these customers are less likely to electrify under any circumstance (Full or Hybrid) than in other regions of NYS. Table 25 presents the weighted average payback periods by fuel type, counterfactual heating equipment, and customer type in the Base scenario.

Table 25: Weighted average payback period by counterfactual fuel & equipment type, Base scenario

Fuel & Equipment	Full Electrification				Hybrid Electrification			
	SF	MFLOW	MF MID	MF HIGH	SF	MFLOW	MF MID	MF HIGH
Natural Gas Furnace	14.9	5.7	N/A	N/A	16.0	14.3	N/A	N/A
Natural Gas Boiler	15.3	10.5	11.9	12.2	16.0	15.7	16.0	16.0
Fuel Oil / Propane Furnace	3.0	N/A	N/A	N/A	5.8	N/A	N/A	N/A
Fuel Oil / Propane Boiler	8.5	13.1	12.7	14.3	10.7	14.9	15.9	15.9

Payback analysis by income level

Low-income customers generally had better paybacks than non-LMI customers, but the differences in weighted average payback were not significant. Low-income customers receive higher levels of electrification incentives through EmPower+ and are eligible to receive discounts through the Enhanced Energy Affordability Program, which can provide around discounts of \$100 per year (or more) on natural gas and electricity bills. A conflating factor may be that LMI customers are more likely to live in older buildings, which typically exhibited less favorable economics for electrification than newer construction. Moderate-income customers, however, tend to have access to electrification incentives through EmPower+ that are comparable to non-LMI customer incentives available through NYS Clean Heat. CRA’s modeling assumed that these customers chose the highest available incentive. As a result, the payback periods for moderate-income customers were not always superior to non-LMI.

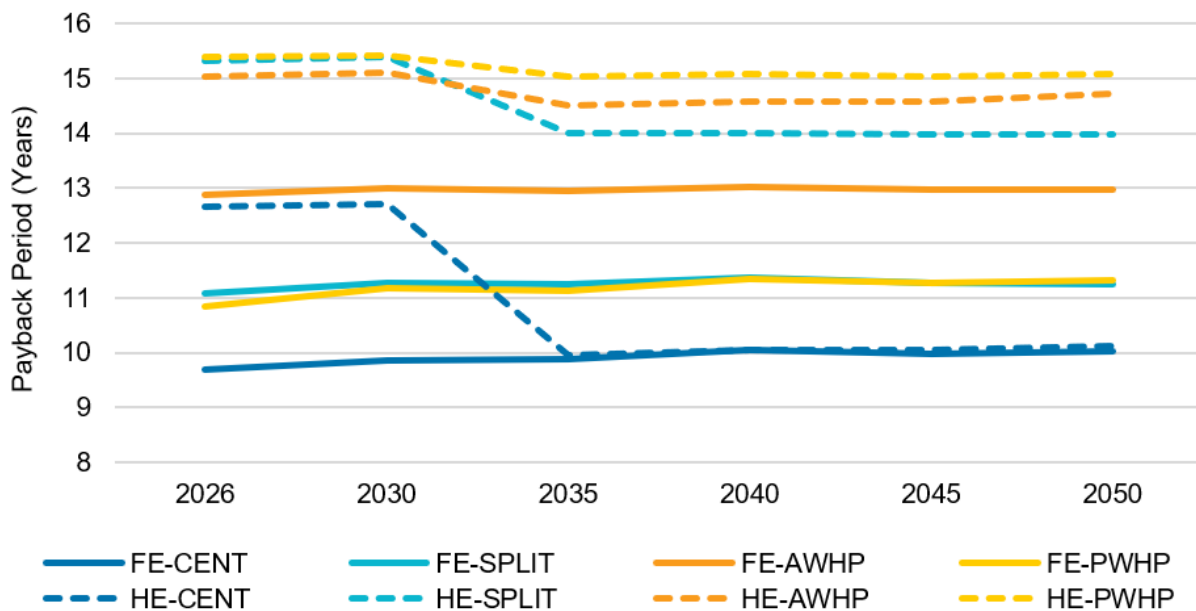
Table 26: Weighted average payback period by income level, Base scenario

Income Level	Full Electrification				Hybrid Electrification			
	SF	MFLOW	MF MID	MF HIGH	SF	MFLOW	MF MID	MF HIGH
Non-LMI	11.7	11.1	12.2	13.1	13.0	15.5	16.0	16.0
Moderate-Income	14.6	10.5	13.2	10.8	14.9	16.0	16.0	16.0
Low-Income	11.7	10.1	12.0	13.0	13.9	15.4	16.0	16.0

5.2.2 Scenario analysis and comparison to Base scenario

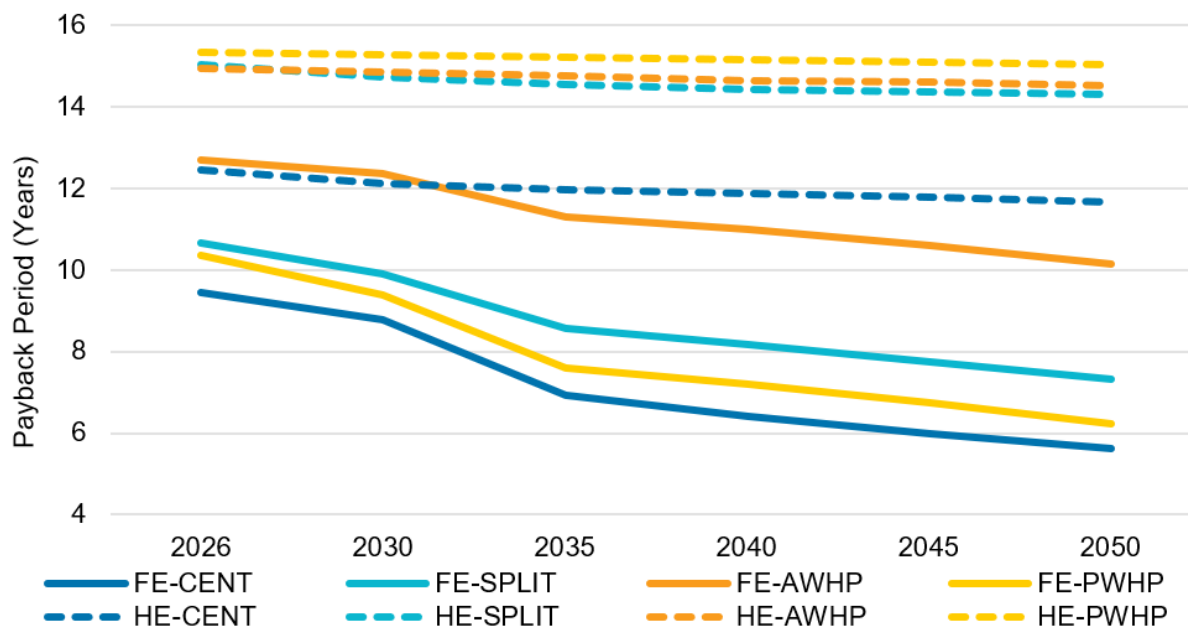
In the Hybrid scenario, average paybacks for Hybrid Electrification technologies are improved relative to Full Electrification technologies. The introduction of incentives in 2031 (equivalent to those offered for Full Electrification) is the largest driver of improvements in payback. Central ASHP systems see the most significant improvement, with average paybacks falling to around 10 years and remaining there over the forecast period. Paybacks remain stagnant after 2031 for all technologies, due in part to rising real electricity rates relative to gas and fuel prices (+15% over the forecast period) and the assumption of no improvements in heat pump performance (average COP) over the forecast period. See Figure 24 below.

Figure 24: Weighted average payback period by technology and electrification type, hybrid scenario



In the Full Electrification scenario, payback periods for FE options fall steadily over the forecast period due to a combination of factors: falling real electricity rates relative to gas and fuels (-15% over forecast period), a boost in the available incentive levels in 2031 (+15%), and gradual improvements in the average ASHP COP (+22% over forecast period). In reality, paybacks for many customers for specific FE technologies commonly fall below six years. Figure 25 charts the weighted average payback period by technology in the Full Electrification scenario over the forecast period.

Figure 25: Weighed average payback period by technology, Full Electrification scenario



The charts above are modestly biased upward due to the number of customer archetypes with no superior payback. The “best” choice for each customer type (i.e., the upgrade with the lowest payback period) changes more significantly for single-family customers between scenarios.

The relative economics of FE and HE vary most notably for single-family customers across scenarios. In the Base scenario, FE is the most economic option for 71 single-family archetypes, while HE is the most economic option for only three archetypes. An additional 67 archetypes show no clear economic preference, typically because all options reach the 16-year payback cap, indicating that electrification is not meaningfully economic under Base scenario assumptions.

In the Hybrid scenario, this pattern reverses. HE becomes the most economic option for 62 single-family archetypes, while FE is the most economic option for only 21 archetypes. By contrast, in the Full Electrification scenario, FE is the most economic option for a majority of single-family archetypes, with 104 archetypes favoring FE and only two favoring HE.

For multifamily customers, differences across scenarios are less pronounced. This outcome is driven in part by the high share of multifamily archetypes located in New York City, including mid- and high-rise buildings, and by the favorable economics of PWHP systems as a pathway for Full Electrification in multifamily buildings. As a result, the number of multifamily archetypes for which FE is the most economic option remains relatively stable across scenarios. However, the number of multifamily archetypes for which HE is the most economic option increases from 1 in the Base scenario to 62 in the Hybrid scenario. Table 27 below presents these results by scenario.

Table 27: Number of customer archetypes with lowest payback period by customer archetype

Customer Type	Electrification Type	Base Scenario	Hybrid Scenario	Full Scenario
Single-Family	Full Electrification	71	21	104
	Hybrid Electrification	3	62	2
	Neither or Tie	67	58	35
Multifamily	Full Electrification	215	213	219
	Hybrid Electrification	1	62	1
	Neither or Tie	62	3	58
Total	Full Electrification	286	234	323
	Hybrid Electrification	4	124	3
	Neither or Tie	129	61	93

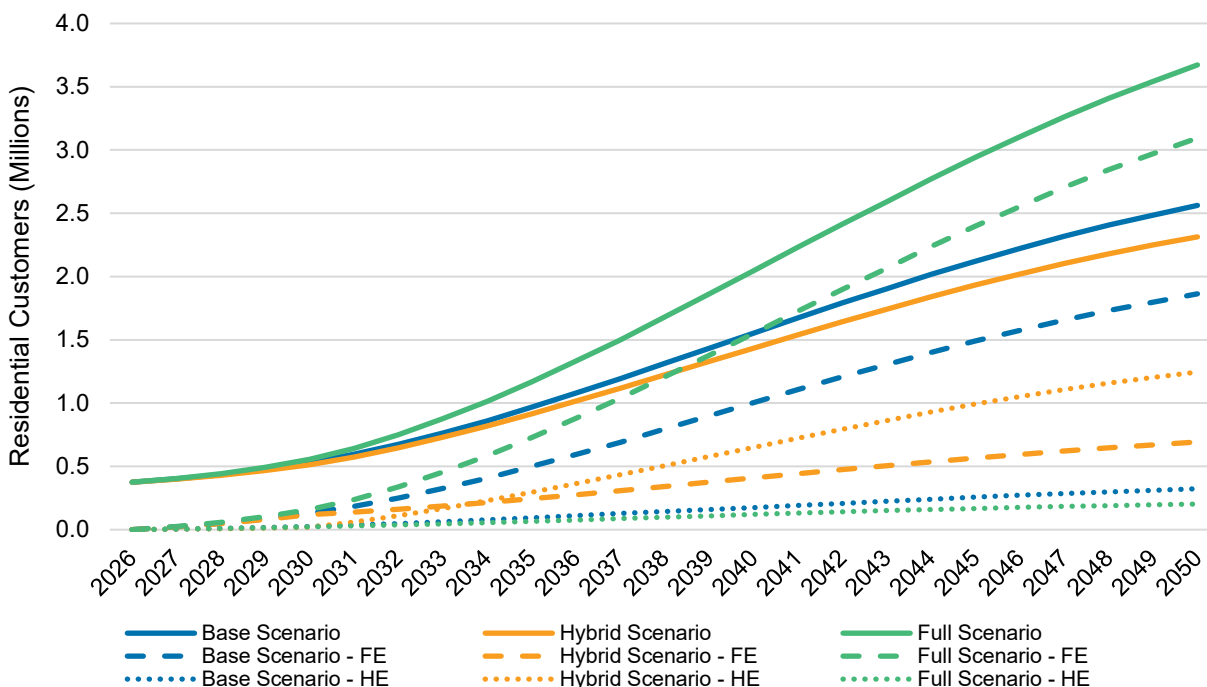
The next section presents the forecasted electrification adoption in NYS under each scenario, which is driven by the granular payback periods analyzed above.

5.3 Electrification adoption in NYS

Electrification adoption rates are the primary driver of all key outputs in this study. The overall level of adoption, the split between FE and HE configurations, and the fuel type being displaced collectively determine the study’s impacts on annual energy usage, seasonal peak demand, and emissions. The results presented in this subsection therefore serve as the foundation for the system impacts that follow.

HE Study residential building electrification adoption results across all three scenarios are shown in Figure 26 below. Total electrification (Full + Hybrid) across the three scenarios ranges from 1.9 million customers electrifying in the Hybrid scenario to 3.3 million in the Full scenario, with the Base scenario representing a middle ground of 2.2 million customers adopting heat pumps by 2050.

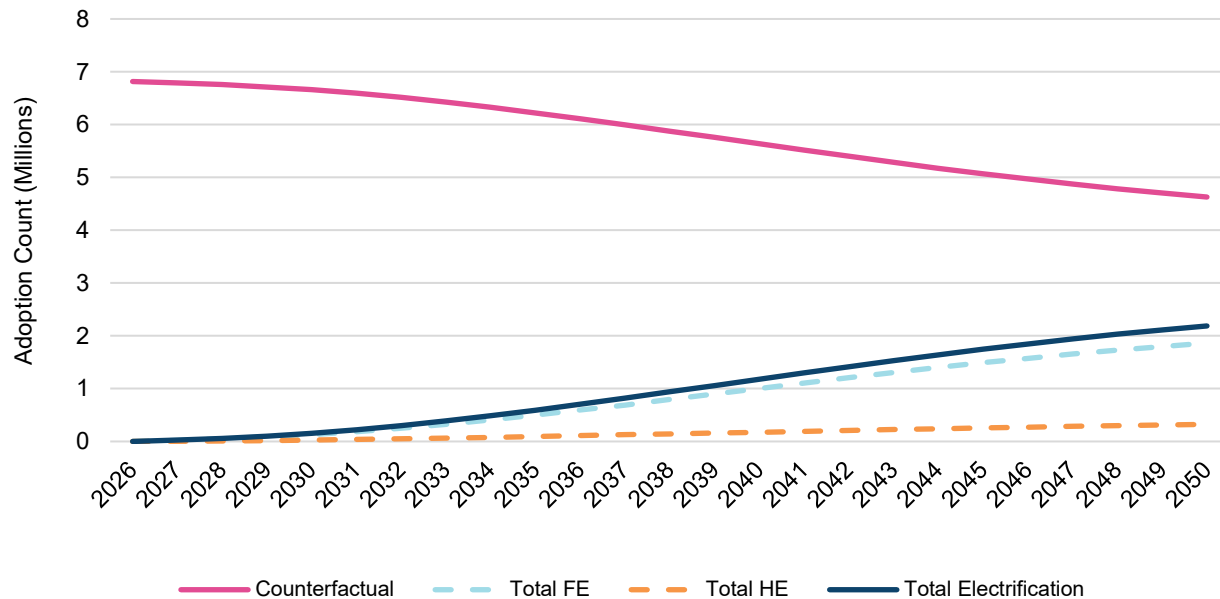
Figure 26: Cumulative electrification adoption by scenario



Whereas the Base scenario reaches 32% of 6.8 million modeled dwelling units electrifying (shown in Figure 27), the Hybrid scenario has a lower rate of 28%. The Full Electrification scenario achieves a considerably higher 48% penetration. As a result of scenario design, the adoption of FE or HE configuration is amplified by its corresponding scenario. The Hybrid scenario is the only of the three where HE adoption outpaces FE, comprising 64% of adoption. The inverse is true in the Full Electrification scenario, where 94% of adoption is the FE configuration.

Most adoption in the Base scenario (85%) is for the FE configuration, which aligns with the FE measures generally having lower payback periods than HE. Notably, delivered fuel customers accounted for 59% of all electrification adoption over the forecast period. NYC (Region 5) achieves cumulative residential electrification of 20% by 2050, compared to 41% for the Rest of State. This is reflective of the generally poorer economics for electrification in NYC, including a large concentration of mid and high-rise multifamily units. Among multifamily units statewide, 41% are electrified in some form by 2050 in the Base scenario, of which 57% are MF low-rise dwellings.

Figure 27: Electrification adoption by type, Base scenario

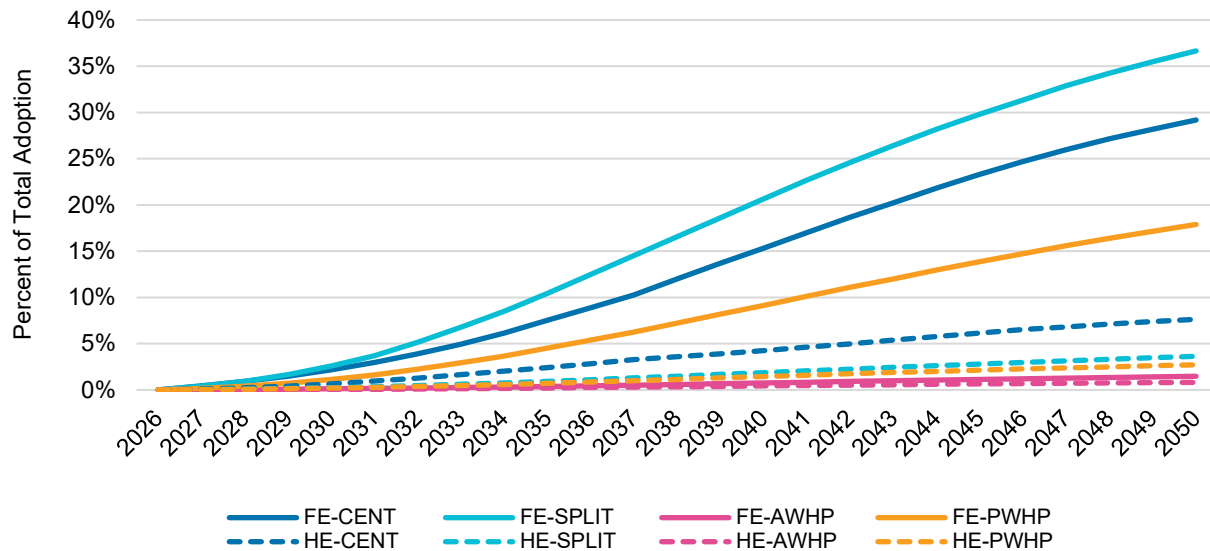


Electrification adoption by technology

Full Electrification configurations dominate adoption under the Base scenario, as established in the overall adoption results. At the measure level, central ducted and mini-split heat pump systems together account for the majority of installations across all customer archetypes and configurations, comprising 37% and 40% of total adoption, respectively. The split between these two measures is not uniform across configurations, central ducted systems are adopted at higher rates under Hybrid Electrification configurations, while mini-split systems account for the largest share of Full Electrification adoptions.

Among multifamily units, PWHPs are the primary electrification measure, comprising more than half of multifamily adoption and reaching approximately 450,000 installations by 2050. AWHPs represent a smaller share of total adoption due to limited applicability across the housing stock, though they are relatively more economic for FE configurations. Finally, an additional consideration to make on stock-wide measure adoption is the prevalence of each archetype a measure is viable for – mini-split heat pumps are available for every archetype and therefore have a numerical advantage aside from payback economics.

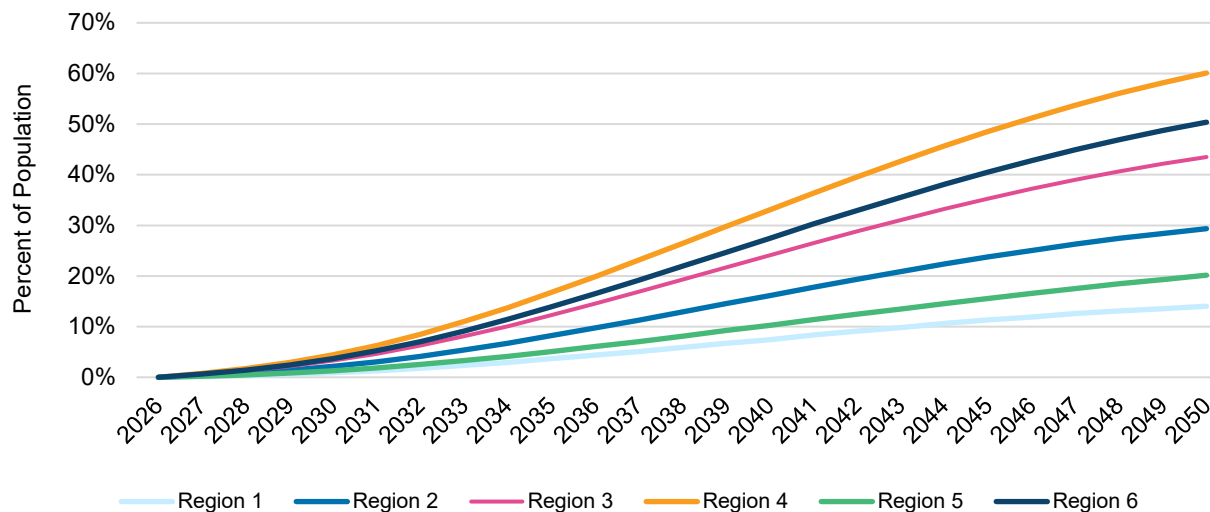
Figure 28: Electrification adoption by technology type (Base scenario)



Electrification adoption by region

When partitioned by region, electrification penetration varies considerably across the state, reflecting differences in housing stock composition, incumbent fuel mix, and the relative economics of heat pump adoption by geography. Region 4 (Hudson Valley) leads all regions, reaching electrification penetration above 60% by 2050, followed by Regions 6 (Long Island) and 3 (Capital Region / Upstate), both landing in the 40-50% range. At the lower end, Region 1 (Western NY) and Region 5 (New York City) exhibit the lowest penetration rates despite representing opposite ends of the housing stock size spectrum. Figure 29 below charts cumulative electrification adoption by Region as a percentage of the residential housing stock.

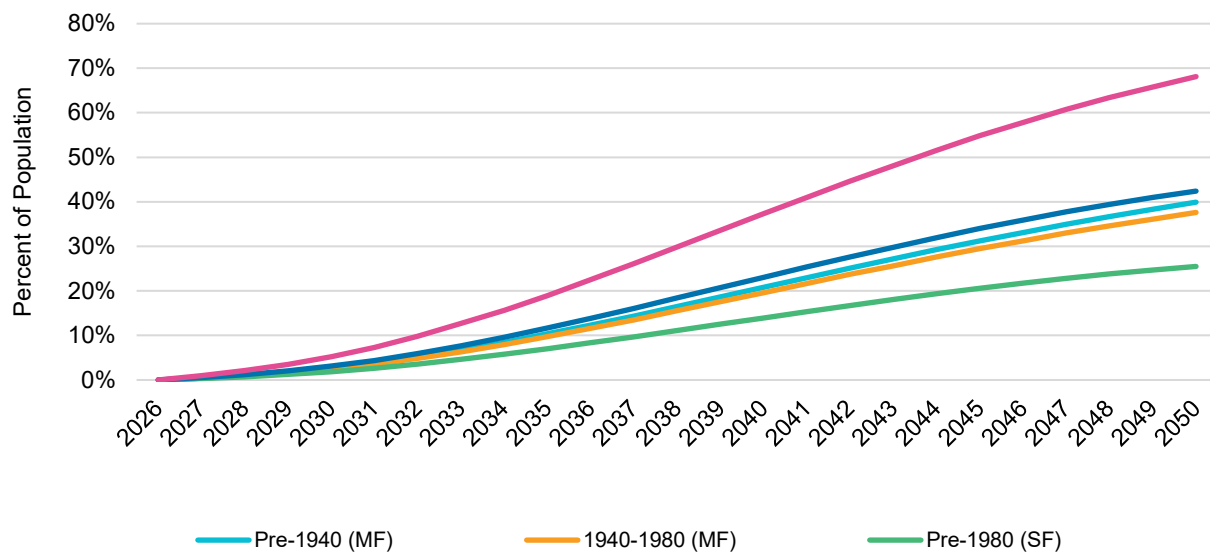
Figure 29: Electrification adoption by region (Base scenario)



Electrification adoption by vintage

When partitioned by building vintage, adoption rates are highest among new construction, encompassing both multifamily and single-family units, reflecting the superior envelope performance of more recently built homes and correspondingly stronger economics of heat pump installations where heating loads are lower and efficiency gains more pronounced. At the opposite end of the spectrum, the pre-1980 single-family vintage, a segment characterized by a long-tailed age distribution skewed towards the oldest and least efficient homes in the stock, exhibits the lowest adoption rate, reaching approximately 25% by 2050. The combination of older envelope characteristics and higher likelihood of requiring envelope upgrades suppress the economic outlook for this vintage relative to the rest of the stock.

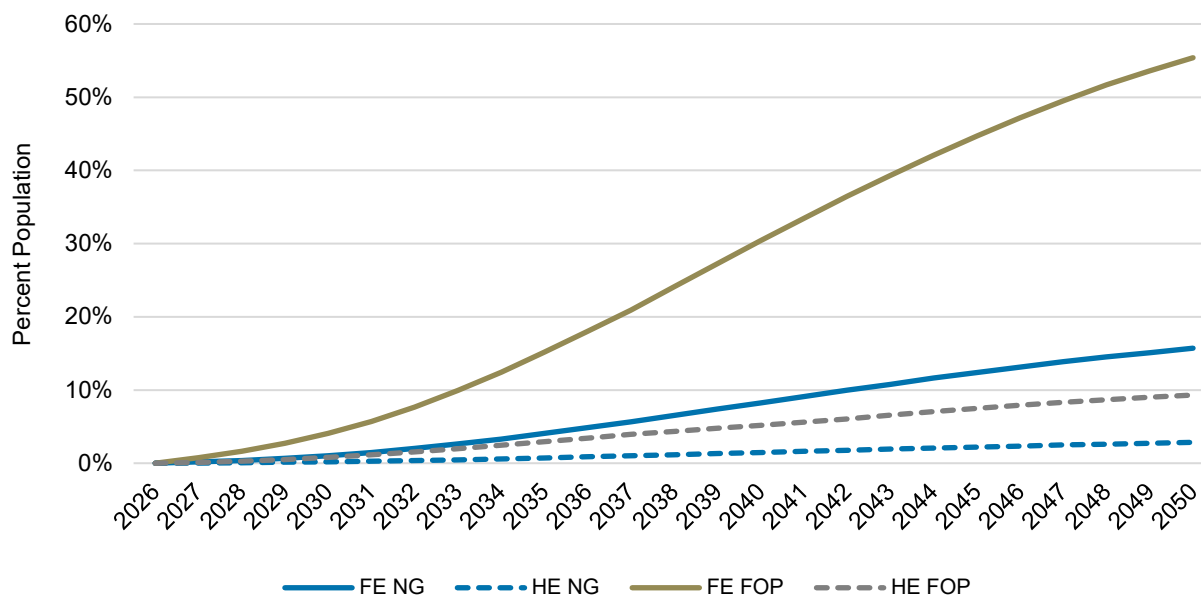
Figure 30: Electrification adoption by vintage (Base scenario)



Electrification adoption by fuel type

Stratifying electrification results by the type of fuel that was switched away from, the clear largest proportion of adoption was from homes previously heating with delivered fuels. Combined across FE and HE configurations, electrification adoption amongst former delivered fuel customers reached 65% in 2050, with the majority (55% of the total population) adopting Full Electrification measures. This result is driven by the competitiveness of heat pumps and electric rates against delivered fuel cost, which are considerably higher than natural gas in most cases.

