2017 Update: Challenges for Electric System Planning

Reasonable Alternatives to ISO-NE's Discounts for Uncertainty

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Synapse Energy Economics prepared this 2017 Update on behalf of several clients as part of our ongoing work with the New England Power Pool (NEPOOL). The New Hampshire Office of Consumer Advocate, one of those clients, provided additional support to assemble our NEPOOL data and analysis in this format.

We gratefully acknowledge the invaluable support from current and former clients that have sponsored this analysis over the last several years. The views, opinions, and conclusions expressed in this paper are those of Synapse Energy Economics and do not necessarily reflect the views of any of our clients.

The 2015 report *Challenges for Electric System Planning* is available at http://www.synapse-energy.com/sites/default/files/Challenges-for-Electric-System-Planning_0.pdf.

CONTENTS

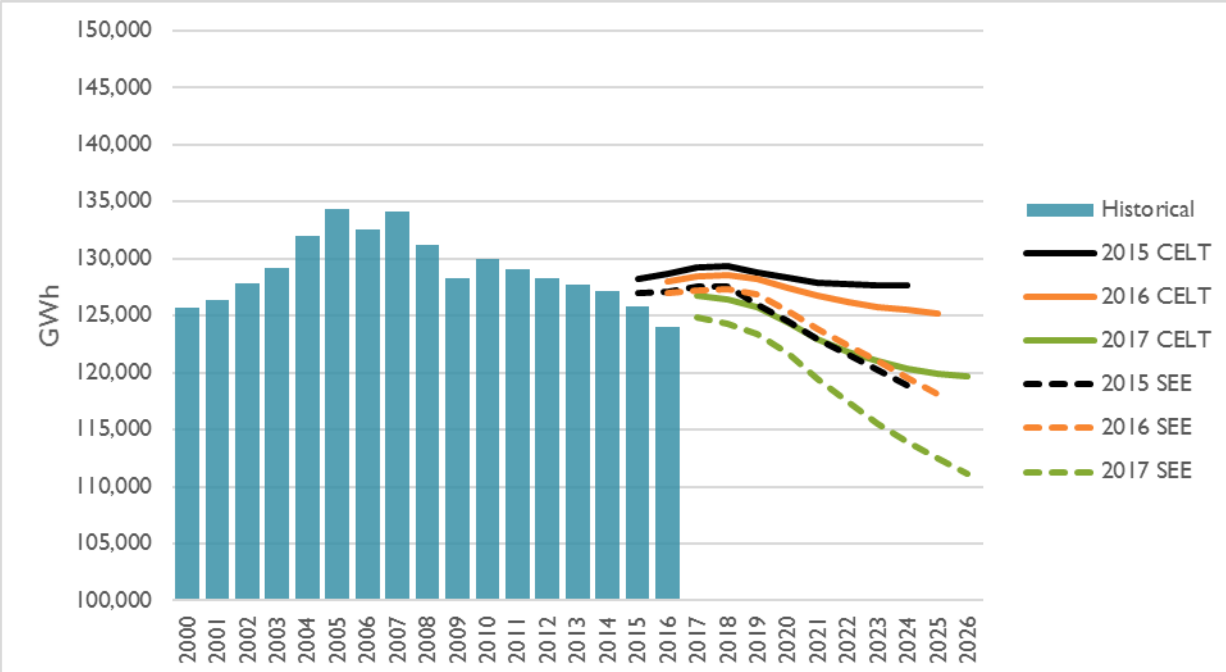
2017 UPDATE EXECUTIVE SUMMARY

In our 2015 report, we identified several long-term trends that affect forecasts of future loads that ISO New England uses to identify bulk power system needs through their regional system plan (RSP) process. Those trends include reduced annual energy consumption and declining future peak loads, along with substantial investments in energy efficiency (EE) and photovoltaic (PV) resources through specific initiatives in each New England state. We noted that each year, ISO New England's ten-year forecasts for annual energy and peak loads (CELT) were consistently off by 10-20 percent, and always over forecast, never under. We noted that this consistent over-statement of future electric loads will distort the ISO's evaluation of the bulk power system and identify transmission facility upgrades that may not be needed if the CELT forecasts are more accurate.

This paper updates the analysis we did in 2015, as applied to the 2015 CELT values, by including the same relative metrics (annual energy consumption, summer peak, and winter peak) for the 2016 and 2017 CELT reports. As with the 2015 report, we made no adjustment to the underlying growth rate produced by the ISO model that relies on an econometric forecast, as well as historical consumption data and weather. We only adjusted the ISO assumptions about "discounts" that it applies to the separate EE and PV forecasts. As explained in the 2015 paper, the discounts that the ISO applies to both forecasts are not well-established values; they are assumptions that the ISO believes are appropriate to apply, despite annual stakeholder comments to the contrary. We noted in 2015 that the discounts seemed likely to understate estimates of future EE and PV resources and produce load forecasts that exceed current trends. To its credit, the ISO reduced the size of the discounts in some categories in both 2016 and 2017 based on stakeholder feedback and new data.

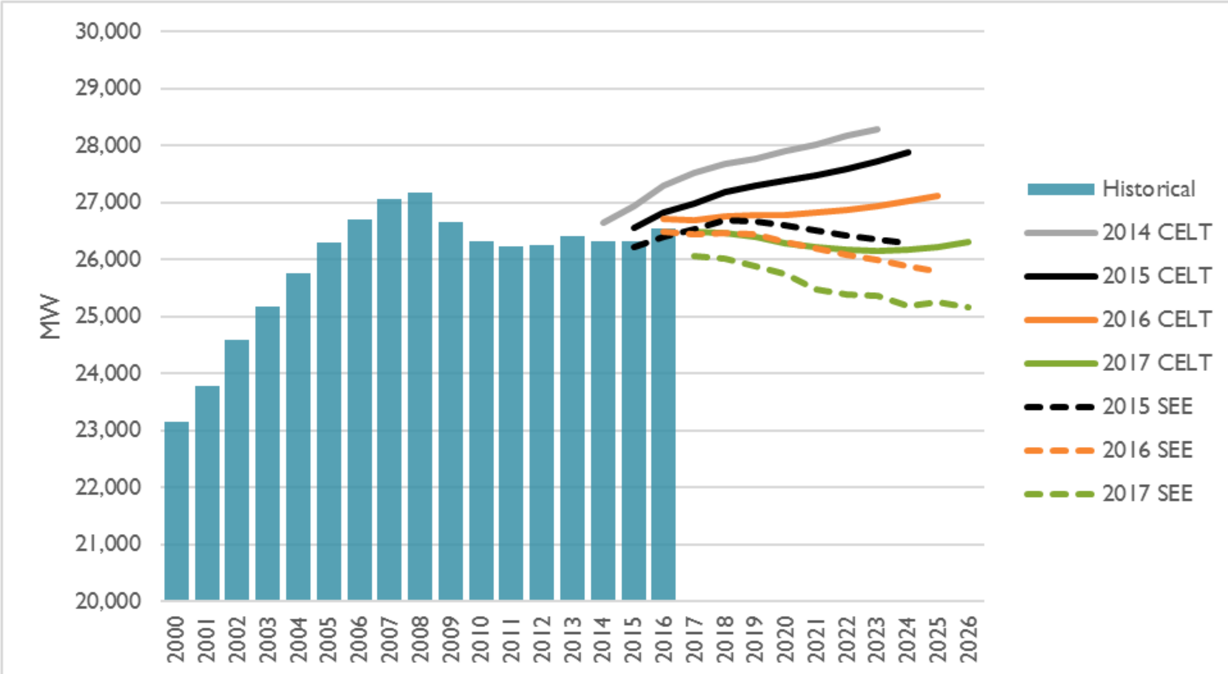
Our 2017 Update shows significant differences between the CELT forecasts and Synapse forecasts for the last three years. In all cases, the Synapse forecasts are lower than the CELT forecasts. This is a simple mathematical result: by removing and reducing the discounts to the EE and PV forecasts, there are greater quantities of each resource in future years. These greater quantities show up as "load reductions" in the CELT forecasts, as seen in the differences among recent CELT net energy for load forecasts in Figure 1.

