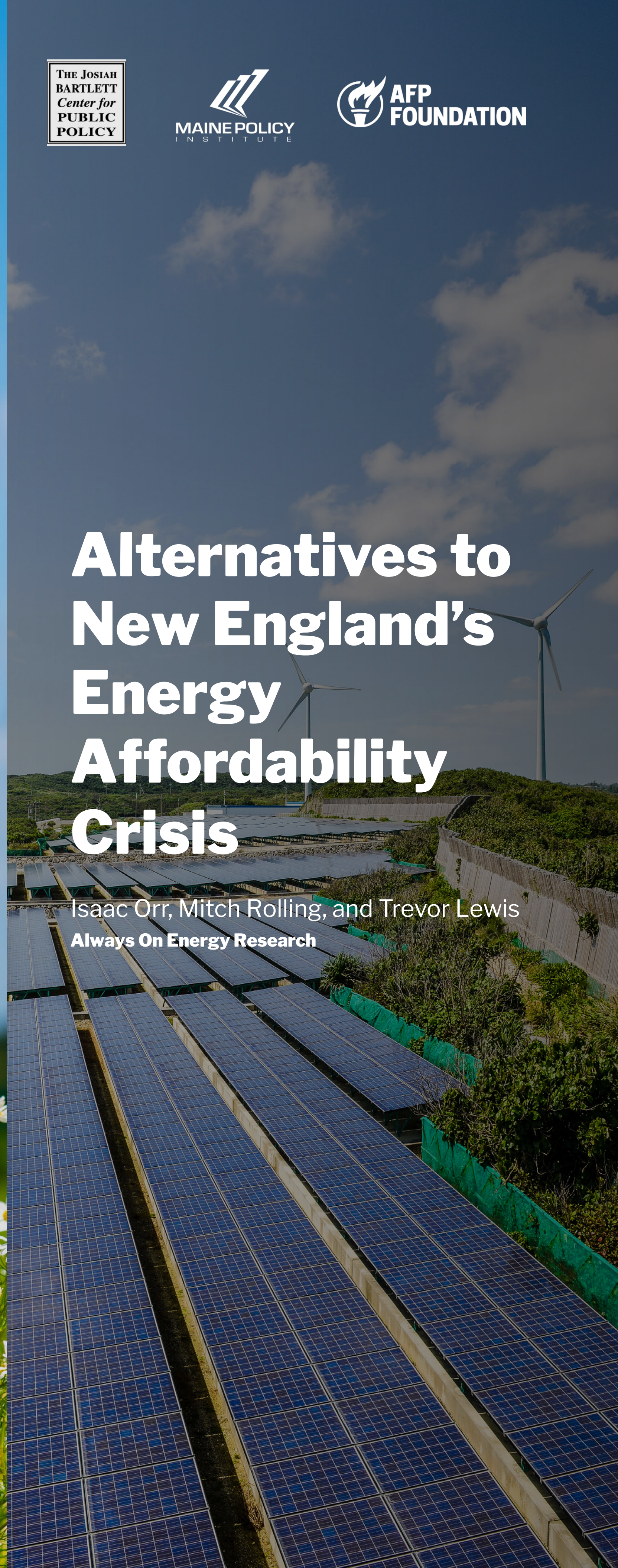

Alternatives to New England's Energy Affordability Crisis

Isaac Orr, Mitch Rolling, and Trevor Lewis

Always On Energy Research

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January 2026 Authors' Note: This report is a continuation of the work performed by the authors at Always On Energy Research, modeling the cost of energy portfolios in states throughout the country. Portions of this report have been repurposed and modified to reflect the result of state decarbonization plans in the Independent System Operator of New England.

Introduction

In 2024, Always On Energy Research (AOER) modeled the economic and reliability impacts of the energy policies passed in the six New England states: Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont, and published these findings in "The Staggering Costs of New England's Green Energy Policies."[1]

Each of these states, with the exception of New Hampshire, has established aggressive installation requirements for solar, offshore wind, onshore wind, and battery storage and requires deep reductions in carbon dioxide emissions from the power sector, primarily by reducing the use of natural gas for power generation in the Independent System Operator of New England (ISO-NE) region.

Decarbonization policies in these states also require a shift away from natural gas and fuel oil for home heating, as well as a transition from gasoline and diesel-powered vehicles to electric vehicles. For a more comprehensive discussion of the energy policies enacted by each New England state, please see Section I in the previous report.[2]

Requiring the electrification of the home heating and transportation sectors will nearly double peak electricity demand on the ISO-NE system and increase overall electricity demand by 106 percent.[3] Building enough capacity to meet these requirements—a challenge that is compounded by the shift toward non-dispatchable generation resources like offshore wind, onshore wind, solar photovoltaic systems, and battery storage, and away from natural gas generation—will cause electricity prices to skyrocket.[4,5]

Our analysis determined that meeting these decarbonization and electrification policies would nearly cost New England electricity customers an additional $815 billion through 2050, compared to the cost of operating the current electric grid, and make the region more vulnerable to rolling blackouts.

Increasing costs by an additional $815 billion (in constant 2024 dollars) would more than double electricity bills for the average New England family, with yearly expenses rising from $2,100 per year in 2024 ($175 per month) to $4,600 per year in 2050 ($383 per month), creating real hardship for families who already pay some of the highest electricity prices in the United States.

However, there are lower-cost ways to reliably meet electricity demand and reduce greenhouse gas (GHG) emissions in the region. This report demonstrates how a focus on deploying reliable nuclear and natural gas power plants could yield hundreds of billions of dollars in savings for New England electricity customers compared to the grid outlined in the Renewable scenario in the previous report.

Our analysis examines three new scenarios: a Nuclear scenario, where rising demand for carbon-free electricity and electrification are met with new nuclear power plants, a Natural Gas scenario, where the region meets rising demand with new natural gas power plants and pipeline capacity, and a Happy Medium scenario, where a blend of technologies achieves a cost-optimized, 50 percent carbon-free electricity grid by 2050.

Of these new scenarios, the Nuclear scenario would yield the largest reductions in GHG emissions, but it would also cost the most, increasing costs by an additional $415.3 billion through 2050, compared to the current grid. While this scenario would save nearly $399.5 billion compared to the Renewable scenario, it demonstrates that decarbonization will not be easy or inexpensive.

At an additional $106.9 billion, compared to the current grid, the Natural Gas scenario is the lowest cost, and lowers total annual GHG emissions by 24.5 percent across the electric, home heating, and transportation sectors in 2050. The Happy Medium scenario would balance costs and reduce total annual emissions by 50 percent in 2050, at an additional cost of $195.8 billion, compared to the current grid.

While meeting the rising demand for power due to the electrification of the home heating and transportation sectors in each of these scenarios is expensive, all the studied scenarios offer significant savings compared to the Renewable scenario described in our previous report and do not result in rolling blackouts. Therefore, these portfolios offer a more affordable, reliable, and reasonable path forward for energy policy in the New England states.

SECTION I

Alternative Scenarios for Meeting New England's Rising Power Demand

Our previous report detailed how meeting the electrification and decarbonization mandates passed in five of the six New England states, with a portfolio heavily reliant upon solar, battery storage, onshore wind, and offshore wind, will cost an additional $815 billion through 2050 compared to operating the existing grid. This report focuses on three additional scenarios that can meet this rising demand at a much lower cost.

As a reminder, ISO-NE expects these electrification and decarbonization mandates to trigger a substantial increase in the total amount of electricity consumed in the coming decades. AOER's previous analysis found that electrifying the transportation and home heating sectors will cause ISO-NE's annual electricity consumption to grow by 106 percent in 2050.

The increase in electricity use for transportation and home heating will also drive peak electricity demand substantially higher than it is today. According to the Internal Market Monitor (IMM), the average hourly electricity demand in ISO-NE in 2024 was 13.2 gigawatts (GW), with a peak demand of 24.9 GW.[6] For context, there are 1,000 megawatts (MW) in each gigawatt.

ISO-NE's "2050 Transmission Study" suggests that by 2050, winter peak demand could hit 57 GW, more than doubling the current winter peak record of 23 GW (see Figure 1).[7] The ISO's "Economic Planning for the Clean Energy Transition" report estimates this figure could reach 60 GW, and these projections do not include estimated demand increases from data centers that are expected to drive massive increases in electricity demand nationally.[8]

The vast majority of new winter load growth is due to home heating, as shown in the dark blue bars in Figure 1, which becomes the single-largest component of peak electricity demand in 2050.[9] The light blue and light orange bars indicate the increase in electricity demand from the electrification of the transportation sector.

Our analysis adopts many of the same assumptions as the "2050 Transmission Study" by assuming the five states with decarbonization policies will completely adopt electric vehicles and electric home heating systems. However, our modeling assumes New Hampshire residents will continue to utilize natural gas power plants as well as conventional home heating systems and internal combustion engines. This results in a reduction of peak electricity demand by 4,457 MW on the ISO-NE system, for

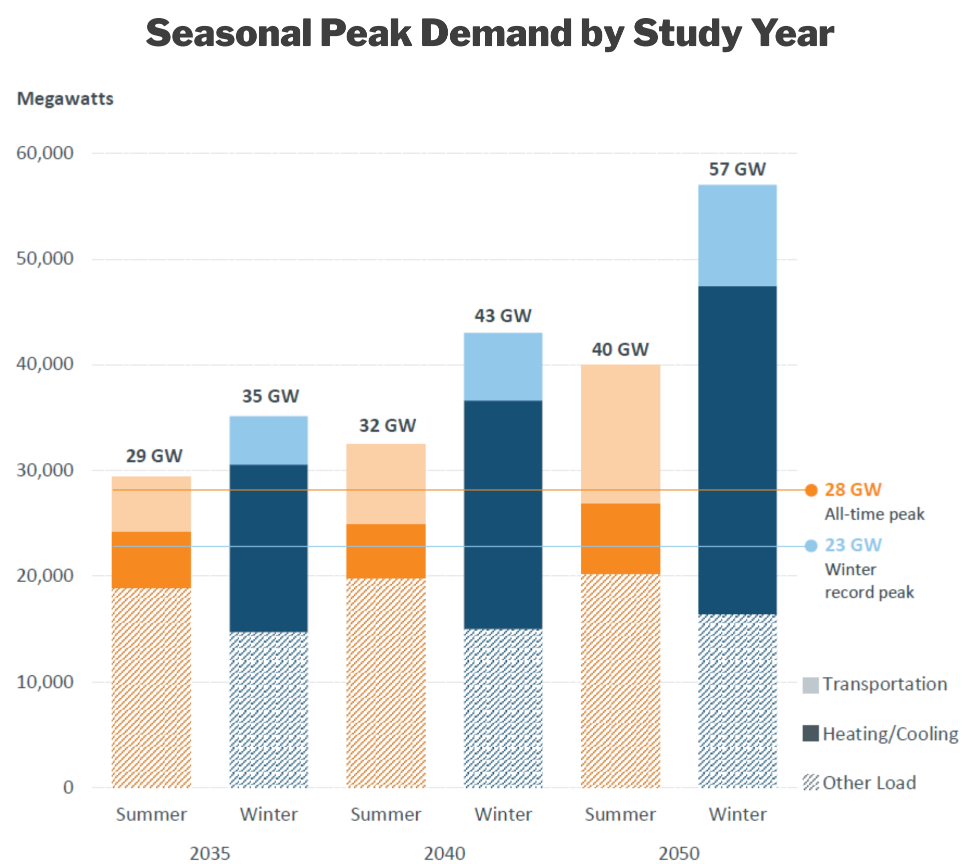


FIGURE 1. The vast majority of new winter load growth is due to home heating, as shown in the dark blue bars, which becomes the single-largest component of peak electricity demand in 2050. The light blue and light orange bars indicate the increase in electricity demand from the electrification of the transportation sector.

a new total peak demand of 52.5 GW.

Meeting this growing demand will require a substantial buildout of new power plant capacity. Each of the four scenarios discussed below seeks to meet these new peak and annual demands for electricity in its own unique way.

The Renewable Scenario

The Renewable scenario is the resource portfolio modeled in our 2024 report, where state mandates for renewable resources and decarbonization shift electricity generation away from the current reliance on natural gas toward greater reliance on solar, battery storage, onshore wind, and

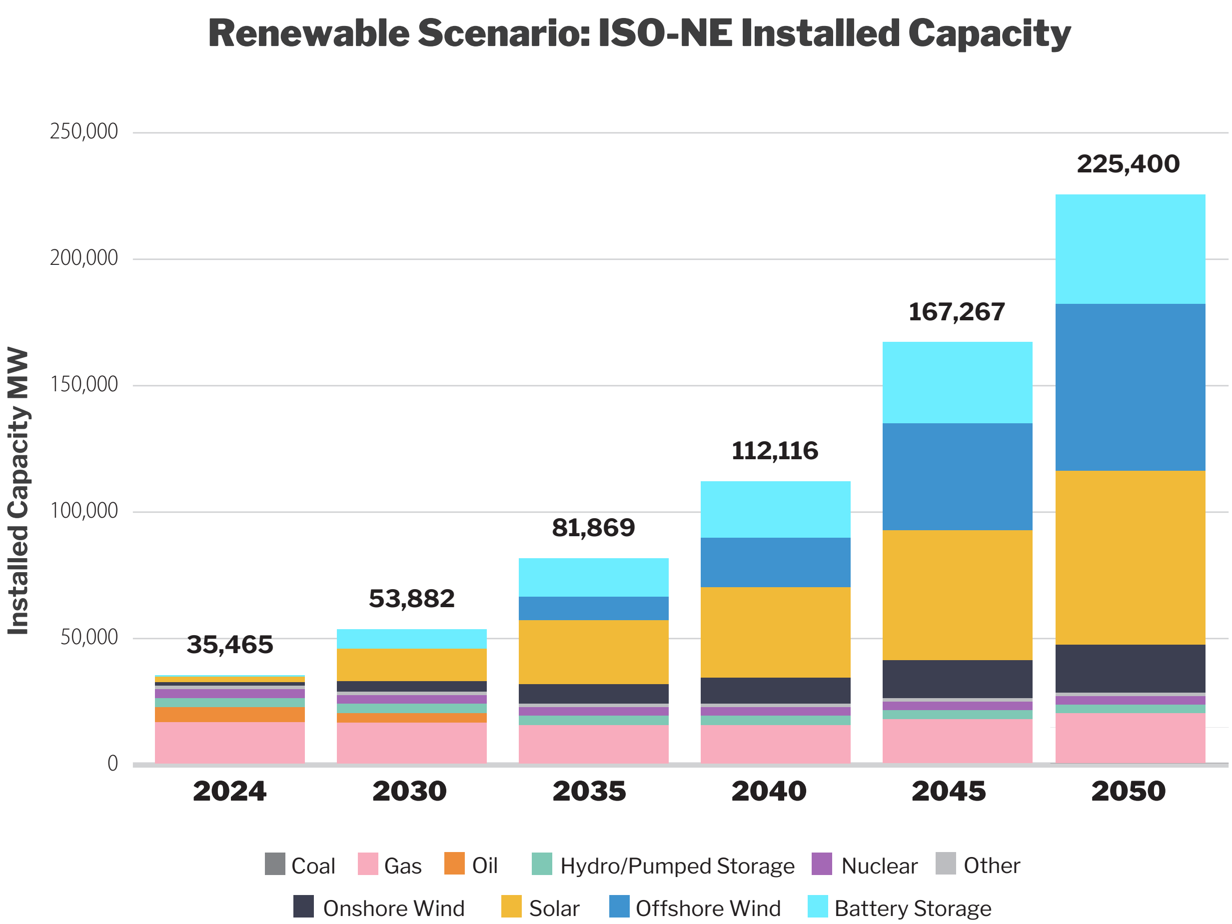


FIGURE 2. Total installed capacity in the Renewable scenario increases to 225 GW of installed capacity to meet the projected peak demand. Data from AOER's capacity expansion model.

offshore wind. This scenario requires the largest increase in power plant capacity of any of the scenarios studied.

Under this scenario, offshore wind installations would increase from 30 MW of installed capacity in 2022 to 66 GW of capacity in 2050 (see Figure 2). Onshore wind would increase from 1,546 MW to 19.2 GW. Solar capacity would grow from 2,242 MW to 68.4 GW, and battery storage would increase from 303 MW to 43 GW, with four hours of storage per MW.

The Nuclear Scenario

The Nuclear scenario builds 20,400 MW of large nuclear power plants

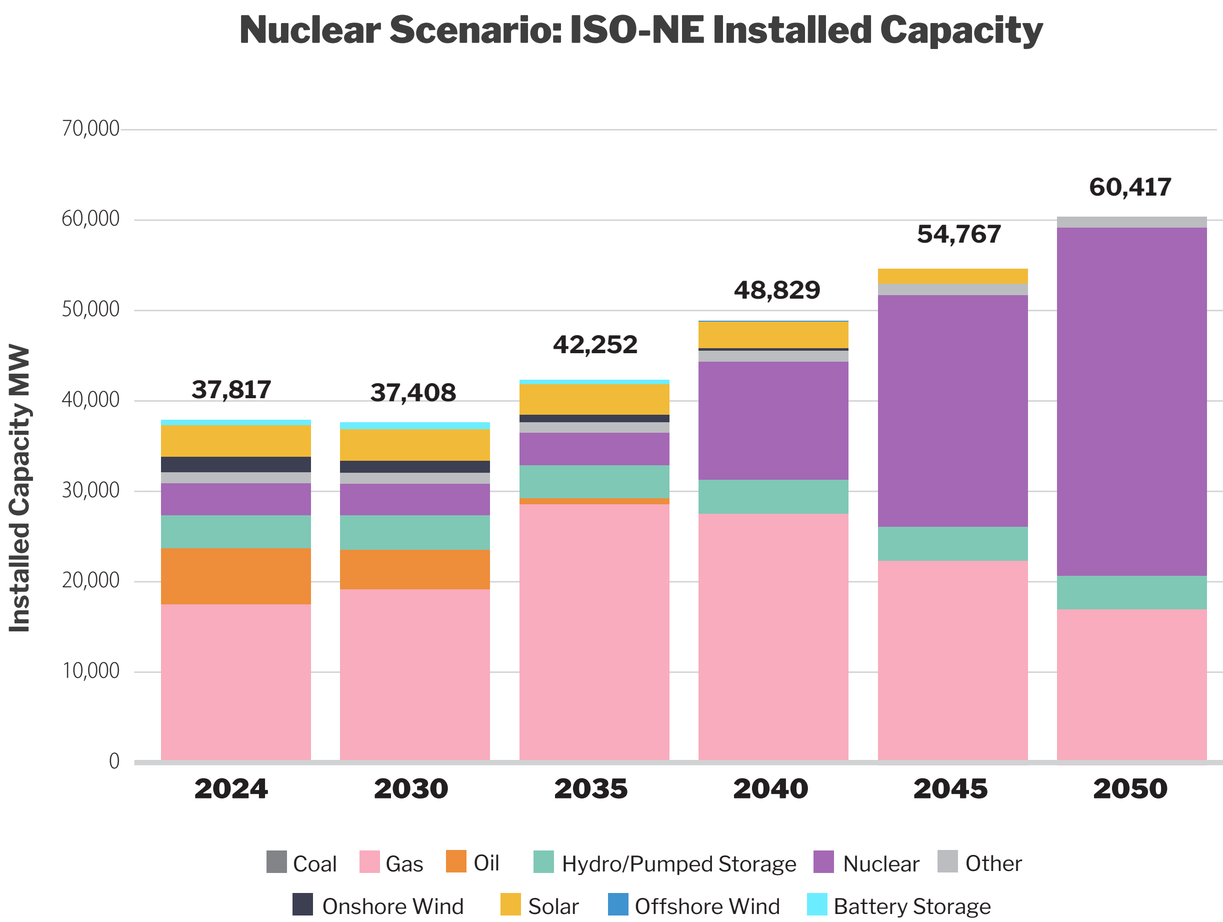


FIGURE 3. New nuclear capacity comes online in 2036, and nuclear becomes the largest source of capacity on the ISO-NE system by 2045. Natural gas plants are built in the early years to meet growing demand before nuclear facilities are completed. While many natural gas facilities are retired, others are kept online to provide electricity during times of peak demand. Data from AOER's capacity expansion model.

by 2050 and 14,700 MW of small modular reactors (SMRs) to replace nearly all the carbon dioxide-emitting resources on the grid. It adds 13,700 MW of natural gas capacity as necessary to meet projected future peak demand, with natural gas being an important bridge in the medium-term years in the 2030s to allow construction for nuclear plants while also maintaining reliability (see Figure 3).

Due to the long lead time for building nuclear power plants, the first nuclear plants would come online in 2036, affording 10 years for planning, construction, testing, and initial operations.

This analysis uses overnight capital cost assumptions for nuclear light

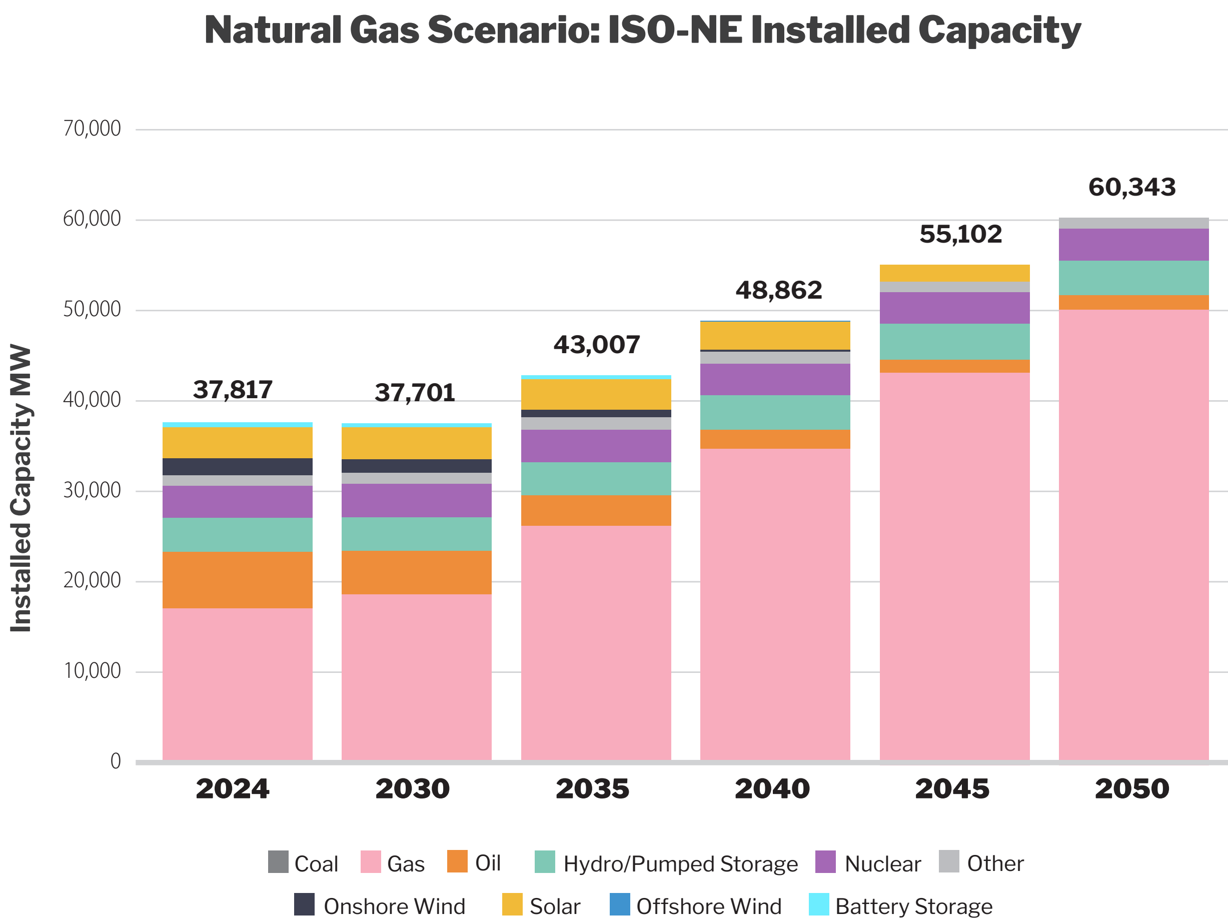


FIGURE 4. Natural gas capacity is added to meet peak demand growth throughout the course of the model. Data from AOER's capacity expansion model.

water reactors and small modular reactors from the U.S. Energy Information Administration (EIA) in its "Electricity Market Module" for the Annual Energy Outlook 2025 (AEO) in the ISO-NE region.[10]

New natural gas plants are built to meet rising demand in the early years, then nuclear plants are used to phase out reliance on natural gas on the system, utilizing them as peaking resources in later years. As a result, the system achieves 92 percent carbon-free generation on an annual basis by 2050. Like the Natural Gas scenario discussed below, ISO-NE's existing wind, solar, and battery storage capacity are utilized until the end of their useful lifetimes, but no additional intermittent capacity is built.