Figure 31: Electrification adoption by incumbent fuel type (Base scenario)



Electrification adoption by income level

Electrification adoption rates vary across income groups, with a notable pattern emerging across all three scenarios. Low-income customers consistently electrify at higher rates than both moderate-income and non-LMI customers. Under the Base scenario, low-income customers reach 37% adoption compared to 31% for non-LMI and just 21% for middle-income customers – a pattern that holds across the Hybrid (32%, 28%, and 17% respectively) and Full scenario (64%, 44%, and 31%). The relatively high low-income adoption rate likely reflects the availability and targeting of incentive programs that improve the economics of electrification for this segment. The consistently lower adoption among moderate-income customers across all scenarios is a notable finding, suggesting this group does not benefit from the high-level of incentive that low-income customers do (incentives for non-LMI customers through Clean Heat are often higher than moderate-income customer incentives available through EmPower+) while still facing cost barriers that slow adoption relative to non-LMI customers – producing a “missing middle” scenario in electrification planning. The effect of this gap on the system, however, is small considering there are only approximately 401,000 middle-income dwellings, compared to 1.8 million low-income dwellings, and 4.5 million non-LMI dwellings.

A potentially conflating variable is that low- and moderate-income customers may occupy a higher share of older construction vintage housing, while non-LMI customers may occupy a higher share of the newer construction vintage stock. As observed in Section 5.1, above, this has a meaningful impact on the economics.

As described in Section 4, CRA did not assume any programmatic budget constraints in scenario modeling, which avoids introducing uncertainty related to future program funding decisions and allows the analysis to focus on relative technology economics rather than

program design constraints. In practice, adoption among LMI customers may be more constrained due to heightened sensitivity to upfront costs, limited ability to finance incremental expenditures, and administrative factors such as program enrollment caps, waitlists, or eligibility requirements that can affect participation rates.

5.4 Scenario outputs

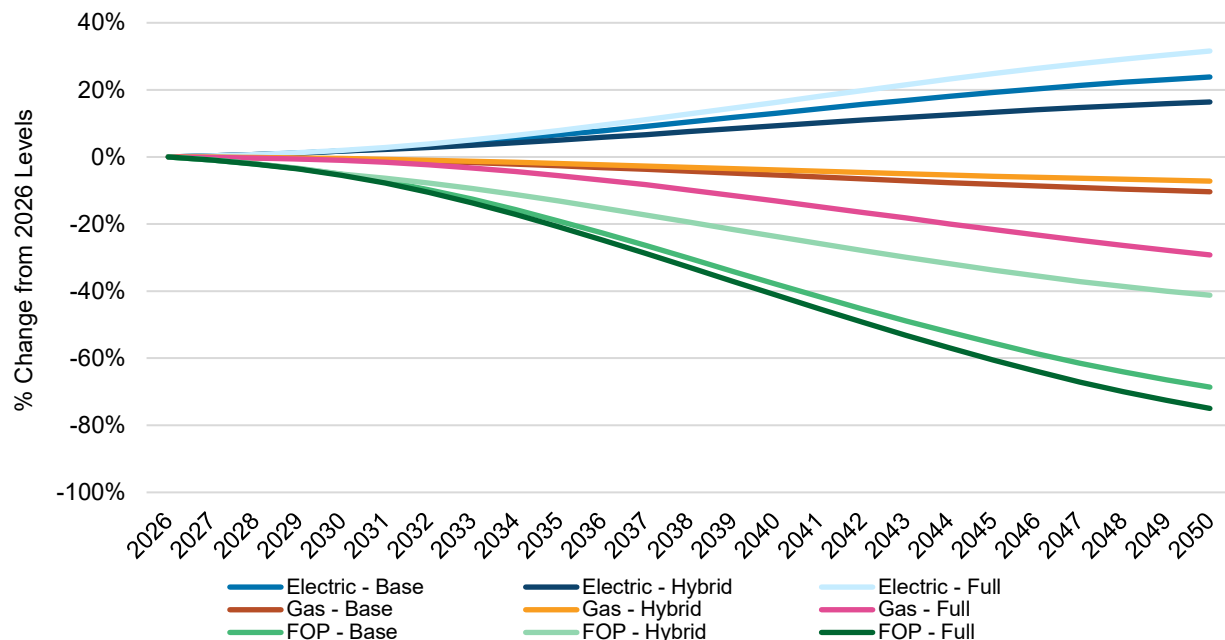
5.4.1 Energy consumption and sales

Electric sales increase across all scenarios with the Base scenario yielding a 24% increase in annual electric demand, equating to 48.9 TWh of total demand in 2050. The Full Electrification scenario has the highest increase at 32% and the Hybrid scenario sees half of that growth at 16%.

The customer group most affected by modeled electrification adoption consists of households heated with delivered fuels, which experience sales declines of approximately 68-75% in the Base and Full Electrification scenarios, reflecting the relatively strong economics of electrification options for these customers. Under the Hybrid scenario, where the majority of electrification is hybrid systems and all heating hours lower than 30°F are served by the backup system, sales drop by 40% by 2050. In the Base and Full Electrification scenarios, FE systems dominate the adoption for FOP systems and drive the large decreases.

Sales for natural gas, on the other hand, decline modestly over the forecast period – 7% in the Hybrid scenario and 10% in the Base scenario. This is largely due to the economic competitiveness of natural gas. The Full Electrification scenario, which models more aggressive FE configuration, sees natural gas sales decline a cumulative 29% in 2050.

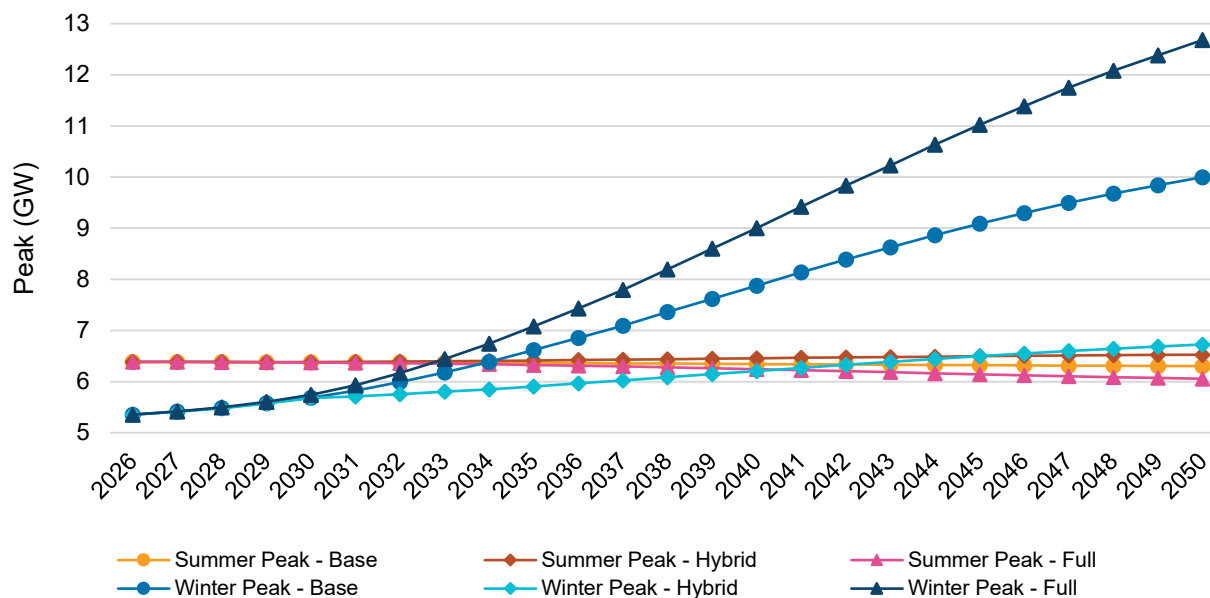
Figure 32: Change in annual fuel usage relative to current levels, by scenario



5.4.2 Peak demand

The residential peak demand follows the directional trends of the electrification adoption results. In all scenarios, the residential building electrification causes winter peak demands to increase which in turn causes the NYS electric system to transition to become winter-peaking, with the highest and earliest peak occurring under the Full Electrification scenario. Under the Hybrid scenario, the statewide coincident winter peak demand only modestly outpaces the summer peak by about 200 MW in 2050. By the end of the study period, the Base scenario's winter peak demand is ~10 GW, nearly doubling from the starting value of 5.6 GW. Across the scenarios, summer peak demand slightly increases in the Hybrid scenario and decreases in the Base and Full Electrification scenarios. The relatively small changes are due to the mixed impact of (1) eligible units having an envelope upgrade with their electrification choice (reducing demand), (2) older air conditioning units being replaced by more efficient heat pumps (reducing demand), and (3) a portion of units that did not have air conditioning under the counterfactual gaining cooling capability (increasing demand).

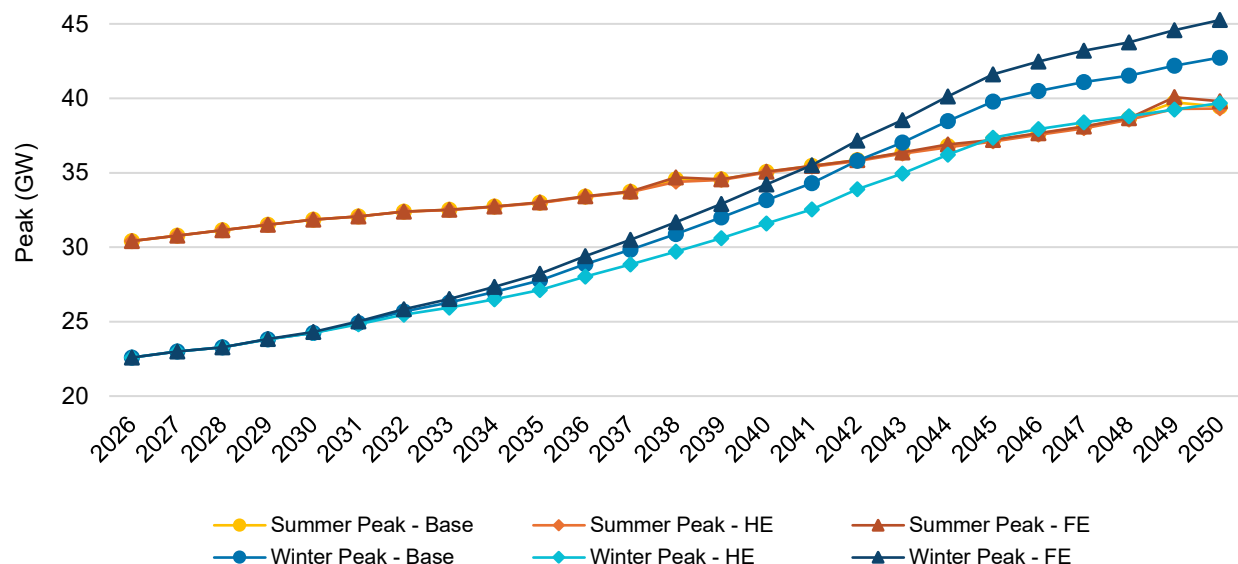
Figure 33: (Residential only) seasonal peak demand comparison



When considering system-wide impacts, the residential electrification scenarios are evaluated within the context of a larger electric system that is initially summer-peaking, with a total peak demand of 30.4 GW. As in the residential-only analysis, summer peak demand changes little across electrification scenarios. However, while residential building electrification contributes meaningfully to winter peak growth, residential load represents only one component of total system demand. As a result, the timing of a winter-peaking system occurs later at the system-wide level than in the residential-only view. In the Hybrid scenario, the winter peak gradually rises to nearly match the summer peak and remains within approximately 500 MW during the final five years of the forecast period. In the Base scenario, NYS becomes winter-

peaking in 2043, reaching a 42.7 GW winter peak (compared to a 39.4 GW summer peak) in 2050. The Full Electrification scenario begins winter-peaking two years earlier in 2041 and widens the gap to approximately 5.5 GW between the winter and summer peak in 2050.

Figure 34: Statewide seasonal NYCA bulk power system peak demand, by scenario



5.4.3 Peak demand by geography

The greatest amount of incremental winter peak growth occurs in the eastern part of the state by absolute MW addition: Region 3 (Upstate & Capital Region), Region 4 (Hudson Valley), and Region 6 (Long Island), as shown in Figure 35, *Incremental* winter peak additions follow an inverted-U trajectory, peaking at 264 MW in 2038 before tapering as the remaining pool of customers with the option to electrify decreases. The geographic trends become clearer when viewing annual peak demand by zone, differentiating when the annual peak is in the winter vs. summer in Table 28.

The transition from summer to winter-peaking varies considerably across zones, reflecting differences in climate, existing building stock, and the pace of heat pump adoption. Zone D enters the study period already winter-peaking, consistent with its colder climate and historically high heating loads. As heat pump electrification accelerates across the state, a growing number of zones follow suit. By the mid-2030s, Zones C, E, and F have all transitioned to winter-peaking, reflecting the colder inland climates of Upstate New York where heating demand is more pronounced relative to cooling demand. Zones B, GHI, and K complete their transitions by the late 2030s to early 2040s, as cumulative heat pump installations reach sufficient scale to shift the seasonal peak. Zone A is among the later NYISO zones to transition to winter-peaking in 2044. Zone J, encompassing NYC, remains summer-peaking throughout the entire study period. This seasonal distinction is significant from a planning perspective, as NYC’s system is still forecasted to be stressed the most in the summer months while the rest of

the state faces winter peak conditions. The geographic divergence suggests that a single statewide solution to capacity planning may not capture zone-level needs, and that planning for winter and summer needs will require careful consideration of zone-level demand growth.

Figure 35: Incremental winter peak demand growth (Base scenario)

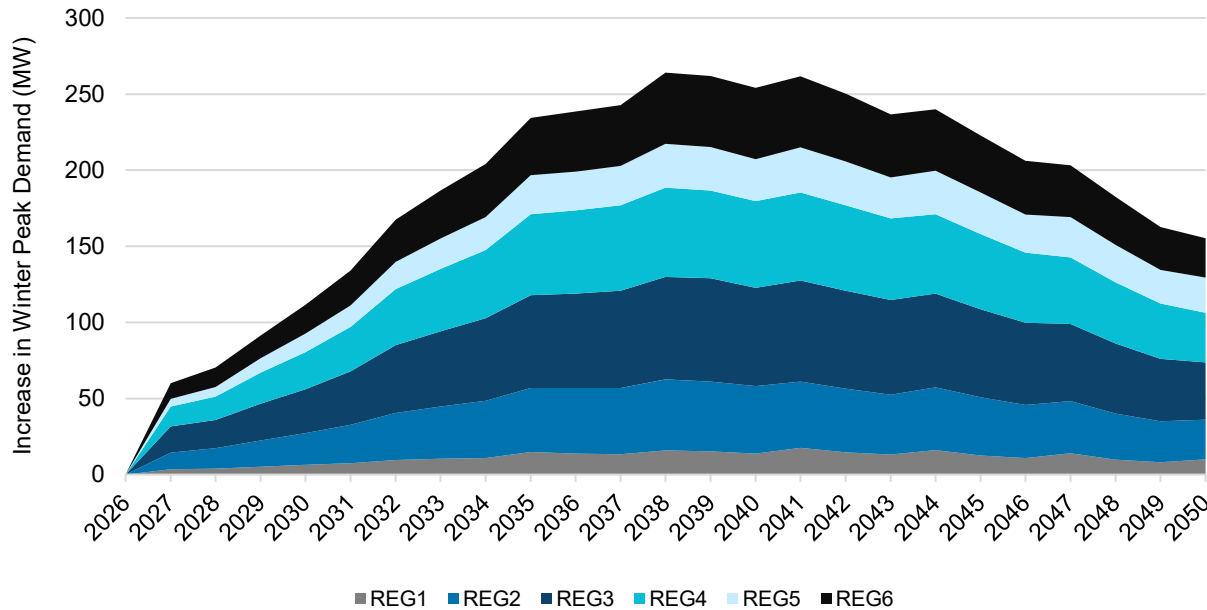


Table 28: Annual peak demand by zone, labeled **summer and **winter** (Base scenario)**

Year	NY_A	NY_B	NY_C	NY_D	NY_E	NY_F	NY_GHI	NY_J	NY_K
2026	2,840	1,642	2,309	1,277	1,167	2,079	3,771	11,647	4,129
2027	2,861	1,643	2,391	1,348	1,181	2,111	3,798	11,687	4,167
2028	2,888	1,653	2,537	1,356	1,197	2,149	3,824	11,727	4,207
2029	2,983	1,719	2,594	1,363	1,250	2,227	3,850	11,766	4,246
2030	2,929	1,678	2,913	1,372	1,266	2,189	3,878	11,806	4,285
2031	2,931	1,672	3,027	1,384	1,298	2,197	3,904	11,824	4,331
2032	2,977	1,696	3,170	1,397	1,330	2,198	3,941	11,878	4,397
2033	2,941	1,672	3,330	1,406	1,371	2,206	3,958	11,862	4,424
2034	2,961	1,685	3,429	1,421	1,424	2,227	3,984	11,876	4,468
2035	2,996	1,706	3,537	1,447	1,493	2,258	4,015	11,911	4,519

2036	3,038	1,726	3,634	1,463	1,566	2,298	4,086	12,021	4,583
2037	3,086	1,767	3,707	1,481	1,637	2,356	4,147	12,087	4,714
2038	3,245	1,833	3,820	1,500	1,739	2,444	4,234	12,172	4,809
2039	3,164	1,805	3,920	1,526	1,812	2,562	4,417	12,266	5,021
2040	3,215	1,877	4,045	1,549	1,894	2,698	4,649	12,382	5,262
2041	3,251	1,947	4,144	1,586	1,979	2,821	4,978	12,469	5,457
2042	3,291	2,045	4,188	1,608	2,037	2,977	5,167	12,568	5,867
2043	3,359	2,080	4,257	1,634	2,112	3,021	5,403	12,704	6,040
2044	3,373	2,149	4,459	1,639	2,204	3,179	5,521	12,845	6,109
2045	3,538	2,301	4,640	1,658	2,333	3,394	5,640	12,946	6,185
2046	3,607	2,310	4,703	1,694	2,375	3,459	5,662	13,096	6,346
2047	3,708	2,418	4,832	1,710	2,481	3,622	5,692	13,239	6,366
2048	3,639	2,567	4,965	1,726	2,654	3,548	5,833	13,415	6,410
2049	3,723	2,547	5,032	1,722	2,634	3,718	5,921	13,582	6,500
2050	3,740	2,595	5,224	1,735	2,817	3,763	5,907	13,686	6,540

5.4.4 Greenhouse gas emissions

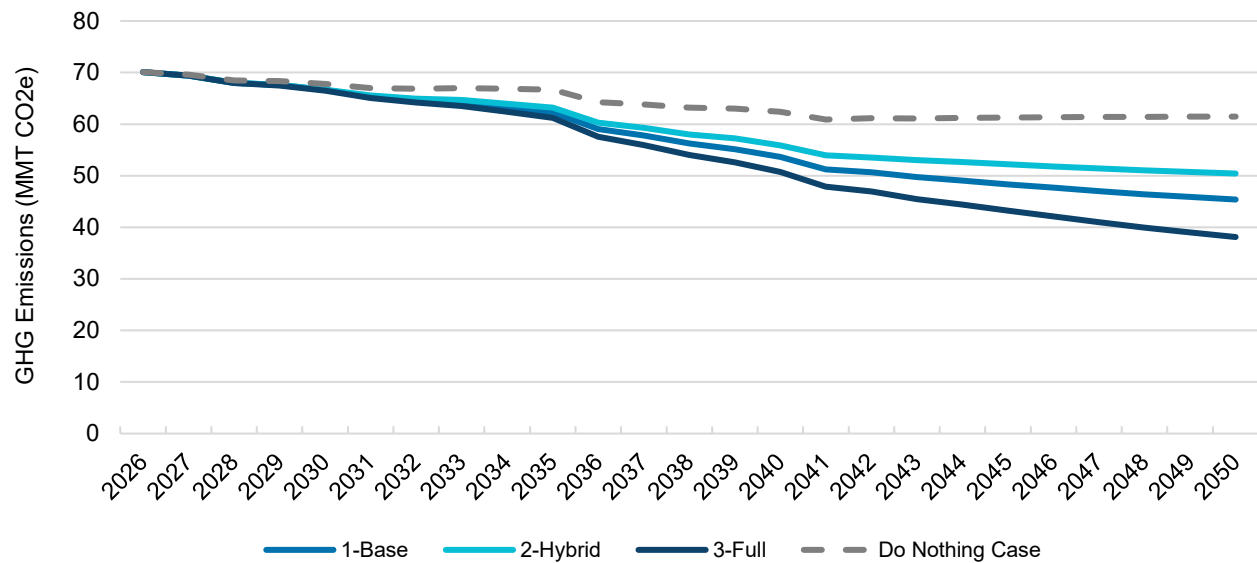
Annual emissions follow the trends expected from altered gas and delivered fuel usage and account for the gradual modeled decarbonization of the NYS electric grid. The figures reported account for CO₂e at 20-year global warming potential across the emission components for the electric grid and on-site residential gas and delivered fuel combustion. For the purpose of comparison of GHG emissions only, a 'Do Nothing' scenario is shown, holding statewide electric and fuel usage fixed, while following the same grid emission intensity trend.

The gap in annual emissions between the Base scenario and the 'Do Nothing' scenario is 16 million mmt by 2050, accounting for a cumulative 184 mmt decrease over the study period. The Hybrid scenario has a 28% increase in emissions from the Base over the study period, and the Full scenario results in a 37% decrease relative to Base. The gradual decrease of the 'Do Nothing' scenario is driven by the decarbonization of the electric grid. In the Base scenario, about half (49%) of the decrease in emissions is due to reductions in FOP usage, and 35% due to the decarbonization of the grid. Table 29 below presents the cumulative change in GHG emissions by scenario and Figure 36 presents the total emission trends by scenario.

Table 29: Cumulative GHG emissions reductions by scenario

Metric	Base	Hybrid	Full
mmt Change by 2050	-16	-11	-23
Cumulative mmt Change by 2050	-184	-132	-251
End of Period Change to 'Do Nothing' Scenario	-26%	-18%	-38%
End of Period Change from Base	0%	+11%	-16%
Cumulative Change from Base	0%	-28%	37%

Figure 36: Annual GHG emissions comparison (MMT CO₂e GWP20)



6. Electric system impacts

This section details the impacts on the NYS electric system from the modeled heat pump adoption across the three electrification scenarios. CRA's market model was calibrated to the Additional Action Scenario (AAS) of the State Energy Plan, establishing an initial system view on top of which the effects of residential electrification are evaluated. Full details of the initial system view are provided in Data Annex 3. This calibrated initial model includes residential load growth from heating electrification as assumed in the AAS, which is then replaced by the electric load growth pertaining to the modeled adoption. The assumptions presented in Data Annex 3 fall into three categories: those held constant across all runs (reflecting system views that are intentionally held constant or do not vary with residential electrification changes), those modified directly by the adoption outputs, and those that change as a consequence of altered electrification, specifically the market responses to shifting residential load.

Table 30: Structural assumptions for electricity market model simulation

Assumption	Constant	Modified by Electrification Outputs	Changes as Market Response to Electrification
Coal Commodity Price	X		
Gas Commodity Price			X
CO ₂ Emission Price	X		
Inflation	X		
Production Tax Credit and Investment Tax Credit Assumptions	X		
Generation Additions and Retirements	X		
Residential Electric Load		X	
Rest of System Electric Load	X		
Annual Wholesale Power Prices			X
NYS Emissions			X
Natural Gas Demand			X
Natural Gas Commodity Price			X

6.1 Load growth and peak demand

The primary impact of the residential heating electrification modeled is the shift of New York from a summer-peaking system to a winter-peaking one. The total annual peak of residential electric demand under the Base scenario increases from 6,385 MW (summer) in 2026, to 9,996 MW (winter) in 2050. This presents a 56% increase in overall residential peak, and a near-doubling of winter electric demand from NY homes from their starting value of 5,354 MW in 2026.

The winter peak is driven by heating load shifting away from FOP and NG, which account for 59% and 41% of electrification adoption, respectively. With 85% of Base scenario adopters choosing fully electric configurations, heating demand in these homes shifts entirely to the electric system. Notably, the summer peak slightly decreases over the years due to a mix of higher efficiency heat pumps replacing older AC units and envelope upgrades installed with heat pumps reducing cooling demand.

When put in context of the entire NYISO system, the residential sector represents only 22% of total system summer peak at the start of the study period, moderating the pace of the system-wide transition. While the residential portion becomes winter-peaking in the mid-2030s, the system-wide outcome shifts to winter peak in 2042 under the Base scenario, ending at a gap of 2.7 GW between the winter and summer peak by 2050. This aligns with the NYISO Gold Book winter peak shift timing.⁴⁰

The system planning considerations stemming from a growing gap between winter and summer peak in a historically summer-peaking system puts the potential benefits of the Hybrid Electrification scenario in perspective. Under the Hybrid scenario, the winter peak surpasses the summer peak later in the period (2045), and the two peaks remain within 500 MW of each other the remainder of the period. A relatively balanced dual-peaking system allows for more efficient utilization of system infrastructure buildout to serve both summer and winter demand growth. Additionally, the HE Study models the utilization of hybrid systems under a fixed switchover temperature of 30°F. A residential stock equipped with more HE configurations has the flexibility to alter switchover behavior under times of system strain.

6.2 Generation & capacity implications

CRA developed a generation capacity outlook for New York's electric grid based upon the data provided by the Additional Action scenario (AAS) of the SEP.^{xvi} The AAS represents a forward-looking planning case that forecasts accelerated clean energy deployment, while also being constrained by practical factors like costs, citing, supply chains, and federal policy uncertainty. CRA chose to adopt the variant of the AAS that included 3.3GW of new nuclear capacity.

^{xvi} Certain methodology steps utilized the NYISO Gold Book, such as the regional breakouts of annual electric demand, but generally, CRA's modeling aligned with the SEP's Additional Action Scenario.

Importantly, the capacity outlook adopted from the SEP remained constant across the Base, Hybrid, and Full Electrification scenarios. This design allowed for the isolation of the impact of residential building electrification as the driver of scenario outcomes, rather than differences in wholesale power market dynamics or other assumptions partially driving scenario results. CRA did not model scenario-specific capacity prices as part of this exercise, based on the view that, in a long-term NYS decarbonization context, sufficient new generation and storage resources would be added to meet growing demand and maintain relatively adequate capacity supply in the future.

