16. Pathways Analysis

Draft New York State Energy Plan

July 2025

Record of Revision

Date	Revision Made
July 25, 2025	Original Posting
July 30, 2025	Added Figures A-2 and A-3 and associated descriptive text.

1. Overview

The 2025 State Energy Plan Pathways Analysis provides an analytic lens on how New York's energy system could change over the coming decades using a scenario-based approach. The analysis focuses on identifying common themes and major drivers of change. It highlights the challenges and benefits associated with reducing fossil fuel dependence, scaling clean energy technologies, and meeting growing energy demand from new large commercial and industrial loads as well as building and transportation electrification.

This analysis draws on the best available data through early 2025. Conducted by Energy and Environmental Economics, Inc. (E3), informed by input and analysis across State agencies, this work estimates stocks and sales of key energy technologies, energy demand, supply, greenhouse gas (GHG) emissions, and cost implications across multiple scenarios. The modeling integrates technical assumptions, policy trajectories, and sectoral detail, providing a foundation for evaluating tradeoffs and informing energy planning.

This chapter outlines the modeling framework, summarizes core scenarios, and presents key findings to inform decisions about energy investments and infrastructure planning in the years ahead and the discussion in other chapters of this Plan. The Annexes offer greater detail on the modeling methodology, input data, data sources, scenario assumptions, and results. Model inputs and assumptions are compiled in more detail in Annex 1, and key outputs in Annex 2.

The Pathways Analysis aggregates key input data from NYSERDA's industry studies and programs and uses a stock turnover approach to model equipment stocks over time across key energy sectors, such as buildings and transportation. This approach helps in understanding the deployment of technologies like heat pumps, electric vehicles (EVs), and efficiency measures. The Pathways Analysis produces an outlook on fuel use, electric loads and peaks, and gross and net greenhouse gas emissions by sector.

In addition, the Pathways Analysis includes an assessment of the energy supply sectors and how the energy supply across the economy changes over time to meet projected demand. This energy supply outlook captures changes in the gas system, fuel system, and electric sector. The electric sector toolkit includes capacity expansion and dispatch capability, which builds out an electric system to meet demand load shapes while maintaining reliability standards and achieving scenario-specific constraints such as specified renewable build or policy targets like a zero-emissions grid by 2040. It enables exploration of contributions from various resources, such as solar, wind, batteries, and thermal units, to the generation mix over time.

While the Plan primarily focuses on energy sectors, it also includes high-level representations of emissions from non-energy sectors like waste and agriculture, based on New York State Department of Environmental Conservation (DEC) forecasts. This comprehensive approach allows for an assessment of the impacts of non-energy sectors on economy-wide emissions limits. The toolkit also includes modules for analyzing refrigerant emissions and fugitive gas system emissions, while receiving information on air quality and health outcomes from parallel analysis.

2. Scenario Design

Given future uncertainty, the Pathways Analysis takes a scenario-based approach which allows exploration of outputs across different potential energy futures. These scenarios are briefly summarized in the table below, with more details available in Annex 1.

Table 1. Summary of scenarios

Scenario	Assumptions	Purpose
No Action	Includes Federal incentives (e.g., IRA) and legacy NY policies, but excludes the Climate Act and more recent additional State and Local climate measures. Federal incentives reflect those in place during the first quarter of 2025 when the analysis was conducted.	Counter-factual baseline to gauge relative impacts and incremental benefits and costs of State action
Current Policies	Layers on top of the No Action case current progress toward achievement of enacted State and local policies (e.g. Clean Energy Standard, building code updates, Advanced Clean Cars/Trucks)	Illustrates what existing commitments achieve under current market conditions and headwinds
Additional Action	Includes Current Policies plus ongoing progress toward adoption of clean technologies through a mix of future programs and investments aligned with recommendations in the State Energy Plan.	Core planning case for the Energy Plan, reflecting ambitious but achievable progress
Net Zero A	Accelerates adoption of clean energy technologies in all sectors toward achievement of economywide net zero by 2050, emphasizing all electric space heating	Reflects what would be needed for full achievement of the 2050 emission limit with a smaller gas network
Net Zero B	Accelerates adoption of clean energy technologies in all sectors toward achievement of economywide net zero by 2050 with greater use of supplementary gas heating systems	Reflects what would be needed for full achievement of the 2050 emission limit with a larger gas network

The first scenario is No Action. It includes historical policies, market-driven adoption, and federal programs like the Inflation Reduction Act (IRA) but excludes New York's Climate Act and other recent State and local clean energy policies. This scenario provides a baseline to assess the incremental benefits and costs of state action. While the future of federal clean energy and emissions programs remains uncertain, this analysis includes them in the Draft as of the first quarter of 2025, with plans to explore any changes to those federal programs through sensitivity analysis. The impacts of federal rollback of the IRA are not included in the modeling at this time but will be explored in the final State Energy Plan.

The second scenario, Current Policies, builds on the No Action case by incorporating progress toward achievement of enacted State policies and local actions across sectors. In the buildings sector, this includes the implementation of all-electric new construction, advanced building codes, and utility- and state-funded programs promoting energy efficiency and heat pump adoption. Examples include Clean Heat, Empower+, Direct Injection, and housing programs implemented through Housing and Community Renewal (HCR). In the transportation sector, the scenario includes progress toward meeting Advanced Clean Cars (ACC) and Advanced Clean Trucks (ACT) standards. Although future implementation of these standards carries uncertainty due to federal actions, they are included as current policy—consistent with the treatment of federal policies in the No Action case—since outcomes of legal and regulatory processes are not yet determined. In the electricity sector, this scenario assumes progress toward the Climate Act's zero-emission electricity goal by 2040 ("0x40"), consistent with near-term Clean Energy Standard (CES) Biennial Review trajectories. These trajectories account for deployment challenges and reach the 70% renewable electricity projection by 2033 in line with the CES Biennial review. Comparing this scenario to No Action helps clarify the added benefits and costs of current State and local policies. As a bottom-up assessment of the energy future under current policies, this case is one of the two main planning cases developed for the State Energy Plan.

The third scenario, Additional Action, builds on Current Policies by showing consistent and steady improvements in the adoption of clean energy technologies. This acceleration could result from new policies, investments, environmental market mechanisms, or other initiatives as described in the State Energy Plan. As a forward-looking case that assumes continuous improvement, it serves as the core planning scenario for the State Energy Plan.

The final two scenarios, Net Zero A and Net Zero B act as a point of comparison to understand what would be needed to achieve 2050 emissions targets, including 85% reductions in gross emissions and net-zero, including significant increases in electricity use and the steep declines in other fuel consumption, driven by widespread efficiency and electrification.

The key difference between the two lies in building heating technologies:

- **Net Zero A** emphasizes all-electric heating.
- **Net Zero B** assumes greater adoption of supplementary heating systems, where customers retain a gas backup for the coldest days.

Although heat pump customers with supplementary heating systems use significantly less gas in Net Zero B, managing their backup use would require careful coordination. However, this approach may reduce peak electricity demand and underscore the potential value of maintaining a larger residual gas network.

3. Energy Demand Sectors

Based on information in NYSERDA Patterns and Trends for New York State, the sectors with the most energy consumption today include buildings (50%) and transportation (40%), with industry making up much of the remainder (Figure 1). The analysis of the energy demand sectors utilizes E3 PATHWAYS model, a bottom-up, technology-rich tool that operates on a stock-turnover framework to project long-term energy consumption.

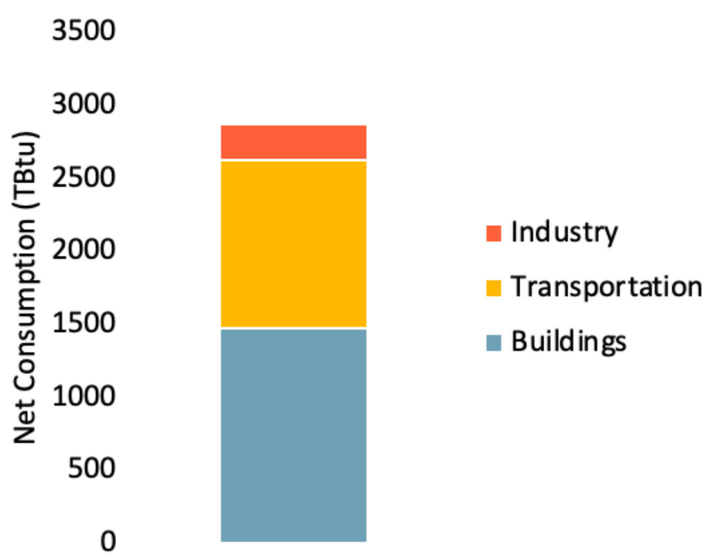

Figure 1. Energy consumption by sector in New York (2025)

3.1. Buildings

Residential and commercial buildings remain the largest energy consumers in the state, primarily due to space conditioning (heating, ventilation, and air conditioning, or HVAC) and water heating. While the state's overall population is expected to remain stable, based on projections from Cornell's Program on Applied Demographics, a shift from upstate to downstate will increase aggregate cooling loads and reduce heating demand.[1] Multiple studies conclude that climate change will increase the frequency and severity of extreme summer temperatures.[2,3] Climate trends are expected to increase summer cooling demands, and warmer winters are expected to reduce overall winter heating demands. The Pathways analysis, consistent with the NYSERDA Climate Impacts Assessment, accounts for increased summer load due to warming, but this effect remains relatively modest within the 2040 timeframe of the State Energy Plan. Further information on modeling methods is available in the Appendix.

Across all scenarios, key drivers of change include energy efficiency investments, HVAC equipment turnover and new technology adoption, and new construction with improving building codes. In the No Action case—absent State policy—heat pump and efficiency adoption continue at a moderate pace, driven by federal incentives and consumer preferences. New construction is largely natural gas, and many buildings with existing oil and electric resistance switch to gas. However, even as gas customer counts increase, replacements in kind of gas equipment lead to lower consumption due to the impact of federal appliance standards.

In contrast, the Current Policies and Additional Action scenarios feature stronger State and local policy influence. Measures such as all-electric new construction, advanced building codes, efficiency and electrification programs drive higher rates of heat pump and efficiency adoption. The projected trajectories for heat pump and efficiency sales and stock under these varying policy conditions are detailed in Figure 2 and Figure 3, respectively. Energy efficiency remains foundational, with whole home building envelope upgrades across the building stock (shell measures) outpacing heat pump adoption due to their lower cost and higher project returns. New building codes taking effect in the mid-2020s will further improve both envelope and equipment efficiency, helping reduce the increased electricity demand from electrified heating. By 2040, heat pump sales outpace the sales of gas equipment in the Additional Action scenario.

Achieving net-zero emissions economywide requires more aggressive action, as reflected in the Net Zero scenarios. These require near-universal efficiency upgrades with a focus on building shell upgrades and, due to the long service life of HVAC systems, 100% heat pump sales by 2035 to achieve the 2050 limits—a significant step beyond current policy trajectories.

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[1] Statewide projections show relatively flat to declining population statewide https://pad.human.cornell.edu/state_projections/datatools.cfm. Accessed June 2025

[2] NYISO, Climate Change Impact Study, Phase 1: Long-Term Load Impact, December 2019, available at: https://www.nyiso.com/documents/20142/10773574/NYISO-Climate-Impact-Study-Phase1-Report.pdf

[3] NYSERDA, Impacts of Climate Change on the New York Energy System, December 2023, available at: https://www.nyserda.ny.gov/About/Publications/Energy-Analysis-Reports-and-Studies/Greenhouse-Gas-Emissions

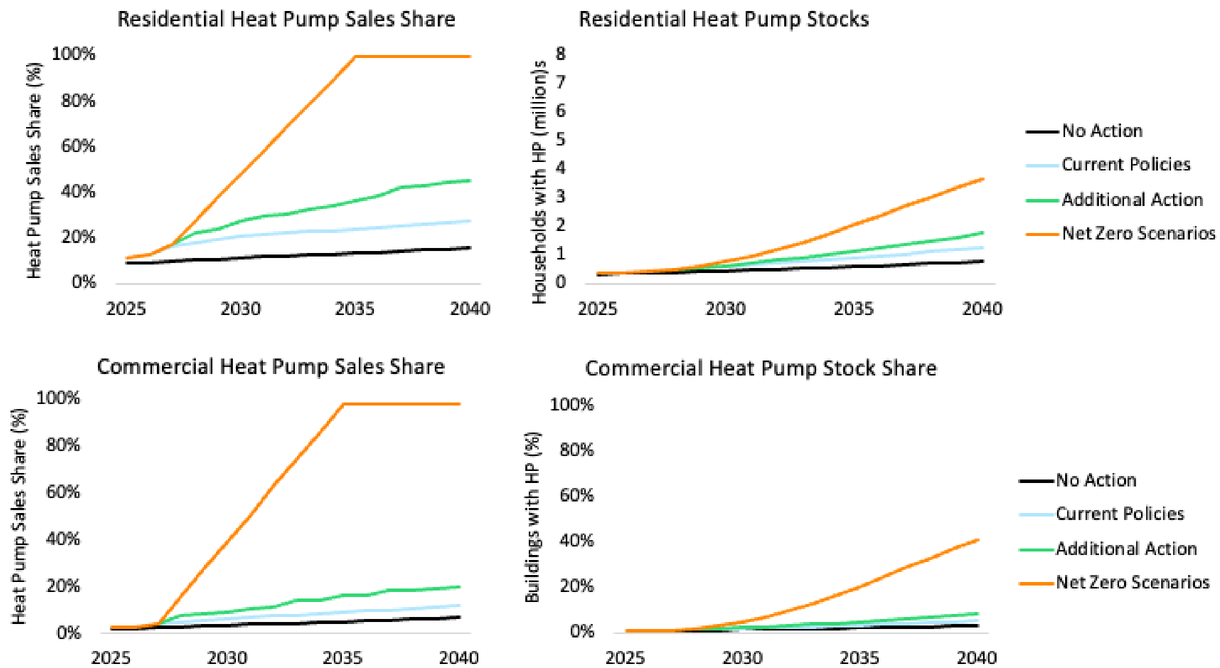

Figure 2. Residential and commercial heat pump sales and stock trajectory

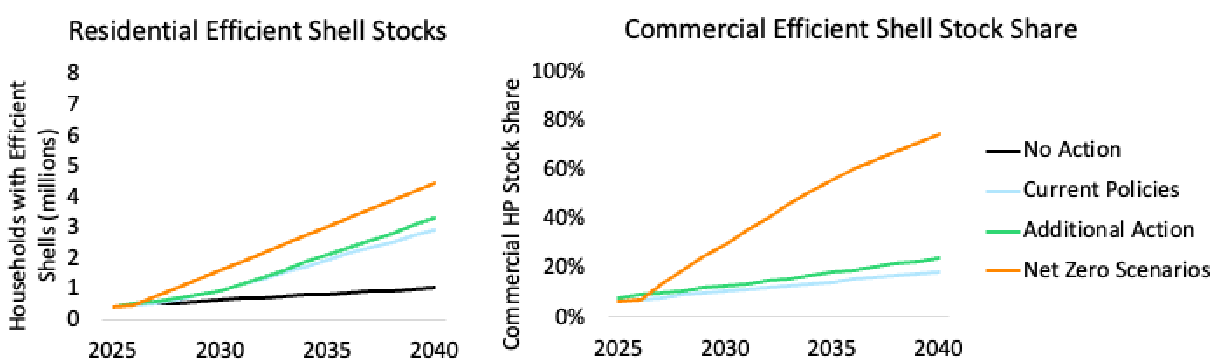

Figure 3. Residential and commercial efficient building shells stock trajectory

Heat pump adoption varies substantially by scenario. In all cases, cold-climate air source heat pumps (ASHPs) dominate, with a notable role for ground source heat pumps (GSHPs). Most heat pumps sold in the state are already cold-climate models, so all ASHPs discussed in this analysis are cold-climate.[4] ASHPs are more efficient than electric resistance heating but lose efficiency during the coldest periods, increasing peak electricity demand although still less than resistance-only systems. Heat pumps with supplementary heating backup rely on combustion or thermal systems to provide heat during the coldest periods. GSHPs, by contrast, maintain efficiency even in extreme cold with minimal performance loss and in this analysis also serve as a proxy for thermal networks. To represent potential for a lower range of electric peak system impacts in the more highly electrified Net Zero scenarios, Net Zero

[4] Cold-climate heat pumps must meet stringent criteria set by the Northeast Energy Efficiency Partnerships, ensuring the unit can operate efficiently and reliably even when outside temperatures drop significantly.

Scenario B includes a larger share of ASHPs with fuel backup than Net Zero Scenario A. For reference, the total number of households in New York is roughly 7.3 million.

Table 2. Summary of residential heat pump and efficient shell retrofits

Scenario	2040 heat pump share of annual sales	2040 heat pump stock	2040 efficient shell stock
No Action	15%	760 thousand	1 million
Current Policies	27%	1.2 million	2.9 million
Additional Action	45%	1.7 million	3.3 million
Net Zero A/B	100% (by 2035)	3.6 million	4.5 million

Table 3. Residential household heating stocks, 2040

Device	No Action	Current Policies	Additional Action	Net Zero A	Net Zero B
Heat Pumps	0.76	1.26	1.76	3.66	3.66
ASHP	*0.61*	*0.96*	*1.30*	*2.54*	*2.17*
ASHP with supplemental heating system	*0.03*	*0.06*	*0.09*	*0.31*	*0.68*
GSHP	*0.13*	*0.25*	*0.37*	*0.81*	*0.81*
Electric	0.57	0.57	0.54	0.40	0.40
Gas	4.81	4.33	3.87	2.46	2.46
Other	1.15	1.14	1.13	0.78	0.78

Another important lever for decarbonizing the buildings sector is renewable fuel blending. All scenarios include current state policy of at least 20% biodiesel blending (B20) for heating fuels by 2030. The Additional Action case layers in a targeted role for renewable natural gas at a blending of 20 TBtu, or 3% of building pipeline gas use, by 2040, while the Net Zero cases build upon this to hit a blending of 100 TBtu, or 33% of building pipeline gas use, by 2040. Blending at rates up to 33% is only achievable in the Net Zero cases alongside significant reductions in gas throughput from increased efficiency and electrification.

3.2. Transportation

The transportation sector consumes the second most energy in the state, behind buildings. Most of this energy use comes from fuel consumption in light-, medium-, and heavy-duty vehicles, with the remaining transportation sector energy consumption coming from non-road vehicles such as airplanes, trains, and boats. More detail on methods is available in the Appendix.

Across all scenarios, many fundamental drivers of transportation demand remain consistent. Fleet size per capita in each region stays flat, while aviation demand continues to grow. The downstate migration of households relocates on-road transportation energy demand, especially for the light duty vehicle fleet, towards the downstate zones and reduces vehicle population over time as there are fewer vehicles per capita downstate.

The major driver of change between the scenarios is the accelerating shift towards zero emission vehicles (ZEV) across vehicle segments, a shift which is already underway. Electric vehicles are the most common ZEV, but there is also a targeted role for hydrogen fuel cell vehicles, especially in the heavier duty truck segment. The No Action case sees some adoption of electric vehicles driven by federal incentives and organic market adoption (Figure 4).

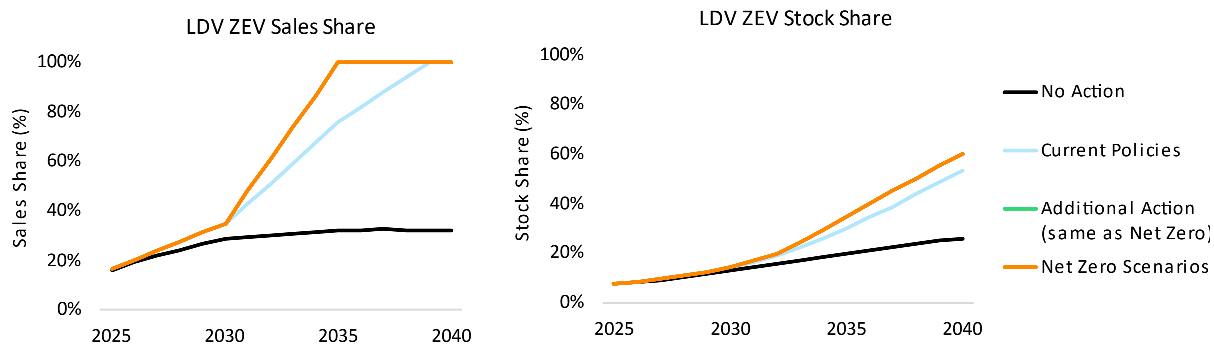

Figure 4. Light Duty Vehicle Zero Emission Vehicle (ZEV) sales and stock shares

The Current Policies case sees significant additional electrification across vehicle segments driven by ACC II and ACT.[5,6] While federal action could impact the future of these programs, they are still included in the policy cases given uncertain outcomes. Different trajectories towards achievement are assumed across the cases, reflecting uncertainty on current and near-term progress towards achieving the ACC II and ACT policy targets. Further uncertainty from federal impacts to these programs will be explored in the final State Energy Plan. Specifically, Current Policies assumes a 4-year delay in achievement based on a comparison of current progress toward deployment relative to deployment pace seen in California. The Additional Action case assumes that the gap is consistent through 2030, but acceleration post-2030 results in achievement of both the ACC target by 2035 and ACT target by 2045.

The Net Zero cases further accelerate the pace of adoption, especially in the medium and heavy-duty vehicle fleet where these sectors achieve 100% ZEV sales shares by 2040 (Figure 5). In these heavier vehicle classes, where battery-electric solutions face greater challenges for long-haul and heavy-load duty cycles, hydrogen fuel cell vehicles are expected to constitute a more substantial share of new ZEV sales. The gap between the impacts of current policies and the Net Zero cases are narrower than what was seen in buildings, especially through the 2040 planning horizon, reflecting the ambition of existing policies.

[5] Advanced Clean Cars II was enacted by NYSDEC as 6 NYCRR Part 218, available at: https://extapps.dec.ny.gov/docs/air_pdf/218acc2.pdf

[6] Advanced Clean Trucks was enacted by NYSDEC as 6 NYCRR 218, available at: https://dec.ny.gov/sites/default/files/2024-01/218act.pdf

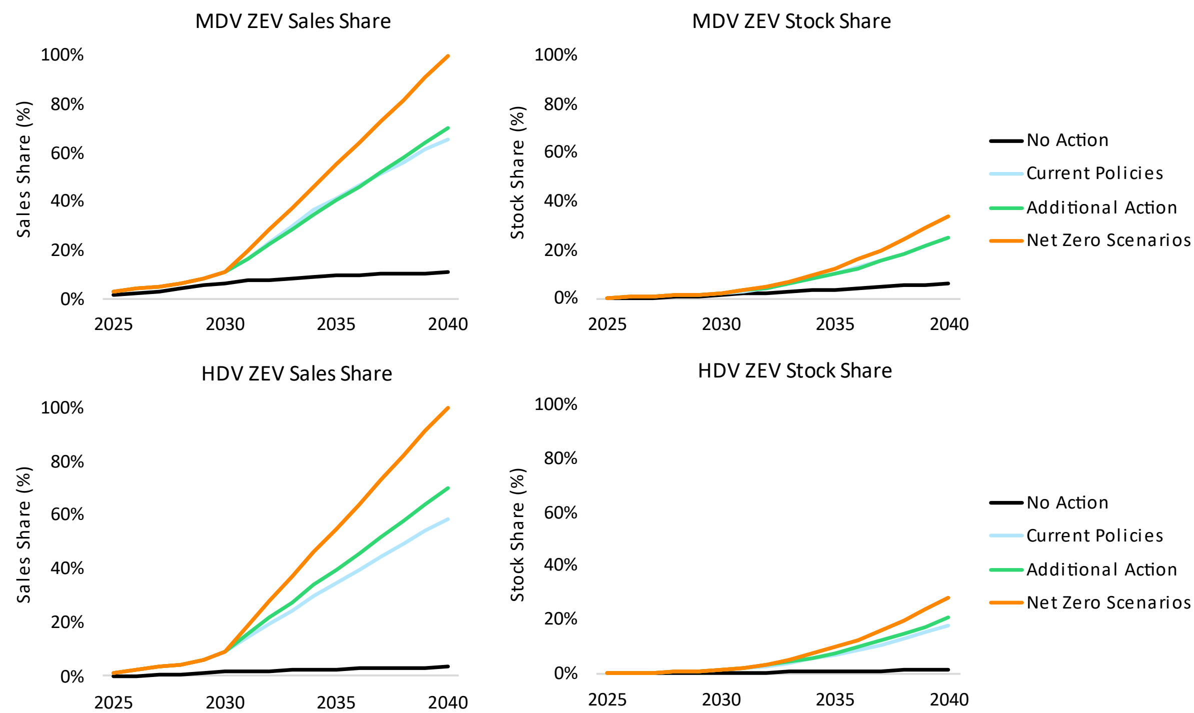

Figure 5. Medium and Heavy-duty vehicle ZEV sales and stock shares

Another important lever for decarbonizing the transportation sector is renewable fuel blending. The Additional Action case layers in renewable fuel blending at a scale of 20% renewable distillate and 35% sustainable aviation fuel by 2040, while the Net Zero cases build upon this to hit 33% renewable distillate and hit the same 35% sustainable aviation fuel target by 2040; due to the significant growth in ZEVs, the share of total transportation energy demand met by electricity and hydrogen grows to 16% by 2040 in the Additional Action case, and reaches 29% in the Net Zero cases (Figure 6).

