3. Regional and Environmental Evolution

REGIONAL ELECTRICITY MARKET

The New England states operate as a single electricity system managed by the New England Independent System Operator (ISO-New England). In this role, ISO-New England is responsible for both operating a wholesale power market and overseeing a long-term planning process to ensure that adequate generating capacity and transmission infrastructure is constructed for the future.

In the ISO-New England wholesale electric energy market, the price of energy is set by the marginal, most-expensive generating units supplying power at any given time. These marginal energy costs (prices) vary by location within New England taking into consideration local differences in losses and congestion on the transmission system. Because natural gas generation is the most prevalent supply source in the region, wholesale locational marginal prices (LMPs) track the price of natural gas delivered to New England fairly closely during most of the year with some notable exceptions, for instance when energy demand is very high in the winter season or when energy demand is low in the spring and fall season.

To supplement the wholesale energy market, ISO-New England also operates a wholesale capacity market. The Forward Capacity Market (FCM) is designed to provide an additional financial incentive (beyond revenues from the short-term energy market) to ensure that sufficient resources (power plants, demand side resources, or imports) are in place to meet peak energy demands. In the FCM, prices are established through an annual auction process for a period three years in advance. Subsequent to these annual auctions, additional reconfiguration auctions are conducted closer to the delivery period to address changes in supply and demand expectations (for example, updates to the regional demand forecast) that may occur in the intervening years.

In addition to the two primary short-term markets, ISO-New England also operates ancillary service markets (such as spinning reserve, frequency regulation, and black start) that maintain grid reliability through adjustments to supply and demand on time frames from a few seconds to a few hours. Figure 3-1 represents the scale in dollars of all of these markets in New England.[16]

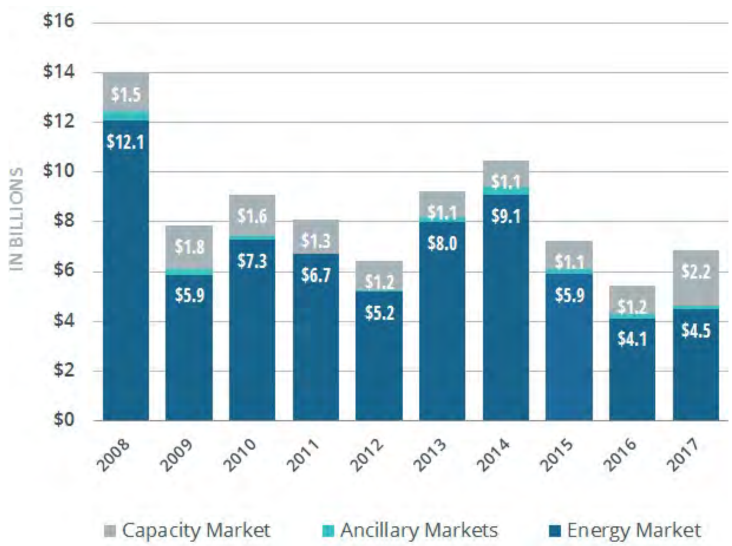

Figure 3-1. Annual Value of Wholesale Electricity Markets[17]

As Figure 3-1 demonstrates, energy is the dominate cost for load serving entities like GMP, showing significant year-to-year fluctuations based primarily on fluctuations in natural gas prices and weather (for example, polar vortex conditions during the 2013 and 2014 winters). However, capacity costs have represented a significant proportion of total wholesale costs in some periods. In 2017 in particular the capacity market price more than doubled, as retirements of significant existing generating capacity triggered the need for new generating capacity to be built in the region. Ancillary service costs are relatively small by comparison, but they do provide revenue opportunities for some resources (for example, battery storage, responsive load, quick-start generators) that are capable of responding quickly to changes in system conditions.

Regional wholesale market prices and trends like these are significant to us because the dominant share of our supply resources and energy needs all pass through and participate in the market. In addition, the conditions in the market and its prevailing

[16] For illustrative purposes, all energy, capacity, and ancillary services are supplied at spot market clearing prices.

[17] Source: ISO-New England.

prices influence the cost at which we can purchase additional supplies, irrespective of the fuel used to generate those supplies.

REGIONAL SUPPLY—EVOLVING RAPIDLY

In New England, the current generation fleet is composed of a variety of grid-connected resources, with the largest single type being natural gas-fired power plants. All together, these power plants represent approximately 30,000 MW of regionally installed generating capability. This amount is further supplemented by over 4,000 MW of import transmission connections to the neighboring New York, Québec, and New Brunswick control areas.

How the Energy Market Operates in New England

New England's wholesale electricity marketplace includes two electric energy markets that work together in what's called a multi-settlement system.

Day-Ahead Energy Market. Allows market participants to commit to buy or sell wholesale electricity one day before the operating day, which helps limit price volatility. This market produces one financial settlement.

Real-Time Energy Market. Allows market participants to buy and sell wholesale electricity during the course of the operating day. The Real-Time Energy Market balances the differences between day-ahead commitments and the actual real-time demand for the production of electricity. The Real-Time Energy Market produces a separate, second financial settlement. It establishes the real-time LMP that is either paid or charged to participants in the Day-Ahead Energy Market for demand or generation that deviates from the day-ahead commitments.[18]

In the last decade, the type and quantity of New England's generating supply has continued to change significantly with the addition of more new, efficient combined-cycle natural gas generators that helped drive a decrease in the amount of oil and coal generation that historically made up larger portion of the regions supply (see Figure 3-4).

In more recent years and over this IRP's planning horizon, the region's supply is expected to continue to evolve rapidly. In this next transition, however, renewable generating supplies (both grid-connected and distributed) are expected to represent the largest category of new supply. Since our 2014 IRP, there have been significant new wind resources and over 2,000 MW of new solar resources (mostly operating as behind-the-meter and not participating directly in the ISO-New England market) added to the region's energy supply. With continued support from state policies (such as Renewable Portfolio Standards (RPS), Vermont's Renewable Energy Standard (RES), and net metering laws), the supply contribution from these two categories is expected to more than double from current levels by the mid-2020s.

[18] For example, if we purchase 500 MWh of energy in the Day Ahead Energy Market to meet the estimated needs of our customers in a given hour, but 510 MWh was needed in that hour, we would purchase the 10 MWh difference in the Real Time Energy Market.

Beyond these new supplies of wind and solar, one of the most significant changes to the regional energy supply in the next few years could result from surrounding states' return to long-term supply procurements (requests for proposals) for substantial renewable and carbon-free energy in support of ambitious greenhouse gas reduction and renewable power goals.

For us, the implication of this return of the surrounding states to long-term planning and procurement—as opposed to procuring power overwhelmingly on a short-term basis from the wholesale market—could represent new opportunities for our energy portfolio as new supply proposals and resource developments are brought into focus for these large regional solicitations. Specifically, the potential transmission import projects (TDI, Vermont Green Line, and Granite State Power Link) that would deliver power to Vermont or through Vermont, and which have been proposed in response to RFPs in neighboring states, could present opportunities to Vermont through power purchase opportunities or other mechanisms (such as economic activity and financial payments to Vermont entities). At the same time, we will seek to understand the extent to which such large projects could pose reliability risks or economic risks for customers (in the form of congestion on the VELCO transmission system) and to ensure that such risks are effectively mitigated.

Current and Historical Generation Supply

Lower emitting sources fuel most of the region's generation. In 2017, natural gas-fired generation, nuclear, other low- or no-emission sources, and imported electricity (mostly hydroelectricity) provided roughly 99% of the region's electricity. New England's dependency on natural gas for electricity generation has grown significantly in recent years, and is expected to be continue well into the future. Figure 3-2 shows the share of electricity generated by natural gas increased from about 13% in 2000 to over 40% in 2017. The remainder of the region's energy supply comes from a combination of oil-fired, wind, hydroelectric, and nuclear power sources, with nuclear the second-largest source at over 20%, despite recent and announced retirements.

Figure 3-2. Annual New England Net Energy by Source[19]

* Total does not equal 100% because of rounding.

** "Other" represents resources using a fuel type that does not fall into any of the existing categories and may include new technologies or fuel types without sufficient quantity to have their own category.

While natural-gas-fired generation's proportion of the system capacity mix is expected to grow somewhat from 44.5% in 2017 to approximately 50.9% by 2020 (as new, efficient gas-fired capacity is scheduled to enter the market), the current situation where natural gas fuel prices typically set the marginal price for wholesale electricity is projected to continue over the planning horizon.

