SIERRA CLUB

VIA EMAIL AND FEDERAL EXPRESS

April 26, 2017

Connecticut Siting Council
Attn: Hon. Robert Silvestri, Acting Chairman
10 Franklin Square
New Britain, CT 06051

RE: Docket No. 470B: NTE Connecticut, LLC application for a Certificate of Environmental Compatibility and Public Need

Dear Chairman Silvestri:

On behalf of the Connecticut Fund for the Environment, Not Another Power Plant, Sierra Club and Wyndham Land Trust, please find attached the Responses to Pre-Hearing Questions, Set One to Connecticut Fund for the Environment, Not Another Power Plant, Sierra Club and Wyndham Land Trust in Docket No. 470B. Should you have any questions regarding the filing, please contact me.

Sincerely,

Joshua Berman

Joshua Berman
Senior Attorney
Sierra Club
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josh.berman@sierraclub.org

Encl.

BEFORE THE CONNECTICUT SITING COUNCIL

In re: NTE Connecticut, LLC application for a Certificate of Environmental Compatibility and Public Need for the construction, maintenance, and operation of a 550-megawatt dual-fuel combined cycle electric generating facility and associated electrical interconnection switchyard located at 180 and 189 Lake Road, Killingly, Connecticut. Reopening of this Application based on changed conditions pursuant to C.G.S. § 4-181a(b)	Docket No. 470B April 26, 2019

RESPONSES TO PRE-HEARING QUESTIONS, SET ONE
TO CONNECTICUT FUND FOR THE ENVIORNMENT,
NOT ANOTHER POWER PLANT, SIERRA CLUB AND WYNDHAM LAND TRUST

On April 16, 2019, NTE issued Pre-Hearing Questions to Connecticut Fund for the Environment, Not Another Power Plant, Sierra Club, and Wyndham Land Trust (Grouped Parties), relating to Docket No. 470B. Below are the Grouped Parties' responses.

Question No .1

For the information contained in Table 1 – Estimated Reserve Margin, 2019-2028, New England, with and without KEC, of the Pre-Filed Testimony, in particular the rows entitled "Small PV (BTM) Peak Period Capacity Contribution" and "EE Capacity Contribution," these data do not appear in the sources cited: Synapse Tabulation. ISO-NE Draft Load Forecast, Energy Efficiency Forecast, and Solar PV Forecast. Results of FCA13. 2018 CELT. Please provide the sources of this data or the bases for the numbers found in those rows of Table 1. If these numbers were calculated based on the draft ISO-New England Energy Efficiency and Solar PV Forecasts, please provide those calculations.

Response

Small PV (BTM) Peak Period Capacity Contribution

The "Small PV (BTM) Peak Period Capacity Contribution" is computed in the table below, which is also included as an Excel file as Attachment 1-1 to this response. The estimated contribution was based on the projected increase (2019 vintage draft forecast, versus the 2018 vintage final forecast) in total solar PV nameplate capacity for a given future year, multiplied by the capacity contribution used in the 2018 solar PV forecast. The three graphics that follow show the 2018 final solar PV forecast, the 2019 draft solar PV forecast, and the capacity contribution for BTM solar PV in 2018 as included in the draft 2019 load forecast. The 2019 draft solar PV forecast and the 2019 draft load forecast are included as Attachments 1-2 and 1-3 to this response.

Estimate of Capacity Contribution from BTM Solar PV, Based on 2019 Forecast

Year:	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
18 Vintage Fcst Cumulative Nameplate	2,865.8	3,261.6	3,657.4	4,026.9	4,388.8	4,731.4	5,072.5	5,331.8	5,585.3	5,832.9	
19 Vintage Fcst Cumulative Nameplate	2,883.8	3,346.9	3,813.8	4,252.2	4,683.0	5,086.6	5,420.8	5,725.5	6,023.6	6,314.9	6,599.4
Percentage Increase, '19 vs. '18 Fcst	0.63%	2.62%	4.28%	5.59%	6.70%	7.51%	6.87%	7.38%	7.85%	8.26%	#DIV/0!
2018 Fcast Capacity Contribution		721	790	851	901	945	980	1009	1031	1051	
Estimate 2019 Fcst Capacity Contribution (=% increase x 2018		740	824	899	961	1,016	1,047	1,084	1,112	1,138	1,164

Sources: 2019 Draft Load Forecast, 2019 Draft Solar PV Forecast.

Final 2018 PV Forecast

Nameplate Capacity, MW_{ac}

States	Annual Total MW (AC nameplate rating)											Totals
	Thru 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	
CT	365.6	88.6	86.8	89.8	80.6	72.9	53.7	52.2	50.6	49.0	47.4	**1,037.3**
MA	1602.3	**296.7**	228.0	228.0	215.3	215.3	215.3	215.3	135.1	130.9	126.7	**3,608.9**
ME	33.5	10.2	10.2	10.2	9.6	9.6	9.6	9.6	9.6	9.6	9.6	**131.4**
NH	69.7	13.8	13.8	13.8	13.1	13.1	13.1	13.1	13.1	13.1	13.1	**202.7**
RI	62.2	34.5	34.5	31.4	29.6	29.6	29.6	29.6	29.6	29.6	29.6	**370.2**
VT	257.2	**31.5**	22.5	22.5	21.3	21.3	21.3	21.3	21.3	21.3	21.3	**482.5**
Regional - Annual (MW)	**2390.5**	**475.3**	**395.8**	**395.8**	**369.5**	**361.9**	**342.7**	**341.1**	**259.3**	**253.5**	**247.7**	**5,832.9**
Regional - Cumulative (MW)	**2390.5**	**2865.8**	**3261.6**	**3657.4**	**4026.9**	**4388.8**	**4731.4**	**5072.5**	**5331.8**	**5585.3**	**5832.9**	**5,832.9**

Notes:

(1) Forecast values include FCM Resources, non-FCM Energy Only Generators, and behind-the-meter PV resources

(2) The forecast values are net of the effects of discount factors applied to reflect a degree of uncertainty in the policy-based forecast

(3) All values represent end-of-year installed capacities

(4) Forecast does not include forward-looking PV projects > 5MW in nameplate capacity

Draft 2019 PV Forecast

Nameplate Capacity, MW_{ac}

States	Annual Total MW (AC nameplate rating)											Totals
	Thru 2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	
CT	464.3	68.4	85.2	77.8	76.4	49.1	47.7	46.3	44.9	43.5	42.1	**1,046.0**
MA	1871.3	292.0	288.0	272.0	272.0	272.0	204.0	176.0	170.7	165.3	160.0	**4,143.2**
ME	41.4	7.1	7.1	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	**109.7**
NH	83.8	12.7	12.7	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	**205.6**
RI	116.7	51.3	51.3	48.5	42.4	42.4	42.4	42.4	42.4	42.4	42.4	**564.6**
VT	306.3	31.5	22.5	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	**530.3**
Regional - Annual (MW)	**2883.8**	**463.1**	**466.9**	**438.3**	**430.8**	**403.6**	**334.2**	**304.8**	**298.0**	**291.3**	**284.6**	**6,599.4**
Regional - Cumulative (MW)	**2883.8**	**3346.9**	**3813.8**	**4252.2**	**4683.0**	**5086.6**	**5420.8**	**5725.5**	**6023.6**	**6314.9**	**6599.4**	**6,599.4**

Notes:

(1) Forecast values include FCM Resources, non-FCM Energy Only Generators, and behind-the-meter PV resources

(2) The forecast values are net of the effects of discount factors applied to reflect a degree of uncertainty in the policy-based forecast

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(4) Forecast does not include forward-looking PV projects > 5MW in nameplate capacity

Sources of Above Graphs: Slide 27 and Slide 28 of the 2019 Draft Solar PV Forecast.

New England Gross and Net Summer Peak Forecast

Net + EE + BTM PV

Fcst 2019 (MW)						
Year	Gross 50/50	Gross 90/10	BTM PV*	EE*	Net 50/50	Net 90/10
2019	28,943	30,832	721	3,066	25,157	27,046
2020	29,130	31,050	790	3,416	24,923	26,843
2021	29,341	31,291	851	3,757	24,732	26,683
2022	29,561	31,543	901	4,072	24,588	26,570
2023	29,774	31,786	945	4,359	24,470	26,483
2024	29,987	32,030	980	4,617	24,389	26,433
2025	30,196	32,271	1009	4,848	24,339	26,414
2026	30,406	32,511	1031	5,052	24,322	26,428
2027	30,616	32,753	1051	5,229	24,336	26,473
2028	30,831	32,999				

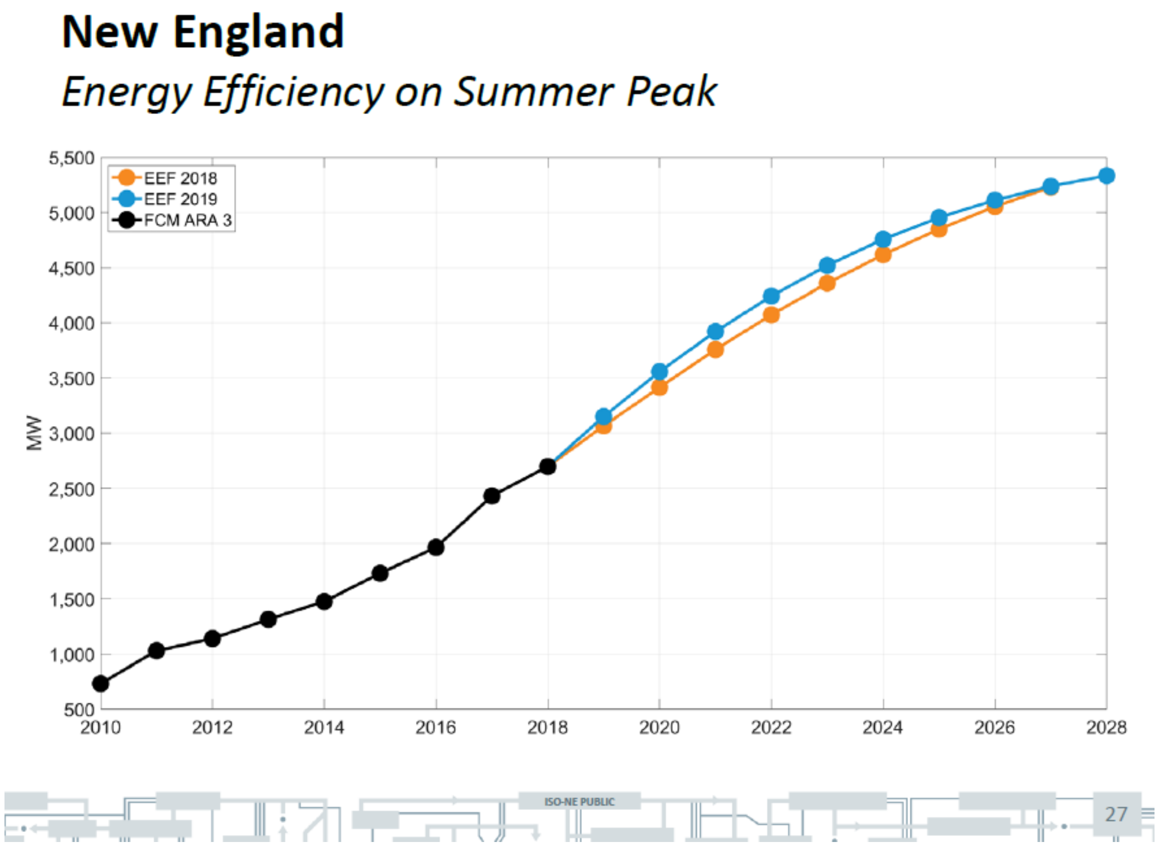
* 2018 EE and BTM PV forecast values used since 2019 draft EE and BTM PV forecasts are under development

ISO-NE PUBLIC 27

Source of Above Table: Slide 27 of the 2019 Draft Load Forecast (2/11/2019).

EE Capacity Contribution

The “EE Capacity Contribution” was made by inspection of the following graph, which appears on slide 27 of the “Draft 2019 Energy Efficiency Forecast,” February 8, 2019, ISO NE Energy Efficiency Forecast Working Group. A copy of the presentation is provided as Attachment 1-4 to this response.



Source: Slide 27, Draft Energy Efficiency Forecast, February 8, 2019.

<u>Question No. 2</u>

With respect to Figure 2 on page 39 of the Pre-Filed Testimony, there is no data provided as a source for the information contained in this figure. Please provide the data used to develop Figure 2, the list of power plants described in the figure, including the status, heat rate, age, operational capacity factors, etc. related to those facilities. Please provide any and all assumptions for the estimate of winter minimum and maximum demand and please provide any and all assumptions regarding resource outages.

<u>Response</u>

See Attachment 2-1: "Emissions by capacity Graph for NTE" for illustrative emissions graphs and plant data, plant status, emissions rate, and winter capacity availability.

See attachment 2-2: “2018 Emissions Data CAMD_2” for EPA Clean Air Markets Division (DAMD) Air Markets Program Data available at https://ampd.epa.gov/ampd/. Note that due to file size Attachment 2-2 is being provided on a USB drive.

I HEREBY CERTIFY that a copy of the foregoing document was electronically mailed to the following service list on April 26, 2019:

Kenneth C. Baldwin, Esq. Earl W. Phillips, Jr., Esq. Robinson & Cole LLP 280 Trumbull Street Hartford, CT 06103-3597 kbaldwin@rc.com ephillips@rc.com	John Bashaw, Esq. Mary Mintel Miller, Esq. Reid and Riege, P.C. One Financial Plaza, 21st Floor Hartford, CT 06103 jbashaw@rrlawpc.com mmiller@rrlawpc.com
Timothy Eves, Vice President NTE Energy 24 Cathedral Place, Ste. 300 St. Augustine, FL 32804 teves@nteenergy.com kec.notices@nteenergy.com	Mary Calorio Town Manager Town of Killingly 172 Main Street Killingly, CT 06239 mcalorio@killinglyct.org
Chris Rega, Senior Vice President Engineering & Construction NTE Energy, LLC 800 South Street, Ste. 620 Waltham, MA 02453 crega@nteenergy.com	Katherine Fiedler, Esq. Roger Reynolds, Esq. Connecticut Fund for the Environment 900 Chapel St., Upper Mezzanine New Haven, CT 06510 kfiedler@ctenvironment.org rreynolds@ctenvironment.org
Paul R. McCary Murtha Cullina, LLP CityPlace 1 185 Asylum Street Hartford, CT 06103 pmccary@murthalaw.com	John W. Gulliver, Esq. Pierce Atwood LLP Merrill's Wharf 254 Commercial Street Portland, ME 04101 jgulliver@pierceatwood.com jwgulliver@gmail.com

This 26th day of April, 2019.

Joshua Berman

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Draft 2019 Photovoltaic (PV) Forecast

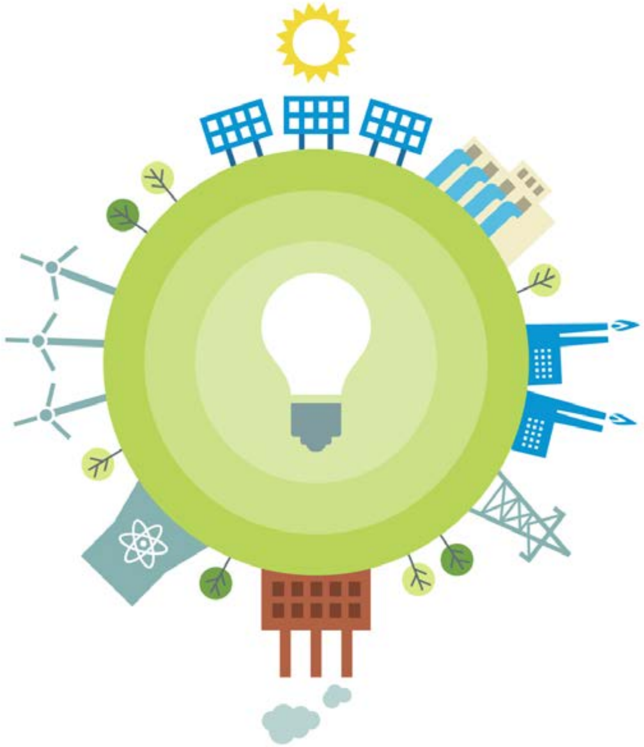
Distributed Generation Forecast Working Group

Jon Black

MANAGER, LOAD FORECASTING

Outline

- Introduction and Background
- 2018 PV Growth: Forecast vs. Reported
- Forecast Assumptions and Inputs
- Draft 2019 PV Forecast - Nameplate
- Next Steps for the 2019 Capacity, Energy, Loads, and Transmission (CELT) Forecast



INTRODUCTION & BACKGROUND

Introduction

- The majority of state-sponsored distributed PV does not participate in wholesale markets, but reduces the system load observed by ISO
- The long-term PV forecast helps the ISO determine future system load characteristics that are important for the reliable planning and operation of the system
- To properly account for PV in long-term planning, the finalized PV forecast will be categorized as follows:
    1. PV as a capacity resource in the Forward Capacity Market (FCM)
    2. Non-FCM Energy Only Resources (EOR) and Generators
    3. Behind-the-meter PV (BTM PV)

Similar to energy efficiency (EE), behind-the-meter PV is reconstituted into historical loads*

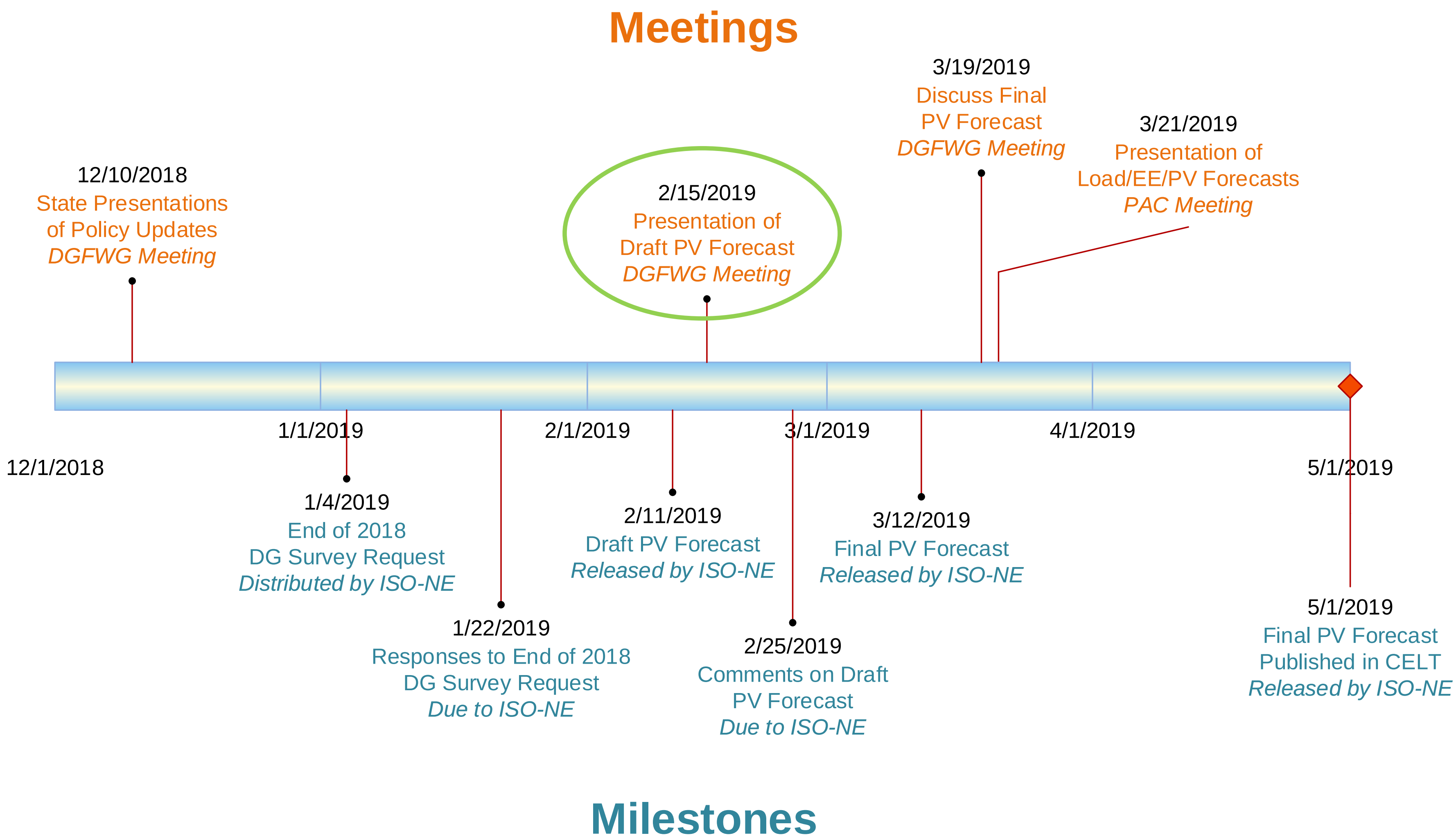
The 2019 gross load forecast reflects loads without PV load reductions

**Existing BTM PV decreases the historical loads seen by the ISO, which are an input to the gross load forecast*

Background: PV Forecast Focuses on DG

- The focus of the DGFWG is distributed generation projects:
  - "…defined as those that are typically 5 MW or less in nameplate capacity and are interconnected to the distribution system (typically 69 kV or below) according to state-jurisdictional interconnection standards."
- Therefore, the forecast does not consider policy drivers supporting larger-scale projects (i.e., those >5 MW)
  - E.g., projects planned as part of the three-state Clean Energy RFP
- Large projects are generally accounted for as part of ISO's interconnection process and participate in wholesale markets

2019 PV Forecast Schedule



The PV Forecast Incorporates State Public Policies and Is Based on Historical Data

- The PV forecast process is informed by ISO analysis and by input from state regulators and other stakeholders through the Distributed Generation Forecast Working Group (DGFWG)
- The PV forecast methodology is straightforward, intuitive, and rational
- The forecast is meant to be a reasonable projection of the anticipated growth of out-of-market, distributed PV resources to be used in ISO's System Planning studies, consistent with its role to ensure prudent planning assumptions for the bulk power system
- The forecast reflects and incorporates state policies and the ISO does not explicitly forecast the expansion of existing state policies or the development of future state policy programs

Forecast Focuses on State Policies in All Six New England States

- A policy-based forecasting approach has been chosen to reflect the observation that trends in distributed PV development are in large part the result of policy programs developed and implemented by the New England states
- The ISO makes no judgment regarding state policies, but rather utilizes the state goals as a means of informing the forecast
- In an attempt to control related ratepayer costs, states often factor anticipated changes in market conditions directly into policy design, which are therefore implicit to ISO's policy considerations in the development of the forecast

Many Factors Influence the Future Commercialization Potential of PV

Policy Drivers

- Feed-in-tariffs (FITs)/Long-term procurement
- State Renewable Portfolio Standards (RPS) programs
- Net energy metering (NEM) and retail rate structure
- Federal investment tax credit (ITC) and federal depreciation
- Federal trade policy

Other Drivers

- Role of private investment in PV development
- Future equipment and installation costs
- Future wholesale and retail electricity costs
- Interconnection costs and issues

Summary: Draft CELT 2019 PV Forecast

- The 2019 forecast reflects:
  - PV development trends in the region
  - Discussions with stakeholders and data exchange with the New England states and Distribution Owners
- According to data provided by Distribution Owners, approximately 493 MW of PV development occurred in 2018, totaling about 2,884 MW installed across the region
  - Values include FCM, EOR, and BTM PV projects < 5 MW_{ac} in nameplate capacity
- Approximately 3,716 MW of PV development is projected from 2019 through 2028 for a total of 6,599 MW in 2028
  - Values include FCM, EOR, and BTM PV projects < 5 MW_{ac} in nameplate capacity
- Overall, the draft 2019 PV forecast projects steadier PV growth over the forecast horizon than last year's forecast

Background and Forecast Review Process

- The draft 2019 forecast will be discussed today
- Stakeholders provided comments on the draft forecast are due by February 25, 2019
- The final PV forecast will be discussed at the March 19th DGFWG, and will be published in the 2019 CELT (Section 3):
  - See: https://www.iso-ne.com/system-planning/system-plans-studies/celt/

2018 PV GROWTH: FORECAST VS. REPORTED

2018 PV Growth

Total Nameplate Capacity

- Comparison of the state-by-state 2018 PV growth and the reported growth for 2018 reported by utilities is tabulated below
  - Values include FCM, EOR, and BTM PV projects < 5 MW_{ac} in nameplate capacity
- Regionally, 2018 growth reported by utilities totaled 493.3 MW, which is 18 MW higher than the forecast growth
  - Results vary by state

State	2018 Reported Growth	2018 Forecast Growth	Difference
CT	98.7	88.6	10.1
MA	269.0	296.7	-27.7
ME	7.9	10.2	-2.2
NH	14.2	13.8	0.3
RI	54.4	34.5	19.9
VT	49.1	31.5	17.6
Region	493.3	475.3	18.0

FORECAST ASSUMPTIONS AND INPUTS

Federal Investment Tax Credit

- The federal residential and business Investment Tax Credit (ITC) is a key driver of PV development in New England
- There are no changes to the ITC since the 2017 forecast

Residential ITC

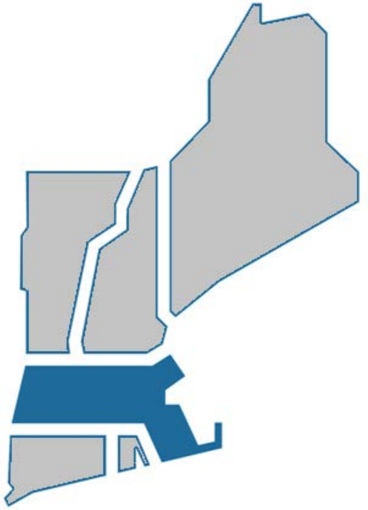
Maximum Allowable Residential ITC	
Year	Credit
2016	30%
2017	30%
2018	30%
2019	30%
2020	26%
2021	22%
Future Years	0%

Business ITC

ITC by Date of Construction Start	
Year construction starts	Credit
2016	30%
2017	30%
2018	30%
2019	30%
2020	26%
2021	22%
2022	10%
Future Years	10%

Sources: http://programs.dsireusa.org/system/program/detail/658 and http://programs.dsireusa.org/system/program/detail/1235

Massachusetts Forecast Methodology and Assumptions

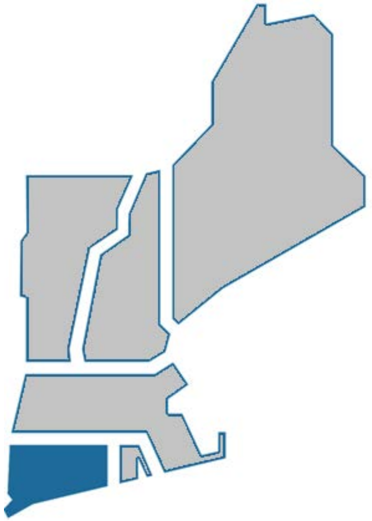


- MA DPU’s 12/10/18 DGFWG presentation serves as primary source for MA policy information
- MA Distribution Owners survey results:
  - 1,871.3 MW_{AC} installed by 12/31/18
- Solar Carve-Out Renewable Energy Certificate (SREC) program
  - A total of 2,416 MW_{DC} will be developed as part of SREC-I and SREC-II
    - 2,306.4 MW_{DC} installed by 12/31/18
    - Remaining 106.9 MW_{DC} will be installed in 2019 (84.4 MW_{AC} assuming an 83% AC-to-DC ratio)
- Solar Massachusetts Renewable Target (SMART) Program
  - Program 1,600 MW_{AC} goal achieved over the period 2019-2024 (5+ years)
    - Assume program capacity is divided over years as tabulated below

Year	2019	2020	2021	2022	2023	2024
%	15	20	20	20	20	5
MW	240	320	320	320	320	80

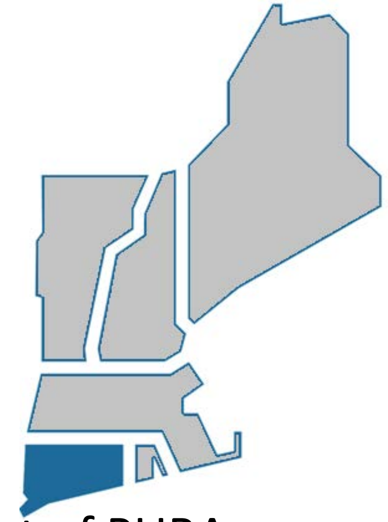
- Post-policy development assumed to occur such that 320 MW is carried forward from 2023 onward at constant rate throughout the remaining years of the forecast period, and post-policy discount factors are applied as necessary