The Natural Gas Scenario

The Natural Gas scenario utilizes new combined cycle (CC) natural gas plants to provide high-efficiency, baseload power with manageable fuel costs to meet rising demand. When appropriate, natural gas combustion turbine (CT) plants are installed to meet peak demand.

Existing natural gas, nuclear, oil, wind, and solar facilities on the ISO-NE grid are utilized until they reach the end of their useful lives, as it would not make sense to decommission them. Nuclear plants are relicensed, but no more intermittent capacity is placed into service, and these facilities are not repowered at the end of their useful lifetimes (see Figure 4). Existing coal facilities are retired on the same timeline as the Renewable scenario.

The Happy Medium Scenario

The Happy Medium scenario aims to balance affordability and emissions reductions by optimizing the system to lower GHG emissions while keeping costs lower than those of the Nuclear and Renewable scenarios. Under the Happy Medium scenario, 50 percent of the electricity on the ISO-NE system would be generated by carbon-free sources by 2050.

To achieve these emissions reductions, the scenario builds 10,800 MW of nuclear power plants and 24,300 MW of natural gas capacity by 2050 to meet rising demand. Nuclear capacity additions are backloaded due to the long construction timelines for the projects, but the new natural gas plants needed to meet incremental demand are not retired at the end of the scenario.

The Happy Medium scenario also maintains the existing wind and solar resources on the grid throughout the end of their lifespans, as it would not make sense to decommission them, but places no more intermittent capacity into service, and these facilities are not repowered at the end of their useful lifetimes (see Figure 5).

Are Any of These Plans Realistic?

The decarbonization plans in the five states will require a massive buildout of new power plant capacity, transmission lines, natural gas pipelines, electric vehicle infrastructure, and the widespread deployment of heat pumps and other electric heating equipment on an aggressive timeline that may not even be possible. Each of the scenarios studied in this report faces real obstacles that could prevent them from coming to fruition.

For example, AOER's previous analysis concluded that the Renew-

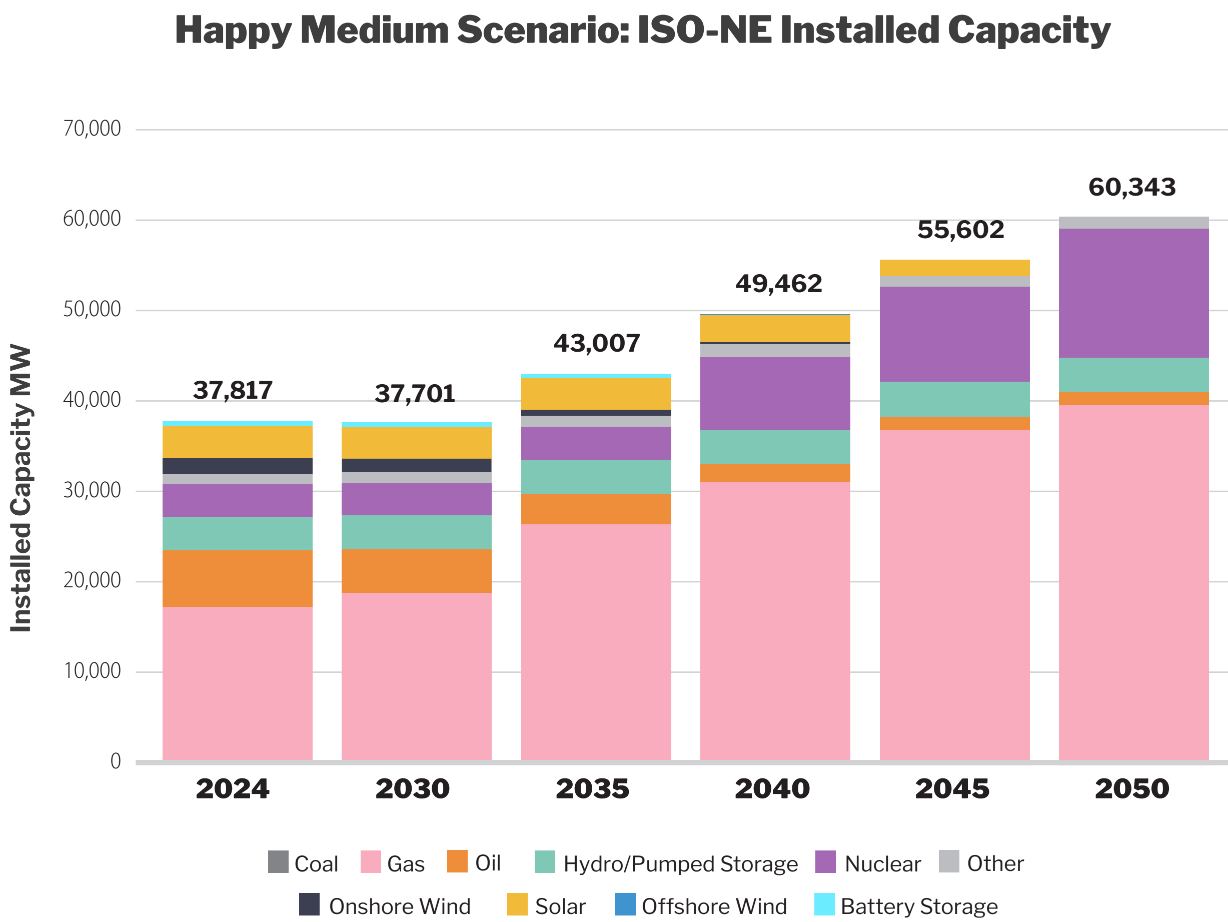


FIGURE 5. This figure shows the increase in installed capacity in each year of the Happy Medium scenario. Data from AOER's capacity expansion model.

able scenario would require a massive buildout of solar, battery storage, offshore wind, and onshore wind capacity. The assumptions for offshore wind capacity additions were almost always overly optimistic, but recent actions by the Trump administration, such as offshore wind lease cancellations and the stop-work order issued on Revolution Wind, have compounded the uncertainty for the industry in the region despite a court ruling allowing the project to continue construction.[11]

The Nuclear scenario would require 20,400 MW of large nuclear reactor capacity and 14,700 MW of SMRs to meet the projected peak demand with a healthy reserve margin. However, this quantity of nuclear power plants would be over 13 times more nuclear capacity than was built from 2009 to 2024.[12] This buildout is further complicated by the fact that as of the time of this writing, no SMRs have been installed anywhere in the United States on a commercial basis to date.[13]

For the Natural Gas and Happy Medium scenarios, the primary constraint for building and operating enough new natural gas plants is a shortage of pipeline infrastructure to deliver fuel to the new natural gas capacity. In the past, these pipelines were abandoned when New York regulators blocked water quality permits, leaving their future status deeply uncertain.[14]

Increasing natural gas pipeline capacity and building new nuclear power plants will be a significant regulatory challenge. As a result, the main benefit of examining these scenarios is to illustrate the relative benefits of these nuclear and natural gas portfolios compared to the Renewable scenario described in our previous report.

SECTION II

Impacts on ISO-NE Energy Production

The policies designed to decarbonize the power grid will have a profound impact on the way New Englanders produce their electricity.

According to the IMM for ISO-NE, 50 percent of the region's electricity was generated at natural gas fired power plants in 2024, 22 percent from nuclear power, 9 percent from imports—largely hydro imports from Hydro-Quebec (HQ)—7 percent was hydroelectric and pumped storage, 5 percent was "other," 3 percent was wind, 4 percent solar, and coal, oil, and battery storage constituted 0.2 percent, 0.2 percent, and 0.3 percent of the region's electricity supply, respectively (see Figure 6).[15]

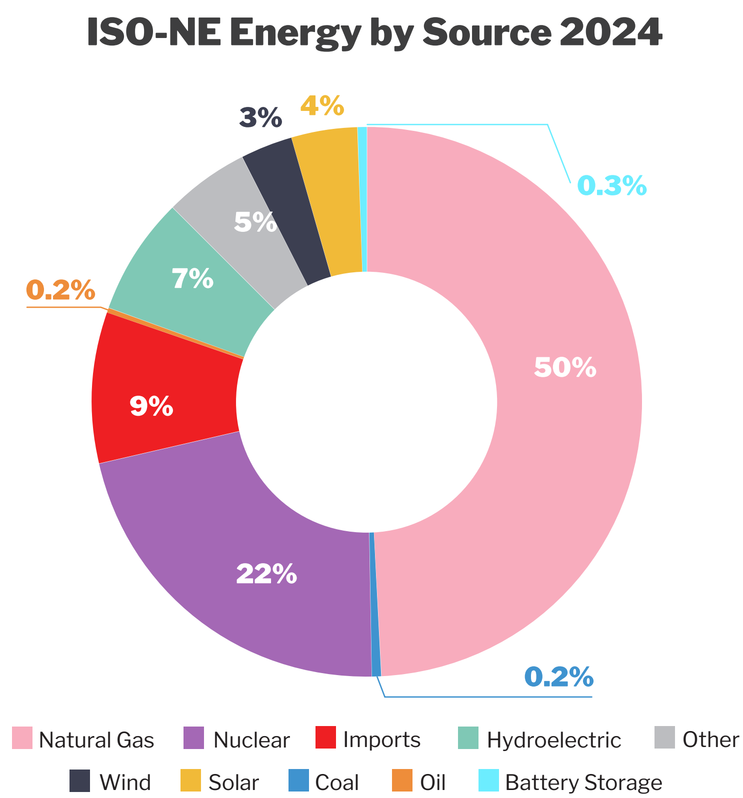


FIGURE 6. Natural gas and nuclear power produce the largest shares of electricity in New England, followed by imports and hydroelectric power. Wind and solar produced 3 percent and 4 percent, respectively, of the total electricity consumed in the region in 2024.

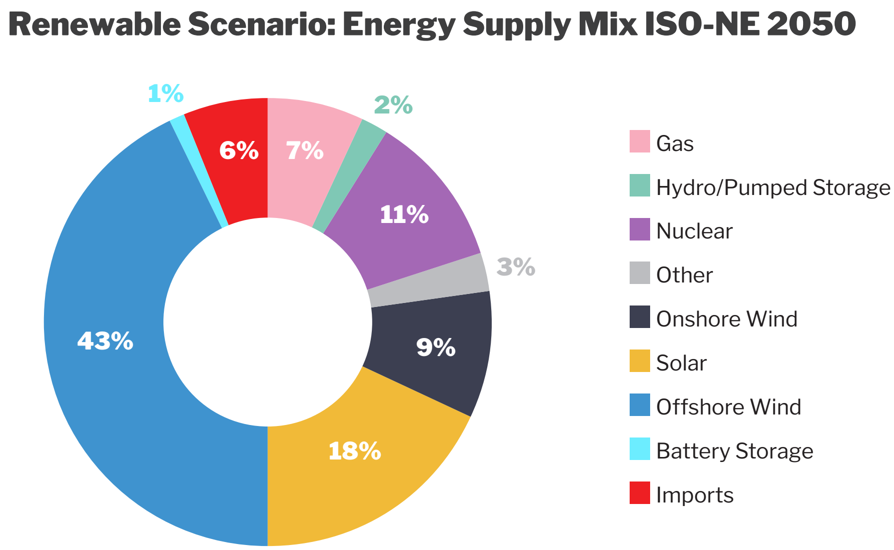


FIGURE 7. Offshore wind becomes the largest source of electricity in New England in the Renewable scenario. Data from AOER modeling.

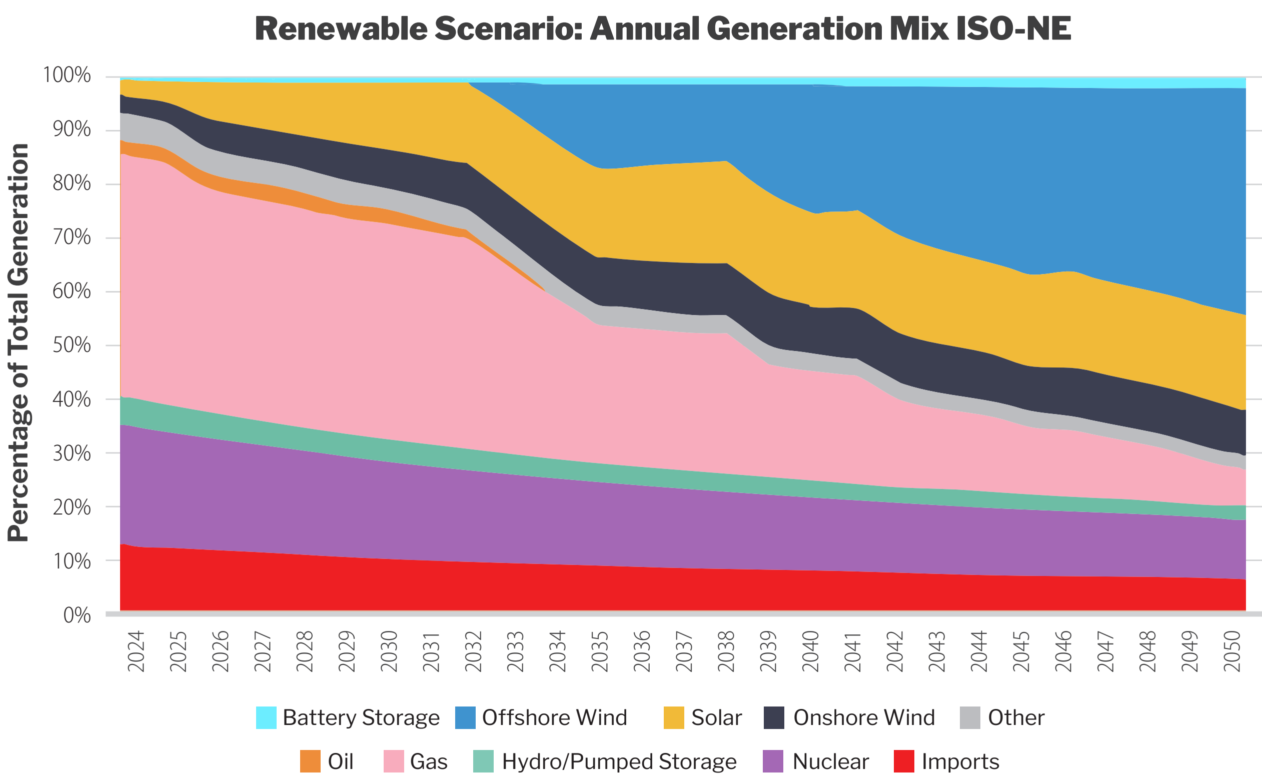


FIGURE 8. Offshore wind and solar become the largest energy sources under the energy policies of the New England states. Existing nuclear plants continue to operate but constitute a smaller share of overall generation as demand for power increases due to the electrification of transportation and home heating. Data from AOER modeling.

This resource mix will change substantially due to the policies of the five decarbonizing states under each of the modeled scenarios.

In the Renewable scenario, ISO-NE reaches 84 percent of generation from carbon-free resources by 2050 from sources within the region, and 90 percent when imports, which primarily consist of hydroelectric power purchased from Canada, are included. Offshore wind and solar become the largest sources of electricity on the ISO-NE system, constituting 43 percent and 18 percent of total generation, respectively. Onshore wind provides 9 percent, nuclear provides 11 percent, natural gas generates 7 percent, imports account for 6 percent, hydroelectric and pumped storage account for 2 percent, and "other" constitutes 3 percent (see Figure 7).

Figure 8 shows the annual shift in generation in the Renewable scenario as ISO-NE reduces its use of natural gas and adds more offshore wind, solar, and onshore wind. Nuclear power generation remains constant in this scenario, but its overall share of power delivered to the grid falls as demand rises, meaning the same amount of nuclear power is being generated over time, but it constitutes a smaller percentage of the overall supply.

Under the Nuclear scenario, the energy mix will consist of 90 percent nuclear, 5 percent natural gas, 2 percent hydroelectric and pumped storage, and 3 percent other, meaning 92 percent of the electricity is provided by carbon-free sources (see Figure 9).

The natural gas remaining on the system serves mainly as a peaking resource in the region in later years. Figure 10 shows the change in electricity generation over time.

Under the Natural Gas scenario, the energy mix will consist of 12 percent nuclear, 83 percent natural gas, 2 percent hydroelectric and pumped storage, and 3 percent other (see Figure 11).

Figure 12 shows the growth in gas generation over time. The share of power generated from nuclear decreases over time as overall demand increases, and generation from wind and solar decreases as these facilities eventually reach the end of their useful lives and are not replaced.

Under the Happy Medium scenario, the energy mix will consist of 47 percent nuclear, 47 percent natural gas, 3 percent hydroelectric and pumped storage, and 3 percent other (see Figure 13).

Figure 14 shows the growth in natural gas and nuclear generation over time as existing wind and solar resources eventually reach the end of their useful lives.

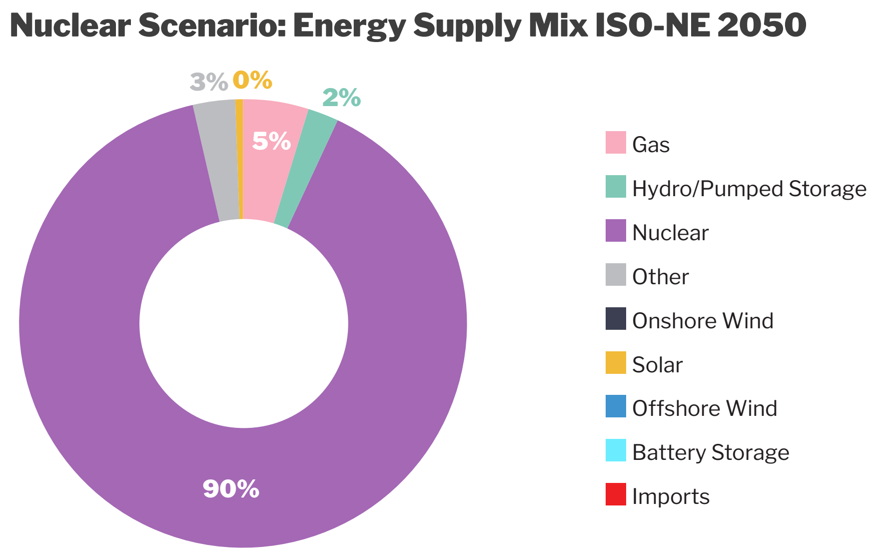


FIGURE 9. Nuclear grows from 22 percent of the resource mix in the Nuclear scenario to 90 percent. Data from AOER modeling.

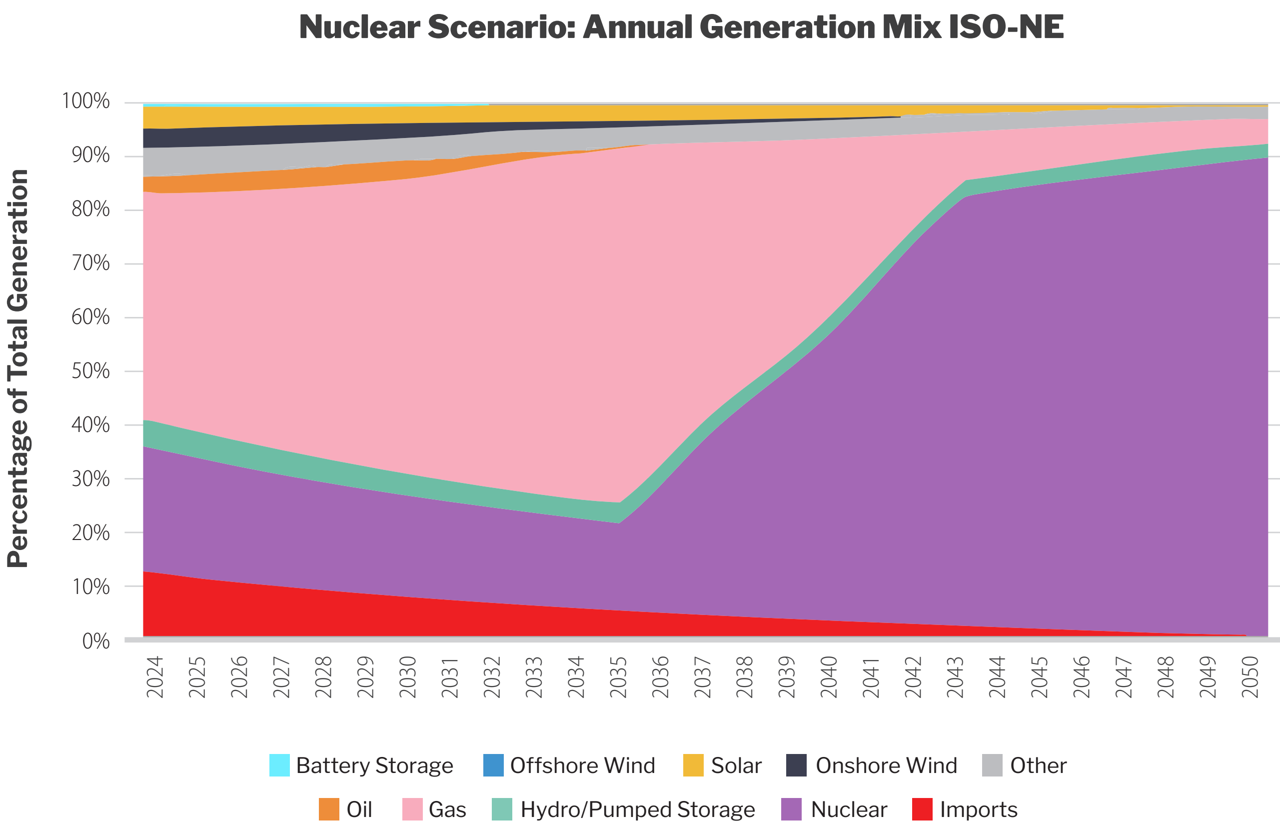


FIGURE 10. Nuclear is the largest energy source under the energy policies of the New England states, and natural gas serves as a load-balancing resource. Data from AOER modeling.

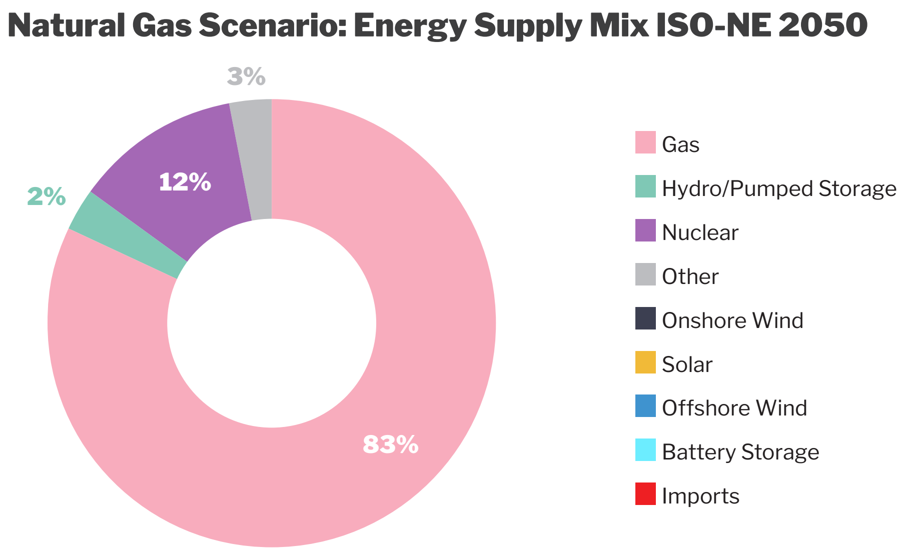


FIGURE 11. Natural gas generation grows from approximately 50 percent of total generation in 2024 to 83 percent of generation in 2050. Data from AOER modeling.