Two of the biggest changes in the region's resource mix since our 2014 IRP have been the announcement of the retirement of the Pilgrim nuclear energy plant in 2019 and the tremendous growth in regional solar photovoltaic (PV) capacity (mostly behind-the meter). Many of the potential retirements of older resources (mostly oil and coal) noted in our 2014 IRP have occurred (see our 2014 IRP, page 6-13) although since these plants did not operate frequently, their retirement has had little impact on the disposition of the region's energy supply.

[19] Source: ISO-New England *Net Energy and Peak Load by Source Report.*

Figure 3-3 represents the scale of developments in New England's transforming supply mix.

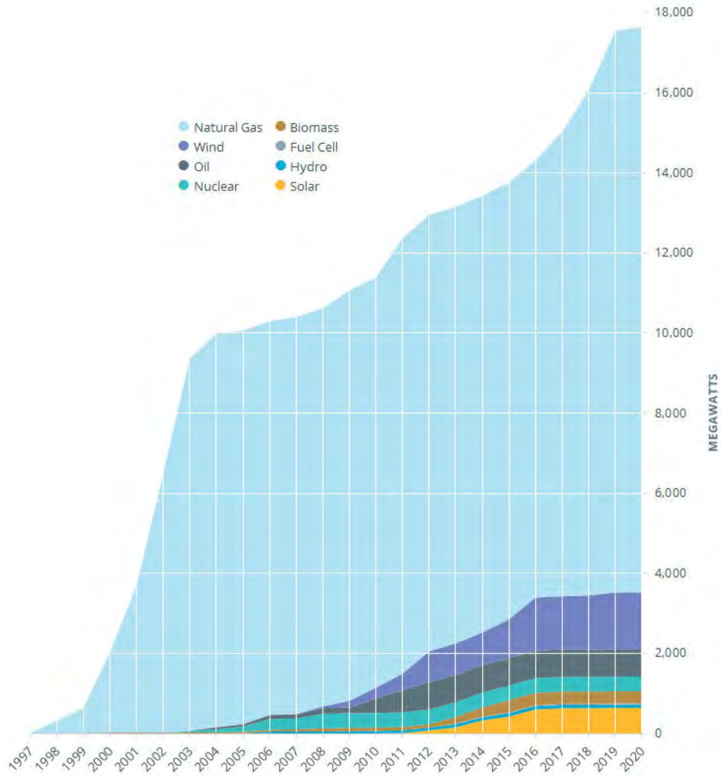

Figure 3-3. Cumulative New Generating Capacity in New England[20]

Note: New generating capacity for years 2016–2020 includes resources clearing in the recent Forward Capacity Auctions.

New Grid Scale Renewable Resources

Largely as a result of increasing state RPS goals and solicitations of large, long-term purchases—along with supportive rules for the development of distributed solar capacity at the state level—*the amount of renewable generation in the region is expected to increase substantially in the next decade*. This magnitude of growth in the renewable generation rate can have many implications for the operation of the energy market. Solar PV in particular is expected to have impacts ranging from the suppression of LMPs during sunny days and hours by reducing peak demands to greater price volatility driven by the fluctuations between sunny and cloudy periods. For wind resources, there is the potential that the large proposed offshore projects could supplant the need for costly oil-fired generation during the challenging winter months, meaningfully lowering prices while improving the region's emissions profile. Figure 3-4 and Figure 3-5 illustrate the potential growth in renewables and other resource types, although it is important to keep

[20] ISO-New England.

in mind that not all of the proposed volumes of various resources will necessarily be developed.

Many of these state-supported renewable policies are expanding over the planning horizon of this IRP, driving continued expansion of grid-scale renewables. One potential issue that could determine the pace and scale of this renewable development is the suitability and availability of transmission facilities to carry these resources from more remote locations (where they are proposed to be built) to where the energy is consumed.

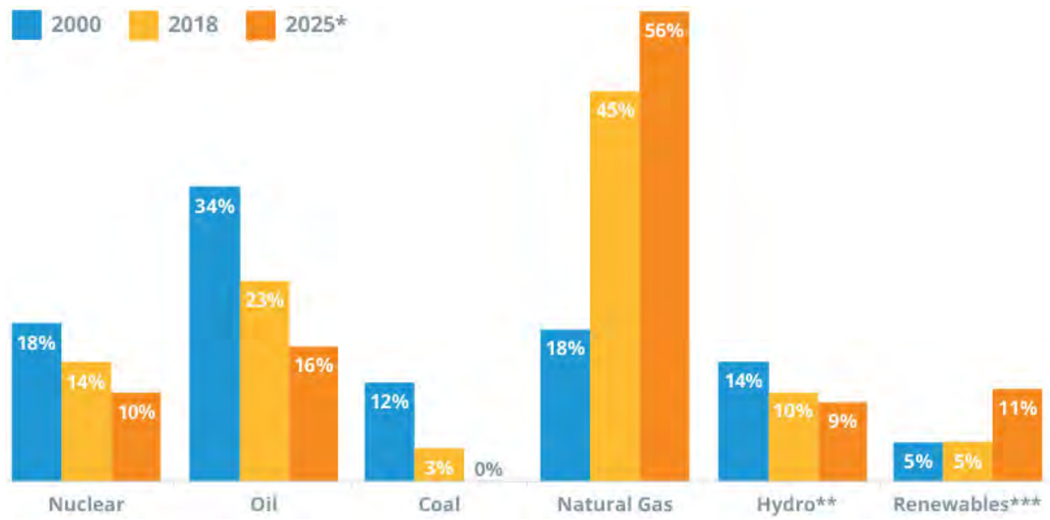

Figure 3-4. Percent of Total New England System Capacity by Fuel Type[21]

* 2025 values are hypothetical and assume new resources proposed in the ISO interconnection queue and non-price retirement requests for coal, oil, and nuclear resources as of early 2018. Values for coal, oil, and nuclear also reflect the possible loss of over 5,000 MW of generation at risk because of plant age and infrequent operation.

** Includes pondage, run-of-river, and pumped storage.

*** Resources and fuels include battery storage, landfill gas, methane, refuse, grid-connected solar, steam, wind, and wood. Hydro is not included primarily because the various sources that comprise hydroelectric generation are not universally defined as renewable in the six New England states. The nameplate capacity values of proposed grid-connected solar and wind projects were adjusted to reflect estimated actual generating capacity.

[21] ISO-New England

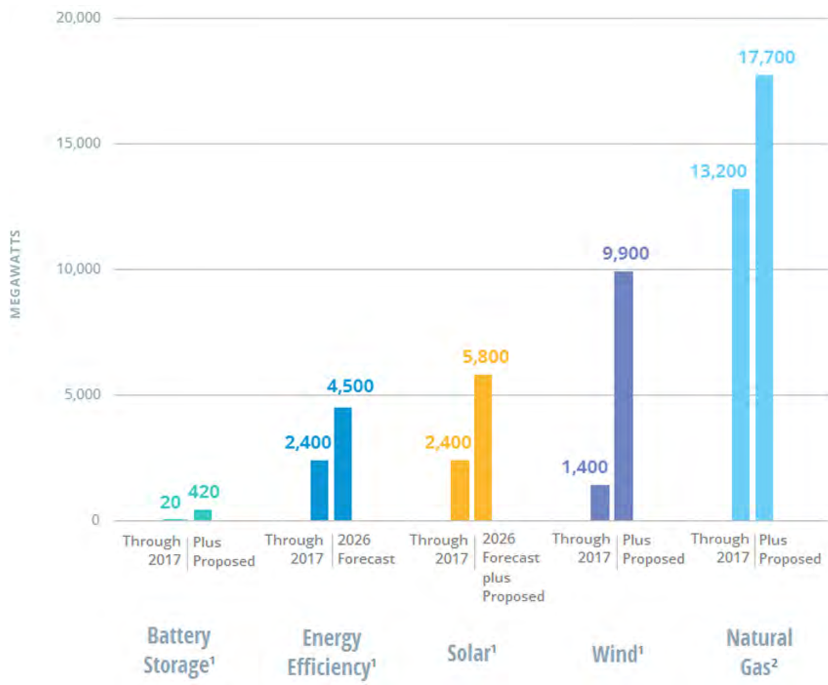

Figure 3-5. New England Efficiency and Power Resources with Significant Growth[22]

Note: Numbers are rounded. These figures include all proposed new projects; historically, however, almost 70% of proposed new megawatts in the ISO Generator Interconnection Queue are ultimately withdrawn and thus not built.

