6. Regional Context for the Resource Plan

New England's electric power sector continues to evolve under the influence of both long and short-term trends. Long-term trends include increasing reliance on natural-gas-fired generation and the moderation of load growth. Shorter-term trends include recent policy developments such as the New England States Committee on Electricity's (NESCOE) Initiative, which proposes to develop new infrastructure that would enable additional natural gas and renewable energy imports to New England.

This chapter presents a summary of these regional market trends from the perspective of La Capra Associates (LCA), whose consulting practice and market modeling expertise is well-established in New England and other regional markets. The following sections provide an outlook on the demand, supply, and transmission of electricity at the regional level, as well as outlooks for the wholesale markets for energy and capacity. The chapter concludes with LCA's 20-year market price forecast from its Northeast Market Model (NMM).

6.1 Regional Demand

Forecasted Peak and Energy Load

Each year ISO-NE prepares a 10-year forecast of New England's peak load and energy demand as part of its Capacity, Energy, Loads, and Transmission (CELT) report. The 2014 CELT[1] report forecasts energy and peak load before the effects of future state energy efficiency programs[2]. This forecast is known as the 'gross load forecast' for purposes of this report. The next two figures show that ISO-NE forecasts the summer peak load and annual energy load to grow over the next decade at compound annual growth rates (CAGR) of 1.3 percent/year and 1.0 percent/year respectively. Key drivers of the forecast demand growth include economic growth, Federal Electric Appliance Standards, and air conditioning penetration.[3]

[1] "2014 CELT Report", ISO-NE, http://iso-ne.com/trans/celt/report/2014/index.html.
[2] ISO-NE refers to energy efficiency as passive demand resources (PDR).
[3] For more, see "Forecast Model Structures of the ISO New England Long-Run Energy and Seasonal Peak Load Forecasts" available at http://www.iso-ne.com/trans/celt/fsct_detail/2014/forecast_model_structures_2014.pdf.

Figure 6.1.1: Gross New England Coincident Peak Load Forecast[4]

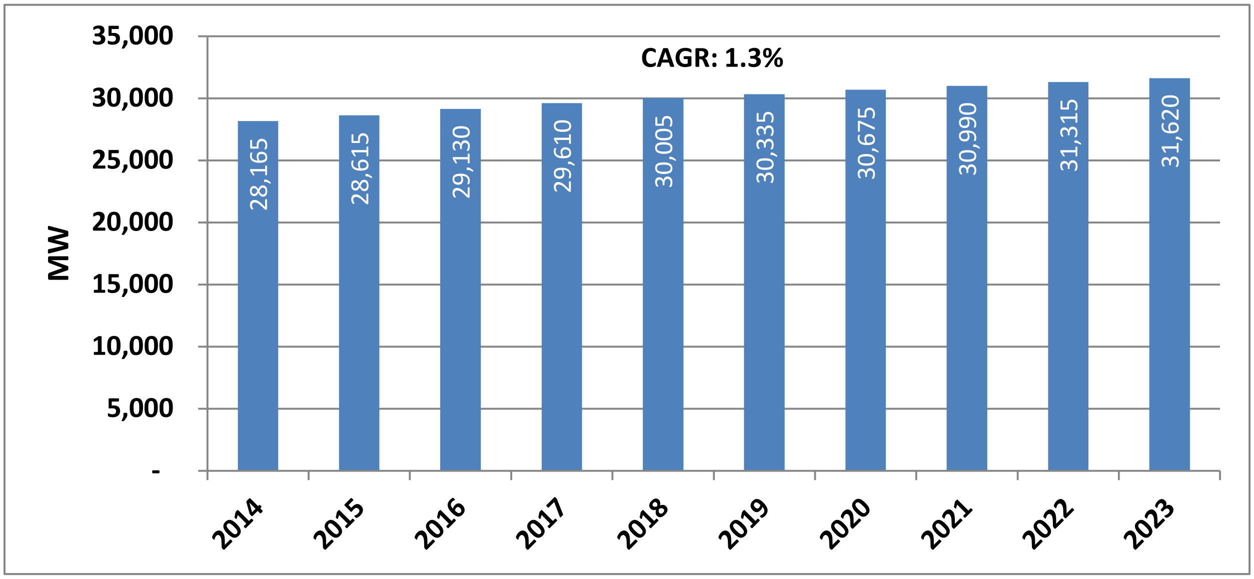
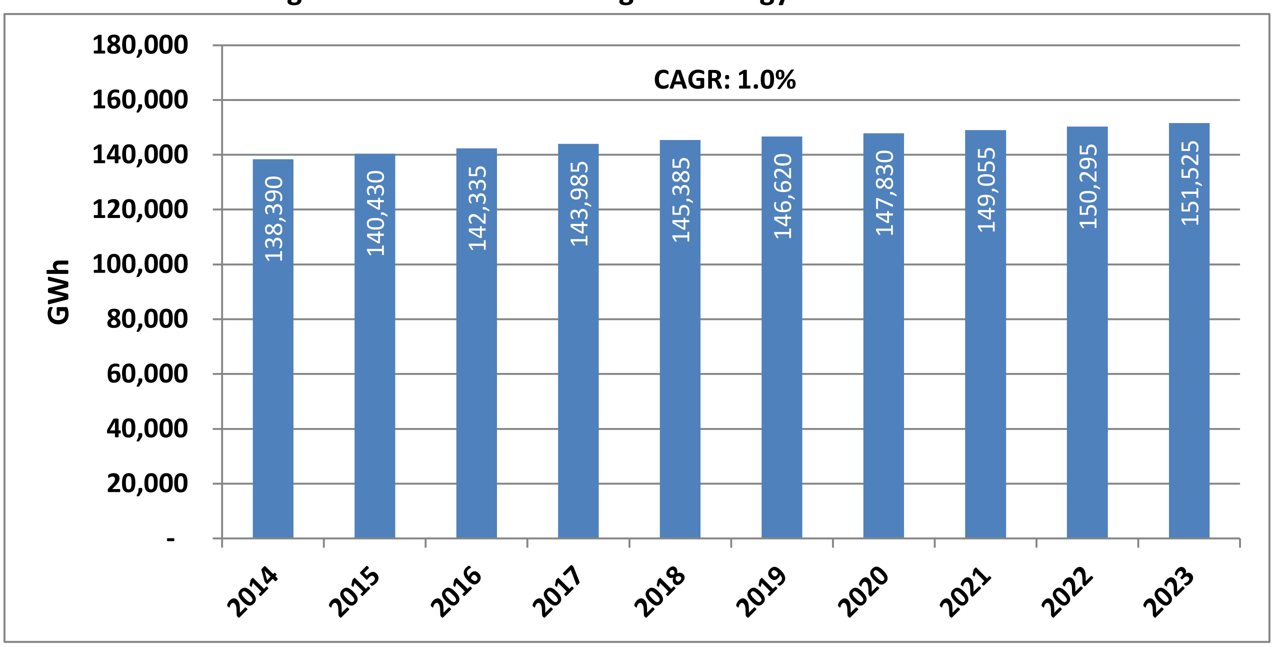


Figure 6.1.2: Gross New England Energy Load Forecast[5]

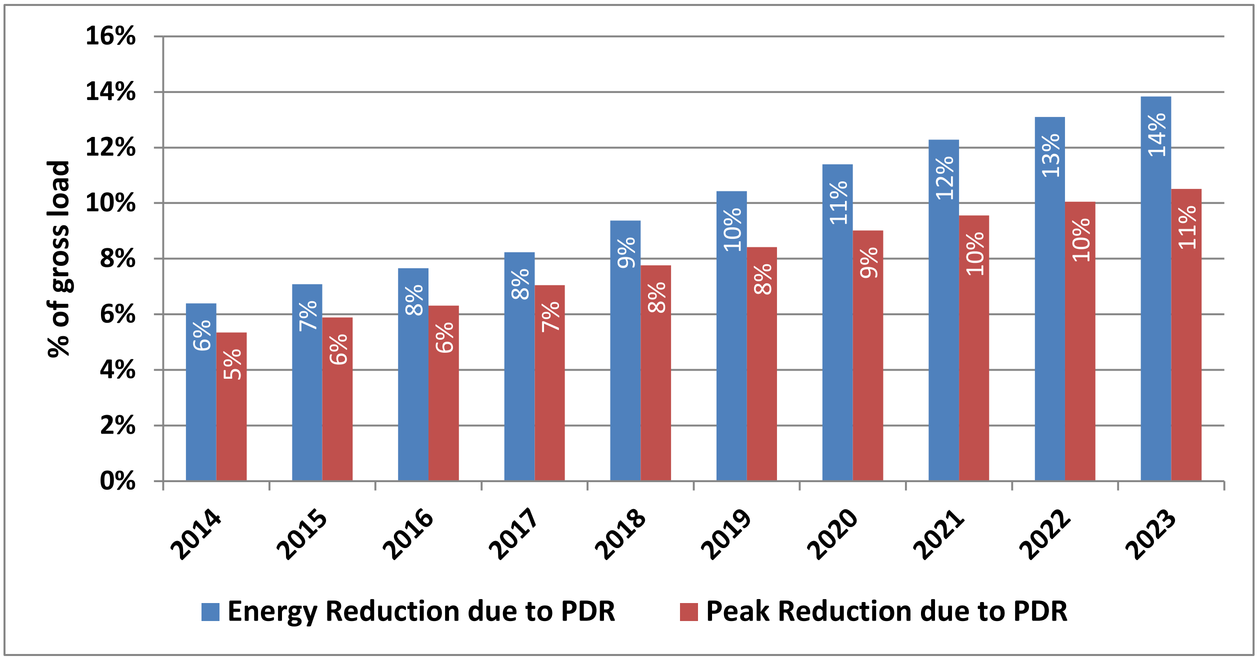


[4] "2014 CELT Report", ISO-NE. Does not include the impact of state energy efficiency programs.
[5] "2014 CELT Report", ISO-NE. Does not include the impact of state energy efficiency programs.

Energy Efficiency (EE) & Passive Demand Resources (PDR) Outlook

The CELT Report also includes a forecast of energy efficiency based on the passive demand response (PDR) resources[6] that have cleared in the Forward Capacity Auction (FCA).[7] For the FCA period that begins in 2018-2019, ISO-NE's forecast includes additional/incremental energy efficiency as a result of investments from state energy efficiency programs. The figure below shows the projected reductions in load as a percentage of gross load from the 2014 CELT.

Figure 6.1.3: New England Energy and Peak Demand Reduction from PDR/EE



Demand Response (DR)

Both active and passive demand resources participate in the FCA. The figure below shows the amount of active DR resources that have cleared the auction from 2014 through 2017 for each New England state. For 2016-17 (FCA7), the level of active DR dropped significantly from the level that had been clearing previously, and in 2017-18 (FCA8), it remained close to this lower level. Market participants have cited low capacity market prices in recent years, along with the administrative requirements of FCM participation, among reasons for the reduction in cleared DR capacity.

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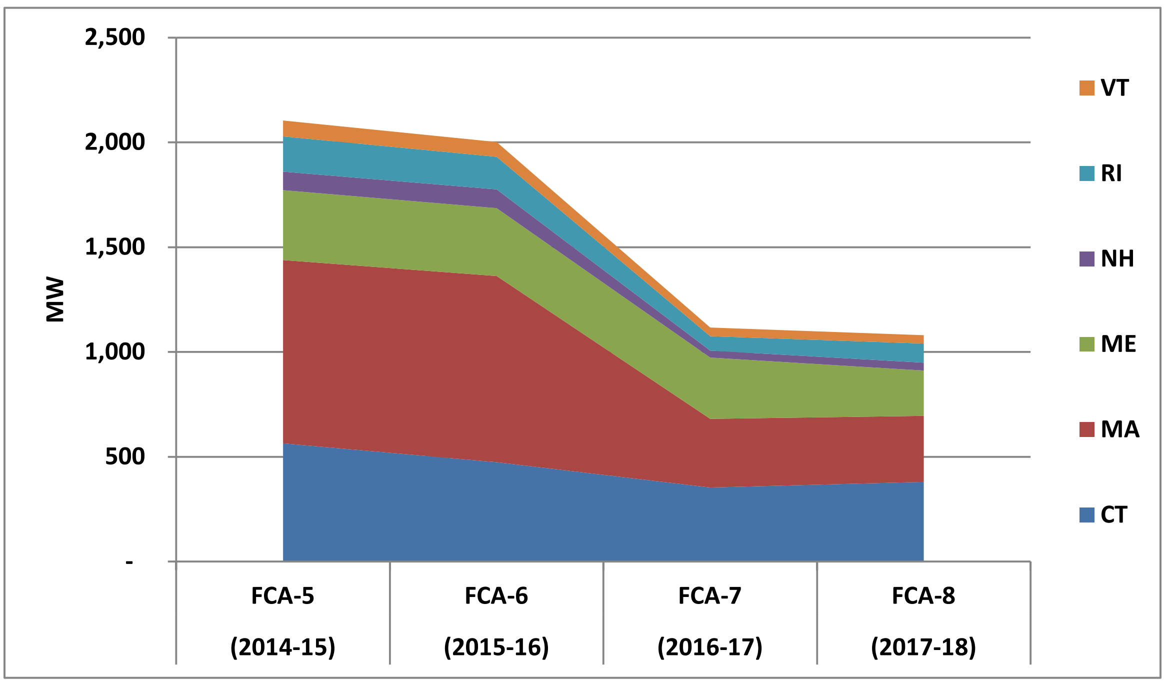
[6] Passive demand resources are energy efficiency measures; they do not involve dynamic deployment by the system operator.
[7] For more on the ISO-NE FCA, see the section below on Capacity Markets.

