Final 2020 PV Forecast

Outline

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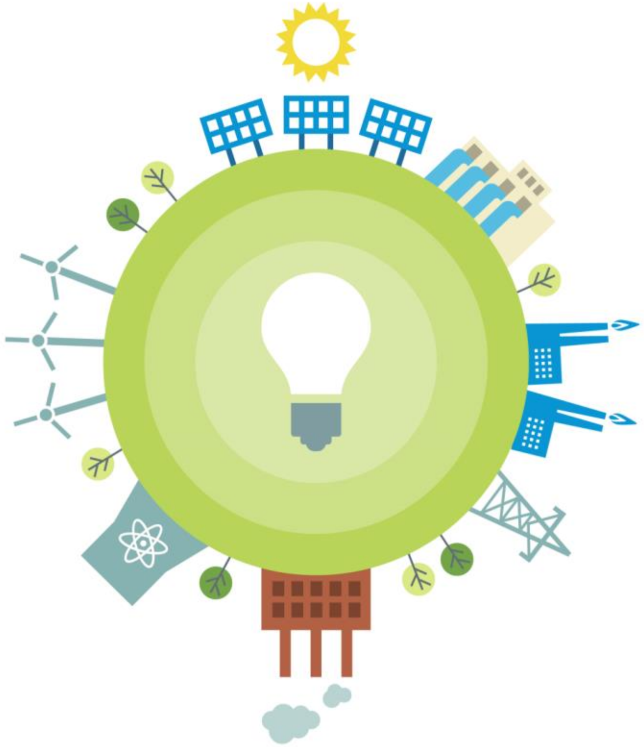
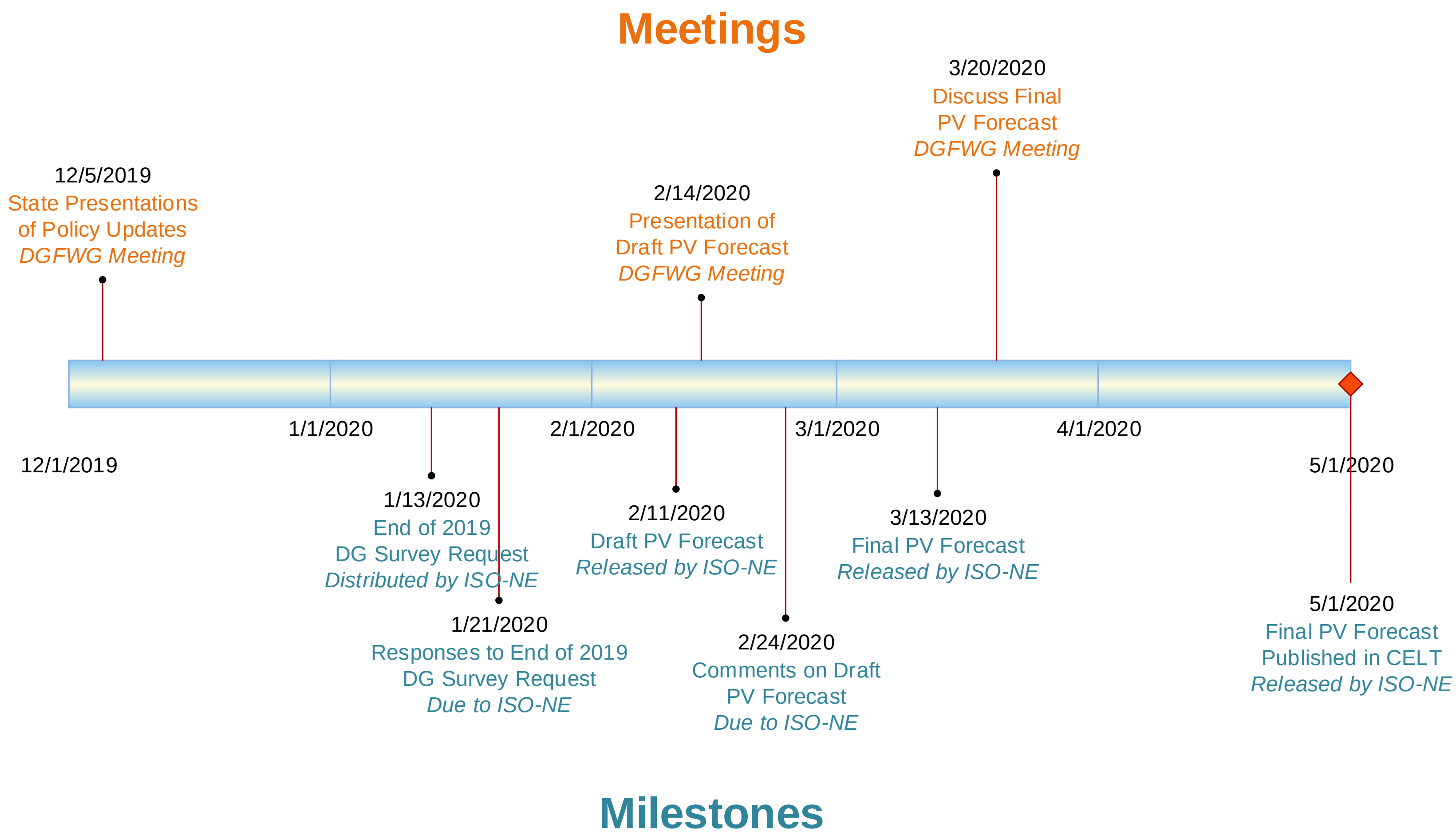
- Geographic Distribution of PV Forecast
- Appendix: Example Calculation of Estimated Summer Peak Load Reductions from BTM PV