1 Nameplate capacity. Battery storage includes existing and proposed grid-connected resources. Energy efficiency includes resources participating in the capacity market, as well as forecasted future capacity. Solar includes existing and proposed grid-connected resources, as well as existing and forecasted behind-the-meter resources.

2 Nameplate capacity for proposed projects; summer season claimed capability for existing units is based on primary fuel type. This total does not include oil units that can switch to natural gas.

New Distributed Renewable Resources

For the first time, the most significant new supply of resources in the region is not coming from grid-scale developments. Instead, driven by state-specific goals and incentives at the retail customer level, solar PV resources are now being added at a significant rate as distributed, behind-the-meter resources connected to the distribution system. Already about 2,500 MW of solar is estimated to have been installed in the region (Figure 3-6), the vast majority being small-scale systems that are not connected to the regional high-voltage transmission system.

[22] Sources: ISO-New England; ISO-New England generator Interconnection Queue, January 29, 2018; CELT Report: 2010, 2016, 2017; Final 2017 ISO-New England Solar PV Forecast and Final Energy Efficiency Forecast Report for 2021 to 2026; and Seasonal claimed Capability Monthly Report, January 2018.

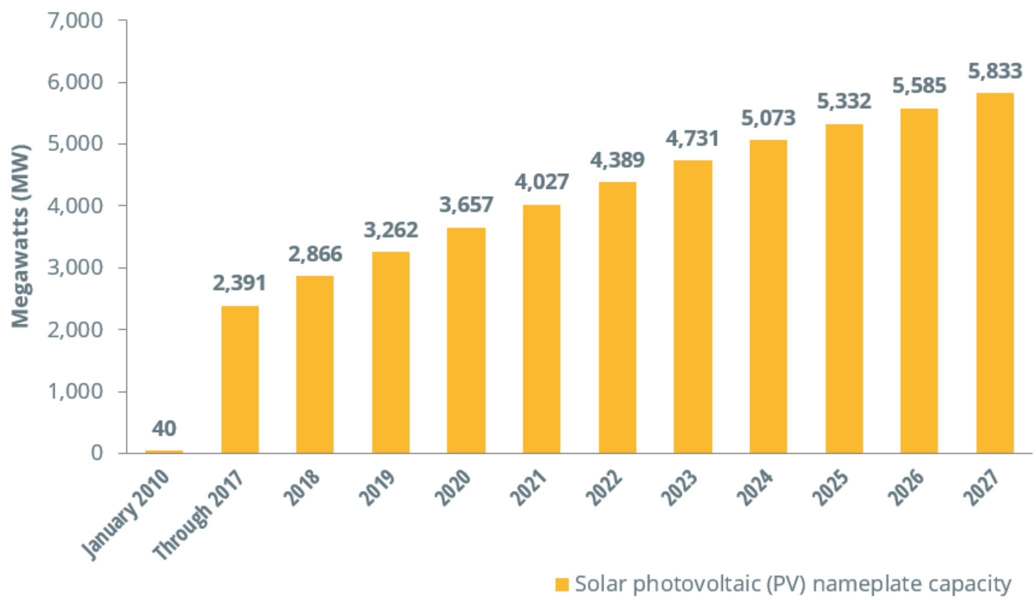

Figure 3-6. Projected Cumulative Growth in New England Solar Power: May 2018 Forecast[23]

Note: Amounts include PV connected behind-the-meter as well as PV participating in the wholesale electricity marketplace. Megawatt values are AC nameplate.

The growth in this category is expected to increase further during the planning horizon and represents one of the most significant transformational resources impacting the markets and the delivery of electricity to consumers. Unlike traditional supply, these behind-the-meter resources are tracked by the reductions they cause to the hourly energy needs on the bulk transmission system, displacing the need for grid-connected supply and lowering peak demands during the summer months. By 2025, ISO-New England predicts that these solar resources will double from the current amount to over 5,000 MW installed.

23 Source: ISO-New England *2018 PV Forecast*, May 2018.

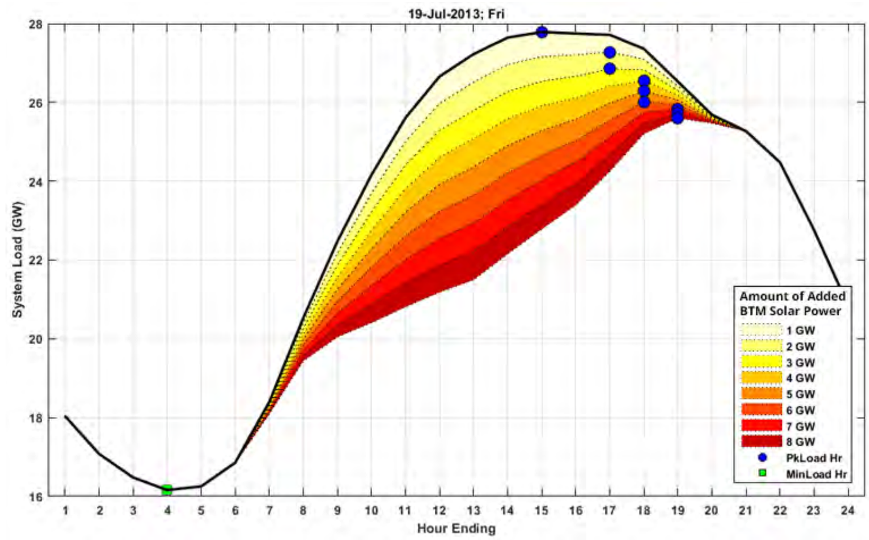

Figure 3-7. Summer Load Profile with Increasing Behind-the-Meter Solar Power[24]

Summer comprises the highest electricity use in New England, largely because of air conditioning. PV clearly helps "shave the peak" when the peak falls during the daylight hours. Greater amounts of PV will shift the timing of peak demand for grid electricity to later in the afternoon or evening (as illustrated in Figure 3-7), where increasing volumes of behind-the-meter solar would shift the ISO-New England peak hour from hour 15 to hour 17 and ultimately to hour 19. As a result, as PV penetration grows, its ability to reduce peak demand will diminish. Because regional capacity obligations are allocated to load serving entities like GMP based on their respective loads at the time of the annual ISO-New England peak, this trend is lowering the financial value of additional solar resources to our customers.

State-Sponsored Supply Procurements

Since our 2014 IRP, the surrounding states have also taken further steps into the long-term procurement of energy resources to make progress toward greenhouse gas emission reduction and renewable power goals, and to become less exposed to fluctuations in short-term ISO-New England market prices.

In the next five years, significant new generation supplies are expected to be added from this return to long-term procurement. Supplies from surrounding states include:

Massachusetts:

- Section 83C Offshore Wind Procurement: ramping from 200 MW installed in Q4 2022 to a cumulative total of 1,600 MW by 2030.

24 ISO-New England.

- Section 83D Clean Energy Procurement: 1,200 megawatts of transmission capacity to supply New England with power from reliable hydroelectric generation.
- Solar Massachusetts Renewable Target (SMART) Program: 1,600 MW no later than 2025.

Connecticut:

- Public Act 13-303 and Public Act 15-107.
- Section 8 of PA 13-303. This RFP allows for the procurement of up to 889,250 MWh per year, and it is geared toward offshore wind (capped at 825,000 MWh per year), fuel cells, and anaerobic digesters.
- Connecticut Low Emissions Renewable Energy Certificate (LREC) and Zero Emissions Renewable Energy Certificate (ZREC) Program.
- Connecticut Fuel Cell Procurement Program: 30 MW by 2021.
- Connecticut Solar Home Renewable Energy Certificate (SHREC) Program: 300 MW by 2023.

Rhode Island:

- Clean Energy RFP rolled into an assumed future procurement. Offshore wind procurement is also assumed. Rhode Island procurements are assumed separate from the Massachusetts 83D process: 80 MW of land-based renewables (25% wind, 75% solar) and 100 MW of offshore wind.
- Rhode Island Renewable Energy Growth Program: 160 MW of contracts by 2019, followed by 35 MW of contracts per year (net of contract attrition) through 2029.
- Net Metering: 100 MW in service by 2022 under virtual net metering.

