# An Analysis of the Massachusetts Renewable Portfolio Standard

Prepared for NECEC in Partnership with Mass Energy

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Synapse Energy Economics, Inc.

Pat Knight
Ariel Horowitz, PhD
Patrick Luckow
Tyler Comings

Sustainable Energy Advantage, LLC

Jason Gifford
Po-Yu Yuen
Edward Snook
Jordan Shoesmith

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**About NECEC**

NECEC (Northeast Clean Energy Council & NECEC Institute) is the premier voice of businesses building a world-class clean energy hub in the Northeast, helping clean energy companies start, scale, and succeed with our unique business, innovation and policy leadership. NECEC includes the Northeast Clean Energy Council (a nonprofit business member organization), and NECEC Institute (a nonprofit focused on industry research, innovation, policy development and communications initiatives). NECEC brings together business leaders and key stakeholders to engage in influential policy discussions and business initiatives while building connections that propel the clean energy industry forward.

**About Mass Energy**

Mass Energy Consumers Alliance is a 501(c)3 consumer and environmental advocacy organization dedicated to making energy affordable and environmentally sustainable and to reducing carbon emissions 80 percent by 2050. Since 1982, Mass Energy has been at the forefront of energy policy and consumer programming designed to help people gain access to and benefit from efficiency and renewable energy technology.

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# EXECUTIVE SUMMARY

Massachusetts has long been a national leader in efforts to advance clean energy in order to enhance energy diversity and security, increase economic development, and reduce environmental impacts including greenhouse gas emissions. The state's Renewable Portfolio Standard (RPS) is the foundation for clean energy markets and a proven policy tool for supporting successful, cost-effective renewable energy development at the state level. It is also an important part of the leadership needed to address climate change. Along with 29 other states across the country, Massachusetts has enacted an RPS policy mandating that clean energy sources supply a minimum percentage of the Commonwealth's electricity. The RPS is a market-based mechanism that creates demand for clean energy, which can be met by a variety of cost-effective resources. Throughout New England, RPS compliance is tracked through the sale of Renewable Energy Credits (RECs), which are either embedded in contracts for renewable energy or bought separately on an open market. The price for RECs is determined by market transactions and is affected by the relative balance of demand for RECs—created by the RPS—and supplied by renewable resources.

The Massachusetts RPS requires that retail electricity suppliers provide customers with a minimum percentage of electricity from renewable energy. This percentage currently increases by 1 percent each year. In 2016, the Massachusetts RPS required suppliers to purchase enough renewable energy to cover 11 percent of their customers' retail load; under the existing policy, this number will reach 25 percent by 2030. This increase alone will not be enough to comply with the state's clean energy and climate goals.

The RPS and supporting policies have successfully spurred the development of the existing renewable energy fleet—creating jobs, tax revenue, and price-hedging opportunities for electricity customers in the process. Existing policies have driven both centralized and, increasingly, distributed generation. Projects facilitated by the RPS, built after 1998, have expected useful lives of 30 years or more. However, as the Commonwealth moves to fulfill its obligations under the Massachusetts Global Warming Solutions Act (GWSA) to reduce emissions by 80 percent by 2050, new policies are likely to be needed to support and accelerate continued growth in renewable resources. In 2016, Massachusetts enacted *An Act to Promote Energy Diversity* (Energy Diversity Act), which requires Massachusetts investor-owned utilities to enter long-term contracts with offshore wind, large hydroelectric, and other renewable resources. Laws with similar requirements have also been enacted in Connecticut and Rhode Island. Other recent policies have contributed to substantial solar development, with more on the horizon, and the expectation is that this supply will increasingly be coupled with energy storage. These laws and policies will contribute to the Commonwealth's clean energy and climate goals. However, it is possible and even necessary for Massachusetts to go further to achieve the GWSA-mandated greenhouse gas emission reductions and align its clean energy policies.

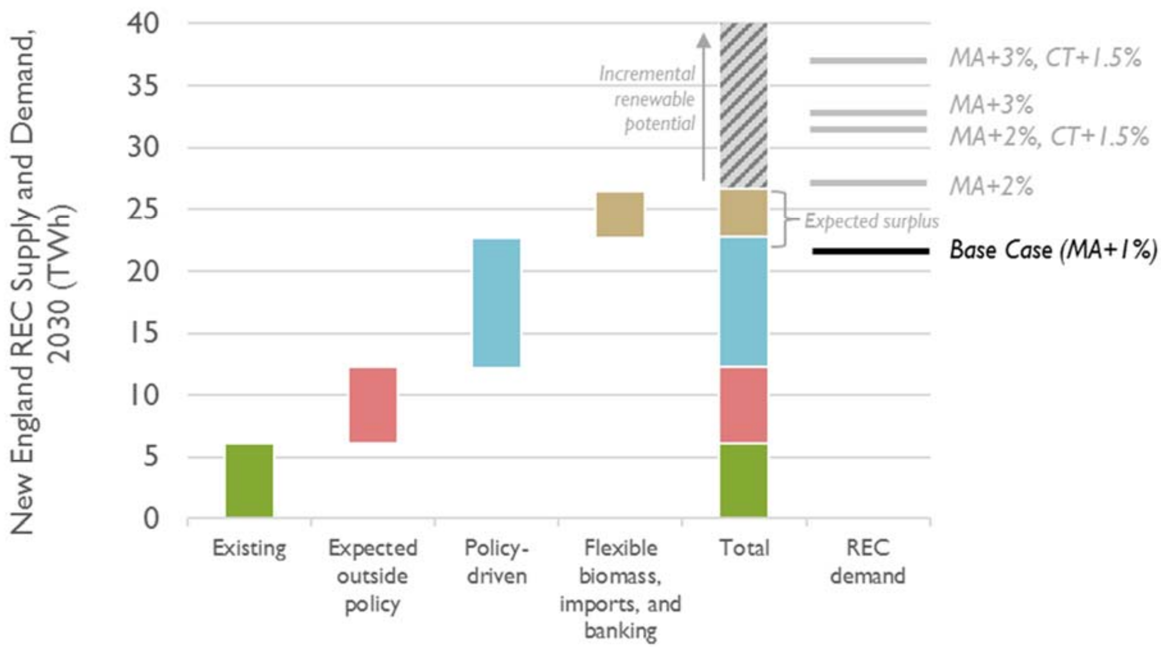
An increase in the Commonwealth's annual RPS growth rate is likely necessary to correct the existing imbalance between policies that impact renewable energy supply and policies that impact demand for renewable energy. While the Commonwealth's historic success and recent policy enhancements will increase the *supply* of renewables, policies like the RPS that create *demand* for renewables have not kept pace. A remedy to this supply and demand imbalance is necessary both to maintain the current renewable energy fleet and to encourage new investment and production in a cost-effective and sustainable manner. Market research and analysis demonstrates that a technical correction to annual RPS targets is likely required to maintain a balanced and stable market while fulfilling existing policies. Massachusetts relies on both existing and new (or planned) renewable energy projects to meet its RPS and GWSA obligations. A successful policy will support not only new projects but also those built in response to the early years of the RPS, allowing the Commonwealth to incentivize new, incremental, cost-effective renewable generation.

Synapse Energy Economics (Synapse) and Sustainable Energy Advantage (SEA) have partnered to examine the impacts of the current RPS policy and potential changes in the RPS policy on the future renewable energy market in New England through 2030. Using a set of sophisticated electricity models, we modeled future New England electricity markets through 2030 under four different RPS scenarios and three sensitivity cases. The Base Case assumes full implementation of the Energy Diversity Act, Massachusetts solar policy changes, and other "business-as-usual" policies, and assumes that there are no other changes to the current Massachusetts Class I RPS policy. We then compared the results for the Base Case with those for three different potential increases in the RPS: an increase of 2 percent per year in the Massachusetts RPS, an increase of 2 percent per year in the Massachusetts RPS alongside a 1.5 percent per year increase in the Connecticut RPS, and an increase of 3 percent per year in the Massachusetts RPS alongside a 1.5 percent per year increase in the Connecticut RPS. In addition, we analyze the results of each of these four scenarios under different market conditions of natural gas prices and greater vehicle electrification. Our analysis and findings follow.

### In a Base Case future with no changes to RPS policies, the New England electricity system is unlikely to see substantial additions of renewables before 2030, beyond those expected from recently-enacted long-term contracting policies and other non-RPS programs.

We estimate that meeting current on-the-books laws and regulations such as existing RPS policies will require an increase in renewable capacity of 7,700 megawatts (MW) by 2030. These laws and regulations include long-term contracting requirements under the Energy Diversity Act, which require 1,600 MW of RPS-eligible offshore wind and 9.45 million megawatt-hours (MWh) of clean energy (part of which includes RPS-eligible renewables), other long-term renewable energy contracting policies in place in Connecticut and Rhode Island, as well as solar incentive policies throughout New England. These policies will result in new renewable supply exceeding the demand for RECs established under the existing RPS policies (see Figure ES-1).

**Figure ES-1. Demand for Class I RECs in New England, relative to existing supply and supply anticipated to be available from resources in the future (measured in TWh, or million MWh)**






**This increase in REC supply, without a corresponding increase in REC demand, is likely to reduce spot REC prices and undermine efforts to sustain existing resources and finance new renewable investment.**

In the Base Case, as the supply of renewables increases without commensurate increases in demand, the price for Class I RECs in the New England market is expected to drop from $16 per megawatt-hour (MWh), where it is today, to below $5 per MWh between 2025 and 2030. Sustained surplus and low REC prices may impair the financial viability of existing Class I resources and are not likely to enable the financing required for new renewable development, undermining the use of the RPS as a means to achieve the Commonwealth's climate goals. Existing biomass facilities (representing approximately 400 megawatts (MW) of renewable capacity) and other RPS-eligible projects either wholly or partially uncontracted are particularly susceptible. Policymakers should consider the impact of policy changes on investors in existing projects, as these entities are largely responsible for delivering the RPS successes claimed to date. Policy choices also affect the willingness of entities considering investments that will lead to new generation, new jobs, and reduced greenhouse gas emissions to meet the Commonwealth's clean energy and climate goals.

**Increasing the rate of growth in the RPS to 2 percent per year will align renewable energy supply and demand but is unlikely to drive incremental new renewable capacity additions, beyond those supported by recent policies, before 2030. Increasing the RPS even further can drive additional new renewable capacity and generation.**

Our analysis shows that an increase in the Massachusetts RPS to 2 percent per year (up from the current 1 percent per year) is likely to produce a demand for renewables in line with anticipated supply from non-RPS programs. In this future, supply from existing capacity (including biomass and Class I imports from New York, Québec, and New Brunswick) and expected additions from already-authorized policies and programs will be sufficient to meet annual increases at a rate of 2 percent in RPS demands. Very few additional new renewables will be built.

If RPS polices are altered, our analysis shows that between 2,000 and 4,900 GW of new renewables could be built by 2030, beyond what is already called for in existing laws and regulations. These alternatives include: (a) an increase of 2 percent per year in the Massachusetts RPS and a continuation of the 1.5 percent per year increase in the Connecticut RPS, (b) an increase of 3 percent per year in the Massachusetts RPS and a continuation of the 1.5 percent per year increase in the Connecticut RPS, or (c) if New England's electricity usage were to increase due to increased electrification as a result of greater deployment of electric vehicles.

### Increasing RPS requirements can lead to lower wholesale electricity market prices for customers. After accounting for incremental REC price increases, transmission costs, and displaced fossil fuel generation, residential customers are expected to experience only moderate monthly bill increases.

Renewable resources frequently have variable operating costs of close to $0 per MWh, unlike resources such as natural gas and coal that require staff operation and fuel to run. As more renewables come online, the hourly cost to provide electricity decreases. With increased levels of renewables, we estimate that by 2030 wholesale market prices for energy will decrease between 0.5 percent and 8.1 percent (depending on the rate of RPS expansion), relative to a future in which RPS policies in Massachusetts or Connecticut are not changed. At the same time, higher REC prices will increase the cost of RPS compliance. When decreases in wholesale electricity prices are aggregated with increases in REC prices, we find that monthly average retail electric bills for residential ratepayers in Massachusetts are expected to increase $0.15 to $2.17 per month (depending on the rate of RPS expansion), compared to a future in which the Massachusetts and Connecticut RPS are not changed.

### Increasing the RPS can result in up to 37,000 new jobs in New England between 2018 and 2030.

In addition to reducing wholesale electricity prices, more renewable energy leads to more jobs. Our comprehensive job impact analysis finds that increasing the Massachusetts RPS requirements, alongside maintaining the annual increase in Connecticut's RPS, could drive up to 37,000 net jobs over the study period. In a future with a high natural gas price, or high electrification, even more jobs could be created across the region. This analysis accounts for job losses associated with both higher REC prices and displaced natural gas and coal generation, as well as job increases associated with new renewable construction.

### Increasing the RPS can provide a price hedge against rising natural gas prices and volatility.

While natural gas prices have remained at historically low levels for several years, it is possible that future increases in natural gas prices could drive up the wholesale energy price in New England. Between 2018 and 2030, increasing the diversity of New England's electricity mix by adding more renewables and reducing reliance on natural gas could save New England up to $2.1 billion in wholesale energy costs, in the face of a higher natural gas price.

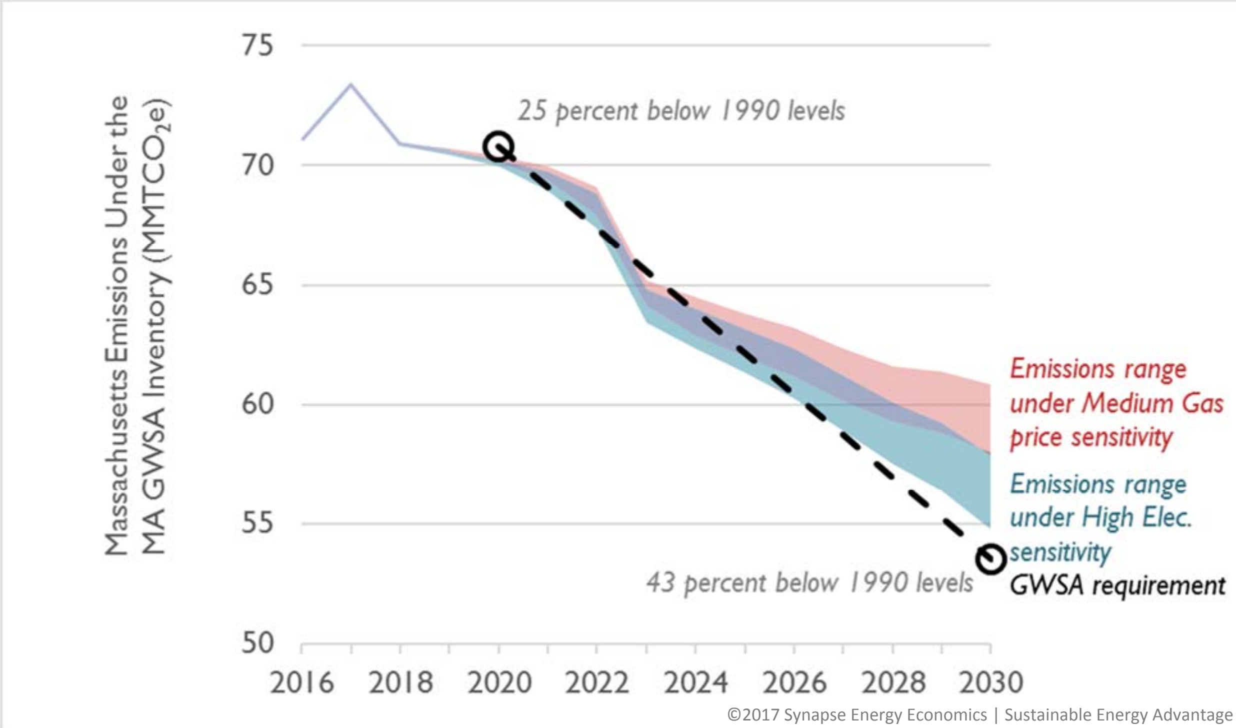
### Increasing the RPS drives new renewables and reduces natural gas and coal generation.

As more renewables come online, they act as "must-take" resources, causing generation from conventional resources like natural gas and coal to reduce or be displaced. Even in the Base Case, the anticipated growth of renewables results in the retirement of all but one New England coal unit during the study period. This growth also causes an estimated 32 percent reduction in natural gas consumption for electric power generation between 2016 and 2030. In other cases, 2030 natural gas-fired generation is 21 to 55 percent below 2016 levels, depending on the natural gas price, the level of renewables, and demand for electricity from electric vehicles.

### Using the RPS to shift generation away from natural gas and coal to renewables leads to reductions in carbon dioxide emissions in all scenarios.

As generation from fossil fuels declines, so do carbon dioxide emissions. In our Base Case, we estimate that 2030 carbon dioxide emissions from the electricity sector in New England will be 60 percent lower than they were in 1990. Other, higher levels of renewables could increase this reduction to between 62 and 71 percent. When taking electric sector emissions together with carbon dioxide emissions from all sectors (i.e., the residential, commercial, industrial, and transportation sectors) in New England, we observe 2030 emission reductions of 27 to 33 percent relative to 1990 levels, with the largest emission reductions occurring in scenarios with high levels of vehicle electrification. However, these emission reductions still fall short of the reductions required for the six New England states to meet their climate change targets. For Massachusetts in particular, we find that all scenarios meet the 2020 Massachusetts GWSA requirement (a 25 percent reduction in all-sector, all-greenhouse gas emissions, relative to 1990 levels), but some scenarios are outside the compliance trajectory as soon as 2021. Despite the inclusion of new regulations by the Massachusetts Department of Environmental Protection (MassDEP) which apply unit-specific carbon dioxide caps to in-state generators and promulgate a Clean Energy Standard through 2050, all scenarios fall short of the trajectory required to achieve an 80 percent reduction in greenhouse gas emissions by 2050 (see Figure ES-2).

Figure ES-2. Massachusetts greenhouse gas emissions under the Massachusetts inventory




## Conclusion

Massachusetts' key renewable energy policies require harmonization in order for the Commonwealth to meet its long-term clean energy and climate goals. If RPS requirements are not increased to re-align with supply policies such as large scale long-term contracting and distributed generation incentives, Massachusetts is likely to observe existing renewable investors exiting the market and few new renewable additions beyond those required under recent long-term contracting laws and other non-RPS renewable policies. Increasing the Massachusetts Class I RPS targets can drive new, incremental, cost-effective, market- based renewables that lower wholesale electricity prices, reduce carbon dioxide and other power plant emissions, and increase jobs and other economic benefits in the Commonwealth and surrounding states.

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# 1. RECENT CHANGES TO THE NEW ENGLAND RENEWABLE ENERGY MARKET

Massachusetts has long been a national leader in efforts advance clean energy in order to, enhance energy diversity and security, increase economic development and reduce environmental impacts such as greenhouse gas emissions. The state's Renewable Portfolio Standard (RPS) is the foundation for clean energy markets and a proven policy tool to support successful, cost-effective renewable energy development at the state level. It is also an important part of the leadership need to address climate change. Along with 29 other states across the country, Massachusetts has enacted an RPS policy mandating that clean energy sources supply a certain percentage of the Commonwealth's electricity. The RPS is a market-based mechanism that creates demand for clean energy, which can be met by a variety of cost-effective resources. Throughout New England, RPS compliance is tracked through the sale of Renewable Energy Credits (RECs), which are either embedded in contracts for renewable energy or purchased separately on an open market. The price for RECs is determined by market transactions and is affected by the relative balance of demand for RECs—created by the RPS—and renewable energy supply.

The Massachusetts RPS requires that a certain percentage of the electricity that retail electricity suppliers provide to customers comes from renewable energy. This percentage currently increases by 1 percent each year. In 2016, the Massachusetts RPS required suppliers to purchase enough renewable energy to cover 11 percent of their customers' retail load; under the existing policy, this number will reach 25 percent by 2030. This increase alone will not be enough to comply with the state's climate goals.

The RPS and supporting policies have successfully spurred the development of the existing renewable energy fleet—creating jobs, tax revenue, and price-hedging opportunities for customers in the process. Existing policies have driven both centralized and, increasingly, distributed generation. These projects achieved commercial operation after 1998 and have expected useful lives of 30 years or more. However, as the Commonwealth moves to fulfill its obligations under the Massachusetts Global Warming Solutions Act (GWSA) to reduce emissions by 80 percent by 2050, new policies are likely needed to support and accelerate continued growth in renewable resources.

In 2016, Massachusetts enacted *An Act to Promote Energy Diversity* (Energy Diversity Act), which requires Massachusetts investor-owned utilities to enter into long-term contracts with offshore wind, large hydroelectric, and other renewable resources. Laws with similar requirements have also been enacted in Connecticut and Rhode Island. Other recent policies have contributed to substantial solar development, with more on the horizon, and the expectation that this supply will increasingly be coupled with battery storage. At the same time, the Massachusetts Department of Environmental Protection (MassDEP) has moved to comply with the Massachusetts GWSA. It has promulgated draft regulations aimed at requiring the procurement of clean energy technologies through a Clean Energy

Standard (CES) and reducing carbon dioxide ($CO_2$) emissions from electric power generators through a $CO_2$ emissions cap. Such a cap may also directly or indirectly encourage additional renewable generation. These laws, regulations, and policies, some of which act as new drivers for RPS-eligible resources, will also contribute to the Commonwealth's climate and clean energy goals. However, it is possible and even necessary for Massachusetts to go further to achieve its greenhouse gas emission reduction goals and align its clean energy policies.

Recent measures notwithstanding, Massachusetts will need to take further action to achieve its greenhouse gas emissions goals. An increase in the Commonwealth's annual RPS growth rate could provide additional benefits in terms of lowered wholesale electricity market prices, hedges against natural gas price volatility, and increased clean energy jobs in the region. At the same time, other states around the country have recently put forth ambitious renewable energy requirements that exceed Massachusetts' 2030 RPS requirement: California and New York's RPS policies require 50 percent renewables by 2030, while Hawaii's RPS policy requires 40 percent renewables by 2030 and 100 percent renewables by 2045.[1] Within New England, Rhode Island expanded and extended its Renewable Energy Standard last year to achieve 38.5 percent by 2035.

An increase in the Commonwealth's annual RPS growth rate is likely necessary to correct the existing—and presumably unintended—imbalance between policies that impact renewable energy supply, such as large-scale long-term contracting and distributed clean energy incentives and policies that impact renewable energy demand, like the RPS. While the Commonwealth's historic success and recent policy enhancements should increase the *supply* of renewables, policies which create *demand* for renewables have not kept pace.

An approximate supply-demand balance would be required to both maintain the current renewable energy fleet (built since the Commonwealth's restructuring legislation was passed in 1997) and encourage new investment and production in a cost-effective and sustainable manner. Because the RPS market is currently in surplus, without an increase in RPS demand targets to balance the market, REC prices may not be sufficient to continue to support the projects initially built in response to the RPS. Further, recent policies supporting supply-side development may lead to a continuing surplus and imbalance between demand and supply. An extended market surplus will produce low REC prices year-over-year. This may threaten the continued operation of existing RPS generation and could cause job losses or emissions increases if these projects go offline. It will not, however, necessarily translate into lower REC prices and RPS compliance costs for Massachusetts ratepayers. Any benefits associated with lower REC prices are more likely to accrue to other New England states. This is because Massachusetts has extensive long-term contracting obligations. To this end, Massachusetts will satisfy substantial volumes of its forward-looking RPS obligation with RECs purchased at known, bid-based prices under long-term contracts. The cost of RECs will, therefore, not be affected by spot market prices. Further, if long-term contracts lead to excess RECs for Massachusetts utilities, these excess RECs will be sold into a

[1] Note that all states have different requirements for the types of resources that are eligible to be used to comply with RPS policies. See Section 2.1 below for more information on eligibility criteria in New England states.

price-suppressed short-term REC market. Since utility long-term contracts include cost recovery provisions, any financial loss associated with the sale of excess RECs is expected to be recovered from Massachusetts electricity customers through utility distribution charges.

A balanced market represents the opportunity to meet the Commonwealth's goals in the most sustainable and cost-effective manner. To this end, the purpose of the analysis in this report is to provide insights that support informed decision-making toward the objectives of achieving RPS and GWSA targets at the least cost to Massachusetts ratepayers. Only after this supply and demand imbalance is corrected will the RPS be able to achieve its original purpose—to use the market to incentivize new, cost-effective renewable generation.

Synapse Energy Economics (Synapse) and Sustainable Energy Advantage (SEA) have partnered to examine the impacts of the current RPS policy and potential changes in the RPS policy on the future renewable energy market in New England through 2030. Using a set of sophisticated electricity models, we modeled future New England electricity markets through 2030 under four different RPS scenarios and three sensitivity cases. The Base Case assumes full implementation of the Energy Diversity Act, Massachusetts solar policy changes, and other "business-as-usual" policies. It assumes that there are no other changes to the current Massachusetts Class I RPS policy. We compared the results for the Base Case with those for three different potential increases in the RPS: an increase of 2 percent per year in the Massachusetts RPS, an increase of 2 percent per year in the Massachusetts RPS alongside a 1.5 percent per year increase in the Connecticut RPS, and an increase of 3 percent per year in the Massachusetts RPS alongside a 1.5 percent per year increase in the Connecticut RPS. In addition, we analyze the results of each of these four scenarios under different market conditions of natural gas prices and greater vehicle electrification. Our analysis and findings follow.

The following section gives an overview of the New England electricity and renewables markets as they are today, including the impact of recent changes. Chapter 2 and Chapter 3 contain detailed information on our modeling findings, including data on capacity, generation, emissions, prices, bill impacts, emission impacts, and jobs across each of our modeled scenarios.

## 1.1. Overview of the New England electricity market

The six New England states operate as a single electricity system. Electric utilities in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont work together in a single power pool managed by the New England Independent System Operator (ISO-NE). ISO-NE oversees competitive wholesale electricity markets and coordinates the dispatch of power plants to ensure reliable electricity is provided to all New England ratepayers. ISO-NE also oversees long-term planning to ensure that adequate generating capacity and transmission infrastructure are available for the future. Most of the electricity consumed in New England is generated in-region, with 5–15 percent imported from New York and Canada.