2020 PV Forecast Schedule



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 2020 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 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
- 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

Background and Forecast Review Process

- The ISO discussed the [draft 2020 PV forecast] with the DGFWG at the February 14, 2020 meeting
- Stakeholders provided comments on the draft forecast
  - See: https://www.iso-ne.com/committees/planning/distributed-generation/?eventId=140046
- The final PV forecast is published in the 2020 CELT (Section 3):
  - See: https://www.iso-ne.com/system-planning/system-plans-studies/celt/

2019 PV GROWTH: FORECAST VS. REPORTED

2019 PV Growth

Total Nameplate Capacity

- Comparison of the state-by-state 2019 forecast PV growth and the growth for 2019 reported by utilities is tabulated below
  - Values include FCM, EOR, and BTM PV projects < 5 MW_{ac} in nameplate capacity
- Regionally, 2019 growth reported by utilities totaled 548.6 MW, which is more than 85 MW higher than the forecast growth
  - Results vary by state

State	2019 Reported Growth	2019 Forecast Growth	Difference
CT	102.2	68.4	33.8
MA	309.2	292.0	17.2
ME	14.9	7.1	7.8
NH	21.4	12.7	8.7
RI	43.1	51.3	-8.2
VT	57.8	31.5	26.3
Region	548.6	463.1	85.5

Larger-Scale PV

Projects >5 MW_{ac}

- Tabulated below is a summary of in-service, larger-scale (i.e., non-DG) PV projects included as part of Distribution Owner survey data responses
- These projects are not included in the PV forecast, and are excluded from installed PV totals reported herein

State	# Projects Listed	Total Nameplate (MW_{ac})
CT	3	66.4
MA	-	-
ME	1	9.9
NH	-	-
RI	8	60.25
VT	-	-
Total	**12**	**136.55**

DISTRIBUTION OWNER SURVEY RESULTS

Installed PV – December 2019

Determining Cumulative PV Totals

December 2019 Distribution Owner Survey Data

- 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, 2019
  - 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 2019 Cumulative PV Totals

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 12/31/19.

State	Installed Capacity (MW_{AC})	No. of Installations
Massachusetts*	2,180.45	102,381
Connecticut	566.53	44,514
Vermont*	364.24	13,863
New Hampshire	105.24	9,587
Rhode Island	159.75	7,776
Maine	56.32	5,387
New England	**3,432.53**	**183,508**

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

December 2019 Cumulative PV Totals (1 of 2)

Summary of Distribution Owner PV Data

State	Utility	Installed Capacity (MW_{AC})	No. of Installations
CT	Connecticut Light & Power	431.85	32,291
	Connecticut Municipal Electric Energy Co-op	13.43	7
	United Illuminating	121.25	12,216
	Total	**566.53**	**44,514**
MA	Braintree Electric Light Department	5.24	29
	Chicopee Electric Light	13.13	32
	Unitil (FG&E)	26.85	1,785
	National Grid	1,113.31	52,943
	NSTAR	608.88	34,593
	Reading Municipal Lighting Plant	7.74	146
	Shrewsbury Electric & Cable Operations	6.18	85
	SREC I	54.21	589
	SREC II	96.60	1,672
	Western Massachusetts Electric Company	248.30	10,507
	Total	**2,180.45**	**102,381**
ME	Central Maine Power	48.84	4,568
	Emera	7.48	819
	Total	**56.32**	**5,387**

December 2019 Cumulative PV Totals (2 of 2)

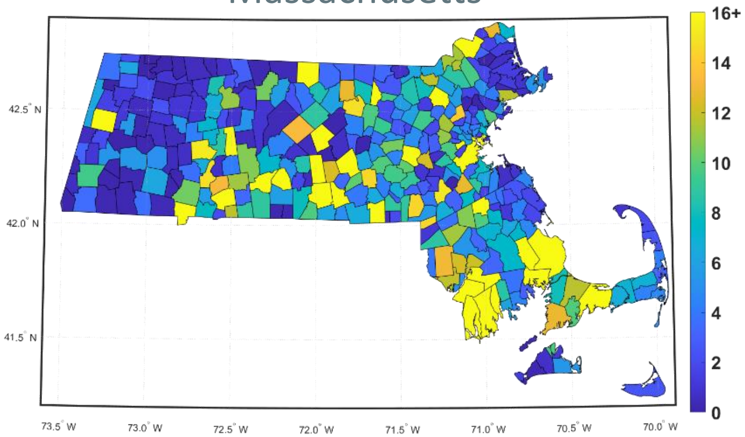
Summary of Distribution Owner PV Data

State	Utility	Installed Capacity (MW_{AC})	No. of Installations
NH	Liberty Utilities	8.21	631
	New Hampshire Electric Co-op	11.30	1,133
	Public Service of New Hampshire	75.35	6,871
	Unitil (UES)	10.38	952
	Total	**105.24**	**9,587**
RI	National Grid	159.75	7,776
	Total	**159.75**	**7,776**
VT	Burlington Electric Department	7.07	286
	Green Mountain Power	303.58	10,759
	Stowe Electric Department	2.68	106
	Vermont Electric Co-op	32.33	1,562
	Vermont Public Power Supply Authority	11.80	583
	VT Other Municipals	0.10	1
	Washington Electric Co-op	6.69	566
	Total	**364.24**	**13,863**
New England		**3,432.53**	**183,508**