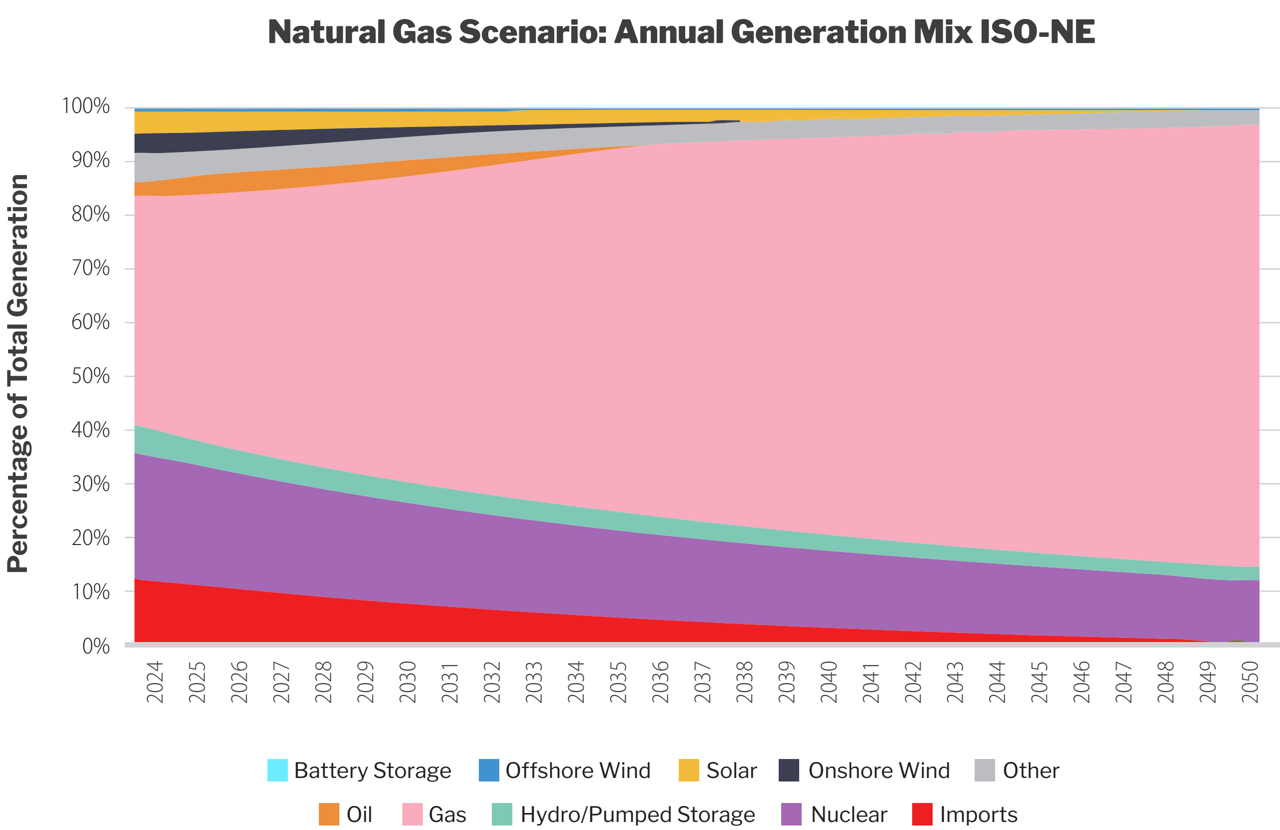


FIGURE 12. Natural gas generation reaches 83 percent while the relative contribution of other generating sources falls. Data from AOER modeling.

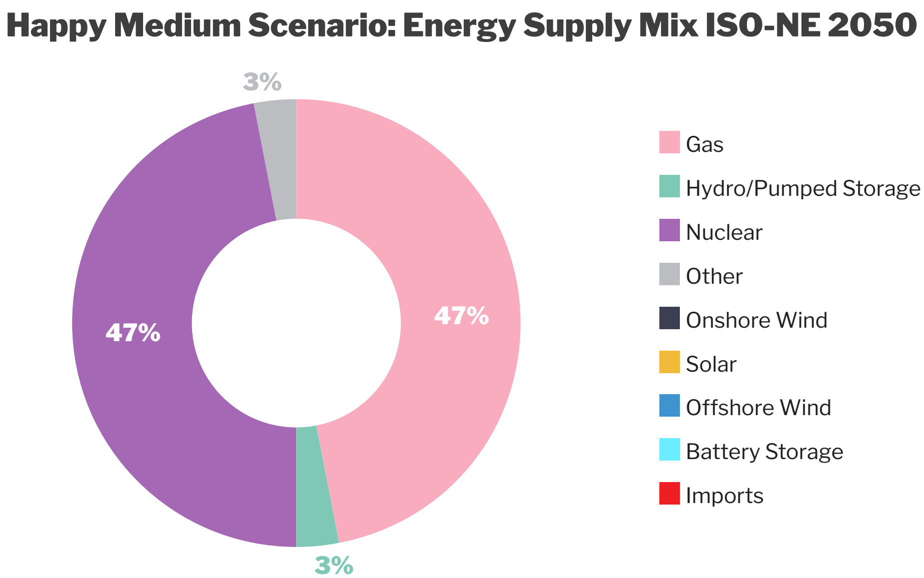


FIGURE 13. Under this scenario, 50 percent of the electricity generated on the ISO-NE System would come from carbon-free nuclear resources.

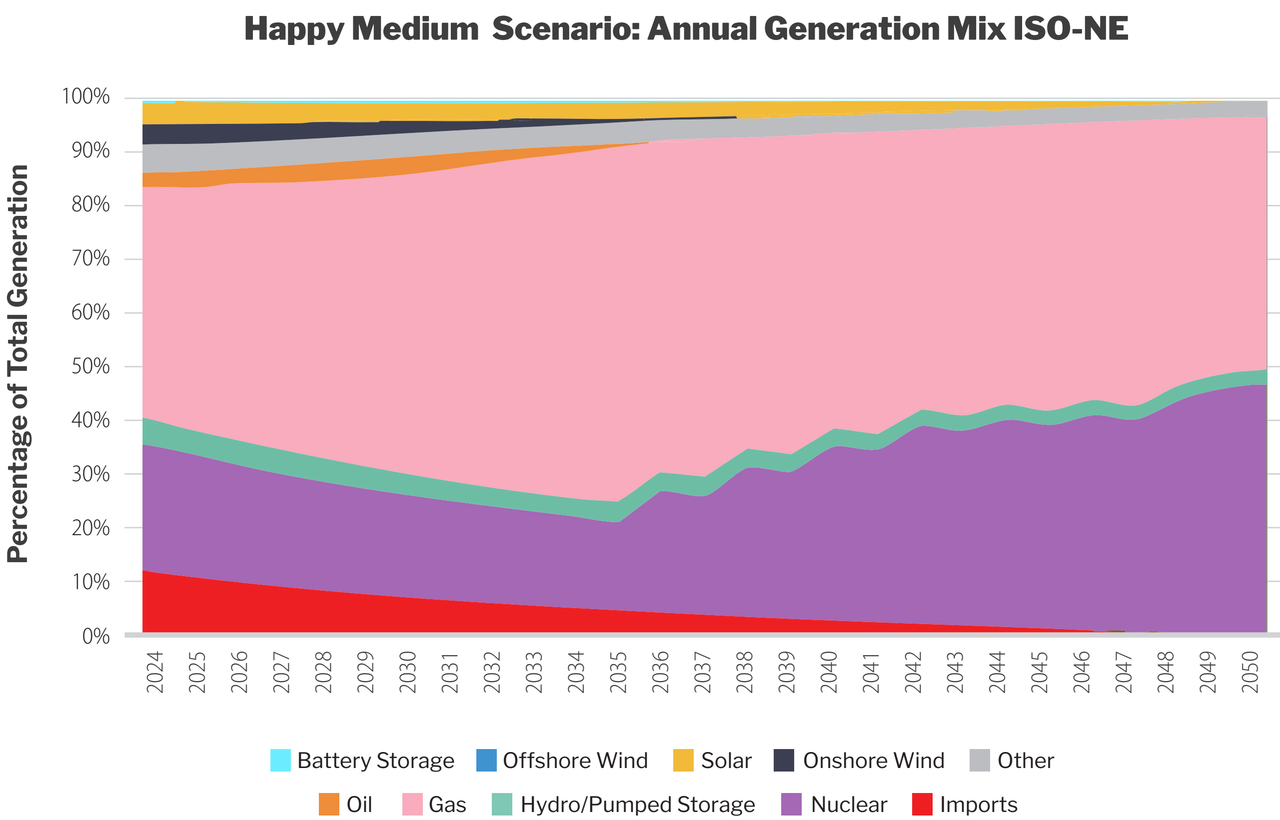


FIGURE 14. Natural gas generation expands through the midpoint in the model to meet rising demand, and new nuclear plants are added in the later years to reduce GHG emissions.

SECTION III

Calculating the Cost of the Three Scenarios

New England residents already pay some of the highest electricity prices in the country, and these prices would rise significantly in each of the scenarios, but they would be far less expensive in the Nuclear, Natural Gas, and Happy Medium scenarios than in the Renewable scenario.[16]

Our modeling indicates that complying with the Nuclear scenario will cost an additional $415.3 billion (in constant 2024 dollars) compared to operating the current electric grid without the inclusion of federal subsidies.[17] The Natural Gas scenario will cost an additional $106.9 billion, and the Happy Medium scenario will cost an additional $195.8 billion. Figure 15 shows each of these scenarios is far lower in cost than the Renewable scenario, which would cost nearly an additional $815 billion through 2050.

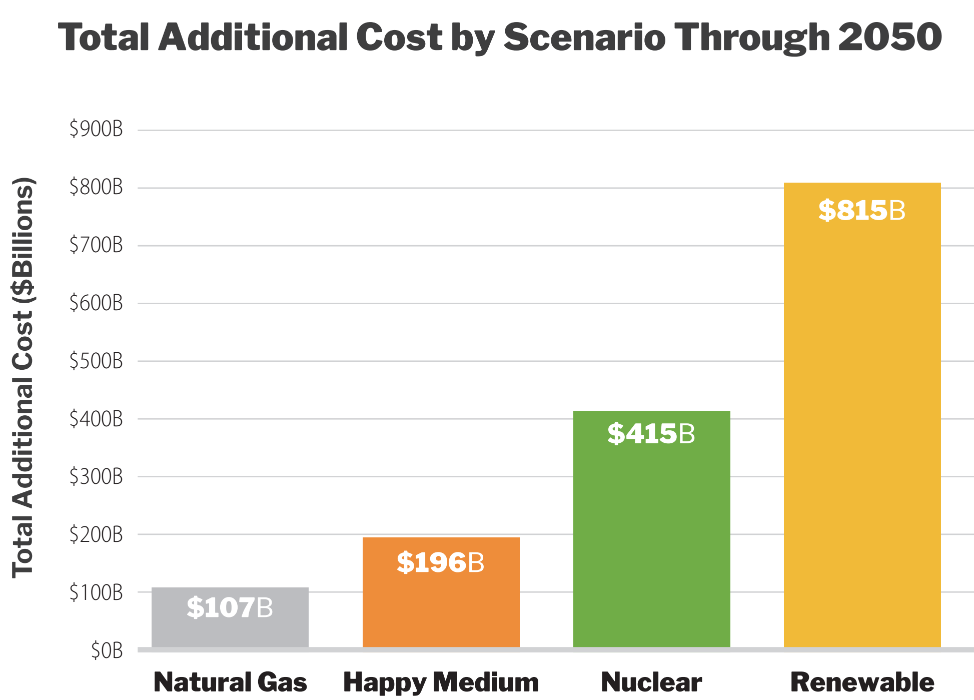


FIGURE 15. This figure shows the total additional cost, compared to the current grid, of each of the four scenarios studied in this report through 2050. Data from AOER's cost modeling.

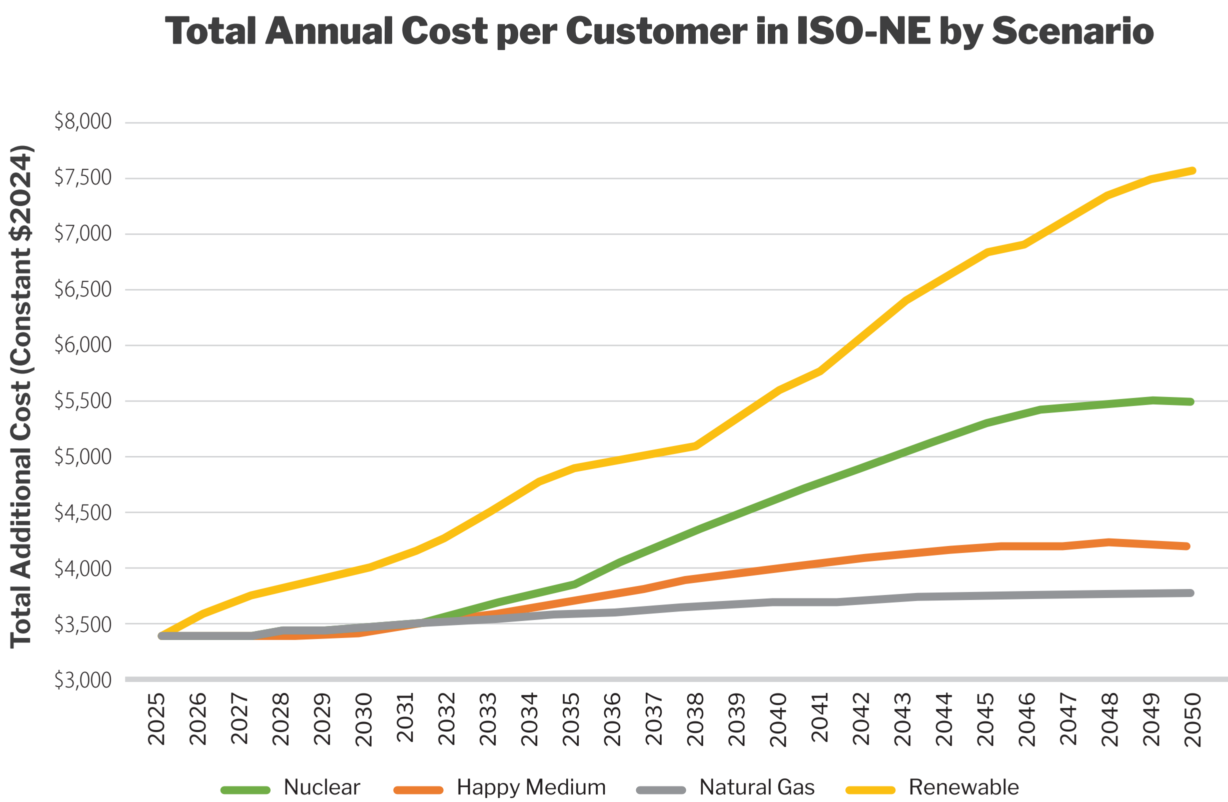


FIGURE 16. The Natural Gas scenario would cost the least, while the Renewable scenario would be the highest-cost portfolio for meeting New England's growing electricity needs. Data from AOER's cost modeling.

This would increase electricity prices by 64.8 percent in the Nuclear scenario, 13 percent in the Natural Gas scenario, and 26.5 percent in the Happy Medium scenario. These increases are still far less than the Renewable scenario, which would increase prices by 126.4 percent.

Figure 16 shows the average additional cost of complying with the New England decarbonization plans from 2025 through 2050 in each of the four scenarios. This number is obtained by dividing the annual cost of the four scenarios among all New England utility customers, including residential, commercial, and industrial electricity users.

In our previous report, we concluded the Renewable scenario would increase the average annual electricity costs to $7,555 in 2050. Prices would rise by $2,471 in the Nuclear scenario for a total bill of $5,472 in 2050. Annual costs would increase by $771 in the Natural Gas scenario, for a total bill of $3,772 in 2050, and the Happy Medium scenario would increase annual bills by $1,209, resulting in a total bill of $4,211 in 2050 (see Figure 16).

The Renewable scenario immediately increases electricity costs as offshore wind, onshore wind, solar, battery storage, and transmission projects are built, while the other scenarios have longer investment runways for new nuclear or natural gas capacity, which keeps costs lower for longer.

It is important to note that these rate analyses do not calculate the cost savings that would accrue to New Hampshire residents by continuing to use natural gas for power generation. Instead, these savings are evenly distributed throughout the entire ISO-NE region.

Residential Customers

In 2024, residential customers paid an average yearly cost of $2,100 for their electricity. Under the Renewable scenario, residential electricity prices would more than double by 2050, causing New England families to see their annual electricity costs increase to $4,610 in 2050 (see Figure 17). Bills would rise to $3,339 annually in the Nuclear scenario in 2050, $2,302 annually in the Natural Gas scenario in 2050, and $2,569 annually in the Happy Medium scenario by 2050.

Commercial Customers

In 2024, commercial customers paid an average yearly cost of $10,627 for their electricity. Under the Renewable scenario, commercial customers like small businesses, grocery stores, and other retailers would see their electricity costs increase to $22,794 in 2050 (see Figure 18). Bills would increase to $16,510 in 2050 in the Nuclear scenario, $11,381 in 2050 in the Natural Gas scenario, and $12,703 in 2050 in the Happy Medium scenario.

These higher electricity costs would likely be passed on to consumers in the form of inflationary prices for goods and services at grocery stores and other retailers, making life less affordable for everyone.

Industrial Customers

Industrial companies in New England, such as manufacturers, used roughly 13 percent of the electricity consumed in the region in 2023 and paid an average of $113,281 for their electricity in 2024.[18] Under the Renewable scenario, electricity costs for these firms would increase to $245,883 in 2050 (see Figure 19).[19] Bills would increase to $178,096 in

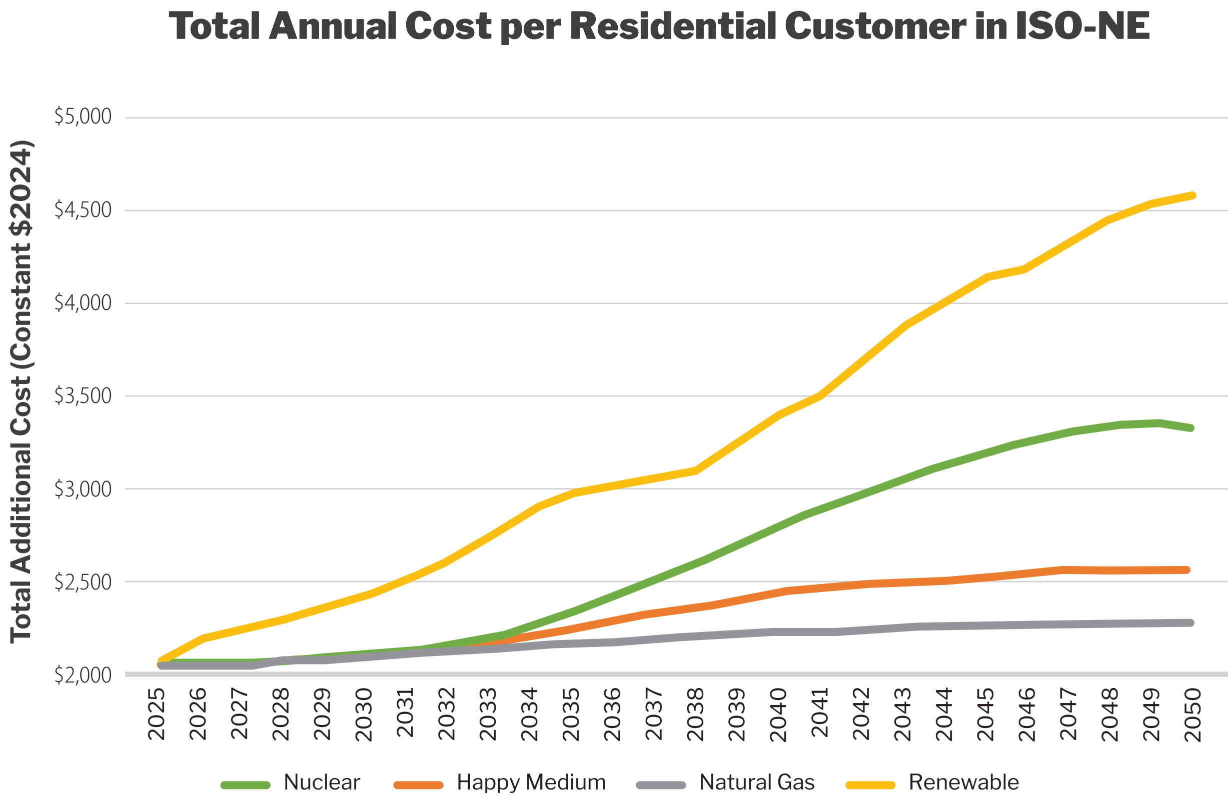


FIGURE 17. New England families would see their electric bills increase the most in the Renewable scenario and the least in the Natural Gas scenario. Bills increase to $4,610 per year in the Renewable scenario, $3,339 in the Nuclear scenario, $2,569 in the Happy Medium scenario, and $2,302 in the Natural Gas scenario. Data from AOER's cost modeling.

2050 in the Nuclear scenario, $122,766 in 2050 in the Natural Gas scenario, and $137,036 in 2050 in the Happy Medium scenario.

Total Cost per Capita

Figure 20 shows the cumulative cost of each scenario in 2030, 2040, and 2050 on a per-capita basis for each New England resident. The costs are highest in the Renewable scenario and lowest in the Natural Gas scenario.

The Renewable scenario costs $2,061 in 2030, $15,552 by 2040, and $51,914 by 2050. The Nuclear scenario, the second-most expen-

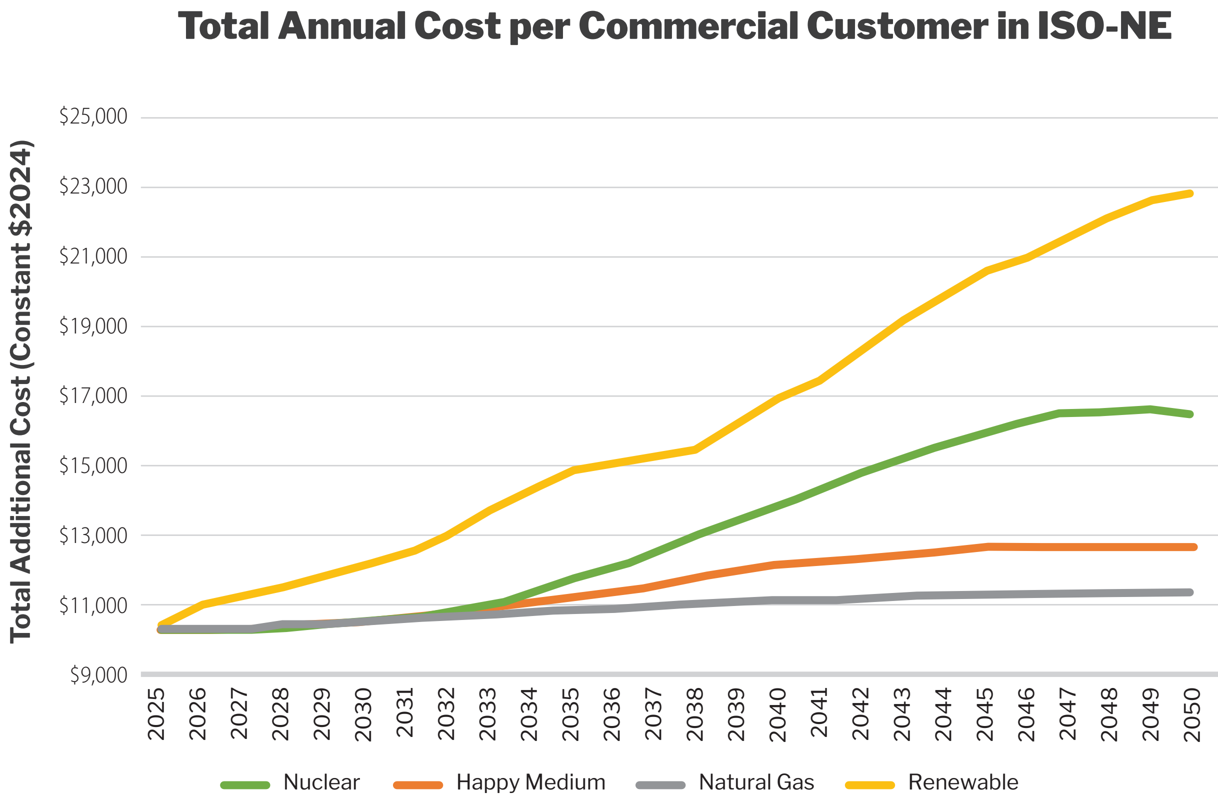


FIGURE 18. Costs for commercial customers, such as small businesses, rise quickly, peaking at $22,794 annually in 2050 in the Renewable scenario. Annual costs rise to $16,510 in 2050 in the Nuclear scenario, $11,381 in 2050 in the Natural Gas scenario, and $12,703 in 2050 in the Happy Medium scenario. Data from AOER's cost modeling.

sive scenario, costs $433 in 2030, $6,795 by 2040, and $26,458 by 2050. The Happy Medium scenario costs $441 in 2030, $4,186 by 2040, and $12,479 by 2050. The Natural Gas scenario costs $471 in 2030, $2,692 by 2040, and $6,808 by 2050.