Connecticut Forecast Methodology and Assumptions



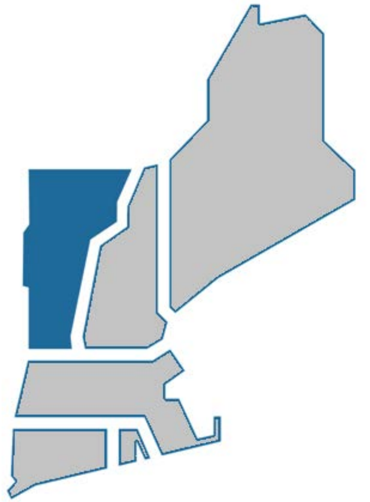
- CT DEEP's 12/10/18 DGFWG presentation serves as primary source for CT policy information
- CT Distribution Owner survey results
  - 464.3 MW_{AC} installed by 12/31/18
- LREC/ZREC program assumptions
  - 121.7 MW remaining, divided evenly over 4 years, 2019-2022
- Residential Solar Investment Program (RSIP) assumptions
  - Remaining 84 MW, divided evenly over 2 years, 2019-2020
- Other policy-driven projects:
  - DEEP Small Scale Procurement (< 5MW)
    - 4.98 MW project in service in 2020
  - Shared Clean Energy Facility (SCEF) Pilot Program
    - 3.62 MW project in service in 2019
    - 1.6 MW project in service in 2020

Connecticut Forecast Methodology and Assumptions *continued*



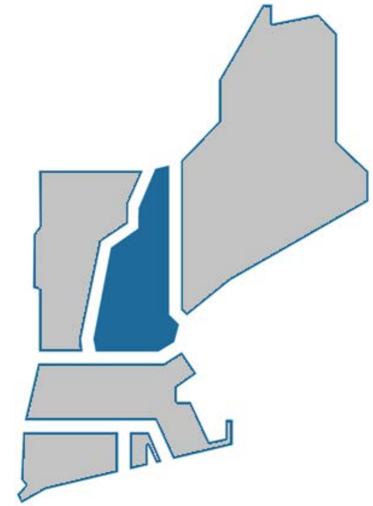
- CT WISE "Successor" programs
  - Design and implementation details of successor programs to SCEF, RSIP, and ZREC are currently being discussed as part of PURA Docket No. 18-08-33
  - Since these programs are not yet finalized, estimated MWs and start/end dates associated with these programs have been incorporated into the 2019 forecast, with post-policy discount factors applied

Vermont Forecast Methodology and Assumptions



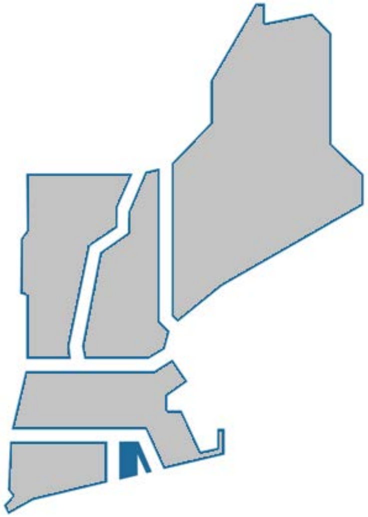
- VT DPS’ 12/10/18 DGFWG presentation serves as the primary source for VT policy information
- VT Distribution Owner survey results
  - 306.3 MW_{AC} installed by 12/31/18
- DG carve-out of the Renewable Energy Standard (RES)
  - Assume 85% of eligible resources will be PV and a total of 25 MW/year will develop
- Standard Offer Program
  - Will promote a total of 110 MW of PV (of the 127.5 MW total goal)
  - All forward-looking renewable energy certificates (RECs) from Standard Offer projects will be sold to utilities and count towards RES DG carve-out]
- Net metering
  - In all years after 2019 (see below), all renewable energy certificates (RECs) from net metered projects will be sold to utilities and count towards RES DG carve-out, resulting in 25 MW/year as stated above
- For 2019, a total of 35 MW is anticipated in VT, which is in excess of the 25 MW/year due to the RES DG carve-out
  - This reflects expectations that, similar to the past couple of years, PV development will be greater than that needed for compliance with the RES DG carve out for one more year

New Hampshire Forecast Methodology and Assumptions



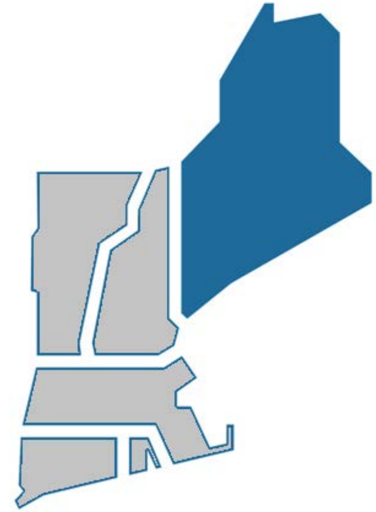
- NH PUC's 12/10/18 DGFWG presentation serves as the primary source for NH policy information
- NH Distribution Owners survey results
  - 83.8 MW_{AC} installed by 12/31/18
  - 14.2 MW_{AC} installed in 2018
- Assume the Net Energy Metering Tariff (NEM 2.0, effective September 2017), continues to support the 2018 rate of growth throughout the forecast horizon
  - No limit on state-wide aggregate net metered capacity

Rhode Island Forecast Methodology and Assumptions



- RI OER's 12/10/18 DGFWG presentation serves as the primary source for RI policy information
- RI Distribution Owners reported a total of 62.2 MW of growth in 2018
- DG Standards Contracts (DGSC) program
  - A total of 33.6 MW of 40 MW program goal will be PV
  - Approximately 11.1 MW cancelled/terminated, will be procured as part of 2019 REGP (see below) ; assumed 33.3% of capacity goes into service in each of next 3 years
- Renewable Energy Growth Program (REGP)
  - Assume REGP supports 36 MW_{DC}/year of PV throughout forecast horizon
    - Convert: 36 MW_{DC} = 29.88 MW_{AC} (83% AC-to-DC ratio assumed)
  - Approximately 10.4 MW_{AC} cancelled/terminated from previous program procurements; assumed 33.3% of capacity goes into service in each of next 3 years
- Renewable Energy Development Fund, Net Metering, and Virtual Net Metering (VNM)
  - No limit on state-wide aggregate net metered capacity
  - Significant VNM project interest activity over recent two years
  - Assumed to yield 20 MW/year over the forecast horizon

Maine Forecast Methodology and Assumptions



- ME PUC's 12/10/18 DGFWG presentation serves as the primary source for ME policy information
- ME Distribution Owners reported a total of 7.9 MW of PV growth in 2018
- Assume the new Net Energy Billing Rule (effective April 1, 2018), with gradually reduced rates of compensation, continues to support the 2018 rate of growth throughout the forecast horizon
  - No limit on state-wide aggregate net metered capacity

Discount Factors

- Discount factors are:
  - Developed and incorporated into the forecast to ensure a degree of uncertainty in future PV commercialization is considered
  - Developed for two types of future PV inputs to the forecast, and all discount factors are applied equally in all states
  - Applied to the forecast inputs (see slide 29) to determine total nameplate capacity for each state and forecast year

Policy-Based *PV that results from state policy*	**Post-Policy** *PV that may be installed after existing state policies end*
Discounted by values that increase over the forecast horizon up to a maximum value of 15%	**Discounted by 35-50% due to the high degree of uncertainty associated with possible future expansion of state policies and/or future market conditions required to support PV commercialization in the absence of policy expansion**

Discount Factors Used in Draft 2019 Forecast

Policy-Based

Forecast	Final 2018	Draft 2019
2019	10%	10%
2020	10%	10%
2021	15%	15%
2022	15%	15%
2023	15%	15%
2024	15%	15%
2025	15%	15%
2026	15%	15%
2027	15%	15%
2028	N/A	15%

Post-Policy

Forecast	Final 2018	Final 2018
2019	36.7%	35.0%
2020	38.3%	36.7%
2021	40.0%	38.3%
2022	41.7%	40.0%
2023	43.3%	41.7%
2024	45.0%	43.3%
2025	46.7%	45.0%
2026	48.3%	46.7%
2027	50.0%	48.3%
2028	N/A	50.0%

Draft 2019 Forecast Inputs

Pre-Discounted Nameplate Values

States	Pre-Discount Annual Total MW (AC nameplate rating)											Totals
	Thru 2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	
CT	464.3	76.0	101.3	114.7	114.7	84.3	84.3	84.3	84.3	84.3	84.3	**1,376.5**
MA	1871.3	324.4	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	**5,075.7**
ME	41.4	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	**120.8**
NH	83.8	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	**225.5**
RI	116.7	57.0	57.0	57.0	49.9	49.9	49.9	49.9	49.9	49.9	49.9	**636.9**
VT	306.3	35.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	**566.3**
Pre-Discount Annual Policy-Based MWs	**2883.8**	**514.6**	**503.1**	**454.6**	**447.4**	**417.0**	**177.0**	**97.0**	**97.0**	**97.0**	**97.0**	**5,785.4**
Pre-Discount Annual Post-Policy MWs	**0.0**	**0.0**	**22.3**	**84.3**	**84.3**	**84.3**	**324.3**	**404.3**	**404.3**	**404.3**	**404.3**	**2,216.3**
Pre-Discount Annual Total (MW)	**2883.8**	**514.6**	**525.4**	**538.8**	**531.7**	**501.2**	**501.2**	**501.2**	**501.2**	**501.2**	**501.2**	**8,001.6**
Pre-Discount Cumulative Total (MW)	**2883.8**	**3,398.4**	**3,923.8**	**4,462.6**	**4,994.2**	**5,495.5**	**5,996.7**	**6,497.9**	**6,999.2**	**7,500.4**	**8,001.6**	**8,001.6**

Notes:

(1) The above values **are not the forecast**, but rather pre-discounted inputs to the forecast (see slides 20-26 for details)

(2) Yellow highlighted cells indicate that values contain post-policy MWs

(3) All values include FCM Resources, non-FCM Settlement Only Generators and Generators (per OP-14), and load reducing PV resources

(4) All values represent end-of-year installed capacities

2018 PV NAMEPLATE CAPACITY FORECAST

Includes FCM, non-FCM EOR, and BTM PV

Final 2018 PV Forecast

Nameplate Capacity, MW_{ac}

States	Annual Total MW (AC nameplate rating)											Totals
	Thru 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	
CT	365.6	88.6	86.8	89.8	80.6	72.9	53.7	52.2	50.6	49.0	47.4	**1,037.3**
MA	1602.3	**296.7**	228.0	228.0	215.3	215.3	215.3	215.3	135.1	130.9	126.7	**3,608.9**
ME	33.5	10.2	10.2	10.2	9.6	9.6	9.6	9.6	9.6	9.6	9.6	**131.4**
NH	69.7	13.8	13.8	13.8	13.1	13.1	13.1	13.1	13.1	13.1	13.1	**202.7**
RI	62.2	34.5	34.5	31.4	29.6	29.6	29.6	29.6	29.6	29.6	29.6	**370.2**
VT	257.2	**31.5**	22.5	22.5	21.3	21.3	21.3	21.3	21.3	21.3	21.3	**482.5**
Regional - Annual (MW)	**2390.5**	**475.3**	**395.8**	**395.8**	**369.5**	**361.9**	**342.7**	**341.1**	**259.3**	**253.5**	**247.7**	**5,832.9**
Regional - Cumulative (MW)	**2390.5**	**2865.8**	**3261.6**	**3657.4**	**4026.9**	**4388.8**	**4731.4**	**5072.5**	**5331.8**	**5585.3**	**5832.9**	**5,832.9**

Notes:

(1) Forecast values include FCM Resources, non-FCM Energy Only Generators, and behind-the-meter PV resources
(2) The forecast values are net of the effects of discount factors applied to reflect a degree of uncertainty in the policy-based forecast
(3) All values represent end-of-year installed capacities
(4) Forecast does not include forward-looking PV projects > 5MW in nameplate capacity

Draft 2019 PV Forecast

Nameplate Capacity, MW_{ac}

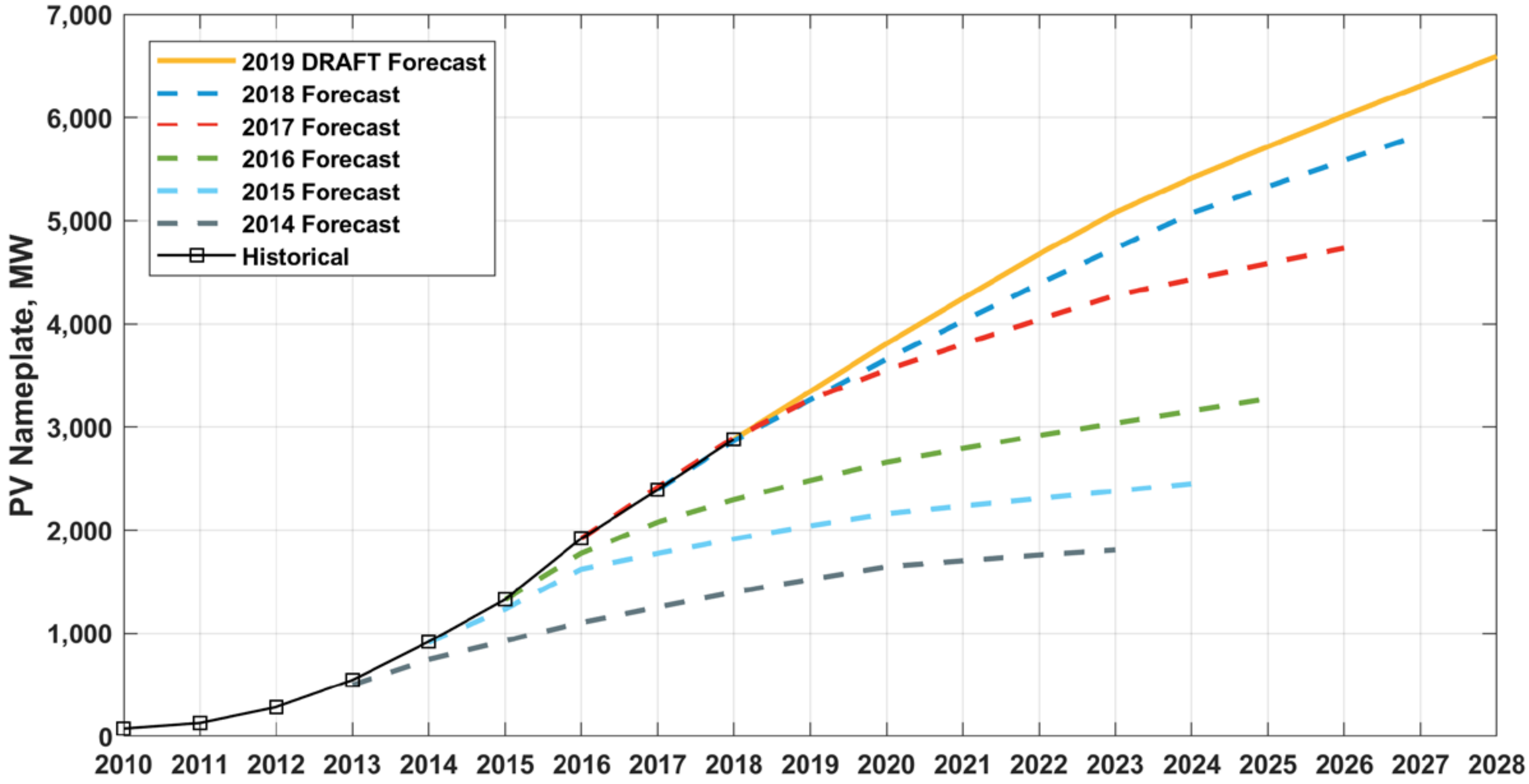
States	Annual Total MW (AC nameplate rating)											Totals
	Thru 2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	
CT	464.3	68.4	85.2	77.8	76.4	49.1	47.7	46.3	44.9	43.5	42.1	**1,046.0**
MA	1871.3	292.0	288.0	272.0	272.0	272.0	204.0	176.0	170.7	165.3	160.0	**4,143.2**
ME	41.4	7.1	7.1	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	**109.7**
NH	83.8	12.7	12.7	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	**205.6**
RI	116.7	51.3	51.3	48.5	42.4	42.4	42.4	42.4	42.4	42.4	42.4	**564.6**
VT	306.3	31.5	22.5	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	**530.3**
Regional - Annual (MW)	**2883.8**	**463.1**	**466.9**	**438.3**	**430.8**	**403.6**	**334.2**	**304.8**	**298.0**	**291.3**	**284.6**	**6,599.4**
Regional - Cumulative (MW)	**2883.8**	**3346.9**	**3813.8**	**4252.2**	**4683.0**	**5086.6**	**5420.8**	**5725.5**	**6023.6**	**6314.9**	**6599.4**	**6,599.4**

Notes:

(1) Forecast values include FCM Resources, non-FCM Energy Only Generators, and behind-the-meter PV resources
(2) The forecast values are net of the effects of discount factors applied to reflect a degree of uncertainty in the policy-based forecast
(3) All values represent end-of-year installed capacities
(4) Forecast does not include forward-looking PV projects > 5MW in nameplate capacity

PV Nameplate Capacity Growth

Historical vs. Forecast



NEXT STEPS:
FINAL 2019 CELT PV FORECAST

Next Steps for CELT 2019

- Once the 2019 nameplate PV forecast is finalized, ISO will:
  - Break down the forecast by market participation category
    - For reference, approximately 63% of PV was behind-the-meter at the end of 2017; however, note that BTM shares differ across states
  - Create the PV energy forecast
  - Develop the estimated summer peak load reductions
  - Accounting for PV panel degradation will be same as last year
- ISO will reconstitute PV into the historical loads used to develop the long-term gross load forecast
  - Overall accounting in the net load forecast will be the same
  - As in prior forecasts, three PV categories will be used for CELT 2019:
    1. PV as a capacity resource in the FCM
    2. EOR
    3. BTM PV
- ISO will use the same approach as previous forecasts to estimate the geographic distribution of the PV forecast
  - Assumes future development is in existing areas of PV development

We Want Your Feedback …

- Please share your comments today
- ISO requests written comments on draft 2019 PV forecast by February 25, 2019 @ 5:00 p.m.
- Please submit comments to DGFWGMatters@iso-ne.com

Questions

Draft 2019 Energy and Summer Peak Forecasts for Region and States

NEPOOL Load Forecast Committee

Fred Ninotti

LOAD FORECASTING

Outline

	Slide
• Objectives	3
• Introduction	4
• 2019 Load Forecast Development Timeline	5
• Draft 2019 Energy Forecast	6
• Draft 2019 Summer Peak Demand Forecast	17
• Next Steps	35
• Appendix (Summer Demand Model Statistics)	38

Objectives

1. Discuss draft 2019 energy forecasts for the region and states
2. Discuss draft 2019 summer peak demand forecasts for the region and states
3. Discuss changes in modeling methodology in the 2019 forecast

Introduction

Explanation of Gross and Net Energy Forecasts

- The ISO annually develops 10-year forecasts of energy and demand that are published as part of the Capacity, Energy, Loads, and Transmission (CELT) report;
- ISO first develops "gross" load forecasts that reflect a forecast of load without reductions from energy efficiency (EE) and behind-the-meter photovoltaic (BTM PV)
  - EE and BTM PV are reconstituted into both historical energy and demand used to estimate gross energy and demand models
    - The purpose is to properly account for EE and BTM PV, which are both forecast separately
  - Reconstitution also includes load reductions from active demand resources
- "Net" energy and demand forecasts are developed by subtracting EE and BTM PV from the gross forecasts
  - Historical net energy and demand includes reconstitution of load reductions from active demand resources beginning on June 1, 2018
  - Net energy and demand forecast values are shown for illustrative purposes and reflect 2018 EE and BTM PV forecast values
    - Draft 2019 EE and BTM PV forecasts are being developed
- All forecasts described herein are draft and subject to change

2019 Load Forecast Development Timeline

- Recent activities:
  - October 2018 – Received Moody's Macroeconomic Forecast
  - November 15, 2018 – Moody's presentation at the Planning Advisory Committee (PAC): https://www.iso-ne.com/static-assets/documents/2018/11/a5_moodys_analytics_2018_economic_update.pdf
  - December 2018 – ISO published Summer 2018 Weather Normal Peak Load report at: https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/summer-and-winter-normalized-peaks
- LFC meetings:
  - December 14, 2018 – Moody's forecast, draft energy forecast
  - February 11, 2019 – Final draft energy forecast, 2018 summer peak review and draft 2019 summer peak forecast
  - March 29, 2019 – Final draft seasonal peak forecasts
  - July 2019 – Summer LFC meeting (Date TBD)
- May 1, 2019 – Final forecast published in 2019 CELT report

DRAFT ENERGY FORECAST

New England and States

Changes in Energy Forecast Methodology

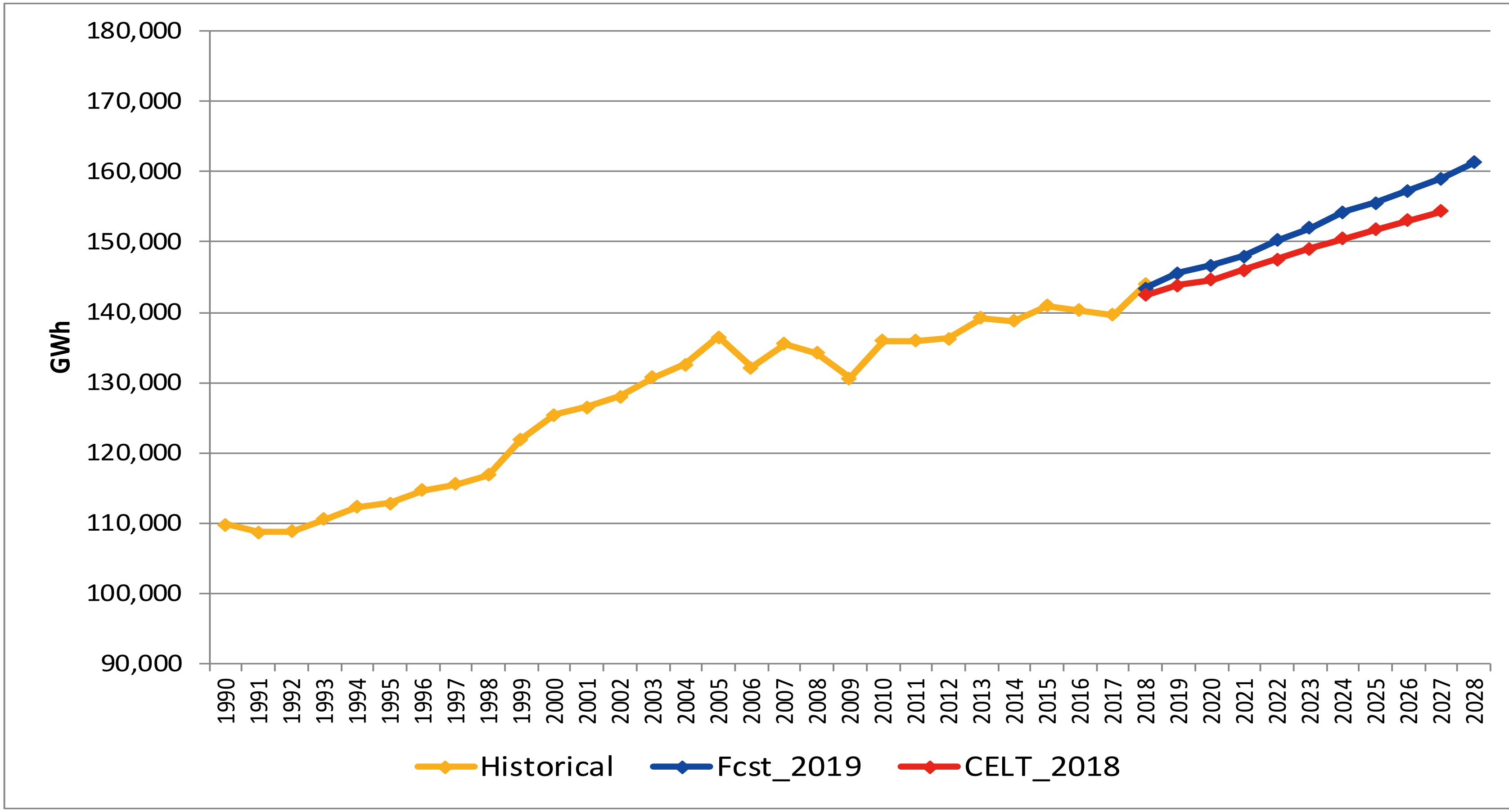
- As previously discussed with the LFC, monthly energy models were developed and implemented for the 2019 CELT forecast
  - Monthly energy models are better able to capture seasonal trends that are anticipated to shift in coming years
- A trend variable interacted with heating degree days (HDDs) was used in the winter monthly models to help better capture shifts in winter electric energy usage over time

2019 Draft Energy Forecast

- Energy models were estimated using reconstituted monthly energy from 1991-2018 (28 years)
- Energy models used the updated Moody's macroeconomic forecast published in October 2018
  - Bureau of Economic Analysis revised some historical values
- ISO assumed normal weather for the energy forecast
  - Normal weather is defined as the 20 year average from 1996-2015
- Some monthly models were estimated using initial load settlement data
  - Data reconciliation process is not yet complete
- Preliminary net energy forecast values were based on the 2018 EE and BTM PV forecasts
- The monthly energy forecast was an input into the monthly peak demand models

New England Gross Energy Forecast

Net + EE + BTM PV



2019 (+1.2%, 1,790 GWh) 2023 (+2.0% , +2,917 GWh) 2027 (+3.0%, +4,635 GWh)

Energy Forecast

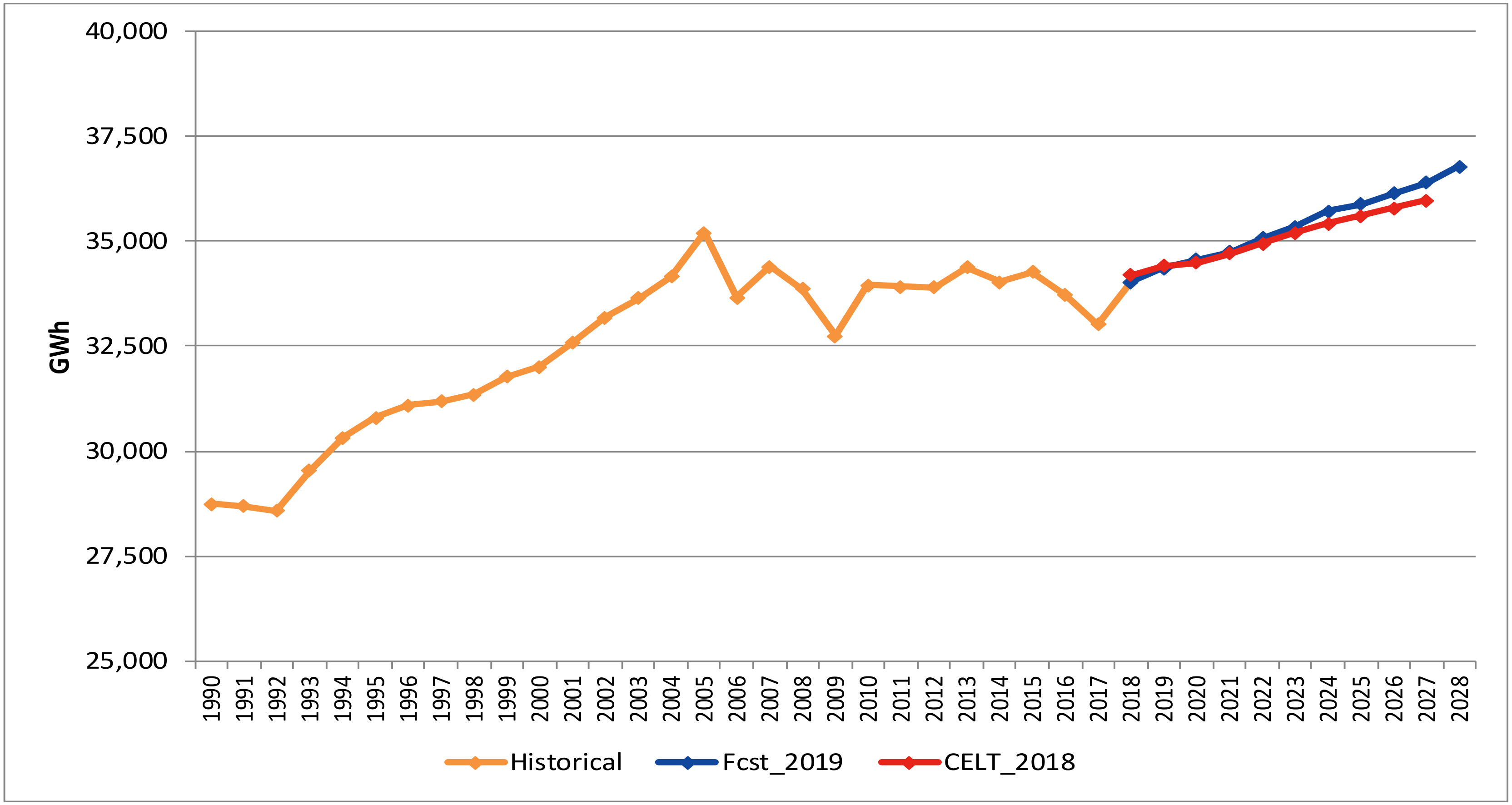
New England Gross and Net

Draft 2019 CELT (GWh)				
Year	Gross	BTM PV*	EE*	Net
2019	145,610	2,558	18,764	124,288
2020	146,650	2,906	21,332	122,411
2021	148,012	3,233	23,827	120,952
2022	150,201	3,540	26,128	120,533
2023	152,017	3,834	28,228	119,956
2024	154,242	4,115	30,121	120,006
2025	155,572	4,361	31,811	119,400
2026	157,253	4,575	33,302	119,377
2027	158,999	4,783	34,601	119,616
2028	161,312			

