STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

IN RE: THE NARRAGANSETT ELECTRIC COMPANY	:	
d/b/a NATIONAL GRID – ELECTRIC AND GAS	:	DOCKET NO. 4770
DISTRIBUTION RATE FILING	:	

COMMISSION'S TWELFTH SET OF DATA REQUESTS
DIRECTED TO NATIONAL GRID
(Issued May 21, 2018)

Forecasting/Energy Efficiency

12-1. In Mr. Gredder's Rebuttal Testimony on Bates page 68, lines 10-11, he states: "The Company's forecasting methods incorporate PUC-approved short-term energy efficiency program goals and ISO-NE's long-term methods and targets for PV generation projections."

(a) Does Mr. Gredder's forecast incorporate the persistence of the Energy Efficiency Plan and Three-Year Plan or just the current year plan? If the answer is just the current year plan, please provide the rationale.
(b) Does ISO-NE's forecast discount Rhode Island's energy efficiency savings in any way?
(c) Does Mr. Gredder make any adjustments from the ISO-NE energy efficiency projections? Why or why not?
(d) Does Mr. Gredder make any adjustments from the ISO-NE PV projections? Why or why not?

Response can be found on Bates page(s) 1-54.

12-2. In Mr. Gredder's Rebuttal Testimony on Bates page 69, lines 1-9, he states: "The Company's forecasting methods take into account all relevant and reliable information to develop the most accurate forecast possible. <u>That includes the Company's reasonable expectation for the impacts of Power Sector Transformation. Power Sector Transformation does not have specific goals for energy efficiency and solar energy generation.</u> The most reliable indicators of increased reliance on energy efficiency and solar generation for the period covered by the proposed rates and rate design are the energy efficiency programs approved by the PUC and the ISO-NE forecasts for solar generation. Accordingly, the Company's use of those data points is the most reasonable and reliable forecasting method." (emphasis added)

(a) Please explain how, if Power Sector Transformation does not have specific goals for energy efficiency and solar energy generation, the Company nonetheless included the impacts in its forecasting.

Response can be found on Bates page(s) 55.

12-3. How, if at all, were Mr. Gredder's forecasts affected by the proposed increases in the customer charge? If the rate design proposals were not considered in the electric forecasts, please explain why not.

Response can be found on Bates page(s) 56.

12-4. Please explain any analysis the Company conducted regarding the effect of increasing the various customer charges of the electric rate classes on the value of Energy Efficiency measures.

Response can be found on Bates page(s) 57.

12-5. For each rate class, using a "typical" customer (please define) provide the following:

(a) Percentage of the May 2018 bill that is made up of fixed charges and the percentage that is made up of variable charges under current rates.
(b) Dollar amounts on the May 2018 electric bill that are fixed charges and the dollar amounts that are variable charges under current rates.
(c) Using the same non-distribution rates as used in the responses to (a) and (b), what percentage of the bills would be made up of fixed charges and what percentage would be made up of variable charges under the proposed Rebuttal rates.
(d) Using the same non-distribution rates as used in the responses to (a) and (b), what dollar amount of the bills would be made up of fixed charges and what dollar amount would be made up of variable charges under the proposed Rebuttal rates.
(e) For A-60 customers, please also provide the responses to (c) and (d) assuming no customer charge.

Response can be found on Bates page(s) 58-61.

12-6. Please explain the differences between forecasting the effects of energy efficiency on gas and electric. Please include an explanation of any difference in the timing of when efficiency savings (actual and/or projected) influence forecasts.

Response can be found on Bates page(s) 62.

12-7. Please specifically compare the following two statements and explain how they are similar or different approaches.

(1) Mr. Poe's Rebuttal on Bates page 80, lines 1-7: As Narragansett Gas' historical volume data reflects the impact of its historical energy efficiency programs on the market, Narragansett Gas will adjust its forecast for future energy efficiency programs when those programs lead to demand reductions greater than its historical reductions. Through this process, Narragansett Gas ensures that it does not double count the impact of its energy efficiency programs on its volume forecast (see Poe Direct Testimony at page 9). Narragansett Gas' energy efficiency goals are established in a separate proceeding.

(2) Mr. Gredder's Rebuttal Testimony on Bates page 69, lines 1-2, he states: "The Company's forecasting methods take into account all relevant and reliable information to develop the most accurate forecast possible."

Response can be found on Bates page(s) 63-64.

Personnel

12-8. Please provide any updated information on the number of expected retirements in each of the rate year and two data years compared to the eligible retirements.

Response can be found on Bates page(s) 65-66.

Distributed Generation

12-9. Has the Company considered any formal industry outlook for distributed generation in Rhode Island or the region in its projections of interconnection application work?

Response can be found on Bates page(s) 67.

12-10. Has the Company considered the expiration of the Investment Tax Credit in its projections of distributed generation interconnection application work? If so, how? If not, why not?

Response can be found on Bates page(s) 68

Low Income/Competitive Supply

12-11. With respect to A-60 customers who make a 50% partial payment, please explain how application of the payments would be made to the bill charges under the current rate structure and the proposed rate structure (assuming a 25% discount) under the following circumstances:

(a) Customer had no arrearage prior to the month of the partial payment and is on standard offer.
(b) Customer had no arrearage prior to the month of the partial payment and is on competitive supply.
(c) Customer had an arrearage prior to the month of the partial payment and was not on a payment plan or AMP but is on standard offer.
(d) Customer had an arrearage prior to the month of the partial payment and was not on a payment plan or AMP but is on competitive supply.
(e) Customer was in a payment plan, was current on payment plan, and is on standard offer service.
(f) Customer was in a payment plan, was current on payment plan, and is on competitive supply.
(g) Customer was in the AMP, was current on the AMP, and is on standard offer.
(h) Customer was in the AMP, was current on the AMP, and is on competitive supply.

Response can be found on Bates page(s) 69-71.

12-12. Under each of the scenarios in 12-11, where there is a competitive supplier, under the new low-income rate proposal, how much is recovered through the reconciliation provision?

Response can be found on Bates page(s) 72.

Benefit-Cost Analysis

12-13. On Bates page 36 of Mr. Sheridan's Rebuttal testimony, he states: "The Company agrees that it can, in most cases, perform a BCA for projects that are not foundational (i.e., not a "core component" of grid modernization). However, the Company believes that BCA is not appropriate for the foundational Grid Modernization investments the Company proposed in Chapter 3 of the PST Plan." Please explain how this position is consistent with the following from the Docket 4600 Guidance Document: "In addition, in any case that proposes new programs or capital investment that will affect National Grid's electric distribution rates, the impact of any increased ratepayer recovery should also reference the goals, rate design principles, and Benefit-Cost Framework. National Grid should apply the Benefit-Cost Framework to changes in its cost of service for the primary purpose of complying with State policy or to expand a current program… the Framework should serve as a starting point in the making of a business case for a proposal." (Public Utilities Commission's Guidance on Goals, Principles and Values for Matters Involving The Narragansett Electric Company d/b/a National Grid at 6-7).

Response can be found on Bates page(s) 73.

12-14. Please indicate which projects outlined in the Power Sector Transformation Panel Rebuttal and Supplemental Testimony are affected by the Massachusetts Department of Public Utilities order on grid modernization, and provide updated costs and cost-benefit analyses for such projects if the certainty of sharing costs for these projects with Massachusetts ratepayers has changed.

Response can be found on Bates page(s) 74-75.

PUC 12-1

Request:

In Mr. Gredder's Rebuttal Testimony on Bates page 68, lines 10-11, he states: "The Company's forecasting methods incorporate PUC-approved short-term energy efficiency program goals and ISO-NE's long-term methods and targets for PV generation projections."

(a) Does Mr. Gredder's forecast incorporate the persistence of the Energy Efficiency Plan and Three-Year Plan or just the current year plan? If the answer is just the current year plan, please provide the rationale.

(b) Does ISO-NE's forecast discount Rhode Island's energy efficiency savings in any way?

(c) Does Mr. Gredder make any adjustments from the ISO-NE energy efficiency projections? Why or why not?

(d) Does Mr. Gredder make any adjustments from the ISO-NE PV projections? Why or why not?

Response:

(a) The forecast for energy efficiency does account for the persistence of the program goals. By using both the Public Utilities Commission-approved program goals for the short term and the ISO-NE goals for the longer term, all expected energy efficiency reductions are captured over time. As shown on Schedule JFG-10 to Schedule JFG-13 in Company Witness Joseph F. Gredder's pre-filed direct testimony, energy efficiency savings continue to grow and increase cumulatively over time. Had only the current year been used and persistence of savings not included, then one would see the energy efficiency targets drop off over time instead of continuing to grow.

(b) The process used by the ISO-NE to forecast energy efficiency savings is fully described in Attachment PUC 12-1, ISO-NE "Final 2018 Energy Efficiency Forecast." Pages 8 to 12 of that document describe the main assumptions to the forecast. There is a reduction for state energy efficiency budget uncertainty and a reduction due to production cost escalation. The production cost escalator has two components - a static inflation rate of 2.5 percent and a graduated escalation rate of 1.25 percent in the first year continuing to grow 1.25 percent each year forward. Page 27 of the attachment shows the resulting factors. In the forecast, the budget spend rate modifier was set to zero, meaning that, although the factor is present if needed, for Rhode Island there was no discount applied because of it.

(c) No adjustments to the ISO-NE's energy efficiency projections are made because their process fully incorporates all reasonable and expected impacts collectively discussed among the ISO, utilities, regulators, state agencies, and other market participants during the development process each year.

(d) No adjustments to the ISO-NE's PV projections are made because their process fully incorporates all reasonable and expected impacts collectively discussed among the ISO, utilities, regulators, state agencies, and other market participants during the development process each year.

Prepared by or under the supervision of: Joseph Gredder

MAY 1, 2018 | HOLYOKE, MA

Final 2018 Energy Efficiency Forecast

Table of Contents

INTRODUCTION

Acronyms

EE	Energy Efficiency
EEFWG	Energy Efficiency Forecast Working Group
FCM	Forward Capacity Market
FCA	Forward Capacity Auction (FCM)
CSO	Capacity Supply Obligation (FCM)
ARA 3	Third Annual Reconfiguration Auction (FCM)
ICR	Installed Capacity Requirement
PA	Program Administrator
RGGI	Regional Greenhouse Gas Initiative
SBC	System Benefit Charge
CELT	10-year forecast of Capacity, Energy, Loads and Transmission

Introduction

- This presentation contains the final EE forecast for the period 2018 through 2027
- The forecast estimates reductions in energy and demand from state-sponsored EE programs in the New England control area by region and state (CT, MA, ME, NH, RI, VT)
- The data used to create the forecast originates from state-sponsored EE Program Administrators and state regulatory agencies

Introduction

Process

- This forecast follows the same fundamental forecast process and methodology used in prior years, starting in 2012
- The EE forecast is based on average production costs, peak-to-energy ratios, and projected budgets of state-sponsored EE programs
- The EE forecast is updated annually and is incorporated into the CELT report
- A generalized characterization of the forecast process can be found in the "Energy-Efficiency Forecast Background Report" available at https://www.iso-ne.com/static-assets/documents/2016/05/Final_EEF_Background_Report_050116.pdf

Introduction
Impacts

- The EE forecast is used in ISO studies including:
  - Long-term transmission planning studies
  - Economic planning studies
- EE forecast will not impact:
  - ICR/Local Sourcing Requirement/Maximum Capacity Limit/Demand Curves
  - FCM auctions
  - FCM related reliability studies (qualification, de-list bid reliability reviews)

FORECAST ASSUMPTIONS AND METHODOLOGY

Forecast Model

General Assumptions

- Annual EE budgets provided by the Commissions or representatives on their behalf were used in the model and held constant in years after the latest approved budget
- Production cost baselines were derived from a three-year average of recent performance
- Peak-to-Energy Ratios were derived from a three-year average of recent performance and held constant through the forecast period
- Inflation rate set at 2.5% per year
- Current CELT energy forecast used in conjunction with SBC rates to forecast SBC dollars
- FCM revenue has no effect on overall budget in ME, VT, MA, and RI

Forecast Model

Input Assumptions

- 2017 CELT Energy Forecast
- 2017 CELT FCM CSOs and FCA #12 clearing price used for calculating budgets
- Starting Production Cost: PA 2014-2016 average
- Peak-to-Energy Ratio: PA 2014-2016 average
- Production Cost Escalation Rate: 2.5% inflation + 1.25% graduated rate (beginning in year 1)
- No Budget Spend Rate deduction

Forecast Model

Assumptions Regarding the Forward Capacity Market

- FCM clearing price was held constant at the FCA #12 clearing price of $4.63/kW-month†
- ISO assumes that all achieved EE capacity will be bid into and clear in future FCA's‡

† FCA clearing price used is for modeling purposes only and should not be considered an indication of future clearing prices.

‡ The ISO assumption that all achieved EE capacity would be bid into and clear in future FCA's is only for modeling purposes and should not be considered an indication of any future FCA outcome.

Forecast Model

Fundamentals

- Compute Annual Energy Savings

$$\textbf{Annual Energy Savings} = \frac{\textbf{(1 − Budget Spend Rate Modifier)} * \textbf{(Budget)}}{\textbf{(Production Cost)} * \textbf{(Production Cost Esclator)}}$$

- Compute Annual Demand Savings

$$\textbf{Annual Demand Savings} = \textbf{(Annual Energy Savings)} * \textbf{(Peak−to−Energy Ratio)}$$

- Where:
  - Budget Spend Rate Modifier (%) = % to reduce state budgets
  - Budget ($) = $SBC + $RGGI + $FCM + $Policy
  - Production Cost ($/MWh) = cost to develop a MWh of annual savings
  - Production Cost Escalator (%) = % increase in annual production cost
  - Peak-to-Energy Ratio (MW/MWh) = ratio of annual demand to annual energy savings

UPDATE TO FORECAST METHODOLOGY

Incorporating ARA 3 Qualification

2018 Update to Forecast Methodology

Background

- FCM values are used as the starting point for the EE forecast and determine the overall magnitude of the EE forecast
- In 2012 and 2013 the actuals in the EE forecast were FCM CSO as acquired through the primary FCA
  - The CSO values were found to under represent EE in the market
  - Projects that delisted or failed to clear in the primary FCA were still in operation
- Beginning in 2014, the EE forecast actuals were represented by FCM Existing Qualified + New Cleared
  - Existing Qualified + New Cleared is a value determined over 3-years prior to the start of the relevant Capacity Commitment Period
- Qualification for ARA 3 is held just a few months prior to the start of the relevant Capacity Commitment Period
- ISO has observed that ARA 3 Qualification diverges from, and is higher than, Existing Qualified + New Cleared, especially in recent years

2018 Update to Forecast Methodology

Background

- In early Capacity Commitment Periods the Existing Qualified + New Cleared values line up with ARA 3 Qualification
- In more recent years the qualification values diverge
  - Projects come online early and participate in ARA 3 for earlier Capacity Commitment Periods
  - Terminated projects are removed from ARA 3 Qualification
- ARA 3 Qualification values are the best FCM indicator of what will actually be installed and operating for a given Capacity Commitment Period

2018 Update to Forecast Methodology

Structural Changes

- Replace Existing Qualified + New Cleared with ARA 3 Qualification
  - ARA 3 Qualification is the most up to-date annual FCM quantity available for any given Capacity Commitment Period
  - ARA 3 Qualification accounts for projects that come online early as well as those that undergo full or partial termination
- Impacts
  - Year 1 of the forecast will be ARA 3 Qualification (fixed)
  - Years 2 through 10 of the forecast will be forecast values
    - Forecast methodology will remain unchanged (budgets, production costs, peak-to-energy ratios)

FORECAST INPUTS

Summary of Program Administrator Data and Model Parameters

Summary of Program Performance Changes

2015 PA Data Versus 2016 PA Data

- Production Cost
  - Decreased in majority of states
  - Decreased for New England
- Peak-to-Energy Ratio
  - Decreased in majority of states
  - Decreased slightly for New England
- Budget Spend Rate
  - Decreased in majority of states
  - Decreased for New England

Program Data Summary

Period	Budget ($1000's)	Total Costs ($1000's)	Achieved Annual Energy (MWh)	Dollars per MWh	Achieved Summer Peak (MW)	Dollars per MW	% Energy Achieved	% Budget Spent	% Peak Achieved	Peak to Energy Ratio Achieved (MW/GWh)	Achieved Lifetime Energy (MWh)	Lifetime Dollars Per MWh
New England												
2011	665,087	518,865	1,575,302	329	200	2,588,882	90%	78%	75%	0.127	17,638,158	29
2012	745,761	648,848	1,723,357	377	221	2,930,052	98%	87%	86%	0.128	18,384,080	35
2013	727,655	707,930	1,833,883	386	254	2,787,351	109%	97%	105%	0.138	20,414,118	35
2014	857,984	862,384	2,063,624	418	275	3,140,299	139%	101%	99%	0.133	18,120,338	48
2015	897,172	923,581	2,375,192	389	333	2,774,547	123%	103%	129%	0.140	26,658,969	35
2016	976,266	908,011	2,454,794	370	335	2,707,974	117%	93%	122%	0.137	23,522,755	39
Avg 2013-2015	827,604	831,298	2,090,899	398	287	2,900,732	123%	100%	111%	0.137	21,731,142	39
Avg 2014-2016	910,474	897,992	2,297,870	392	314	2,874,273	126%	99%	117%	0.137	22,767,354	40
Massachusetts												
2011	432,796	283,898	777,100	365	101	2,823,162	86%	66%	67%	0.129	10,177,753	28
2012	508,987	400,607	980,105	409	125	3,198,050	88%	79%	75%	0.128	10,724,658	37
2013	499,584	438,951	1,116,236	393	160	2,737,910	93%	88%	92%	0.144	11,999,747	37
2014	511,262	517,796	1,217,150	425	166	3,115,182	151%	101%	103%	0.137	9,264,658	56
2015	518,345	541,862	1,396,513	388	195	2,771,794	116%	105%	129%	0.140	16,295,573	33
2016	579,676	533,147	1,471,088	362	206	2,593,869	110%	92%	118%	0.140	12,591,048	42
Avg 2013-2015	509,730	499,536	1,243,300	402	174	2,874,962	120%	98%	108%	0.140	12,519,993	42
Avg 2014-2016	536,428	530,935	1,361,584	392	189	2,826,948	126%	99%	117%	0.139	12,717,093	44
Connecticut												
2011	129,909	119,426	381,974	313	43	2,769,490	93%	92%	87%	0.113	3,163,706	38
2012	120,177	121,826	308,428	395	40	3,032,738	131%	101%	124%	0.130	3,116,688	39
2013	97,955	121,612	271,480	448	33	3,648,317	139%	124%	130%	0.123	2,885,413	42
2014	174,992	176,459	377,073	468	50	3,507,071	103%	101%	106%	0.133	4,067,290	43
2015	181,980	179,351	411,055	436	64	2,816,838	108%	99%	113%	0.155	4,282,544	42
2016	199,205	199,188	427,036	466	59	3,396,595	107%	100%	110%	0.137	4,977,875	40
Avg 2013-2015	151,642	159,141	353,203	451	49	3,324,075	117%	108%	117%	0.137	3,745,082	42
Avg 2014-2016	185,392	184,999	405,055	457	58	3,240,168	106%	100%	110%	0.142	4,442,569	42
Rhode Island												
2011	48,649	36,494	96,009	380	14	2,673,405	94%	75%	71%	0.142	1,076,778	34
2012	61,246	48,870	119,666	408	20	2,504,009	93%	80%	82%	0.163	1,288,325	38
2013	64,179	61,547	149,033	413	25	2,453,415	104%	96%	123%	0.168	1,602,369	38
2014	73,766	74,537	193,613	385	24	3,161,426	107%	101%	59%	0.122	1,781,643	42
2015	86,326	84,400	214,512	393	27	3,069,598	116%	98%	112%	0.128	2,121,586	40
2016	88,468	73,867	213,865	345	27	2,722,154	107%	83%	105%	0.127	2,027,270	36
Avg 2013-2015	74,757	73,494	185,720	397	25	2,894,813	109%	98%	98%	0.139	1,835,199	40
Avg 2014-2016	82,853	77,601	207,330	375	26	2,984,393	110%	94%	92%	0.126	1,976,833	39