Prior to replacing residential electrification demand with outputs from the diffusion model, CRA calibrated its model to best align with the generation, capacity, and demand for NYISO as defined in the AAS. However, there were differences in assumptions regarding several items including:

- Natural gas prices
- The complete replacement of all natural gas and oil power plants in NYISO with firm zero carbon resources – specifically green hydrogen.

Additionally, the SEP did not provide visibility into surrounding regions supply, demand, and environmental policies for which CRA had to develop assumptions. These included:

- Demand in neighboring markets including PJM, the Independent System Operator of New England (ISO-NE), the Independent Electricity System Operator (IESO) of Ontario, and Hydro Quebec.
- Capacity and generation in the same surrounding markets.

These differences resulted in different expectations regarding wholesale power prices, overall unit dispatch, and carbon emissions, while maintaining the core components of the AAS and allowing for further understanding of the relationship between electrification, power sector demand, natural gas demand, and natural gas prices.

Modeled resource mix

The capacity buildout used by CRA is shown in Table 31. Under the AAS, by 2040, 28 GW of solar, 6 GW of land-based wind, 5-7 GW of offshore wind, and 2-3 GW of new nuclear were added to New York's already decarbonizing generation mix, which contributed to the system's resource diversity. CRA modeled the 3.3GW variant which sees nuclear capacity grow to 6.6 GW by 2040 and 8.7 GW by 2050. The use of green hydrogen in the SEP buildout was replaced by 2 GW of natural gas with Carbon Capture and Sequestration (CCS).

Table 31: CRA modeled capacity mix (MW)

Fuel Mix (Capacity)	Nuclear	Gas & Fuel Oil	Gas CCS	Other	Hydro and Pumped Storage	Wind	Offshore Wind	Solar	Storage
2026	3,326	25,774	0	351	6,366	2,984	132	6,757	490
2030	3,326	21,365	0	351	6,580	4,972	1,870	14,877	6,001
2035	3,326	16,696	0	351	6,580	5,809	1,870	20,926	9,069
2040	6,656	14,969	0	0	6,542	8,080	4,809	30,522	9,069
2045	7,450	14,112	1,720	0	6,542	8,414	4,809	36,043	9,360
2050	8,700	14,112	2,650	0	6,542	8,414	4,809	38,444	9,922

The resulting generation mix under the Base scenario is shown in Table 32. The differences between scenarios in annual GWh energy generation were relatively minimal. Fluctuations between lower bidding resources (nuclear, hydro, onshore wind, offshore wind, solar, and battery energy storage) were less than 1% across the three scenarios. In 2050, gas generation was 11% lower in the Hybrid scenario case than Base scenario, and 9% higher in the Full Electrification scenario. The net effect of the Full Electrification scenario was that residential gas demand decreased by more than electric gas demand increased compared to the Base scenario. Conversely, net effect of the Hybrid scenario was that residential gas demand increased by more than electric gas demand decreased compared to the Base scenario.

Table 32: Generation mix under Base scenario (GWh)

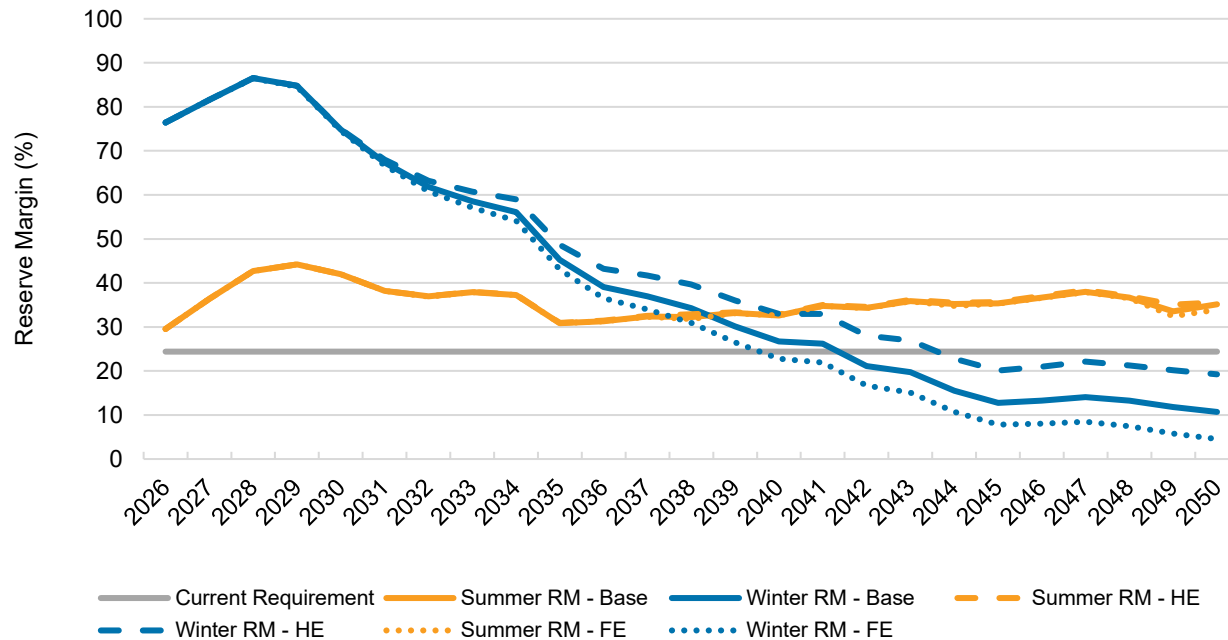
Year	Nuclear	Gas	Gas CCS	Other	Hydro	Wind	Offshore	Solar	Storage
2026	26,916	64,163	0	3,633	31,386	8,734	556	7,516	-145
2030	26,877	40,015	0	3,794	32,302	13,145	7,388	28,124	-1,481
2035	26,469	30,543	0	3,905	30,972	15,869	7,567	39,664	-2,104
2040	49,435	12,032	0	1,123	24,633	23,743	19,463	57,822	-2,333
2045	57,349	8,339	6,529	1,022	23,570	25,120	19,403	66,887	-2,493
2050	62,527	10,956	11,611	1,172	22,997	25,141	19,403	70,132	-2,671

Impacts on generation reserve margin

While the system-wide differences in the annual generation mix driven by the electrification scenarios are small, the effect of increased electric demand using the same capacity mix becomes clear in the seasonal reserve margins reported in Figure 37. The higher rates of electrification under the Full Electrification scenario drives the lowest winter reserve margins by the end of the study period, followed by the Base scenario winter margin, and at a considerably 14% higher margin, the Hybrid Electrification scenario. Under the most recent statewide minimum capacity requirement (May 2025 through April 2026) of 124.4 percent of forecasted peak load, the winter peak begins to fall below targets starting in 2042. Notably, the reserve margin at summer peak remains above target throughout the study period.

While the reserve margin exercise was ultimately one conducted with a capacity mix that was not built for the alternate CRA scenarios of residential electrification, the results bring the logical conclusion to the seasonal system peak forecast: beginning in the 2040s the additional winter peak would require greater system capacity in the winter to remain above current system reserve targets. The Hybrid scenario, with winter and summer peaks similar in magnitude, would need the least additional buildout, while the Full Electrification scenario would need the most to bridge an approximately 19% gap.

Figure 37: Reserve margin by scenario (%)



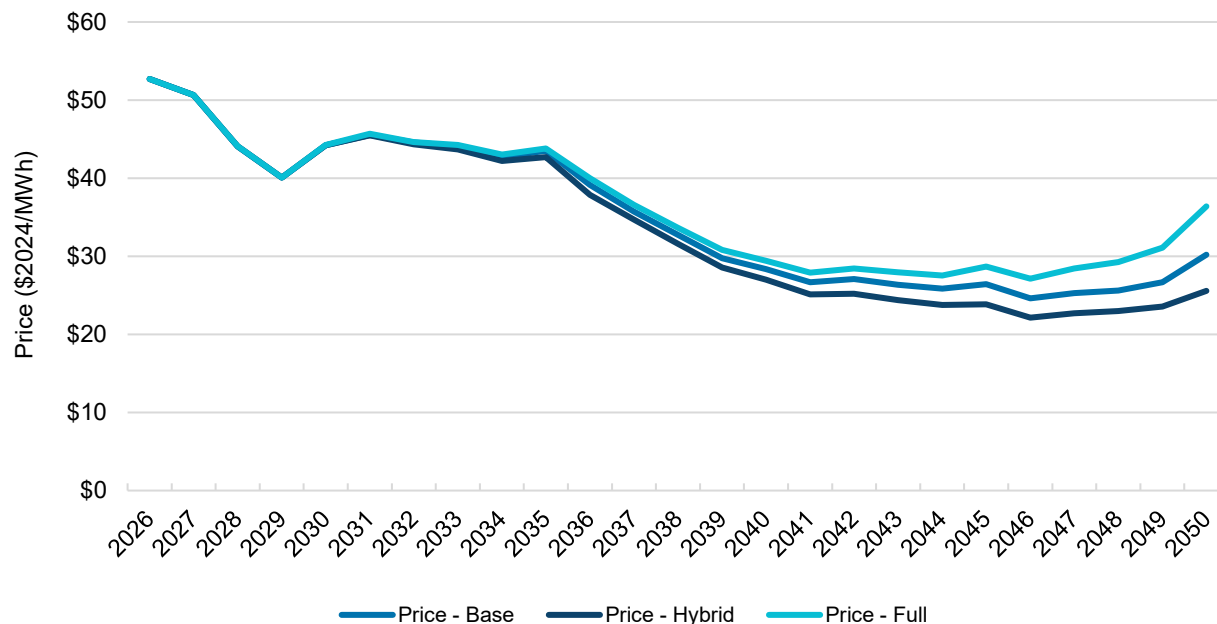
6.3 Wholesale energy price impacts

The wholesale price forecast reflects the same hierarchy established by the reserve margin analysis – with the Full Electrification scenario commanding the highest prices as the winter margin tightens in the 2040s. In the mid-2030s, all scenarios fall below the 2024 statewide

day-ahead average price of \$40.10/MWh as the remainder of the SEP AAS buildout catches up to demand growth and remains below that threshold for the remainder of the study period.

Though the Full Electrification scenario does drive the highest prices and tightest reserve margin of the three, the SEP capacity buildout prevents significant price escalation on an annual basis. The system’s potential strain from electrification lies not in the volume of annual energy demand, but in the emergence of a winter peak that has not previously existed.

Figure 38: Annual average NYS wholesale electric price (\$2024/MWh)



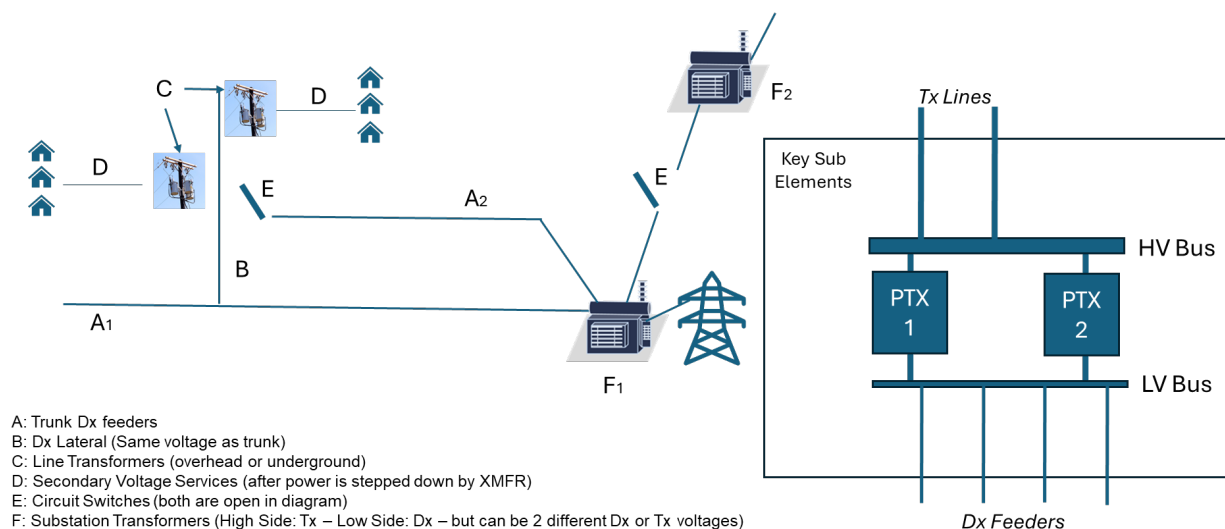
6.4 Transmission and distribution impacts

The HE Study aimed to quantify the impacts of incremental or decremental heat pump adoption on the level of capital investment required by the NY electric utilities in local T&D delivery networks to meet growing residential BE loads. Similar studies of hybrid heating and electrification in other jurisdictions (e.g., Quebec, Oregon) have characterized the ability for widespread adoption of Hybrid Electrification (relative to Full Electrification) to avoid utility T&D capital expenditures otherwise required to meet local winter peak conditions that cause load on certain grid components to exceed rated capacity levels. These impacts are potentially significant in the 2030s and onward as more of the local T&D systems transition to become winter-peaking under a scenario with widespread adoption of ASHPs for full load heating. To this end, HE could be a useful tool for utility planners and policymakers to enhance grid utilization and avoid the replacement of grid components (e.g., substations, overhead lines, service transformers) with higher capacity versions, which could lead to significant costs for utility ratepayers.

This section characterizes how, when, where, and to what degree increased levels of HE could avoid the need to increase the capacity on local utility T&D systems to meet increased winter peak demand, as compared to impacts in the Base and Full Electrification scenarios. Importantly, because the adoption of FE and HE by residential customers is expected to vary both (a) over time and (b) by utility or region, the impacts on local utility T&D networks are also expected to vary over time and by utility.

CRA's analysis quantified the capital investment required in local transmission, distribution substation, distribution primary, and distribution secondary networks. This capacity is measured in MVA or MW of local T&D capacity that would need to be constructed and energized commensurate with the timing of the electrification load.^{xvii} Figure 39 provides an illustrative schematic of a utility T&D system and the components relevant to this analysis.

Figure 39: Illustrative T&D system and key components



CRA relied on each utility's most recent Marginal Cost of Service (MCOS) study to develop estimates for the cost to serve each incremental unit of capacity for each category of T&D investment and convert these estimates into dollars of capital investment. In reality, T&D infrastructure investments are often multi-value and/or growth-related investments that support serving a combination of several types of loads (including economic load growth, commercial and industrial electrification, transportation electrification, etc.). This analysis is intended to reasonably quantify the proportion of T&D system investment that can be attributed to the impacts of residential building electrification. In reality, no T&D investment can be viewed in isolation and wholly attributed to one driver.

^{xvii} CRA uses "MVA" in this memorandum but notes that there is variation amongst the utilities in whether rated capacity, load, and headroom are measured in "MW" or "MVA".

Furthermore, this analysis attempted to capture the effects of the current levels of embedded “headroom” in each utility’s T&D system. In this context, headroom refers to the ability to add additional winter peak loads on the distribution system without triggering the need for new upgrades, given the current differences between each utility’s summer and winter peak coincident demands. This part of the analysis will also influence the comparative value of HE. As an example, utilities with greater winter headroom to support FE growth could see lower tangible benefits from widespread adoption of HE, all else equal, since the avoided T&D cost savings would be smaller. Comparatively, utilities with lower winter headroom may need to invest more immediately and more aggressively to accommodate significant levels of FE adoption, which would lead to HE providing greater potential benefits in the form of avoided system investment.

CRA relied on data from each utility’s Hosting Capacity Maps (also called System Data Portals) that provides information on the summer and winter rated capacity, loading, and headroom for substation transformers and three-phase feeders. The analysis leverages publicly accessible data downloaded from the Hosting Capacity Maps to analyze the winter headroom through time as incremental residential building electrification loads are added to the system. At a high-level, CRA’s analysis tracked when the headroom on a given component of the system was reduced to zero as a proxy for determining when T&D upgrades would be required. CRA is only aware of one other public study effort that uses the New York Utilities’ Hosting Capacity Maps to attempt to characterize the capacity of New York utility networks to serve building electrification loads: Synapse Energy Economics’ *assessment of Electric Grid Headroom for Accommodating Building Electrification* (2024) prepared on behalf of New Yorkers for Clean Power.⁴¹ CRA’s methodology and approach were informed by, but do not rely on, this separate and older study. The following subsections provide additional detail on the methodology and present the findings on local T&D CapEx impacts over the forecast period and across scenarios.

6.4.1 Analysis of electrification hosting capacity

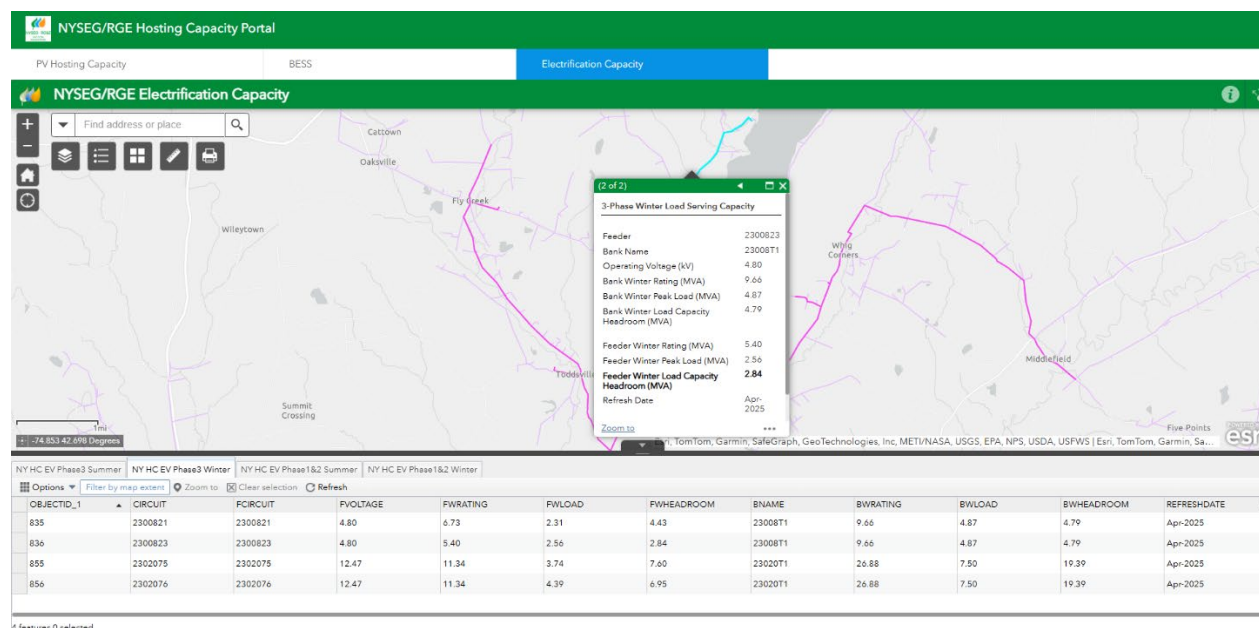
This subsection presents CRA’s analysis of the New York Utilities’ systems’ ability to accommodate new residential BE loads and what the resulting impacts might be on T&D load serving capacity (LSC) requirements. The approach varied based on the types of data available for each utility and whether the system was predominantly overhead or underground; the latter is primarily applicable to the analysis of CECONY’s underground network in NYC.

Analysis of winter headroom on overhead 3-Phase networks

After consultation with and feedback from NY DPS Staff and the Joint Utilities (JU), CRA decided to Base its methodology on data from each New York utility’s Hosting Capacity Maps. The Hosting Capacity Maps contain asset-level information on summer and winter feeder and substation hosting capacity available to support electrification. Specifically, the maps display summer and winter ratings, load, and headroom, measured in MVA or MW. Materials from the JU describe the component ratings as thermal and reflective of normal operating limits and specify that the ratings reflect “no overload margin,” i.e., the ratings assume that 100% of the rating is equal to the maximum load allowed. The JU describes the “Remaining Load Capacity” (or “Headroom”) as the difference between the feeder or substation rating and the seasonal peak load.

Each of the utility’s maps display the calculated summer and winter headroom for three-phase feeders. The JU further recommends that “users must plan to stay within the more constrained season” when analyzing hosting capacity for new electrification loads.^{xviii} Because residential heat pump electrification is presumed to contribute primarily to the winter peak (not the summer peak), CRA is focused primarily on the headroom up to rated capacity in the winter season for three-phase feeders and substation transformers. Figure 40 provides an example of the Electrification Capacity map layer from NYSEG and RG&E’s combined Hosting Capacity Portal.

Figure 40: Example of 3-Phase winter load serving capacity data (NYSEG/RG&E)



CRA used the following steps to determine the amount of load serving capacity required:

- 1. Establish present-day available winter headroom (MVA) for each 3-phase feeder and substation transformer bank.** This is the difference between the rated capacity and the winter peak load and represents the winter headroom available to support increased winter demand growth from building electrification (and other sources of load growth) without triggering upgrades to LSC. In most cases, each 3-phase feeder is mapped to a corresponding substation transformer bank in the data. Most banks have multiple feeders tied to them. The ratings for these groups of assets are related; the combined load at the substation bank correlates to the downstream feeders served by that bank.
- 2. Determine average feeder loading to distribute winter peak load growth across the system.** CRA used the average of the summer and winter load values for each feeder on a utility’s system to determine an “average loading” metric, measured in MW. Incremental winter peak loading was distributed proportionally across the feeders on the system based

^{xviii} Joint Utilities of New York. Hosting Capacity Training Session – Advanced. 21 Nov. 2025.

on its share of the system loading. This approach reflects the reality that (a) electrification will occur unevenly across the system (i.e., not necessarily in places with spare hosting capacity or headroom) and (b) that building electrification loads will cluster proportionally to existing buildings. The Hosting Capacity Maps do not publish data on the composition of customers served by each substation and feeder; CRA recognizes that this methodology may cause residential building electrification to be overstated in some areas (i.e., those with predominantly commercial and/or industrial loads) and understated in others.

3. **Measure feeder- and substation-level winter peak demand growth against available headroom and determine whether LSC upgrades are required.** Measure the allocated winter peak load growth for (a) each individual eligible feeder and (b) each substation transformer bank (with eligible feeders). This creates four potential outcomes, depending on the winter peak loading and headroom of each 3-phase feeder and substation transformer:
 - a) **Outcome 1:** Headroom available on both 3-phase feeders and substation transformer: No T&D upgrades needed.
 - b) **Outcome 2:** Headroom unavailable on 3-phase feeders; available at substation transformer: Assume feeder upgrade needed. Assign costs for upgrades to distribution primary and distribution feeder only.
 - c) **Outcome 3:** Headroom available on individual feeders; but combined load exceeds substation transformer headroom: Assume substation upgrade needed. Assign costs to upgrades for local transmission, distribution substation, and substation transformer.
 - d) **Outcome 4:** Headroom exceeded on both feeder and substation transformer. Assume substation transformer and feeder upgrades required. Use fully-loaded MCOS cost figure with all T&D components assign costs to upgrades.

The level of winter headroom on an individual feeder can vary widely throughout the network. The substation transformers (which correspond to one or more network feeders) have a distinct level of winter loading and winter headroom based on the loading of the constituent feeders. Aggregating this data up within each utility can provide insights into the overall level of winter headroom embedded in the T&D network today. Table 33 below contains the current winter capacity, peak load, and headroom across all three-phase feeders for each utility. Information for NYSEG and RG&E is combined due to the utilities' shared Hosting Capacity Map, while NMPC is split into Upstate and Western NY to provide additional insight into its two separate networks.

Table 33: Winter capacity, peak load, and headroom for 3-Phase Feeders by utility^{xix}

Utility	3-Phase Feeder Count	Winter Capacity (MVA)	Winter Peak Load (MW)	Winter Headroom (MW)	Headroom (% Rated)
NYSEG/RG&E	1,360	12,020	3,555	8,464	70.4%
NMPC, Upstate NY	1,021	8,208	3,180	5,028	61.2%
NMPC, Western NY	886	3,820	1,443	2,376	62.2%
CHG&E	233	1,474	842	632	42.9%
O&R	210	UNK	UNK	911	UNK
CECONY ^{xx}	1,024	UNK	UNK	855	UNK

The Hosting Capacity Maps for CECONY and O&R do not publish the same information as the other utilities; these utilities include the winter headroom by feeder but not the rated capacity or loading. CECONY only publishes its winter load by area substation and O&R only publishes winter load by substation bank transformer.

The maps provide similar information for the substation transformers serving the overhead three-phase network. NYSEG/RG&E and NMPC Western NY have lower combined winter headroom across substation transformers than the 3-phase feeders, while CHG&E and NMPC Upstate have more winter headroom on the 3-phase feeders. Table 34 below summarizes data on the total count, rated capacity, peak load, and headroom on substation bank transformers for each utility.

Table 34: Winter capacity, peak load, and headroom for substation transformers by utility

Utility	Substation Bank Transformer Count	Winter Rated Capacity (MVA)	Winter Peak Load (MW)	Winter Headroom (MW)	Headroom (% Rated)
NYSEG/RG&E ^{xxi}	630	7,863	2,716	5,158	65.5%
NMPC, Upstate NY	418	8,276	2,957	5,319	64.3%
NMPC, Western NY	371	3,845	1,694	2,150	55.9%
CHG&E	61	2,207	842	1,364	61.8%
O&R	98	2,893	1,544	1,437	49.7%

^{xix} “UNK” denotes a utility for which the information was unknown or unobtainable from the Hosting Capacity Maps.

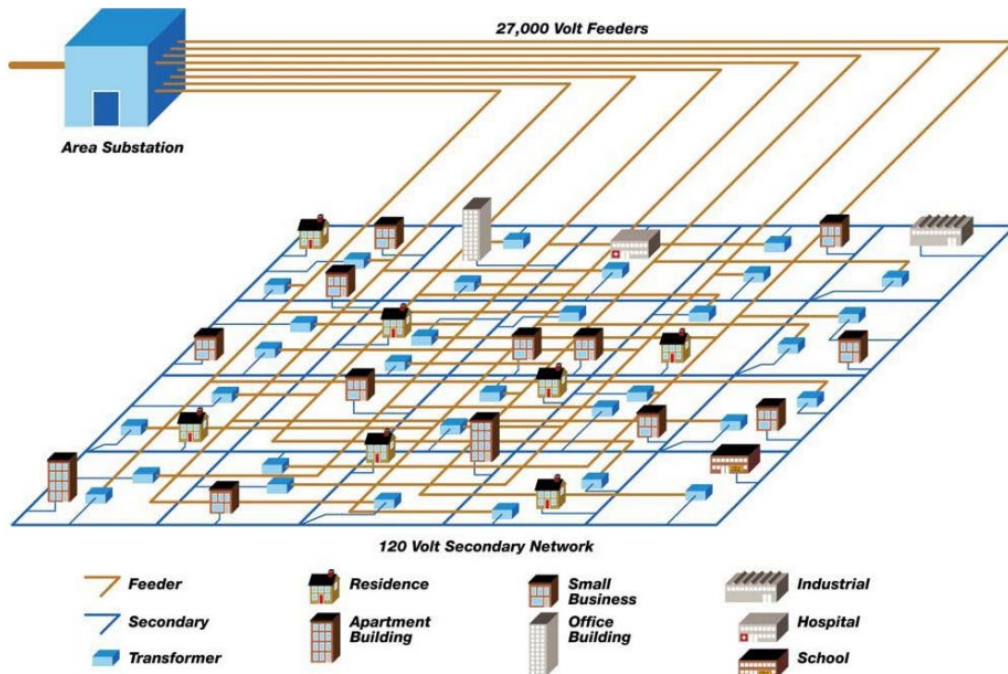
^{xx} Reflects data from CECONY’s overhead 3-phase network, which serves portions of Brooklyn, Queens, Westchester, the Bronx, and Staten Island.