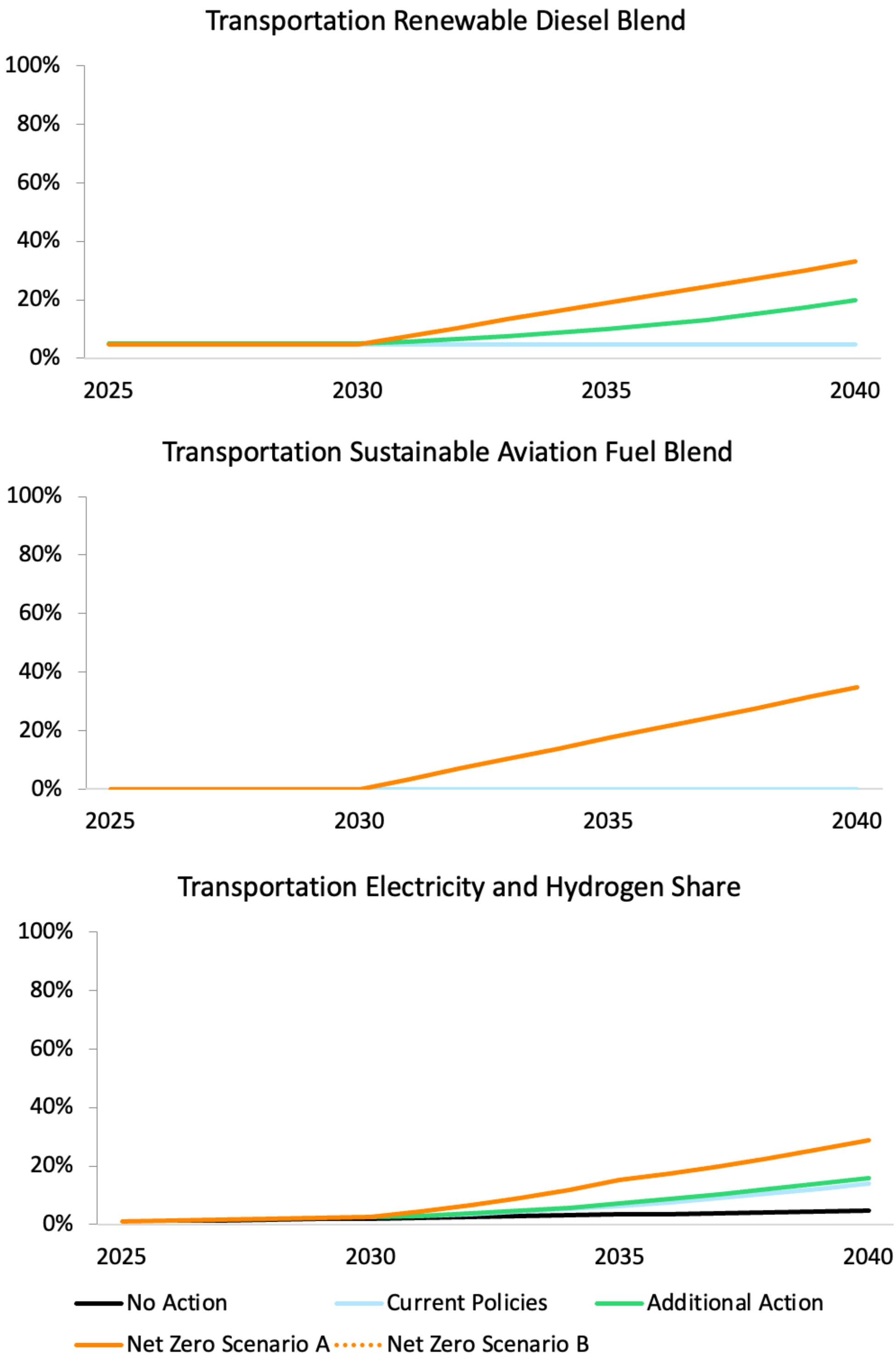

Figure 6. Transportation low carbon fuel blends

3.3. Industry

Industry currently accounts for 10 percent of statewide energy use but accounts for a disproportionate share of expected new load growth: several large manufacturing and data-center projects entering service this coming decade add roughly 16 TWh of electricity demand, which is over 75% of total industrial electricity demand today.[7] Planning for this new energy use is key to ensuring continued opportunities for economic growth in the state.

On top of these discrete large loads, all scenarios see further growth based on the Energy Information Administration (EIA) Annual Energy Outlook (AEO).[8] Industrial actors are often seeking process improvement opportunities, and some amount of efficiency is assumed to be baked into energy trends adopted from AEO to inform No Action and Current Policies.

The Additional Action scenario introduces more cost-effective energy efficiency as identified in the State's Industrial Potential Study while the Net Zero cases layer on more energy efficiency and fuel switching to electricity, hydrogen, and renewable fuels (Figure 7).

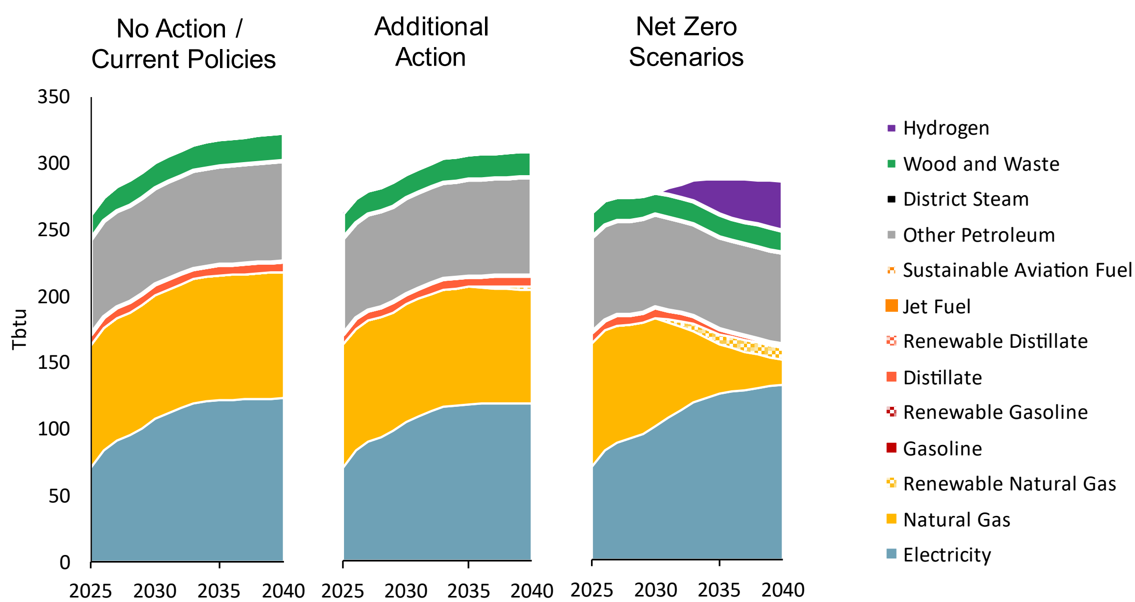

Figure 7. Annual industrial energy demand across scenarios

Note: Industrial activity grows consistently across all scenarios.

[7] NYISO 2025 Load and Capacity Data ("Gold Book"): https://www.nyiso.com/documents/20142/2226333/2025-Gold-Book-Public.pdf/088438e1-02f1-5316-211b-dbca17c01b4b

[8] EIA Annual Energy Outlook: https://www.eia.gov/outlooks/aeo/

4. Energy Supply Sectors

4.1. Gas

New York's natural gas system is a critical energy-delivery asset that requires continued investment to ensure safe and reliable service. When planning for system reliability, utilities distinguish between firm customers, who are guaranteed an uninterrupted supply for essential needs like heating, and interruptible customers, who agree to have their service curtailed during periods of system stress in exchange for lower rates. Firm customers are predominantly residential and commercial users. Their demand defines the system's peak capacity requirements. Interruptible customers, by contrast, are typically large industrial facilities, power plants, or manufacturers that can switch to a backup fuel like oil or propane on short notice. The number of residential and commercial customers serves as an important indicator of the system's core service obligations.

As seen in Figure 8, in the No Action case, absent new state and local policies, the number of firm residential customers is projected to grow due to new construction and conversions from oil or electric-resistance heating. By contrast, the Current Policies and Additional Action scenarios show that well-executed all-electric new construction and electrification programs could check this near-term growth. The most pronounced contraction occurs in the Net Zero scenarios, driven by the acceleration of building electrification. In Net Zero B, which anticipates a larger remaining gas network as many heat pump customers retain a supplementary gas backup, each customer would need to use substantially less gas to stay within the economywide emissions caps.

A comparison to utility forecasts reveals significant regional uncertainty. The most conservative, highest throughput cases from individual utility long-term plans (LTPs, as of the first quarter of 2025) collectively suggest a flat statewide gas customer count, roughly aligned with the projections in the Current Policies case. However, this topline number masks wide regional divergences, with some utilities forecasting customer gains while others project declines. Notably, when more ambitious cases from the utility LTPs are considered, they show declines in both customer counts and gas throughput that are similar to the policy scenarios modeled in the Pathways Analysis. Even with a potential statewide leveling-off of customer numbers, regional demand shifts, peak day needs, and the enduring need for firm supply may necessitate targeted infrastructure investments to maintain service reliability.

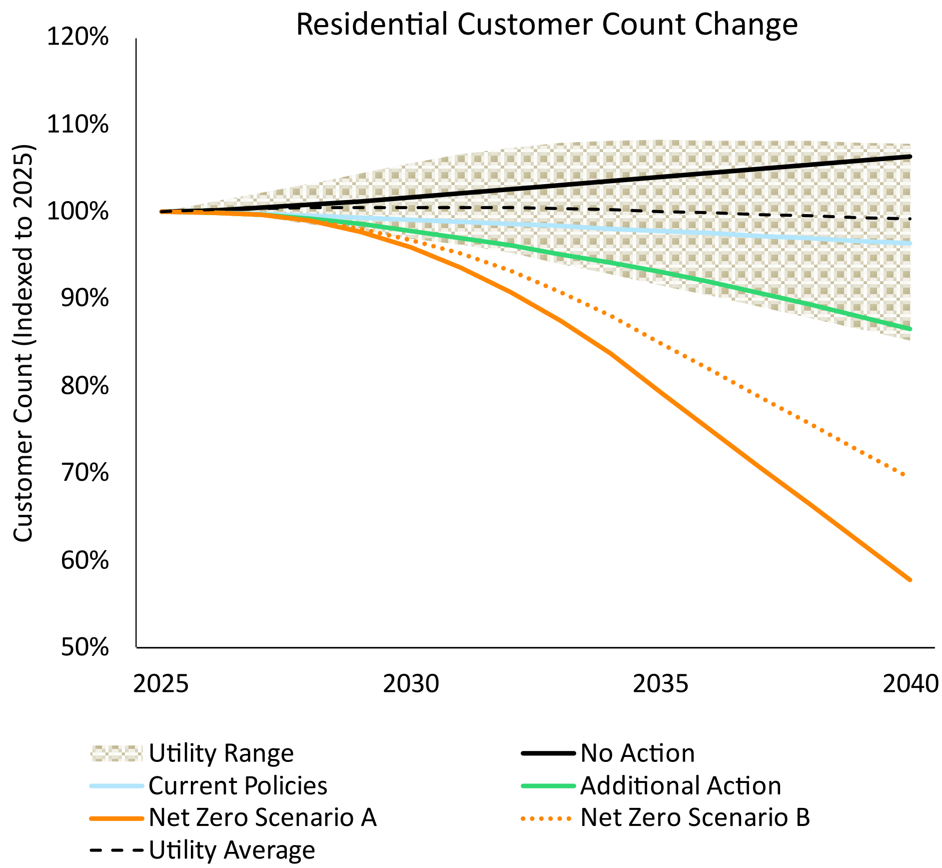

Figure 8. Residential gas customer count [9]

Just as there is uncertainty in the amount of firm gas customers, there is a range in the amount of buildings gas consumption that occurs in these scenarios. In combination, as seen in Figure 9, statewide Residential and Commercial gas consumption declines across all scenarios modeled for the State Energy Plan due to improved energy efficiency and electrification. By 2040, gas throughput to buildings in the Current Policies and Additional Action scenarios falls 14-19 percent below 2025. Electric sector modeling suggests an additional 360-450 TBtu of potential reductions from non-firm electric customers in Additional Action, but while this will lead to meaningful carbon benefits, it may not have a significant impact on system infrastructure needs as these customers typically have interruptible service, and gas distribution networks are more strongly indexed to firm customer counts. The Net Zero cases see transformational consumption declines with accelerated building electrification and shell adoption. Comparison to utility LTP forecasts suggest a range of potential consumption scenarios. As with the gas customer counts, there is regional variability in the gas throughput change seen in the most conservative cases in utility LTPs, as highlighted in Figure 9, below.

[9] Utility range reflects aggregate residential and commercial data due to lack of disaggregated data across all utilities

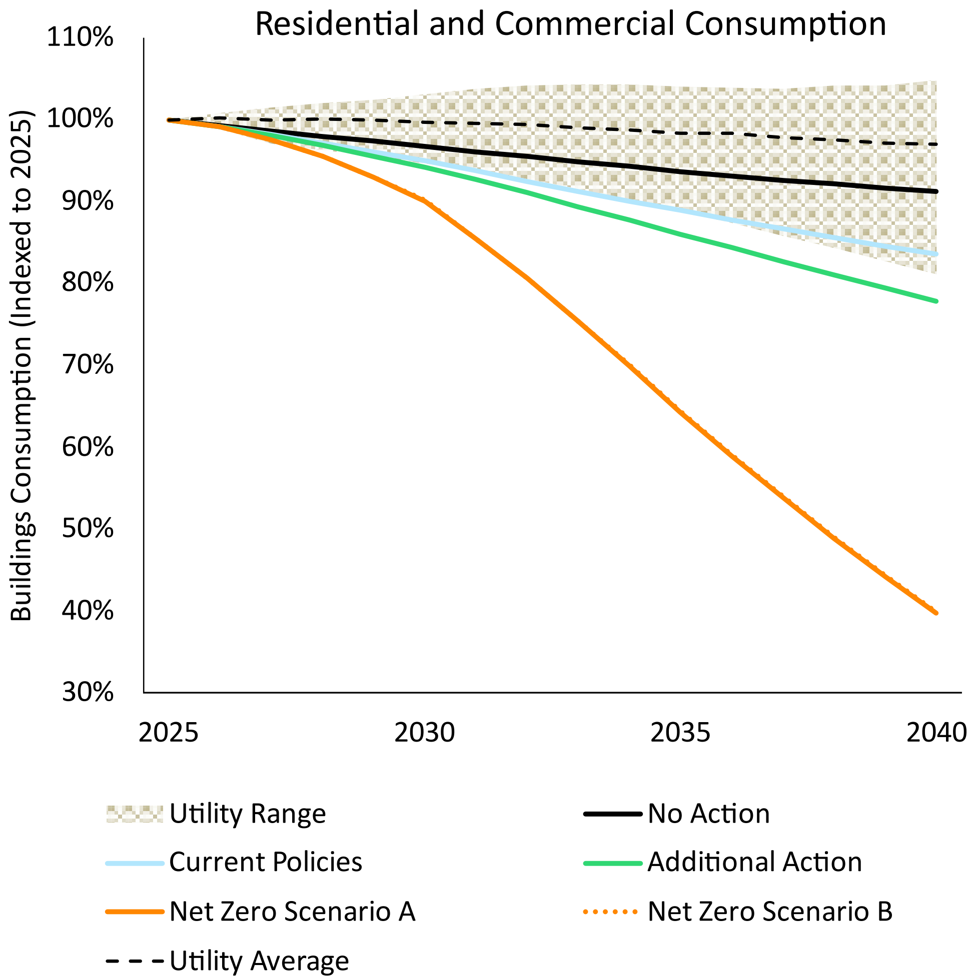

Figure 9. Buildings gas throughput

Renewable Natural Gas (RNG) blending can be another mechanism for decarbonizing the gas system, reaching 110 TBtu in the Net Zero cases by 2040. Due to the Climate Act treatment of biogenic consumption, RNG consumption still produces GHG emissions under the gross emissions target. This means RNG blending alone, without significant reductions in pipeline throughput, would not be a feasible pathway to achieving long term Climate Act emissions targets.

Methane leakage, counted on a 20-year global-warming-potential basis, magnifies the gas system's climate impact. State action can play a significant role in mitigating these emissions. Under the No Action baseline scenario, methane system leakage is forecast to decline slightly, from roughly 14 million metric tons in 2024 to 12 million metric tons in 2040, due to federal policies such as the IRA methane emissions reductions program and the U.S. Environmental Protection Agency (EPA) methane regulations. In the various policy scenarios this decline is accelerated due to the impacts of a reduced gas system size and state actions to reduce leakage, including the impacts of NYSDEC Part 203 on upstream and midstream gas, New York State Public Service Commission (PSC) leak-prone pipe replacement programs, and utility voluntary commitments; all of these scenarios achieve significant emissions reductions of 65% relative to 2024 levels by 2030 and ranging from 85-90% reductions by 2040.

4.2. Electricity

The electric supply analysis relies on an optimization modeling framework designed to identify the most cost-effective generation portfolios to reliably meet growing electricity demand and policy considerations.

4.2.1. Load and Peak

After decades of relatively flat electricity demand, New York's electricity sector is entering a new era of significant growth (Figure 10). Driven by increases in large commercial and industrial loads coupled with the electrification of transportation, buildings, and industry, all future scenarios point towards a substantial increase in electricity consumption and the need for a corresponding expansion of the electric system.

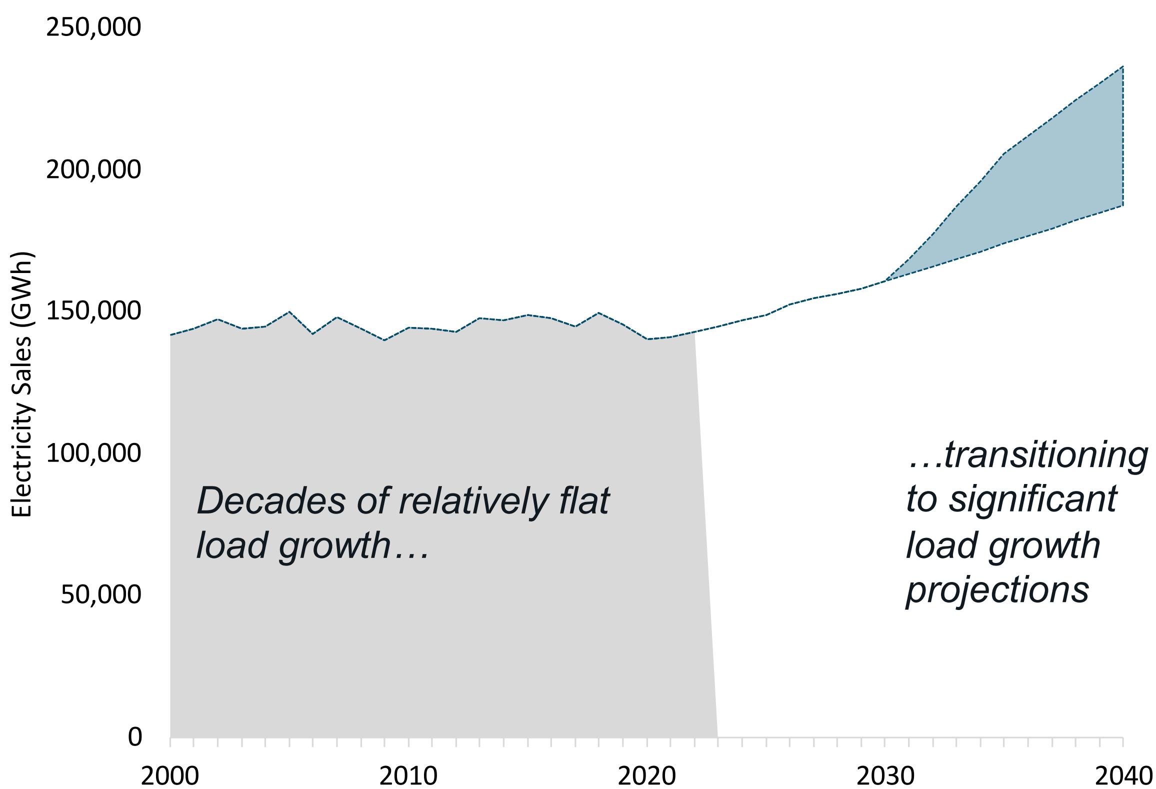

Figure 10. Historical New York State load growth[10]

All scenarios project significant load growth. By 2030, electricity demand is expected to increase by approximately 12-14 TWh from 2025 levels, reaching a total of 172-174 TWh. This initial increase is largely driven by new commercial and industrial projects, as forecast in the New York Independent System Operator (NYISO) 2025 Gold Book's "Large Loads" projections, as well as the initial wave of EV adoption.

Beyond 2030, the scenarios diverge more significantly:

[10] Data for historical load from EIA State Energy Data System: http://eia.gov/state/seds/seds-data-complete.php?sid=NY

- The **No Action** scenario sees demand reaching 181 TWh by 2040, driven by continued EV adoption and additional large industrial loads.
- The **Current Policies** scenario projects 197 TWh by 2040, with more aggressive vehicle electrification. Growth from residential and commercial customers switching to heat pumps is largely offset by concurrent gains in building shell efficiency across the entire stock.
- The **Additional Action** scenario anticipates 202 TWh by 2040. As in the Current Policies scenario, growth from residential and commercial customers switching to heat pumps is largely offset by concurrent gains in building efficiency across the entire stock.
- The **Net Zero** scenarios show the highest demand, with both reaching 255 TWh by 2040 due to the comprehensive electrification of buildings and industry.

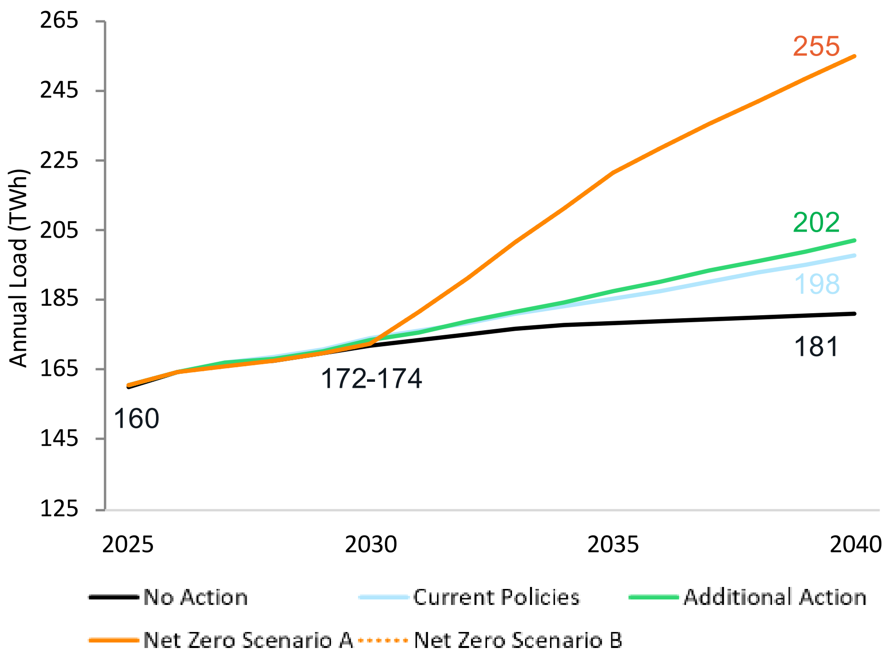

Figure 11. Annual load forecast (without electrolysis demands)

Median peak demand also varies with similar drivers as annual loads. By 2040, the No Action scenario projects a median peak of 35 GW. Both Current Policies and Additional Action scenarios forecast median peaks around 37 GW. Large loads and vehicle electrification are major contributors to peak growth, with building shell efficiency across the entire stock largely offsetting heat pump contributions to peak. Net Zero Scenario A shows a significantly higher peak at 44 GW, while Net Zero Scenario B projects 41 GW, with 3 GW reduction achieved from customers with supplemental heat backup who can switch to gas on the coldest days.