Beyond impacting the carbon emissions profile of the region, these new planned supplies are expected to meaningfully impact energy and capacity prices. For the energy market, these supplies could reduce the impact of natural gas shortages in the winter months, lowering prices considerably. For capacity markets, these resources could ensure that the region has ample supply to meet peak demands, preventing FCM auctions from reaching price levels needed to create incentives for new fossil fuel peaking developments.

NEW ENGLAND MARKET PRICES

Energy Market Prices

In recent years and continuing into the planning period, the two main drivers of wholesale electricity prices in New England are the cost of fuel (mostly natural gas) used to produce electricity and the level of net consumer demand (electricity consumption plus grid losses, less output of distributed generation operation behind-the-meter) on an hour-by-hour basis.

	2012	2013	2014	2015	2016	2017	2018
Jan	$40.59	$86.53	$168.81	$71.14	$38.60	$40.30	$108.75
Feb	$30.92	$122.31	$156.02	$122.77	$29.90	$30.02	$39.58
Mar	$26.16	$53.09	$111.16	$64.25	$20.63	$35.75	$35.38
Apr	$25.88	$42.89	$44.98	$28.43	$28.36	$29.23	$45.00
May	$25.88	$40.31	$36.95	$24.92	$21.24	$27.31	$24.04
Jun	$34.75	$37.09	$37.92	$21.16	$22.61	$25.48	$26.82
Jul	$41.88	$52.07	$37.50	$26.44	$31.12	$27.60	$32.89
Aug	$38.53	$34.72	$30.35	$30.06	$35.54	$24.90	$39.16
Sep	$31.53	$40.43	$34.10	$30.82	$28.62	$23.57	
Oct	$35.27	$33.94	$32.19	$37.01	$21.98	$29.74	
Nov	$54.96	$45.21	$47.71	$29.42	$24.98	$33.98	
Dec	$46.30	$92.96	$43.00	$22.42	$53.28	$71.31	
Avg.	**$36.05**	**$56.79**	**$65.06**	**$42.40**	**$29.74**	**$33.27**	**$43.95**

Table 3-1. Average Monthly Day Ahead Locational Marginal Pricing[25]

Note: Locational Marginal Price points are color coded: green represents the lowest prices; yellow represents medium-level prices; and orange and red represent the highest prices. Thus, the table shows broad trends for prices throughout the year.

In New England, energy price is determined hourly by the marginal unit needed to satisfy the last increment of demand. In most periods, the last unit dispatched is a natural gas plant (over 50% of the generating plants are natural gas fired, and natural gas is estimated to be the region's marginal source during most hours). Thus, the price of natural gas on any given day usually is a key determinant of the hourly price of wholesale electricity. In the years since our 2014 IRP, the general downward trend in natural gas prices and in energy market prices has continued (Table 3-1, although with significant excursions). This decade-long trend has been driven largely by the national decline in United States gas costs brought about by the tremendous increase in shale gas production (see Figure 3-10). For New England, the Marcellus gas producing region has had the greatest influence with its creation of a large gas production hub in the eastern United States.

25 Source: *EnerNOC Insights*: September 2018 New England Monthly Market Commentary; page 4.

For New England, the result of this trend has been ample natural gas supply and moderate prices during non-winter months (as seen in Table 3-1). Figure 3-8 shows the history of wholesale energy prices by month as well as the relationship between the average wholesale electricity prices that prevailed and the price of natural gas available to the generating plants at that time. A notable exception to this gas-based pricing pattern occurs in the winter months where limited pipeline capacity into the region combined with very cold weather can create a condition where the flow of natural gas into New England is insufficient to fuel all of the gas plants. In these circumstances, spot market prices for natural gas in New England can soar to multiples of the prevailing prices in neighboring regions. Some natural gas plants must switch to backup oil fuel, while older, oil-fired and coal-fired generating plants are called into operation and often set the regional LMP far above typical levels. During 2014, 2015, and 2018, this situation occurred enough times to dramatically increase the prevailing price level across the winter months.

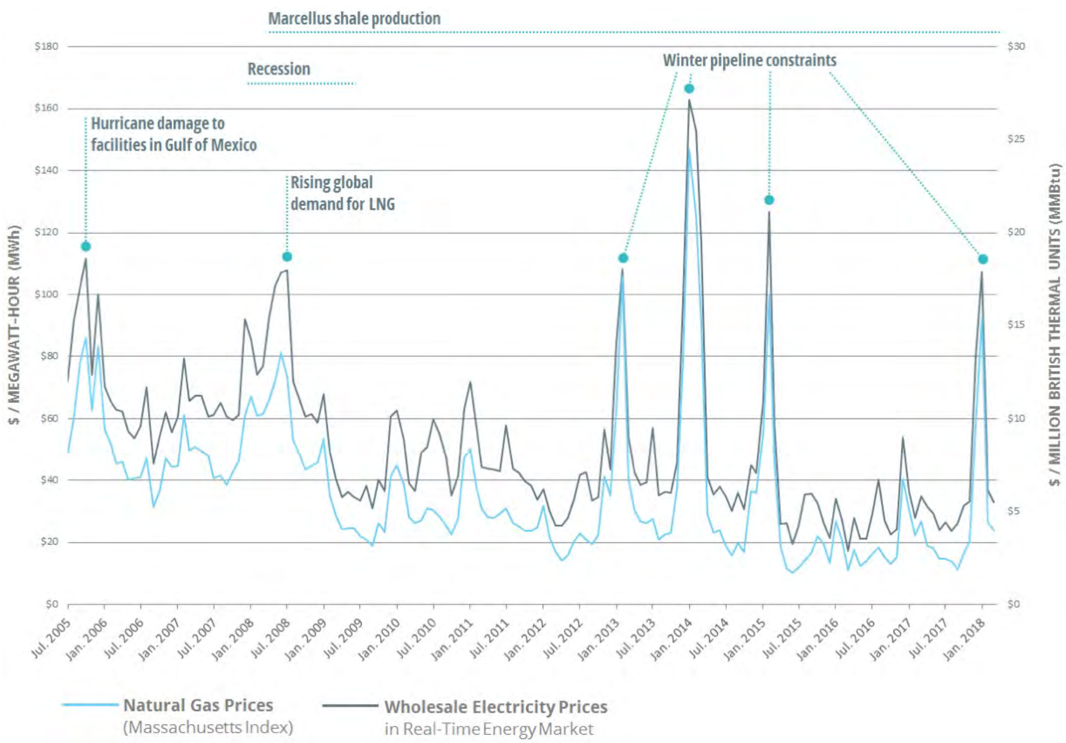

Figure 3-8. The Link Between Wholesale Electricity and Regional Natural Gas Prices[26]

Note: The Massachusetts index price is a volume-weighted average of trades at four natural gas delivery points in the state, including two Algonquin points, the Tennessee Gas Pipeline, and the Dracut Interconnect.

[26] Source: ISO-New England.

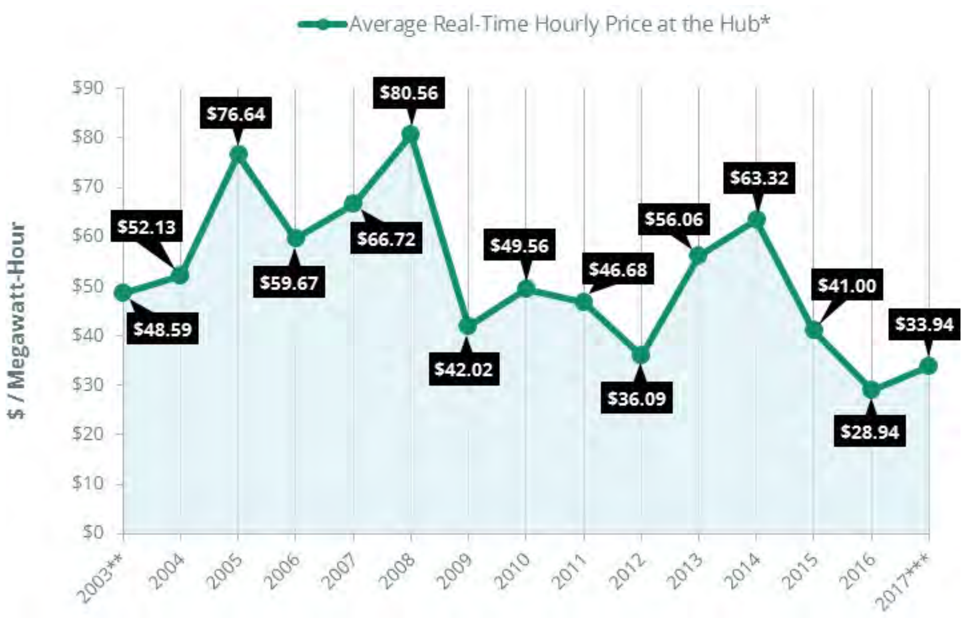

Figure 3-9. Average Annual Price of Wholesale Electricity in New England[27]

* The Hub is a collection of 32 locations in New England used to represent an uncongested price for electric energy. Starting on March 1, 2017, the value reflects the hourly average of five-minute locational marginal pricing.

