1.3.3.2 Development of Elective Transmission Upgrades

Several developers have proposed Elective Transmission Upgrades (ETUs), which are in various stages of study and development.[43] These projects could increase New England's tie capability with its neighbors and improve access to renewable sources of energy. For example, certain generators are considering elective upgrades as a way to mitigate curtailment of wind energy resources. The ISO will continue to monitor the outcomes of these upgrades and their impacts on system conditions and needs. The ISO has initiated an effort to improve the existing Elective Transmission Upgrade process. (Section 5.2.4)

1.3.4 Regional Strategic Planning

In addition to identifying the need for capacity and operating reserves, the ISO assesses the potential impacts of fuel availability and public policies, including environmental initiatives, on the system's need for certain amounts, types, and locations of resources and transmission improvements. The ISO also is addressing issues concerning the development and integration of renewable resources and smart grid technologies.

1.3.4.1 Resource Performance and Natural Gas Dependency

The ISO is addressing several strategic planning issues associated with natural gas dependency, resource performance, and natural gas supplies. These problems have been quantified, and solutions are being implemented to improve infrastructure and markets.

Natural Gas Dependency. New England is increasingly dependent on natural gas as a primary fuel for generating electric energy and decreasing its dependence on oil. In 2000, 17.7% of the region's capacity was natural-gas-fired generation, which produced 14.7% of the region's electric energy, whereas in 2012, natural gas plants represented 43.0% of the region's capacity and 51.8% of the system's electric energy production. In 2000, oil units represented 34.0% of the region's capacity and produced 22.0% of the region's electric energy that year, but in 2012, oil units represented 21.6% of the capacity and produced 0.6% of the region's electric energy. Over the same period, the capacity reduction of coal units has been less severe from 11.7% to 7.8%; their energy production decreased from 17.9% to 3.2%. (Section 6.1)

The high regional use of natural gas to generate electricity is the result of the addition of new, efficient natural-gas-fired units over the past decade; the recent low price of natural gas; and the displacement of older, less efficient oil- and coal-fired units in economic dispatch. As the revenues from the wholesale electricity markets decline for these oil and coal units and more units retire, the regional reliance on natural gas for providing capacity and energy will increase. Further dependency on natural-gas-fired generation will likely occur, resulting from the loss of other types of generation subject to risks, such as nuclear and hydro units that may not be relicensed. Many units also do not have effective dual-fuel capability (in terms of the amount of time they need to switch to using oil or the availability of secondary fuel inventory). Accompanying the increased use of natural gas are concerns regarding the adequacy of the region's natural gas pipeline capacity and gas supply in the pipelines to serve electric power generation reliably; at any time of the year, natural and geopolitical events of all types could interrupt supplies of gas and other fuels, such as oil and coal. (Section 6.2)

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[43] An *Elective Transmission Upgrade* is an upgrade to the New England transmission system voluntarily funded by one or more participants that have agreed to pay for all the costs of the upgrade. *Merchant transmission facilities* are independently developed and funded and subject to the operational control of the ISO, pursuant to an operating agreement specific to each of these facilities.

Resource Performance. System events that occurred during 2012 and winter 2013 brought into focus the vulnerabilities and limitations of the system when generators have not made adequate arrangements for all types of fuel to support their energy offers, particularly during severe winter or other stressed system conditions. These events also highlighted reliability issues with infrequently operated oil- and coal-fired generators. In light of these resource availability concerns in 2012 and early 2013, the ISO is implementing, with stakeholder input, near-term improvements to the wholesale electricity markets to enhance system reliability. Plans call for the following improvements to be in place by the end of 2014:[44] (Section 6.2.6)

- Improve the use of the daily reoffer period, which enables resources to more closely reflect their true cost of fuel in their energy market offers, which is essential for appropriate energy market pricing
- Accelerate the timing of the Day-Ahead Energy Market and associated reliability commitments to align more closely with existing natural gas trading and nomination cycles, which will improve the ability of generators to procure needed natural gas and allow the ISO additional time to activate non-gas-fired generators, if needed
- Allow reserve prices to increase under tight system conditions to better reflect the costs of maintaining these reserves, which will improve energy market pricing and associated incentives for resources to deliver power when needed
- Increase the amount of needed operating reserves, which will more closely reflect system operator action and improve the pricing of reserves and electric energy
- Update the shortage-event trigger in the Forward Capacity Market to improve incentives for resources to make adequate arrangements for fuel during tight system conditions

In addition, the ISO is planning to implement several out-of-market measures to address fuel supply and reliability for the 2013/2014 winter.[45] These include ways of compensating generators that maintain oil inventories, increasing access to demand resources, and verifying the ability of dual-fueled units to switch fuels. These measures are intended to supplement the near-term market changes until the medium- and long-term changes can be implemented. (Section 6.2.6)

The ISO is working with stakeholders over the medium and long terms on additional improvements to the wholesale electricity markets. These improvements, expected to be implemented over the next few years, include the following: (Section 6.2.6)

- More fully integrating demand resources into the energy market, which will broaden the conditions under which demand resources could be called on to help meet the region's energy needs
- Further modifying the FCM shortage-event trigger and replacing the shortage-event penalty structure with a pay-for-performance model so that resources will have even stronger incentives to perform when system needs are greatest

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[44] For additional information on the near-, medium-, and long-term measures, see *Interdependencies of Market and Operational Changes to Address Resource Performance and Gas Dependency*, ISO white paper (2013), http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/interdependency_of_iso_proposals_to_key_spi_risks.pdf. *ISO New England Inc. and New England Power Pool, Docket No. ER13-___-000, Energy Market Offer Flexibility Changes*, FERC filing (July 1, 2013), http://www.iso-ne.com/regulatory/ferc/filings/2013/jul/index.html.

[45] FERC, *Order Conditionally Accepting Tariff Revisions,* 144 FERC ¶ 61,204 (September 16, 2013), http://www.iso-ne.com/regulatory/ferc/orders/2013/sep/index.html.