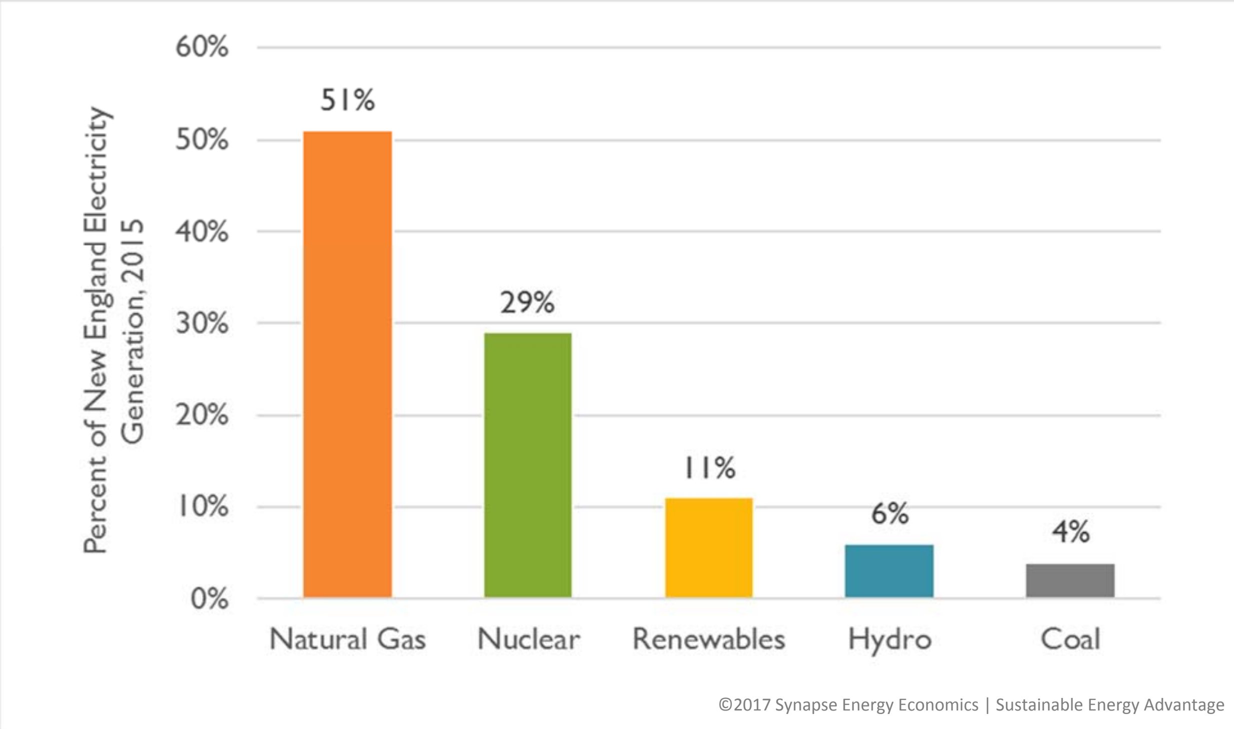
Today, New England primarily relies on natural gas to generate electricity. In 2015, more than half of in-region electricity generation was supplied through natural gas, with 4 percent of generation coming from coal-fired power plants (see Figure 1).[2] The remaining 45 percent of in-region generation came from non-emitting renewable and hydroelectric sources (17 percent), as well as from nuclear power plants (29 percent). These resources have very low marginal generation costs or have operational constraints that do not allow them to quickly respond to changes in electricity demand from consumers. Accordingly, when renewable or non-emitting energy sources increase in future years (as a result of mandated reductions in emissions, increases in renewable portfolio standards, long-term contracting for offshore wind and imports, or general market forces) or when sales decrease as a result of energy efficiency, natural gas use will decrease, since it is the only resource available to be displaced.[3]

Note that despite the support for clean energy that is currently in place in New England states, generation from hydroelectricity and other renewables constitutes less than one-fifth of total New England electricity production today.

[2] Historically, over 25 percent of New England's electricity was powered by burning petroleum. Since 2000, this type of generation has dwindled to just 2 percent of total generation. Today, petroleum is largely used at natural gas-fired power plants that switch to petroleum only when faced with high prices for natural gas at times of peak demand. Given this, we have included petroleum consumed for electricity-generating purposes in with the "natural gas" category throughout this report, except where noted.

[3] This is a simplification of the electric market's complex system interactions for illustrative purposes. Synapse's modeling uses forecasted price modeling and operational dynamics to estimate what resources will be displaced in future years as more renewables come online. In addition, without additional new renewable energy, natural gas generation has the potential to increase in the short term as coal and nuclear generating units retire.

**Figure 1. Distribution of New England's in-region generation, 2015**




*Note: In this figure and elsewhere in this document, "Renewables" includes wind, solar, biomass, and landfill gas (i.e., resources that can fulfill the "Class I" requirement under each New England state's RPS). In this figure, "Natural Gas" generation includes generation from both natural gas and petroleum that is consumed at primarily natural gas-fired power plants.*

## 1.2. Class I RPS Policies in New England

In 29 states around the country, renewable portfolio standards have been implemented as means to drive low-carbon generation. RPS policies are commonly regarded as a way to allow market forces to optimize for the most cost-effective resources. All six New England states have RPS legislation. RPS policies require electricity suppliers in each of the states to purchase a specified amount of electricity from qualifying renewable resources in each year. Typically these standards are based on a percentage of electricity sold by each supplier or load-serving entity (e.g., 20 percent of electricity sales must be met by renewables).[4] These standards generally increase over time until a target percentage is achieved (e.g., 1 percent per year until a level of 20 percent is reached in 2030) (see Table 1), allowing renewable developers and suppliers long-term certainty of the state's desired renewable requirement in a future year. In many states, these standards apply only to a subset of entities (i.e., investor-owned utilities and competitive suppliers, but not municipally owned utilities or cooperatives). RPS policies are frequently updated, amended, and enhanced by state legislatures.

[4] Depending on the state, obligated entities may be required to base this percentage on their metered retail sales or their retail sales plus transmission and distribution losses (i.e., the total electricity purchased to serve demand).

A primary feature of RPS policies is segmentation of renewable and clean energy resources into different "Classes" or "Tiers." These classes are differentiated by eligibility criteria, which may include technology, geography, emissions, fuel standards, or vintage (for example, Massachusetts Class I requires a commercial operation start date after December 31, 1997). RPS classes may represent carve-out requirements for specific types of resources, such as distributed photovoltaics, waste-to-energy systems, or other alternative (though not necessarily zero-emitting) resources. Most frequently, the "Class I" category of resources includes new renewables and is limited to wind, solar, hydro, biomass, and landfill gas, although many states have customized criteria.[5]

Entities demonstrate that they have met their annual RPS requirements by purchasing and retiring RECs. RECs can be produced either from renewable resources built directly in response to an RPS policy or from RPS-eligible renewables built in response to other renewable policies, such as long-term contracting. A power plant that is eligible to qualify under a Class I policy produces one REC for every megawatt-hour (MWh) of electricity produced. Obligated entities may purchase these RECs on the open market through short- or long-term bilateral or spot market transactions. By over-complying at the state level, obligated entities can effectively bank compliance for use in either of the two following years. Obligated entities also have the option of making an Alternative Compliance Payment (ACP), in lieu of purchasing a REC. The ACP level effectively sets a ceiling on REC prices, although in recent years, most states' ACPs have significantly exceeded the price paid for RECs.[6]

The New England states have achieved a remarkable degree of inter-state consistency in their REC markets. In all six states, resources are only eligible to produce RECs if they are either (a) physically located in one of the six states or (b) can deliver electricity directly to ISO-NE. This means that renewable resources located in New York, Québec, or New Brunswick can be used for compliance in New England states (as long as the resource's electricity is also sold to the ISO-NE wholesale market), but renewable resources that produce RECs in other markets (such as the Midwest or California) are ineligible for New England RPS compliance.

[5] Depending on the state, these other resources could include hydrogen, fuel cells (using renewables only), fuel cells (using any resource), distributed thermal (i.e., residential or commercial heat pumps or solar hot water systems), microturbines, biodiesel, or geothermal.

[6] Commonly, revenues generated from ACPs are transferred to state-sponsored funds and used to support renewable energy projects.

**Table 1. Class I RPS structures**

| State | Annual Increase | Share of sales covered by Class I RPS in 2030 | Applies to municipal utilities or cooperatives? | Sales percentage application | Last change to Class I RPS increase or resources |
|---|---|---|---|---|---|
| Connecticut | 1.5 percent per year until 2020 | 20 percent | No | Retail sales plus T&D losses | June 2013 |
| Maine | 1 percent per year until 2017 | 10 percent | No | Retail sales plus T&D losses | June 2011 |
| Massachusetts | 1 percent per year, indefinitely | 25 percent | No | Retail sales plus T&D losses | June 2009 |
| New Hampshire | 0.9 percent per year until 2025 | 15 percent | Yes | Retail sales only | January 2017 (delayed the annual increase for a subset of Class I resources) |
| Rhode Island | 1.5 percent per year until 2035 | 29 percent | No | Retail sales plus T&D losses | June 2016 |
| Vermont* | 0.6 percent per year until 2032 | 8.8 percent | Yes | Retail sales plus T&D losses | June 2016 |

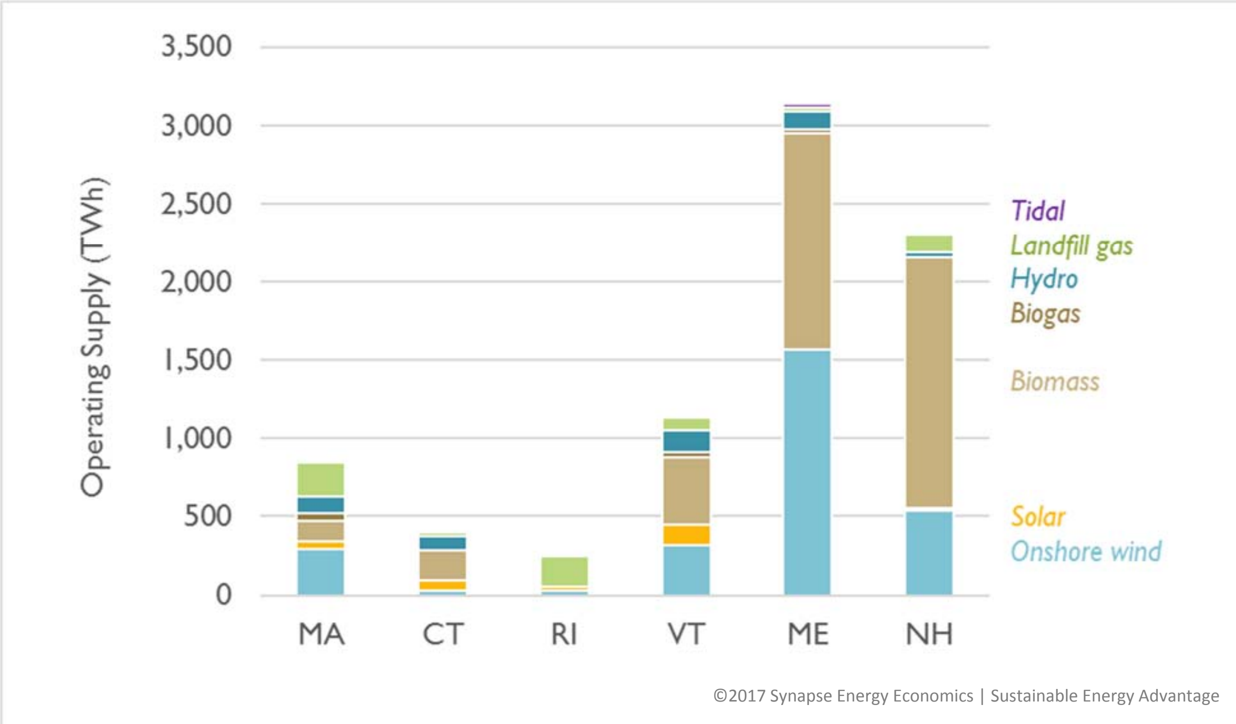
**Here we describe the requirements for Vermont's "Tier II" policy, the component of Vermont's RPS policy that applies to new rather than existing renewables. In all the RPS structures detailed here, electricity from new large hydroelectric facilities (both in New England and in adjacent power control areas) is ineligible to be used for RPS compliance.*

## RPS policies have resulted in substantial renewable energy additions to date

The operating Class I renewable energy supply in this analysis includes generation units that are operating and have been RPS-certified in one or more New England states. Figure 2 shows the estimated production for operating premium-tier supply by technology in each of the six New England states through 2015. This supply has been built in response to the RPS, and related policies, to date. In addition, RPS policies have been able to provide other benefits. In a January 2016 study, the Lawrence Berkeley National Laboratory (LBNL) and National Renewable Energy Laboratory (NREL) found that in 2013, nationwide RPS policies had reduced up to 59 million metric tons of greenhouse gases, avoided thousands of tons of emissions from criteria pollutants (including sulfur dioxide, nitrogen oxides, and particulate matter), and reduced water withdrawals and consumption by 830 billion gallons and 27 billion gallons, respectively.[7] In addition, this study found that existing RPS policies had supported nearly 200,000 jobs in the U.S. through 2013, and added over $20 billion to the national gross domestic product (GDP). Nationwide, existing RPS policies have yielded an estimated $1.2 billion in wholesale energy cost savings to consumers, and have avoided the consumption of 422 million MMBtu of natural gas.

[7] Wiser, Ryan et al. *A Retrospective Analysis of the Benefits and Impacts of U.S. Renewable Portfolio Standards.* Lawrence Berkeley National Laboratory (LBNL) and National Renewable Energy Laboratory. January 2016. Available at https://emp.lbl.gov/sites/default/files/lbnl-1003961.pdf

**Figure 2. Estimated production from operating Class I renewable energy resources, 2015**




*Note: Imported renewable supply from adjoining regions of New York and eastern Canada are modeled but not represented in this figure.*

## 1.3. Recent changes to energy legislation and regulations

In recent years, several states in New England have enacted legislation or regulations that will directly or indirectly drive increases in renewables. Some of these changes occurred through existing or new renewable portfolio policies—Rhode Island and Vermont respectively updated and enacted RPS policies in 2016.

However, other updates to renewable policy have come in forms other than RPS policy adjustments. In 2016, Massachusetts enacted the Energy Diversity Act, which included two major new renewable energy procurements: Section 83C, which requires Massachusetts utilities to enter into long-term contracts for 1,600 MW of offshore wind by June 2027 and Section 83D, which requires Massachusetts utilities to enter into long-term contracts for 9.45 terawatt-hours (TWh) of clean energy generation by December

2022.[8, 9] Notably, prior versions of this legislation also included proposals to increase Massachusetts' RPS—S.2372, for example, proposed an RPS increase to 2 percent per year beginning in 2017.[10] These procurement provisions built upon previous renewable energy contracting authority established through the Green Communities Act of 2008.[11]

Other states have established similar long-term contracting requirements. Connecticut, through Public Acts 15-107 and 13-303, has the authority to procure up to 4,250 GWh of renewable energy per year. Rhode Island has entered long-term contracts with several regional renewable energy facilities and has the flexibility and authority for further purchases. In 2015 and 2016, Connecticut, Massachusetts, and Rhode Island jointly pursued a three-state Clean Energy RFP, resulting in contracts awarded to 460 MW of renewable capacity.

Other recently enacted policies, sucha s distributed generation incentive programs, will also likely affect renewable energy procurement. In addition, in December 2016, the Massachusetts Department of Environmental Protection (MassDEP) issued a set of proposed regulations aimed at achieving compliance with the GWSA. Two of these regulations directly affect the electric sector: 310 CMR 7.74 establishes a 2.5 percent declining cap on $CO_2$ emissions from electric generators located in Massachusetts, while 310 CMR 7.75 establishes a Clean Energy Standard. The Clean Energy Standard requires that all electricity suppliers (including investor-owned and municipal utilities) procure clean energy certificates (CECs) equal to 14 percent of load in 2018, increasing to 38 percent of total load in 2030. As the emissions cap becomes more stringent, Massachusetts electricity suppliers will have to rely more on alternative sources of energy, including both increased imports from other states, increased renewables in-state, or some combination thereof. Under the proposed Clean Energy Standard, MassDEP has effectively established a "wrap around" policy, with the Massachusetts RPS Class I demand requirements as a component of the overall Clean Energy Standard requirements. Eligible resources for the proposed Clean Energy Standard may include existing and new Class I renewables, non-RPS-eligible hydroelectricity, and other low-emission or zero-emission resources.

With the exception of Vermont's new (distributed generation) RPS and the recent demand target adjustments in Rhode Island, each of these policies stimulates renewable energy supply. In coming years, the success of these and other incentive policies will cause renewable energy supply to catch—and surpass—renewable energy demand. An increasing proportion of new supply has come in the form

[8] See https://malegislature.gov/Bills/189/House/H4568 for detail on the 2017 legislation *An Act to Promote Energy Diversity.* Under this legislation, the 9.45 TWh of "clean energy generation" may be made up of resources that are currently eligible under Massachusetts' Class I RPS, or generation from new, large hydroelectric sources (which are not eligible to produce RECs under Massachusetts' Class I RPS policy).

[9] In this analysis, we report capacity values (or potential electricity output) in terms of gigawatts (GW), which are equal to one thousand MW. We report generation values (or annual estimated electricity production) in terms of TWh, which are equal to one thousand GWh or one million MWh.

[10] The full text of S.2372 is available at https://malegislature.gov/Bills/189/Senate/S2372.

[11] More information on the Green Communities Act can be found at https://malegislature.gov/Laws/SessionLaws/Acts/2008/Chapter169.

of distributed generation, often interconnected behind the retail meter. This supply has the dual impact of adding RECs to the market while also reducing RPS demand. At the same time, regional forecasts now project load reductions over the next 10 years. The cumulative effect is a renewables or REC market that requires demand-side adjustments in order to bring supply and demand back into alignment.

# 2. BASE CASE FINDINGS

At the outset of this analysis, Synapse and SEA developed a "Base Case"—which represents our best estimate of a business-as-usual future in which no changes are made to existing or anticipated laws, regulations, or policies. The Base Case uses a reasonable set of assumptions (described below and detailed in Appendix A, Appendix B, and Appendix C) for electricity sales, energy efficiency, new and retiring power plants, natural gas prices, and other variables. Analysis of this Base Case finds that without any adjustments to Massachusetts' Class I RPS policy, renewable energy—including in-region hydroelectricity—will increase from one-fifth to one-third of in-region generation, $CO_2$ emissions will decrease by 27 percent compared to 1990, and the RPS market will be in surplus (i.e., supply will exceed demand for RECs) throughout the analysis period.

## 2.1. Base Case modeling assumptions

Under our Base Case, we assume that the econometric forecast for electricity sales follows the one published by ISO-NE in its CELT 2016 forecast.[12] Rather than assuming the levels of energy efficiency and distributed solar forecasted by ISO-NE in CELT 2016, Synapse and SEA developed our own estimates.[13] The energy efficiency forecast used is based on the most recent available information on program administrator energy efficiency plans, as they are submitted to state entities. We assume the levels of energy efficiency specified in these plans are continued into the future. For distributed solar, we assume that states meet their goals under programs such as Connecticut's Zero-Emission Renewable Energy Credit (ZREC) program, Massachusetts' Solar Massachusetts Renewable Target (SMART) program, Rhode Island's Renewable Energy Growth (REGrowth) program through 2019, and Vermont's distributed solar carve-out. In our Base Case, we use the same electrification assumptions as ISO-NE's CELT forecast, which does not make any explicit assumptions regarding electric vehicle adoption rates.

This Base Case also includes a number of "known" unit additions and retirements. These include resources such as Brayton Point closing in 2017 and Pilgrim Nuclear Power Station closing in 2019, among others. These also include new unit additions such as the 800 MW Footprint Salem Harbor natural gas combined-cycle power plant coming online in 2017 and the 850 MW CPV Towantic natural gas combined-cycle power plant coming online in 2018, among others. We also assume that 600 MW of battery storage are constructed in Massachusetts by 2025, in line with recommendations to build storage per Governor Baker's Energy Storage Initiative and stipulations of Massachusetts Chapter 188

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[12] The Capacity, Energy, Loads, and Transmission (CELT) forecast for 2016 is available at https://www.iso-ne.com/system-planning/system-plans-studies/celt. Note that on May 1, 2017, ISO-NE published a new forecast, CELT 2017. In this new forecast, the econometric growth rate for electric sales was estimated to be 0.92 percent per year, compared to 0.95 percent per year in CELT 2016, and 1.04 percent per year in CELT 2015. After accounting for the ISO's own forecasts for energy efficiency and distributed solar, the net electricity sales forecast is -0.65 percent per year in CELT 2017, down from -0.25 percent in CELT 2016 and -0.04 percent in CELT 2015.

[13] See Synapse's 2015 report *Challenges for Electric System Planning* for information on discrepancies between the ISO-NE's energy efficiency and distributed solar forecast and current data and trends for these resources.

requiring the Massachusetts Department of Energy Resources (MA DOER) to determine targets for cost-effective storage additions.[14] In the Base Case, we assume that New England builds out incremental transmission in the region in line with the ISO-NE capacity zone development for the 11th Forward Capacity Auction.[15] This includes 575 MW of transfer capacity on the North-South interface in 2019, followed by an incremental 50 MW on the same interface in 2020, along with an incremental 100 MW of transfer capacity on the Northern New England-Scobie interface in 2020.

Importantly, our Base Case also assumes that each of the New England states fulfills its on-the-books requirements to procure renewable energy. This includes the requirements stated under each state's RPS, as well as long-term contracting requirements independently established by state legislatures and distributed clean energy incentive programs. For Massachusetts, this means that long-term contracts for 1,600 MW of offshore wind are procured by June 2027 (MA Chapter 188 Section 83C), that 9.45 TWh of clean energy generation are procured by December 2022 (MA Chapter 188 Section 83D), and that the SMART program achieves 1,600 MW of solar by 2023. While the clean energy generation in the 83D procurement can come from any new resources that would otherwise qualify under Massachusetts' Class I RPS policy, portions of it may also come from imports of hydroelectricity over new, dedicated transmission lines, which does not qualify for under Massachusetts' Class I RPS. It is most likely that this requirement will be fulfilled through some mix of these two resources; in the Base Case (and all other scenarios), we assume that 90 percent of this 9.45 TWh requirement is supplied through non-RPS qualified new hydro imports. Because these imports are present in all scenarios, we do not make any assumptions or determinations on the location or cost associated with any new transmission lines needed to deliver it to customers. The remaining 10 percent of the 9.45 TWh is assumed to be RPS Class I eligible renewables. Our Base Case also assumes that other long-term contracting requirements established by Connecticut (under Public Acts 13-303 and Public Acts 15-107), Massachusetts (under renewable contract replacement requirements with Eversource), and Rhode Island (under renewable contract replacement requirements with National Grid) are fulfilled. Finally, we assume that the proposed regulations by MassDEP under 310 CMR 7.75 establishing a Clean Energy Standard are in effect.[16] See Appendix B for more information about assumed non-RPS policies.

Our Base Case assumes a "medium" natural gas price, based on the natural gas price projection developed by the Energy Information Administration (EIA) in its 2017 Annual Energy Outlook (AEO). In this future, we project natural gas prices to increase by about 4 percent per year (in real 2015 dollars),

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[14] More information is available at http://www.mass.gov/eea/pr-2016/administration-releases-energy-storage-report.html.

[15] ISO-NE. "Forward Capacity Auction 11 Transmission Transfer Capabilities & Capacity Zone Development." March 22, 2016. https://www.iso-ne.com/static-assets/documents/2016/03/a2_fca11_zonal_boundary_determinations.pdf.

[16] For the time period analyzed in this study, we assume that the long-term contracting supply contracted under Sections 83C and 83D are sufficient to address the requirements under the Clean Energy Standard. See http://www.mass.gov/eea/agencies/massdep/air/climate/section3d-comments.html for more information about the proposed Clean Energy Standard.

resulting in a 2030 price that is 71 percent greater than the 2016 price for natural gas delivered to electric power generators in New England.

Finally, in the Base Case, we assume that the six New England states continue to comply with the emissions requirements specified under the Regional Greenhouse Gas Initiative (RGGI) and that the emissions cap associated with this program remains unchanged through 2030.[17] We also assume that emitting generators in Massachusetts comply with MassDEP's proposed regulations to cap in-state $CO_2$ emissions from the electric sector under 310 CMR 7.74.[18] All six New England states have requirements, targets, or goals for all-sector greenhouse gas emissions reductions (e.g., Massachusetts' GWSA). Because these emissions reduction requirements and targets are economy-wide, and the focus of this analysis is on the electric sector alone, we have not constrained our modeling to meet these caps in future years. However, we do provide an assessment of whether our Base Case and other scenarios comply with the Massachusetts GWSA and a more general, regionwide emissions reductions target.

Table 2 displays an overview of the general assumptions in place in the Base Case (and all other modeling runs). Please see Appendix A for more information on the modeling methodology used in this analysis, Appendix B for additional detail on modeling inputs assumed in the Base Case and all other cases, and Appendix C for information on our natural gas price projection.