** The Data start on March 1, 2003 with the launch of the redesigned wholesale electricity markets (that is, Standard Market Design).

Forward prices in the region tend to exhibit the same pattern of seasonal variation that has occurred in the spot market (Figure 3-9). This seasonal dichotomy is expected to continue and could become more pronounced to the extent that Solar PV dominates new resource additions.

Domestic Shale Gas Production

Gross production of natural gas in the United States has generally been increasing for more than a decade. This growth has been driven by production in the Appalachian Basin in the Northeast, the Permian Basin in western Texas and New Mexico, and the Haynesville Shale in Texas and Louisiana (Figure 3-10). These three regions collectively accounted for less than 15% of total U.S. natural gas production as recently as in 2007, but now they account for nearly 50% of total production.

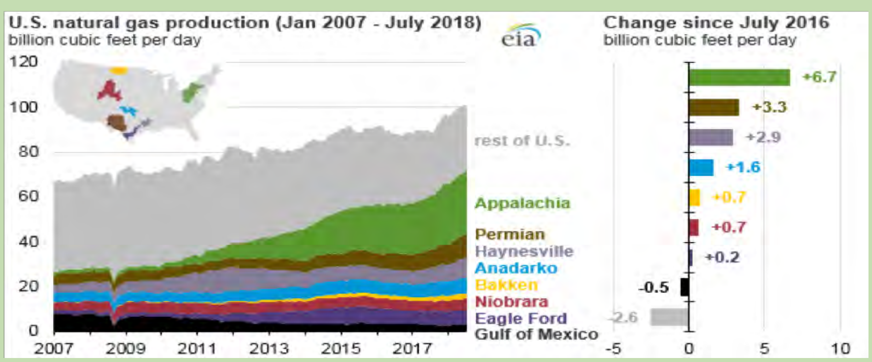

Figure 3-10. United States Natural Gas Production: January 2007–July 2018[28]

27 Source: ISO-New England.

28 U.S. Energy Information Administration (EIA).

Regional Greenhouse Gas Initiative

Current and future prices also continue to be influenced by the Regional Greenhouse Gas Initiative (RGGI) carbon trading program. Since our 2014 IRP, the nine-state program has continued to evolve. In 2017, a redesign extended the program through 2030. In the new program, changes are implemented to ensures there will be a moderate price for GHG emissions from major electric generators in New England and much of the Northeast.

In particular, changes have been made to:

- Add an accelerated annual base cap reduction of 3% per year from 2021 to 2030.
- Adjust the number of allowances auctioned in 2021–2025 by one-fifth of the 2020-ending allowance bank.
- Introduce of a new, dynamic price floor mechanism beginning in 2021 that withholds a finite number of allowances from an auction if prices fall below threshold levels.

Previously the program approach of implementing a gradual downward trend in the RGGI cap resulted in only a mild upward influence on energy prices in New England. A comprehensive national program has not yet materialized.

These changes to the RGGI (which we anticipate will result in slightly higher compliance costs) plus the implementation of a national program with national GHG emission reduction target to levels needed to address climate change, we expect, would have a significant impact on energy prices. This prospect and the new Vermont statutory framework established under RES make carbon emission reductions one of the most important long-term considerations in the design of our energy supply portfolio.

Capacity Market Prices

The goal of the capacity market is "to purchase enough qualified resources to satisfy the region's future electricity needs and allow enough time to construct new capacity resources." To accomplish this, Forward Capacity Auctions (FCAs) are held each year approximately three years before the commitment period or delivery year where the resources have an obligation to be ready to run when called on.

Ahead of each auction, ISO-New England determines the necessary volume to procure and creates sloped demand curves designed to ensure that the region procures sufficient capacity to meet its mandatory resource adequacy planning criterion. These demand curves are designed to raise capacity prices when the region needs new power resources (for example, as aging plants retire) and lower capacity city prices when there is sufficient or excess supply and additional capacity would not materially improve reliability.

One system curve specifies a price for each capacity level for the region as a whole. Separate zonal demand curves are also used to reflect the additional congestion price to be paid on top of the system capacity price for specific constrained capacity zones—geographic sub regions of New England that may be export-constrained or import-constrained.

Since the start of this capacity market in 2008, most of the annual auction outcomes have been administratively determined where prices were not allowed to drop below the pre-established floor price. In 2014, prices moved off the floor price and remained elevated for the next two auctions, as the retirement of significant existing generating capacity in the region led to the clearing of significant new capacity (combined cycle and combustion turbine plants) in FCA #7, FCA #8 and FCA #9 (Table 3-2). This rapid doubling in the annual capacity price for these years drove significant rate pressure for us and other load serving entities in the region, but it also stimulated significant activity on the supply side.

More recently, and following this sharp increase, we have seen the capacity auctions return to very low prices as no further supply has been needed and few older plants have retired. This pattern of boom and bust can be seen in the annual prices of capacity commitment payments (CCP) for the FCAs starting in 2010 and projected through 2022.

Year-to-year volatility of regional capacity costs is a significant exposure for us, making it appropriate to consider stable-priced forward capacity purchases and to deploy resources (such as controllable loads or battery storage) that can reduce our contribution to the annual ISO-New England peak load and associated share of regional capacity obligations.

Auction Commitment Period	Total Capacity Acquired (MW)	New Demand Resources (MW)	New Generation (MW)	Clearing Price ($/kW per month)
FCA #1 in 2008 for CCP 2010–2011	34,077	1,188	626	$4.50 (floor price)
FCA #2 in 2008 for CCP 2011–2012	37,283	448	1,157	$3.60 (floor price)
FCA #3 in 2009 for CCP 2012–2013	36,996	309	1,670	$2.95 (floor price)
FCA #4 in 2010 for CCP 2013–2014	37,501	515	144	$2.95 (floor price)
FCA #5 in 2011 for CCP 2014–2015	36,918	263	42	$3.21 (floor price)
FCA #6 in 2012 for CCP 2015–2016	36,309	313	79	$3.43 (floor price)
FCA #7 in 2013 for CCP 2016–2017	36,220	245	800	$3.15 (floor price) NEMA, Boston: $14.99
FCA #8 in 2014 for CCP 2017–2018	33,712	394	30	$15.00-new and $7.025-existing
FCA #9 in 2015 for CCP 2018–2019	34,695	367	1,060	System-wide: $9.55 SEMA, Rhode Island: $17.73-new & $11.08-existing
FCA #10 in 2016 for CCP 2019–2020	35,567	371	1,459	$7.03
FCA #11 in 2017 for CCP 2020–2021	35,835	640	264	$5.30
FCA #12 in 2018 for CCP 2021–2022	34,828	514	174	$4.63

Table 3-2. Annual Forward Capacity Auction Results

KEY DEVELOPMENTS IN MARKET DESIGN

Since our 2014 IRP, and largely as a result of the introduction of new renewable supplies into the market, there have been some notable changes in the structure of the ISO-New England markets. In the energy market, the most notable of these changes are the implementation of a market-based rationing system for renewable generation called Do-Not-Exceed (DNE) dispatch together with new operating procedures to ensure fuel security in the challenging winter months. In the capacity market, there are changes to include performance incentives called Pay-for-Performance and a change to allow state sponsored, "out-of-market" resource an ability to participate in the market (for example, the CASPR rule—see "Changes to Allow State Procurement Resource (CASPR)" on page 3-21).