* Note: 2018 EE and BTM PV forecast values used for reference only; 2019 EE and BTM PV forecasts are under development

Connecticut Gross Energy Forecast

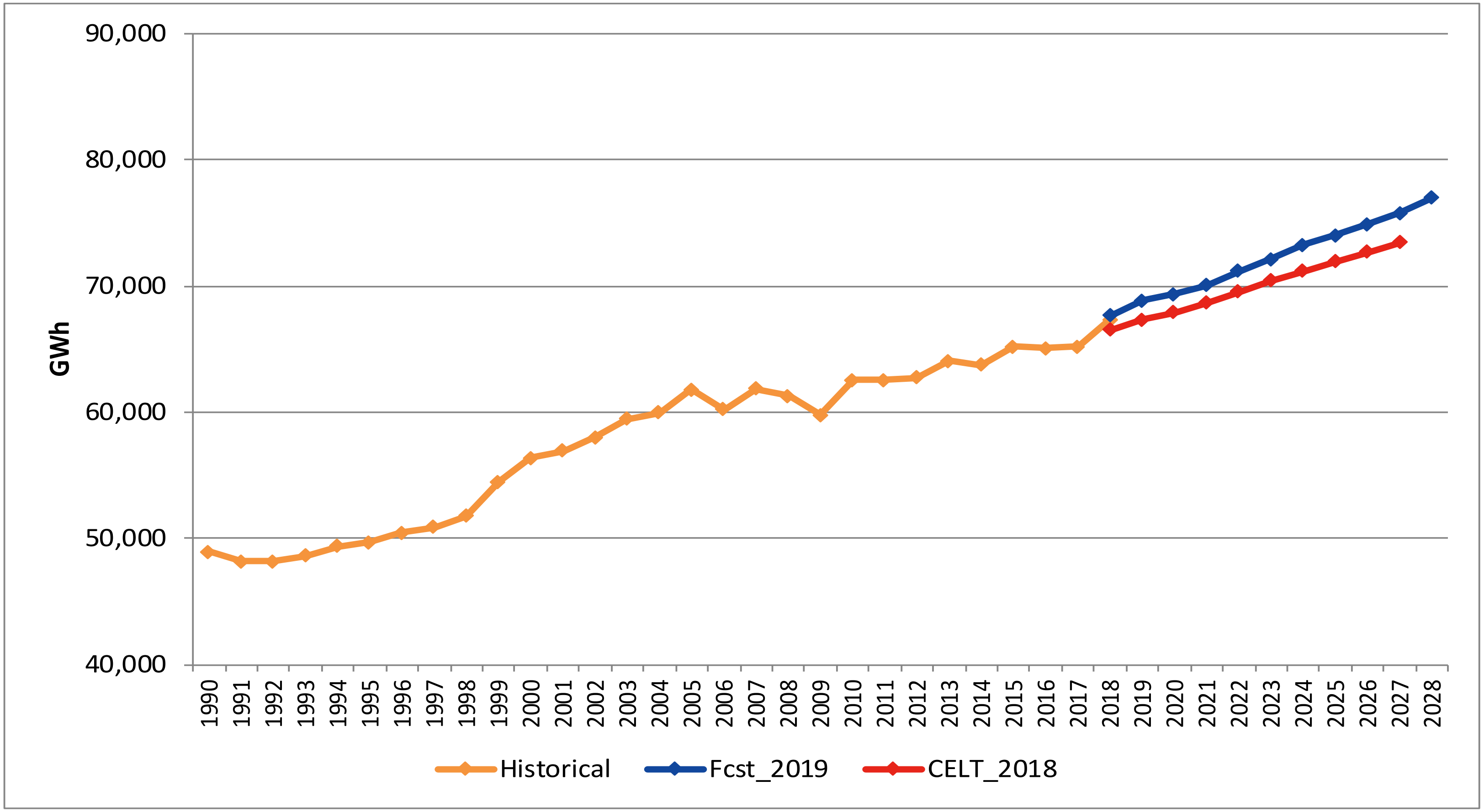
Net + EE + BTM PV



2019 (-0.1%, -41 GWh) 2023 (+0.4%, +147 GWh) 2027 (+1.2%, +420 GWh)

Massachusetts Gross Energy Forecast

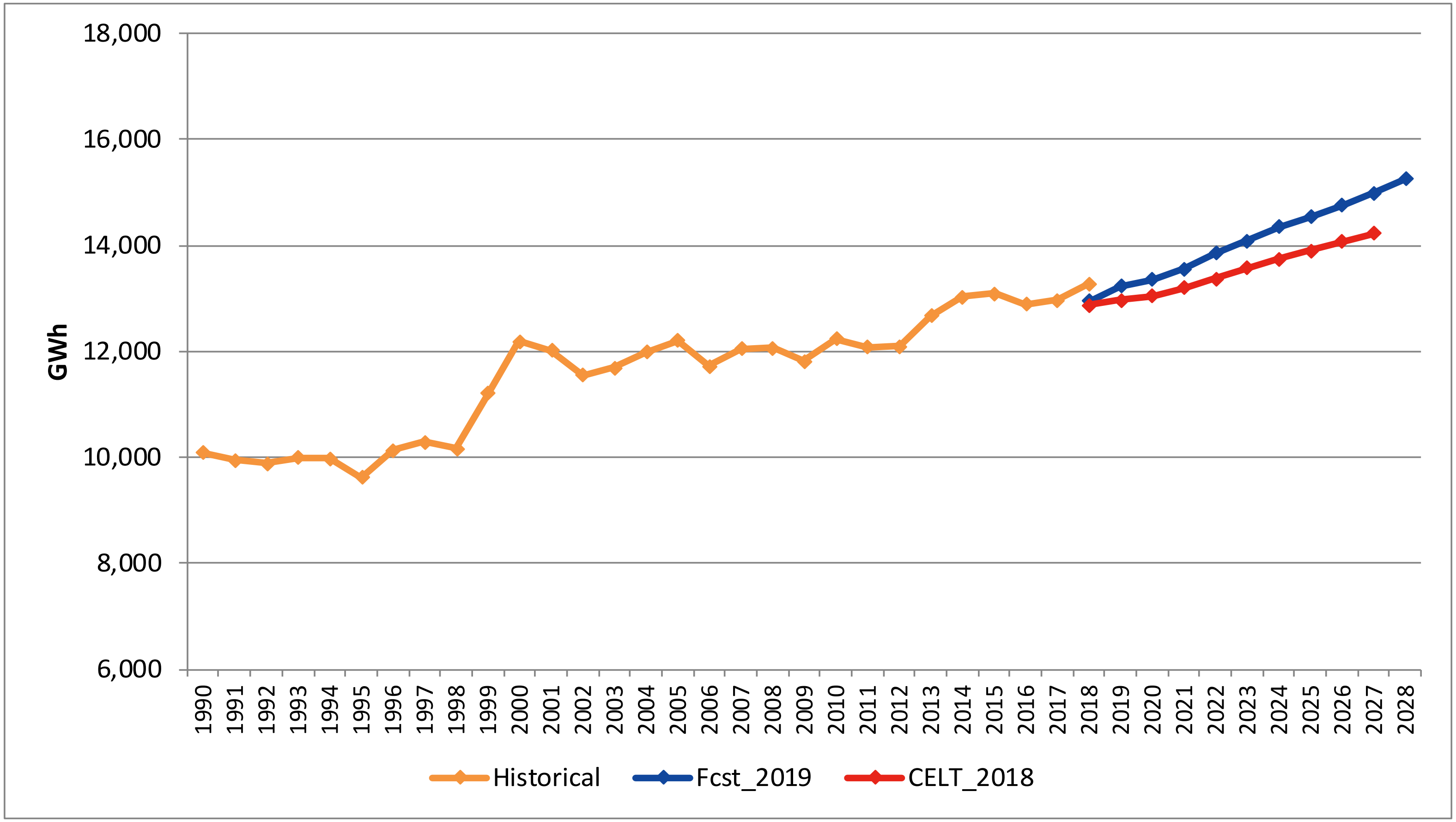
Net + EE + BTM PV



2019 (+2.2%, +1,473 GWh) 2023 (+2.54%, +1,719 GWh) 2027 (+3.2%, +2,360 GWh)

Maine Gross Energy Forecast

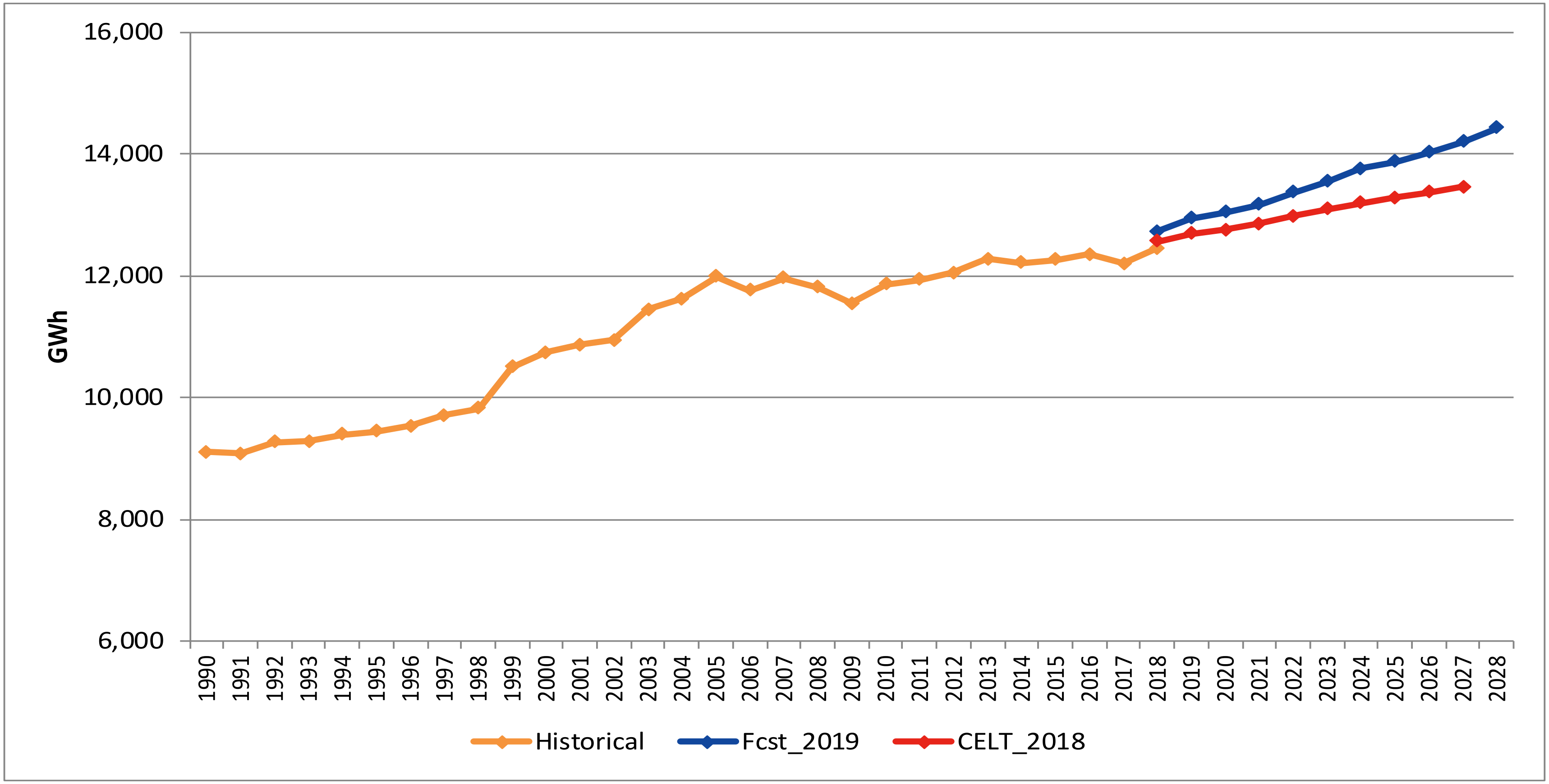
Net + EE + BTM PV



2019 (+2.7%. +353 GWh) 2023 (+4.0%, +549 GWh) 2027 (+5.2%, +740 GWh)

New Hampshire Gross Energy Forecast

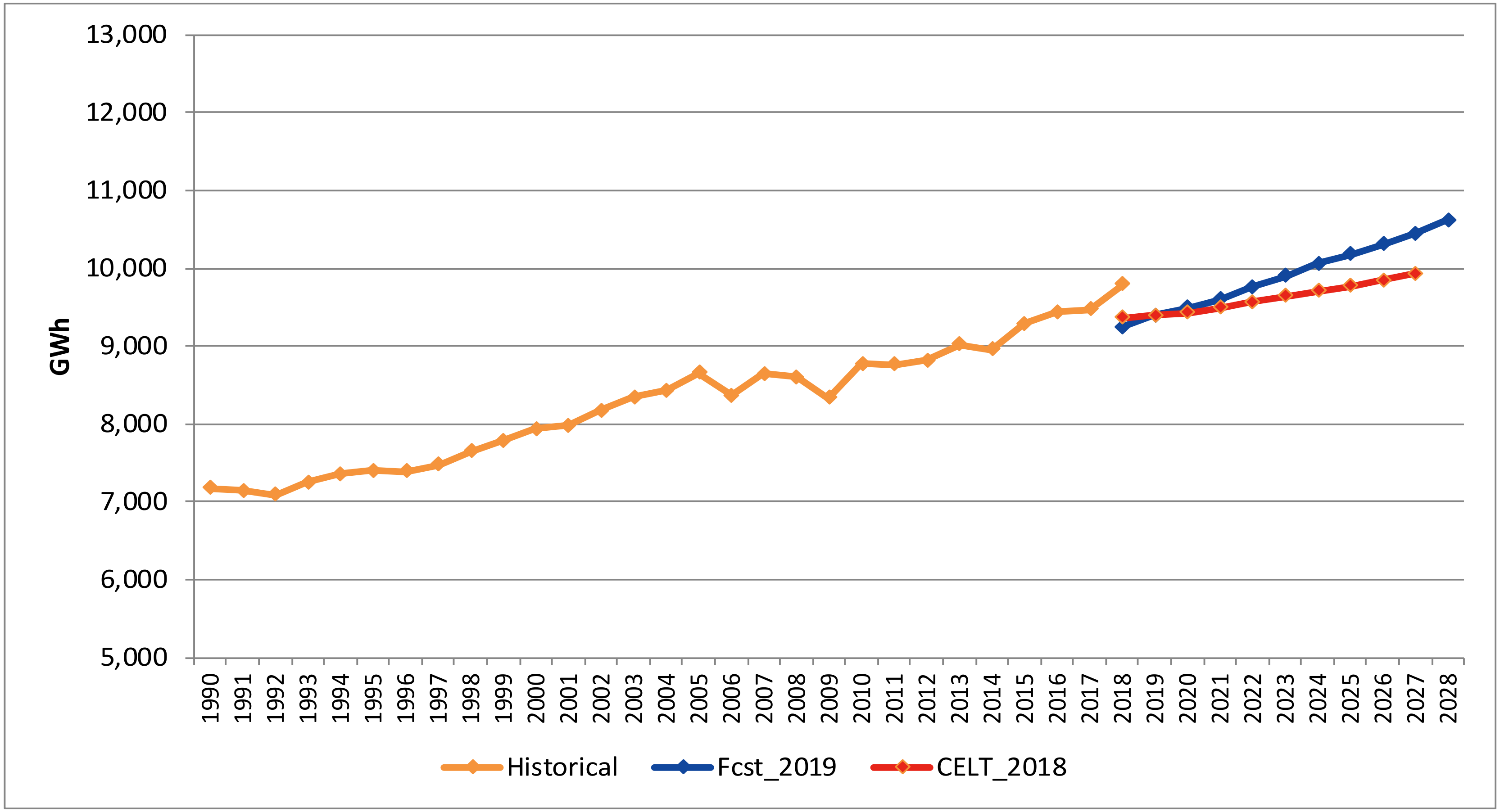
Net + EE + BTM PV



2019 (+2.0%, +253 GWh) 2023 (+3.4% , +453 GWh) 2027 (+5.4%, +733 GWh)

Rhode Island Gross Energy Forecast

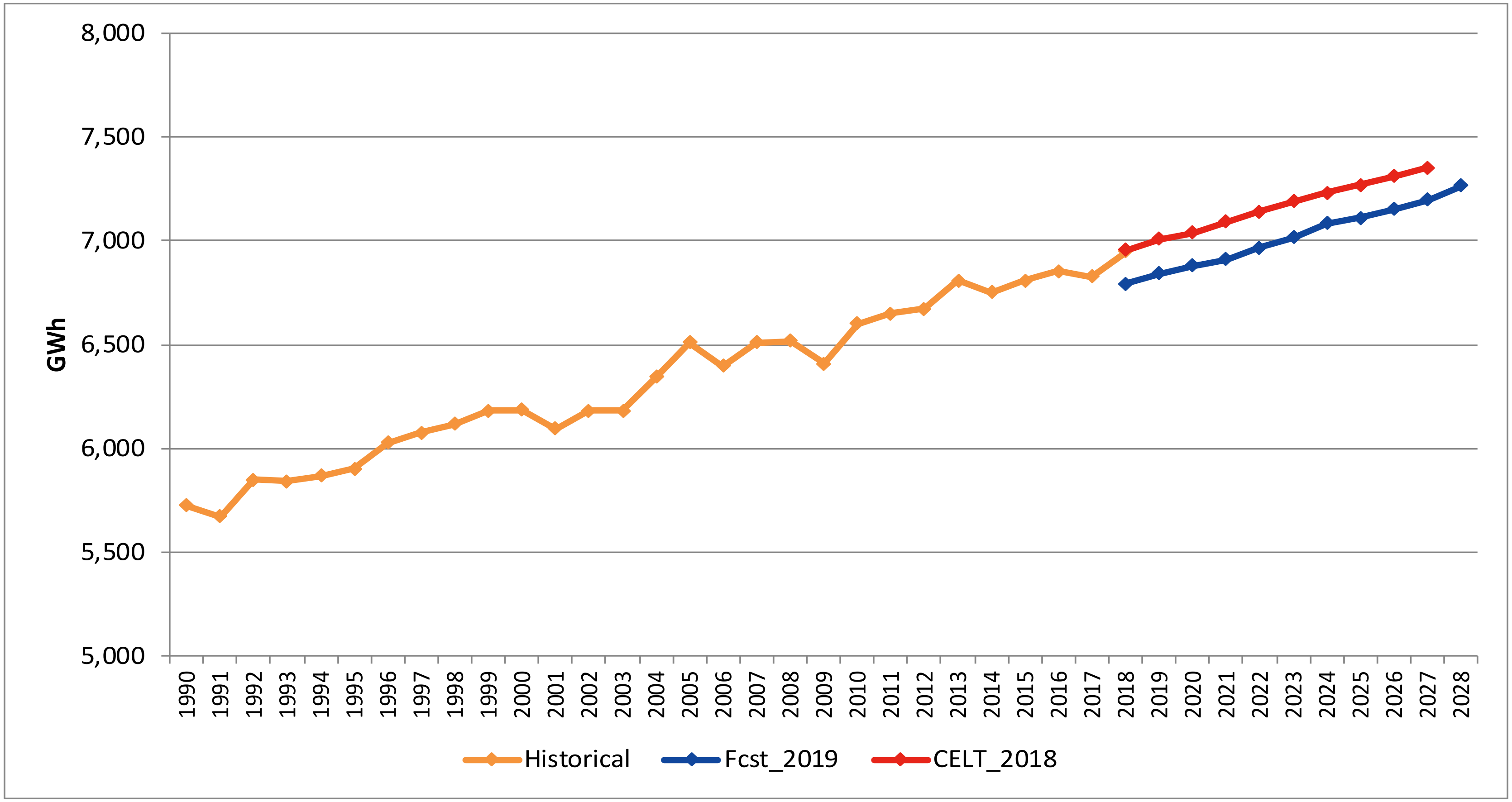
Net + EE + BTM PV



2019 (0.0% , +4 GWh)   2023 (+2.7, +261 GWh)   2027 (+5.2%, +515 GWh)

Vermont Gross Energy Forecast

Net + EE + BTM PV



2019 (-2.5% , -164 GWh) 2023 (-2.4% , -172 GWh) 2027 (-2.1%, -157 GWh)

DRAFT SUMMER PEAK DEMAND FORECASTS

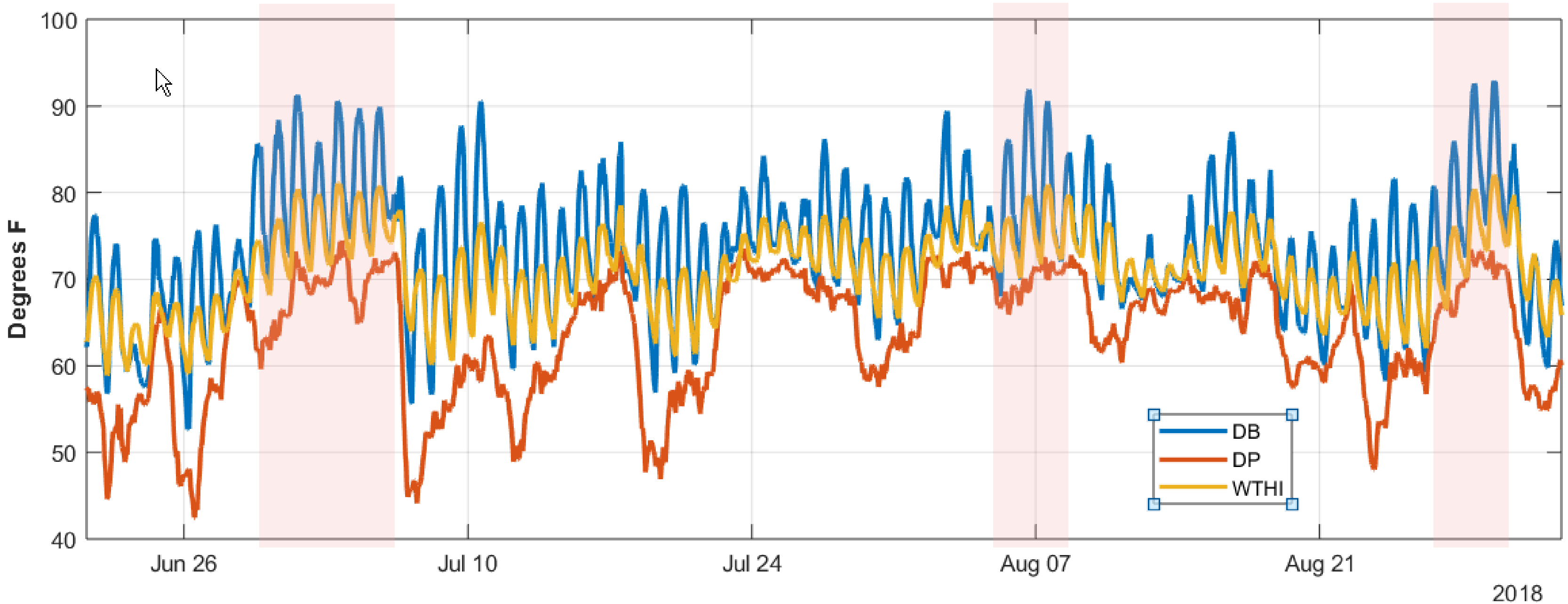
Review of 2018 Summer Peaks

2019 Draft Gross Summer Peak Forecast (Region and States)

Introduction

2018 Summer Peak Demand

- Several periods of consecutive extreme weather days occurred during this past summer and provided an opportunity to better understand the current regional peak load response
  - July 1-6 (impacted by the July 4th holiday, which occurred on a Wednesday)
  - August 5-7
  - August 27-29
- Plot below illustrates 8-city weighted dry bulb temperature (DB), dew point temperature (DP) and three day weighted temperature-humidity index (WTHI)



Review of 2018 Summer Peak Demand

Forecast and Actual

Peak Day*	Type	Day of Week	Gross Peak	Net Peak	Peak Hour Gross (Net)	WTHI @ Gross Peak	BTM PV Peak Reduction**
CELT2018 90/10	***Forecast***	**-**	***31,451***	***28,119***	**-**	***82.0***	***633***
CELT2018 50/50	***Forecast***	**-**	***29,060***	***25,728***	**-**	***79.9***	***633***
8/29/2018	Actual	Wed	29,898	26,024	15 (17)	82.0	915
8/28/2018	Actual	Tue	29,133	25,600	16 (18)	80.4	574
8/7/2018	Actual	Tue	28,952	24,938	15 (16)	80.9	1,055
8/6/2018	Actual	Mon	28,527	25,049	17 (18)	79.6	518
8/2/2018	Actual	Wed	27,874	24,071	15 (17)	78.1	844

Notes:

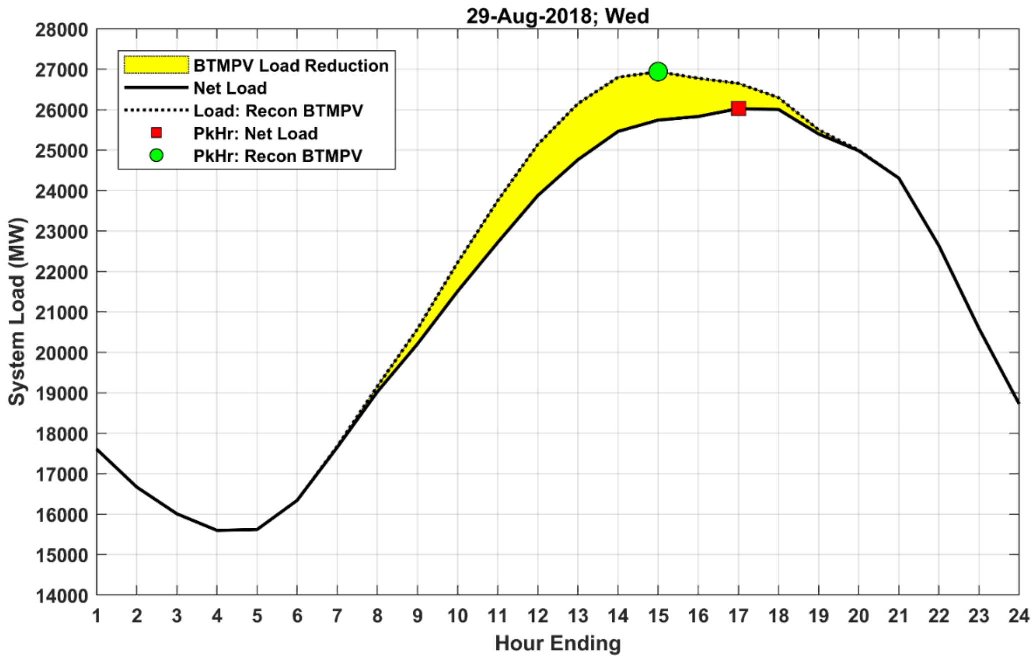
* Peak days during week of July 4th were removed due to holiday effects

** Calculation of BTM PV peak reduction values illustrated on next slide

Example of BTM PV Impact on Peak Day

August 29, 2018

- The figure below illustrates the calculation of BTM PV peak load reductions for the summer peak day, August 29, 2018
  - BTM PV peak reduction is the difference between the peak load after BTM PV is reconstituted (green circle) and net of BTM PV (red square)



Changes in Peak Demand Forecast Methodology

- Relative to the 2018 summer peak demand models, the following changes were made:
  1. Model Specification – To address summer peak demand forecast performance issue identified this past summer, a second weather variable, cooling degree days (CDD), was incorporated into summer demand models
     - WTHI was only weather variable used for CELT 2018
     - Use of two weather variables enables models to better capture the impacts of different weather features on peak demand
  2. Model Estimation Period – Peak models were estimated using daily peak loads and weather over the historical period 2004 to 2018
     - Last year's historical period was 2003 to 2017
  3. Weather History – Weather historical period used to generate probabilistic forecast shortened from 40 years to 25 years
     - Based on ad hoc survey of other ISO long-term load forecast practices, most use a 20 year period
     - 40-year period included years 1975-2014
     - 25-year period includes years 1991-2015

Change in 50/50 and 90/10 Weather Points

Summer Peak

	CELT 2018	CELT 2019
50/50	WTHI = 79.9	WTHI = 79.1 to 81.8 CDD = 15.0 to 17.4
90/10	WTHI = 82.0	WTHI = 80.6 to 82.5 CDD = 18.0 to 21.6

