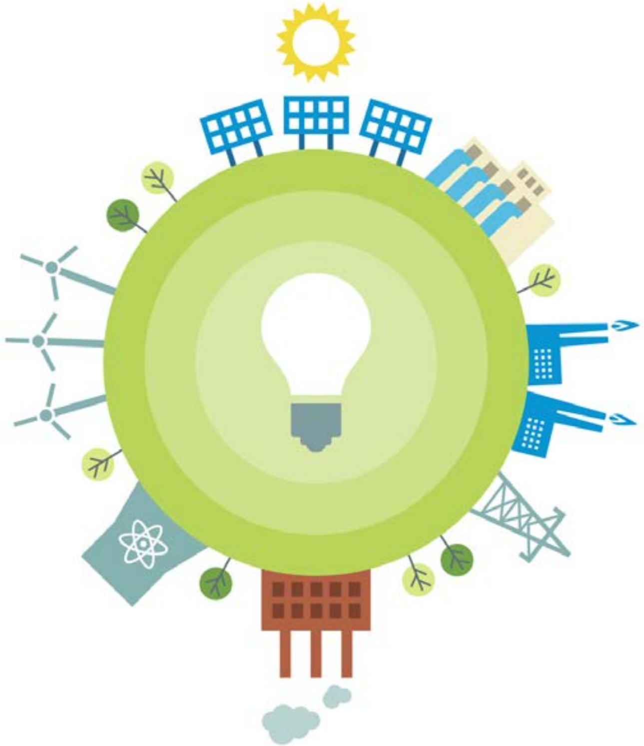
Final 2019 PV Forecast

Outline

- Background & Overview
- Distribution Owner Survey Results
- Forecast Assumptions and Inputs
- 2019 PV Forecast - Nameplate MW
- 2019 PV Energy Forecast
- Classification of PV Forecast
  - Background & Methods
- Classification of 2019 PV Forecast
- 2019 Behind-the-meter PV (BTM PV) Forecast
- Geographic Distribution of PV Forecast
- Appendix: Example Calculation of Estimated Summer Peak Load Reductions from BTM PV



BACKGROUND & OVERVIEW

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

- Many factors influence the future commercialization potential of PV resources, some of which include:
  - Policy drivers:
    - Feed-in-tariffs (FITs)/Long-term procurement
    - State RPS programs
    - Net energy metering (NEM)
    - Federal Investment Tax Credit (ITC)
  - Other drivers:
    - Role of private investment in PV development
    - PV development occurs using a variety of business/ownership models
    - Future equipment and installation costs
    - Future wholesale and retail electricity costs

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

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

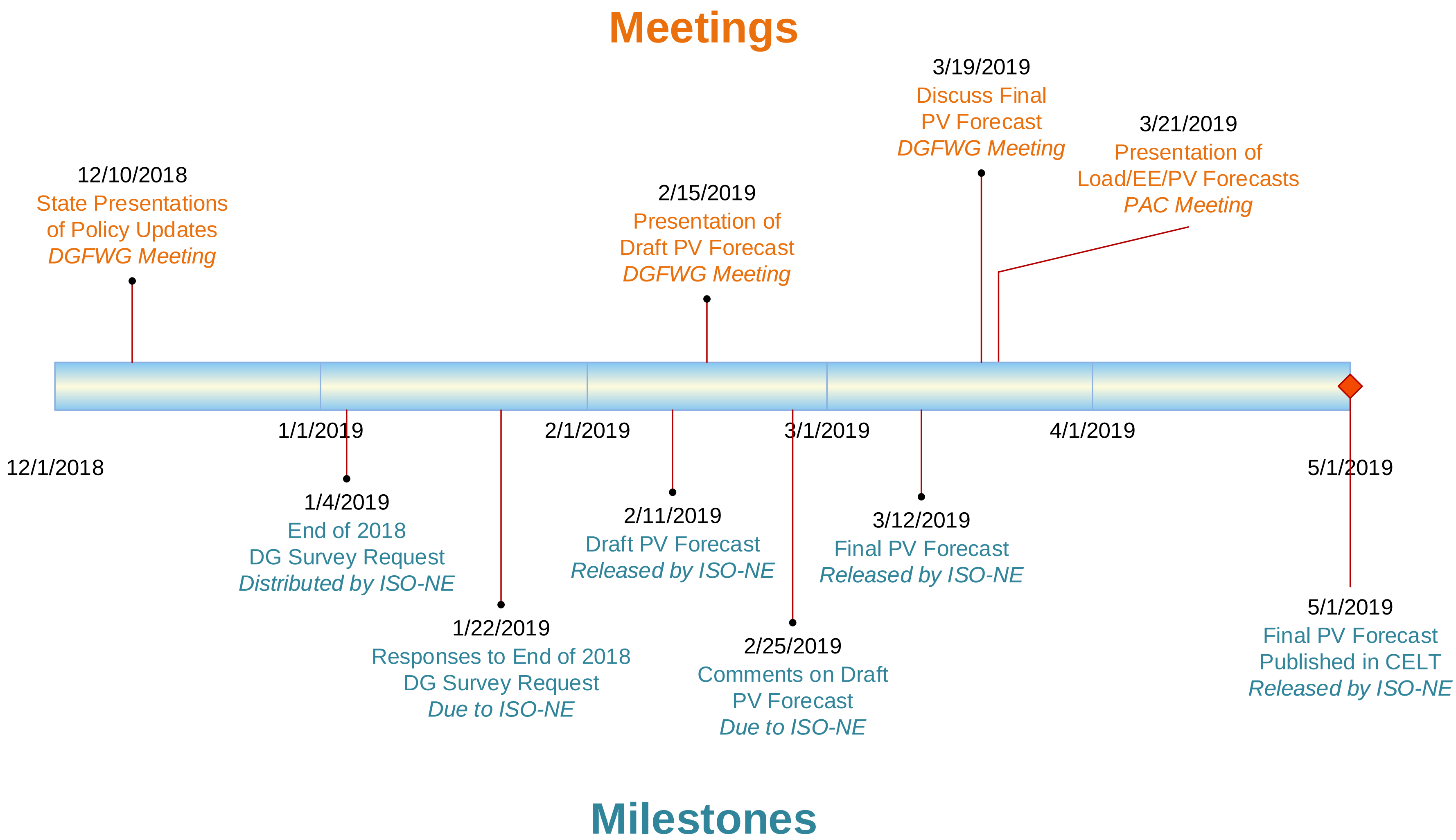
Forecast Focuses on State Policies in All Six New England States

- 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

Background and Forecast Review Process

- The ISO discussed the [draft 2019 PV forecast] with the DGFWG at the February 15, 2019 meeting
- Stakeholders provided comments on the draft forecast
  - See: https://www.iso-ne.com/committees/planning/distributed-generation/?eventId=137521
- The final PV forecast is published in the 2019 CELT (Section 3):
  - See: https://www.iso-ne.com/system-planning/system-plans-studies/celt/

2019 PV Forecast Schedule



DISTRIBUTION OWNER SURVEY RESULTS

Installed PV – December 2018

Determining Total PV Installed Through December 2018

- ISO requested distribution owners to provide the total nameplate of all individual PV projects (in MW_{AC}) that is already installed and operational within their respective service territories as of December 31, 2018
  - PV projects include FCM, EOR, and BTM PV projects that are < 5 MW_{AC} in nameplate capacity
- The following Distribution Owners responded:

CT	CL&P, CMEEC, UI
ME	CMP, Emera Maine
MA	Braintree, Chicopee, Reading, National Grid, NSTAR,
	Shrewsbury, Unitil, WMECO
NH	Liberty, NHEC, PSNH, Unitil
RI	National Grid
VT	Burlington, GMP, Stowe, VEC, VPPSA, WEC

- Thank you to all respondents for providing timely information
- Based on respondent submittals, installed and operational PV resource totals by state and distribution owner are listed on the next slides

December 2018 Year-To-Date PV Installed Capacity

State-by-State

The table below reflects statewide aggregated PV data provided to ISO by regional Distribution Owners. The values represent installed nameplate as of 12/31/18.

State	Installed Capacity (MW_{AC})	No. of Installations
Massachusetts*	1,871.27	90,720
Connecticut	464.34	35,889
Vermont*	306.30	11,864
New Hampshire	83.84	8,231
Rhode Island	116.66	5,993
Maine	41.40	4,309
New England	**2,883.81**	**157,006**

* Includes values based on MA SREC data or VT SPEED data

December 2018 Year-to-Date Installed PV by Distribution Owner

State	Utility	Installed Capacity (MW_{AC})	No. of Installations
CT	Connecticut Light & Power	353.86	26,827
	Connecticut Municipal Electric Energy Co-op	13.43	7
	United Illuminating	97.05	9,055
	Total	**464.34**	**35,889**
MA	Braintree Electric Light Department	4.36	27
	Chicopee Electric Light	13.11	30
	Unitil (FG&E)	24.55	1,647
	National Grid	986.80	46,583
	NSTAR	524.74	31,016
	Reading Municipal Lighting Plant	7.68	138
	Shrewsbury Electric & Cable Operations	6.44	81
	SREC I	54.21	589
	SREC II	78.76	1,649
	Western Massachusetts Electric Company	170.61	8,960
	Total	**1,871.27**	**90,720**
ME	Central Maine Power	36.12	3,623
	Emera	5.28	686
	Total	**41.40**	**4,309**

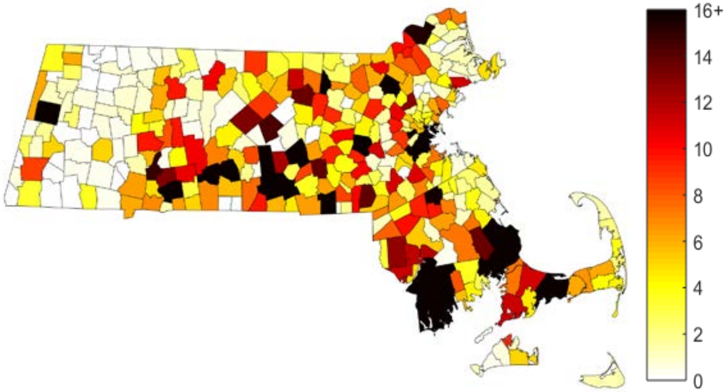
December 2018 Year-to-Date Installed PV by Distribution Owner

State	Utility	Installed Capacity (MW_{AC})	No. of Installations
NH	Liberty Utilities	3.89	411
	New Hampshire Electric Co-op	10.16	1,008
	Public Service of New Hampshire	60.86	5,978
	Unitil (UES)	8.92	834
	Total	**83.84**	**8,231**
RI	National Grid	116.66	5,993
	Total	**116.66**	**5,993**
VT	Burlington Electric Department	6.58	253
	Green Mountain Power	253.99	9,294
	Stowe Electric Department	2.41	80
	Vermont Electric Co-op	27.38	1,230
	Vermont Public Power Supply Authority	10.37	535
	VT Other Municipals	0.10	1
	Washington Electric Co-op	5.46	471
	Total	**306.30**	**11,864**
New England		**2,883.81**	**157,006**

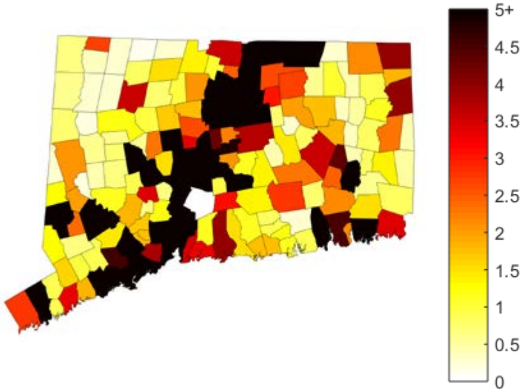
Installed PV Capacity as of December 2018