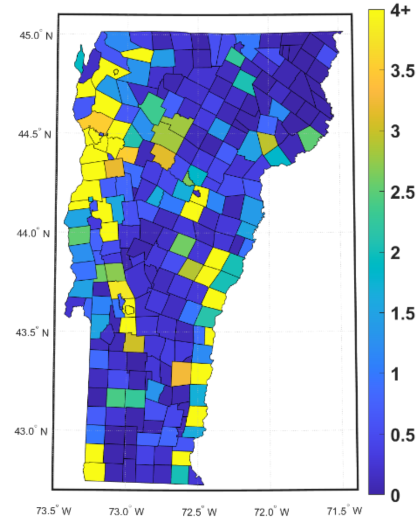
Installed PV Capacity as of December 2019

State Heat Maps

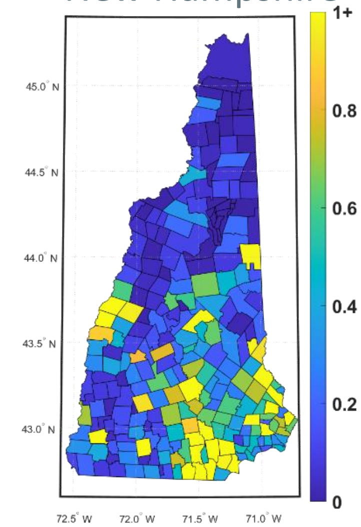
Massachusetts



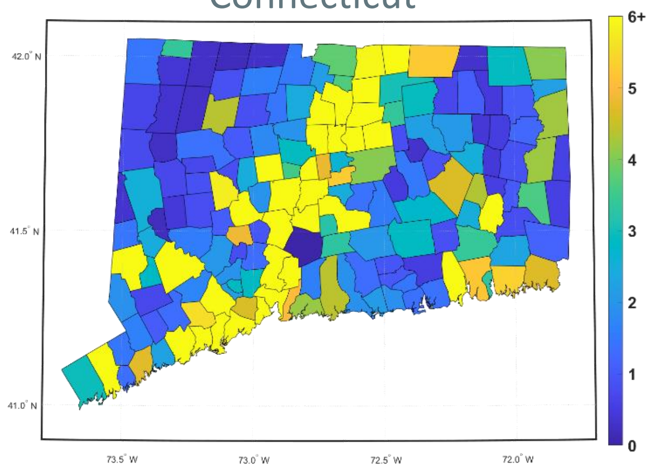
Vermont



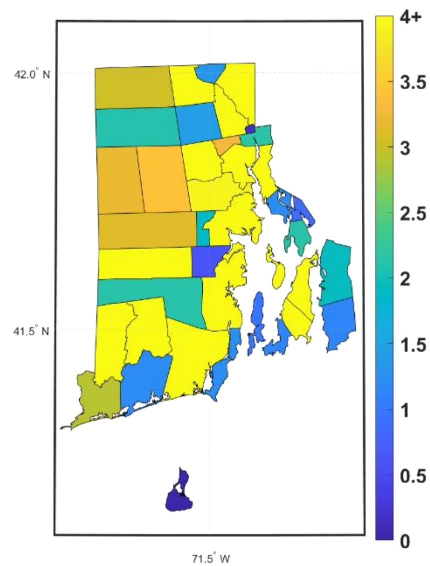
New Hampshire



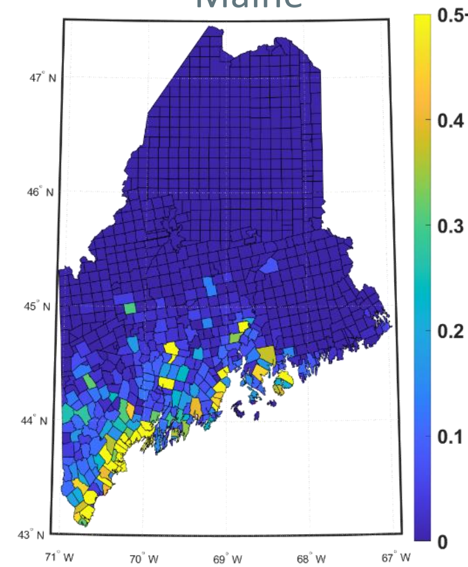
Connecticut



Rhode Island



Maine



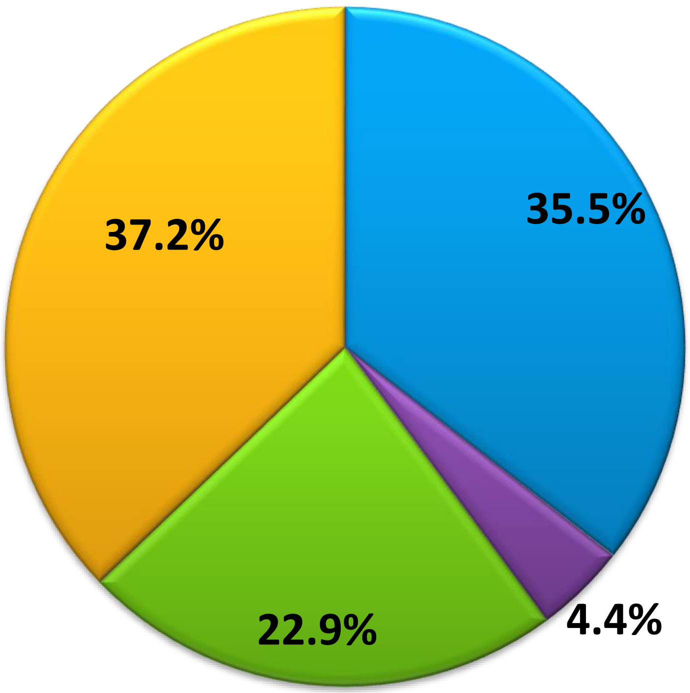
<u>Note</u>: Legend to the right of each state plot shows color scale of nameplate megawatts per town