Program Data Summary

Period	Budget ($1000's)	Total Costs ($1000's)	Achieved Annual Energy (MWh)	Dollars per MWh	Achieved Summer Peak (MW)	Dollars per MW	% Energy Achieved	% Budget Spent	% Peak Achieved	Peak to Energy Ratio Achieved (MW/GWh)	Achieved Lifetime Energy (MWh)	Lifetime Dollars Per MWh
Maine												
2011	-	22,817	152,663	149	18	1,248,326	117%	0%	100%	0.120	1,447,766	16
2012	-	23,712	143,532	165	12	1,904,497	101%	0%	114%	0.087	1,266,751	19
2013	-	24,279	141,978	171	15	1,603,990	0%	0%	0%	0.107	2,043,036	12
2014	26,976	21,972	115,847	190	14	1,621,745	0%	81%	0%	0.117	1,014,155	22
2015	41,991	45,493	166,500	273	21	2,124,405	0%	108%	0%	0.129	1,499,177	30
2016	39,288	32,608	139,037	235	21	1,564,454	0%	83%	0%	0.150	1,518,286	21
Avg 2013-2015	22,989	30,581	141,442	211	17	1,783,380	0%	63%	0%	0.117	1,518,789	21
Avg 2014-2016	36,085	33,358	140,461	232	19	1,770,201	0%	91%	0%	0.132	1,343,873	24
Vermont												
2011	36,066	37,325	109,514	341	15	2,502,506	72%	103%	69%	0.136	1,099,092	34
2012	35,678	35,130	117,653	299	16	2,172,427	119%	98%	109%	0.137	1,320,789	27
2013	39,495	35,989	96,323	374	12	2,966,434	97%	91%	81%	0.126	1,119,186	32
2014	44,690	45,795	96,557	474	11	4,121,184	113%	102%	74%	0.115	1,141,386	40
2015	44,637	46,598	113,112	412	13	3,516,048	101%	104%	89%	0.117	1,457,163	32
2016	45,189	46,346	134,107	346	15	3,140,437	117%	103%	99%	0.110	1,455,297	32
Avg 2013-2015	42,941	42,794	101,997	420	12	3,534,555	104%	99%	81%	0.119	1,239,245	35
Avg 2014-2016	44,839	46,246	114,592	411	13	3,592,556	110%	103%	88%	0.114	1,351,282	35
New Hampshire												
2011	17,667	18,904	58,042	326	10	1,910,689	123%	107%	121%	0.170	673,064	28
2012	19,673	18,703	53,973	347	8	2,376,052	106%	95%	101%	0.146	666,868	28
2013	26,442	25,552	58,833	434	8	3,207,104	111%	97%	107%	0.135	764,368	33
2014	26,298	25,826	63,384	407	10	2,622,172	124%	98%	76%	0.155	851,207	30
2015	23,894	25,877	73,499	352	12	2,240,227	129%	108%	119%	0.157	1,002,926	26
2016	24,441	22,856	69,661	328	8	2,724,396	139%	94%	103%	0.120	952,980	24
Avg 2013-2015	25,545	25,752	65,239	398	10	2,689,834	121%	101%	101%	0.149	872,834	30
Avg 2014-2016	24,878	24,853	68,848	363	10	2,528,932	131%	100%	99%	0.144	935,705	27

FCM and RGGI Funds

RGGI Dollars ($1000's) Applied to EE Annually							
	New England	MA	CT*	ME	RI	VT	NH
	76,513	64,757	7,192	-	2,009	-	2,555
FCM MW							
	New England	MA	CT	ME	RI	VT	NH
2021	2,975	1,609	681	165	280	120	121
FCM Dollars ($1000's, clearing price of $4.63*)							
	New England	MA	CT	ME	RI	VT	NH
2021	149,549	89,439	37,862	-	15,544	-	6,704
FCM Dollars for EE ($1000's)							
	New England	MA	CT	ME	RI	VT	NH
2019	174,753	107,268	41,694	-	18,293	-	7,498
2020	162,353	98,301	39,448	-	16,964	-	7,641
2021	149,549	89,439	37,862	-	15,544	-	6,704
2022	149,549	89,439	37,862	-	15,544	-	6,704
2023	149,549	89,439	37,862	-	15,544	-	6,704
2024	149,549	89,439	37,862	-	15,544	-	6,704
2025	149,549	89,439	37,862	-	15,544	-	6,704
2026	149,549	89,439	37,862	-	15,544	-	6,704
2027	149,549	89,439	37,862	-	15,544	-	6,704

* RGGI dollars were discounted in 2019, 2020, and 2021 to account for CT budget cuts
** Auction clearing price for Rest-of-Pool

Energy Forecast

2017 CELT Energy Forecast (GWh)							
	New England	MA	CT	ME	RI	VT	NH
2019	143,447	66,996	34,587	12,885	9,347	6,953	12,679
2020	144,611	67,706	34,733	13,003	9,410	6,992	12,767
2021	145,799	68,400	34,909	13,137	9,472	7,035	12,845
2022	147,127	69,147	35,128	13,291	9,542	7,085	12,933
2023	148,507	69,919	35,359	13,453	9,611	7,137	13,028
2024	149,884	70,691	35,586	13,611	9,685	7,189	13,122
2025	151,233	71,453	35,802	13,763	9,760	7,240	13,215
2026	152,593	72,227	36,018	13,910	9,836	7,291	13,311
2027	153,953	73,002	36,234	14,058	9,911	7,342	13,406

2017 CELT Energy Forecast - FCM Passive Demand Resources (GWh)							
	New England	MA	CT	ME	RI	VT	NH
2019	128,536	59,055	31,617	11,622	8,036	6,147	12,059
2020	127,573	58,437	31,126	11,825	7,861	6,263	12,062
2021	128,761	59,131	31,302	11,958	7,924	6,306	12,140
2022	130,089	59,878	31,521	12,113	7,994	6,356	12,227
2023	131,469	60,650	31,752	12,275	8,063	6,408	12,322
2024	132,846	61,421	31,979	12,433	8,136	6,460	12,416
2025	134,195	62,183	32,195	12,585	8,211	6,511	12,509
2026	135,555	62,958	32,411	12,732	8,287	6,562	12,605
2027	136,915	63,733	32,626	12,880	8,363	6,613	12,701

Energy Forecast

SBC Eligible							
		MA	CT	ME	RI	VT	NH
		85.9%	94.7%	98.7%	100.0%	100.0%	100.0%

SBC Eligible 2017 Energy Forecast - FCM Passive Demand Resources (GWh)							
	New England	MA	CT	ME	RI	VT	NH
2019	118,382	50,728	29,941	11,471	8,036	6,147	12,059
2020	117,530	50,197	29,476	11,671	7,861	6,263	12,062
2021	118,609	50,793	29,643	11,803	7,924	6,306	12,140
2022	119,818	51,435	29,850	11,955	7,994	6,356	12,227
2023	121,075	52,098	30,069	12,115	8,063	6,408	12,322
2024	122,329	52,761	30,284	12,272	8,136	6,460	12,416
2025	123,557	53,416	30,488	12,422	8,211	6,511	12,509
2026	124,795	54,081	30,693	12,567	8,287	6,562	12,605
2027	126,032	54,746	30,897	12,712	8,363	6,613	12,701

Energy Sales and System Benefit Charge

Sales (GWh)

	New England	MA	CT	ME	RI	VT	NH
2019	111,682	47,857	28,247	10,821	7,581	5,799	11,377
2020	110,877	47,356	27,808	11,010	7,416	5,908	11,379
2021	111,895	47,918	27,965	11,135	7,475	5,949	11,453
2022	113,036	48,524	28,161	11,279	7,541	5,996	11,535
2023	114,222	49,149	28,367	11,429	7,606	6,045	11,625
2024	115,405	49,774	28,570	11,577	7,675	6,094	11,714
2025	116,563	50,392	28,763	11,718	7,747	6,142	11,801
2026	117,731	51,020	28,955	11,855	7,818	6,190	11,892
2027	118,898	51,648	29,148	11,993	7,889	6,239	11,982

SBC Rate ($/kWh)

		MA	CT	ME	RI	VT	NH
		0.00250	0.00300	-	0.01122	-	0.00275

SBC Dollars ($1000's)

	New England	MA	CT*	ME	RI	VT	NH
2019	320,715	119,642	11,858	-	85,047	-	31,286
2020	321,848	118,390	25,330	-	88,743	-	31,292
2021	325,218	119,796	78,966	-	90,032	-	31,494
2022	328,865	121,310	79,553	-	91,351	-	31,722
2023	332,557	122,873	80,172	-	92,615	-	31,968
2024	336,228	124,436	80,780	-	93,870	-	32,212
2025	339,820	125,980	81,358	-	95,098	-	32,454
2026	343,398	127,550	81,937	-	96,280	-	32,702
2027	346,928	129,119	82,516	-	97,415	-	32,950

* Reflects reduced SBC funds to account for CT budget cuts

Impacts of New EE on Revenue Streams

Lost SBC Dollars ($1000's)							
	New England	MA	CT	ME	RI	VT	NH
2022	14,808	6,854	2,212	-	5,247	-	494
2023	21,297	9,850	3,180	-	7,556	-	712
2024	27,154	12,548	4,052	-	9,645	-	908
2025	32,382	14,953	4,829	-	11,516	-	1,084
2026	36,997	17,071	5,515	-	13,172	-	1,239
2027	41,028	18,918	6,112	-	14,623	-	1,375
New FCM Dollars ($1000's)							
	New England	MA	CT	ME	RI	VT	NH
2022	31,662	21,141	5,814	-	3,265	-	1,442
2023	45,514	30,380	8,357	-	4,701	-	2,076
2024	58,003	38,704	10,650	-	6,001	-	2,649
2025	69,138	46,120	12,693	-	7,165	-	3,161
2026	78,958	52,654	14,494	-	8,195	-	3,614
2027	87,522	58,350	16,064	-	9,097	-	4,010

Policy Dollars and Total Budgets

Policy Dollars ($1000's)*

	New England	MA	CT	ME	RI	VT	NH
2019	525,897	423,965	81,409	39,494	-	53,911	-
2020	555,472	434,184	85,659	39,494	-	54,229	-
2021	610,803	434,205	86,877	39,494	-	55,156	-
2022	603,128	425,839	86,877	39,494	-	55,847	-
2023	596,073	418,032	86,877	39,494	-	56,598	-
2024	589,755	410,844	86,877	39,494	-	57,470	-
2025	585,577	404,288	86,877	39,494	-	59,847	-
2026	580,384	398,303	86,877	39,494	-	60,639	-
2027	575,211	392,885	86,877	39,494	-	60,885	-

Total Budget Dollars ($1000's)

	New England	MA	CT	ME	RI	VT	NH
2019	1,097,879	715,631	142,153	39,494	105,350	53,911	41,339
2020	1,116,186	715,631	157,629	39,494	107,715	54,229	41,488
2021	1,173,606	715,631	212,771	39,494	109,308	55,156	41,246
2022	1,177,892	715,631	215,086	39,494	109,905	55,847	41,928
2023	1,182,103	715,631	217,281	39,494	110,508	56,598	42,591
2024	1,186,280	715,631	219,308	39,494	111,165	57,470	43,212
2025	1,191,773	715,631	221,153	39,494	111,858	59,847	43,790
2026	1,195,513	715,631	222,847	39,494	112,566	60,639	44,336
2027	1,198,538	715,631	224,399	39,494	113,286	60,885	44,844

* Policy dollars are funds not from SBC, RGGI, or FCM revenues. Policy dollars are present in states that set the SBC rate based on budget alone (VT and ME) and states that have a surcharge to cover the balance of the total budget (MA and CT). MA is adjusted to reflect a lower portion of budget coming from SBC due to higher FCM revenue.

Production Costs and Peak-to-Energy Ratio

Production Cost Multiplier (includes inflation)

	MA	CT	ME	RI	VT	NH
2017	1.0250	1.0250	1.0250	1.0250	1.0250	1.0250
2018	1.0375	1.0375	1.0375	1.0375	1.0375	1.0375
2019	1.0500	1.0500	1.0500	1.0500	1.0500	1.0500
2020	1.0625	1.0625	1.0625	1.0625	1.0625	1.0625
2021	1.0750	1.0750	1.0750	1.0750	1.0750	1.0750
2022	1.0875	1.0875	1.0875	1.0875	1.0875	1.0875
2023	1.1000	1.1000	1.1000	1.1000	1.1000	1.1000
2024	1.1125	1.1125	1.1125	1.1125	1.1125	1.1125
2025	1.1250	1.1250	1.1250	1.1250	1.1250	1.1250
2026	1.1375	1.1375	1.1375	1.1375	1.1375	1.1375
2027	1.1500	1.1500	1.1500	1.1500	1.1500	1.1500

Production Cost ($/MWh)

	MA	CT	ME	RI	VT	NH
2017	402	468	238	384	421	372
2018	417	486	247	398	437	386
2019	438	510	260	418	458	405
2020	465	542	276	444	487	430
2021	500	583	296	478	524	462
2022	544	634	322	520	570	503
2023	598	697	355	572	626	553
2024	665	776	395	636	697	615
2025	748	872	444	715	784	692
2026	851	992	505	814	892	787
2027	979	1,141	581	936	1,026	906

Peak-to-Energy Ratio (MW/GWh)

	MA	CT	ME	RI	VT	NH
	0.139	0.142	0.132	0.126	0.114	0.144

FINAL FORECAST

New England

Energy and Summer Peak EE Forecast

Energy Savings (GWh)

	New England	MA	CT	ME	RI	VT	NH
2019	2,690	1,733	295	161	267	125	108
2020	2,568	1,631	308	152	257	118	102
2021	2,494	1,517	387	141	243	112	95
2022	2,302	1,395	360	130	224	104	88
2023	2,099	1,269	330	118	205	96	82
2024	1,893	1,140	300	106	185	87	74
2025	1,690	1,014	269	94	166	81	67
2026	1,490	891	238	83	147	72	60
2027	1,299	775	208	72	128	63	52
Total 2019-2027	18,527	11,366	2,696	1,058	1,822	857	729
Average	2,059	1,263	300	118	202	95	81

Demand Savings (MW)

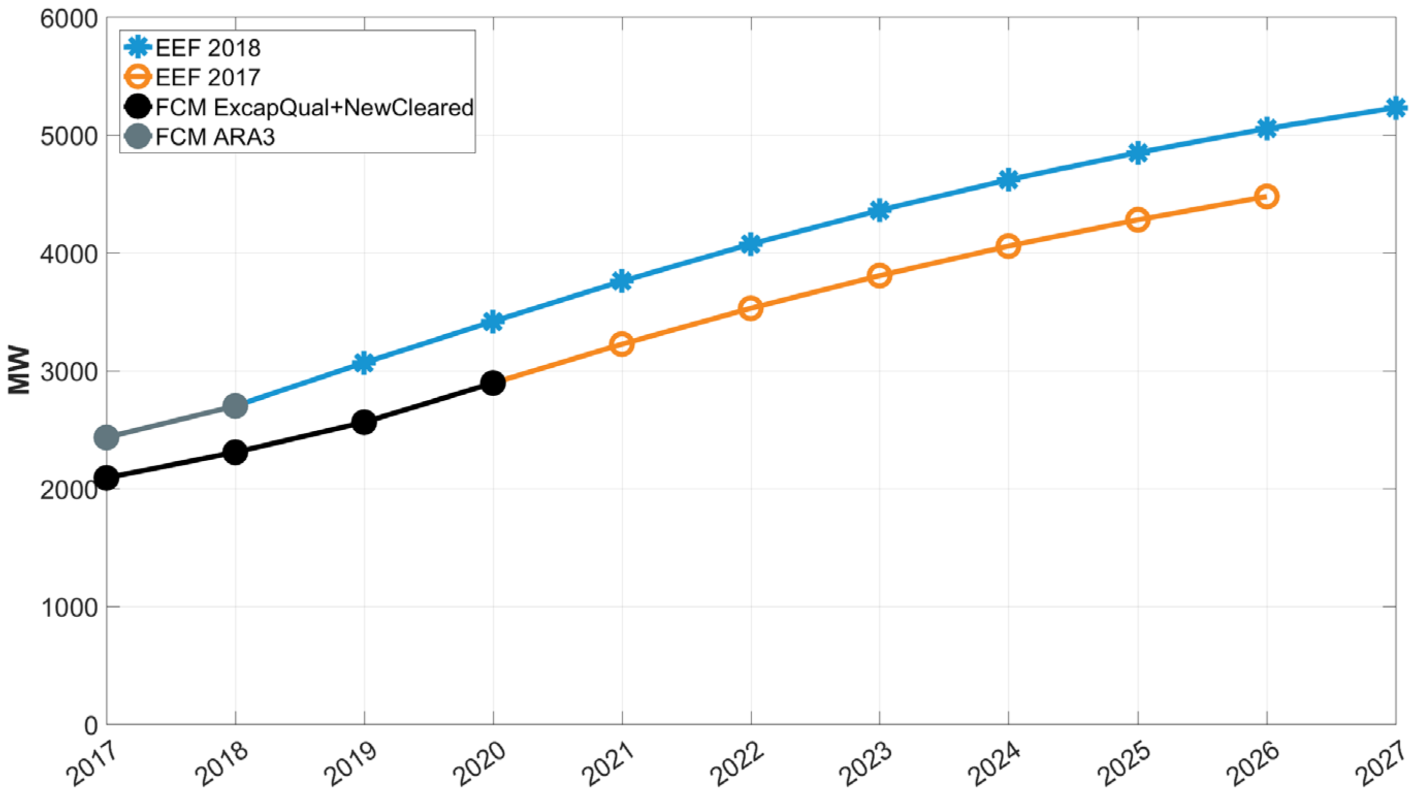
	New England	MA	CT	ME	RI	VT	NH
2019	367	241	42	21	34	14	16
2020	351	226	44	20	32	13	15
2021	341	211	55	19	30	13	14
2022	315	194	51	17	28	12	13
2023	287	176	47	16	26	11	12
2024	259	158	43	14	23	10	11
2025	231	141	38	12	21	9	10
2026	204	124	34	11	18	8	9
2027	177	108	30	10	16	7	8
Total 2019-2027	2,531	1,577	382	139	229	98	105
Average	281	175	42	15	25	11	12