Energy Market Changes

Do-Not-Exceed Dispatch and Negative Prices

In May 2016, ISO-New England implemented DNE dispatch changes to the market rules to incorporate wind and hydro resources into the economic dispatch and price formation process of the energy market. Now competitive energy offer prices are used to determine the economic dispatch of generating units, including during some conditions where transmission limits prevent all generators in an export-constrained area from operating at the same time. This new DNE method for curtailment eliminates the historical practice of manually curtailing resources in congested situations. These achievements are made possible by making better use of economic dispatch signals to manage transmission system congestion and minimizing the need to use manual curtailment processes.

One result of this DNE process is that sometimes the negative offer prices of generating plants (particularly renewable resources) that have a strong incentive to operate without curtailment can result in the prevailing marginal price for the entire region to be negative for a short time.

Figure 3-11 illustrates the frequency of negative energy price events in New England during 2017 and 2018, compared to electricity markets in some other countries.

Figure 3-11. Daily Negative Power Prices Worldwide: 2018–2019[29]

* Northeast Massachusetts, Boston zone, real time.

[29] Source: Epex Spot, National electricity Market of Australia, ERCOT.

As the supply of intermittent renewable sources increases in future years, the location of many of these resources in relatively remote areas of the transmission system could lead to more frequent instances of negative pricing in these export-constrained areas. As the proportion of zero- or negative-priced energy offers from renewable supplies grows relative to the amount provided by fossil-fuel-based units in the energy market, we are also likely to see increases in the number of negative pricing periods occurring across the entire region—especially during the hours and seasons that feature relatively low energy usage.

Negative energy pricing has also occasionally occurred in two instances: during daytime hours (afternoon minimum load periods, or when actual solar generation exceeds the intra-day forecast); and during hours when large thermal generating plants in the region are being started in anticipation of higher loads later in the day. The increasing occurrence of negative spot market energy price events would tend to be favorable for quick, flexible resources (for instance, some types of battery storage and responsive loads) that can consume additional energy if and when such events occur.

Fuel Security Initiatives to Address Winter Gas Pipeline Constraints

During the winter, regional gas distribution utilities have the first priority—called firm reservations—for the available capacity on the pipelines that carry natural gas into New England (Figure 3-12). During very cold periods when heating demand is high, this leaves very little to no non-firm pipeline capacity for electric generators. In recent years, this has meant that on the coldest days, thousands of megawatts of natural-gas-fired generation are unable to operate. The region then must rely on older, more expensive oil- and coal-fired power plants with stored fuel to meet hourly energy needs.

Many of these non-gas-fired power resources are slated for retirement and are facing greater restrictions to their operation for environmental reasons. As a result, concerns have emerged that steps need to be taken to address the reliability of the energy market in the winter. (For greater detail, see the January 2018 *ISO-New England Operational Fuel-Security Analysis*.)[30]

30 https://www.iso-ne.com/static-assets/documents/2018/01/20180117_operational_fuel-security_analysis.pdf.

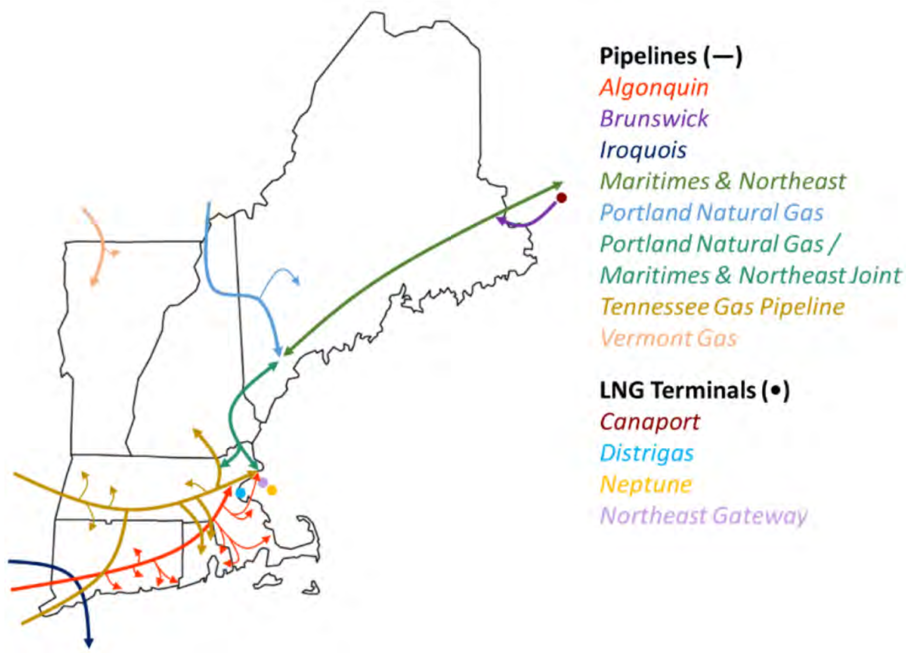

Figure 3-12. Regional Gas Distribution Patterns[31]

In 2018, ISO-New England took a significant step to seek an out-of-market cost recovery agreement for the large Mystic facility to keep it from retiring. The ISO is hoping this is only a short-term measure. In accordance with FERC's order in EL18-182-000, ISO-New England is developing improvements to the market design to better address regional fuel security for the long term.[32]

Forward Capacity Market

Pay-for-Performance

As foreshadowed in our 2014 IRP, ISO-New England has now implemented a significant modification to the FCM known as Pay-for-Performance. This approach more closely aligns the capacity payment a resource receives with its performance during critical periods. When a critical event occurs, a capacity resource that over-performs relative to its obligation will receive an additional capacity payment collected from underperforming units. These changes were approved in 2014 and first included in capacity obligations awarded through Forward Capacity Auction #9, which took effect in June 2018. This Pay-for-Performance construct is expected to reward generating units that can start quickly and reliably if a scarcity event occurs, reliable baseload units (which may already be generating during a scarcity event), and potentially intermittent renewable

[31] Source: *Avoided Energy Supply Components in New England: 2018 Report*, Synapse Energy Economics, Inc., March 30, 2018; page 34.

[32] A specific proposal is required by July 1, 2019.

generators if their typical output exceeds their seasonal FCM capacity obligation. Generators that require many hours to start up, cannot start reliably, or tend to have high unplanned outage rates will be penalized.

The first shortage event triggering a pay-for-performance settlement in 2018 occurred on the Labor Day holiday shortly after the implementation. In this event, the region was in a Capacity Scarcity Condition for about two hours and 40 minutes. Underperforming resources were penalized at a rate of $2,000 per MWh for failing to meet their capacity obligation during energy shortfalls, while resources that over-performed (including resources with no obligation) received $2,000 per MWh of additional revenue. While it remains to be seen if these types of events become associated with the fuel security concerns identified for the winter months, the frequency of these events will likely have significant bearing on the economics of continuing to operate the older, oil-fired units in the region. Our capacity resources performed well during this event. We did not incur any significant penalties or receive significant supplemental payments. Some resources (particularly our wind resources) over performed on their expected capacity obligations enough to offset the unavailability of one of our fuel units that was out for maintenance and unable to respond.

Changes to Allow State Procurement Resource (CASPR)

To accommodate resources that are being added to the regional supply through state-sponsored solicitations, ISO-New England is making changes to the rules for participating in Forward Capacity Auctions. Under the CASPR rule change, ISO-New England is now conducting each FCA in two stages. In the primary auction, ISO-New England clears the FCA (as it currently does) with limited opportunity for new units with support coming from policy arrangements outside of the ISO market to clear. In the secondary stage, ISO-New England administers a voluntary Substitution Auction immediately following the primary auction where these state-sponsored resources can purchase a capacity obligation. In the Substitution Auction, existing generation resources willing to permanently leave the markets could elect to transfer their Capacity Supply Obligations (CSOs) to state-sponsored policy resources that did not acquire CSOs in the primary stage.

The result of this change is a two-settlement system whereby new resources can clear the FCA and exiting resources can receive a retirement payment. With this change, ISO-New England hopes state-sponsored renewable energy resources can participate in the important New England capacity market (thus increasing their deployment and cost-competitiveness) without eroding the competitive dynamics of that FCM. We expect to monitor the Substitution Auction to determine whether, in the event that an existing oil-fired peaking unit is reaching the end of its economic life, sale of a capacity obligation could provide additional value to our customers.