Figure 1. Net energy for load, ISO-NE forecasted versus Synapse forecasted, GWh



The most significant variations occur in the annual energy consumption forecasts. This is understandable because both energy efficiency and photovoltaic resources produce large quantities of load reduction over numerous hours, 365 days a year. Note that the 2017 ISO CELT forecast is now consistent with the 2015 Synapse forecast, as seen in Figure 1. Also, the 2017 Synapse forecast for 2026 is 10,000 GWh lower than the 2017 CELT. This would be 10 million fewer MWh sold in 2026; at an average price of $45/MWh it would mean almost a half-billion dollars less in annual energy market revenues.

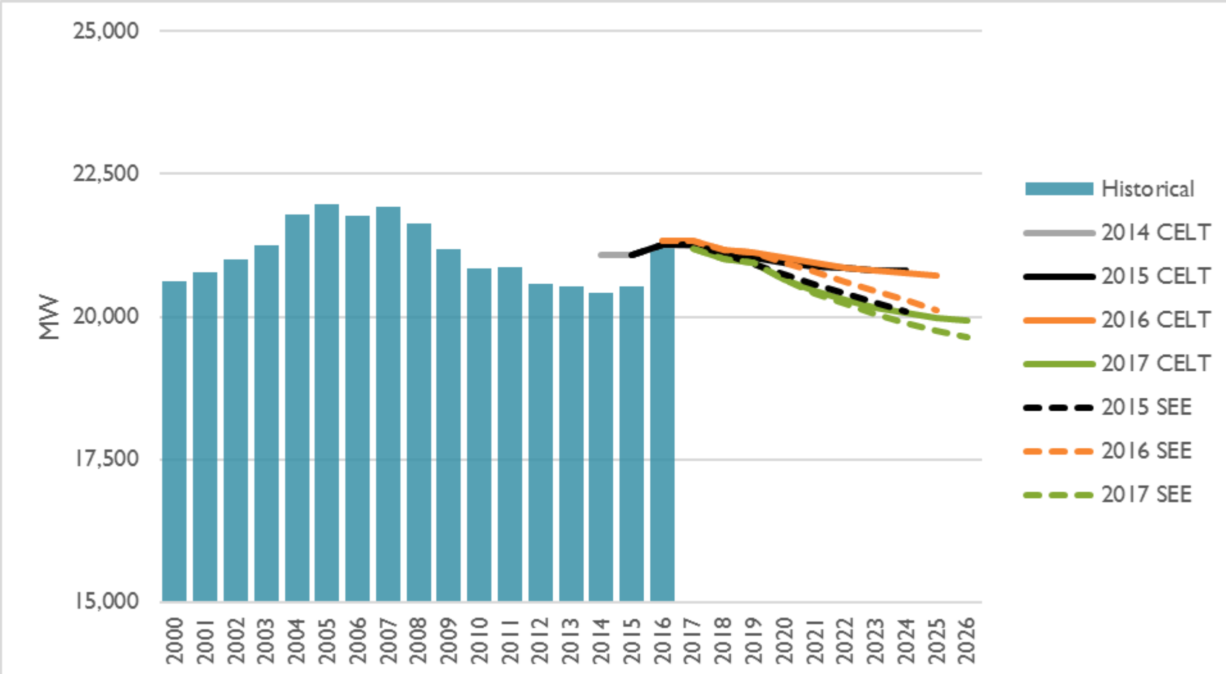
Figure 2. Summer peak load, ISO-NE forecasted versus Synapse forecasted, MW



The variations in the forecasts for summer peak loads are smaller because photovoltaic resources are shifting the summer peaks to later in the day (5-7pm) when the energy contributions from PV panels are reduced. Adding more PV does little to lower the peak, while adding energy efficiency resources still contributes to peak load reductions.

As seen in Figure 3, the winter peak load forecasts show the smallest variation because photovoltaic resources provide no energy during the dark hours of the winter peaks that occur from 4-7 pm. Energy efficiency resources continue to contribute to lower winter peaks, but not as substantially as the summer peaks due to the absence of air conditioners in winter (and the substantial efficiency improvements in those appliances).

Figure 3. Winter peak load, ISO-NE forecasted versus Synapse forecasted, MW



Although we are confident that our adjustments to the ISO discounts improve both the EE and PV forecasts, we are still concerned that other components of the CELT forecasts contribute to the decade long overstatement of future loads when compared to the actual loads. One of our primary suspects is the use of Moody's econometric forecast and its relationship to historical loads. The ISO model may need adjustments to reflect the new diminished correlation between general economic growth and increased use of electricity.

Other factors that deserve study include the potential for non-program actions by consumers of electricity. ISO New England has repeatedly stated that it only intends to include state program activities when developing their EE and PV forecasts. Non-program actions may include consumers (small and large) who actively manage their demand profiles to reduce their installed capacity obligations and the costs associated with them. Other consumers may be installing energy efficiency measures that are not part of state-sponsored or utility operated programs. And finally, individuals may be installing new distributed energy resources (combined heat and power, solar panels, or other onsite generation) on their own initiative and without the benefit of rebates or subsidies. A specific example may be the sudden, wide-spread availability of LED bulbs to replace incandescent or compact fluorescent light fixtures. This would be consistent with the market transformation process that occurred with appliances: the efficiency of all refrigerators and air conditioners has increased because higher efficiency items are the only units on the showroom floor for consumers to purchase. ISO New England has been an industry leader in its support for evaluating the impacts of state programs that encourage energy efficiency and distributed generation (DG); but further refinements to and expansions of its data sources and forecasting methods are still urgently needed to correct for the over-stated ten-year forecasts published in the annual CELT reports.

This updated paper reinforces the significant discrepancies identified in 2015 between current data and trends and ISO forecasts. Synapse adjustments to ISO New England uncertainty factors (discounts) improve the forecasts, but still do not account for the full gap between forecasts and actual data on energy consumptions and peak loads. In 2015 we emphasized the potential for over forecasting to lead to unnecessary transmission upgrades and excessive costs to consumers. Our updated analysis does not lessen that concern. However, we also note a new concern regarding supply side resources: their energy market revenues are shrinking on a New England wide basis. The ISO 2017 CELT forecast shows a decline of about 6,000 GWh over the next ten years; our Synapse forecast shows a reduction of approximately 16,000 GWh over the same period of time. At an average hourly price of $45/MWh, those annual revenue reductions amount to $270 million (CELT) and $720 million (Synapse) respectively. Owners of existing resources and developers of new resources need to be informed of this likely revenue erosion over the next decade.

Forecasting electricity consumption ten years into the future is a challenging task. ISO New England has responded to stakeholder concerns in the past and made adjustments to its forecasting process (most significantly the development of the EE forecast in 2012 and the PV forecast in 2015). Although forecasts will inevitably vary from actual electricity consumption, the reasons for those variances need to be evaluated and understood in order to improve future forecasts. Our analysis shows that ISO New England needs to improve its EE and PV forecast methodologies to better reflect the current implementation trends for those resources. In addition, ISO New England needs to acquire better and more granular data on actual system conditions and resource additions that may reflect actions outside of officially tracked state programs. These improvements are necessary to enable more informed and cost-effective decisions about the need for both generation resources and transmission upgrades.

1. 2017 UPDATED ANALYSIS

1.1. Economic trends

The 2015 report included discussion of overall trends in electricity consumption and identified numerous factors that have contributed to reduced consumption as measured by annual energy sales growth. Figure 4 and Figure 5, based on Energy Information Administration (EIA) data on utility sales, show that both national and New England trends in annual electricity sales growth have continued their decline. The New England sales growth has slowed at a faster pace than the national average.