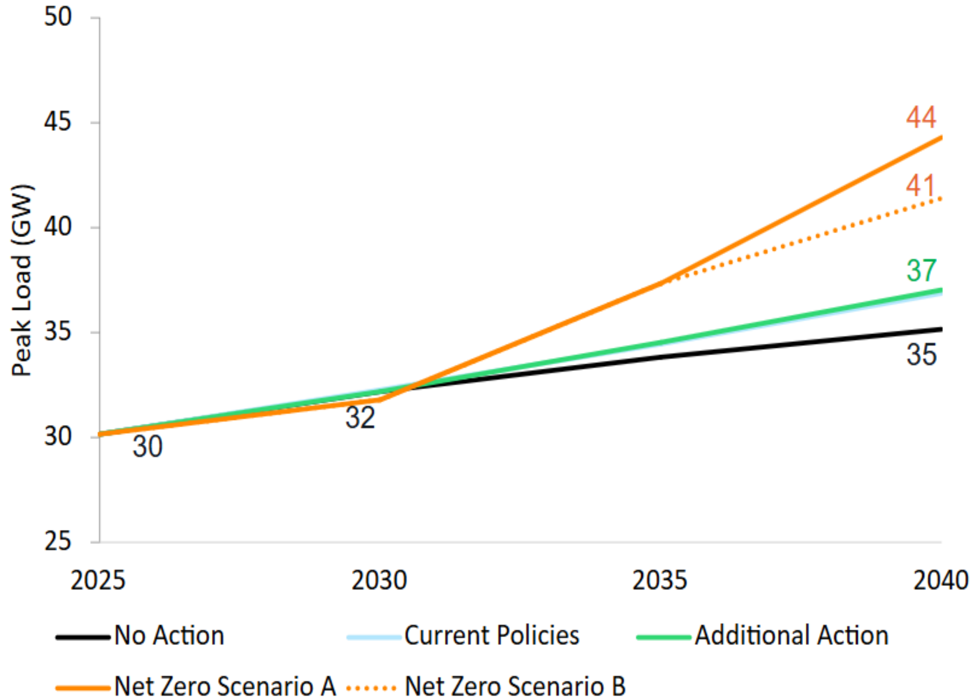

Figure 12. Annual peak load forecast (without flexible load impacts)

The timing of system peak is critical for electric system planning. No Action, Current Policies, and Additional Action remain summer-peaking through 2040. However, the gap between summer and winter peaks declines meaningfully in the policy cases which may necessitate a review of the potential risk of non-firm generators that do not have oil backup. Net Zero Scenario A, with its high degree of building electrification, demonstrates a clear shift to being winter-peaking by 2040, with a median winter peak of 44 GW compared to a summer peak of 41 GW. Net Zero Scenario B, with a 2040 winter peak of 41 GW and a summer peak also of 41 GW, is a dual peaking system, where both seasons' peaks could conceivably occur depending on the weather and must be carefully planned for.

Table 4. Peak demand projections by scenario, 2030 and 2040: annual peak bolded

Seasonal Peak (GW)	2030		2040	
	Winter	Summer	Winter	Summer
No Action	23	**32**	24	**35**
Current Policies	24	**32**	30	**37**
Additional Action	24	**32**	32	**37***
Net Zero A	25	**32**	**44**	41
Net Zero B	24	**32**	**41**	**41**

Note: *Additional Action remains summer peaking through 2040, but by mid-century the winter peak continues to grow faster than the summer peak and this scenario becomes dual peaking.

All state policy cases (Current Policies, Additional Action, and Net Zero) include flexible buildings and vehicle loads. The Current Policies and Additional Action cases assume that, by 2040, up to 20% of light duty vehicles and 10% of water heaters have some capacity to shift their charging behavior to avoid system peak impacts. Under the Net Zero cases this penetration of flexibility increases to 40% of light duty vehicles, 30% of water heaters, and 30% of space heaters.[11] These demand-side resources provide similar hourly and sub-hourly balancing services to the system as battery storage, supporting the integration of renewable energy by shifting demand to better align with times of high renewable output.

4.2.2. Electricity Supply Resource Mix

The analysis identifies portfolios of resources and infrastructure investments across the scenarios that meet projected loads and peaks at lowest cost, subject to reliability constraints and compliance with specified policy requirements applicable under each scenario.

Renewable electricity capacity grows in every pathway analyzed, but the magnitude and composition of the resource builds varies greatly. In Current Policies, Additional Action, and the Net Zero Cases, headwinds affecting the pace of builds are anticipated to delay the target of 70% renewable electricity by 2030 (70x30), consistent with the findings for the CES Biennial Review. By 2040, the divergence in resource mix across scenarios becomes even more pronounced.

No Action Scenario

This scenario, which excludes the Climate Act and more recent New York State clean energy policies, such as 0x40 and firm resource requirements, and reflects only modest adoption of clean energy technologies, projects a substantial increase in natural gas-fired capacity and generation through 2040. By 2040, a net increase of approximately 1.5 GW statewide in combustion capacity relative to current levels is anticipated, with most additions occurring upstate and some in Zone J. As existing units retire when they reach an age threshold of 60 years, total new combustion-based capacity (including replacements for retiring units) reaches about 13 GW. These fossil fuel-fired units provide an additional 30 TWh of generation in 2040 compared to current levels. This increased reliance on natural gas is driven by overall load growth, nuclear retirements, the assumed absence of power imports via the Champlain Hudson Power Express (CHPE), and a lack of policy drivers for alternative resource additions. Wind and solar capacity in the No Action scenario reaches 13 GW in total by 2040, with about 10.5 GW sourced from existing and near-term contracted additions. Only 2.5 GW of utility solar and 4 GW of battery storage are economically selected absent State policies. Without any policy support for low-carbon energy, it is assumed that all nuclear facilities retire at the end of their 60-year licenses, which expire between 2029 and 2046. Summarized capacity and generation results for the No Action scenario are included in Figure 13 and Figure 15 below, while incremental capacity addition and retirements are included in Figure 14.

[11] These flexibility penetrations are in line with the ranges seen in the Grid of the Future study.

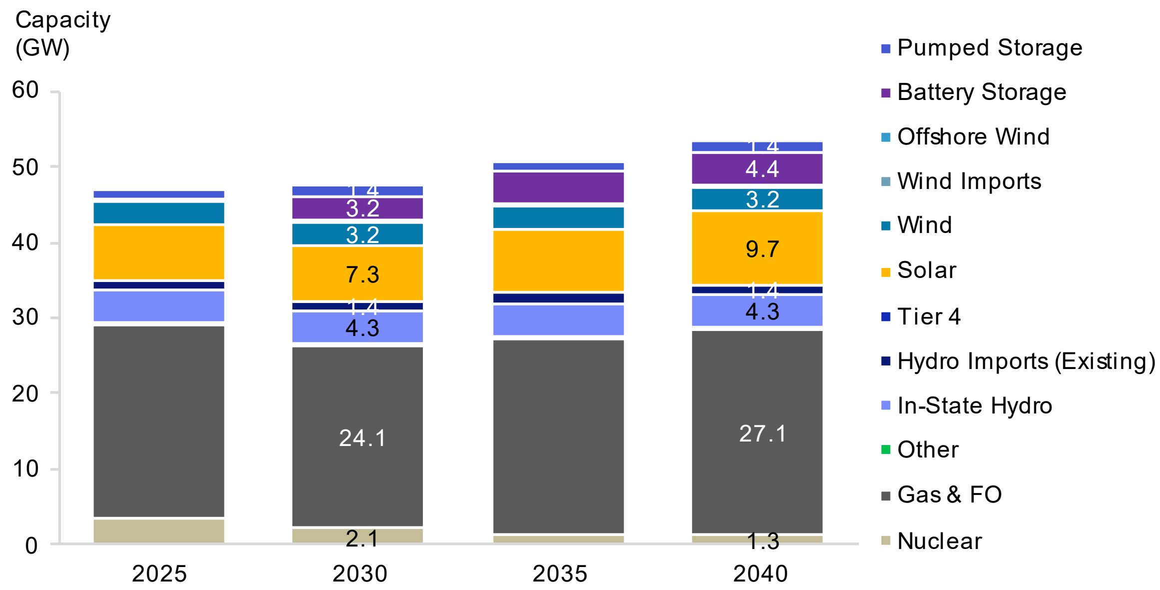

Figure 13. No Action Total Installed Capacity

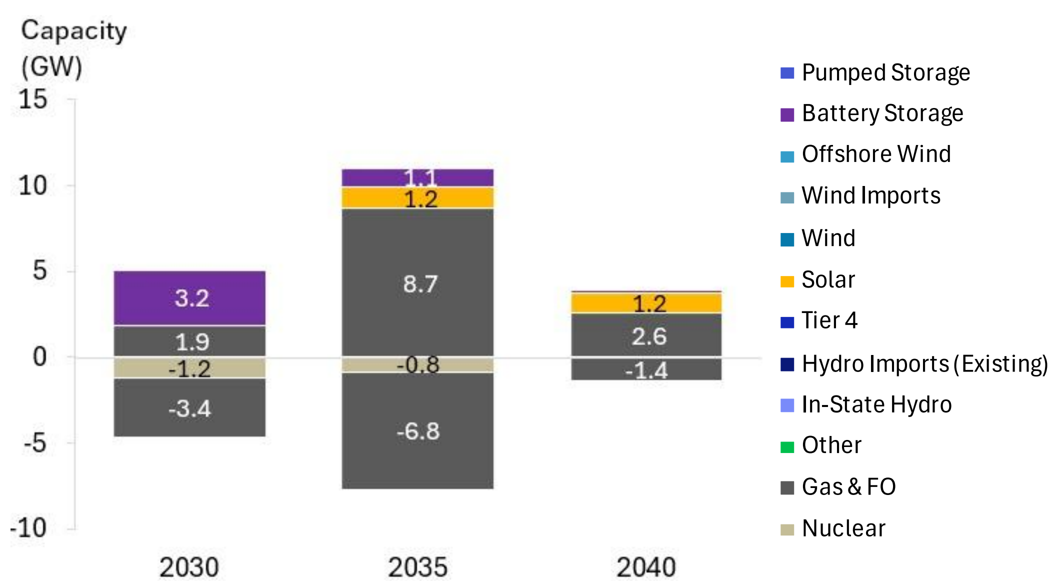

Figure 14. No Action Incremental Capacity Additions and Retirements

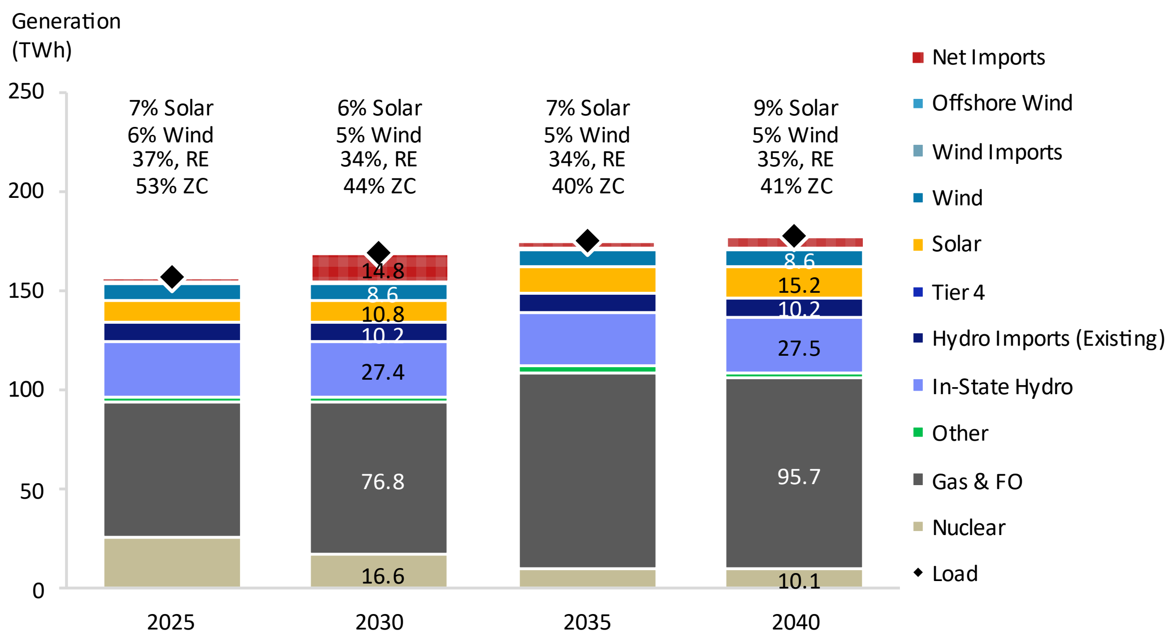

Figure 15. No Action Generation

Current Policies Scenario

Relative to the No Action scenario, this scenario has greater load and peak growth driven by State actions, including policies influencing vehicle electrification. Electric sector policies are also included. It assumes the achievement of 70% renewable electricity by 2033 in line with the CES Biennial Review and a zero-emission electricity sector by 2040 (0x40 Emissions target), as well as interim resource targets, such as 9 GW offshore wind by 2035.

Relative to the No Action scenario, the Current Policies scenario adds an incremental 5 GW of land-based wind and 8.8 GW of offshore wind (the latter driven by the 9 GW by 2035 target), alongside 25 GW of incremental solar capacity and 5 GW of battery storage toward achievement of 0x40.[12] While the renewable fraction in 2030 is below the 70% target, planned additions from future RFPs for land-based and offshore resources would meet the CES Biennial Review projection of 70% by 2033. To achieve the zero emissions 2040 target, 16 GW of zero-carbon firm resources, primarily existing gas CCGTs and CTs, are converted to run on hydrogen by 2040 to provide reliability. The total combustion capacity in 2040 is approximately 9.5 GW lower than at the start of the modeling period, with all NYISO zones having comparable or lower combustion capacity than today even as peak demand grows, reflecting the value of new resources like CHPE and storage that can provide contributions to reliability. For instance, by 2040, NYISO A-E is projected to have 3.6 GW of combustion capacity, NYISO J 5.3 GW, and NYISO K 2.5 GW. Between 2036 and 2040, in addition to converting existing thermal generation assets to be able to combust hydrogen, an additional 3.4 GW of hydrogen-ready thermal generation must be built to meet reliability needs. Statewide installed capacity and capacity changes by period for the Current Policies

[12] Across scenarios, deployment of solar and battery energy storage includes both distributed and utility-scale projects.

scenario are included in Figure 16 and Figure 18, below, while incremental capacity addition and retirements are included in Figure 17.

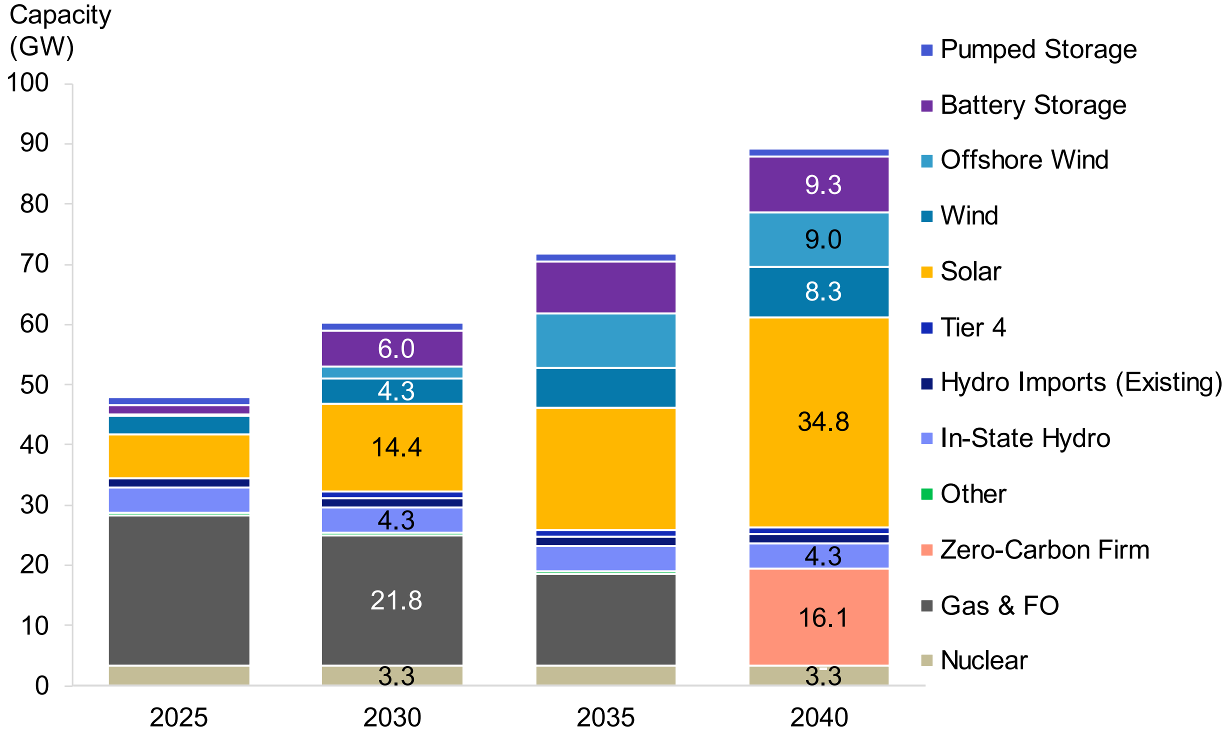

Figure 16. Current Policies, Total Installed Capacity

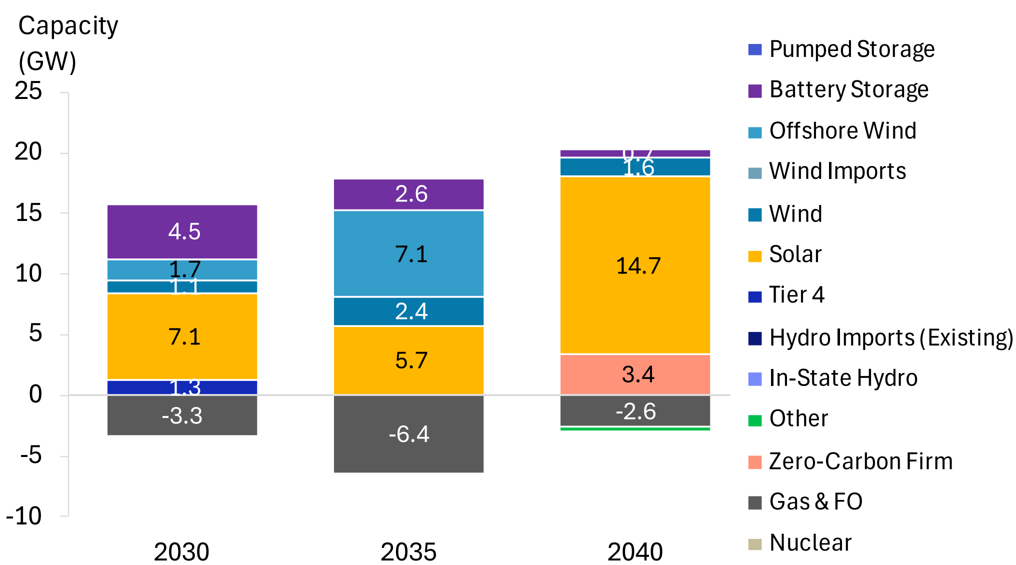

Figure 17. Current Policies, Incremental Capacity Additions and Retirements by Period

Hydrogen-based combustion resources are just one of many emerging technologies that could provide firm dispatchable power to support achievement of a zero-emissions electricity system. Consistent with past analysis practices, green hydrogen is used in this modeling as a proxy resource.[13] Due to the high costs of hydrogen, those units are rarely dispatched except during the most challenging reliability periods, providing 330 GWh of power.

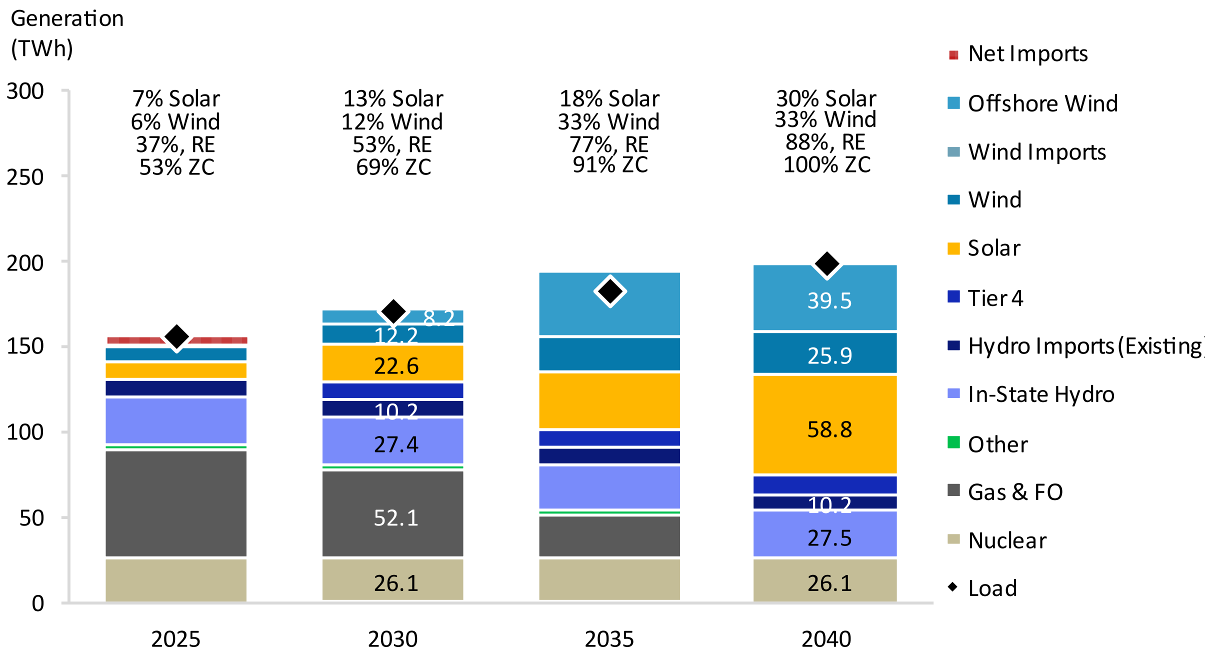

Figure 18. Current Policies, Annual Generation

The model also selects 1.1 GW of incremental transmission between Zone I and Zone J to alleviate congestion in the downstate region; however, additional modeling tools are needed to fully assess the value of transmission additions.

Additional Action Scenario

Annual and peak load growth is higher as a result of additional policy actions relative to the Current Policies scenario, but the electricity generation mix to meet higher demand is broadly similar to the Current Policies scenario. An additional 700 MW of land-based wind and 350 MW of hydroelectric upgrades are selected relative to current policies to meet slightly larger peaks and loads. Total capacity and capacity changes by period are summarized in Figure 19 and Figure 21 below, while incremental capacity addition and retirements are included in Figure 20.

[13] The color of hydrogen refers to its production method. Green hydrogen is produced through electrolysis powered by renewable energy, making it a zero-carbon fuel.