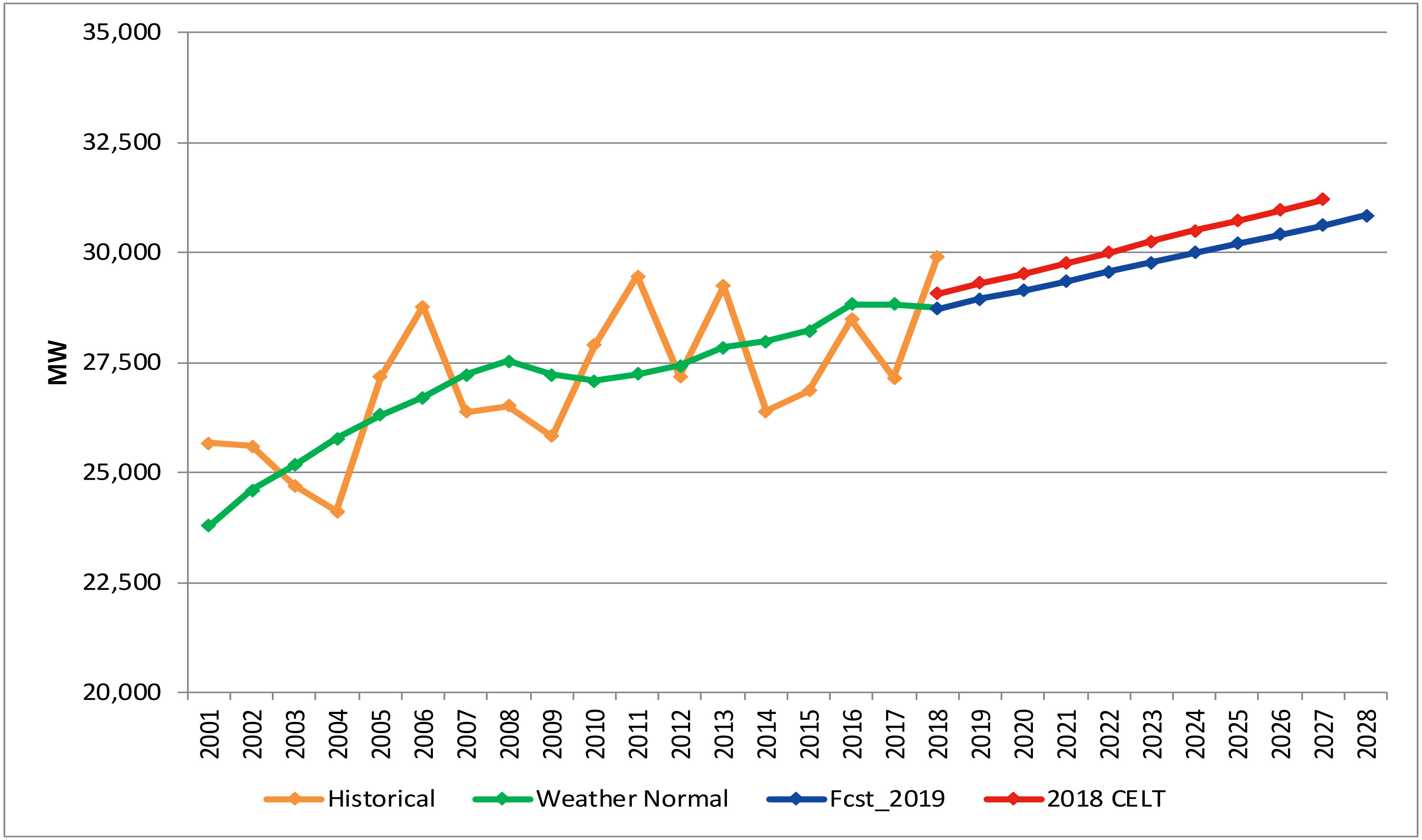
Draft 2019 Gross Summer Peak Demand Forecast

Observations

- The draft 2019 gross 50/50 summer peak demand forecast for the region is lower than the CELT 2018 forecast by 1.2% in 2019 and 1.8% in 2027
  - Percent differences vary over the forecast horizon and across states
- Gross summer peak demand for the region is forecast to increase at a compound annual growth rate (CAGR) of 0.70% from 2019 thru 2028, down slightly from 0.79% from CELT 2018
  - CAGRs vary by state from 0.20% in Connecticut to 1.1% in Rhode Island.
- Net demand forecasts presented are illustrative and will change when the 2019 EE and BTM PV forecasts are developed
  - Both the EE and BTM PV forecasts are under development as part of the EEFWG and DGFWG stakeholder processes

New England Gross 50/50 Summer Peak Forecast

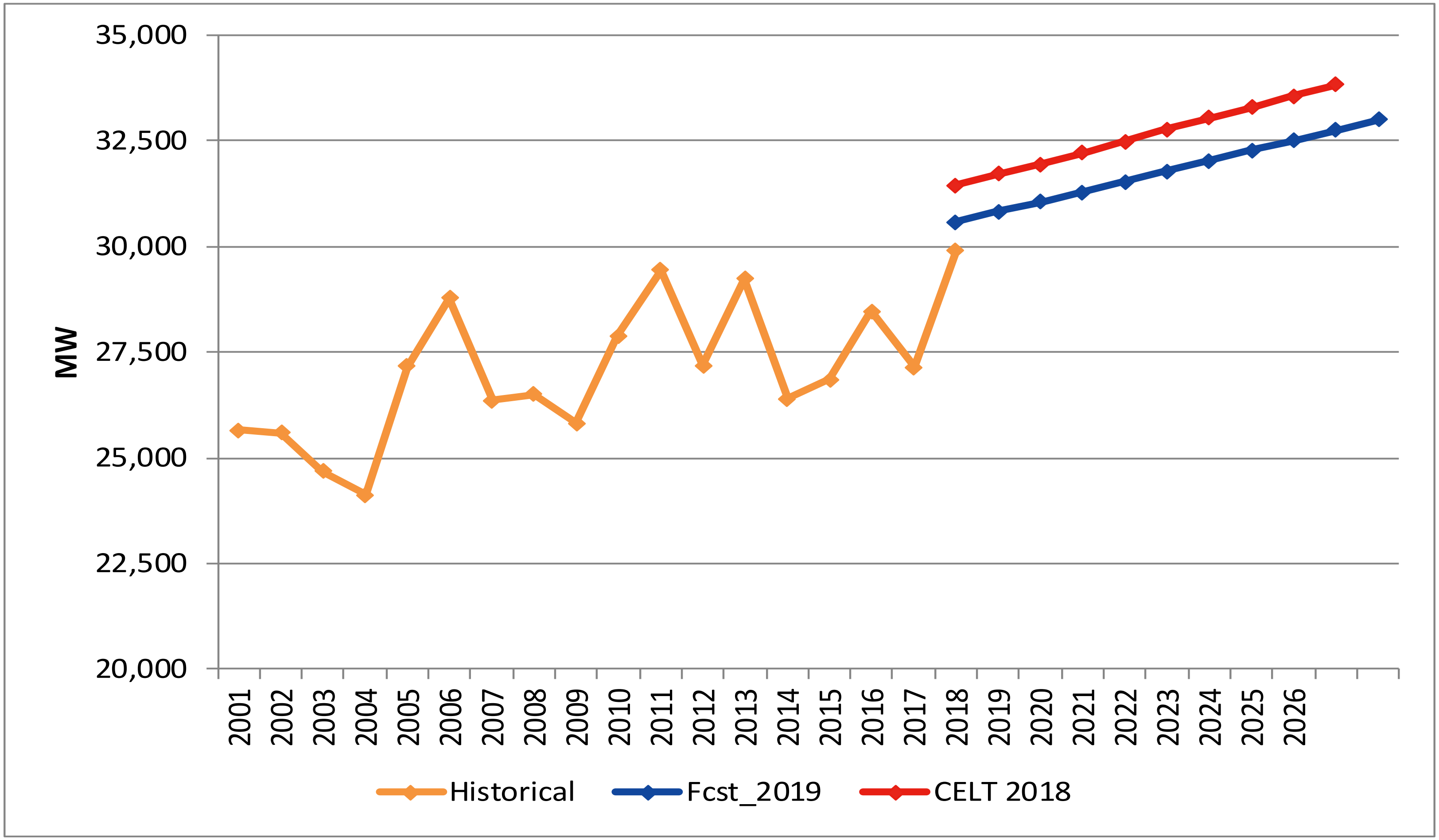
Net + EE + BTM PV



2019 (-1.2% , -355 MW) 2023 (-1.6% , -471 MW) 2027 (-1.8%, -576 MW)

New England Gross 90/10 Summer Peak Forecast

Net + EE + BTM PV



2019 (-2.8% , -884 MW) 2023 (-3.0% , -987 MW) 2027 (-3.2%, -1,075 MW)

New England Gross 50/50 Summer Peak Forecast

Net + EE + BTM PV

Year	Fcst 19	CELT 2018	Change	%Change
2019	28,943	29,298	-355	-1.2%
2020	29,130	29,504	-374	-1.3%
2021	29,341	29,744	-403	-1.4%
2022	29,561	29,994	-433	-1.4%
2023	29,774	30,245	-471	-1.6%
2024	29,987	30,486	-499	-1.6%
2025	30,196	30,721	-525	-1.7%
2026	30,406	30,957	-551	-1.8%
2027	30,616	31,192	-576	-1.8%
2028	30,831			

New England Gross and Net Summer Peak Forecast

Net + EE + BTM PV

Fcst 2019 (MW)						
Year	Gross 50/50	Gross 90/10	BTM PV*	EE*	Net 50/50	Net 90/10
2019	28,943	30,832	721	3,066	25,157	27,046
2020	29,130	31,050	790	3,416	24,923	26,843
2021	29,341	31,291	851	3,757	24,732	26,683
2022	29,561	31,543	901	4,072	24,588	26,570
2023	29,774	31,786	945	4,359	24,470	26,483
2024	29,987	32,030	980	4,617	24,389	26,433
2025	30,196	32,271	1009	4,848	24,339	26,414
2026	30,406	32,511	1031	5,052	24,322	26,428
2027	30,616	32,753	1051	5,229	24,336	26,473
2028	30,831	32,999				

* 2018 EE and BTM PV forecast values used since 2019 draft EE and BTM PV forecasts are under development

Impact of Changes in Summer Peak Demand Model

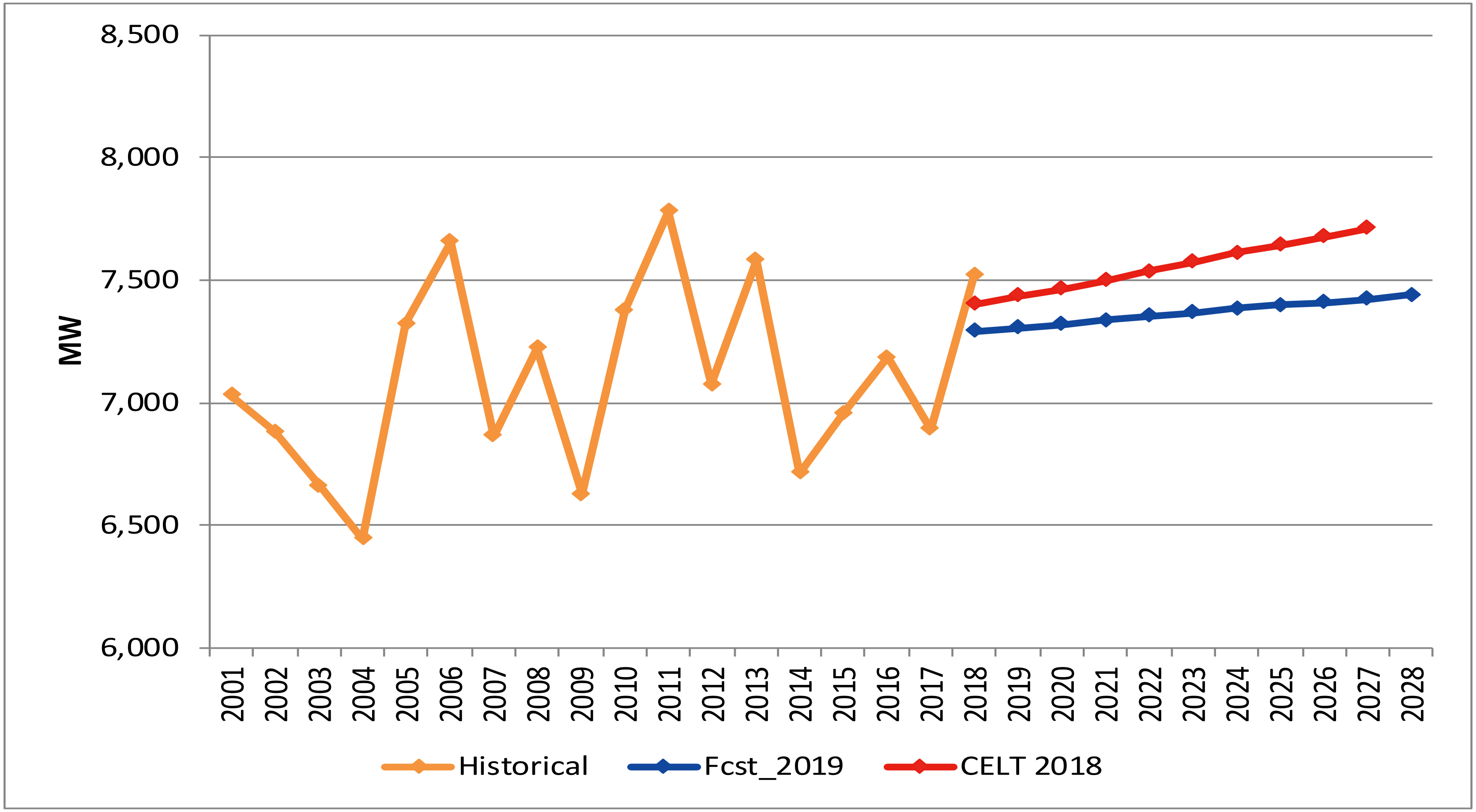
New England

- Approximate attribution of decrease in forecast to forecast model changes are as follows:
  1. Model specification – 80% of decrease
  2. Model estimation period – 20% of decrease
  3. Weather history – negligible impact
- Draft CELT 2019 model demonstrates improved performance relative to CELT 2018 model based on a comparison of out-of-sample mean absolute percent error (MAPE) during 2018 summer (July/August, non-holiday) days, as tabulated below

Model	All Non-Holiday Weekdays (42 days)	Highest 10 Demand Days
CELT 2018	3.35%	4.01%
Draft CELT 2019	2.23%	1.46%

Connecticut Gross 50/50 Summer Peak Forecast

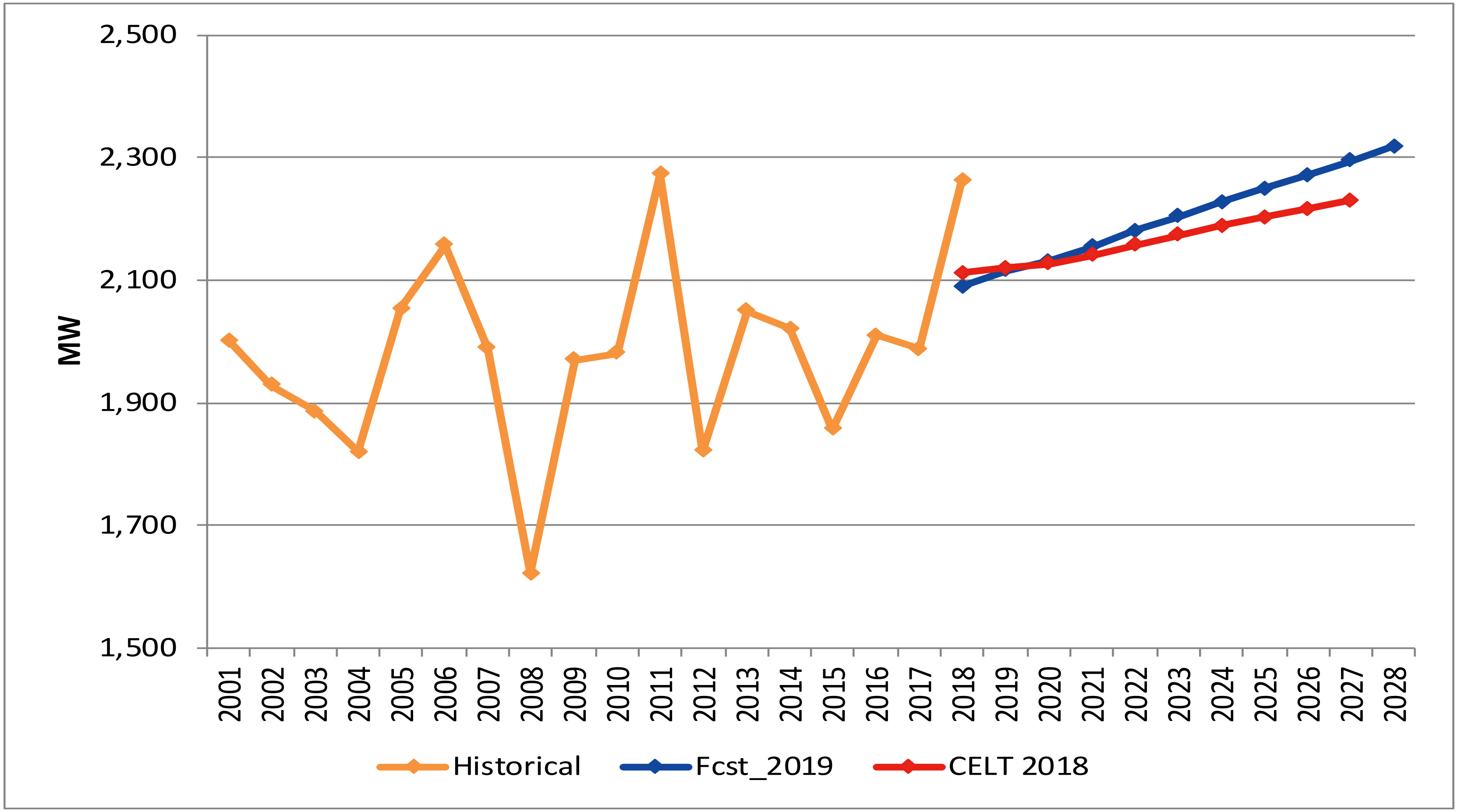
Net + EE + BTM PV (coincident with NE)



2019 (-1.7% , -130 MW) 2023 (-2.7% , -206 MW) 2027 (-3.7%, -288 MW)

Maine Gross 50/50 Summer Peak Forecast

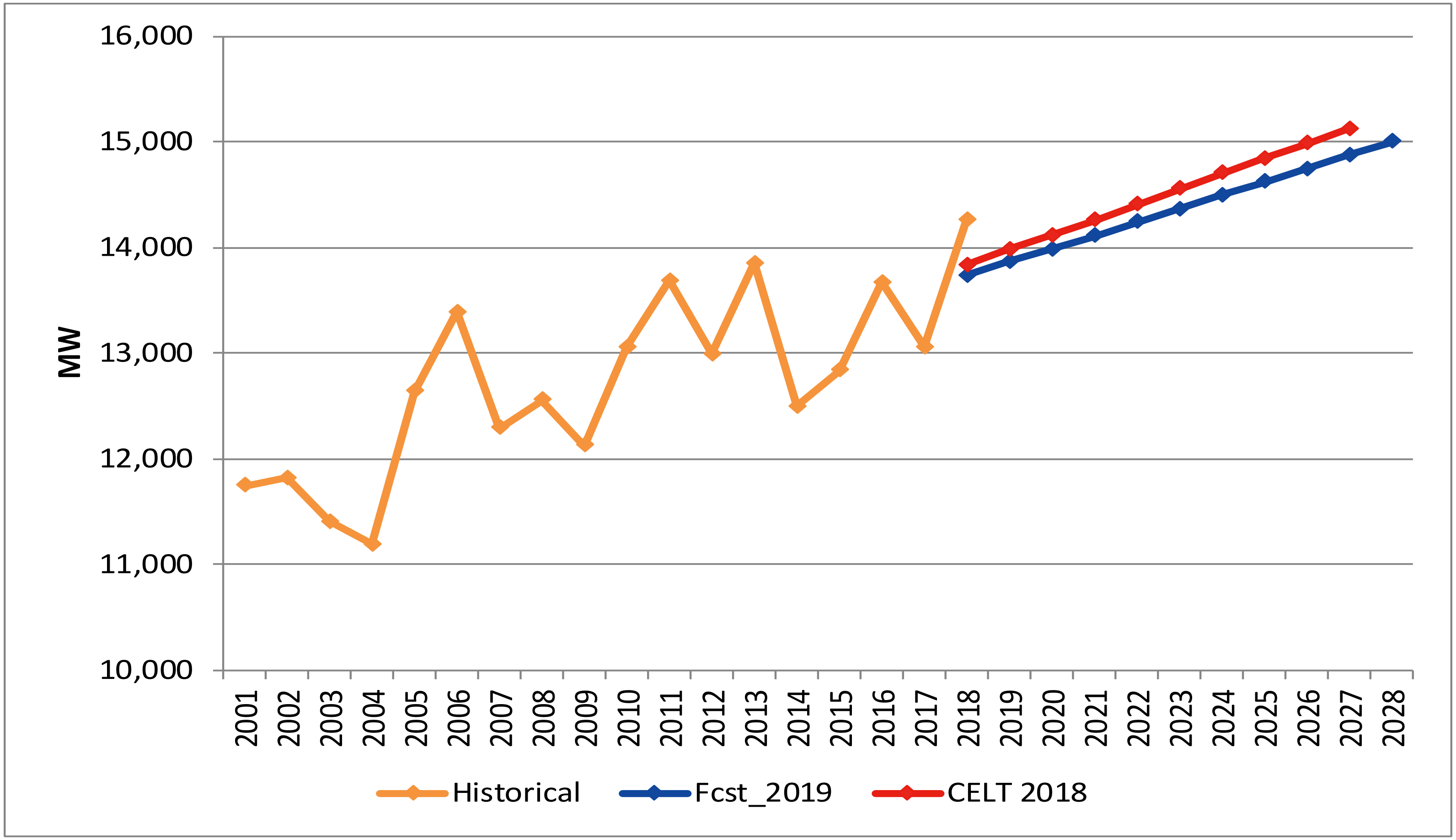
Net + EE + BTM PV (coincident with NE)



2019 (-0.2% , -5 MW)   2023 (+1.4% , +31 MW)   2027 (+2.9%, +64 MW)

Massachusetts Gross 50/50 Summer Peak Forecast

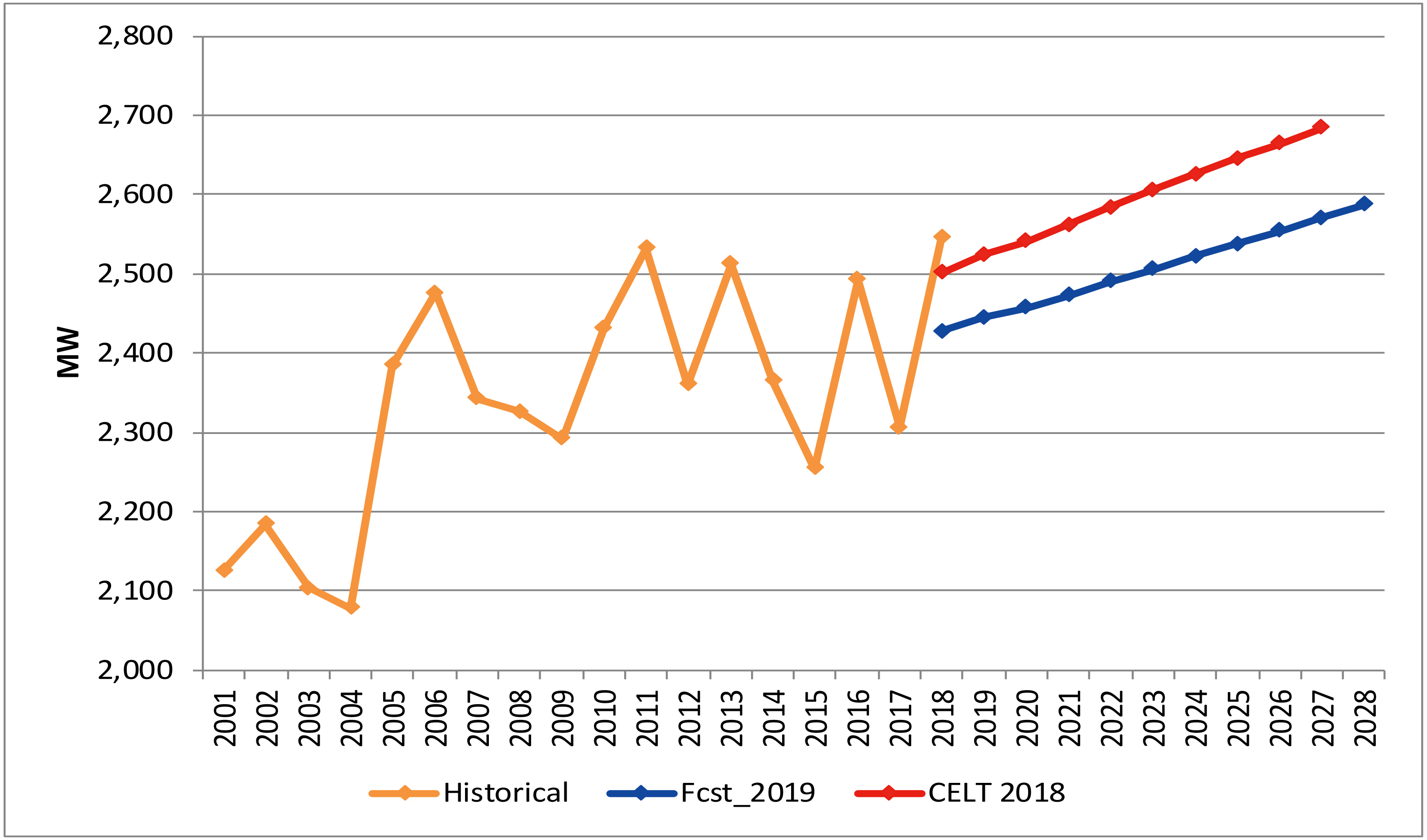
Net + EE + BTM PV (coincident with NE)



2019 (-0.8% , -118 MW) 2023 (-1.3% , -193 MW) 2027 (-1.7%, -253 MW)

New Hampshire Gross 50/50 Summer Peak Forecast

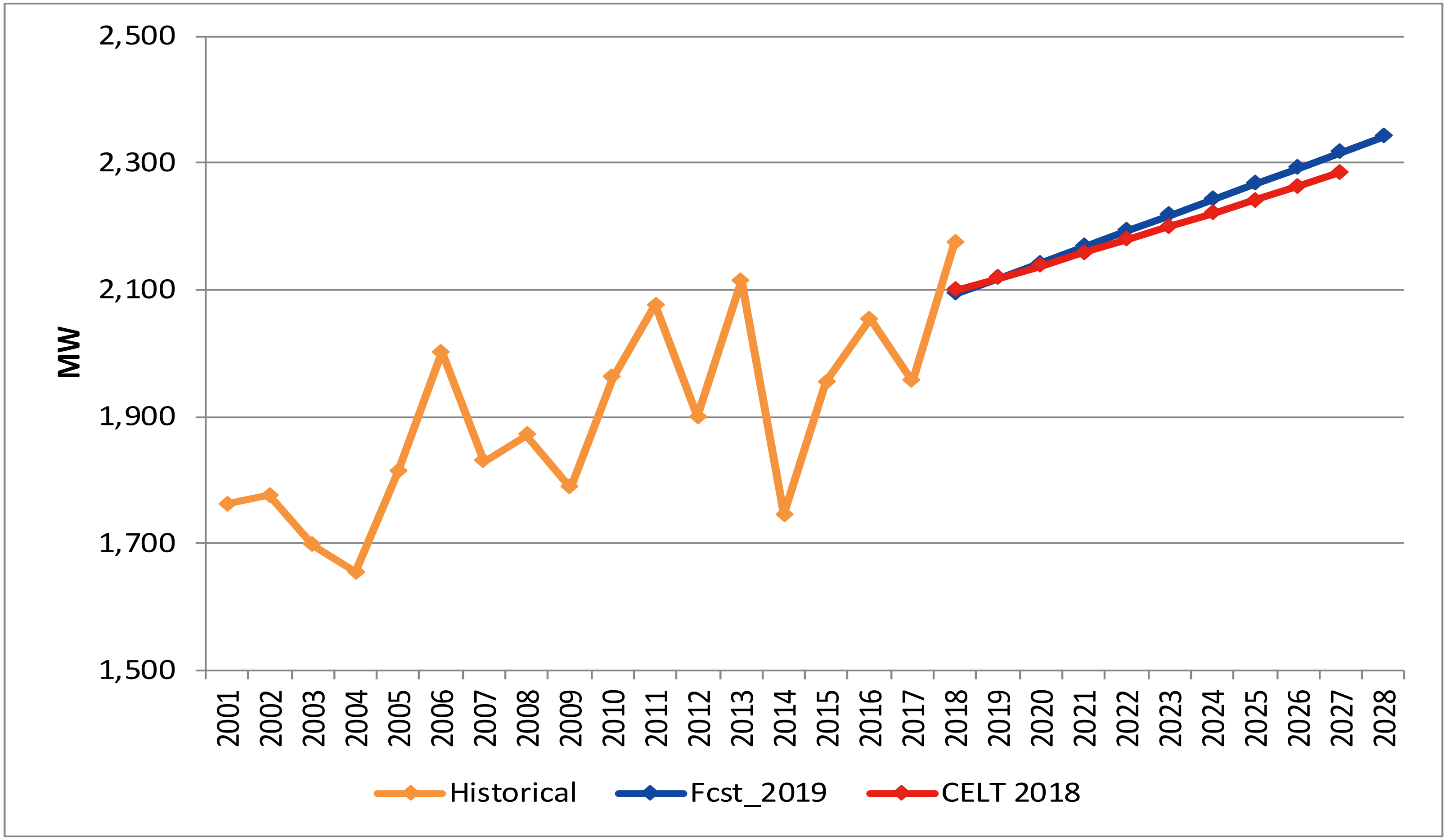
Net + EE + BTM PV (coincident with NE)