Figure 4. National trends in electricity sales

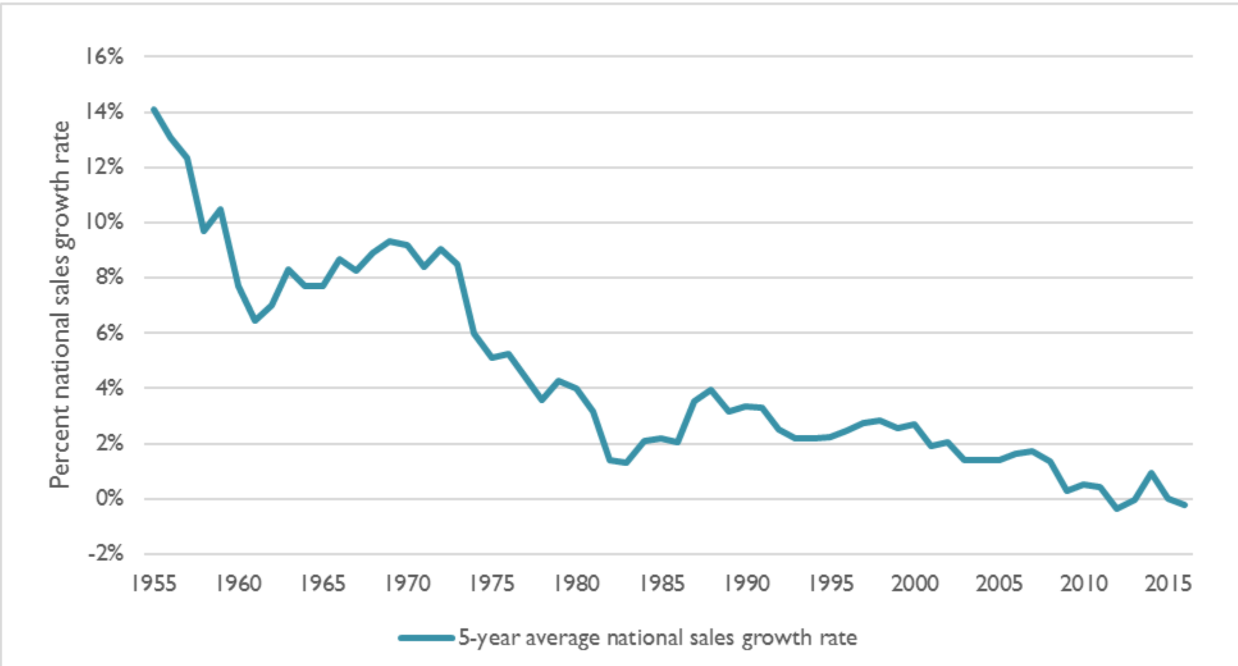


Figure 5. New England trends in electricity sales

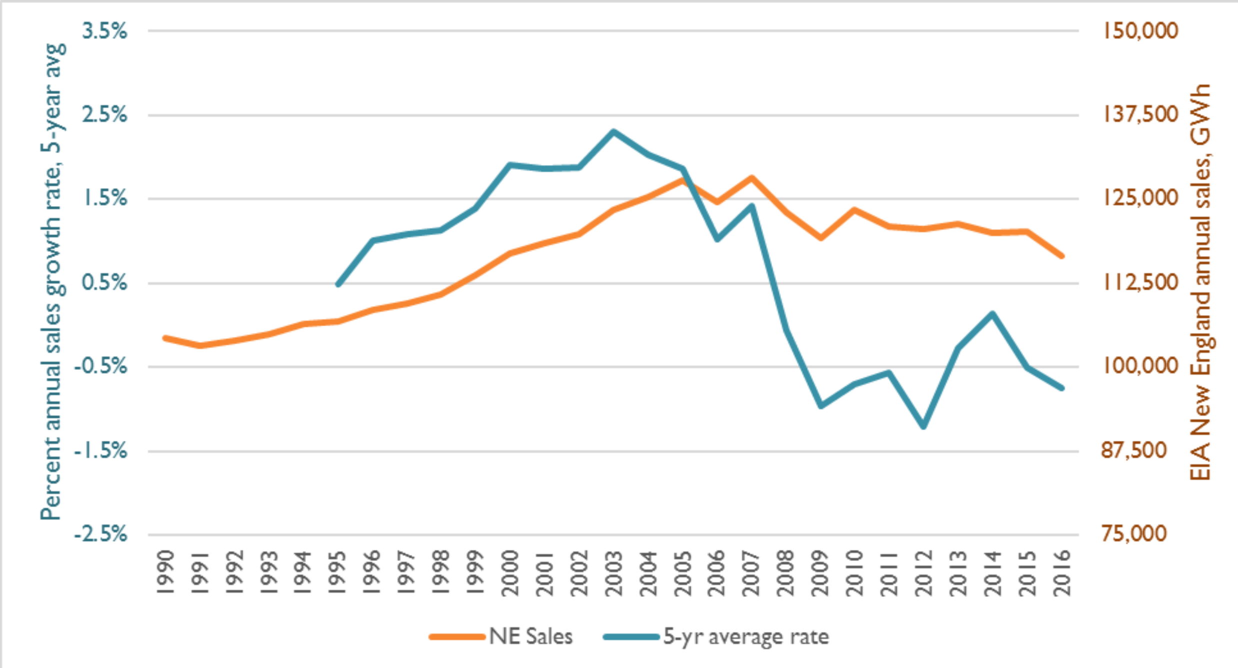
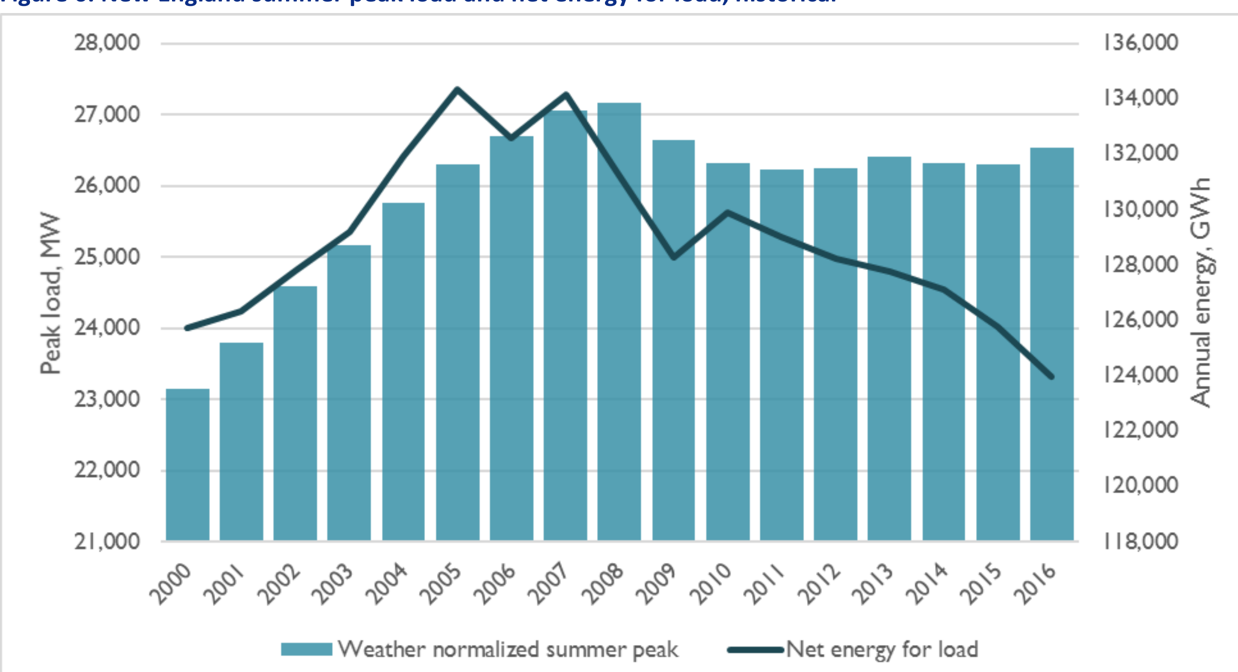


Figure 6, based on ISO New England CELT reports, shows similar trends for New England summer peak load (megawatts or MW) and annual energy consumption (gigawatt-hours or GWh). The data show that peak loads are flat to slightly declining and that annual net energy for load is decreasing steeply. The CELT reports use weather-normalized data and include transmission and distribution (T&D) losses, which make the GWh values slightly higher than the EIA sales data.