**Table 2. Modeling assumptions in the Base Case**

| Category | Assumption |
|---|---|
| Electric sales | ISO-NE's forecast for electric demand from CELT 2016 |
| Energy efficiency | All New England states maintain their current levels of energy efficiency |
| Non-renewable unit additions | All under construction plants and all plants that have cleared the most recent ISO-NE Forward Capacity Auction |
| Unit retirements | All plants that have announced retirement dates (e.g., Brayton Point, Pilgrim Nuclear) |
| Incremental transmission | Transmission built in line with the most recent ISO-NE Forward Capacity Auction |
| RPS policies | All states (except MA and CT, in some scenarios) maintain existing RPS policies with no changes |
| Non-RPS renewable policies | State goals for distributed generation are met for ZRECs, SMART, REGrowth, etc.; MA's requirements under MA Chapter 188 Section 83C and 83D (new offshore wind and new clean energy resources) and long-term contracting requirements in CT and RI are fulfilled; MA's proposed Clean Energy Standard is in effect; 600 MW new energy storage by 2025 |
| Natural gas price | "Medium" natural gas price based on 2017 Annual Energy Outlook Reference case |
| Carbon dioxide emission caps | RGGI is maintained at 2020 level in all years after 2020; MassDEP's proposed in-state $CO_2$ emission cap is met |

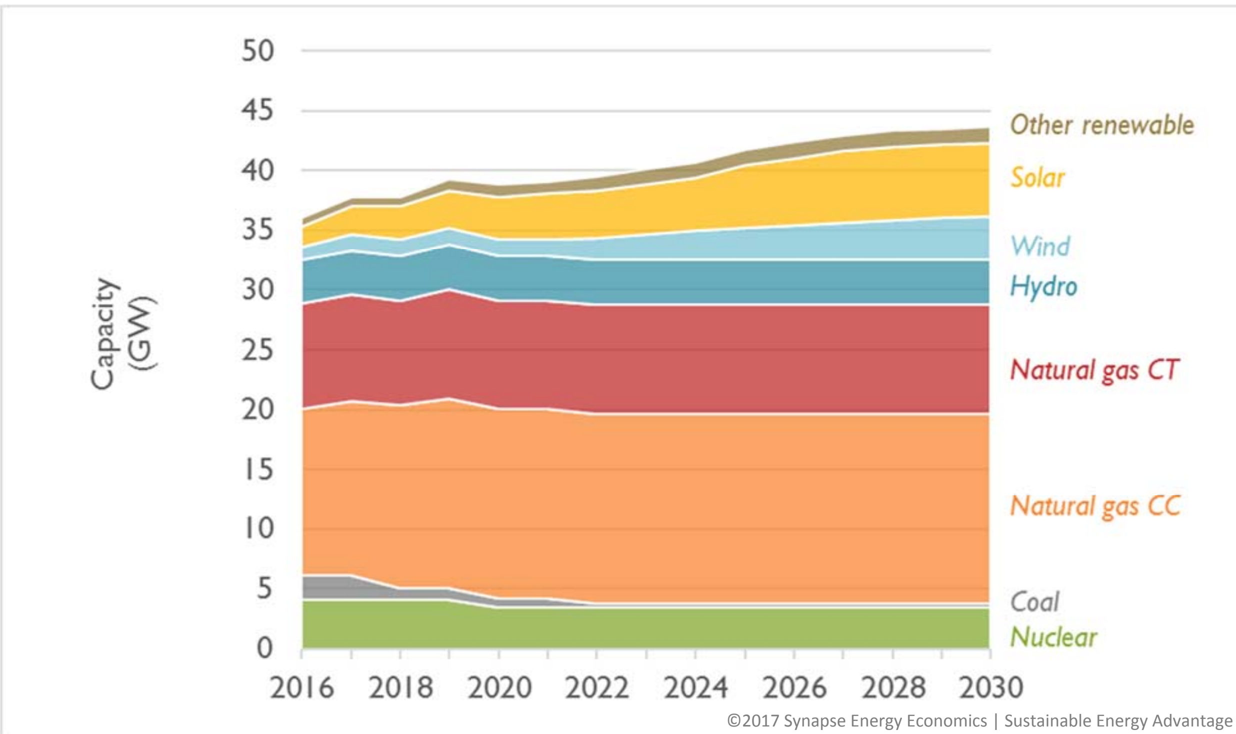
[17] While federal $CO_2$ reduction policy (i.e., the Clean Power Plan) is currently uncertain, it is likely that the New England states will ultimately rely on RGGI or a program like it to comply with federally mandated $CO_2$ emission reductions. In addition, the 2020 cap under RGGI will likely be more stringent than the emission caps mandated for New England states under the Clean Power Plan.

[18] See http://www.mass.gov/eea/agencies/massdep/air/climate/section3d-comments.html for more detail on 310 CMR 7.74.

## 2.2. Modeled changes to capacity and generation

Under the Base Case assumptions, we observe an increase in in-region hydroelectric and renewable capacity of 7.7 GW, roughly a doubling over the renewable capacity that existed at the end of 2016 (see Figure 3). An estimated 57 percent of this increase in New England's renewable capacity (4.4 GW) is projected to come from utility-scale and distributed solar projects and one-third of this increase (2.6 GW) is projected to come from onshore and offshore wind projects. The remainder (0.8 GW) comes from increases in in-region hydroelectric, biomass, or other miscellaneous renewable capacity.[19] Three-quarters of the total increase in renewable capacity occurs in Massachusetts.

**Figure 3. New England-wide electric generating capacity in the Base Case**




In the Base Case, we also see an increase in natural gas capacity (including both combustion turbines, or "CTs", and combined cycle plants, or "CCs") of 2.2 GW. Importantly, this increase in capacity is entirely based on known unit additions. In our modeling, we do not build any natural gas or other conventional resources on an economic basis to meet projected demand requirements.[20] The Base Case also includes 0.7 GW of retirements (in the form of Pilgrim Nuclear Plant retiring in 2019) and 1.7 GW of coal

[19] In this case, "other renewable" capacity includes biomass, biogas, biodiesel, fuel cells, landfill gas, low emission advanced renewables, and tidal energy. For aggregation purposes, battery storage is also included in this category. Note that "hydro" in this context does not include incremental hydroelectric power imported from outside New England.

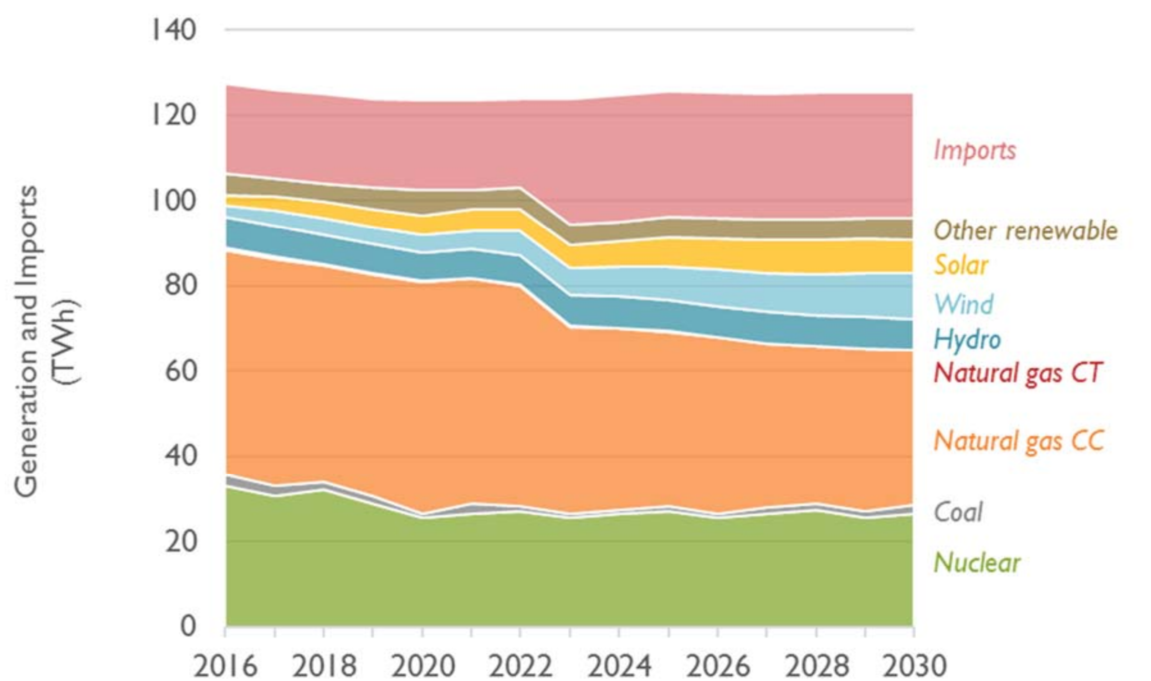
[20] Please see Appendix B for more information about the incremental natural gas units assumed to be online in all modeling runs.

retirements. These coal retirements include the units with known retirement dates (including Brayton Point and Bridgeport Station) and economic retirements at Merrimack 1, Schiller 4, and Schiller 6.

The increase in renewable capacity has significant implications for New England's generation profile. By 2030, generation from in-region renewables and hydroelectricity increases by 17.7 TWh, or 79 percent, relative to 2016 (see Figure 4). This causes total regional hydroelectric and renewable generation to increase from 11 percent in 2015 to 32 percent in 2030. In addition, we observe an additional 8.5 TWh of increased imports from Canada, caused by the requirements under section 83D of Massachusetts' Energy Diversity Act and the MassDEP's proposed Clean Energy Standard.

Because electricity sales are not expected to significantly increase, this increase in renewable generation and imports primarily displaces electricity production from natural gas combined-cycle plants throughout the regional New England market. Between 2016 and 2030, natural gas combined-cycle generation in New England falls 17.0 TWh, or 32 percent.[21]

**Figure 4. New England electric generation and net imports in the Base Case**





[21] Resulting in part from MassDEP regulation 310 CMR 7.74, which puts a 2.5-percent-per-year declining cap on $CO_2$ emissions from in-state electric generating units, generation from Massachusetts natural gas-fired power plants decreases by 53 percent in 2030, relative to 2016. However, this shift is not accompanied by an increase in natural gas in the other New England states—instead, natural gas-fired generation in the other five states also decreases by 20 percent in 2030, relative to 2016.

Please see Appendix D for additional resource-specific detail on capacity and generation in Massachusetts and the New England region as a whole.

## 2.3. Modeled changes to prices

In our Base Case, we assessed how business-as-usual trends in electricity sales, natural gas prices, and renewable energy are expected to impact wholesale prices for energy and capacity, as well as the price of RECs.

### Energy and capacity prices

In our Base Case, we find that the wholesale cost of energy (in real 2015 dollars-per-MWh) increases by 2 percent per year from $31 per MWh in 2016 to $45 per MWh in 2030 (see Figure 5).[22] This constitutes an increase of 42 percent over this 15-year period. Over this entire period, the energy price does not exceed the historically observed average price from 2010 to 2015 of $50.35 per MWh. Meanwhile, we project relatively flat capacity market prices from 2021 through 2030. The region is currently long on supply, and with peak demand growth flat, the market price will be set by existing resources choosing to leave rather than the cost of new entry. On average, our model forecasts these capacity prices to be $5.30 in the Base case, or within 1 percent of the most recent capacity clearing price of $5.297 (set for the 2020/2021 time period).[23]

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[22] All costs discussed in this analysis do not incorporate a social cost of carbon, cost of compliance with the Massachusetts GWSA, or any other carbon price except those associated with (a) RGGI and (b) MassDEP's proposed emission caps for in-state generators under 310 CMR 7.74.

[23] Note that capacity market prices are notoriously difficult to forecast for any one specific year because of changing market rules and supply conditions. Historically, rather than converging around an average price (as estimated in this analysis), capacity market prices have instead swung between very low and very high prices (constrained by administrative limits), as the available capacity has swung between over- and under-supply. Just as occurred in the most recent capacity auction, our modeling forecasts that future capacity prices are set by the fixed cost of the resource that would otherwise have retired without capacity market revenues.

**Figure 5.Wholesale energy price for New England in the Base Case**

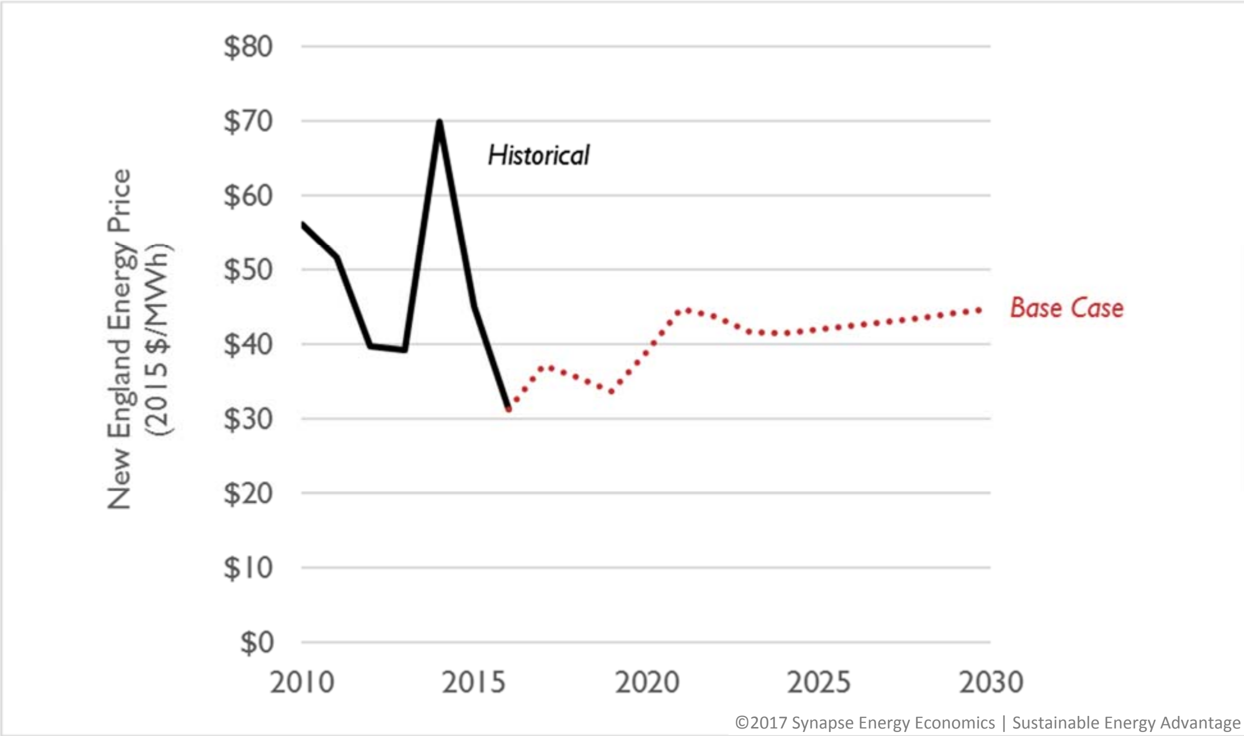
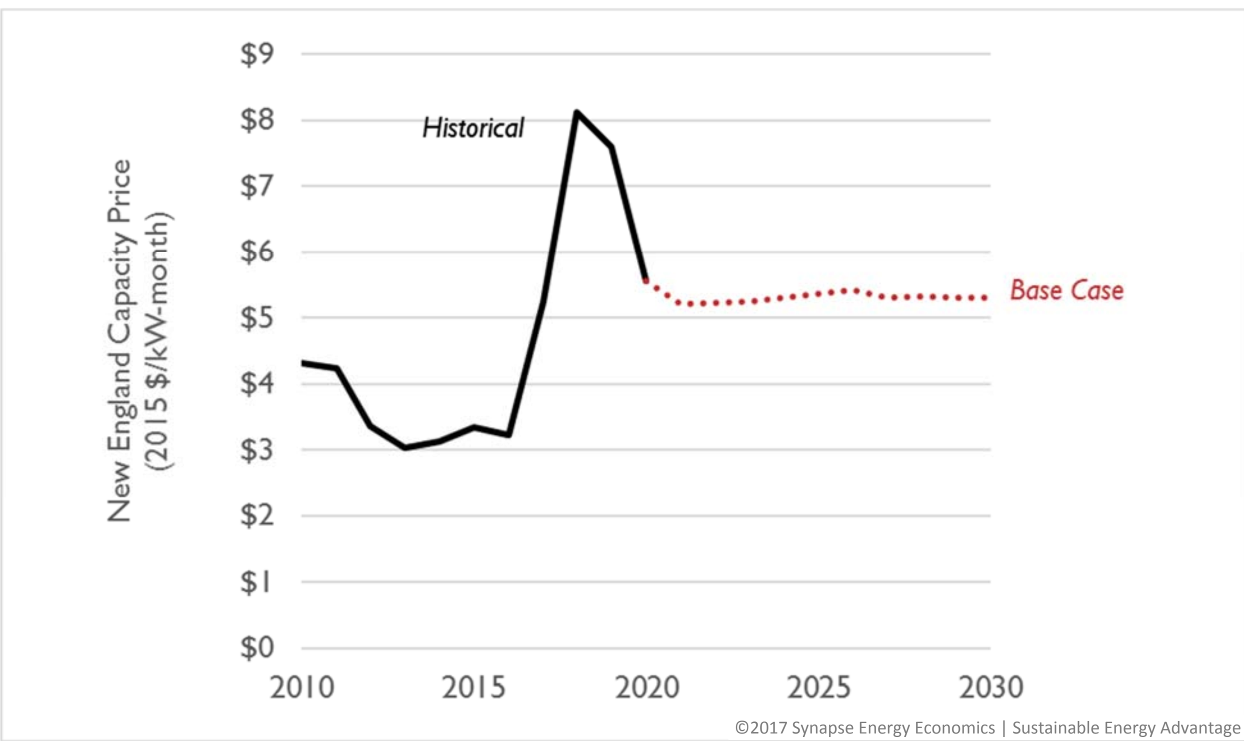



**Figure 6. Wholesale capacity price for New England in the Base Case**

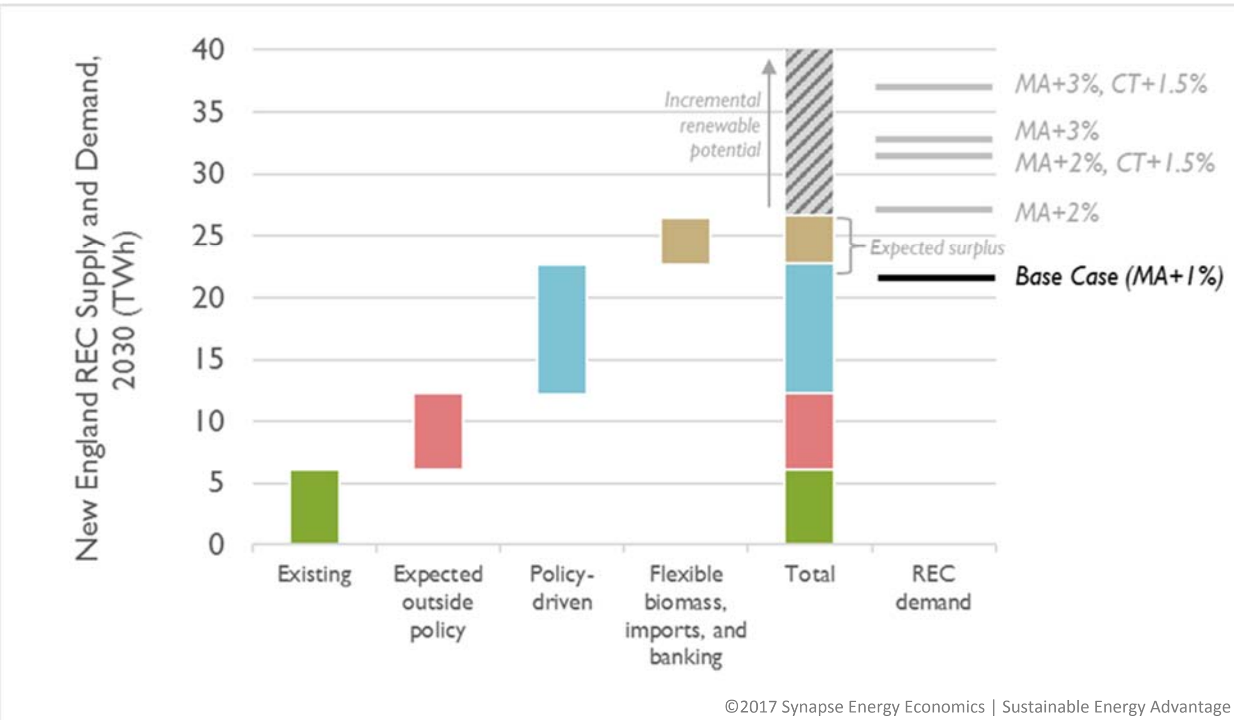



*Note: Capacity prices are established by ISO-NE-administered Forward Capacity Auctions, which take place three years in advance of a commitment period. Thus, the capacity price is already known through May 2021. Capacity prices are issued on a "commitment period" basis, which spans June through May of each year; these prices have been converted into calendar-year prices for the purposes of this figure.*

## REC Prices

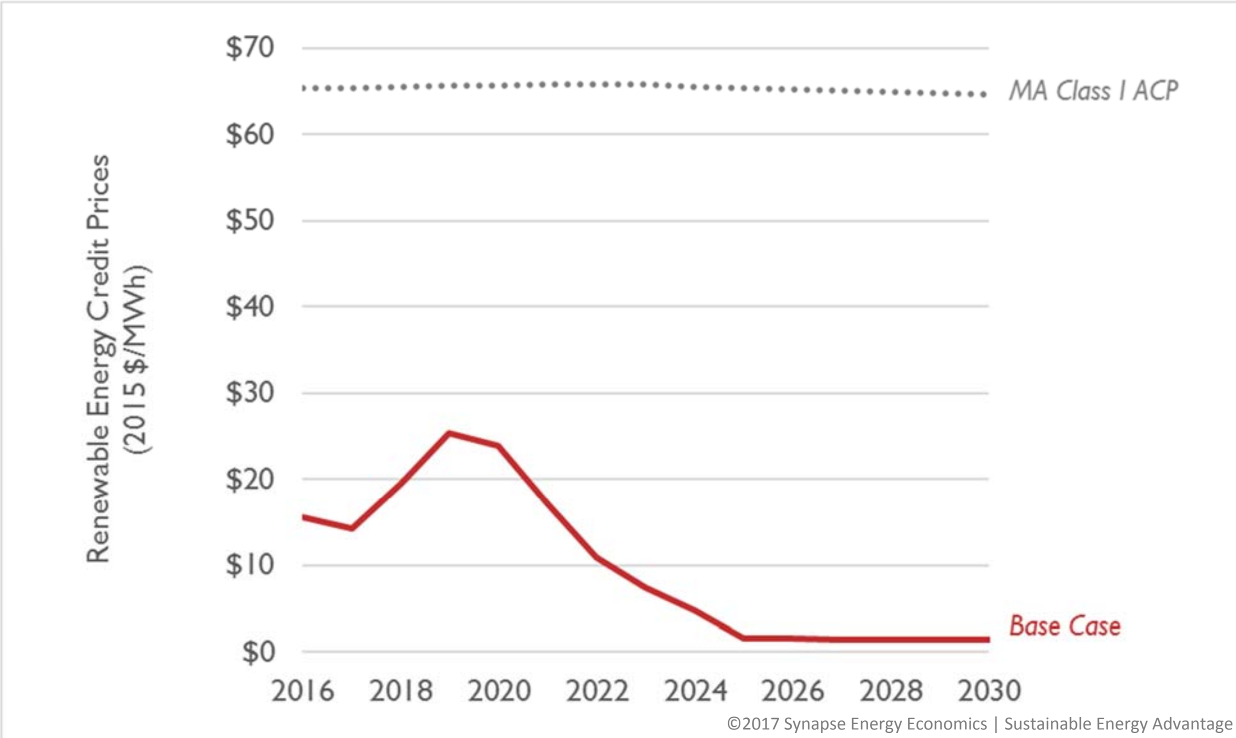
Between today and the early 2020s, the supply of Massachusetts Class I RECS is expected to moderately exceed Class I RPS demand in the Base Case. As a result, short-term market REC prices are expected to reside in the rage of $10 to $25 per MWh (see Figure 7 and Figure 8).[24] During this period, RECs for RPS compliance come from existing long-term contracts, spot market purchases, and over-compliance banked from previous years. Spot REC markets are balanced by discretionary supply from resources like biomass and imports, which are expected to generate (or import, respectively) only when price signals dictate. Beginning in the early 2020s, decreasing load, new distributed generating assets built in response to existing policy, and the implementation of existing policies mandating long-term contracts for additional renewables are expected to define a market in significant surplus. Without a technical correction to realign RPS demand targets with recently enacted RPS supply policy mandates, Base Case REC prices are expected to fall below $5 per MWh through 2030. At these REC price levels, there is a financial viability risk for both existing renewable energy facilities and planned resources expected to come online during the analysis period. As a result, the projects assumed to be built may not, in fact, be constructed. In order to meet greenhouse gas, jobs, RPS, and other public policy goals, the REC market must send stable price signals that encourage both market entry and continued market participation.

**Figure 7. Projected Class I REC demand and supply for New England in the Base Case**




24 In this comparison and all following comparisons, we use the MA Class I REC price as a proxy for REC prices throughout New England. Because of the commonalties between RPS policies in the New England states, prices for RECs retired to meet RPS compliance in Massachusetts and the other five states are typically very similar.

**Figure 8. Projected Class I REC prices in the Base Case**




*Note: This figure illustrates the price for Massachusetts Class I RECs. Because of commonalties between RPS policies in the New England states, prices for RECs retired to meet RPS compliance in Massachusetts and the other five states are typically very similar.*

# 3. INCREASING THE RENEWABLE PORTFOLIO STANDARD

In addition to a Base Case, we modeled 11 other cases. These cases include scenarios in which the Massachusetts Class I RPS policy is increased, scenarios in which the Massachusetts RPS policy is increased alongside RPS increases in Connecticut, and sensitivities in which the effects of a high natural gas price and high vehicle electrification are tested.[25] In general, we examined how electric dispatch, wholesale electricity costs, retail bills, emissions, and jobs respond to the following parameters:

- **Base Case:** This scenario analyzes a business-as-usual future in which no changes are made to existing RPS policies in Massachusetts or any other state. By 2030, this results in 25 percent of retail electricity suppliers' sales in Massachusetts being covered by renewables.[26] See Chapter 2 (above) for more information about the modeling results under the Base Case.

- **+2% MA RPS:** This scenario analyzes a future in which Massachusetts Class I RPS targets increase by 2 percent per year beginning in 2018 (as opposed to 1 percent per year, as in years prior).[27] This requirement will continue to apply only to retail electricity suppliers. By 2030, this results in 38 percent of their sales in Massachusetts being covered by renewables.[28]

- **+2% MA RPS and +1.5% CT RPS:** This scenario analyzes a future in which Massachusetts Class I RPS targets increase by 2 percent per year beginning in 2018 (as opposed to 1 percent per year, as in years prior). This scenario also assumes that beginning in 2021, the Connecticut Class I RPS increases by 1.5 percent per year (the current Connecticut Class I RPS remains flat beginning in 2020).[29] In this scenario, we assume a 600 MW high-voltage direct current (HVDC) transmission line is constructed from central Maine to central Massachusetts in order to alleviate transmission congestion resulting from large quantities of new wind constructed in northern New England.[30] By 2030, this scenario results in an RPS requirement of 38 percent of retail electricity supplier sales in

[25] We focus on Massachusetts and Connecticut in this study as these two states feature (a) active legislative proposals for RPS stringency increases and (b) the largest number of electric sales of any New England states—together, Massachusetts and Connecticut constitute 70 percent of total regional electric sales.

[26] Note that this does not include electricity sold by municipal utilities.

[27] The Class I RPS target increase for 2018 (only) is modeled at 1.5 percent as a proxy for the impact of an exemption for retail contracts that were already in effect at the time the MA Omnibus Energy Bill was passed in this scenario and all scenarios with a Massachusetts RPS increase greater than 1 percent per year.