Natural Gas Supplies. Recent improvements to the interregional natural gas infrastructure have helped improve the supply of natural gas from the Marcellus Shale production areas to the Northeast. Additional enhancements to the regional pipeline network would allow New England to access the larger quantities of natural gas for the region's power generators. Unlike the electric power industry, which proactively plans the expansion of the transmission network, natural gas transportation requires firm contractual arrangements before natural gas pipeline facilities can be constructed. (Section 6.2)

A planning study of regional natural gas issues quantified the regional need for additional natural gas system supply or the use of non-gas-fired resources under a number of scenarios. The analysis considered several scenarios, including the replacement of older oil- and coal-fired generating units with natural-gas-fired generators and natural gas infrastructure outages affecting reliable electric power operation.[46] Additionally, a follow-up natural gas study has begun for determining the potential risks of energy shortfalls for the region under a variety of scenarios. The ISO also is coordinating an interregional study of the natural gas system with the NYISO, PJM, the Midcontinent Independent System Operator (MISO), the Independent Electricity System Operator (of Ontario) (IESO), and the Tennessee Valley Authority (TVA). (Section 6.2.5)

1.3.4.2 The Potential Impacts of Environmental Regulations on the Power System

Existing and pending state, regional, and federal environmental requirements addressing air pollution, greenhouse gas emissions, cooling water drawn from rivers and bays, and wastewater discharges that flow back into these water bodies as well as public treatment works will affect many New England generators in the 2015 to 2022 timeframe. Many generators in the region already have installed needed control technologies because of state environmental rules requiring earlier compliance, and new transmission upgrades have reduced the dependence on older, less efficient oil- and coal-fired units previously needed to address more local reliability concerns. These changes and the greater reliance on natural gas for power generation have lessened air pollution emissions and thermal pollution into rivers and bays in the region.

Between 2001 and 2011, systemwide emissions of nitrogen oxides (NO_X) declined by 58%, sulfur dioxide (SO_2) emissions by 71%, and carbon dioxide (CO_2) emissions by 11%. The decrease appears attributable to a nearly 50% decline in both oil- and coal-fired generation in 2011, combined with a significant increase in natural gas generation, which has a substantially lower SO_2 emission rate.[47] In addition to required compliance with regulations, the future regional emissions could vary because of a number of factors; regional emissions would increase with production by oil-fired generating units during periods of natural gas shortages and could decrease through the greater use of energy efficiency and wind and photovoltaic resources. (Section 6.3)

Using assessments of the potential impact of existing and proposed state and EPA regulations on identified fossil steam units in the region, the ISO is identifying existing generation across New England affected by these environmental requirements. Uncertainty remains over the extent to which the final

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[46] ICF International, *Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short- and Near-Term Electric Generation Needs*, final report (June 15, 2012), https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/reports/2012/gas_study_ceii.pdf.

[47] *2011 ISO New England Electric Generator Air Emissions Report* (February 2013), http://www.iso-ne.com/genrtion_resrcs/reports/emission/2011_emissions_report.pdf. These changes in generation are consistent with New England fuel consumption in 2010 and 2011, as reported by the US Energy Information Administration (EIA). Coal consumption for electric generators fell from 6.2 million short tons in 2010 to 3.0 million short tons in 2011, and residual fuel oil consumption fell from 1.5 million barrels in 2010 to 0.7 million barrels in 2011.

Section 3
Forecasts of New England's Peak Demand, Annual Use of Electric Energy, and Energy Efficiency

Load forecasts provide key inputs for evaluating the reliability and economic performance of the electric power system under various conditions and for determining whether and when improvements are needed. This section summarizes the forecasts for the annual use of electric energy and peak loads, New England-wide and in individual states and subareas. It also describes the economic and demographic factors that drive the forecasts and explains the forecasting methodology. For RSP13, the underlying methodology for forecasting annual energy use and peak loads has not changed. This section also provides the results of the ISO's regional energy-efficiency (EE) projections for the 10-year RSP planning horizon.

3.1 ISO New England Load Forecasts

The ISO load forecasts are estimates of the total amounts of electric energy the New England states will need annually and during seasonal peak hours. This year's forecast horizon runs from 2013 through winter 2022/2023. Each forecast cycle updates the data for the region's historical annual use of electric energy and peak loads by adding an additional year of data, the most recent economic and demographic forecasts, and resettlement adjustments that include meter corrections.[85]

The economic recession that ended in 2009 significantly affected regional electric energy consumption and had a corresponding impact on annual electric energy use and seasonal peak load forecasting, as reflected in the *2012 Regional System Plan* (RSP12) and continuing through the RSP13 forecast.[86] Compared with last year's economic forecast, the RSP13 economic outlook shows less growth in 2013 and, higher growth in 2015 through 2017, and similar growth for the remaining years. The outlook for 2013 to 2022 shows the growth in the gross domestic product (GDP) of 2.5% in 2013, rising to a high of 4.0% in 2015, and declining to about 2.1% by 2018 through 2022.

Table 3-1 summarizes the ISO's forecasts of annual electric energy use and seasonal peak load (50/50 and 90/10) for New England overall and for each state.[87] RSP13 forecasts of annual energy use, and both summer and winter seasonal peaks under 50/50 conditions are approximately the same as those

[85] The ISO's *Capacity, Energy, Load, and Transmission* (CELT) Reports and associated documentation contain more detailed information on short- and long-run forecast methodologies, models, and inputs; weather normalization; regional, state, subarea, and load-zone forecasts of annual electric energy use and peak loads; high- and low-forecast bandwidths; and retail electricity prices. They are available at "CELT Forecasting Details 2013," http://www.iso-ne.com/trans/celt/fsct_detail/index.html. Also see *2013–2021 Forecast Report of Capacity, Energy, Loads, and Transmission* (May 2013), http://www.iso-ne.com/trans/celt/report/, and *ISO Seasonal Peaks since 1980* (May 13, 2013), http://www.iso-ne.com/markets/hstdata/rpts/ann_seasonal_pks/index.html.

[86] Edward Friedman, *Fiscal Policy Remains Key to Outlook*, PAC presentation (Moody's Analytics, January 16, 2013), http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2013/jan162013/index.html.

[87] The 50/50 "reference" case peak loads have a 50% chance of being exceeded because of weather conditions. For the reference case, the summer peak load is expected to occur at a weighted New England-wide temperature of 90.2°F, and the winter peak load is expected to occur at 7.0°F. The 90/10 "extreme" case peak loads have a 10% chance of being exceeded because of weather. For the extreme case, the summer peak is expected to occur at a temperature of 94.2°F, and the winter peak is expected to occur at a temperature of 1.6°F.

published in RSP12.[88] Compared with the RSP12 forecast, the RSP13 50/50 load forecast for summer peak demand is 75 MW higher in 2013 and 50 MW lower in 2021.