The tighter regional capacity balance and expected increase in FCA clearing prices (discussed later in this section) will tend to increase the financial value of reliable DR resources, and could potentially lead to a resurgence of cleared DR capacity in the FCM. This market context also makes it appropriate for GMP to explore additional DR resources – whether through the FCM or through GMP-administered retail pricing and load-control programs. One operational consideration that could limit the scale and/or increase the price of available DR resources in the future is that with a lower regional capacity surplus than in recent years, such resources could be called upon (i.e., participating customers may have to actually reduce their consumption) more frequently or for longer periods than they have in the past.

Recently, a federal appeals court ruled that the States, not FERC, have jurisdiction to regulate DR.[8] This ruling only affected FERC Order 745, covering Locational Marginal Price (LMP) payments to DR resources, but the ruling adds uncertainty to the outlook for DR's inclusion in future capacity markets. For now, ISO-NE is proceeding on the expectation that DR resources will be included in its wholesale markets for energy, capacity, and ancillary services.

Figure 6.1.4: Active Demand Response Cleared in Recent FCAs.[9]



[8] RTO Insider, "Court Throws Out Demand Response Rule", 23 May 2014, http://www.rtoinsider.com/demand-response-rule/.
[9] Data available from: http://iso-ne.com/markets/othrmkts_data/fcm/cal_results/index.html.

Net Demand Forecast

The following two figures show forecasted load growth from the 2014 CELT Report net of energy efficiency or PDR. The net forecasted growth rates are substantially lower than those of the gross load forecasts, at 0.7 percent/year and 0.1 percent/year for peak load and energy demand respectively.

Figure 6.1.5: New England Coincident Peak Load Forecast Net of EE/PDR

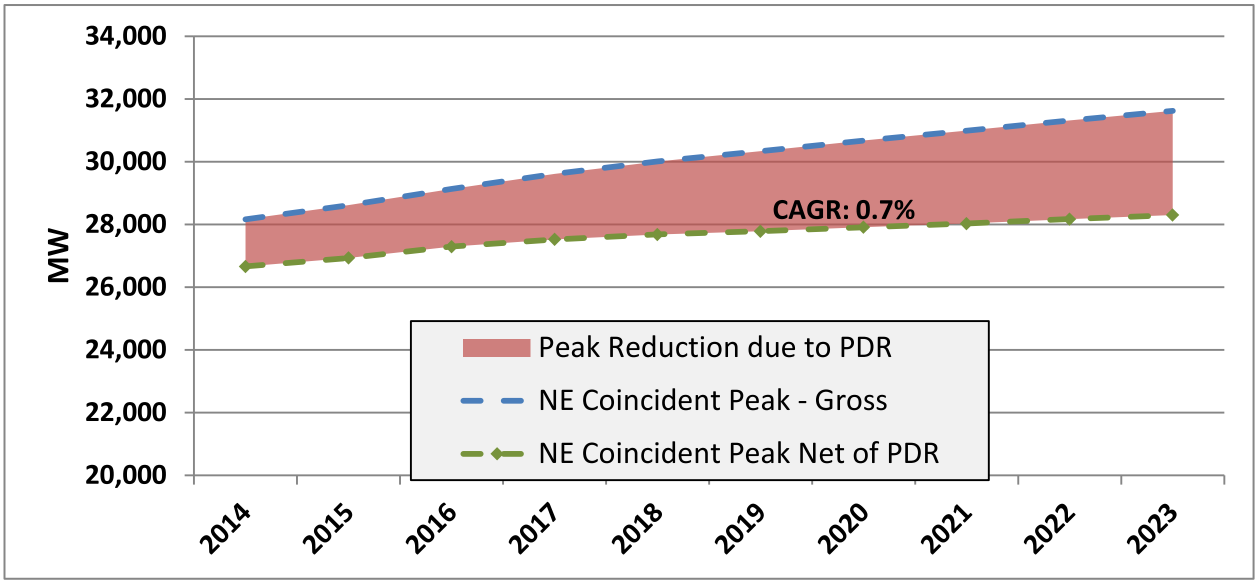
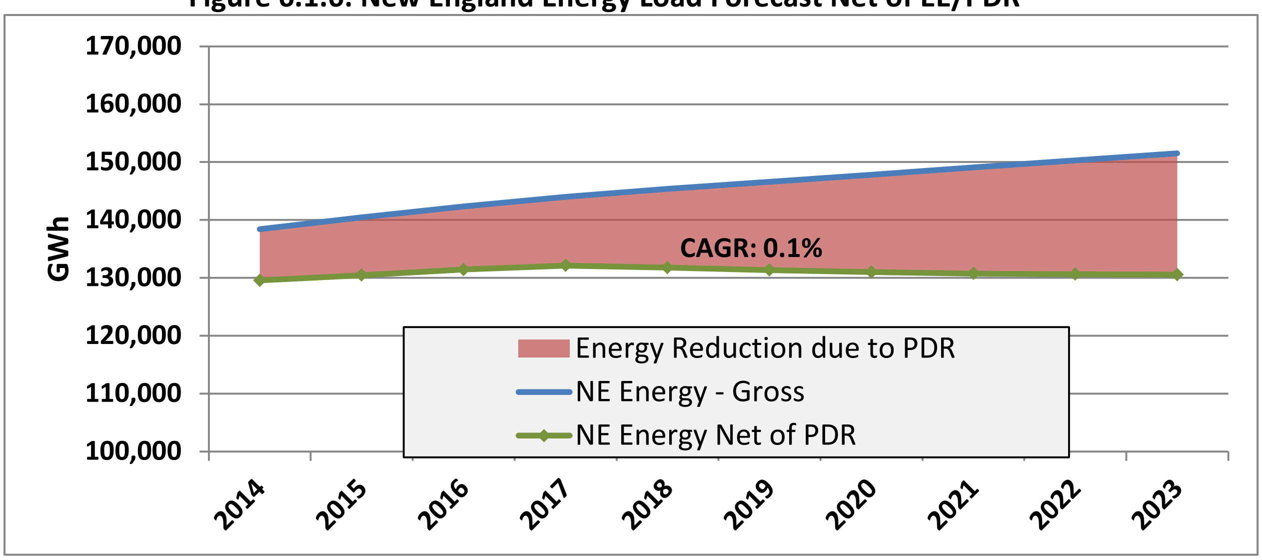


Figure 6.1.6: New England Energy Load Forecast Net of EE/PDR

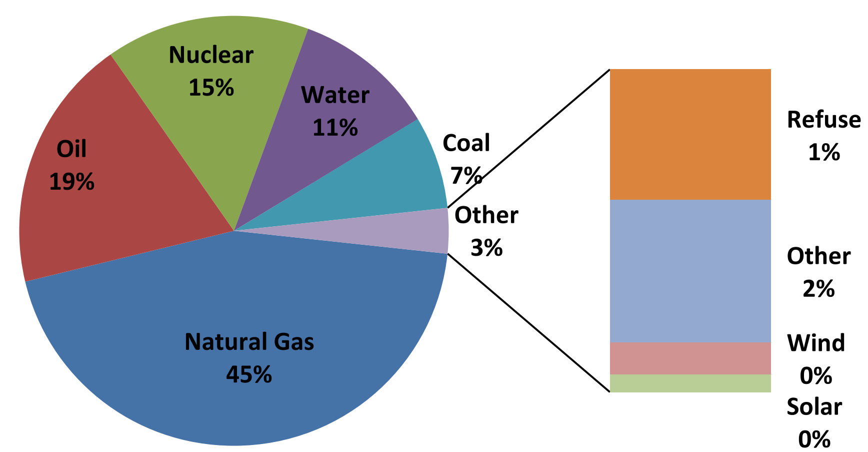


6.2 Regional Supply

Current and Historical Generation Mix

In New England, the current generation fleet is composed of a variety of resources, especially natural gas plants, with significant amounts of oil, nuclear, coal and hydro resources as well. Figure 6.2.1 shows the composition of the current fleet on a capacity basis by fuel type.

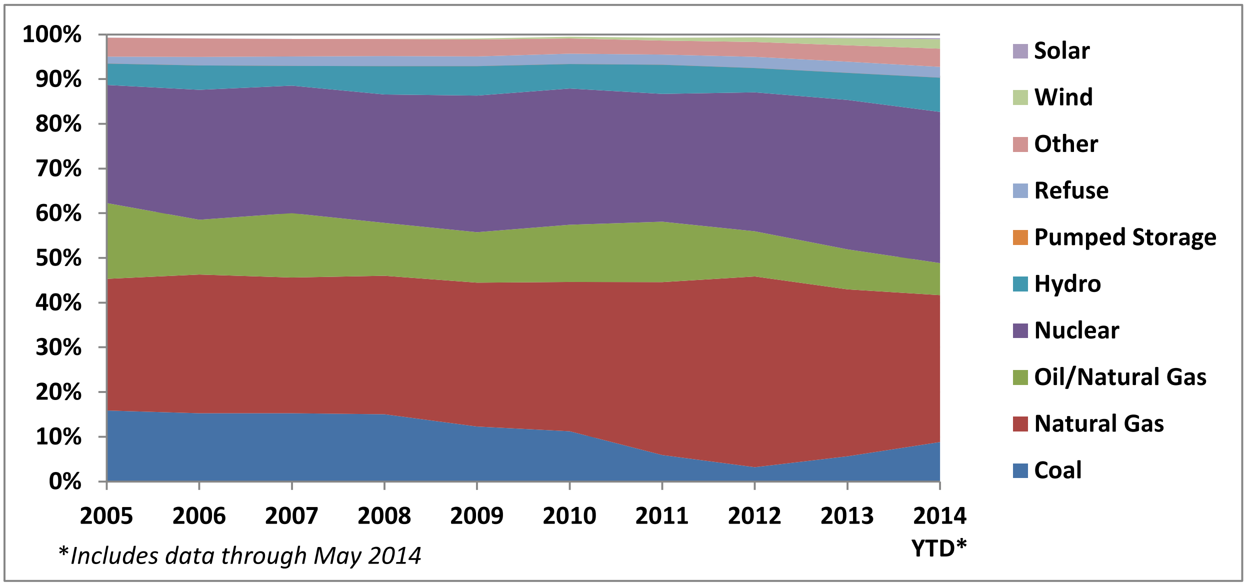
Figure 6.2.1: New England Summer Seasonal Claimed Capability by Fuel Type[10]



Since the late 1990s, New England has become increasingly reliant on natural gas generation and less reliant on oil and coal. However, the actual energy generated by fuel type can depend significantly on the relative prices of natural gas, oil and coal. Figure 6.2.2 shows historical energy generation in the ISO-NE region by fuel type. With low gas prices in 2012, natural gas generation increased significantly that year, mostly at the expense of coal generation. Higher New England natural-gas prices since then have increased the demand met by coal, but not to levels experienced prior to 2008.

[10] ISO-NE, "2014 CELT Report", Section 2.1, http://iso-ne.com/trans/celt/report/2014/index.html. The 'Other' category includes biomass and landfill gas.

Figure 6.2.2: Historical New England Energy Generation by Fuel Type.[11]



Environmental Policies Affecting the New England Generation Fleet

Renewable Energy

All New England States aside from Vermont have mandatory renewable portfolio standard (RPS) policies. These policies require the Load-Serving Entities to serve customers with certain percentages of new renewable generation. Though some of the details vary, all five RPS policies have separate requirements for "new" resources that come online after a cutoff date (Class I), and existing resources.

The eligibility requirements are relatively consistent across the New England States, meaning that many renewable resources (such as wind and solar) qualify for Class I Renewable Energy Certificates or Credits (RECs) in multiple states. In addition, most of the RPS requirements can be met with new renewable energy generated anywhere in the region. Because Maine has made allowances for some existing biomass to qualify for Class I, which does not qualify elsewhere, the Maine RPS does not appear likely to stimulate substantial additional new development in the way that the Connecticut, Massachusetts, Rhode Island or New Hampshire Policies are doing. That said, new renewables in Maine could be key suppliers to help the other states meet their goals.

[11] ISO-NE, "Net Energy and Peak Load by Source", http://www.iso-ne.com/markets/hstdata/rpts/net_eng_peak_load_sorc/index.html

The eligibility requirements for new renewables (i.e., the detailed definitions of fuels and technologies that count as renewable) in the other four states feature some notable differences which are beyond the scope of this IRP, but the requirements are sufficiently similar that it is reasonable to group these four markets as part of the "Premium Class I REC markets". Compliance entities must purchase class-eligible RECs equivalent to a certain percentage of obligated load by a certain date each year. The competitive retail electric suppliers and distribution utilities that provide retail generation service in these states generally pass through the cost of these REC purchases to customers through their retail electricity prices. All four states allow some form of REC banking, enabling the application of a limited number of surplus RECs in a particular year toward future obligations. The table below summarizes the minimum percentage requirements by class from 2014 to 2023.