^{xxi} Many of NYSEG and RG&E’s substation transformers had no data available in the Hosting Capacity Map, which leads to lower overall rated capacity, peak load, and winter headroom versus 3-phase feeders.

Analysis of winter headroom on underground delivery networks (Con Edison)

CRA used a different approach to evaluating the winter hosting capacity for CECONY’s underground low-voltage network, which serves 87% of the utility’s peak load all of Manhattan and significant portions of Brooklyn, Queens, and the Bronx. Figure 41 below provides an illustrative schematic of CECONY’s underground network system.

Figure 41: Illustration of Con Edison’s Primary and Secondary Network System



CECONY publishes the peak loading information for its area substations. CECONY does not publish the winter peak load or headroom, however, so only the annual peak load and headroom are available. See Table 35 below.

Table 35: Rated capacity, peak load, and headroom for CECONY area substations

Utility	Substation Count	Winter Capacity (MVA)	Peak Load (MW)	Headroom (MW)	Headroom (% Rated)
CECONY	30	8,478	6,334	2,144	25.3%

CECONY provides the winter hosting capacity for its network distribution transformers. Its Hosting Capacity Map provides four levels of winter load capacity for all 460v and 208v network transformers: “Less than 200 kVA”, “Up to 499 kVA”, “Up to 1,000 kVA”, and “More than 1,000 kVA”. CECONY’s Distribution System Implementation Plan (DSIP) recommends that “winter ratings can be used in combination with summer ratings to determine available capacity for building electrification.”⁴² There are over 26,000 individual transformers on the underground network. CRA assumed the lower bound of the published winter load capacity was

representative of the available winter load capacity. shows the count of transformers by winter load capacity level and the implied amount of winter headroom by transformer type (460v and 208v) and in total across the underground network.

Table 36: CECONY underground network distribution transformer winter load capacity

Winter Load Capacity	Count 460V XFMRs	Count 208V XFMRs	Winter Headroom Per XFMR (MVA)	460V XFMR Headroom (MVA)	208V XFMR Headroom (MVA)	Total Headroom (MVA)
1000+ kVA	3,191	118	1.00	3,191	118	3,309
500 kVA to 1000 kVA	492	6,833	0.50	246	3,417	3,663
200 kVA to 499 kVA	77	10,211	0.20	15	2,042	2,058
0-200 kVA	43	5,693	0.00	0	0	0
Total	3,803	22,855	-	3,452	5,577	9,029

Long Island Power Authority and PSEG Long Island

PSEG Long Island operates the transmission and distribution system on Long Island. It does not have a publicly available Hosting Capacity Map with comparable data on its network’s electrification hosting capacity as the Joint Utilities.^{xxii} To estimate the T&D capital expenditures for LIPA, CRA took a simplified approach based on the overall summer-winter peak difference on Long Island (Zone K). The current Zone K summer peak demand is approximately 4,129 MW while the winter peak demand is 2,967 MW, a difference of 1,162 MW or 28%. CRA’s modeling adds winter peak loads to Zone K and, once it becomes winter-peaking, estimates the cost of new T&D LSC upgrades at \$1.60/MW (\$2026) for each additional MW of residential building electrification that contributes to the net winter peak.

6.4.2 Cost of utility transmission & distribution load serving capacity

Assigning a cost to T&D upgrades required an estimate for the cost of incremental LSC for distinct types of T&D infrastructure (i.e., dollars per MVA) and applying this against incremental annual winter peak load due to modeled electrification adoption.^{xxiii} CRA used forward-looking data on planned T&D capital projects for the JU’s 2025 DSIP MCOS studies. Each utility

^{xxii} PSEG LI is not a participant in the Joint Utilities of New York and is not subject to the same level of data sharing. PSEG LI has a Hosting Capacity Portal, but it is not publicly accessible and is focused on small generator interconnection, not identifying electrification hosting capacity.

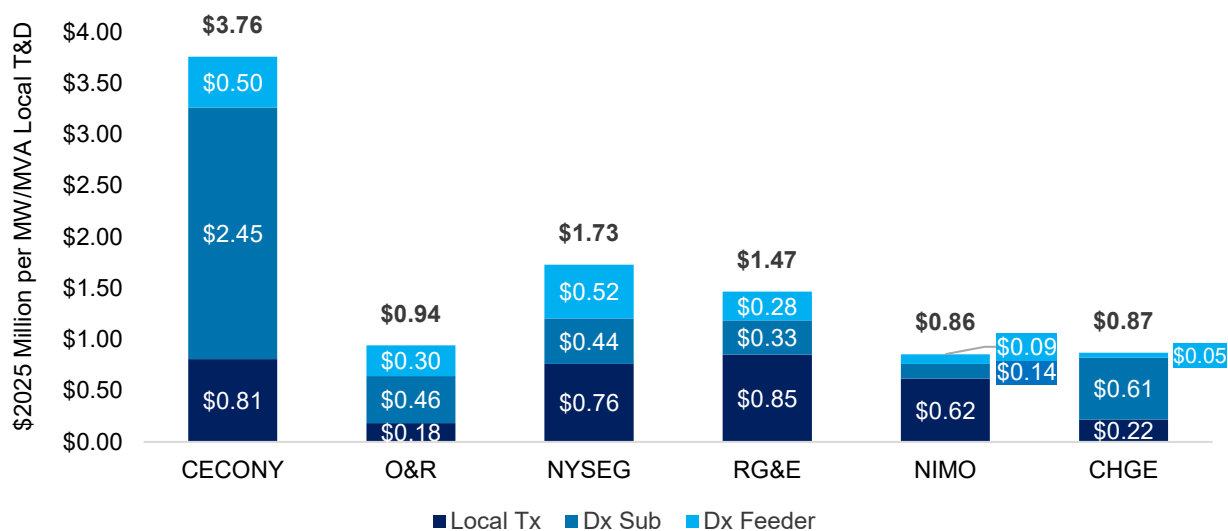
^{xxiii} It is CRA’s understanding that, in NY, utility grid planners will plan capacity expansions looking at both winter and summer peak load, but primarily summer peak load in the next five to six years because even in cases where the winter peak load becomes slightly higher, the grid has lower effective capacity in the summer.

identified discrete T&D capital projects on its system over the next 5-10 years, including the associated capital investment (\$) and the amount of LSC enabled by the project (MVA).^{43 xxiv} While the presentation and categorization of the data varied by utility, CRA followed a similar process across all utilities to transform these discrete planned capital projects into an average estimate for the cost of incremental LSC (\$2025/MW):

1. Collect the forecasted capital investment amounts for all LSC projects in each year for which MCOS is forecasted (in nominal dollars).
2. As relevant, segment costs by type: transmission substation, transmission lines, distribution substation, distribution primary, and distribution secondary. Note that not all utilities used the same categorizations for T&D costs in their MCOS studies.
3. Collect the enabled capacity for each LSC project (in MW or MVA).
4. Discount the capital investment to present-day (2025) dollar amounts using a 2.1% discount rate (assumed rate of general inflation).
5. Divide the present-day capital investment (step 3) by the capacity enabled (step 2) to estimate the cost of incremental LSC by T&D component in each forecast year. For years where investment is non-zero, calculate the average cost of incremental LSC by averaging across years.
6. Divide the total incremental cost of LSC by summing the incremental cost of LSC across all relevant T&D component for each utility.

Figure 42 shows CRA's preliminary estimates for the average cost of incremental LSC (\$2026 million per MW) for each utility.

Figure 42: Average cost of incremental load serving capacity by NY utility (\$2026 million / MW)

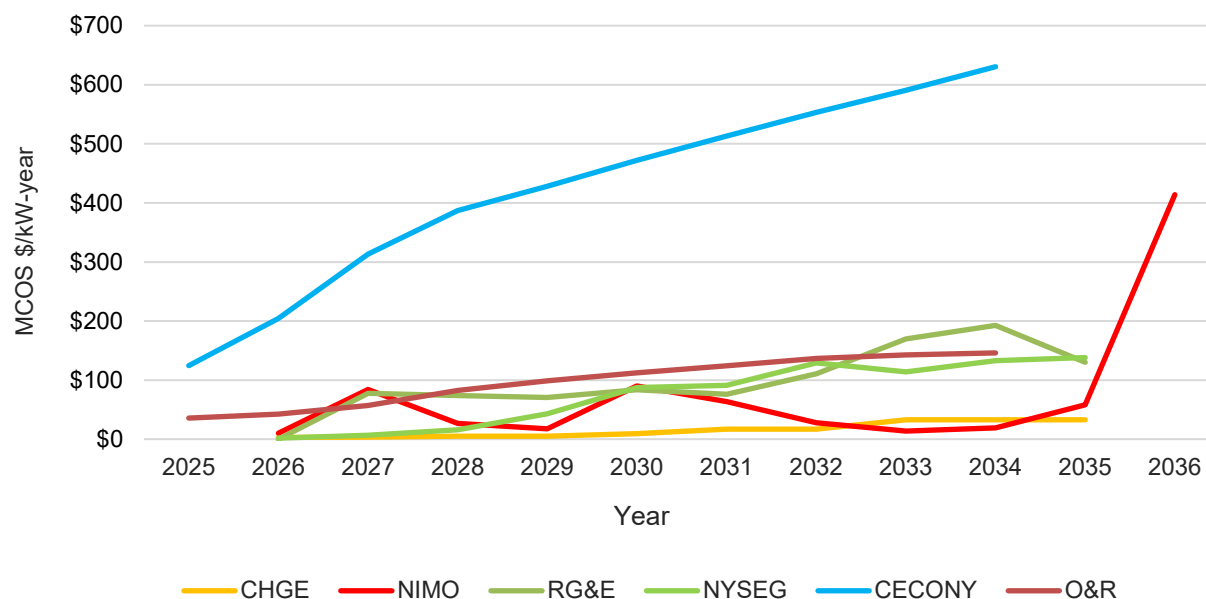


^{xxiv} These data were included and published as a part of the workpapers filed in Case 19-E-0283.

CRA assumed that LIPA's cost of T&D was equivalent to the average of the other utilities: \$1.61 million/MW. Note that these estimates reflect only those projects (or capital investment) included in each utility's forward-looking MCOS study. CRA uses these average cost figures for each utility to estimate the total cost of T&D LSC CapEx by utility based on the capacity of T&D upgrades modeled.

The published MCOS values are derived from the same data on planned capital projects, but these are different in two key ways: 1) MCOS values reflects the marginal cost to serve new peak capacity based on system-wide average headroom against forecasted load growth and 2) MCOS is a revenue requirement figure, loaded with O&M/A&G, return of/on capital, taxes, and other cost of service items. For comparison, Figure 43 charts each NY utility's published MCOS forecast (\$2025/kW).

Figure 43: System-wide average marginal cost of service by NY utility (2025-2036) (\$/kW-year)



6.4.3 Impacts of electrification on distribution secondary

CRA separately evaluated the impacts of its electrification adoption forecasts on the local T&D CapEx needs to upgrade the distribution secondary, including pole and pad-mount line transformers and distribution services. Residential building electrification could cause binding constraints on distribution pole-mount and pad-mount transformers and distribution services (together, the distribution secondary). For areas of the network primarily serving residential customers, where fewer than ten individual customers might be served by a single distribution transformer, adoption of Full Electrification by only a handful of customers could lead to coincident winter peak demand that exceeds the capacity of the distribution transformer. For example, a single 25 kVA pole transformer might serve five customers. Based on CRA's ResStock modeling, the average increase in winter peak demand for single-family homes that fully electrify is 3.75 kW.

The Utilities do not publish publicly available data on the winter ratings, loading, and headroom for their distribution secondary. CRA conducted a high-level analysis to estimate the number and cost of distribution transformer upgrades required over the forecast period in each planning scenario. The analysis contained the following steps:

1. Develop number, type, and rating assumptions for service transformers;
2. Develop a view on present-day (2026) loading for service transformers;
3. Add winter peak loading to transformers over the forecast period (2026-2050);
4. Use a normal distribution to identify the number of transformers that become overloaded and require replacement in a given year (i.e., transformers where winter load exceeds 100% of rated capacity);
5. Assign upgrade costs to the different transformer types/ratings to determine the cost per upgraded component; and
6. Multiply quantities in steps 4 & 5 above to calculate the total nominal capital expenditure on service transformer upgrade.

A 2024 study from NREL provides data on the national average share of transformer counts and types by service level (i.e., single-phase vs. three-phase), transformer type (pole- and pad-mount), and rating. CRA used this data to develop a high-level view of the stock of substation transformers by utility. Figure 44 below provides the national-level NREL data used to inform the analysis. Importantly, the actual count and capacity of distribution transformers by New York utility could vary substantially from the estimates below.

Figure 44: Distribution in number of transformers and capacity by unit and phase type (NREL)

		Transformer Type	% Number of Assets	% of Capacity
Single-Phase	Pole	10–100 kVA	72.1	27.6
		>100–250 kVA	0.6	1.3
		>250–1000 kVA	0.1	0.6
	Pad	10–100 kVA	19.5	13.6
		>100–250 kVA	0.8	1.6
		>250–1000 kVA	0.0	0.1
Three-Phase	Pole	30–100 kVA	0.1	0.1
		100–250 kVA	0.1	0.2
	Pad	30–100 kVA	0.7	0.6
		100–250 kVA	1.6	3.2
		250–1000 kVA	3.2	21.5
		1,000–5,000 kVA	1.1	27.7
	Other	>500 kVA	0.1	1.7

Only two New York utilities had recently published data on their distribution transformer counts – NMPC and CHG&E.^{44,45} CRA used this data to calibrate its assumptions of the number of distribution transformers and average number of customers per asset for each utility.

Table 37: Select data on utility distribution transformer counts

Utility	Distribution Transformer Count (2024)	Residential Customer Count (2024)	Customers Per Transformer
NMPC	422,763	1,430,208	3.4x
CHG&E	85,948	229,592	2.7x

CRA assumed there were an average of three residential customers per overhead pole-/pad-mount transformer 10-100 kVA, 10 per transformer rated 250-1000 kVA, and 20 per transformer 250-1000 kVA. This is a general assumption; in reality, there are likely fewer customers per transformer where the distribution network is predominantly overhead and/or rural and more where the network is urban and/or underground. CRA further assumed a rated capacity value (in kVA) for each transformer type. The most common transformer type and rating is the 25 kVA pole transformer; for many utilities, this is the minimum rated distribution transformer. Table 38 shows the assumed customer count and rating per transformer type.

Table 38: Key assumptions for distribution transformers

Transformer Type	Share of Single-Phase Transformer Count	Average Customers Per Transformer	Assumed Rating (kVA)
Pole, 10-100 kVA	77.44%	3	25
Pole, 100-250 kVA	0.64%	10	100
Pole, 250-1000 kVA	0.11%	20	250
Pad, 30-100 kVA	20.95%	3	50
Pad, 100-250 kVA	0.86%	10	100
Pad, 250-1000 kVA	0.00%	20	250

Distribution transformer loading

In most cases, summer is binding season due to demands from air conditioning. CRA assumes that transformer loading is normally distributed, with an average (mean) loading of 80% of rated capacity in summer and a standard deviation of 20% of rated capacity. CRA used the difference between the summer and winter peak demands for each New York utility to establish a mean winter loading. Table 39 summarizes this data for each utility.

Table 39: Mean loading for distribution transformers, by utility

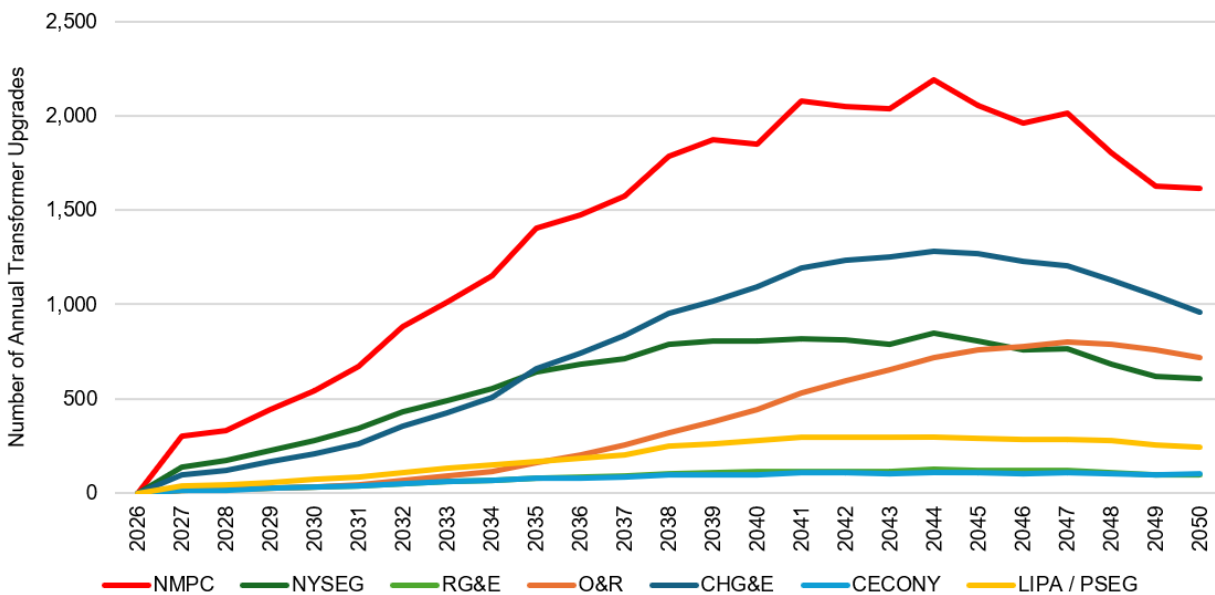
Utility	(A) Winter Peak (MW)	(B) Summer Peak (MW)	(C) = (A) / (B) Winter % Summer	(D) Mean Summer Loading (%)	(E) = (C) * (D) Mean Winter Loading (%)
NMPC	4,956	6,019	82.3%	80%	65.9%
NYSEG	2,543	2,966	85.7%	80%	68.6%
RG&E	1,061	1,542	68.8%	80%	55.0%
O&R	894	1,480	60.4%	80%	48.3%
CHG&E	912	1,103	82.7%	80%	66.1%
CECONY	3,705	5,905	62.7%	80%	50.2%
LIPA / PSEG	3,252	5,003	65.0%	80%	52.0%

The result is that mean winter loading today ranges from 48.3% to 68.6% of rated capacity, depending on the utility, and is normally distributed with a standard deviation equal to 20% of rated capacity. The Upstate utilities, including NMPC, NYSEG, RG&E, and Central Hudson, tend to see a higher mean winter loading under this methodology. This is driven by the higher relative winter peaks of the Upstate utilities, which reflects, in part, a higher proportion of dwellings with electric resistance heating Upstate, which would lead to higher winter loading on the distribution secondary. This normal distribution is used to track how the mean winter loading changes through time as residential building electrification loads are added and the type and number of transformers that need to be upgraded due to winter peak loads exceeding rated capacity.

Modeling transformer upgrades

As winter peak loads grow from the adoption of residential building electrification, the “tail” of the distribution representing transformers whose loading exceeds the rated capacity grows. The model tracks the number of distribution pole- and pad-mount transformers by type whose loading exceeds the rated capacity, and thus requires an upgrade, for each year over the forecast period. Figure 45 charts the annual 25 kVA pole transformer replacements (upgrades) modeled for each utility in the Base scenario.

Figure 45: Annual 25 kVA pole transformer upgrades by utility, Base scenario



For a sense of scale, data from National Grid’s Asset Condition Report indicates that the utility replaced around 8,000 transformers per year during most of the 2000s. At the same time, a significant portion of the transformer population might be nearing the end of its useful life and could be scheduled for replacement for age- or asset condition-related reasons. Depending on

the granular distribution of electrification adoption, utilities may have an opportunity to simultaneously replace and upsize aging equipment to accommodate new BE loads.

Cost of distribution transformer upgrades

CRA assumed that distribution transformers that exceed their rated capacity would need to be upgraded to a higher capacity to continue serving load. CRA used internal equipment cost estimates for different overhead and underground distribution transformers and loaded these costs with labor (+50% of equipment), secondary wiring (+25%), and pole upgrades (+10%) to estimate the CapEx requirement per transformer upgrade. For example, CRA estimates the most common 25 kVA overhead pole transformers would require approximately \$22,000 in CapEx to upsize to a 50 kVA equivalent. contains the corresponding upgrade for each transformer type and its associated cost for modeling purposes.

Table 40: Cost of distribution secondary transformer upgrades

Transformer Type	Assumed Rated Capacity	Upgraded Capacity	Equipment Cost (\$)	Labor Cost (\$) (+50%)	Secondary Winding Cost (\$) (+25%)	Pole Upgrade (\$) (+10%)	Total Capital Cost (\$)
Pole, 10-100 kVA	25 kVA	<=50 kVA	\$11,742	\$5,871	\$2,936	\$1,174	\$21,723
Pole, 100-250 kVA	100 kVA	<=167 kVA	\$19,081	\$9,541	\$4,770	\$1,908	\$35,301
Pole, 250-1000 kVA	250 kVA	<=333 kVA	\$28,622	\$14,311	\$7,156	\$2,862	\$52,951
Pad, 30-100 kVA	50 kVA	<=75 kVA	\$36,695	\$18,348	\$9,174	\$3,670	\$67,886
Pad, 100-250 kVA	100 kVA	<=167 kVA	\$44,034	\$22,017	\$11,009	\$4,403	\$81,463
Pad, 250-1000 kVA	250 kVA	<=500 kVA	\$58,712	\$29,356	\$14,678	\$5,871	\$108,617

Results

The total capital investment required to upgrade distribution transformers is approximately \$3.4B in the Base scenario. This is largely concentrated in a handful of utilities: NMPC sees the highest total amount, driven by a high proportion of Full Electrification customers adoption electrification in its Upstate territory and its relatively higher winter peak loading today. CHG&E also sees significant investment requirements relative to its size. The Hybrid scenario sees much lower levels of CapEx required, only \$442M over the forecast period, as Hybrid Electrification reduces the winter peak demand impacts and fewer transformers in the “tail” of the distribution exceed their rated capacity and require upgrades. The Full Electrification scenario would require more than \$6.4B of CapEx for upgrades to distribution secondary across all customers. below summarizes these results for each utility and scenario.

Table 41: Total CapEx for distribution secondary upgrades by utility and scenario (\$M, nominal)

Utility	1. Base Scenario	2. Hybrid Scenario	3. FE Scenario
NMPC	\$1,389M	\$127M	\$2,721M
NYSEG	\$586M	\$82M	\$1,294M
RG&E	\$79M	\$8M	\$206M
CHG&E	\$340M	\$15M	\$599M
O&R	\$753M	\$84M	\$1,083M
CECONY	\$76M	\$38M	\$243M
LIPA / PSEG LI	\$190M	\$88M	\$316M
Total	\$3,414M	\$442M	\$6,461M
Difference vs. Base Scenario (\$M)		-\$2,972M	+\$3,048M
Difference vs. Base Scenario (%)		-87%	+89%

It is important to remember that residential BE does not exist in a vacuum. Actual investment requirements to upgrade the distribution secondary in the future will depend greatly on the combined impacts of vehicle electrification and building electrification, as well as any offsetting contributions from EE or other demand-side management solutions to optimize asset utilization.

6.4.4 Total forecasted local T&D LSC capital expenditures by scenario

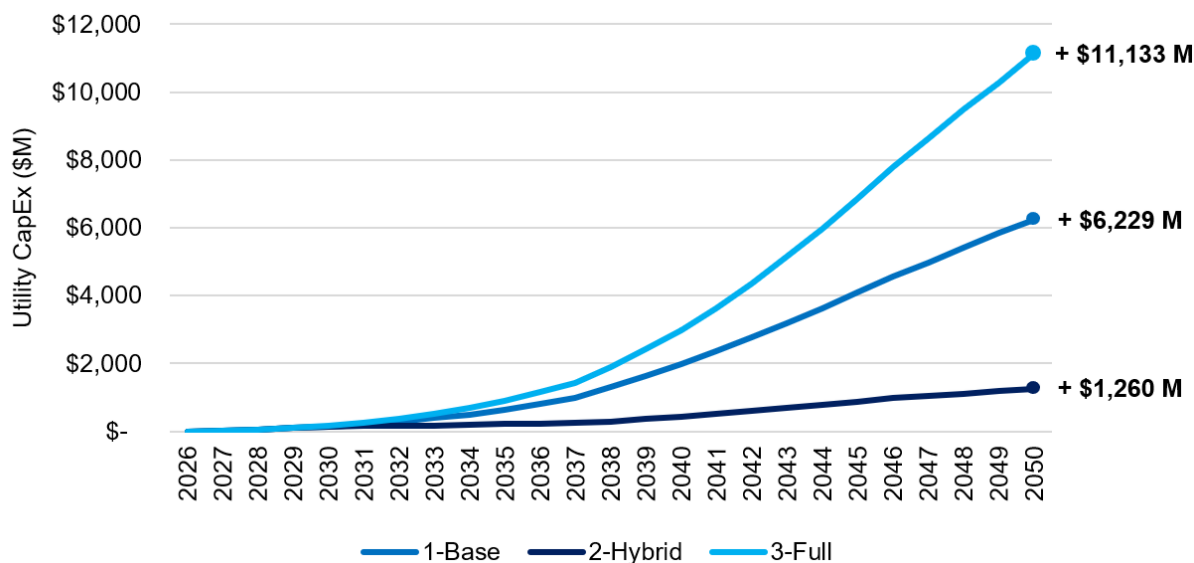
Together, the two analyses described above were combined to create forecasts for local T&D LSC CapEx—inclusive of local transmission, distribution substation, distribution primary, and distribution secondary—over the period 2026-2050 for each utility under each planning scenario. Table 42 below provides the total nominal T&D LSC CapEx by utility by scenario.

Table 42: Total local T&D LSC capital expenditures by scenario (\$M, nominal)

Utility	1. Base Scenario	2. Hybrid Scenario	3. FE Scenario
NMPC	\$1,876M	\$153M	\$3,667M
NYSEG	\$969M	\$134M	\$2,078M
RG&E	\$239M	\$30M	\$532M
CHG&E	\$974M	\$112M	\$1,380M
O&R	\$606M	\$55M	\$952M
CECONY	\$244M	\$120M	\$619M
LIPA / PSEG LI	\$1,322M	\$656M	\$1,905M
Total	\$6,229M	\$1,260M	\$11,133M
Difference vs. Base Scenario (\$M)		-\$4,969M	+\$4,904
Difference vs. Base Scenario (%)		-80%	+79%

On an annual basis, capital expenditures rise gradually during the 2020s and early 2030s while electrification adoption is still growing and embedded levels of headroom largely defer the need for investment. Starting in the late 2030s, investment requirements accelerate as headroom begins to run out and electrification continues to accelerate. Figure 46 charts cumulative T&D LSC CapEx over time in each scenario.