Table 3-1
Summary of Annual Electric Energy Use and Peak Demand for New England and the States

State[(a)]	Net Energy for Load (1,000 MWh)			Summer Peak Loads (MW)					Winter Peak Loads (MW)				
				50/50		90/10		CAGR[(b)]	50/50		90/10		CAGR[(b)]
	2013	2022	CAGR[(b)]	2013	2022	2013	2022		2013/14	2022/23	2013/14	2022/23	
CT	34,145	37,400	1.0	7,310	8,110	7,975	8,825	1.1	5,750	5,925	5,860	6,045	0.3
ME	12,090	13,125	0.9	2,065	2,285	2,205	2,450	1.2	1,905	1,965	2,000	2,065	0.4
MA	63,060	70,195	1.2	12,955	14,890	13,985	16,055	1.5	10,280	11,055	10,490	11,295	0.8
NH	12,310	13,740	1.2	2,525	2,925	2,710	3,150	1.7	2,050	2,185	2,155	2,300	0.7
RI	8,745	9,435	0.8	1,895	2,140	2,130	2,405	1.4	1,395	1,445	1,445	1,495	0.4
VT	6,695	7,110	0.7	1,090	1,175	1,130	1,220	0.9	1,070	1,130	1,130	1,190	0.6
New England	137,045	151,005	1.1	27,840	31,520	30,135	34,105	1.4	22,445	23,700	23,080	24,395	0.6

(a) A variety of factors cause state growth rates to differ from the overall growth rate for New England. For example, New Hampshire has the fastest-growing economy in New England, and Maine has the slowest-growing economy in the region.

(b) CAGR stands for compound annual growth rate.

Net energy for load (NEL) is the generation output within an area, accounting for electric energy imports from other areas and electric energy exports to other areas. It also accounts for system losses and excludes the electric energy consumed to operate pumped-storage hydroelectric plants. The compound annual growth rate (CAGR) for the ISO's electric energy use is 1.1% for 2013 through 2022, 1.4% for the summer peak, and 0.6% for the winter peak.[89] The systemwide *load factor* (i.e., the ratio of the average hourly load during a year to peak hourly load) continues to decrease, from 56.2% in 2013 to 54.6% in 2022, but at a slower rate than in the past, and it begins to flatten by the end of forecast.[90]

Figure 3-1 shows a comparison of the ISO's actual summer peak demand (i.e., the load reconstituted to include the megawatts that had been reduced because of OP 4 and FCM passive demand resources) with the 50/50 load forecast and with the 90/10 load forecast.[91] The actual load has been near or has

[88] *Preliminary ISO-NE Annual Energy & Seasonal Peak Forecast 2013–2022*, PAC presentation (Preliminary Forecast 2013–2022 presentation) (February 12, 2013), http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2013/feb122013/a3_load_forecast.pdf.

[89] The compound annual growth rate (CAGR) is calculated as follows:

$$\text{Percent CAGR} = \left\{ \left[\left(\frac{\text{Peak in Final Year}}{\text{Peak in Initial Year}} \right)^{\left(\frac{1}{\text{Final Year} - \text{Initial Year}} \right)} - 1 \right] \times 100 \right\}$$

[90] Preliminary Forecast 2013–2022 presentation, slide 18.

[91] OP 4 actions include allowing the depletion of the 30-minute reserves and partial depletion of the 10-minute reserves (1,000 MW) (see Section 4.2), scheduling market participants' submitted emergency transactions and arranging emergency purchases between balancing authority areas (1,600 to 2,000 MW), and implementing 5% voltage reductions (400 to 450 MW). System conditions and the effectiveness of OP 4 actions affect the extent of the actions. Operating Procedure No. 4, *Action during a Capacity Deficiency* (December 9, 2011), http://www.iso-ne.com/rules_proceds/operating/isone/op4/index.html.

exceeded the 90/10 forecast six times over the last 20 years because of hot and humid weather conditions, and it has been near or above the 50/50 forecast 10 times during same period.[92]

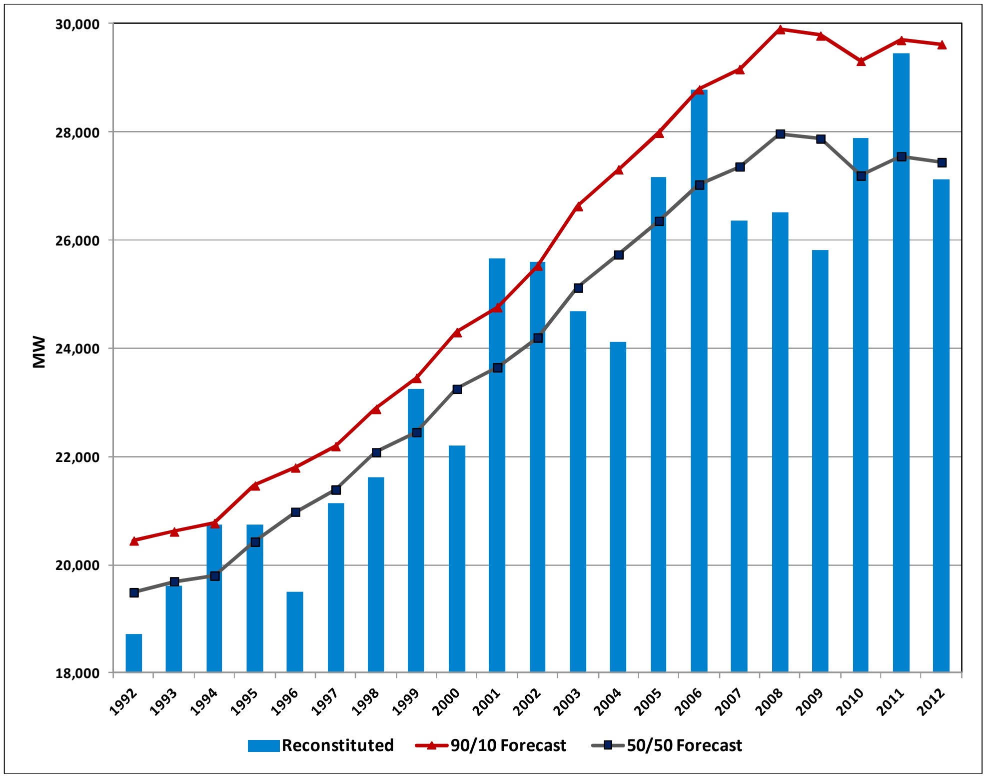

Figure 3-1: The ISO's actual summer peak loads (i.e., reconstituted for OP 4 and FCM passive demand resources) and the 50/50 and 90/10 forecasts (MW).