Installed PV Capacity as of December 2019

ISO-NE by Size Class

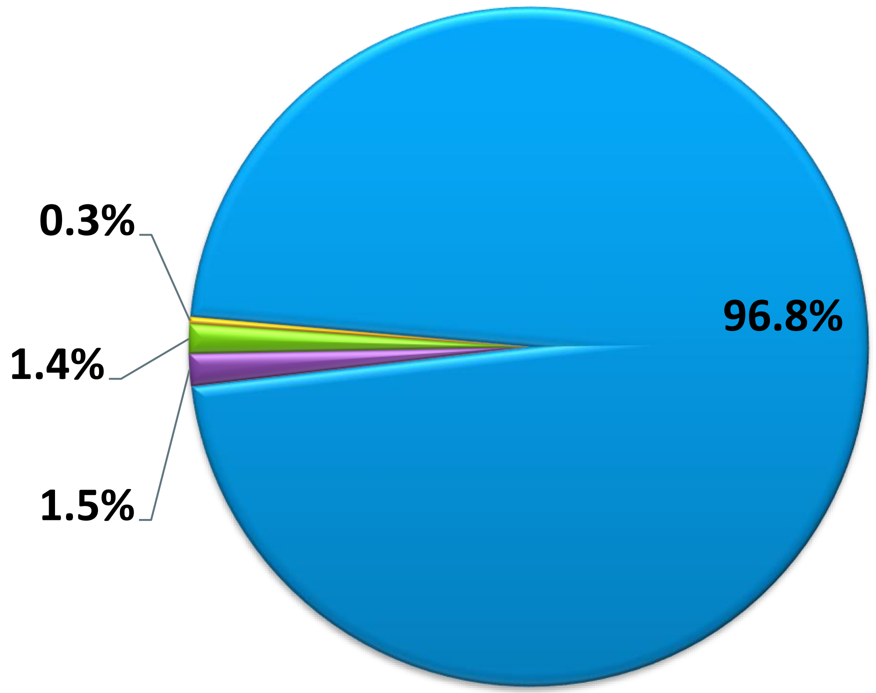
Installed Capacity (MW_{AC})

Total = 3,433 MW_{AC}



Number of Sites

Total = 183,508



■ <25kW ■ 25kW-<100kW ■ 100kW-<1000kW ■ >=1000kW

TOTAL NAMEPLATE CAPACITY 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 2019 forecast
- For the business ITC only, IRS provisions allow project developers two methods of pre-qualifying for the ITC by meeting commence construction standards, as long as the project is placed in service before 1/1/2024:
  1. Physical Work Test: Continuing work of a significant nature
  2. Five Percent Safe Harbor: Having paid or incurred 5% or more of the total cost of the project

Residential ITC

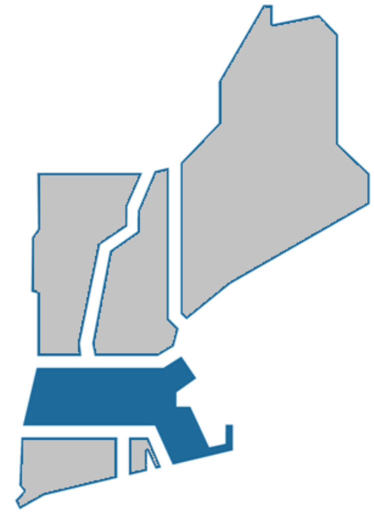
Maximum Allowable Residential ITC	
Year	Credit
2019	30%
2020	26%
2021	22%
Future Years	0%

Business ITC

ITC by Date of Construction Start	
Year construction starts	Credit
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 Assumptions

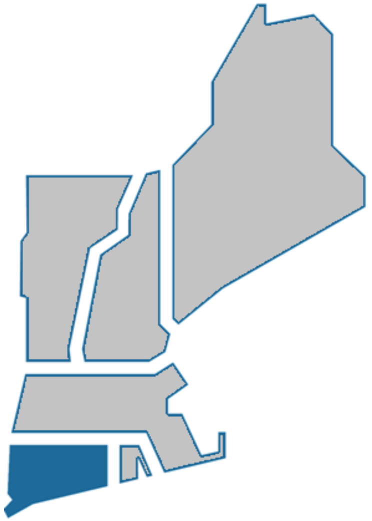


- MA DPU's 12/5/19 DGFWG presentation serves as primary source for MA policy information
- MA Distribution Owners survey results:
  - 2,180.5 MW_{AC} installed by 12/31/19
- Solar Carve-Out Renewable Energy Certificate (SREC) program
  - A total of 2,412.5 MW_{DC} will be developed as part of SREC-I and SREC-II
    - 2,386.7 MW_{DC} installed by 12/31/19
    - Remaining 25.8 MW_{DC} will be installed in 2020 (21.5 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)
  - Approximately 200 MW_{AC} installed by end of 2019
    - Assume program capacity is divided over years as tabulated below

Year	2020	2021	2022	2023	2024
%	22.5	22.5	22.5	22.5	10
MW	315	315	315	315	140

- Post-policy development assumed to occur such that 315 MW is carried forward from 2024 onward at constant rate throughout the remaining years of the forecast period, and post-policy discount factors are applied as necessary