Figure 6. New England summer peak load and net energy for load, historical



1.2. Adjustments to discounts

Over the last few years, the ISO New England (ISO) has adjusted its methodology for forecasting both energy efficiency and distributed PV capacity and energy in the region. In some cases, this included adopting previous suggestions that stakeholders raised to the Energy-Efficiency Forecast Working Group and Distributed Generation Forecast Working Group. In other cases, the ISO brought its own comments to the working groups to support its changes to its forecast methodology. As such, Synapse's adjustments to the EE and distributed PV forecasts varied from year to year as the ISO's methodology changed. The following section outlines the adjustments Synapse made to the EE and PV forecasts the ISO produced in 2016 and 2017.

2016 Adjustments

EE adjustments

In 2016, the ISO's energy efficiency forecast was a product of two key elements: annual energy efficiency budgets by state and the cost of saved energy. The ISO made a series of adjustments to both elements. For example, annual budgets are based on historical levels combined with forecasted future policy dollars, but the ISO discounted future budgets based on each state's historical spend rate for previous efficiency budgets. If a state only spent 90 percent of its efficiency budget in the past, then the ISO assumed that state will continue to only spend 90 percent of its efficiency budget into the future. Next, the ISO increased the cost of saved energy both for inflation and for assumed increases in the cost of procuring efficiency savings. Overall, this amounts to an annual increase in the cost of saved energy of 7.5 percent. However, the ISO made no such adjustment for inflation to the program budgets, failing to capture the change in spending power of program budgets in the future. Using this methodology, the ISO forecasted that efficiency capacity in the region would decline steadily from historical observed levels through 2025, as seen in Table 1.

For the revised forecast of energy efficiency in the region in 2016, Synapse removed the ISO's state budget spend rate discount, removed the inflation adder from the future cost of saved energy, and dropped the production cost multiplier down from 5 percent per year to just 1 percent per year, consistent with observed changes in the cost of saved energy from year to year in the region. The resulting forecast begins in the realm of historical cleared efficiency in the capacity market and declines slightly in future years to account for the increasing cost of saved energy. As seen in Table 2, the cumulative impact of our adjustments to the ISO's forecast is 700 MW more energy efficiency between 2020 and 2025, more than the size of two new gas combustion turbines in the region.

Table 1. ISO-NE 2016 EE forecast, MW

MW Savings	ME	NH	VT	CT	RI	MA	ISO-NE
FCM cleared							
2016	15	8	18	63	18	121	**243**
2017	22	14	2	6	22	254	**320**
2018	0	8	1	60	31	176	**276**
2019	18	9	1	1	31	238	**297**
ISO forecasted							
2020	15	9	14	50	21	127	**234**
2021	14	8	13	47	19	119	**220**
2022	13	8	13	45	18	111	**206**
2023	12	8	12	42	17	104	**194**
2024	11	7	12	40	16	97	**182**
2025	10	7	11	38	14	91	**171**
Total 2020-25	73	47	74	261	104	648	**1,207**

Table 2. Synapse adjusted 2016 EE forecast, MW

MW Savings	ME	NH	VT	CT	RI	MA	ISO-NE
FCM cleared							
2016	15	8	18	63	18	121	**243**
2017	22	14	2	6	22	254	**320**
2018	0	8	1	60	31	176	**276**
2019	18	9	1	1	31	238	**297**
Synapse forecasted							
2020	20	13	20	71	28	176	**329**
2021	20	13	20	70	28	175	**325**
2022	19	13	20	70	28	173	**322**
2023	19	13	20	69	27	171	**319**
2024	19	12	19	68	27	169	**316**
2025	19	12	19	68	27	168	**313**
Total 2020-25	116	76	118	416	166	1,032	**1,924**

PV adjustments

The ISO forecast distributed PV capacity additions in an entirely different manner than it forecasts efficiency. First, the ISO gathers data on current installed levels of PV in each state and asks each state energy offices for a "best guess" of the amount of PV that will be installed in order to meet existing state policies. Next, the ISO shuffles around the timing of installs, generally front-loading installation of solar during policy years and assuming that installs drop off when existing policies end. Finally, the ISO takes this "best guess" forecast of PV installations and discounts the forecasted capacity in each year by 5 to 20 percent during policy years and by 50 percent for all post-policy years. As a result, the ISO's final PV forecast assumes that many states will not meet state targets for PV adoption.

Synapse made two key adjustments to this forecast methodology: we removed the discount factor in all years and held installations constant following the end of policy years. Adding together all of these adjustments, the Synapse forecast predicts 600 MW more PV growth between 2016 and 2025 than the ISO forecast, as seen in Table 3 and Table 4.

Table 3. ISO-NE 2016 distributed PV forecast, MW

2016 PV forecast	Thru 2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
CT	188	86	105	81	81	81	56	54	45	45	45	**866**
MA	947	123	123	78	78	78	43	43	43	43	43	**1,640**
ME	15	5	5	4	4	4	4	4	4	4	4	**58**
NH	26	13	8	4	4	4	4	4	4	4	4	**79**
RI	24	22	39	36	36	26	9	7	7	7	7	**217**
VT	125	30	30	23	23	23	21	20	20	20	20	**354**
Regional - Annual MW	**1,325**	**278**	**308**	**225**	**225**	**215**	**137**	**132**	**123**	**123**	**123**	**3,214**
Regional - Cumulative MW	**1,325**	**1,603**	**1,911**	**2,137**	**2,362**	**2,578**	**2,715**	**2,847**	**2,969**	**3,092**	**3,214**	**3,214**

Table 4. Synapse 2016 distributed PV forecast, MW

Synapse PV forecast	Thru 2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
CT	188	90	110	90	90	90	90	90	90	90	90	**1,108**
MA	947	129	129	86	86	86	86	86	86	86	86	**1,894**
ME	15	5	5	5	5	5	5	5	5	5	5	**64**
NH	26	14	8	8	8	8	8	8	8	8	8	**112**
RI	24	23	41	40	40	29	11	11	11	11	11	**250**
VT	125	32	32	25	25	25	25	25	25	25	25	**388**
Regional - Annual MW	**1,325**	**293**	**325**	**254**	**254**	**243**	**225**	**225**	**225**	**225**	**225**	**3,817**
Regional - Cumulative MW	**1,325**	**1,618**	**1,942**	**2,196**	**2,450**	**2,693**	**2,918**	**3,143**	**3,367**	**3,592**	**3,817**	**3,817**

Note: These values are the forecast values, not the actual levels of PV that are included in the CELT forecast. To get from these forecasts to the levels of PV included in the CELT forecast, the ISO makes an adjustment for capacity rating and an assumption of how much capacity is behind the meter versus settlement-only-resources. We made no changes to these ISO adjustments.