EE Forecast Comparison

PA Average Production Cost ($/MWh)							
	New England	MA	CT	ME	RI	VT	NH
2017 EE Forecast		402	451	211	398	420	398
2018 EE Forecast		392	457	232	375	411	363
PA Average Peak-to-Energy Ratio (MW/GWh)							
	New England	MA	CT	ME	RI	VT	NH
2017 EE Forecast		0.140	0.137	0.117	0.139	0.119	0.149
2018 EE Forecast		0.139	0.142	0.132	0.126	0.114	0.144
Total EE Dollars (1000s)							
	New England	MA	CT	ME	RI	VT	NH
2017 EE Forecast							
Total 2018-2026	10,699,221	6,451,205	2,188,561	355,446	825,036	568,241	310,733
Average	1,188,802	716,801	243,173	39,494	91,671	63,138	34,526
2018 EE Forecast							
Total 2019-2027	10,519,771	6,440,682	1,832,627	355,446	991,660	514,582	384,774
Average	1,168,863	715,631	203,625	39,494	110,184	57,176	42,753
Summer Peak Impacts (MW)							
	New England	MA	CT	ME	RI	VT	NH
2017 EE Forecast							
Total 2018-2026	2,386	1,491	509	56	212	37	80
Average	265	166	57	6	24	4	9
2018 EE Forecast							
Total 2019-2027	2,531	1,577	382	139	229	98	105
Average	281	175	42	15	25	11	12