State Heat Maps

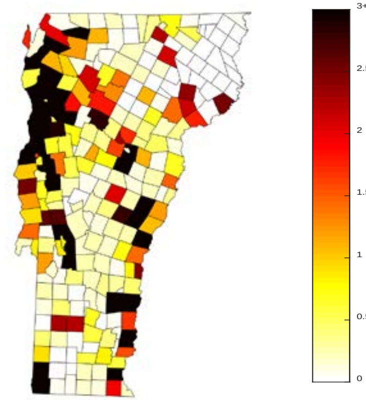
Massachusetts



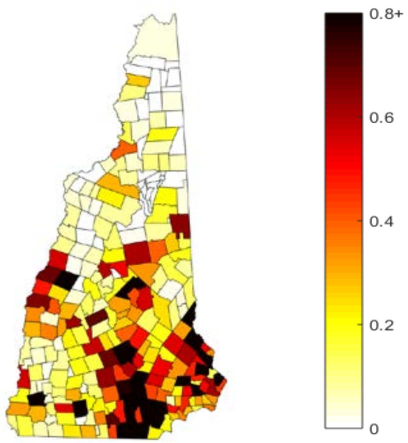
Connecticut



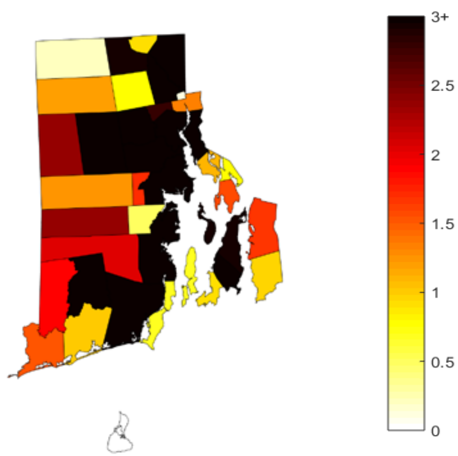
Vermont



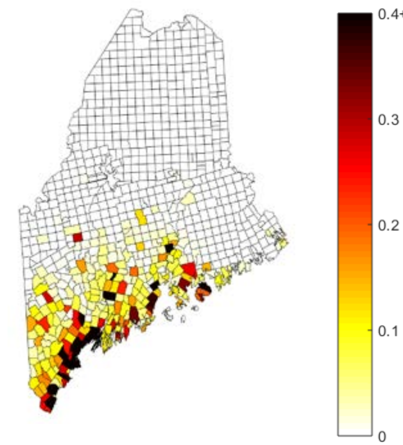
New Hampshire



Rhode Island



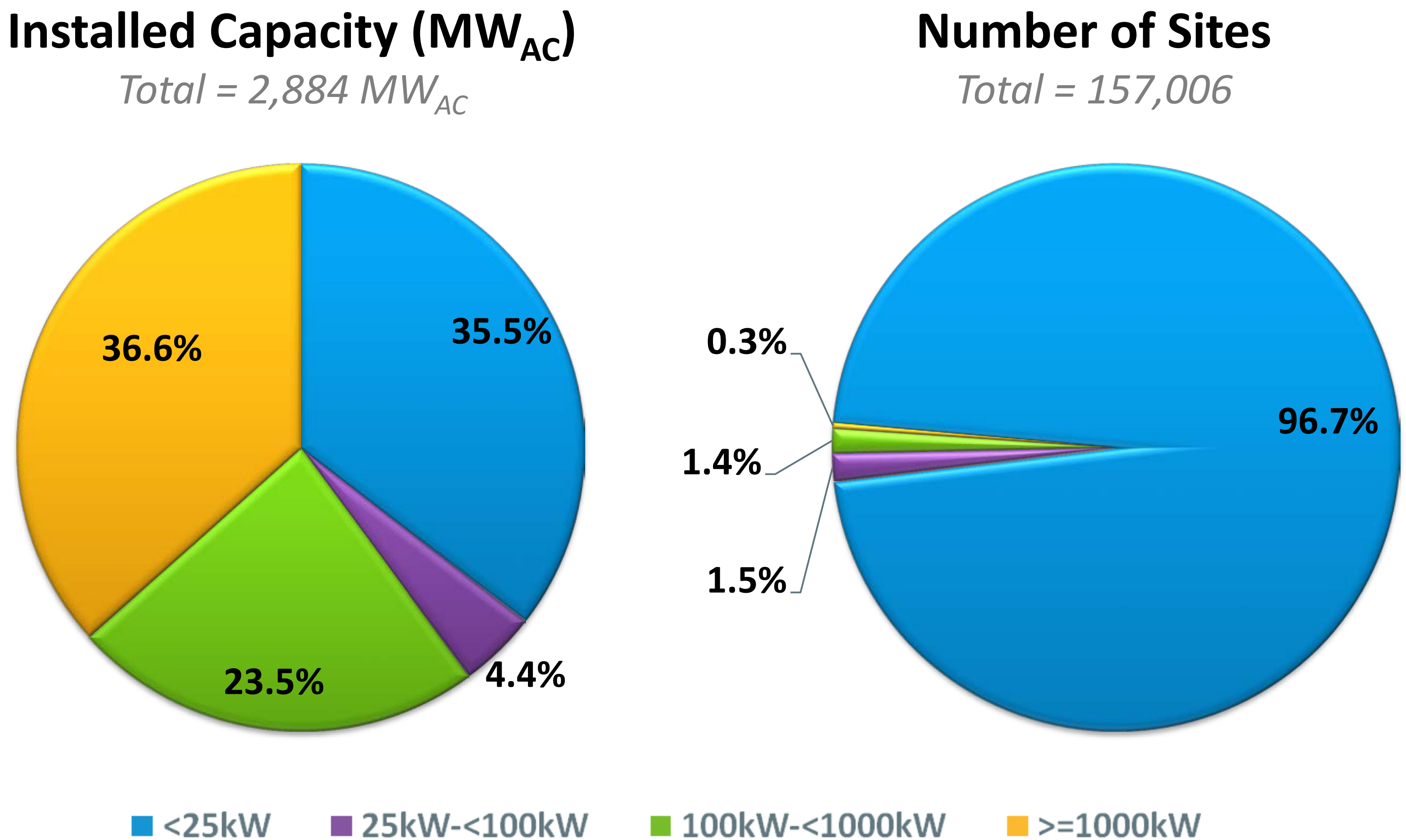
Maine



Note: Legend to the right of each state plot shows color scale of nameplate megawatts per town

Installed PV Capacity as of December 2018

ISO-NE by Size Class



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

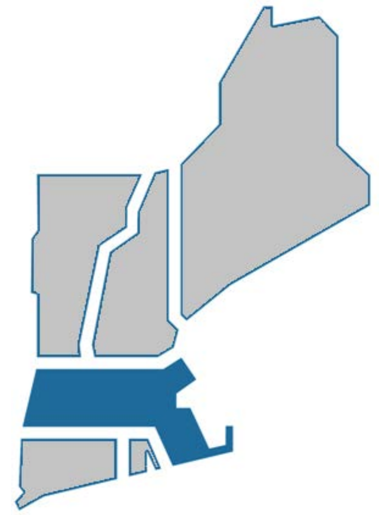
Maximum Allowable Residential ITC	
Year	Credit
2016	30%
2017	30%
2018	30%
2019	30%
2020	26%
2021	22%
Future Years	0%

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

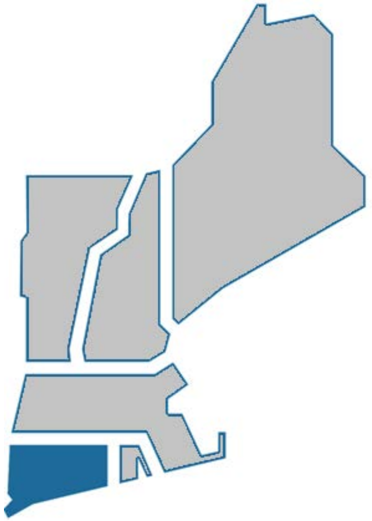


- MA DPU's 12/10/18 DGFWG presentation serves as primary source for MA policy information
- MA Distribution Owners survey results:
  - 1,871.3 MW_{AC} installed by 12/31/18
- Solar Carve-Out Renewable Energy Certificate (SREC) program
  - A total of 2,416 MW_{DC} will be developed as part of SREC-I and 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

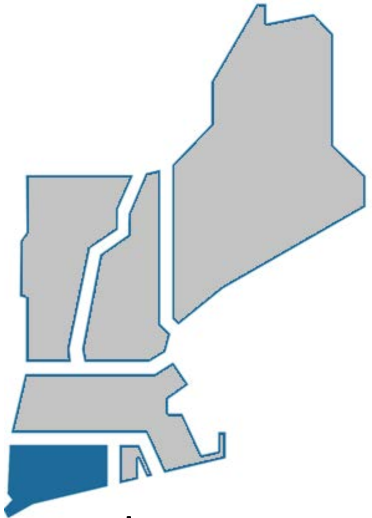
- Post-policy development assumed to occur such that 320 MW is carried forward from 2023 onward at constant rate throughout the remaining years of the forecast period, and post-policy discount factors are applied as necessary

Connecticut Forecast Methodology and Assumptions



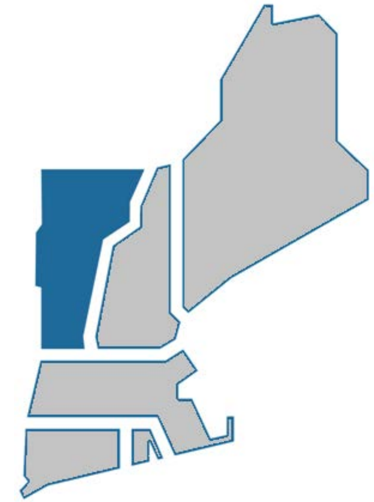
- CT DEEP's 12/10/18 DGFWG presentation serves as primary source for CT policy information
- CT Distribution Owner survey results
  - 464.3 MW_{AC} installed by 12/31/18
- LREC/ZREC program assumptions
  - 121.7 MW remaining, divided evenly over 4 years, 2019-2022
- Residential Solar Investment Program (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*



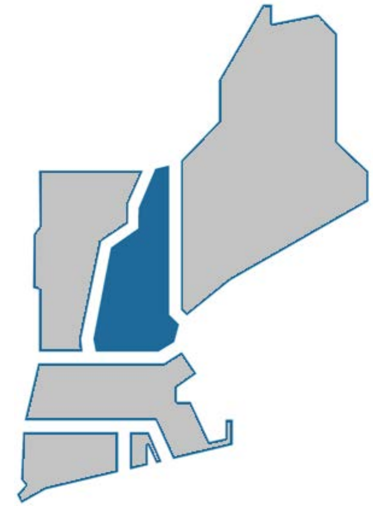
- CT WISE “Successor” programs
  - Design and implementation details of successor programs to SCEF, RSIP, and ZREC are under discussion as part of PURA Docket No. 18-08-33
  - ISO used growth values provided by CT DEEP within their 12/10/2018 presentation for these programs

Vermont Forecast Methodology and Assumptions



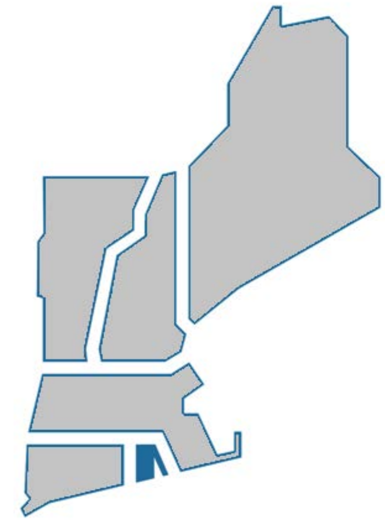
- VT DPS' 12/10/18 DGFWG presentation serves as the primary source for VT policy information
- VT Distribution Owner survey results
  - 306.3 MW_{AC} installed by 12/31/18
- DG carve-out of the Renewable Energy Standard (RES)
  - Assume 85% of eligible resources will be PV and a total of 25 MW/year will 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