[28] Other options exist for modifying RPS policies in Massachusetts and other New England states to drive new construction of wind and solar. Changes could include: precluding certain resource types from participating in future RPS compliance, early sun-setting of currently-banked RECs, and expanding RPS policies to utilities other than investor-owned (i.e., municipal or cooperative utilities).

[29] Increasing the Connecticut RPS to 1.5 percent per year at the same time as the Massachusetts RPS is increased to 2 percent per year is analogous to increasing the Massachusetts RPS alone by 2.75 percent per year.

[30] This level of transmission eliminated most of the wind curtailments that would have resulted from inadequate transmission capacity. See Appendix B for further discussion of this assumption.

Massachusetts and 35 percent of supplier sales in Connecticut being covered by renewables.

- **+3% MA RPS and +1.5% CT RPS:** This scenario analyzes a future in which Massachusetts Class I RPS targets increase by 3 percent per year beginning in 2018 (as opposed to 1 percent per year, as in years prior). This scenario also assumes that beginning in 2021, the Connecticut Class I RPS increases by 1.5 percent per year (the current Connecticut Class I RPS increases by 1.5 percent per year, but stops increasing in 2020).[31] In this scenario, we assume a 1,200 MW HVDC transmission line is constructed from central Maine to central Massachusetts in order to alleviate transmission congestion resulting from large quantities of new wind constructed in northern New England. By 2030, this results in 51 percent of electricity sold by electric suppliers in Massachusetts and 35 percent of electricity sold by electric suppliers in Connecticut being covered by renewables.

- **High natural gas price:** This sensitivity analyzes each of the above four scenarios under a future in which the Henry Hub natural gas price follows a trajectory laid out in the Annual Energy Outlook (AEO) 2017 "Low oil and gas resource and technology case," rather than the AEO 2017 "Reference case," which is used to develop the medium natural gas price.[32] From 2019 to 2030, the Henry Hub natural gas price in this case is expected to grow by 5.0 percent each year, compared to 2.0 percent per year in the AEO 2017 Reference case. Please see Appendix C for more information on the gas price methodology. In this sensitivity, we do not make any incremental assumption regarding vehicle electrification rates.

- **High electrification:** This sensitivity analyzes each of the four scenarios under a future in which the six New England states follow a trajectory towards high vehicle electrification. Under this sensitivity, we apply a vehicle electrification trajectory based on the "high case" in Navigant's Q2 2016 *Electric Vehicle Geographic Forecasts*.[33] Please see Appendix B for more information on the vehicle electrification trajectory used. Note that this sensitivity does not make any incremental assumptions regarding electrification of heating, hot water, or other systems that commonly consume fossil fuels as an end-use today. Under this sensitivity, we apply the medium natural gas price.

Table 3 summarizes the parameters for each of the 12 modeling runs.

[31] Increasing the Connecticut RPS to 1.5 percent per year at the same time as the Massachusetts RPS is increased to 3 percent per year is analogous to increasing the Massachusetts RPS alone by 3.5 percent per year.

[32] Energy Information Administration. 2017. Annual Energy Outlook 2017, released January 6, 2017.

[33] See https://www.navigantresearch.com/research/electric-vehicle-geographic-forecasts for more information.

**Table 3. Overview of modeling runs**

| | Medium natural gas price sensitivity | High natural gas price sensitivity | High electrification sensitivity |
|---|---|---|---|
| **Base Case** (+1% MA RPS) | Base Case, Medium natural gas price | Base Case, High natural gas price | Base Case, High electrification |
| **+2% MA RPS** | MA Class I RPS increases to 2% per year in 2018, Medium natural gas price | MA Class I RPS increases to 2% per year in 2018, High natural gas price | MA Class I RPS increases to 2% per year in 2018, High electrification |
| **+2% MA RPS and +1.5% CT RPS** | MA Class I RPS increases to 2% per year in 2018, CT Class I RPS increases to 1.5% per year in 2021, Medium natural gas price | MA Class I RPS increases to 2% per year in 2018, CT Class I RPS increases to 1.5% per year in 2021, High natural gas price | MA Class I RPS increases to 2% per year in 2018, CT Class I RPS increases to 1.5% per year in 2021, High electrification |
| **+3% MA RPS and +1.5% CT RPS** | MA Class I RPS increases to 3% per year in 2018, CT Class I RPS increases to 1.5% per year in 2021, Medium natural gas price | MA Class I RPS increases to 3% per year in 2018, CT Class I RPS increases to 1.5% per year in 2021, High natural gas price | MA Class I RPS increases to 3% per year in 2018, CT Class I RPS increases to 1.5% per year in 2021, High electrification |

In essence, the only variables we modify across scenarios are (1) demand for renewables in Massachusetts and/or Connecticut, (2) natural gas prices, and (3) electricity sales forecasts inclusive of vehicle electrification. We do not make any adjustments to energy efficiency, long-term contracting policies, other distributed renewable and clean energy incentives, prescribed unit additions or retirements, incremental energy storage, inter-regional transmission, proposed MassDEP regulations, or greenhouse gas emissions reductions compliance.

## 3.1. Variations in capacity and generation

Despite increases in 2030 REC demand in the non-Base Case scenarios, there are typically only small differences in terms of total incremental supply by that year. Under a future with a medium natural gas price and no incremental electrification, we find that if the Massachusetts RPS growth rate is increased from 1 percent to 2 percent per year, demand policies for renewables meet and only marginally exceed the level of otherwise-expected supply.

However, in other scenarios, the demand for renewables exceeds the anticipated business-as-usual supply. In a future where Massachusetts increases its RPS to 2 percent and Connecticut increases its RPS to 1.5 percent per year, 2.0 GW of incremental renewables are built by 2030 (see Figure 9 and Table 4). In a scenario where Massachusetts increases its RPS to 3 percent per year alongside an RPS increase in Connecticut, we see 4.1 GW of renewables added by 2030.

Generally, we see little difference in the inflection point between supply and demand and corresponding renewable builds between the medium natural gas price scenarios and the high natural gas price modeling runs. However, because high levels of vehicle electrification will lead to increased electricity sales, renewable demand is likely to substantially exceed expected business-as-usual supply in a future in which the Massachusetts RPS is increased to 2 percent per year, resulting in 1.1 GW of incremental renewables by 2030. In a case where both Massachusetts and Connecticut increase their RPS policies under high electrification, we see 2.6 GW of additional renewables by 2030; in the case where Massachusetts goes even further to a 3 percent per year increase, we see 4.9 GW of additional renewables by 2030, relative to the low electrification Base Case.

**Figure 9. New England-wide electric generating capacity in 2030 compared to 2016**

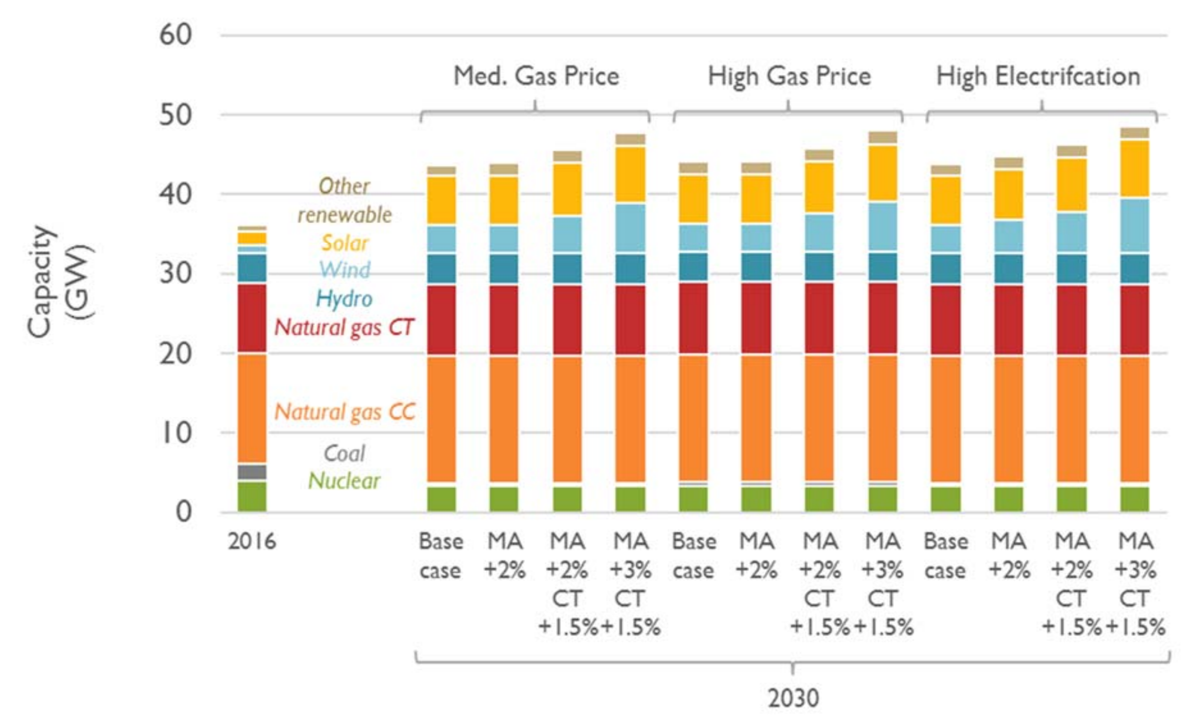


**Table 4. Incremental in-region renewable and hydroelectric capacity in 2030, relative to the Base Case**

| *2030 capacity delta relative to Base Case (GW)* | **Medium natural gas price sensitivity** | **High natural gas price sensitivity** | **High electrification sensitivity** |
|---|---|---|---|
| **Base Case** (+1% MA RPS) | - | 0.3 | 0.1 |
| **+2% MA RPS** | 0.3 | 0.3 | 1.1 |
| **+2% MA RPS and +1.5% CT RPS** | 2.0 | 2.0 | 2.6 |
| **+3% MA RPS and +1.5% CT RPS** | 4.1 | 4.1 | 4.9 |

*Note: This figure does not include incremental future generation from new hydroelectric imports from Canada. These resources are assumed to be the same in all scenarios.*

These changes in renewable capacity (described above in GW) translate to commensurate increases in renewable generation (terawatt-hours or TWh). Raising the Massachusetts RPS rate of increase to 2 percent per year has little effect on incremental renewable generation, over and above that assumed to result from existing procurement and incentive polices. This scenario drives generation increases of 1.9 TWh in the medium and high natural gas price sensitivities and 4.0 TWh in the high electrification sensitivity relative to the Base Case—about 2 to 3 percent of total electric sales (see Figure 10 and Table 5).

Increasing the Massachusetts RPS to 2 percent per year alongside a 1.5 percent increase in the Connecticut RPS results in a 6.0 TWh increase in renewables in 2030 relative to the Base Case under a medium natural gas price sensitivity, or an increase in the share of total regional electricity sales covered by renewables of 4 percent.[34] Under this scenario, in the high natural gas price sensitivity, renewables increase to 6.2 TWh relative to the Base Case.

Finally, increasing the Massachusetts RPS to 3 percent per year alongside a 1.5 percent increase in the Connecticut RPS results in 11.8 TWh of additional renewable generation in 2030, above what exists in the Base Case. With high electrification, the incremental renewable generation jumps to 14.1 TWh.

[34] In the scenarios in which the Massachusetts RPS is increased (to 2 percent or 3 percent per year) alongside an increase in the Connecticut RPS, we assume additional transmission is constructed to avoid curtailment of wind generators in Maine. Please see Appendix B for more information on transmission assumptions.

In addition, in all modeling runs, we observe substantial reductions in natural gas generation by 2030. By 2030, each scenario achieves at least a 21 percent reduction in the use of natural gas for electricity production relative to 2016, with this low bound occurring in the scenario where electricity sales are increased due to high levels of electrification, but no changes are made to state RPS policies. On the other end of the range, the scenario in which Massachusetts expands its RPS to 3 percent per year alongside Connecticut increasing its RPS under a high natural gas price achieves a 55 percent reduction in natural gas generation in 2030.

**Figure 10. New England-wide electric generating capacity in 2030 compared to 2016**

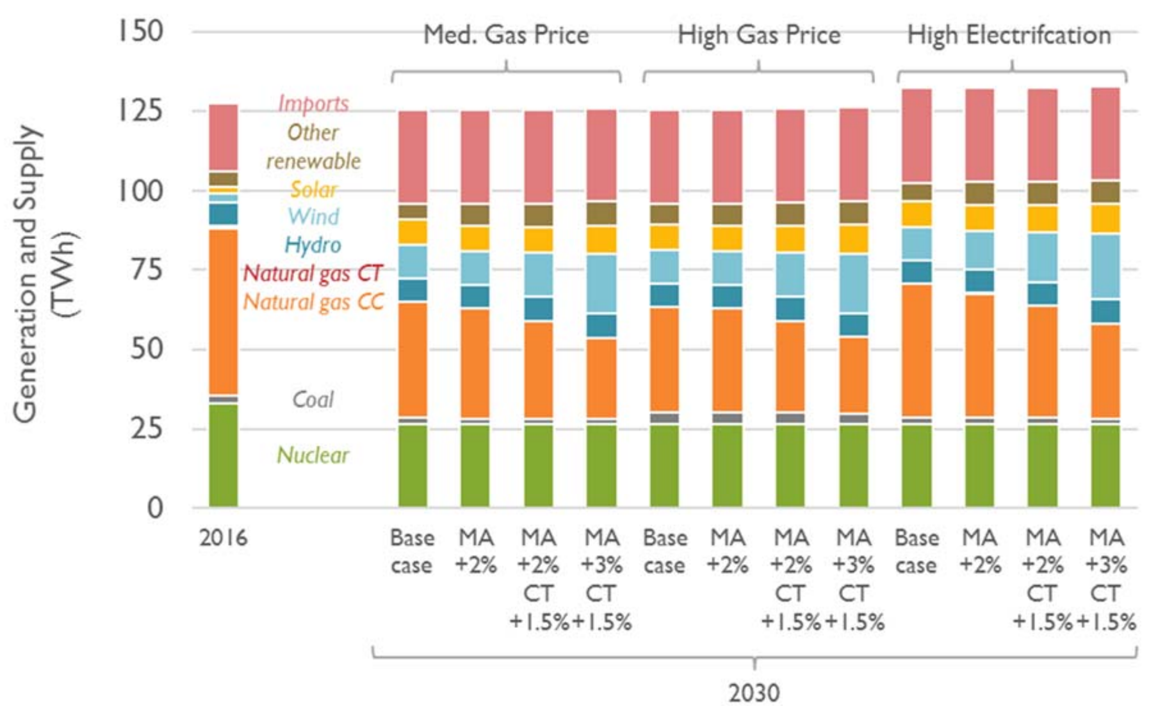


**Table 5. Incremental in-region renewable generation and hydroelectric generation in 2030, relative to the Base Case**

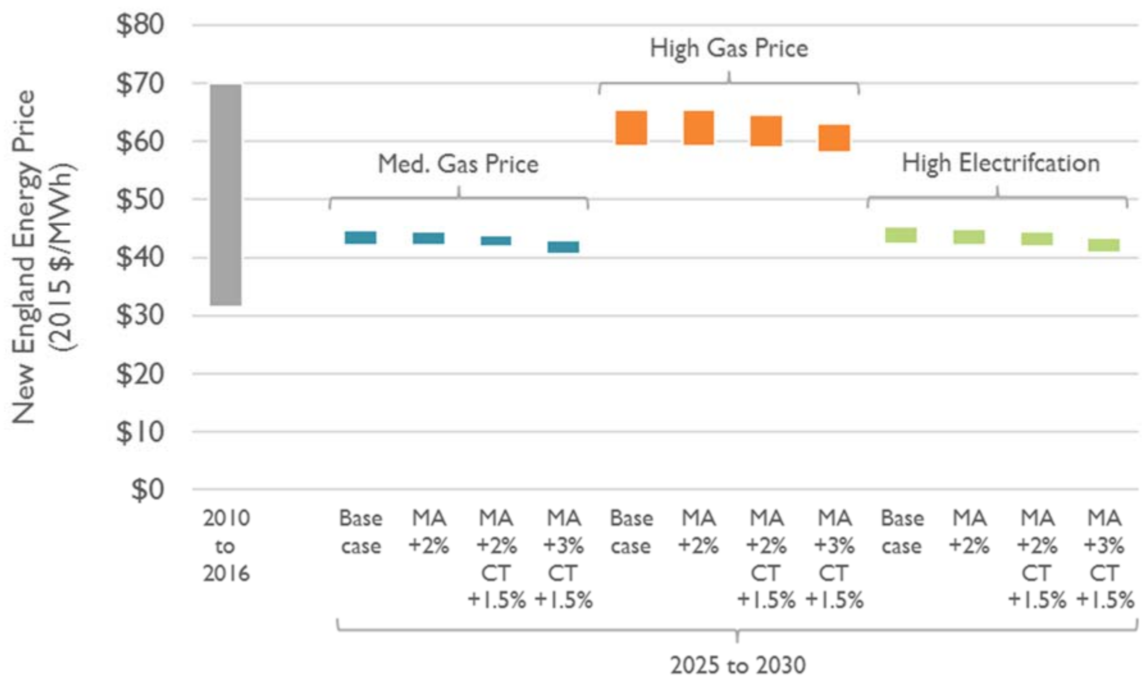
| *2030 generation delta relative to Base Case (TWh)* | **Medium natural gas price sensitivity** | **High natural gas price sensitivity** | **High electrification sensitivity** |
|---|---|---|---|
| **Base Case** (+1% MA RPS) | - | 1.6 | 1.0 |
| **+2% MA RPS** | 1.9 | 1.9 | 4.0 |
| **+2% MA RPS and +1.5% CT RPS** | 6.0 | 6.2 | 7.9 |
| **+3% MA RPS and +1.5% CT RPS** | 11.8 | 12.0 | 14.1 |

Please see Appendix D for additional resource-specific detail on capacity and generation in Massachusetts and the New England region as a whole.

## 3.2. Market prices, REC prices, and residential monthly bill impacts

As more renewables are added to the New England system, we observe lower wholesale market prices. Increasing the RPS growth requirement for Massachusetts from 1 percent per year to 2 percent per year lowers average wholesale energy prices by an average of 0.3 percent over the period of 2025 to 2030. Increasing the Connecticut RPS at the same time lowers wholesale energy prices by an additional 1.0 percent over the same period, and increasing the Massachusetts RPS again to 3 percent year provides an additional 2.9 percent reduction in wholesale energy prices. Similar reductions can be observed in the high natural gas and high electrification sensitivities (see Figure 11).

**Figure 11. Wholesale energy price for New England as ranges for historical years (2010 to 2016) and future modeled years (2025 to 2030) under each scenario**

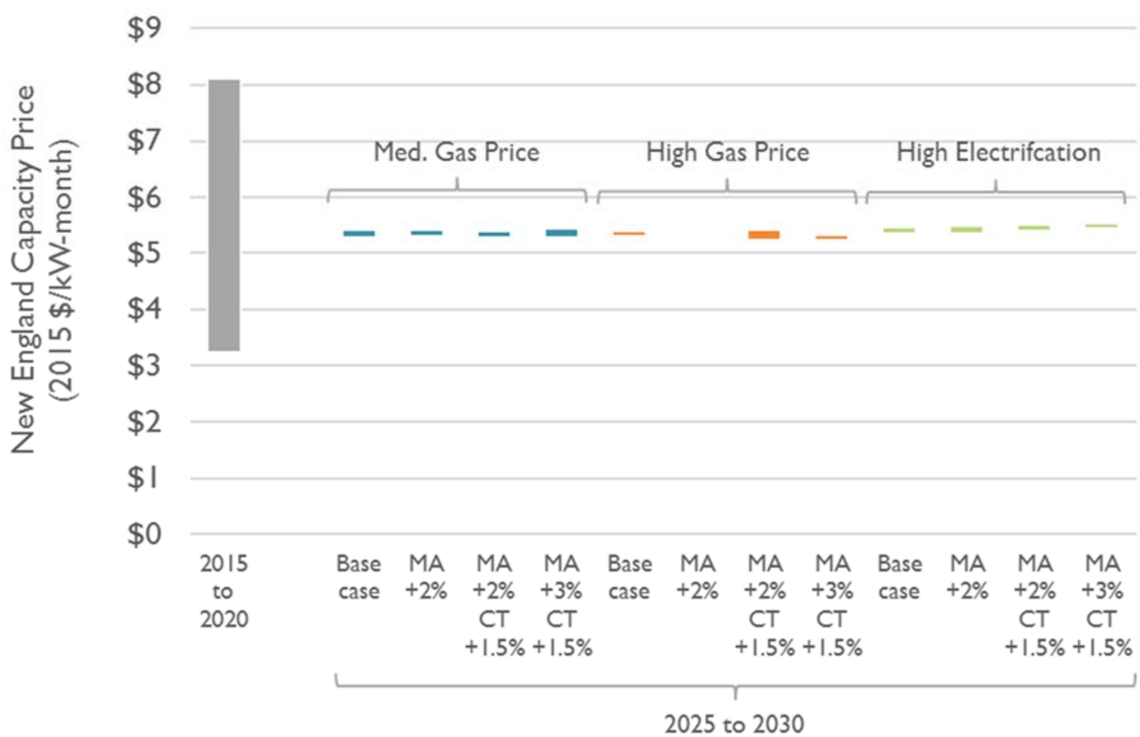





Importantly, we find that increasing the level of renewables can act as a hedge against volatile natural gas prices. Our "high" natural gas price assumes a 2030 regional gas price that is over 150 percent higher than 2016 natural gas prices and 50 percent higher than the 2030 price in the medium natural gas case. In a future with high natural gas prices, increasing the diversity of New England's electricity mix by adding more renewables and reducing reliance on natural gas can reduce wholesale energy costs throughout New England by up to $640 million in 2030 alone or $2.1 billion over the time period of 2018 to 2030.

Meanwhile, increasing the amount of renewables has relatively little impact on the capacity price (see Figure 12). Regardless of the amount of renewable energy or the natural gas price, we find average capacity prices from 2025 to 2030 deviate from the Base Case by only +/- 2 percent.

**Figure 12. Wholesale capacity price for New England as ranges for historical years (2015 to 2020) and future modeled years (2025 to 2030) under each scenario**



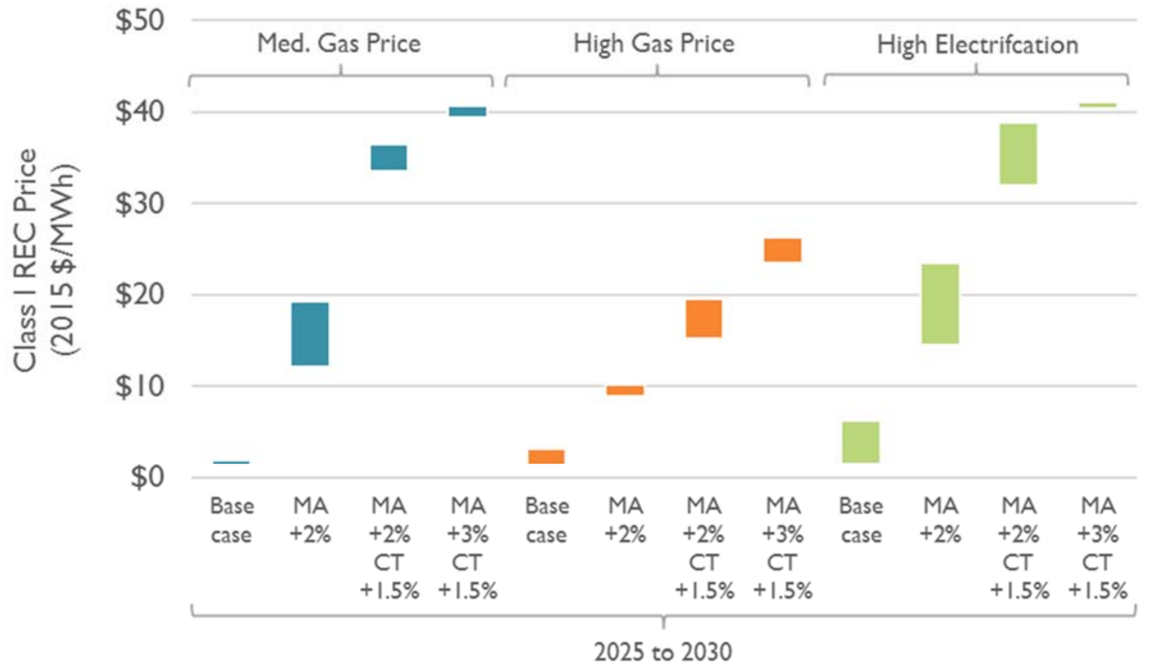



## Increasing the RPS requirement increases REC prices

One main result of increasing the RPS requirement is a corresponding increase in Class I REC prices (see Figure 13). Under a medium natural gas price with no incremental electrification, an increase in the Massachusetts RPS from 1 percent to 2 percent results in a $14 per MWh increase in REC price between 2025 and 2030, supporting existing and assumed-to-be-built renewables (driven by procurement and incentive policies), along with 0.3 GW of new renewables. When the demand for RECs is increased again (by increasing the RPS in Connecticut), both the REC price and incremental capacity increases. In a future where the Massachusetts RPS increases to 3 percent alongside an RPS increase in Connecticut, REC prices could be as high as $40 per MWh, driving 4.1 GW of incremental renewable capacity. In all cases REC prices are projected to remain well below the Alternative Compliance Payment (ACP) level.

In general, REC prices are lower in a future where natural gas prices are higher, largely because renewables can recover more of their costs through increased energy prices, requiring a lower REC price. In a future with high electrification, REC prices are higher than in a lower-sales future. This is largely because electricity sales are higher, increasing the number of MWh that need to be covered by the RPS, driving an increase in the demand for RECs.

**Figure 13. Range of spot Class I REC prices between 2025 and 2030 in each scenario**

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## Increasing the levels of renewables has a limited impact on monthly residential bills

For residential ratepayers in Massachusetts, increasing the RPS requirement has a limited impact on monthly bills.[35] Increasing the RPS requirement to 2 percent per year increases residential bills by an average of $0.15 per month between 2018 and 2030, relative to the Base Case (see Table 6). For reference, note that the average monthly electric bill in 2015 for Massachusetts residential customers was $119.[36] Increasing the RPS requirement to 2 percent alongside an increase in the Connecticut RPS yields monthly bill impacts of $0.70 per month, relative to the Base Case, and increasing the Massachusetts RPS requirement to 3 percent with the Connecticut RPS at 1.5 percent yields a monthly bill impact of $2.17.