2017 Adjustments

EE adjustments

In 2017, the ISO overhauled a substantial portion of its forecast methodology. First, the ISO adjusted the assumption on state by state budget spend rates to assume that each state spends its budget in entirety. Next, and most importantly, the ISO completely changed the production cost adder approach, opting instead for a production cost escalator to represent both the increasing cost of saved energy and potential future uncertainty. The escalation factor is incremental and additional to inflation, and it adds an additional 1.25 percent per year to the cost of saved energy. In other words, in 2017, the cost saved energy is 3.75 percent higher than in 2016, representative of 2.5 percent inflation and the 1.25 percent production cost escalation factor. In 2018, this jumps to 5 percent, to account for an additional 1.25 percent per year from the escalation factor. By 2026, the last year of the forecast, the cost of saved energy is assumed to be 15 percent higher than in 2016.

For the 2017 forecast, Synapse only adjusted the production cost escalation factor. As opposed to beginning to increase production costs immediately in 2017, we begin to apply the escalation factor in 2021, the first forecast year. The forecast only covers the years from 2021 through 2026, whereas the capacity of efficiency in the forecast for the years from 2016 through 2020 represents actual levels that cleared in the ISO's forward capacity market. As such, the cost of saved energy is known through 2020 and should only begin to increase as of the first year forecasted. As seen in Table 5, this adjustment alone produces a difference of 320 MW from the ISO's initial forecast, more than the size of a new gas combustion turbine.[1]

Table 5. Synapse 2017 energy efficiency forecast as compared to ISO 2017 forecast

	CT	ME	MA	NH	RI	VT	Total	ISO Forecast	Difference
2021	64	20	225	11	29	16	**364**	**327**	37
2022	62	19	215	11	27	15	**348**	**302**	46
2023	59	18	202	10	25	15	**329**	**275**	53
2024	55	17	188	10	24	14	**307**	**248**	59
2025	51	15	173	9	22	14	**283**	**222**	62
2026	47	14	157	8	20	13	**258**	**195**	63
Total	**337**	**102**	**1,159**	**58**	**146**	**87**	**1,889**	**1,569**	**320**

[1] In Section 2, we briefly discuss the FCA-11 results where over 500 MW of EE resources cleared for delivery for the power year June 2020 - May 2021.

PV adjustments

The 2017 ISO PV forecast uses largely the same methodology as previous iterations. While the ISO adjusted a few details regarding the shifting contribution of PV to peak load as a result of the shifting of peak load itself into later hours during summer days, the methodology for building the actual forecast is largely unchanged. The forecast still relies upon information from state energy offices regarding distributed PV required to meet existing state goals, to which the ISO then applies an uncertainty discount factor throughout the forecast years. As with the 2016 PV forecast, Synapse only made two adjustments to the 2017 PV forecast—removing the uncertainty discount factor and holding the last policy year of installations constant throughout post-policy forecast years. As seen in Table 6 and Table 7, these two adjustments alone result in a substantial difference in assumed PV growth in the region.

Table 6. ISO-NE 2017 distributed PV forecast, MW

Final Nameplate capacity, MWac	Thru 2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
CT	282	133	133	133	59	45	44	42	41	40	38	**988**
MA	1,325	274	260	164	160	156	151	147	71	69	67	**2,843**
ME	22	7	7	7	6	6	6	6	6	6	6	**84**
NH	54	18	12	7	7	7	7	7	6	6	6	**138**
RI	37	41	41	35	32	15	11	11	11	11	10	**256**
VT	198	25	25	25	23	21	21	21	21	21	21	**424**
Regional - annual (MW)	**1,918**	**498**	**478**	**372**	**287**	**250**	**240**	**234**	**156**	**152**	**149**	**4,733**
Regional - cumulative (MW)	**1,918**	**2,416**	**2,894**	**3,266**	**3,552**	**3,802**	**4,042**	**4,275**	**4,432**	**4,584**	**4,733**	**4,733**

Table 7. Synapse 2017 distributed PV forecast, MW

Final nameplate, pre-discount, final year held	Thru 2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
CT	282	133	133	133	133	133	133	133	133	133	133	**1,610**
MA	1,325	274	358	358	358	358	358	358	358	358	358	**4,821**
ME	22	7	7	7	7	7	7	7	7	7	7	**91**
NH	54	18	12	12	12	12	12	12	12	12	12	**180**
RI	37	41	41	35	35	18	18	18	18	18	18	**297**
VT	198	25	25	25	25	25	25	25	25	25	25	**448**
Regional - annual (MW)	**1,918**	**498**	**576**	**571**	**570**	**553**	**553**	**553**	**553**	**553**	**553**	**7,447**
Regional - cumulative (MW)	**1,918**	**2,416**	**2,992**	**3,562**	**4,132**	**4,685**	**5,237**	**5,790**	**6,342**	**6,895**	**7,447**	

1.3. Comparative results

The next several figures show how our adjustments to the EE and PV forecasts impact the forecasts of the 2016 and 2017 ISO New England CELT reports in regard to three metrics: annual net energy for load, summer peak load, and winter peak load.

Figure 7. Net energy for load forecast in 2016, CELT net versus Synapse EE and DG, TWh

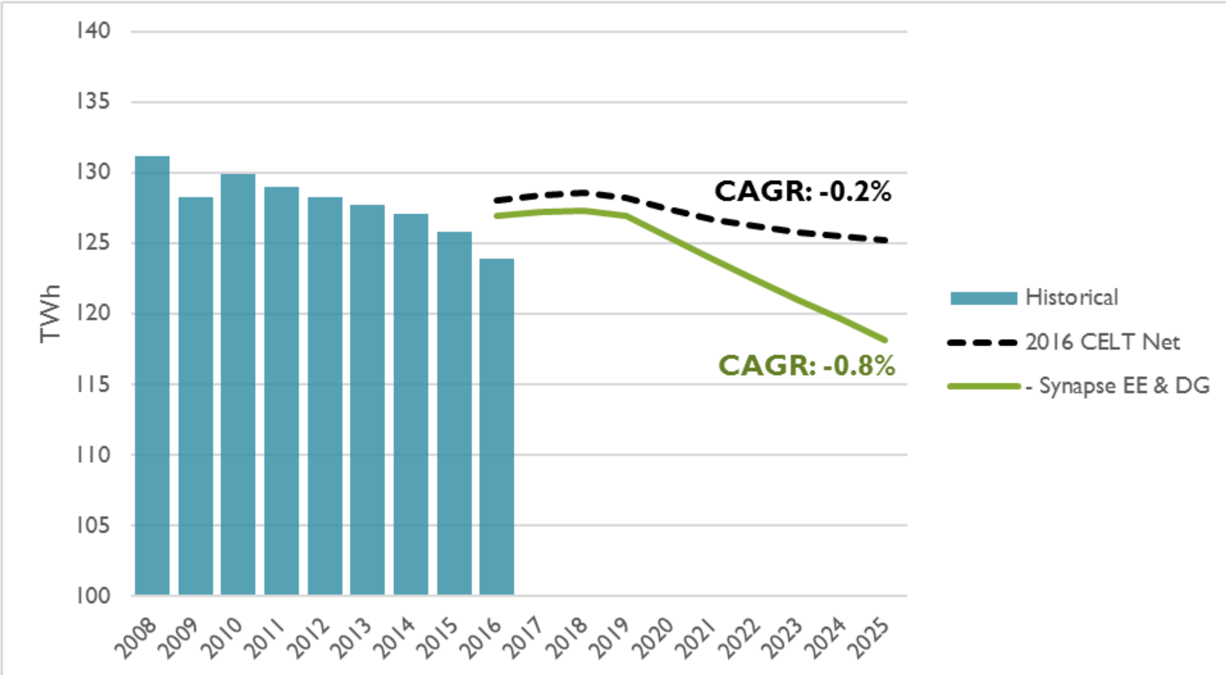


Figure 8. Net energy for load forecasts in 2017, CELT net versus Synapse EE and DG, TWh