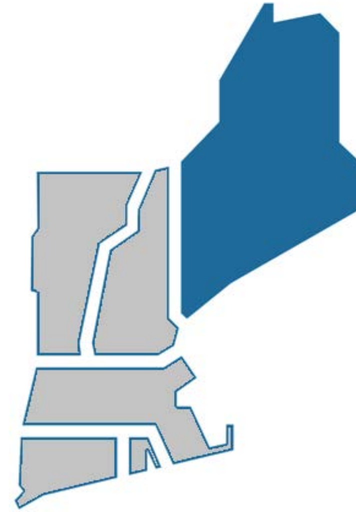
- NH PUC's 12/10/18 DGFWG presentation serves as the primary source for NH policy information
- NH Distribution Owners survey results
  - 83.8 MW_{AC} installed by 12/31/18
  - 14.2 MW_{AC} installed in 2018
- Assume the Net Energy Metering Tariff (NEM 2.0, effective September 2017), continues to support 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 2019 Forecast

Policy-Based

Forecast	Final 2018	Final 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 2019
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%

Final 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**	**525.4**	**538.8**	**531.7**	**501.2**	**261.2**	**181.2**	**181.2**	**97.0**	**97.0**	**6,313.1**
Pre-Discount Annual Post-Policy MWs	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**240.0**	**320.0**	**320.0**	**404.3**	**404.3**	**1,688.5**
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

2019 PV NAMEPLATE CAPACITY FORECAST

Includes FCM, non-FCM EOR, and BTM PV

Final 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	91.1	97.5	97.5	71.6	71.6	71.6	71.6	43.5	42.1	**1,190.9**
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**	**472.8**	**458.0**	**451.9**	**426.0**	**358.0**	**330.0**	**324.7**	**291.3**	**284.6**	**6,744.4**
Regional - Cumulative (MW)	**2883.8**	**3346.9**	**3819.8**	**4277.8**	**4729.7**	**5155.7**	**5513.8**	**5843.8**	**6168.5**	**6459.8**	**6744.4**	**6,744.4**

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

Final 2019 PV Forecast

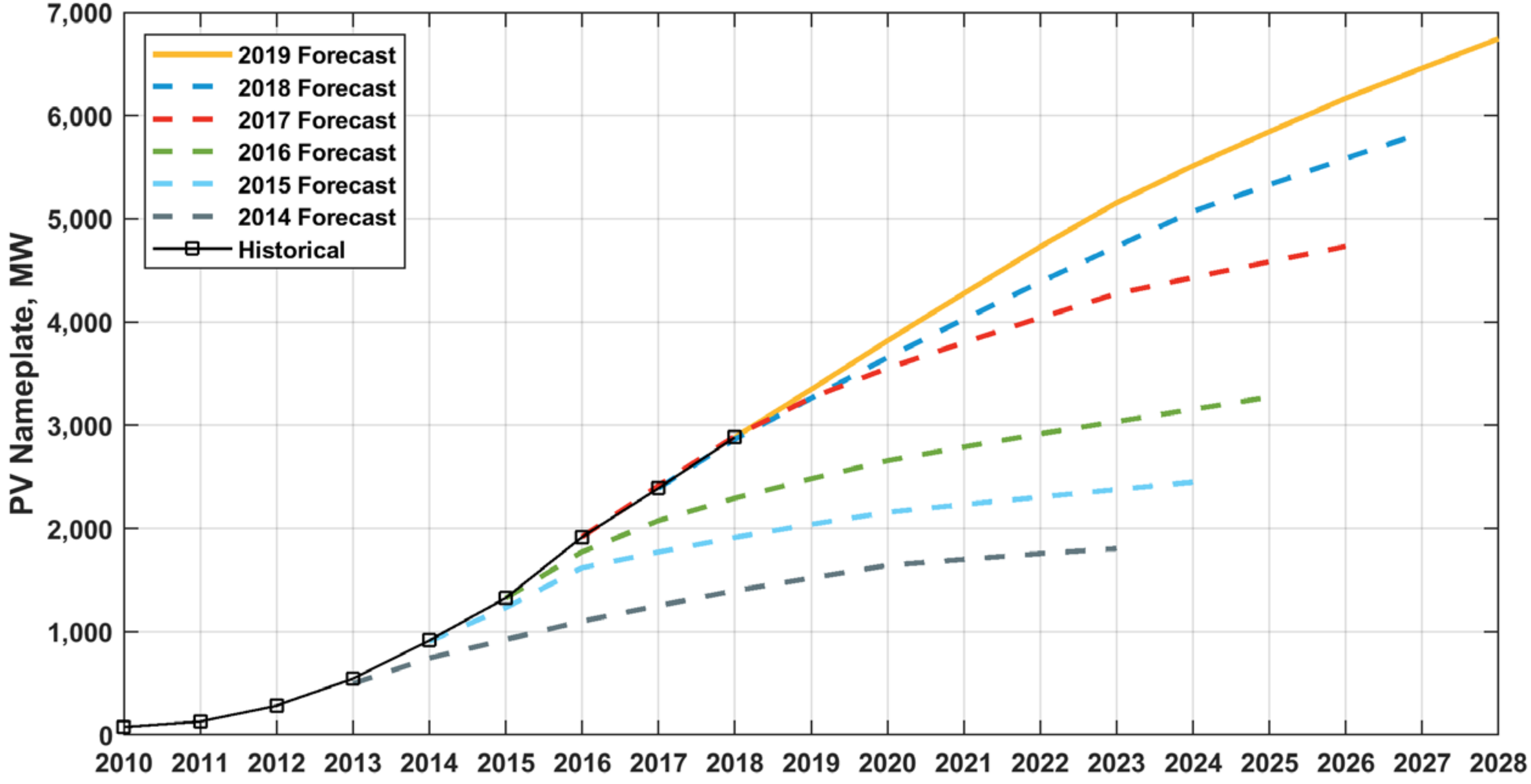
Cumulative Nameplate, MW_{ac}

States	Cumulative Total MW (AC nameplate rating)										
	Thru 2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
CT	464.3	532.8	623.9	721.4	818.8	890.5	962.1	1033.7	1105.3	1148.8	1190.9
MA	1871.3	2163.2	2451.2	2723.2	2995.2	3267.2	3471.2	3647.2	3817.9	3983.2	4143.2
ME	41.4	48.5	55.7	62.4	69.2	75.9	82.7	89.4	96.2	102.9	109.7
NH	83.8	96.6	109.3	121.4	133.4	145.4	157.5	169.5	181.6	193.6	205.6
RI	116.7	168.0	219.3	267.8	310.2	352.6	395.0	437.4	479.8	522.2	564.6
VT	306.3	337.8	360.3	381.6	402.8	424.1	445.3	466.6	487.8	509.1	530.3
Regional - Cumulative (MW)	**2883.8**	**3346.9**	**3819.8**	**4277.8**	**4729.7**	**5155.7**	**5513.8**	**5843.8**	**6168.5**	**6459.8**	**6744.4**

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 Growth: Reported Historical vs. Forecast



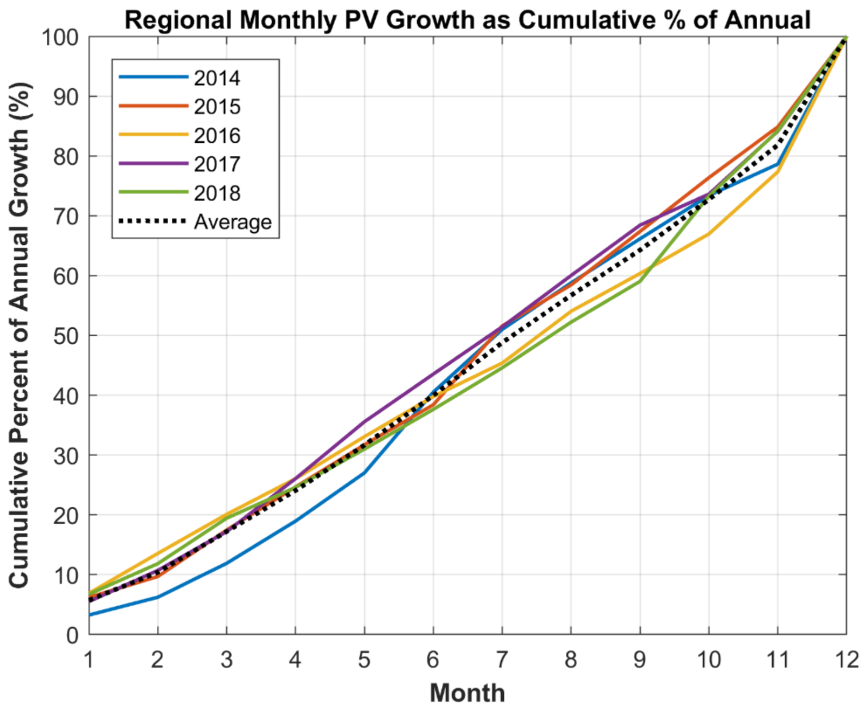
2019 PV ENERGY FORECAST

Development of PV Energy Forecast

- The PV nameplate forecast reflects end-of-year values
- Energy estimates in the PV forecast are inclusive of incremental growth during a given year
- ISO assumed that historical PV growth trends across the region are indicative of future intra-annual growth rates
  - Growth trends between 2014 and 2018 were used to estimate intra-annual incremental growth over the forecast horizon (*see next slide*)
- The PV energy forecast was developed at the state level, using state monthly nameplate forecasts and state average monthly capacity factors (CF) developed from 5 years of PV performance data (2014-2018)
  - Resulting state CFs are tabulated to the right, and plots of individual monthly capacity factors in each state are shown on slide 15

State	Average CF, %
CT	14.7
ME	14.5
NH	14.1
RI	14.8
VT	13.8
MA	14.5

Historical Monthly PV Growth Trends, 2014-2018



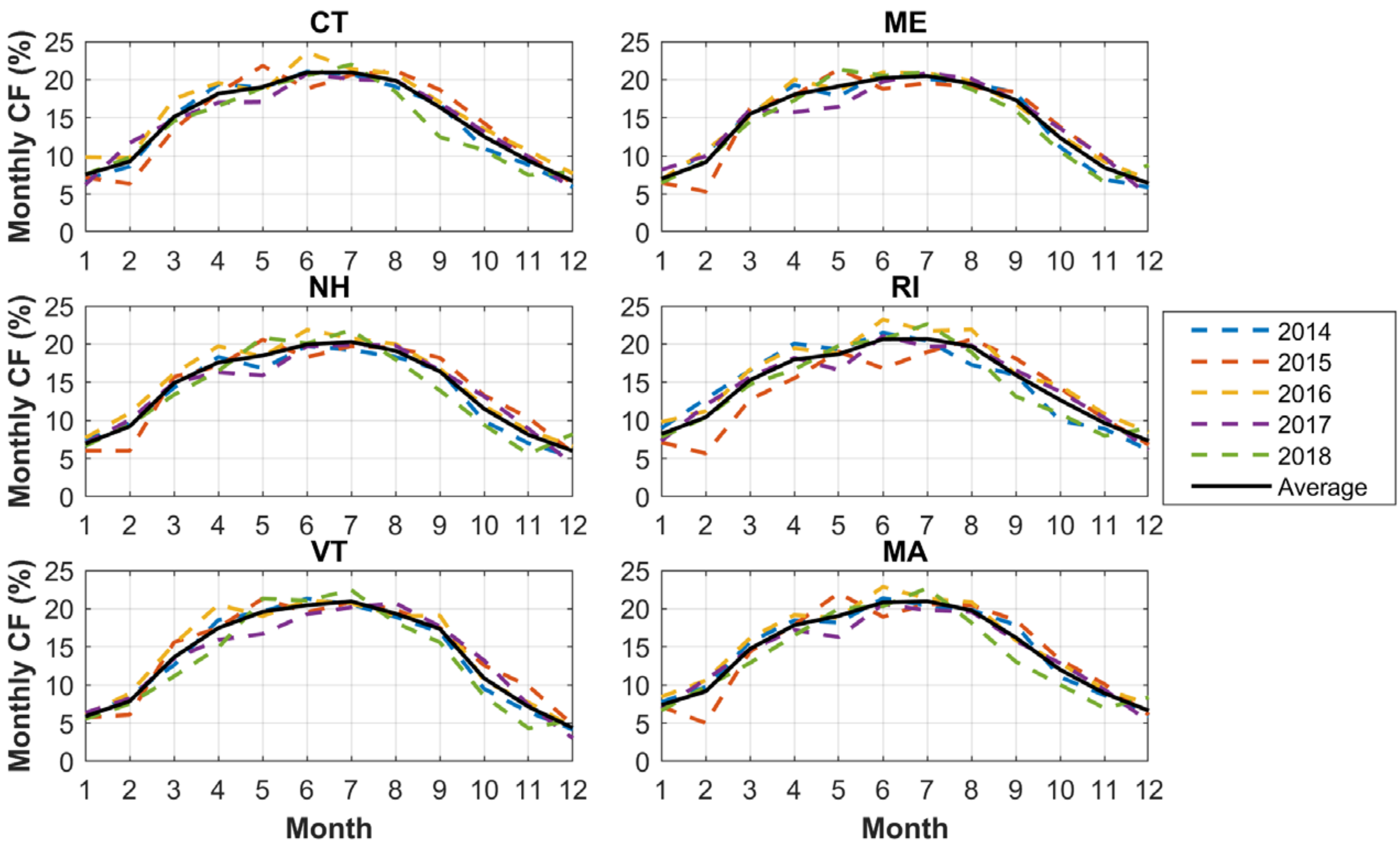
Average Monthly Growth Rates, % of Annual