REGIONAL MARKETS FOR RENEWABLE ENERGY

State policymakers in New England and across the country support the integration of renewable energy through a combination of supply-side and demand-side initiatives. In New England, title to the descriptive characteristics of renewable energy purchases, and compliance with RPS obligations, are demonstrated through the purchase and retirement of Renewable Energy Certificates (RECs). The supply, demand, and price dynamics and expectations in New England REC markets are distinct from the other New England markets and have grown in importance for our resource portfolio.

All six New England states have active RPS or RES policies. Each RPS program has multiple Classes—referred to as Tiers in Vermont—which are used to differentiate purchase obligations by technology, vintage, emissions, and other criteria, based on state-specific policy objectives. Regional Class I[33] requirements (as well as Class II in New Hampshire and Tier II in Vermont) are intended to create demand for new renewable energy additions. As a result, the RPS targets for these classes increase each year, either until a specified maximum obligation is reached, or indefinitely (as in Massachusetts).

RPS eligibility varies by state and Class, creating complex relationships among the New England states and between New England and adjacent control areas.[34]

33 Referred to as "New" in Rhode Island.

34 New York ISO (NYISO), Québec, and New Brunswick.

Figure 3-13 depicts the overlapping eligibility of RPS policies in New England. In other words, the eligibility for Tiers or Classes in the various states are sometimes the same, and sometimes unique. For instance, Vermont Tier II has the same eligibility requirements as Maine Class I, although Maine has additional eligibility requirements. While Vermont Tier I has the same eligibility requirements as Connecticut Class II, Maine Class II, and Rhode Island New class, it doesn't share any of the eligibility requirements of Class I in any other New England state. Finally, the regional market can interact because of these partially overlapping eligibility requirements.

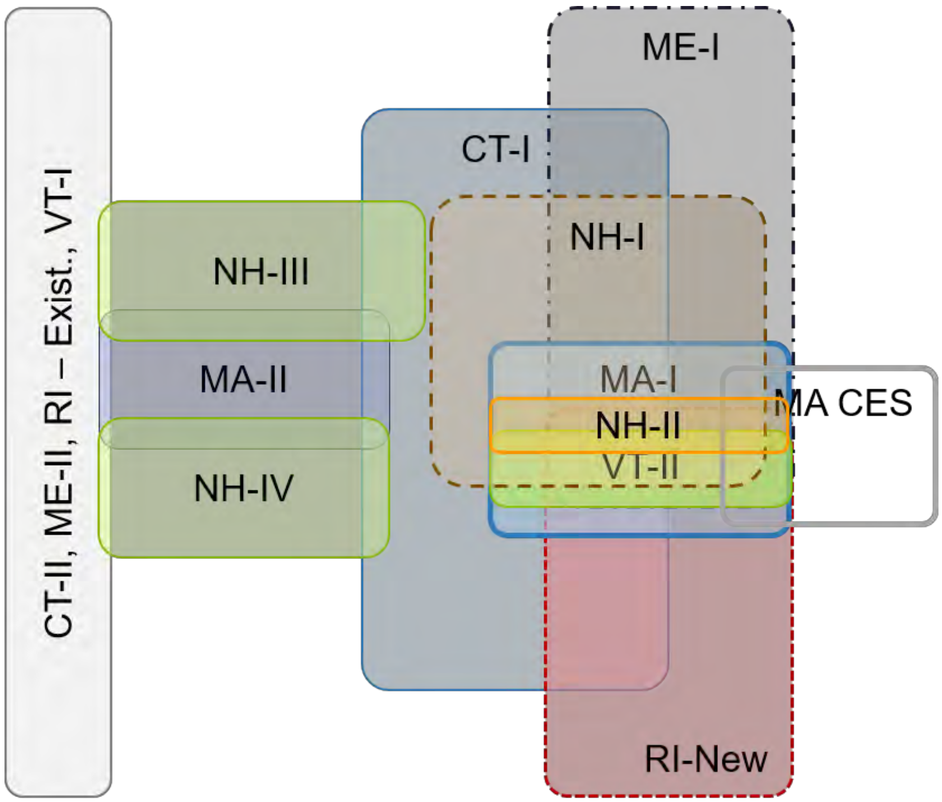

Figure 3-13. New England RPS Eligibility Map[35]

Since the Class I RPS compliance began in 2003,[36] the market has demonstrated that small differences in eligibility can cause state-by-state REC prices to either converge or diverge as supply and demand conditions vary over time. We have historically been a significant seller of RECs to the Class I markets in Massachusetts and Connecticut for customers, and to a lesser degree the Massachusetts Class II market.

[35] Source: Sustainable Energy Advisors (SEA).

[36] Maine Class 2 compliance began in 2000. The legislature defined supply eligibility to dramatically exceed demand, however, resulting in surplus conditions and permanently suppressed REC prices.

REGIONAL MARKETS FOR NEW RENEWABLES

Historic Conditions in Class I RPS and REC Markets

Early RPS markets were characterized by shortages, as Class I demand—driven by state policy—grew faster than new renewable energy supply. As a result, Class I RECs were transacted in the short-term bilateral market (which resembles a spot market) at prices just below the administratively-determined price cap—referred to as the Alternative Compliance Payment. Periodic price-variability in early RPS markets was largely driven by adjustments to legislation or regulation. Such changes often had dramatic effect because of their ability to add (or less frequently, subtract) eligible supply overnight by granting eligibility to facilities already in service.

Figure 3-14 uses historical Connecticut Class I REC prices to illustrate the impact of legislative and regulatory adjustments to existing polies. In Connecticut's case, policymakers granted eligibility to additional sources of existing supply in mid-2005, and again in mid-2008. These regulatory adjustments were the primary contributors to price declines observed in the Connecticut Class I market in those years.

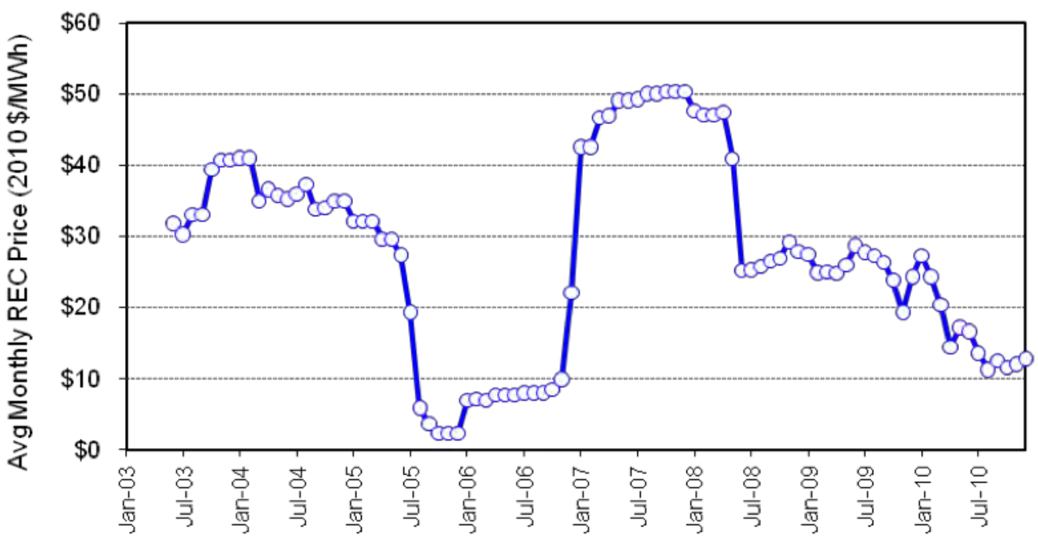

Figure 3-14. REC Price Volatility Example Resulting from Legislative or Regulatory Adjustment[37]

Note: Plotted values are the last trade (if available) or the mid-point of Bid and Offer prices for the current or nearest compliance year.

37 Chart data source: Evolution Markets and Spectron.

Current Conditions in Class I RPS and REC Markets

By comparison, the Class I market is currently experiencing a surplus of supply over demand. Between 2015 and 2018, regional Class I supply caught up to and surpassed demand. As a result of these new surpluses across the region, Class I markets concluded the 2017 compliance year with RECs trading below $10 per MWh.