Note: The forecasted load values are the first-year values of the CELT forecast for each year. For example, the forecasted loads for 2012 are the loads for the first year of the 2012 CELT report.

3.1.1 Economic and Demographic Factors and Electric Energy Use

The price of electricity and other economic and demographic factors drive the annual use of electric energy and the growth of the seasonal peak. In addition to net energy for load, the forecasts account for the effects of future federal long-term energy-efficiency goals, as well as the historical effects of energy efficiency, but do not reflect the peak and electric energy savings attributable to passive demand resources (see Section 3.1.2).

The ISO's forecasts of electric energy use in New England and each state are based on a total energy-use concept, which sums the total electric energy used residentially (about 38%), commercially (about 42%), and industrially (about 20%). Real gross state product (RGSP) and the real price of electricity serve as proxies for overall economic and demographic conditions. These variables are the primary forces driving the model of electric energy use. Table 3-2 summarizes these and other indicators of the New England economy.

[92] Weather conditions during the actual peak summer loads were slightly below the expected 90/10 weather conditions for 1994, 1999, 2001, and 2002, and weather conditions were slightly above the expected 90/10 weather during both the 2006 and 2010 peaks. A spreadsheet containing historical annual peak loads and associated weather conditions since 1980 is available at http://www.iso-ne.com/markets/hstdata/rpts/ann_seasonal_pks/seasonal_peak_data_summary.xls.

Table 3-2
New England Economic and Demographic Forecast Summary

Factor	1980	2012	CAGR	2013	2022	CAGR
Summer peak (MW)	14,539	27,430	2.0	27,840	31,520	1.4
Net energy for load (1,000 MWh)	82,927	136,162	1.6	137,045	151,005	1.1
Population (thousands)	12,378	14,558	0.5	14,614	14,971	0.3
Real price of electricity (¢/kWh, 2012$)[a]	17.289	14.156	−0.7	14.156	14.156	0.0
Employment (thousands)	5,483	6,856	0.7	6,909	7,484	0.9
Real income (millions, 2005 $)	280,918	661,204	2.7	671,990	885,085	3.1
Real gross state product (millions, 2005 $)	310,452	732,663	2.7	750,722	954,927	2.7
Energy per household (MWh)	18.954	23.749	0.7	23.740	24.705	0.4
Real income per household (thousands) (2005 base year)	64.207	115.324	1.8	116.405	144.804	2.5

(a) kWh stands for kilowatt-hour.

The forecast of the retail electricity prices assumes that the prices will grow at the rate of inflation (2.7% average annual growth) and have fully incorporated the capacity costs from the Forward Capacity Market.

The *Economy.com* November 2012 economic forecast of real gross state product was used to represent overall economic activity in the RSP13 forecast models. Compared with the November 2011 *Economy.com* economic forecast, the November 2012 *Economy.com* forecast of real gross state product shows less growth from 2011 through 2013, higher growth from 2014 through 2017, and the same growth for the remaining years.[93] Figure 3-2 compares the RGSP forecasts from November 2012 with the forecasts from November 2011.[94]

[93] Economy.com forecasts of New England gross state product (millions of 2005 $) from November 2012 and November 2011 forecasts.

[94] Preliminary Forecast 2013–2022 presentation, slide 10.

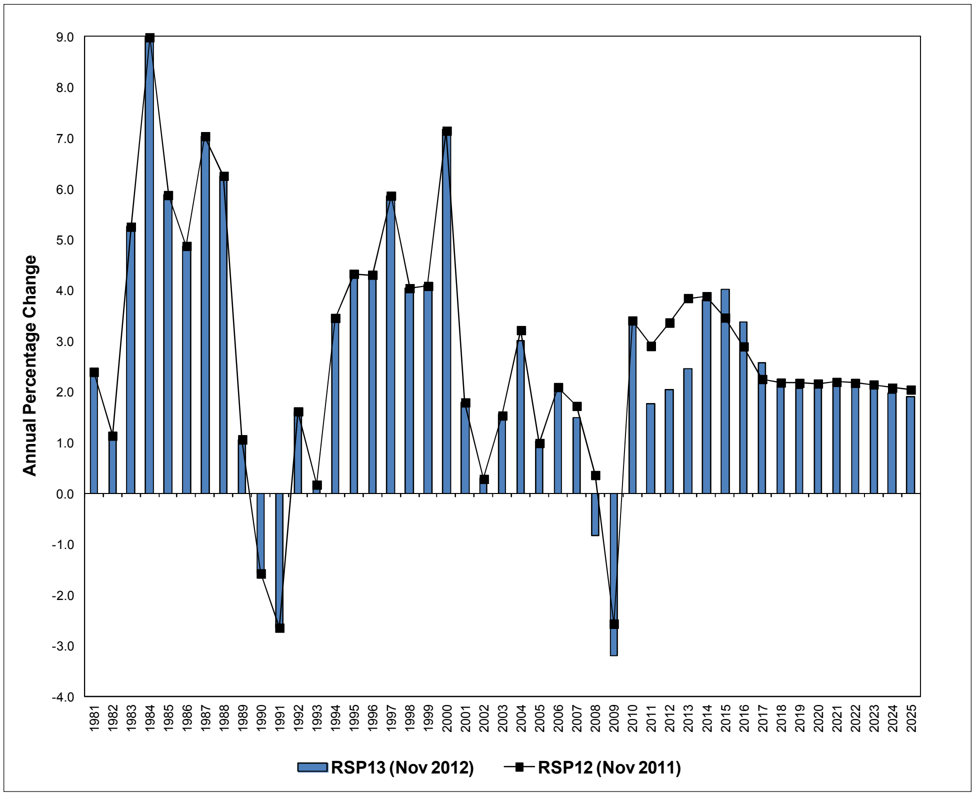

Figure 3-2: "Economy.com" forecasts of New England gross state product from November 2012 and November 2011 forecasts.

Source: Moody's Analytics, Economy.com.
Notes: Years 1981 to 2012 reflect actual gross state product. Note the US Bureau of Economic Analysis revisions to the historical data for 2007 to 2011.