Month	Monthly PV Growth (% of Annual)	Monthly PV Growth (Cumulative % of Annual)
1	6	6
2	5	10
3	7	17
4	7	24
5	8	32
6	8	40
7	9	49
8	8	57
9	8	64
10	8	73
11	9	82
12	18	100

Note:
Monthly percentages represent end-of-month values, and may not sum to total due to rounding

Monthly PV Capacity Factors by State

PV Production Data, 2014-2018



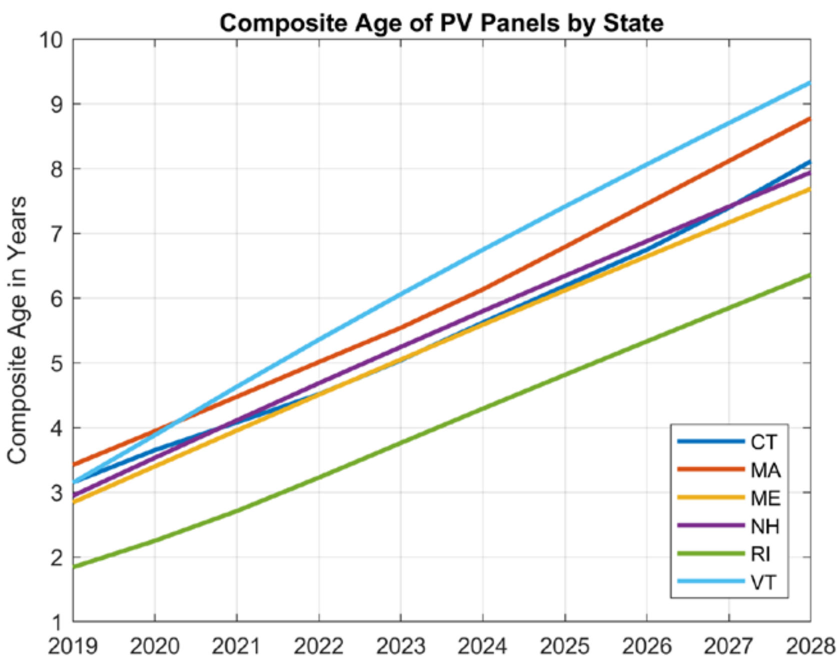
PV Panel Degradation Factors

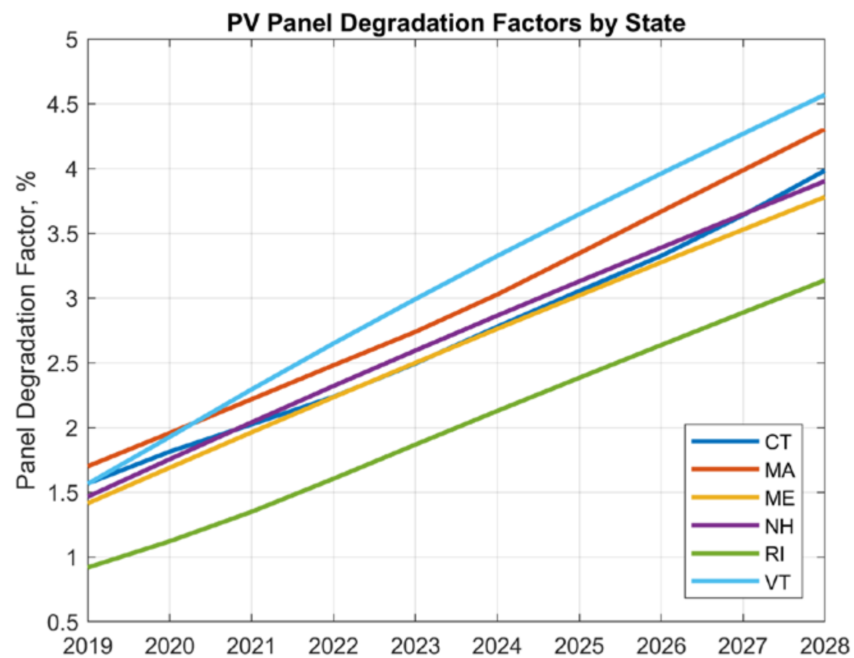
- No changes to the methodology to account for panel degradation were made since last year's forecast
- Forecasts of BTM PV energy and estimated summer peak load reductions include the effects of a 0.5%/year panel degradation rate to account for the expected declining conversion efficiency of solar panels over time
  - Accounting for this degradation becomes more important as the region's PV panels age
- Long-term panel degradation is often caused by:
  - Degradation of silicon or solder joints
  - Problems with the encapsulant that cause delamination, increased opacity, or water ingress
- Based on research by the National Renewable Energy Laboratory (NREL), the median rate of degradation is 0.5%/year, and is assumed to be linear over time
  - More information available here: https://www.nrel.gov/pv/lifetime.html
- The ISO estimated the capacity-weighted composite age of the forecasted PV fleet to develop appropriate degradation factors to use for the forecast

PV Panel Degradation Factors

Composite Age (left) & Degradation Factors (right) by State

- The resulting capacity-weighted, composite age of PV in each state (left plot) and corresponding degradation factors (right plot) over the forecast horizon are plotted below
- The degradation factors are the assumed percent reduction of PV performance over time that reflect the anticipated degradation of PV panels





Final 2019 PV Energy Forecast

Total PV Forecast Energy, GWh

States	Total Estimated Annual Energy (GWh)									
	2019	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
CT	660	763	885	1,014	1,129	1,223	1,313	1,404	1,480	1,534
MA	2627	3,010	3,370	3,719	4,067	4,386	4,618	4,829	5,032	5,235
ME	59	68	77	86	94	103	112	120	129	137
NH	114	131	146	161	176	191	206	221	235	250
RI	185	255	323	385	441	498	553	608	664	720
VT	402	437	462	487	512	537	561	585	610	635
Regional - Annual Energy (GWh)	**4047**	**4,664**	**5,263**	**5,852**	**6,419**	**6,939**	**7,361**	**7,767**	**8,149**	**8,511**

Notes:

(1) Forecast values include energy from FCM Resources, non-FCM Energy Only Generators, and behind-the-meter PV resources
(2) Monthly in service dates of PV assumed based on historical development
(3) Values include the effects of an assumed 0.5%/year PV panel degradation rate
(4) All values are grossed up by 6.5% to reflect avoided transmission and distribution losses

CLASSIFICATION OF PV FORECAST: BACKGROUND & METHODS

Classification Needed to Determine BTM PV

- Ultimately, the ISO needs to determine the amount of PV that is not expected to participate in wholesale markets, and instead reduces load
  - This is the amount of BTM PV that should be reflected in the long-term load forecast
- In order to properly account for existing and future PV in planning studies and avoid double counting, ISO classifies PV into three distinct categories related to its assumed market participation/non-participation
- Accounting for these market distinctions is performed for both installed nameplate capacity (historical and forecast) and estimates of hourly energy production (historical), and is important for the ISO's use of the PV forecast for load forecasting and a wide range of planning studies

Three Mutually Exclusive Categories

1. **PV as a resource in the Forward Capacity Market (FCM)**
   - Qualified for the FCM and have acquired capacity supply obligations
   - Size and location identified and visible to the ISO
   - May be supply or demand-side resources
2. **Non-FCM Energy Only Resources (EOR) and Generators**
   - ISO collects energy output
   - Participate only in the energy market
3. **Behind-the-Meter (BTM) PV**
   - Not in ISO Market
   - Reduces system load
   - ISO has an incomplete set of information on generator characteristics
   - ISO does not collect energy meter data, but can estimate it using other available data

Nameplate Classification By State

- Classification varies by state
  - – Market disposition of PV projects can be influenced state policies (*e.g.*, net metering requirements)
- The following steps were used to determine PV resource types for each state over the forecast horizon:
  1. **FCM**
     - Identify all Generation and Demand Response FCM PV resources for each Capacity Commitment Period (CCP) through FCA 13
  2. **Non-FCM EOR/Gen**
     - Determine the % share of non-FCM PV participating in energy market at the end of 2018 and assume this share remains constant throughout the forecast period
  3. **BTM**
     - Subtract the values from steps 1 and 2 from the annual state PV forecast, the remainder is the BTM PV

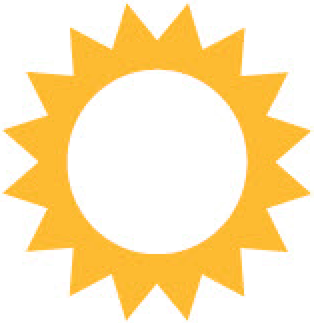
PV in ISO New England Markets

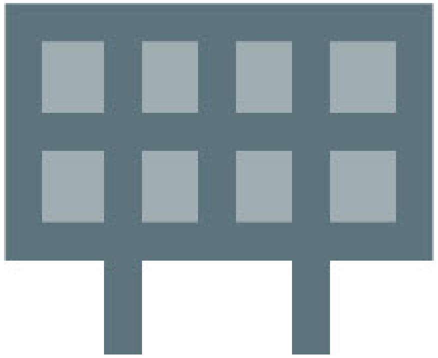
Data and Assumptions

- **FCM**
  - ISO identified all PV generators or demand resources (DR) that have Capacity Supply Obligations (CSO) in FCM up through FCA 13
  - Assume aggregate total PV in FCM as of FCA 13 remains constant from 2022-2028
- **Non-FCM Gen/EOR**
  - ISO identified total nameplate capacity of PV in each state registered in the energy market as of 12/31/18
  - CT, MA, ME, NH, VT: Assume % share of nameplate PV in energy market as of 12/31/18 remains consistent throughout the forecast horizon
  - RI: Average of 60% of forward-looking MWs are assumed to be EOR, based on
    - Assume % share of nameplate in energy market as of 12/31/18 applies to all growth driven by REGP and DGSC programs (52.9%)
    - Assume 85% of net metered/virtual net metered projects become EOR
- Other assumptions:
  - Supply-side FCM PV resources operate as EOR/Gen prior to their first FCM commitment period (this has been observed in MA and RI)
  - Planned PV projects known to be > 5 MW_{ac} nameplate are assumed to trigger OP-14 requirement to register in ISO energy market as a Generator

Estimation of Hourly BTM PV For Reconstitution

January 1, 2012 – December 31, 2018





- Historical BTM PV production estimates are needed at the hourly level for reconstitution in the development of the long-term gross load forecast
- The ISO estimates historical hourly BTM PV using:
  1. Historical BTM PV performance data
  2. Installed capacity data submitted by utilities
  3. Historical energy production of market-facing PV
- In order to estimate historical hourly BTM PV production, ISO develops hourly state PV profiles as described on the next slide

Estimation of Hourly BTM PV For Reconstitution

January 1, 2012 – December 31, 2018 (Continued)