Figure 46: cumulative utility local T&D LSC CapEx by scenario (\$M, nominal)



While the CapEx is significant in the Reference and Full Electrification scenarios, the slow growth over the next decade in all scenarios demonstrates that the state’s utilities have ample headroom to support additional residential BE and growth in winter peak demands in the near- and medium-term on their local delivery systems. In the longer-term, starting in the late 2030s, residential BE creates meaningful T&D CapEx requirements when utility systems begin to strain to meet winter peak in some areas. This emphasizes the potential value of Hybrid Electrification in certain areas of the state in defraying additional T&D upgrades by enhancing grid utilization, which ultimately can support energy system affordability.

The majority of CapEx (55%) over the forecast period is for upgrading the distribution secondary. Upgrades to local transmission (19%), distribution substation (18%), and distribution primary (8%) make up the remainder. See Figure 47 below.

Figure 47: Total annual utility T&D CapEx by category, Base scenario (\$M, nominal)

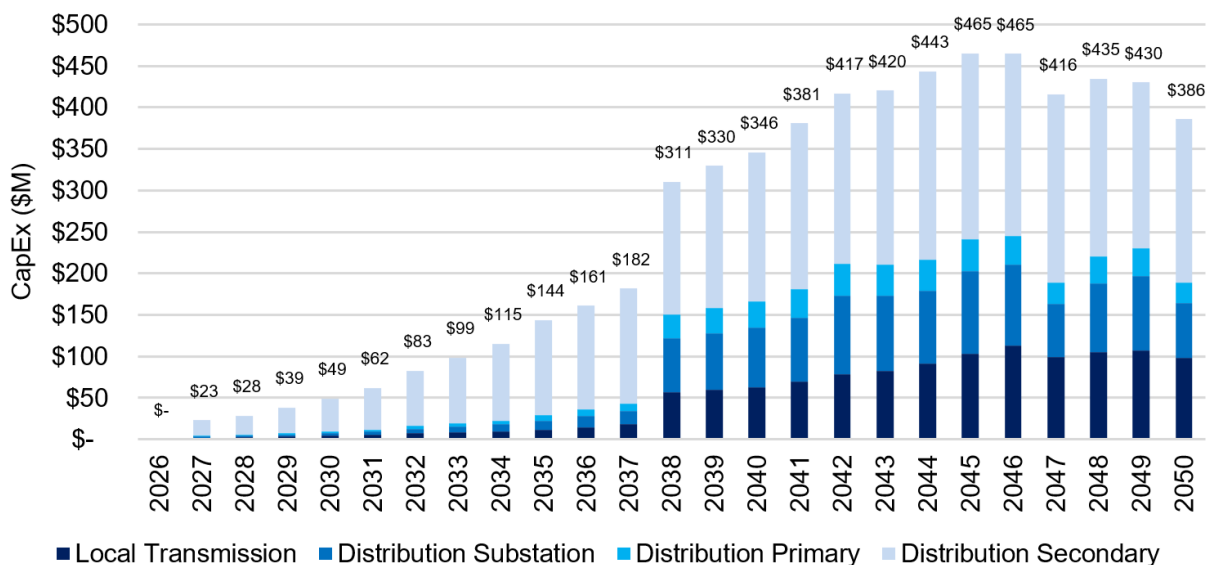
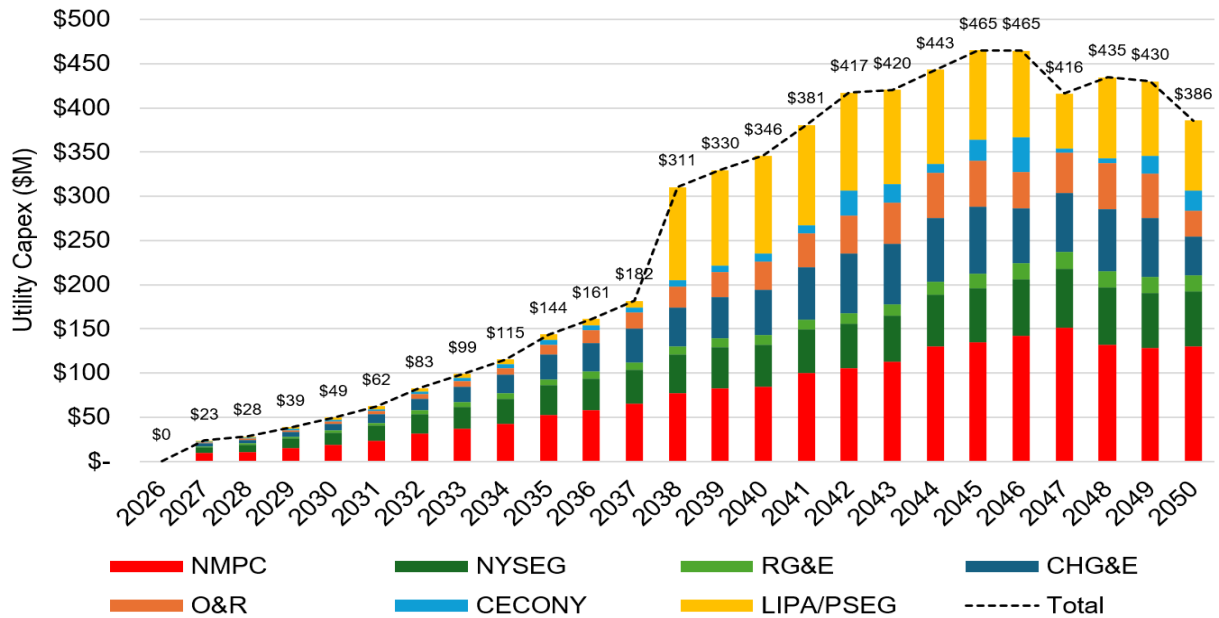


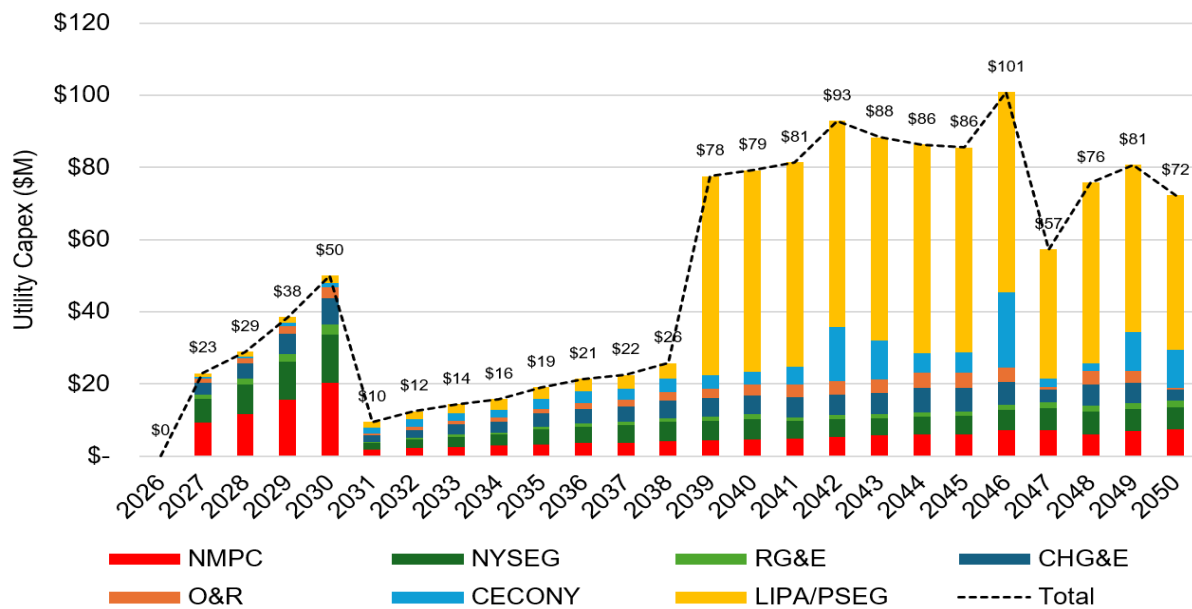
Figure 48 below provides a granular view of annual T&D CapEx by utility in the Base scenario. The total annual CapEx amounts are the same as in the figure above but, instead, consolidated across categories and divided across utilities.

Figure 48: Total annual T&D CapEx by utility, Base scenario (\$M, Nominal)



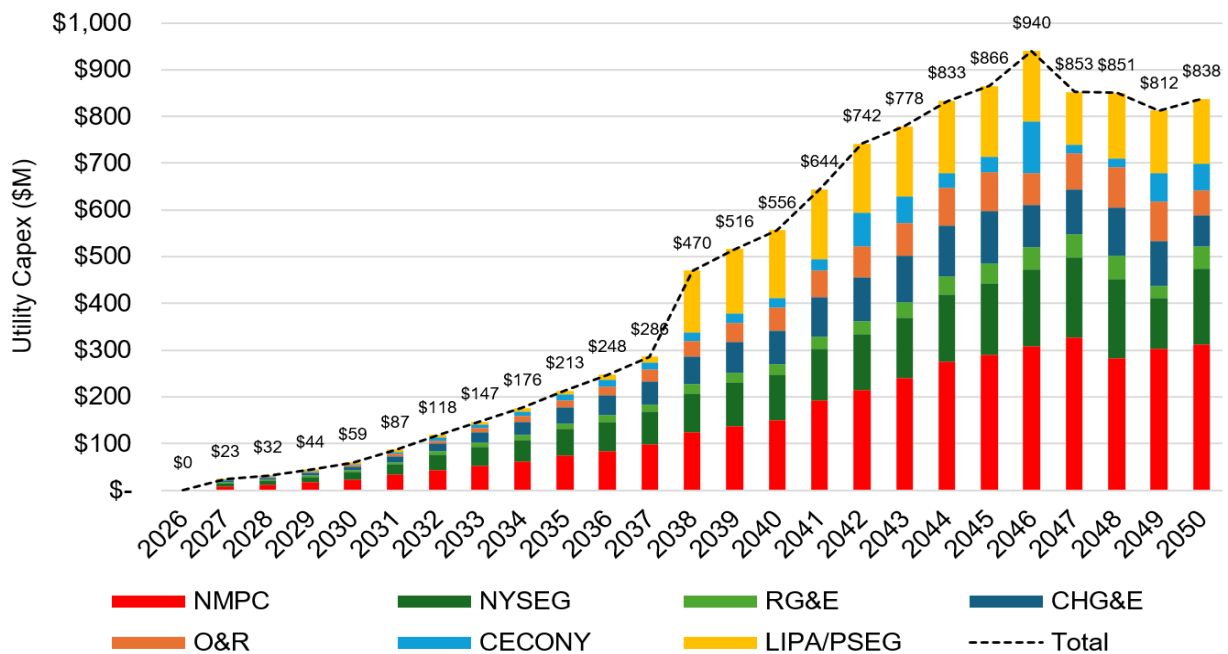
In the Hybrid Transition Case, T&D LSC CapEx grows slowly through 2030 commensurate with the levels in the Reference Case. Once the incentives are added for Hybrid Electrification starting in 2031, CapEx remains muted over the remainder of the forecast period (with the exception of LIPA) due to lower adoption of Full Electrification. Figure 49 below charts annual T&D CapEx by utility in the Hybrid scenario (note the change of scale in the y-axis).

Figure 49: Total annual T&D LSC CapEx by utility, hybrid scenario (\$M, Nominal)



In the Full Electrification scenario, T&D LSC CapEx grows slowly steadily over the forecast period and before stabilizing around \$800-900M per year in the mid-2040s and remains elevated over the remainder of the forecast. Figure 50 below charts annual T&D CapEx by utility in the Full Electrification scenario (note the change of scale in the y-axis).

Figure 50: Total annual T&D LSC CapEx by utility, Full Electrification scenario



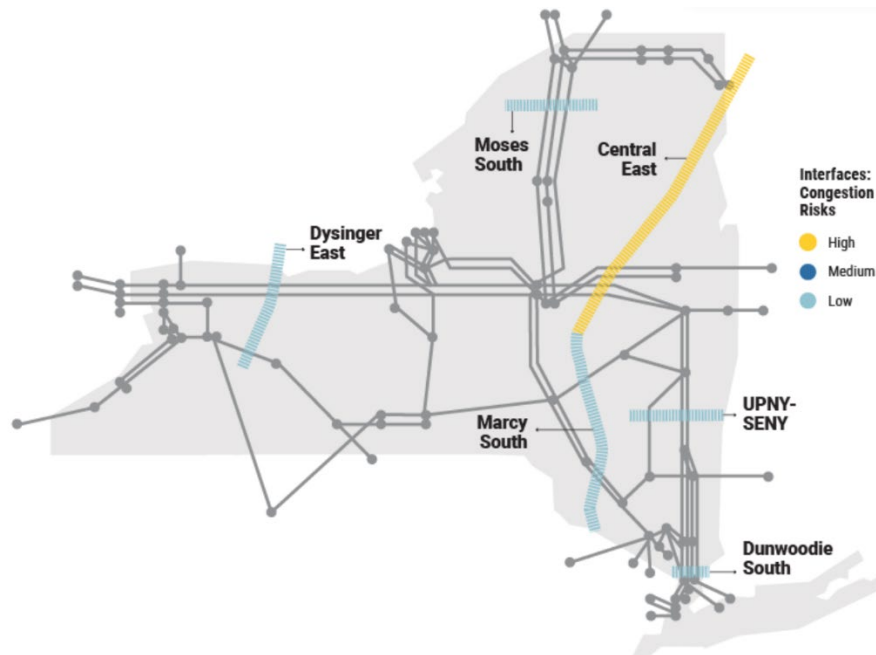
6.4.5 Bulk power system impacts

The HE Study examined the impact of residential BE on the bulk transmission system resulting from increases in winter peak demand across modeled scenarios. Importantly, the goal of this analysis was not to forecast bulk power needs across NYS. Rather, it was to develop order of magnitude estimates for potential bulk power system impacts specifically tied to residential building electrification. CRA acknowledges that bulk power needs are often driven by range of factors, including supply-side factors (including clean energy goals), import/export limits, and demand-side drivers other than residential BE. However, as this study quantifies potential system-wide impacts of Hybrid Electrification, CRA’s methodology estimated potential incremental bulk power transmission needs that may result from an increase in residential BE demand.

CRA reviewed persistent constraints on NYISO bulk transfer interfaces and found that the most significant limitations – Central East and UPNY-SENY – restricted the flow of electricity from Upstate to Downstate, resulting in recurring congestion costs and sustained locational price separation.^{46,47} While new renewable generation could partially offset transmission needs by serving load closer to where it was produced, incremental residential BE demand in Upstate regions was assumed to be largely served by local or regional generation resources. In contrast,

this option was limited in Downstate regions, which relied heavily on imports from other zones due to structural siting and deliverability constraints. As a result, incremental residential BE demand in Downstate areas was assumed to be met largely through increased imports, which triggers the need for bulk transmission upgrades. Figure 51 below provides a map of significant transmission interfaces in NYISO, including Central East and UPNY-SENY.

Figure 51: Map of significant NYISO transmission interfaces



Although detailed power flow modeling would be required for more precise estimates, CRA developed a high-level approach that translated increases in Downstate winter peak demand into corresponding increases in required bulk transfer capability. This analysis was conducted as a stand-alone assessment to evaluate the order of magnitude of bulk transmission costs attributable specifically to residential building electrification only and did *not* consider transmission investments required to meet CLCPA targets or broader system expansion needs.

CRA's methodology evaluated whether residential BE caused Downstate zones to transition from summer-peaking to winter-peaking conditions, under the premise that such a transition would require incremental winter deliverability. Of the two Downstate regions evaluated (Zones J and K), only Zone K was projected to become winter-peaking; accordingly, the bulk transmission assessment focused on estimating the incremental transfer capability required to serve higher winter peak demand in Zone K.

Estimated increases in winter peak demand for Zone K were used to develop corresponding bulk transmission investment estimates, applying indicative cost-per-megawatt metrics informed by recent bulk transmission projects. CRA averaged available data from recent bulk transmission projects on a \$/MW basis, resulting in an estimated cost of approximately \$1.5 million per MW to mitigate incremental bulk transmission needs.

A reliability up mark of 20% was applied to reflect transmission sizing requirements under contingency conditions. The adjusted unit costs were then multiplied by the incremental winter peak deliverability required for Zone K across the modelling period.

Zone K was projected to transition to winter-peaking in 2036-2038 timeframe across the scenarios, and hence the bulk transmission upgrades were assumed to be required only after that period. Further, these estimates were not intended to represent specific NYISO projects, but rather directional capital requirements associated with reinforcing bulk transmission capability to meet higher winter peak demand.

Table 43 summarizes the estimated bulk transmission investment associated with residential building electrification over the 2026–2050 period.

Table 43: Estimated bulk transmission upgrades driven by residential BE (\$M, Nominal)

Scenario	Bulk Transmission Upgrades, 2026-2050
Base	\$891M
Hybrid	\$440M
Full Electrification	\$1,235M

Estimated bulk transmission investment varied meaningfully across scenarios. The Hybrid scenario resulted in the lowest estimated transmission requirement, approximately \$440 million, reflecting its ability to moderate winter peak demand through diversified heating configurations. The Base scenario required approximately \$891 million in bulk transmission upgrades. The Full Electrification scenario exhibited the highest estimated requirement, approximately \$1.2 billion, driven by widespread heat pump adoption and the resulting increase in coincident winter peak demand. These results indicated that managing winter peak demand through Hybrid Electrification materially reduced the scale of required bulk transmission upgrades.

6.4.6 Total forecasted T&D (Local + Bulk) LSC capital expenditures by scenario

Combining the results in the previous two sections, the total forecasted T&D capital expenditures driven by residential building electrification by scenario, when considering both local T&D and bulk power system impacts, is shown below in Table 44.

Table 44: Total T&D LSC capital expenditures by scenario (\$M, nominal)

Scenario	Total T&D Upgrades, 2026-2050
Base	\$7,120M
Hybrid	\$1,700M

Full Electrification	\$12,368M
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The results above show that the Hybrid scenario avoids approximately \$5.4B in potential capital expenditures compared to the Base scenario, illustrating the potential value of hybrid heating.

6.5 Role of hybrid systems in peak mitigation

The results across load growth, reserve margins, and wholesale prices consistently highlight the Hybrid Electrification scenario as a moderating force on system strain. While it delivers lower total emissions reductions and electrification adoption than the Base and Full Electrification scenarios, its distinct value lies in how it reshapes the seasonal demand profile rather than simply the magnitude of demand growth.

The core mechanism is the retention of a fossil fuel system to cover heating demand once temperatures drop below 30°F. By serving the coldest heating hours, which drives the sharpest winter peak events, through FOP and the NG system, HE configurations substantially limit the contribution of electrification to winter peak demand. The result is a system that approaches dual-peak parity by 2050, with winter and summer peaks remaining within 500 MW of each other. This balance allows the same infrastructure built to serve summer demand to be more fully utilized in the winter, rather than requiring additional capacity dedicated solely to a narrow band of the coldest winter hours. The reserve margin analysis illustrates this benefit clearly. The Hybrid scenario maintains a winter reserve margin approximately 14% higher than the Base scenario by 2050, remaining closer to the current minimum capacity requirements of 124.4% of forecasted peak load. The avoided capacity need represents a meaningful reduction in the infrastructure investment required to maintain system reliability as electrification scales over time.

Beyond the fixed 30°F switchover temperature modeled, HE configurations offer additional operational flexibility. A residential building stock equipped with hybrid systems can adjust switchover behavior in response to grid conditions, effectively functioning as a distributed demand response resource during peak winter stress events. While further analysis would be required to quantify the magnitude of this potential benefit, this flexibility is not available under FE configurations, which lack an alternative heating source to draw upon during periods of system strain. The tradeoff from a system-impact perspective therefore boils down to the Hybrid scenario delivering lower emissions reduction, while being able to serve as a tool for managing winter peak risk during the transition to a winter-peaking bulk power system.

7. Natural gas system impacts

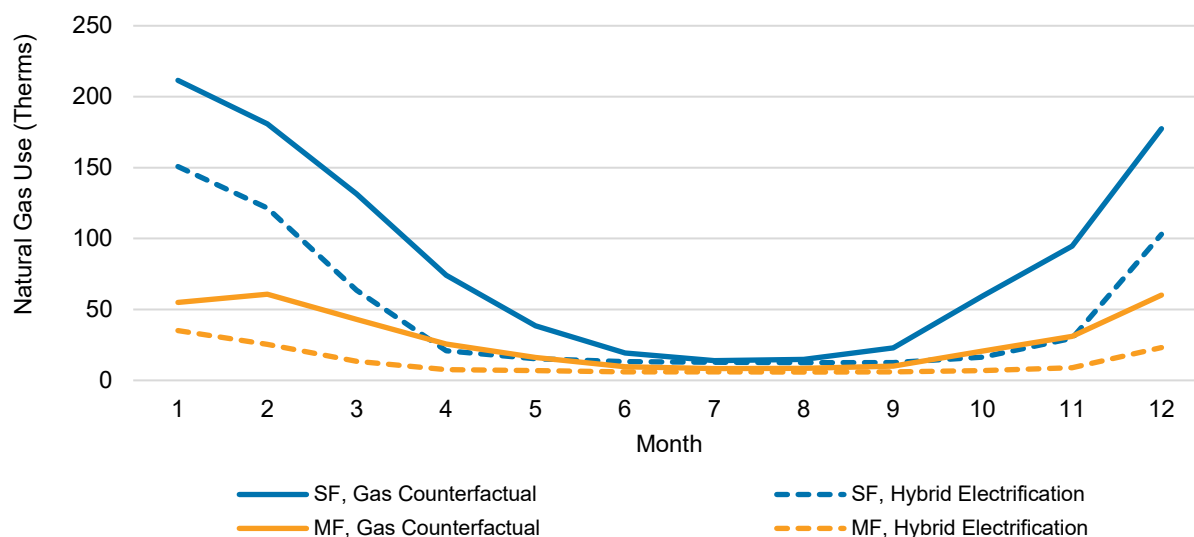
This section explores the potential impacts of Full and Hybrid Electrification on New York’s natural gas systems. Significant adoption of Full Electrification would impact natural gas customer counts, throughputs, and natural gas design day demand. Significant adoption of Hybrid Electrification would lead gas customer counts and peak design day demands to remain relatively stable, since peak demand is primarily driven by space heating requirements. These impacts could be felt unevenly across the regions of NYS under different scenarios, depending on the relative economics for natural gas heating relative to Full and Hybrid Electrification options.

The following subsections identify the forecasted impacts on natural gas throughputs that might be expected for different customer archetypes that adopt Hybrid Electrification. They analyze the forecasted reductions in natural gas customer counts and annual throughputs by utility under each scenario. Last, they discuss the implications for gas system planning and gas decarbonization efforts.

7.1 Natural gas throughputs

CRA’s development of EULPs for customer archetypes that adopt Hybrid Electrification measures assumed a 30°F switchover temperature. This meaningfully reduces, but does not eliminate, natural gas consumption during the winter heating months. Among customers that adopt HE, total annual natural gas consumption is reduced by an average of 45% for single-family archetypes and 57% for multifamily archetypes. Figure 52 illustrates the change in monthly natural gas consumption for Hybrid Electrification customers as compared to their counterfactual gas heating equipment.

Figure 52: Average monthly natural gas consumption, counterfactual vs. Hybrid Electrification



Full Electrification measures were assumed to completely eliminate natural gas usage for heating for all customer archetypes.

By tracking customer archetypes through time in its modeling, CRA calculated the cumulative reductions in natural gas heating consumption by residential customers over the forecast period, for each scenario. In the Base scenario, total statewide decline in gas throughputs to residential customers is approximately 10% by 2050.

Regions that have a higher proportion of natural gas consumption and better economics for Full Electrification have a greater decline in gas throughputs. Region 4, which primarily includes electric utilities CHG&E and O&R, sees the largest relative decline in the Base scenario, with cumulative natural gas throughputs declining nearly 30% by 2050 from current levels. Region 1, which primarily includes NFG, only sees natural gas usage decline by 3-4% over the same time period, due in large part to lower rates for utility gas and natural gas supply (including due to its proximity to the Marcellus Shale region). Similarly, Upstate, Regions 2 and 3, observed modest decline in gas throughputs despite stronger adoption of electrification. The electrification in these regions is largely driven by replacement of fuel oil and propane heating systems relative to other regions. New York City and Long Island observed cumulative throughput declines of 12% and 15%, respectively. Table 45 shows the cumulative decline in annual natural gas throughputs by Regions in five-year increments in the Base scenario.

Table 45: Cumulative percent decline in natural gas throughputs by region, Base scenario

Region	2030	2035	2040	2045	2050
Region 1	-0.15%	-0.78%	-1.69%	-2.83%	-3.56%
Region 2	-0.26%	-1.15%	-2.38%	-3.67%	-4.62%
Region 3	-0.30%	-1.32%	-2.77%	-4.34%	-5.46%
Region 4	-2.05%	-8.04%	-16.16%	-23.96%	-29.95%
Region 5	-0.72%	-2.90%	-5.86%	-8.92%	-11.53%
Region 6	-0.94%	-3.79%	-7.72%	-11.72%	-14.80%
Total	-0.64%	-2.64%	-5.37%	-8.17%	-10.37%

In the Hybrid scenario, overall throughputs decline by only 7% statewide by 2050. Notably, throughput reductions are more balanced across the Regions, with Regions 1, 2, and 3 seeing greater reductions in throughput under a Hybrid scenario relative to the Base scenario. This is driven principally by more natural gas customers in these regions favoring Hybrid Electrification when they would have reverted to the counterfactual otherwise. Table 46 presents similar data for the Hybrid scenario.

Table 46: Cumulative reduction in natural gas throughputs by region, hybrid scenario

Region	2030	2035	2040	2045	2050
Region 1	-0.13%	-0.93%	-1.95%	-2.96%	-3.74%
Region 2	-0.24%	-1.64%	-3.43%	-5.17%	-6.54%
Region 3	-0.24%	-1.84%	-3.95%	-6.03%	-7.66%
Region 4	-1.62%	-5.29%	-9.96%	-14.36%	-17.60%
Region 5	-0.52%	-1.83%	-3.45%	-5.13%	-6.53%
Region 6	-0.54%	-1.91%	-3.58%	-5.20%	-6.42%
Total	-0.47%	-1.98%	-3.88%	-5.75%	-7.21%

In the Full Electrification scenario, gas throughput declined more precipitously in all Regions as Full Electrification solutions dominated, with gas throughput falling roughly 29% statewide by 2050. Region 4 sees a 30% decline by 2040 and a greater than 60% decline by 2050. Table 47 presents similar data for the Full Electrification scenario.

Table 47: Cumulative reduction in natural gas throughputs by region, Full Electrification scenario

Region	2030	2035	2040	2045	2050
Region 1	-0.40%	-3.00%	-7.56%	-13.77%	-19.61%
Region 2	-0.48%	-4.59%	-11.58%	-19.41%	-26.29%
Region 3	-0.51%	-2.62%	-7.59%	-14.51%	-21.07%
Region 4	-2.61%	-13.44%	-30.49%	-48.62%	-64.36%
Region 5	-1.06%	-5.69%	-12.64%	-20.07%	-26.55%
Region 6	-1.34%	-6.83%	-15.47%	-25.11%	-33.82%
Total	-0.96%	-5.58%	-13.09%	-21.61%	-29.20%

Crucially, these are only natural gas throughput reductions in the residential heating end-use sector *relative* to a 2026 baseline. This analysis does not characterize the impacts to overall economy-wide natural gas consumption under the planning scenarios. Section 8 of the Study explores the high-level impact of declining natural gas throughputs on gas utility cost recovery and the indicative customer bill impacts under each planning scenario.