2019 (-3.1% , -79 MW) 2023 (-3.9% , -100 MW) 2027 (-4.2%, -114 MW)

Rhode Island Gross 50/50 Summer Peak Forecast

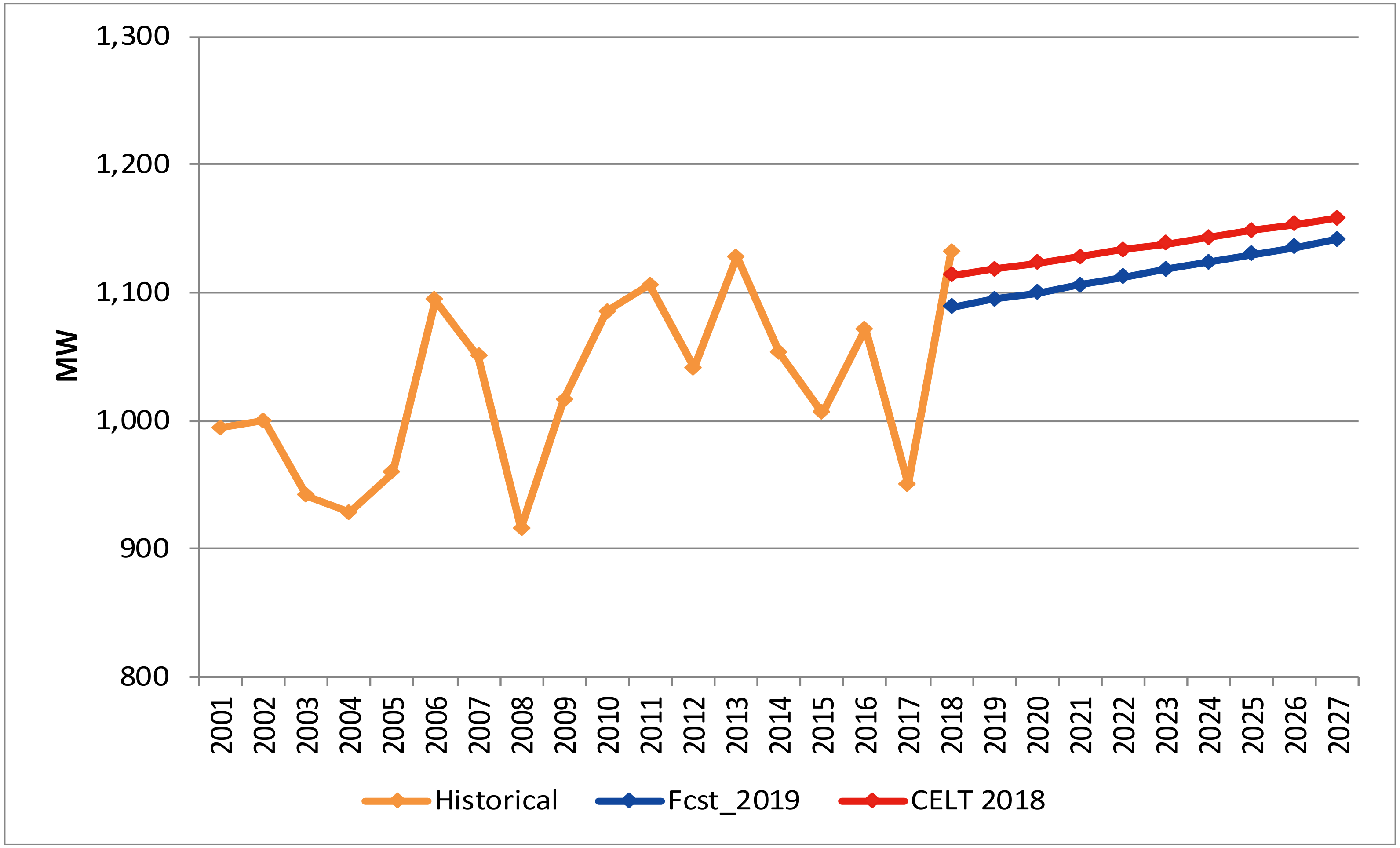
Net + EE + BTM PV (coincident with NE)



2019 (0.0% , 0 MW) 2023 (+0.8% , +18 MW) 2027 (+1.4%, +32 MW)

Vermont Gross 50/50 Summer Peak Forecast

Net + EE + BTM PV (coincident with NE)



2019 (-2.1% ,-23 MW)   2023 (-1.8% , -20 MW)   2027 (-1.4%, -17 MW)

NEXT STEPS

Next Steps

- Next LFC meeting is March 29, 2019
  - Final draft summer peak forecast will be discussed along with draft winter peak forecast
- Presentations at the Planning Advisory Committee (PAC)
  - March 21, 2019
  - April 25, 2019 (tentative)
- The final forecast will be published as part of the 2019 CELT by May 1st

Questions

APPENDIX

Summer Peak Demand Model Statistics

Summer Peak Model Variables

Variable	Definition
Intercept	Constant Term
Gross peak (dependent variable)	Net peak + EE + BTM PV
Monthly_energy	Monthly energy
WTHI	3-day Weighted Temperature-Humidity Index at the time of the daily peak, base = 55,
TIMEWTHI	Year indicator; 2004=1,…, 2018=15*WTHI
WeekendWTHI	Weekend*WTHI
July_04WTHI	July_04*WTHI
CDD	Cooling Degree Days (daily)
Friday, Saturday, Sunday, weekend, various Holidays	Dummy variables = 1 if condition is true; 0 otherwise
Yxxxx	Dummy variable = 1 if Year=xxxx; 0 otherwise
AR(1)	Correction for autocorrelated errors of the first order

2019 New England Summer Peak Model Statistics

Dependent Variable: Reconstituted Peak
Sample: 2004-2018

Parameter Estimates

Variable	Estimate	Standard Error	t Value	Approx PR>|t|
Intercept	-6981	2040	-3.42	0.0007
Monthly Energy	0.172	0.071	2.40	0.0167
WTHI	325.750	27.054	12.04	<.0001
Time*WTHI	0.287	0.030	9.54	<.0001
CDD	279.340	20.941	13.34	<.0001
WeekendWTHI	-7.914	0.197	-40.09	<.0001
July4th_WTHI	-36.296	2.674	-13.57	<.0001
AR(1)	-0.308	0.045	-6.91	

F-test

Source	DF	Mean Square	F Value	Pr > F
Numerator	1	46480858	106.21	<.0001
Denominator	457	437635		

Other Statistics

MSE	437635	Standard Error	661.54
MAE	524.99	MAPE	2.56
Durbin-Watson	1.8828	R-Square	0.9544

2019 Connecticut Summer Peak Model Statistics

Dependent Variable	Reconstituted Peak
Sample	2004:2018

Parameter Estimates

Variable	Estimate	Standard Error	t Value	Approx Pr>|t|
Intercept	-3041.000	583.48	-5.21	<.0001
Monthly Energy	0.178	0.084	2.13	0.0334
WTHI	97.712	7.672	12.74	<.0001
Time*WTHI	0.017	0.007	2.32	0.0211
CDD	87.765	5.919	14.83	<.0001
WeekendWTHI	-1.772	0.053	-33.35	<.0001
July4th_WTHI	-9.177	0.820	-11.19	<.0001
AR(1)	-0.294	0.045	-6.58	

Test 'F-test'

Source	DF	Mean Square	F Value	Pr > F
Numerator	1	5502117	126.40	<.0001
Denominator	457	43531		

Other Statistics

MSE	43531	Standard Error	208.64
MAE	166.18	MAPE	3.12
Durbin-Watson	1.9391	R-Square	0.9397

2019 Maine Summer Peak Model Statistics

Dependent Variable	Reconstituted Peak
Sample	2004:2018

Parameter Estimates

Variable	Estimate	Standard Error	t Value	Approx PR>|t|
Intercept	348	166.677	2.09	0.0376
Monthly Energy	0.590	0.114	5.19	<.0001
WTHI	9.710	1.487	6.53	<.0001
Time*WTHI	0.016	0.004	4.27	<.0001
CDD	11.982	1.079	11.10	<.0001
Saturday	-159.052	5.911	-26.91	<.0001
Sunday	-164.583	6.112	-26.93	<.0001
July4th	-159.300	14.390	-11.07	<.0001
AR(1)	-0.525	0.040	-13.17	

Test 'F-test'

Source	DF	Mean Square	F Value	Pr > F
Numerator	1	727299	320.73	<.0001
Denominator	455	2267.604		

Other Statistics

MSE	2268	Standard Error	47.62
MAE	37.23	MAPE	2.15
Durbin-Watson	1.9490	R-Square	0.9130

2019 Massachusetts Summer Peak Model Statistics

Dependent Variable	Reconstituted Peak
Sample	2004:2018

Parameter Estimates

Variable	Estimate	Standard Error	t Value	Approx Pr>|t|
Intercept	-4982	1018	-4.89	<.0001
Monthly Energy	0.179	0.074	2.41	0.0165
WTHI	173.329	13.513	12.83	<.0001
Time*WTHI	0.176	0.016	10.75	<.0001
CDD	110.218	9.867	11.17	<.0001
WeekendWTHI	-3.814	0.103	-36.88	<.0001
July4th_WTHI	-18.082	1.430	-12.65	<.0001
AR(1)	-0.289	0.045	-6.44	

Test 'F-test'

Source	DF	Mean Square	F Value	Pr > F
Numerator	1	15603188	122.83	<.0001
Denominator	455	127029		

Other Statistics

MSE	127029	Standard Error	356.41
MAE	283.66	MAPE	2.97
Durbin-Watson	1.9490	R-Square	0.9478

2019 New Hampshire Summer Peak Model Statistics

Dependent Variable	Reconstituted Peak
Sample	2004:2018

Parameter Estimates

Variable	Estimate	Standard Error	t Value	Approx Pr>|t|
Intercept	-95	126	-0.76	0.45
Monthly Energy	0.270	0.064	4.23	<.0001
WTHI	20.787	1.619	12.84	<.0001
Time*WTHI	0.017	0.002	7.84	<.0001
CDD	23.726	1.326	17.90	<.0001
Saturday	-235.971	7.133	-33.08	<.0001
Sunday	-251.428	7.111	-35.36	<.0001
July4th	-248.988	15.659	-15.90	<.0001
AR(1)	-0.242	0.045	-5.34	

Test 'F-test'

Source	DF	Mean Square	F Value	Pr > F
Numerator	1	3266248	1124.11	<.0001
Denominator	456	2905.634		

Other Statistics

MSE	2906	Standard Error	53.90
MAE	42.83	MAPE	2.34
Durbin-Watson	1.9800	R-Square	0.9588

2019 Rhode Island Summer Peak Model Statistics

Dependent Variable	Reconstituted Peak
Sample	2004:2018

Parameter Estimates

Variable	Estimate	Standard Error	t Value	Approx Pr>|t|
Intercept	-591	159	-3.71	0.0002
Monthly Energy	0.171	0.079	2.16	0.0312
WTHI	22.688	2.054	11.05	<.0001
Time*WTHI	0.033	0.003	12.25	<.0001
CDD	19.449	1.522	12.78	<.0001
Weekend WTHI	-0.477	0.015	-31.33	<.0001
July_WTHI	-2.606	0.227	-11.47	<.0001
AR(1)	-0.337	0.044	-7.64	

Test 'F-test'

Source	DF	Mean Square	F Value	Pr > F
Numerator	1	3252438	997.98	<.0001
Denominator	457	3259.023		

Other Statistics

MSE	3259	Standard Error	57.09
MAE	45.59	MAPE	3.17
Durbin-Watson	1.9070	R-Square	0.9459

2019 Vermont Summer Peak Model Statistics

Dependent Variable	Reconstituted Peak
Sample	2004:2018

Parameter Estimates

Variable	Estimate	Standard Error	t Value	Approx Pr>|t|
Intercept	213.635	58.43	3.66	0.0003
Monthly Energy	0.366	0.071	5.17	<.0001
WTHI	6.468	0.559	11.57	<.0001
Time*WTHI	0.006	0.001	6.07	<.0001
CDD	5.227	0.446	11.73	<.0001
Saturday	-118.242	2.395	-49.37	<.0001
Sunday	-126.370	2.397	-52.72	<.0001
July4th	-1.680	0.076	-22.07	<.0001
AR(1)	-0.360	0.044	-8.25	

Test 'F-test'

Source	DF	Mean Square	F Value	Pr > F
Numerator	1	220193	639.86	<.0001
Denominator	456	344.12765		

Other Statistics

MSE	344.13	Standard Error	18.55
MAE	14.31	MAPE	1.59
Durbin-Watson	1.9773	R-Square	0.9600

Draft 2019 Energy Efficiency Forecast

Energy Efficiency Forecast Working Group

Victoria Rojo

SYSTEM PLANNING

Outline

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• Forecast Inputs	15-25
• Draft 2019 Forecast – New England	26-31
• Draft 2019 Forecast – States	32-50
• Next Steps	51-54

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 draft EE forecast for the period 2020 through 2028
- The forecast estimates reductions in energy and demand from state-sponsored EE programs in the New England control area by 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
- The draft forecast excludes the results of FCA #13
  - FCA #13 results will be included in final forecast

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 Energy-Efficiency Forecast Working Group (EEFWG) provided input during two prior meetings on October 19, 2018 and December 14, 2018
- The EE forecast is updated annually
- The final EE forecast will be incorporated into the CELT report

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)

Introduction

Looking Forward

- The ISO will accept formal public comments on this draft forecast through February 22, 2019
  - Please submit comments to: eeforecast@iso-ne.com
  - Comments will be posted at: http://www.iso-ne.com/eefwg
  - Background information is available at: http://www.iso-ne.com/eefwg
- The ISO will issue the final EE forecast by May 1, 2019 as an updated slide deck
  - 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

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

2019 Draft Forecast Input Assumptions

- 2018 CELT Energy Forecast
- 2018 CELT FCM CSOs and FCA #12 clearing price used for calculating budgets
  - Final forecast will use FCA #13 clearing price
- Production Cost: PA 2015-2017 average
- Peak-to-Energy Ratio: PA 2015-2017 average
- Production Cost Escalation Rate: 2.5% inflation + 2.75% graduated rate (starting in year 1)
- No Budget Spend Rate deduction

Forecast Model

2019 Update to Graduated Production Cost Escalator

- All else unchanged, decreases in recent historical production costs result in an increased EE forecast
- Benchmarking of the 2018 EE forecast suggests the current forecast may be too high
- The ISO does not have sufficient evidence to support an increase in the outermost years of the EE forecast
  - Evolving measure mix (refer to the ISO's February 2018 presentation for background analysis on the potential impact of the phase out of claimable lighting savings)
  - Uncertainty around the level of EE funding 10 years out
  - Near-term production costs predicted in the EE forecast fall short of those expected by the MA PAs in the next three years
- A graduated production cost escalator of 2.75% was utilized to reflect the significant uncertainty in the outermost years of the forecast
  - Near term savings increase slightly
  - Level of savings in later years of the forecast are relatively consistent with the 2018 EE forecast at the regional level
- The ISO will continue to work with stakeholders to gain further insight into the expected outlook on these important topics, and incorporate them into future forecasts

Forecast Model

Assumptions Regarding the Forward Capacity Market

- FCM clearing price was held constant at $4.63/kW-month[†] , which was the clearing price for FCA #12
  - Final forecast will use FCA #13 clearing price
  - 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) = unit 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

FORECAST INPUTS

Summary of Program Administrator Data and Model Parameters

Summary of Program Performance Changes
2016 PA Data Versus 2017 PA Data

- Production Cost
  - Decreased in majority of states
  - Decreased for New England
  - Decrease in most recent rolling 3-year average
- Peak-to-Energy Ratio
  - Decreased in majority of states
  - Decreased for New England
  - Increase in most recent rolling 3-year average

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												
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	863,025	2,093,423	412	275	3,142,634	115%	101%	99%	0.131	22,253,410	39
2015	902,490	926,779	2,375,192	390	333	2,784,155	123%	103%	129%	0.140	26,658,969	35
2016	984,622	912,277	2,465,462	370	355	2,572,930	117%	93%	128%	0.144	23,614,098	39
2017	1,042,235	894,105	2,532,331	353	347	2,573,479	119%	86%	125%	0.137	25,233,171	35
Avg 2014-2016	915,032	900,694	2,311,359	391	321	2,833,240	118%	99%	119%	0.138	24,175,492	37
Avg 2015-2017	976,449	911,054	2,457,662	371	345	2,643,521	119%	94%	127%	0.140	25,168,746	36
Massachusetts												
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%	93%	0.144	11,999,747	37
2014	511,262	518,438	1,246,950	416	166	3,119,041	110%	101%	103%	0.133	13,397,730	39
2015	523,663	545,060	1,396,513	390	195	2,788,155	116%	104%	129%	0.140	16,295,573	33
2016	588,032	537,413	1,475,270	364	224	2,397,873	110%	91%	128%	0.152	12,652,697	42
2017	584,643	541,581	1,487,372	364	200	2,701,962	108%	93%	111%	0.135	14,419,722	38
Avg 2014-2016	540,985	533,637	1,372,911	390	195	2,768,356	112%	99%	120%	0.142	14,115,333	38
Avg 2015-2017	565,446	541,351	1,453,052	373	207	2,629,330	111%	96%	123%	0.142	14,455,998	38
Connecticut*												
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
2017	191,244	158,917	457,866	347	64	2,469,681	120%	83%	127%	0.141	4,780,069	33
Avg 2014-2016	185,392	184,999	405,055	457	58	3,240,168	106%	100%	110%	0.142	4,442,569	42
Avg 2015-2017	190,810	179,152	431,986	417	62	2,894,371	111%	94%	117%	0.144	4,680,163	38
Rhode Island												
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
2017	141,104	83,715	232,023	361	32	2,602,619	115%	59%	127%	0.139	2,327,916	36
Avg 2014-2016	82,853	77,601	207,330	375	26	2,984,393	110%	94%	92%	0.126	1,976,833	39
Avg 2015-2017	105,299	80,660	220,134	367	29	2,798,123	113%	80%	115%	0.131	2,158,924	37

* CT 2017 budgets were not restated to reflect the impact of budget cuts, caused by the diversion of funds by the State of CT.

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												
2012	0	23,712	143,532	165	12	1,904,497	101%	0%	114%	0.087	1,266,751	19
2013	0	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
2017	48,614	31,435	92,185	341	20	1,590,962	0%	65%	0%	0.214	1,119,512	28
Avg 2014-2016	36,085	33,358	140,461	232	19	1,770,201	0%	91%	0%	0.132	1,343,873	24
Avg 2015-2017	43,297	36,512	132,574	283	21	1,759,940	0%	85%	0%	0.164	1,378,992	27
Vermont												
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	140,592	330	15	3,002,514	123%	103%	104%	0.110	1,484,990	31
2017	49,926	51,542	181,361	284	19	2,724,177	158%	103%	128%	0.104	1,565,673	33
Avg 2014-2016	44,839	46,246	116,754	405	13	3,546,582	112%	103%	89%	0.114	1,361,180	34
Avg 2015-2017	46,584	48,162	145,022	342	16	3,080,913	127%	103%	107%	0.110	1,502,609	32
New Hampshire												
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
2017	26,704	26,915	81,525	330	12	2,281,136	132%	101%	158%	0.145	1,020,279	26
Avg 2014-2016	24,878	24,853	68,848	363	10	2,528,932	131%	100%	99%	0.144	935,705	27
Avg 2015-2017	25,013	25,216	74,895	337	11	2,415,253	133%	101%	127%	0.141	992,062	25

FCM and RGGI Funds

RGGI Dollars ($1000's) Applied to EE Annually							
	New England	MA	CT	ME	RI	VT	NH
	32,589	20,254	9,769	-	-	-	2,566
FCM MW							
	New England	MA	CT	ME	RI	VT	NH
2022	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
2022	149,549	89,439	37,862	-	15,544	-	6,704
FCM Dollars for EE ($1000's)							
	New England	MA	CT	ME	RI	VT	NH
2020	162,353	98,301	39,448	-	16,964	-	7,641
2021	149,549	89,439	37,862	-	15,544	-	6,704
2022	138,860	83,046	35,155	-	14,433	-	6,225
2023	138,860	83,046	35,155	-	14,433	-	6,225
2024	138,860	83,046	35,155	-	14,433	-	6,225
2025	138,860	83,046	35,155	-	14,433	-	6,225
2026	138,860	83,046	35,155	-	14,433	-	6,225
2027	138,860	83,046	35,155	-	14,433	-	6,225
2028	138,860	83,046	35,155	-	14,433	-	6,225

* Auction clearing price for Rest-of-Pool

Energy Forecast

2018 CELT Energy Forecast (GWh)							
	New England	MA	CT	ME	RI	VT	NH
2020	144,633	67,891	34,489	13,042	9,422	7,040	12,749
2021	146,010	68,675	34,707	13,195	9,488	7,090	12,855
2022	147,537	69,527	34,956	13,380	9,563	7,140	12,971
2023	149,099	70,401	35,209	13,576	9,636	7,188	13,089
2024	150,485	71,196	35,419	13,749	9,702	7,230	13,189
2025	151,766	71,935	35,604	13,909	9,771	7,270	13,277
2026	153,071	72,685	35,794	14,067	9,846	7,311	13,368
2027	154,365	73,422	35,981	14,222	9,926	7,353	13,461
2028	155,659	74,159	36,168	14,377	10,006	7,395	13,554

2018 CELT Energy Forecast - FCM Passive Demand Resources (GWh)							
	New England	MA	CT	ME	RI	VT	NH
2020	123,301	55,886	30,518	11,513	7,479	6,000	11,905
2021	122,184	55,153	30,349	11,525	7,302	5,939	11,916
2022	123,711	56,005	30,598	11,710	7,377	5,989	12,032
2023	125,273	56,879	30,851	11,906	7,450	6,037	12,150
2024	126,659	57,674	31,061	12,079	7,516	6,079	12,250
2025	127,940	58,413	31,246	12,239	7,585	6,119	12,338
2026	129,245	59,163	31,436	12,397	7,660	6,160	12,429
2027	130,539	59,900	31,623	12,552	7,740	6,202	12,522
2028	131,833	60,637	31,810	12,707	7,820	6,244	12,615

Energy Forecast

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

SBC Eligible 2018 Energy Forecast - FCM Passive Demand Resources (GWh)							
	New England	MA	CT	ME	RI	VT	NH
2020	113,654	48,006	28,901	11,363	7,479	6,000	11,905
2021	112,649	47,376	28,741	11,375	7,302	5,939	11,916
2022	114,040	48,108	28,976	11,558	7,377	5,989	12,032
2023	115,463	48,859	29,216	11,751	7,450	6,037	12,150
2024	116,724	49,542	29,415	11,922	7,516	6,079	12,250
2025	117,889	50,177	29,590	12,080	7,585	6,119	12,338
2026	119,076	50,821	29,770	12,236	7,660	6,160	12,429
2027	120,254	51,454	29,947	12,389	7,740	6,202	12,522
2028	121,432	52,087	30,124	12,542	7,820	6,244	12,615

Energy Sales and System Benefit Charge

Sales (GWh)							
	New England	MA	CT	ME	RI	VT	NH
2020	107,221	45,289	27,265	10,720	7,056	5,660	11,231
2021	106,273	44,695	27,114	10,731	6,889	5,603	11,242
2022	107,585	45,385	27,336	10,904	6,959	5,650	11,351
2023	108,928	46,093	27,562	11,086	7,028	5,695	11,462
2024	110,117	46,738	27,750	11,247	7,091	5,735	11,557
2025	111,216	47,337	27,915	11,396	7,156	5,773	11,640
2026	112,336	47,944	28,085	11,543	7,226	5,811	11,725
2027	113,447	48,542	28,252	11,688	7,302	5,851	11,813
2028	114,559	49,139	28,419	11,832	7,377	5,891	11,901
SBC Rate ($/kWh)							
		MA	CT	ME	RI	VT	NH
		0.00250		-	0.01000	-	0.00373
SBC Dollars ($1000’s)							
	New England	MA	CT*	ME	RI	VT	NH
2020	239,294	113,222	-	-	84,180	-	41,892
2021	239,069	111,737	-	-	85,401	-	41,931
2022	244,681	113,463	-	-	88,879	-	42,339
2023	248,993	115,234	-	-	91,005	-	42,754
2024	252,794	116,844	-	-	92,843	-	43,106
2025	256,256	118,341	-	-	94,499	-	43,416
2026	259,615	119,861	-	-	96,019	-	43,736
2027	262,833	121,354	-	-	97,416	-	44,063
2028	265,907	122,847	-	-	98,669	-	44,391

* CT SBC funding is discontinued beginning in 2020

Impacts of New EE on Revenue Streams

Lost SBC Dollars ($1000’s)							
	New England	MA	CT	ME	RI	VT	NH
2023	10,865	6,354	-	-	3,745	-	765
2024	15,113	8,832	-	-	5,215	-	1,066
2025	18,616	10,872	-	-	6,430	-	1,315
2026	21,441	12,514	-	-	7,412	-	1,515
2027	23,670	13,807	-	-	8,190	-	1,674
2028	25,392	14,803	-	-	8,792	-	1,797
New FCM Dollars ($1000’s)							
	New England	MA	CT	ME	RI	VT	NH
2023	27,438	18,652	4,760	-	2,536	-	1,490
2024	38,143	25,926	6,609	-	3,531	-	2,076
2025	46,956	31,914	8,128	-	4,354	-	2,560
2026	54,052	36,733	9,349	-	5,019	-	2,951
2027	59,642	40,529	10,308	-	5,546	-	3,260
2028	63,953	43,454	11,045	-	5,954	-	3,500

Policy Dollars and Total Budgets

Policy Dollars ($1000's)*							
	New England	MA	CT	ME	RI	VT	NH
2020	741,797	487,372	154,186	46,010	-	54,229	-
2021	740,532	486,361	152,943	46,071	-	55,156	-
2022	739,427	484,424	152,943	46,212	-	55,847	-
2023	732,713	476,959	152,943	46,212	-	56,598	-
2024	727,177	470,552	152,943	46,212	-	57,470	-
2025	724,109	465,107	152,943	46,212	-	59,847	-
2026	720,204	460,410	152,943	46,212	-	60,639	-
2027	716,454	456,414	152,943	46,212	-	60,885	-
2028	715,484	452,992	152,943	46,212	-	63,336	-
Total Budget Dollars ($1000's)							
	New England	MA	CT	ME	RI	VT	NH
2020	1,176,033	719,149	203,403	46,010	101,143	54,229	52,099
2021	1,161,738	707,791	200,574	46,071	100,945	55,156	51,201
2022	1,164,459	707,791	200,426	46,212	102,664	55,847	51,518
2023	1,169,728	707,791	202,627	46,212	104,229	56,598	52,270
2024	1,174,449	707,791	204,477	46,212	105,593	57,470	52,907
2025	1,180,153	707,791	205,996	46,212	106,856	59,847	53,452
2026	1,183,879	707,791	207,216	46,212	108,059	60,639	53,963
2027	1,186,708	707,791	208,175	46,212	109,205	60,885	54,440
2028	1,191,399	707,791	208,913	46,212	110,264	63,336	54,884

* 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
2018	1.0250	1.0250	1.0250	1.0250	1.0250	1.0250
2019	1.0525	1.0525	1.0525	1.0525	1.0525	1.0525
2020	1.0800	1.0800	1.0800	1.0800	1.0800	1.0800
2021	1.1075	1.1075	1.1075	1.1075	1.1075	1.1075
2022	1.1350	1.1350	1.1350	1.1350	1.1350	1.1350
2023	1.1625	1.1625	1.1625	1.1625	1.1625	1.1625
2024	1.1900	1.1900	1.1900	1.1900	1.1900	1.1900
2025	1.2175	1.2175	1.2175	1.2175	1.2175	1.2175
2026	1.2450	1.2450	1.2450	1.2450	1.2450	1.2450
2027	1.2725	1.2725	1.2725	1.2725	1.2725	1.2725
2028	1.3000	1.3000	1.3000	1.3000	1.3000	1.3000
Production Cost ($/MWh)						
	MA	CT	ME	RI	VT	NH
2018	382	427	290	376	350	345
2019	402	449	305	395	369	363
2020	434	485	330	427	398	392
2021	481	538	365	473	441	435
2022	546	610	414	537	501	493
2023	635	709	482	624	582	573
2024	756	844	573	743	693	682
2025	920	1,028	698	904	843	831
2026	1,145	1,279	869	1,126	1,050	1,034
2027	1,457	1,628	1,106	1,432	1,336	1,316
2028	1,894	2,117	1,437	1,862	1,737	1,711
Peak-to-Energy Ratio (MW/GWh)						
	MA	CT	ME	RI	VT	NH
	0.142	0.144	0.164	0.131	0.110	0.141