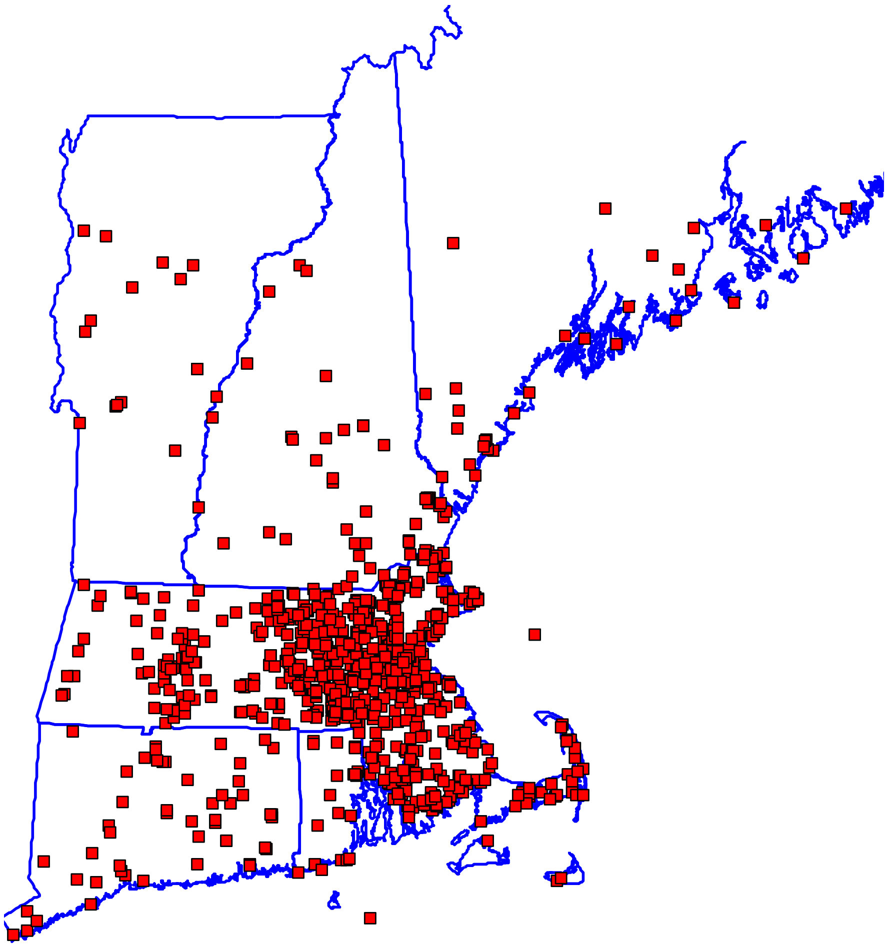
- Historical performance and installed capacity data are combined into normalized (i.e., a per MW-of-nameplate) PV profiles for each state that reflect the effects of both localized weather and geographical distribution of installed capacity
  - Historical PV performance data sources are described on the next two slides
- Using the normalized PV profiles, total state PV production (i.e., FCM+EOR+BTM) is then estimated by scaling the profiles up to the total PV installed over the period according to distribution utility data
  - (Normalized Hourly Profile) x (Total installed PV Capacity) = Total Hourly PV production
- Subtracting the hourly PV settlements energy (where applicable) from the total hourly PV production yields the hourly BTM PV for each state
  - Resulting hourly BTM PV is used for reconstitution in the development of the gross load forecast

Historical PV Performance Data

1/1/12-12/31/13

- Hourly state PV profiles developed for two years (2012-2013) using production data using Yaskawa-Solectria Solar's web-based monitoring system, SolrenView*
  - Represents PV generation at the inverter or at the revenue-grade meter
- A total of more than 1,200 individual sites representing more than 125 MW_{ac} in nameplate capacity were used
  - Site locations depicted on adjacent map

Yaskawa-Solectria Sites



**Source:* http://www.solrenview.com/

Historical PV Performance Data
1/1/14-12/31/18

- ISO has contracted with a third-party vendor for PV production data service
  - Includes data from more than 9,000 PV installations
  - Data are 5-minutely and at the town level
  - Broad geographic coverage
- An example snapshot of regional data is plotted to the right
  - Data are for February 8, 2019 at 1:00 pm
  - Yellow/red coloring shows level of PV production
  - No data available in towns colored gray
  - Data not requested in towns colored blue

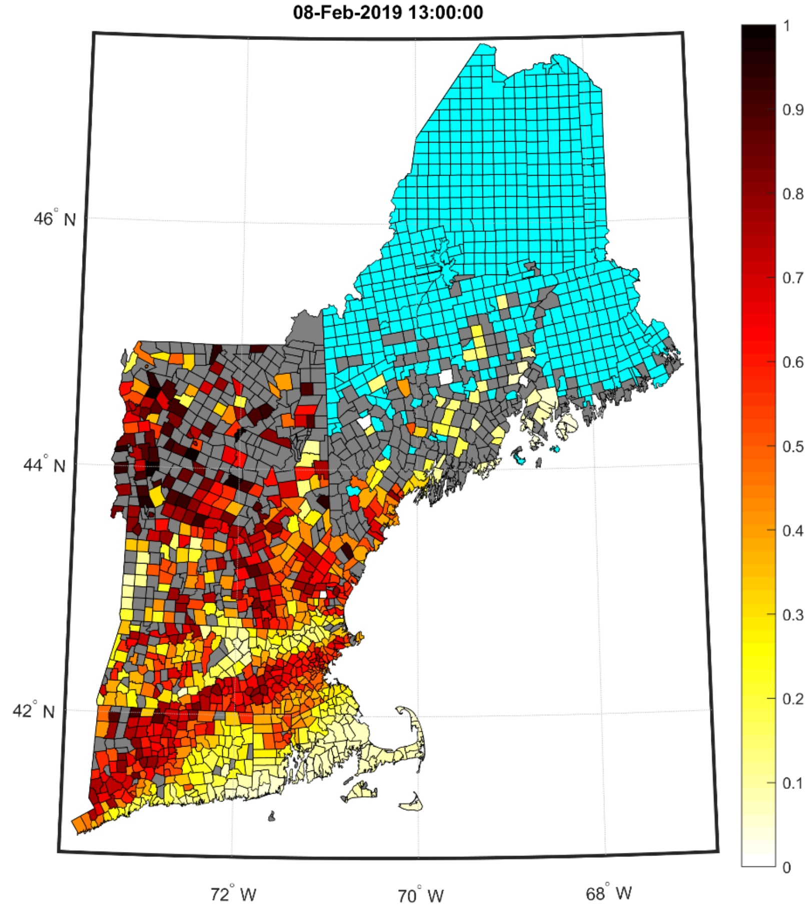


Figure notes:
1. Graphic developed by ISO New England
2. Data source: Quantitative Business Analytics, Inc.

CLASSIFICATION OF FINAL 2019 PV FORECAST

Final 2019 PV Forecast

Cumulative Nameplate, MW_{ac}

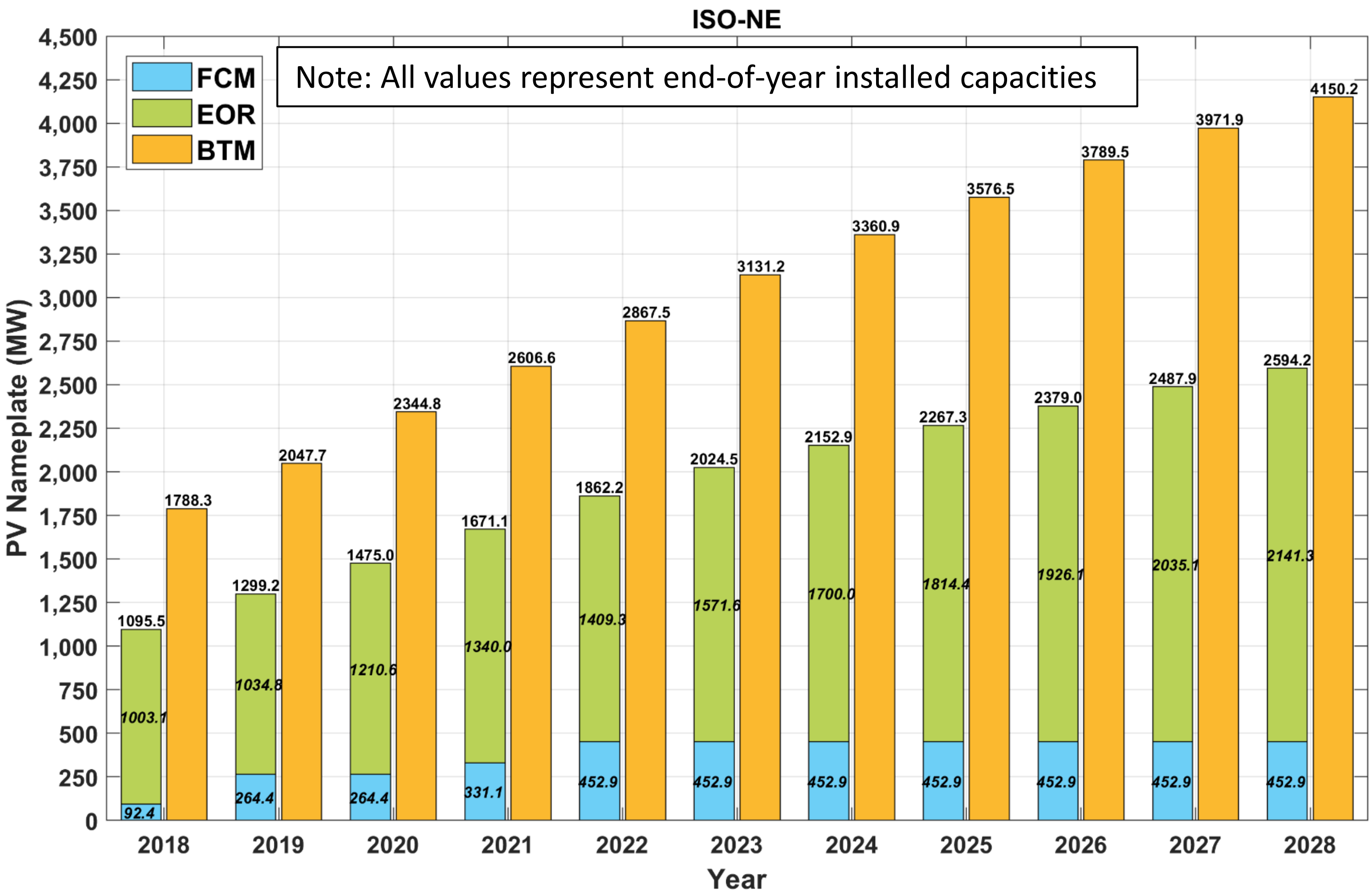
States	Cumulative Total MW (AC nameplate rating)										
	Thru 2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
CT	464.3	532.8	623.9	721.4	818.8	890.5	962.1	1033.7	1105.3	1148.8	1190.9
MA	1871.3	2163.2	2451.2	2723.2	2995.2	3267.2	3471.2	3647.2	3817.9	3983.2	4143.2
ME	41.4	48.5	55.7	62.4	69.2	75.9	82.7	89.4	96.2	102.9	109.7
NH	83.8	96.6	109.3	121.4	133.4	145.4	157.5	169.5	181.6	193.6	205.6
RI	116.7	168.0	219.3	267.8	310.2	352.6	395.0	437.4	479.8	522.2	564.6
VT	306.3	337.8	360.3	381.6	402.8	424.1	445.3	466.6	487.8	509.1	530.3
Regional - Cumulative (MW)	**2883.8**	**3346.9**	**3819.8**	**4277.8**	**4729.7**	**5155.7**	**5513.8**	**5843.8**	**6168.5**	**6459.8**	**6744.4**

Notes:

(1) Forecast values include FCM Resources, non-FCM Energy Only Generators, and behind-the-meter PV resources
(2) The forecast reflects discount factors to account for uncertainty in meeting state policy goals
(3) All values represent end-of-year installed capacities