Connecticut Forecast Assumptions

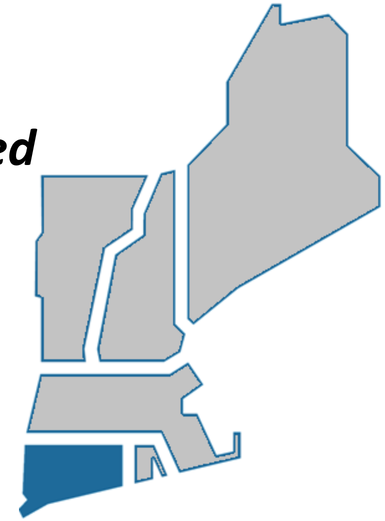


- CT DEEP's 12/5/19 DGFWG presentation serves as primary source for CT policy information
- CT Distribution Owner survey results
  - 566.5 MW_{AC} installed by 12/31/19
- LREC/ZREC program assumptions
  - Assume a total of 630 MW are procured in Years 1-10 of program (Approximately 220 MW in-service)
  - Assume 45% attrition rate for remaining 410 MW, with at total of 255 MW (226 MW after discount factors) divided over 4 years, 2020-2023, as tabulated below:

Year	2020	2021	2022	2023
MW	59.44	62.74	66.43	66.43

- Combination of Residential Solar Investment Program (RSIP) and net-metering extension (Public Act 19-35), after discount factors, will promote 42 MW in 2020, 32 MW in 2021, and 40 MW in 2022
- Other policy-driven projects:
  - Shared Clean Energy Facility (SCEF) Pilot Program
    - Two projects totaling 3.6 MW reach commercial operation in 2020
  - DEEP Small Scale Procurement (< 5MW)
    - 4.98 MW project in service in 2021

Connecticut Forecast Assumptions *continued*

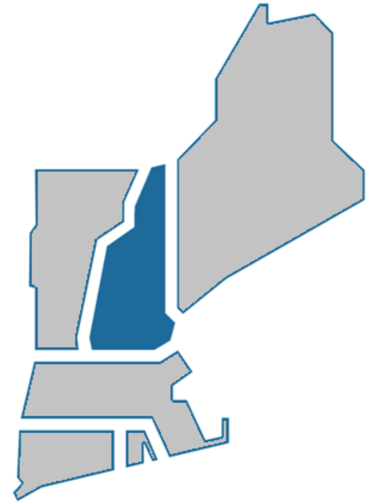


- CT “successor” programs
  - LREC/ZREC successor procurements begin in 2020
    - Result in 31.2 MW/year (26.5 MW/year after discount) from 2022-2027
  - RSIP successor begins in 2022
    - Results in 42.5 MW/year from 2022-2027
  - SCEF successor begins in 2022
    - Results in 17.7 MW/year (15 MW/year after discount) from 2022-2027
- All MWs from successor programs are carried forward until 2029 at a constant rate, and post-policy discount factors are applied

Vermont Forecast Assumptions

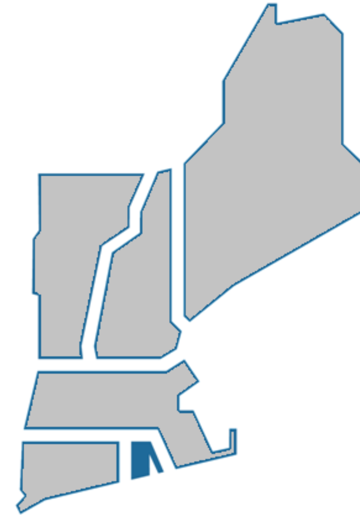
- VT DPS' 12/5/19 DGFWG presentation serves as the primary source for VT policy information
- VT Distribution Owner survey results
  - 364.1 MW_{AC} installed by 12/31/19
- DG carve-out of the Renewable Energy Standard (RES)
  - Assume ~85% of eligible resources will be PV and a total of 26 MW/year will 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 2020 (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 26 MW/year as stated above
- For 2020, a total of 31 MW is forecast in VT, which is in excess of the 26 MW/year due to the RES DG carve-out
  - This reflects expectations that, similar to the past few years, PV development will be greater than that needed for compliance with the RES DG carve out for one more year

New Hampshire Forecast Assumptions



- NH PUC's 12/5/19 DGFWG presentation serves as the primary source for NH policy information
- NH Distribution Owners survey results
  - 105.2 MW_{AC} installed by 12/31/19
  - 21.4 MW_{AC} installed in 2019
- Assume the Net Energy Metering Tariff continues to support the 2019 rate of growth throughout the forecast horizon
  - No limit on state-wide aggregate net metered capacity

Rhode Island Forecast Assumptions



- RI OER's 12/5/19 DGFWG presentation serves as the primary source for RI policy information
- RI Distribution Owner survey results
  - 159.7 MW_{AC} installed by 12/31/19
  - 43.1 MW installed in 2019
- DG Standards Contracts (DGSC) program
  - A total of 22.55 MW of PV is operational, and no further pending projects exist
- 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 6.488 MW_{DC} (~5.39 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 a total of 20 MW/year of projects < 5 MW_{ac} nameplate capacity over the forecast horizon

Maine Forecast Assumptions

- ME PUC's 12/5/19 DGFWG presentation serves as the primary source for ME policy information
- ME Distribution Owner survey results
  - 56.3 MW_{AC} installed by 12/31/19
  - 14.9 MW installed in 2019
- Assume the Net Energy Billing Rule (according to L.D. 1711) continues to support the 2019 rate of growth throughout the forecast horizon
  - No limit on state-wide aggregate net metered capacity
  - Commercial and Institutional net energy billing supported
  - System sizes up to 5 MW are eligible (increased from 660kW as part of L.D. 1711)
- Additionally, assume the new incentives established as part of Maine's "Act to Promote Solar Energy Projects and Distributed Generation Resources in Maine" (L.D. 1711) will support a total of 375 MW of additional installed PV by July 1, 2024 according to the following tabulated timeline:

Year	2021	2022	2023	2024
%	20	26.66	26.66	26.66
MW	75	100	100	100

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 31) 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 2020 Forecast

Policy-Based

Forecast Year	Discount Factor
2020	5%
2021	10%
2022	15%
2023	15%
2024	15%
2025	15%
2026	15%
2027	15%
2028	15%
2029	15%

Post-Policy

Forecast Year	Discount Factor
2020	35.0%
2021	36.7%
2022	38.3%
2023	40.0%
2024	41.7%
2025	43.3%
2026	45.0%
2027	46.7%
2028	48.3%
2029	50.0%

Final 2020 Forecast Inputs

Pre-Discounted Nameplate Values

States	Pre-Discount Annual Total MW (AC nameplate rating)											Totals
	Thru 2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	
CT	566.5	105.0	99.7	157.8	157.8	91.3	91.3	91.3	91.3	91.3	91.3	**1,634.7**
MA	2180.4	336.5	315.0	315.0	315.0	315.0	315.0	315.0	315.0	315.0	315.0	**5,351.9**
ME	56.3	14.9	89.9	114.9	114.9	114.9	14.9	14.9	14.9	14.9	14.9	**580.5**
NH	105.2	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	**319.2**
RI	159.7	51.7	51.7	51.7	49.9	49.9	49.9	49.9	49.9	49.9	49.9	**663.9**
VT	364.1	31.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	**629.1**
Pre-Discount Annual Policy-Based MWs	**3432.4**	**560.5**	**603.7**	**686.8**	**685.0**	**443.5**	**203.5**	**203.5**	**203.5**	**112.2**	**112.2**	**7,246.8**
Pre-Discount Annual Post-Policy MWs	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**175.0**	**315.0**	**315.0**	**315.0**	**406.3**	**406.3**	**1,932.6**
Pre-Discount Annual Total (MW)	**3432.4**	**560.5**	**603.7**	**686.8**	**685.0**	**618.5**	**518.5**	**518.5**	**518.5**	**518.5**	**518.5**	**9,179.5**
Pre-Discount Cumulative Total (MW)	**3432.4**	**3,992.9**	**4,596.6**	**5,283.4**	**5,968.3**	**6,586.9**	**7,105.4**	**7,623.9**	**8,142.4**	**8,661.0**	**9,179.5**	**9,179.5**

Notes:

(1) The above values **are not the forecast**, but rather pre-discounted inputs to the forecast (see slides 22-28 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

FINAL 2020 PV NAMEPLATE FORECAST

Final 2020 PV Forecast

Nameplate Capacity, MW_{ac}

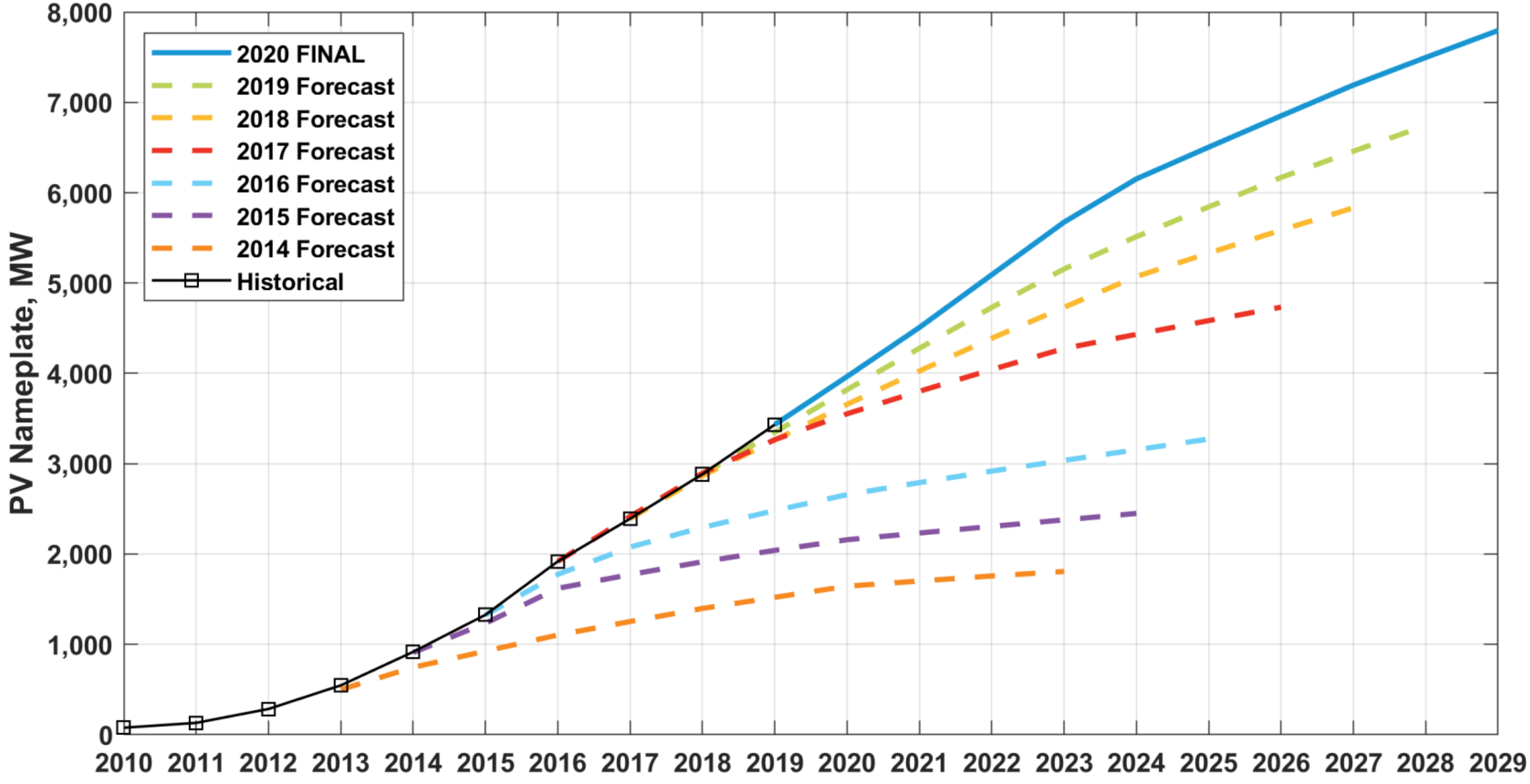
States	Annual Total MW (AC nameplate rating)											Totals
	Thru 2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	
CT	566.5	99.8	89.8	134.1	134.1	77.6	77.6	77.6	77.6	47.2	45.7	**1,427.6**
MA	2180.4	319.6	283.5	267.8	267.8	221.1	178.5	173.3	168.0	162.8	157.5	**4,380.2**
ME	56.3	14.2	80.9	97.7	97.7	97.7	12.7	12.7	12.7	12.7	12.7	**507.9**
NH	105.2	20.3	19.3	18.2	18.2	18.2	18.2	18.2	18.2	18.2	18.2	**290.3**
RI	159.7	49.1	46.5	43.9	42.4	42.4	42.4	42.4	42.4	42.4	42.4	**596.1**
VT	364.1	29.5	23.4	22.1	22.1	22.1	22.1	22.1	22.1	22.1	22.1	**593.8**
Regional - Annual (MW)	**3432.4**	**532.5**	**543.3**	**583.7**	**582.2**	**479.1**	**351.5**	**346.2**	**341.0**	**305.3**	**298.5**	**7,795.8**
Regional - Cumulative (MW)	**3432.4**	**3964.9**	**4508.2**	**5092.0**	**5674.2**	**6153.3**	**6504.8**	**6851.0**	**7192.0**	**7497.3**	**7795.8**	**7,795.8**