This dynamic is in dramatic contrast to historic shortages and high REC prices, and is primarily driven by three factors:

1. Long-term procurements of Class I supply quantities that exceed current and future incremental demand, based on current RPS targets. These procurements originate almost entirely from Massachusetts, Connecticut, and Rhode Island.
2. Aggressive distributed generation policies, which have been implemented effectively, and have resulted in hundreds of MWs of Class I supply, much of which is interconnected behind the retail meter and also reduces load.
3. Reductions in current and expected load. ISO-New England is producing lower region-wide load forecasts each year—a function of consumption behavior, energy efficiency penetration, and on-site generation.

Figure 3-15 summarizes the REC price declines between 2015 and 2018.

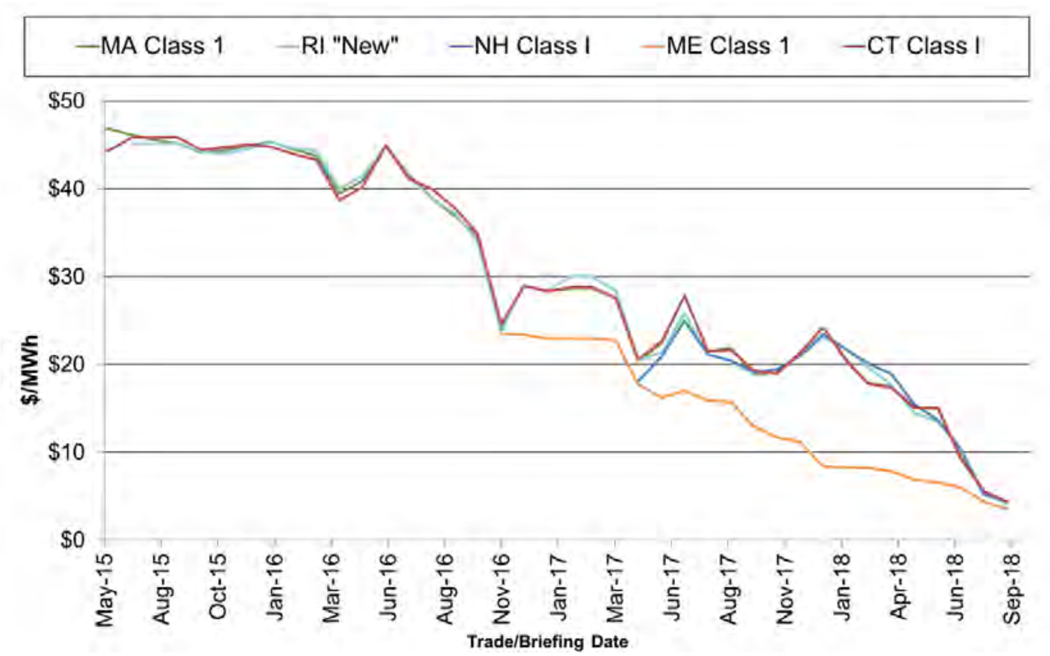

Figure 3-15. New England Class I REC Spot Market Prices: 2015–2018[38]

[38] Source: Sustainable Energy Advisors (SEA).

Current market conditions underscore that historical REC prices should not be used to set expectations for future revenues. Over the IRP planning period, we expect that the evolution of regional supply and demand dynamics will continue to create REC price uncertainty, leading to variability for GMP and our customers. The current surplus in regional Class I REC markets is expected to persist for at least the next five years.

These conditions are driven primarily by:

- Overestimating the annual load in each of the last several years, and the expectation for year-over-year reductions in actual load compared to recent ISO forecasts.
- Recent policymaker actions to support the continued operation of five existing New Hampshire biomass facilities for the next three years—and, in one case, through 2022.
- The continued success of regional distributed generation policies.

Over this period, prices for RECs produced by projects currently in operation[39] are expected to be substantially below historical levels.

Moderating this trend in surplus Class I resource, the new Massachusetts Clean Energy Standard (CES) is expected to create modest upward pressure on REC prices from approximately 2020 to 2022. The ultimate impact of Massachusetts CES demand will depend on the degree of continued load declines, energy efficiency deployment, and distributed generation penetration in the near term, and the date on which CES-eligible hydroelectric generation is ultimately delivered to New England over new transmission.

Beyond 2022 and the influence of the CES, the primary drivers of the expectation for continued regional Class I market surplus include:

- The selection of 1,400 MW of offshore wind developments.
- Massachusetts' additional authority to solicit up to 2,400 MW of additional offshore wind.
- Existing contracts with hundreds of MWs of competitively procured onshore renewable energy resources that have not yet—or only recently—come online.
- Forecasted reductions in New England load.

[39] New projects may be able to secure higher REC prices through competitive solicitations for long-term contracts aimed at projects not yet in operation.

Key Market Uncertainties

Uncertainty in regional Class I REC markets can be attributed to several primary factors, summarized in Table 3-3.

Key Uncertainty: Primary Contribution	Near-Term	Long-Term
Will Maine terminate its Class I RPS after 2022?	✓	
Will Massachusetts add capacity blocks to the SMART policy?	✓	
When will Connecticut implement the biomass REC-MWh phase-down?	✓	✓
Will New York RES Tier I demand trigger exports from New England?	✓	✓
New England project delay or attrition.	✓	✓
Energy and capacity market pricing.	✓	✓
Continued energy efficiency and consumption behavior.	✓	✓
Additional potential changes in RPS demand targets.	✓	✓
Will New York adopt a Tier II policy, causing supply to remain in that state?		✓

Table 3-3. Near-Term and Long-Term Regional Class I Rec Market Uncertainties

As of late 2018, regional renewable energy supply and demand policies are out of alignment. The supply-side policies are expected to produce substantially more RECs than are currently called for by incremental RPS demands. While Massachusetts, Connecticut, and Rhode Island have all either increased or extended their Class I RPS targets in recent years, these increases have not matched new renewable energy supply commitments. We also observe that the supply of new renewable energy in the region has become increasingly dependent on a small number of large projects (for example, offshore wind and import projects delivering energy from outside New England), as opposed to a larger number of smaller projects as was the case in past years. This raises the potential for significant, discrete movements in REC market prices in future years depending on whether or not those large projects reach completion on time.

REGIONAL MARKETS FOR EXISTING RENEWABLES

Vermont Tier I and other existing renewable supply obligations apply to facilities that were already in operation prior to the adoption of RPS and RES programs. Regionally, this type of renewable energy policy has been promoted to maintain the current fleet of renewable, carbon-free resources that tend to be cost-effective, rather than spur greater development of new generating facilities at potentially higher cost. Existing classes cover a wide range of technologies, including but not limited to: hydroelectric, biomass, landfill gas, waste-to-energy, and—in some cases—combined heat and power. Overall, the existing renewable market supply is expected to be adequate for the demand, with REC prices sufficient to keep the existing fleet in operation, but not enough to create incentives for new development.

Because of the more static supply and demand relationship in the existing renewable market, policy-based adjustments to either supply eligibility or demand targets can alter market dynamics quickly. While historical REC prices in existing markets have remained largely stable, it is possible that state-level preferences and objectives (more than market forces) could spur a policy adjustment that causes REC prices in existing RPS classes to increase in future years.

We believe it important to monitor market conditions and dynamics to determine if:

- Production variances based on resource availability may have an impact on REC prices, particularly in the short-term.
- The sum of energy, capacity, and REC prices could be insufficient to cover operating expenses for some existing plants.
- The cost and effort required to maintain RPS certification impacts participation (for example, LIHI) could limit supply.
- Changes in the role of imports and exports could impact supply, demand, and price dynamics.

In our experience, Tier I-eligible RECs tend to be available on a long-term basis only when bundled with the output of a renewable facility (that is, through a long-term PPA or asset purchases). REC-only purchases tend to only be available on a short-term basis (that is, up to a couple of years at a time).

For Vermont Tier I, during the planning period, REC prices are expected to reside within the range of approximately $1 to $9 per MWh. Prices at the low end of this range represent a market in which the majority of existing supply continues to operate, and demand for existing RECs in neighboring states remains stable. Prices at the high end of this range reflect a future with a combination of attrition among existing generators and increased demand—including both compliance and voluntary markets—in neighboring states that leads to higher REC prices. For Vermont Tier I, REC price risk is bounded by a $10 per MWh alternative compliance payment. The range between these values represents a market characterized by modest demand increases, most likely as a result of increased demand for both new and existing renewables by corporate and institutional purchasers.