Table 6.2.1: Premium Market RPS Requirements

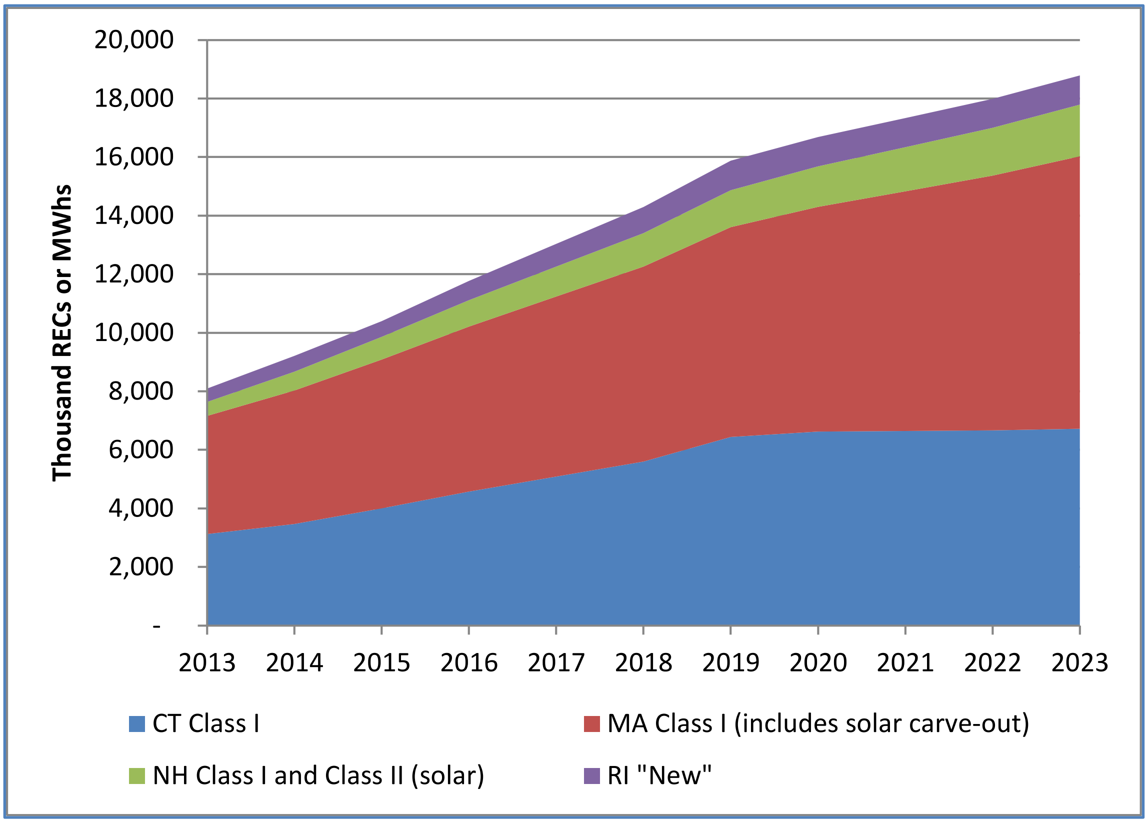
	2014	2015	2016	2017	2018	2019	2020	2021-2023
CT Class 1	11.0%	12.5%	14%	15.5%	17%	19.5%	20.0%	20.0%
MA Class 1	9%	10%	11%	12%	13%	14%	15%	16%+[12]
NH Class 1	5.0%	6.0%	6.9%	7.8%	8.7%	9.6%	10.5%	11%+[13]
NH Class 2	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%
RI New	6.5%	6.5%	8.0%	9.5%	11.0%	12.5%	12.5%[14]	12.5%
Load-Weighted Average	9.0%	10.1%	11.2%	12.4%	13.6%	15.1%	15.9%	16.5%+

This percentage schedule is likely to require vigorous development and/or imports of new renewable supplies. These requirements would result in about 16 percent of all New England electric energy being supplied by premium renewables in 2020.

The Figure 6.2.3 illustrates the forecasted demand from 2013 to 2023, based on the state RPS policies. Demand is expected to grow from 8 million RECs to over 18 million RECs per year in 2023. Voluntary demand for new renewables (e.g., electricity customers seeking to increase their own reliance on renewables) will increase the demand above these RPS-driven levels by some amount, although the level of voluntary demand is presently modest.

[12] After 2020, an additional 1 percent per year with no stated expiration date. Percentages include an in-state solar carve-out.
[13] Yearly increments are 0.9 percent until reaching 15 percent in 2025 and maintained thereafter.
[14] Maintained in 2020 and thereafter, unless modified by state regulators.

Figure 6.2.3: Forecasted Premium REC Demand, 2013-2023



There has been a shortage of Class I RECs recently, which has driven REC prices close to Alternative Compliance Payment[15] levels. Two states have responded to this shortage by changing their RPS requirements. Rhode Island delayed the schedule of increases in minimum requirements by one year starting in 2015, as reflected above. This also reduces the maximum renewable requirement in the last year of the RPS.

More significantly, Connecticut has allowed the possibility of large hydro offsetting up to a quarter of its Class 1 requirements by 2020 under certain conditions. If the Public Utility Regulatory Authority (PURA) determines through a multi-step investigation that there is a shortage of Class I RECs, up to 1% per year of the requirement may be allowed to be satisfied by large-scale hydropower starting in 2016. Such purchases, which would be capped at 5 percent, must be determined to be in the best interest of ratepayers, and may be procured by contracts up to 15 years long.

[15] Alternative Compliance Payments (ACP) are prescribed payments (in $/MWh) to be paid by retail suppliers that are unable to meet state RPS requirements for a given period. In Connecticut and Massachusetts, the current ACPs are $55/MWh and about $66/MWh, respectively.

Greenhouse Gas Emissions

All New England states participate in the Regional Greenhouse Gas Initiative (RGGI), a cap-and-trade program aimed at reducing CO_2 emissions from the power sector. This affects prices by increasing the variable costs of large fossil-fuel-fired generators that are almost always on the margin. RGGI allowance prices have been minimal (generally below $3/ton) since the program began in 2009 because actual CO_2 emission levels in the RGGI region have fallen well below the initial program caps.

On Feb. 7, 2013 the RGGI states announced an Updated Model Rule that would tighten the caps significantly in 2014. A RGGI-commissioned study of the Updated Model Rule projects that emission allowance prices will rise from about $4 (2010$) per ton in 2014 to over $10 (2010$) per ton by 2020.[16] RGGI auction results to date have benchmarked well to the Updated Model Rule forecast.

Federal policy regarding greenhouse gas emissions in the electric sector remains uncertain. In recent years, Congress has considered several legislative options that would create a cap-and-trade market for CO_2 emissions. So far, Congress has passed no bills. As legislative efforts to regulate CO2 emissions have stalled, the U.S. Environmental Protection Agency (EPA) has released proposed rules that would regulate carbon emissions at new and existing power plants under Section 111 of the Clean Air Act.

Clean Power Plan

On June 2, 2014 the EPA proposed regulations on carbon dioxide emissions from existing electric generating units (EGUs), with the goal of reducing emissions 30 percent relative to 2005 levels by 2030. The draft rule, known as the Clean Power Plan, is part of President Obama's Climate Action Plan issued in 2013. Authority for the Clean Power Plan is derived from section 111(d) of the Clean Air Act, and the proposed rule applies to fossil fuel-fired EGUs in operation or under construction by January 2014. The EPA proposed New Source Performance Standards (NSPS) for carbon dioxide emissions from new EGUs projects under section 111(b) of the Clean Air Act in September 2013.

The Clean Power Plan would require each state to set a standard of performance for carbon emissions from affected sources using what is known as Best System of Emission Reduction (BSER). The EPA has proposed BSER based on a combination of four basic "building blocks":

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[16] RGGI, Inc, Press Release, 2/7/2013, http://www.rggi.org/docs/PressReleases/PR130207_ModelRule.pdf

1. Efficiency improvements at affected plants;
2. Increased dispatch of gas-fired units over coal-fired units;
3. Adding and preserving generation from renewable and nuclear energy; and
4. Demand-side management.

The EPA has set proposed state emission rate targets based on its view of a reasonable state-by-state application of BSER. States may collaborate with other states to propose multi-state compliance plans, including emission trading-based plans. However, other New England states could likely meet the proposed performance standards through existing state and regional policies such as renewable portfolio standards and RGGI.

The timetable for implementation of the Clean Power Plan is highly uncertain. The EPA has proposed a timeline in which the rule is finalized in June 2015, and State Plans are due by June 2016 with interim and final target deadlines are set for 2020 and 2030, respectively. However, numerous court, legislative and administrative challenges remain to be resolved before the rule can be implemented. Republican gains in the 2014 midterm elections appear to bolster opposition to the President's entire Climate Action Plan. As a result, it appears highly unlikely that the Clean Power Plan will be implemented as proposed, or on the EPA's timeline.

Vermont is not covered by the EPA's Clean Power Plan, because it has no affected plants, but since energy and capacity are traded in a regional market, changes in the regulation of emissions from in neighboring states could strongly affect the prices that GMP and other Vermont utilities pay for future wholesale market purchases.

Generation Retirements

Last year there were two major New England generation retirement announcements. First, Entergy announced in August 2013 that it plans to retire Vermont Yankee (VY) by the end of 2014. Second, Energy Capital Partners announced in October, just 5 weeks after purchasing the 1,500 MW Brayton Point plant from Dominion, that it intends to retire the coal plant by 2017.[17] These announcements followed several other plant shutdown announcements. The table below summarizes some of them.

[17] Providence Journal, "New owners to shutter outmoded Brayton Point Power Station by 2017", Oct 8, 2013, http://www.providencejournal.com/breaking-news/content/20131008-new-owners-to-shutter-outmoded-brayton-point-power-station-in-2017.ece

Table 6.2.2: Recent or Announced Generation Retirements in New England

Name	Capacity (MW)	Location	Fuel Type	Status	Planned or Actual Shutdown
Vermont Yankee	600	Vernon, VT	Nuclear	Shutdown Announced	End of 2014
Brayton Point (Units 1-4)	1,500	Somerset, MA	Coal/Oil	Shutdown Announced	2017
Salem Harbor (Units 1-4)	750	Salem, MA	Coal/Oil	Closed	2011-2014
AES Thames	450	Montville, CT	Coal	Demolition	2011
Mt. Tom	150	Holyoke, MA	Coal	Shutdown Announced	2014
Bridgeport Harbor 2	130	Bridgeport Harbor, CT	Oil	Shutdown Announced	2017
Norwalk Harbor (Units 1, 2, 10)	350	Norwalk, CT	Oil	Deactivated	2013

New Thermal Generation Development

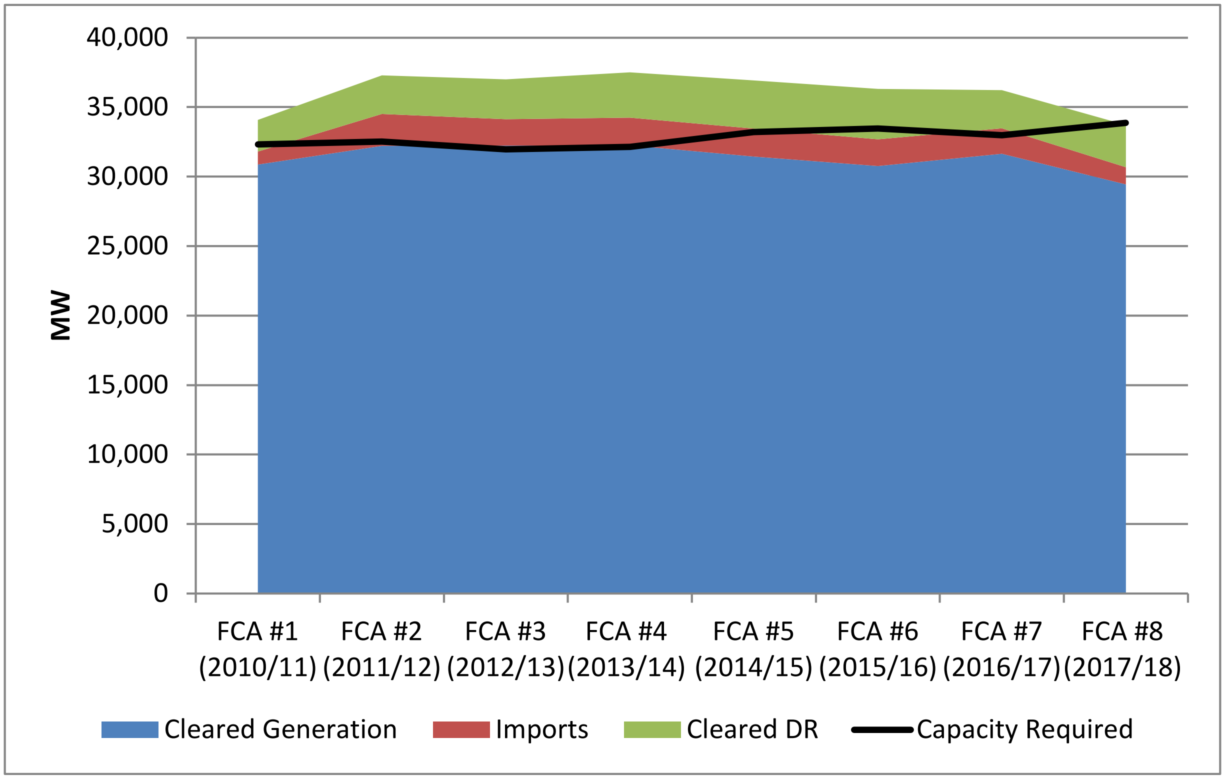
There has been little official activity regarding planned additions of thermal generation in recent years, when the ISO-NE market was in a surplus capacity position. The one major exception is Footprint Power's plan to place a new natural-gas-fired, combined-cycle plant on the old Salem Harbor plant site in Massachusetts. Footprint faces opposition to the 674-MW facility, creating uncertainty around its future.[18] Looking forward, it is likely that a more balanced regional capacity market, combined with emerging capacity market rules that incent reliable performance of capacity resources during shortage events, will stimulate significant power plant development activity.