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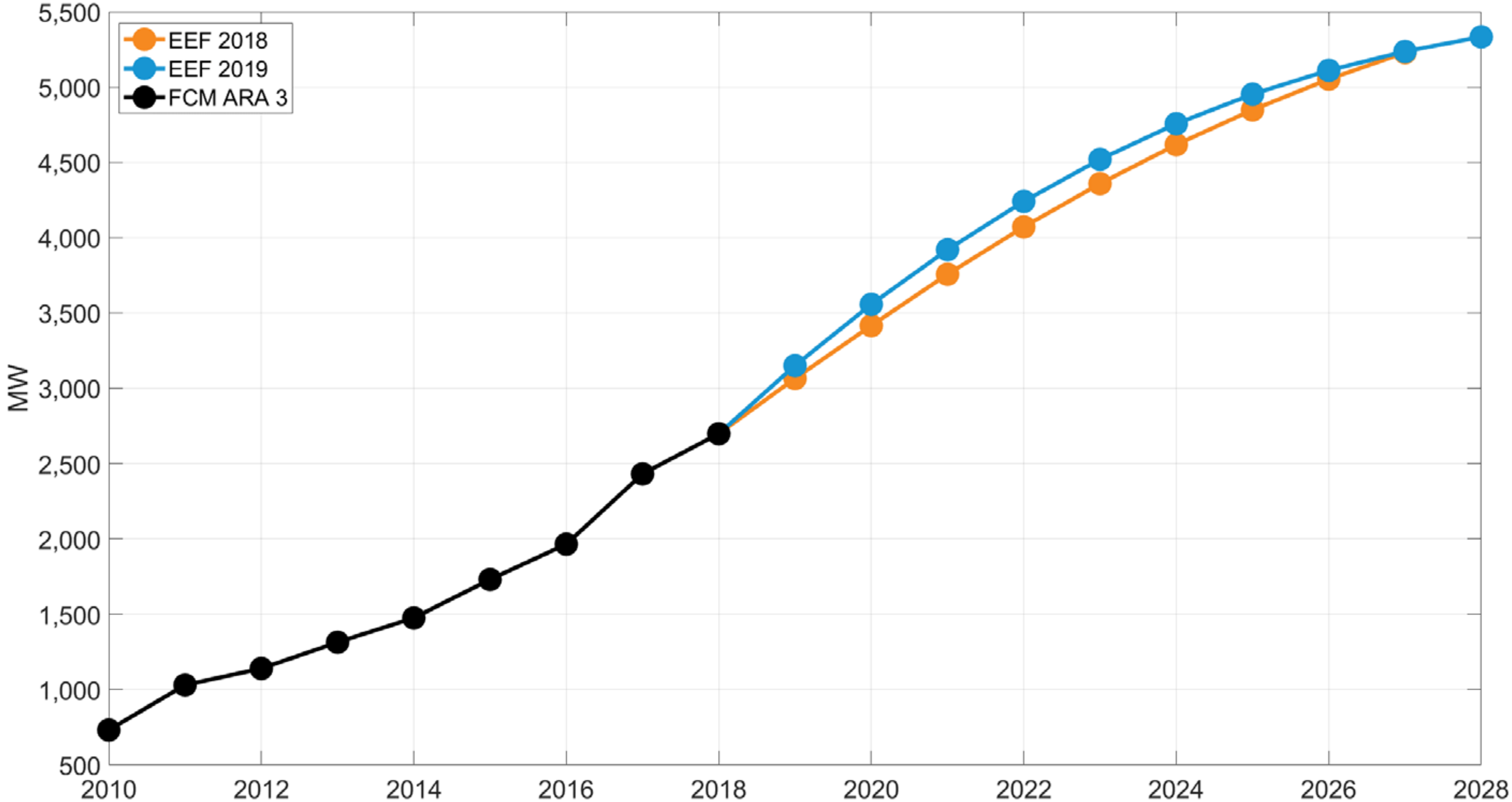
New England

New England

Energy Efficiency on Summer Peak

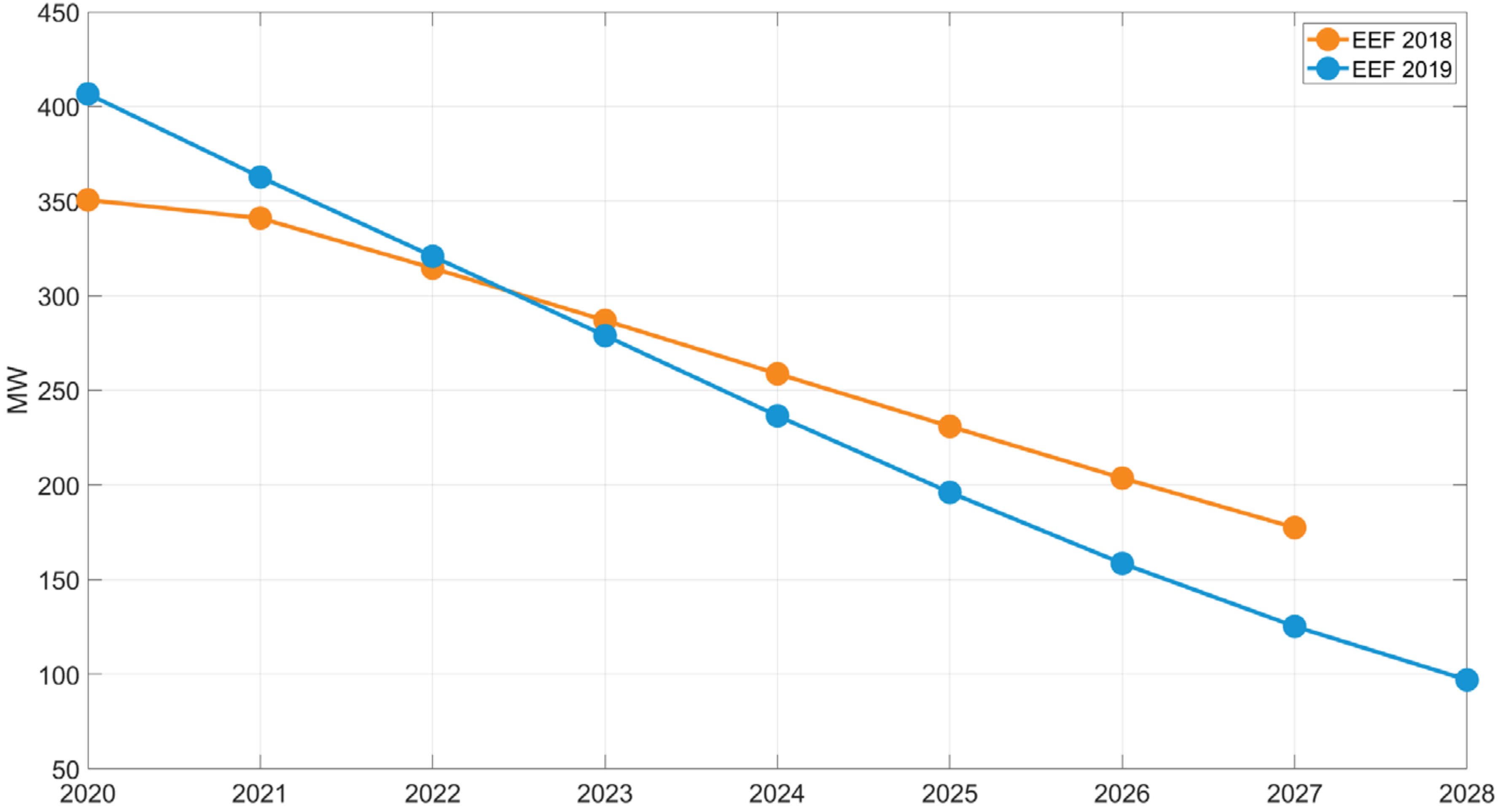


Energy and Summer Peak EE Forecast

Energy Savings (GWh)							
	New England	MA	CT	ME	RI	VT	NH
2020	2,883	1,755	444	148	251	144	141
2021	2,572	1,559	395	134	226	133	125
2022	2,276	1,378	348	118	203	118	111
2023	1,979	1,197	303	102	177	103	97
2024	1,678	1,015	257	85	151	88	82
2025	1,391	840	212	70	125	75	68
2026	1,125	679	172	56	102	61	55
2027	889	537	136	44	81	48	44
2028	689	415	105	34	63	39	34
Total 2020-2028	15,483	9,375	2,372	792	1,378	809	757
Average	1,720	1,042	264	88	153	90	84
Demand Savings (MW)							
	New England	MA	CT	ME	RI	VT	NH
2020	407	250	64	24	33	16	20
2021	363	222	57	22	30	15	18
2022	321	196	50	19	27	13	16
2023	279	170	44	17	23	11	14
2024	237	144	37	14	20	10	12
2025	196	119	31	12	16	8	10
2026	159	97	25	9	13	7	8
2027	125	76	20	7	11	5	6
2028	97	59	15	6	8	4	5
Total 2020-2028	2,182	1,333	342	130	181	89	107
Average	242	148	38	14	20	10	12

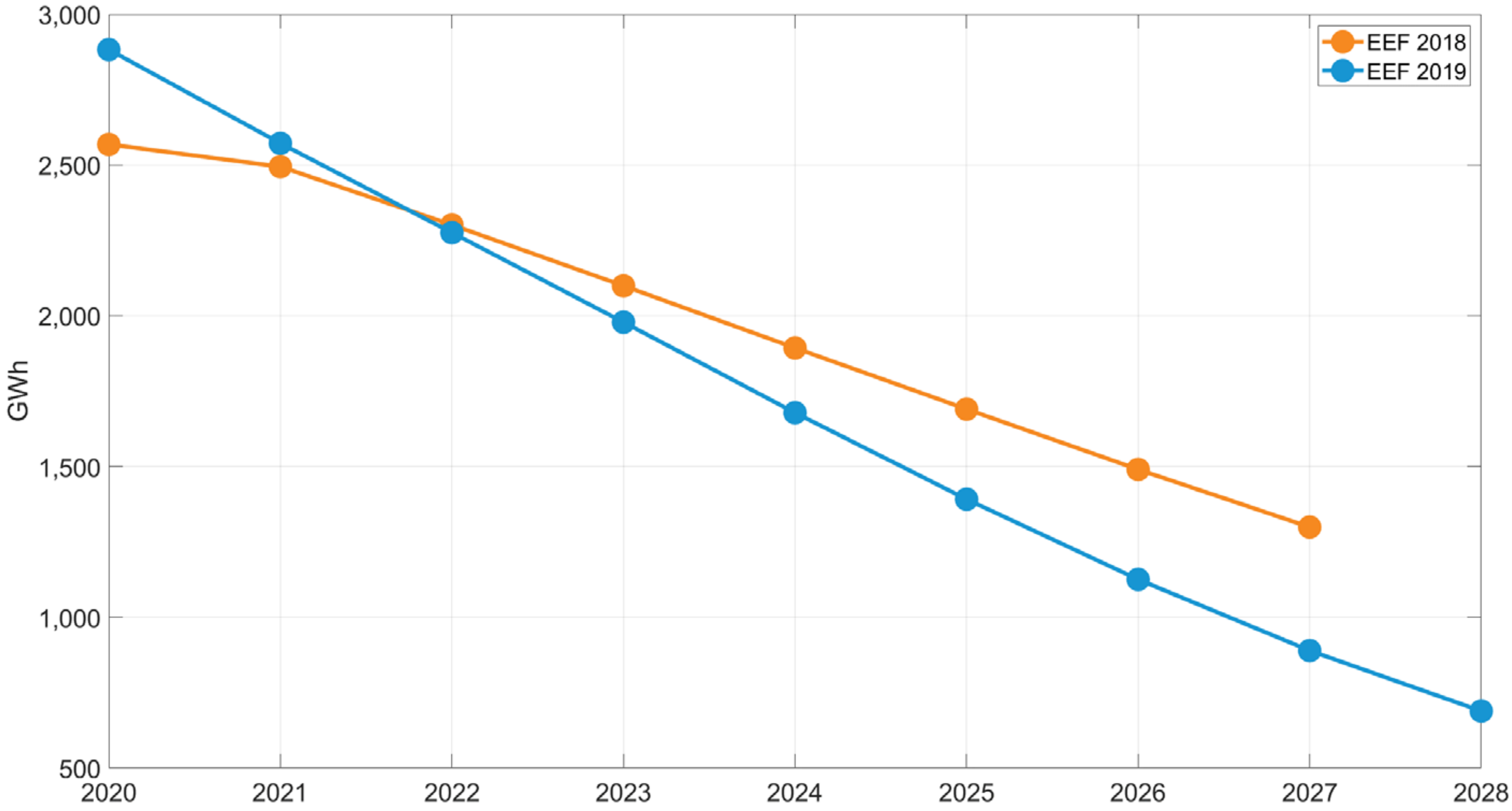
New England

Energy Efficiency on Summer Peak



New England

Energy Efficiency on Annual Energy



EE Forecast Comparison

PA Average Production Cost ($/MWh)							
		MA	CT	ME	RI	VT	NH
2018 EE Forecast		392	457	232	375	411	363
2019 EE Forecast		373	417	283	367	342	337
PA Average Peak-to-Energy Ratio (MW/GWh)							
		MA	CT	ME	RI	VT	NH
2018 EE Forecast		0.139	0.142	0.132	0.126	0.114	0.144
2019 EE Forecast		0.142	0.144	0.164	0.131	0.110	0.141
Total EE Dollars (1000s)							
	New England	MA	CT	ME	RI	VT	NH
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
2019 EE Forecast							
Total 2020-2028	10,588,546	6,381,474	1,841,808	415,565	948,958	524,007	476,734
Average	1,176,505	709,053	204,645	46,174	105,440	58,223	52,970
Summer Peak Impacts (MW)							
	New England	MA	CT	ME	RI	VT	NH
2018 EE Forecast							
Total 2019-2027	2,531	1,577	382	139	229	98	105
Average	281	175	42	15	25	11	12
2019 EE Forecast							
Total 2020-2028	2,182	1,333	342	130	181	89	107
Average	242	148	38	14	20	10	12

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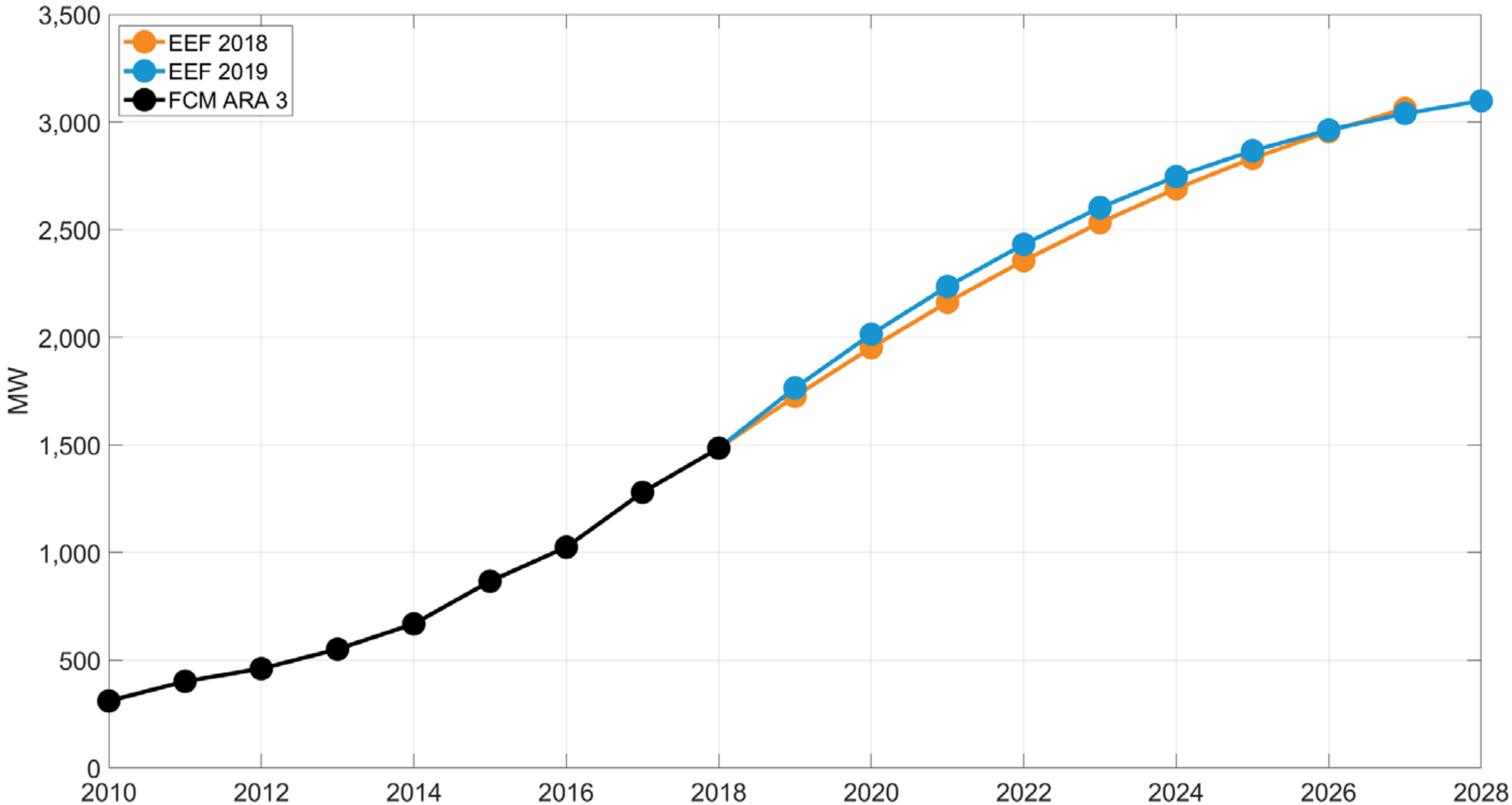
States