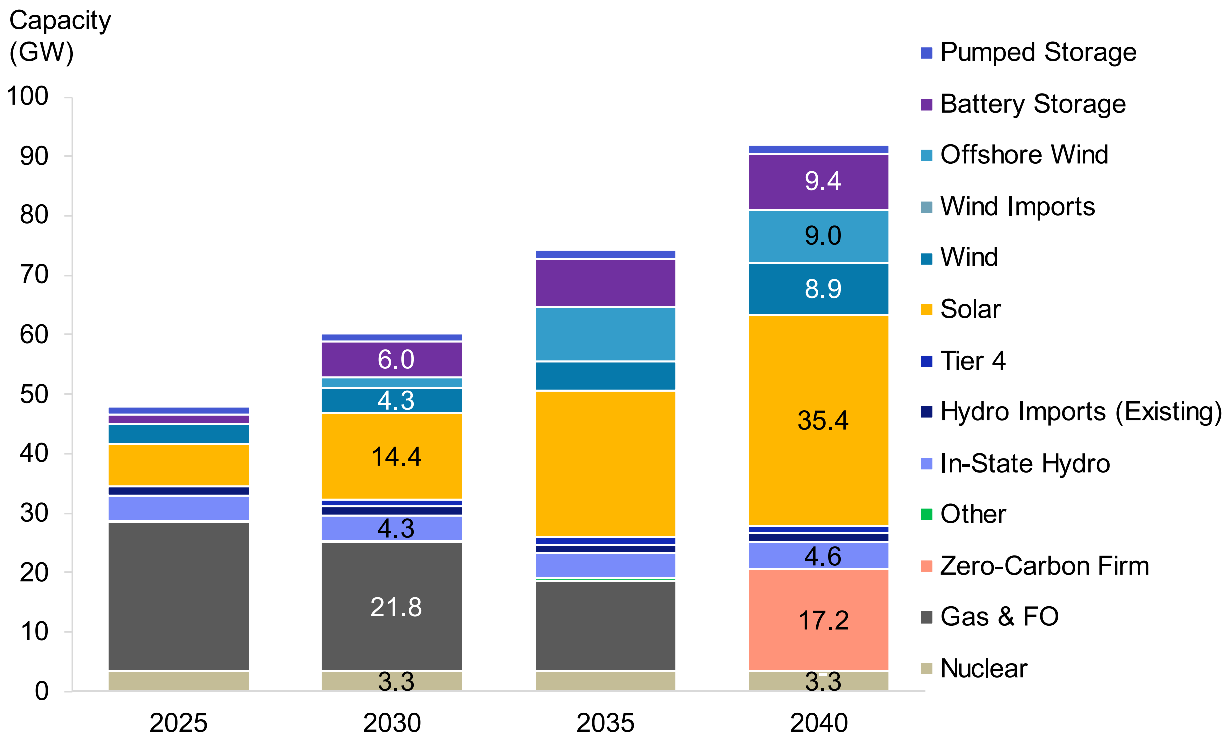

Figure 19. Additional Action, Total Installed Capacity

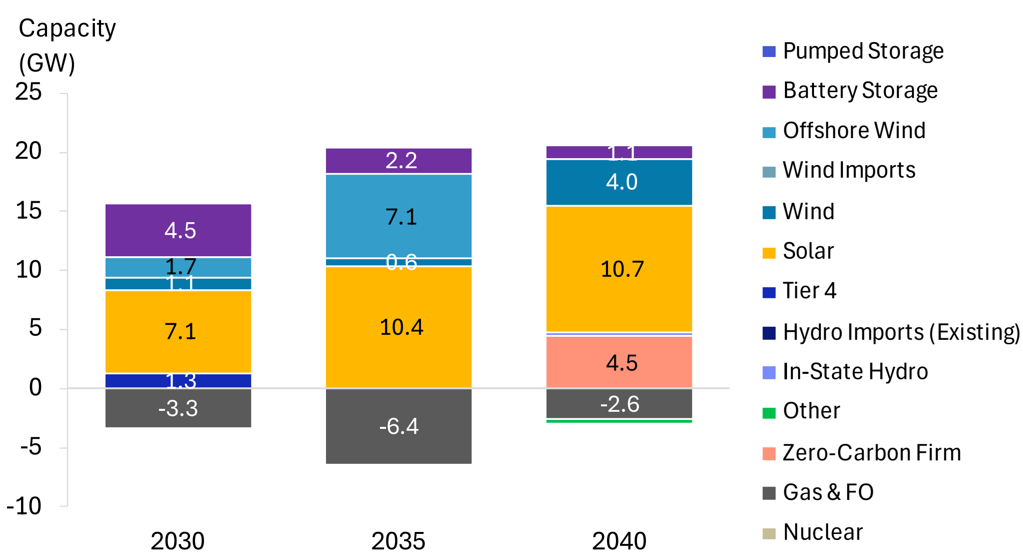

Figure 20. Additional Action, Incremental Capacity Additions and Retirements by Period

Combustion resource builds by 2040 are very similar to those in the Current Policies scenario, resulting in a total combustion fleet that is significantly lower than today. Of the 17 GW of statewide capacity, Zones A-E are projected to have 3.2 GW of combustion capacity, Zone F has 3 GW, Zones G-I have 1.7 GW, Zone J has 5.3 GW, and Zone K has 2.5 GW by 2040. However, beginning in 2036 or quickly thereafter, 4.5 GW of additional hydrogen-ready thermal generation must be built on top of conversions of existing gas generation units to hydrogen-ready facilities. Transmission additions are also similar to Current Policies, with a +1.1 GW upgrade from Zone I to Zone J selected. Similar to Current Policies, these combustion resources are dispatched infrequently to meet needs in the most constrained hours; these resources provide 750 GWh of power annually. It should be noted that this analysis was conducted before the Governor's announcement directing NYPA to pursue a new nuclear plant, which is therefore not included in this analysis but can be explored further in the final State Energy Plan. Full generation results for the Additional Action scenario are included in Figure 21.

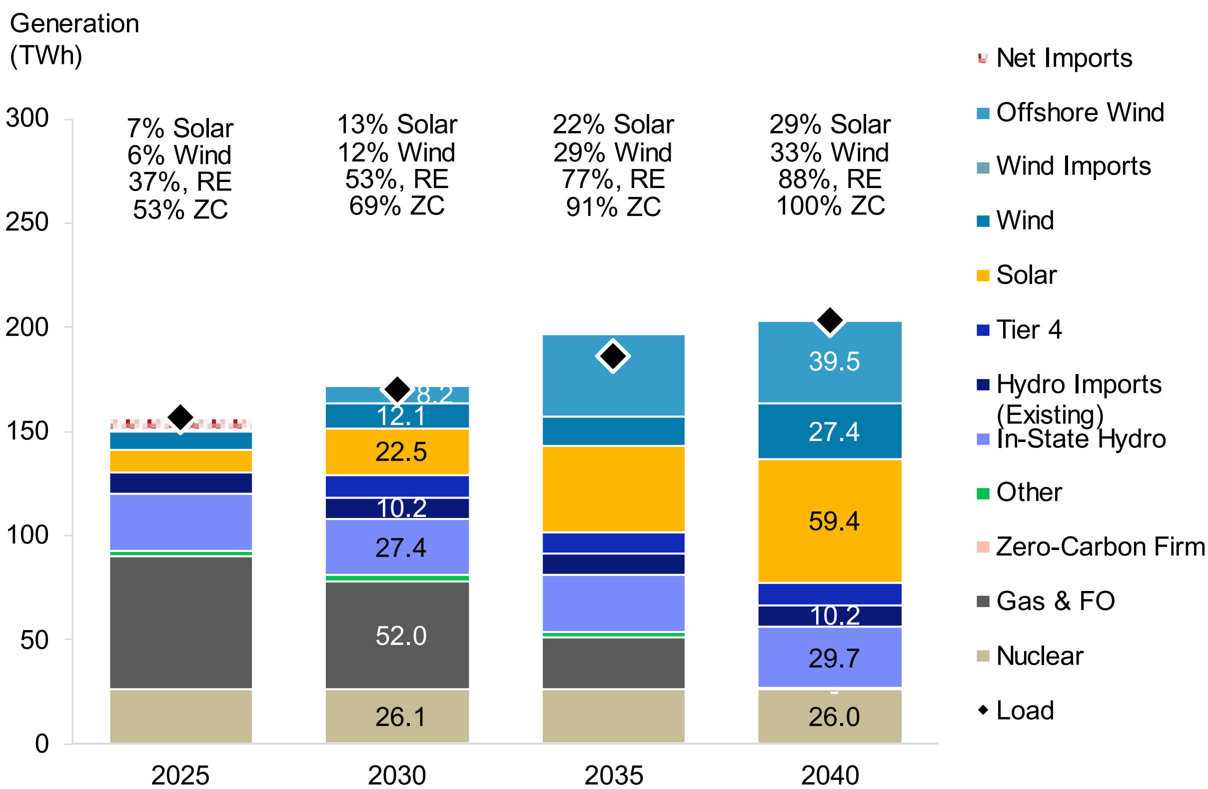

Figure 21. Additional Action, Annual Generation

Additional Action Scenario (constrained build sensitivity)

Given deployment headwinds from economic and federal uncertainty, a constrained build sensitivity was performed on the Additional Action case. In this case, build limits were imposed on the maximum annual capacity additions for all renewable resources, as summarized in the table below. The 70% projection set forth in the CES Biennial Review and the 9 GW by 2035 offshore wind target were also removed from this case, though it still aims to achieve the 0x40 emissions target.

Table 5. Additional Action constrained annual renewable sensitivity build limits

	Existing and Near-term Planned	Annual Build Limits
Distributed Solar	Achievement of 10 GWdc target by 2030	1 GWdc/yr, starting 2031
Utility Solar	Contracted additions through 2028, less 30% attrition and with 1 year re-contracting delay imposed 2026-2027	Contribution of 2.8 TWh/yr starting 2028, at least 20% of which is land-based wind
Land Based Wind		
Offshore Wind	Only South Fork, Sunrise, and Empire 1 online through 2035, totaling 1.87 GW	1.4 GW/yr, starting 2036

A delay in the availability of renewable resources presents significant challenges to achieving the 0x40 zero emissions grid target. In the medium term, this scenario necessitates an increase of nearly 23 TWh in natural gas generation in 2035, leading to over 10 million metric tons of higher GHG emissions and increased reliance on energy imports from neighboring states. To ensure reliability, an additional 1,900 MW of thermal units would also need to be repowered in 2035. Statewide installed capacity results from this case are provided in Figure 22, and incremental capacity addition and retirements are included in Figure 23.

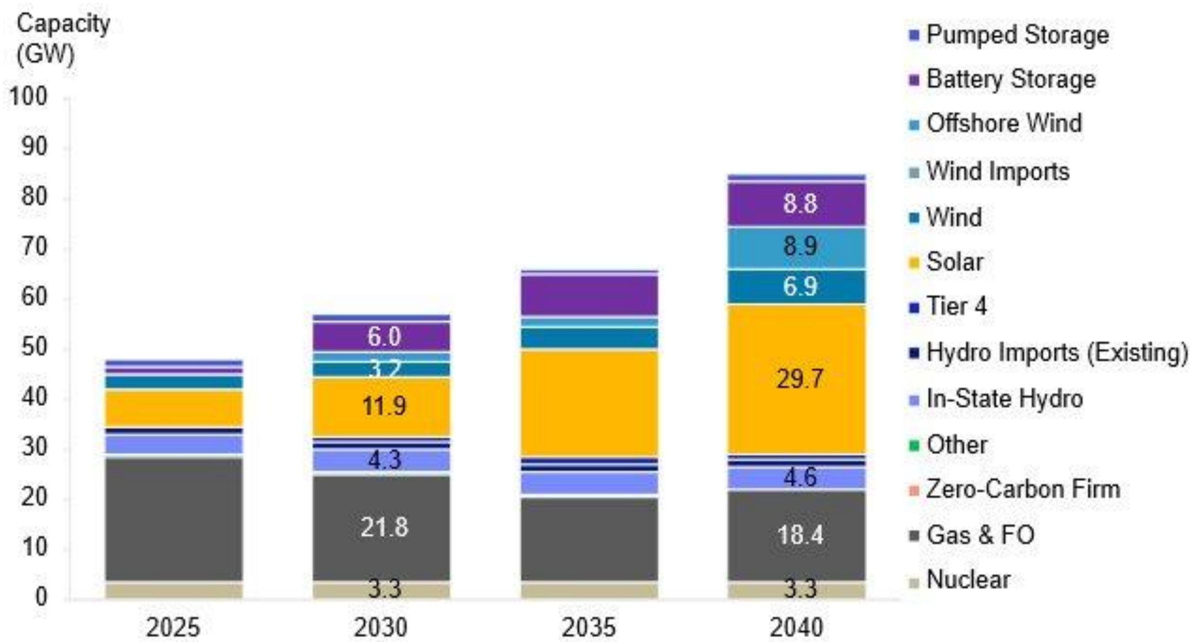

Figure 22. Constrained Annual Build Sensitivity, Total Installed Capacity

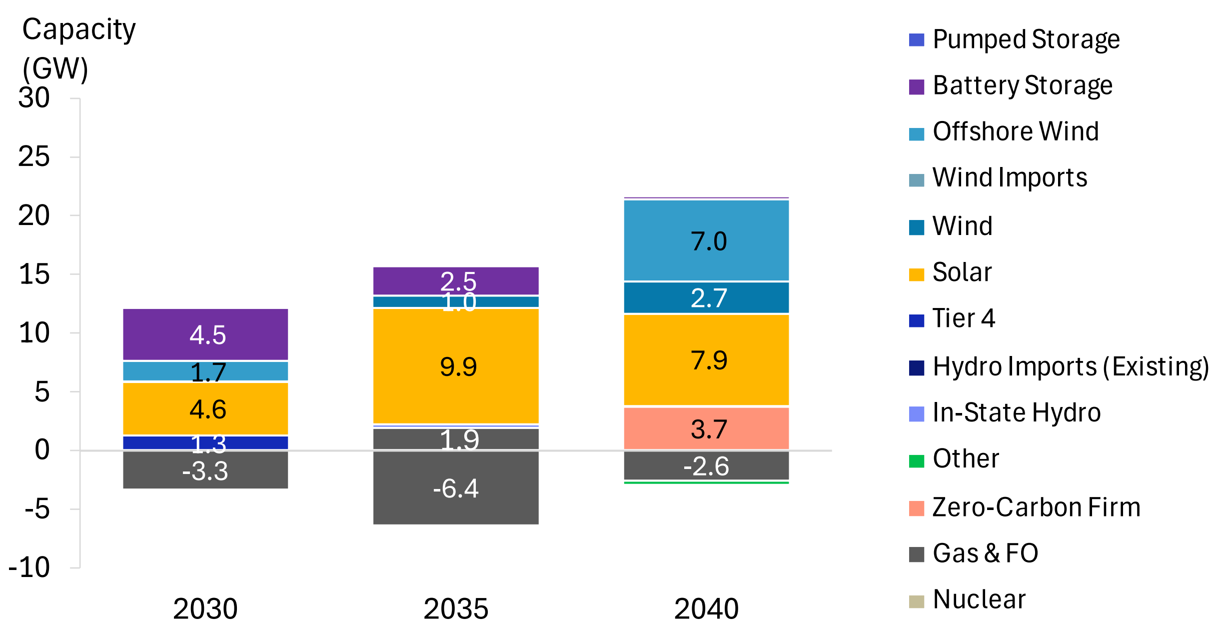

Figure 23. Constrained Annual Build Sensitivity, Incremental Additions and Retirements by Period

By 2040, the persistent shortfall in renewable energy limits green hydrogen availability. To meet load requirements in all hours, the power system continues depending on natural gas-fired plants, resulting in a failure to meet the statutory 2040 zero-emissions constraint. This would amount to 8% of load not met by zero-carbon power, or approximately 17 TWh of natural gas generation in 2040, producing over 7 million metric tons of greenhouse gas emissions. Full generation results from this sensitivity are provided in Figure 24 below. To avoid this outcome, the energy gap could instead be filled by other resources that were not available in the modeling run, such as 2 GW of new nuclear capacity accompanied by additional transmission, dispatchable generation using renewable natural gas, or a combination of these resources. Nevertheless, even under these annual build constraints, continued renewable additions beyond 2040 could lead to the achievement of a zero-emission system by 2045, provided loads remain consistent with the Additional Action case, though a gap would persist if load growth accelerates, e.g. if the pace of electrification converges to the trajectory of the Net Zero cases.

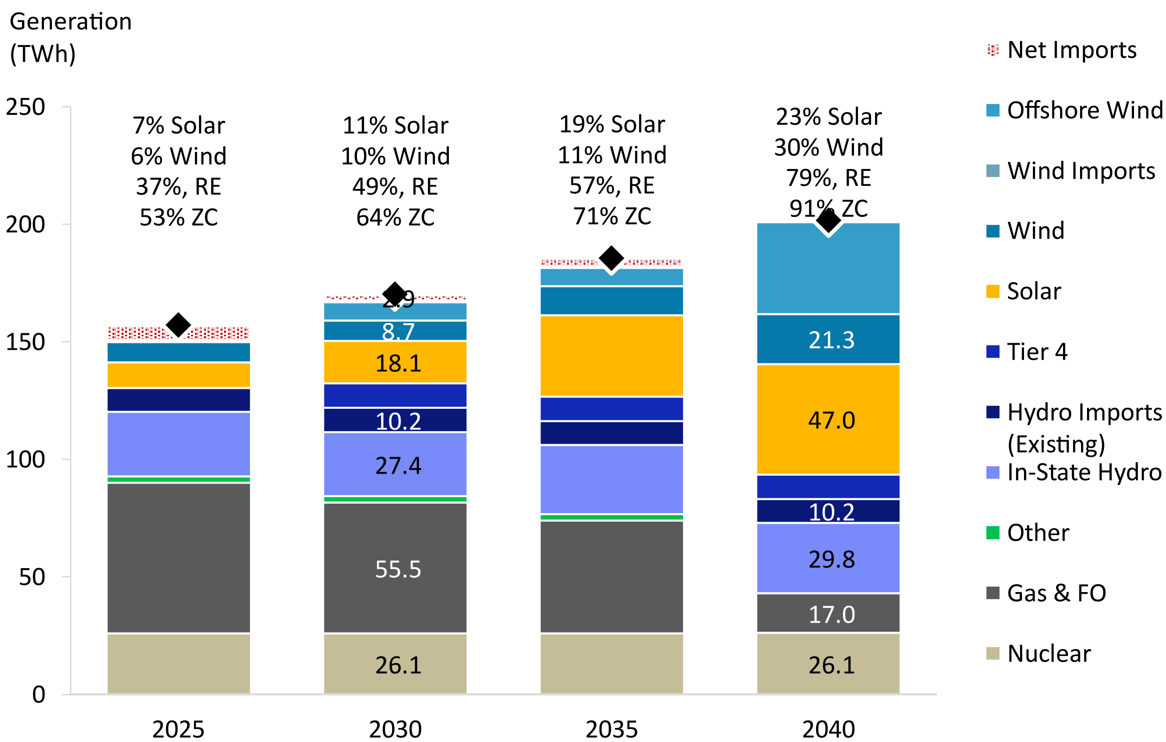

Figure 24. Constrained Annual Build Limit Sensitivity, Annual Generation

Net Zero Scenarios (A and B)

These scenarios see the most transformational load growth necessitating a significant system expansion. Varying degrees of supplementary heating impact firm resource builds.

Net Zero A exhibits substantially higher annual and peak loads compared to the Additional Action scenario. By 2040, peak loads are approximately 7 GW higher. This drives the deployment of an additional 2 GW of battery storage and 7.6 GW of zero-carbon firm capacity additions on top of the Additional Action case. Renewable capacity also sees significant increases through 2040 compared to Additional Action: +6.7 GW of land-based wind, +5.6 GW of offshore wind (exceeding the 2035 target), and +10 GW of solar. Meeting this accelerated pace of additions would require land-based resource procurements to roughly double the currently projected rate every year between now and 2040. Net Zero B sees a similar build trajectory, though requires lower levels of Zero-carbon Firm Resources and storage due to lower peak load requirements, reflecting the value of backup gas heating to mitigate electric system needs. Full portfolio results for both scenarios are shown in Figure 25 below, while incremental capacity addition and retirements are included in Figure 26.

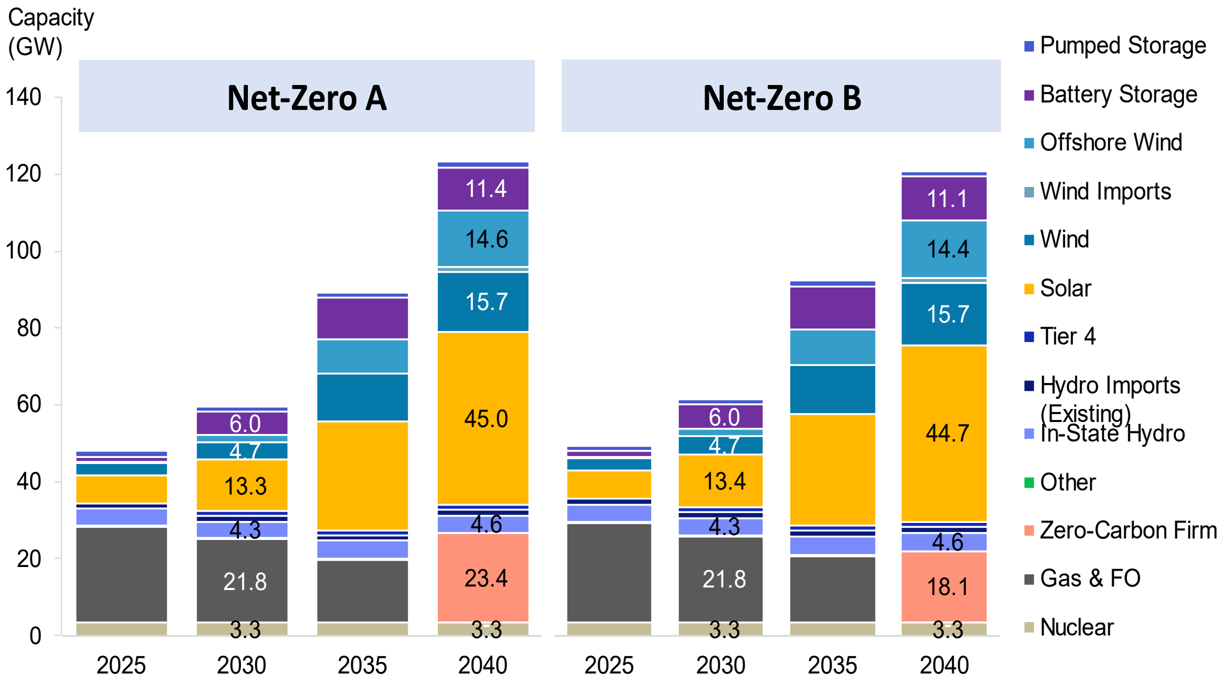

Figure 25. Net-Zero A and B, Installed Capacity Results

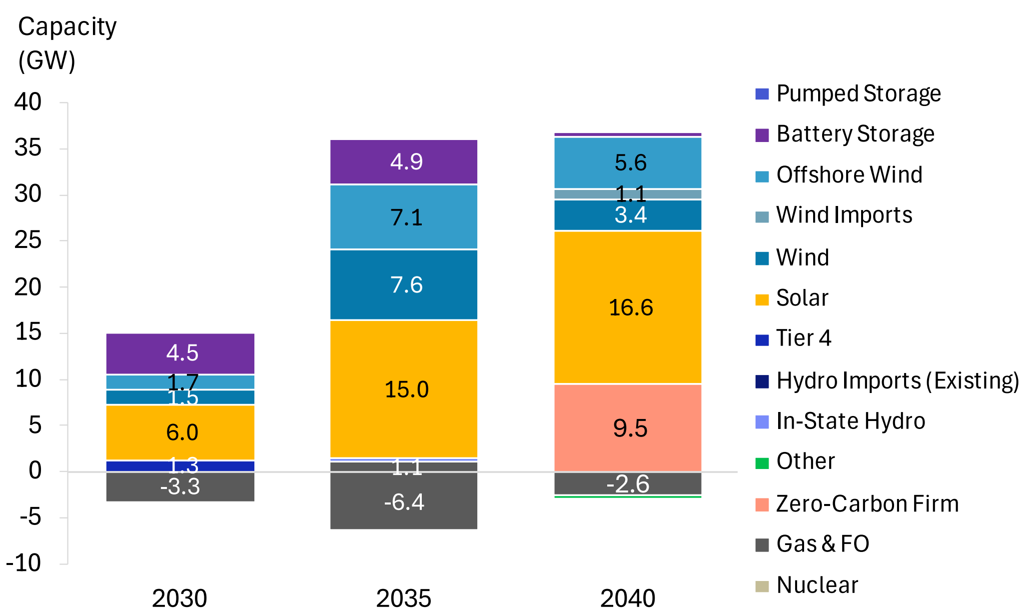

Figure 26. Net Zero A, Incremental Capacity Additions and Retirements by Period

Combustion capacity additions are more substantial, with upstate zones seeing the largest combustion turbine additions and significant repowering also occurring in both Zone J and Zone K. There is 23 GW of total combustion capacity in 2040 statewide in the Net Zero A scenario, including: 7.4 GW in Zones A-E, 3 GW in Zone F, 2.4 GW in Zones G-I, 6.5 GW in Zone J, and 4 GW in Zone K. 1 GW of newly built combustion capacity in this scenario must be deployed starting in 2035, with total new builds reaching nearly 10 GW by 2040. Transmission upgrades include +0.6 GW from Zone I to Zone J and +0.2 GW from Zone E to Zone G by 2035/2040, although additional modeling is needed to fully assess the value of potential transmission additions.