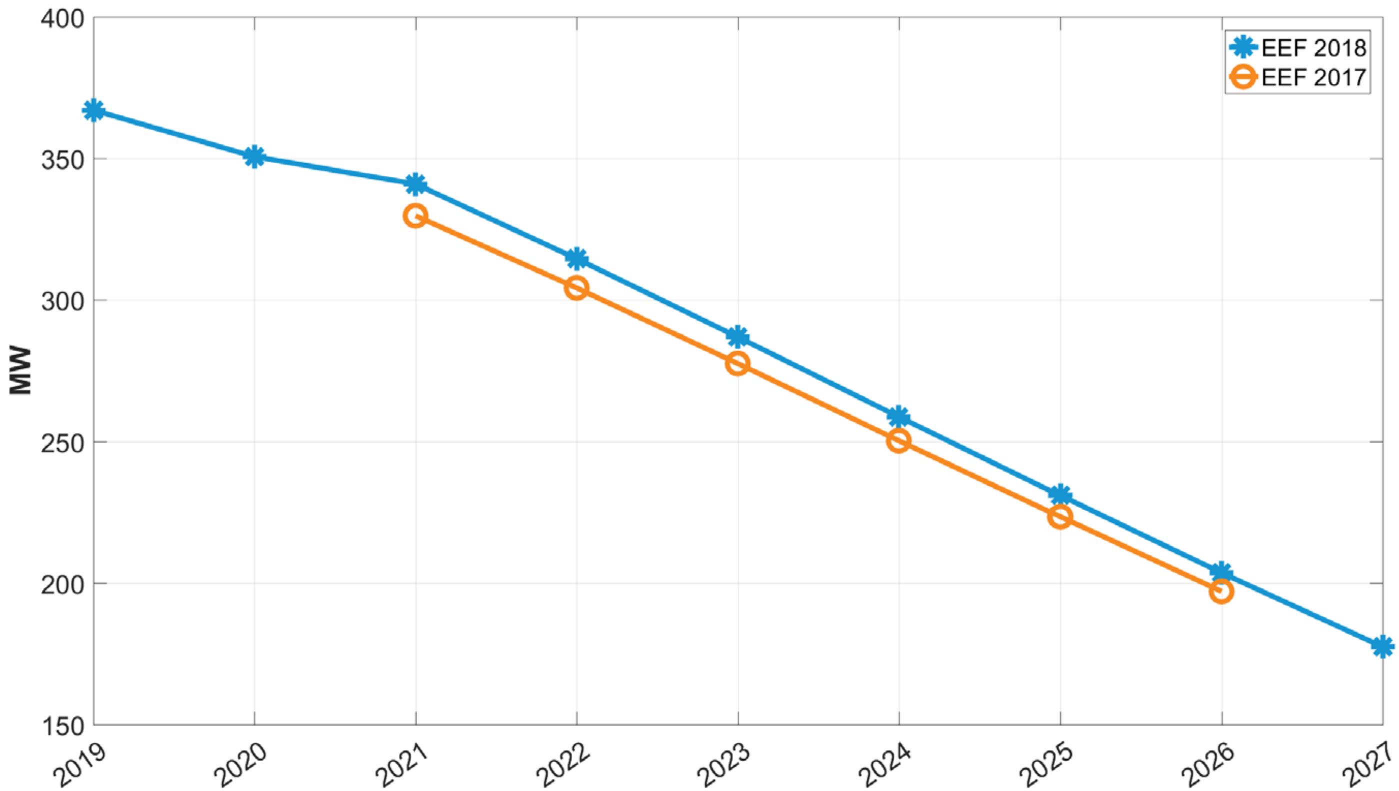
New England

Energy Efficiency on Summer Peak



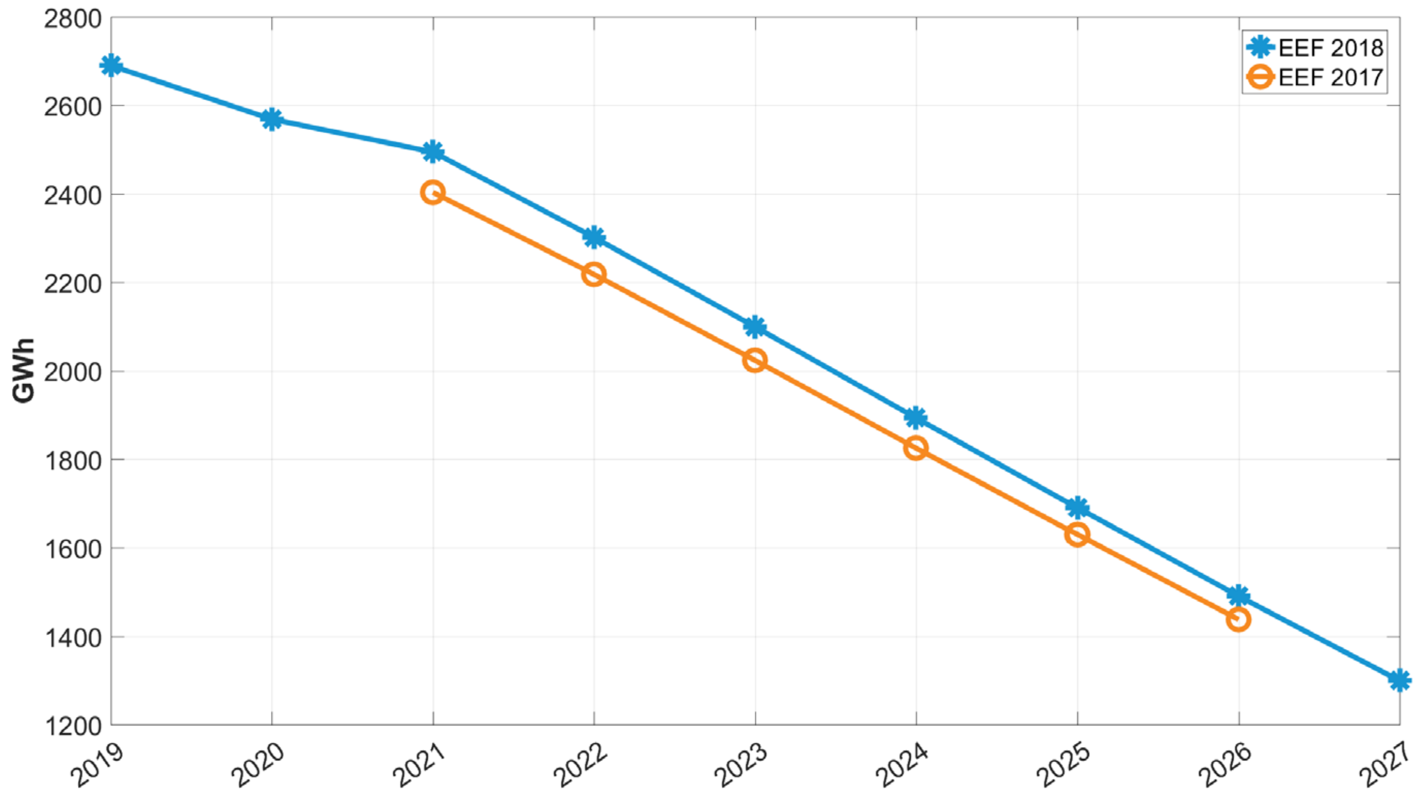
New England

Energy Efficiency on Summer Peak



New England

Energy Efficiency on Annual Energy

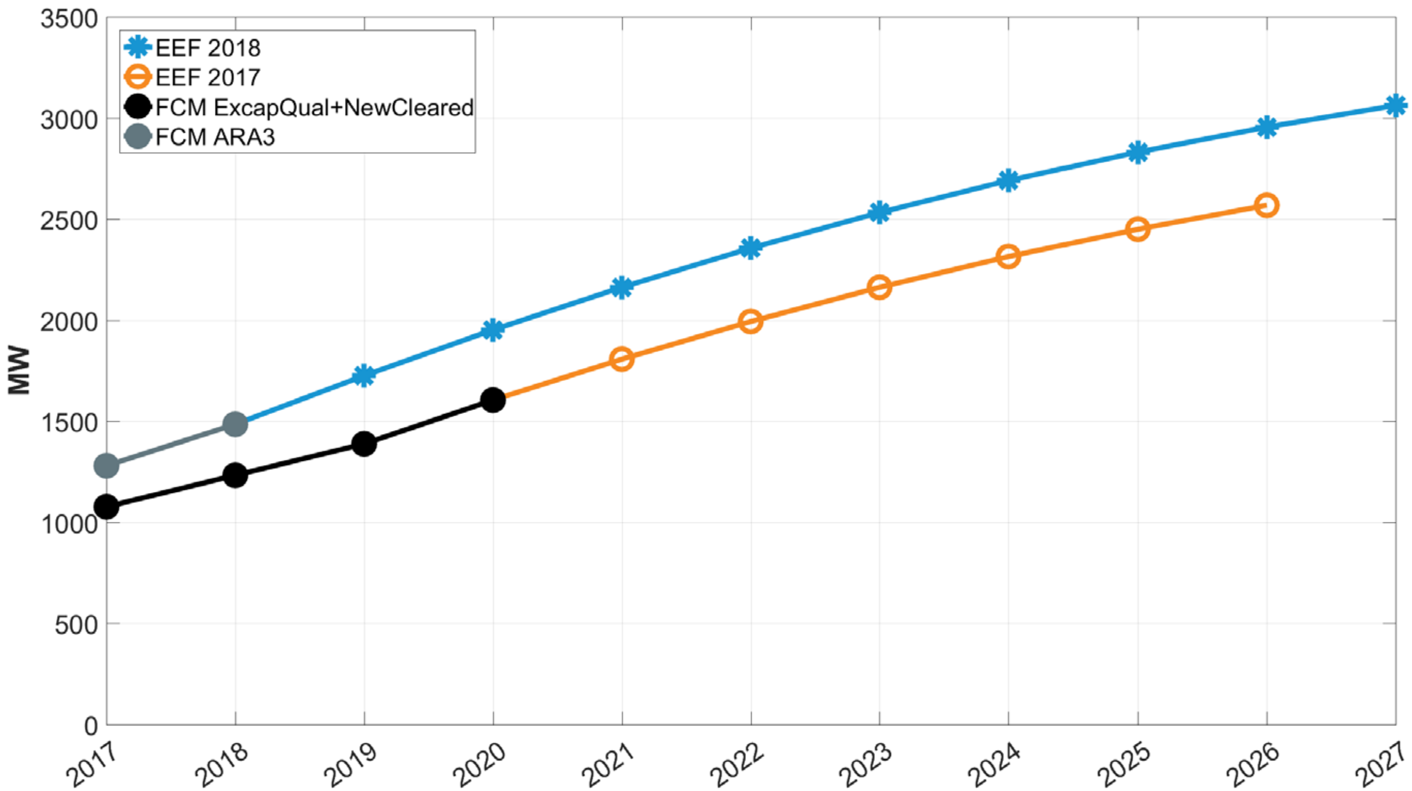


FINAL FORECAST

States

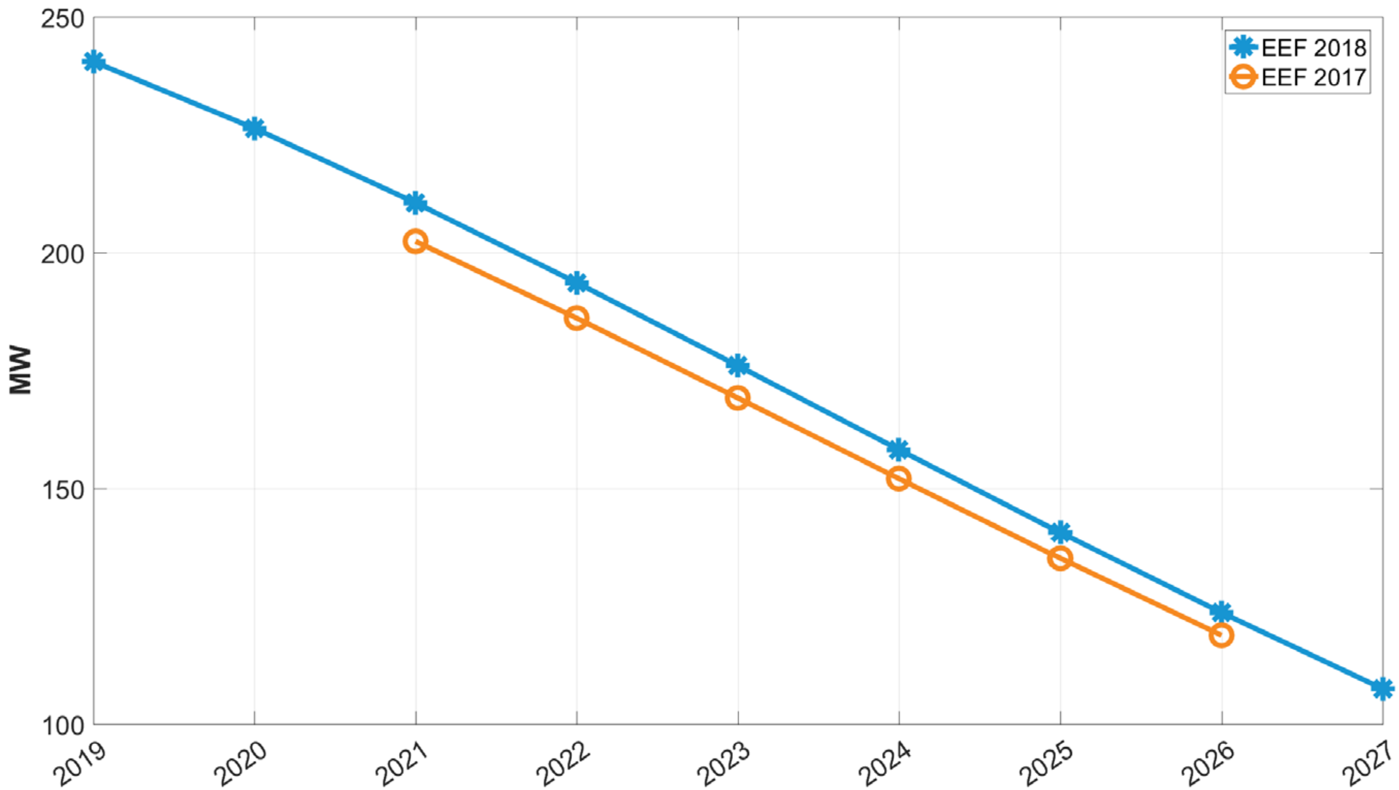
Massachusetts

Energy Efficiency on Summer Peak



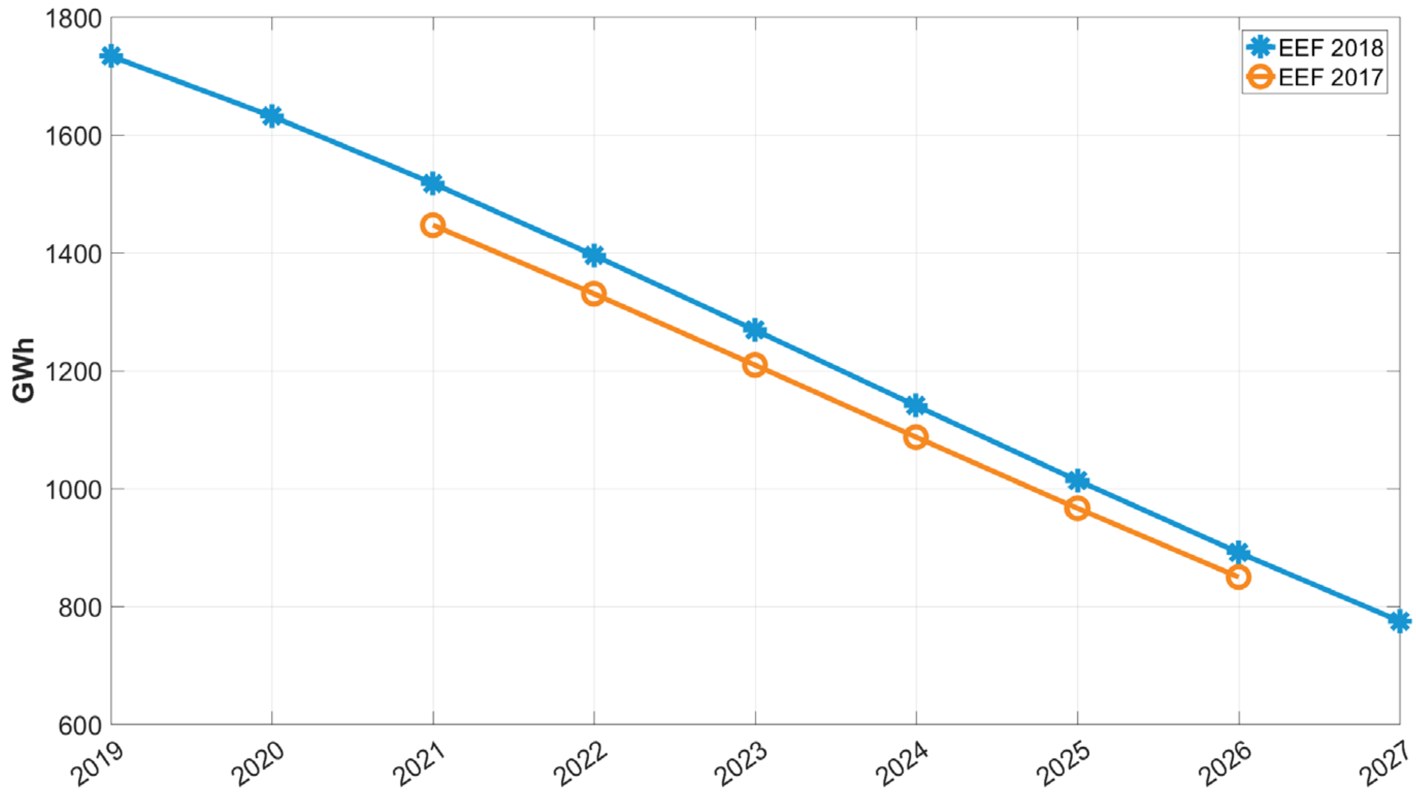
Massachusetts

Energy Efficiency on Summer Peak



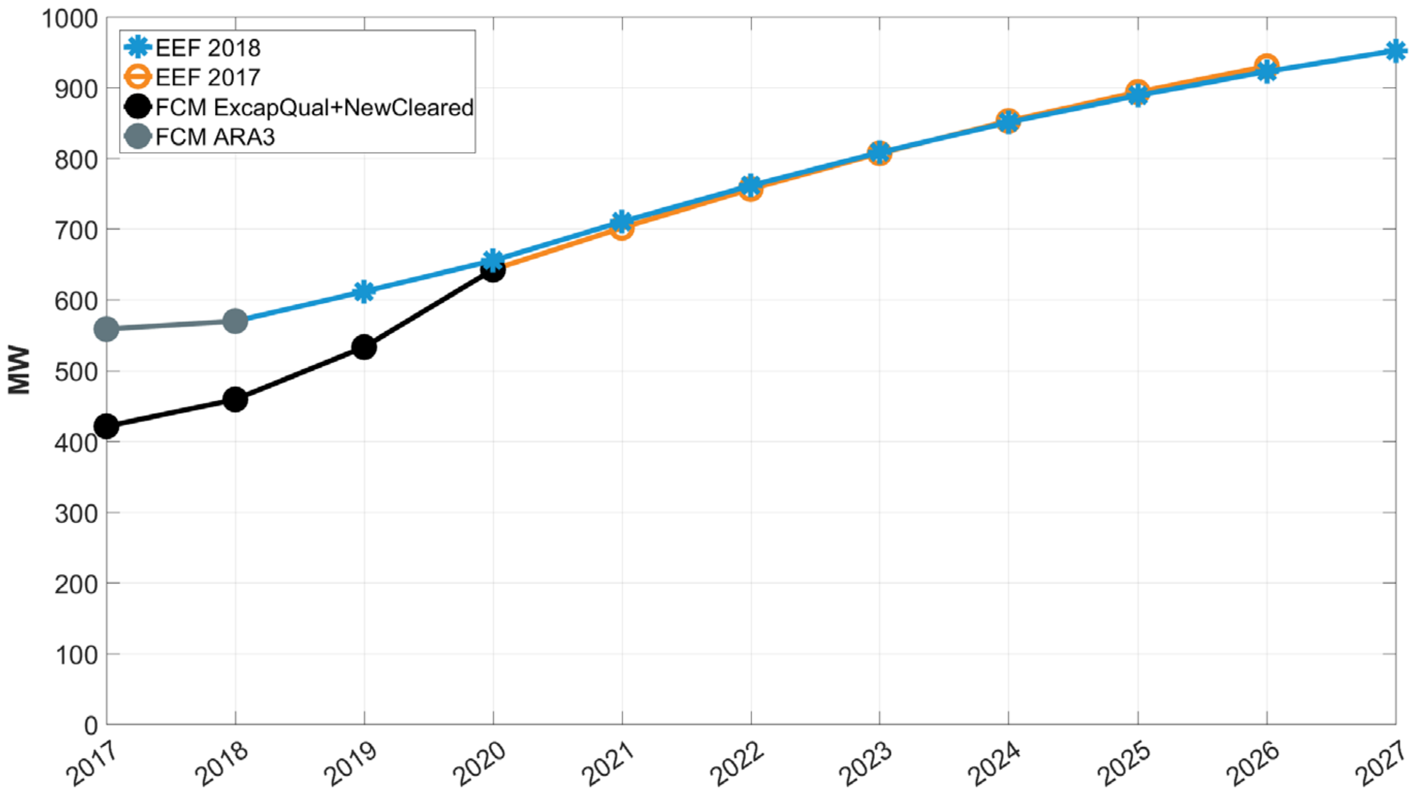
Massachusetts

Energy Efficiency on Annual Energy



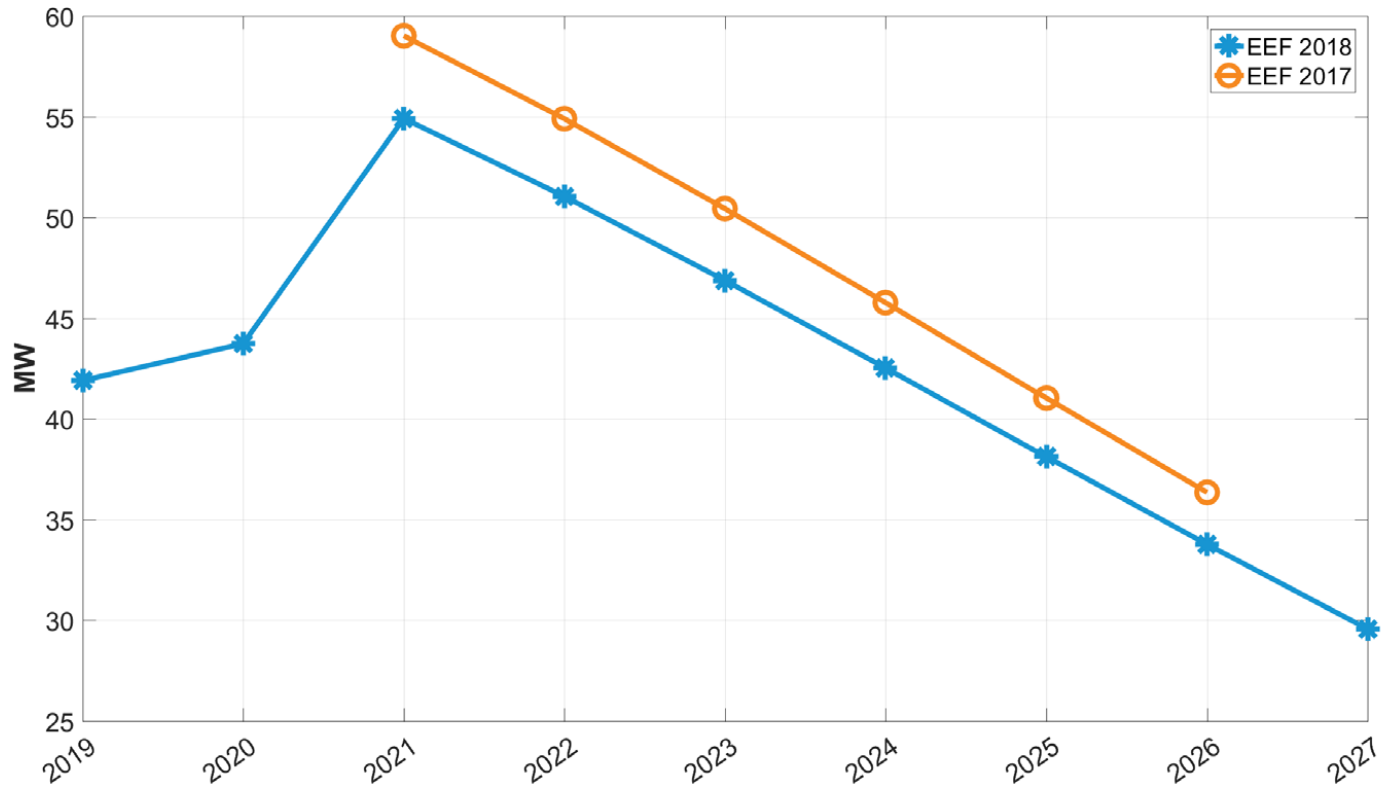
Connecticut

Energy Efficiency on Summer Peak



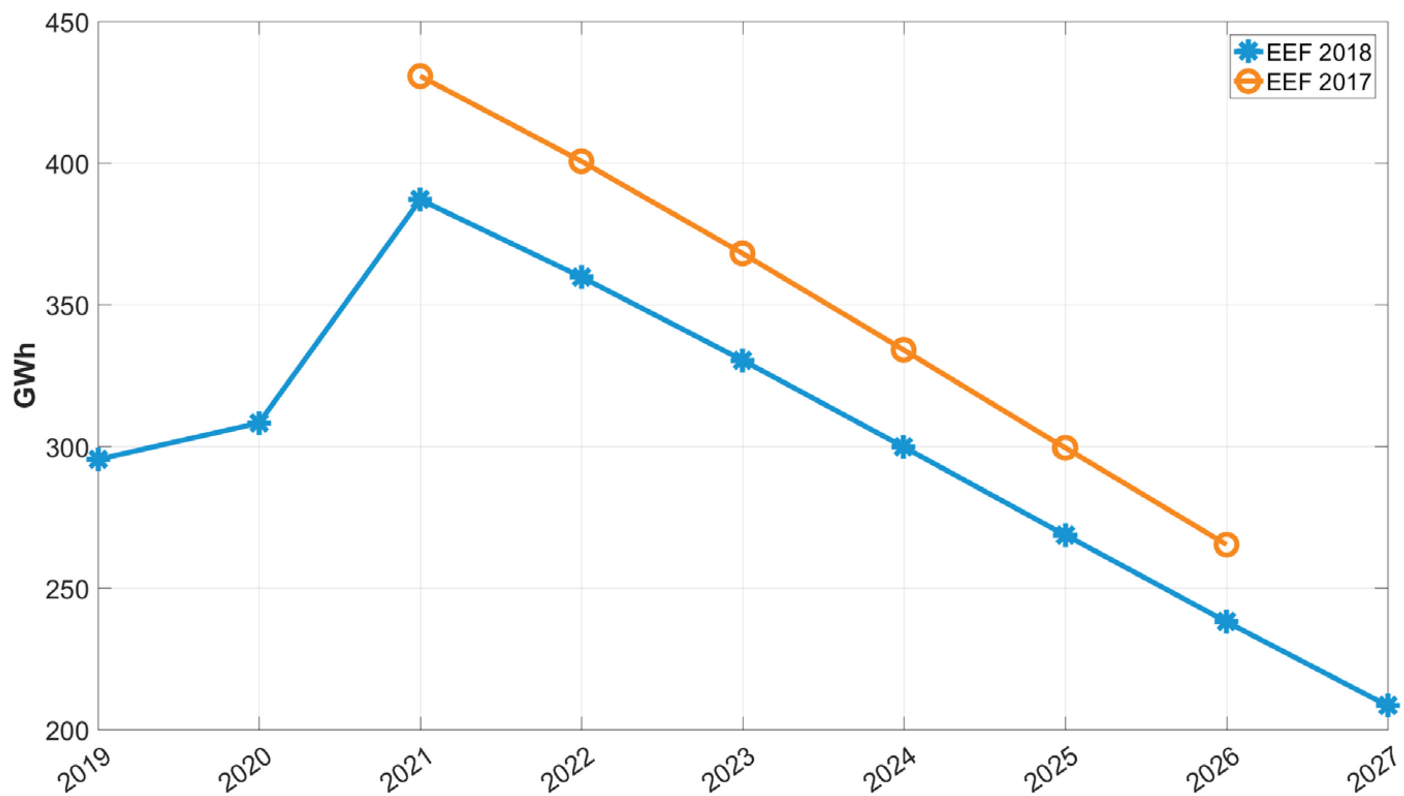
Connecticut

Energy Efficiency on Summer Peak



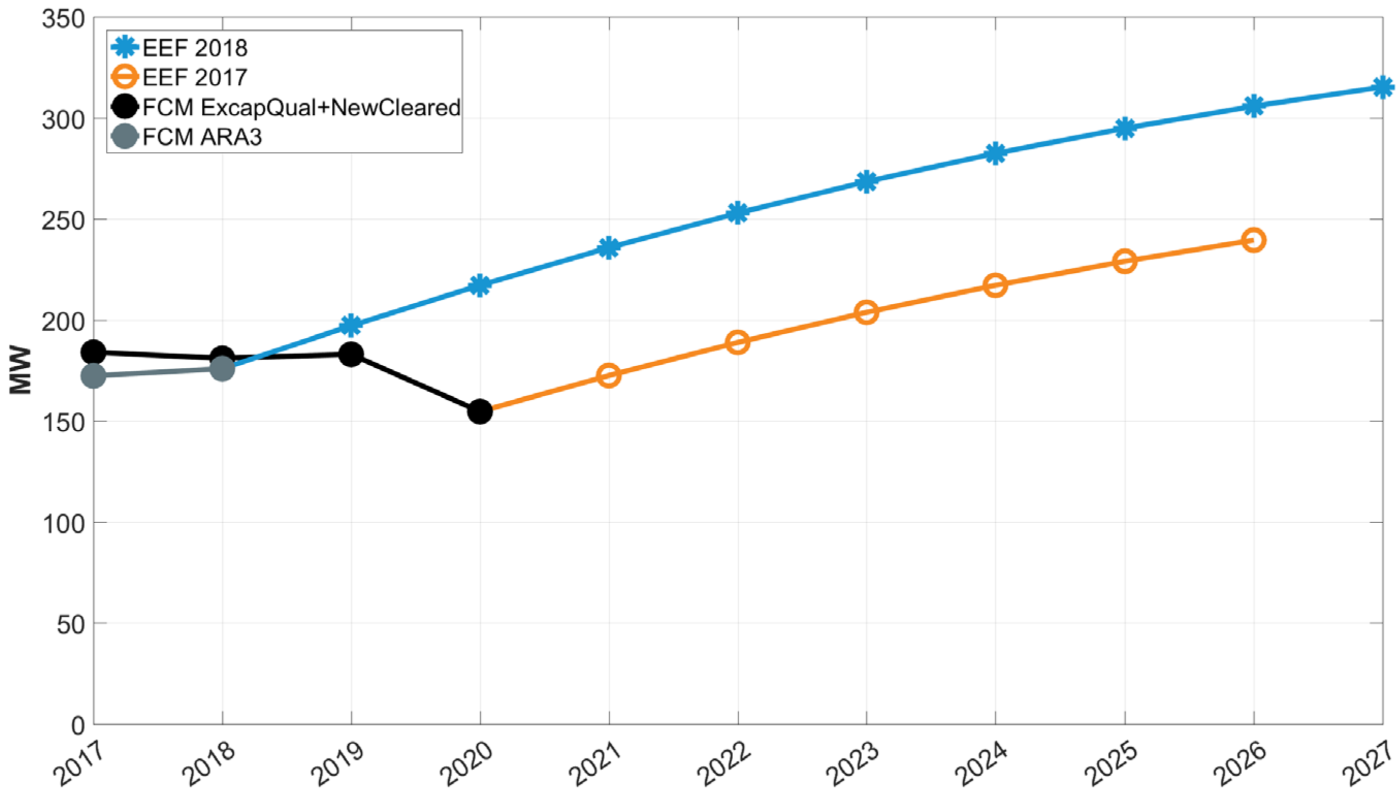
Connecticut

Energy Efficiency on Summer Peak



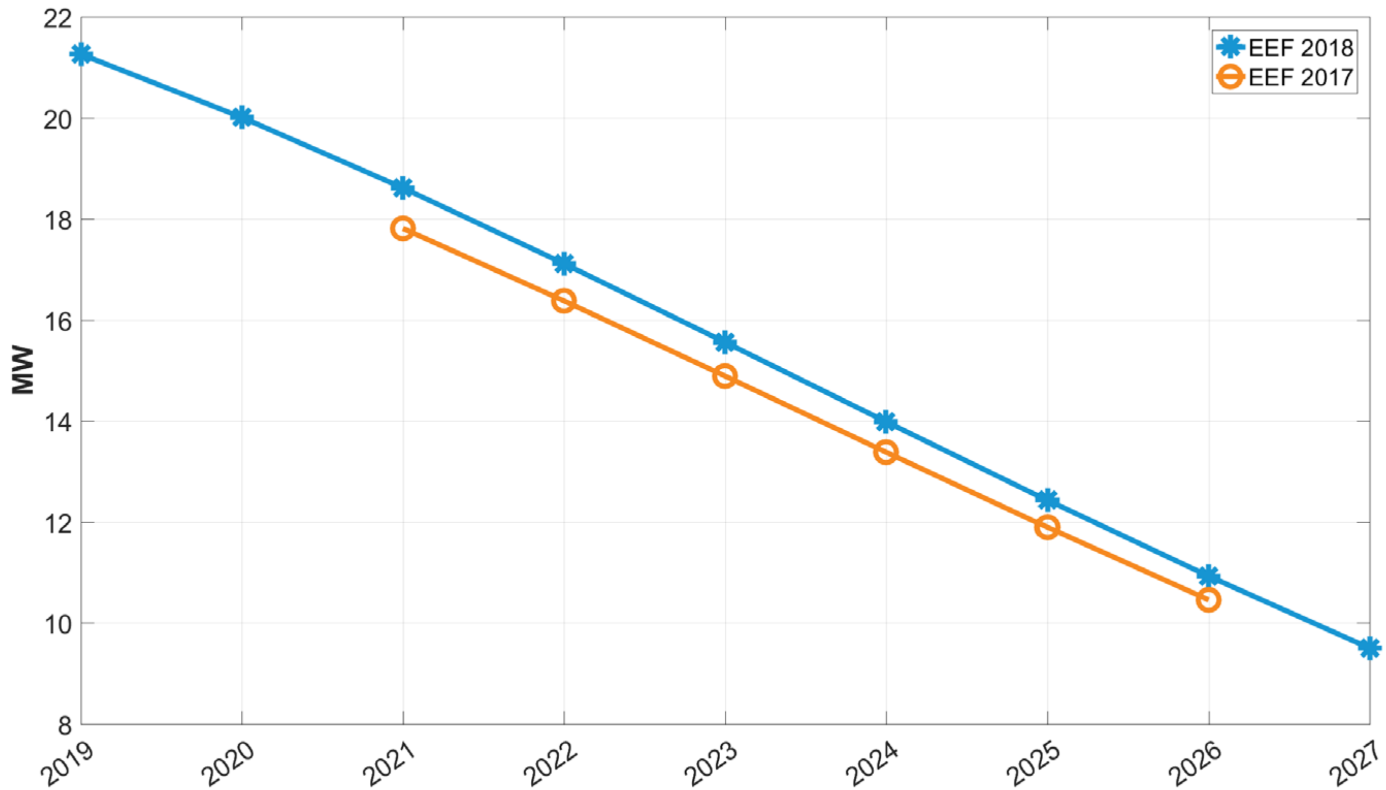
Maine

Energy Efficiency on Summer Peak



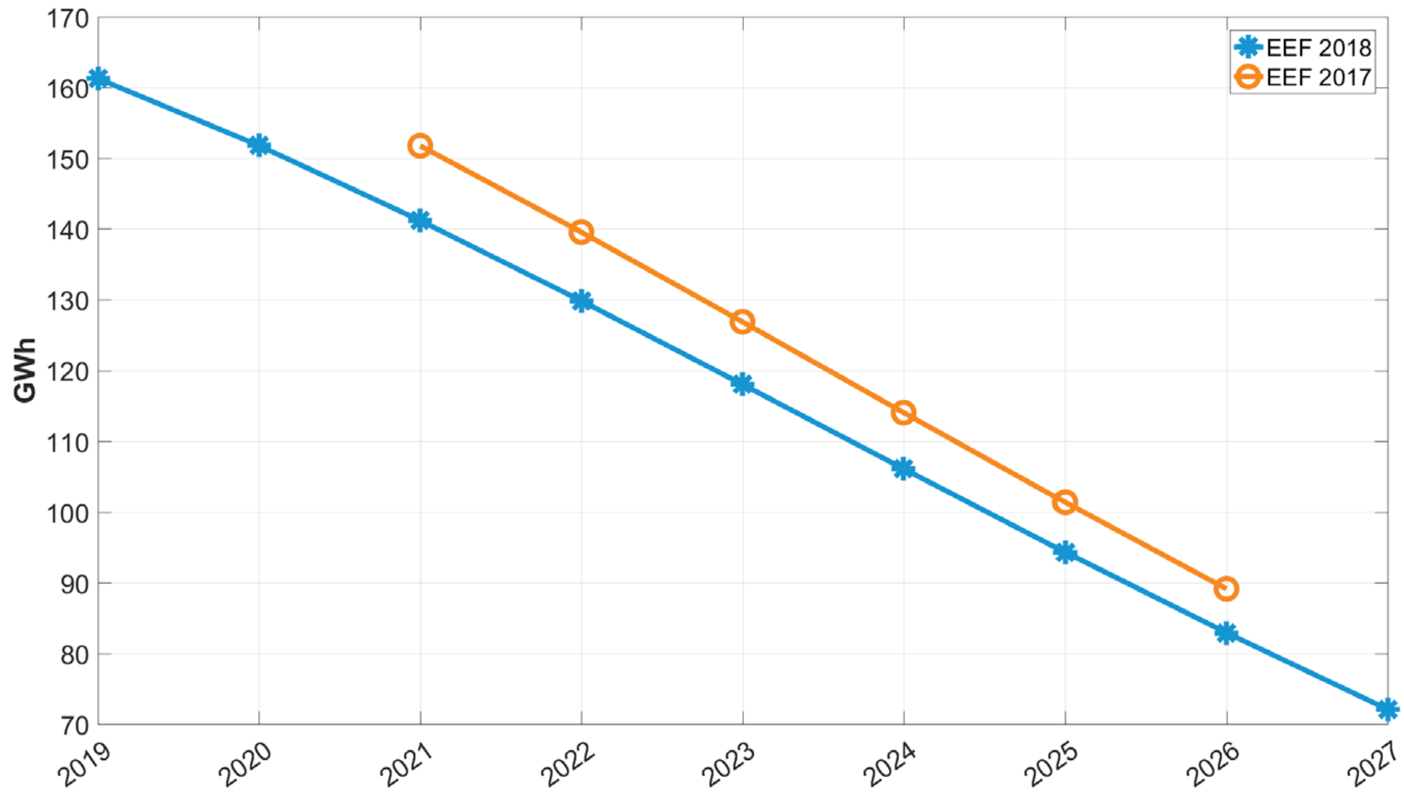