7.2 Natural gas utility customer counts

CRA also explored the potential impacts to natural gas utility customer counts across different scenarios. While the proliferation of Hybrid Electrification would reduce natural gas throughputs, these dwellings would remain natural gas utility customers as networks shift strongly to capacity-based resources with more pronounced winter peaks and shoulder season troughs. Adoption of Full Electrification as modeled within the HE Study, on the other hand, does not necessarily mean that individual customers will abandon the natural gas system.

As described in Section 3, the Full Electrification upgrades entail a customer converting both space heating and water heating to electric technologies. CRA's adoption modeling focused on the conversion of space and water heating and did not explicitly evaluate the costs and benefits associated with converting other non-heating fossil fuel appliances. Decisions regarding these appliances typically occur at different replacement points and were outside the scope of the modeled adoption framework. Therefore, other end-uses such as cooking appliances, clothes dryers, and fireplaces, were not converted as part of the FE archetype and may continue to be fueled by natural gas.

In practice, customer outcomes would vary. Some customers already utilize electric appliances beyond space and water heating and would therefore immediately disconnect entirely from the gas system upon electrifying those end-uses. Other customers would continue to require gas service due to the presence of remaining fossil-fueled appliances. Accordingly, the FE archetype reflects conversion of major thermal end-uses without assuming full household electrification in all cases.

Nevertheless, for customers that electrify both space and water heating, the remaining natural gas consumption associated with non-heating end-uses represents only a small share of total consumption. Among CRA's modeled customer archetypes, prior to any electrification, approximately 96% of total annual natural gas consumption is attributable to space and water heating. Once these end-uses are electrified, customers retaining natural gas equipment for minor gas loads would face ongoing fixed customer charges (which can range from approximately \$17 to \$25 per month for residential non-heating customers, depending on the utility) to serve an extremely limited amount of remaining gas usage. This dynamic may create a stronger economic incentive for these customers to fully disconnect from the gas system rather than remaining.

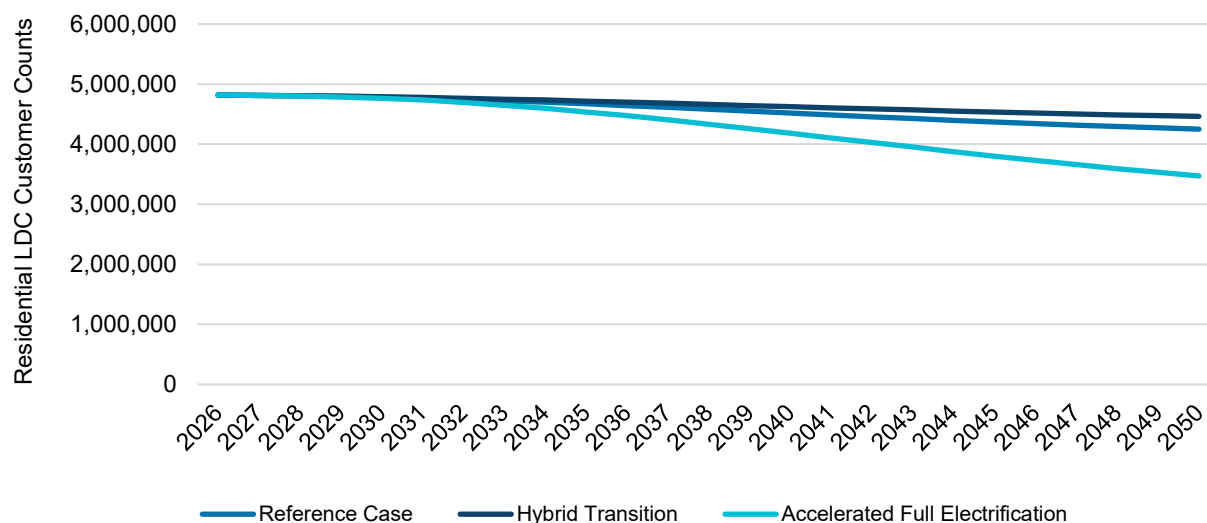
CRA modeled the statewide impacts on residential natural gas customer counts, assuming that 1 in 4 customers that adopt Full Electrification choose to stay with gas (3 in 4 fully defect from the gas system at the point of heat pump adoption). This is a modeling simplification that accounts for both:

- Customers that already have electric appliances at the point of space and water heating conversion and therefore would immediately defect from the natural gas system; and

- Customers that would defect from the natural gas system shortly after their space and water heating conversion due to the strong financial incentive to do so

Figure 53 illustrates the resulting differences in residential natural gas customer counts over the forecast period under each scenario.

Figure 53: Residential natural gas heating customer counts in New York State (all scenarios)



7.3 Implications for New York State policy goals related to natural gas

The results from the scenario analysis above indicate a wide range of plausible futures for residential customers of New York State’s natural gas utilities. The natural turnover of natural gas heating appliances in the NYS housing stock (which are relatively long-lived) limits the pace of change, but the change accelerates in the 2030s in all cases as heat pumps diffuse into the market and become more widely-accepted by customers and contractors. In a world with significant adoption of Hybrid Electrification, potentially encouraged by a combination of economic factors and policies, the impacts to the state’s natural gas utilities are relatively muted. Natural gas throughputs decline modestly, resulting in GHG emissions reductions, but customer counts and peak demands remain largely stable.

In a world with significant adoption of Full Electrification, natural gas throughputs and customers fall more precipitously, potentially straining affordability for remaining customers as the recoverable Base of therms and metered customers gradually declines. GHG emissions reductions are more significant than in the Hybrid scenario, but this could create challenges for fixed asset recovery and gas system reinvestment. Simultaneously, uptake of Full Electrification may create more opportunities for targeted non-pipeline alternative (NPA) investments to transition customers in a managed way to electrification.

An important implication of these results relates to the feasibility of gas system decommissioning under different electrification pathways. In all scenarios, electrification

adoption is driven by customer choice, the underlying economics, and the natural turnover of heating equipment rather than by geographically targeted electrification strategies. As a result, even in scenarios with high levels of Full Electrification, customer attrition from the gas system may occur in a dispersed manner across service territories. This pattern may limit near-term opportunities for targeted gas system “pruning” or decommissioning in the absence of complementary policies or non-pipeline alternative (NPA) programs designed to promote or effectuate electrification in specific locations.

Over time, however, declining customer counts could change the calculus for gas system planning. As the share of fully electrified customers increases, utilities may find it incrementally easier to identify and prioritize remaining customer clusters for targeted transition efforts than would be possible today. For example, if 60% of customers being served by a specific gas main have electrified, the remaining 40% of customers may be more readily addressed through focused programs or infrastructure decisions than in a fully subscribed gas system. This suggests that while widespread Full Electrification does not automatically create decommissioning opportunities, it may, over the longer-term, lower the barriers to targeted interventions aimed at reducing or retiring portions of the gas distribution system.

The results also highlight a potential tension between hybrid adoption and long-term gas system transition objectives. Customers who adopt Hybrid Electrification in the 2030s are modeled to install new fossil heating equipment with multi-decade useful lives, which could result in extended reliance on gas infrastructure even as overall customer counts decline. Absent additional incentives or policy interventions, these customers may remain on hybrid configurations for the life of the equipment, potentially slowing progress toward full building decarbonization. While the introduction of zero-carbon fuels could, in theory, alter this outcome, such pathways would require significant cost reductions for zero-carbon fuels and infrastructure investment to become economically viable at scale. As a result, Hybrid Electrification may reduce near-term system impacts and emissions, but it may also complicate longer-term gas system transition planning if not paired with clear future pathways for customer conversion or system downsizing.

8. Revenue requirement and bill impact analysis

8.1 Methodological approach

8.1.1 Context of analysis

In order to determine the magnitude and direction of the impact of varying degrees of residential building electrification on average residential bills in different parts of NYS, CRA was tasked with modeling revenue requirement for purposes consistent with the scope and assumptions of the HE Study.

CRA acknowledges that a utility's revenue requirement is unique, complex, and depends on many factors, including interrelated operational, capital, and regulatory drivers, such as:

- **System delivery needs:** Including the need to expand or reinforce its asset Base to meet all of its load obligations, particularly those driven by peak demand growth and locational constraints.
- **Asset age and condition:** Utilities will need to re-invest in the system to maintain and replace certain assets that are at or near end of life to maintain safe and reliable service.
- **Customer Base:** Including changes in customer counts or types that change the system footprint.
- **Technology and measure adoption:** Including EE, heat pumps, and other measures that influence a customer's use of electricity and natural gas.
- **Utility-specific ratemaking:** Including carrying charge factors that reflect various components of cost recovery specific to the utility and for which the utility has secured regulatory approval for recovery in cost of service.
- **Procurement costs:** Electric utilities in NYS must procure energy and capacity through NYISO or other agreements, and gas utilities must similarly procure commodity supply and capacity to meet firm demand obligations.

However, to answer the question of how varying degrees of Hybrid and Full Electrification in different parts of NYS may impact energy affordability for customers both on the gas and electric system at different magnitudes and on different time horizons, CRA determined that a bottom-up, all-in revenue requirement build of each utility would not be meaningful for purposes of isolating electrification-driven impacts and would risk conflating electrification effects with unrelated capital, policy, and operational drivers. Instead, CRA modeled the utility system costs impacted by more or less electrification, all else equal, and forecasted how the recovery of these costs from its customer Base evolves through time, considering changes to energy consumption and customer counts on the gas and electric systems. This allows CRA to estimate the incremental or decremental change in customer bills due to residential building electrification, rather than taking a specific view on long-term utility capital and O&M spend outside the purview of this study.

In this way, the positive or negative impact on customer bills of Full and Hybrid Electrification scenarios relative to an informed baseline can serve as an effective metric.

8.1.2 Revenue requirement and cost allocation

CRA approached revenue requirement and cost allocation modeling in three layers, each intended to isolate a distinct channel through which electrification affects customer bills:

1. **The cost of energy supply:** This includes the cost to procure electricity and gas to serve the energy needs of customers throughout the year, which may differ based on defined market conditions and system impacts of different levels of electrification. This aspect applies both to the cost to enable electrification for utilities and the indirect impact of electrification on gas utilities. The methodology to derive energy supply costs is further described in Section 6.3.
2. **The cost to enable electrification for electric utilities:** This includes the investment and ultimate recovery of costs related to capital investments on the bulk transmission system as well as on the local transmission and distribution system of each electric utility included in this study. The cost to enable electrification not only includes capital recovery but also the incremental expense associated with operating and managing such incremental facilities.
3. **The impact of electrification on gas utilities:** This includes the impact on how Base delivery revenue requirement (non-commodity) is spread across a gas utility's customer Base. CRA explored how a gas utility's revenue requirement may need to be recovered over a diminishing customer Base under the three modeled scenarios as more customers electrify and leave the gas system.

The traditional revenue requirement calculation can be described in terms of the following formula:

$$\text{Revenue Requirement} = \text{Operating Expenses} + \text{Depreciation} + \text{Taxes} + (\text{Rate Base} \times \text{WACC})$$

Where:

- Operating Expenses includes operations and maintenance (O&M) and administrative and general (A&G) expenses, including labor, materials, insurance, and other ongoing costs of operating the system.
- Depreciation represents the annual recovery of gross utility plant investment - also known as gross plant in service (GPIS) - over each asset's service life, inclusive of approved net salvage.
- Taxes include property taxes and other non-income taxes, as well as income tax allowances associated with the return on equity.^{xxv}

^{xxv} LIPA is tax-exempt and thus does not pay income taxes.

- Rate Base represents the net investment used and useful in providing utility service and approved for recovery, generally including net plant in service (NPIS) and working capital, and reduced by accumulated deferred income taxes (ADIT).
- Weighted Average Cost of Capital (WACC) reflects the utility's approved capital structure and weighted costs of equity and debt, which together comprise its weighted average cost of capital.

In typical cost of service and rate design, a utility's test year(s) revenue requirement is functionalized, classified, and allocated across rate classes. This is necessary for ratemaking, as it ensures each class of customers is apportioned a fair share of the revenue requirement based on cost causation principles. The functionalization, classification, and class allocation steps are described in more detail below:

- **Functionalization:** Revenue requirement is categorized into relevant functions, including generation, transmission, distribution, and customer.
- **Classification:** Revenue requirement is further split into cost drivers including demand-, energy-, and customer-related components. Classification is based on the underlying driver causing costs to be incurred by the utility. For example, primary distribution lines are generally sized to meet localized demands (i.e., are demand-related) while meters are generally required on a per-customer basis (i.e., are customer-related).
- **Class allocation:** Using class-level detail on items like coincident and non-coincident peak demand, customer counts, etc., revenue requirement is allocated to rate classes based on their "cost-causing" contribution to the plant item or expense in question.

Although CRA did not develop new utility-specific class allocators for purposes of this study, traditional ratemaking principles provide the analytical framework for assessing which categories of incremental system costs are likely to be borne by residential customers and in what approximate proportion. Consistent with that framework, CRA apportioned revenue requirement to the residential rate class for each utility using the most recent publicly available embedded cost of service study available and selecting the underlying allocation factors applicable to each investment category, including Bulk Transmission, Local Transmission, Primary Substations and Feeders, and Secondary Network and Services.

CRA assumed these allocation factors remain constant throughout the study's time horizon, rather than taking a position on how class allocation outcomes may evolve in future proceedings, which remain subject to Commission review and utility filing positions. The specific allocation factors used for each utility are presented in Data Annex 3.

8.1.3 Energy supply costs

The cost of energy supply is an O&M item inclusive of applicable revenue-based taxes and surcharges. Although customers may enter into agreements with retail power marketers as an alternative to having a utility procure energy on their behalf, CRA assumed all energy supply costs align with the gas and electric commodity pricing results described in Section 6.3 above.

CRA passed through energy supply revenue requirement to residential customers by using weighted system average annual \$/kWh and \$/therm values for electricity and natural gas for relevant NYISO zones and gas delivery regions on average annual residential customer usage. As a result, there was no need to allocate this revenue requirement further through class allocation procedures.

8.1.4 Incremental utility transmission & distribution capital investment

The cost to enable electrification touches all aspects of revenue requirement related to the incremental T&D capital investment identified in Section 6.4. To model this, CRA applied a simplified, traditional revenue requirement model to directionally approximate cost recovery needs under alternative electrification pathways rather than forecast filed or approved revenue requirements.^{xxvi} To convert capital expenditures into revenue requirement, CRA developed carrying charges for an indicative NYS transmission operator, the Utilities, and LIPA to apply that could be applied to the forecasted investments required to enable electrification on the bulk transmission system and the local T&D system. These carrying charges reflect approved WACC for the return on rate Base, plus depreciation, O&M and A&G expenses, and taxes (both income- and non-income related).

The Utilities already develop and use economic carrying charge rates in their MCOS studies to convert capital investment into levelized revenue requirement for the purpose of calculating marginal cost. CRA utilized these studies, utility rate case filings, and other known information to develop carrying charges for investments in bulk transmission, local transmission, primary substations and feeders, and secondary network and services. Each of these investment categories carries different asset lives, salvage values, and incremental O&M relationships. CRA worked with publicly available information and NY DPS Staff support to produce reasonable carrying charges for LIPA since they do not participate in the MCOS docket. The spectrum of inputs ultimately used to inform these carrying charges and revenue requirement through time are found in Data Annex 3.

In order to determine the impacts to residential class customers, CRA allocated this modeled revenue requirement using utility-specific allocation factors.

8.1.5 Impacts of electrification on gas utility customers

CRA took a high-level approach to characterizing the impact of electrification on gas customers, focusing on how the gradual increase in Base delivery costs (including fixed cost recovery but excluding commodity costs) required to maintain the natural gas system under a Hybrid or Full Electrification scenario is spread across the customers remaining on the gas system. For

^{xxvi} PSEG LI / LIPA's capital cost recovery is determined based on the Public Power / Debt-Service Coverage Method rather than Traditional IOU Cost-of-Service Ratemaking. This means debt service replaces depreciation and the return on equity portion of WACC. As a simplifying assumption, CRA assumes depreciation serves as a proxy for future principal and LIPA's interest expense divided by its adjusted debt is its cost of debt and ultimate WACC.

example, significant declines in natural gas customers and sales could raise bills for natural gas customers without a proportional drop in capital investment or Base recovery needs.

To model this portion of the analysis, CRA initialized the Base gas delivery revenue requirement of each utility's most recently settled rate plan. CRA did not take a position on the revenue requirement of the gas utilities, nor on the prudence or timing of future gas system investments, instead choosing to grow the currently filed test year revenue requirements by inflation over the analysis period. CRA then observed the per-customer impact on customer bills from changes in customer counts and natural gas sales volumes, holding Base delivery revenue requirement constant in real terms.

More detail on methodological approach may be found in Appendix B with starting values found in Data Annex 3.

8.2 Resulting customer bill impacts

The results in this section translate the scenario outcomes described in prior sections into indicative residential customer bill impacts as a helpful lens to view the study's broader findings on adoption, electric load growth, winter peak demand, electric infrastructure requirements, and changes in the remaining natural gas customer Base. Therefore, the figures below should not be read in isolation. Rather, they show how the differing pathways under the Hybrid and Full Electrification scenarios, relative to the Base scenario, would be expected to affect average residential electric and gas bills over time. These results are intended to illustrate the relative magnitude and direction of residential building electrification-driven bill impacts under consistent assumptions, rather than to forecast future filed rates or precise customer tariff outcomes.

For electric customers, the bill impacts are decomposed into three components:

- Transmission, which reflects residential recovery of bulk transmission investments;
- Delivery, which reflects residential recovery of local transmission as well as primary and secondary distribution investments; and
- Supply, which reflects the cost of electricity in the relevant NYISO regions.

For gas customers, the bill impacts are separated into Base and Commodity components to distinguish between broader gas commodity cost changes and the impact of recovering gas delivery revenue requirement over a changing customer Base.

As described in previous sections of the report, the Full Electrification scenario produces greater electrification uptake, higher electric sales growth, and a more pronounced winter peak. On the electric side, this leads to greater electric system cost recovery needs which impact each of the studied utilities in unique but directionally similar ways. On the other hand, the Hybrid Electrification moderates winter peak growth and reduces electric infrastructure requirements which correspondingly lowers electric system cost recovery and therefore electric bills. On the gas side, the bill effects are shaped primarily by the extent to which customers remain on or

leave the gas system under each scenario, thereby affecting the Base over which fixed delivery costs must be recovered.

8.2.1 Electric bill impacts

For electric customers, the bill impacts reflect three principal channels through which electrification affects cost recovery. Transmission reflects residential recovery of bulk transmission investments, Delivery reflects residential recovery of local transmission and distribution investments (including primary and secondary facilities), and supply reflects the cost of electricity supply. Together, these components show how differing levels of electrification adoption alter the magnitude and composition of electric bills relative to the Base scenario

Figure 54 illustrates the annual residential electric bill delta under the Full Electrification scenario relative to the Base scenario, by electric utility. As discussed in the preceding sections, the Full Electrification scenario produces the greatest increase in electric demand and accelerates the shift toward a winter-peaking electric system. For the majority of utilities, this shift is shared by Supply and Delivery-related cost drivers as the changing profile of the electric system in a Full Electrification scenario influences market prices and required system buildout. For CECONY, more resilience in system buildout leaves greater emphasis on changing Supply costs. For LIPA, the delta is driven primarily by Supply costs but has a uniquely balanced impact on the Transmission and Delivery side.

Figure 55 titrates these results into a statewide average. The chart shows that the statewide average annual residential electric bill increase under the Full Electrification scenario grows from approximately \$0.44 in 2030 to \$173 in 2050. The increase is driven by all three electric bill components, though transmission is minimal since that is isolated to LIPA service territory. By 2050, the statewide average delta consists of approximately \$65 in Delivery, \$4 in Transmission, and \$104 in Supply.

To reiterate, the bill impacts presented here reflect only the incremental or decremental effects of residential building electrification modeled in this study. CRA did not develop comprehensive utility-specific revenue requirement or capital expenditure forecasts for all drivers of future electric and gas bills. As a result, these results should be interpreted as indicative of the directional and relative magnitude of residential building electrification-driven bill impacts under consistent assumptions, rather than as projections of future filed rates or customer tariff outcomes.

Figure 54: Cumulative change in annual residential electric bill in Full Electrification scenario vs. Base scenario, all utilities

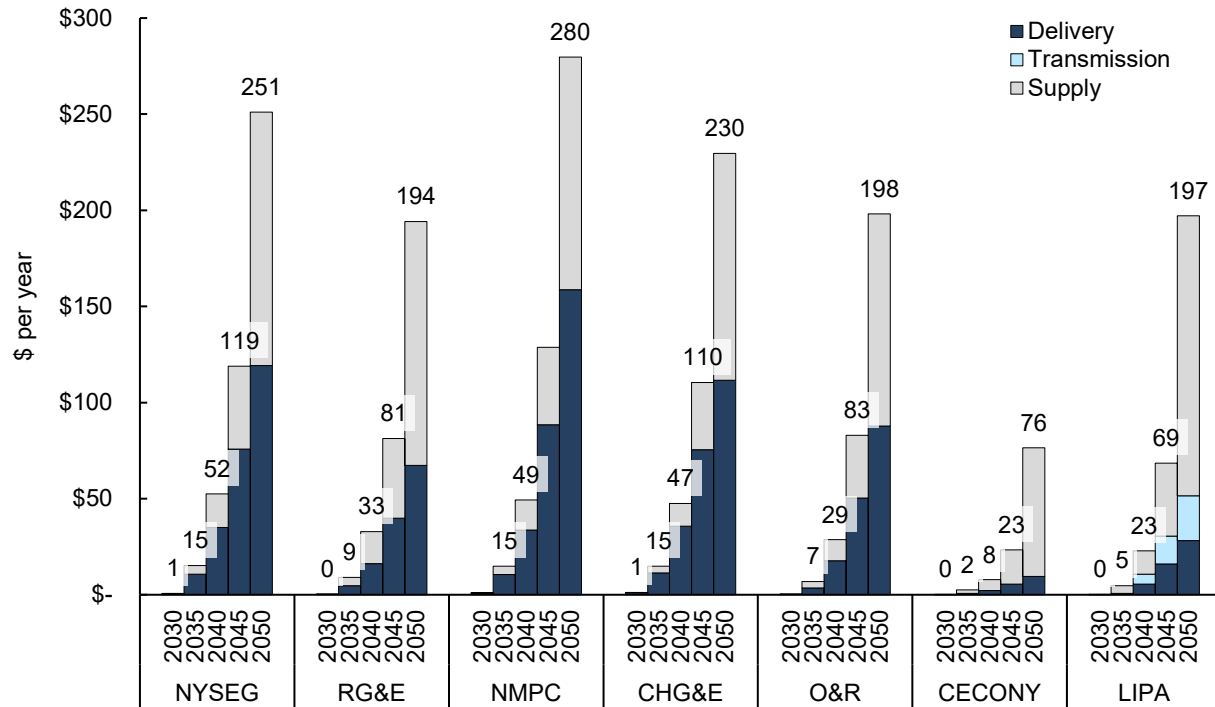


Figure 55: Cumulative change in annual residential electric bill in Full Electrification scenario vs. Base scenario, statewide average

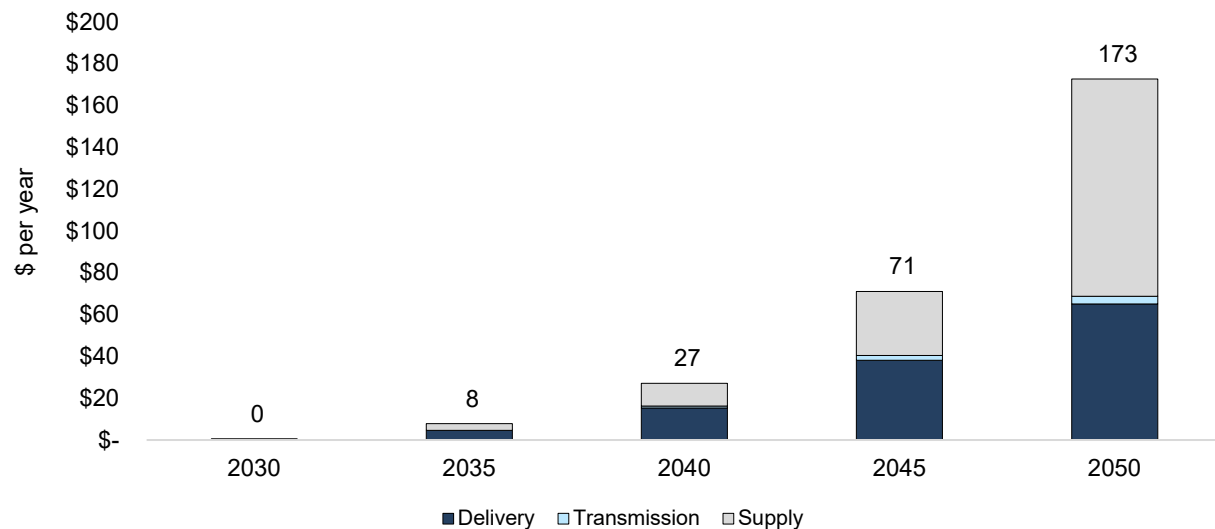


Figure 56 and Figure 57 illustrate the annual residential electric bill delta under the Hybrid Electrification scenario relative to the Base scenario, by electric utility and statewide, respectively. In contrast to Figure 54 and Figure 55, these charts show that the Hybrid

Electrification scenario reduces residential electric bills relative to the Base scenario. This aligns with the electric system findings in earlier sections of the report where the Hybrid scenario produces lower electric sales than the Base scenario and substantially moderates winter peak growth. Those lower electric system impacts translate into lower delivery-related and supply-related electric bill effects relative to the Base scenario.