Using state-level population forecasts for 2030, 2040, and 2050 from the non-partisan Weldon Cooper Center, the premier organization in charge of population projects based on U.S. Census data, we estimated that Massachusetts residents would pay the most under each of these scenarios (see Table 1).

Massachusetts would pay the most in each scenario, more than twice

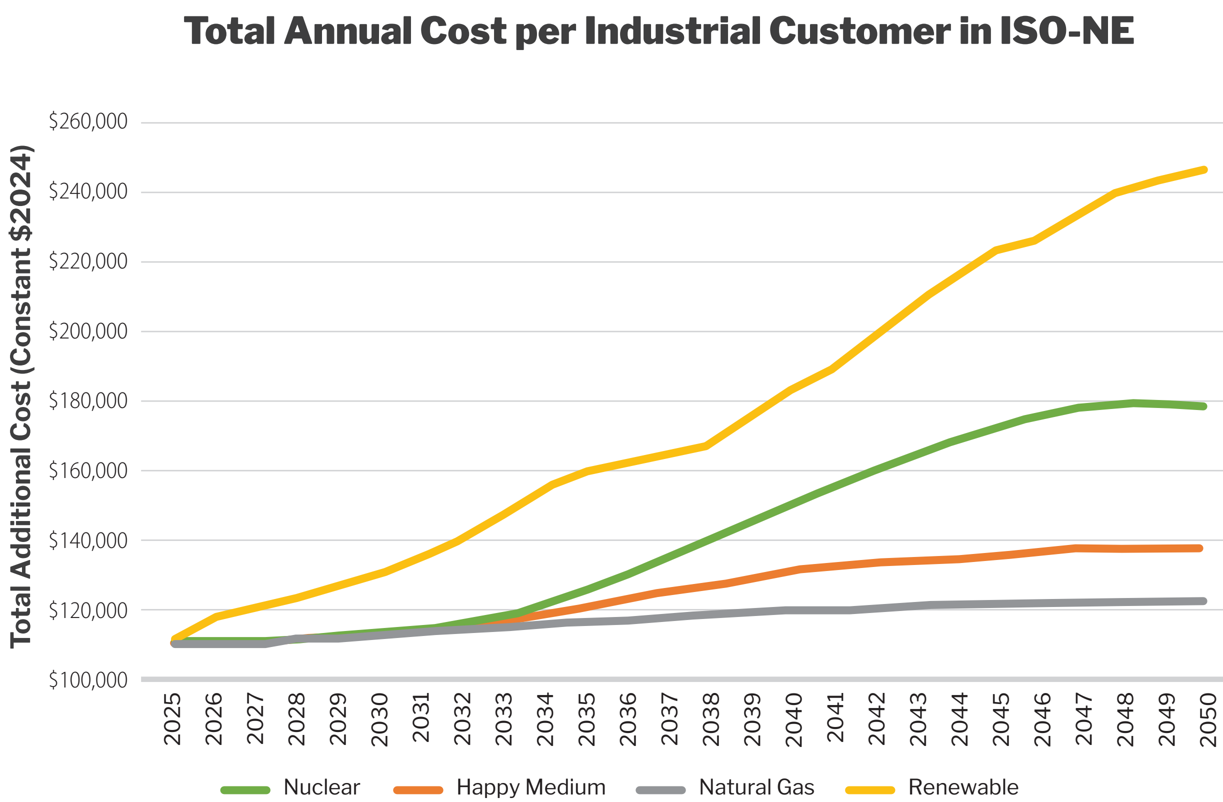


FIGURE 19. By 2050, industrial electricity consumers would experience an annual cost increase to $245,883 under the Renewable scenario, $178,096 in the Nuclear scenario, $122,766 in the Natural Gas scenario, and $137,036 in the Happy Medium scenario. Data from AOER's cost modeling.

as much as Connecticut, due to its higher population. Connecticut would pay the second-highest costs, followed by New Hampshire, Maine, Rhode Island, and Vermont.

The actual costs for a resident of an individual state will vary beyond per-capita cost calculations due to several factors. States that serve more rural customers may have to build more transmission and distribution lines and pass those costs on to ratepayers. States with more aggressive emissions reductions goals will incur higher costs on behalf of ratepayers (such as Massachusetts and Vermont), while states with less aggressive reduction goals will incur lower costs for ratepayers (New Hampshire).

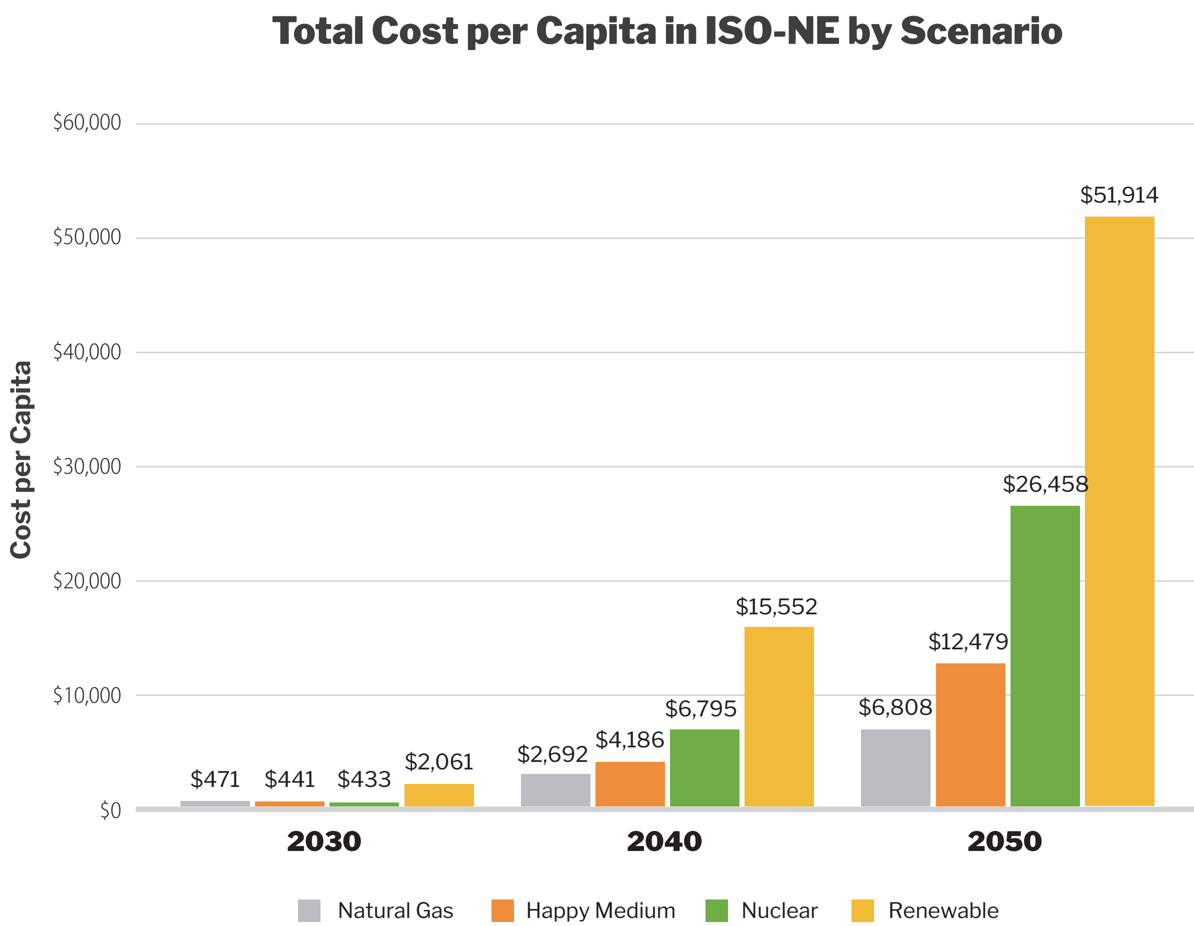


FIGURE 20. The Renewable scenario imposes the most financial hardship on New England residents through 2050, costing $45,106 more than the Natural Gas scenario. Data from AOER's cost modeling.

Cumulative Total Costs by State

Scenario	State	2030	2040	2050
Renewable	Rhode Island	$2.3B	$17.6B	$58.4B
	Maine	$2.9B	$21.3B	$69.3B
	Massachusetts	$15.3B	$118.9B	$405.1B
	Connecticut	$7.5B	$54.8B	$175.2B
	Vermont	$1.4B	$10.1B	$32.9B
	New Hampshire	$2.9B	$22.3B	$74.0B
Nuclear	Rhode Island	$0.5B	$7.7B	$29.7B
	Maine	$0.6B	$9.3B	$35.3B
	Massachusetts	$3.2B	$52.0B	$206.4B
	Connecticut	$1.6B	$23.9B	$89.3B
	Vermont	$0.3B	$4.4B	$16.8B
	New Hampshire	$0.6B	$9.7B	$37.7B
Happy Medium	Rhode Island	$0.5B	$4.7B	$14.0B
	Maine	$0.6B	$5.7B	$16.6B
	Massachusetts	$3.3B	$32.0B	$97.4B
	Connecticut	$1.6B	$14.7B	$42.1B
	Vermont	$0.3B	$2.7B	$7.9B
	New Hampshire	$0.6B	$6.0B	$17.8B
Natural Gas	Rhode Island	$0.5B	$3.1B	$7.7B
	Maine	$0.7B	$3.7B	$9.1B
	Massachusetts	$3.5B	$20.6B	$53.1B
	Connecticut	$1.7B	$9.5B	$23.0B
	Vermont	$0.3B	$1.7B	$4.3B
	New Hampshire	$0.7B	$3.9B	$9.7B

TABLE 1. Massachusetts would bear the highest costs for these decarbonization plans, while Vermont would pay the least on a statewide basis.

SECTION IV

Cost Drivers in Each Scenario

Thus far, this report has summarized how the Renewable scenario increases costs to a far greater extent than the Nuclear scenario, the Natural Gas scenario, and the Happy Medium scenario. In this section, we will discuss how attempting to run a reliable electric grid using mostly offshore wind, onshore wind, solar, imports, and battery storage drives up costs to a much greater extent than building a grid using reliable nuclear and natural gas plants.

The most important thing to know about the electric grid is that the supply of electricity must be in perfect balance with demand at every second of every day.[20] If demand rises as New Englanders turn on their air conditioners, heaters, or charge their electric vehicles, an electric company must increase the supply of power to meet that demand. If companies are unable to increase supply to meet demand, grid operators are forced to cut power to consumers—i.e., initiate brownouts or blackouts—to keep the entire grid from crashing.

Generating more electricity is relatively easy with dispatchable power plants—plants that can be turned up or down on command—like those powered with coal, natural gas, nuclear fuel, or hydroelectric plants. But adjusting to second-by-second fluctuations in electricity demand is much more difficult with wind and solar, whose electricity production is subject to second-by-second fluctuations in the weather.

It is possible, but costly, to mitigate some of the inherent unreliability of wind and solar by building battery storage facilities or new networks of transmission lines. However, these strategies require vastly increasing the amount of wind and solar capacity on the grid (known as "overbuilding" wind and solar installations) to charge the batteries and allow electricity demand to be met even on cloudy or low-wind days by transporting power from distant windy or sunny areas that have extra power to export, and curtailing, or turning off, much of this capacity when wind and solar production is higher and battery facilities are fully charged.

These mitigations come with other additional costs, including higher profits for transmission and distribution companies and higher state and federal taxes. Each of these additional costs will be discussed in greater detail below.

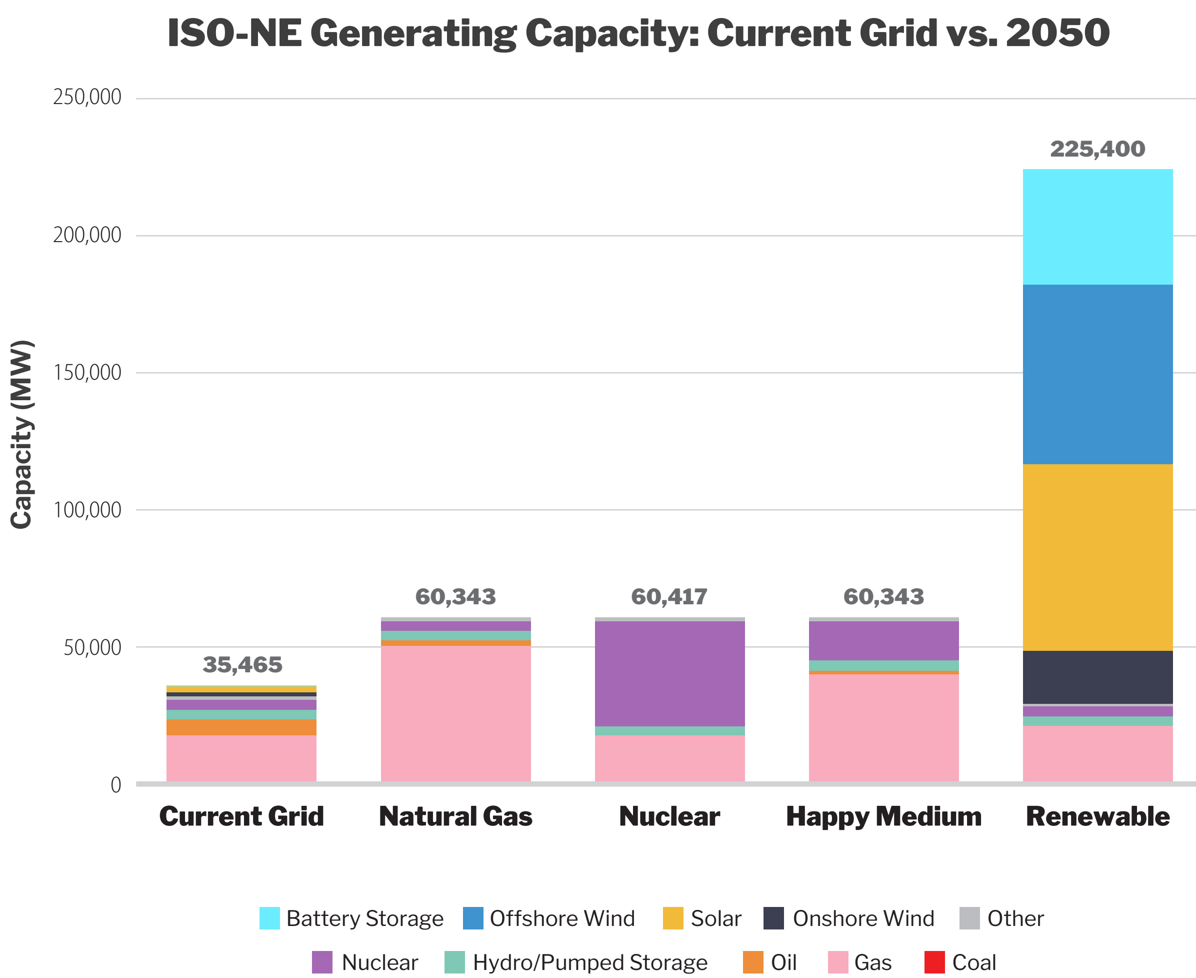


FIGURE 21. The Renewable scenario would require almost 6.4 times more installed capacity on the New England electric grid than is currently in service to maintain a reliable system, based on 2023 wind and solar output. This massive buildout of capacity would drive significant cost increases for families and businesses. Data from AOER's capacity expansion model.

Increasing Electricity Generation Capacity

Building and operating new power plants is expensive. As we discussed in the previous report, the New England decarbonization plans, particularly the policies forcing the electrification of the home heating and transportation sectors, will greatly increase the amount of new power plant capacity needed on the New England electric grid, which is why these policies are so costly.

In 2022, New England had roughly 35,500 MW of installed power plant capacity on the grid and could draw from 4,475 MW of import capacity—supplying 13 percent of electricity in ISO-NE—to meet electricity demand. These imports mostly come from Quebec, New Brunswick, and the state of New York.[21]

Under the Renewable scenario, the amount of installed power plant capacity in New England would increase from 35,500 MW in 2022 to 225,400 MW by 2050 (not including imports). However, only 60,417 MW would be needed in the Nuclear scenario, 60,343 MW would be needed in the Natural Gas scenario, and 60,343 MW would be needed in the Happy Medium scenario (see Figure 21).

Under the Renewable scenario, offshore wind installations would increase from 29 MW of installed capacity in 2022 to 66 GW of capacity in 2050. Onshore wind would increase from 1,546 MW to 19.2 GW. Solar capacity would grow from 2,242 MW in 2022 to 68.4 GW in 2050, and battery storage would increase from 303 MW in 2022 to 43 GW, with four hours of storage per MW (see Figure 21). Additionally, transmission capacity to neighboring regions would grow from 4,475 MW to 6,675 MW by 2050, but these figures are not reflected in Figure 21.[22, 23, 24]

In the Nuclear scenario, nuclear capacity would increase from 3,356 MW to 38,602 MW by 2050, and natural gas capacity would decrease slightly, from 16,817 MW to 16,753 MW. Solar capacity would fall from 2,242 MW to 0 MW, onshore wind would fall from 1,546 MW to 0 MW, and offshore wind capacity would fall from 29 MW to 0 MW.

This means the Renewable scenario would require nearly 6.4 times more power plant capacity than is currently used to meet New England's electricity demand, while the Nuclear, Natural Gas, and Happy Medium scenarios would require 1.7 times the current grid. The increase in capacity in the Renewable scenario is consistent with the ISO-NE "Future Grid Reliability Study" Scenario 1 replacement rate of 8.61 MW of renewables and storage for every 1 MW of conventional resources retired.[25]

While adding power plant capacity to the grid may sound like a good thing, building more capacity due to artificially increasing electricity demand through decarbonization mandates will constitute an extra cost of delivering power to New England families and businesses, harming the region's economy.

Summary of Costs

Figure 15 shows the cost of each scenario through 2050. The Renewable scenario costs an additional $815 billion, compared to the current costs. This scenario is the most expensive due to the overbuilding of wind,

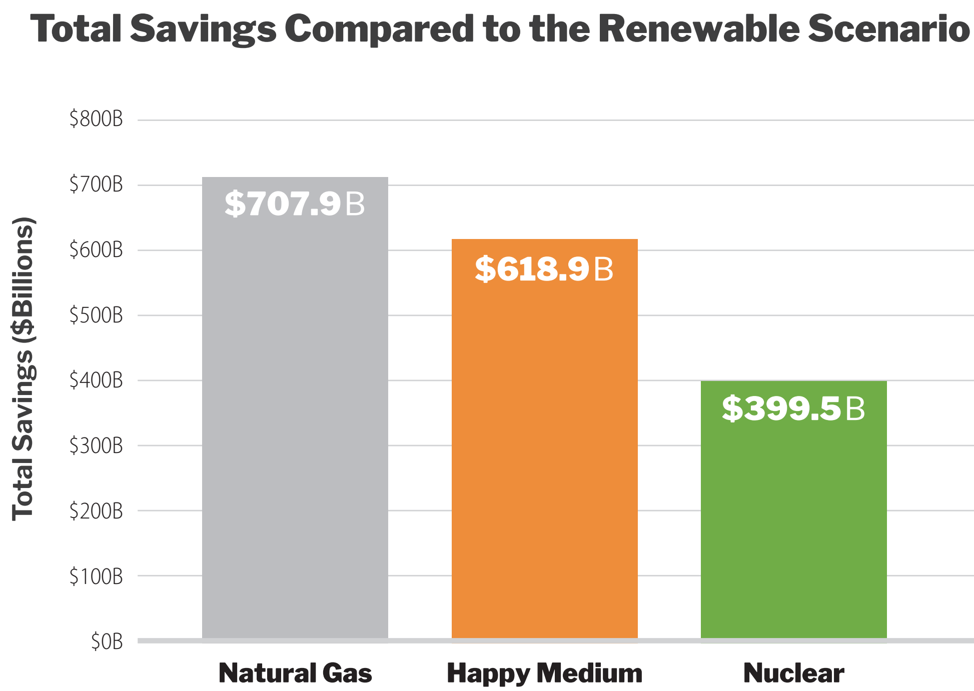


FIGURE 22. The Natural Gas scenario saves New England residents $707.9 billion through 2050, the Happy Medium scenario saves them $618.9 billion, and the Nuclear scenario saves them $399.5 billion, compared to the Renewable scenario. Data from AOER's compliance cost model.

solar, and battery storage capacity required to accommodate the intermittency of wind and solar.[26, 27]

In the Nuclear scenario, the high cost of nuclear power plants makes it the second-most expensive scenario at an additional $415.3 billion. The Natural Gas scenario is a much lower cost—$106.9 billion—due to the affordability of natural gas equipment and U.S. fuel prices, and the Happy Medium scenario costs an additional $195.8 billion due to nuclear and natural gas investments.

In the end, New England families will reap massive "dispatchability dividends" compared to the Renewable scenario because building reliable power plants will require far less overall capacity to meet peak system demand, resulting in massive system cost savings for families and businesses (see Figure 22).

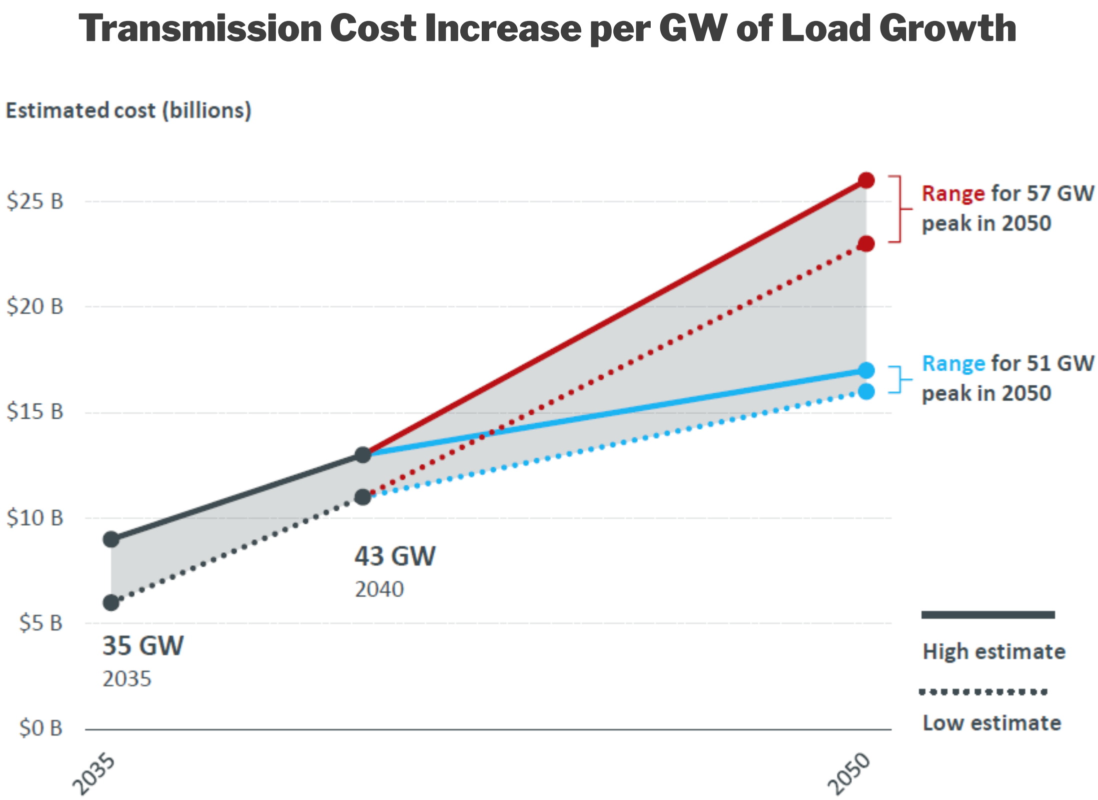


FIGURE 23. Transmission costs would increase substantially to accommodate a peak load of 57 GW.