Net Zero B has similar total energy requirements to Net Zero A but features lower system peak needs due to the 3 GW of peak reduction from more heat pump heating customers with supplementary heating systems. This reduction avoids the need for about 5.3 GW of zero-carbon firm capacity statewide relative to Net Zero A by 2040, and also leads to minor reductions in offshore wind, solar, and storage builds compared to Net Zero A.

The zonal pattern of combustion additions is similar to Net Zero A, but with smaller total volumes, reaching 18 GW statewide in 2040. Of this 18 GW, Zones A-E have 3.5 GW, Zone F has 3 GW, Zones G-I have 2.2 GW, Zone J has 6 GW, and Zone K has 3.4 GW of combustion capacity. Transmission additions include +0.6 GW from Zone I to Zone J and +0.2 GW from Zone E to Zone G.

The Net Zero cases see the largest levels of annual load growth, with total loads approaching 270 TWh by 2040 in both cases, a more than 70% increase relative to today's levels. On an annual basis, these loads are met predominantly with renewables, which serve 91% of loads by 2040 (inclusive of both in-state and imported hydro). Existing nuclear generators – all of which are assumed to receive license extensions in these cases – provide most of the rest of the needed generation. Due to the high costs of hydrogen fuel, combustion resources are still only utilized sparingly even in cases with higher annual demand, and generate primarily during challenging periods of high load and low renewable output. In both Net Zero A and B, these resources contribute 3.6 TWh in 2040. Full generation results for Net Zero A are included in Figure 27, below. Net Zero B generation results are nearly identical as the cases have minimal differences in annual loads.

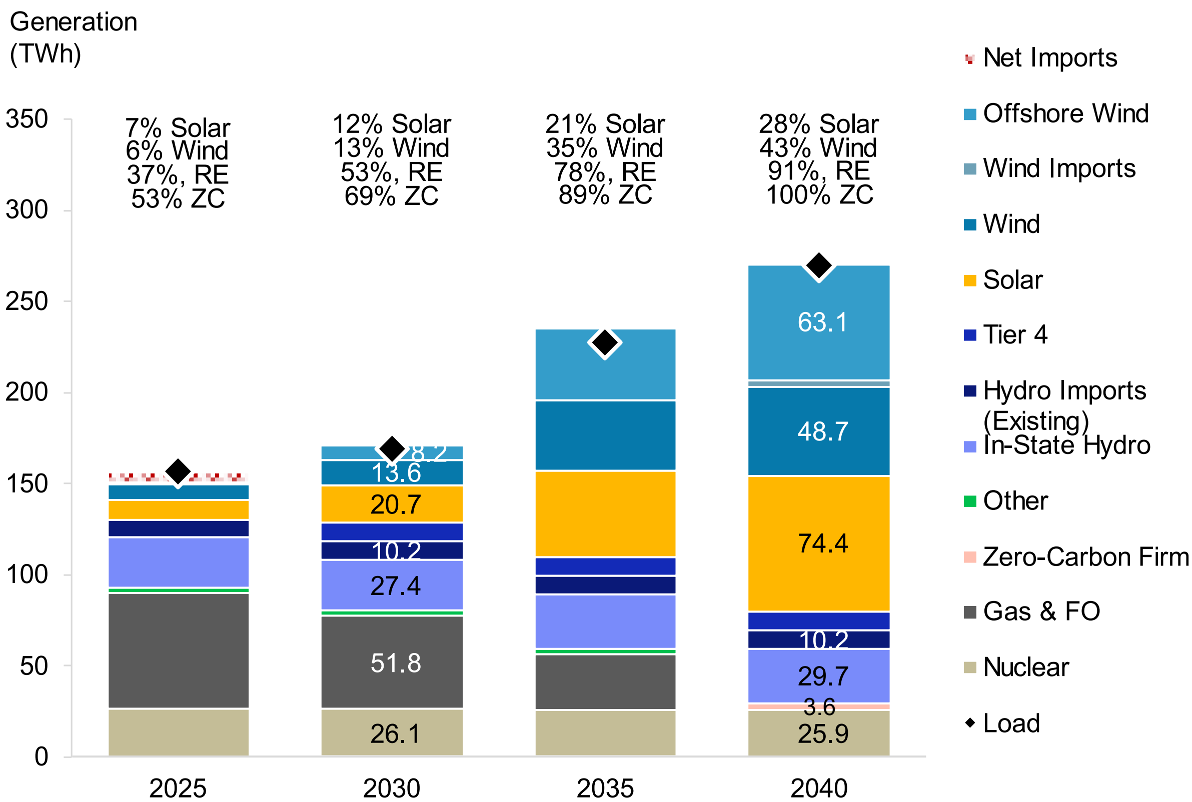

Figure 27. Net Zero A, Annual Generation

Utilization of Zero-Carbon Firm Resources

Across all scenarios that achieve a zero-emissions electricity sector by 2040, there is a need for firm resources that can provide power to maintain system reliability during multi-day periods of high load and low renewable output. In this modeling, this need for zero-carbon firm capacity is met by hydrogen in combustion-based generation resources; however, the need could also be met by a number of other emerging clean firm technologies.

This analytical framework pairs a capacity expansion model with a resource adequacy model, which simulates hundreds of years of plausible weather conditions to ensure systemwide and local reliability criteria are met. Below, the resource adequacy model has been used to examine the utilization of zero-carbon firm capacity over a wider distribution of weather for a few select scenarios and model years. Due to its high fuel costs, hydrogen utilization is generally limited to the most challenging reliability periods, as seen in Figure 28 and Figure 29. Under typical weather conditions, hydrogen generation reaches 1.25 TWh/year in the Additional Action scenario and grows to 3.28 TWh/year during a 1-in-10 weather year (in which winter temperatures may be colder than average, and solar and wind output may be lower than average). In addition to weather conditions, sub-zonal and local transmission constraints may also impact the utilization of zero-carbon firm resources if other resources cannot be delivered into load pockets. Local transmission constraints are best suited for further analysis using a more granular representation of the New York transmission system, such as the models being used as part of the Coordinated Grid Planning Process.

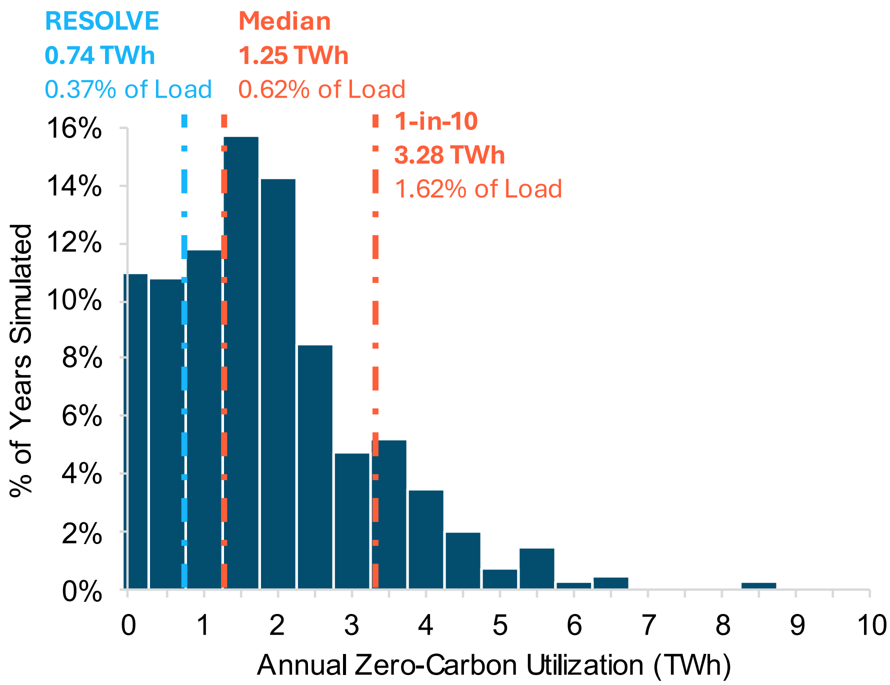

Figure 28. Additional Action, Zero-Carbon Firm Utilization Across 400 Simulated Weather Years

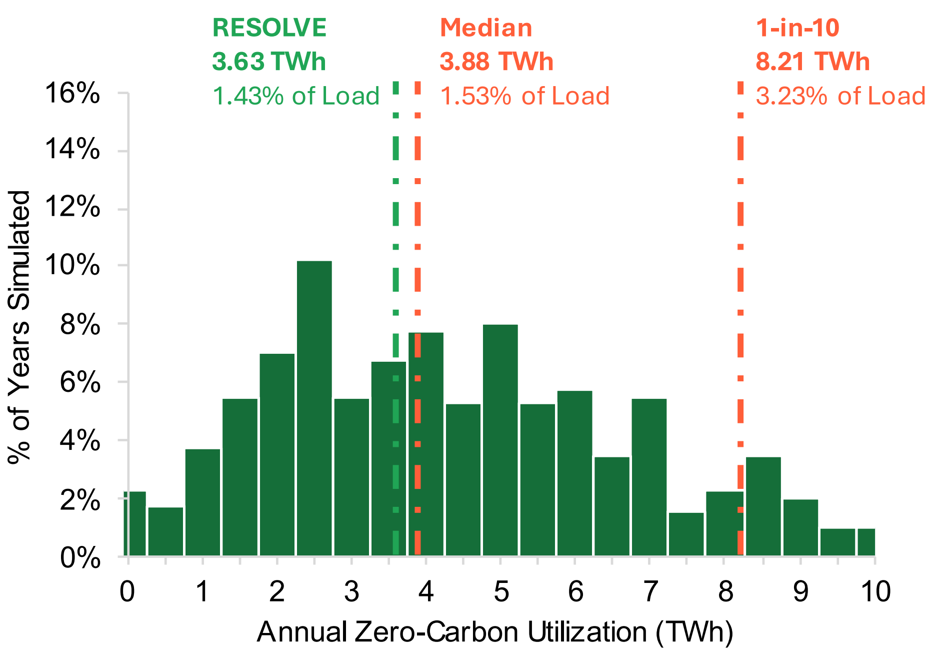

Figure 29. Net Zero A, Zero-Carbon Firm Utilization Across 400 Simulated Weather Years

4.3. Fuels Overview

Electrification and efficiency drive significant reductions in the use of petroleum and other fossil fuels across all scenarios over time (Figure 30). Current Policies layers on statewide biofuel blending mandates, while Additional Action includes renewable fuel blending across natural gas, distillate, and jet fuel as a potential decarbonization lever. The supply of low-carbon fuels is approximately 34 TBtu in 2030 and approximately 100 TBtu in 2040 in Additional Action, with further blending in the Net Zero Cases (Figure 31). Biofuel feedstock supply was sourced from the 2023 US Department of Energy (DOE) Billion Ton Report and NYSERDA Potential Studies. The Additional Action scenario focused on in-state supply of wastes and residues, while the Net Zero scenarios included a regional supply of wastes, residues, and purpose grown biomass.

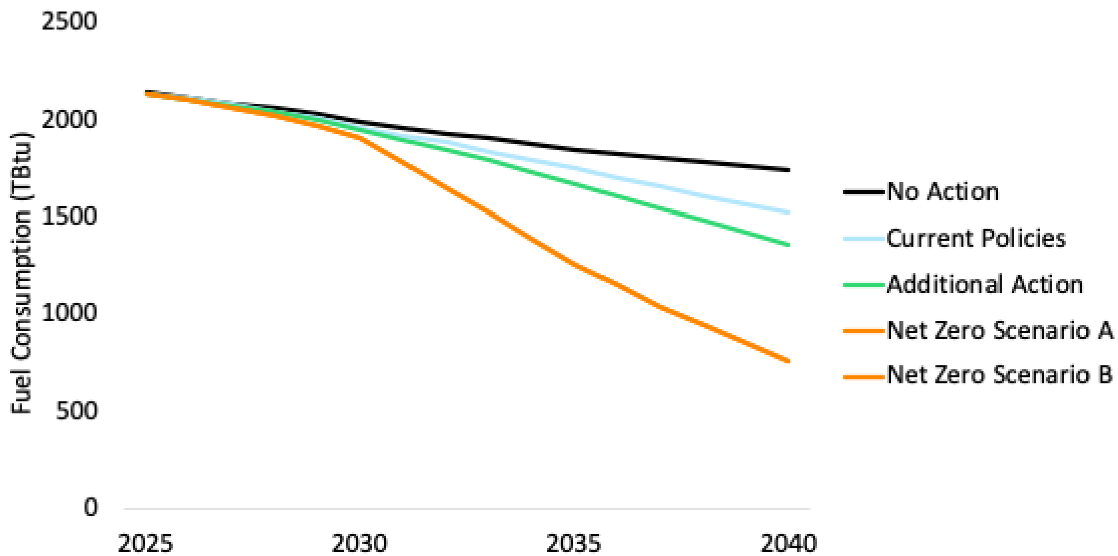

Figure 30. Fossil fuel consumption by scenario

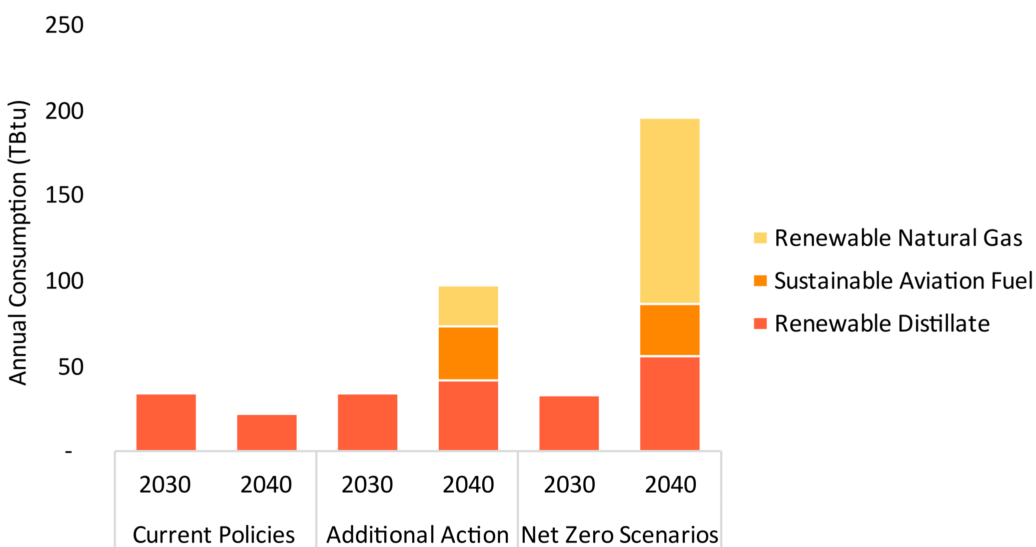

Figure 31. Low-carbon fuel consumption, 2030 and 2040

5. Economy-wide

While the Plan is focused on the implications of State policies and actions on energy demand and supply, it is important to consider emissions in the non-energy sectors, especially in tracking progress towards achieving the economywide decarbonization goals as outlined in the Climate Act.

5.1. Non-Energy Sectors

Emissions for Agriculture, Waste, and Land Use were provided by DEC using updated forecasts based on the trajectories modeled in the Final Scoping Plan.

Hydrofluorocarbon (HFC) emissions were sourced from an analysis performed by Guidehouse. A key finding is that even the No Action case sees significant declines in HFC emissions through the modeling horizon, driven by EPA rulemaking in 2023-2024. If EPA rules are rolled back, emissions would be expected to increase in the No Action case, in the absence of New York State rules. The Current Policies scenario reflects New York State rules including the HFC regulations in 6 NYCRR Part 494, which support a meaningful reduction in HFC emissions. The Additional Action scenario builds upon the 2024 rules by including more stringent constraints on leakage reduction in HFCs, while the Net Zero cases see further emissions reductions driven by including reclamation of HFCs at end of life (Figure 32).

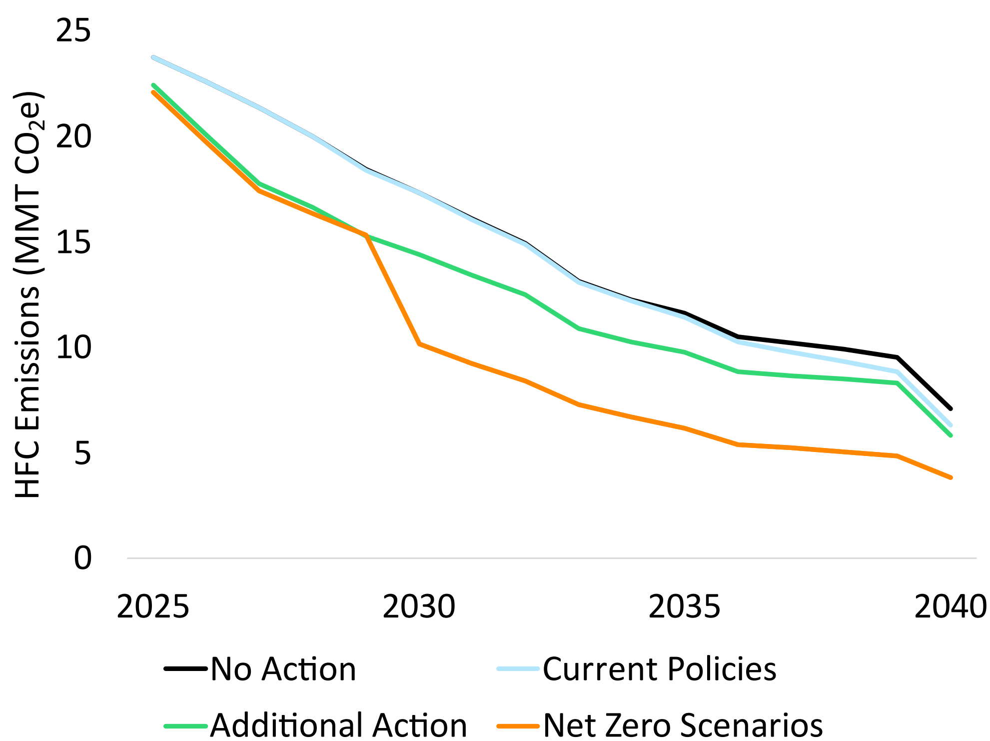

Figure 32: HFC emissions forecast

5.2. Total Emissions

According to the 2024 Statewide GHG Emissions Report, under Climate Act accounting, New York has already reduced its emissions by more than 9 percent relative to the 1990 baseline and 20% relative to emission peaks in 2005. Across all scenarios, 2030 gross reductions total between 15–28 percent. In the No Action scenario, the most significant near-term emissions reductions come from transportation electrification, efficiency gains in end-use devices, and tighter building envelopes, In the Current Policies and Additional Action scenarios, deeper savings also flow from faster renewable-electricity buildout, more ambitious electrification of buildings and vehicles, and stronger building codes. As a result, Current Policies and Additional Action are projected to achieve the 40 percent reduction target between 2036 and 2038. The Net Zero cases achieve the target in 2033, reflecting the time it would take for any new actions to translate into emission reductions (Figure 33).

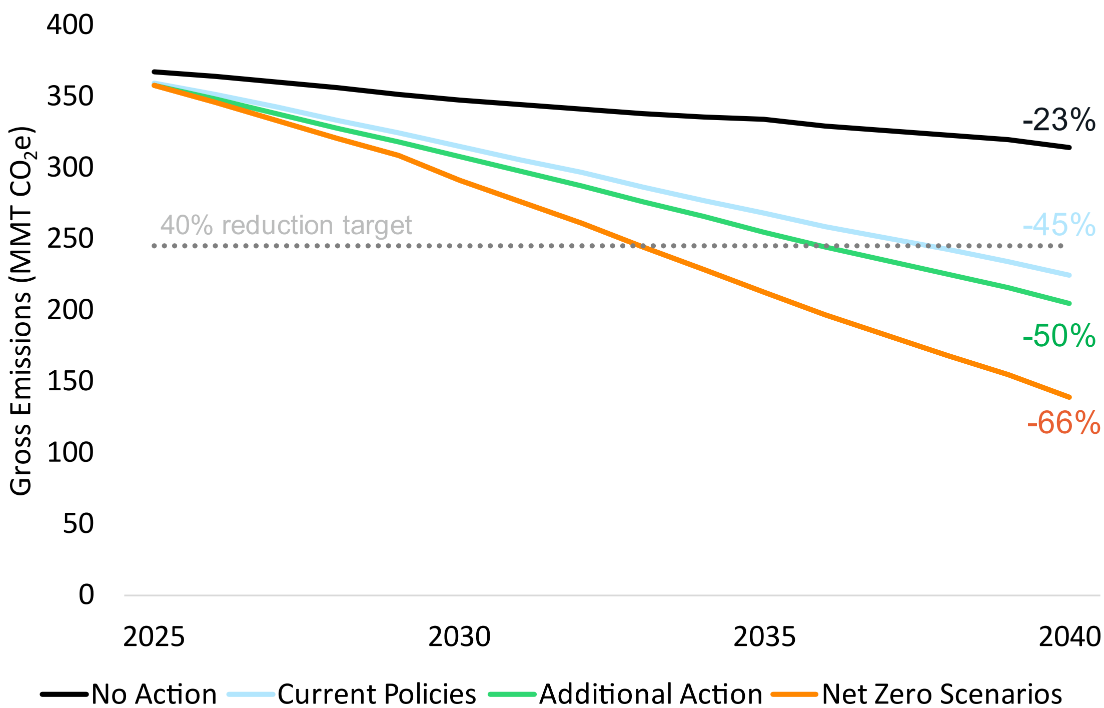

Figure 33. Economy-wide emissions under Climate Act accounting

Emission reductions were also calculated using Intergovernmental Panel on Climate Change (IPCC) accounting to allow for more direct comparison with other jurisdictions. Calculating emissions consistent with the IPCC accounting framework requires excluding out of state upstream fossil emissions, treating biofuel combustion as carbon neutral, and applying 100-year (rather than 20-year) global-warming potentials. Using this accounting framework, New York's current net emissions already stand 23 percent below 1990 levels, and the modeled pathways achieve greater reductions: by 2030, the Additional Action scenario attains 40 percent net emissions reduction and the Current Policies scenario misses that mark by just 2 million metric tons. By 2040, both of these scenarios drive emissions roughly 60–70 percent below the 1990 baseline, and the Net Zero scenarios achieve emissions reduction of 88% (Figure 34).

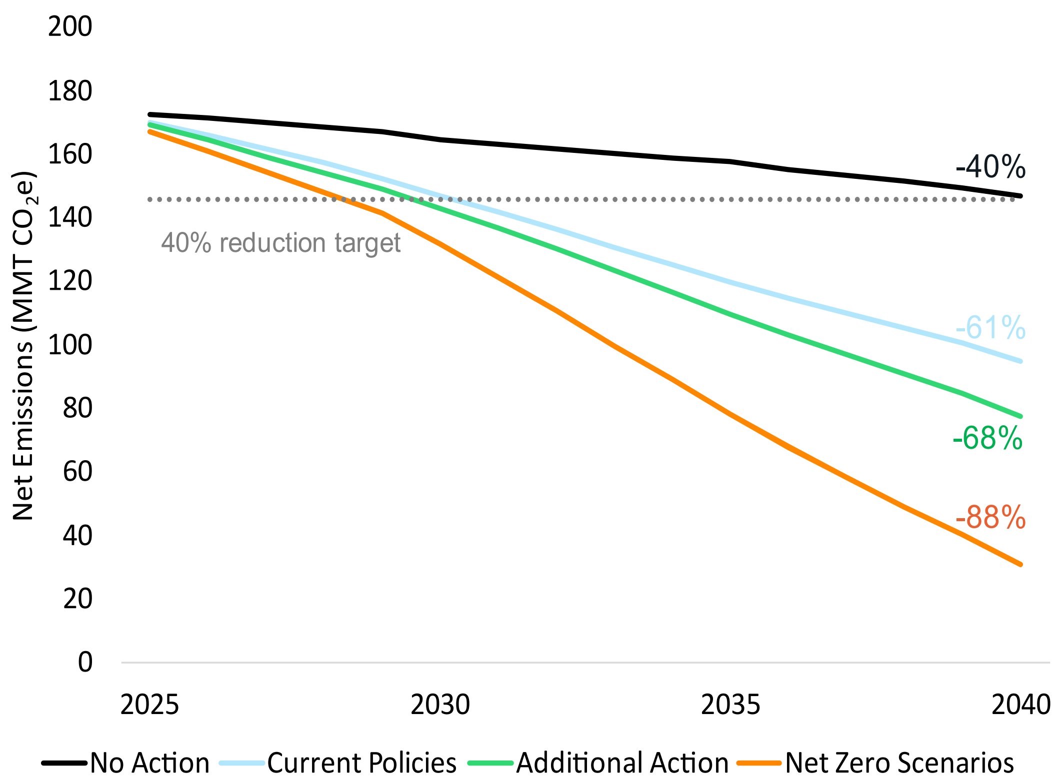

Figure 34. Economy-wide emissions under IPCC accounting

5.3. Benefit and Cost Analysis

Regardless of the scenario, New York State has substantial energy investment needs over the course of the planning period. Aging infrastructure across all energy sectors, including electricity and natural gas, will require investment to maintain safety and reliability. Economic development, while creating new opportunities for workers and communities across New York, will require substantial expansion in energy infrastructure to ensure abundant, accessible supply. Building owners will need to replace aging space heating and water heating systems, and individuals and fleet owners will need to purchase new vehicles. All of these systems will need to adapt to a new paradigm with warmer winters and more extreme heat in the summer. As a result, while the planning scenarios include modest increases in annual spending, the bulk of energy system investment will be required regardless of the pathway the state ultimately pursues.