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

Total PV Nameplate Capacity Growth

Reported Historical vs. Forecast (FCM+EOR+BTM), MW_{ac}



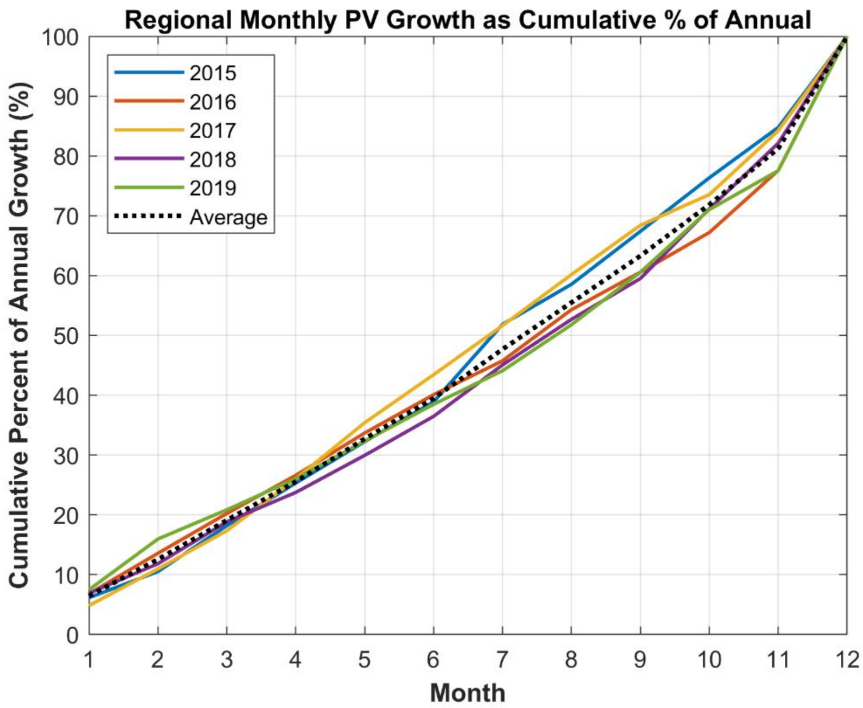
2020 PV ENERGY FORECAST

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 2015 and 2019 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 6 years of PV performance data (2014-2019)
  - Resulting state and regional CFs are tabulated to the right, and plots of individual monthly capacity factors in each state are shown on slide 38

State	Average CF, %
CT	14.7
ME	14.5
NH	14.1
RI	14.8
VT	13.7
MA	14.5
ISO-NE	**14.5**