Transmission and Pipeline Costs

Transmission lines are important: It does no good to generate electricity if it cannot be transported to the homes and businesses that rely upon it. Similarly, natural gas power plants cannot meet electricity demand without access to sufficient fuel via pipeline.

As discussed in our previous report, increasing peak electricity demand requires a substantial buildout of new transmission infrastructure, which will serve to increase electricity prices. This report also accounts for the substantial investments in new pipeline infrastructure needed to accommodate the demand for gas plants during the winter season, when demand is highest.

ISO-NE estimates that a grid with 100 percent heating and transportation electrification is expected to result in a peak load of around 57 GW, but a lower peak load could be achieved with less electrification of the transportation and home heating sectors.[28] As with our previous analysis, New Hampshire serves to reduce peak load by nearly 4.5 GW by continuing to heat homes with natural gas and fuel oil and by continuing to use internal combustion engines.[29, 30]

Estimates from ISO-NE show rising peak demand will cost roughly $750 million per GW of load added from roughly 29 GW to 51 GW, and roughly $1.5 billion per GW from 51 GW to 57 GW (see Figure 23).[31] As a result, the necessary increase in transmission spending in each of the four scenarios grows to $18.75 billion.

Transmission costs would increase substantially to accommodate a peak load of 57 GW.[32]

In addition to the transmission needed to accommodate higher peak demands, our study evaluates interconnection costs for each resource type on the grid.[33] These interconnection costs add an additional $9.3 billion in the Renewable scenario, $2.1 billion in the Nuclear scenario, $1.05 billion in the Natural Gas scenario, and $1.3 billion in the Happy Medium scenario through 2050.

New England also needs more pipeline capacity to accommodate more natural gas power plants. Currently, New England is only able to import 6.37 billion cubic feet (Bcf) per day of natural gas from existing pipeline infrastructure, which is enough to accommodate winter home heating demand and most natural gas power plant generation. However, New England also relies heavily on oil burning power plants during the coldest stretches of the year.

Substantially increasing natural gas generation will require new pipeline capacity in each scenario. Table 2 shows the amount of gas needed to accommodate the increase in fuel needs in each scenario, and the cost of building new pipelines and storage facilities to transport and store the fuel for times of peak demand.

In the Natural Gas scenario, New England would require 3.675 Bcf of new pipeline capacity, which would cost $10.18 billion. The Happy Medium scenario would require 2.4 Bcf of new pipeline capacity at a cost of $5.47 billion, and the Nuclear scenario would require an increase of 0.5 Bcf at a cost of $1.5 billion.

Generator Profits

Unlike areas of the country with vertically integrated monopoly utilities, power generators in ISO-NE are not monopolies and therefore they are not entitled to recover the cost of providing service to ratepayers with a government-approved rate of return on investment. Instead, generators

Scenario	Total Additional Gas Needed per day (Bcf)	Pipeline Costs ($Billions)	Storage ($Billions)	Total Cost ($Billions)
Natural Gas	3.675	$7.93	$2.25	$10.18
Happy Medium	2.437	$3.97	$1.50	$5.47
Nuclear	0.562	$1	$0.50	$1.50

TABLE 2. New gas demand is highest in the Natural Gas scenario, resulting in the need for the most natural gas transportation and storage infrastructure.

sell their power and reliability attributes into the wholesale energy, capacity, and ancillary service markets.

However, according to ISO-NE, several states have established public policies that direct electric power companies to enter into ratepayer-funded, long-term contracts for large-scale, carbon-free energy that would cover most, if not all, of the resource's costs.[34] These contracts must be lucrative enough to attract investment to the industry and allow companies to recover the upfront capital cost of the generators with a reasonable rate of return for shareholders.

As these carbon-free resources produce increasing amounts of electricity on the grid, they are expected to reduce the wholesale clearing prices for all generators, including new wind and solar generators.[35, 36] While there are advantages to lower wholesale energy costs, the trend toward lower, and potentially negative, clearing prices will deprive dispatchable generators of some of the revenue needed to remain on the system for the important periods when there is low wind or solar generation.

This is why the "Economic Planning for the Clean Energy Transition" document released by ISO-NE stated that dispatchable units that are infrequently run may result in these generators receiving more of the revenues needed to operate the plant through capacity and ancillary service markets, or these generators may obtain separate contracts to remain on the system to generate electricity when it is needed—as was the case for the Mystic Generating Station.[37, 38]

ISO-NE's "Economic Planning" document notes: "During the final years of analysis, the majority of revenue for all generators is earned through either the capacity market or out-of-market PPAs [Power Purchase Agreements]."[39] Therefore, AOER assumed that all generation assets built in our model would be able to recover their upfront capital costs, with a 7.05 percent return on investment.

As a result, additional generator profits stemming from the Renewable scenario would be $323 billion through 2050. Additional generator profits would cost $244.6 billion in the Nuclear scenario, $44.9 billion in the Natural Gas scenario, and $105.4 billion in the Happy Medium scenario.

Additional Property, State, and Federal Taxes

Property taxes increase under each of the scenarios studied because, compared to the current grid, there is much more property to tax. While the property taxes assessed on power plants are often a crucial revenue stream for local communities that host power plants, these taxes also effectively increase the cost of producing and providing electricity for everyone.

Some New England states exempt renewable energy facilities from property taxes entirely, while others assess a "payment in lieu of tax" payment on these facilities, and in some jurisdictions, these facilities are taxed at normal rates. To simplify these differences, this model assumes a property tax rate of 1 percent of net capital investment (gross plant value minus depreciation).

Additionally, state and federal income taxes increase due to the growth in income for power producers in the region. As a result, additional taxes are $115 billion through 2050 in the Renewable scenario, $79.4 billion in the Nuclear scenario, $14.5 billion in the Natural Gas scenario, and $34.1 billion in the Happy Medium scenario.

Natural Gas Price Sensitivities

Costs in the Natural Gas scenario and the Happy Medium scenario could be impacted by rising electricity costs generated at natural gas power plants. Currently, a shortage of natural gas turbines for power plants to supply electricity to the artificial intelligence (AI) boom has caused the price of these turbines to nearly triple since 2021.[40] Furthermore, rising electricity demand and liquefied natural gas (LNG) exports are putting upward pressure on fuel prices for gas plants, which increases the cost of electricity for these facilities.

For the sake of consistency, our methodology utilized the overnight capital cost assumptions for all resources in the EIA "Annual Energy Outlook Assumptions" and maintained current fuel prices in both scenarios. However, AOER conducted a "worst case" cost analysis for these scenarios, assuming natural gas capital costs of $2,500 per kilowatt (kW) of installed capacity and fuel costs of $4.90 per million British thermal units (MMBtu) from the EIA "Short-Term Energy Outlook."[41]

If these conditions remain consistent through the model run, the Nat-

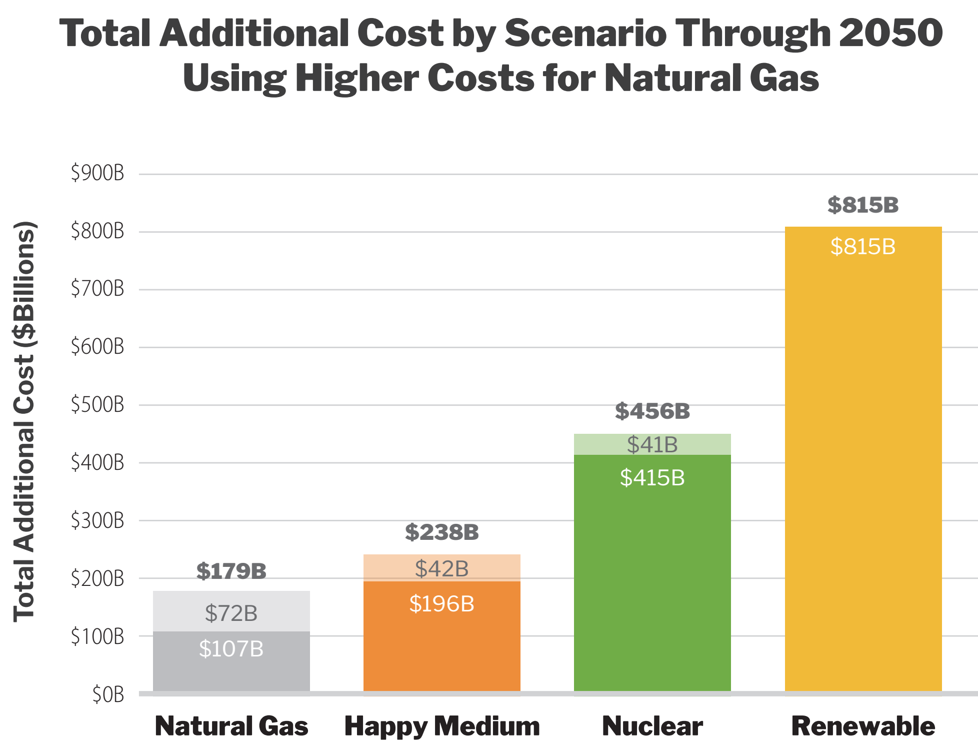


FIGURE 24. Even using the most expensive assumptions seen in the current market for natural gas turbines and price forecasts, the Natural Gas scenario is by far the lowest-cost means of meeting New England's electricity demand. Data from AOER's compliance cost model.

ural Gas scenario would cost $179.1 billion, the Happy Medium scenario would cost $238.1 billion, and the Nuclear scenario would cost $456.1 billion. While these assumptions would increase the cost of these scenarios by $72.3 billion, $42.2 billion, and $40.9 billion, respectively, the Natural Gas scenario would still constitute the lowest-cost scenario of the four, with the Happy Medium being the second-least expensive scenario (see Figure 24).

Unquantified Costs and Benefits

This analysis focuses on the additional generation and transmission costs associated with building and operating the electricity generation portfolios in each of the four scenarios. Quantifying the additional distribution-level costs, the expenses associated with electrifying households in the ISO-NE service territory, or the fuel savings of electrification is outside the scope of this analysis.

For example, there would be fuel savings from electrifying home heating and transportation, as New England households would no longer need to purchase natural gas, fuel oil, or propane for home heating or gasoline or diesel fuel for transportation. However, there would also be substantial new costs associated with these plans that extend beyond the costs detailed in this report.

These additional costs include purchasing heat pumps and upgrading home electric service panels to accommodate greater electricity use, purchasing electric vehicles, which frequently cost more than conventional vehicles, building electric vehicle charging infrastructure at homes and in public spaces, and there would also be a need for significant grid upgrades for the distribution system, which would cost between $42 billion and $96 billion in the New England region.[42]

SECTION V

The Always On Levelized Cost of Energy for Different Generating Resources

A common way of comparing the cost of electricity from various resources is called the Levelized Cost of Energy, or LCOE.[43] LCOE estimates reflect the cost of generating electricity from different types of power plants, on a per-unit of electricity generated basis (generally megawatt hours), over an assumed lifetime and quantity of electricity produced by the plant.

In other words, LCOE estimates are essentially like calculating the cost of your car on a per-mile-driven basis after accounting for expenses like initial capital investment, loan and insurance payments, fuel costs, and maintenance, divided by the number of miles driven in the car. This approach works well for dispatchable resources, which can be turned on to generate power, but it does not work as well for non-dispatchable resources because they do not provide the same reliability value to the grid.

Wind and solar advocates often misrepresent LCOE estimates from Lazard or EIA to claim that wind and solar are now lower-cost than other sources of energy. However, Lazard and EIA show the cost of operating a single wind or solar facility at its maximum reasonable output; they do not convey the cost of reliably operating an entire electricity system with high penetrations of wind and solar, which costs exponentially more.[44]

In our previous report, we discussed how wind and solar LCOE estimates created by Lazard and EIA do not account for the expenses of building new transmission lines, additional taxes, the cost of providing backup electricity with battery storage when the wind is not blowing or the sun is not shining (referred to as battery storage costs in this report), and the massive overbuilding and curtailment costs incurred by building excess capacity to charge the batteries.[45, 46]

AOER's model corrects for these shortcomings by accounting for these additional expenses and attributing them to the cost of wind and solar to get an "Always On" LCOE value for these energy sources, thereby proving an apples-to-apples comparison of the reliability value of each generating technology in each of the four scenarios.

Under the Renewable scenario, low-cost, existing natural gas plants would be largely replaced with a significant overbuilding of offshore wind, onshore wind, solar, and battery storage by 2050. Figure 25 shows the Always On LCOE of new offshore wind, onshore wind, and solar reaches

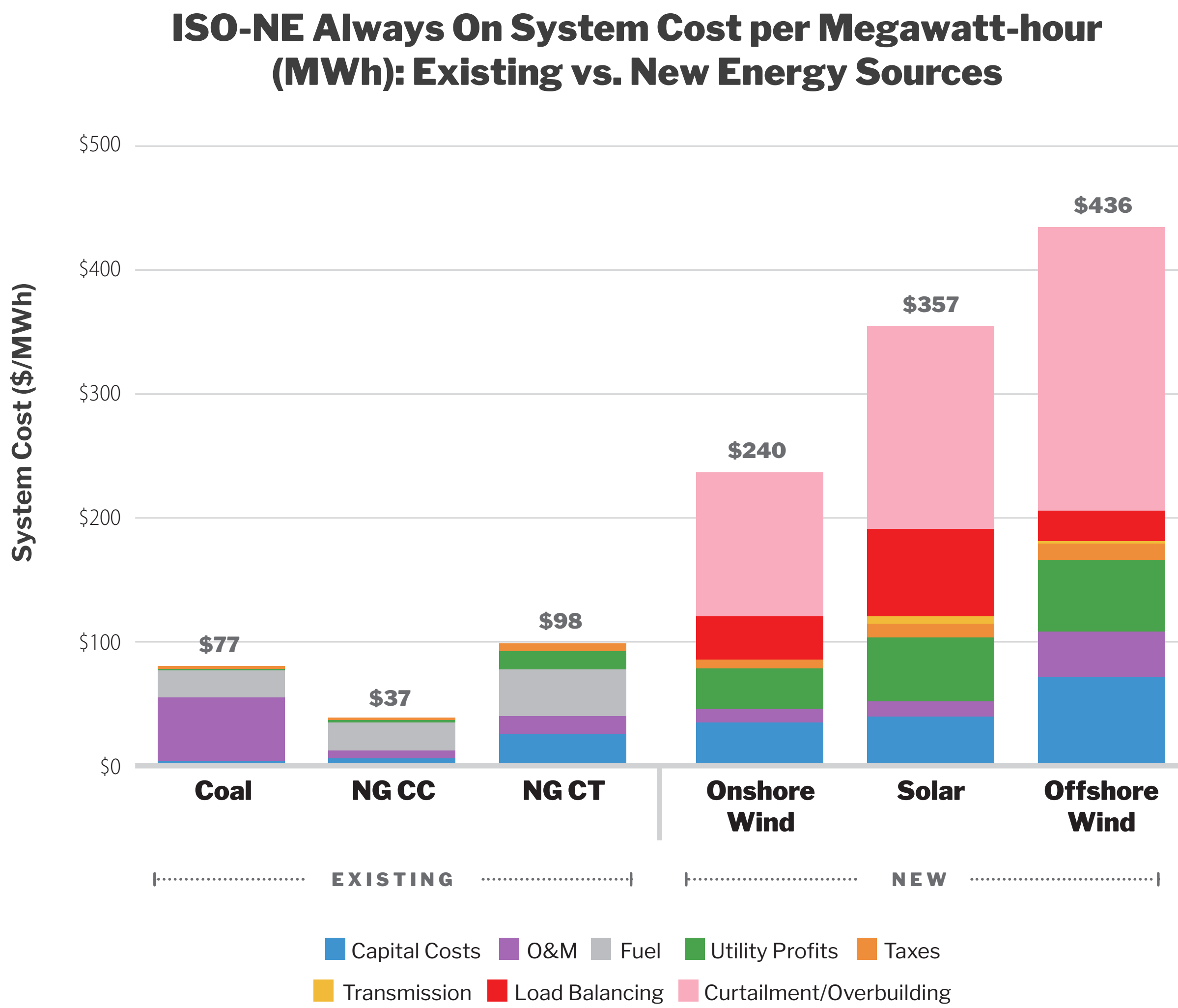


FIGURE 25. New offshore wind facilities are the most expensive form of new electricity generation built under the New England decarbonization plans. Once costs such as state taxes, transmission, utility returns, battery storage, and overbuilding and curtailment are accounted for, new offshore wind costs $436 per MWh, onshore wind costs $240 per MWh, and new solar costs $357 per MWh. Data from AOER's Always On LCOE model.

approximately $436, $240, and $357 per megawatt hour (MWh), respectively, in 2050.

Because curtailment rates reach 64 percent by 2050, overbuilding and curtailment costs are the primary drivers of wind and solar due to the need to build nearly 6.4 times more capacity than would be required to meet peak demand with dispatchable power plants.[47] As a result, the cost of battery storage, overbuilding, and curtailing in Figure 25 can be thought of as a Levelized Cost of Intermittency (LCOI), or unreliability.

As we discuss in greater detail in the Appendix, the Always On LCOE

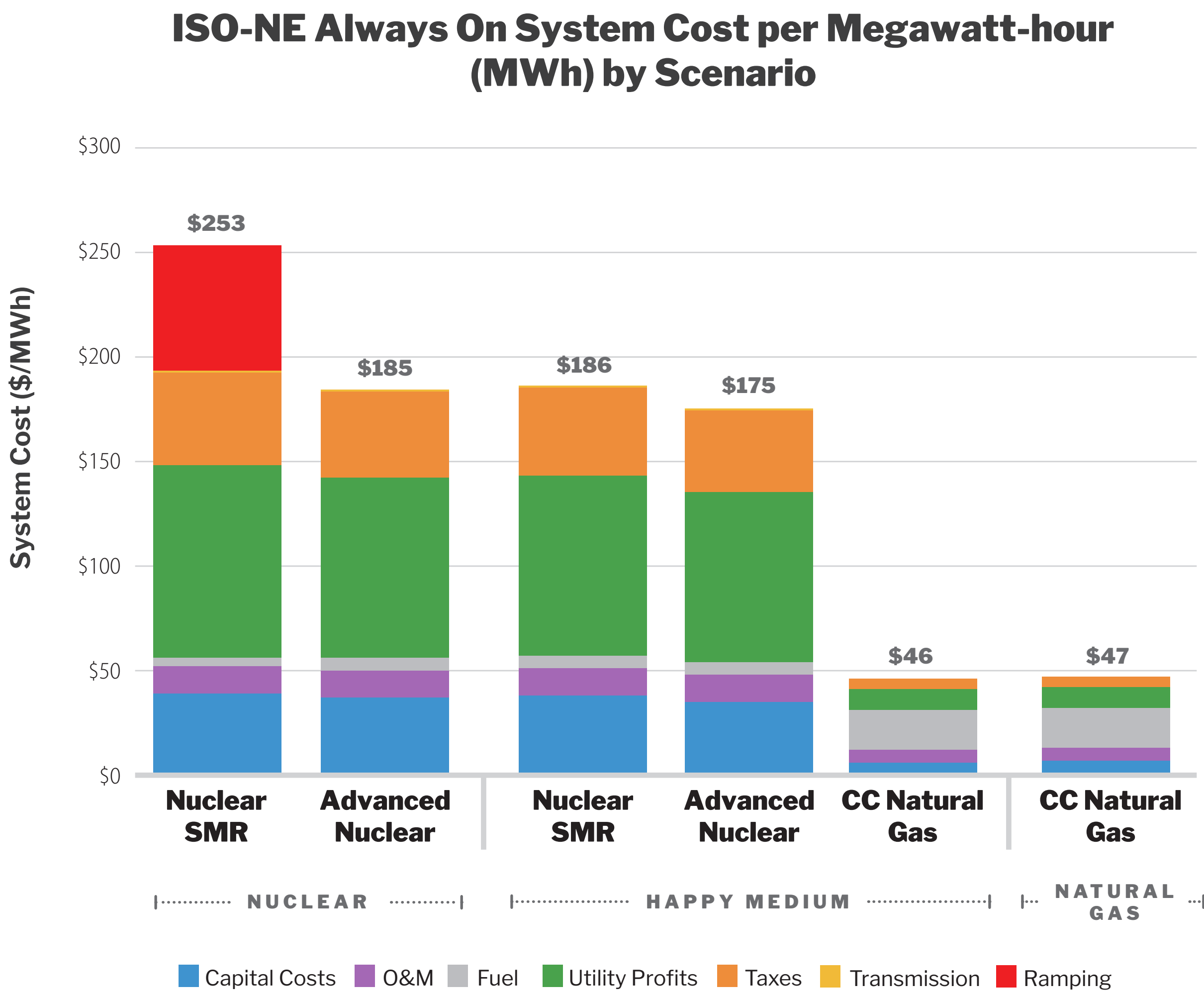


FIGURE 26. The Always On LCOE for each new resource in each scenario is shown in the chart above. Variations in cost between natural gas and nuclear are mostly driven by differences in utilization rates, or capacity factors, in the Natural Gas, Nuclear, and Happy Medium scenarios. Data from AOER's Always On LCOE model.

calculations are based on system-specific costs that change for each resource in each portfolio. Figure 26 shows the Always On LCOE for the new natural gas and nuclear technologies built in the Natural Gas, Nuclear, and Happy Medium scenarios.

In the Nuclear scenario, generation from nuclear SMR facilities is ramped more often, thus increasing the cost per MWh, shown as "Ramping" in Figure 26. SMRs have lower LCOEs in the Happy Medium scenario because they operate more frequently, and natural gas is able to handle the peaking hours, which reduces the cost per MWh. In essence, the total cost of the cars is being divided over more miles driven.

SECTION VI

Implications for Reliability

As we stated in our previous report, reliability is the most crucial function of the electric grid. Our lives have never been more dependent upon electronic devices, and it is highly unlikely that we will be less dependent upon them in the future.

The Renewable scenario will seriously undermine the reliability of the electric grid by making it more dependent on fluctuations in the weather. This dependency will end in blackouts. In contrast, the Nuclear, Natural Gas, and Happy Medium scenarios maintain reliability due to their reliance on dispatchable capacity, not weather-dependent resources, to meet peak demand.

Renewable Scenario

AOER's modeling determined the amount of offshore wind, onshore wind, solar, and battery storage capacity needed for the Renewable scenario by using hourly electricity demand data based on ISO-NE projections for 2050 demand, and real-world data from the U.S. Energy Information Administration for onshore wind and solar generation output in 2023, and offshore wind output from ISO-NE variable energy resource data for the year 2019.[48]

Figure 27 shows electricity demand and supply by type in the Renewable scenario for a hypothetical period in the future stretching from December 14, 2050 to December 18, 2050. As you can see, offshore wind, onshore wind, solar, battery storage, and New England's existing nuclear and natural gas power plants are able to provide enough electricity to meet demand, shown in the black line.

While our model shows there is enough electricity to meet demand for every hour based on 2023 offshore wind, onshore wind, and solar productivity, it is important to remember that this conclusion is based on just one year's worth of weather-driven wind and solar generation data.[49]

Given that wind and solar generation are subject to weather patterns, it is important to evaluate whether changes in the weather would result in a situation where electricity supply could not meet demand—a capacity shortfall—resulting in rolling blackouts or brownouts.