3.1.2 The CELT Forecast and Passive Demand Resources

The seasonal peak load and energy-use forecast, as published in the *2013–2022 Forecast Report of Capacity, Energy, Loads, and Transmission* (2013 CELT Report) and used for calculating the Installed Capacity Requirement (ICR), fully accounts for historical energy efficiency, passive demand resources, and future federal appliance standards.[95] The forecast does not expressly reflect the future reduction in peak demand and energy use that will result from the passive demand resources that clear the Forward Capacity Auctions and the energy-efficiency forecast (described in detail in Section 3.2). Historical reductions in load from "other demand resources" in the transition period leading up to the FCM and from the passive demand resources in the FCM have been added back into the historical loads used for load forecasting.[96]

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[95] 2013 CELT Report (May 2013), http://www.iso-ne.com/trans/celt/report/index.html. Copies of all CELT reports are available at http://www.iso-ne.com/trans/celt/index.html. The ICR is the amount of capacity the New England region will need in a particular year to meet its NPCC resource adequacy planning criteria; see Section 4.1.1 for additional information.

[96] *Other demand resources*, an asset category that was retired on May 31, 2010, at the end of the transition period leading to the FCM, consisted of energy-efficiency measures, load management, and distributed generation—typically nondispatchable resources that tend to reduce end-use demand on the electricity network across many hours but usually not in direct response to changing hourly wholesale prices. For additional information on ODRs, refer to AMR10, Section 2.7, http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/index.html.

3.1.3 Subarea Use of Electric Energy

Much of the RSP13 reliability and production cost analysis depends on the forecasts of annual electric energy use and peak demand in the subareas. Table 3-3 summarizes these forecasts and provides important market information to stakeholders.[97] Table 3-4 shows the forecast for the RSP subareas and their relationship to the load zones and states.[98] The forecasts for the peak demand and annual energy use in the subareas are based on allocating the ISO's state forecasts to distribution companies within the states (on the basis of historical shares), allocating the distribution company forecasts to busses using the ISO model of the transmission network, and then aggregating the busses for each of the subareas.

Table 3-3
Forecasts of Annual Use of Electric Energy and Peak Demand in RSP Subareas, 2013 and 2022

Area	Net Energy for Load (1,000 MWh)			Summer Peak Loads (MW)					Winter Peak Loads (MW)				
				50/50 Load		90/10 Load			50/50 Load		90/10 Load		
	2013	2022	CAGR	2013	2022	2013	2022	CAGR	2013/14	2022/23	2013/14	2022/23	CAGR
BHE	1,825	1,985	0.9	310	345	330	370	1.3	290	300	305	315	0.4
ME	5,665	6,400	1.4	925	1,070	985	1,150	1.7	935	995	985	1,045	0.7
SME	4,275	4,385	0.3	760	790	815	850	0.5	640	630	675	665	−0.2
NH	10,755	11,975	1.2	2,180	2,515	2,335	2,705	1.6	1,780	1,900	1,875	2,000	0.7
VT	7,425	7,995	0.8	1,280	1,405	1,335	1,475	1.1	1,200	1,275	1,265	1,340	0.6
BOSTON	28,320	31,240	1.1	5,835	6,620	6,300	7,140	1.4	4,600	4,925	4,695	5,035	0.8
CMA/NEMA	8,410	9,255	1.1	1,720	1,950	1,855	2,100	1.4	1,380	1,470	1,410	1,505	0.7
WMA	10,890	12,025	1.1	2,165	2,465	2,335	2,655	1.4	1,820	1,945	1,860	1,990	0.8
SEMA	14,095	15,765	1.3	2,945	3,440	3,185	3,720	1.7	2,260	2,415	2,310	2,470	0.7
RI	11,705	13,090	1.3	2,510	2,920	2,790	3,240	1.7	1,870	2,010	1,930	2,070	0.8
CT	16,615	18,165	1.0	3,555	3,940	3,875	4,290	1.1	2,800	2,875	2,855	2,935	0.3
SWCT	11,300	12,380	1.0	2,415	2,680	2,635	2,920	1.1	1,905	1,965	1,940	2,005	0.4
NOR	5,760	6,345	1.1	1,240	1,375	1,355	1,495	1.1	965	1,005	985	1,025	0.4
ISO total[a, b]	137,045	151,005	1.1	27,840	31,520	30,135	34,105	1.4	22,445	23,700	23,080	24,395	0.6

(a) The total load-zone projections are similar to the state load projections and are available at the ISO's "2013 Forecast Data File," http://www.iso-ne.com/trans/celt/fsct_detail/index.html; tab #2, "ISO-NE Control Area, States, Regional System Plan (RSP13) Subareas, and SMD [Standard Market Design] Load Zones Energy and Seasonal Peak-Load Forecast."

(b) Totals may not equal the sum because of rounding and may not exactly match the results for other tables in this section.

[97] Forecasts of net energy for load and peak loads are "gross loads." Additional details of the loads are available at "CELT Forecasting Details 2013," http://www.iso-ne.com/trans/celt/fsct_detail/index.html. Also see the full 2013 CELT report, *2013–2024 Forecast Report of Capacity, Energy, Loads, and Transmission* (May 2013), http://www.iso-ne.com/trans/celt/report/.

[98] For additional information, refer to the pricing node tables available at "Settlement Model Information," http://www.iso-ne.com/stlmnts/stlmnt_mod_info/index.html.

Table 3-4
Forecasts of RSP Subarea Peak Demand, 2013[a]

RSP Subarea	Load Zone	State	50/50 Summer Peak Load			90/10 Summer Peak Load		
			MW	% of RSP Subarea	% of State	MW	% of RSP Subarea	% of State
BHE	ME	Maine	310	100.0	15.0	330	100.0	15.0
ME	ME	Maine	925	100.0	44.8	985	100.0	44.7
SME	ME	Maine	760	100.0	36.8	815	100.0	37.0
NH	ME	Maine	70	3.2	3.4	75	3.2	3.4
	NH	New Hampshire	2,035	93.5	80.6	2,180	93.4	80.4
	VT	Vermont	75	3.4	6.9	80	3.4	7.1
			2,180			2,335		
VT	NH	New Hampshire	335	26.2	13.3	360	26.9	13.3
	VT	Vermont	945	73.9	86.7	980	73.3	86.7
			1,280					
BOSTON	NH	New Hampshire	85	1.5	3.4	90	1.4	3.3
	NEMA/ Boston	Massachusetts	5,755	98.6	44.4	6,210	98.6	44.4
			5,835			6,300		
CMA/NEMA	NH	New Hampshire	75	4.4	3.0	80	4.3	3.0
	WCMA	Massachusetts	1,645	95.7	12.7	1,775	95.7	12.7
			1,720			1,855		
WMA	VT	Vermont	70	3.2	6.4	75	3.2	6.6
	CT	Connecticut	100	4.6	1.4	110	4.7	1.4
	WCMA	Massachusetts	1,995	92.1	15.4	2,155	92.3	15.4
			2,165			2,335		
SEMA	RI	Rhode Island	170	5.8	9.0	190	6.0	8.9
	SEMA	Massachusetts	2,775	94.2	21.4	2,995	94.0	21.4
			2,945			3,185		
RI	RI	Rhode Island	1,725	68.7	91.0	1,940	69.6	91.1
	SEMA	Massachusetts	785	31.3	6.1	845	30.3	6.0
			2,510			2,790		
CT	CT	Connecticut	3,555	100.0	48.6	3,875	100.0	48.6
SWCT	CT	Connecticut	2,415	100.0	33.0	2,635	100.0	33.0
NOR	CT	Connecticut	1,240	100.0	17.0	1,355	100.0	17.0