Maine

Energy Efficiency on Summer Peak



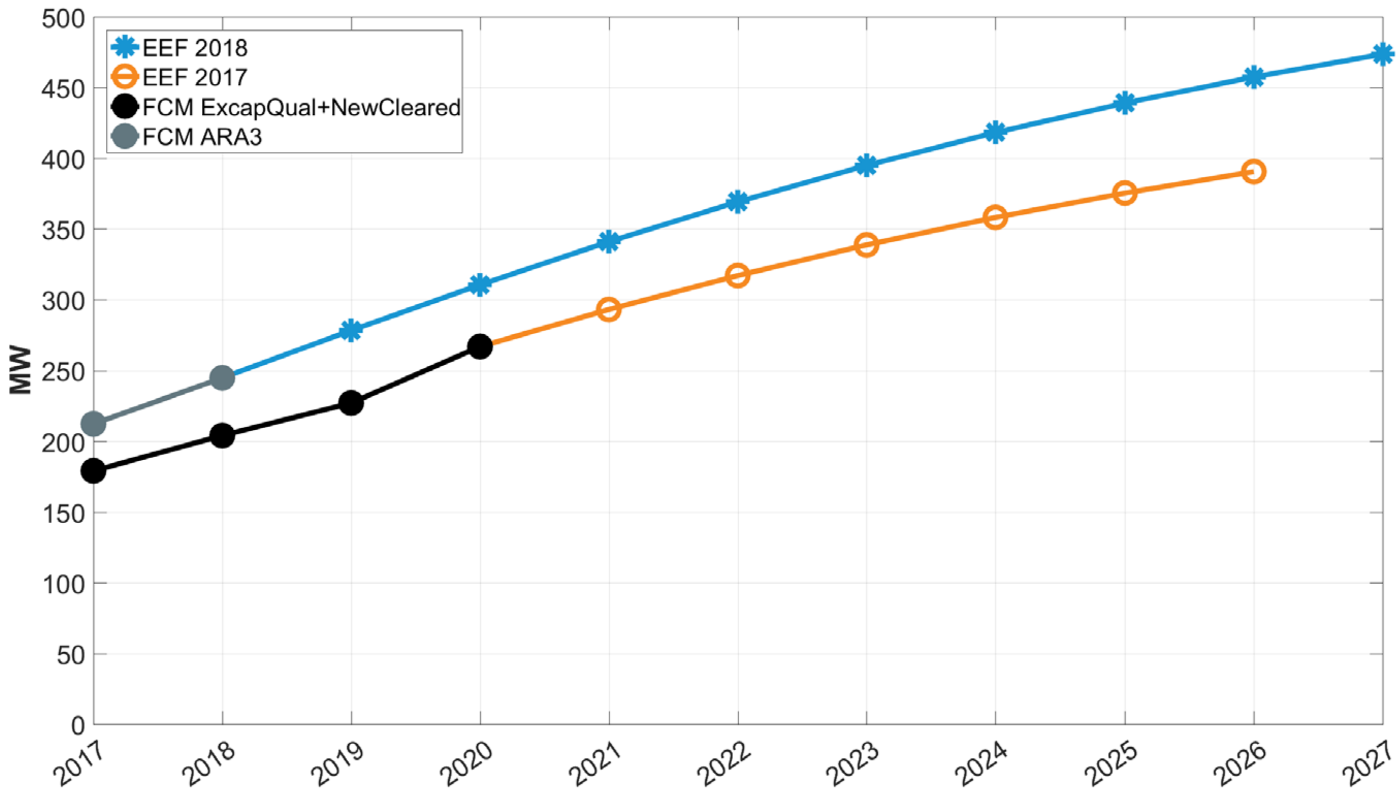
Maine

Energy Efficiency on Annual Energy



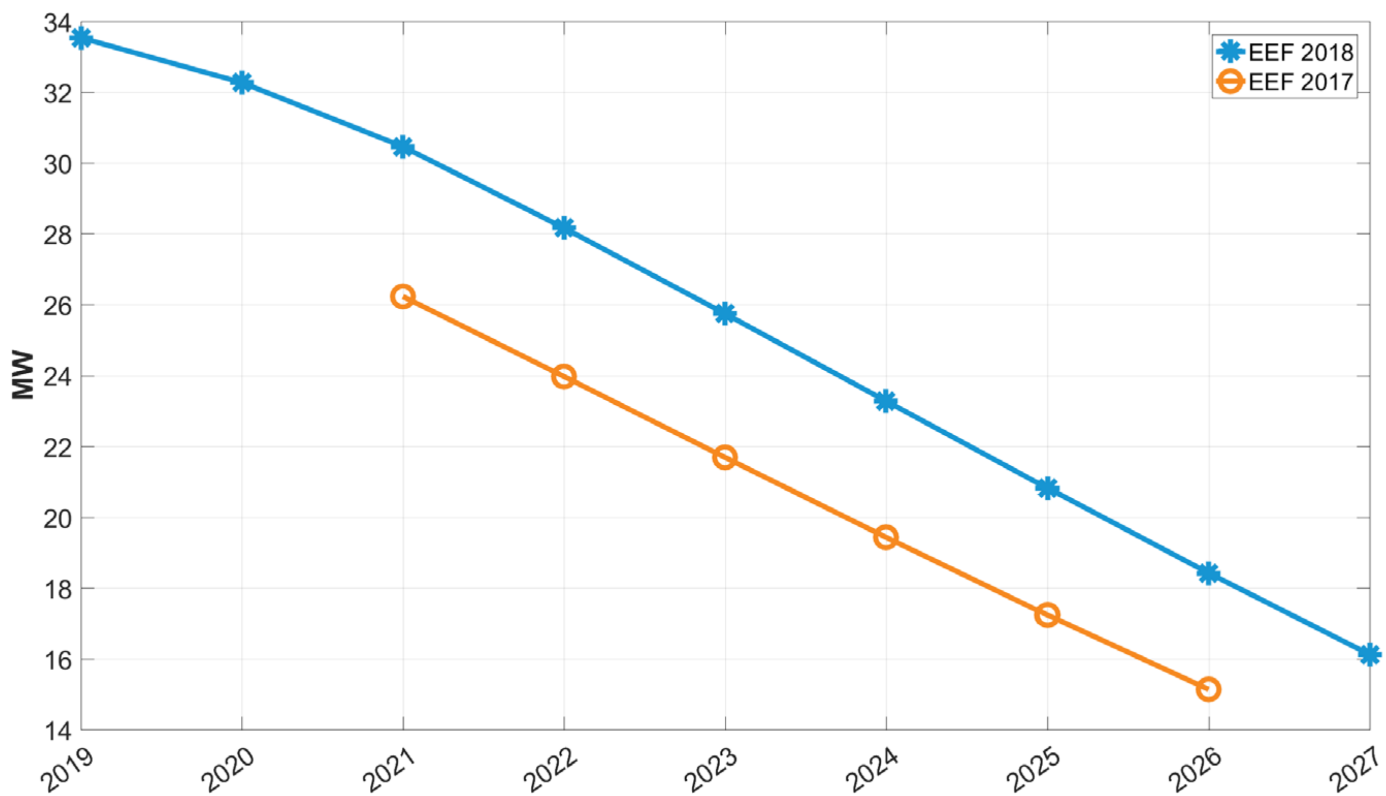
Rhode Island

Energy Efficiency on Summer Peak



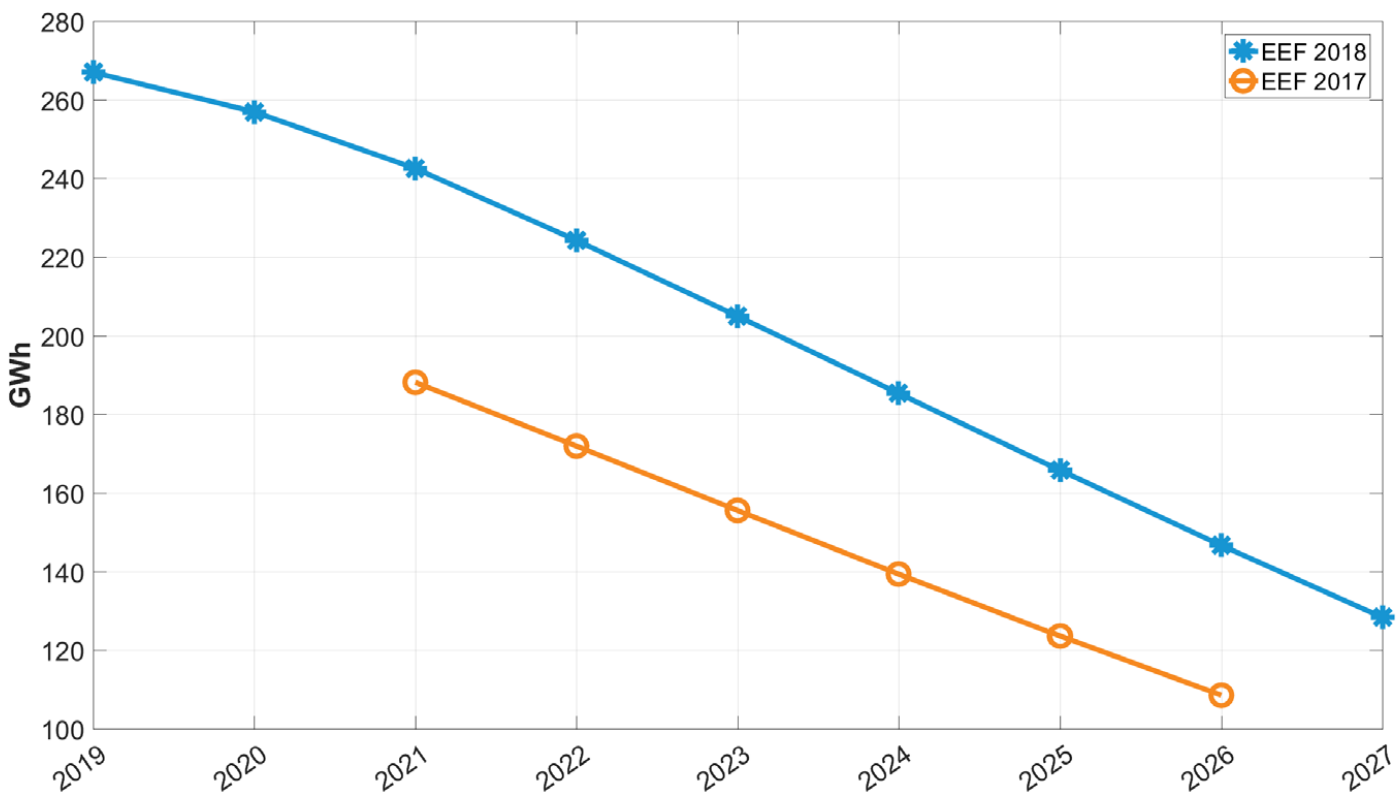
Rhode Island

Energy Efficiency on Summer Peak



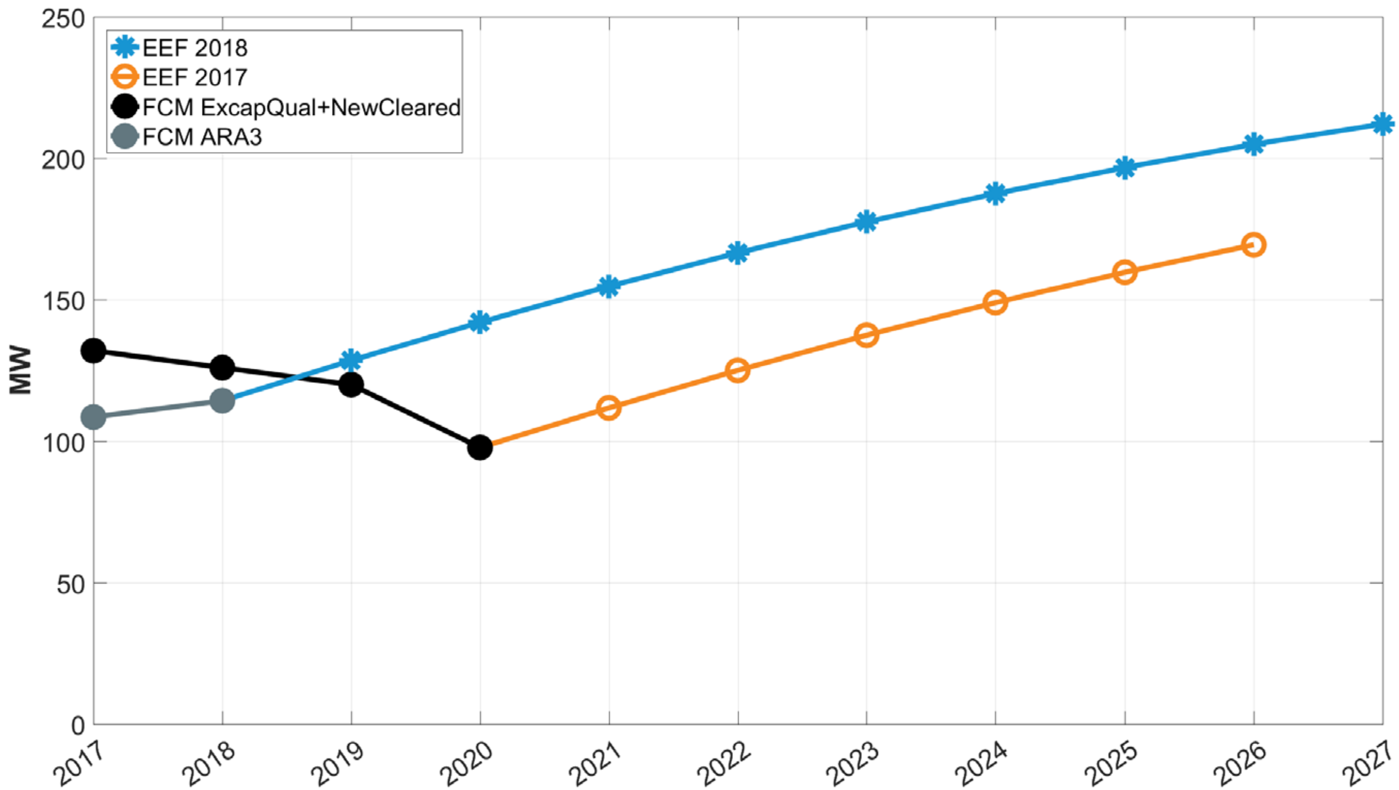
Rhode Island

Energy Efficiency on Annual Energy



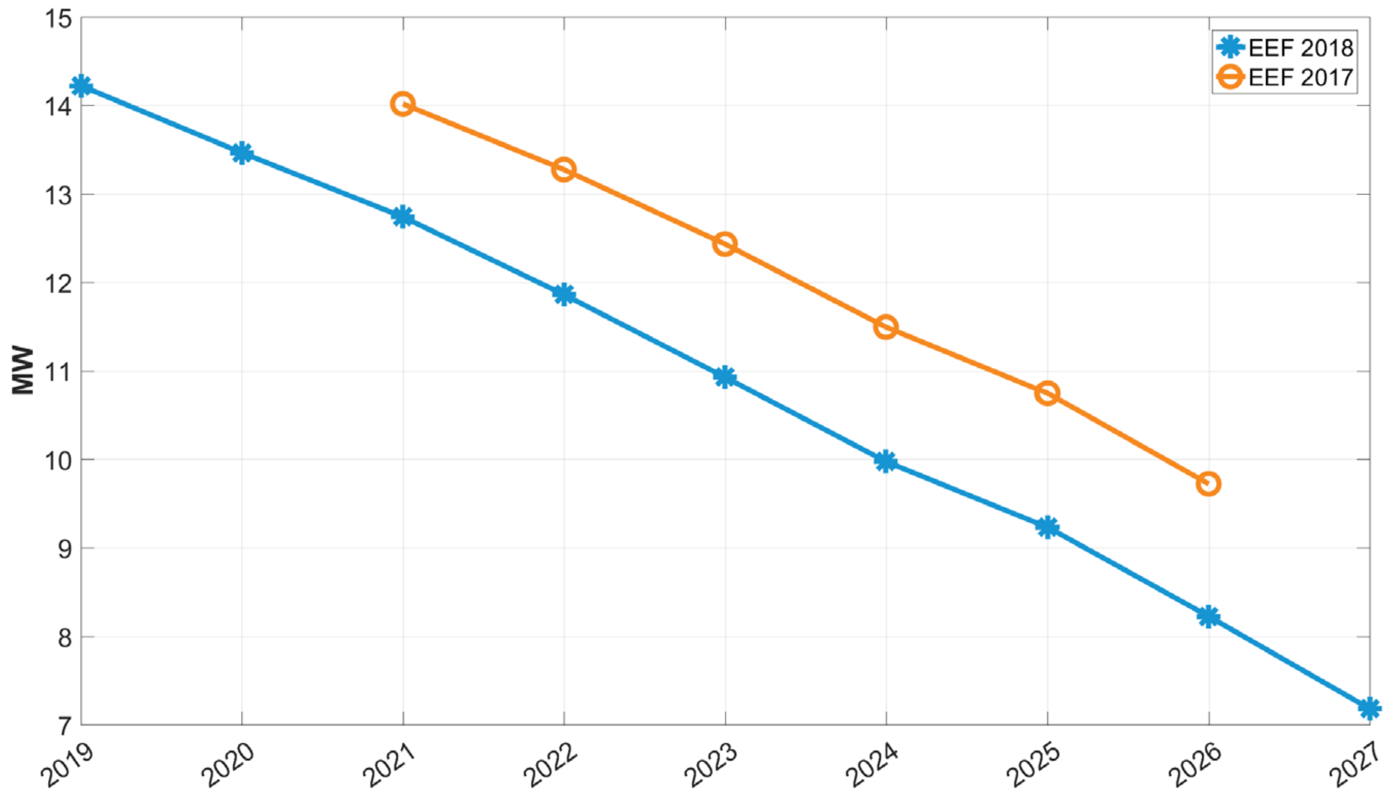
Vermont

Energy Efficiency on Summer Peak



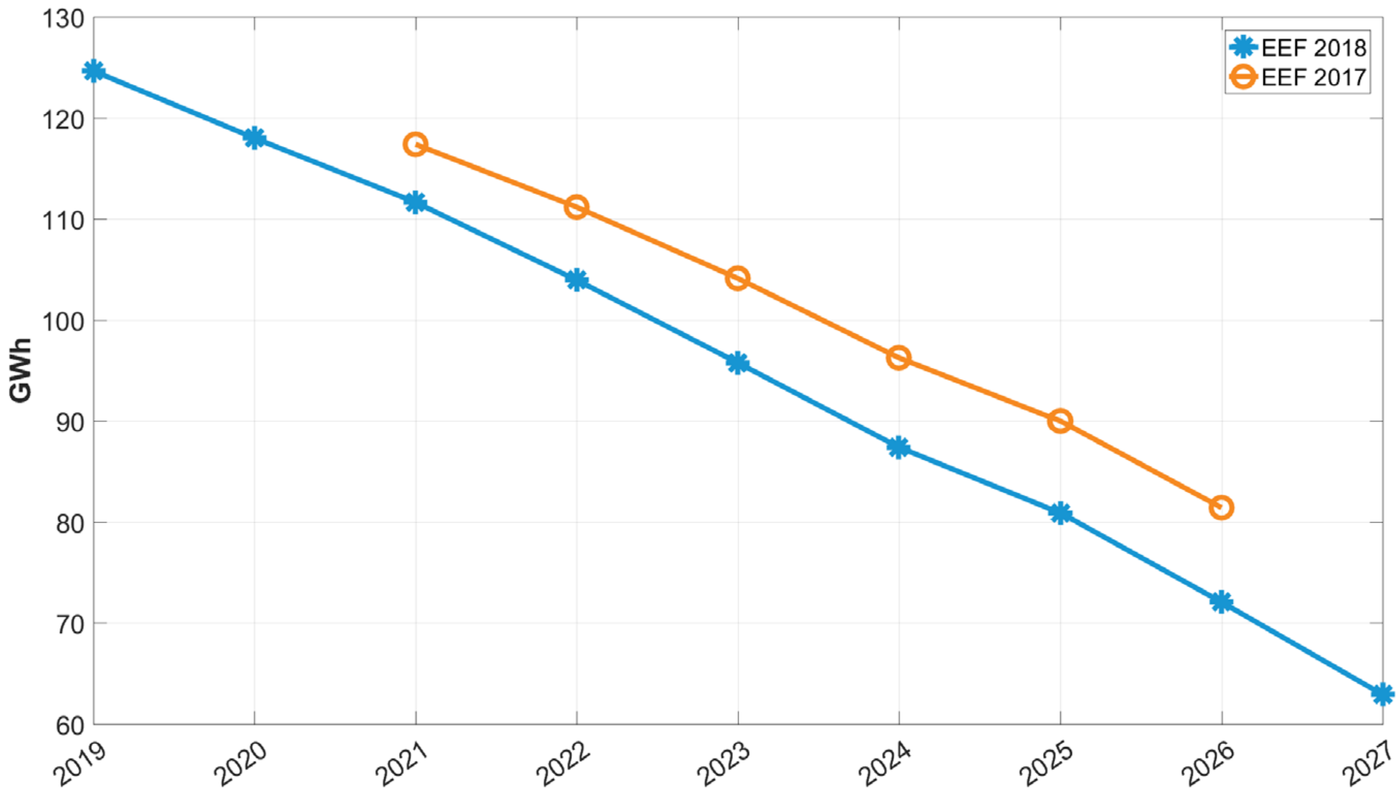
Vermont

Energy Efficiency on Summer Peak



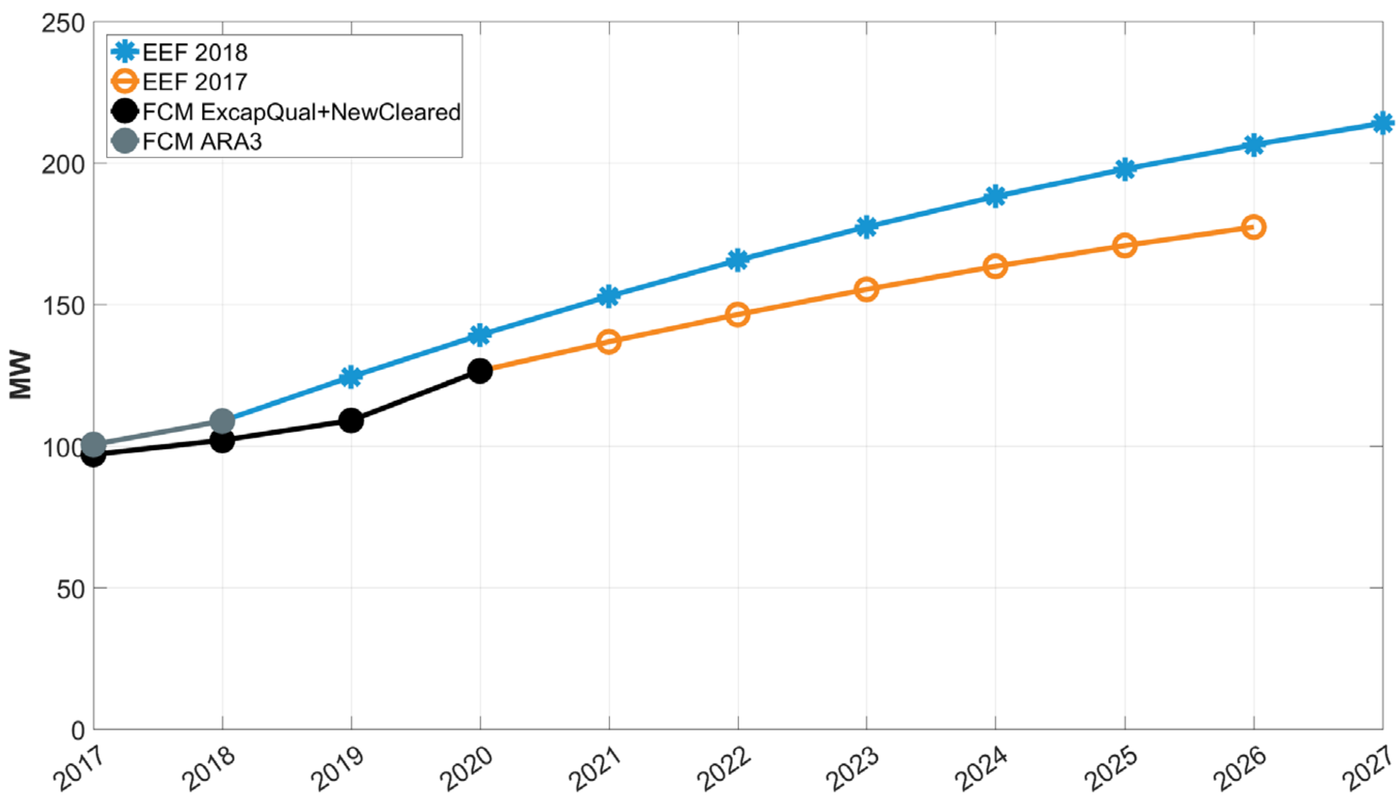
Vermont

Energy Efficiency on Annual Energy



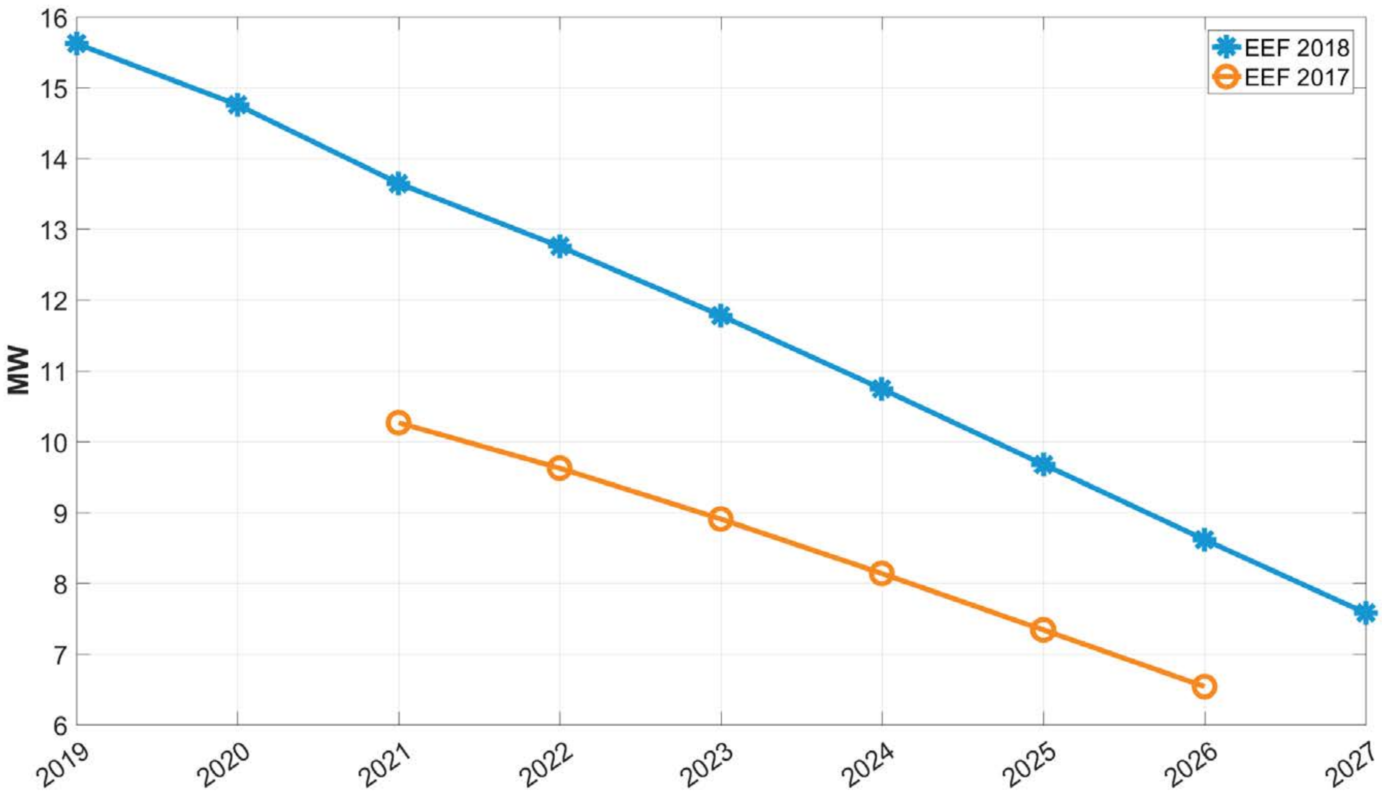
New Hampshire

Energy Efficiency on Summer Peak



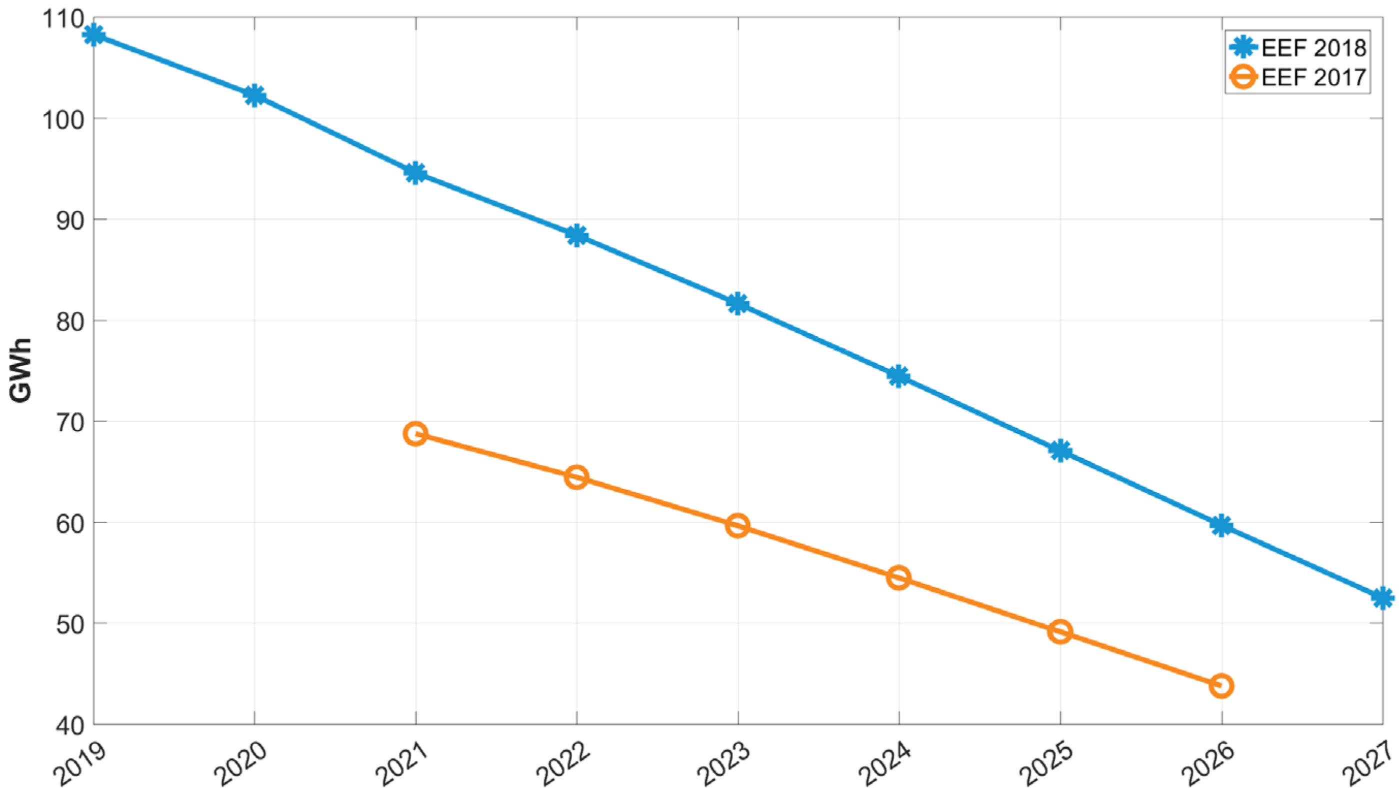
New Hampshire

Energy Efficiency on Summer Peak



New Hampshire

Energy Efficiency on Annual Energy



PUC 12-2

Request:

In Mr. Gredder's Rebuttal Testimony on Bates page 69, lines 1-9, he states: "The Company's forecasting methods take into account all relevant and reliable information to develop the most accurate forecast possible. That includes the Company's reasonable expectation for the impacts of Power Sector Transformation. Power Sector Transformation does not have specific goals for energy efficiency and solar energy generation. The most reliable indicators of increased reliance on energy efficiency and solar generation for the period covered by the proposed rates and rate design are the energy efficiency programs approved by the PUC and the ISO-NE forecasts for solar generation. Accordingly, the Company's use of those data points is the most reasonable and reliable forecasting method." (emphasis added)

(a) Please explain how, if Power Sector Transformation does not have specific goals for energy efficiency and solar energy generation, the Company nonetheless included the impacts in its forecasting.