[18] Aljazeera America, "Salem Power Plant Sparks Electric Debate", http://america.aljazeera.com/articles/2014/3/28/salem-power-plantsparkselectricdebate.html

Total Regional Supply and Demand Outlook

The New England power sector operates with significant surplus supply, but with the announced retirements and anticipated peak load growth, there will likely be a need for new capacity supply to meet reliability needs within the next five years. The most recent ISO-NE FCA auction for 2017-2018 failed to secure enough capacity to meet the 33,855-MW installed capacity requirement, leaving the region with a shortfall of 143 MW.[19] The figure below shows the auction results graphically.

Figure 6.2.4: ISO-NE FCA Results – Cleared Capacity vs. Capacity Requirements[20]



The resources that will ultimately fill the gap are not known, but new generation sources that compete to fill it are anticipated to primarily be renewable and natural-gas-fired plants. Imports from neighboring control areas, demand-side resources and repowering or reactivation of older plants in the region, in addition to new generating capacity, could also play a significant role in meeting regional capacity needs (and in setting capacity market prices).

[19] "Finalized Auction Results Confirm Slight Power System Resource Shortfall in 2017-2018", ISO-NE, 2/28/14
[20] Ibid.

6.3 Regional Transmission Developments

NESCOE Infrastructure Initiatives

The New England states have collaborated in recent years through the New England States Committee on Electricity (NESCOE) to investigate areas of resource and policy development where a regional solution can prove to be in the best interest of each state. Key questions have included:

- Can regional procurement of renewable electricity sources increase renewable development, and help the States meet portfolio standards and greenhouse gas emission goals at the lowest possible cost?
- How can the limitations on getting natural gas into New England, which is resulting in extremely high electricity prices in winter months, be alleviated?
- Can a NESCOE Infrastructure Initiative facilitate the development of electric transmission between New England and neighboring regions, including Canadian Provinces?

NESCOE commissioned studies to determine how increased natural gas pipeline capacity or increased imports from Canada would help lower the cost of electric energy in New England. These studies, while not universally accepted, indicated that significant but plausible increases in natural gas pipeline and/or electric transmission capacity can lower electric prices to a level indicative of expectations one would have for a working and relatively unconstrained ISO-NE market.

One portion of the NESCOE initiatives relates to the development of additional electric transmission capacity to import more clean energy. NESCOE is working with stakeholders to develop an RFP for new transmission to bring 1,200 to 3,600 MW of low/no-carbon resources into the region. The introduction of such resources into the New England market would be thematically consistent with GMP's resource planning goals, and GMP understands that over 3,000 MW of proposed electric transmission import projects have been proposed for delivery into Vermont. It is not yet clear, however, how cost-competitive the electric import projects would be, or which project (or combination) would be preferable based on relative cost and other factors. GMP's expectation, however, is that the capital costs associated with each of the proposed projects would be substantial.

NESCOE representatives had also adopted a plan to increase natural gas pipeline capacity into New England, based on funding through the electric markets and ultimately electric customers in New England. This plan stalled during 2014 since the failure of the administration in Massachusetts to secure legislative support for the initiative.

Both the electric and natural gas components of the potential NESCOE initiatives could have significant implications for GMP's electric customers – through their potential impacts on the wholesale electricity market (particularly during winter months), and through regional sharing of some or all of the associated costs. GMP plans to continue to monitor the proposed electric and natural gas import projects, and to work with key Vermont stakeholders (including VELCO, other electric distribution utilities, and the Public Service Department to determine which, if any, of the proposed projects would be beneficial for our customers.

Other Transmission Developments

In addition to the potential for new transfer capability for imports of clean power, New England utilities and ISO-NE have completed or initiated several transmission projects within New England that will eliminate congestion and increase power transfer capability both north-south and east-west. These projects were pursued primarily to address potential reliability deficiencies on the bulk transmission system, and will enable the system to accommodate greater imports. These transmission projects are:

- **Maine Power Reliability Program:** Six new substations, upgrades to numerous existing substations, and the installation or rebuilding of 440 miles of transmission line in the communities from Eliot to Orrington in Maine.[21] Expected in service date is 2015.[22]

- **New England East-West Solution**: A group of related transmission projects addressing reliability needs in New England, including:
    - **The Greater Springfield Reliability Project**: Upgrades to 39 miles of transmission lines between Ludlow, MA, and Bloomfield, CT[23] that are now fully in service.[24]

[21] Central Maine Power, "Maine Power Reliability Program Overview", http://www.mainepower.com/program-overview.htm

[22] ISO-NE, "Transmission Interface Transfer Capabilities: 2014 Regional System Plan Assumptions-Part 3", 17 March 2014, p. 14, http://iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2014/mar172014/a8_rsp14_transmission_interface_transfer_capabilities.pdf

[23] Northeast Utilities, "Greater Springfield Reliability Project", http://www.transmission-nu.com/residential/projects/springfield/default.asp

- **The Interstate Reliability Project**: Transmission upgrades spanning three states on a line from Millbury, MA to Card Street Substation in Lebanon, CT.[25] Expected in-service date is December 2015.[26]

- **Central Connecticut Reliability Project**: Now in development to remedy reliability concerns in the central Connecticut area.[27]

- **Rhode Island Reliability Project**: Includes several transmission upgrades in Rhode Island, including a new 345-kV line from West Farnum to Kent County.[28] Now in service.[29]

- **Boston Upgrades:** Transmission upgrades due to the retirement of Salem Harbor and advanced NEMA/Boston upgrades, increasing Boston import capability in 2014.[30]

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[24] Northeast Utilities, "New England East-West Solution", http://www.transmission-nu.com/residential/projects/neews/default.asp

[25] Northeast Utilities, "Interstate Reliability Project", http://www.transmission-nu.com/residential/projects/IRP/default.asp#

[26] ISO-NE, "Transmission Interface Transfer Capabilities: 2014 Regional System Plan Assumptions-Part 3", 17 March 2014, p. 11, http://iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2014/mar172014/a8_rsp14_transmission_interface_transfer_capabilities.pdf

[27] Northeast Utilities, "Central Connecticut Reliability Project," http://www.transmission-nu.com/residential/projects/central/default.asp

[28] ISO-NE, "Regional System Plan Transmission Projects March 2013 Update", p. 3, http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/projects/2013/final_march_2013_rsp_project_presentation.pdf

[29] ISO-NE, "Regional System Plan Transmission Projects March 2014 Update", p. 25, http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/projects/2013/final_march_2013_rsp_project_presentation.pdf

[30] ISO-NE, "Transmission Interface Transfer Capabilities: 2014 Regional System Plan Assumptions-Part 3", 17 March 2014, p. 14, http://iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2014/mar172014/a8_rsp14_transmission_interface_transfer_capabilities.pdf

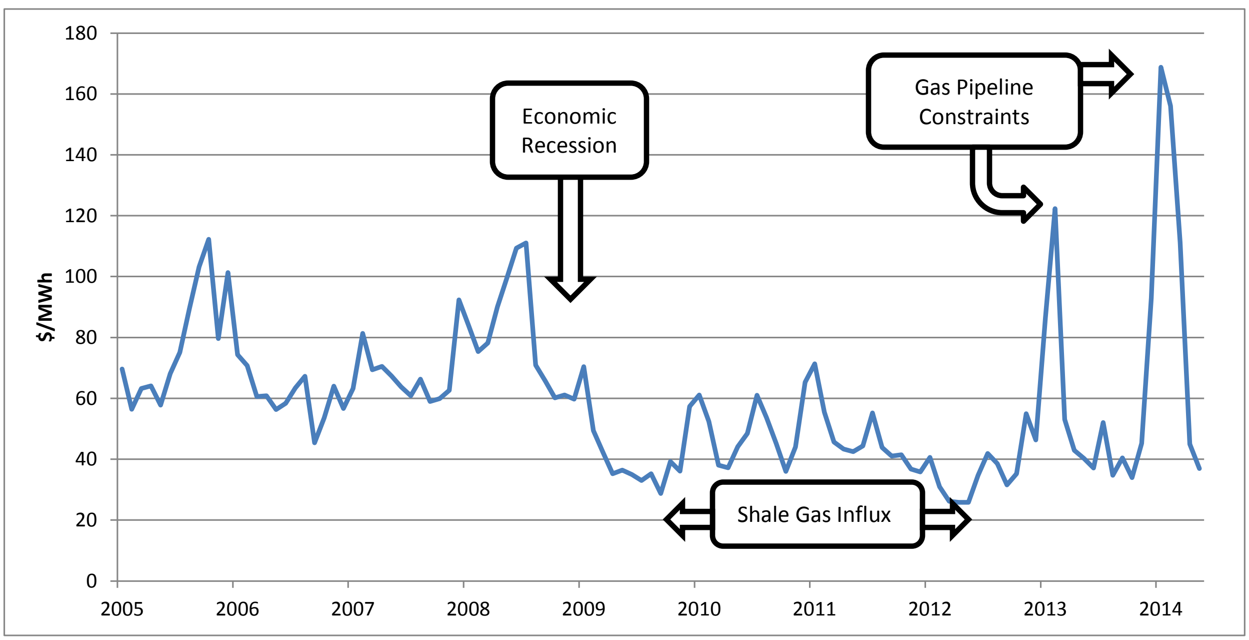
6.4 Regional Markets

Energy Markets and Prices

ISO-NE operates a wholesale electric energy market in New England. The price of energy is set by the marginal, most-expensive generating units supplying power in each hour. The marginal energy costs/prices vary with location within New England in some hours, based on locational differences in losses and congestion on the transmission system. Because natural gas generation generally operates on the margin in New England, wholesale locational marginal prices (LMPs) track the price of natural gas (delivered to New England) fairly closely during most of the year.

With the influx of shale gas and the stagnation of the national economy, natural gas prices and LMPs decreased in 2008 and 2009 and remained at lower levels than they had been historically through 2012. However, in the past two winter seasons natural gas pipeline constraints into New England led to regional natural gas shortages and increased reliance on oil-fired generation, which produced significantly higher LMPs. The chart below shows monthly historical Day Ahead LMPs for the ISO-NE Hub, which illustrates these trends.

Figure 6.4.1: Average Monthly ATC Day Ahead LMPs for the ISO-NE Hub.[31]



[31] ISO-NE, "Summary of Hourly Data", http://www.iso-ne.com/markets/hstdata/znl_info/monthly/index.html

Natural Gas Availability and NESCOE Initiative

Due in part to the winter LMP price spikes, NESCOE launched an Infrastructure Initiative to address the pipeline capacity shortage by increasing capacity to 1 Bcf/day above 2013 levels. This additional pipeline capacity is intended to benefit the generation sector, and the costs will be borne primarily by electricity ratepayers. As noted above, the near-term outlook for this initiative is uncertain.

Capacity Markets and Prices

ISO-NE operates a forward capacity market (FCM) to procure enough generation capacity to meet its planning reserve margin and, therefore, maintain adequate system reliability. The ISO procures capacity primarily through the use of an auction. Initially, ISO-NE's approved market design procured a fixed amount of capacity equal to the planning reserve margin in a form of a vertical demand curve. A vertical demand curve implies that a target amount of capacity will be procured regardless of the price. The resulting prices could swing dramatically from near zero or the established floor price when there was excess supply, to near the maximum when supply was insufficient.

The established clearing prices for capacity were set by administrative floor prices through 2016-2017 (FCA7), due to a material excess of capacity above ISO-NE's estimated minimum requirement. This changed in the next auction, when the market experienced a slight resource shortfall that resulted in steep capacity price elevation - a byproduct of the vertical demand curve. Historical clearing prices are shown in the table below.

Table 6.4.1: Summary of ISO-NE Forward Capacity Auction Closing Prices.[32]

	FCA-1 2010/11	FCA-2 2011/12	FCA-3 2012/13	FCA-4 2013/14	FCA-5 2014/15	FCA-6 2015/16	FCA-7 2016/17	FCA-8 2017/18
$/kW-mo	$4.50	$3.60	$2.95	$2.95	$3.21	$3.43	$3.15*	$7.02/ $15**

* FCA #7 concluded at the floor price of $3.15/kW-month in three zones—CT, ME, and ROP—with excess supply. In the NEMA/Boston zone, the auction concluded at $14.99/kW-month. All new resources in NEMA/Boston will receive the $14.99/kW-month clearing price; existing resources in the zone will receive $6.66/kW-month.

** Administrative pricing rules were triggered in FCA #8. Most existing resources will receive $7.02/kW-month and all new resources will receive $15/kW-month in all zones except NEMA/Boston. In NEMA/Boston, the administrative pricing rules require all resources to receive $15/kW-month except one resource, which in the previous auction (FCA #7) opted for a five-year price commitment of $14.99/kW-month.