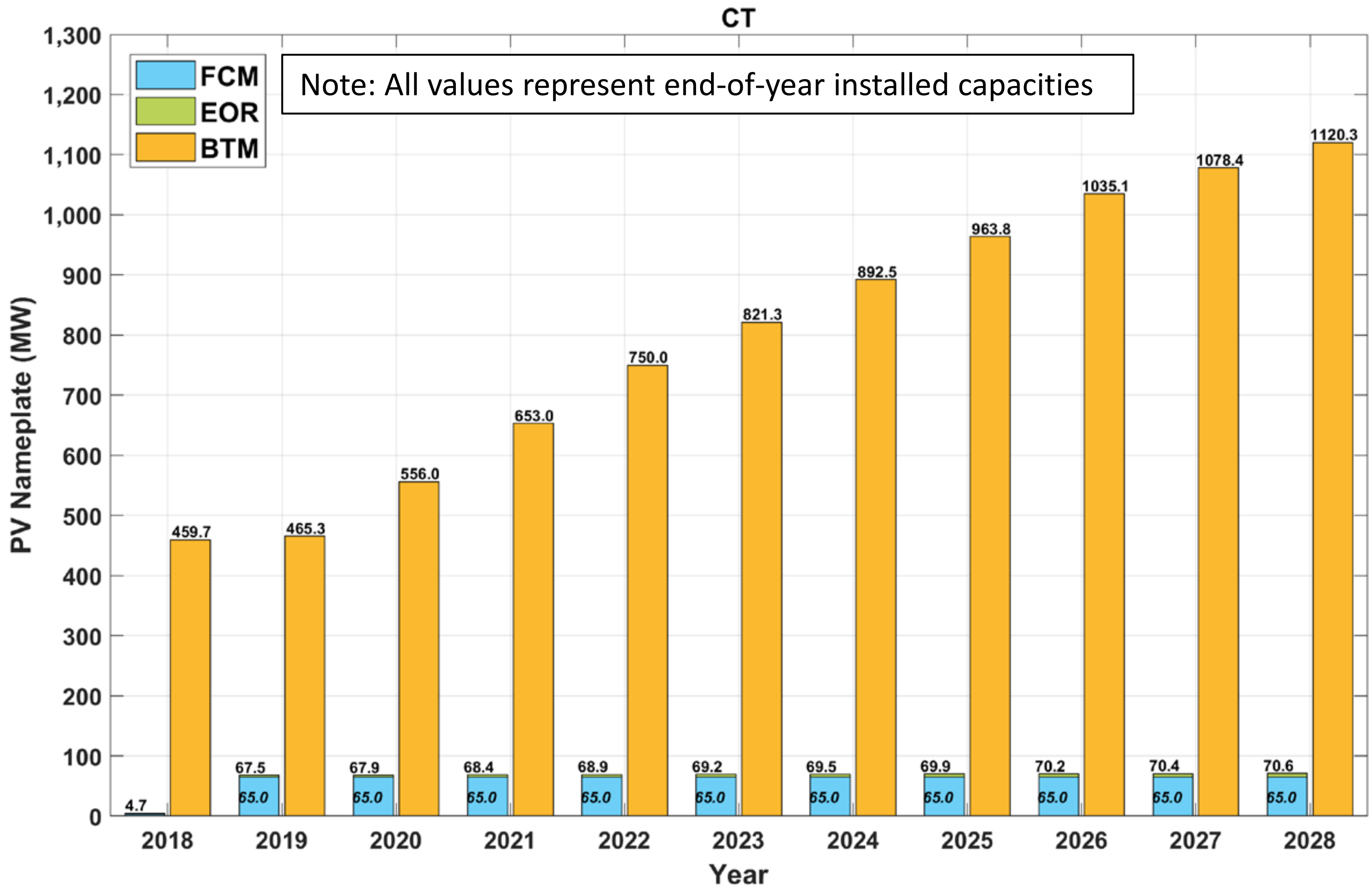
Final 2019 PV Forecast

Cumulative Nameplate, MW_{ac}



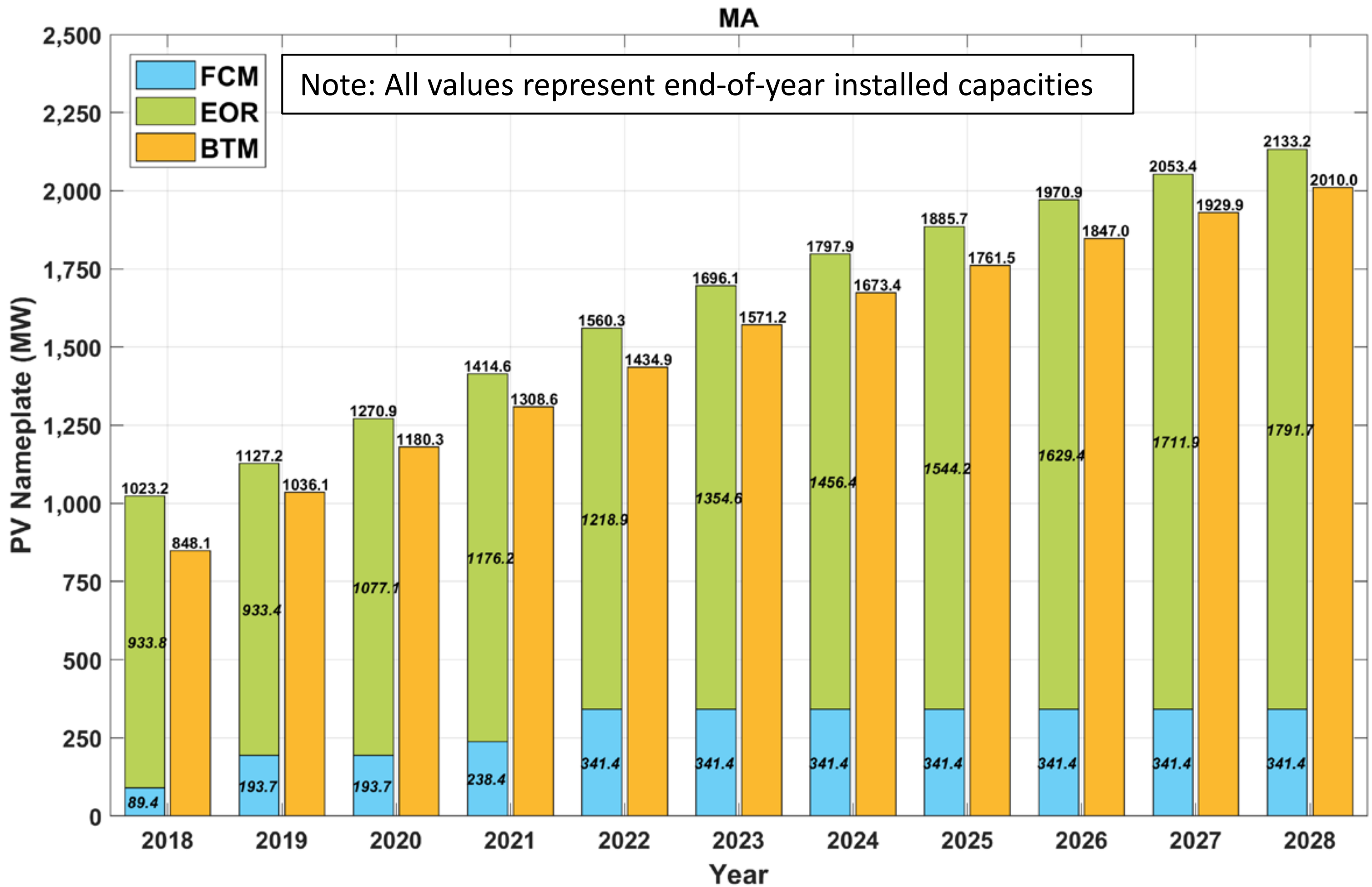
Cumulative Nameplate by Resource Type, MW_{ac}

Connecticut



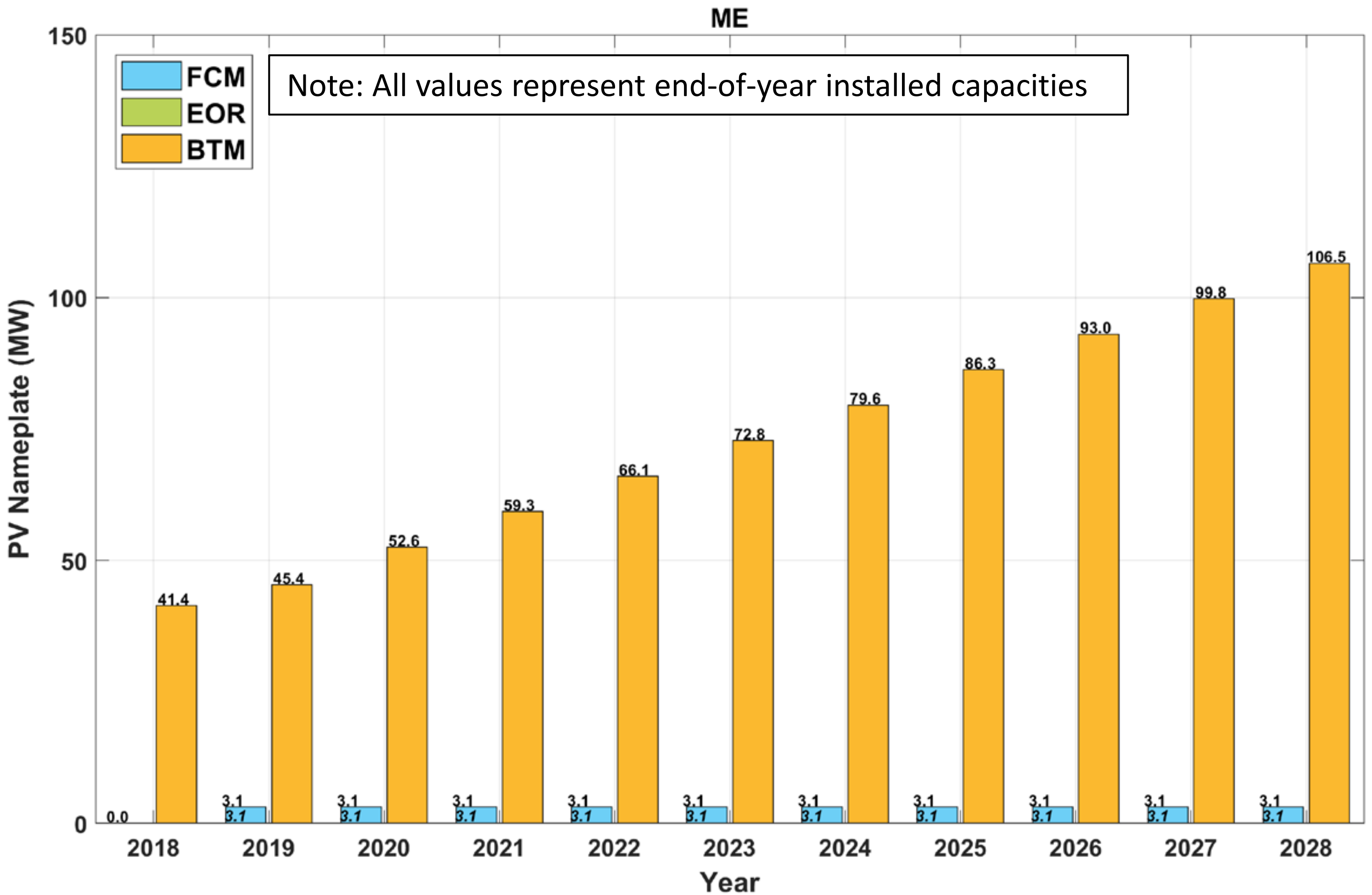
Cumulative Nameplate by Resource Type, MW_{ac}