[35] In this analysis, we focus on bill impacts for residential ratepayers in Massachusetts who are customers for suppliers that are required to comply with the RPS. We do not analyze bill impacts for commercial or industrial ratepayers. In both these sectors, there is a wide distribution in electricity consumption and increased complexity in rate structure (such as the inclusion of demand charges), which can make producing an average or typical bill impact for these customers problematic or even misleading. It is likely that these customers would see similarly small bill impacts to those described for residential customers here. See Appendix B for more information on the bill impact methodology used in this analysis.

[36] Note that this bill impact analysis is focused on the difference in costs between scenarios. This means that while we account for differences in energy prices, capacity prices, REC prices, and transmission costs, we do not account for cost impacts that are assumed to be the same in all scenarios (for example, any transmission costs associated with incremental hydroelectric imports from Canada). This bill impact analysis is also focused on the difference in residential bills within a year, rather than the difference in bills from one year to the next. Information on 2015 monthly bills is based on data from EIA's Form 861, available at https://www.eia.gov/electricity/data/eia861/.

Under a high electrification future with a medium gas price, relative bill impacts are generally very similar to a future with no incremental electrification and a medium gas price. However, in a future with a high natural gas price, monthly bill impacts are reduced, as a result of renewables acting as a hedge against high natural gas prices. In this future, average monthly bill impacts range from about $0.10 per month to $1.30 per month.

**Table 6. Average monthly bill impacts for residential customers of investor-owned utilities in Massachusetts, relative to each sensitivity's Base Case**

| *2018-2030 average bill impact (2015 $ / month)* | **Medium natural gas price sensitivity** | **High natural gas price sensitivity** | **High electrification sensitivity** |
|---|---|---|---|
| **Base Case** (+1% MA RPS) | - | - | - |
| **+2% MA RPS** | $0.15 | $0.10 | $0.20 |
| **+2% MA RPS and +1.5% CT RPS** | $1.70 | $0.49 | $0.88 |
| **+3% MA RPS and +1.5% CT RPS** | $2.17 | $1.30 | $2.34 |

## 3.3. More renewables avoid more emissions

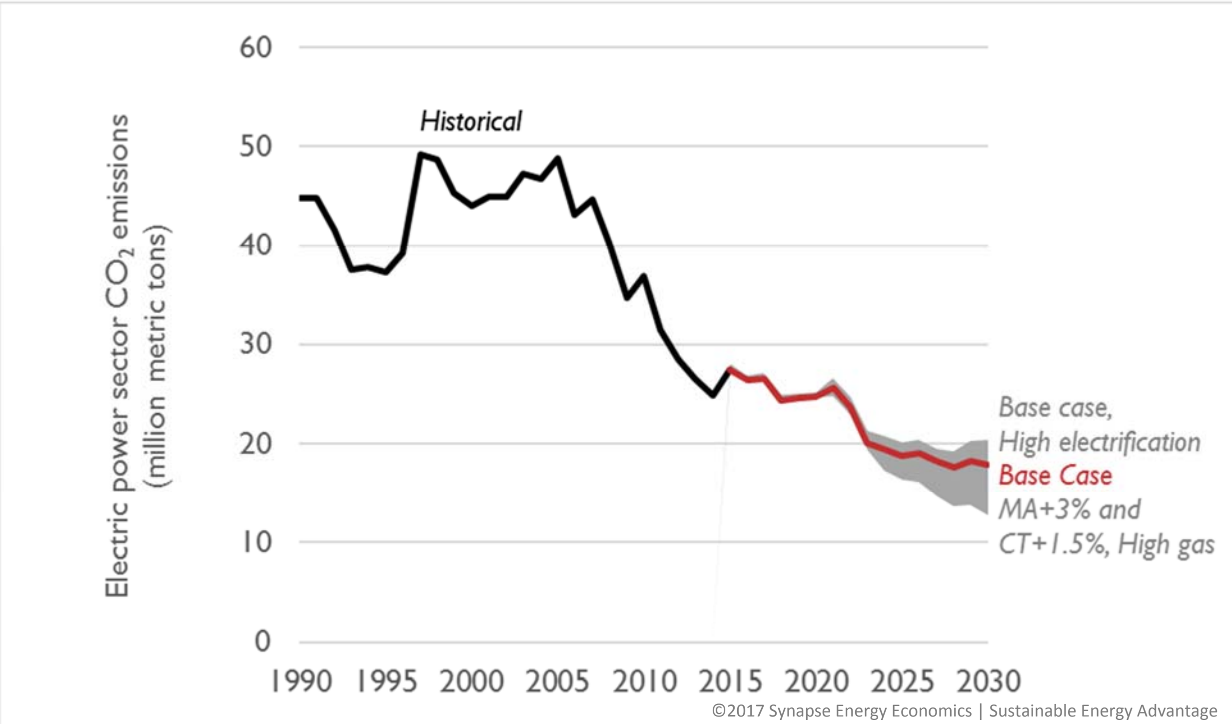
Under the Base Case, given assumptions that sufficient renewables are built to meet procurement and incentive targets, New England's electricity sector achieves $CO_2$ emission reductions of 60 percent relative to 1990 (see Figure 14).[37] As would be expected, as more renewables are added to the electricity system, fewer tons of $CO_2$ are emitted. Under the medium natural gas price sensitivity, when the Massachusetts RPS is increased to 2 percent per year, the 2030 emissions reduction is slightly larger than in the Base Case at 62 percent emissions reduction relative to 1990. When the Massachusetts RPS is increased alongside the Connecticut RPS, 2030 emission reductions are larger, reaching a level of 66 percent relative to 1990. And, when the Massachusetts RPS is increased instead to 3 percent per year

[37] In line with current policy in Massachusetts and the other New England states, biomass, landfill gas, hydroelectricity, and other resources defined as "renewable" are all assumed to have $CO_2$ emission rates of 0 metric tons per MWh. This effectively assumes that no emissions result from carbon decay of flooded biomes to create new hydroelectricity reservoirs and that any emissions resulting from biomass incineration are sequestered at a one-for-one rate within the timeframe of this study period. See http://www.synapse-energy.com/sites/default/files/SynapseReport.2012-02.CLF%2BPEW.GHG-from-Hydro.10-056.pdf and http://www.synapse-energy.com/sites/default/files/Carbon-Footprint-of-Biomass-11-056.pdf for further discussion on these topics.

alongside a Connecticut RPS increase, emission reductions reach levels of 71 percent relative to 1990. Note that since changing the natural gas price has little impact on the amount of renewables built, it has a correspondingly small effect on any incremental emission reductions.

In the high electrification sensitivity, we see additional significant emissions reductions relative to 1990 levels. However, because the demand for electricity in these scenarios is greater, despite greater amounts of renewable energy, natural gas generation is high relative to the medium gas price scenarios, resulting in greater electric-sector $CO_2$ emissions. With high electrification, 2030 emission reductions range from a 54 percent to a 67 percent decrease, relative to 1990 $CO_2$ emission levels.

**Figure 14. New England electric-sector $CO_2$ emissions, highlighting the low, high, and range of estimates for emissions, alongside Base Case emissions**



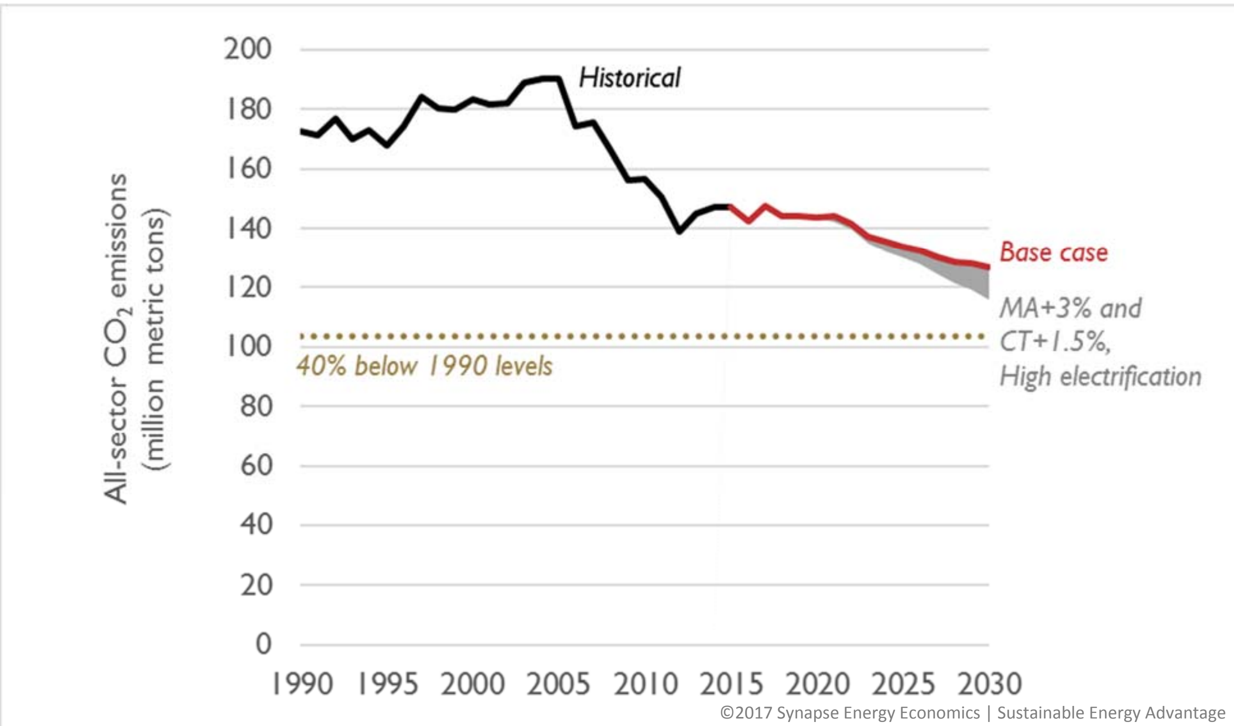

*Note: This figure does not take into account emissions from other sectors (e.g., the residential, commercial, industrial, or transportation sectors), upstream emissions, or emissions from greenhouse gases other than $CO_2$.*

However, the electric sector is only one part of the economy: in 2015, this sector was responsible for only 19 percent of $CO_2$ emissions from all sources in New England. As a result, the large emission reductions modeled in the electric sector translate into comparatively smaller changes to all-sector $CO_2$ emissions. After taking into account emissions from the residential, commercial, industrial, and transportation sectors, we observe 2030 emission reductions from 27 to 33 percent, relative to 1990 (see Figure 15).

When we take into account $CO_2$ emissions from all sectors of the economy (including emission reductions associated with vehicle electrification and reduced gasoline use), the high electrification scenarios achieve the highest level of emission reductions. Without vehicle electrification, all-sector emission reductions are smaller. In the Base Case, we find that 2030 emissions are reduced 27 percent relative to 1990 levels. While increasing the Massachusetts RPS to 2 percent without making any other changes does not result in significantly different emission levels, increasing the Connecticut RPS at the same time, or raising the Massachusetts RPS to 3 percent and also including a Connecticut increase result in 2030 emission reductions of 28 percent and 29 percent, relative to 1990 levels.[38]

Importantly, none of these scenarios result in 2030 emissions reductions of 40 percent or greater. An emission reduction of this amount is effectively the agreed-upon target by New England state governments that would help ensure that the New England states are on their way to meeting an emissions reduction of 80 percent by 2050, the level of emissions reductions needed to comply with state mandates (see Appendix B for more information on state-specific emission requirements, targets, and goals).

**Figure 15. New England all-sector $CO_2$ emissions, highlighting the low estimate and range of estimates for emissions, alongside Base Case emissions (which is identical to the high estimate)**




*Note: This figure does not take into account upstream emissions or emissions from greenhouse gases other than $CO_2$. This figure uses projections from AEO 2017 for non-electric emissions in the New England census region.*

[38] As with electric-sector-only $CO_2$ emissions, all-sector emissions under the high natural gas price sensitivity are nearly identical to their respective medium natural gas price scenarios.

Massachusetts specifically is required under the state's GWSA to achieve greenhouse gas emissions reduction targets of 25 percent in 2020 and 80 percent in 2050. Although an emissions reduction requirement for 2030 has not yet been set, a linear interpolation between the 2020 and 2050 requirements yields a reduction level of 43 percent in 2030.[39]

Massachusetts uses a specific emissions inventory that accounts for both in-state emissions (from the electric generating units as well as other sources) and imports of electricity from neighboring New England states and adjacent power control areas in New York and Canada.[40] In part because of recently-proposed MassDEP regulations setting in-state $CO_2$ emission caps and a Clean Energy Standard, we find that although the Massachusetts 2020 requirement is met by every scenario, in 2030, none of the scenarios comply with the estimated requirement. In fact, in all scenarios without high electrification, emissions from sources other than $CO_2$-emitting electric generating units alone are enough to exceed the 2030 emission reduction requirement under the GWSA. Further increases to the RPS policy, particularly in the early 2020s, could help to ensure that the Commonwealth is on track to meet its greenhouse gas emissions reduction requirements.

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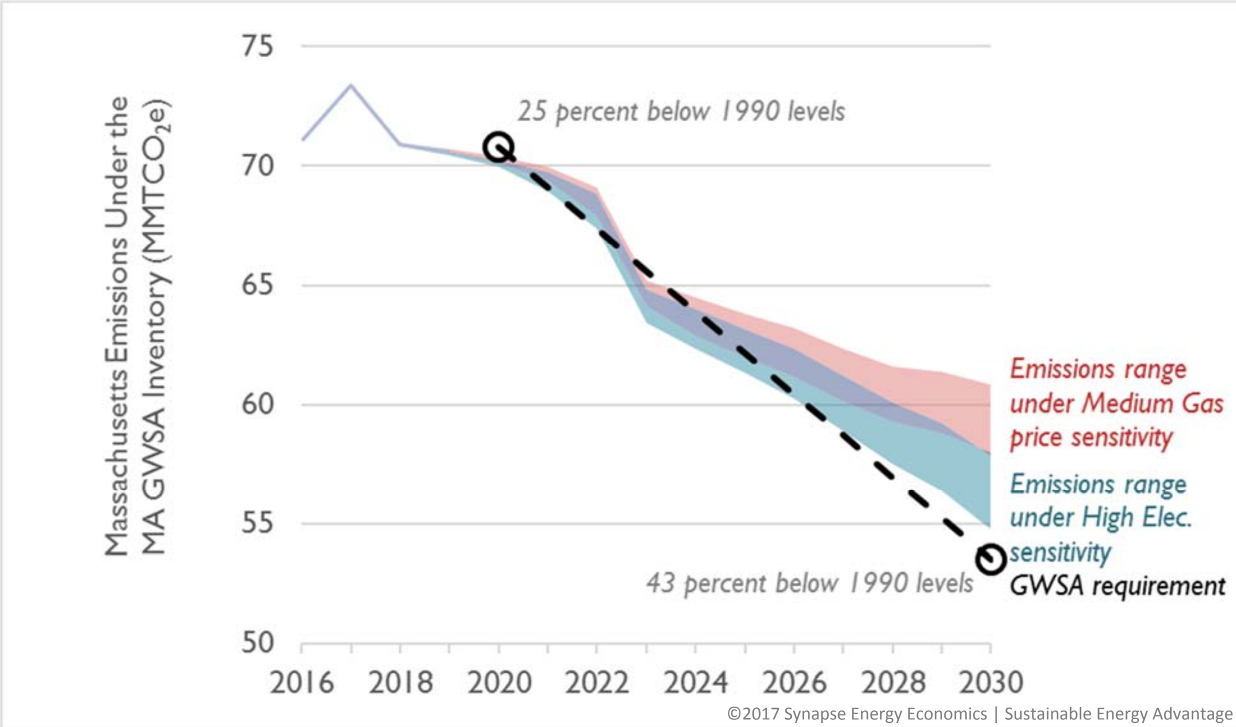
[39] The Massachusetts Supreme Judicial Court affirmed in the 2016 decision *Kain et al.* that the Commonwealth is required to both promulgate annual emission reductions for each year between 2020 and 2050 as well as specific regulations that will result in these emission reductions. The full text of *Kain et al.* is available at http://masscases.com/cases/sjc/474/474mass278.html. MassDEP's proposed regulations to meet the requirements laid out in the MA GWSA are available at http://www.mass.gov/eea/agencies/massdep/air/climate/section3d-comments.html.

[40] See http://www.mass.gov/eea/agencies/massdep/climate-energy/climate/ghg/greenhouse-gas-ghg-emissions-in-massachusetts.html for more information on Massachusetts' greenhouse gas baseline, inventory, and projections.

**Figure 16. Massachusetts greenhouse gas emissions under the Massachusetts inventory**




*Note: In this chart, the red+purple area is the full range for the emissions under the medium natural gas price sensitivity and the blue+purple area is the full range for the emissions under the high electrification sensitivity. The purple area alone is the overlap between these two ranges. This chart does not display a range of emissions for the high natural gas price sensitivity since they are nearly identical to the emissions in the medium natural gas price sensitivity. As in Figure 15, this figure uses $CO_2$ emissions projections from AEO 2017 for the residential, commercial, industrial, and transportation sectors. In all other emission categories accounted for under the MA GWSA (such as biogenic, non-$CO_2$, natural gas pipeline, agriculture and land use, industrial process, and land use emissions), we assume that the level of emissions recorded by Massachusetts in 2014 are continued in all future years. This calculation also accounts for other emission reductions expected under proposed MassDEP regulations other than those expected under 310 CMR 7.74 and 310 CMR 7.75 (e.g., $SF_6$ reductions, pipeline leak repairs, and partial electrification of vehicle fleets at state agencies).*

## 3.4. Policies driving significant increases in renewables lead to more jobs

In addition to providing benefits in terms of reduced emissions, more renewables can drive jobs in clean energy and other sectors of the economy. Using the IMPLAN model, we analyzed the net job impacts of implementing increasing RPS requirements. Over the 13-year time period between 2018 (when the modeled RPS policies diverge) and 2030 (the end of the study period) we find that increasing the

Massachusetts RPS requirements can produce up to 37,000 more jobs in New England, relative to the Base Case (see Table 7).[41] This translates into about 2,900 jobs per year (see Table 8).

In a future in which the Massachusetts RPS is increased by 2 percent, the supply and demand balance for RECs is restored, leading to increased REC prices. These increased REC prices translate into higher electric system costs, which lead to job losses. However, these job losses are offset by job increases associated with the new renewables that are built in response to the increased REC demand. When these job losses and job increases are added together, the result is that there is no net change in jobs between the Base Case and the 2 percent scenario.

However, if the Massachusetts RPS is increased alongside an increase in the Connecticut RPS, many more renewables are built. This increase in new renewable capacity directly translates into many new construction jobs. Even after taking into account increased costs associated with RECs, as well as job losses associated with the coal and natural gas industries, this scenario leads to 21,000 new net job-years over the 13 period, or about 1,600 jobs added in each year. If the Massachusetts RPS is increased to 3 percent, even more renewables are built, and the total cumulative jobs increases to 37,000, or 2,900 jobs added in each year.

In a future with high natural gas prices, we see a very similar trend to the medium natural gas price. Increasing the Massachusetts RPS requirement to 2 percent increases REC costs, but the job losses associated with this increased cost are offset by job gains associated with small, incremental levels of new renewables. As a result, we observe no net jobs created in this scenario. In higher-renewable futures under a high natural gas price, job increases are slightly larger than in the medium natural gas price case, largely because REC prices do not increase as much as they otherwise do in the medium natural gas price futures since the wholesale energy price is larger, reducing the need for a high REC price to support more expensive new resources. This results in fewer job losses and overall larger net jobs.

Finally, in a future with medium natural gas prices and high levels of electrification, net jobs are larger than zero in all scenarios, ranging from 10,000 cumulative net jobs in a case where the Massachusetts RPS is increased to 2 percent per year to 43,000 cumulative net jobs in a case where the Massachusetts RPS is increased to 3 percent per year alongside an increase in the Connecticut RPS policy.[42] In these scenarios, higher electric sales drive a greater demand for RECs, resulting in more renewables. Also,

[41] Our job impact analysis quantifies jobs as "job-years." One job-year is equivalent to one full-time job that lasts for one year. We model net job impacts, meaning we account for both increases in jobs resulting from renewable construction (for example) alongside jobs that decrease as a result of decreasing coal and natural gas generation (for example). This also means that jobs that exist in all scenarios (such as those that could be caused by the 1,600 MW of offshore wind mandated under Massachusetts Chapter 188 Section 83C) are effectively "netted out" and are not evident in the job impact results.

[42] Note that none of our scenarios model job impacts associated with sectors other than the electric sector, such as the job impacts associated with switching internal-combustion vehicles and infrastructure to electric vehicles.

because natural gas generation is comparatively higher in these scenarios, there are fewer negative jobs associated with decreased natural gas generation.

**Table 7. Cumulative incremental New England-wide job impacts (measured in net job-years), relative to each sensitivity's Base Case**

| *2018 to 2030 net job years, cumulative* | Medium natural gas price sensitivity | High natural gas price sensitivity | High electrification sensitivity |
|---|---|---|---|
| **Base Case** (+1% MA RPS) | - | - | - |
| **+2% MA RPS** | 0 | 0 | 10,000 |
| **+2% MA RPS and +1.5% CT RPS** | 21,000 | 23,000 | 24,000 |
| **+3% MA RPS and +1.5% CT RPS** | 37,000 | 45,000 | 43,000 |

**Table 8. Average annual incremental New England-wide job impacts (measured in net job-years), relative to each sensitivity's Base Case**

| *2018 to 2030 net job years, average annual* | Medium natural gas price sensitivity | High natural gas price sensitivity | High electrification sensitivity |
|---|---|---|---|
| **Base Case** (+1% MA RPS) | - | - | - |
| **+2% MA RPS** | 0 | 0 | 700 |
| **+2% MA RPS and +1.5% CT RPS** | 1,600 | 1,800 | 1,900 |
| **+3% MA RPS and +1.5% CT RPS** | 2,900 | 3,500 | 3,300 |

Please see Appendix B for more information on the job impact methodology used in this analysis.

# 4. MAJOR FINDINGS

Adjusting the RPS requirements in Massachusetts and Connecticut has the primary impact of bringing the expected renewable energy supply into balance with renewable energy demand. In addition, increasing the RPS requirements beyond a technical fix has the advantage of increasing the total amount of renewable generation, reducing greenhouse gas emissions, and creating jobs, all with limited impacts to residential electric bills.

**In a Base Case future with no changes to RPS policies, the New England electricity system is unlikely to see substantial additions of renewables before 2030, beyond those expected from recently-enacted long-term contracting policies and other non-RPS programs.**

We estimate that meeting current on-the-books laws and regulations such as existing RPS policies will require an increase in renewable capacity of 7,700 megawatts (MW) by 2030. These laws and regulations include long-term contracting requirements under the Energy Diversity Act, which require 1,600 MW of RPS-eligible offshore wind and 9.45 million megawatt-hours (MWh) of clean energy (part of which includes RPS-eligible renewables), other long-term renewable energy contracting policies in place in Connecticut and Rhode Island, as well as solar incentive policies throughout New England. These policies will result in new renewable supply exceeding the demand for RECs established under the existing RPS policies.

**This increase in REC supply, without a corresponding increase in REC demand, is likely to reduce spot REC prices and undermine efforts to sustain existing resources and finance new renewable investment.**

In the Base Case, as the supply of renewables increases without commensurate increases in demand, the price for Class I RECs in the New England market is expected to drop from $16 per megawatt-hour (MWh), where it is today, to below $5 per MWh between 2025 and 2030. Sustained surplus and low REC prices may impair the financial viability of existing Class I resources and are not likely to enable the financing required for new renewable development, undermining the use of the RPS as a means to achieve the Commonwealth's climate goals. Existing biomass facilities (representing approximately 400 megawatts (MW) of renewable capacity) and other RPS-eligible projects either wholly or partially uncontracted are particularly susceptible. Policymakers should consider the impact of policy changes on investors in existing projects, as these entities are largely responsible for delivering the RPS successes claimed to date. Policy choices also affect the willingness of entities considering investments that will lead to new generation, new jobs, and reduced greenhouse gas emissions to meet the Commonwealth's clean energy and climate goals.

**Increasing the rate of growth in the RPS to 2 percent per year will align renewable energy supply and demand but is unlikely to drive incremental new renewable capacity additions,**

**beyond those supported by recent policies, before 2030. Increasing the RPS even further can drive additional new renewable capacity and generation.**

Our analysis shows that an increase in the Massachusetts RPS to 2 percent per year (up from the current 1 percent per year) is likely to produce a demand for renewables in line with anticipated supply from non-RPS programs. In this future, supply from existing capacity (including biomass and Class I imports from New York, Québec, and New Brunswick) and expected additions from already-authorized policies and programs will be sufficient to meet annual increases at a rate of 2 percent in RPS demands. Very few additional new renewables will be built.

If RPS polices are altered, our analysis shows that between 2,000 and 4,900 GW of new renewables could be built by 2030, beyond what is already called for in existing laws and regulations. These alternatives include: (a) an increase of 2 percent per year in the Massachusetts RPS and a continuation of the 1.5 percent per year increase in the Connecticut RPS, (b) an increase of 3 percent per year in the Massachusetts RPS and a continuation of the 1.5 percent per year increase in the Connecticut RPS, or (c) if New England's electricity usage were to increase due to increased electrification as a result of greater deployment of electric vehicles.

**Increasing RPS requirements can lead to lower wholesale electricity market prices for customers. After accounting for incremental REC price increases, transmission costs, and displaced fossil fuel generation, residential customers are expected to experience only moderate monthly bill increases.**

Renewable resources frequently have variable operating costs of close to $0 per MWh, unlike resources such as natural gas and coal that require staff operation and fuel to run. As more renewables come online, the hourly cost to provide electricity decreases. With increased levels of renewables, we estimate that by 2030 wholesale market prices for energy will decrease between 0.5 percent and 8.1 percent (depending on the rate of RPS expansion), relative to a future in which RPS policies in Massachusetts or Connecticut are not changed. At the same time, higher REC prices will increase the cost of RPS compliance. When decreases in wholesale electricity prices are aggregated with increases in REC prices, we find that monthly average retail electric bills for residential ratepayers in Massachusetts are expected to increase $0.15 to $2.17 per month (depending on the rate of RPS expansion), compared to a future in which the Massachusetts and Connecticut RPS are not changed.