To evaluate the impact of annual changes in wind and solar generation on the reliability of the grid, AOER obtained hourly capacity factor data for offshore wind, onshore wind, and solar from 2019 through 2022 to see if the amount of installed wind, solar, battery storage, nuclear, and

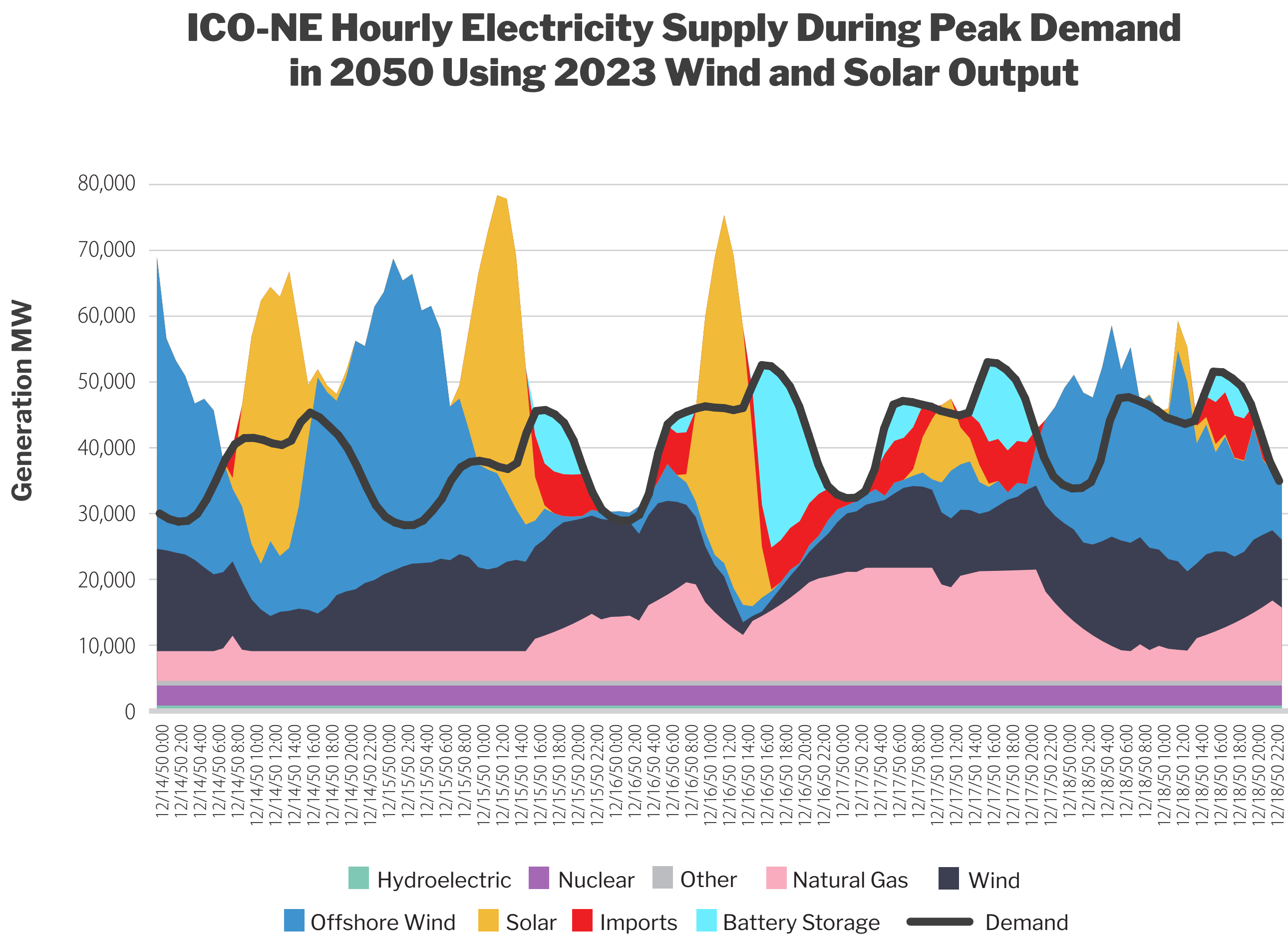


FIGURE 27. Offshore wind, onshore wind, solar, battery storage, nuclear, and natural gas can meet electricity demand for every hour of the year 2050, based on 2023 historic generation profiles for wind and solar. Data from AOER's Hourly Reliability model.

natural gas capacity in the Renewable scenario would be enough to meet electricity demand at all hours of every year, regardless of these changes in wind and solar productivity.[50]

It is not.

Using 2019 wind and solar generation data from ISO-NE, AOER determined that there would be 6 total hours of capacity shortfalls throughout the year, with a maximum capacity shortfall of more than 22,500 MW, which is approximately 40 percent of demand during the blackout period, and near the current peak of the ISO-NE system.

Figure 28 shows a 6-hour blackout during the same hypothetical period in the future stretching from December 14, 2050 to December 18, 2050, as offshore wind, onshore wind, solar, battery storage, and New

ISO-NE Hourly Electricity Supply During Peak Demand in 2050 Using 2019 Wind and Solar Output

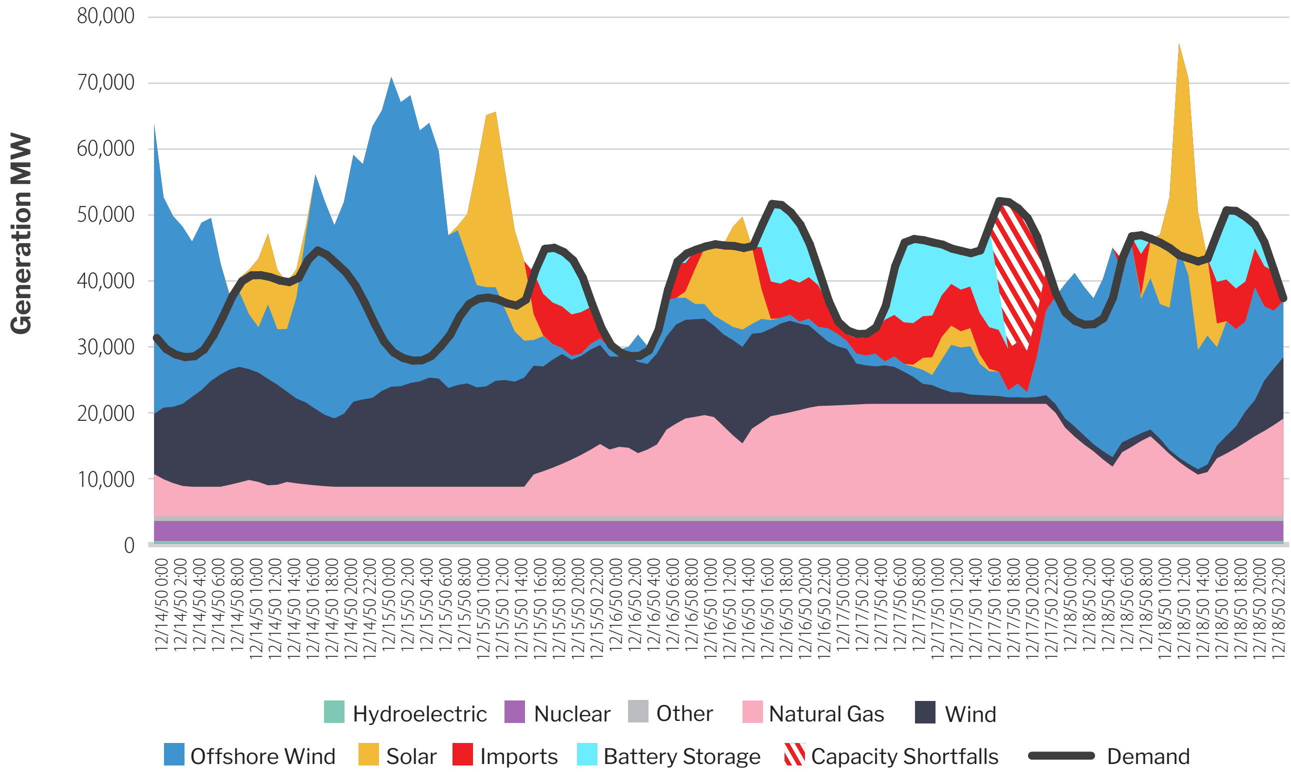


FIGURE 28. The resources on the ISO-NE under the Renewable scenario are unable to meet electricity demand every hour of the year, resulting in a 6-hour capacity shortfall in December 2050. Data from AOER's Hourly Reliability model.

England's existing nuclear and natural gas power plants are unable to provide enough electricity to meet demand.

The capacity shortfall on December 17, 2050 is caused by low wind and solar output and insufficient battery storage capacity to store excess wind generation from previous days—even with more than 170,000 MWh of storage available. During this period, solar capacity factors were just 1 percent, onshore wind capacity factors were 8 percent, and offshore wind capacity factors were 5 percent.

These findings are consistent with the ISO-NE "2050 Transmission Study," which found that the modeled resource mix in the All Options Pathway, when combined with the resource availability assumptions made by the ISO, was "insufficient to meet the snapshot loads for the Summer

Nuclear Scenario: ISO-NE Hourly Electricity Supply During Peak Demand in 2050

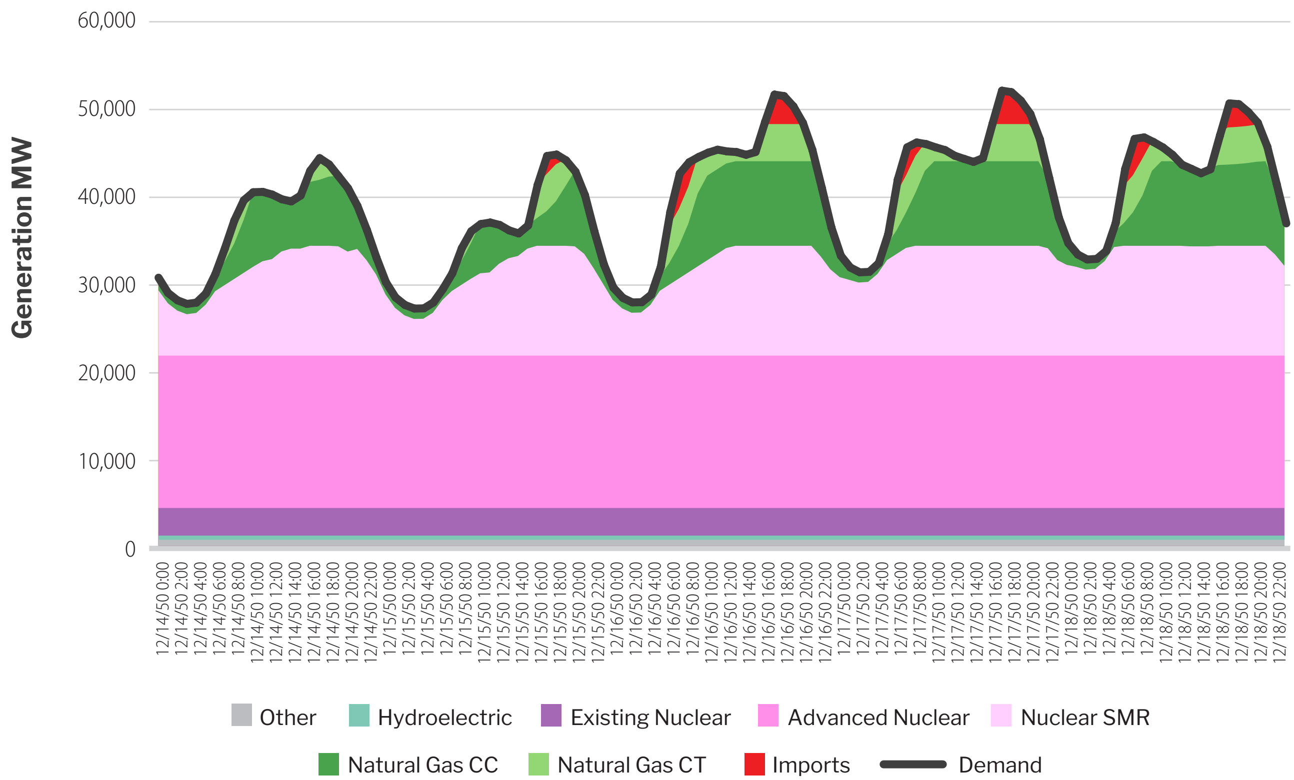


FIGURE 29. Demand is easily met as nuclear and natural gas plants are turned up and down to meet demand. Data from AOER's Hourly Reliability model.

Evening and Winter Evening Peaks of 2035, 2040, and 2050. The largest observed shortfall was roughly 12,000 MW in the 2050 57 GW Winter Peak snapshot."[51]

Nuclear, Natural Gas, and Happy Medium Scenarios

While the Renewable scenario resulted in blackouts, the other three scenarios studied in this report have sufficient dispatchable capacity to meet the projected peak demand in the ISO-NE system in 2050 and thus do not result in rolling blackouts.

The figures show the resource mix for each scenario during the same hypothetical period, from December 14, 2050 through December 18,

Natural Gas Scenario: ISO-NE Hourly Electricity Supply During Peak Demand in 2050

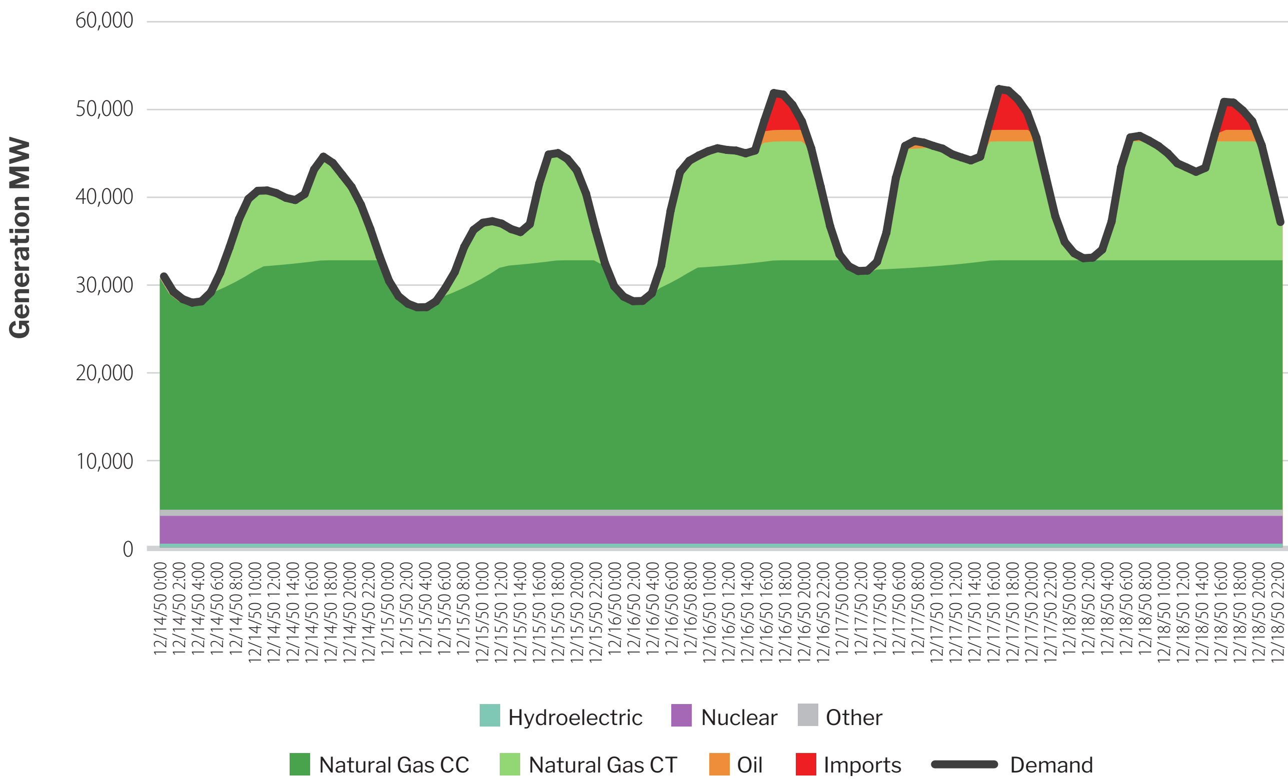


FIGURE 30. Combined cycle natural gas plants produce a steady state of electricity throughout the week, while combustion turbine plants are used to meet intermediate and peak demands. Data from AOER's Hourly Reliability model.

2050, that resulted in rolling blackouts in the Renewable scenario.

Figure 29 shows the resource mix in the Nuclear scenario during this period. The large nuclear power plants provide steady baseload power during the entire duration of the event, and small modular reactors are used in a load-following and peaking capacity, meaning their generation output rises and falls to match demand.

In the Natural Gas scenario, the new and existing natural gas capacity on the system is utilized to meet the winter peak demand, while the existing nuclear provides baseload power (see Figure 30).

Electricity demand is met in the Happy Medium scenario by the nuclear and natural gas facilities on the system. In this scenario, both the SMRs and large nuclear reactors operate in a baseload capacity during

Happy Medium Scenario: ISO-NE Hourly Electricity Supply During Peak Demand in 2050

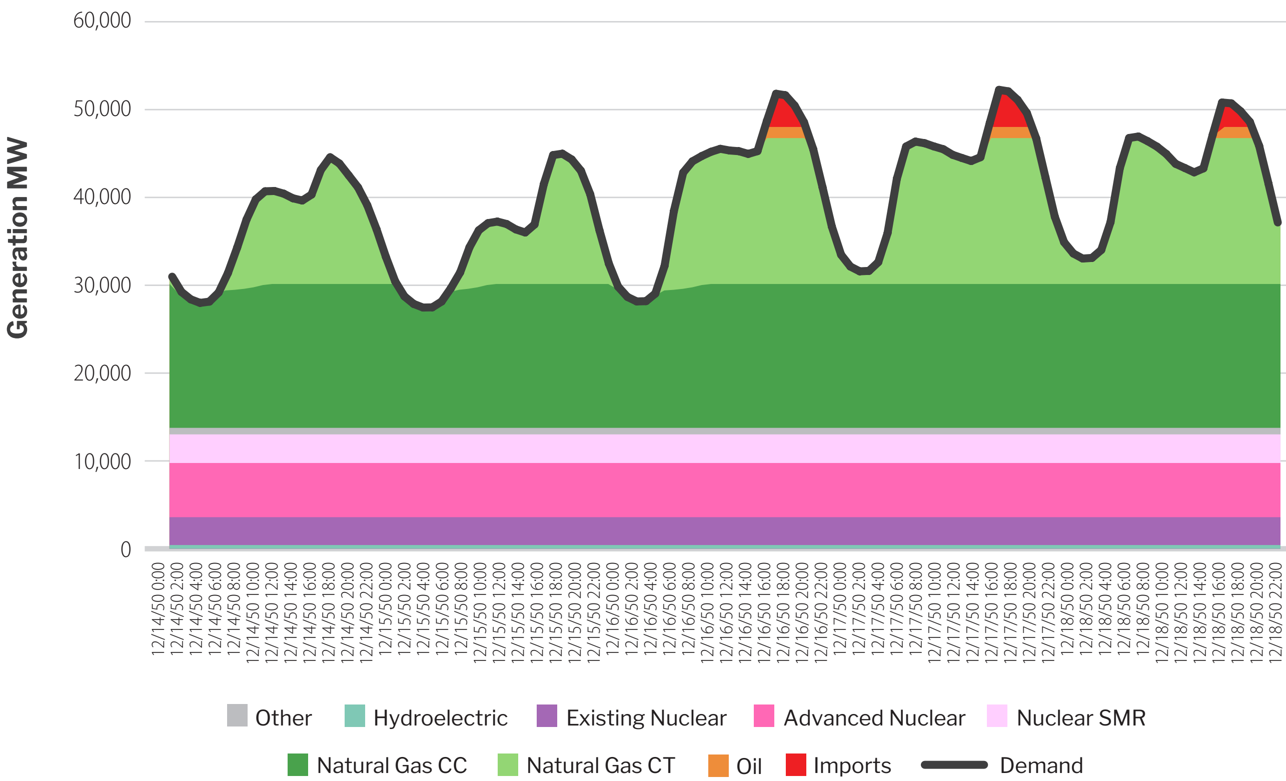


FIGURE 31. A mix of nuclear and natural gas technologies is used to reliably meet demand in this scenario. Data from AOER's Hourly Reliability model.

the event, while natural gas is utilized as an affordable load-following resource (see Figure 31).

The presence of dispatchable resources on the grid provides tremendous reliability value for the ISO-NE grid in each of the three additional scenarios studied in this report, allowing electricity demand to be met in all hours studied with far less total installed capacity and cost.

SECTION VII

Emissions Reductions

When evaluating energy policies aimed at reducing greenhouse gas emissions, it is important to weigh the cost of reducing emissions against the expected benefits of doing so. If the costs of reducing emissions exceed the expected benefits, the policy does not make sense to enact.

To conduct this cost-benefit analysis, policymakers often use a tool called the Social Cost of Carbon (SCC) to estimate the economic costs, or damages, of emitting one additional ton of carbon dioxide into the atmosphere.[52] While the SCC has serious shortcomings, it can help illustrate when the costs of a proposed policy obviously outweigh the benefits.[53]

Figure 32 shows the annual decline in carbon dioxide emissions in each of the four scenarios.[54] Emissions fall fastest in the Renewable scenario because this scenario most closely conforms to the energy policies enacted by the five states with aggressive decarbonization mandates. Emissions in the Nuclear scenario reach a slightly lower endpoint than the Renewable scenario, and emissions reductions fall substantially and then plateau as new nuclear plants are brought online.

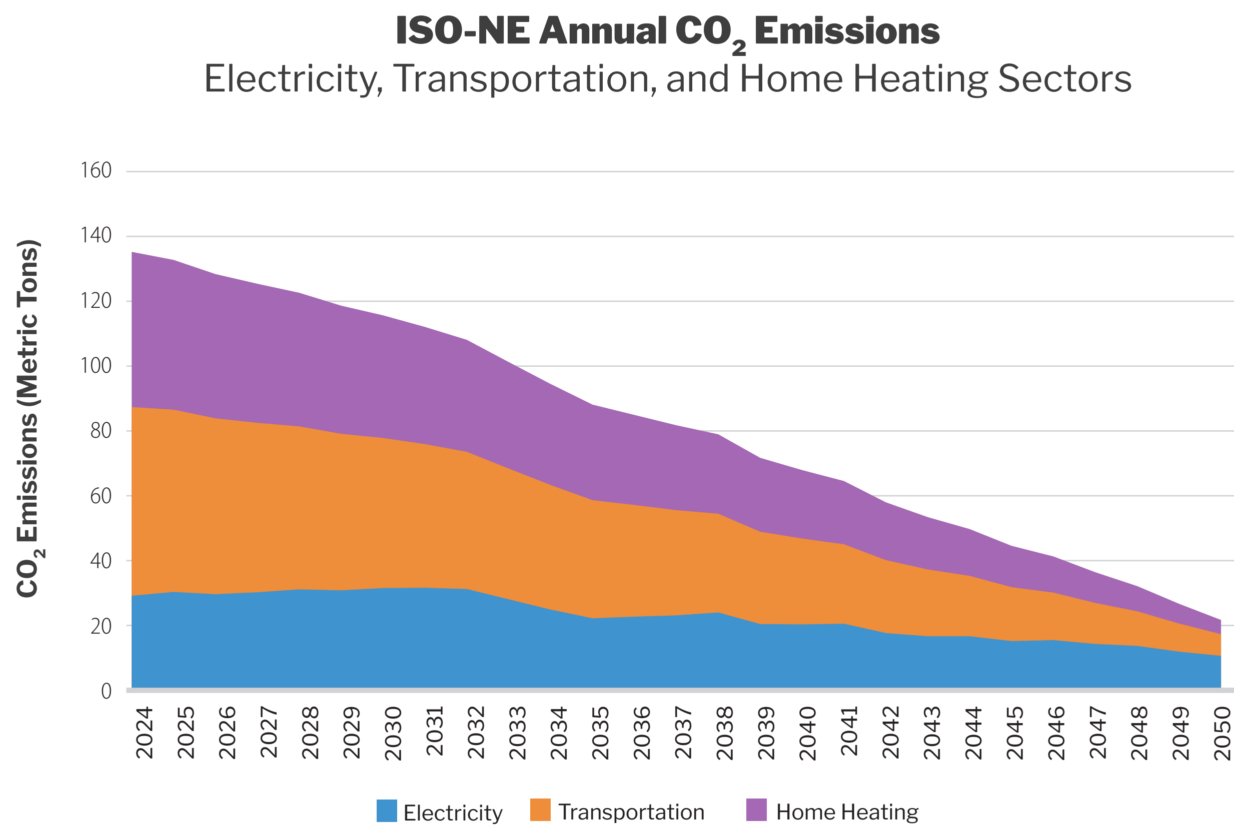
Emissions decrease by roughly 25 percent in the Natural Gas scenario and decrease by roughly 50 percent in the Happy Medium scenario.

Figure 33 shows the cost of reducing a ton of carbon dioxide in each year under each of the four scenarios and compares it to the SCC estimates established by the Biden administration, which are four times higher than the SCC estimates produced by the Obama administration.

Figure 33 shows that the cost of reducing carbon dioxide emissions exceeds the Biden SCC in only the Renewable scenario, meaning the costs of reducing carbon dioxide emissions under the Renewable scenario exceed the benefits of doing so.

In short, the Renewable scenario imposes net harm on the New England economies after accounting for the impacts of climate change, while the other three scenarios reduce GHG emissions at a far lower cost.