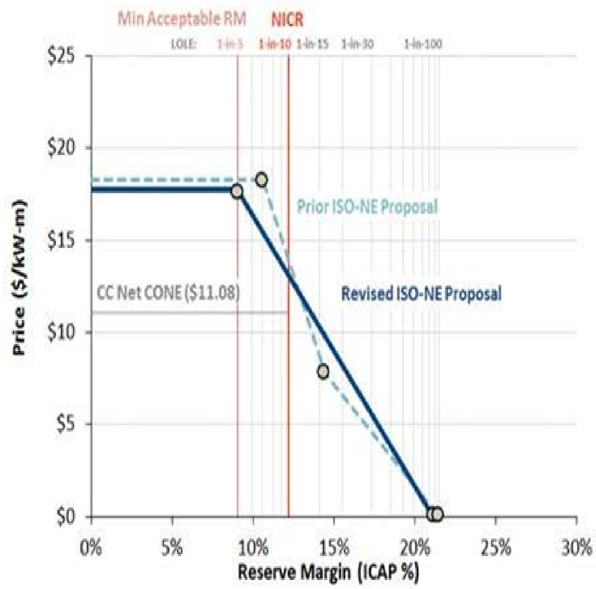
[32] ISO-NE, "Finalized Auction Results Confirm Slight Power System Resource Shortfall in 2017-2018", p. 3, http://www.iso-ne.com/nwsiss/pr/2014/fca8_final_results_final_02282014.pdf.

Besides the effect of the vertical demand curve, the capacity price for 2017-18 was likely affected by uncertainties from potential new market design changes. The Pay for Performance initiative proposed by ISO-NE included modifications to the design to make each resource's revenue contingent, in part, on its actual performance during periods when the amount of available capacity in New England did not meet ISO-NE system reserve requirements (typically from a few minutes to several hours at a time).

The new market rules, partially approved by FERC, will result in payment transfers from under-performing to over-performing resources, providing strong incentives for better performance during regional shortage conditions. These incentives will place a performance risk on all FCM resources, and this risk will presumably be priced in each resource's bid in future capacity auctions, potentially elevating the prices. There is also a possibility that a significant amount of resources did not participate in the 2017-18 auction due to uncertainties regarding these market design changes. A relatively small amount of withholding or withdrawal for this reason or others has the ability to force a meaningful increase in the auction clearing price, particularly if the total amount of offered supply is close to the planning reserve margin target.

In May 2014, FERC issued an order accepting ISO-NE's revised system-wide demand curve and some changes related to the Pay-for-Performance initiative. The implementation of a sloped demand curve in the 2018-19 auction is important because it allows a tradeoff between reliability and cost. The sloped demand curve also helps mitigate strategic bidding in the market because it provides an auction price cap and flexibility to procure less capacity if the price is particularly high. The revised ISO-NE proposal is illustrated below.

Figure 6.4.2: ISO-NE's Sloped Capacity Demand Curve and Key Points on the Curve



	Price Cap*	Net ICR	Foot
% of Net CONE	1.60x		0.0x
$/kW-month in FCA #9	$17.73	$13.20	$0.00
Correlates to X axis at reserve margin yielding	1 in 5 LOLE**	1 in 10 LOLE**	1 in 87 LOLE**
Corresponding reserve margin (using FCA #7 data)	9.00%	12.10%	21.10%

The approval of the demand curve and the partial approval of the Pay-for-Performance market rules by FERC removed significant uncertainty around the new structure of the market. However, the slight shortfall realized for 2017-18 and the retirements of inefficient resources may continue to place an upward pressure on capacity prices. In addition, to the extent that market participants include the risk of penalties for non-performance in their bidding strategies, there will be upward pressure on future clearing prices.

On the other hand, the high capacity prices should encourage developers to build new, more efficient power plants, and encourage potential capacity suppliers of all types (including demand-side resources and imports) to fully evaluate their options to provide capacity to this more lucrative regional market. A large increase in qualified capacity for the next auction confirmed this dynamic.

La Capra Associates' (LCA) most recent base case capacity price outlook is shown in the table below. It is important to note that, given the changes to market rules and potential need for new resources in the near future, this forecast is subject to lots of uncertainty in the near term and the long term. It is also important to note that clearing prices under the sloped demand curve construct will likely feature large year-to-year volatility (e.g., price changes on the order of several $/kW-month), as changes of even a few hundred MW of capacity supply or demand in a particular auction can meaningfully alter the point at which the supply and demand curves intersect (and therefore the resulting clearing price).

Table 6.4.2: LCA New England Capacity Price Outlook

Planning Year	Closing Price ($/kW-month)
FCA-9 (2018/19)	$11.86
FCA-10 (2019/20)	$12.04
FCA-11 (2020/21)	$12.28
FCA-12 (2021/22)	$12.53
FCA-13 (2022/23)	$12.79
FCA-14 (2023/24)	$13.06
FCA-15 (2024/25)	$13.33
FCA-16 (2025/26)	$13.61
FCA-17 (2026/27)	$13.89
FCA-18 (2027/28)	$14.19
FCA-19 (2028/29)	$14.49

Ancillary Services Markets & Prices

Power systems require ancillary services to maintain reliability and support their primary function of delivering energy to customers. At ISO-NE ancillary services are divided into the locational reserves market (which is comprised of Forward and Real-Time Reserves Markets), and the regulation market. The Forward Reserve Market is in place to ensure that sufficient sources capable of providing operating reserves will be available, while the Real-Time Reserves Market compensates units for operating reserves needed in Real Time.

Ancillary services represent a relatively small fraction of wholesale electricity market costs in New England (roughly 3 percent in 2013, compared to 12 percent for capacity and 85 percent for energy), but their importance may increase in the future. State environmental policies in New England incentivize the integration of large amounts of renewable resources into the grid, including intermittent resources such as wind and solar. This integration effects the power system's reserve, regulation, ramping and capacity needs, and are not easily quantifiable. Furthermore, these effects may grow over time as renewable resources become a larger percentage of the region's generation. Studies[33] suggest that the New England grid and market will be able to accommodate substantial amounts of intermittent power sources at costs that are not excessive, although the costs associated with integration of intermittent renewables could become meaningful over time as penetration increases.

[33] New England Wind Integration Study, December, 2010. See www.uwig.org/newis_es.pdf and http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2010/nov162010/newis_iso_summary.pdf

Scale of New England's Wholesale Electricity Market

The table below shows the wholesale electricity costs by market in 2013 compared with 2012. It is important to understand what these prices represent. There are three major market components related to the supply of electricity: energy, capacity and ancillary services. To serve customer load, the market participant referred to as the Load-Serving Entity (LSE) is charged for specific amounts of energy each hour, capacity each month and ancillary services based upon the amount of load it serves. A LSE may purchase all these components directly from the ISO-NE wholesale market. The LSE may also have supply of one or more of these components via contract or owned generation or demand resources. Contracts made directly between market participants are often referred to as bilateral arrangements. An LSE's supply of these components serves to hedge all or some of the costs to serve their loads. These prices also indicate the revenue wholesale suppliers would receive if they sell each of these components directly into the market rather than through bilateral arrangements.

Table 6.4.3: ISO-NE Wholesale Market Cost Summary[34]

Type	Annual Costs ($B)			Average Costs ($/MWh)		
	2012	**2013**	**% Change**	**2012**	**2013**	**% Change**
Energy	4.77	7.49	57%	37.42	58.14	55%
Capacity	1.19	1.06	-11%	9.36	8.20	-12%
Ancillary Services	0.13	0.27	107%	1.04	2.12	105%
Total	6.10	8.82	45%	47.81	68.46	43%

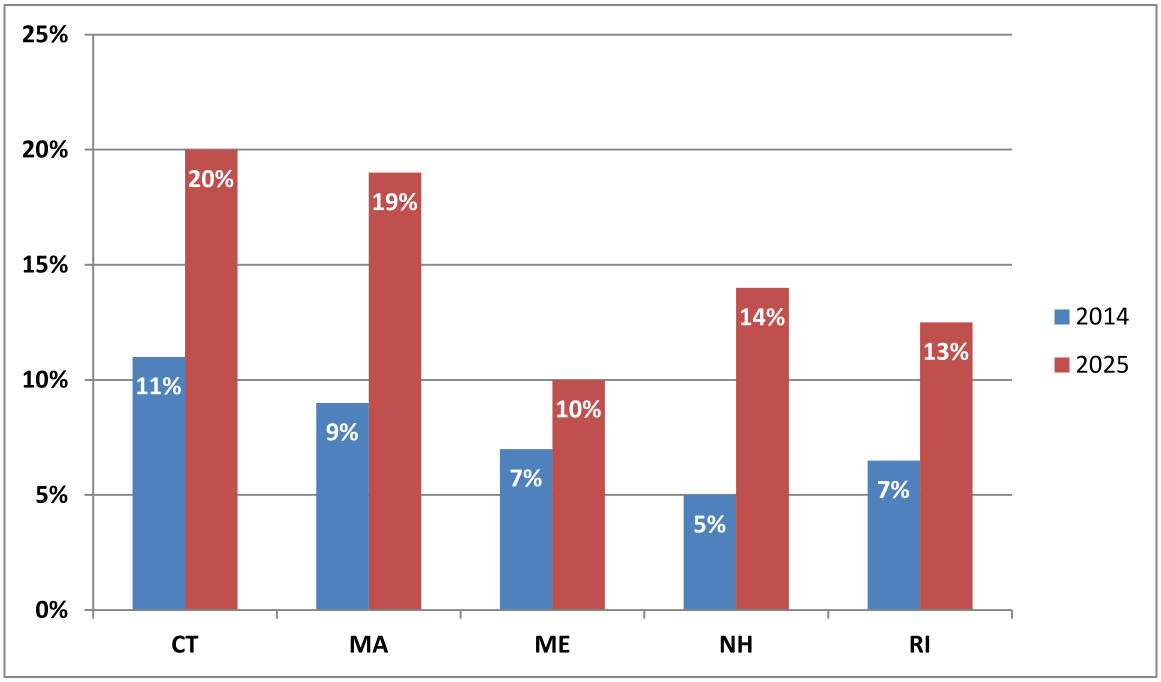
The table also shows the year-over-year variation that has occurred recently in each market. It shows that the 55 percent increase in market clearing prices for energy drove a 43 percent overall increase in average electricity costs for all of New England. This does not account for effects of bilateral arrangements, but represents the assumption for comparative purposes that all energy, capacity and ancillary services are supplied at their respective market clearing prices. In 2012 energy costs represented 78 percent of the total electricity costs. In 2013, the growth in energy market prices raised this to 85 percent.

[34] ISO-NE, 2013 Annual Markets Report, Table 1-2, p. 2, http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/2013/2013_amr_final_050614.pdf.

REC Markets and Prices

All six New England states have passed some form of energy policy legislation designed to encourage development of renewable energy projects. All except for Vermont have passed a Renewable Portfolio Standard (RPS) that requires minimum amounts of renewable energy by a specified date. The following chart shows the current RPS requirements in 2025.

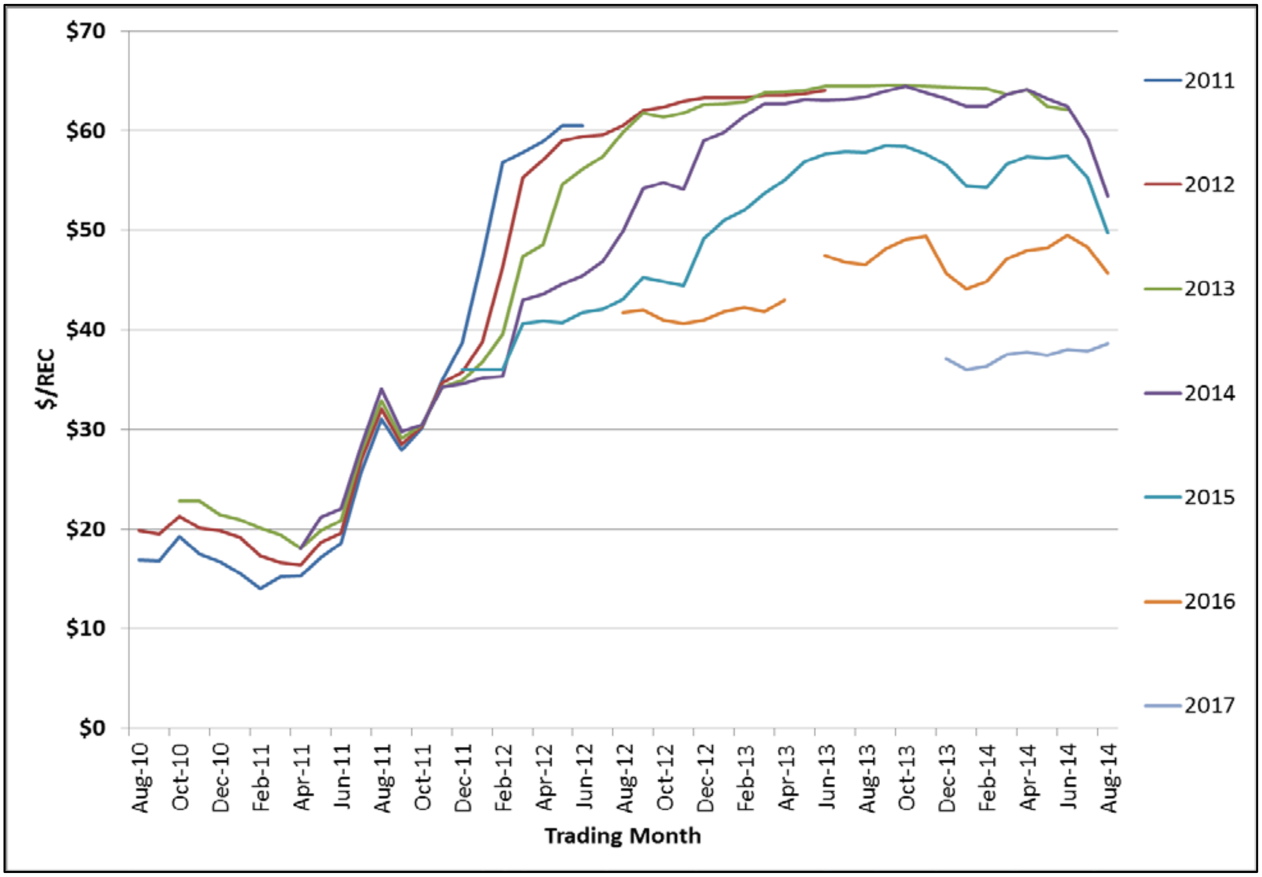
Figure 6.4.3: State Renewable Portfolio Standards[35]



Based in part on the fact that Massachusetts consumes the most electricity in New England, the RPS in Massachusetts has created the most significant incentives for the development of new renewable energy projects across the region. The following chart shows the price of MA Class I RECs over the past four years, based on broker quotes for RECs for delivery in each calendar year from 2011 to 2018. The market price for MA Class I RECs has ranged from a low of \$15/MWh to a high of over \$60/MWh. This means that in some recent years, the value of RECs to eligible new renewable generators has been comparable to the value of the energy they produce.