Figure 35 shows the annual gross costs across scenarios in 2030 and 2040. Costs are net of federal IRA incentives which were in place at the time of modeling, adjustments to the modeling will occur in the final to reflect federal policy changes. The No Action scenario sees relatively flat economywide costs; increases in capital expenditures and increases in electric system costs are offset by reduced fuel costs due to electrification of buildings and transportation reducing the quantity of fossil fuels required for purchase. Note that this analysis does not include changing costs for existing pipeline gas systems or existing electric infrastructure assets; any such changes in costs would be consistent across scenarios so including those dynamics would impact overall gross costs but not impact the comparison across scenarios. The Current Policies and Additional Action scenarios have similarly flat costs, with a 1% and 3% increase in gross annual costs over the same time period, respectively.

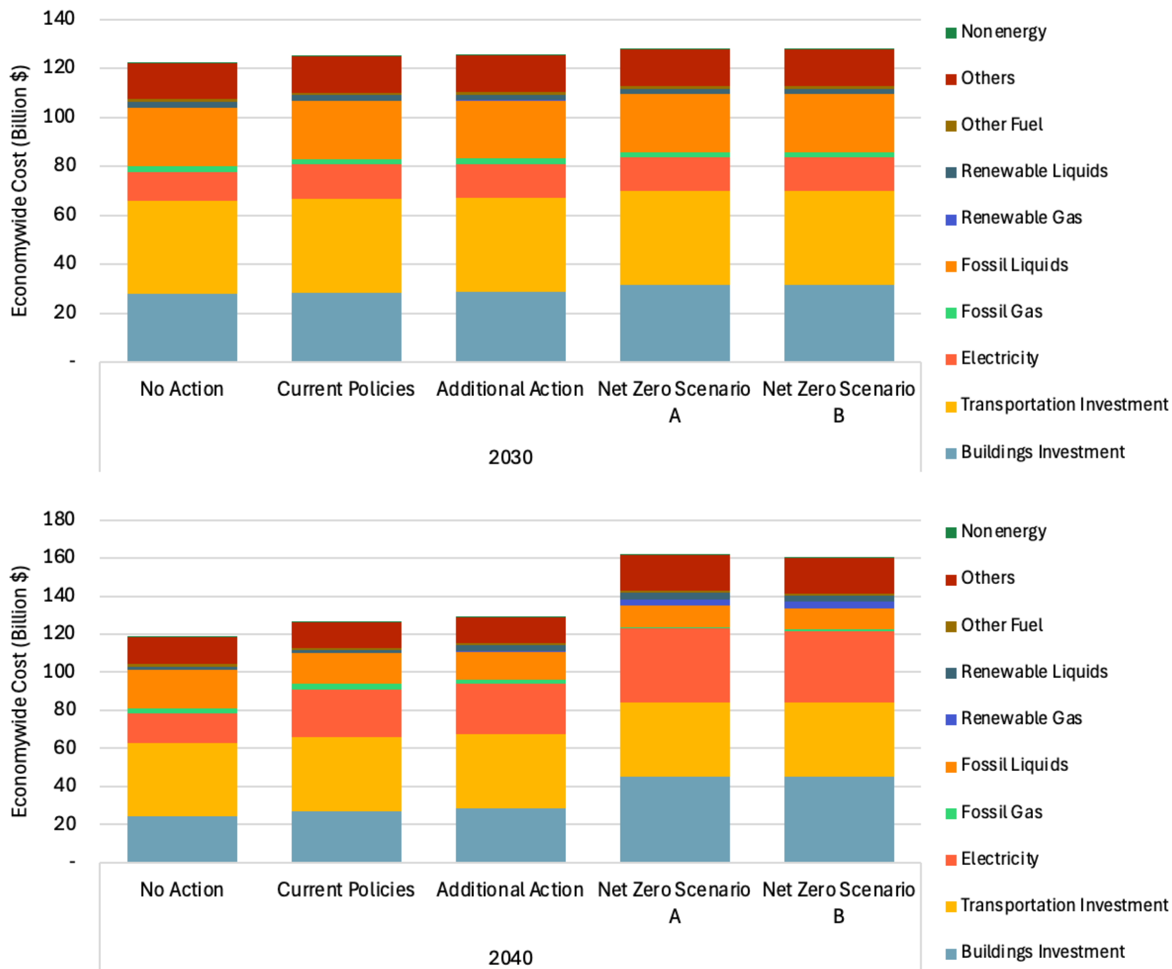

Figure 35. Gross annual costs across scenarios in 2030 and 2040 (2024$)

Most added costs when comparing the planning cases to the No Action scenario are from higher capital outlays—chiefly for heat pumps—and incremental power sector costs. These capital costs are partially offset by lower fuel and operations-and-maintenance expenses and by the projected decline in EV and heat-pump prices over time. In 2030 and 2040, incremental costs of the Additional Action scenario relative to the No Action scenario are $3.1 billion and $10.3 billion, which represents a modest 2% and 9% premium, respectively.

While the costs shown above show the gross system costs required under each scenario, these metrics do not include the benefits attributed to reducing emissions, in particular the health benefits and avoided social cost of emissions benefits. Decarbonization can result in substantial health benefits to New Yorkers from improved air quality relative to the No Action case. The health benefits associated with air quality improvements are documented in more detail in the Public Health Impacts Analysis chapter of this Plan. The social cost of emissions (SCE) is meant to measure the economic impact of climate change. The reduction in SCE can be significant for scenarios with increased emissions abatement.

Figure 36, Figure 37, and Figure 38 below show the annual costs, benefits, and net benefits relative to the No Action scenario across scenarios in the key years of 2030, 2035, and 2040. As shown, each of the planning scenarios provides a net benefit relative to the No Action scenario. Across scenarios, the net benefit increases in later years. This is due to higher annual greenhouse gas emission reductions, leading to higher SCE savings and health benefits. The costs in Net Zero B are slightly lower than in Net Zero A, reflecting potential value of electric system reductions that can be achieved from coordinated use of backup gas heating equipment.

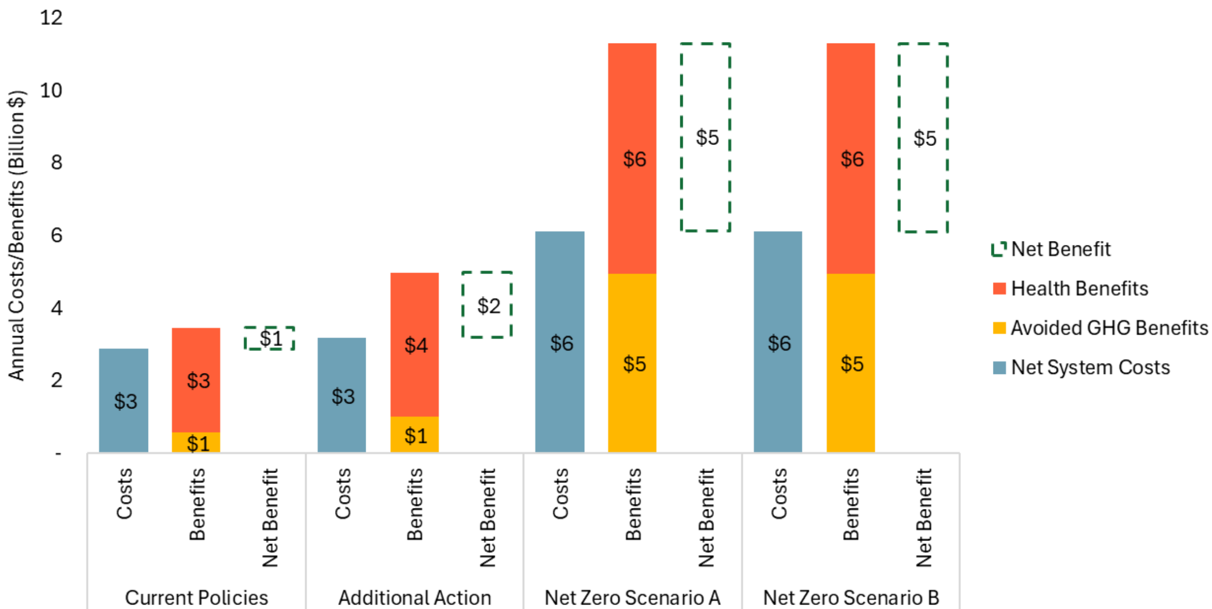

Figure 36. 2030 annual net costs and benefits by scenario (billion 2024$)

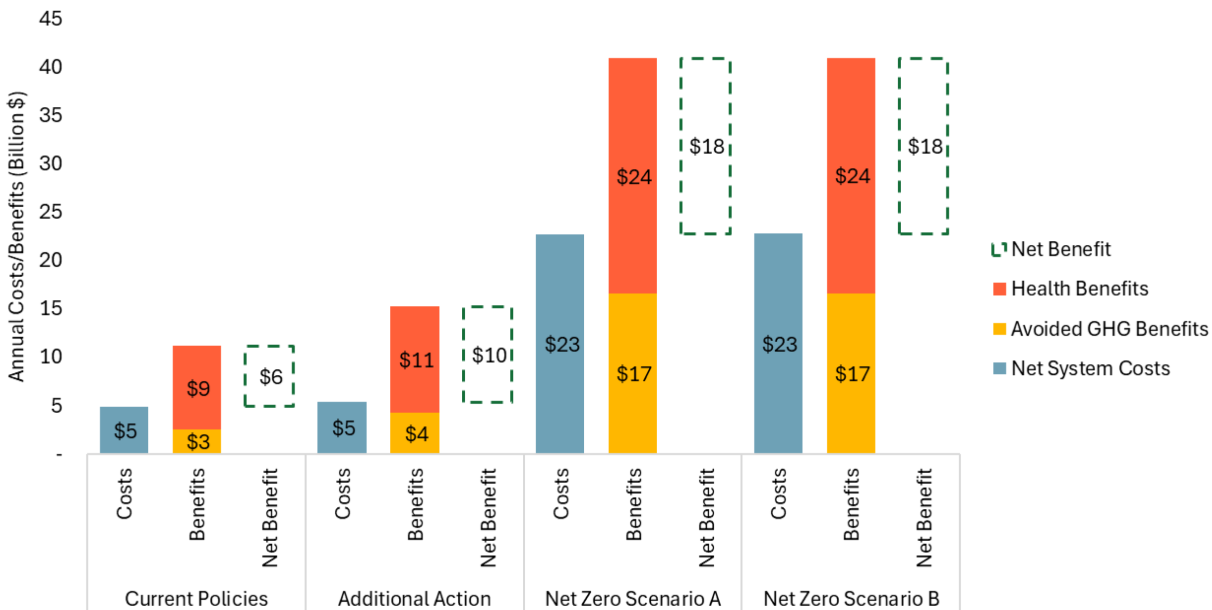

Figure 37. 2035 annual net costs and benefits by scenario (billion 2024$)

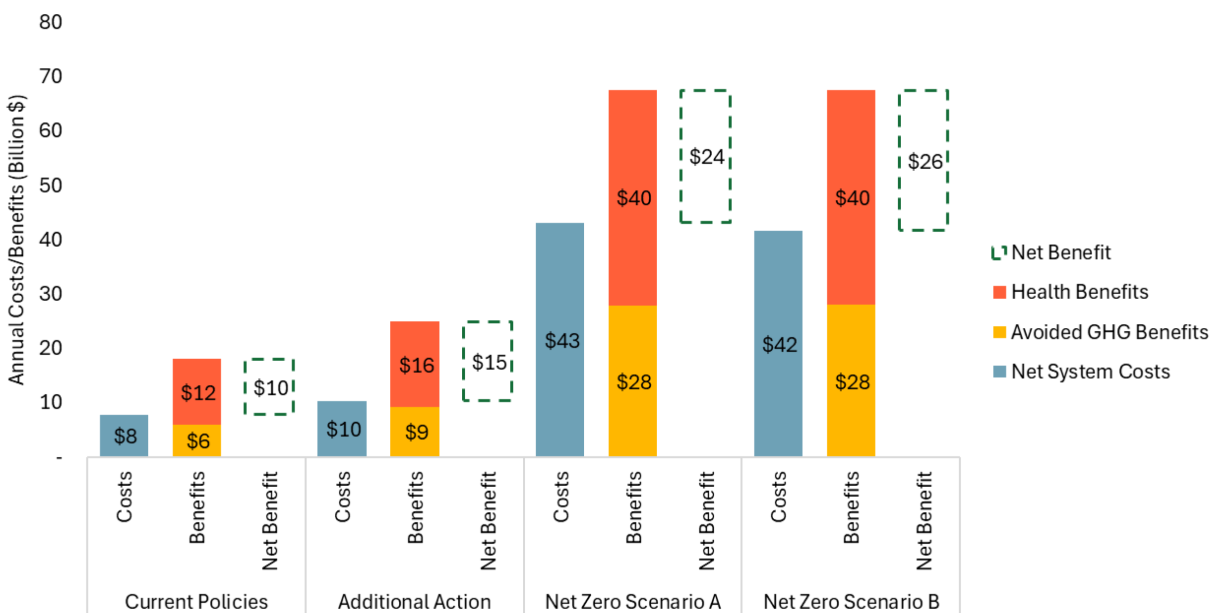

Figure 38. 2040 annual net costs and benefits by scenario (billion 2024$)

When calculating net benefits over the planning horizon of the State Energy Plan, 2025-2040, the net present value of net benefits for the Additional Action case relative to the No Action case is +$48.1 billion (in 2024$). This reflects population-level estimates, indicating that the combined public health and SCE benefits are expected to outweigh the net costs associated with Additional Action. These estimates do not reflect impacts at the individual level but rather reflect modeled outcomes at the societal level.

6. Summary of Findings

The Draft Plan is underpinned by analysis of possible future energy demand and supply across a range of future scenarios. Through economywide modeling of multiple future energy pathways for New York, this analysis simulates possible future energy systems that meet energy needs and advance policy objectives. The two planning scenarios include a Current Policies scenario reflecting progress toward achievement of enacted policies and Accelerated Action reflecting further acceleration of adoption of clean energy technologies from some mix of future policies aligned with the Draft Plan recommendations. The core planning scenario is Accelerated Action. The analysis also includes a No Action scenario absent New York actions from the Climate Act as a reference point and the net zero scenarios reflecting what would be needed for full achievement of the 2050 emission reduction targets for comparison.

As shown in Figure 39 for the planning scenarios, the energy system undergoes a meaningful transformation in final energy demand between 2025 and 2040.

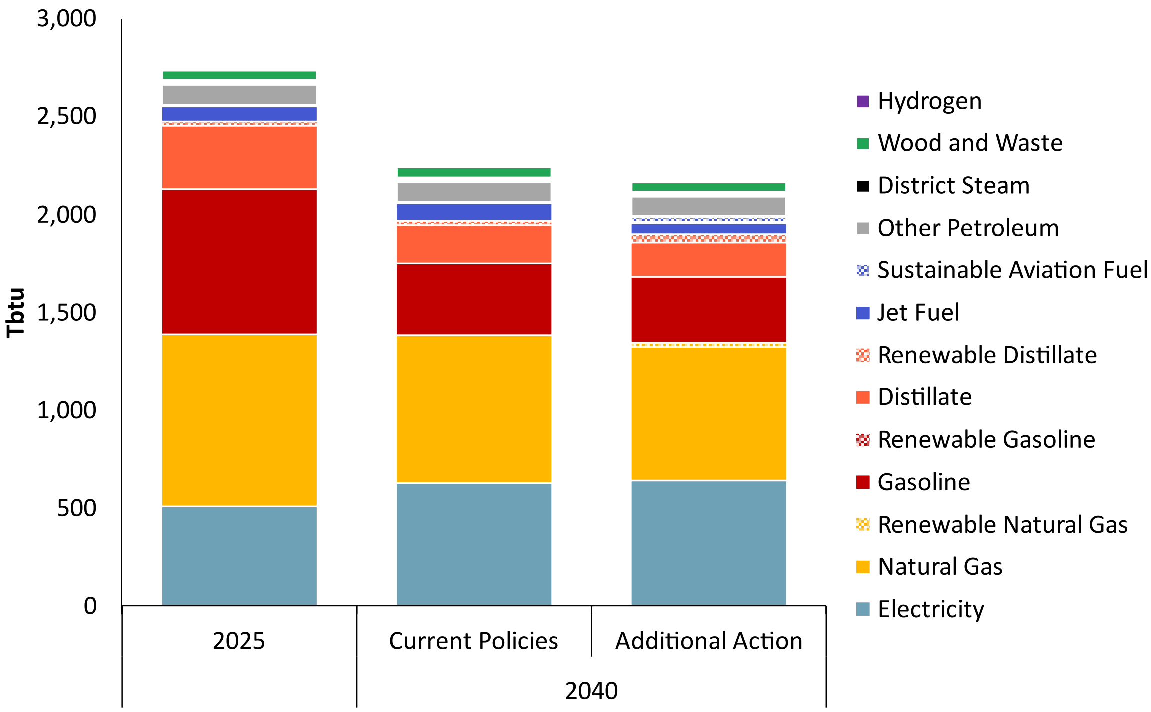

Figure 39. 2025 vs 2040 Final Energy Demand by Fuel

6.1. Annual and Peak Electricity Demands

In all pathways, new large loads interconnecting to the system drive growing electricity demand, across both annual loads and peaks (Figure 40). Planning early for abundant supply for these projects can ensure continued opportunities for economic growth.

Electricity demand is also projected to grow due to electrification of transportation and buildings. Adoption of clean energy technologies, such as electric vehicles, building energy efficiency, and heat pumps, is already underway driven by consumer preferences and federal, State, and local policies and programs. As existing heating and cooling appliances and vehicles age out and are replaced, State actions—such transportation initiatives and investments, all electric new construction and advanced building codes, and heat pump incentive programs—will accelerate adoption of more efficient and electrified alternatives. By 2040 in the planning scenarios, 17-24% of the residential heating stock is heat pumps and 53-59% of the light-duty vehicle (LDV) stock is a zero-emission vehicle (ZEV). These shifts lead to further electric system growth.

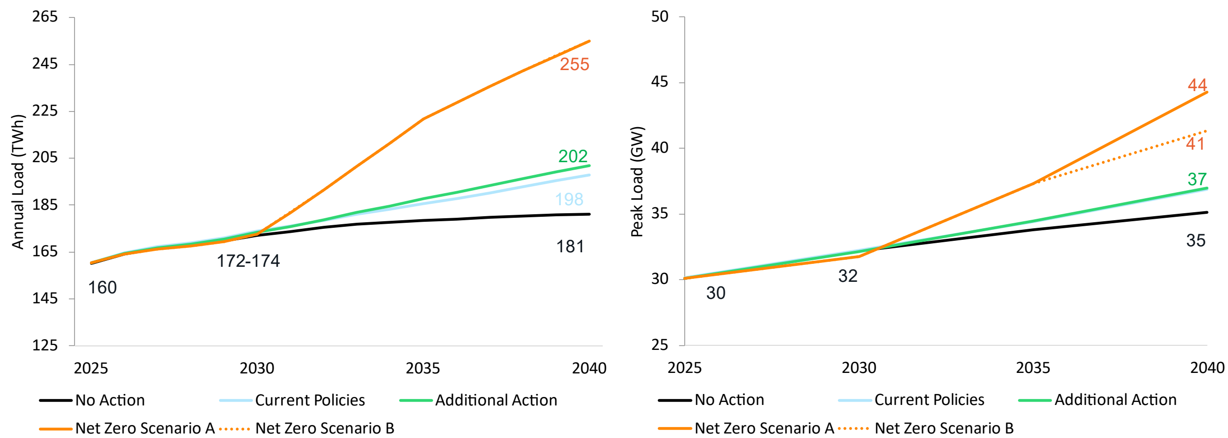

Figure 40. Annual Electric Loads (TWh, left) and NYCA Peak Loads (GW, right) for each Pathway

6.2. Electricity Supply

Meeting this growing electricity load, while maintaining system reliability, will require investments in expansion of the electricity system under all pathways. Moreover, progress toward a zero-emission electric grid will necessitate a transformation of the generation mix, building upon the deployment of renewables already underway from the CES program. Consistent with the findings of the CES biennial review, the modeling shows achievement of a 70% renewable grid in 2033 and provides insight into the continued build-out of generation and transmission infrastructure to support the decarbonization of the electricity system.

In the core planning scenario, additions of renewable energy and battery storage are foundational to decarbonizing the state's electricity system. By 2040, 35 GW of solar and 9 GW each of storage, offshore wind, and onshore wind have been added to New York's generation mix, which add to the system's resource diversity (Figure 41, left). Reliably integrating large quantities of variable renewable energy into the electricity system requires flexibility and balancing over multiple timescales, including sub-hourly and hourly balancing as well as ensuring that firm, dispatchable capacity is available to provide adequate amounts of power during multi-day periods of low renewable output.

Battery storage and demand-side flexibility provide key contributions to system reliability and support the balancing of renewables with demand. Existing nuclear and hydroelectric generation provide large quantities of zero-emissions energy and firm, dispatchable capacity during prolonged periods of low renewable output. While the process for establishing a zero-emission generation definition is still underway, the modeling assumes that the remainder of multi-day reliability needs are met by generators powered by green hydrogen. Under this assumption, the combustion generation fleet remains critical, with 17 GW of repowered and new capacity available to run on hydrogen. The size of the overall combustion fleet declines relative to today's levels (~25 GW) even as peak demand increases, reflecting the reliability contributions of other new resources like the Champlain Hudson Power Express transmission project, new battery storage, and additional renewable capacity.

However, a sensitivity off of the core planning scenario shows that if deployment headwinds persist (as experienced through delayed renewable generation build rates due to challenges such as changes in federal policy for permitting offshore wind), there would be greater reliance on combustion units than in the core scenario, including 2.2 GW of additional repowered capacity in Zone J in 2035 and an overall 1.2 GW larger fleet in 2040 (Figure 41, right). Given insufficient renewable energy generation, natural gas units would need to provide 15 TWh of electricity under this sensitivity; or alternatively, this electricity could be supplied by other resources like new nuclear with transmission and/or renewable natural gas.