Response:

On Page 5 (Bates Page 69 of Rebuttal Book 2) of Company Witness Joseph Gredder's rebuttal testimony is a discussion to show that the Company used the most reasonable and reliable forecasting method based on all relevant and reliable information to develop its forecast. Power Sector Transformation is and will continue to include distributed energy resources including energy efficiency and photovoltaics that are being captured as part of the Company's process. As discussed on Page 5 of Mr. Gredder's rebuttal testimony (Bates Page 69 of Rebuttal Book 2), in the absence of Power Sector Transformation-specific goals, the most reliable indicators of what those might be are the programs already approved by the Public Utilities Commission and the ISO-NE projections.

As further discussed on Page 7 of the Mr. Gredder's Rebuttal Testimony (Bates Page 71 of Rebuttal Book 2), the use of these data points are best suited to account for the impacts of Power Sector Transformation.

Prepared by or under the supervision of: Joseph Gredder

PUC 12-3

Request:

How, if at all, were Mr. Gredder's forecasts affected by the proposed increases in the customer charge? If the rate design proposals were not considered in the electric forecasts, please explain why not.

Response:

The forecasts were not adjusted for rate design pricing proposals. As stated on Pages 16, 18, and 20 of Company Witness Joseph Gredder's pre-filed direct testimony (Bates Pages 19, 21, and 23 of Book 3), price was not found to be a statistically significant explanatory variable for the residential non-electric heating, the residential electric heating, and the commercial sales models, respectively. As stated on Page 22 of Mr. Gredder's pre-filed direct testimony (Bates Page 25 of Book 3), for the industrial model, the price "delta" between electric and gas prices was found to be statistically significant and used in the regression model; however, this is a delta between the two fuel types and not an absolute electric price indicator. Schedule JFG-7 of Mr. Gredder's pre-filed direct testimony (Bates Page 53 of Book 3) lists the explanatory variables used in the econometric regression models, including a column regarding the inclusion or non-inclusion of pricing variables.

Prepared by or under the supervision of: Joseph Gredder

PUC 12-4

Request:

Please explain any analysis the Company conducted regarding the effect of increasing the various customer charges of the electric rate classes on the value of Energy Efficiency measures.

Response:

The Company has not conducted any such analysis..

Prepared by or under the supervision of: Howard Gorman

PUC 12-5

Request:

For each rate class, using a "typical" customer (please define) provide the following:

(a) Percentage of the May 2018 bill that is made up of fixed charges and the percentage that is made up of variable charges under current rates.

(b) Dollar amounts on the May 2018 electric bill that are fixed charges and the dollar amounts that are variable charges under current rates.

(c) Using the same non-distribution rates as used in the responses to (a) and (b), what percentage of the bills would be made up of fixed charges and what percentage would be made up of variable charges under the proposed Rebuttal rates.

(d) Using the same non-distribution rates as used in the responses to (a) and (b), what dollar amount of the bills would be made up of fixed charges and what dollar amount would be made up of variable charges under the proposed Rebuttal rates.

(e) For A-60 customers, please also provide the responses to (c) and (d) assuming no customer charge.

Response:

Please see Attachment PUC 12-5 for the information requested.

(a) Please see page 1, lines (28) and (29), column (a) for each rate class, and page 2, lines (32) and (33), column (a) for each rate class, for the percentage of an average May 2018 bill that is made up of fixed charges and the percentage that is made up of variable charges under current rates.

(b) Please see page 1, lines (26) and (27), column (a) for each rate class, and page 2, lines (30) and (31), column (a) for each rate class, for the dollar amounts on an average May 2018 electric bill that are fixed charges and the dollar amounts that are variable charges under current rates.

(c) Please see page 1, lines (28) and (29), column (b) for Rate A-16, and columns (b), (c), and (d) for Rate A-60, and page 2, lines (32) and (33), column (b) for each rate class, for the percentage of the average bill that is made up of fixed charges and the percentage that is made up of variable charges using the same non-distribution rates as used in the responses to (a) and (b) and the proposed Rebuttal rates. For the purpose of this response, the Company has removed the May 2018 base CapEx Factors associated with the Infrastructure, Safety, and Reliability Plan capital investment, as the recovery of that capital investment will be transferred to base distribution rates and therefore would not be in effect under this scenario. The impact of this adjustment is a lower variable charge percentage and a higher fixed charge percentage.

(d) Please see page 1, lines (26) and (27), column (b) for Rate A-16, and columns (b), (c), and (d) for Rate A-16, and page 2, lines (30) and (31), column (b) for each rate class, for the dollar amounts on an average bill that are fixed charges and the dollar amounts that are variable charges using the same non-distribution rates as used in the responses to parts (a) and (b) above and the proposed Rebuttal rates. For the purpose of this response, the Company has removed the May 2018 base CapEx Factors associated with the Infrastructure, Safety, and Reliability Plan capital investment, as the recovery of that capital investment will be transferred to base distribution rates and therefore would not be in effect under this scenario. The impact of this adjustment is lower non-distribution variable amounts and lower total billed amounts in these columns.

(e) Please see page 1, column (e), lines (26) through (29).

The Narragansett Electric Company
Fixed vs. Variable Bill Components

		Rate A-16		Rate A-60				
		May 1, 2018	Rebuttal	May 1, 2018	Rebuttal Yr 1	Rebuttal Yr 2	Rebuttal Yr 3	Illustrative
		(a)	(b)	(a)	(b)	(c)	(d)	(e)
	Rates							
(1)	Customer Charge	$5.00	$8.50	$0.00	$2.75	$5.50	$8.50	$0.00
(2)	LIHEAP Enhancement Charge	$0.81	$0.81	$0.81	$0.81	$0.81	$0.81	$0.81
(3)	RE Growth Program	$0.78	$0.78	$0.78	$0.78	$0.78	$0.78	$0.78
(4)	Transmission Charge	$0.03271	$0.03271	$0.03271	$0.03271	$0.03271	$0.03271	$0.03271
(5)	Base Distribution Energy Charge	$0.03664	$0.04182	$0.02317	$0.04182	$0.04182	$0.04182	$0.04159
(6)	Other Distribution Energy Charges	$0.00715	$0.00360	$0.00715	$0.00360	$0.00360	$0.00360	$0.00360
(7)	Transition Charge	($0.00087)	($0.00087)	($0.00087)	($0.00087)	($0.00087)	($0.00087)	($0.00087)
(8)	Energy Efficiency Programs	$0.01002	$0.01002	$0.01002	$0.01002	$0.01002	$0.01002	$0.01002
(9)	Renewable Energy Distribution Charge	$0.00630	$0.00630	$0.00630	$0.00630	$0.00630	$0.00630	$0.00630
(10)	Standard Offer Service Charge	$0.08486	$0.08486	$0.08486	$0.08486	$0.08486	$0.08486	$0.08486
	Usage							
(11)	Monthly kWh	500	500	500	500	500	500	500
	Bill							
(12)	Customer Charge	$5.00	$8.50	$0.00	$2.75	$5.50	$8.50	$0.00
(13)	LIHEAP Enhancement Charge	$0.81	$0.81	$0.81	$0.81	$0.81	$0.81	$0.81
(14)	RE Growth Program	$0.78	$0.78	$0.78	$0.78	$0.78	$0.78	$0.78
(15)	Transmission Charge	$16.36	$16.36	$16.36	$16.36	$16.36	$16.36	$16.36
(16)	Base Distribution Energy Charge	$18.32	$20.91	$11.59	$20.91	$20.91	$20.91	$20.80
(17)	Other Distribution Energy Charges	$3.58	$1.80	$3.58	$1.80	$1.80	$1.80	$1.80
(18)	Transition Charge	($0.44)	($0.44)	($0.44)	($0.44)	($0.44)	($0.44)	($0.44)
(19)	Energy Efficiency Programs	$5.01	$5.01	$5.01	$5.01	$5.01	$5.01	$5.01
(20)	Renewable Energy Distribution Charge	$3.15	$3.15	$3.15	$3.15	$3.15	$3.15	$3.15
(21)	Standard Offer Service Charge	$42.43	$42.43	$42.43	$42.43	$42.43	$42.43	$42.43
(22)	Low Income Discount (15%)	n/a	n/a	n/a	($14.03)	($14.45)	($14.90)	($13.61)
(23)	Total Before Gross Earnings Tax	$95.00	$99.31	$83.27	$79.53	$81.86	$84.41	$77.09
(24)	Gross Earnings Tax	$3.96	$4.14	$3.47	$3.31	$3.41	$3.52	$3.21
(25)	Total Bill	$98.96	$103.45	$86.74	$82.84	$85.27	$87.93	$80.30
	Components of Bill							
(26)	Total of Fixed Charges in Bill	$6.59	$10.09	$1.59	$3.69	$6.03	$8.58	$1.35
(27)	Total of Variable Charges in Bill (includes GET)	$92.37	$93.36	$85.15	$79.15	$79.24	$79.35	$78.95
(28)	Percent of Fixed Charges in Bill	6.7%	9.8%	1.8%	4.5%	7.1%	9.8%	1.7%
(29)	Percent of Variable Charges in Bill	93.3%	90.2%	98.2%	95.5%	92.9%	90.2%	98.3%

The Narragansett Electric Company
Fixed vs. Variable Bill Components

		Rate C-06		Rate G-02		Rate G-32	
		May 1, 2018	Rebuttal	May 1, 2018	Rebuttal	May 1, 2018	Rebuttal
		(a)	(b)	(a)	(b)	(a)	(b)
	Rates						
(1)	Customer Charge	$10.00	$13.00	$135.00	$145.00	$825.00	$1,100.00
(2)	LIHEAP Enhancement Charge	$0.81	$0.81	$0.81	$0.81	$0.81	$0.81
(3)	RE Growth Program	$1.26	$1.26	$11.85	$11.85	$86.86	$86.86
(4)	Transmission Charge	$0.02726	$0.02839	$0.01028	$0.02839	$0.01088	$0.02839
(5)	Base Distribution Energy Charge	$0.03253	$0.04036	$0.00468	$0.00437	$0.00551	$0.00469
(6)	Other Distribution Energy Charges	$0.00699	$0.00377	$0.00350	$0.00350	$0.00353	$0.00353
(7)	Distribution Demand Charge	n/a	n/a	$5.65	$6.50	$4.57	$5.00
(8)	Transmission Demand Charge	n/a	n/a	$4.37	$4.37	$4.69	$4.69
(9)	Transition Charge	($0.00087)	($0.00087)	($0.00087)	($0.00087)	($0.00087)	($0.00087)
(10)	Energy Efficiency Programs	$0.01002	$0.01002	$0.01002	$0.01002	$0.01002	$0.01002
(11)	Renewable Energy Distribution Charge	$0.00630	$0.00630	$0.00630	$0.00630	$0.00630	$0.00630
(12)	Standard Offer Service Charge	$0.08190	$0.08190	$0.08190	$0.08190	$0.06028	$0.06028
	Usage						
(13)	Monthly kWh	1,000	1,000	15,000	15,000	200,000	200,000
(14)	Monthly kW	n/a	n/a	50	50	500	500
	Bill						
(15)	Customer Charge	$10.00	$13.00	$135.00	$145.00	$825.00	$1,100.00
(16)	LIHEAP Enhancement Charge	$0.81	$0.81	$0.81	$0.81	$0.81	$0.81
(17)	RE Growth Program	$1.26	$1.26	$11.85	$11.85	$86.86	$86.86
(18)	Transmission Charge	$27.26	$28.39	$154.20	$425.85	$2,176.00	$5,678.00
(19)	Base Distribution Energy Charge	$32.53	$40.36	$70.20	$65.55	$1,102.00	$938.00
(20)	Other Distribution Energy Charges	$6.99	$3.77	$52.50	$52.50	$706.00	$706.00
(21)	Distribution Demand Charge	n/a	n/a	$226.00	$260.00	$1,371.00	$1,500.00
(22)	Transmission Demand Charge	n/a	n/a	$218.50	$218.50	$2,345.00	$2,345.00
(23)	Transition Charge	($0.87)	($0.87)	($13.05)	($13.05)	($174.00)	($174.00)
(24)	Energy Efficiency Programs	$10.02	$10.02	$150.30	$150.30	$2,004.00	$2,004.00
(25)	Renewable Energy Distribution Charge	$6.30	$6.30	$94.50	$94.50	$1,260.00	$1,260.00
(26)	Standard Offer Service Charge	$81.90	$81.90	$1,228.50	$1,228.50	$12,056.00	$12,056.00
(27)	Total Before Gross Earnings Tax	$176.20	$184.94	$2,329.31	$2,640.31	$23,758.67	$27,500.67
(28)	Gross Earnings Tax	$7.34	$7.71	$97.05	$110.01	$989.94	$1,145.86
(29)	Total Bill	$183.54	$192.65	$2,426.36	$2,750.32	$24,748.61	$28,646.53
	Components of Bill						
(30)	Total of Fixed Charges in Bill	$12.07	$15.07	$592.16	$636.16	$4,628.67	$5,032.67
(31)	Total of Variable Charges in Bill (includes GET)	$171.47	$177.58	$1,834.20	$2,114.16	$20,119.94	$23,613.86
(32)	Percent of Fixed Charges in Bill	6.6%	7.8%	24.4%	23.1%	18.7%	17.6%
(33)	Percent of Variable Charges in Bill	93.4%	92.2%	75.6%	76.9%	81.3%	82.4%

PUC 12-6

Request:

Please explain the differences between forecasting the effects of energy efficiency on gas and electric. Please include an explanation of any difference in the timing of when efficiency savings (actual and/or projected) influence forecasts.

Response:

Please refer to the Company's response to PUC 12-7 for the requested information.

PUC 12-7

Request:

Please specifically compare the following two statements and explain how they are similar or different approaches.

(1) Mr. Poe's Rebuttal on Bates page 80, lines 1-7: As Narragansett Gas' historical volume data reflects the impact of its historical energy efficiency programs on the market, Narragansett Gas will adjust its forecast for future energy efficiency programs when those programs lead to demand reductions greater than its historical reductions. Through this process, Narragansett Gas ensures that it does not double count the impact of its energy efficiency programs on its volume forecast (see Poe Direct Testimony at page 9). Narragansett Gas' energy efficiency goals are established in a separate proceeding.

(2) Mr. Gredder's Rebuttal Testimony on Bates page 69, lines 1-2, he states: "The Company's forecasting methods take into account all relevant and reliable information to develop the most accurate forecast possible."

Response:

The Company's methodology for incorporating the impact of its energy efficiency programs on its gas load forecast are described on Page 9 of Company Witness Theodore Poe's pre-filed direct testimony (Bates Page 128 of Book 3), as well as Page 5 of Mr. Poe's rebuttal testimony (Bates Page 80 of Rebuttal Book 2). The Company's gas load forecast is developed using its actual billing data representing its customers' natural gas requirements net of all energy efficiency measures, including the Company's energy efficiency programs. The forecasted gas load is decremented only by any energy efficiency program reductions that exceed their historical averages of the prior three years. The Company's energy efficiency programs are filed with the Public Utilities Commission (PUC) for review and approval in a separate docket. Through this forecasting process, the Company avoids double-counting the effect of its historical successes in accounting for the effect of its future programs.

The Company's forecasting methods for the electric sales also fully account for the impacts of energy efficiency programs and without any double-counting. The process used is described in detail on Pages 25-27 of Company Witness Joseph Gredder's pre-filed direct testimony (Bates Pages 28-30 of Book 3). The process is to first "reconstruct" the historical data sets to account for the impact of past energy efficiency by adding back historical energy efficiency savings. The econometric regression models are then developed with this reconstructed data set to produce future estimates of sales before energy efficiency impacts. Then, projected energy efficiency savings are used to reduce the model projections to arrive at the Company's final sales forecast.

Prepared by or under the supervision of: Joseph Gredder and Theodore Poe, Jr.

In Mr. Gredder's rebuttal testimony on Pages 4 and 7 (Bates Pages 68 and 71 of Rebuttal Book 2) discusses why the process and data used as input is based on the best available data. The use of PUC-approved energy efficiency program goals in the short term and the ISO-NE projections over the longer term make use of all relevant and reliable information to develop the most accurate forecast possible.

PUC 12-8

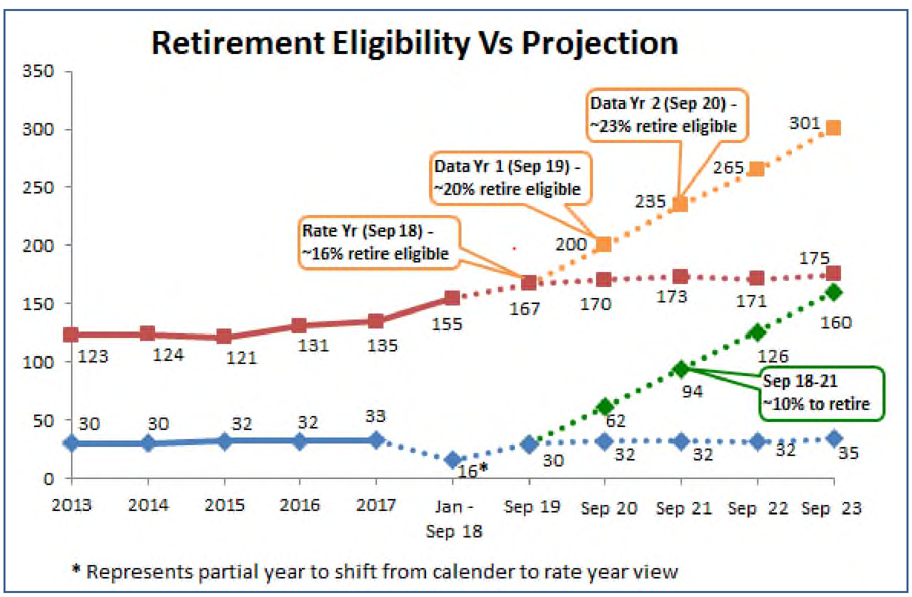
Request:

Please provide any updated information on the number of expected retirements in each of the rate year and two data years compared to the eligible retirements.