[35] Source: Final Regional Profile 2014, ISO-NE, page 2, http://www.iso-ne.com/nwsiss/grid_mkts/key_facts/final_regional_profile_2014.pdf

Figure 6.4.4: MA Class 1 REC Market Prices by Delivery Year[36]



[36] Source: Sustainable Energy Advantage, September 2014

6.5 Natural Gas Supply Constraints

A substantial build-out of interstate gas pipeline transmission infrastructure able to serve the greater Northeast region of the U.S. has been underway for several years. The initial projects began as early as 2011 in Pennsylvania, but they did not provide immediate and direct benefit to the New England energy markets. These early projects were built by Tennessee Gas Pipeline (TGP) and Texas Eastern Transmission (TET) to add interconnections in parts of Pennsylvania that lacked sufficient takeaway capacity to handle the swelling shale gas production that outstripped or were simply too far away from old conventional well pipeline taps.

While these expansions did not provide for incremental delivery capacity across the border into New England, they did create conditions that are more favorable to subsequent pipeline expansions further “downstream”. In this context, “downstream” includes those pipeline segments that directly serve the end-use markets of New York, New Jersey and New England. Because the New York/New Jersey market was seen as potentially huge (with local gas utilities planning to encourage oil-to-gas conversion for densely populated communities and multi-family dwellings in urban areas), gas producers were willing to finance this initial wave of pipeline expansions through long-term contracts to make sure their production could access such a large market. But these producers were not willing to finance further expansions on Algonquin Gas Transmission (AGT), which provides downstream delivery of TET volumes, or on TGP’s 200 Line in Zone 6. Both of these pipelines directly serve Connecticut, Massachusetts, and Rhode Island, and interconnect at Mendon, MA.

In the absence of “producer-push” pipeline expansions like those cited above, the market for natural gas must await the conditions that allow for “demand-pull” projects to be built. These conditions include a similar long-term view of markets as producers have, which means that demand-driven projects are most likely to be supported by local gas utilities, which must submit long-term plans for regulatory approval, and demonstrate sufficient contract resources to meet design peak day and peak winter weather conditions as well as on-system growth.

The passage of legislation in Connecticut in 2013 further enhanced long-term market conditions by providing incentives to convert residential customers from oil to gas heat. As a result, Connecticut’s legislation led to the first major pipeline expansion in New England in decades, AGT’s Algonquin Incremental Market (“AIM”) project. Connecticut’s legislation was followed by the State of Maine’s Energy Cost Reduction Act, which authorized the Maine Public Utilities Commission to enter into a contract for firm pipeline expansion capacity for a term of up to 20 years. Subsequently, NESCOE sponsored a proposal to obtain participation by all six New England state governors in a contract for pipeline expansion capacity designed to serve the electric generation market. The intent was to ensure that residential customers would benefit from lower rates for electricity from gas fired generation by providing for firm delivery of gas supply, elsewhere referred to as “the Governors’ Initiative”.

Gas companies typically contract for incremental pipeline capacity to meet weather conditions. Since design peak day conditions are based on the coldest day in the past 10, 20 or even 30 years, a design day is not necessarily likely to occur in any given winter period. As a result, on many days of the year there is sufficient underutilized interstate pipeline capacity to allow marketers to deliver spot gas supplies to end-users, including electric generation customers. While some marketers may hold pipeline capacity as the original contracting party, many marketers rely upon taking assignment of local companies’ seasonally excess pipeline capacity. However, during the winter season this capacity may be recalled to meet local heat load. At that time, those end users who can switch to alternative fuel for process needs may do so, and remaining customers bid up the price of spot gas delivered via any excess pipeline capacity remaining. These constrained plus the extreme daily spot price volatility experienced over the last two winters has caused projections for the delivered price of natural gas to New England over the next two winters to skyrocket.

Thus, any project that increases capacity to deliver firm gas supply during the winter will have an impact on market prices for gas and electricity. The difference in spot prices here in New England compared to in the producing regions, especially for Marcellus production, is large enough to have caused both AGT and TGP to propose expansions on their systems scheduled to enter service from 2016 through 2019. A recent presentation by Platts/Bentek, which is cited below, summarizes the various producing region and market area pipeline expansions by year over this time frame.

The first of these pipeline expansions is the AIM project, which adds 342,000 Dth/d of additional peak day deliverability and has an expected in-service date of November 2016. As a result of AIM receiving FERC approval to begin construction next year, the futures price for Algonquin City Gate Basis has already shown some moderation for winter 2016 compared to this coming winter. AIM will bring welcome relief to the market in southern New England, but beyond 2016 local companies anticipate load growth that will increase their projections for design peak day requirements. Also, the AIM project extends only through Mendon, M.A., so it address peak day growth requirements for many Massachusetts companies served customers all the way to Maine.

In anticipation of gas demand growth in Maine, AGT has announced a Phase 2 expansion, called the Atlantic Bridge project, which would add at least another 100,000 Dth/d capacity all the way to Dracut, M.A. Significantly, the Atlantic Bridge project also will allow gas to flow north on Maritimes and Northeast Pipeline to ultimately serve Maine, and so far this project includes one anchor shipper, Unitil, which serves customers in Maine as well as Massachusetts and New Hampshire.

TGP has proposed a major expansion to its 200 Line that traverses Northern Massachusetts from Wright, N.Y. to Dracut, M.A. This project, called Northeast Energy Direct ("NED") includes a green-field pipeline, which could be sized between 600,000 Dth/d and 1,200,000 Dth/d. TGP recently announced that is has secured anchor shippers for the project, including four local companies. The project is designed to accommodate another green-field project that will interconnect with TGP at Wright, N.Y., which is also a major interconnection with Iroquois Gas Transmission System (IGTS). IGTS serves New York and Connecticut and can deliver gas supply into New England via Portland Gas Transmission. This green-field project is called Constitution Pipeline, which has an in-service date of winter 2015-2016. The Constitution Pipeline will bring an incremental 0.65 Bcf/d of shale gas supply from Pennsylvania to TGP at Wright, necessitating an upgrade of the facilities at Wright to allow this supply to flow in three directions, west to upstate New York, south and east to Massachusetts.

Interstate pipelines serving the same market compete for throughput, and New England is no exception. In response to the TGP project, AGT has proposed a subsequent expansion to AIM and Atlantic Bridge, called Access Northeast, that it argues is more cost effective because it can be provided with mostly additional compression.[37] All of these projects would have in-service dates after 2016. An open question is whether the NESCOE proposal will go forward with a consortium of states acting as a "multi-party" anchor shipper and, further, whether it ultimately will be served by AGT's Access Northeast or NED.[38] While TGP has anchor shippers for NED that have contracted for 0.5 Bcf/d of capacity, it is encountering some local opposition to the project. AGT recently upped the ante for this competition by announcing that Access Northeast will become a joint venture between its parent, Spectra Energy, and Northeast Utilities, a holding company that includes franchise territories in Connecticut and Massachusetts.

Some entities have argued that incremental pipeline capacity on a year-round basis is not needed to serve what may be only a 30 to 60-day winter deficit in the market. A consortium of energy companies including Liberty Utilities has proposed the development of a greenfield LNG

[37] See Spectra Energy's letter to NESCOE dated June 27, 2014, http://www.nescoe.com/uploads/Spectra_EnhancingElectricReliabilityinNE_27Jun2014.pdf

[38] To remove any ambiguity, FERC recently clarified that there is precedent for approving pipeline projects that have multi-party anchor shippers.

liquefaction, storage and vaporization project designed to meet the winter needs in the region. The current plans are to locate the facility in Southeastern Massachusetts, possibly in Worcester County. Details about this project are minimal, having only been announced publicly last June at the LDC Gas Forum Northeast held in Boston, but early marketing materials present plans to offer up to 0.2 Bcf/d of vaporization capacity and a target in-service date in the 2018-2019 time frame.

While all of these projects may not be built in the time frame specified or to the maximum capacity specified, taken together they have the potential to have a significant impact on the price of gas supply in New England in both summer and winter. Platts/Bentek calculates New England's current winter peak day demand at between 3.5 and 4.0 Bcf/d. Platts/Bentek also estimates northeast Pennsylvania dry gas supply production at 8 Bcf/d in 2014 and growing to 12 Bcf/d by 2019. A key question is whether and when some of this substantial growth in regional supply will find its way to New England.

The combined capacity of AGT's three pipeline expansions totals up to 1.5 Bcf/d. TGP's NED project has anchor shipper commitments for 0.5 Bcf/d. Just this additional 2.0 Bcf/d of capacity alone represents a 50 percent increase in peak day capacity for New England by 2018. The additional 0.2 Bcf/d from the Northeast LNG project, plus a further build out of TGP's NED project could add up to another 1.0 Bcf/d, for a 75 percent increase in peak day deliverability through the existing major constraint points at the Cromwell, C.T., Wright, N.Y., and Mendon, M.A., compressor stations.

Since local gas suppliers must contract for capacity well in advance of when they will need it to meet design peak day requirements, it seems clear that this much incremental capacity would significantly lower the spot gas basis differential for New England. Already, the month-ahead spot basis differential for New England is sometimes negative compared to Henry Hub in the spring and fall shoulder seasons. And while the winter basis differential will likely remain higher than the rest of the year, especially for December through February, it would not be surprising for an equal weighted annual average New England basis to fall substantially, perhaps approaching $1.00 per mmBtu.

6.6 Regional Reliability Initiatives

Winter Reliability Program

On July 11, 2014 ISO-NE filed Docket No. ER14-2407-000 with FERC to ask approval for the 2014-2015 Winter Reliability Program. The Commission approved the filing on September 9, 2014. The Program has six components with assigned requirements:

1. **Compensation for unused oil inventory:** To participate in this component of the program, a Market Participant must notify the ISO by Oct. 1 and include an estimate of its expected level of oil inventory on Dec. 1. On Dec. 1, that inventory must meet or exceed the lesser of (i) 85 percent of the usable fuel storage capability and (ii) supply sufficient to operate the generator for 10 days at full load.

2. **Compensation for Unused LNG Contract Volume:** To participate in this component of the program, a Market Participant must notify the ISO by Oct. 1 and describe the contract for which the Market Participant proposes to receive compensation.

3. **Incentives for Commissioning Dual Fuel Capacity:** Pursuant to this component of the program, which is contained in Section III.K.5 of the rules, gas-fired generators that commission or re-commission dual fuel capability (i.e., the ability to burn oil as a backup fuel) will be eligible for compensation to offset some of those costs. Eligible generators are those that have not operated on oil since at least Dec. 1, 2011. To participate in this component of the program, a Market Participant must notify the ISO by Dec. 1, 2014 and include a plan for commissioning, including a target date on or before Dec. 1, 2016.

4. **Demand Response:** To participate to this component of the program, Market Participants can supply demand reductions to help maintain Thirty-Minute Operating Reserve by utilizing DR assets. These assets may be new resources which are not otherwise participating in the wholesale markets, or may be assets participating in FCM and have capacity in excess of what needed to meet their Capacity Supply Obligation. Instead of bidding into the market, Market Participants must provide a notice by Oct. 1 regarding their interest, and ISO-NE will select assets based on capacity location and historical performance. Also, there is a limitation of 100 assets and a total of 100 MW for this component of the program.

5. **Partial Elimination of Higher-Priced Fuel Burn Requirement:** This component proposes modifications to Appendix A of the Tariff to exempt Market Participants with dual fuel

resources from certain requirements on days when the price of natural gas and the price of oil approach convergence and gas prices are volatile. With these changes, when fuel markets are volatile, a resource will not be required to demonstrate to ISO-NE's Market Monitoring that it burned the fuel associated with its offer that cleared in the Day-Ahead Market.