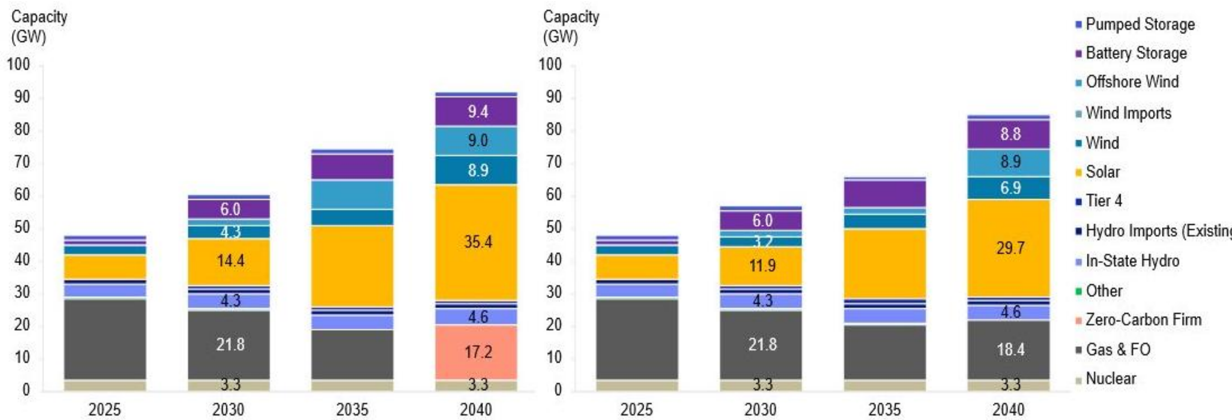

Figure 41. Total Installed Capacity - Additional Action (left) vs Constrained Build Sensitivity (right)

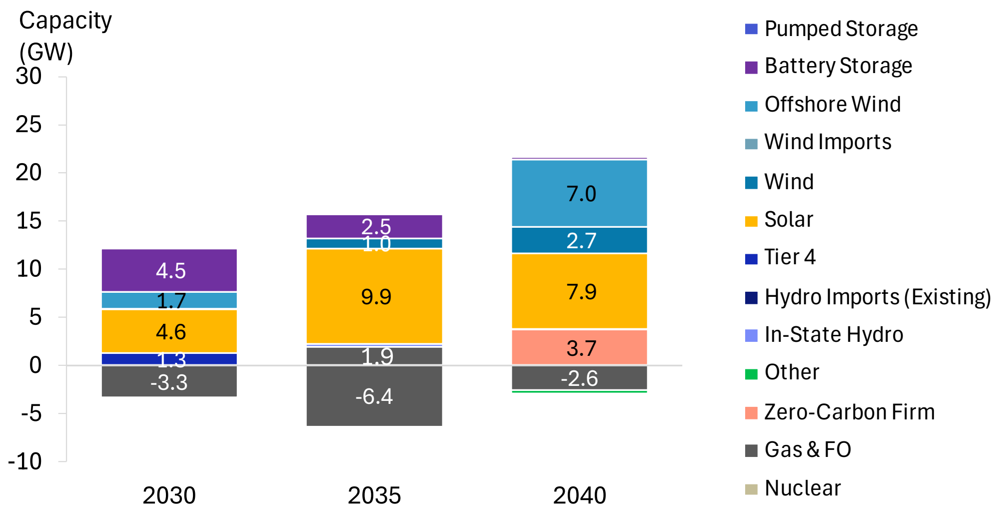

Figure 42. Constrained Build, Incremental Capacity Additions and Retirements by Period

6.3. Gas Supply and Delivery

While the electricity system is expected to grow in all scenarios, the gas system transformation is pathway-dependent. In all scenarios, the gas system remains an important energy delivery system, necessitating investments for reliable ongoing provision of service. Residential and commercial consumption declines in all cases with efficiency improvements and customers switching to heat pumps to varying degrees (Figure 43). Throughput declines even further with electric system progress toward 0x40, although electric generators typically have interruptible service which lowers their impact on overall system infrastructure needs. Residential customers grow in the No Action case absent more recent State action, with new construction and conversions from electric resistance and heating oil driving new connections. Residential customers decline over time in the remaining cases, reflecting the potential for well-implemented all electric new construction and heat pump programs to stem growth. However, regional variability is expected based on the findings of the utility Long Term Plans (LTPs), and targeted regional investment in system expansion may be needed to increase supply diversity and meet peak demand.

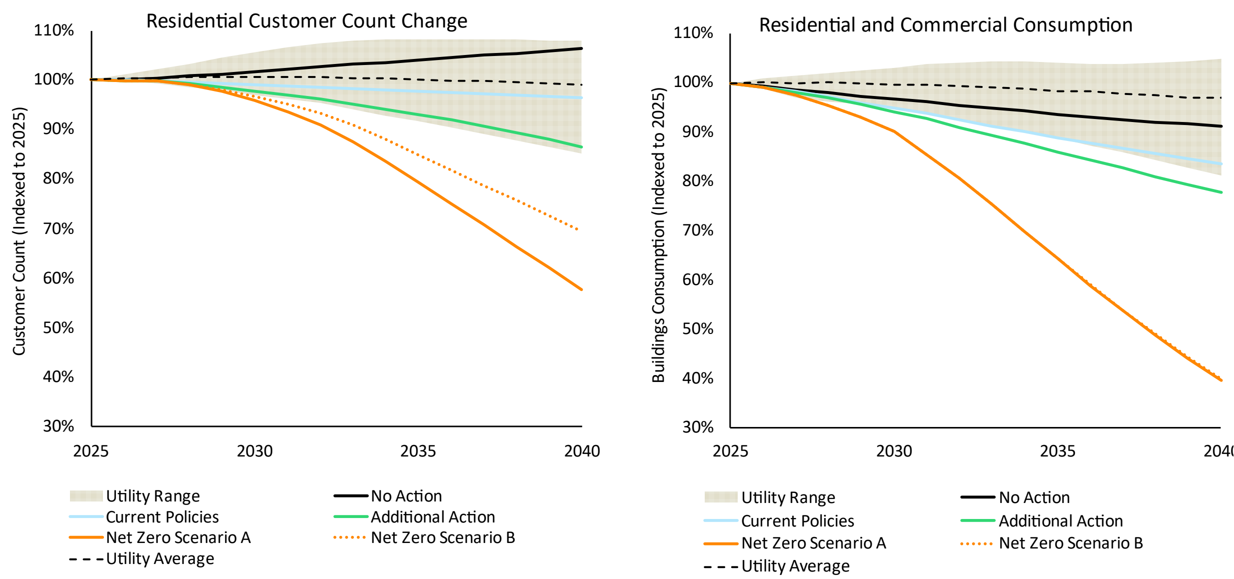

Figure 43. Residential gas customer count change and Residential/Commercial Consumption for all Pathways

Overall, in the Current Policies and Additional Action cases, final energy served by electricity increases from 19% in 2025 to 28-29% in 2040, and final energy served by direct fossil fuel consumption decreases from 78% in 2025 to 63-67% in 2040.

6.4. Greenhouse Gas Emissions

New York's economywide emissions today have already declined more than 9% from 1990 levels and 20% relative to 2005 peak emissions. The modeling finds that existing New York State policies are laying the groundwork for further economywide emissions reductions, with significant contributions from power generation, transportation, buildings, and fugitive emissions including methane and HFCs (Figure 44).

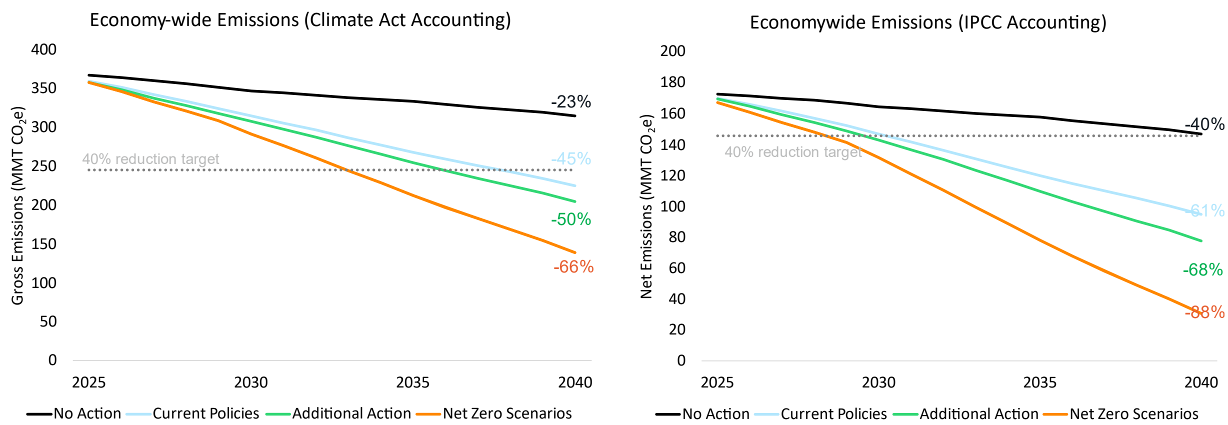

Figure 44. Economy-wide Emissions for all Pathways

Achievement of the net zero economywide emissions target will require significant incremental policy action and technology development beyond what is currently contemplated, including further electrification and decarbonization in buildings and industry, pursuing electrification and fuel-switching in on-road and non-road transportation sectors, and pursuing ambitious non-energy sector mitigation. Recent federal uncertainty and loss of funding will impact New York State policies.

6.5. Societal Costs of the Plan

Regardless of the specific future pathway for New York's energy system, continued investment to maintain and modernize existing infrastructure, replace aging equipment, and purchase fuels to meet energy needs will be necessary. As shown in Figure 45, analysis found that the No Action scenario requires annual spending of approximately $120 billion every year through 2040, with annual spending seeing a slight downward trend over the time period. These funds support replacing end use equipment at end of useful life, constructing new and replacement natural gas generators to meet electricity needs which are being transformed by new large loads and other needs. Because end use equipment is anticipated to grow more efficient over the time period as a result of existing policies, operating fuel expenses trend downwards over time.

By 2030 and 2040, the Additional Action scenario raises costs modestly by 2% and 9%, respectively, relative to the No Action scenario. Additional Action meets over 90% of its investment needs every year by reallocating anticipated spending from legacy energy sources and equipment to energy efficiency and clean alternatives, replacing spending on combustion generators with renewable generation, gas appliances with energy efficient heat pumps, and internal combustion vehicles for battery electric alternatives. In contrast, the cost premium for the Net Zero scenarios reaches in excess of 35% by 2040.

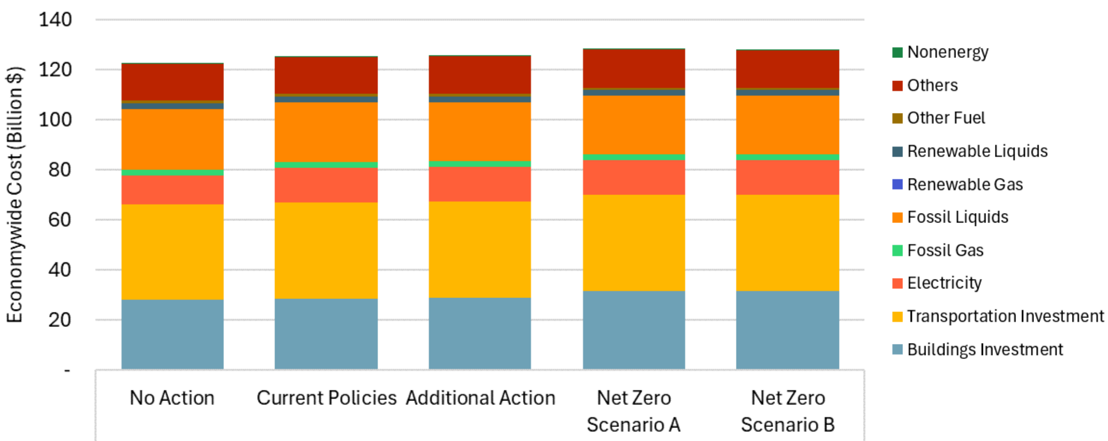

Figure 45. 2030 Gross Annual Costs by Scenario (2024$)

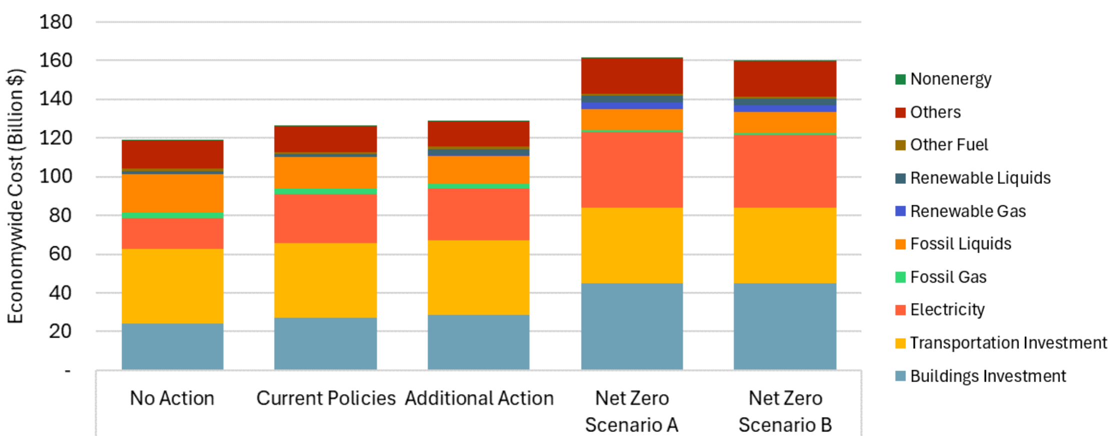

Figure 46. 2040 Gross Annual Costs by Scenario (2024$)

Across each of the scenarios, the emissions mitigation achieved via State policies yields benefits that exceed the incremental costs of the scenario in total over the planning period and in each individual year. The core planning case, Additional Action, sees the total net present value of net benefits reach $48 billion by 2040. These benefits grow substantially over the planning period as greater amounts of clean energy substitute for fossil fuel use across the scenarios. As shown in Figure 47 and Figure 48, Additional Action's 2030 incremental spending of $3 billion secures approximately $5 billion in benefits; by 2040, incremental spending of $10 billion provides benefits of $25 billion. While greenhouse gas emission reductions provide a meaningful share of the cumulative benefits over the full planning period, more than two thirds of the benefits are associated with health improvements, including avoided premature mortality, lost work days, emergency room visits, non-fatal heart attacks and more. For more information on these health benefits see the Public Health Impacts Analysis chapter of this Plan.

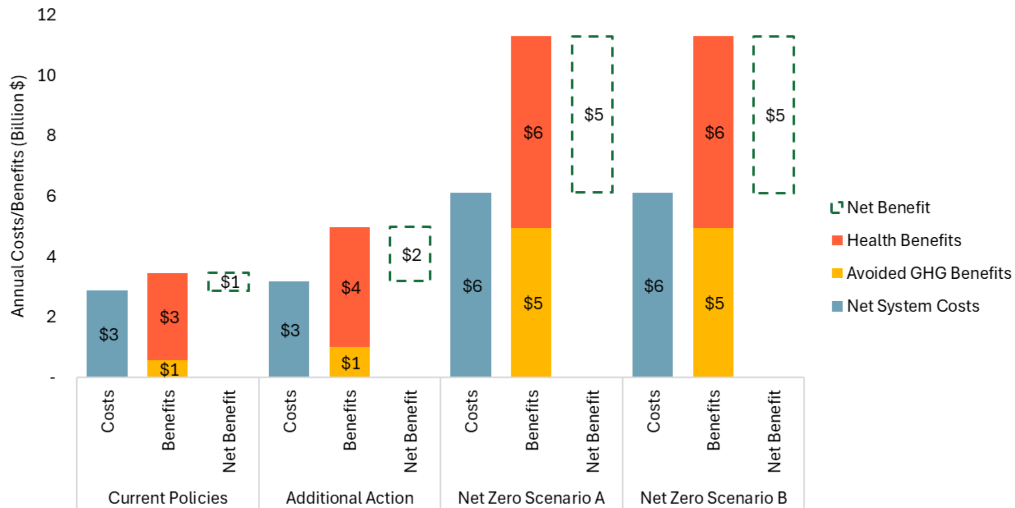

Figure 47. 2030 annual net costs and benefits by scenario (billion 2024$)

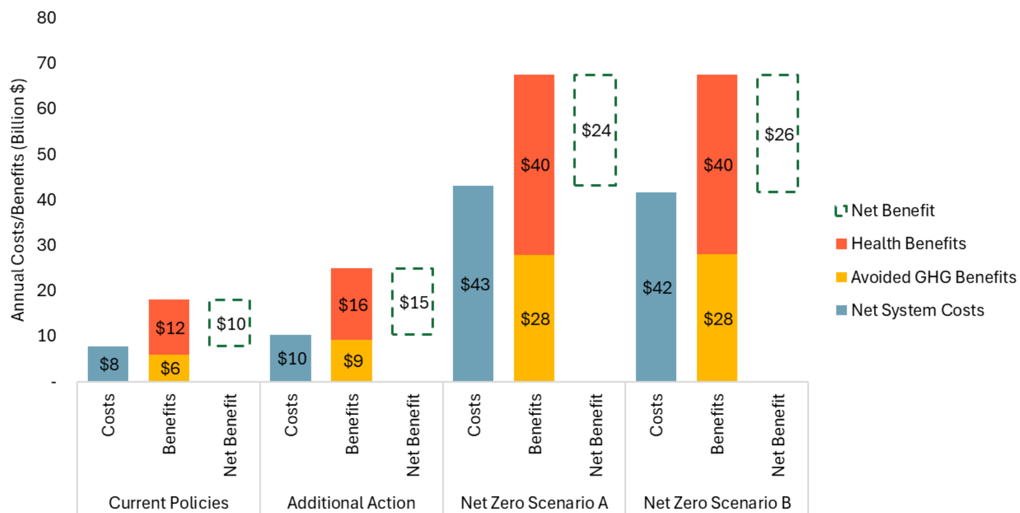

Figure 48. 2040 annual net costs and benefits by scenario (billion 2024$)

6.6. Ability of Energy Systems to Meet Forecast Energy Demand

Across electricity, natural gas, petroleum, and alternative fuels, medium- to long-term demand forecasts are uncertain. Future demand is highly dependent on factors such as economic trends, policy shifts, technology adoption rates, and consumer behavior. To ensure that the state's energy systems are able to reliably meet demand at reasonable cost, New York State policy makers, system operators, and stakeholders will pursue planning and strategies that remain adaptable across a broad set of potential futures.

New York's electricity demand is forecast to grow significantly through 2040 – a marked change from the relatively flat electricity usage over the past decade. New York State is prepared to meet this growing electricity demand while maintaining system reliability and making progress toward a zero-emission grid. New York State likewise will support the reliable provision of natural gas and petroleum fuels, as all major fuels used in the state today are forecast to provide meaningful volumes of energy throughout the planning period.

The core planning scenario developed to inform this Draft Plan projects a 26 percent increase in annual electricity demand and a 23 percent increase in peak demand by 2040 as compared to 2025. This forecast incorporates anticipated new large loads, expanded use of electric vehicle and heat pumps, and energy efficiency upgrades that help manage load growth in buildings. There is uncertainty as to whether the continuous growth in clean energy supply resources will meet growing demand given the federal policy context, broader economic headwinds, and the need for new clean firm technologies to become commercially available. As a result, the State and electricity system operators will continue to pursue careful coordination and planning to adapt as the energy system evolves.

While the State Energy Plan provides statewide and regional forecasts and broad policy direction, multiple ongoing planning processes exist to inform specific decisions such as electricity system investments or whether a given generating unit is needed for system reliability. The NYISO conducts regular reliability planning on both a near-term and long-term basis, including the biennial Reliability Needs Assessment (RNA); if the RNA identifies a reliability need for the bulk system, the NYISO issues competitive solicitations for projects to address it. Importantly, the PSC has initiated changes to the utilities' planning practices in response to clean energy policies and grid modernization needs. For example, the first statewide Coordinated Grid Planning Process (CGPP) is underway.

The scenarios modeled for this Draft Plan suggest declining demand through 2040 for natural gas and petroleum products, though these fuels remain important energy sources. However, notable variability exists across the forecasts that each New York gas utility has developed for natural gas demand in their service area (Figure 43). As directed by the PSC, the gas utilities produced and will regularly update LTPs with gas demand and supply forecasts for multiple scenarios over a 20-year horizon. These LTPs are important to inform gas system investments because they include utility-specific attention to supply sources needed to meet peak day needs during the winter heating months, with consideration of different scenarios that allow for a variety of contingencies to meet energy needs at all times. Electric and gas system planners also need to strengthen coordination measures to ensure fuel adequacy and maintain reliability across both systems.

Appendix

This study models New York's energy system and GHG emissions on an annual basis. Key model outputs include annual energy demand, emissions by fuel, stocks and sales of energy-consuming equipment, and necessary electricity supply infrastructure upgrades. Key inputs include sales forecasts for new technologies (e.g., vehicles, building systems), cost and performance data for supply- and demand-side infrastructure, and fuel price projections.

To perform this analysis, E3 used an integrated suite of modeling tools to analyze the evolution of energy demand, energy supply, and non-energy GHG emissions. A demand-side module calculated direct energy use, associated GHG emissions, and non-combustion emissions and sequestration. This module interacted with models for electricity, low-carbon fuels, and negative emissions technologies. The electricity module used the demand projections to co-optimize investment and operations for the power system, ensuring reliable load service while meeting GHG and renewable energy targets. The low-carbon fuels module assessed the availability of alternative fuels, which the demand-side module could use to reduce emissions by substituting for fossil fuels.

The core analytical tool for energy demand was the New York PATHWAYS model, which projects scenarios to 2050 to align with the Climate Act's targets. The model outputs energy use and GHG emissions for all sectors of the economy, excluding emissions from electricity generation, which were handled by the RESOLVE model. A key feature of PATHWAYS is its characterization of stock rollover, the process of replacing old equipment. By accounting for the long lifetimes of devices like vehicles and heating systems, the model captures the rate of change needed to meet decarbonization goals and highlights the limited window of opportunity to replace fossil-fueled equipment before mid-century. To characterize energy demand, this study used two methods:

1. Stock Rollover Approach: For subsectors with sufficient data, this approach modeled the evolution of infrastructure, energy use, and emissions as new devices are adopted and old ones are retired.
2. Total Energy Approach: For subsectors with less granular data, this approach directly calculated energy consumption based on scenario inputs for energy efficiency, electrification, and fuel switching.

Non-energy sectors were represented by annual emissions by pollutant, informed by parallel modeling efforts which tracked changes in these emissions as driven by policy or infrastructure changes in the scenarios themselves.

1. Buildings

The buildings sector analysis is subdivided into residential and commercial building types, covering energy services such as space conditioning, water heating, lighting, refrigeration, and cooking.

The model calculates building energy demand by first establishing the demand for energy services (e.g., the amount of hot water needed) and then determining the energy demand (e.g., the amount of fuel a water heater consumes) required to meet that service. Energy demand is calculated by dividing the energy service demand by the efficiency of the device providing the service.

The stock rollover approach tracks the lifetimes and efficiencies of the fleet of devices within each end use device type and calculates the energy demand by summing the energy demand for each constituent end use device. For end uses where the total energy approach was applied, E3 characterized energy demand by fuel type directly based on scenario-specific user inputs characterizing energy efficiency, potential for electrification, and potential for switching from fossil fuel combustion to low-carbon fuel combustion.

The analysis begins with a detailed baseline of the current building stock, segmented by type, vintage, and geography across New York's 11 NYISO load zones for a granular assessment. Because residential space heating is a major component of energy consumption that varies by housing type and location, the analysis uses an enhanced segmentation of households into five categories: single-family detached, single-family attached, 2–4 unit buildings, low- to mid-rise multifamily (1–7 stories), and high-rise multifamily (8+ stories).

To generate the distribution of heating devices and building shells across these housing types and fuel sources, the analysis utilizes National Renewable Energy Laboratories (NREL) ResStock database, with targeted adjustments. For other technologies such as cookstoves and lighting, the analysis leveraged federal data sources such as DOE lighting trends reports, EIA National Energy Modeling System (NEMS), and Residential Energy Consumption Survey (RECS). For commercial buildings, the analysis leveraged the New York State Commercial Baseline Survey and federal data sources including NEMS and the Commercial Building Energy Consumption Survey (CBECS) to characterize the existing commercial building stock and energy consumption.

The model then simulates the evolution of this capital stock over the analysis period using a turnover approach. As existing equipment for end uses like space heating, water heating, cooling, and cooking reaches the end of its useful life, it is retired and replaced with new technologies according to defined scenarios. This same turnover logic is also applied to the building shells. The analysis modeled multiple shell types to account for differences in insulation. The reference shell package represents existing buildings prior to 2005 building codes, while the space heating savings for basic, medium, and deep shell packages are summarized by housing type in the table below. All new construction from 2010 onward is assumed to have energy efficiency savings consistent with a medium shell retrofit, while the policy scenarios from 2028 and beyond assume new construction is consistent with deep shell efficiency savings, in line with advanced building codes.

Table A-1. Shell Retrofit Heating Savings

Shell type	Reduction in heating demand (%)
Basic shell	
Single-Family Attached	14%
Single-Family Detached	14%
Single-Family with 2-4 Units	22%
Multifamily with 5+ units, 1-7 stories	9%
Multifamily with 5+ units, 8+ stories	9%
Medium shell	
Single-Family Attached	35%
Single-Family Detached	30%
Single-Family with 2-4 Units	29%
Multifamily with 5+ units, 1-7 stories	13%
Multifamily with 5+ units, 8+ stories	15%
Deep shell	
Single-Family Attached	42%
Single-Family Detached	43%
Single-Family with 2-4 Units	33%
Multifamily with 5+ units, 1-7 stories	50%
Multifamily with 5+ units, 8+ stories	50%

Future technology performance is a key input to the model. For technologies like electric heat pumps, the analysis assumes that their efficiency, or coefficient of performance (COP), will improve over time due to continued technological advancements. For this analysis, an increase in annual average COP was assumed in line with performance improvement growth rates as seen in the NREL Electrification Future Study Moderate Advancement scenario. By calculating the annual energy consumption for each end use within every building segment and tracking the evolution of equipment stock and efficiency, the model creates an aggregate, bottom-up forecast of total energy demand in the buildings sector through 2050. Costs for building shells and heat pumps were aligned with modeling performed in other State energy analyses (BEEM), while costs for other building technologies were sourced from federal data sources (EIA NEMS).