Massachusetts



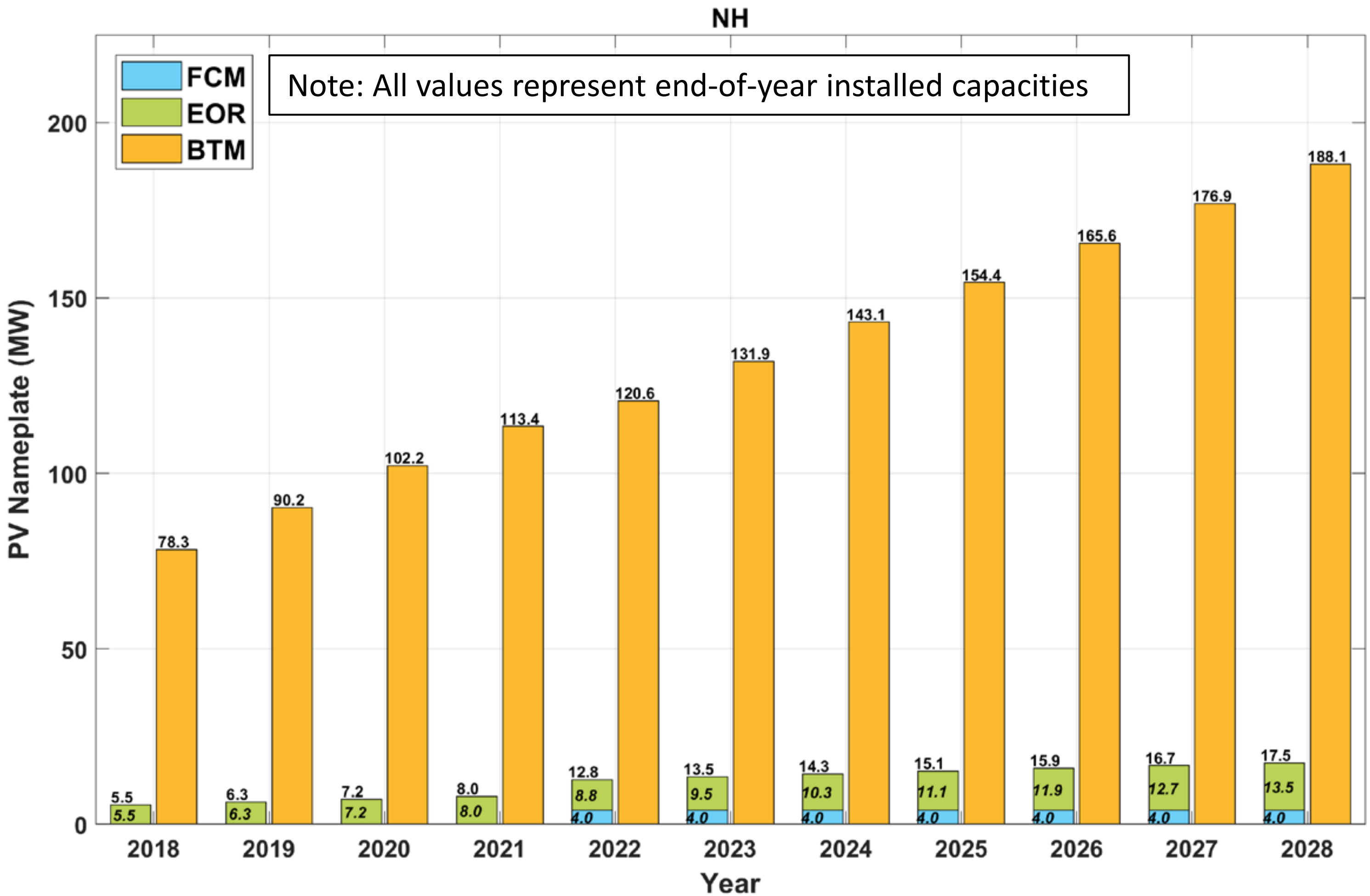
Cumulative Nameplate by Resource Type, MW_{ac}

Maine



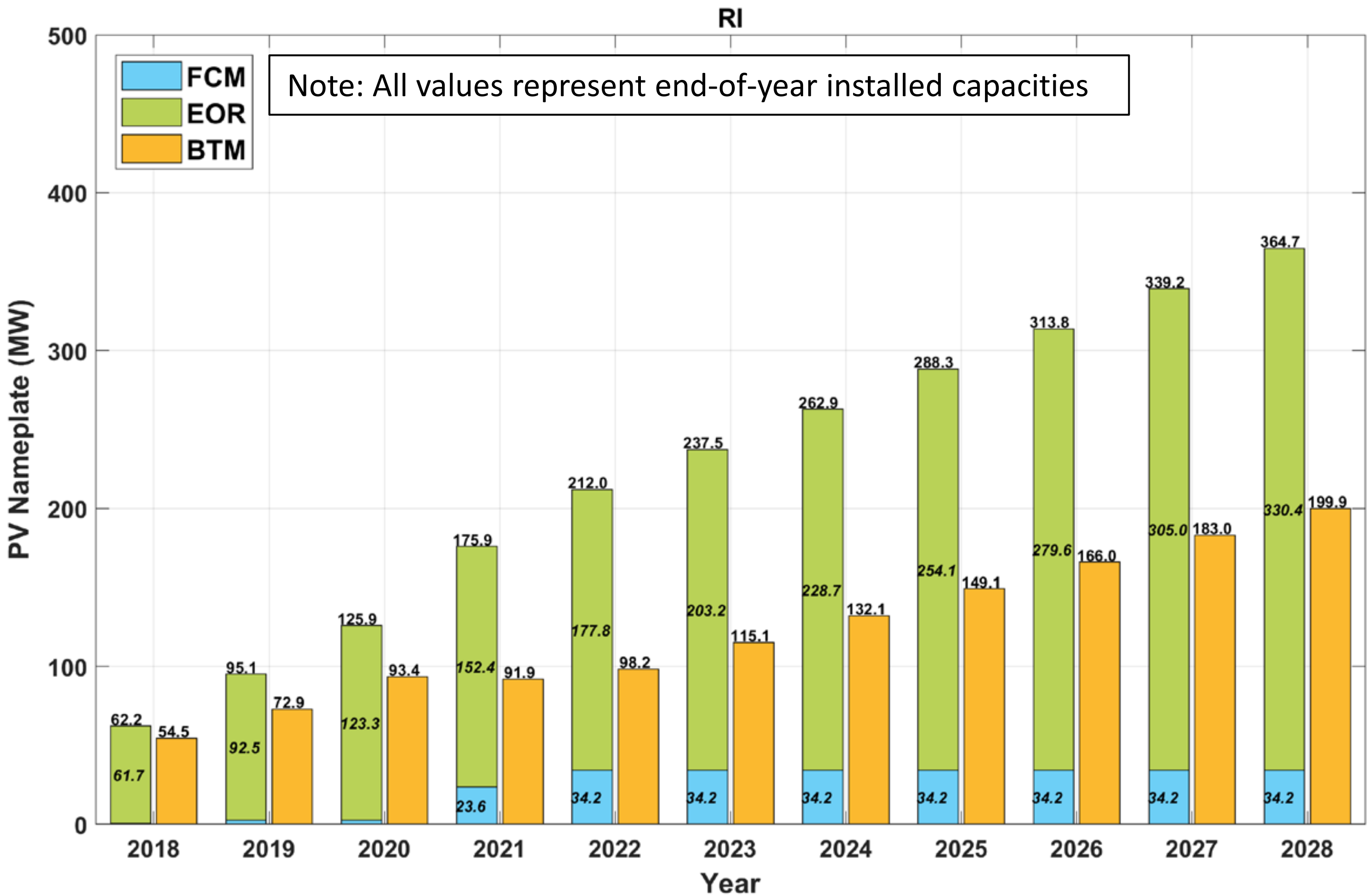
Cumulative Nameplate by Resource Type, MW_{ac}

New Hampshire



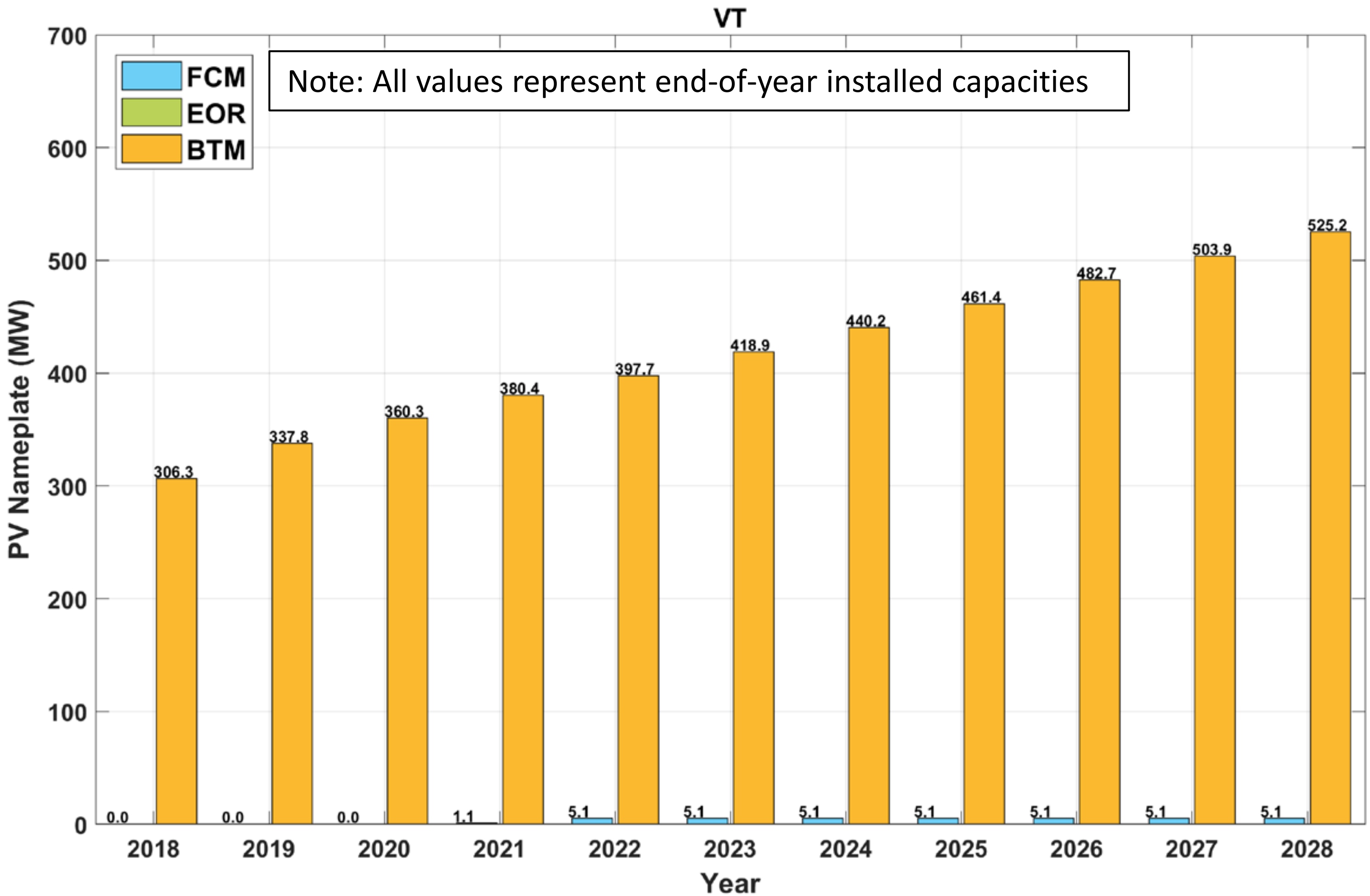
Cumulative Nameplate by Resource Type, MW_{ac}

Rhode Island



Cumulative Nameplate by Resource Type, MW_{ac}

Vermont



BTM PV Forecast Used in CELT Net Load Forecast

- The 2019 CELT net load forecast will reflect deductions associated with the BTM PV portion of the PV forecast
- The following slides show values for annual energy and summer peak load reductions anticipated from BTM PV that will be reflected in the 2019 CELT
  - PV does not reduce winter peak loads, which occur after sunset
- ISO developed estimated summer peak load reductions associated with BTM PV forecast using the methodology established for the 2016 PV forecast
  - See Appendix of 2016 PV Forecast slides: https://www.iso-ne.com/static-assets/documents/2016/09/2016_solar_forecast_details_final.pdf