6. **Dual Fuel Auditing:** ISO maintains the ability to conduct dual fuel audits and compensate the assets through Net Commitment Period Compensation ("NCPC").

GMP plans to participate in the first program component (by maintaining minimum oil inventory at some of its oil-fired peaking units), to offset some of the costs of the Winter Reliability Program. It is also reasonable to expect that during some cold periods, the program will cause LMPs to turn out lower than they would have in absence of the program.

Forward Capacity Market & Pay for Performance Changes

Under the ISO's FCM Pay for Performance ("PfP") initiative approved on May 30, 2014[39], capacity resources that receive a base capacity payment (consistent with the existing market structure) will also be penalized or rewarded based on the energy or reserves they provide during reserve shortage events. These penalties/rewards kick in for zonal or system-wide shortages that last for one five-minute interval or more. The initial penalty/reward rate is \$2,000/MWh; it will increase gradually over seven years to \$5,455/MWh. The losses realized by a capacity resource under the FCM PfP will be subject to certain monthly and annual caps, but the potential loss of revenue from poor performance in shortage events will be very substantial. The PfP incentives will place a performance risk on all FCM resources, and this risk may be priced in each resource's bid in future capacity auctions. All else equal, this change will tend to put upward pressure of FCA clearing prices in the near term.

The PfP initiative also included changes in the structure of the real time energy market. More specifically, pursuant to an Oct. 2nd order, the Reserve Constraint Penalty Factors ("shortage prices" or "RCPF") for 30-minute operating and 10-minute non-spinning reserves were increased from \$500/MWh to \$1000/MWh and from \$850/MWh to \$1500/MWh, respectively. The Commission approved these changes on the impetus that the increase of the PCPFs will

[39] http://www.iso-ne.com/regulatory/ferc/orders/2014/may/er14-1050-000_5-30-14_pay_for_performance_order.pdf

help incentivize performance in real time similarly to the capacity market incentives described in the previous paragraph.

6.7 Northeast Market Model Forecast

La Capra Associates models the ISO-NE electricity market and neighboring market regions using an hourly chronologic electric energy market simulation model on the AURORAxmp® software platform (AURORA). The model provides a zonal representation of the electrical system of New England, New York and neighboring regions.

AURORA is a well-established, industry-standard simulation model that uses and captures the effects of multi-area, transmission-constrained dispatch logic to simulate real market conditions. La Capra Associates utilizes a comprehensive database that includes representations of power generation units, zonal electrical demand and transmission configurations. La Capra Associates supplements AURORA's default database (from its developer, EPIS Inc.) with custom updates and revisions of key inputs for the New England and New York markets, as well as more limited updates to neighboring control areas.

La Capra Associates constructed this database from a number of established sources of information, including:

- The U.S. Department of Energy, Energy Information Administration (EIA);
- ISO-NE;
- The New York Independent System Operator (NYISO); and
- The New York Mercantile Exchange (NYMEX).

The sections that follow provide more detail regarding key market driver variables for the most recent New England electric market outlook as well as a summary of key results.

System Definition

For zonal modeling, AURORA project files define areas and zones, where zones are collections of smaller areas in the model. Each pricing zone in the ISO-NE region is modeled as its own AURORA zone. This is the most granular view of New England that is practical within the AURORA zonal model. In actual practice, energy congestion between zones within New England tends to be modest, so that average energy market clearing prices in Vermont tend to be similar to those in the rest of the region.

New England Load and Demand-Side Management

For the 2014-2023 period, the 2014 CELT report was used to estimate gross peak and energy load and peak and energy load net of energy efficiency (EE) as discussed earlier.

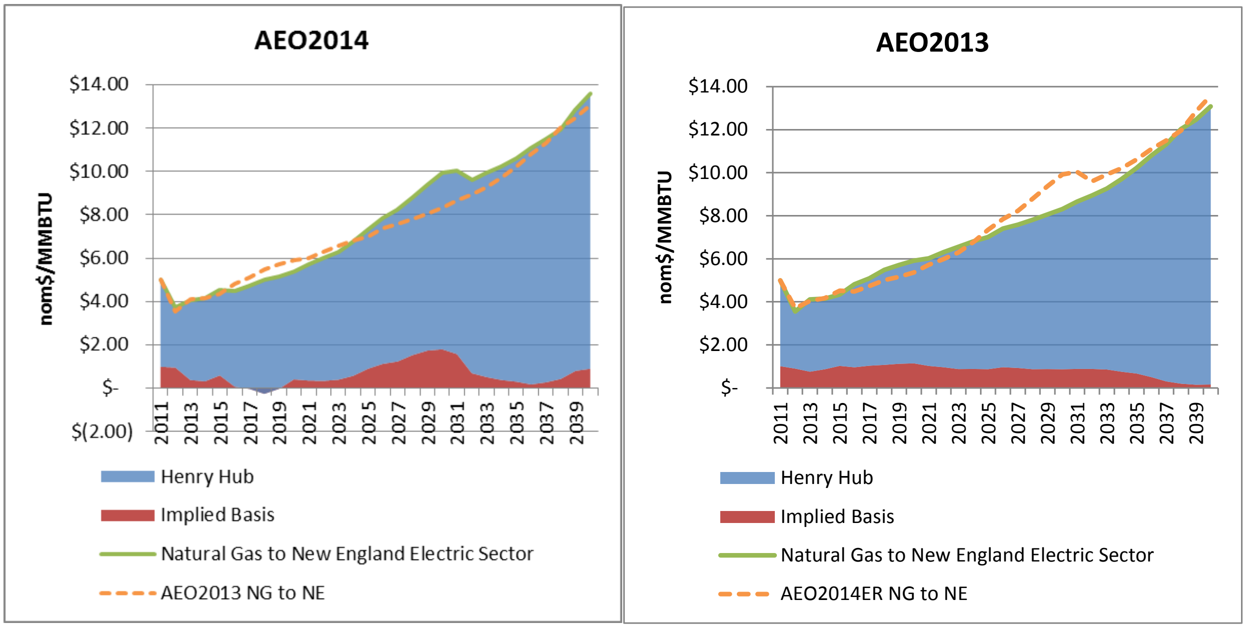
Natural Gas Prices

Because natural-gas-fired generation is so often on the margin in New England electric power markets, the forecast of natural gas prices is perhaps the most important variable to consider when forecasting wholesale energy spot prices. Natural gas price is also one of the most challenging inputs to forecast, due to the uncertainty in the market today. The following summary provides the forecast used by La Capra Associates. Wholesale natural gas prices within New England are described through two components: the commodity price at a benchmark location (the Henry Hub in Louisiana) and the difference between delivered price to New England and the benchmark price, referred to as "basis". Historically this basis closely represented transportation fees to bring natural gas from its distant supplies to New England. However, the transformation of the location of natural gas wellheads with the extractions of shale gas within the northeast U.S. now makes the basis more of an "implied basis" for cost comparison to Henry Hub rather than representative of long-haul transportation fees.

Henry Hub Annual

The primary source of our long-term Henry Hub forecast is the latest Annual Energy Outlook (AEO) Reference Case from the U.S. Energy Information Administration (EIA), which for this Northeast Market Model (NMM) run is the AEO2014 Reference Case (released April 2014). After several years of falling price forecasts, the price outlook has rebounded slightly in the AEO2014. The forecast of delivered prices to the New England electric sector is very similar between AEO2013 and AEO2014 (see Figure 6.7.1). AEO2014 is slightly lower than AEO2013 in the early years, and then a temporary run-up in prices brings AEO2014 higher in the late 2020s, before a drop in prices brings it back in line with AEO2013 in the 2030s.

Figure 6.7.1: Comparison of AEO Forecasts of Delivered Natural Gas Prices to NE Generators



We note, however, that the implied basis differential to Henry Hub has changed significantly between releases. The AEO2014 basis is more volatile than AEO2013, and even goes negative between 2017 and 2019. The AEO2014 Full Report notes a few significant natural gas modeling and assumption changes that help to explain the difference. EIA's summary of key changes includes the following points:

> *Revised network pricing assumptions based on benchmarking of regional natural gas hub prices to historical spot natural gas prices, using flow decisions based on spot prices, setting variable tariffs based on historical spot natural gas price differentials, and estimating the price of natural gas to the electric power sector off a netback from the regional hub prices. Note that estimating NG prices to the electricity generation sector based on hub prices, rather than the citygate prices as was done in prior years, is a better reflection of current market conditions, in which many large natural gas consumers are outside the citygate.*
>
> *Allowed secondary flows of natural gas out of the Middle Atlantic region to change dynamically in the model based on relative prices, which enables a larger volume of*

natural gas from the Middle Atlantic's Marcellus formation to supply neighboring regions. [40]

Furthermore, the market trends discussion notes the following:

Delivered prices to … electric power consumers generally rise with Henry Hub prices in the projection, but the lower 48 average spot price increases at a slightly slower rate than the Henry Hub spot price, because regional production growth in areas that do not serve the Henry Hub is somewhat faster than growth in areas that supply the Henry Hub. In particular, dry gas production in the Marcellus shale play, which predominantly serves the Northeastern and Mid-Atlantic regions, grows from 1.9 Tcf in 2012 to 5.0 Tcf in 2022 in the Reference case, before declining to 4.6 Tcf in 2040. [41]

The EIA points above indicate that the Henry Hub price is less indicative of the commodity price of natural gas in the new modeling approach used for the AEO2014. Extreme caution must be used in developing independent forecasts of the New England basis differential and adding it to the AEO2014 Henry Hub price.

New England Effective or Implied Basis Differential

We assume that the basis differential paid by natural gas generators in New England is tied to the Algonquin City-Gates basis. The basis differential to New England is a highly uncertain variable at this time. After remaining fairly stable at an annual average of around $1/MMBtu for most of the last decade, price spikes in the last two winters brought the 2013 annual average basis to more than $3/MMBtu. Recent prices and current futures prices indicate that the basis will remain high at least through 2015.

LCA does not, however, consider it likely that the current condition of natural gas markets in New England will persist in the long term. Furthermore, it is LCA's judgment based on experiences procuring power on behalf of clients recently that the futures transactions for the basis differential are currently pricing in a very high "risk premium" that caters to only the most risk-averse gas buyers.

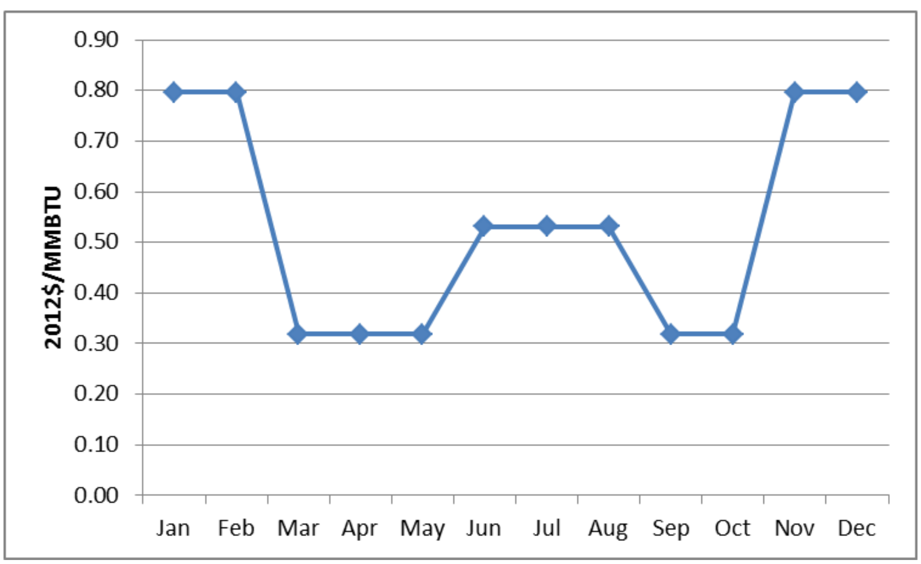
[40] EIA (April 2014) AEO2014 Full Report, pp iv-v. http://www.eia.gov/forecasts/aeo/pdf/0383(2014).pdf.
[41] EIA (April 2014) AEO2014 Full Report, p MT-21 (PDF p 106).
http://www.eia.gov/forecasts/aeo/pdf/0383(2014).pdf.

We expect that over time the extreme basis differentials we are seeing currently, which ISO-NE has labeled "unsustainable", will be mitigated by pipeline expansions underway and being planned, ISO-NE market changes and system operations changes, regional policy initiatives to support pipeline expansion in the region, and market responses from alternative fuel suppliers, demand response providers, and imports of power from Canada and New York (where pipeline expansion is leading those efforts in New England). Some of the market initiatives that support the reduction of basis differential include ISO-NE's strategic planning initiative in 2010 to address natural gas issues affecting electric system reliability; ISO-NE's specific market and operational solutions (e.g., see ISO-NE 2013 Regional Energy Outlook); and the market design enhancements that ISO-NE is developing (including the Pay-for-Performance Initiative discussed above) to provide better incentives for firm fuel supplies and improved operations.

Northern New England Basis

The Algonquin City-Gates price provides a reasonable proxy for delivered natural gas prices for generators in southern New England. Natural gas-fired generators in Maine and New Hampshire face additional expense due to additional distance from inexpensive shale gas supplies to the southwest. The LCA forecast of this additional basis is $0.53/MMBTU on an annual average basis, with seasonal range of $0.32 - $0.80/MMBTU (see Figure 6.7.2 below). The forecast is based on backhaul usage rates on the Maritimes and Northeast Pipeline and Portland Natural Gas Transmission System short term reservation rates.