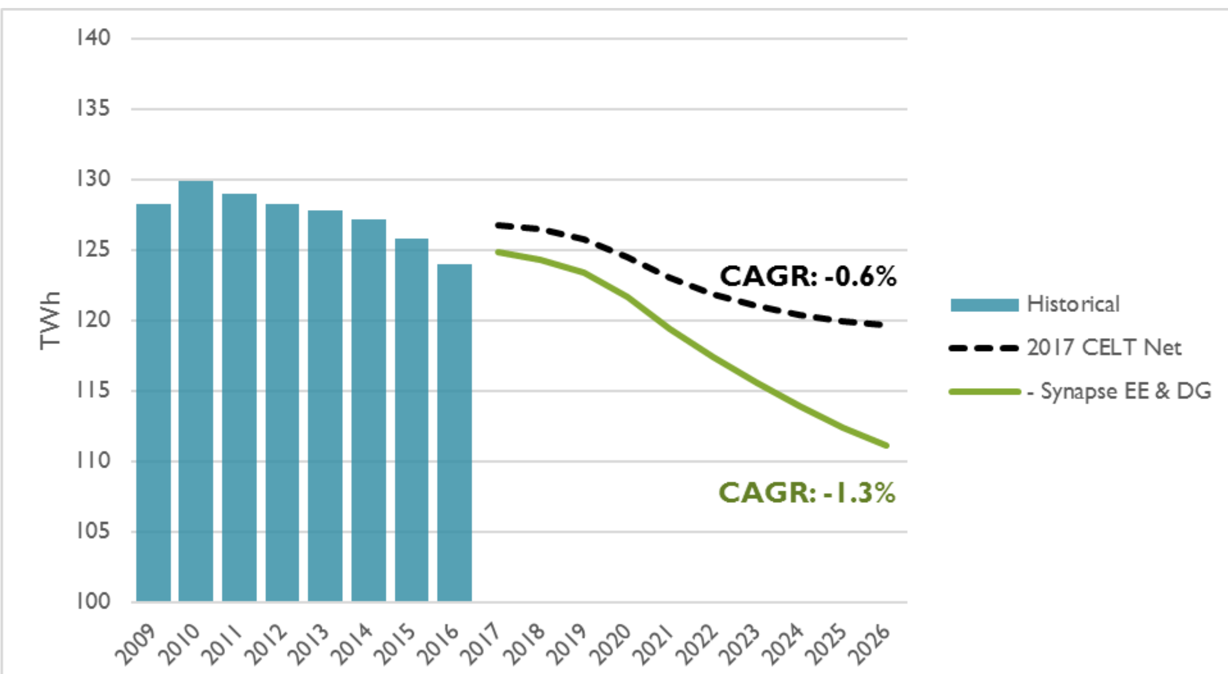


Figure 9. Summer peak load forecasts in 2016, CELT net 50-50 versus Synapse EE and DG, MW

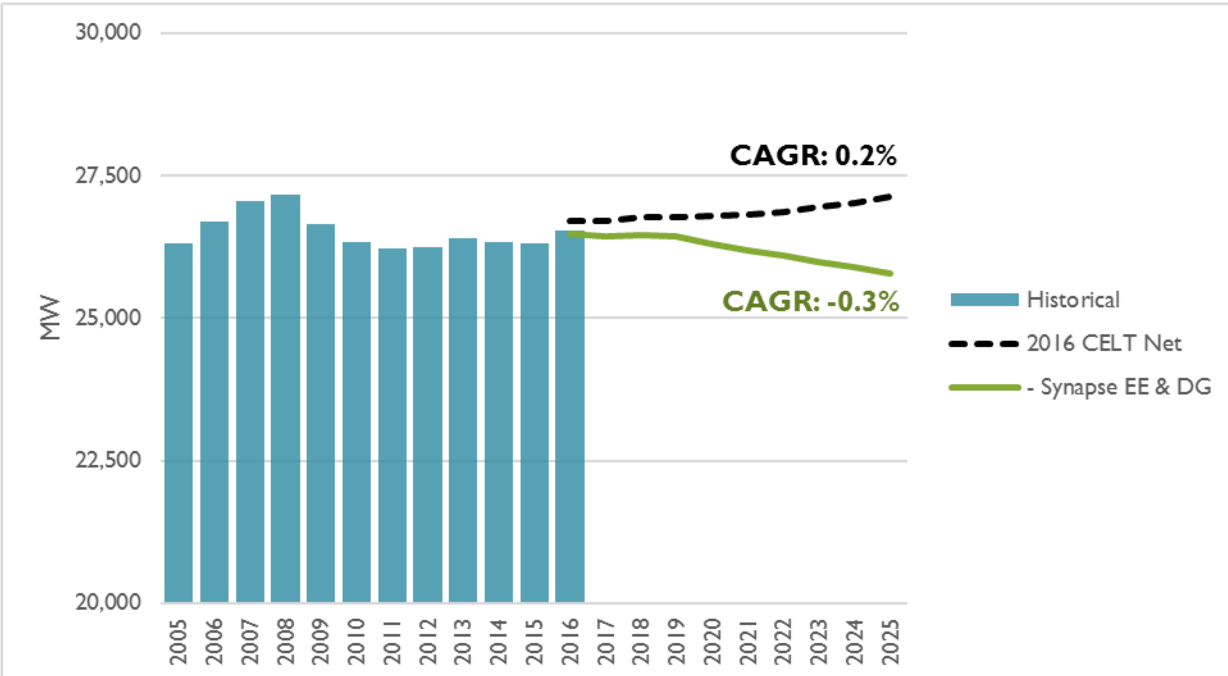


Figure 10. Summer peak load forecasts in 2017, CELT net 50-50 versus Synapse EE and DG, MW

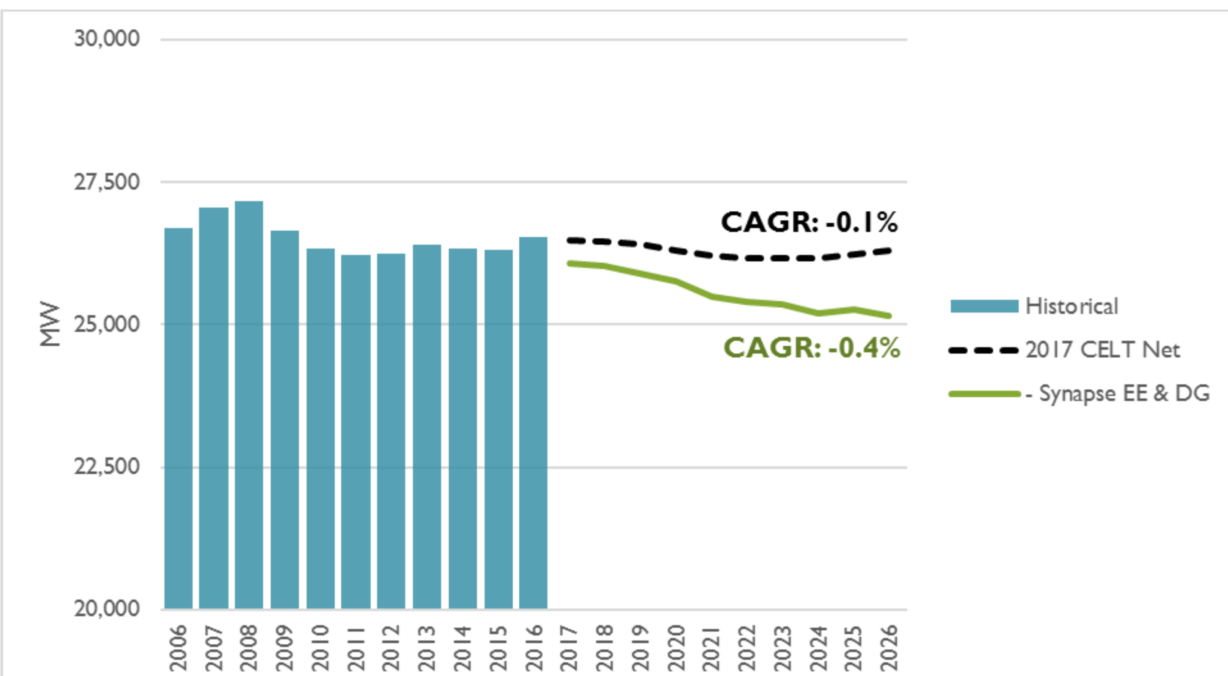


Figure 11. Winter peak load forecasts in 2016, CELT net 50-50 versus Synapse EE and DG, MW