Figure 56: Cumulative change in annual residential electric bill in Hybrid Electrification scenario vs. Base scenario, all utilities

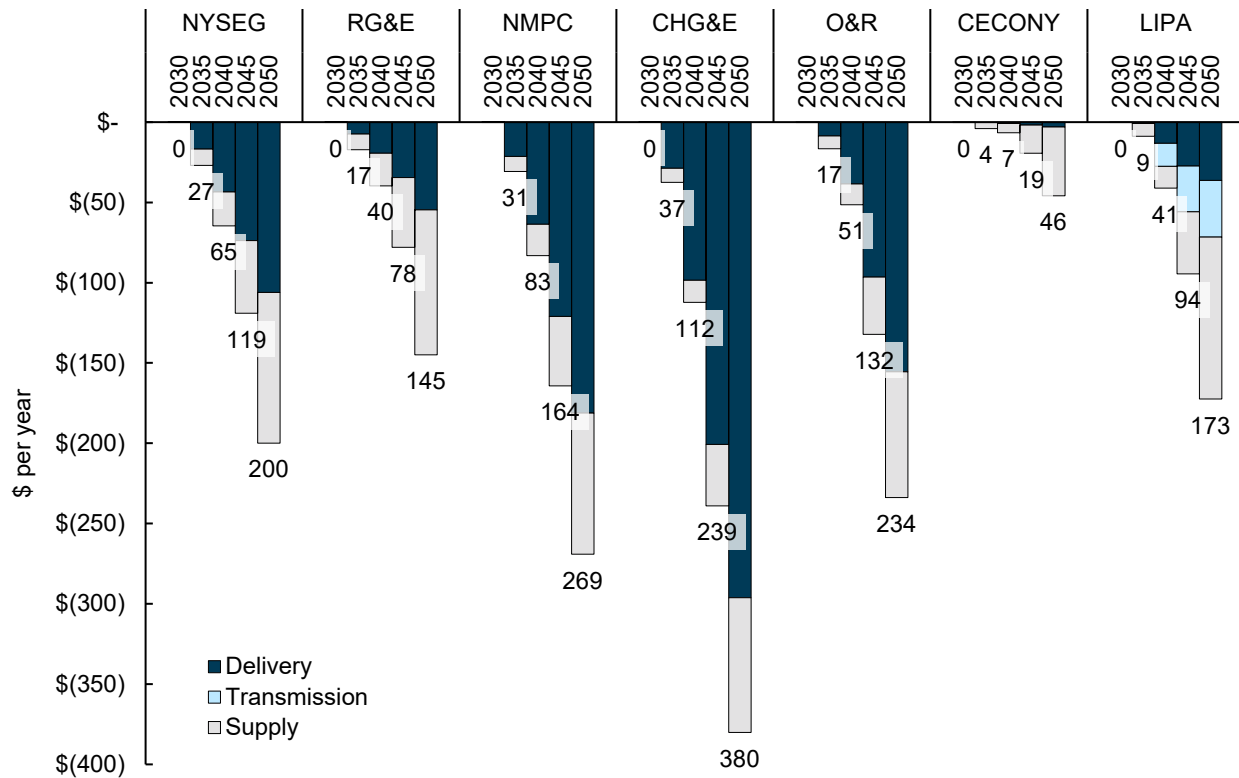


Figure 57: Cumulative change in annual residential electric bill in Hybrid Electrification scenario vs. Base scenario, statewide average

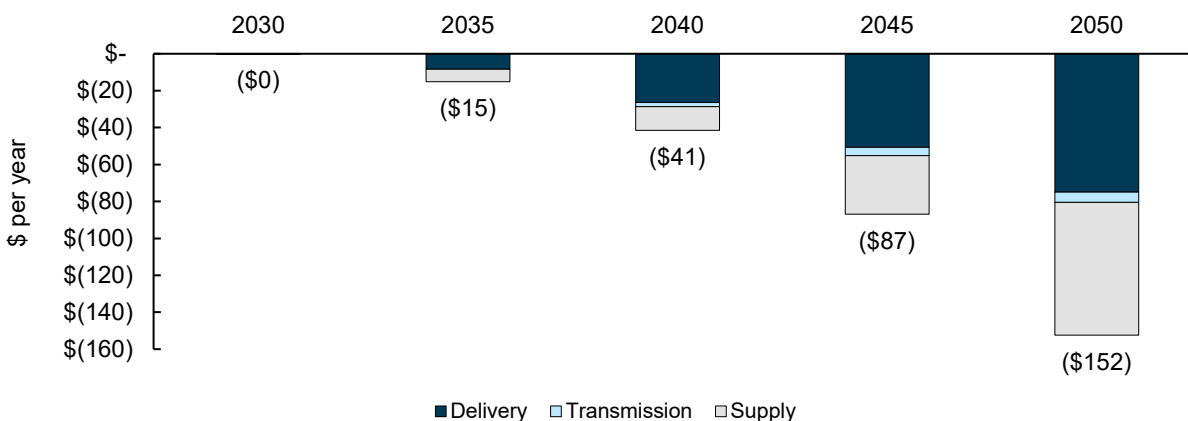


Table 47 provides an additional benchmark for interpreting the electric bill deltas by comparing them to the cumulative inflationary growth of a representative residential electric bill for each utility.^{xxvii} This framing is useful because it places the modeled scenario impacts in the context of bill growth customers may experience absent a change in electrification pathway. Under the Hybrid Electrification scenario, the electric bill delta is negative relative to cumulative inflationary growth across all electric utilities and statewide. By 2050, the Hybrid Electrification scenario electric bill delta equals approximately -15% of cumulative inflationary growth statewide but is more pronounced for utilities like NMPC and CHG&E. Under the Full Electrification scenario, the opposite is true, where the electric bill delta equals approximately 17% of cumulative inflationary growth statewide with a stronger share of inflationary growth seen in NYSEG/RG&E and NMPC service territories. Viewed in this way, the Hybrid Electrification scenario generally offsets a portion of inflationary bill growth, while the Full Electrification scenario contributes more strongly toward it, with the magnitude varying by utility.

Table 48: Residential bill delta relative to Base scenario as % of cumulative inflationary growth on electric bill

Scenario	Utility	2030	2035	2040	2045	2050
Hybrid Electrification	NYSEG	0%	-8%	-12%	-15%	-19%
	RG&E	0%	-5%	-7%	-10%	-14%
	NMPC	0%	-10%	-17%	-23%	-29%
	CHG&E	0%	-8%	-15%	-22%	-27%
	O&R	0%	-4%	-8%	-14%	-19%
	CECONY	0%	-1%	-1%	-2%	-4%
	LIPA	0%	-2%	-5%	-8%	-12%
	Statewide	0%	-5%	-8%	-11%	-15%
Full Electrification	NYSEG	0%	5%	9%	15%	24%
	RG&E	0%	3%	6%	10%	19%
	NMPC	1%	5%	10%	18%	30%
	CHG&E	1%	3%	6%	10%	16%
	O&R	0%	2%	4%	9%	16%
	CECONY	0%	1%	1%	3%	7%
	LIPA	0%	1%	3%	6%	13%
	Statewide	0%	2%	5%	9%	17%

^{xxvii} CRA assumed an annual average inflation rate of 2.1% year-over-year

8.2.2 Gas bill impacts

The gas bill results in this section should be interpreted differently than the electric bill results. As described in the methodological discussion, CRA did not model any specific gas distribution system CapEx. Instead, the analysis focused on how a changing LDC customer Base and natural gas sales profile affects the recovery of gas delivery revenue requirement over time. As a result, the gas bill impacts in this section reflect differences in the extent to which fixed gas system costs must be recovered from the customers who remain on the gas system and combines this with any changes in the cost to procure gas under each scenario.

Figure 58 illustrates the annual residential gas bill delta under the Full Electrification scenario relative to the Base scenario, by gas utility. Since the Full Electrification scenario produces a larger decline in gas sales and customer retention, it places the greatest upward pressure on gas bills for remaining customers. In the Full Electrification scenario, this effect is exaggerated by the attractive economics for heat pumps in Region 4, which includes CHG&E and O&R with significant increases in the bill delta relative to Base case between 2040 and 2050.

Figure 59 aggregates these results into a statewide average. The chart shows that the statewide average annual residential electric bill increase under the Full Electrification scenario grows from approximately \$2.00 in 2030 to \$539 in 2050. The increase is driven almost entirely by the Base portion of the gas bill.

Figure 58: Cumulative change in annual residential gas bill in Full Electrification scenario vs. Base scenario, all utilities

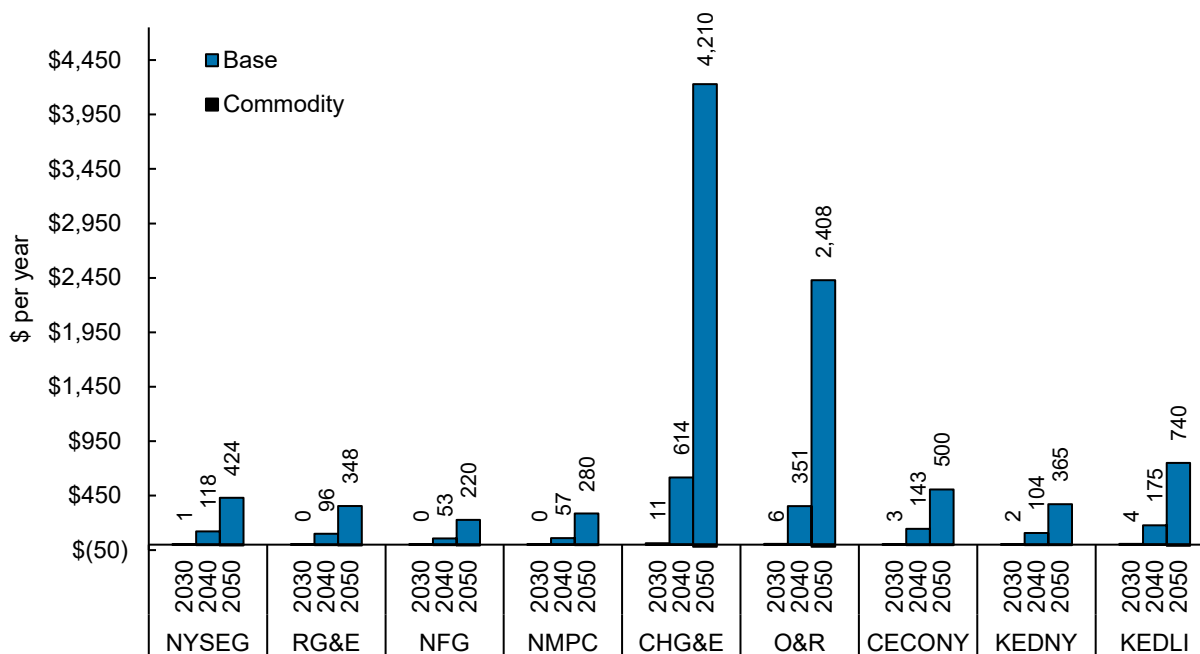


Figure 59: Cumulative change in annual residential gas bill in Full Electrification scenario vs. Base scenario, statewide average

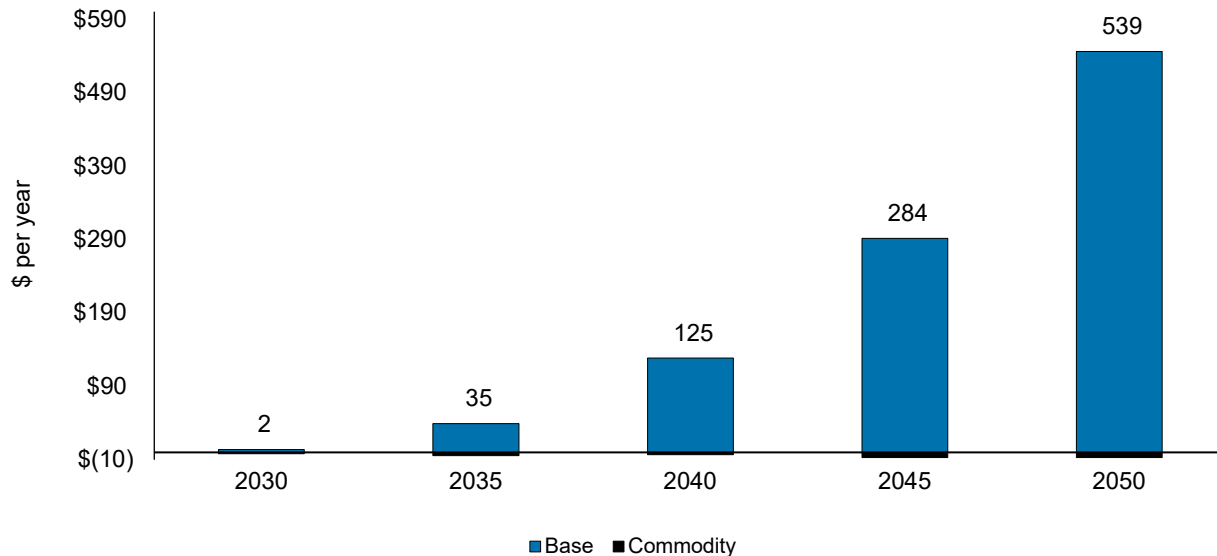


Figure 60 and Figure 61 summarize the annual residential gas bill delta under the Hybrid Electrification scenario relative to the Base scenario, by gas utility and statewide, respectively. Unlike the electric bill results, the utility-level effect under the Hybrid Electrification scenario is mixed rather than uniformly negative. While gas utilities like NYSEG, RG&E, NFG, and NMPC experience flat or modestly positive bill deltas relative to the Base scenario (more costly than Base), others experience negative bill deltas (less costly than Base). This mixed pattern is consistent with the broader gas system impacts discussed earlier in Section 7: the Hybrid Electrification scenario generally reduces gas sales and customer counts less dramatically than the Full Electrification scenario, but the relative effect varies across utility territories depending on adoption patterns and the local composition of the remaining gas customer Base. In this case, NYSEG, RG&E, and NMPC see more natural gas customers adopting HE measures that would have otherwise remained with the counterfactual in the Base scenario, leading to lower natural gas sales versus the Base scenario, which produces the effect shown below.

Figure 60: Cumulative change in annual residential gas bill in hybrid scenario vs. Base scenario, all utilities

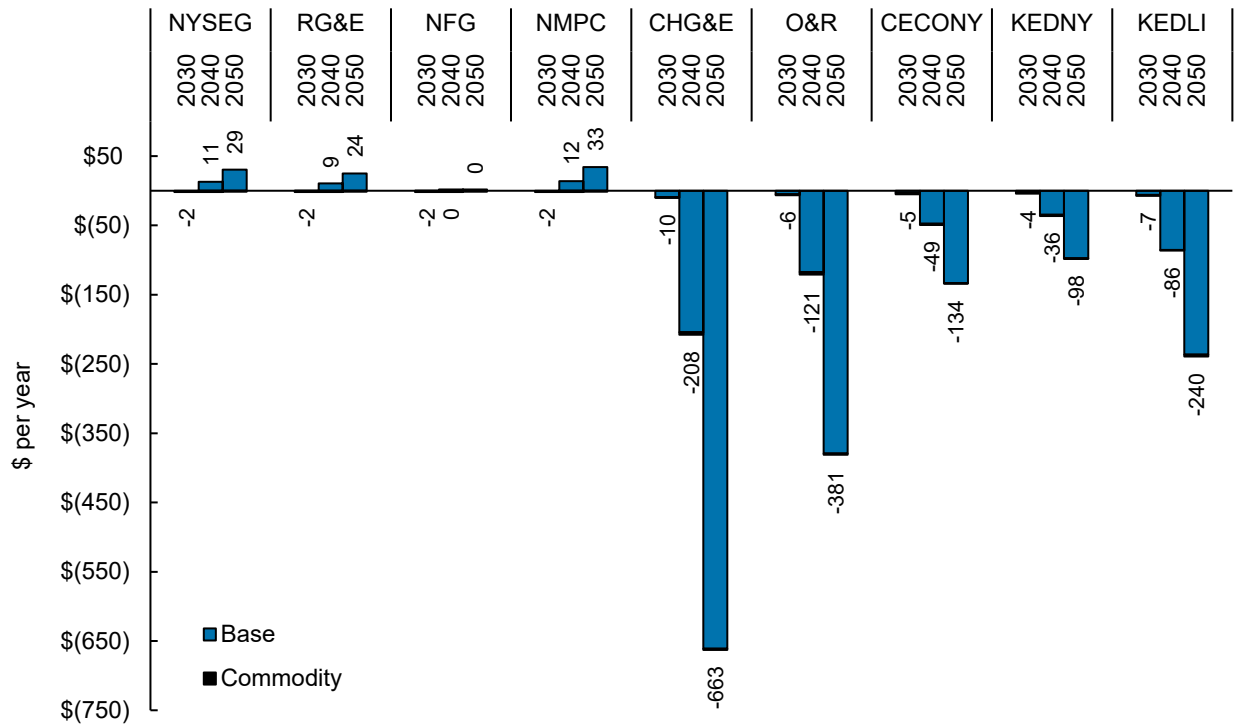


Figure 61: Delta in annual residential gas bill in hybrid scenario vs. Base scenario, statewide average

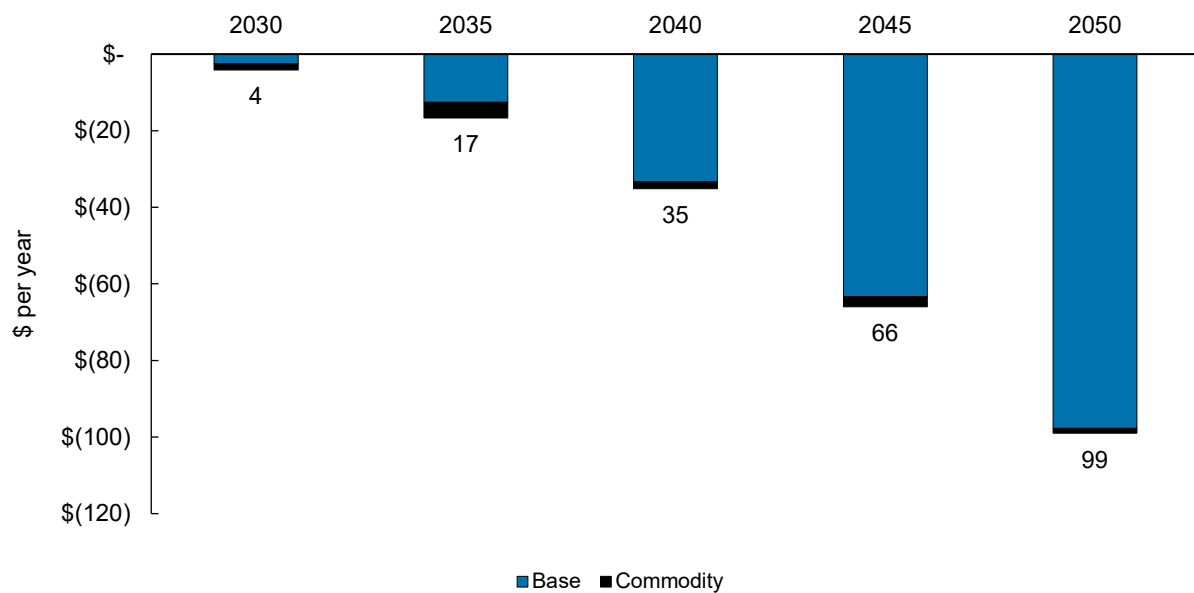


Table 49 places the gas bill deltas in the same inflationary growth context used for electric bills. A primary takeaway from this table compared to Table 47 is that the Full Electrification scenario has a disproportionate impact on gas customer bills than on electric customer bills. While this is more pronounced in CHG&E and O&R service territories specifically, the statewide gas bill delta as a percentage of inflationary growth reaches 28% by 2040, 44% by 2045, and 63% by 2050. As discussed earlier, the statewide electric bill delta under the Full Electrification scenario as a percentage of inflationary growth only approaches 17% by 2050. On the other hand, the statewide gas bill delta as a percent of inflationary growth reaches -11% by 2050 which is comparable to the statewide electric bill delta as a percent of inflationary growth of 15 percent. This phenomenon highlights the resiliency of electric and gas customer bills under the Hybrid Electrification scenario but the disparate sensitivity of gas customer bills under the Full Electrification scenario.

Table 49: Residential bill delta relative to Base scenario as share of cumulative inflationary growth in residential natural gas bills

Scenario	Utility	2030	2035	2040	2045	2050
Hybrid Electrification	NYSEG	-2%	0%	3%	3%	4%
	RG&E	-2%	0%	2%	3%	3%
	NMPC	-2%	0%	3%	4%	5%
	CHG&E	-6%	-19%	-30%	-42%	-50%
	O&R	-5%	-17%	-26%	-35%	-42%
	NFG	-2%	-2%	0%	0%	0%
	CECONY	-4%	-6%	-9%	-12%	-13%
	KEDNY	-4%	-7%	-9%	-12%	-13%
	KEDLI	-5%	-11%	-14%	-19%	-21%
	Statewide	-4%	-6%	-8%	-10%	-11%
Full Electrification	NYSEG	1%	12%	28%	42%	53%
	RG&E	0%	11%	26%	39%	49%
	NMPC	0%	3%	15%	28%	40%
	CHG&E	6%	34%	89%	176%	318%
	O&R	5%	28%	75%	148%	268%
	NFG	0%	6%	15%	24%	32%
	CECONY	2%	14%	26%	38%	48%
	KEDNY	2%	14%	26%	38%	48%
	KEDLI	3%	13%	29%	46%	64%
	Statewide	2%	13%	28%	44%	63%

These results underscore the extent to which widespread Full Electrification, when driven primarily by individual customer economics and natural equipment turnover, can place upward pressure on remaining gas customer bills by shrinking the Base of throughput and customers over which largely fixed system costs are recovered. In such a future, managing gas customer bill impacts may require a more deliberate focus on reducing underlying fixed costs of the gas system through targeted investments, asset retirement, or system downsizing, rather than relying solely on diffuse, customer-driven electrification trends.

However, the modeled Full Electrification scenario in the HE Study does not assume electrification occurs in a geographically targeted manner. As a result, customer attrition from the gas system is dispersed across service territories, which may limit near-term opportunities to materially reduce fixed system costs absent complementary policies or NPA programs explicitly designed to concentrate electrification in specific locations. Targeted electrification strategies could therefore play a vital role in mitigating gas bill impacts in scenarios with significant electrification, by enabling more coordinated system planning and creating clearer opportunities for cost reduction or decommissioning of gas infrastructure.

8.3 Impact of rate design on electrification futures

CRA's analysis assumes that electric customers pay a volumetric retail rate. In reality, residential utility rates can leverage different structures that can have an effect on customer economics, particularly for those customers that would significantly increase their consumption by adopting a heat pump system. Utilities in New York, and throughout the Northeast, are exploring rate designs that are tailored to electrification and heat pump adopters.

For example, Con Edison's optional demand-based rate for residential customers, SC1 Rate IV, offers a higher fixed monthly customer charge with a lower demand charge. It combines seasonal and time-of-use elements to differentiate summer and winter charges. Across 112 enrolled participants with air source heat pumps, 83.2% of customers saved versus their standard tariff, with an average monthly savings of 12.6%. Customers with a higher load factor benefited the most; the shift to fixed and demand-based billing structures benefited the heat pump customers who increased their consumption without contributing to the seasonal peak. Hybrid Electrification customers could similarly benefit from such a rate by reducing their winter peak consumption further.⁴⁸

In Massachusetts, the electric utilities introduced seasonal heat pump rates effective November 1, 2025, which offer customers who adopt a heat pump the option to enroll in a seasonal rate with a higher fixed monthly charge and a significantly reduced winter volumetric energy charge. From November 1 to April 30th, the winter season delivery rate is approximately 1/3 of the standard rate for each Eversource, National Grid, and Unitil. For Eversource, the transmission charge was also reduced in the winter season. From May to October, customers pay the same delivery rates as other residential customers. To facilitate adoption, the utilities auto-enrolled residential customers who received a heat pump through the state's Mass Save programs since January 1, 2019.⁴⁹ The heat pump rates are intended to be revenue neutral, while creating

tangible bill savings for heat pump customers and provide the added benefit of creating more stable, predictable month-to-month bills, which can benefit customers on a fixed income. Eventually, if Massachusetts sees significant additional electrification that increases winter peak demands and the electric system becomes winter-peaking, the rate design would no longer be aligned to cost causation and would likely need to be replaced or transitioned.

New rate designs like the above have the potential to significantly improve affordability outcomes for customers adopting heat pumps in NYS, if implemented correctly and made accessible to residential heat pump owners. Both Full and Hybrid Electrification systems could benefit from optional rate designs with higher fixed charges, demand-based elements, or seasonal winter discounts. Structuring rate designs with auto-enrollment (or “opt-out”) and pairing them with the NYS Clean Heat or EmPower+ programs could meaningfully increase heat pump adoption, if customers and contractors were aware of the potential impacts to customer bills and overall economics.

9. Univariate sensitivities

Incremental to the three scenarios described in this report, the HE Study also includes three distinct univariate sensitivities to assess the impact of the certain variables on the economics of electrification and the resulting impacts on customer adoption. CRA does not examine the downstream energy system and cost implications of adoption under the univariate sensitivities. The main variables involved include the switchover temperature for Hybrid Electrification and the level of upfront incentives available for Full Electrification. The three sensitivities are defined as follows:

1. **Sensitivity 1 (20°F sensitivity):** Adjust the switchover temperature for all Hybrid Electrification configurations to 20°F rather than 30°F. The switchover temperature can impact the relative economics and resulting customer GHG emissions of the HE configuration, as the heat pump will be operating more often at lower switchover temperatures. While this is expected to reduce GHG emissions, it may increase heat pump TCO because a lower switchover temperature in many cases requires a customer to adopt a higher capacity heat pump to meet its design heating load. This also increases the number of operating hours for temperatures between 20-30°F when heat pump efficiency is slightly lower relative to temperatures 30°F and above.
2. **Sensitivity 2 (+15% incentive sensitivity):** Adjust Full Electrification incentives up by +15% starting in 2031. Upfront incentives for electrification have a significant impact on the economics and ultimate adoption of heat pumps and their impact is a primary focus of the HE Study. The scenarios described earlier in this section both adjust multiple variables to portray different electrification pathways. However, given the importance of policymaker and stakeholder understanding of incentives, two univariate sensitivities were included to adjust the incentive for Full Electrification and determine impact on payback periods and potential adoption.
3. **Sensitivity 3 (no incentive sensitivity):** Remove upfront incentives for electrification. This sensitivity examines the relative economics of Full and Hybrid Electrification in the absence of upfront incentives. The customer adoption results in this sensitivity show that the incentive is the primary driver of Full Electrification market activity.

9.1.1 Sensitivity 1: Reduced hybrid system switchover temperature

Average payback periods declined modestly for a 20°F switchover temperature for all Hybrid Electrification archetypes. This is due to a combination of factors. The lower setpoint led to Hybrid Electrification customers needing to size up their heat pump equipment to meet a higher design heating load, which added upfront costs. The effects of operating the heat pump more frequently led to total annual natural gas and fuel consumption being reduced by approximately one third, though the amount varied by archetype.^{xxviii} The weighted average payback periods in

^{xxviii} Average annual natural gas consumption for heating was 206 therms at 30°F across all archetypes, which decreased to 139 therms at 20°F.

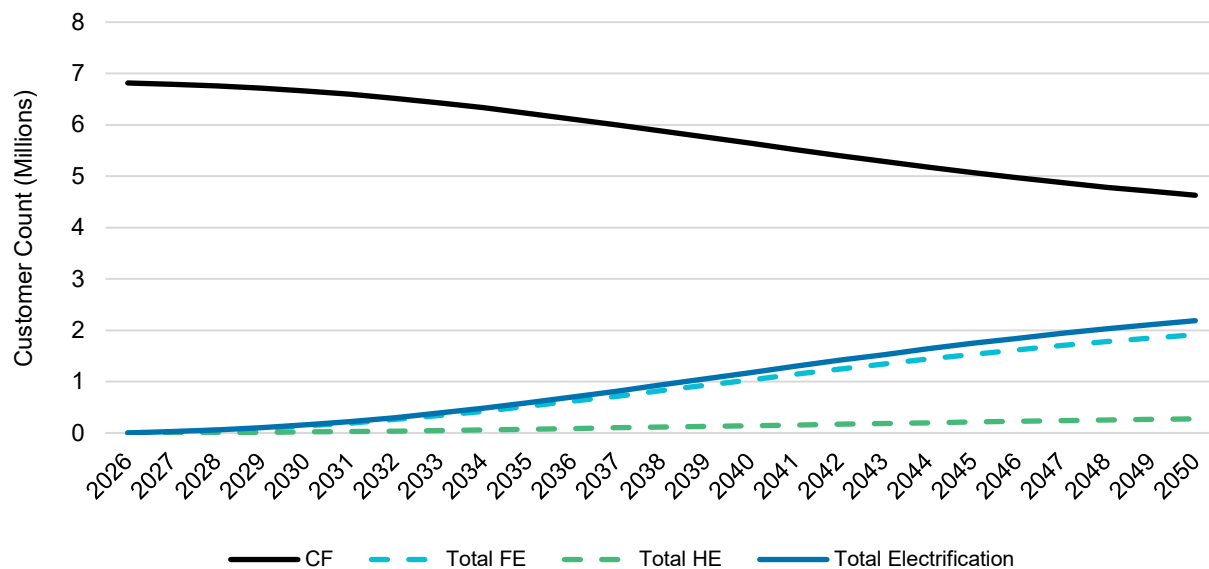
Sensitivity 1 are very similar to the Base scenario, with only some average paybacks for Hybrid Electrification increasing by 0.1 years or less. See Table 50 below.