Figure 6.7.2: Northern New England Basis Differential to Rest of New England (Algonquin City-Gates)



Other Fuel Prices

Currently we rely on the prices in EPIS's default North American database for oil and coal. These assumptions are summarized in Table 6.7.1 below. Note that in AURORA, the actual coal price will vary by unit based on the unique adders for transportation in the default database. In addition, oil prices are indexed to the assumed Henry Hub natural gas prices.

Table 6.7.1: Key Fuel Prices (Nominal $/MMBTU)

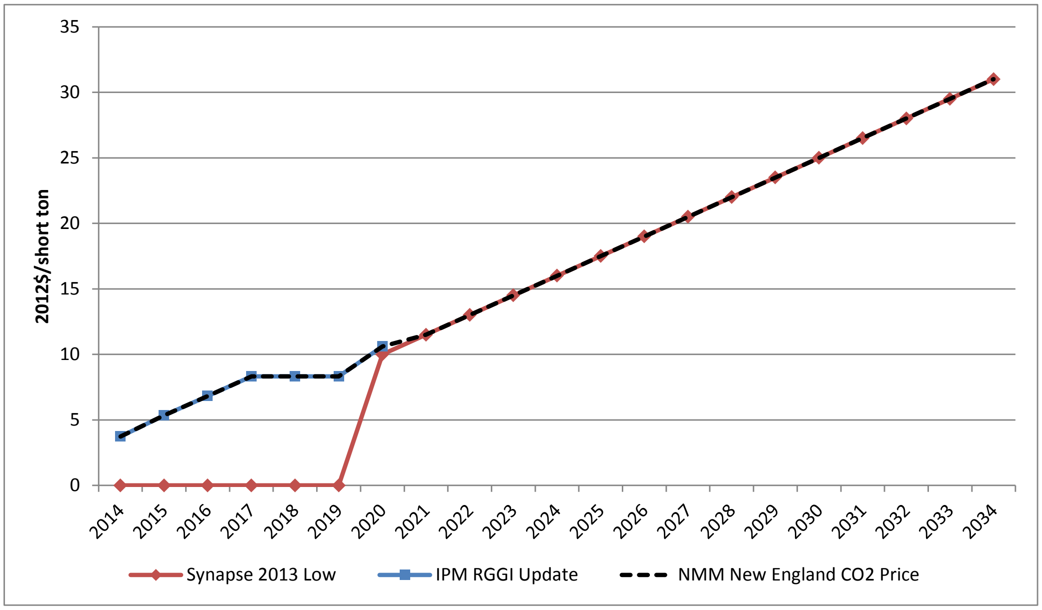
	2014	2019	2024	2029	2033
No. 6 Fuel Oil	$21.88	$23.27	$26.11	$29.41	$32.79
Coal Delivered to NE	$4.10	$4.52	$5.03	$5.59	$6.07

Greenhouse Gas Emission Prices

La Capra Associates' Reference Case of the Northeast Market Model (NMM) incorporates greenhouse emissions pricing from RGGI and from an assumed federal-level policy[42]. RGGI's Updated Model Rule forecast price is also incorporated. Federal policy regarding greenhouse gas emission remains a far more uncertain outcome as discussed in more detail in the Regional Supply section. Our modeling assumes that a national CO_2 pricing program is implemented in 2020 as forecast in the "Low" case of Synapse Energy Economics, Inc.'s 2013 Carbon Dioxide Price Forecast. It is believed that in this analysis, Synapse likely overestimates the current view in the market of potential CO_2 pricing that would result if such a pricing program were implemented, so the "Low" case is appropriate. The following figure shows the forecast for the New England Region.

[42] In the Avoided Cost Docket (7873/7874), the Department chose to adjust the Reference Case to remove the effects of federal-level carbon policy, and it is this case that forms the base assumptions of the Resource Plan in Chapter 7.

Figure 6.7.3: CO_2 Emissions Price Forecast for New England Region



NO_x and SO_2 Emission Prices

NO_x and SO_2 emission allowance prices and applicability (i.e. what generators will be subject to emissions limits) are extremely uncertain right now because the Cross-State Air Pollution Rule was vacated. NO_x and SO_2 emission prices are also a relatively minor component of energy prices in New England because of the low emission rates of marginal generators (mostly gas units). Our forecast assumes zero SO_2 allowance prices and \$27.41/ton (2013\$) NO_x allowances[43] until the onset of national carbon pricing in 2020, which we assume will eliminate any residual NO_x and SO_2 prices. These emissions prices apply for most generators in Connecticut, Rhode Island, and Massachusetts. Most generators in Vermont, New Hampshire, and Maine are assumed to pay no price for NO_x and SO_2 emissions.

New England Existing Resources

We compare the EPIS default database of existing New England resources to the 2014 CELT list of generators (Section 2.1). All generators greater than 25 MW in size are compared individually to their CELT entry for summer and winter capacity, fuel designation, and zone.

[43] Prices are derived from the Avoided Energy Supply Cost Study from 2013. See http://www.synapse-energy.com/Downloads/SynapseReport.2013-07.AESC.AESC-2013.13-029-Report.pdf. See pp 4-2 to 4-4 (PDF pp 102-104).

Other characteristics, such as heat rate, retirement date, and bidding adders, may be spot checked and adjusted based on other sources.

New England Resource Retirements

The assumptions related to retirements of existing generating units are developed as part of the thermal expansion development process. The schedule of retirements is based on the de-list bids from the ISO-NE FCAs and is adjusted to reflect LCA's most current understanding of likely retirements. For years in which no FCA auction had yet cleared, professional judgment was used to determine an expected life for the oil-fired and coal-fired units remaining online in New England. Vermont Yankee is assumed to retire at the end of 2014 in accord with Entergy's announcement that it is closing the plant. Similarly, Brayton Point station is assumed to retire in 2017.

Table 6.7.2: Cumulative Retirements Since 2012
(Cumulative MW of Summer Capacity)

	2014	2019	2024	2029	2034
Coal	150	1,393	1,921	2,304	2,304
Oil	909	1,527	2,538	3,659	4,467
Nuclear	604	604	604	604	604
Total	1,663	3,524	5,063	6,567	7,375

New England Renewable Generation Additions

The New England renewable generation additions assumed are summarized in Table 6.7.3 below. Renewable generation is assumed to be built primarily in response to state RPS policies, not to meet regional capacity needs (though partial credit for capacity is assumed in meeting ISO-NE's net installed capacity requirements).

Table 6.7.3: Cumulative New Renewable Generation Added Since 2012 (Cumulative MW of Summer Capacity)

	2014	2019	2024	2029	2034
Wind	-	1,462	2,243	3,686	4,901
Biomass/Landfill Gas	-	7	10	10	10
Solar Photovoltaic	225	1,349	2,220	2,922	3,484
Hydro/Tidal	-	23	32	35	51
Total	225	2,841	4,505	6,653	8,446

Given the relatively liberal RPS in Maine, we have assumed that Maine will be able to satisfy its RPS going forward with biomass facilities that are already online. For this reason, we have not modeled the Maine RPS in determining the regional RPS demand.

RPS requirements are assumed to continue increasing per their current legislated schedules. Beyond these schedules, RPS requirements are assumed to be fixed. Additional long-term demand for new renewable supply is due to increases in load growth.

New England Thermal Generation Additions

Future additions of thermal generating capacity are calculated by first determining a forecast of future New England installed capacity requirement, (NICR), net of existing tie benefits. This is determined by using the reference case load forecast from the most recent CELT Report and applying an average pool reserve requirement. For this forecast, the pool reserve requirement was determined to be 13.9 percent.

Once the NICR requirement is determined, the available supply is determined. Supply is made up of existing resources less retirements, plus new demand-side management (passive and active), projected imports and forecasted new renewable generation. The 674-MW Footprint project, slated for the current Salem Harbor site, has cleared, and Footprint assumed it to come online in May 2016 at the earliest.

Once the net of these resources is determined, any shortfall in meeting the NICR requirement is met with a combination of generic natural gas-fired combined cycle (CCCT) plants and generic simple cycle combustion turbine (SCCT) units. The first generic SCCT is added in 2017 and the first generic CCCT is added in 2020. Professional judgment is used to determine the location (zone) and type (SCCT or CCCT) of each added unit.

Table following table shows the results of the current ISO-NE thermal build out forecast.

Table 6.7.4: Cumulative New Thermal Generation Added Since 2012
(Cumulative MW of Summer Capacity)

	2014	2019	2024	2029	2034
Natural Gas CCCT	-	674	1,474	2,674	3,474
Natural Gas SCCT	-	300	1,500	3,000	4,500
Total	-	974	2,974	5,674	7,974

Transmission Topography

Transmission is represented as single composite links between zones. Key attributes that can be defined for each individual link are wheeling costs, transfer losses and transfer capability. In addition to the limits on individual links, there are also aggregate constraints on multi-link "internal interfaces" within ISO-NE. AURORA is capable of modeling such multi-link transfer constraints, and our modeling of internal interfaces in ISO-NE is based on the 2013 Regional System Plan assumptions.

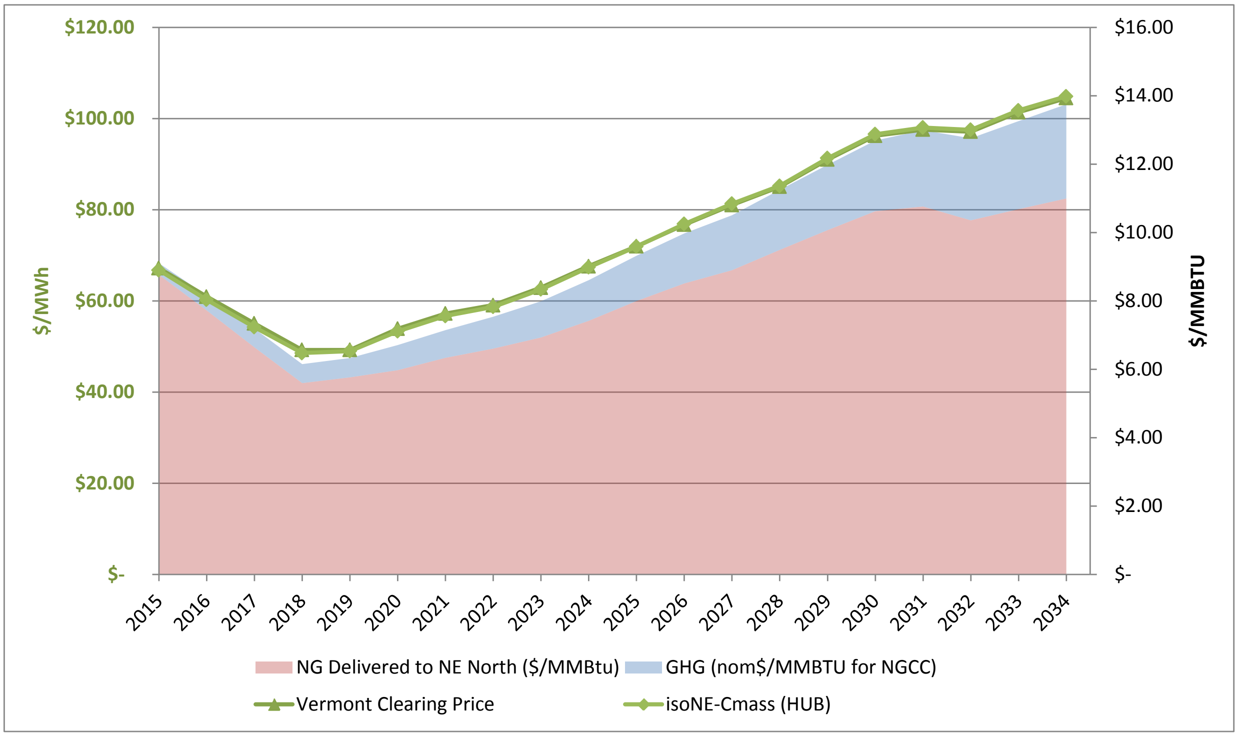
Our model assumes the following upgrades to the existing New England transmission system:

- The Maine Power Reliability Project (in-service 2015);
- Northern Pass (in-service 2019);
- New England East-West Solution (Greater Springfield Reliability Project in-service 2013;
- Interstate Reliability Project in-service 2018); and
- NEMA/Boston upgrades in-service 2014.

Results

Forecasted zonal marginal clearing prices (MCP) largely follow the assumed natural gas and CO_2 emissions prices. The following figure (below) illustrates this trend.

Figure 6.7.4: C-MA (NE Hub proxy), VT Clearing Prices, Natural Gas Fuel Price & CO_2 Price.[44]



In addition, congestion and losses are forecasted to have minimal impact on Vermont prices compared to the Central Massachusetts zone, which is used as proxy for the New England Hub price. However, as indicated earlier, the uncertainty surrounding the markets, especially in regard to natural gas prices and greenhouse case emission prices, creates considerable uncertainty around future electric generation wholesale prices in New England. This forecast should be considered as one credible outlook among many.

[44] For the purposes of plotting CO_2 prices, we assume a marginal CO_2 emissions rate of 120 lb/MMBtu, which is the approximate rate of a gas-fired unit (though on the high side to roughly account for coal and oil occasionally being on the margin).