**Increasing the RPS can result in up to 37,000 new jobs in New England between 2018 and 2030.**

In addition to reducing wholesale electricity prices, more renewable energy leads to more jobs. Our comprehensive job impact analysis finds that increasing the Massachusetts RPS requirements, alongside maintaining the annual increase in Connecticut's RPS, could drive up to 37,000 net jobs over the study period. In a future with a high natural gas price, or high electrification, even more jobs could be created across the region. This analysis accounts for job losses associated with both higher REC prices and displaced natural gas and coal generation, as well as job increases associated with new renewable construction.

### Increasing the RPS can provide a price hedge against rising natural gas prices and volatility.

While natural gas prices have remained at historically low levels for several years, it is possible that future increases in natural gas prices could drive up the wholesale energy price in New England. Between 2018 and 2030, increasing the diversity of New England's electricity mix by adding more renewables and reducing reliance on natural gas could save New England up to $2.1 billion in wholesale energy costs, in the face of a higher natural gas price.

### Increasing the RPS drives new renewables and reduces natural gas and coal generation.

As more renewables come online, they act as "must-take" resources, causing generation from conventional resources like natural gas and coal to reduce or be displaced. Even in the Base Case, the anticipated growth of renewables results in the retirement of all but one New England coal unit during the study period. This growth also causes an estimated 32 percent reduction in natural gas consumption for electric power generation between 2016 and 2030. In other cases, 2030 natural gas-fired generation is 21 to 55 percent below 2016 levels, depending on the natural gas price, the level of renewables, and demand for electricity from electric vehicles.

### Using the RPS to shift generation away from natural gas and coal to renewables leads to reductions in carbon dioxide emissions in all scenarios.

As generation from fossil fuels declines, so do carbon dioxide emissions. In our Base Case, we estimate that 2030 carbon dioxide emissions from the electricity sector in New England will be 60 percent lower than they were in 1990. Other, higher levels of renewables could increase this reduction to between 62 and 71 percent. When taking electric sector emissions together with carbon dioxide emissions from all sectors (i.e., the residential, commercial, industrial, and transportation sectors) in New England, we observe 2030 emission reductions of 27 to 33 percent relative to 1990 levels, with the largest emission reductions occurring in scenarios with high levels of vehicle electrification. However, these emission reductions still fall short of the reductions required for the six New England states to meet their climate change targets. For Massachusetts in particular, we find that all scenarios meet the 2020 Massachusetts GWSA requirement (a 25 percent reduction in all-sector, all-greenhouse gas emissions, relative to 1990 levels), but some scenarios are outside the compliance trajectory as soon as 2021. Despite the inclusion of new regulations by the Massachusetts Department of Environmental Protection (MassDEP) which apply unit-specific carbon dioxide caps to in-state generators and promulgate a Clean Energy Standard through 2050, all scenarios fall short of the trajectory required to achieve an 80 percent reduction in greenhouse gas emissions by 2050.

## Conclusion

Massachusetts' key renewable energy policies require harmonization in order for the Commonwealth to meet its long-term clean energy and climate goals. If RPS requirements are not increased to re-align with supply policies such as large scale long-term contracting and distributed generation incentives, Massachusetts is likely to observe existing renewable investors exiting the market and few new renewable additions beyond those required under recent long-term contracting laws and other non-RPS renewable policies. Increasing the Massachusetts Class I RPS targets can drive new, incremental, cost-effective, market- based renewables that lower wholesale electricity prices, reduce carbon dioxide and other power plant emissions, and increase jobs and other economic benefits in the Commonwealth and surrounding states.

# Appendix A. Modeling Methodology

In this analysis, Synapse and SEA used two models in conjunction: EnCompass (Version 2.0), a state-of-the-art capacity expansion and production cost model produced by Anchor Power Solutions, and the Renewable Energy Market Outlook (REMO) model, a proprietary model developed by SEA for assessing renewable builds and REC prices.

In addition, Synapse also used IMPLAN, an industry-standard job impact model, and M-SEM, a state-specific spreadsheet model developed by Synapse and used for tracking historical and projected energy use and emissions from the residential, commercial, industrial, and transportation sectors.

## The Renewable Energy Market Outlook (REMO) Model

In this analysis, SEA has developed forecasts of scenario-specific renewable energy build-outs and renewable energy certificate (REC) price forecasts relying on the in-house models developed for its New England Renewable Energy Market Outlook. Within this modeling, SEA has defined forecasts for both near-term and long-term project buildout and REC pricing. Near-term renewable builds are defined as projects under development that are in the advanced stages of permitting and have either identified long-term power purchasers or an alternative path to securing financing. These projects are subject to customized, probabilistic adjustments to account for deployment timing and likelihood of achieving commercial operation. The near-term REC price forecasts are a function of near-term renewable builds, regional RPS demand, Alternative Compliance Payment levels in each New England state, and market dynamic factors including banking, borrowing, imports and discretional curtailment of renewable energy. For the forecasts of long-term renewable builds, SEA has conducted a supply curve analysis based on technical resource potential of long-term renewable supply and resource cost and value assumptions to determine the most cost-effective portfolio of resources needed to fulfill the annual regional target demand quantities. The long-term REC price forecast is estimated to be the marginal cost of entry for each year, meaning the premium requirement for the most expensive renewable generation unit deployed for a given year.

## The EnCompass Model

EnCompass is a single, fully integrated power system platform that provides an enterprise solution for utility-scale generation planning and operations analysis. EnCompass is an optimization model that covers all facets of power system planning, including:

- Short-term scheduling including detailed unit commitment and economic dispatch
- Mid-term energy budgeting analysis including maintenance scheduling and risk analysis

- Long-term integrated resource planning including capital project optimization and environmental compliance
- Market price forecasting for energy, ancillary services, capacity, and environmental programs

EnCompass provides unit-specific, detailed forecasts of the composition, operations, and costs of the regional generation fleet given the assumptions described in Appendix B and Appendix C. Synapse populated the model with a custom New England dataset developed by Anchor Power and based on the 2015 Regional System Plan, which has been validated against actual unit-specific 2015 dispatch data.[43] EnCompass was used to optimize the generation mix in New England and to estimate the costs of a changing energy system over time. Because this study focuses on annual generation, costs, and emissions, the model was run in "partial" optimization mode with typical peak/off-peak day temporal resolution. These parameters enabled faster processing time at the expense of some detail at the unit operation level.

More information on EnCompass is available at www.anchor-power.com.

## IMPLAN

All the changes in capacity, generation, emissions, and system costs modeled by the REMO model and EnCompass drive changes in jobs. Synapse used the IMPLAN model to evaluate job impacts of these changes in Massachusetts and each of the other five New England states.[44] IMPLAN is an industry-standard model that evaluates job impacts and re-spending in each scenario. Results from scenarios can then be compared to Base Case results to determine the difference made by policies. For each state, this modeling captures the impacts from spending in-state and on each individual state in the rest of the region. The assumed spending in each New England state comes from following activities:

- Construction of generating resources, transmission, and energy efficiency installations
- Operations of energy resources
- Consumer and business re-spending of electricity, natural gas, petroleum, and transportation cost savings

In this analysis, we have not calculated the job impacts of electric vehicle charging infrastructure or any job impacts not directly associated with the electric sector. We have also adjusted our model to reflect the prevailing wages associated with each resource in each New England state.

In this analysis, job impacts are referred to as "net job-years." These numbers are "net" because they represent the net difference in jobs between one scenario and another. In each scenario, different resources operate at different levels, based on the dynamics of the electric sector dispatch model. This

[43] ISO-NE. "2015 Regional System Plan." Available at: https://www.iso-ne.com/system-planning/system-plans-studies/rsp

[44] IMPLAN is a commercial model developed by IMPLAN Group PLC. Information on IMPLAN is available at: http://implan.com/

results in different levels of jobs in one scenario versus another, requiring us to "net" out the difference. This means that in two given scenarios with very similar capacity builds or generation, we are unlikely to measure observable differences in job impacts. These numbers are called "job-years" because each number represents a single full-time equivalent job that exists for a single year. Some jobs are temporary—construction jobs often last only for a few months to a year at the start of a resource's life. Others are longer-term—many power plants require ongoing staff for operations and maintenance. Defining the term as "job-years" is a way to put all these different jobs on the same playing field.

As usual with IMPLAN analyses, we model three different types of jobs: direct, indirect, and induced.

### Direct impacts

Direct impacts are composed of jobs for contractors, construction workers, and plant operators (among others) working on the building or operation of each energy resource. The development of direct job impacts relies primarily upon three inputs: investment level (i.e., dollars spent), share of that investment spent on labor, and state- and industry-specific wages.

### Indirect impacts

Indirect impacts are the jobs created at suppliers, producing parts, tools, and other inputs to support the construction, and performing operations and maintenance. For instance, an investment in a new wind farm not only creates direct jobs at the wind farm, but also indirect jobs down the supply chain, such as jobs for turbine and other component manufacturers. Of course, the suppliers for each resource are not entirely located within the given state.

### Induced impacts

Induced impacts result from residents spending more money in the local economy. For energy resources, these impacts come from: (1) employees in newly created direct and indirect jobs and (2) customers re-spending energy savings that result from implementing energy efficiency measures.

We model each of these job types for construction and operations and maintenance for several types of resources, including onshore and offshore wind, large and small solar, biomass, natural gas combined cycles, natural gas combustion turbines, and coal plants, along with the induced job impacts that result from customer re-spending. We model the direct job impacts from each resource within each state, as well as the indirect and induced job impacts of each resource in a state and the other five New England states.

## M-SEM

Synapse has developed the Multi-Sector Emissions Model (M-SEM), a state-specific model used for tracking historical energy use and emissions and for projecting future energy use and emissions based on a set of policy changes. This dynamic spreadsheet model includes state-specific information on energy use and emissions in the electric, residential, commercial, industrial, and transportation sectors.

It employs historical data from EIA and AEO 2017, the most recent release of the EIA's annual AEO report.[45]

More information on M-SEM is available at http://www.synapse-energy.com/MSEM

## Temporal Scope

The time period of this analysis is 2016 to 2030. REMO and EnCompass modeling is performed at one-year intervals starting in 2016. Historical data through 1990 and 2010 has been included in the spreadsheet model to serve as a point of comparison for future emissions. M-SEM includes historical energy and emissions data through 1990 and models non-electric energy use and emissions through 2030.

## Geographic Scope

EnCompass was used to model all six New England states with unit-specific resolution. The ISO New England system was modeled as thirteen separate balancing areas. Trade between the areas in New England was constrained by the region's major transmission paths. Transfers between New England and its neighbors, including New York, Québec, and New Brunswick, were modeled as set import/export patterns based on actual 2015 hourly flows.

## Bill Impacts

Our analysis focuses on bill impacts for residential ratepayers in Massachusetts who are customers for investor-owned utilities. We do not analyze bill impacts for commercial or industrial ratepayers; different customers in these sectors can face significantly different electric sales and rate structures, which can make producing an average or typical bill impact for these customers problematic or even misleading. This bill impact analysis is focused on the difference in costs between scenarios, meaning that while we account for differences in energy prices, capacity prices, REC prices, and transmission costs, we do not account for cost impacts that are assumed to be the same in all scenarios (for example, any transmission costs associated with incremental hydroelectric imports from Canada).[46] This bill

[45] Energy Information Administration. 2017. Annual Energy Outlook 2017, released January 6, 2017.

[46] Specifically, our bill impacts include changes to wholesale energy costs, changes to capacity costs, and changes to transmission costs. We also include changes to REC prices and demand, including spot REC prices and priced long-term contracts for RECs. Note that we exclude all policy-based renewable supply (e.g., offshore wind required under 83C), which is assumed have the same prices and quantities in each scenario. In instances in which the utility or energy distribution company as provider of last resort (POLR) banks RECs at a market price and market prices experience a subsequent prolonged crash, there is a material risk that the POLR will either sell additional RECs at a material loss or be unable to sell them at all; if the POLR is allowed to pass such costs through to distribution ratepayers, the bill impacts shown here would be greater. This impact has not been modeled as part of this analysis.

impact analysis is also focused on the difference in residential bills within a year, rather than the difference in bills from one year to the next.

# APPENDIX B. BASE CASE AND POLICY SCENARIOS

In this analysis, Synapse and SEA have examined 12 cases, including scenarios in which the Massachusetts Class I RPS policy is increased, scenarios in which the Massachusetts RPS policy is increased alongside RPS increases in other states, and sensitivities in which the effects of a high natural gas price and high vehicle electrification are tested. In general, we examined how electric dispatch, prices, emissions, and jobs change according to the following parameters:

- **Base Case:** This scenario analyzes a business-as-usual future in which no changes are made to existing RPS policies in Massachusetts or any other state. By 2030, this results in 25 percent of retail electricity suppliers' sales in Massachusetts being covered by renewables.[47] See Chapter 2 (above) for more information about the modeling results under the Base Case.

- **+2% MA RPS:** This scenario analyzes a future in which Massachusetts Class I RPS targets increase by 2 percent per year beginning in 2018 (as opposed to 1 percent per year, as in years prior).[48] This requirement will continue to apply only to retail electricity suppliers. By 2030, this results in 38 percent of their sales in Massachusetts being covered by renewables.

- **+2% MA RPS and +1.5% CT RPS:** This scenario analyzes a future in which Massachusetts Class I RPS targets increase by 2 percent per year beginning in 2018 (as opposed to 1 percent per year, as in years prior). This scenario also assumes that beginning in 2021, the Connecticut Class I RPS increases by 1.5 percent per year (the current Connecticut Class I RPS remains flat beginning in 2020).[49] In this scenario, we assume a 600 MW high-voltage direct current (HVDC) transmission line is constructed from central Maine to central Massachusetts in order to alleviate transmission congestion resulting from large quantities of new wind constructed in northern New England. By 2030, this scenario results in an RPS requirement of 38 percent of retail electricity supplier sales in Massachusetts and 35 percent of supplier sales in Connecticut being covered by renewables.

- **+3% MA RPS and +1.5% CT RPS:** This scenario analyzes a future in which Massachusetts Class I RPS targets increase by 3 percent per year beginning in 2018 (as opposed to 1 percent per year, as in years prior). This scenario also assumes that beginning in 2021, the Connecticut Class I RPS increases by 1.5 percent per year (the current Connecticut

[47] Note that this does not include electricity sold by municipal utilities.

[48] The Class I RPS target increase for 2018 (only) is modeled at 1.5 percent as a proxy for the impact of an exemption for retail contracts that were already in effect at the time the MA Omnibus Energy Bill was passed in this scenario and all scenarios with a Massachusetts RPS increase greater than 1 percent per year.

[49] Increasing the Connecticut RPS to 1.5 percent per year at the same time as the Massachusetts RPS is increased to 2 percent per year is analogous to increasing the Massachusetts RPS alone by 2.75 percent per year.

Class I RPS increases by 1.5 percent per year, but stops increasing in 2020).[50] In this scenario, we assume a 1,200 MW HVDC transmission line is constructed from central Maine to central Massachusetts in order to alleviate transmission congestion resulting from large quantities of new wind constructed in northern New England. By 2030, this results in 51 percent of electricity sold by electric suppliers in Massachusetts and 35 percent of electricity sold by electric suppliers in Connecticut being covered by renewables.

- **High natural gas price:** This sensitivity analyzes each of the above four scenarios under a future in which the Henry Hub natural gas price follows a trajectory laid out in the Annual Energy Outlook (AEO) 2017 "Low oil and gas resource and technology case," rather than the AEO 2017 "Reference case," which is used to develop the medium natural gas price.[51] From 2019 to 2030, the Henry Hub natural gas price in this case is expected to grow by 5 percent each year, compared to 2 percent per year in the AEO 2017 Reference case. Please see Appendix C for more information on the gas price methodology. In this sensitivity, we do not make any incremental assumption regarding vehicle electrification rates.

- **High electrification:** This sensitivity analyzes each of the four scenarios under a future in which the six New England states follow a trajectory towards high vehicle electrification. Under this sensitivity, we apply a vehicle electrification trajectory based on the "high case" in Navigant's Q2 2016 *Electric Vehicle Geographic Forecasts*.[52] Please see Appendix B for more information on the vehicle electrification trajectory used. Note that this sensitivity does not make any incremental assumptions regarding electrification of heating, hot water, or other systems that commonly consume fossil fuels as an end-use today. Under this sensitivity, we apply the medium natural gas price.

Table 3 summarizes the parameters for each of the twelve modeling runs.

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[50] Increasing the Connecticut RPS to 1.5 percent per year at the same time as the Massachusetts RPS is increased to 3 percent per year is analogous to increasing the Massachusetts RPS alone by 3.5 percent per year.

[51] Energy Information Administration. 2017. Annual Energy Outlook 2017, released January 6, 2017.

[52] See https://www.navigantresearch.com/research/electric-vehicle-geographic-forecasts for more information.

**Table 9. Overview of modeling runs**

| | Medium natural gas price sensitivity | High natural gas price sensitivity | High electrification |
|---|---|---|---|
| **Base Case** (+1% MA RPS) | Base Case, Medium natural gas price | Base Case, High natural gas price | Base Case, High electrification |
| **+2% MA RPS** | MA Class I RPS increases to 2% per year in 2018, Medium natural gas price | MA Class I RPS increases to 2% per year in 2018, High natural gas price | MA Class I RPS increases to 2% per year in 2018, High electrification |
| **+2% MA RPS and +1.5% CT RPS** | MA Class I RPS increases to 2% per year in 2018, CT Class I RPS increases to 1.5% per year in 2021, Medium natural gas price | MA Class I RPS increases to 2% per year in 2018, CT Class I RPS increases to 1.5% per year in 2021, High natural gas price | MA Class I RPS increases to 2% per year in 2018, CT Class I RPS increases to 1.5% per year in 2021, High electrification |
| **+3% MA RPS and +1.5% CT RPS** | MA Class I RPS increases to 3% per year in 2018, CT Class I RPS increases to 1.5% per year in 2021, Medium natural gas price | MA Class I RPS increases to 3% per year in 2018, CT Class I RPS increases to 1.5% per year in 2021, High natural gas price | MA Class I RPS increases to 3% per year in 2018, CT Class I RPS increases to 1.5% per year in 2021, High electrification |

## Modeling inputs

All twelve modeling runs share the same assumptions for baseline electricity demand, energy efficiency, resource potentials, and unit additions and retirements. Individual scenarios may vary in terms of levels of electrification, renewable additions, and intra-regional transmission. The following sections detail the key modeling assumptions and sources that are common to all modeling runs in this analysis, as well as the modeling assumptions that differ from scenario to scenario.

### Electricity demand

ISO New England's Forecast Report of Capacity, Energy, Loads, and Transmission (CELT) is the basis for the load forecast used in this study.[53] The 2016 CELT forecast provides peak loads and total

[53] ISO-NE. 2016-2025 Forecast Report of the Capacity, Energy, Loads, and Transmission (CELT Report). Available at: https://www.iso-ne.com/static-assets/documents/2016/05/2016_celt_report.xls

consumption by year through 2025. Synapse's baseline load forecast assumption through 2025 is based on the CELT forecast, grossing up for behind-the-meter solar and passive demand response. Since the ISO's forecast only goes through 2025, for 2026 through 2030 we will rely on the electricity sales forecast modeled for the New England region in the most recent AEO 2017 published by EIA in January 2017.[54] After removing all impacts of energy efficiency, this forecast yields a region-wide annual average growth rate of 0.6 percent from 2015 to 2030.

This baseline load forecast does not assume any new energy efficiency. In every case, Synapse has modified the load forecast to include new energy efficiency as reflected by the most recent data from state compliance filings (when applicable) or from EIA Form 861 for states that do not require energy efficiency compliance filings (see Figure 17).

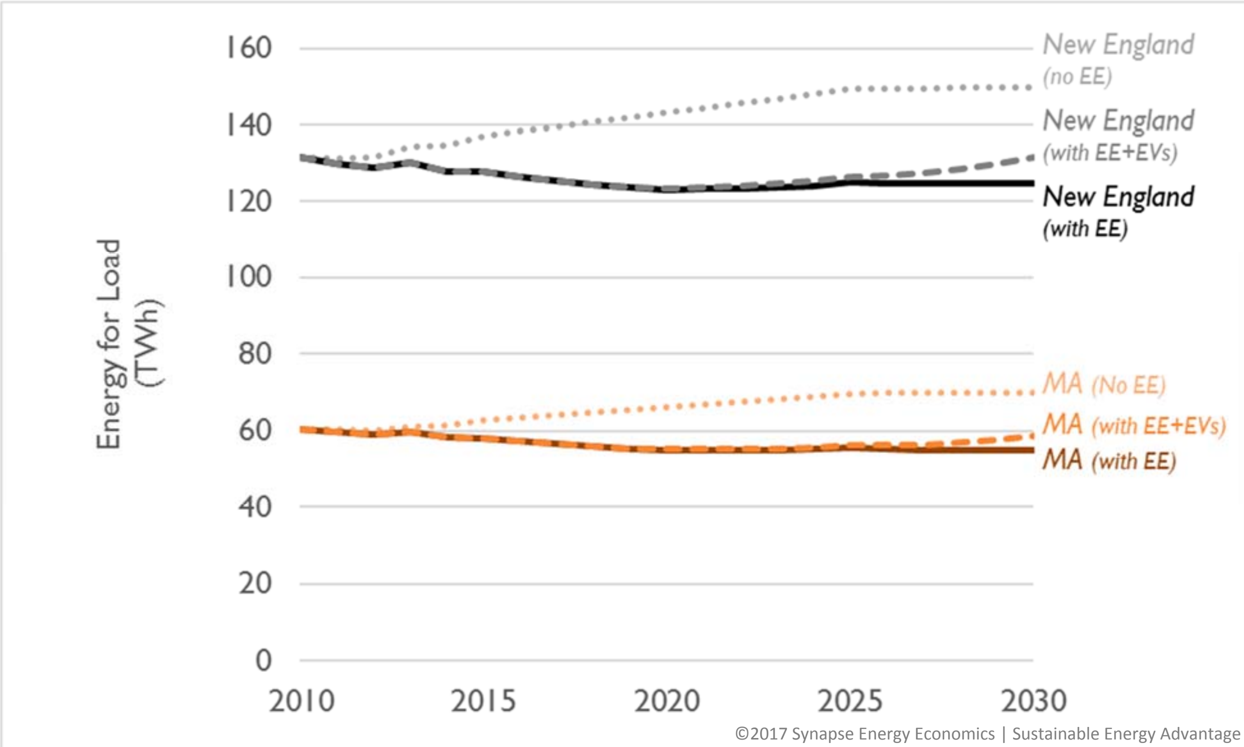
***Energy efficiency***

For our energy efficiency forecast, we have relied on published information from each New England state's program administrators' estimates for energy efficiency. In most cases, these estimates are only made for the next few years. For all years after the last year in which energy efficiency forecasts are published, we assume the same MWh quantity of energy efficiency is installed. We assume that all annual portfolios follow the measure expiration schedule defined by a 2015 LBNL technical report memo *Energy Savings, Lifetimes and Persistence: Practices, Issues, and Data*.[55] This results in annual average energy efficiency savings of 2 percent per year and net cumulative energy efficiency savings of 17 percent in 2030 (relative to a baseline year of 2010). Note that leading states like Massachusetts, Maine, and Rhode Island are expecting to achieve annual savings levels approaching 3 percent over the next few years, while other states (specifically New Hampshire and Connecticut) estimate lower levels of energy efficiency.

[54] For projecting electricity sales, we use the AEO 2017 Reference case with No Clean Power Plan case. Like previous versions of this projection, the AEO 2017 Reference case with No Clean Power Plan case does not assume any future state-specific energy efficiency measures, outside of those expected under federal regulations. Meanwhile, the AEO 2017 Reference case assumes the Clean Power Plan is in effect and that states use energy efficiency as a means to compliance. We do not use this forecast, since it may lead to double-counting of energy efficiency savings.

[55] This is the same measure expiration schedule assumed by EPA in the development of the Clean Power Plan. More information available at https://www.epa.gov/sites/production/files/2015-11/df-cpp-demand-side-ee-at3.xlsx

**Figure 17. Annual energy for load in Massachusetts and New England**




*Note: The "with EE" series are used for all modeling runs in the Medium natural gas and High natural gas sensitivities. The "with EE+EVs" series are used for the three modeling runs in the High electrification sensitivity. The "no EE" series is shown only for reference.*

### *Electrification*

The electric vehicle growth trajectory used in the High Electrification scenarios is based on Navigant's *Electric Vehicle Geographic Forecasts*, a report published in Q2 2016, from which the "high" case has been selected.[56] The Navigant forecast is based on market trends and assumptions about consumer behavior. In this document, Navigant determined electric vehicle sales for each technology segment based on an estimate of market share for each technology competing against all of technology platforms as a function of a series of variables that influence regional consumer choice, which include vehicle costs and capability, state and regional infrastructure, consumer sociopolitical concerns, and automotive industry support. Under this trajectory, 13 percent of petroleum used in the transportation sector under the Base Case is replaced with vehicle electrification.

The Navigant study is separate from state policy objectives and does not assume that Connecticut, Massachusetts, Rhode Island, and Vermont meet the 2025 vehicle electrification goals established in the *State Zero-Emission Vehicle Programs: Memorandum of Understanding* (the "ZEV MOU"), signed by eight state governors (including the four New England states listed above). The ZEV MOU established a

[56] See https://www.navigantresearch.com/research/electric-vehicle-geographic-forecasts for more information.

target of 3.3 million electric vehicles on the road by 2025.[57] That said, for the four states listed above, the number of electric vehicles specified in the "high" case developed by Navigant in 2025 is within one percent of the total electric vehicles specified in the 2025 ZEV MOU target.

Note that in the non-High Electrification modeling runs, we rely on the CELT 2016 sales forecast published by ISO-NE which does not make any explicit assumptions regarding electric vehicle adoption rates.

## Renewable resource potentials and costs

This analysis recognizes that Massachusetts' Class I RPS is implemented within the context of a broader marketplace of states and provinces (i.e., ISO-New England and adjoining regions of New York and eastern Canada) with similar renewable energy target mandates. Most of these markets have overlapping eligibility criteria for renewable resources, so they compete with one another on the margin for adequate renewable energy supplies to meet their respective demands. This regional approach is taken into account in the forecasts of new renewable builds and REC prices.