(a) Totals may not equal the sum because of rounding and may not exactly match the results for other tables in this section.

3.2 Energy-Efficiency Forecast for New England

The FCM provides the ISO with a comprehensive understanding of the short-term savings in energy use over the FCM horizon. Since 2009, the ISO also has been analyzing energy-efficiency programs and studying how to model incremental, future long-term EE savings for five to 10 years. This deliberate and analytic effort advanced the ISO's understanding of energy efficiency from anecdotal to empirical. The result was the nation's first regional (multistate) long-term forecast of energy efficiency. The ISO's regional energy-efficiency forecast, as summarized in this section for 2016 through 2022, is part of ongoing efforts to analyze the long-term impacts of state-sponsored energy-efficiency programs on future demand.[99]

3.2.1 Results of the 2013 Forecast of Energy Efficiency

The final EE forecast for 2016 to 2022 projects savings in the average, total, and peak energy use for the region and each state. The results, which are based on an average annual spending rate among the six states of approximately $800 million per year, show a regional annual average energy savings of 1,358 gigawatt-hours (GWh). The forecast for total energy savings from 2016 to 2022 is 9,503 GWh. The states' annual average energy savings ranges from a low of 58 GWh in New Hampshire to a high of 761 GWh in Massachusetts.

The regional average savings in peak demand is 193 MW. The forecast for total peak savings is 1,353 MW from 2016 to 2022. The states' annual average peak savings ranges from a low of 10 MW in Maine and New Hampshire to a high of 110 MW in Massachusetts. Table 3-5 shows the results of ISO's final EE forecast for 2016 to 2022.

[99] State-sponsored EE programs consist of various efforts designed to reduce energy consumption. These efforts generally are funded by multiple sources, including a system benefits charge (SBC) applied to customer bills, the Regional Greenhouse Gas Initiative (RGGI) auction revenues (see Section 6.3.2.4), and state EE policy funds. More information on the methodology used to develop the EE forecast is available at the ISO's "Energy-Efficiency Forecast Working Group," web page (2013), www.iso-ne.com/eefwg.

Table 3-5
ISO New England's Final Energy-Efficiency Forecast for 2016 to 2022 (GWh, MW)[(a)]

Forecast of Electric Energy Savings (GWh)							
Year	Sum of States	States					
		ME	NH	VT	CT	RI	MA
2016	1,621	108	68	120	246	161	919
2017	1,529	102	65	119	232	150	861
2018	1,435	97	61	113	218	140	806
2019	1,349	91	58	109	204	131	754
2020	1,268	86	55	107	192	122	706
2021	1,187	81	52	100	180	114	660
2022	1,114	76	49	97	169	106	618
Total	9,503	641	408	765	1,441	924	5,324
Average	**1,358**	**92**	**58**	**109**	**206**	**132**	**761**

Forecast of Peak Demand Savings (MW)							
Year	Sum of States	States					
		ME	NH	VT	CT	RI	MA
2016	231	12	11	18	31	26	133
2017	218	12	11	18	29	24	124
2018	204	11	10	17	27	23	116
2019	192	10	10	16	26	21	109
2020	180	10	9	16	24	20	102
2021	169	9	9	15	23	18	95
2022	159	9	8	14	21	17	89
Total	1,353	73	68	114	181	149	768
Average	**193**	**10**	**10**	**16**	**26**	**21**	**110**

(a) The forecast results are available at www.iso-ne.com/eefwg.

Individual program administrators and state regulatory agencies provide the ISO with the EE program performance and budget data used to create the forecast. ISO New England's Energy-Efficiency Forecast Working Group assesses the forecast assumptions and offers input.

3.3 Load Forecast Incorporating FCA #7 Results and 2013 Energy-Efficiency Forecast

The section presents the load forecast reflecting FCM passive demand resources, including the results of the seventh Forward Capacity Auction (FCA #7) for the 2016/2017 capacity commitment period (CCP) and the 2013 energy-efficiency forecast for 2017–2022 (not from 2016, as presented in Section 3.2.1, which discusses the forecast prepared before FCA #7).[100] Figure 3-3 and Figure 3-4 show a revised load forecast of annual energy use and summer peak loads, incorporating FCM passive demand resources through 2016 and the EE forecast data for 2017 to 2022, as presented in Table 3-5. Thus, these figures differ from those included in the *Final 2013 Energy-Efficiency Forecast 2016-2022*, which incorporate FCM passive resources from FCA #6 through 2015 and the 2013 EE forecast for 2016 to 2022.[101]

[100] A *capacity commitment period,* also referred to as a *capability year*, is the one-year period from June 1 through May 31 of the following year for which Forward Capacity Market obligations are assumed and payments are made (see Section 4.1).

[101] ISO New England, *2013 Energy Efficiency Forecast* (February 22, 2013), http://www.iso-ne.com/eefwg.