Final 2019 BTM PV Energy Forecast

Annual Energy, GWh

		Estimated Annual Energy (GWh)										
Category	**States**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Behind-the-Meter PV	CT	490	623	672	794	922	1037	1131	1220	1311	1388	1441
	MA	972	1218	1445	1621	1785	1951	2111	2228	2334	2436	2538
	ME	48	57	64	73	82	90	99	108	116	125	133
	NH	87	107	122	137	149	159	174	187	201	215	229
	RI	40	84	110	126	128	141	164	186	209	231	253
	VT	310	402	437	462	484	505	531	555	579	603	628
Behind-the Meter Total		**1947**	**2490**	**2849**	**3213**	**3549**	**3884**	**4210**	**4483**	**4749**	**4996**	**5222**

Notes:

(1) Forecast values include energy from behind-the-meter PV resources only

(2) Monthly in service dates of PV assumed based on historical development

(3) Values include the effects of an assumed 0.5%/year PV panel degradation rate

(4) All values are grossed up by 6.5% to reflect avoided transmission and distribution losses

Final 2019 BTM PV Forecast

July 1st Estimated Summer Peak Load Reductions

		Cumulative Total MW - Estimated Summer Seasonal Peak Load Reduction										
Category	**States**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Behind-the-Meter PV	CT	152.9	172.8	180.0	204.6	227.9	245.3	256.8	267.9	278.0	284.1	285.1
	MA	319.4	345.0	392.0	422.8	446.5	468.2	485.8	495.4	501.3	505.7	509.1
	ME	13.7	16.1	17.3	19.0	20.4	21.7	22.8	23.9	24.9	25.9	26.7
	NH	27.2	31.1	34.1	36.7	38.3	39.4	41.2	42.9	44.5	45.9	47.3
	RI	12.5	23.3	29.3	32.1	31.3	33.3	37.1	40.7	44.0	47.0	49.8
	VT	104.5	119.3	124.3	126.4	127.0	127.3	128.4	129.7	130.8	131.7	132.6
Total	**Cumulative**	630.3	707.6	777.2	841.6	891.4	935.2	972.1	1000.5	1023.5	1040.3	1050.6

% of BTM AC nameplate	36.5%	35.2%	33.9%	32.5%	31.2%	29.9%	28.8%	27.8%	26.8%	25.9%	25.1%

Notes:

(1) Forecast values are for behind-the-meter PV resources only

(2) Values include the effect of diminishing PV production as increasing PV penetrations shift the timing of peaks later in the day

(3) Values include the effects of an assumed 0.5%/year PV panel degradation rate

(4) All values represent anticipated July 1st installed PV, and are grossed up by 8% to reflect avoided transmission and distribution losses

(5) Different planning studies may use values different that these estimated peak load reductions based on the intent of the study

GEOGRAPHIC DISTRIBUTION OF PV FORECAST

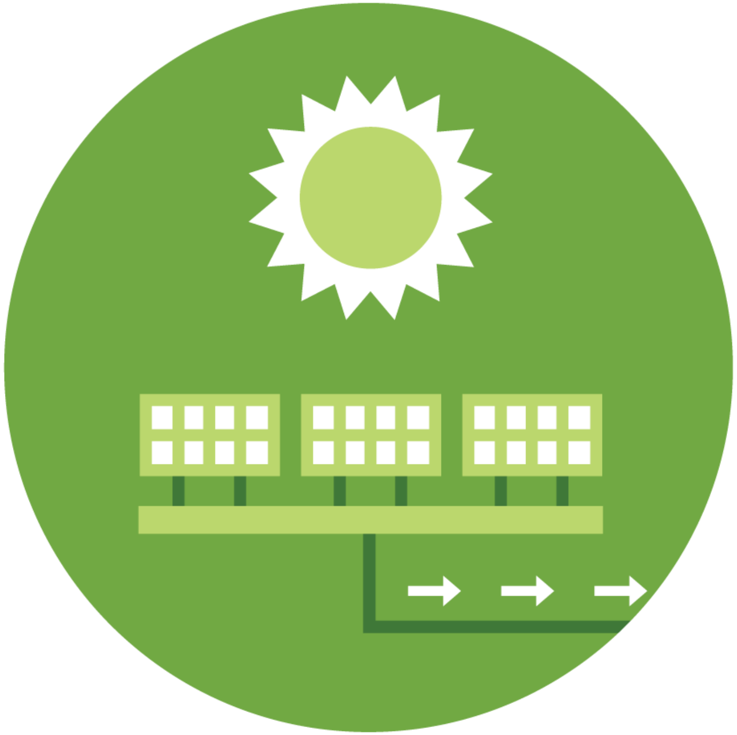
Background

- A reasonable representation of the locations of existing and future PV resources is required for appropriate modeling
- The locations of most future PV resources are ultimately unknown
- Mitigation of some of this uncertainty (especially for near-term development) is possible via analysis of available data

Forecasting PV By DR Dispatch Zone

- Demand Response (DR) Dispatch Zones were created as part of the DR Integration project
- These zones were created in consideration of electrical interfaces
- Quantifying existing and forecasted PV resources by Dispatch Zone (with nodal placement of some) will aid in the modeling of PV resources for planning and operations purposes

Geographic Distribution of PV Forecast



- Existing MWs:
  - Apply I.3.9 project MWs nodally
  - For remaining existing MWs, determine Dispatch Zone locations of projects already interconnected based on utility distribution queue data (town/zip), and apply MWs equally to all nodes in Zone
- Future MWs:
  - Apply I.3.9 project MWs nodally
  - For longer-term forecast, assume the same distribution as existing MWs

Dispatch Zone Distribution of PV

Based on December 31, 2018 Utility Data

State	Load Zone	Dispatch Zone	% of State
CT	CT	EasternCT	18.7%
	CT	NorthernCT	18.6%
	CT	Norwalk_Stamford	7.3%
	CT	WesternCT	55.4%
ME	ME	BangorHydro	14.6%
	ME	Maine	49.9%
	ME	PortlandMaine	35.5%
MA	NEMA	Boston	11.9%
	NEMA	NorthShore	5.8%
	SEMA	LowerSEMA	15.1%
	SEMA	SEMA	21.2%
	WCMA	CentralMA	14.0%
	WCMA	SpringfieldMA	7.1%
	WCMA	WesternMA	24.9%
NH	NH	NewHampshire	90.6%
	NH	Seacoast	9.4%
RI	RI	RhodeIsland	100.0%
VT	VT	NorthwestVermont	62.3%
	VT	Vermont	37.7%

APPENDIX

Example Calculation of BTM PV Estimated Summer Peak Load Reduction

Introduction

- The following slides describe an example calculation of estimated summer peak load reductions published in CELT
- The example calculation shown is for Massachusetts in July 2019

Description of Example Calculation Steps & Inputs

Massachusetts BTM PV July 2018 Summer Peak Load Reduction

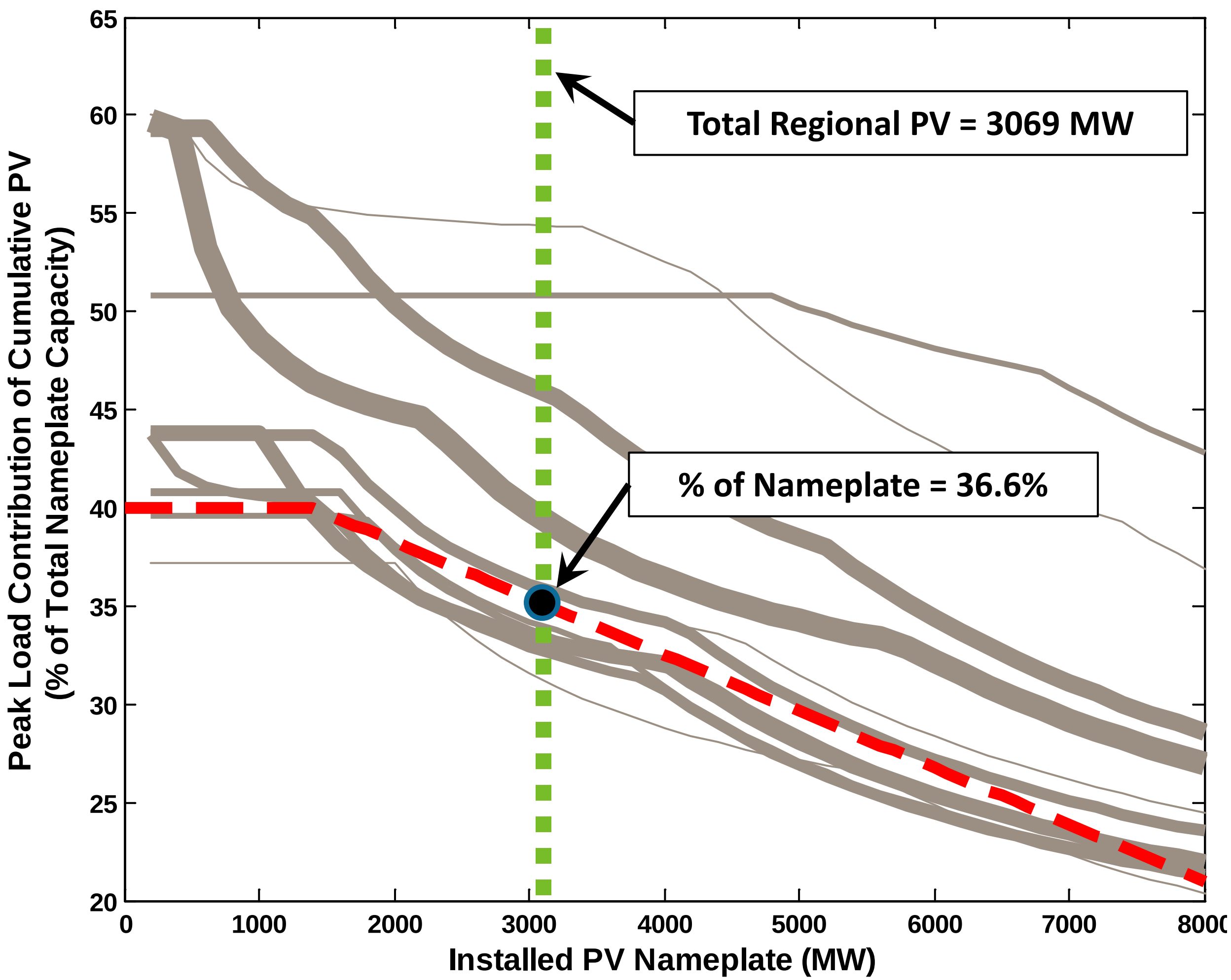
1. State monthly BTM PV nameplate forecast
   - Find BTM PV share of total end-of-year nameplate forecast based on state accounting for categories (FCM, non-FCM EOR, and BTM) – see slide 54
   - Input uses the conversion of cumulative end-of-year state nameplate forecast (slide 51) into monthly forecast using monthly capacity growth rates (slide 36)
2. % of nameplate contribution to summer peak
   - Value is determined by finding the intersection point of total PV nameplate with sloped line shown on next slide
3. Panel degradation multiplier
   - Assumed annual degradation rate (ADR) = 0.5% per year
   - Based on forecasted composite age (CA) in years using equation below
   - State composite ages are plotted on slide 39

$$DegradeMultiplier = (1 - ADR)^{CA}$$

4. Gross-up for assumed transmission & distribution losses
   - Value of 8% is used

% of Nameplate Determination

Estimated Summer Peak Load Reduction



Note:
Graphic is from Appendix of 2016 PV Forecast slides (slide 89): https://www.iso-ne.com/static-assets/documents/2016/09/2016_solar_forecast_details_final.pdf

Final Calculation

Massachusetts BTM PV July 2019 Summer Peak Load Reduction

Calculation Line Item	Relevant Region	
July 2018 Total Nameplate PV Forecast (MW)	ISO-NE	3069
July 2018 BTM PV Nameplate Forecast (MW)	MA	923.2
% of Nameplate (from previous slide)	ISO-NE	0.352
Panel Degradation Multiplier	MA	0.9830
Peak Gross Up Factor	ISO-NE	1.08
Final BTM PV Summer Peak Load Reduction (MW)	MA	**345.0**

Final estimated peak load reduction calculated by multiplying all values highlighted in yellow