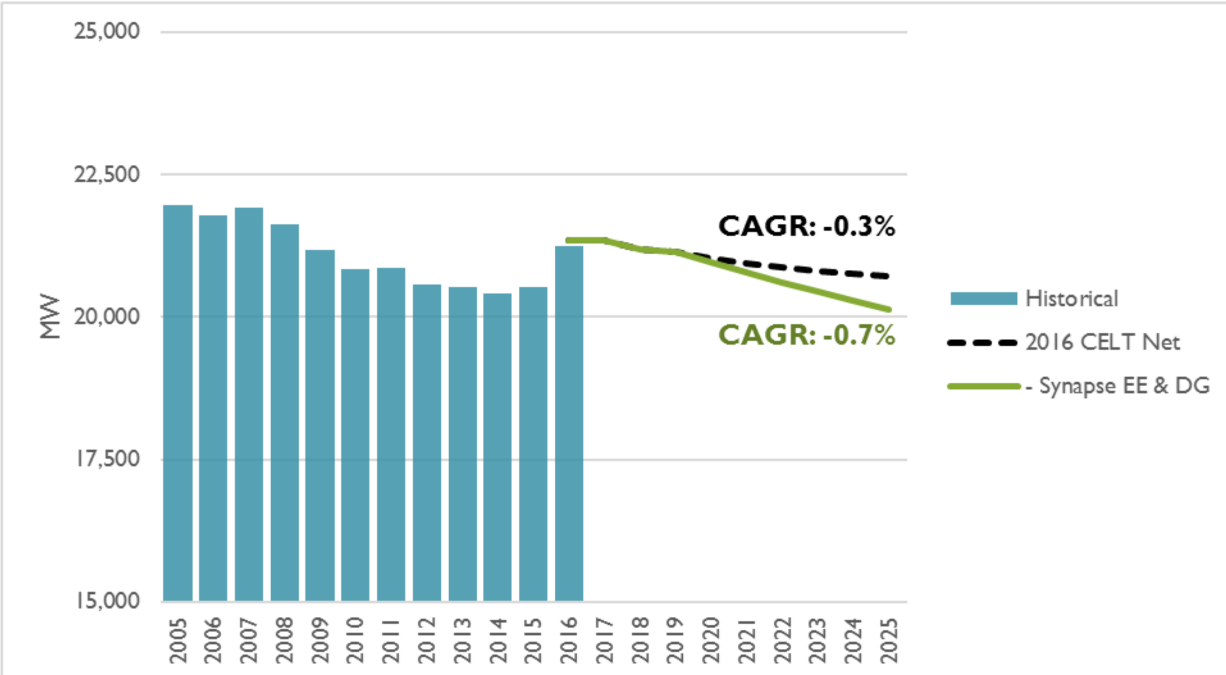
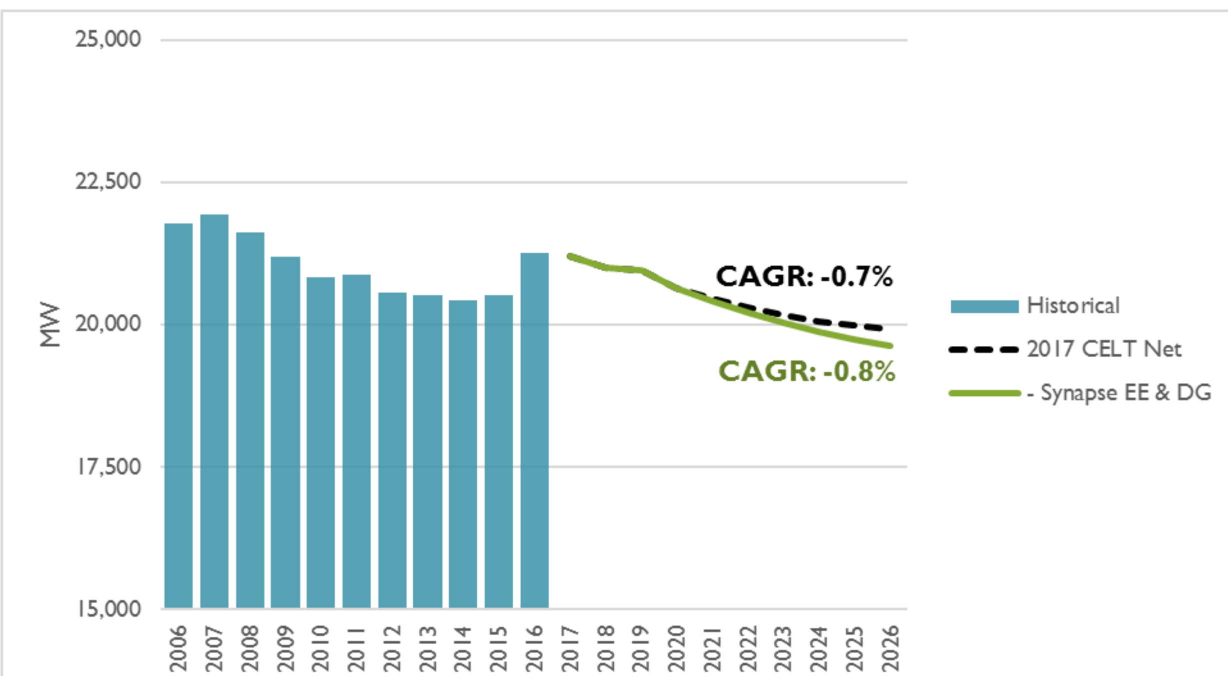


Figure 12. Winter peak load forecasts in 2017, CELT net 50-50 versus Synapse EE and DG, MW



2. OTHER CONCERNS

2.1. Forward Capacity Market trends

In our 2015 report, we noted that the ISO forecast of energy efficiency resources for specific years was less than the quantity of energy efficiency resources that clear in the annual Forward Capacity Market (FCM) auctions. We suggested that energy efficiency resources actually installed are even greater than the FCM cleared amounts due to conservatism in the estimates of energy efficiency program administrators.

In our updated table below we show that the ISO's trend of underestimating FCM cleared quantities continues. The ISO explained the 2020 quantity of 553 MW as a one-time anomaly caused by energy efficiency program administrators' decisions to true-up their backlogs of resources that had not been offered into prior FCM auctions. This result demonstrates exactly the type of conservative behavior that we suggested in 2015.

Table 8. ISO-NE energy efficiency forecasts versus actual cleared efficiency capacity

	2015	2016	2017	2018	2019	2020	2021
2012 forecast	249	233	218	205	192	179	168
2013 forecast		231	218	204	192	180	169
2014 forecast				239	225	211	198
2015 forecast					246	231	218
2016 forecast						251	235
2017 forecast							330
FCM Cleared	**246**	**243**	**320**	**276**	**338**	**553**	

At a minimum, the ISO's forecasts of future energy efficiency resources need to be consistent with the quantities that clear in the annual FCM auctions. An even stronger forecast would include all qualified resources (not just the cleared resources) and also represent the non-FCM eligible energy efficiency resources that programs administrators have been acquiring.