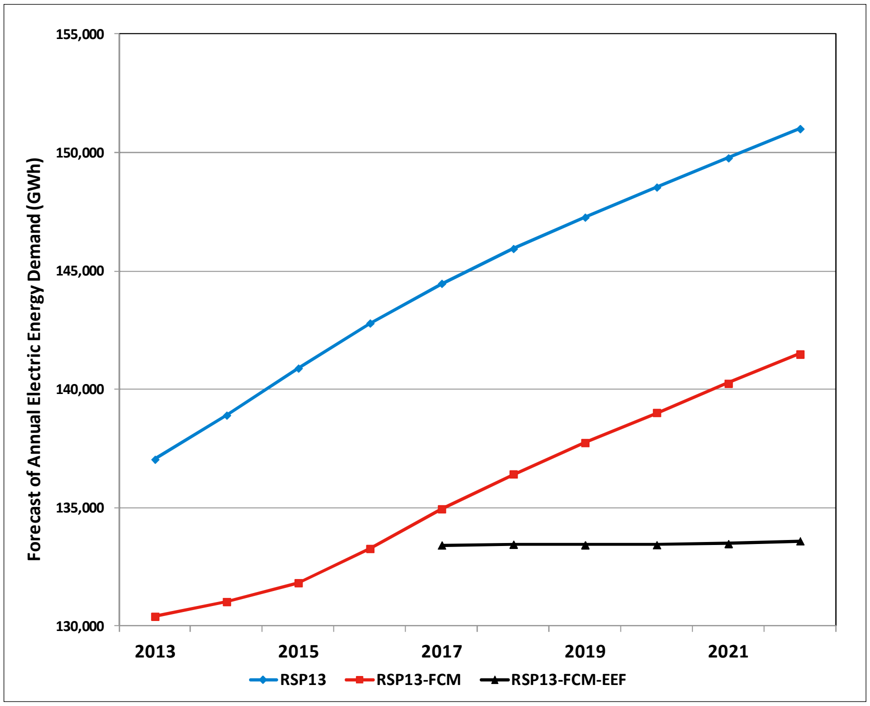

Figure 3-3: Revised RSP13 annual energy-use load forecast (diamond), load forecast minus FCM #7 results through 2016 (square), and load forecast minus FCM results and minus the energy-efficiency forecast (triangle) for 2017 to 2022 (GWh).

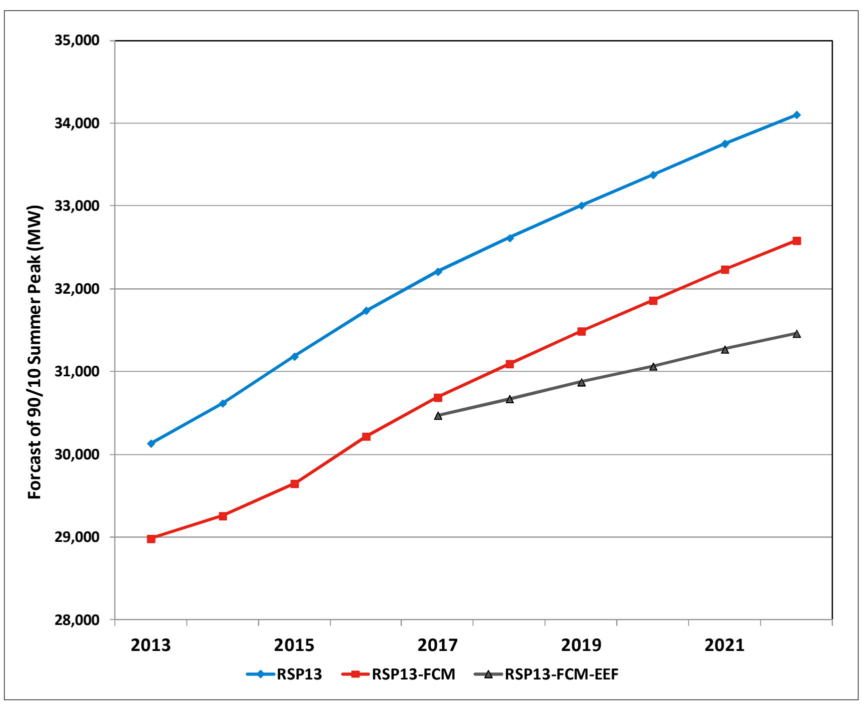

Figure 3-4: Revised RSP13 summer peak demand forecast (90/10) (diamond), load forecast minus FCM #7 results through 2016 (square), and load forecast minus FCM results and minus the energy-efficiency forecast (triangle) for 2017 to 2022 (MW).

As shown in Table 3-6, the annual energy use forecast, minus both the FCM passive resources projected for 2013–2016 and the results of the 2017–2022 energy-efficiency forecast, shows essentially no long-run growth in electric energy use. The summer peak 90/10 forecast, when adjusted for both the existing FCM passive resources projected for 2013–2016 and the 2017–2022 energy-efficiency forecast, is projected to increase at a more modest rate, approximately half the projected growth rate of the forecast.

Table 3-6
2013 Forecasts of Annual and Peak Electric Energy Use Compared with the Forecast Minus FCM Passive Resources (2013 to 2016) and Energy-Efficiency Forecast Results (2017 to 2022)

	Gross	Gross – (FCM + EEF)
NEL	1.1	0.3
50/50 and 90/10 Summer	1.4	0.9
50/50 and 90/10 Winter	0.6	−0.1

3.4 Summary of Key Findings of the Load and Energy-Efficiency Forecasts

The RSP13 forecasts of annual net energy use and peak loads are key inputs in establishing the system needs discussed in Section 4 through Section 7. The RSP13 forecasts for the annual use of electric energy and summer and winter peak are essentially the same as in RSP12. The key points of the forecast are as follows:

- The recent recession ended in 2009, followed by relatively slower economic growth beginning in the early years of the forecast. The forecast for the economy shows faster growth through 2017 compared with the previous few years and then return to a long-run sustainable growth rate.
- The forecasts for annual energy use and the summer and winter peaks are not materially different from the RSP12 forecast.
- The ISO will continue examining ways to improve the load forecast further.
- The gross compound annual growth rate for the ISO's electric energy use is 1.1% for 2013 through 2022, 1.4% for the summer peak, and 0.6% for the winter peak.
- The annual load forecast minus both the FCM passive resources and the ISO EE forecast shows essentially no long-term growth in energy consumption and reductions in the peak load.

Similar to any forecast, some level of uncertainty exists in the ISO's energy-efficiency forecast. Nevertheless, as the region gains experience using this EE forecast methodology, the ISO and regional stakeholders will consider adjusting the methodology to ensure that the results are as accurate as possible. The ISO's planning activities have incorporated the EE forecast, and regional transmission assessments and other planning studies appropriately reflect this forecast and the impacts from the region's large investments in EE, as appropriate.