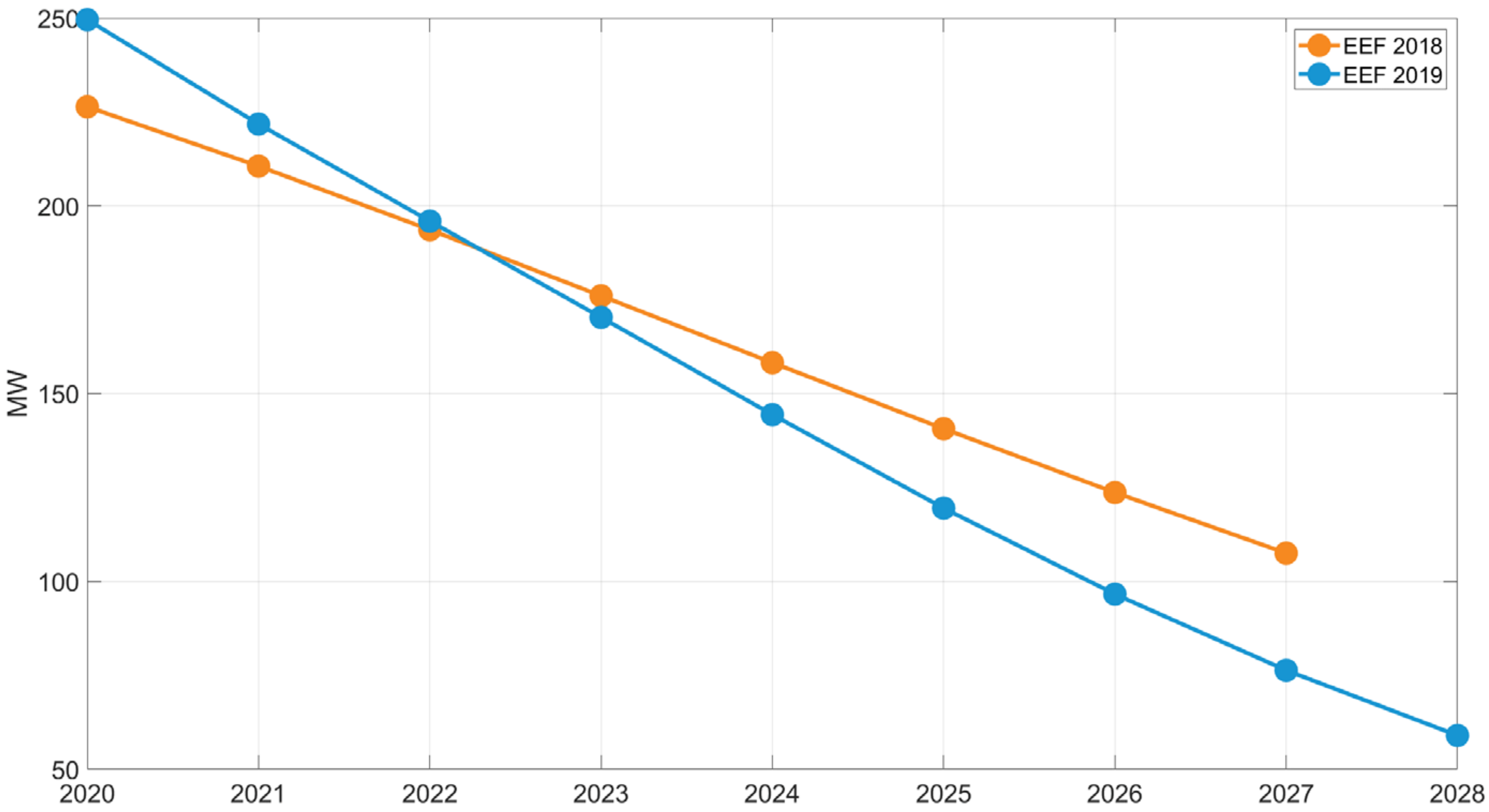
Massachusetts

Energy Efficiency on Summer Peak



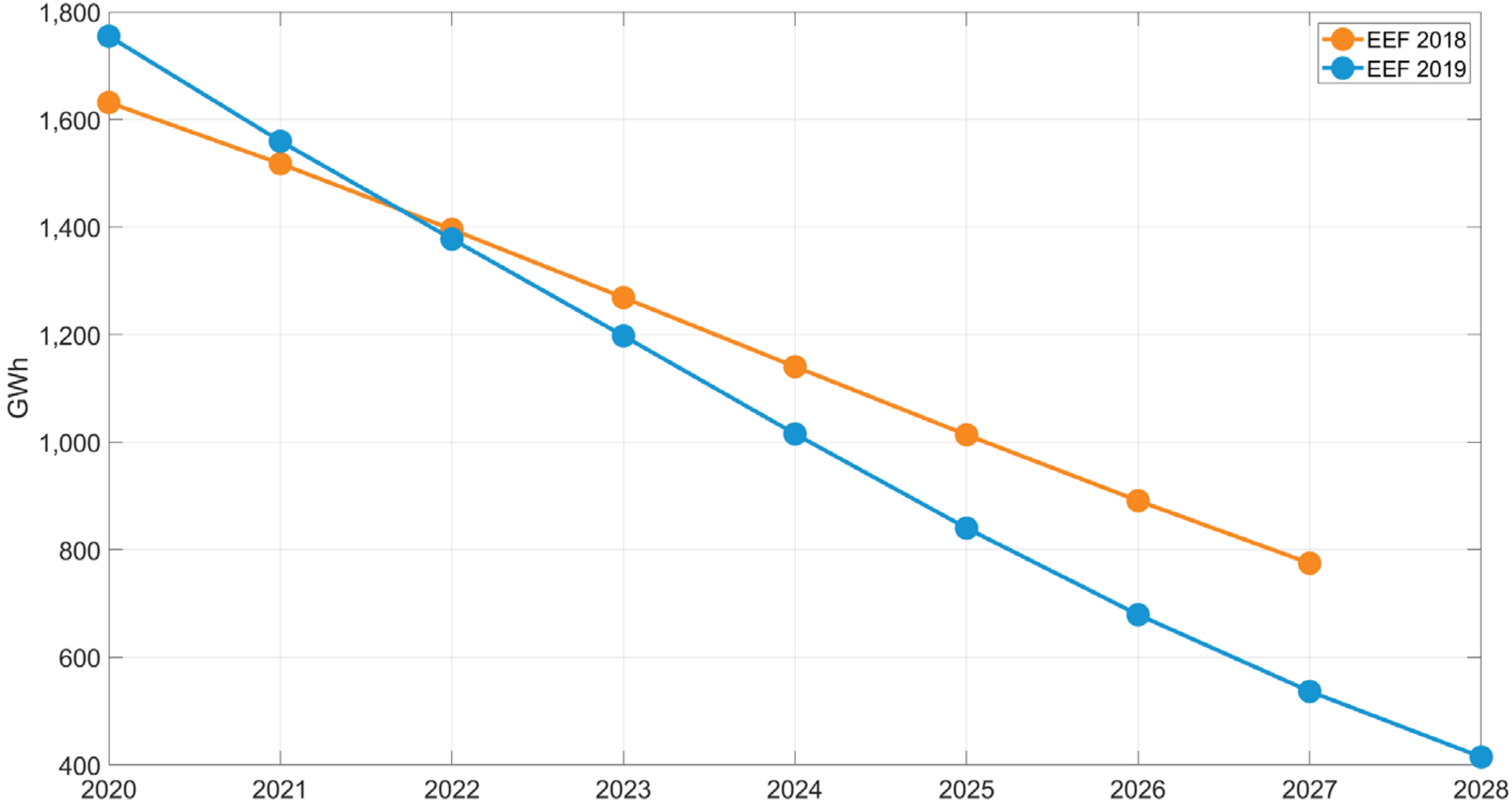
Massachusetts

Energy Efficiency on Summer Peak



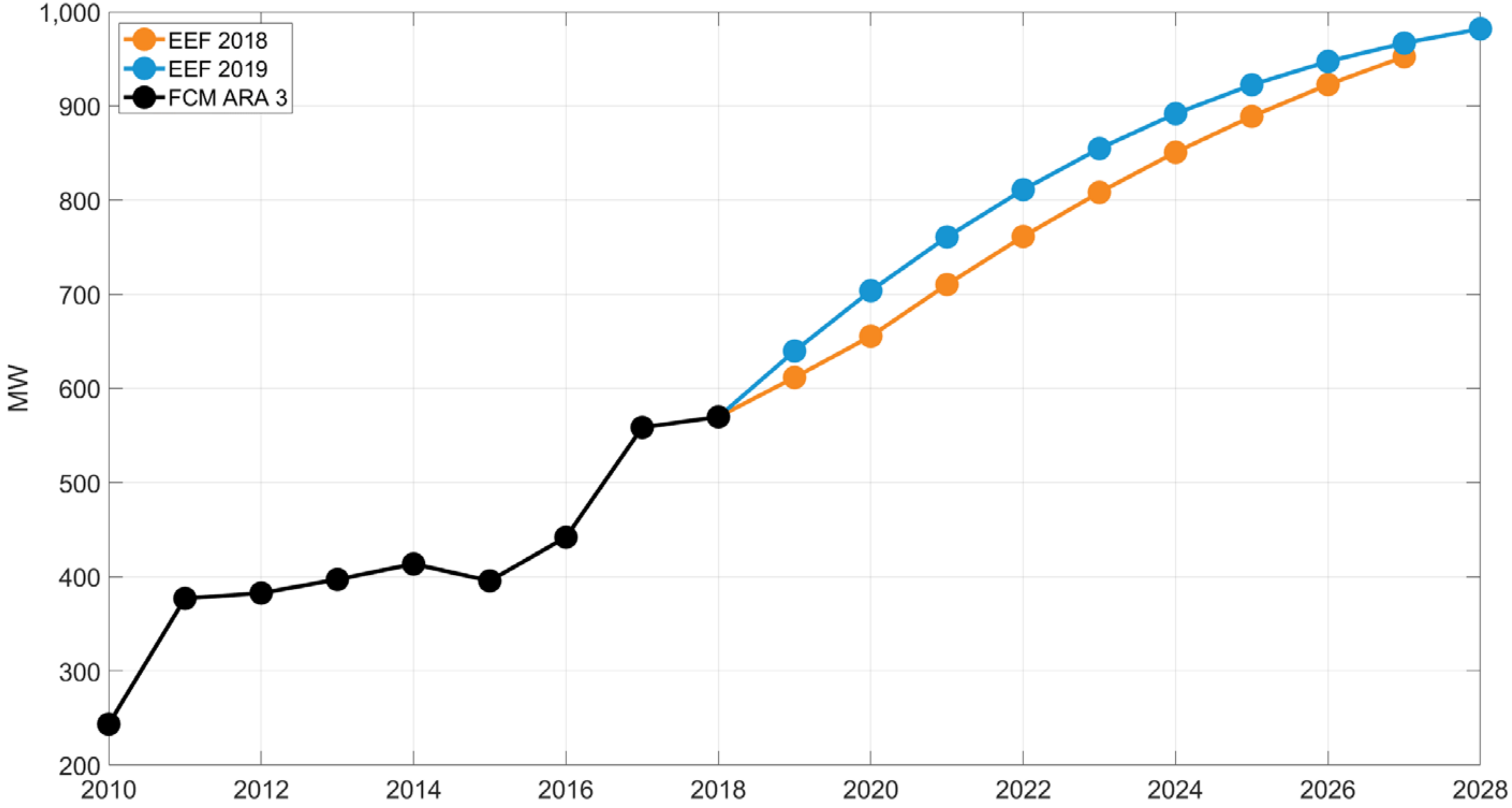
Massachusetts

Energy Efficiency on Annual Energy



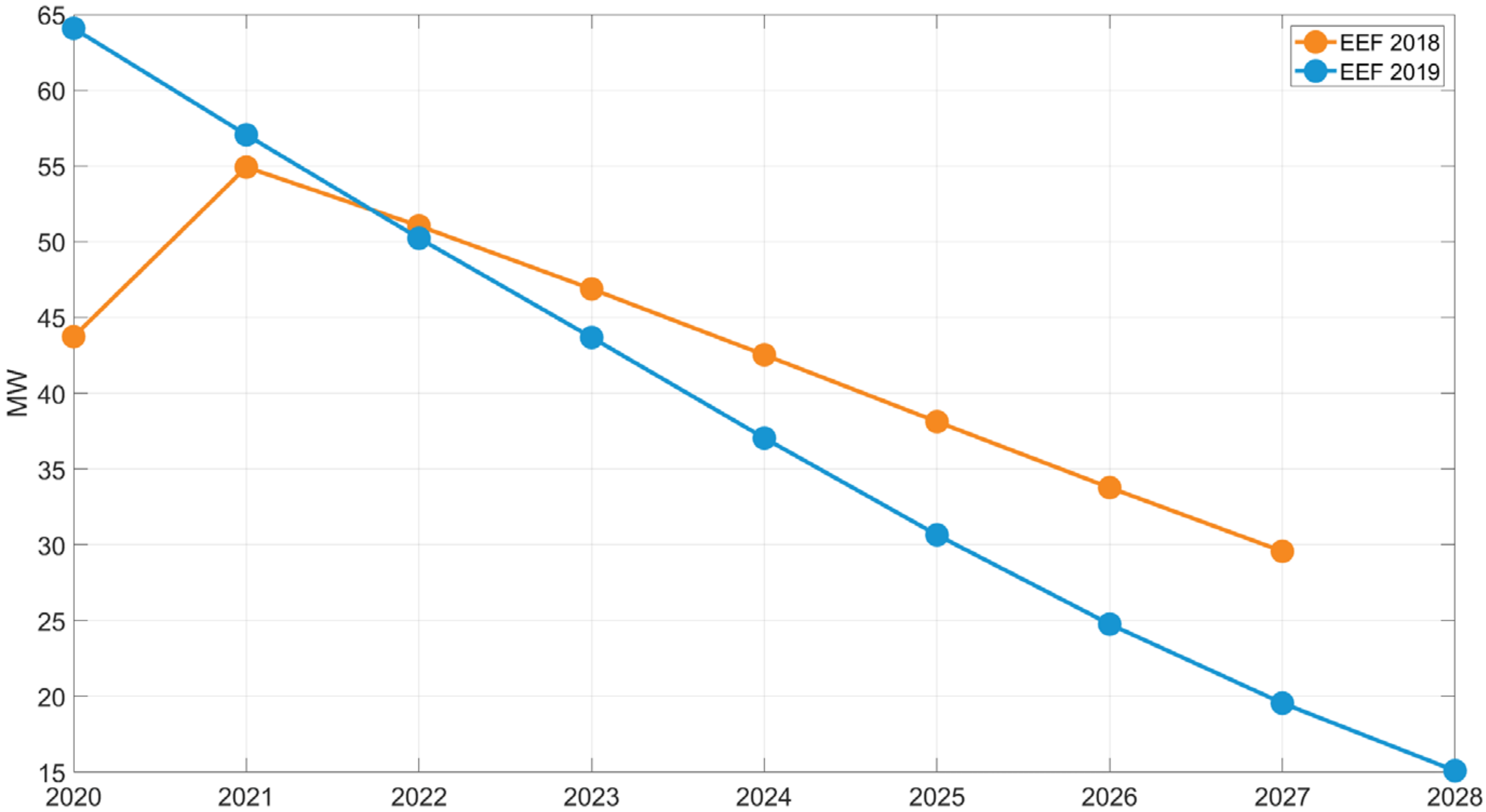
Connecticut

Energy Efficiency on Summer Peak



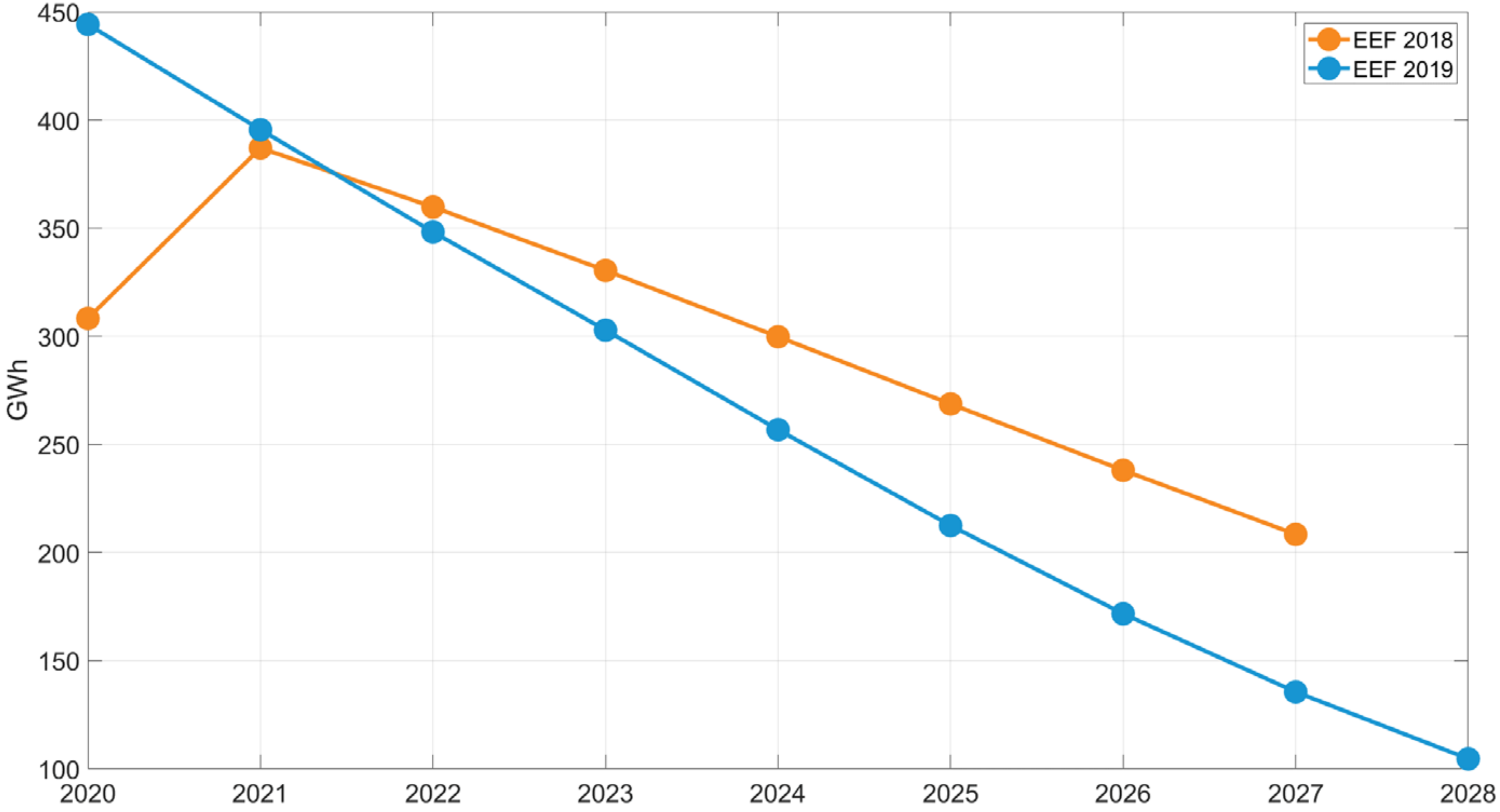
Connecticut

Energy Efficiency on Summer Peak



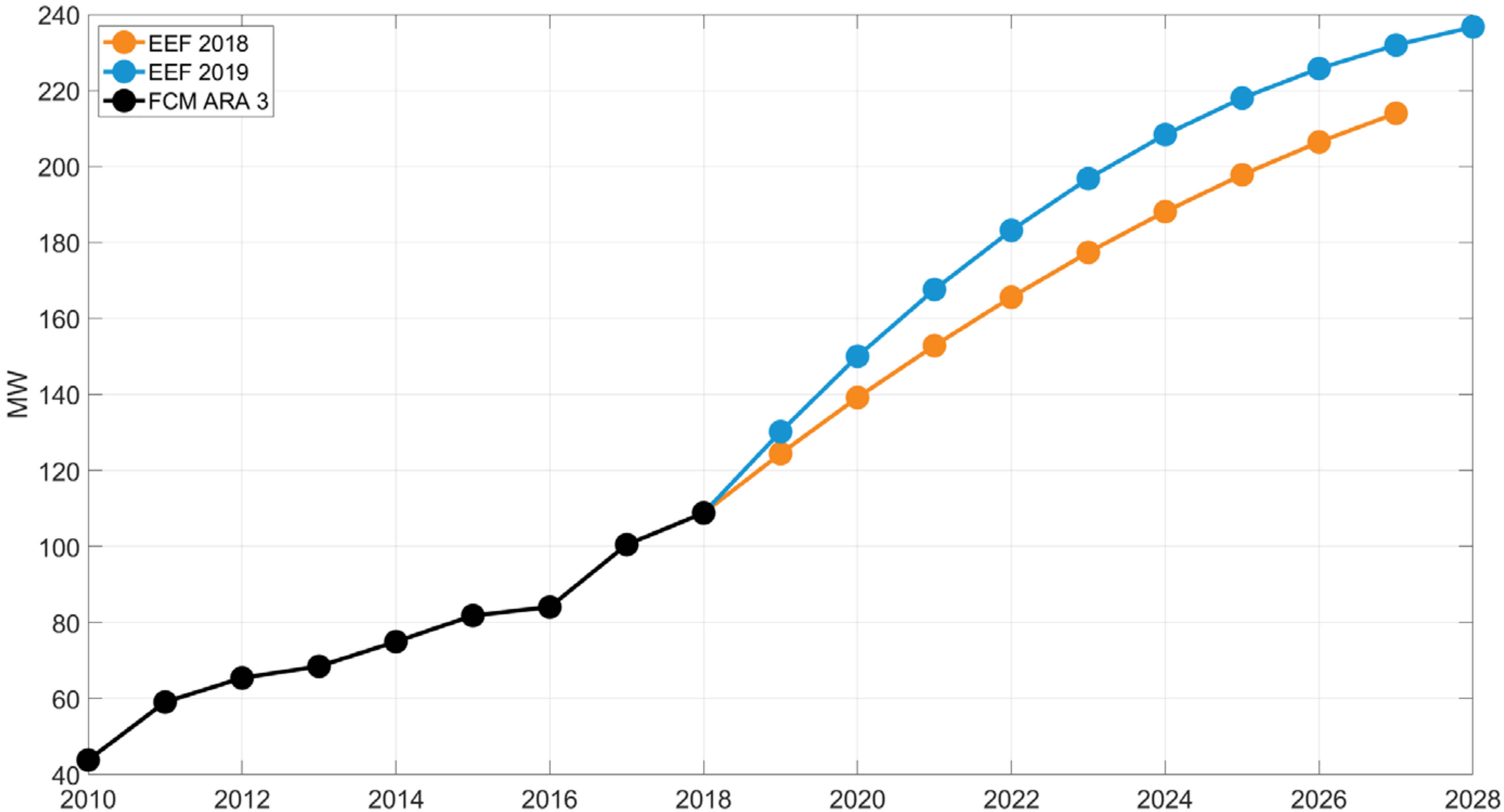
Connecticut

Energy Efficiency on Annual Energy



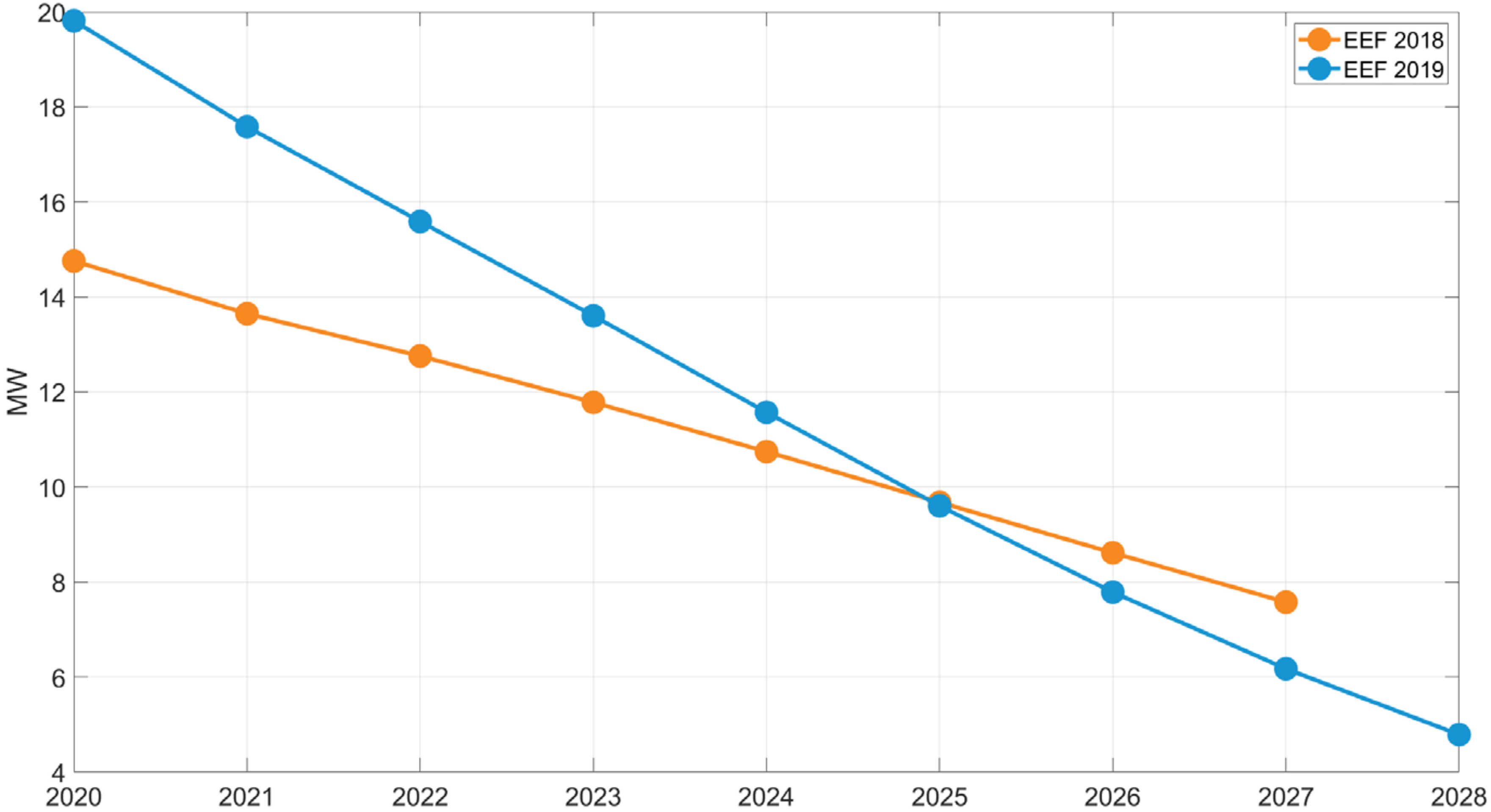
New Hampshire

Energy Efficiency on Summer Peak



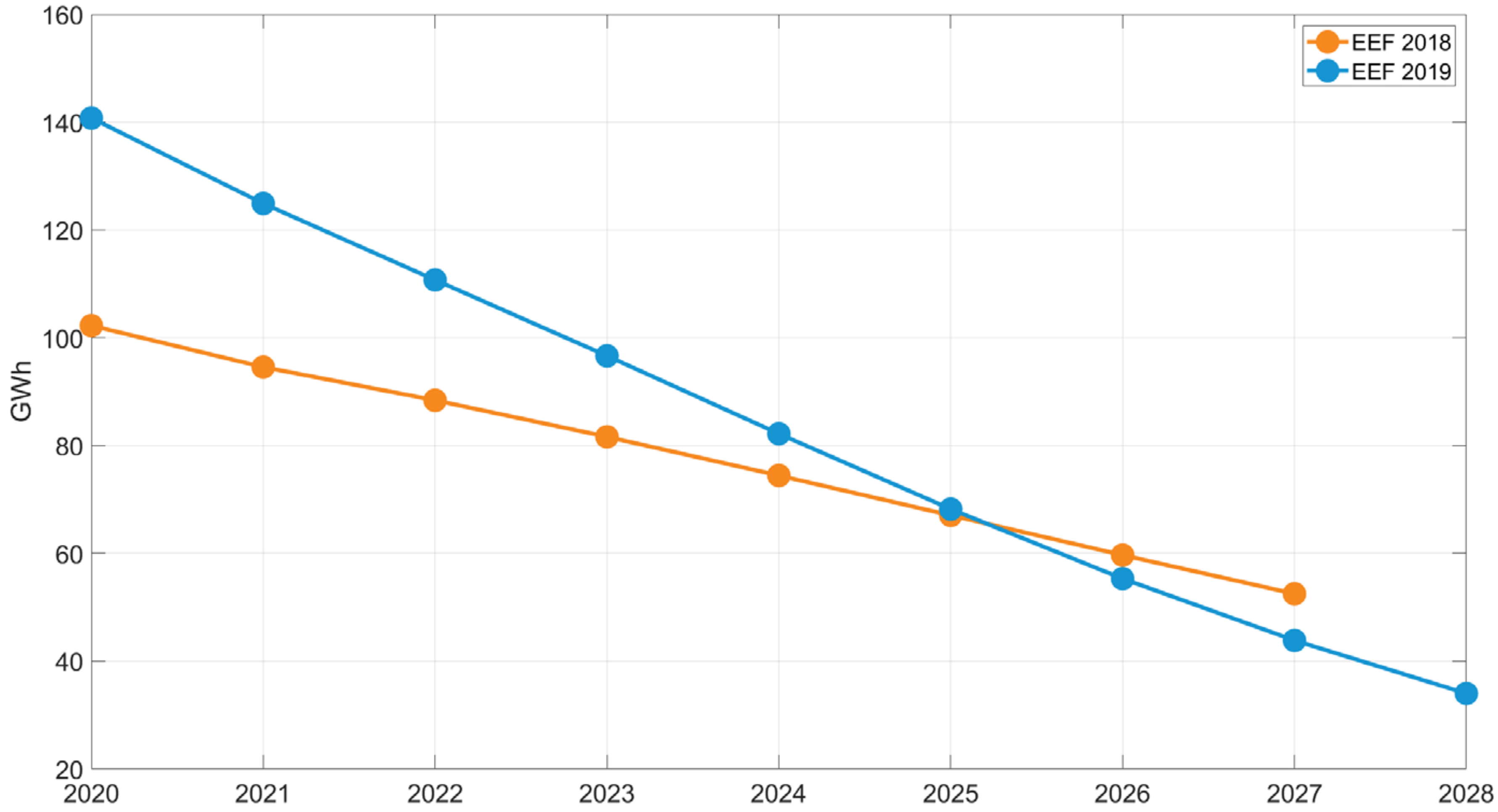
New Hampshire

Energy Efficiency on Summer Peak



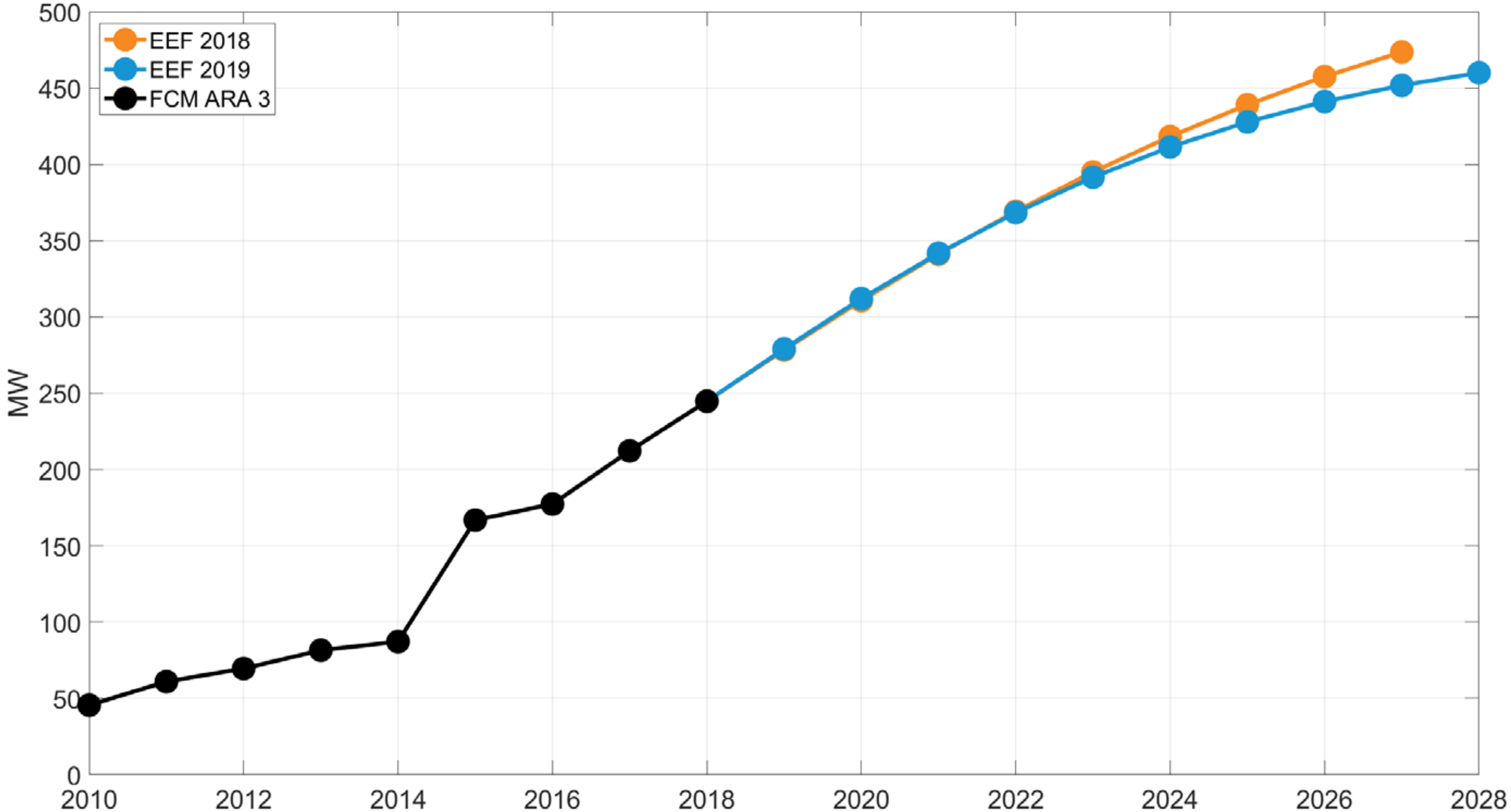
New Hampshire

Energy Efficiency on Annual Energy



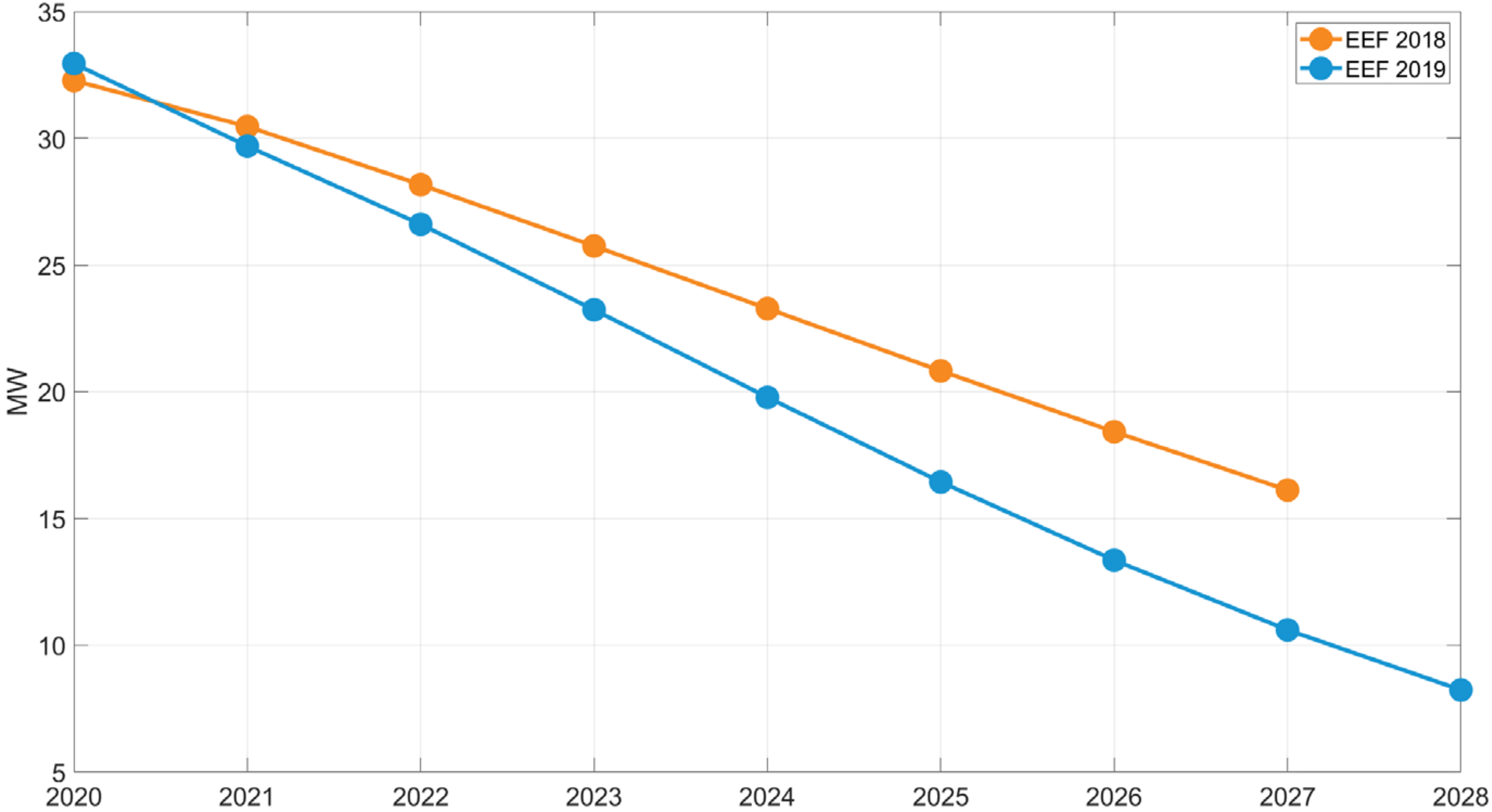
Rhode Island

Energy Efficiency on Summer Peak



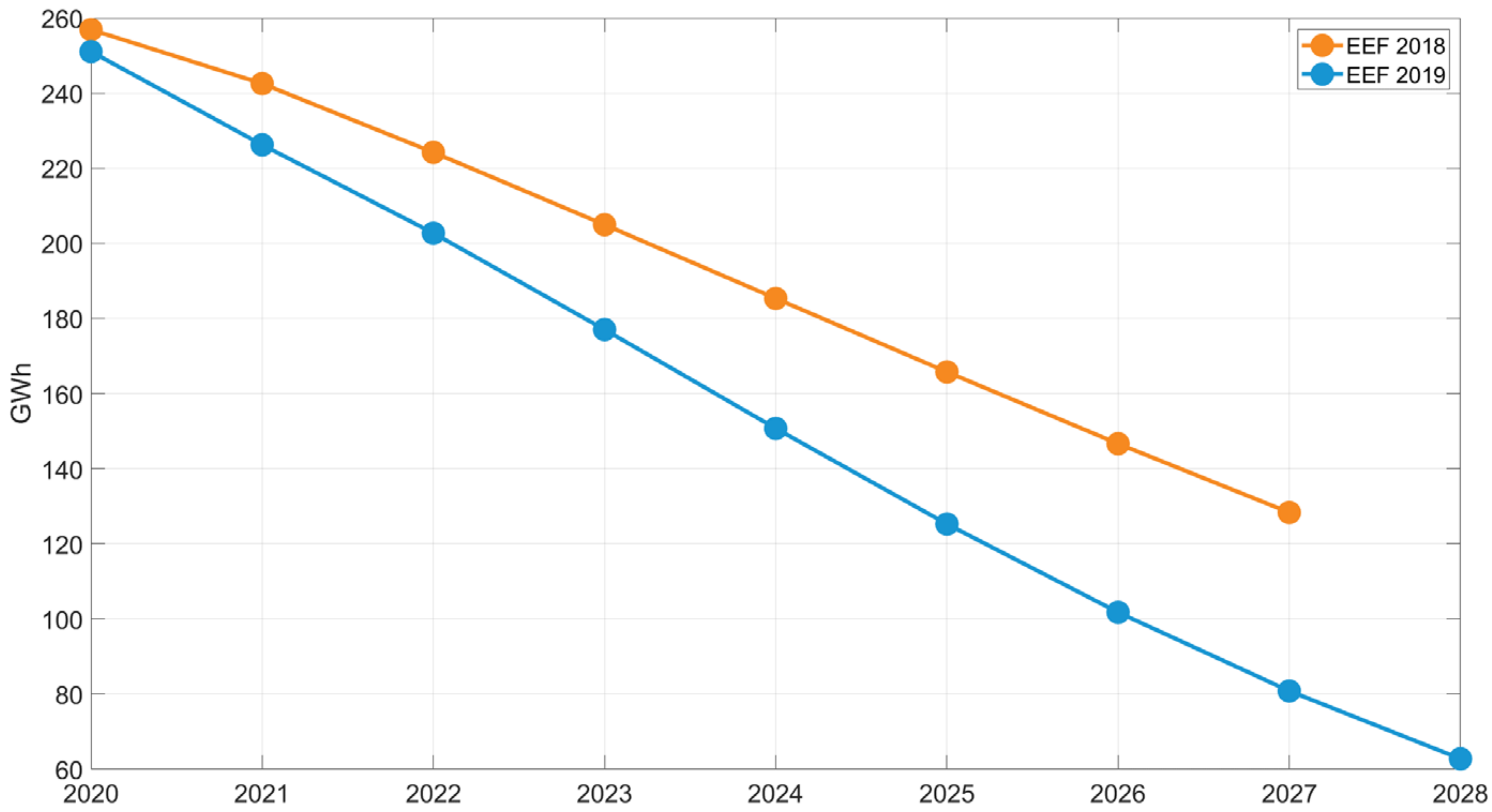
Rhode Island

Energy Efficiency on Summer Peak



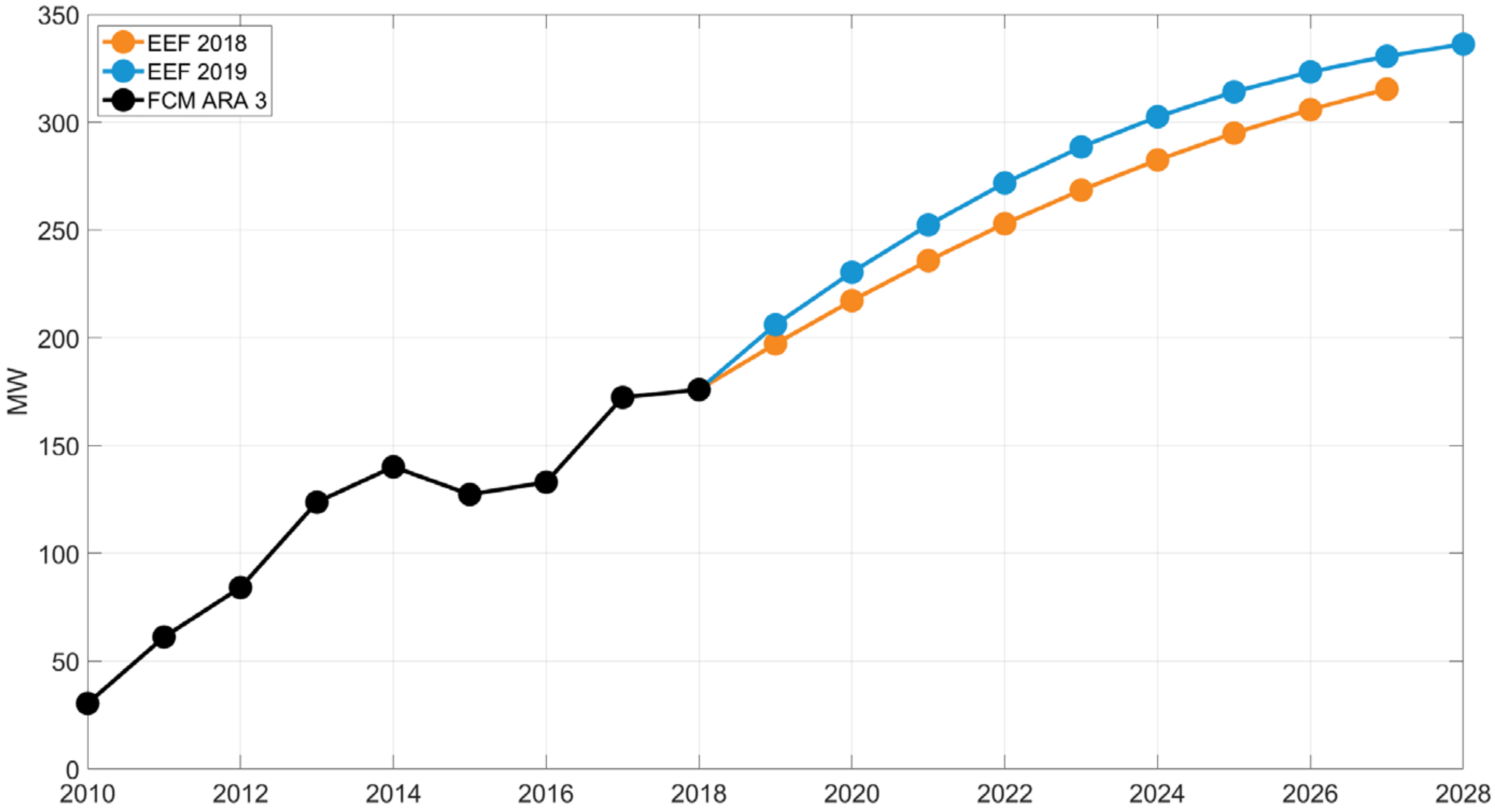
Rhode Island