Table 50: Weighted average payback period by technology (20°F sensitivity)

Technology	Full Electrification				Hybrid Electrification			
	SF	MFLOW	MF MID	MF HIGH	SF	MFLOW	MF MID	MF HIGH
Central ASHP	10.1	8.9	N/A	N/A	11.4	16.0	N/A	N/A
Mini-split ASHP	11.8	11.1	14.0	15.3	13.7	15.7	16.0	16.0
AWHP	14.6	9.8	15.8	15.9	15.7	14.4	16.0	16.0
PWHP	N/A	9.9	9.0	10.3	N/A	15.3	15.9	15.8

Total electrification adoption in the Base scenario was nearly identical: 2.19 million customers over the forecast period. However, the composition of adoption shifted slightly towards Full Electrification. Only 273k customers adopted Hybrid Electrification, versus 323k in the Base scenario.

Table 51: Cumulative electrification adoption (20°F switchover sensitivity)



CRA also examined the GHG emission reduction benefits under this sensitivity. The additional emissions reductions from a lower switchover temperature were minimal: 0.2 mmt more reductions between the Base scenarios. This demonstrates that while there may be some customer- and system-level GHG emissions benefits to operating hybrid systems less via a lower switchover temperature, the reductions are not very significant and may come at the

expense of additional customer adoption (vs. reversion to their counterfactual heating systems). Table 52 below shows the total GHG emission reductions with the assumption of a 20°F switchover.

Table 52: Total GHG emission reductions (20°F switchover sensitivity)

Metric	Base	Hybrid	Full
mmt Change by 2050	-16	-11	-24
Cumulative mmt Change by 2050	-186	-131	-254
End of Period Change to 'Do Nothing' Scenario	-27%	-18%	-38%
End of Period Change from Base	0%	+12%	-16%
Cumulative Change from Base	0%	-30%	36%

9.1.2 Sensitivity 2: Full Electrification incentive +15%

This sensitivity was a variation on the Full Electrification scenario which considered a future where no variables are adjusted except the increase in Full Electrification incentives in 2031 by +15%. This isolates the effects of the incentive decision but removes the combined effects of: 1) a roughly -15% decline in the real total installed costs of heat pumps, 2) a +22% improvement in average COP for heat pumps, and 3) a roughly +15% decline in real electricity rates relative to those for gas and fuels. These three factors are largely outside of the control of any one party.

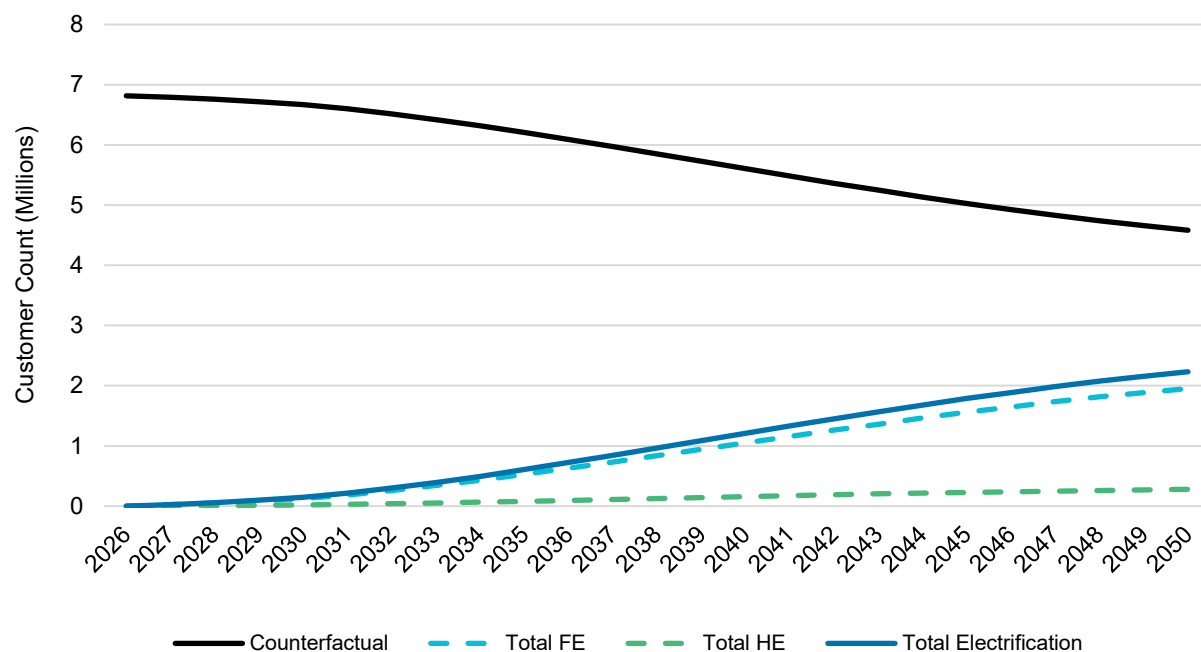
The customer economics, as measured by the weighted average payback periods, are slightly improved for Full Electrification versus the Base scenario and slightly worse for Hybrid Electrification (due to the removal of heat pump efficiency gains over the forecast period). Payback periods significantly lag the Full Electrification scenario, indicating that the other factors falling over time played a key role in spurring adoption of FE by nearly 1 million more customers than in the Base scenario.

Table 53: Weighted average payback period by technology (115% incentive sensitivity)

Technology	Full Electrification				Hybrid Electrification			
	SF	MFLOW	MF MID	MF HIGH	SF	MFLOW	MF MID	MF HIGH
Central ASHP	10.1	8.6	N/A	N/A	11.5	16.0	N/A	N/A
Mini-split ASHP	11.8	11.1	14.1	15.4	14.0	15.7	16.0	16.0
AWHP	14.5	9.8	15.8	15.9	15.7	14.2	16.0	16.0
PWHP	N/A	9.8	8.9	10.2	N/A	15.3	16.0	16.0

The resulting customer adoption shown in Figure 62 demonstrates that total adoption would look similar to the Base scenario, with end of period electrification increasing to 2.23 million from 2.18 million. Similarly, the number of FE configurations in this sensitivity also remains at 85% of electrification measures taken. The implications of this sensitivity therefore are that the +15% increase in incentives is a relatively small contributor to the high adoption of FE measures in the Full Electrification scenario, with the majority of differentiation in the scenario driven by the declines in real electricity rates, declines in heat pump total installed costs, and assumed heat pump COP improvements.

Figure 62: Cumulative electrification adoption (115% Incentive Sensitivity)



9.1.3 Sensitivity 3: No electrification incentives

This sensitivity examines the impact of completely removing all incentives for Full and Hybrid Electrification. It looks at how customer adoption preferences would shift between Full and Hybrid Electrification in the absence of any incentive and examines how overall electrification adoption would change (relative to reversion to the counterfactual).

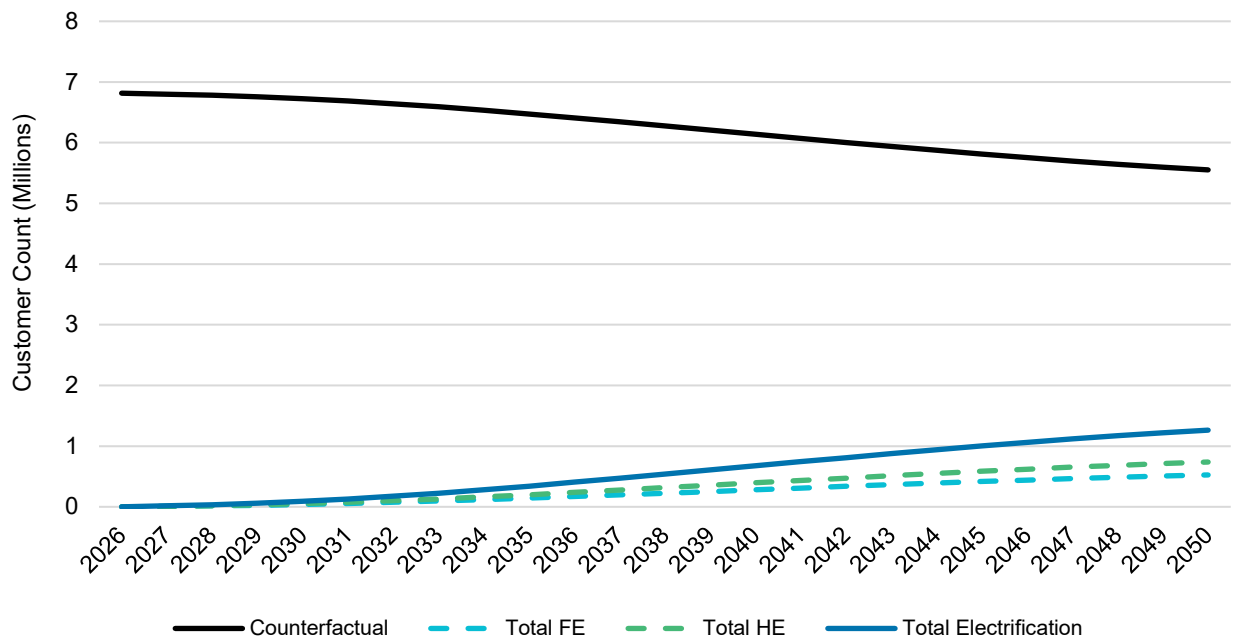
The economics of FE and HE shift without any Full Electrification incentive; in fact, HE has a slightly better average payback for central ASHP than FE (11.4 years vs. 11.7 years). FE still maintains the edge, on average, in all other categories. However, central systems for single-family dwellings are very prevalent in the non-NYC residential stock. FE continues to be generally more economic than HE for multifamily dwellings. See Table 54 below.

Table 54: Weighted average payback period by technology (no incentive sensitivity)

Technology	Full Electrification				Hybrid Electrification			
	SF	MFLOW	MF MID	MF HIGH	SF	MFLOW	MF MID	MF HIGH
Central ASHP	11.7	13.3	N/A	N/A	11.4	16.0	N/A	N/A
Mini-split ASHP	13.1	13.8	15.8	15.9	13.7	15.6	16.0	16.0
AWHP	15.1	11.3	15.9	16.0	15.7	14.0	16.0	16.0
PWHP	N/A	14.2	14.3	14.7	N/A	15.3	16.0	15.9

The lack of electrification incentives reduces end of period adoption in the Base scenario significantly – from 2.18 million customers electrifying down to 1.23 million. Under this sensitivity, FE configurations are substantially reduced from 85% to only 42% of total electrification under Base scenario conditions, while HE becomes the majority of electrification adoption. See Figure 63 below.

Figure 63: Cumulative electrification adoption (no incentive sensitivity)



10. Policy summary and conclusion

10.1 Hybrid Electrification vs. Full Electrification pathways

The results of the HE Study demonstrate that the system-level impacts of consumers making economics-led decisions about their heating equipment can lead to vastly different outcomes under the core scenarios analyzed, each representing distinct and plausible futures for New York State. The Base scenario reflects market-driven adoption under current policy and rate conditions. The Hybrid scenario represents a future where energy rate differentials tilt further in favor of gas and a leveling of the playing field for hybrid heating technology, making such systems more economically attractive to a larger share of residential customers. The Full Electrification scenario represents the inverse: falling costs for heat pump installations, improving heat pump efficiency, a boost in incentive, and a narrowing rate differential that makes fully electric configurations increasingly compelling versus fossil fuel alternatives.

Under these economic assumptions, the Base and Full Electrification scenarios yield strong adoption of Full Electrification systems, at 85% and 94% of total electrification adoption respectively, delivering the greatest emissions reductions at 184 and 251 cumulative mmt through 2050. However, they do so at the cost of the most significant winter peak growth and the tightest reserve margins – with the Full Electrification scenarios requiring additional capacity to bridge approximately a 19% winter reserve margin gap by end of period. The Hybrid scenario, where hybrid systems comprise 64% of adoptions driven by incentives specifically structured to favor hybrid systems from 2031 onwards, delivers a more modest 132 cumulative mmt reduction but produces a materially different system outcome: winter and summer peaks remaining within 500 MW of each other through the end of the study period and a winter reserve margin approximately 8% higher than the Base scenario by 2050.

This tradeoff is one to be considered when planning a strategy from the system-level. The scenario structures offer guidance as to what the system impacts could be given directional system-wide factors that propagate throughout the modeling. The Full Electrification scenario requires both declining installed costs and improved rate economics to materialize – conditions that are plausible but not guaranteed. The Hybrid scenario, by contrast, represents a different plausible future, especially in the near-term, with gas remaining economically competitive and hybrid incentives being introduced to support a closer managed transition to electrified heating.

Electric system spend varies considerably across the scenarios. The Hybrid scenario results in approximately \$5.5 billion lower spend on the local T&D (\$5.0B) and bulk power (\$450M) systems by 2050 compared to the Base case. Inversely, the Full Electrification scenario results in approximately \$5.25B of incremental system spend compared to the Base scenario – \$4.9B from local T&D and \$350M on the bulk power system.

Additionally, a critical dimension of the hybrid and Full Electrification pathway is timing. The reserve margin analysis shows that under the Base and Full Electrification scenarios; winter reserve margins begin falling below the most recent statewide minimum capacity requirement of

124.4% of forecasted peak load starting in 2042. The capacity buildout modeled (drawn from the SEP's AAS) was not designed around the residential electrification levels this study projects, and the results make clear that additional winter capacity would be required to bridge the gap, reaching approximately 19% under the Full Electrification scenario.

This creates a sequencing problem. The capacity resources and T&D infrastructure additional to the AAS required to reliably support a fully electrified residential stock must be in place by the time the reserve margin begins to fall under desired levels in the 2040s. Whether pursuing a Hybrid or Full Electrification focused pathway, the overall rate of demand increase cannot outpace the availability of capacity and headroom to serve it.

10.2 Alternative technologies to reduce system peak

The emergence of a winter peak in New York's electric system—reaching as high as 42.7 GW under the Base scenario by 2050—represents a materially different planning challenge than the summer-peaking system the grid was designed around. The reserve margin analysis in Section 6.2 shows available capacity falling considerably below historical targets for the Base and Full Electrification scenarios starting in 2043. While additional supply-side capacity could help address this gap, a coordinated suite of demand-side technologies is capable of reducing, shifting, and managing the new winter heating peak with substantially lower capital requirements. Smart electric panels, advanced metering infrastructure (AMI), and virtual power plants (VPPs) each operate at a different layer of the demand-side stack (device, meter, and system) and their value is most fully realized when understood as an integrated system rather than independent interventions.

10.2.1 Smart electric panels

At the device level, smart electric panels provide the hardware foundation for grid-responsive load control within individual homes. Unlike traditional breaker panels, smart panels provide granular, high-frequency data on individual circuit consumption and can be programmed to curtail, shift, or shed specific loads in response to grid signals without user intervention. A DOE-funded project partnering NREL with a smart panel manufacturer, SPAN, targeted the integration of smart panels with multi-objective optimization-based control of household loads and behind-the-meter energy resources, integrating NREL's foresee Home Energy Management System tool.⁵⁰ The 2023 project evaluated deployment across various U.S. climates in real homes, advancing toward the now commercially available smart panels. Most homes tested achieved at least a 10% reduction in energy costs, with the degree of flexibility found to be primarily determined by the extent to which total home energy was served by electrical end-uses.⁵¹ This finding has direct implications for the impact of electrification rates shown in this study: the 85% FE adoption rate under the Base scenario creates a housing stock that is largely electrically served, creating greater opportunities for coordinated demand management through technologies such as smart electric panels.

In fully electrified homes, smart panels have the potential to help customers manage a range of electric appliances, including heat pumps, electrified water heating, and other electric loads that can create sharp demand spikes during cold weather events. A smart panel equipped with grid-responsive controls can automatically reduce heat pump set points or shift water heating loads during winter peak events – reducing each home’s contribution to the system peak without occupant action. This capability is especially valuable under the Full Electrification scenario, where 94% of customer adoption is FE with no fossil fuel heating backup available during winter peak events. As adoption scales toward the levels projected in the Base scenario (over 2 million electrified homes by 2050), the aggregate winter demand response potential of a housing stock with greater smart panel penetration can be substantial.

10.2.2 Advanced metering infrastructure

AMI provides a communication and data layer that transforms individual smart panel actions into coordinated system-level responses. AMI systems, comprising smart meters, two-way communication networks, and data management software, give utilities and grid operators highly granular visibility into customer-level consumption, enabling time-of-use rate design, automated demand response dispatch, and distributed system monitoring. The FERC annual Assessment of Demand Response and Advanced Metering found that advanced meter penetration in the U.S. reached 76.8% of all meters in operation as of 2023, approximately 128.4 million meters, representing 7.6% annual growth.⁵² Within the Middle Atlantic Census Division (encompassing NY, PA, and NJ), residential AMI penetration lags behind the national average at 53.1%.⁵³ With AMI, utilities can offer time-of-use rates and automated programs for electrified customers to respond to in winter-peaking events.

10.2.3 Virtual power plants

VPPs represent the aggregation layer that converts the individual flexibility enabled by smart panels and AMI into utility-scale, dispatchable grid resources. VPPs aggregate distributed energy resources—including smart thermostats, heat pumps, battery storage, rooftop solar, and EV chargers—through a distributed energy resource management system (DERMS) that dispatch enrolled customer decides in response to grid operator signals. The DOE’s *Pathways to Commercial Liftoff: Virtual Power Plants (2023)* found that deploying 80 to 160 GW of VPPs nationally by 2030 – enough to serve 10-20% of peak demand – could save approximately \$10 billion annually in grid costs by deferring or avoiding new peaking generation capacity.⁵⁴ A 2025 update to the report noted that near-term pressures on the U.S. grid had only intensified since 2023, with rapid peak demand growth and increasingly frequent extreme weather events reinforcing the urgency of VPP deployment.⁵⁵ Despite this momentum, LBNL’s August 2024 report *the State of Demand Flexibility Programs and Rates*, drawing on data from 148 programs and 93 rates across 38 states, found that demand flexibility programs overwhelmingly target summer afternoon and evening peaks and concluded that program design would need to change if the electrification of end-uses shifts peak demand into winter mornings in cold regions.⁵⁶ This gap maps directly to the challenges brought about by an increasingly winter-peaking system in NYS. In the future, VPPs and other DR programs could leverage or

enroll Hybrid Electrification customers as resources for shedding winter peak demand, by switching to the backup heating system, in exchange for event-based compensation.

Finally, while Hybrid Electrification configurations retain flexibility in the form of shifting energy demand to another fuel source, the demand management stack overviewed offers increasingly developed forms of managing electric demand, which is particularly relevant to Full Electrification configurations where there is no alternative fuel to switch to.

Taken together, these technologies illustrate how demand-side flexibility can play a key role in managing the winter peak impacts associated with widespread residential building electrification. While the HE Study explicitly models electrification adoption, load growth, and resulting impacts on winter peak demand, it does not assume widespread deployment of smart electric panels, AMI-enabled demand response, or large-scale VPPs as an endogenous mitigation strategy. As a result, the winter peak outcomes presented in this study should be interpreted as reflective of electrification occurring largely without coordinated demand-side management.

As residential building electrification scales toward the levels projected under the Base and Full Electrification scenarios, particularly in futures that are predominantly fully electric, the ability to manage and shape electrified heating load becomes increasingly important. Device-level controls, enabled by smart panels and coordinated through AMI and VPP frameworks, offer a pathway to reduce coincident winter peak demand, improve system utilization, and mitigate the need for incremental supply- and infrastructure-side investments. Accordingly, these technologies represent a potentially important complementary toolset for managing long-term system impacts in highly electrified futures, even though they are not explicitly captured in the modeling results presented in this study.

10.3 Barriers to electrification adoption

The diffusion modeling approach taken by CRA incorporated real-world mechanisms to prudently estimate customer economic adoption of heat pumps but is limited by the aspects of adoption that are non-economic and difficult to quantify. At the core of the diffusion model is the decision to electrify occurring at the point of unit failure. The number of customers in the pool to potentially electrify was based on the annual probabilistic failure rate of the incumbent heating system across the housing stock, which captured the natural replacement cycle for gradual adoption, but does not include opportunistic adoption not based on economics or pre-emptive adoption ahead of unit failure.

Additionally, the failure-decision framework was calculated on the annual level, not accounting for the seasonal timing of replacement. An emergency replacement for a heating system that fails in the middle of winter may prioritize speed of replacement over economic payback. In these situations, a heat pump installation, especially one requiring weatherization upgrades, may not be feasible. While the adoption measures made available to each archetype are limited by physical realities identifiable through ResStock, outlier cases such as a building not being

able to install a heat pump due to permitting, rental or Homeowners Association structure, or niche construction limitations are not captured in the model.

The shortfalls of difficult-to-predict replacement timing can be partially mitigated through proactive measures. Contractors conducting annual maintenance checks can identify a system nearing failure ahead of the winter season, giving customers a wider timeline to make an economics-based decision rather than an emergency one. This points to a broader barrier to the adoption levels modeled in the study: the availability and capability of a trained contractor workforce to identify, recommend, and install heat pump systems at scale. New York has made strides on this front through the NYSERDA Workforce Development and Training program, having trained 9,400 contractors as of 2024.⁵⁷

Taken together, these modeling limitations and real-world barriers suggest that the adoption trajectories presented in this study should be interpreted as reflecting economically viable demand for electrification realized through a diffusion process, rather than a guarantee of one-for-one realized installations. While customer economics determine whether electrification is financially attractive at the point of equipment replacement, the pace and extent of adoption are further shaped by the diffusion dynamics embedded in the modeling framework (Bass Diffusion), which represent the gradual uptake of new technologies across the housing stock over time.

As a result, the realized adoption of heat pumps may diverge from modeled outcomes due to factors outside the scope of an economic-diffusion model, including emergency replacement timing, contractor availability, site-specific constraints, and administrative or ownership barriers. The gap between modeled adoption and realized installations will therefore depend not only on customer economics, but also on the capacity of programs and markets to support timely, informed decision-making and deployment. Investments in contractor training, proactive equipment assessments, and early customer engagement can help reduce these frictions and improve the likelihood that economically viable electrification demand translates into realized adoption outcomes.

10.4 Implications for utility planning and regulation

The results from the HE Study demonstrate the range of possible outcomes for residential building electrification in NYS. These outcomes are driven fundamentally by economics and customer choice. However, there are ways in which utility planning and regulation can intervene to maximize value to all parties. To-date, hybrid heating proposals introduced by LDCs have been centered around affordably reducing GHG emissions. Regulators must consider how such pilots or programs, if approved, can validate the value proposition of hybrid heating and provide important learnings to all stakeholders.

To this end, there are several potential areas for which LDC hybrid heating proposals could be augmented, grounded in the findings of this HE Study:

- **Require gas-electric utility coordination:** Require gas utilities sponsoring hybrid heating programs or pilots to coordinate with the relevant overlapping electric utilities in their service territories to jointly identify, quantify, and prioritize locations where hybrid heating can provide system value, including avoided or deferred electric T&D investment. This can validate whether hybrid systems can meaningfully improve grid utilization and reduce winter peak impacts that can trigger new upgrades on the system. If so, NY DPS can adjust incentive structures accordingly.
- **Develop a formal targeting framework for Full and Hybrid Electrification deployment:** NY DPS Staff should consider establishing a standardized analytical framework to identify where Full Electrification, Hybrid Electrification, or non-electrification solutions provide the greatest system and ratepayer value. Such a framework would integrate electrification adoption modeling, spatial electric and gas system constraints, marginal infrastructure costs, and customer characteristics to support consistent, data-driven siting decisions across utilities.
- **Explore utility- or operator-controlled solutions that include hybrid heating:** Explore the value of hybrid heating in the context of utility demand response or aggregator programs, including structured pilots that compare modeled versus observed performance during winter peak events. This would ensure that hybrid heating could be demonstrably relied upon to reduce or eliminate electricity consumption during high demand events when it can provide the most value. This would also provide information on customer willingness to participate and respond to price signals.
- **Engage in test and evaluation (T&E) and measurement and verification (M&V) of operating characteristics of hybrid systems:** Require utility-led hybrid heating programs to engage in significant T&E and M&V on the operating characteristics of hybrid systems. This may include analyzing switchover temperatures, simultaneous operation (to the extent this is within code), equipment operating efficiencies, and integrated control systems. These learnings would help NY DPS Staff and other stakeholders to develop a robust understanding of tradeoffs and technical specifications.
- **Analyze the total installed costs of hybrid systems and customer willingness to pay:** There is very little data on the actual costs of hybrid systems that are not designed to meet full heating load. Verification of whether and by how much heat pump sizing and other upfront installation costs can be reduced in hybrid installations relative to Full Electrification would provide valuable information on whether hybrid systems can be an affordable solution for customers. This may also include analysis of the replacement costs for new, high-efficiency natural gas heating equipment. Potentially, this can be used to inform sizing of customer rebates for hybrid systems based on a target payback period. These analyses should also be used to refine customer adoption assumptions and payback thresholds over time, enabling future planning studies to better distinguish between economic potential and realizable adoption.

- **Periodically refresh electrification adoption and system-impact modeling to reflect new data and program experience:** As hybrid heating pilots, targeted electrification programs, and demand-side management technologies are deployed, NY DPS Staff should require periodic updates to adoption forecasts and system-impact analyses to incorporate observed costs, operating behavior, and customer response. This iterative approach would reduce uncertainty over time and improve the accuracy of long-term planning.
- **Assess the capacity and reliability value of hybrid heating within resource adequacy planning:** Future analyses could evaluate the extent to which controlled hybrid heating can contribute to winter peak capacity needs, either through avoided generation capacity investments or as a complement to other demand-side resources, and how this value should be reflected in program design or compensation structures.

In the context of long-term planning, NY DPS Staff should consider the relationship between Hybrid Electrification and NPAs in light of proposals for increased gas and electric utility coordination and a shift towards “integrated” or coordinated planning. Hybrid Electrification is perhaps best thought of as a tool for a targeted non-wires alternative, just like how Full Electrification can be thought of as a targeted NPA. As discussed earlier in this report, there is a fundamental tension between Hybrid Electrification, which appears to primarily provide value in the longer-term amidst a shift to a winter-peaking system, and NPAs as a gas decommissioning strategy.

Collectively, these recommendations highlight that the role of Hybrid Electrification, and electrification more broadly, is not static but evolves as adoption scales, system conditions change, and new operational data becomes available. Realizing the potential system and customer value identified in this study will therefore require continued analytical refinement, targeted pilots, and iterative updates to planning assumptions. As New York advances toward a more electrified and increasingly winter-peaking system, ongoing, data-driven analysis will be essential to translate modeled outcomes into actionable, cost-effective policy and planning decisions.

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