2.2. Non-program consumer activities

ISO New England developed its EE and PV forecasts with the goal of accurately estimating the resources that would be developed through state-managed or state-authorized EE and PV programs. This goal was based on a widely-held assumption that the development of EE and PV resources would not occur without the financial support and technical assistance provided by the state initiatives. A similar assumption prevails in regard to demand response programs: without market-based revenues providing financial support, customers would not offer to reduce their electric consumption on peak load days.

ISO forecasts would improve if they were able to incorporate behavioral changes associated with market transformations. The evolution of appliance rebate programs provides an apt example of market transformation. Initially, consumers purchased more efficient refrigerators because of the rebate they received through a utility- or state-sponsored energy efficiency program. Eventually, however, manufacturers only produce the more efficient refrigerators and the need for an incentive, or rebate, becomes unnecessary. Today, the rapid proliferation of LED products may create just such a market transformation in lighting options.

We have anecdotal evidence that consumers are making decisions to reduce peak loads by curtailing their electrical use on peak days because of the direct benefit to their peak load charge. While they may not enroll in demand response programs to receive a payment for their curtailment, they voluntarily act as if they were in such a program. We do not have a recommendation for how to identify and measure this activity, but we suspect that these voluntary actions contribute to the discrepancy between the ISO forecast and actual, measured peak loads.

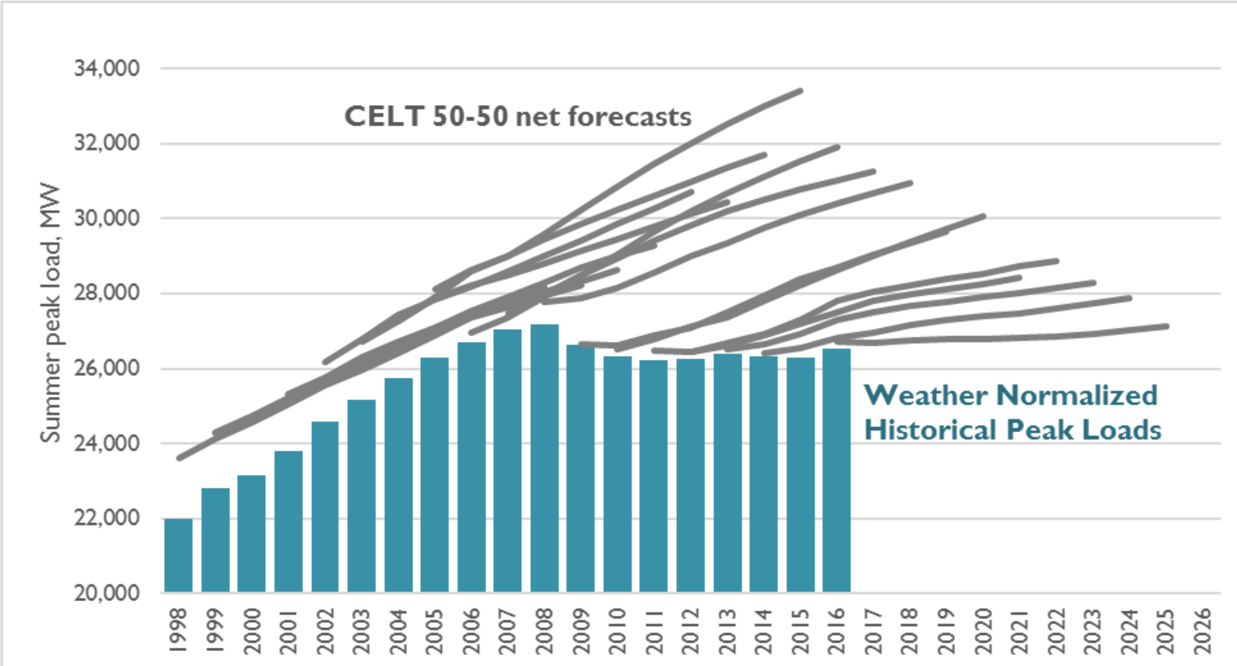
We also suspect that increasing numbers of consumers are implementing energy efficiency measures without the support of rebates or incentives. Home improvements such as replacement windows and doors, insulation upgrades, and weather-sealing measures are becoming standard practice. These actions not all captured as efficiency measures, verified by program administrators, and bid into the FCM as resources. As such, they are mostly invisible to the ISO forecasting process; yet, they are reducing peak loads and lowering annual energy consumption.

In regard to PV installations and other distributed energy resources, most activity today is supported by state rebates and other mechanisms. But as the cost of PV installations continues to decline, non-program installations will likely increase. While the timing is uncertain, the technological changes that will make PV more affordable are highly probable. This is probably the largest uncertainty factor that the ISO faces regarding forecasts of future peak loads and annual energy from the grid. Preliminary results for the 2016 Economic study suggest that there will be substantial operational and grid stability issues associated with a major shift from fossil fuel resources to PV, wind, and other distributed resources. Preparing for this grid transformation should be a high priority for ISO management and leadership.

2.3. CELT forecast error

In our 2015 report, we documented the consistent, substantial error in the forecasts in the ISO CELT reports; 10-20 percent over-forecast over ten years. Although recent forecasts show slight improvements, the general trend continues as shown in Figure 13. For the decade beginning in 1990, the ISO model that meshes econometric forecasts with historical New England data on electrical loads and weather needed to anticipate three percent annual growth in consumption. In the last decade, annual consumption has barely averaged one-half percent growth; the ISO model has not responded well to that change and may need to be revised.

Figure 13. New England forecasts versus weather normalized peak loads, MW



In the 2015 report, our major concern was how the over-stated ISO forecasts would impact planning studies. Forecasts that overstate peak loads and annual energy consumption have the potential to influence ISO assessments of future needs in a negative manner and lead to inefficient and unnecessary transmission upgrades. Our findings for this updated report have not eliminated that concern.

In addition to the possible negative impacts on the ISO system planning process, the overstatement of peak loads and annual energy consumption also raises concerns about the financial health of new and existing resources. If annual energy consumption is actually decreasing at a faster pace than estimated in the CELT forecasts, that information needs to be available to the market place to alert existing and new resources about reduced future revenues.

3. Conclusions

In 2015, we identified how the ISO's traditional approach to load forecasting had consistently produced substantial overstatements of future peak loads (summer and winter) and annual energy consumption, despite leading edge changes to their forecasting methodology to reflect state policy driven investments in energy efficiency and photovoltaic resources. We closely examined the EE and PV forecast methodologies and removed some of the discounts that the ISO applies to these two forecasts. Using revised EE and PV forecasts, we improved the overall forecasts of peak loads and annual energy consumption—our results more closely matched historical trends.

In this 2017 update, we show incremental improvements to the ISO CELT forecasts based on incremental changes that the ISO has made to their discount factors. But we still find significant gaps between ISO forecasts and historical data. The gaps are greatest for annual energy consumption, more modest for summer peak loads, and smallest for winter peak loads. Most importantly, all three forecasts are on a downward trend when the ISO discounts are removed. The ISO CELT forecasts still show increasing loads, particularly in the outer years of the ten-year forecasts.

We recommend that the ISO remove most of the discount factors in the EE and PV forecasts as a first step towards better aligning their CELT forecasts with the actual impacts of state-policy resource choices as shown in the historical data. We further recommend that the ISO undertake a comprehensive inventory of new resources that can be updated on a periodic basis; this will require working closely with distribution system operators who must approve the interconnections of distributed resources. Finally, we recommend that the ISO revise its load forecast methodology to better align econometric and historical data inputs to twenty-first century conditions and realities.

Improved forecasts are critical for both system planning and markets. CELT reports that consistently over-forecast will likely lead to inefficient and unnecessary investments by New England consumers in bulk power system facilities and other infrastructure. Over-forecasting will also encourage the development of generation resources that are unnecessary and unable to be supported by the markets.