Energy Efficiency on Annual Energy



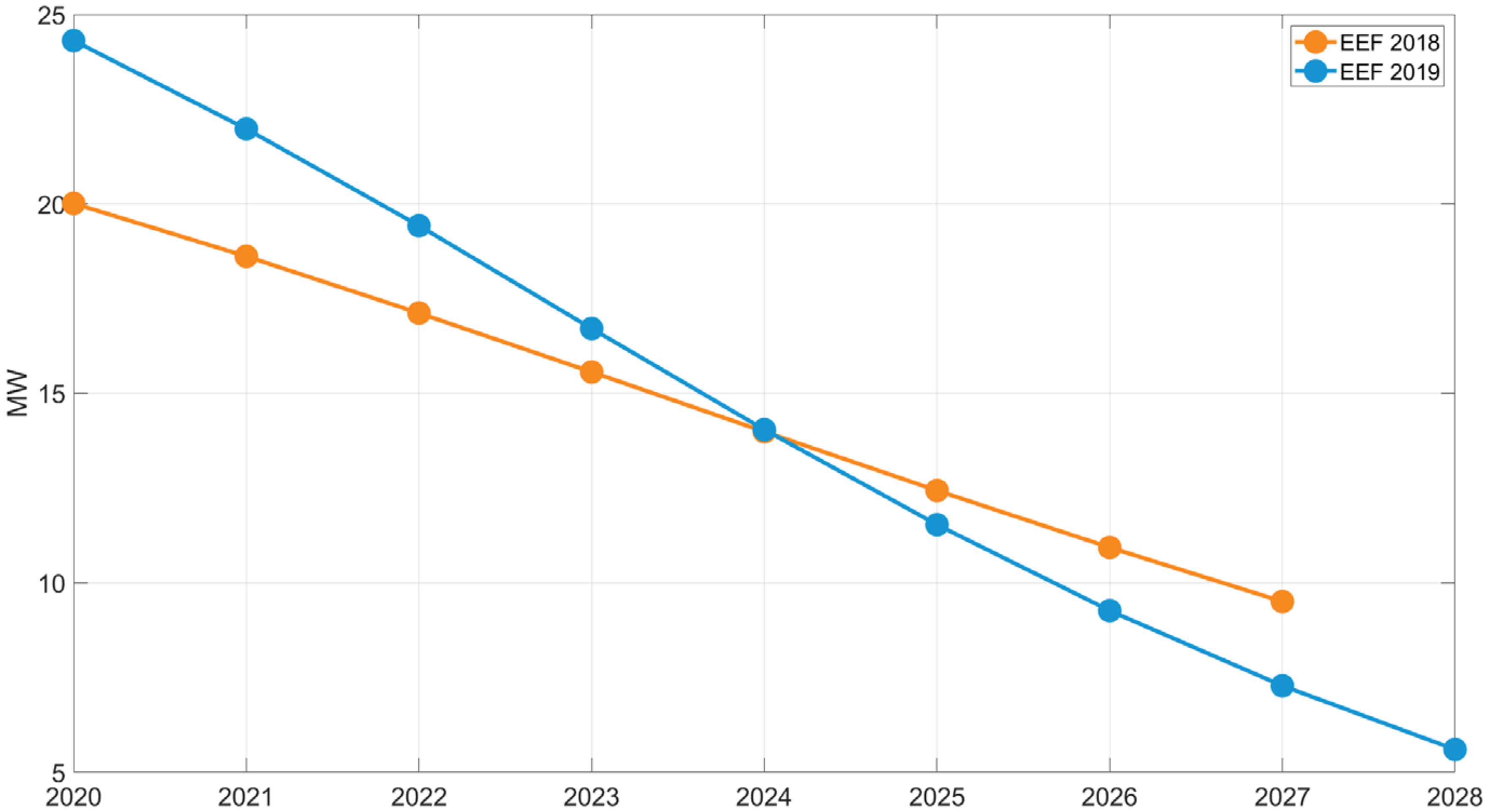
Maine

Energy Efficiency on Summer Peak



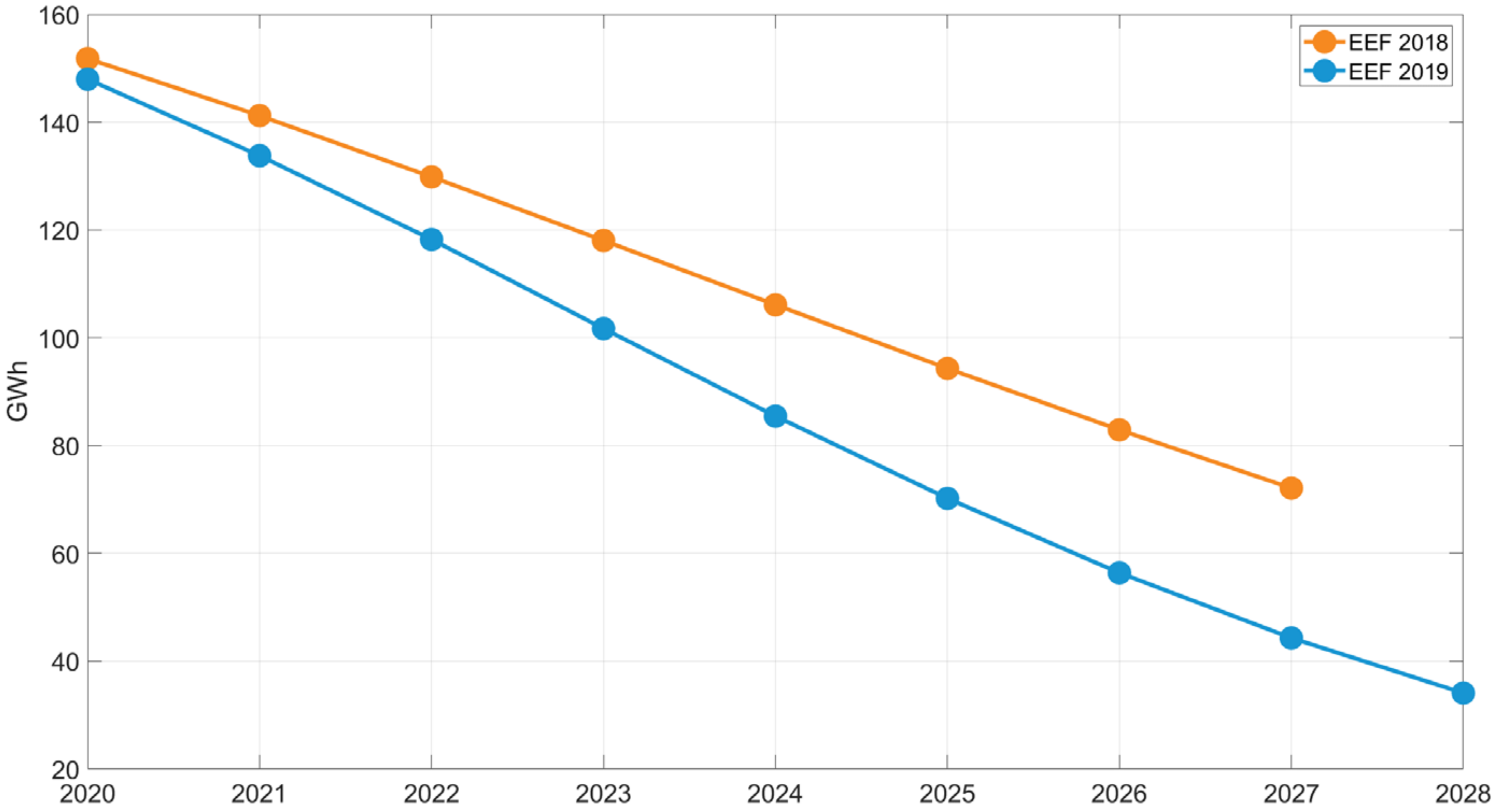
Maine

Energy Efficiency on Summer Peak



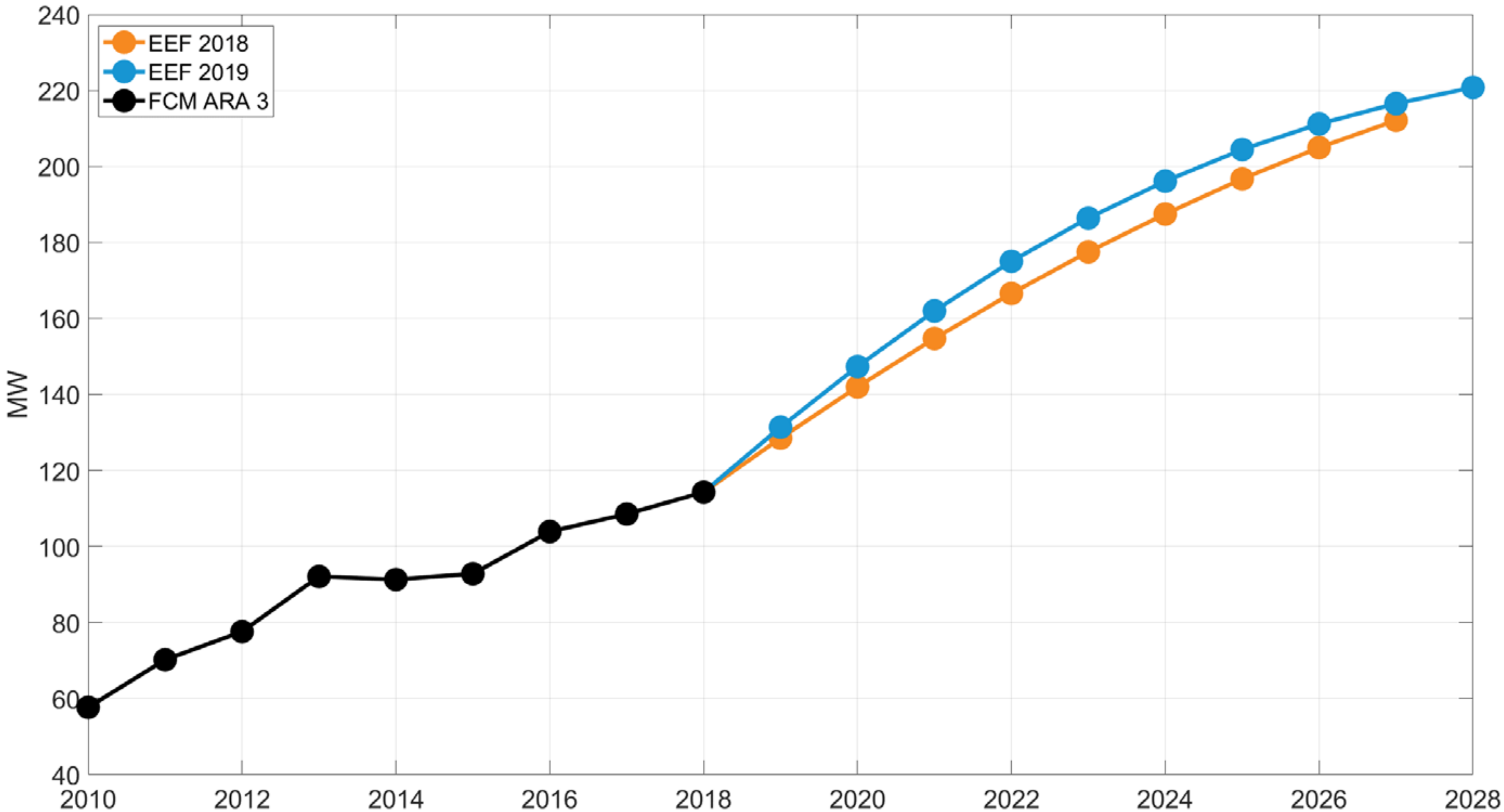
Maine

Energy Efficiency on Annual Energy



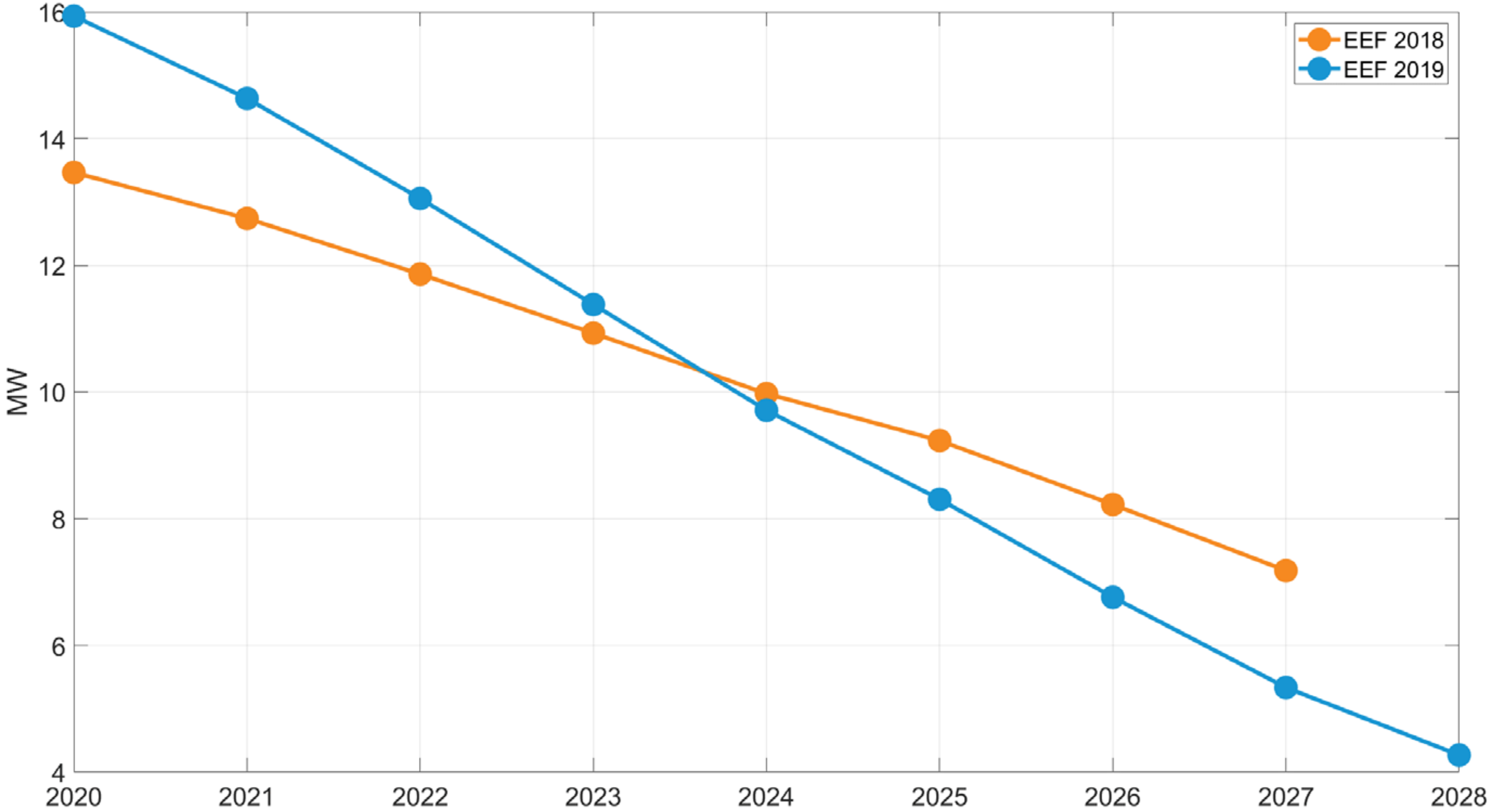
Vermont

Energy Efficiency on Summer Peak



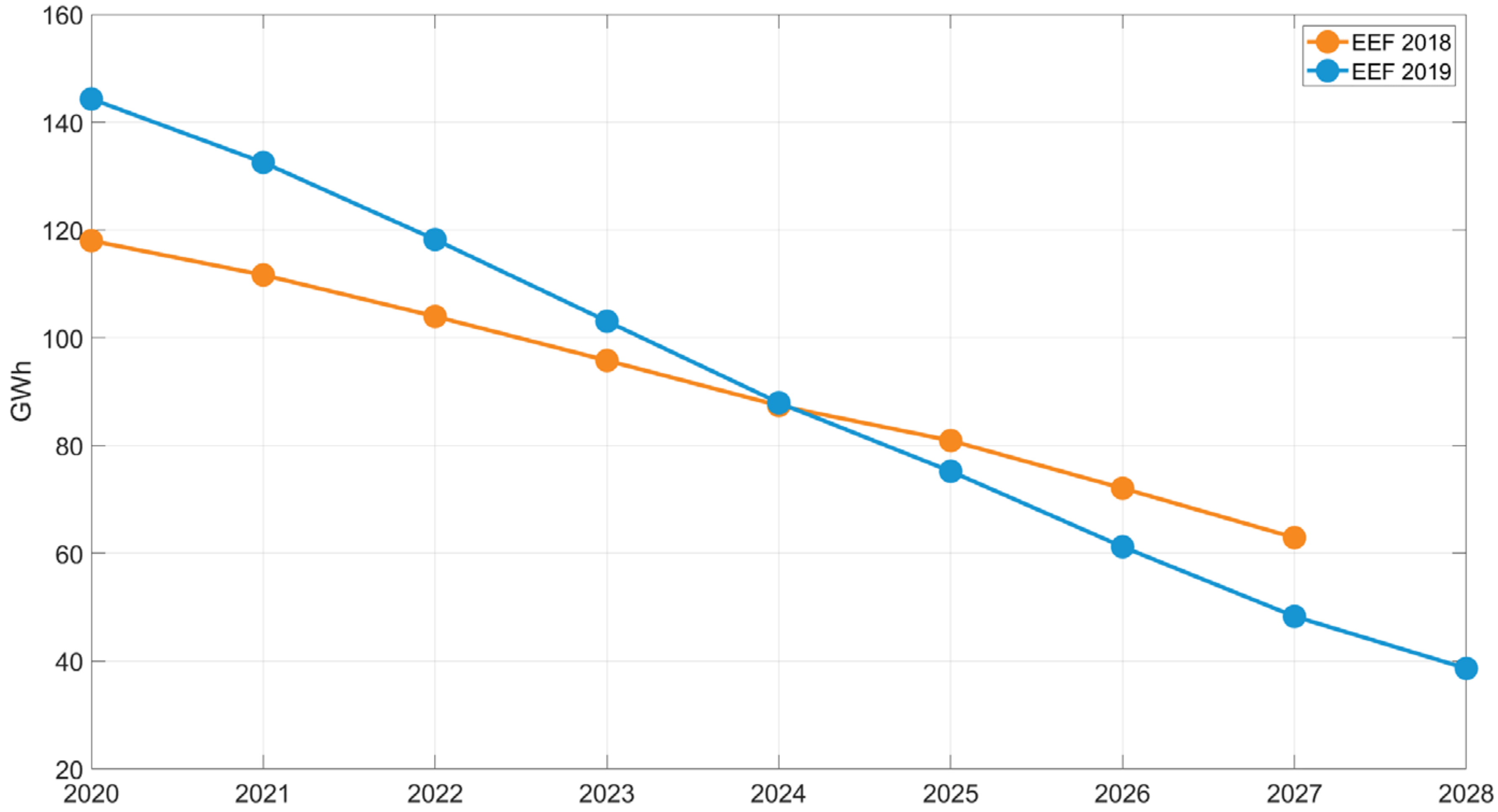
Vermont

Energy Efficiency on Summer Peak



Vermont

Energy Efficiency on Summer Peak

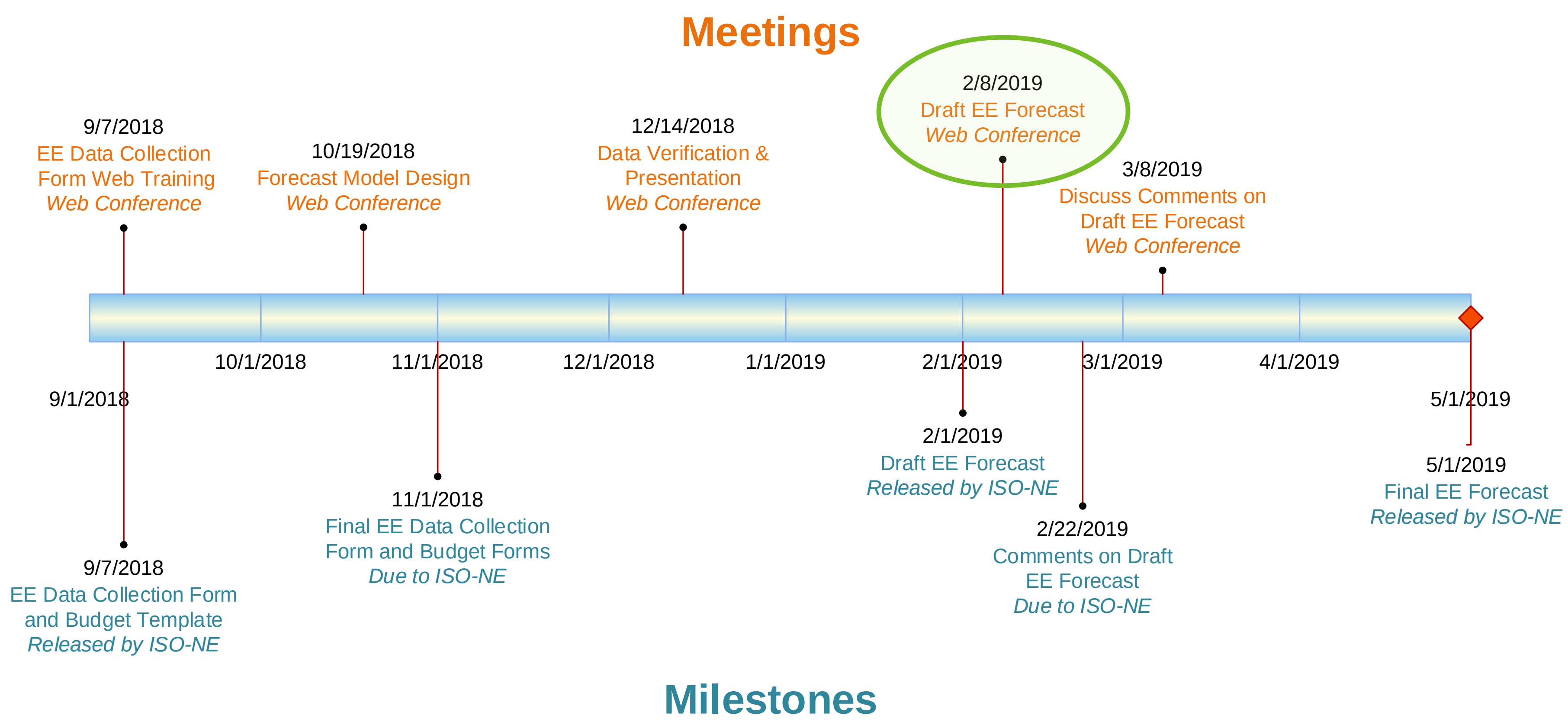


NEXT STEPS

Looking Ahead

- **February 22, 2019** – Comments on the Draft EE Forecast due to ISO New England (eeforecast@iso-ne.com)
- **March 8, 2019** – Energy Efficiency Forecast Working Group (EEFWG) meeting to discuss comments on the Draft EE Forecast
- **March 21, 2019** - Presentation of the Draft EE Forecast to the Planning Advisory Committee
- **May 1, 2019** – Final EE Forecast released by ISO New England

2019 Energy Efficiency Forecast Schedule



Effective: 08-03-2018
(Schedule subject to change)

Questions