2. Transportation

The transportation sector analysis is conducted using the PATHWAYS model, which projects energy consumption, costs, and emissions by modeling the evolution of the vehicle and equipment stock over time. The model is divided into distinct sub-models for on-road vehicles and non-road transport modes to capture their unique characteristics.

For the on-road stock subsectors, which include light-duty, medium-duty, and heavy-duty vehicles, the model employs a detailed stock-turnover framework. The analysis begins with a detailed inventory of the current on-road vehicle fleet, disaggregated by vehicle class, size, vintage, and fuel type, leveraging data sources including USDOT Vehicle Inventory and Use Survey, EIA State Energy Data System, DEC MOVES modeling. The model then projects future vehicle sales and retirements annually, using survival curves to determine when existing vehicles are removed from the stock and replaced with new ones. Total energy consumption is calculated by multiplying the number of vehicles in each category by their projected annual vehicle miles traveled (VMT) and their fuel economy. For this analysis, VMT per vehicle was assumed to hold constant over time, consistent with recent historical experience suggesting economic growth and VMT growth are not causally correlated in New York. Vehicle classes modeled include light duty autos and trucks, medium and heavy-duty trucks, and buses.

For non-road subsectors such as aviation, rail, and marine transport, a detailed stock-turnover model is not employed. Instead, these "non-stock" subsectors are modeled based on projections of future energy demand. The model accounts for improvements in energy intensity over time and potential fuel switching to alternatives like electricity, hydrogen, or biofuels. By combining the outputs from both the on-road and non-road sub-models, a comprehensive, bottom-up forecast of total energy demand for the entire transportation sector is developed.

3. Industry

Electricity and natural gas use in the starting year are drawn from the NYSERDA statewide Industrial Potential Study performed by DNV, while demand for all other fuels is taken from the EIA SEDS.

The resulting set of modeled subsectors comprises agriculture; primary metals; computer and electronic products; chemicals; construction; food processing; transportation equipment; fabricated metal products; mining and upstream oil and gas; paper; petroleum and coal products; nonmetallic mineral products; and a residual “other” category. An additional large loads category is included to capture new large electricity users, with their projected demand taken directly from NYISO’s annual Gold Book.

4. Electricity

To develop a detailed understanding of future electricity demand, this analysis translates annual energy forecasts into hourly load profiles. This process begins with annual projections for the adoption of new technologies, such as EVs, heat pumps, large loads, and savings from energy efficiency measures. These annual figures are combined with historical hourly usage patterns to create detailed hourly demand profiles. This method captures both the increase in electricity use from new electric technologies and the offsetting savings from efficiency. For the most impactful technologies, namely EVs and electric space heating, a specialized tool called RESHAPE was utilized to generate more granular hourly load profiles by considering factors like local weather patterns, housing characteristics, and driving behavior.

The analysis pairs a least-cost capacity expansion model (RESOLVE) with a resource adequacy model (Renewable Energy Capacity Planning Model, RECAP) to ensure that the selected portfolios maintain system reliability under a wide range of weather conditions. This framework captures the level of temporal detail needed to ensure resource adequacy standards are met under an extensive set of weather conditions, without explicitly modeling all weather conditions within the capacity expansion model. The analytical linkages between the resource adequacy modeling and capacity expansion modeling are described below.

1. **Reliability Modeling (RECAP)**: The first step of the modeling process is conducted in RECAP, which performs Monte Carlo simulations of future loads and renewable outputs under hundreds of years of plausible weather conditions. This modeling is used to identify the reliability contributions of weather-dependent and limited-duration resources, which are measured using an effective load-carrying capability (ELCC) metric. ELCC curves are developed to represent the reliability value of renewable and storage resources as a function of their penetration on the system.

2. **Least-Cost Capacity Expansion (RESOLVE)**: Using annual and hourly load projections from the PATHWAYS analysis coupled with ELCC curves from RECAP, the capacity expansion framework in RESOLVE is then used to identify the least-cost portfolio of investments across New York State to reliably meet projected electricity demands while complying with applicable policy objectives.

3. **Iterative Validation (RECAP)**: The portfolio of generation, storage, and transmission investments selected by RESOLVE is passed back to RECAP to validate that the portfolio meets resource adequacy criteria under the full set of simulated weather conditions. RECAP simulates the reliability performance of the selected portfolio to determine whether the portfolio meets or exceeds the 1-day-in-10-years reliability standard required by the New York State Reliability Council across its thousands of simulations. This step is an iterative step and the portfolio is not finalized until the reliability standard is met.

This integrated process ensures that investment decisions are grounded in a deep, probabilistic understanding of resource reliability, yielding a plan that is both achievable and dependable.

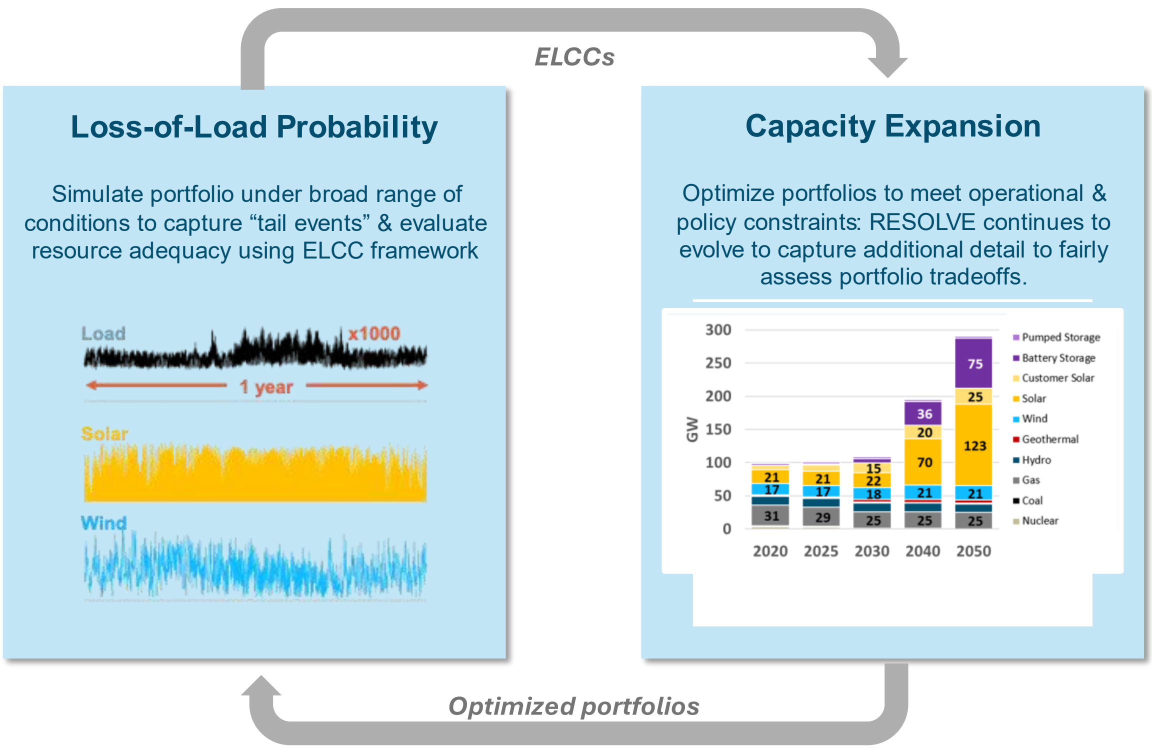

Figure A- 1. Interactions between capacity expansion and reliability within electricity modeling

The resource adequacy modeling performed using RECAP leverages a probabilistic Monte Carlo simulation method. RECAP performs hundreds of unique simulations of a full year of grid operations. In each run, it randomly combines historical weather patterns (affecting wind/solar output and electricity demand) with potential unexpected power plant or transmission outages. By analyzing when and how often supply fails to meet demand across these thousands of simulations, RECAP calculates the effective load carrying capacity (ELCC) for variable resources like wind and solar, and for limited-duration resources like batteries.[14] The ELCCs of variable and limited-duration resources serve as inputs into the capacity expansion modeling. After the least-cost portfolios of resources are identified within the capacity expansion analysis, RECAP is then used to validate that a given portfolio of resources is adequate to meet demand under a comprehensive set of weather conditions, including to ensure the system meets the statewide standard (a loss-of-load expectation of no more than 1 day in 10 years).

The capacity expansion modeling performed in RESOLVE uses optimization methods to identify a least-cost portfolio of generation facilities, energy storage, and/or transmission lines to meet New York's electricity demand. It considers both the upfront capital cost to build new infrastructure and the long-term operational costs (e.g. fuel, operations, and maintenance) of both existing and new facilities. The portfolios must meet the statewide reserve margin as well as local capacity requirements in the Lower Hudson Valley, New York City, and Long Island localities, consistent with the structure of NYISO capacity market requirements. The contributions of the selected portfolio of resources towards resource adequacy constraints are measured using an ELCC framework, leveraging inputs from the RECAP modeling as described above.

Under an ELCC framework, the nameplate capacity of each resource is derated to reflect each resource's availability and limitations during critical reliability periods, as well as its interactive effects with other resources in the portfolio, as reflected in the Figure A- 2 and Figure A- 3 below. In all cases, firm resources (gas, nuclear, hydro, and/or hydrogen) provide the majority of system reliability needs, and renewable and storage additions also provide meaningful contributions. In the constrained build sensitivity, reduced renewable buildout leads to a need for higher contributions from gas units, as compared to the core Additional Action Case.

[14] ELCC represents the capacity contribution as an equivalent amount of "perfect" capacity (capacity that is always available); for example, if solar has an ELCC of 50%, then 100 MW of solar provides the same reliability contributions as 50 MW of perfect capacity. The ELCC of a resource is not fixed; it changes based on a number of factors including the penetration of that resource on the system, its interactive effects with other resources, and the timing of system reliability needs (e.g. as loads change over time).

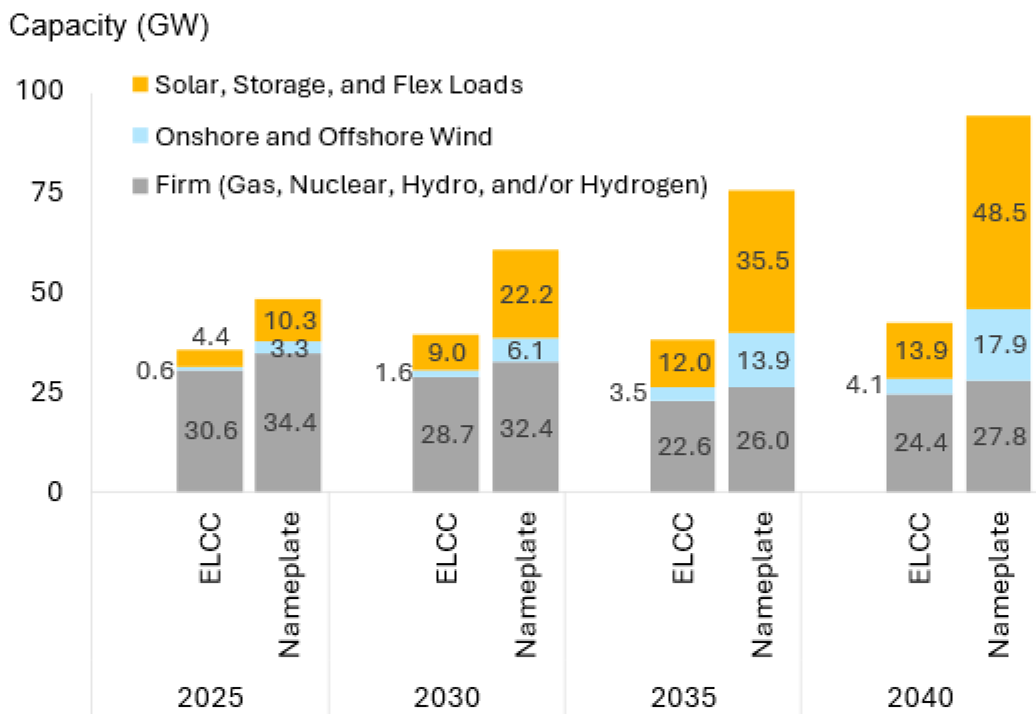

Figure A- 2. Reliability Contributions – Additional Action

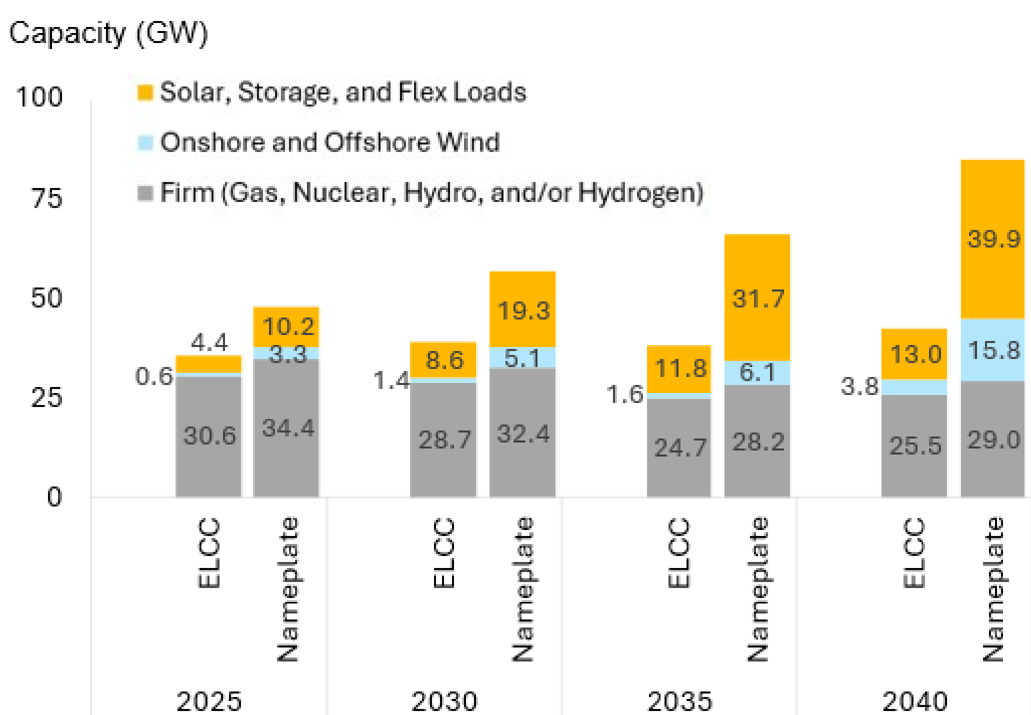

Figure A- 3. Reliability Contributions - Constrained Build Sensitivity

The model leverages a "pipe-and-bubble" framework to capture the transmission system and account for physical constraints on moving power from where it's generated (e.g., remote wind farms) to where it's consumed (e.g., cities). This framework reflects key transmission constraints both within New York and between New York and neighboring markets. New York is represented as a series of distinct electrical zones or "bubbles" interconnected by transmission "pipes", aligned with the 11 NYISO load zones (A-K), as shown in Figure A- 4, below. RESOLVE also includes a simplified representation of neighboring power systems—PJM, ISO-New England, Hydro-Quebec, and Ontario—to capture the ability for New York to trade power with those markets.

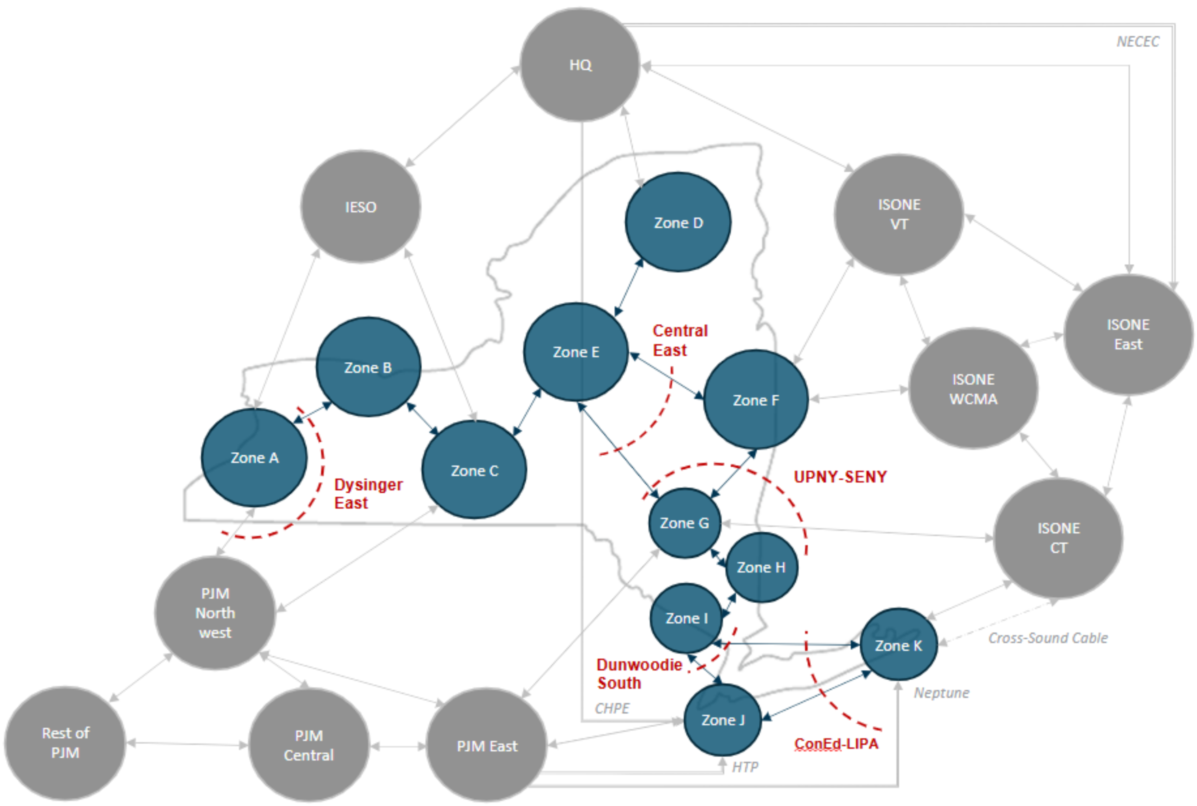

Figure A- 4. Zonal Topology Representation[15]

Combustion units are aggregated into generator blocks in order to simulate their operations while reducing the model size. In each zone, combustion resources are first grouped by their primary fuel—natural gas, residual fuel oil (RFO), or distillate fuel oil (DFO)—and then by technology—combined-cycle gas turbine (CCGT), combustion turbine (CT), or steam turbine (ST). Within every fuel-technology pair, existing units are further stratified into three efficiency tiers defined by heat-rate performance. The representation of combustion resources also reflects units' announced retirement dates and those reaching end-of-life, assuming a 60-year lifetime from commercial-operation date and deferring end-of-life retirements until after 2025. Starting in 2030 upstate and 2035 downstate, the model may choose to

[15] Sources for this topology include the NYISO 2024 RNA, Energy Exemplar, and MA CECP 2050 [add more formal citations if needed]

retire additional capacity based on their going-forward economics, with the extent of these retirements varying by scenario.

The model chooses from a wide menu of candidate resources to create a portfolio that meets reliability and policy constraints while minimizing total cost. Inputs and assumptions come from a variety of sources including alignment with NYSERDA's Large-Scale Renewables Supply Curve Analysis, with adjustments to reflect recent procurement; detailed performance and cost data for these resources can be found in Annex 1. Note that the federal investment tax credit (ITC) and production tax credit (PTC) are both included as at the time of modeling they are current federal policy.

- Land-based and offshore wind
- Imported wind resources with dedicated transmission
- Utility-scale and distributed solar
- Battery storage (between 2–8 hour duration)
- Upgrades to existing hydropower
- New transmission within the state
- Zero-carbon firm resources like hydrogen fuel cells

In cases subject to the 0x40 emissions constraint, hydrogen consumption in the power sector is supplied in part by in-state electrolyzers. The demand from in-state electrolyzers is dynamically reflected in RESOLVE, and this integration ensures that the electric sector's hydrogen budget is tied to actual consumption patterns. The model takes a comprehensive approach to co-optimizing hydrogen consumption and production in the power sector by considering both the commodity price of hydrogen (aligned with data from the NYSERDA Hydrogen Roadmap) and the marginal cost of energy required for the electrolysis process.

Within the capacity expansion framework, the model simulates the operations of the system over 30 representative days. These days are chosen through rigorous statistical analysis and then weighted such that they span a broad range of historical load and renewable-generation conditions while keeping the computations tractable. The dispatch and operations of the selected portfolios can then also be examined over the entire year, e.g. to better understand the operations of the combustion fleet during challenging periods, especially under achievement of the Zero by 2040 requirements.

5. Low-carbon fuel modeling

Mitigation scenarios can incorporate different amounts of advanced biofuels, specifically renewable natural gas (RNG), renewable diesel, and renewable jet fuel, with consumption levels varying significantly between scenarios. Feedstock supply estimates were based on the U.S. Department of Energy's 2023 Billion-Ton Report and the NYSERDA Renewable Natural Gas Potential report, with scenario-specific adjustments to the amount of each feedstock category which is available for use.

The feedstocks considered are classified into three categories:

1. Wastes: Includes animal manure, landfilled or incinerated municipal solid waste (MSW), and byproducts from wastewater treatment. These feedstocks are byproducts of existing economic activities and require no additional land or agronomic inputs.
2. Forest and Agricultural Residues: Consists of logging residues, mill wood waste, and materials from forest management (e.g., thinning and fuel reduction). It also includes agricultural residues like corn stover, cereal straws, and sugarcane bagasse. As byproducts of current forestry and agriculture, these require no new land cultivation.
3. Dedicated Energy Crops: Encompasses cellulosic crops (miscanthus, switchgrass, sorghum) and woody crops (willow, poplar, eucalyptus) grown specifically for energy production. Unlike wastes and residues, these crops require land, which could include marginal agricultural lands or land converted from other uses. These are distinct from conventional biofuel crops like corn (for ethanol) and soybeans (for biodiesel).

An in-house biofuel production model was used to convert biomass feedstocks into one of the three eligible fuels (RNG, renewable diesel, or renewable jet kerosene). The model optimizes this conversion by selecting feedstock-to-fuel pathways that deliver the greatest greenhouse gas emissions mitigation at the lowest cost. Feedstocks from the NYSERDA report, already quantified in energy units of RNG, were not processed through this tool.

Finally, the model generates an average price for each biofuel. This price is determined by the average of the price for feedstock-to-fuel conversion pathways utilized to meet the scenario's demand. These prices serve as key inputs for the broader economy-wide costing analysis and are detailed in Annex 1.

6. Benefit-Cost Approach

This study estimated benefits for two categories: avoided damages from GHG pollution and avoided public health impacts. These benefits were then compared with energy system costs, which include the capital costs of energy-consuming devices and energy supply infrastructure (including electricity generation and electricity imports) in addition to fuel costs. More information on underlying cost assumptions can be found in Annex 1, and more information on the health co-benefits analysis can be found in the Public Health Impacts Analysis chapter.

The value of avoided GHG emissions calculations are based on DEC Value of Carbon guidance, developed under the Climate Act.[16] The DEC Value of Carbon guidance recommends a damages-based approach to valuing avoided GHG emissions, which means that the values are estimates of the monetary impacts on society of GHG pollution. In this study, the total value of avoided GHG emissions is measured in each scenario relative to the No Action Case. The total value of avoided GHG emissions was calculated individually for carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). For other GHGs, avoided emissions were converted to carbon dioxide equivalent (CO_2e) using the AR5-20year GWP values. The avoided GHG emissions time series in each year was multiplied by the annual social cost of GHG based

[16] The value of avoided GHG emissions calculations are based on DEC guidance: https://www.dec.ny.gov/regulations/56552.html, accessed June 2025.

on the DEC Value of Carbon guidance appendix, using the central case estimate for each GHG (2% discount rate for GHG emissions). When calculating NPV of avoided GHG emissions benefits to compare with NPV of costs, NPV calculations apply a discount rate of 5.03% to all annual benefit and costs streams.