Section 6
Studies and Other Actions Supporting the Strategic Planning of the Region

The ISO has been conducting a number of studies to assist regional stakeholders in understanding the risks identified through the Strategic Planning Initiative, some of which are as follows:[211]

- Resource performance and flexibility
- Increased reliance on natural-gas-fired capacity
- Retirement of generators
- Planning and operating a greater level of intermittent resources (i.e., variable energy resources; VERs) to maintain system reliability

These risks are interrelated, and many of the studies are providing information and data on the broader issues facing the region, the extent of these issues, and potential solutions. Some of the main issues are fuel diversity and supply; the impacts of environmental regulations on generators and the power system overall, including the potential for unit retirements; and the large-scale integration of wind and photovoltaic resources.

This section summarizes some of these major planning issues under study to address the region's strategic risks and actions the ISO and the region are taking to address them, which include developing improvements to the wholesale electricity markets and system operations and planning.

6.1 Changing Mix of Fuels and Diminishing Fuel Diversity

In a little more than a decade, New England has seen a major shift in its generation fleet. In this time, the region has moved from a more balanced mix of oil, coal, nuclear, and natural gas generators, to a system where 51.8% of the electric energy produced in the region is by natural gas power plants, representing 43.0% of the region's capacity. In 2000, 17.7% of the region's generating capacity was natural-gas-fired generation, which produced 14.7% of the region's electric energy. Also showing this shifting emphasis of fuel types, oil units represented 34.0% of the region's capacity in 2000 and produced 22.0% of the region's electric energy that year, but in 2012, oil units represented 21.6% of the capacity and produced only 0.6% of the region's electric energy. Over the same period, the capacity reduction of coal units has been less severe, from 11.7% to 7.8%; their energy production decreased from 17.9% to 3.2%. Figure 6-1 illustrates this shifting emphasis of New England's generating capacity and fuel types for electric energy production for 2000 and 2012.

[211] ISO New England, "Strategic Planning Initiative," web page (2013), http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/index.html.

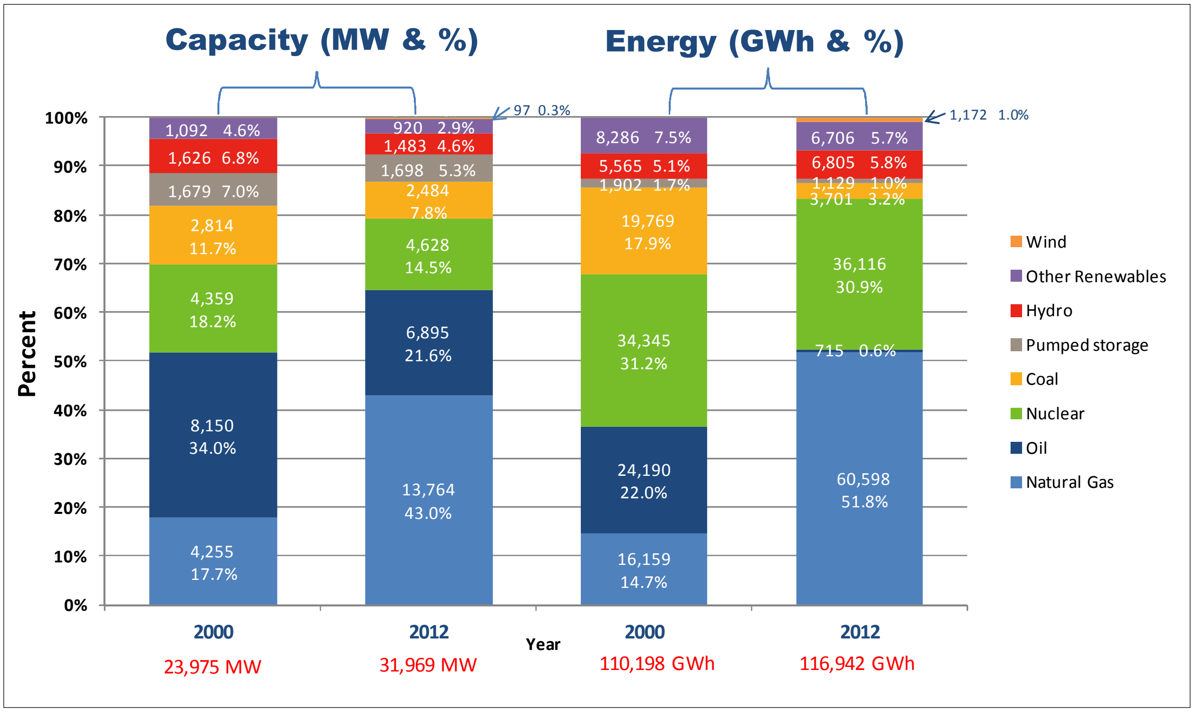

Figure 6-1: New England's generating capacity and electric energy production by fuel type, 2000 and 2012.

Note: The capacity and energy statistics illustrated in the figure do not include capacity and energy associated with imports or behind-the-meter generation not registered in the region's wholesale energy market.

Sources: The capacity data are from the *2012 Regional System Plan* (http://www.iso-ne.com/trans/rsp/index.html), the energy data for 2000 are from the 2001 CELT Report (http://www.iso-ne.com/trans/celt/report/2001/index.html), and the energy data for 2012 are from the 2013 CELT Report (http://www.iso-ne.com/trans/celt/report/).

The future fuel mix of the region will show continued dependence on natural-gas-fired generation and the addition of intermittent renewable resources. Recent FCM auction results have shown the beginning of the retirement of coal- and oil-fired generators in the region, as well as the introduction of a diverse set of renewable and demand resources.[212] As additional generators retire, units in the ISO Generator Interconnection Queue, which primarily are natural-gas-fired generation and wind resources (see Section 4.4.3) will likely replaced them. Further increases in the use of natural-gas-fired generation will likely occur, resulting from the loss of other types of generation subject to risks, such as nuclear and hydro units that may not be relicensed. The region also is beginning to experience the addition of photovoltaic resources, and future growth is expected.

6.2 Natural Gas and Oil Supply Issues for Power Generation

The region faces a number of concerns for ensuring the reliability of the fuel supply, particularly the supply of natural gas and oil. Operating experience has exposed some vulnerabilities associated with the strategic risks of resource performance and flexibility and the increased reliance on natural-gas-fired capacity. Market rules that allow resources to constrain their operation when they have limited fuel and

[212] Generating capacity has retired at Salem Harbor, AES Thames, and Somerset; Bridgeport Harbor failed to qualify for FCA #7; and Norwalk Harbor Stations dynamically delisted in FCA #7, for a total of 1,493 MW (596 MW coal fired and 897 MW oil fired).