It's important to note that AOER does not endorse the Biden administration's SCC estimates but provided them to demonstrate that even with inflated assumptions for the SCC, building the electric grid in the Renewable scenario would exceed the Biden SCC.


ISO-NE Annual CO_2 Emissions
Electricity, Transportation, and Home Heating Sectors
CO_2 Emissions (Metric Tons)
0
20
40
60
80
100
120
140
160
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
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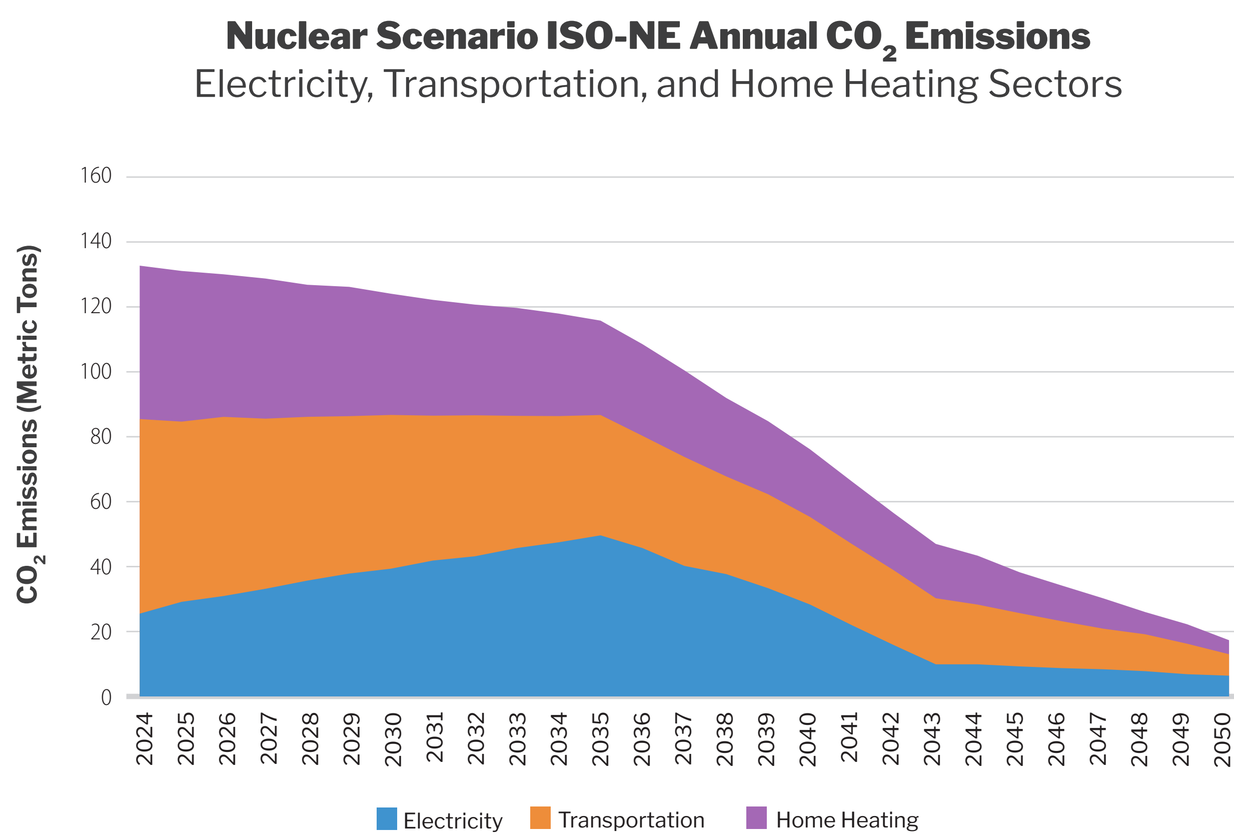
2050
Electricity
Transportation
Home Heating


Nuclear Scenario ISO-NE Annual CO_2 Emissions
Electricity, Transportation, and Home Heating Sectors
CO_2 Emissions (Metric Tons)
0
20
40
60
80
100
120
140
160
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
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2040
2041
2042
2043
2044
2045
2046
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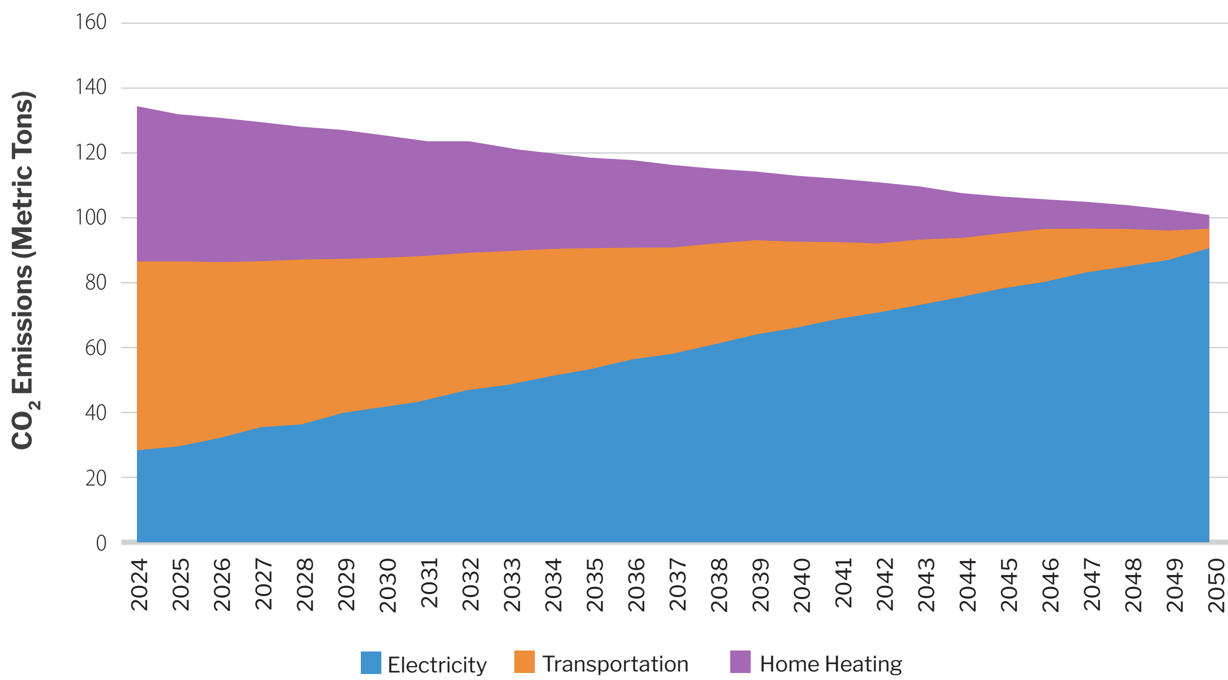
2048
2049
2050
Electricity
Transportation
Home Heating

Natural Gas Scenario ISO-NE Annual CO_2 Emissions
Electricity, Transportation, and Home Heating Sectors



Happy Medium Scenario ISO-NE Annual CO_2 Emissions
Electricity, Transportation, and Home Heating Sectors

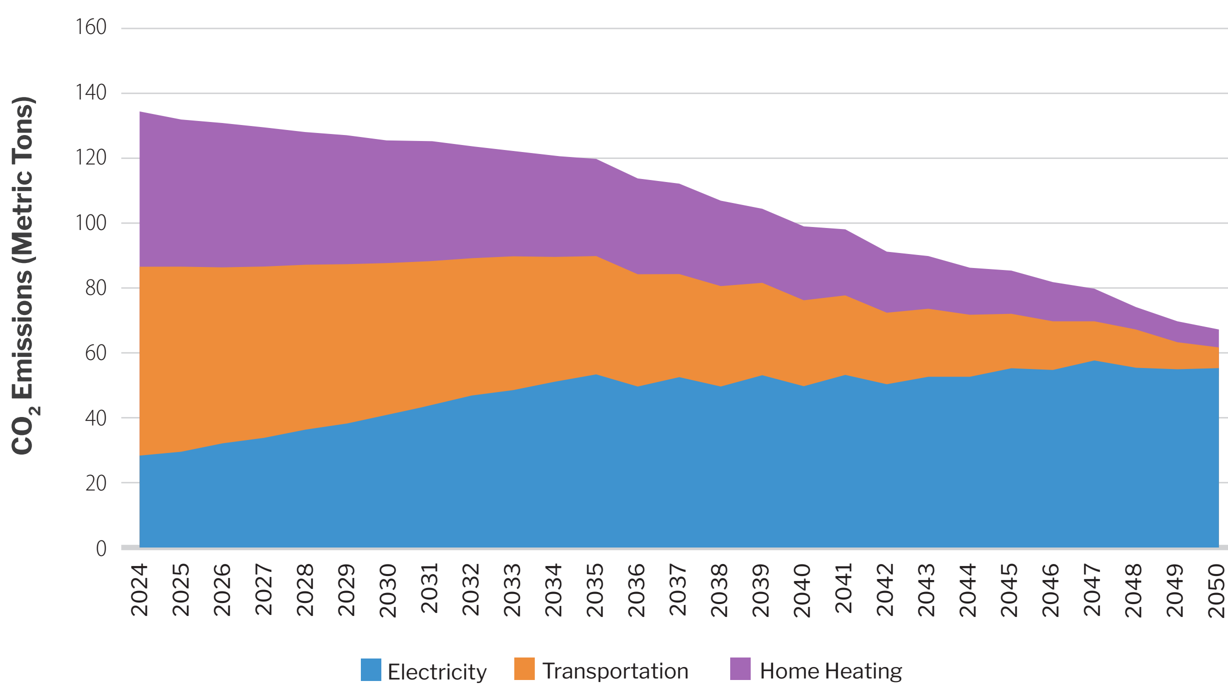


FIGURE 32. (PREVIOUS SPREAD) Emissions fall most in the Nuclear scenario, followed by the Renewable scenario, the Happy Medium scenario, and the Natural Gas scenario. Data from AOER modeling.

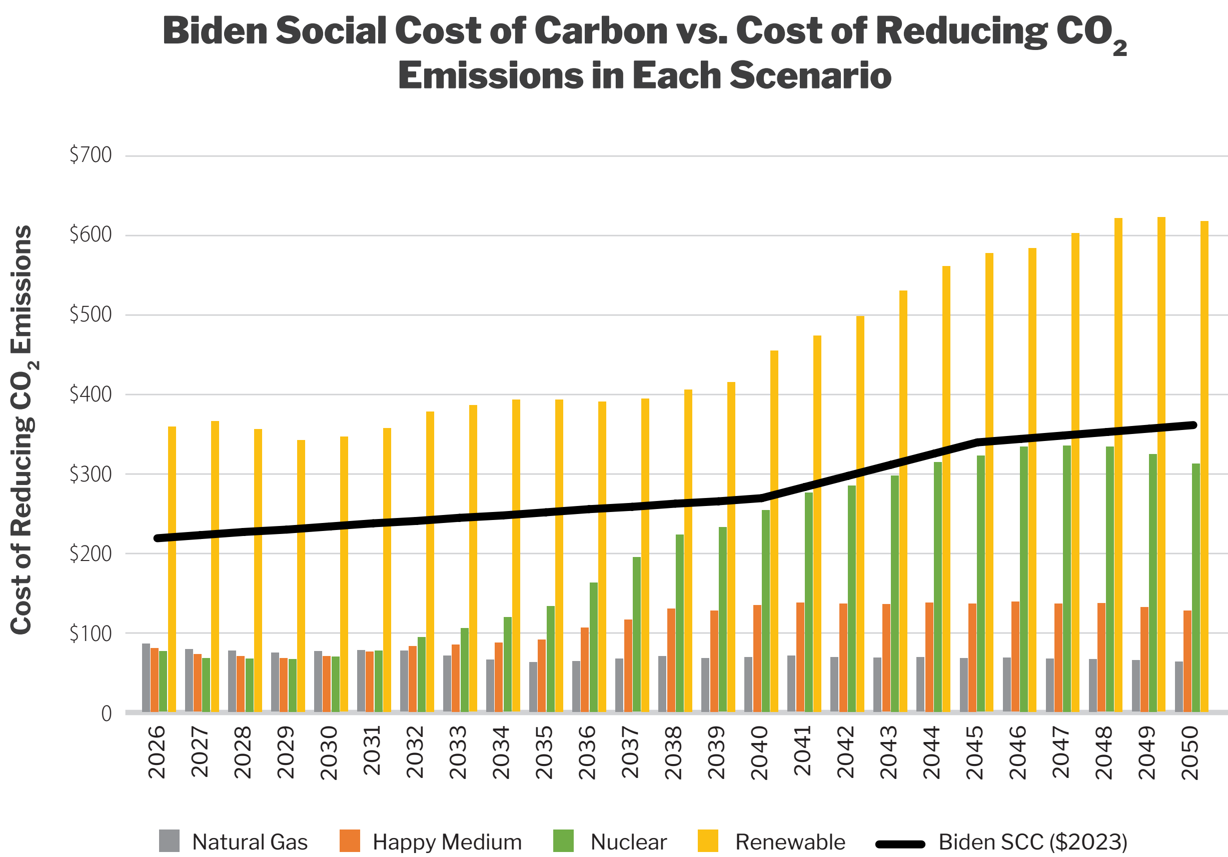


FIGURE 33. The cost of reducing emissions under the Renewable scenario vastly exceeds the Biden SCC estimates in every year studied. However, the modest costs of the other three scenarios deliver more cost-effective reductions in GHG emissions. Data from AOER modeling.

Conclusion

Decarbonizing New England's economy will not be easy or affordable. Each of the four scenarios studied will have significant inflationary impacts on electricity costs in the ISO-NE region, harming families and businesses in the region by causing their power bills to rise.

The Renewable scenario would achieve a significant reduction in carbon dioxide emissions, but it would also cost ratepayers the most money. This scenario would increase costs by an additional $815 billion through 2050 compared to the current grid, causing New England families to see their electricity bills increase from $175 per month in 2024 to $384 per month by 2050.

The Nuclear scenario would achieve the highest decarbonization, reaching 92 percent carbon-free power in 2050, but at a lower cost. In total, this scenario would cost $415.3 billion. The Natural Gas and Happy Medium scenarios would cost far less, at $106.9 billion and $195.8 billion, respectively.

In other words, dispatchable generation saves New England hundreds of billions of dollars and avoids blackouts. In the end, the idea that New England can run its electric grid on wind turbines, solar panels, and batteries is a dangerous and unserious proposition.

There is a smarter path forward, if New Englanders will take it.

Always On Energy Research. AOER believes every resident in every state has the right to know how much energy policy passed at local, state, and federal levels will cost them in terms of standard of living, including monetary and reliability.

The Josiah Bartlett Center for Public Policy. The mission of the Josiah Bartlett Center for Public Policy is to develop and advance practical, free-market policies that promote prosperity and opportunity for all in New Hamphire.

Maine Policy Institute is a nonprofit, nonpartisan organization that works to expand individual liberty and economic freedom in Maine. Maine Policy is the strongest voice in Augusta for taxpayers and believes in an open, transparent, and accountable state government.

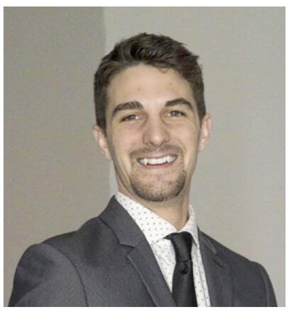
The Rhode Island Center for Freedom and Prosperity is dedicated to providing concerned citizens, the media, and public officials in Rhode Island with empirical research data, while also advancing market-based solutions to major public policy issues in the state.

Yankee Institute is the eyes, ears and voice for hard-working people who want a prosperous Connecticut. Our commonsense solutions drive positive legislative results to strengthen our communities and build a vibrant, hopeful future.

Americans for Prosperity Foundation. We believe in people. When Americans have freedom and opportunity, they can achieve extraordinary things. At Americans for Prosperity Foundation, we empower and educate Americans on the proven and principled solutions to our country's most challenging issues.

The Fiscal Alliance Foundation is focused on increasing public awareness regarding the benefits of greater fiscal responsibility, transparency, and accountability in state government. The organization also engages in legal challenges related to measures that involve the public at large and of private citizens when their rights are abridged by the absence of a fiscally responsible, transparent, and accountable government.

Isaac Orr is a founder and Vice President of Research at Always On Energy Research, where he conducts energy modeling and writes about energy and environmental issues, electricity policy, and natural resource development. His writings have appeared in The Wall Street Journal, USA Today, the New York Post, The Hill, and many other publications. He and his colleague Mitch Rolling have modeled the cost and reliability impacts of Environmental Protection Agency regulations in the Midcontinent Independent System Operator (MISO) and Southwest Power Pool (SPP). They have also evaluated the cost and reliability implications of energy policies in more than 12 states. Isaac grew up on a small family dairy farm in Wisconsin, so he cares deeply about the issues affecting rural America.



Mitch Rolling is a founder and Director of Research at Always On Energy Research, where he models energy proposals, analyzes the energy industry and electricity policy, and writes about energy and environmental issues. His research has been featured in publications such as The Wall Street Journal and Forbes. Mitch and his colleague Isaac Orr co-authored an award-winning report highlighting the impact of Minnesota's 50 percent renewable energy proposal and have designed several energy models to analyze the impact of energy proposals in 12 states and Environmental Protection Agency regulations in the Midcontinent Independent System Operator (MISO) and Southwest Power Pool (SPP). Mitch graduated from the University of Minnesota in 2018 with a bachelor's degree in history, and he earned an MS in finance and economics at West Texas A&M University in 2022.

Appendix

Annual Average Additional Cost per Customer

The annual average additional cost per customer was calculated by dividing the average yearly expense of each of the four scenarios by the number of electricity customers in the region.[55] This methodology is employed because rising electricity prices increase the costs of all goods and services as businesses attempt to pass these additional energy costs on to consumers, effectively increasing the overall cost of everything. Therefore, this method helps convey the total cost of each scenario for New England households in a way that is more representative than calculating the costs associated with higher residential electric bills.

Annual Average Rate per Customer Class

The annual average additional cost per residential, commercial, and industrial rate class customer was calculated by applying the overall cost per kilowatt hour (kWh) in each scenario studied during the time horizon to rate classes based on historical rate factors in New England. Rate factors are determined by the historical rate ratio (rate factor) of each customer class.

For example, electricity prices for residential, commercial, and industrial rate classes in New England were 28.72, 19.23, and 15.80 cents per kWh in 2023, respectively. Based on general electricity prices of 22.78 cents per kWh, residential, commercial, and industrial rates had rate factors of 1.26, 0.84, and 0.69, respectively. This means that, for example, residential customers have historically seen electricity prices 26 percent above general rates. This analysis continues these rate factors to assess future rate impacts for each rate class.

See "Impact on Electricity Rates," below, for a more detailed table of the impact of each scenario on electricity rates by customer class.

Assumptions for Levelized Cost of Energy (LCOE) Calculations

The main factors influencing the Levelized Cost of Energy (LCOE) estimates are capital costs for power plants, annual capacity factors, fuel costs, heat rates, variable operation and maintenance (O&M) costs, fixed O&M costs, the number of years the power plant is in service, and how much electricity the plant generates during that time (which is based on the capacity—megawatts, or MW—of the facility and the capacity factor).

LCOE values for existing natural gas generators were estimated using historical construction costs based on the average plant life of each energy source and current variable and fixed operation and maintenance (O&M) expenses. This method was chosen in the absence of relevant FERC Form 1 filings in the ISO-NE region and similar data for Independent Power Producers (IPP). All other existing generators were estimated using the U.S. average cost for power plants in FERC Form 1 filings.

These LCOE values are inserted into the model and adjusted annually based on annual capacity factors for existing resources.

LCOE values for new power plants were calculated using data values presented in the "Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies" for the Annual Energy Outlook 2025.[56] These values are held constant during the model run. The cost of repowering power facilities that need it at the end of their useful lives is accounted for in each value. These values are described in greater detail below.

Capital Costs, and Fixed and Variable Operation and Maintenance Costs

Capital costs and expenses for fixed and variable O&M for new offshore wind, onshore wind, solar, battery storage, natural gas, and nuclear facilities were obtained from the "Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies" for the Annual Energy Outlook 2025.[57] Region 7 capital costs were used, and national fixed and variable O&M costs were obtained from the "Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies" for the Annual Energy Outlook 2025 report.[58]

Unit Lifespans

Different power plant types have different useful lifespans. Our analysis takes these lifespans into account for our Levelized Cost of Energy analysis.

Onshore and Offshore Wind Turbines Last 20 years

Federal LCOE estimates seek to compare the cost of generating units over a 30-year time horizon.[59] This is problematic for wind energy LCOE estimates because the National Renewable Energy Laboratory reports the useful life of a wind turbine is only 20 years before it must be repowered.

Our analysis corrects for this error by using a 20-year lifespan for wind projects before they are repowered and need additional financing.

Solar Panels Last 25 Years

Our analysis uses a 25-year lifespan for solar because this is the typical warranty period for solar panels. These facilities are rebuilt after they have reached the end of their useful lifetimes.

Battery Storage Lasts 15 Years

Battery storage facilities are expected to last for 15 years. Battery facilities, like wind and solar, are rebuilt after reaching the end of their useful lifetimes.

Fuel Cost Assumptions

Fuel costs for existing power facilities were estimated using the estimates from the ISO-NE "2023 Annual Markets Report."[60] These fuel prices were the most recent prices available when we conducted our first analysis, and these values were held constant for this report to ensure that the results were comparable and not influenced by changes in fuel costs.

Nuclear Fuel Costs

Fuel costs for existing nuclear plants were assumed to be $6.35 per megawatt hour (MWh), which was the latest available price according to the U.S. Energy Information Administration (EIA).

Natural Gas Fuel Costs

Fuel prices for new and existing natural gas power plants were assumed to be $3 per million British thermal units (MMBtu) based on data obtained from the ISO-NE "2023 Annual Markets Report."[61] We held this fuel cost constant through 2050. However, we included a higher fuel price sensitivity that examined the impact of natural gas prices at $4.90 MMBtu and determined that natural gas was still the most cost-effective way to meet ISO-NE's electricity needs.

Coal Fuel Costs

Existing coal fuel cost assumptions of $22.09 per MWh were based on 2020 FERC Form 1 filings.

Levelized Cost of Transmission, Taxes, and Transmission Lines

This report calculated the additional levelized transmission, property, income tax, and generator profit expenses resulting from each new power source built and operated during the course of the model. Costs were attributed according to the additional capacity, measured in megawatts (MW) installed, and generation in MWh of that given source. Capacity installed is used to determine capital costs and additional expenses (transmission, state taxes, and utility profits) of each electricity source over the course of its useful lifespan.[62]

Assumptions for Levelized Cost of Intermittency (LCOI) Calculations

This report also calculated and quantified the Levelized Cost of Intermittency (LCOI) for offshore wind, onshore wind, and solar energy on the entire energy system. These intermittency costs stem from the need to build backup battery storage facilities to provide power during periods of low wind and solar output, which we call "battery storage costs" in this report, and the need to "overbuild and curtail" wind and solar facilities to limit the need for battery storage. It is important to note that these costs are highly system-specific to the mix of resources being built and operated in any given area and are not broadly representative of costs, especially in systems with low penetrations of intermittent resources.

Battery Storage Costs

We calculate battery storage costs by determining the total cost of building and operating new battery storage facilities to meet electricity demand during the time horizon studied in the New England decarbonization plans. These costs are then attributed to the LCOE values of wind and solar by dividing the cost of load balancing by the generation of new wind and solar facilities (capacity-weighted).

Attributing battery storage costs to offshore wind, onshore wind, and solar allows for a more equal comparison of the expenses incurred to meet electricity demand between non-dispatchable energy sources, which require a backup generation source to maintain reliability, and dispatchable energy sources like coal, natural gas, and nuclear facilities that do not require backup generation.

Overbuilding and Curtailment Costs

The cost of using battery storage for meeting electricity demand during periods of low wind or solar output is prohibitively high, so many wind and solar advocates argue that it is better to overbuild renewables, often by a factor of five to eight, compared to the dispatchable thermal capacity on the grid, to meet peak demand during these low wind and solar periods.[63] These intermittent resources would then be curtailed when wind and solar output improve.