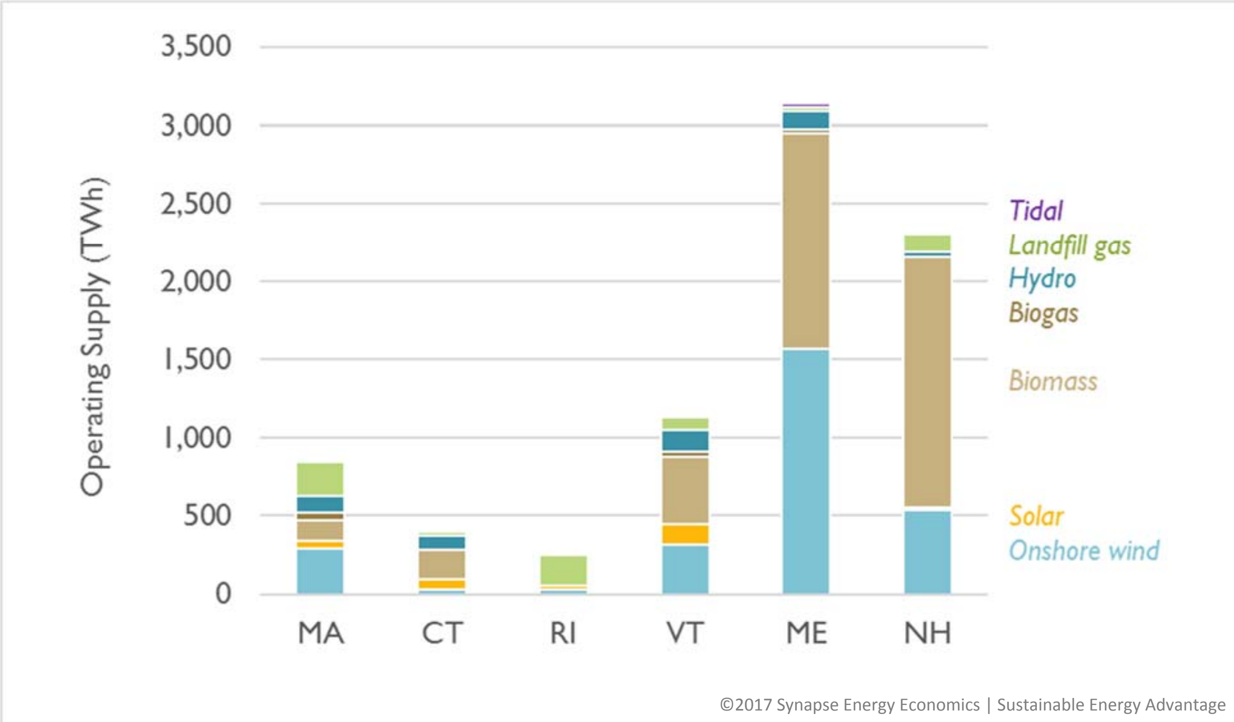
### *Renewable resource potentials*

Figure 18 shows the estimated production for operating Class I supply by technology in each of the six New England states.[58] This supply has been built in response to the RPS, and related policies, to date. The forecast of new renewable builds required to meet incremental RPS demands in this analysis is conducted in three steps: near-term, policy-driven distributed generation, and long-term.

[57] See www.nescaum.org/documents/zev-mou-8-governors-signed-20131024.pdf for more information.

[58] Importing renewable supply from adjoining regions of New York and eastern Canada are modeled but not represented here.

**Figure 18. Operating supply by technology by state based on estimated annual production (GWh)**




***Near-term committed renewable supply***

In the near-term, it is expected that proposed projects will be built subject to probabilistic adjustments to account for deployment timings and individual likelihood of achieving commercial operation. Near-term new renewable builds are defined as projects that are in the advanced stages of permitting and have either identified long-term power purchasers or an alternative path to securing financing. All proposed generators for which information has entered the public domain are included in this analysis. Specifically, these generators include units that (i) are on the interconnection queue; (ii) have been RPS-certified in the one or multiple New England states; (iii) secured financing; or (iv) obtained long-term contracts (including policy-driven distributed generation resources and long-term procurement policies). This generation is derated to reflect the likelihood that not all proposed projects will ultimately be built, and may not be built on the timetable reflected in the queue. This information is grouped by load area as an input to the REMO model. Figure 19 shows the total available resource potential for near-term supply by technology in each of the six New England states.[59]

The near-term committed renewable supply category also includes estimated generation from renewable resources that are developed in proportion to various state policies, including:

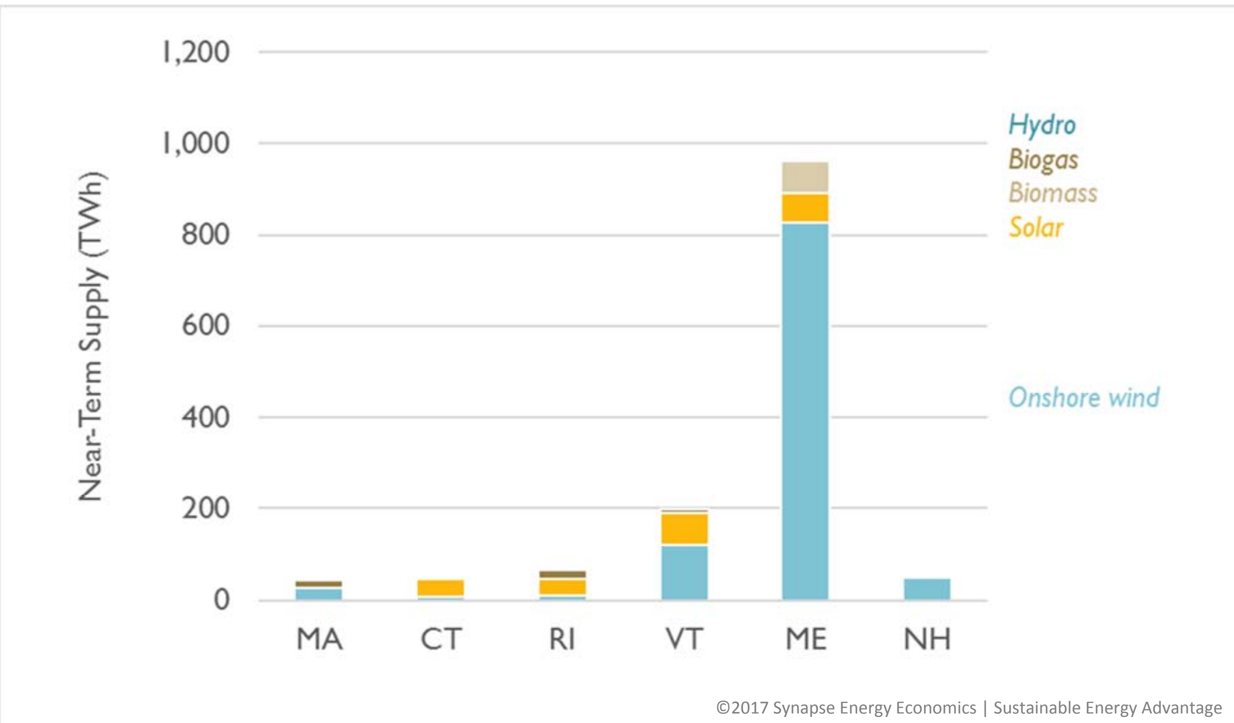
- Massachusetts Section 83C Offshore Wind Procurement

[59] Importing renewable supply from adjoining regions of New York and eastern Canada are modeled but not represented here.

- Massachusetts SMART Program
- Massachusetts Section 83D Clean Energy Procurement
- Assumed replacement of NSTAR's contract with Cape Wind
- Remaining procurement authority under Connecticut Public Act 13-303 Section 6
- Remaining procurement authority under Connecticut Public Act 13-303 Section 7
- Remaining procurement authority under Connecticut Public Act 15-107
- Rhode Island Replacement of Bowers Wind contract

An economic analysis is used to determine the technology build for long-term procurement using a supply curve model. The model identifies the least-cost deployment portfolio for meeting the total procurement demand throughout the study period.

**Figure 19. Near-term renewable resource supply under development by technology by state based on estimated annual production (GWh)**




***Policy-driven distributed generation resources***

In addition to the resources described in the previous section, the near-term committed renewable supply category includes other estimated generation from distributed generation resources that are developed in proportion to various state policies intended to promote distributed generation throughout the study period. These policies include:

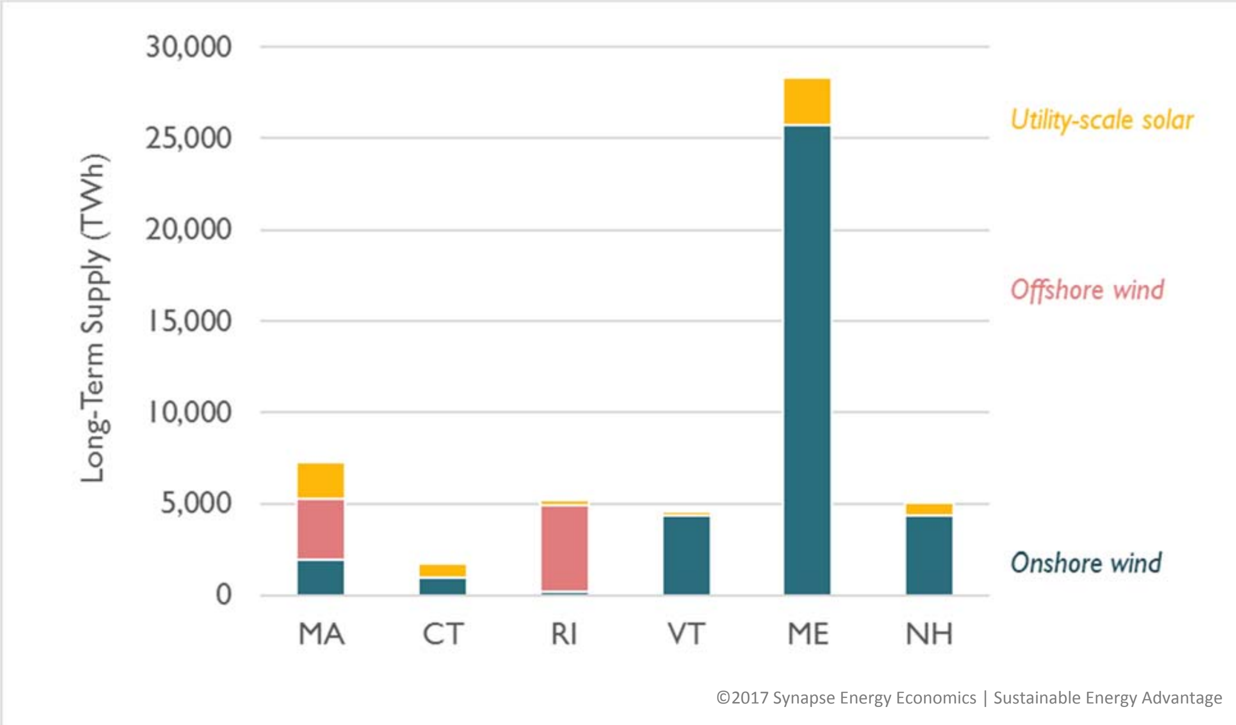
- Massachusetts Solar Carve-out
- Solar Massachusetts Renewable Target (SMART) Program
- Connecticut Low Emissions Renewable Energy Certificate (LREC) and Zero Emissions Renewable Energy Certificate (ZREC) Program
- Connecticut Solar Home Renewable Energy Certificate (SHREC) Program
- Rhode Island Renewable Energy Growth Program
- Vermont Standard Offer Program

***Long-term renewable supply***

Long-term new renewable builds are determined based on an economic analysis to select the least-cost portfolio of resources from a resource pool sufficient to satisfy the regional RPS demand in each year. Figure 20 shows the maximum resource potential of land-based wind, utility-scale solar, and offshore wind available to be deployed in the economic analysis in each of the six New England states.[60] Based on current technologies, and policies for offshore leasing, this analysis limits offshore wind development potential to Massachusetts and Rhode Island.

[60] This potential represents the total of technical resource potential of each technology and each state, subject to developable potential adjustment factors driven by assumed probability of permitting success differentiated by technologies and geographical locations.

**Figure 20. Long-term renewable resource supply potential by technology by state based on estimated annual production (GWh)**




***Renewable resource costs***

The economic analysis used to determine the long-term renewable energy builds has been conducted using a supply curve model composed of resource blocks representing the available renewable resource potential of a particular technology and uniform cost within each of the six New England states. Each resource block is defined by a 20-year levelized cost of energy (LCOE) intended to represent the annualized revenue requirement of the supply in nominal $/MWh, accounting for capital expenditures, ongoing fixed and variable operational expenditures, integration costs, financing parameters (e.g., cost of capital, capital structure, financing requirements), depreciation, tax inputs (including federal Production Tax Credits and Investment Tax Credits), incentives, performance (i.e., capacity factors), generator-lead interconnection costs. Table 10 shows the LCOE input assumptions for representative wind, offshore wind, and utility photovoltaic (PV) generators.[61]

[61] The financing inputs assume the generators would be able to monetize 100 percent of the Production Tax Credit value (or 30 percent Investment Tax Credit value for PV) and secure 20-year long-term bundled power purchase agreements.

**Table 10. LCOE cost inputs of representative generators (all costs are in 2013 dollars)**

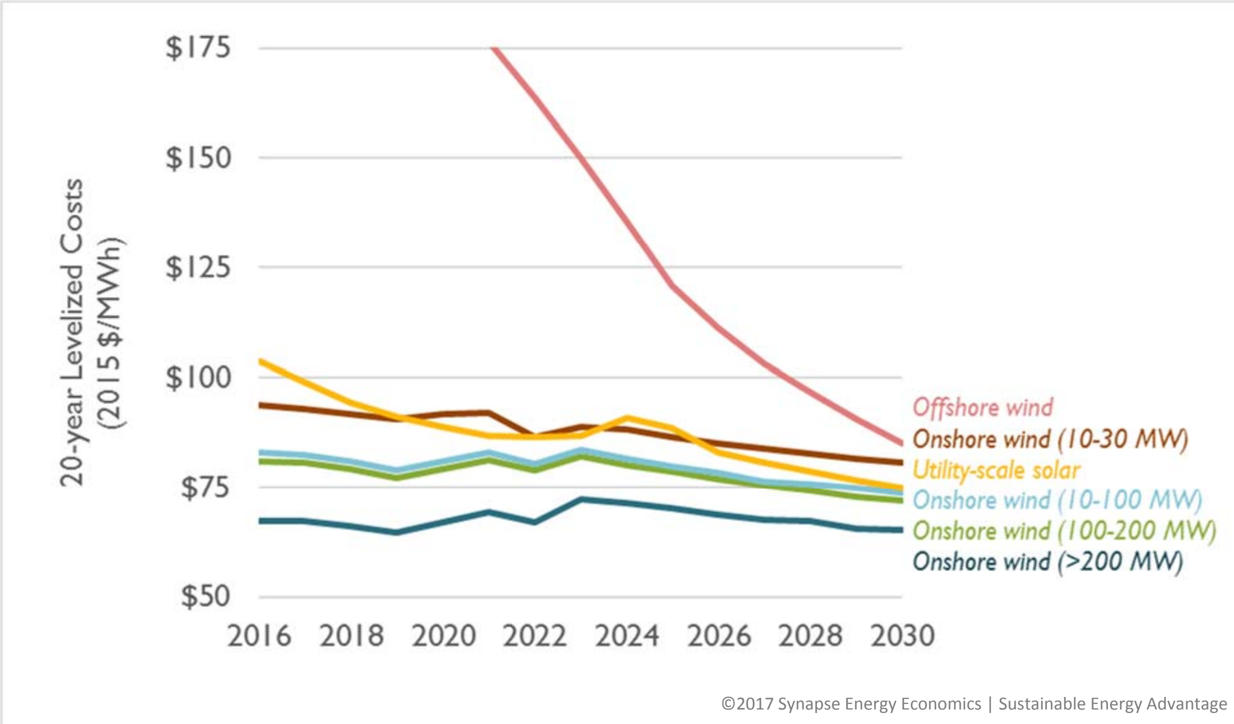
| | Land-based wind (10 MW) | Land-based wind (60 MW) | Land-based wind (125 MW) | Offshore Wind (200+ MW) | Utility PV (20 MW) |
|---|---|---|---|---|---|
| Economic Life | 20 Years | 20 Years | 20 Years | 20 Years | 25 Years |
| Tax Depreciation | 5-Year Modified Accelerated Cost Recovery System (MACRS) | | | | |
| Debt Cost | 6.25% | | | | |
| Debt Term | 18 Years | 18 Years | 18 Years | 18 Years | 15 Years |
| Equity Cost (w/PTC) | ~10.5% - ~12.5% | | | | |
| Debt:Equity (w/PTC) | 55:45 | | | 65:35 | 35:65 |
| Capital Cost ($/kW) | $2,673 | $2,365 | $2,097 | $3,572 | $1,400 |
| Transmission or Interconnection Cost Adder ($/kW) | $193 | $110 | $133 | $986 | N/A |
| Fixed O&M ($/kW-Yr) | $67.59 | $67.59 | $67.59 | $100 | $31.61 |

Throughout the study period, the LCOE values for different resources are expected to undergo a number of changes.[62] Changes include impacts resulting from technology cost decline, technological improvements, as well as changes to federal incentives (including the investment tax credit for solar and the production tax credit for wind). Figure 21 shows the comparative cost of renewables from 2016 to 2030.[63]

[62] A levelized cost of energy is an "average" cost of energy that assumes any upfront capital costs are amortized or spread over the lifetime of the resource and are added to any fuel, operating, or maintenance costs.

[63] Note that operating and maintenance costs for existing conventional generation will be based on the unit-specific data contained in EnCompass. Capital, operating, and maintenance costs for new conventional generation will be based on data from the 2017 Annual Energy Outlook.

Figure 21. 20-year levelized cost of renewables




The LCOEs shown in Figure 21 assume that the new renewable energy supply will be able to secure 20-year long-term bundled power purchase agreements (PPAs) for RECs, energy, and capacity.

## Unit additions

In addition to the renewables modeled under the Class I RPS for each of the New England states, Synapse included known resource additions that are likely to come online in the next several years (see Table 11 and Table 12). To construct this list, Synapse compiled the units listed as "under construction" in the final 2015 version of EIA form 860.[64] This list was checked against and supplemented by the data reported in EIA's Electric Power Monthly.[65] Second, Synapse included any units that have cleared in the most recent ISO New England Forward Capacity Market.[66] Finally, we assume that 600 MW of battery storage are constructed in Massachusetts by 2025, in line with recommendations to build storage per Governor Baker's Energy Storage Initiative and stipulations of Massachusetts Chapter 188 requiring the Massachusetts Department of Energy Resources to determine whether to set targets for cost-effective

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64 Available at http://www.eia.gov/electricity/data/eia860/

65 Available at http://www.eia.gov/electricity/monthly/

66 In February 2016, a capacity auction (FCA-10) took place which indicates the resources that have capacity obligations for the June 2019 to May 2020 period. In February 2017, FCA-11 took place, which provided capacity obligations for resources through 2021. However, unit-specific data from this most recent auction was not available until March 2017, making it unfeasible to include this data in modeling. This document only lists resources that have obligations through 2020. More information is available at https://www.iso-ne.com/isoexpress/web/reports/auctions/-/tree/fcm-auction-results

storage additions.[67] Synapse also allowed EnCompass to add new units if doing so lowered overall system costs.

**Table 11. Natural gas additions**

| State | Plant Name | Utility | Capacity (MW) | Online Year | Fuel Type | Unit Type | Source |
|---|---|---|---|---|---|---|---|
| CT | Bridgeport Harbor 6 | PSEG | 484.3 | 2019 | Natural Gas | Combined Cycle | FCA10 |
| RI | Burrillville Energy Center 3 | Invenergy | 485.0 | 2019 | Natural Gas | Combined Cycle | FCA10 |
| CT | CPV Towantic Energy Center CTG1 | CPV Towantic, LLC | 285.0 | 2018 | Natural Gas | Combined Cycle | EIA 860 2015 |
| CT | CPV Towantic Energy Center CTG2 | CPV Towantic, LLC | 285.0 | 2018 | Natural Gas | Combined Cycle | EIA 860 2015 |
| CT | CPV Towantic Energy Center STG | CPV Towantic, LLC | 280.5 | 2018 | Natural Gas | Combined Cycle | EIA 860 2015 |
| MA | Salem Harbor 5 | Footprint Salem Harbor Development LP | 158.4 | 2017 | Natural Gas | Combined Cycle | EIA 860 2015 |
| MA | Salem Harbor 6 | Footprint Salem Harbor Development LP | 158.4 | 2017 | Natural Gas | Combined Cycle | EIA 860 2015 |
| MA | Salem Harbor 7 | Footprint Salem Harbor Development LP | 240.7 | 2017 | Natural Gas | Combined Cycle | EIA 860 2015 |
| MA | Salem Harbor 8 | Footprint Salem Harbor Development LP | 240.7 | 2017 | Natural Gas | Combined Cycle | EIA 860 2015 |
| MA | Canal 3 | NRG | 333.0 | 2019 | Natural Gas | Combustion Turbine | FCA10 |
| MA | Medical Area Total Energy Plant CT3 | Medical Area Total Egy Plt Inc | 13.8 | 2017 | Natural Gas | Combustion Turbine | EIA 860 2015 |
| MA | Medway Peaker 1 | Exelon | 194.8 | 2018 | Natural Gas | Combustion Turbine | FCA9 |
| CT | Wallingford CTG6 | Wallingford Energy LLC | 50.0 | 2018 | Natural Gas | Combustion Turbine | FCA9 |
| CT | Wallingford CTG7 | Wallingford Energy LLC | 50.0 | 2018 | Natural Gas | Combustion Turbine | FCA9 |

*Note: The Killingly Energy Center (a 550 MW NGCC) is not included on this list as it has not yet cleared the capacity market and is not under construction. Similarly, only the first half of the proposed Burrillville Energy Center is included here.*

[67] Battery storage is assumed to be added in Massachusetts starting in 2018, with incremental additions of 50 MW per year until 2020 and 100 MW per year from 2020 through 2024. Battery discharge duration is also assumed to increase over time, from 0.5 hours in 2018 to 4 hours in 2025. The entirety of the battery systems' capacity is assumed to be available to provide regulation starting in 2018. Battery capacity is considered "firm," or available to bid into the forward capacity market, once total discharge duration is at least two hours. More information on the MA DOER requirements is available at http://www.mass.gov/eea/pr-2016/administration-releases-energy-storage-report.html.

**Table 12. Storage additions**

| State | Plant Name | Utility | Capacity (MW) | Online Year | Fuel Type | Unit Type | Source |
|---|---|---|---|---|---|---|---|
| MA | Generic Battery I | TBD | 600 | 2025 | Battery | Storage | Based on MA DOER "State of Charge" Report |

### Unit retirements

Table 13, Table 14, and Table 15 list all announced unit retirements for the six New England states. Retirement data is based on the 2015 edition of EIA's Form 860, supplemented by ongoing Synapse research. Similar to the prescribed unit additions, the EnCompass model will dynamically retire unused capacity. Note that several units (i.e., at the Merrimack and Schiller power plants) listed in Table 13 do not have announced retirement dates as of yet and are listed for informational purposes only.

**Table 13. Coal retirements**

| State | Plant Name | Utility | Capacity (MW) | Year Offline | Fuel Type | Unit Type | Source |
|---|---|---|---|---|---|---|---|
| MA | Brayton Point 1 | Brayton Point Energy LLC | 241.0 | 2017 | Coal | Steam Turbine | EIA 860 2015 |
| MA | Brayton Point 2 | Brayton Point Energy LLC | 241.0 | 2017 | Coal | Steam Turbine | EIA 860 2015 |
| MA | Brayton Point 3 | Brayton Point Energy LLC | 642.6 | 2017 | Coal | Steam Turbine | EIA 860 2015 |
| CT | Bridgeport Station 3 | PSEG Power Connecticut LLC | 400.0 | 2021 | Coal | Steam Turbine | Announced by owner |
| NH | Merrimack 1 | Public Service Co of NH | 113.6 | None | Coal | Steam Turbine | EIA 860 2015 |
| NH | Merrimack 2 | Public Service Co of NH | 345.6 | None | Coal | Steam Turbine | EIA 860 2015 |
| NH | Schiller 4 | Public Service Co of NH | 50.0 | None | Coal | Steam Turbine | EIA 860 2015 |
| NH | Schiller 5 | Public Service Co of NH | 50.0 | None | Coal/ Biomass | Steam Turbine | EIA 860 2015 |
| NH | Schiller 6 | Public Service Co of NH | 50.0 | None | Coal | Steam Turbine | EIA 860 2015 |

*Note: Units at the Merrimack and Schiller power plants do not currently have announced retirement dates. These two plants represent the remaining coal capacity in New England and are listed for informational purposes only. The plant owner, Eversource, is under an NH Public Utilities Commission requirement to sell the Merrimack and Schiller plants by the end of 2017.*

**Table 14. Nuclear retirements**

| State | Plant Name | Utility | Capacity (MW) | Year Offline | Fuel Type | Unit Type | Source |
|---|---|---|---|---|---|---|---|
| MA | Pilgrim Nuclear Power Station 1 | Entergy Nuclear Generation Co | 670.0 | 2019 | Nuclear | Steam Turbine | EIA 860 2015 |

**Table 15. Natural gas and oil retirements**

| State | Plant Name | Utility | Capacity (MW) | Year Offline | Fuel Type | Unit Type | Source |
|---|---|---|---|---|---|---|---|
| MA | Brayton Point 4 | Brayton Point Energy LLC | 475.5 | 2017 | Oil | Steam Turbine | EIA 860 2015 |
| CT | Bridgeport Station 4 | PSEG Power Connecticut LLC | 18.6 | 2017 | Oil | Combustion Turbine | EIA 860 2015 |
| MA | Exelon L Street GT1 | Exelon Power | 16.0 | 2016 | Oil | Combustion Turbine | Electric Power Monthly |
| MA | Mass Inst Tech Cntrl Utilities/Cogen Plt CTG1 | Massachusetts Inst of Tech | 21.2 | 2019 | Natural Gas | Combustion Turbine | EIA 860 2015 |

### Incremental transmission

In all modeling runs, we assume that the ISO-NE transmission grid undergoes the same set of transmission upgrades that are described in Section 2.1.[68] In general, these transmission enhancements will result in a moderate amount of incremental North-South transmission capability, as well as alleviation of certain local area constraints. Scenarios 3 and 4 assume incremental transmission capability beyond these levels.

In each scenario, we assume that 90 percent of the 9.45 TWh of long-term contracts defined under Section 83 D of 2017's Energy Diversity Act is met through procuring long-term contracts with Canadian entities over new transmission lines.[69] Because the same transmission is implemented in all scenarios, we have not made any assumptions about where this transmission is placed or at what cost.