Response:

The chart below provides the number of expected (projected) retirements in each of the Rate Year and two Data Years compared to the eligible retirements. This reflects updated information as of April 1, 2018.

Retirement eligibility for Data Year 2 (beginning September 2020) is approximately 23 percent of the current employee population in Rhode Island and represents a worst case scenario of retirement risk compared to the forecast of projected retirements of approximately 10 percent between September 2018 through 2020 (*i.e.*, Rate Year, Data Year 1, and Data Year 2). Typically, because fewer employees retire than are eligible, the Company relies on its retirement projections for workforce planning purposes and eligibility forecasts to test those assumptions. The eligibility forecast below shows that fewer employees are expected to retire through the Rate Year and Data Years, respectively.



Legend:

- Retirement Actuals
- Retirement Projection for 5 years
- Retirement Projection - Cumulating exits for 5 years, starting Sep 18
- Employees Eligible to retire with benefits at beginning of year
- Employees Eligible to retire with benefits for 5 years, starting Sep 18
- Employees Eligible to retire – Cumulative

PUC 12-9

Request:

Has the Company considered any formal industry outlook for distributed generation in Rhode Island or the region in its projections of interconnection application work?

Response:

No, the Company has not considered a formal industry outlook for distributed generation in Rhode Island or the region in its projections of interconnection application work. The Company is not aware of an industry outlook that considers the specific energy policy and socio-economic factors of Rhode Island.

Prepared by or under the supervision of: Ryan Constable

PUC 12-10

Request:

Has the Company considered the expiration of the Investment Tax Credit in its projections of distributed generation interconnection application work? If so, how? If not, why not?

Response:

No, the Company has not considered the expiration of the Investment Tax Credit (ITC) in its projections of distributed generation interconnection application work. The ITC was originally established by the Energy Policy Act of 2005 and was set to expire at the end of 2007. The expiration date was extended multiple times (2008 and 2015). Although the ITC expires for residential systems in 2021, it continues indefinitely at 10 percent for commercial solar systems. Because the ITC has a history of extensions, a significant remaining life, and the intent to create a sustained renewable energy industry, the Company did not consider it in its projections of distributed generation interconnection application work.

Prepared by or under the supervision of: Ryan Constable

PUC 12-11

Request:

With respect to A-60 customers who make a 50% partial payment, please explain how application of the payments would be made to the bill charges under the current rate structure and the proposed rate structure (assuming a 25% discount) under the following circumstances:

(a) Customer had no arrearage prior to the month of the partial payment and is on standard offer.

(b) Customer had no arrearage prior to the month of the partial payment and is on competitive supply.

(c) Customer had an arrearage prior to the month of the partial payment and was not on a payment plan or AMP but is on standard offer.

(d) Customer had an arrearage prior to the month of the partial payment and was not on a payment plan or AMP but is on competitive supply.

(e) Customer was in a payment plan, was current on payment plan, and is on standard offer service.

(f) Customer was in a payment plan, was current on payment plan, and is on competitive supply.

(g) Customer was in the AMP, was current on the AMP, and is on standard offer.

(h) Customer was in the AMP, was current on the AMP, and is on competitive supply.

Response:

Partial payments are applied in the manner set forth in National Grid's Terms and Conditions for Distribution Service, RIPUC No. 2130: "Payments made through the Company for electricity purchased from a nonregulated power supplier will be applied first to any Narragansett charges or arrearages." The application of payments would be the same under both the current rate structure and the proposed rate structure. In the proposed rate structure, the 25 percent discount would be reflected as a reduction to the Company's receivable. Based on the Terms and Conditions, the following is how the payments under the scenarios above would be applied:

(a) If the customer had no arrearage prior to the month of partial payment and is on Standard Offer Service, the partial payment would be applied to the balance of the current month's total charges, which consists of delivery service and Standard Offer Service charges.

(b) If the customer had no arrearage prior to the month of partial payment, was receiving electric supply from a non-regulated power producer (NPP), and Narragansett Electric billed the NPP's charges, the partial payment would first be applied to the balance of Narragansett Electric's delivery service charges. If the partial payment exceeded the balance of Narragansett Electric's delivery service charges, the remainder of the payment would be applied to the balance of the NPP's charges.

(c) If the customer had an arrearage prior to the month of the partial payment and was not on a payment plan or the Arrearage Management Program (AMP) but is receiving Standard Offer Service, the partial payment would first be applied to the arrears balance. If the partial payment exceeded the arrears balance, the remainder of the payment would be applied towards the balance of the current month's charges, which consists of delivery service charges and Standard Offer Service charges.

(d) If the customer had an arrearage prior to the month of the partial payment and was not on a payment plan or the AMP, is receiving electric supply from a NPP, and Narragansett Electric billed the NPP's charges, the partial payment would be applied to Narragansett Electric's arrears balance first and, if the payment exceeded this arrears balance, to the arrears balance of the NPP. If the payment exceeded the total arrearages, the remainder of the payment would be applied towards the balance of Narragansett Electric's current month's delivery service charges and any remaining payment would be applied towards the balance of the NPP's current charges.

(e) If the customer was on a payment plan, was current on the payment plan, and is receiving Standard Offer Service, the partial payment would be applied to the arrears balance first, and, if the payment exceeded the total arrearage, the remainder of the payment would be applied towards the balance of the current month's total charges, which consists of delivery service charges and Standard Offer Service charges.

(f) If the customer was on a payment plan, was current on the payment plan, is receiving electric supply from a NPP, and Narragansett Electric billed the NPP's charges, the partial payment would be applied to Narragansett Electric's arrears balance first and, if the payment exceeded this arrears balance, to the balance of the NPP's arrears. If the payment exceeded the total arrearages, the remainder of the payment would be applied towards the balance of Narragansett Electric's current month's delivery service charges and any remaining payment would be applied towards the balance of the NPP's current charges.

Prepared by or under the supervision of: Jody Allison

(g) If the customer was in the AMP, was current on the AMP, and is receiving Standard Offer Service, the partial payment would be applied to the arrears balance first and, if the payment exceeded the total arrearage, the remainder of the payment would be applied towards the balance of Narragansett Electric's current month's charges, which consists of delivery service charges and Standard Offer Service charges.

(h) This is not a valid scenario as customers receiving electric supply from a NPP are not enrolled in the AMP.

PUC 12-12

Request:

Under each of the scenarios in 12-11, where there is a competitive supplier, under the new low-income rate proposal, how much is recovered through the reconciliation provision?

Response:

This data request would only be applicable to electric low-income customers, as residential gas customers are not able to receive gas supply from third party suppliers.

Under Narragansett Electric's proposal, the low income discount would be calculated by multiplying the total amount of current charges on a Rate A-60 bill by the low income discount percentage (i.e., 15 percent). Total current charges include delivery service charges and supplier charges, with supplier charges being either Standard Offer Service (SOS) charges or non-regulated power producer (NPP) charges for those customers receiving electric supply from a NPP. The Company is proposing to recover the total amount of the low income discount, which is based on the total of delivery service and supplier charges and would be shown as a single amount on the customer's bill, through the proposed Low Income Discount Recovery Factor (LIDRF). The amount to be recovered through the LIDRF would not be impacted by the balance on a customer's bill and whether or not the balance is associated with delivery service charges, SOS charges, or NPP charges.

Prepared by or under the supervision of: Scott McCabe

PUC 12-13

Request:

On Bates page 36 of Mr. Sheridan's Rebuttal testimony, he states: "The Company agrees that it can, in most cases, perform a BCA for projects that are not foundational (i.e., not a "core component" of grid modernization). However, the Company believes that BCA is not appropriate for the foundational Grid Modernization investments the Company proposed in Chapter 3 of the PST Plan." Please explain how this position is consistent with the following from the Docket 4600 Guidance Document: "In addition, in any case that proposes new programs or capital investment that will affect National Grid's electric distribution rates, the impact of any increased ratepayer recovery should also reference the goals, rate design principles, and Benefit-Cost Framework. National Grid should apply the Benefit-Cost Framework to changes in its cost of service for the primary purpose of complying with State policy or to expand a current program… the Framework should serve as a starting point in the making of a business case for a proposal." (Public Utilities Commission's Guidance on Goals, Principles and Values for Matters Involving The Narragansett Electric Company d/b/a National Grid at 6-7).

Response:

Docket 4600 articulates several distinct goals for the electric system in Rhode Island, all of which relate to the following important question: What can and should the new electric system be able to accomplish? The Company has applied the Benefit-Cost Framework to the extent it is able. The Docket 4600 Guidance Document recognizes that "there is still significant work [sic] left to be done so that the Framework can be applied in a fully quantitative manner."[1] All elements of the Company's Power Sector Transformation (PST) Plan, including its proposed Grid Modernization investments, have been qualitatively assessed against the Docket 4600 goals, both individually and as a portfolio. Where the Company is able to quantify and monetize benefits, the Company has applied a Rhode Island-specific Benefit-Cost Analysis (BCA) methodology considering the guidance provided in the Docket 4600 BCA Framework. Where benefits cannot be quantified or reasonably attributed to specific investments, a best-fit/least cost methodology is appropriate, and the Company has applied this methodology to justify the foundational (or core platform) Grid Modernization investments the Company proposed in Chapter 3 of the PST Plan.

[1] Public Utilities Commission's Guidance on Goals, Principles and Values for Matters Involving The Narragansett Electric Company d/b/a National Grid; October 27, 2017 (the Docket 4600 Guidance Document), at 6.

Prepared by or under the supervision of: Robert Sheridan

PUC 12-14

Request:

Please indicate which projects outlined in the Power Sector Transformation Panel Rebuttal and Supplemental Testimony are affected by the Massachusetts Department of Public Utilities order on grid modernization, and provide updated costs and cost-benefit analyses for such projects if the certainty of sharing costs for these projects with Massachusetts ratepayers has changed.

Response:

There is no need to adjust any Grid Modernization or Advanced Meter Functionality (AMF) costs or benefit-cost analysis to the multi-jurisdictional scenarios presented in the Company's Power Sector Transformation Plan in consideration of the Massachusetts Department of Public Utilities order on grid modernization.

As described in Chapter 3 of Schedule PST-1, the Company presented Grid Modernization project costs (i.e., five-year cash flows) assuming a Multi-Jurisdiction Deployment Scenario for projects where significant cost synergies may be possible if the scope and schedule of certain projects could be coordinated with similarly proposed initiatives by the Company's affiliates in New York or Massachusetts. Projects with Multi-Jurisdiction Deployment scenarios that were dependent on Massachusetts Grid Modernization Plan approval were the "GIS Data Enhancement" and "DSCADA & ADMS" projects, both of which fall under the Control Center Enhancements project category. The Company is pleased that these elements of the Massachusetts Grid Modernization plan have been authorized by the Massachusetts Department of Public Utilities so that multi-jurisdiction synergies can be realized. The Multi-Jurisdiction Scenario cost estimates previously presented remain applicable.

Table 3-24 in Schedule PST-1, Chapter 3 - Modern Grid (Bates Page 66 of PST Book 1) provided a consolidated table of cost estimates for the Grid Modernization projects under the Multi-Jurisdiction Deployment Scenario. This table was updated in Attachment NERI 27-13-1, a copy of which is provided as Attachment PUC 12-14 for ease of reference, using the latest project cost information described in the Company's response to Division 19-8, including shifting costs for the DSCADA & ADMS project by one fiscal year to better align with the Company's New York jurisdiction.

All other Multi-Jurisdiction Deployment Scenario project costs presented in Schedule PST-1 or in the PST Rebuttal and Supplemental Testimony, including Operational Data Management, Telecommunications, Cybersecurity, and AMF investments, were dependent on similar projects being adopted by the Company's affiliate in New York but not in Massachusetts.

Table 3-23: Power Sector Transformation Cash Flow Estimate – Rhode Island Only Deployment Scenario (updated 3/27/18)

RI Only Scenario		**Capex ($m) - Cash Flow**						**O&M ($m) - Cash Flow**						**Total ($m) - Cash Flow**					
Project	**Op Co.**	**FY19**	**FY20**	**FY21**	**FY22**	**FY23**	**5-Yr Sum**	**FY19**	**FY20**	**FY21**	**FY22**	**FY23**	**5-Yr Sum**	**FY19**	**FY20**	**FY21**	**FY22**	**FY23**	**5-Yr Sum**
System Data Portal	NECO	0.000	0.000	0.000	0.000	0.000	0.0	0.00	0.70	0.70	0.70	0.00	2.1	0.00	0.70	0.70	0.70	0.00	2.1
Feeder Monitoring Sensors	NECO	0.000	0.455	0.455	0.455	0.455	1.8	0.00	0.00	0.01	0.01	0.00	0.0	0.00	0.46	0.46	0.47	0.46	1.8
Control Center Enhancements																			
DSCADA & ADMS	SvcCo	0.000	0.000	2.524	3.425	1.797	7.7	0.00	0.44	0.00	0.09	0.14	0.7	0.00	0.44	2.52	3.51	1.93	8.4
RTU Separation	NECO	0.000	0.570	0.950	0.190	0.000	1.7	0.00	0.06	0.06	0.06	0.00	0.2	0.00	0.63	1.01	0.25	0.00	1.9
GIS Data Enhancement (IS)	SvcCo	0.000	0.000	0.000	0.000	0.000	0.0	3.05	0.00	0.00	0.00	0.00	3.0	3.05	0.00	0.00	0.00	0.00	3.0
GIS Data Enhancement (BR)	NECO	0.000	0.000	0.000	0.000	0.000	0.0	0.00	0.00	1.03	1.03	1.03	3.1	0.00	0.00	1.03	1.03	1.03	3.1
Operational Data Management																			
Enterprise Service Bus	SvcCo	0.000	5.501	8.919	1.492	0.000	15.9	0.00	0.80	1.95	2.05	0.00	4.8	0.00	6.30	10.87	3.54	0.00	20.7
Data Lake	SvcCo	0.000	1.394	0.000	0.000	0.000	1.4	0.00	0.84	1.21	1.64	1.73	5.4	0.00	2.24	1.21	1.64	1.73	6.8
PI Historian	SvcCo	0.000	0.451	0.000	0.000	0.000	0.5	0.00	0.05	2.05	2.05	0.05	4.2	0.00	0.50	2.05	2.05	0.05	4.7
Advanced Analytics	SvcCo	0.000	4.727	5.419	3.309	0.622	14.1	0.00	0.11	1.35	1.59	1.95	5.0	0.00	4.84	6.77	4.90	2.57	19.1
Telecommunications	SvcCo	0.000	0.304	0.152	0.152	0.000	0.6	0.00	0.00	1.95	2.93	3.90	8.8	0.00	0.30	2.10	3.08	3.90	9.4
Cybersecurity	SvcCo	0.000	13.844	6.734	4.427	12.330	37.3	0.00	8.37	4.22	3.37	3.65	19.6	0.00	22.22	10.96	7.79	15.98	57.0
TOTAL		**-**	**27.2**	**25.2**	**13.5**	**15.2**	**81.1**	**3.0**	**11.4**	**14.5**	**15.5**	**12.4**	**56.9**	**3.0**	**38.6**	**39.7**	**29.0**	**27.7**	**138.0**

Table 3-24: Power Sector Transformation Cash Flow Estimate – Multi-Jurisdiction Deployment Scenario (updated 3/27/18)

Multiple Jurisdiction Scenario		**Capex ($m) - Cash Flow**						**O&M ($m) - Cash Flow**						**Total ($m) - Cash Flow**					
Project	**Op Co.**	**FY19**	**FY20**	**FY21**	**FY22**	**FY23**	**5-Yr Sum**	**FY19**	**FY20**	**FY21**	**FY22**	**FY23**	**5-Yr Sum**	**FY19**	**FY20**	**FY21**	**FY22**	**FY23**	**5-Yr Sum**
System Data Portal	NECO	0.000	0.000	0.000	0.000	0.000	0.0	0.00	0.70	0.70	0.70	0.00	2.1	0.00	0.70	0.70	0.70	0.00	2.10
Feeder Monitoring Sensors	NECO	0.000	0.455	0.455	0.455	0.455	1.8	0.00	0.00	0.01	0.01	0.02	0.0	0.00	0.46	0.46	0.47	0.47	1.9
Control Center Enhancements																			
DSCADA & ADMS	SvcCo	0.000	0.000	2.524	3.425	1.797	7.7	0.00	0.44	0.00	0.09	0.14	0.7	0.00	0.44	2.52	3.51	1.93	8.4
RTU Separation	NECO	0.000	0.570	0.950	0.190	0.000	1.7	0.00	0.06	0.06	0.06	0.00	0.2	0.00	0.63	1.01	0.25	0.00	1.9
GIS Data Enhancement (IS)	SvcCo	0.000	0.000	0.000	0.000	0.000	0.0	0.43	0.00	0.00	0.00	0.00	0.4	0.43	0.00	0.00	0.00	0.00	0.4
GIS Data Enhancement (BR)	NECO	0.000	0.000	0.000	0.000	0.000	0.0	0.00	0.00	1.03	1.03	1.03	3.1	0.00	0.00	1.03	1.03	1.03	3.1
Operational Data Management							0.0												
Enterprise Service Bus	SvcCo	0.000	2.063	3.770	0.375	0.000	6.2	0.00	0.27	0.62	0.78	0.00	1.7	0.00	2.34	4.39	1.15	0.00	7.9
Data Lake	SvcCo	0.000	0.350	0.000	0.000	0.000	0.4	0.00	0.37	0.60	0.84	0.93	2.7	0.00	0.72	0.60	0.84	0.93	3.1
PI Historian	SvcCo	0.000	0.113	0.000	0.000	0.000	0.1	0.00	0.01	0.52	0.52	0.01	1.1	0.00	0.13	0.52	0.52	0.01	1.2
Advanced Analytics	SvcCo	0.000	3.148	1.470	0.940	0.622	6.2	0.00	0.11	0.46	0.52	0.61	1.7	0.00	3.26	1.93	1.46	1.24	7.9
Telecommunications	SvcCo	0.000	0.120	0.060	0.060	0.000	0.2	0.00	0.00	0.66	0.98	1.31	3.0	0.00	0.12	0.72	1.04	1.31	3.2
Cybersecurity	SvcCo	0.000	3.958	1.926	1.275	3.243	10.4	0.00	2.42	1.24	0.96	1.42	6.0	0.00	6.38	3.16	2.24	4.66	16.4
TOTAL		**-**	**10.8**	**11.2**	**6.7**	**6.1**	**34.8**	**0.4**	**4.4**	**5.9**	**6.5**	**5.5**	**22.6**	**0.4**	**15.2**	**17.0**	**13.2**	**11.6**	**57.4**