As wind and solar penetration increase, a greater portion of their output will be curtailed for each additional unit of capacity installed.[64]

This "overbuilding" and curtailing vastly increases the amount of installed capacity needed on the grid to meet electricity demand during periods of low wind and solar output. The subsequent curtailment during periods of high wind and solar availability effectively lowers the capacity factor of all wind and solar facilities, which greatly increases the cost per MWh produced.

Our model indicated there would be large periods of curtailment in the Renewable scenario due to the large capacity additions of offshore wind, onshore wind, and solar resources. This is consistent with the findings of the ISO-NE "2021 Economic Study: Future Grid Reliability Study Phase 1":

> On high-renewable days, typically during the spring or fall seasons, there is a large amount of both offshore wind and PV [photovoltaic], which leads to large amounts of curtailment. During peak solar output hours, we observed that even with simultaneous charging of BESS [Battery Energy Storage System], pumped storage, and EV Flex (as explored in Alternative B), and external tie-lines exporting at their limits, there was more than 15.4 GWh of energy that needed to be curtailed in a single hour. The system was unable to capture this renewable energy for use at a later time due to insufficient storage (600 MW of BESS plus existing pumped hydro storage). The system would require increased energy storage capability to utilize this curtailed, renewable energy.[65] ... Regardless of the specific gas type in use, the FGRS [Flare Gas Recovery Systems] analysis shows immense amounts of renewable energy curtailment in most cases, but particularly in aggressive electrification and renewable deployment cases.

Annual curtailment levels for this model were estimated based on hourly load forecasts and were found to reach up to 64 percent of total wind and solar generation by the end of the model in the Renewable scenario (see Figure 34).

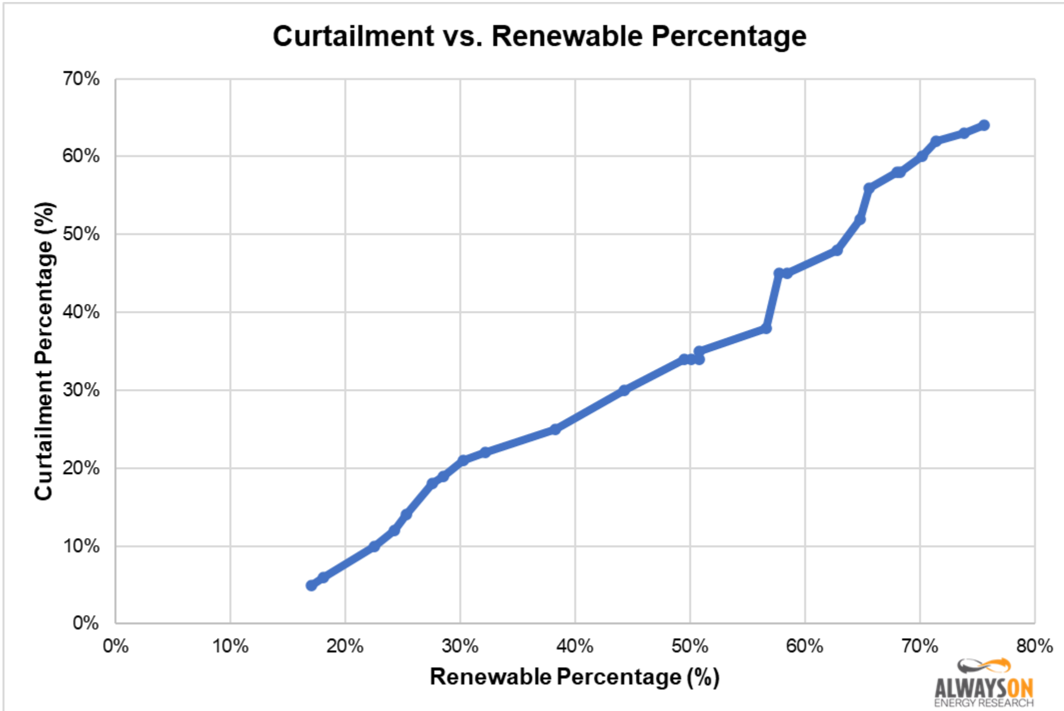


FIGURE 34. Curtailment increases to nearly 64 percent by 2050 as more intermittent generation is brought online. Data from AOER modeling.

Rising rates of curtailment stemming from the overbuilding of the grid effectively lower the capacity factor of all generating resources on the grid, thereby increasing the levelized cost of energy, which is a calculation of power plant expenses divided by the generation of the plant.

Coincident Peak Load

Our analysis assumed coincident winter peak periods of demand throughout the ISO-NE region because the "2050 Transmission Study" found that for winter periods, each state in New England was at or near its own peak load while New England as a whole was at its overall peak load, so a single snapshot in time captured worst-case or near-worst-case conditions in all six states.

Cost-of-Compliance Modeling

This analysis utilizes cost-of-compliance modeling to determine the cost of the electric system in New England. This approach, which does not consider the impact of the resource portfolio on wholesale prices, is appropriate because most large-scale wind and solar facilities are procured through state-sponsored, long-term contracts.[66]

As the system becomes more saturated with these non-dispatchable resources, it is unclear whether the markets will be able to produce the necessary incentives to keep dispatchable units online, resulting in a circumstance where these generators are issued reliability payments to remain available for periods of peak demand.

AOER applied a cost-of-compliance standard for each scenario to remain consistent. As a result, we assumed generators would secure contracts to recoup their capital costs plus a return of 7.05 percent.

Electricity Consumption Assumptions

Our model estimates electricity consumption in 2050 using the projected hourly load shape for 2033 and the monthly peak demand for 2050 (see below). Electricity consumption is incrementally increased every year from 2024 to 2050 to arrive at this consumption level, which was more than 244 million MWhs in 2050.

Energy Storage Dispatch

Energy storage is assumed to be saved for periods of high demand with low wind and solar output. This differs from modeling exercises performed by ISO-NE, where storage facilities are assumed to use locational marginal price (LMP) arbitrage to determine when these resources would be economically dispatched. For each day modeled, the energy storage algorithm forecasted one week ahead to find opportune times to charge and discharge energy and maximize profitability.[67]

This decision was made because using storage systems to capture higher prices via arbitrage would often lead to situations where the energy storage was depleted before a period of low wind and solar output, leaving the system short of energy even though sufficient capacity may be on the grid.

Export Income Assumptions

As ISO-NE increases the installed capacity on its system, there is an opportunity to sell electricity to neighboring regions, including Quebec, New Brunswick, and New York. However, our analysis did not account for these potential export revenues.

One complication in calculating these revenues is the large uncertainty of wholesale power prices in the coming decades. Larger penetrations of zero-marginal cost wind and solar resources will ultimately drive down wholesale power prices during periods of strong wind and solar production. This will reduce the prices of potential exports to neighboring regions, which can purchase low-cost or even negatively priced electricity, reducing the revenues obtained by wind and solar generators.[68, 69]

In contrast, periods of low wind and solar output will cause wholesale prices to rise, thus increasing the cost of imports into ISO-NE. This may create a "buy high, sell low" dynamic for electricity prices on the ISO-NE system in the coming decades.[70]

Hourly Load, Capacity Factors, and Peak Demand Assumptions

The hourly load shape used in our modeling was extrapolated using ISO-NE projected load shapes for 2033 and projected monthly peak demand in 2050. This resulted in a peak demand of 57 gigawatts (GW) in December 2050. New Hampshire electrification was then taken out of this load shape, assuming the state would not electrify motor vehicles and would continue to use natural gas for home heating. This resulted in a peak demand of roughly 52.5 GW.

Hourly output from intermittent generating resources, such as onshore and offshore wind and solar, was derived from the EIA and ISO-NE variable energy resource (VER) data.[71, 72]

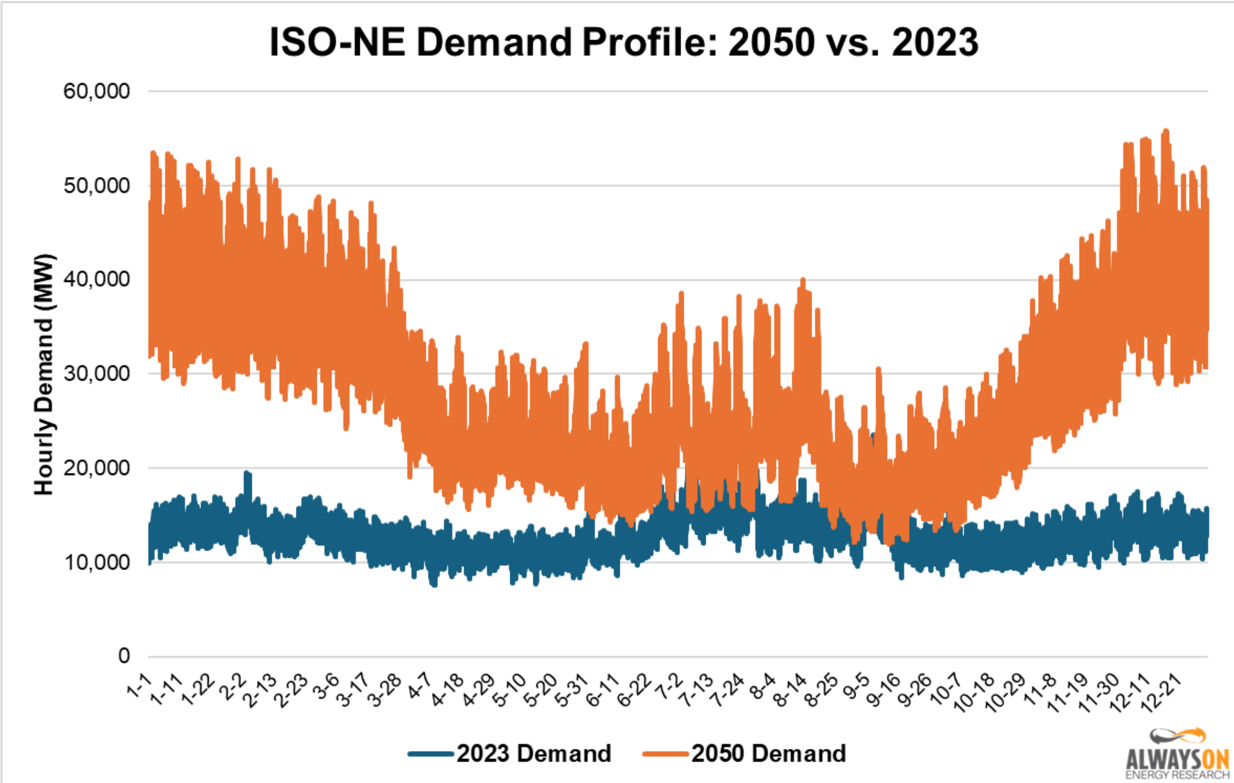


FIGURE 35. This figure shows the difference between the historical 2023 hourly demand in ISO-NE and the projected 2050 hourly demand after load growth and electrification efforts. Data from EIA and ISO-NE.

Impact on Electricity Rates

Table 3 shows annual additional electricity rates by customer class under each scenario, adjusting for the rate factor described above in cents per kWh.

Electricity Rates by Rate Class in Each Scenario (Cents/kWh)																
Rate Class	Residential				Commercial				Industrial				All Sectors			
Scenario	NG	HM	N	R	NG	HM	N	R	NG	HM	N	R	NG	HM	N	R
2025	29.20	29.20	29.20	29.63	19.55	19.55	19.55	19.84	16.07	16.07	16.07	16.30	23.17	23.17	23.17	23.51
2026	29.29	29.25	29.23	31.10	19.61	19.59	19.57	20.83	16.11	16.09	16.08	17.11	23.23	23.20	23.18	24.67
2027	29.45	29.39	29.35	32.10	19.72	19.68	19.65	21.49	16.20	16.17	16.14	17.66	23.36	23.31	23.28	25.46
2028	29.60	29.52	29.49	32.78	19.82	19.77	19.74	21.95	16.28	16.24	16.22	18.04	23.48	23.42	23.39	26.00
2029	29.80	29.71	29.68	33.68	19.95	19.89	19.88	22.55	16.39	16.34	16.33	18.53	23.64	23.56	23.55	26.72
2030	29.99	29.88	29.87	34.43	20.08	20.01	20.00	23.06	16.50	16.44	16.43	18.94	23.79	23.70	23.70	27.31
2031	30.19	30.17	30.19	35.50	20.22	20.20	20.21	23.77	16.61	16.60	16.61	19.53	23.95	23.93	23.94	28.16
2032	30.39	30.52	30.76	36.89	20.34	20.43	20.60	24.70	16.72	16.79	16.92	20.30	24.10	24.21	24.40	29.26
2033	30.58	30.95	31.50	38.85	20.47	20.72	21.09	26.01	16.82	17.03	17.33	21.37	24.26	24.55	24.99	30.82
2034	30.74	31.39	32.37	40.76	20.58	21.02	21.68	27.29	16.91	17.27	17.81	22.42	24.38	24.90	25.68	32.33
2035	30.89	31.87	33.33	42.27	20.68	21.34	22.31	28.31	16.99	17.53	18.33	23.26	24.50	25.28	26.44	33.53
2036	31.02	32.53	34.56	42.72	20.77	21.78	23.14	28.60	17.07	17.89	19.01	23.50	24.61	25.80	27.41	33.88
2037	31.22	33.04	35.94	43.35	20.90	22.12	24.06	29.03	17.17	18.18	19.77	23.85	24.76	26.21	28.51	34.39
2038	31.40	33.67	37.22	44.15	21.02	22.54	24.92	29.56	17.27	18.52	20.47	24.29	24.91	26.71	29.52	35.02
2039	31.57	34.07	38.45	46.10	21.14	22.81	25.75	30.87	17.37	18.74	21.15	25.36	25.04	27.03	30.50	36.57
2040	31.71	34.55	39.71	48.41	21.23	23.13	26.59	32.41	17.45	19.01	21.85	26.63	25.15	27.41	31.50	38.40
2041	31.86	34.83	40.99	49.75	21.33	23.32	27.45	33.31	17.53	19.16	22.55	27.37	25.27	27.63	32.52	39.46
2042	31.98	35.19	42.23	52.31	21.41	23.56	28.27	35.03	17.59	19.36	23.23	28.78	25.37	27.91	33.50	41.49
2043	32.10	35.38	43.33	54.76	21.49	23.69	29.01	36.66	17.66	19.47	23.84	30.12	25.46	28.07	34.37	43.43
2044	32.18	35.63	44.50	56.85	21.55	23.86	29.80	38.07	17.70	19.60	24.48	31.28	25.52	28.26	35.30	45.10
2045	32.26	35.84	45.50	58.76	21.60	24.00	30.47	39.35	17.75	19.72	25.03	32.33	25.59	28.43	36.09	46.61
2046	32.32	36.05	46.36	59.56	21.64	24.14	31.04	39.88	17.78	19.83	25.50	32.77	25.64	28.60	36.77	47.25
2047	32.38	36.16	46.94	61.48	21.68	24.21	31.43	41.17	17.81	19.89	25.82	33.82	25.68	28.68	37.23	48.77
2048	32.44	36.33	47.26	63.24	21.72	24.33	31.64	42.35	17.84	19.99	26.00	34.79	25.73	28.82	37.49	50.17
2049	32.46	36.31	47.33	64.42	21.73	24.31	31.69	43.14	17.86	19.98	26.04	35.44	25.75	28.80	37.54	51.10
2050	32.46	36.24	47.10	65.02	21.74	24.26	31.53	43.54	17.86	19.94	25.91	35.77	25.75	28.74	37.36	51.58
NG = Natural Gas Scenario; HM = Happy Medium Scenario; N = Nuclear Scenario; R = Renewable Scenario																

TABLE 3. This table shows the cost of electricity in each scenario for residential, commercial, and industrial customers. All Sectors prices are an average of all of these subcategories. Data from AOER Compliance Cost modeling.

Imports

Our analysis assumed all the transmission lines in the "2050 Transmission Study" would be operational. These consist of:

- 1,000 MW imported from New Brunswick over existing 345 kV (kilovolt) AC (alternating current) ties.
- 1,850 MW imported from New York over the existing 345 kV, 230 kV, 115 kV, and 69 kV AC ties.
- 1,400 MW imported from Quebec over the existing Phase II HVDC (high-voltage direct current) tie (interconnected at Sandy Pond substation in Ayer, Massachusetts).
- 225 MW imported from Quebec over the existing Highgate HVDC back-to-back converter (interconnected in Highgate, Vermont).
- 1,200 MW imported from Quebec over the under-construction New England Clean Energy Connect HVDC tie (interconnected at Larrabee Road substation in Lewiston, Maine).
- 1,000 MW imported from Quebec over a hypothetical new HVDC tie between Quebec and Vermont (assumed to interconnect at the Coolidge substation in Cavendish, Vermont).

The cost of imports from Hydro-Quebec (HQ) was assumed to be 7.5 cents per kWh based on the most recent annual report published by HQ.[73]

Import Uncertainty

A key component of the ISO-NE decarbonization strategy, especially in the Renewable scenario, consists of importing electricity from Canada and New York during periods of high demand and low wind and solar output. Our analysis is conservative because it assumes all 6,675 MW of the existing and planned transmission projects to import electricity into New England are firm, meaning they can deliver their full-rated capacity at any point when needed.

However, this strategy is fraught with considerable uncertainty because New York—which is also highly dependent upon natural gas—is also seeking to decarbonize its electricity supply using intermittent resources while achieving high levels of electrification in the transportation and home heating sectors.[74, 75]

Due to their close proximity, this could mean that New York will experience high demand at a time when its wind and solar resources, especially its offshore wind installations located off the coast of New England, are not producing enough electricity to satisfy its own internal demand, let alone allow for exports to New England.[76]

Canadian imports could also be subject to interruption. HQ is the largest exporter into the ISO-NE region, sending significant amounts of power to the New England states in the summertime.[77] This is possible because Quebec, with 71.4 percent of households using electric heating and heat pumps in 2021, is a winter peaking system, and ISO-NE is currently a summer peaking system.[78]

This efficient partnership will face challenges in the years ahead as ISO-NE becomes a winter peaking system.

In February of 2023, a cold snap enveloped Quebec, causing electricity demand to reach new all-time highs. During this period, HQ demand reached 42,472 MW, outstripping the installed capacity of 37,200 MW on the HQ system.[79] As a result, HQ had no power to send to New England. In fact, it was importing power from neighboring regions, including New York, Ontario, and ISO-NE.

Increasing transmission capabilities with Hydro-Quebec and New Brunswick greatly diminish the chances of rolling blackouts in ISO-NE in the spring, fall, and summer months, but the potential for region-wide winter cold spells that cause electricity demand to surge will present clear and present dangers to grid reliability.

Interconnection Costs

An interconnection cost for a generation resource refers to the total cost a developer must pay to connect a new power plant (or other generator) to the electric grid. These costs cover the studies, equipment, and construction required to ensure the grid can safely and reliably accommodate the new generation's output.

This study uses the following cost assumptions for each resource type seeking interconnection on the ISO-NE system: wind interconnection costs are assumed to be $48,000 per MW, solar $48,000 per MW, natural gas $30,000 per MW, and $50,000 per MW for nuclear.

Load Modifying Resources

Our model does not allow for the use of Load Modifying Resources (LMRs) or demand response (DR) in determining how much reliable capacity will be needed to meet peak electricity demand in any of the scenarios studied. Instead, enough generation capacity is built to satisfy demand.

In the Renewable scenario, battery capacity and excess wind and solar capacity are built to provide enough power to supply ISO-NE's electricity needs under the decarbonization plans at all times based on a test year using historical generation in ISO-NE in 2023, and hourly capacity factors for wind and solar from the EIA Electric Grid Monitor and ISO-NE VER data.[80] Battery storage capacity was assumed to be 95 percent efficient and fully charged at the start of the test year.

We acknowledge that voluntary LMRs and DRs can play a role in optimizing system cost and reliability. However, we believe that DR resources are being inappropriately used by many wind and solar special interest groups to manipulate their models to unrealistically reduce the amount of capacity needed to meet peak demand, and thus artificially suppress the cost of their proposals. In this way, these groups are essentially manipulating the amount of capacity needed to meet current electricity demand and not providing an apples-to-apples comparison of the cost. Their proposals will effectively place more responsibility on behalf of the customer to keep the grid online.

New Hampshire Electricity Demand

Because New Hampshire has not adopted deep decarbonization policies, this analysis projects that the state will continue to utilize conventional energy sources, such as natural gas and heating oil, for home heating and gasoline and diesel-powered internal combustion engines. This serves to reduce the observed peak load on the ISO-NE system.

New Hampshire's peak load reduction was calculated by taking the difference between New Hampshire's projected demand for electrification and a constant growth of New Hampshire demand based on historical growth rates of 1.25 percent. This difference was subtracted from the hourly load shape to account for New Hampshire's energy policy that does not include electrification efforts seen in other states.

Nuclear Relicensing

All existing nuclear power plants were assumed to remain operational through the model run. This assumption greatly reduced the need for new onshore wind, offshore wind, solar, and battery storage resources in the Renewable scenario, and to a lesser extent in the other scenarios studied. These plants also provide crucial reliability benefits.

This was demonstrated in the ISO-NE "2021 Economic Study: Figure Grid Reliability Study Phase 1," where retiring the existing nuclear power plants resulted in massive blackouts in the region, with customers losing power for 79 hours throughout the year, peaking at 6,160 MWh (19.7 percent of load) of unserved energy during a single hour.

Aside from unserved energy, the retirement of nuclear units led to a 50 percent increase in carbon dioxide emissions.

Nuclear Restrictions

Maine and Connecticut maintain a moratorium until the identification of a demonstrable technology or a means for high-level waste disposal or reprocessing is found.[81] Connecticut in 2022 passed legislation allowing for new reactors to be sited at the existing nuclear facility located in the state.[82]

Massachusetts, Rhode Island, and Vermont prohibit new nuclear power plants unless they are approved by the state legislature.[83] Maine and Massachusetts also require voter approval for new reactors.[84, 85]

Plant Construction by Type

In the Renewable scenario, this analysis assumes no new carbon-dioxide emitting power plants will be built outside of New Hampshire, where the total installed capacity of natural gas power plants is roughly 5,650 MW. Existing natural gas capacity is assumed to remain online but operate at low capacity factors in the remaining five states.

Under the New England decarbonization plans, states would add offshore wind, onshore wind, solar facilities, battery storage capacity, and build new transmission lines to reduce emissions, consistent with the "2050 Transmission Study" assumptions.

New nuclear and natural gas plants are built as needed in the Nuclear, Natural Gas, and Happy Medium scenarios.

Plant Retirement Schedules

For the Renewable and Nuclear scenarios, our model uses retirement assumptions from the "2050 Transmission Study," where all coal, oil, diesel, and municipal solid waste-fueled generators, as well as a portion of today's natural gas-fueled generation, were retired by 2035. For our analysis, existing steam turbine gas plants were retired while others remained in service and were repowered as needed to keep online.

The remainder of today's natural-gas-fueled generation, as well as biomass, nuclear, hydroelectric, and renewable generators, were assumed to remain operational through 2050.

For the Natural Gas and Happy Medium scenarios, these existing plants are retired when they reach the end of their useful lives after 60 years in service.

Time Horizon Studied

This analysis studies the impact of the New England decarbonization plans on electricity prices from 2024 to 2050. This time horizon is examined because, like a mortgage, power plant owners pay off the cost of the plant each year, meaning decisions made today will affect the cost of electricity for decades to come. As such, the total costs highlighted by this study do not represent the total costs incurred by the New England decarbonization plans, but rather the total cost that electricity customers would pay off through 2050.

Transmission

ISO-NE estimates rising peak demand will cost roughly $750 million per GW of load added from 28 GW to 51 GW, and roughly $1.5 billion per GW from 51 GW to 57 GW.[86]

ISO-NE notes that the New England grid, with 100 percent heating and transportation electrification, is expected to result in a peak load of around 57 GW, but a lower peak load could be achieved if less electrification of the transportation and home heating sectors.

In our analysis, New Hampshire serves to reduce peak load by 4.5 GW by continuing to heat homes with natural gas and fuel oil and by continuing to use internal combustion engines, thus producing significant transmission savings.[87, 88]

Wind and Solar Degradation

According to the Lawrence Berkeley National Laboratory, output from a typical U.S. wind farm shrinks by about 13 percent over 17 years, with most of this decline taking place after the project turns 10 years old. According to the National Renewable Energy Laboratory, solar panels lose one percent of their generation capacity each year and last roughly 25 years, which causes the cost per MWh of electricity to increase each year.[89] However, our study does not take wind or solar degradation into account.

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