In the three scenarios in which Massachusetts establishes a Class I RPS growth rate of 3 percent per year alongside an increase in the Connecticut RPS of 1.5 percent per year, we assume that a new 1,200 MW HVDC transmission line is constructed between Maine and central Massachusetts in 2022 per "Project B" established in NESCOE's 2017 report *Renewable and Clean Energy Scenario Analysis and Mechanisms 2.0 Study*.[70] The upfront capital cost of such a project is estimated by NESCOE to be $1.75 billion, or $280 million per year over 20 years at a 16 percent carrying cost. In the three scenarios in which Massachusetts establishes a Class I RPS growth rate of 2 percent per year alongside an increase in the Connecticut RPS of 1.5 percent per year, we assume a smaller HVDC upgrade—600 MW—is required. In

[68] See Section 2.1 for more information. Transmission updates based on ISO-NE capacity zone planning process.

[69] See https://malegislature.gov/Bills/189/House/H4568 for more information.

[70] This report is available at http://nescoe.com/wp-content/uploads/2017/03/Mechanisms_PhaseI-ScenarioAnalysis_Winter2017.pdf. The annualized cost assumptions for "Project B" are heavily based on RLC Engineering's 2011 report for NESCOE *Transmission Costs for Interconnecting 3,000 MW of Windfarm Capacity in Western Maine and Coos County New Hampshire*, available at http://nescoe.com/wp-content/uploads/2015/08/SupplyCurve-Transmission_Report_18Oct2011.pdf. Note that this scenario assumed much more transmission—3,600 MW HVDC—was necessary to meet the renewable requirements in a scenario similar to this study's highest-renewable scenario. However, this study also assumed much more of this renewable capacity would take the form of Central Maine-based onshore wind.

these scenarios, we assume that the same number of substations are required as in NESCOE's 1,200-MW "Project B" at the same cost, but the cost associated with the lines themselves is decreased by 50 percent. This leads to an overall cost about two-thirds of the cost associated with the 1,200 MW project.

For job impact purposes, we assume that one substation each is located in Massachusetts and Maine and that 70 percent of this project's transmission line construction takes place in Maine, 22 percent in Massachusetts, and 8 percent in New Hampshire, in line with this project's expected right-of-way. For bill impact purposes, we assume that this project's annual carrying cost is allocated across the six New England states based two components: 70 percent of the cost is based on each state's demand as a share of the regional total and 30 percent of the cost is allocated according to the project beneficiaries (which is estimated based on each state's share of how many Class I RECs they consume out of the regional pool).[71] For Massachusetts, this results in an annual cost of $131 million per year for the 1,200 MW project and $85 million per year for the 600 MW project.

## Emission caps and carbon markets

Electric generators in the six New England states are subject to three different layers of emission caps: federal (in the Clean Power Plan), regional (under RGGI), and state-specific (under state-specific legislation, regulations, and targets like Massachusetts' Global Warming Solutions Act).

### *The Regional Greenhouse Gas Initiative*

The Regional Greenhouse Gas Initiative (RGGI) is a nine-state program consisting of the six New England states, Delaware, Maryland, and New York. RGGI imposes a decreasing cap on allowable $CO_2$ emissions from most electric generators of 2.5 percent per year until 2020. At this point, RGGI is expected to require more stringent emission limits for the nine-state region than allowed under the federal Clean Power Plan.[72]

A program review is currently underway to determine what should happen in the RGGI program for all years after 2020. In this analysis, we have assumed that that the 2020 cap is extended through 2030 and is not made more stringent in any future year. Because EnCompass only models emissions compliance for the six New England states (and not the other three RGGI participants) we have assumed that these states meet a RGGI cap in line with the total emissions cap for the six states (about 27 million short tons in 2020).[73] We have modeled this RGGI cap as an effective price of $3.55 per ton, the December 2016

[71] This transmission cost allocation is based on the determination made by FERC in Order 1000. See https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_2/oatt/sect_ii.pdf for more information.

[72] Given that the Clean Power Plan requirements for New England are expected to be less stringent than RGGI, it is not modeled in this analysis.

[73] This analysis will assume that all allowances are consumed in the year they are issued (i.e., no banking).

auction clearing price.[74] We assume that the existing policy structure (reserve price, etc.) and routine program reviews maintain the total region cap at a price level consistent with past behavior.

***State-specific emissions caps***

All six New England states have legislation, regulations, and/or targets requiring emission reductions through 2050 (see Table 16). Together, these policies coalesce at a level that requires economy-wide greenhouse gas emissions to reduce by 40 percent below 1990 levels by 2030. While all six states have put forth policies intended to reduce greenhouse gas emissions (including energy efficiency, renewable portfolio standards, and RGGI), only Massachusetts has proposed explicit regulations that are specific to its Global Warming Solutions Act (GWSA) legislation.[75] These proposed regulations will require natural gas generators in Massachusetts to reduce $CO_2$ emissions by 2.5 percent per year beginning in 2020. This analysis assumes that the Massachusetts-specific emissions caps proposed under 310 CMR 7.74 are in place.[76] In this analysis, we have modeled this regulation as an aggregate cap and have assumed that all existing and new generators subject to this cap may trade emissions allowances within the same trading pool.

Note that in this analysis, we have not included additional measures that result in the six states meeting their greenhouse gas emission reduction targets.

[74] The March 2017 auction cleared at $3.00 per short ton. The RGGI price is bounded on the lower end by a minimum reserve price, set at $2.15 for 2017, growing by 2.5 percent per year. See www.rggi.org for further details.

[75] See http://www.mass.gov/eea/agencies/massdep/air/climate/section3d-comments.html for more information on MassDEP's proposed regulations under Section 3(d) of the Massachusetts GWSA.

[76] Note that because of the regional nature of the New England electric market, while Massachusetts may achieve these in-state emission reductions, generation—and emissions—may increase in other adjacent states.

**Table 16. State greenhouse gas emission reduction targets, 2030 and 2050**

| State | 2030 Target | 2050 Target | Sources |
|---|---|---|---|
| Connecticut | 35-45% below 1990 | 80% below 2001 | 2030: Conf. of New England Govs. Resolution 39-1<br>2050: C.G.S. 22a-200a (enacted by H.B. 5600) (https://www.cga.ct.gov/2008/ACT/PA/2008PA-00098-R00HB-05600-PA.htm) |
| Maine | 35-45% below 1990 | 75-80% below 2003 | 2030: Conf. of New England Govs. Resolution 39-1<br>"Long-term" target; date not specified: Maine Rev. Stat. ch. 3-A §576(3) (enacted by PC 2003, C. 237) (http://legislature.maine.gov/statutes/38/title38sec576.html) |
| Massachusetts | 35-45% below 1990 | 80% below 1990 | 2030: Conf. of New England Govs. Resolution 39-1<br>2050: Mass.Gen.L. ch. 21N §3(b) (https://malegislature.gov/Laws/GeneralLaws/PartI/TitleII/Chapter21N/Section3) |
| New Hampshire | 35-45% below 1990 | 80% below 1990 | 2030: Conf. of New England Govs. Resolution 39-1<br>2050: 2009 New Hampshire Climate Action Plan (http://des.nh.gov/organization/divisions/air/tsb/tps/climate/action_plan /documents/nhcap_final.pdf) |
| Rhode Island | 35-45% below 1990 | 80% below 1990 | 2030: Conf. of New England Govs. Resolution 39-1<br>2050: Resilient Rhode Island Act of 2014, Sec. 42-6.2-2 (http://webserver.rilin.state.ri.us/Statutes/TITLE42/42-6.2/42-6.2-2.HTM) |
| Vermont | 35-45% below 1990 | 75% below 1990 | 2030: Conf. of New England Govs. Resolution 39-1<br>2050: 10 V.S.A. § 578 (enacted by S. 259) (http://www.leg.state.vt.us/docs/legdoc.cfm?URL=/docs/2006/acts/ACT168.HTM) |

# APPENDIX C. NATURAL GAS PRICE FORECASTS

In this analysis, we modeled two different natural gas prices: a medium natural gas, approximating the most-likely future for natural gas prices in New England, and a high natural gas price, approximating what prices would be in a future in which natural gas production and availability were more constrained.

## Projecting the price of natural gas

To calculate the medium natural gas price, we rely on NYMEX futures for monthly Henry Hub gas prices through December 2019.[77] For all years after 2019, we assume the annual average prices projected for Henry Hub in the AEO 2017 Reference case.[78] We have applied the trends in average monthly prices observed in the NYMEX futures to this longer-term natural gas price to develop long-term monthly trends.

Next, we apply the NYMEX futures price data for the basis price of the Algonquin Citygate from Henry Hub (i.e., the difference in price between Henry Hub and Algonquin Citygate) from March 2017 through December 2019.[79] For all months before 2020, the monthly NYMEX futures prices for Henry Hub have been added to the Algonquin Citygate basis to forecast Algonquin Citygate Prices. Using the average basis prices from each month in 2017 through 2019, we calculate the average monthly basis price for Algonquin Citygate from Henry Hub. For all months after 2020, the average monthly basis price for Algonquin Citygate are added to the forecasted monthly Henry Hub price.

For the high gas price sensitivity, we follow the same methodology, except instead of using the 2020-2030 prices as projected in the AEO 2017 Reference case, we use the annual average price change from the AEO 2017 low oil and gas resource and technology case. From 2019 to 2030, the Henry Hub natural gas price in this case is expected to grow by 5.0 percent each year, compared to 2.0 percent per year in the AEO 2017 Reference case.

Note that these price forecasts do not account for possible price changes associated with the completed Algonquin Incremental Market (AIM) expansion pipeline project or the proposed Tennessee Gas Pipeline – Connecticut Expansion, or the Atlantic Bridge pipeline projects, beyond what may be factored into the

[77] Henry Hub is the major trading hub for natural gas in the United States. NYMEX futures data is freely available at http://www.cmegroup.com/trading/products/

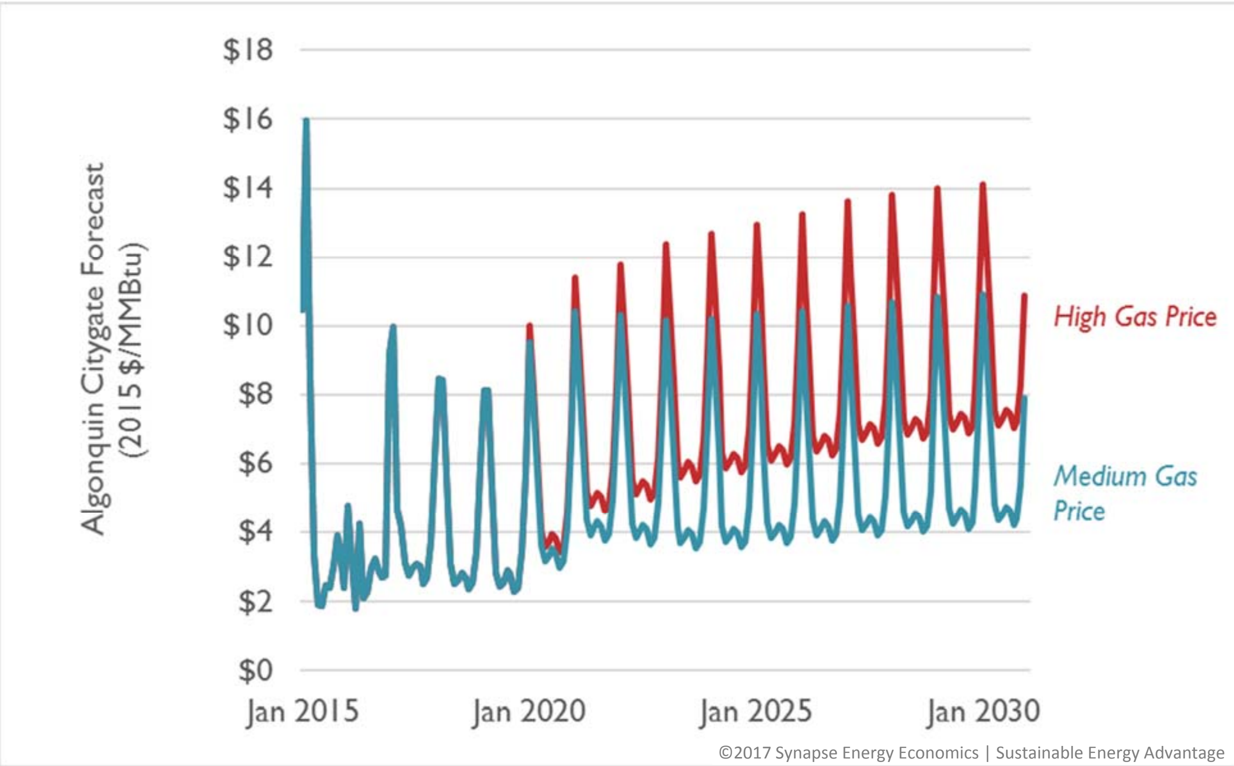
[78] From 2019 to 2030, the average annual price change for Henry Hub in the AEO 2017 Reference case and the AEO 2017 Reference case with No Clean Power Plan are almost identical (2.0 percent versus 1.8 percent, respectively).

[79] Algonquin Citygate is New England’s main pricing hub for natural gas used in electricity generation. Natural gas-fired units in Maine and New Hampshire are assumed to receive gas from the Dracut delivery point. However, Algonquin costs will be used as a proxy for Dracut costs due to a lack of independent pricing data.

NYMEX futures.[80] At this time, sufficient data is not available to determine the impact of the already-existing AIM expansion pipeline project or the possible impacts of the other two projects. These natural gas price forecasts also do not take into account possible annual or seasonal changes to natural gas prices resulting from changes to natural gas demand (such as those caused by increased renewables, new imports, or increased energy efficiency).

Figure 22 shows the monthly natural gas price forecast to be used in the medium and high scenarios.

**Figure 22. Monthly natural gas price forecasts**




In EnCompass, we model natural gas-fired generating units as receiving fuel from one of several delivery points, each of which has a different cost profile. Algonquin Citygate was assumed to be the delivery point for all units in the region, with the following exceptions: the Mystic combined-cycle plant in Massachusetts is assumed to receive LNG from the Everett terminal, and the Milford Power Plant and Bridgeport facilities in Connecticut are assumed to use the Iroquois delivery point.[81] As such, the Algonquin price impacts the delivered fuel costs of most of the fossil-fired units in New England.

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[80] We also do not make any assumptions regarding less-concrete pipeline project proposals like Access Northeast.

[81] In addition, gas-fired units in Maine and New Hampshire are assumed to receive gas from the Dracut delivery point. However, Algonquin costs are used as a proxy for Dracut costs due to a lack of independent pricing data.

# APPENDIX D. CAPACITY AND GENERATION DETAIL

**Table 17. Electric generating capacity detail (GW) for Massachusetts and New England (inclusive of Massachusetts)**

| | 2016 | 2030 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Base case | MA+2% | MA+2%, CT+1.5% | MA+3%, CT+1.5% | High Gas, Base case | High Gas, MA+2% | High Gas, MA+2%, CT+1.5% | High Gas, MA+3%, CT+1.5% | High EV, Base case | High EV, MA+2% | High EV, MA+2%, CT+1.5% | High EV, MA+3%, CT+1.5% |
| **MA** | **15.0** | **19.9** | **19.9** | **20.4** | **20.4** | **19.9** | **20.0** | **20.5** | **20.5** | **19.9** | **20.2** | **20.4** | **20.4** |
| **REC-eligible resources** | 8.5 | 8.5 | 8.6 | 9.1 | 9.1 | 8.6 | 8.6 | 9.2 | 9.2 | 8.6 | 8.9 | 9.1 | 9.1 |
| Biomass | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Hydro | 2.0 | 2.0 | 2.1 | 2.1 | 2.1 | 2.0 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 |
| Landfill Gas | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Solar: Distributed | 0.5 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 |
| Solar: Utility-scale | 0.6 | 3.8 | 3.8 | 4.0 | 4.0 | 3.9 | 3.9 | 4.0 | 4.0 | 3.8 | 4.0 | 4.0 | 4.0 |
| Wind: Offshore | - | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 |
| Wind: Onshore | 0.1 | 0.2 | 0.2 | 0.5 | 0.5 | 0.2 | 0.2 | 0.6 | 0.6 | 0.2 | 0.4 | 0.5 | 0.5 |
| **Other resources** | 11.7 | 11.3 | 11.3 | 11.3 | 11.3 | 11.3 | 11.3 | 11.3 | 11.3 | 11.3 | 11.3 | 11.3 | 11.3 |
| Natural gas CC | 6.4 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 |
| Natural gas CT | 3.5 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 |
| Coal | 1.1 | - | - | - | - | - | - | - | - | - | - | - | - |
| Nuclear | 0.7 | - | - | - | - | - | - | - | - | - | - | - | - |
| Battery | - | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 |
| **New England** | **36.1** | **43.7** | **43.9** | **45.6** | **47.7** | **44.2** | **44.2** | **45.8** | **48.0** | **43.8** | **44.8** | **46.3** | **48.5** |
| **REC-eligible resources** | 7.2 | 14.4 | 14.6 | 16.3 | 18.4 | 14.6 | 14.7 | 16.3 | 18.5 | 14.5 | 15.5 | 17.0 | 19.2 |
| Biomass | 0.7 | 0.6 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 0.8 | 0.9 | 0.9 | 0.9 |
| Hydro | 3.7 | 3.9 | 3.9 | 3.9 | 3.9 | 3.9 | 3.9 | 3.9 | 3.9 | 3.9 | 3.9 | 3.9 | 3.9 |
| Landfill Gas | 0.1 | 0.1 | 0.1 | 0.2 | 0.2 | 0.1 | 0.1 | 0.2 | 0.2 | 0.1 | 0.2 | 0.2 | 0.2 |
| Solar: Distributed | 0.7 | 1.3 | 1.3 | 1.3 | 1.3 | 1.3 | 1.3 | 1.3 | 1.3 | 1.3 | 1.3 | 1.3 | 1.3 |
| Solar: Utility-scale | 1.0 | 4.8 | 4.9 | 5.4 | 5.9 | 4.9 | 4.9 | 5.3 | 5.9 | 4.9 | 5.1 | 5.5 | 6.0 |
| Wind: Offshore | 0.0 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 |
| Wind: Onshore | 1.1 | 2.0 | 2.0 | 3.1 | 4.7 | 2.0 | 1.9 | 3.1 | 4.7 | 2.0 | 2.6 | 3.6 | 5.3 |
| **Other resources** | 28.9 | 29.3 | 29.3 | 29.3 | 29.3 | 29.5 | 29.5 | 29.5 | 29.5 | 29.3 | 29.3 | 29.3 | 29.3 |
| Natural gas CC | 13.9 | 15.9 | 15.9 | 15.9 | 15.9 | 15.9 | 15.9 | 15.9 | 15.9 | 15.9 | 15.9 | 15.9 | 15.9 |
| Natural gas CT | 8.8 | 9.1 | 9.1 | 9.1 | 9.1 | 9.1 | 9.1 | 9.1 | 9.1 | 9.1 | 9.1 | 9.1 | 9.1 |
| Coal | 2.0 | 0.3 | 0.3 | 0.3 | 0.3 | 0.5 | 0.5 | 0.5 | 0.5 | 0.3 | 0.3 | 0.3 | 0.3 |
| Nuclear | 4.1 | 3.4 | 3.4 | 3.4 | 3.4 | 3.4 | 3.4 | 3.4 | 3.4 | 3.4 | 3.4 | 3.4 | 3.4 |
| Battery | - | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 |

*Notes: In this table, "Biomass" includes biomass, biodiesel, and biogas. "Landfill gas" includes fuel cells, landfill gas, and low emission advanced renewables. "Hydro" includes standard hydroelectric generators, tidal power, and pumped storage (which is not eligible for RECs). Values shown as "0.0" are greater than 0 but less than 1; values shown as "-" are truly zero.*

**Table 18. In-state and in-region generation detail (TWh) for Massachusetts and New England (inclusive of Massachusetts)**

| | 2016 | 2030 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Base case | MA+2% | MA+2%, CT+1.5% | MA+3%, CT+1.5% | High Gas, Base case | High Gas, MA+2% | High Gas, MA+2%, CT+1.5% | High Gas, MA+3%, CT+1.5% | High EV, Base case | High EV, MA+2% | High EV, MA+2%, CT+1.5% | High EV, MA+3%, CT+1.5% |
| **MA** | **33.9** | **24.2** | **24.0** | **23.0** | **21.1** | **23.6** | **23.6** | **22.5** | **20.7** | **26.6** | **26.5** | **24.9** | **22.7** |
| **REC-eligible resources** | 3.9 | 12.7 | 12.8 | 14.0 | 14.2 | 12.8 | 13.0 | 14.3 | 14.2 | 12.8 | 13.3 | 13.9 | 14.2 |
| Biomass | 0.1 | 0.1 | 0.2 | 0.15 | 0.15 | 0.2 | 0.2 | 0.15 | 0.15 | 0.1 | 0.2 | 0.2 | 0.2 |
| Hydro | 1.7 | 1.0 | 1.1 | 1.14 | 1.35 | 1.0 | 1.1 | 1.25 | 1.41 | 1.1 | 1.1 | 1.1 | 1.3 |
| Landfill Gas | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 |
| Solar: Distributed | 0.7 | 1.1 | 1.1 | 1.1 | 1.1 | 1.1 | 1.1 | 1.1 | 1.1 | 1.1 | 1.1 | 1.1 | 1.1 |
| Solar: Utility-scale | 0.8 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 |
| Wind: Offshore | - | 4.7 | 4.7 | 4.7 | 4.7 | 4.7 | 4.7 | 4.7 | 4.7 | 4.7 | 4.7 | 4.7 | 4.7 |
| Wind: Onshore | 0.3 | 0.6 | 0.5 | 1.5 | 1.6 | 0.6 | 0.6 | 1.7 | 1.5 | 0.5 | 1.0 | 1.5 | 1.5 |
| **Other resources** | 30.0 | 11.5 | 11.1 | 9.0 | 6.9 | 10.7 | 10.6 | 8.2 | 6.4 | 13.8 | 13.1 | 10.9 | 8.6 |
| Natural gas CC | 22.4 | 11.1 | 10.7 | 8.6 | 6.3 | 10.3 | 10.2 | 7.7 | 5.8 | 13.3 | 12.6 | 10.5 | 8.0 |
| Natural gas CT | 0.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.1 | 0.0 | 0.0 |
| Coal | 1.5 | - | - | - | - | - | - | - | - | - | - | - | - |
| Nuclear | 5.8 | - | - | - | - | - | - | - | - | - | - | - | - |
| Battery | - | 0.4 | 0.4 | 0.4 | 0.6 | 0.4 | 0.4 | 0.5 | 0.7 | 0.4 | 0.4 | 0.4 | 0.5 |
| **New England** | **127.4** | **125.4** | **125.4** | **125.5** | **126.0** | **125.5** | **125.5** | **125.7** | **126.2** | **132.2** | **132.2** | **132.2** | **132.6** |
| **REC-eligible resources** | 17.3 | 30.7 | 32.6 | 36.7 | 42.3 | 32.2 | 32.5 | 36.8 | 42.4 | 31.7 | 34.7 | 38.6 | 44.6 |
| Biomass | 4.2 | 3.8 | 5.7 | 5.7 | 5.7 | 5.4 | 5.7 | 5.7 | 5.7 | 4.8 | 5.7 | 5.7 | 5.7 |
| Hydro | 7.3 | 7.3 | 7.4 | 7.5 | 7.5 | 7.3 | 7.4 | 7.6 | 7.5 | 7.4 | 7.4 | 7.4 | 7.8 |
| Landfill Gas | 0.8 | 0.8 | 0.8 | 1.2 | 1.2 | 0.8 | 0.8 | 1.1 | 1.2 | 0.8 | 1.1 | 1.1 | 1.1 |
| Solar: Distributed | 0.9 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 |
| Solar: Utility-scale | 1.3 | 6.3 | 6.3 | 6.8 | 7.4 | 6.4 | 6.4 | 6.7 | 7.5 | 6.3 | 6.4 | 6.9 | 7.5 |
| Wind: Offshore | 0.0 | 4.9 | 4.9 | 4.9 | 4.9 | 4.9 | 4.9 | 4.9 | 4.9 | 4.9 | 4.9 | 4.9 | 4.9 |
| Wind: Onshore | 2.8 | 5.8 | 5.8 | 9.0 | 14.0 | 5.7 | 5.7 | 9.1 | 14.0 | 5.8 | 7.5 | 10.9 | 15.9 |
| **Other resources** | 89.0 | 65.2 | 63.4 | 59.3 | 54.3 | 63.8 | 63.4 | 59.4 | 54.4 | 71.0 | 68.0 | 64.2 | 58.5 |
| Natural gas CC | 52.7 | 36.3 | 34.6 | 30.6 | 25.5 | 33.1 | 32.8 | 28.7 | 23.7 | 42.0 | 39.1 | 35.3 | 29.8 |
| Natural gas CT | 0.6 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.1 | 0.0 | 0.0 |
| Coal | 2.6 | 2.1 | 1.9 | 1.9 | 1.7 | 3.8 | 3.8 | 3.8 | 3.6 | 2.1 | 2.0 | 2.0 | 1.8 |
| Nuclear | 33.0 | 26.4 | 26.4 | 26.4 | 26.4 | 26.4 | 26.4 | 26.4 | 26.4 | 26.4 | 26.4 | 26.4 | 26.4 |
| Battery | - | 0.4 | 0.4 | 0.40 | 0.56 | 0.4 | 0.4 | 0.46 | 0.66 | 0.4 | 0.4 | 0.4 | 0.5 |
| **Imports** | 21.1 | 29.5 | 29.5 | 29.5 | 29.4 | 29.5 | 29.5 | 29.5 | 29.4 | 29.5 | 29.5 | 29.5 | 29.5 |
| New hydro | 0.0 | 8.5 | 8.5 | 8.5 | 8.4 | 8.5 | 8.5 | 8.5 | 8.4 | 8.5 | 8.5 | 8.5 | 8.5 |
| Other imports | 21.1 | 21.0 | 21.0 | 21.0 | 21.0 | 21.0 | 21.0 | 21.0 | 21.0 | 21.0 | 21.0 | 21.0 | 21.0 |

*Notes: In this table, “Biomass” includes biomass, biodiesel, and biogas. “Landfill gas” includes fuel cells, landfill gas, and low emission advanced renewables. “Hydro” includes standard hydroelectric generators, tidal power, and pumped storage (which is not eligible for RECs). Values shown as “0.0” are greater than 0 but less than 1; values shown as “-“ are truly zero.*