Historical Monthly PV Growth Trends, 2015-2019



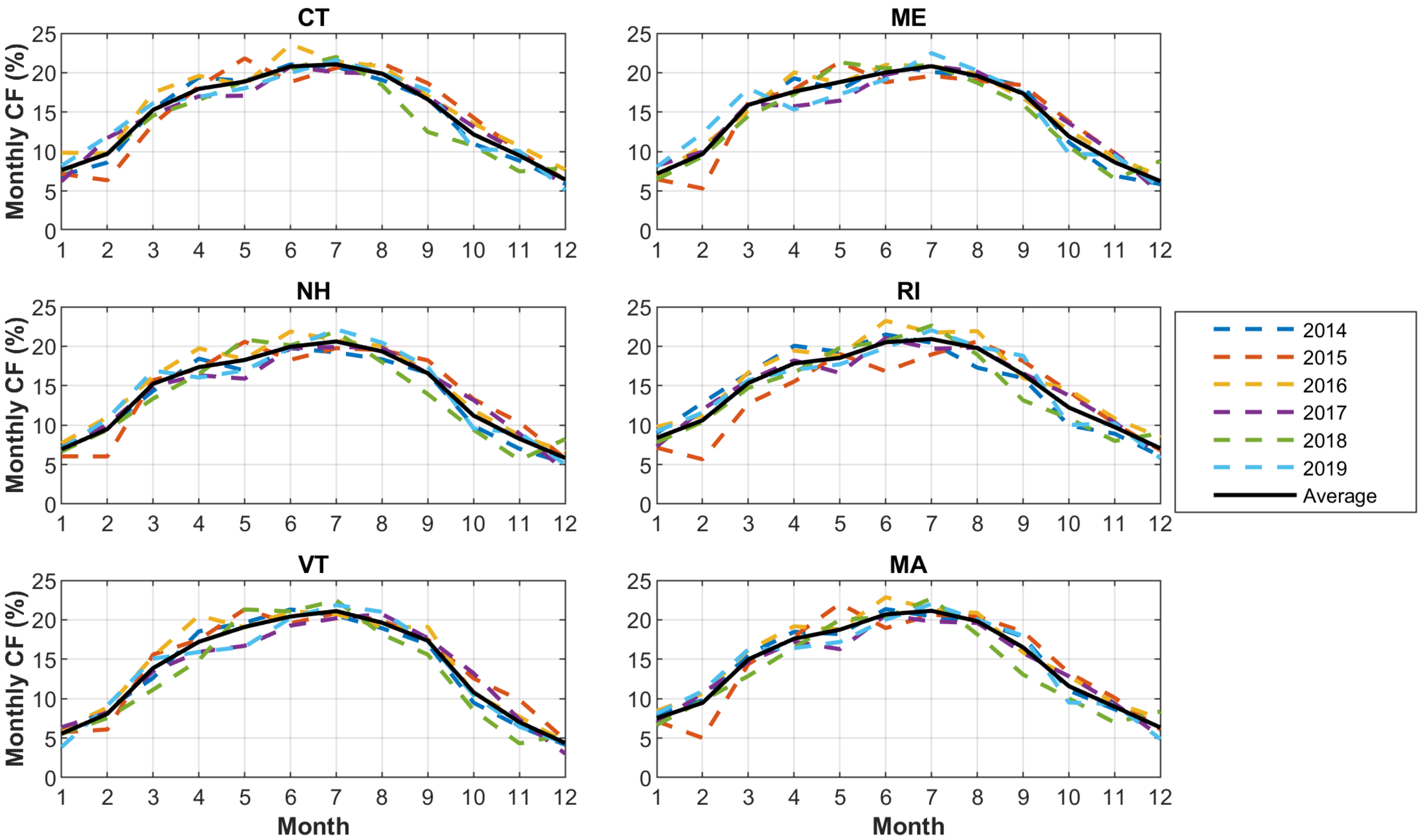
Average Monthly Growth Rates, % of Annual

Month	Monthly PV Growth (% of Annual)	Monthly PV Growth (Cumulative % of Annual)
1	6	6
2	6	13
3	7	19
4	6	26
5	7	33
6	7	39
7	8	48
8	8	55
9	8	63
10	9	72
11	9	81
12	19	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, 2014-2019



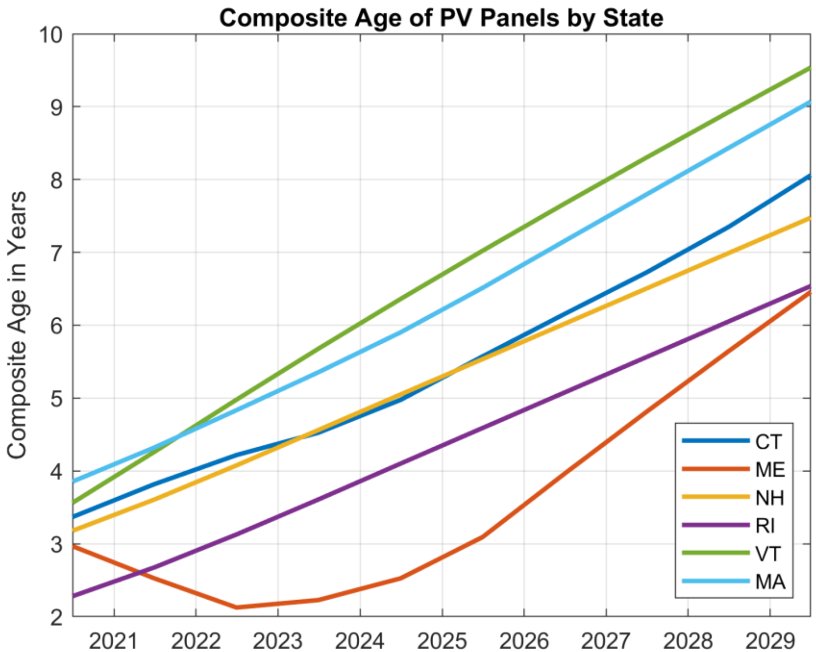
PV Panel Degradation Factors

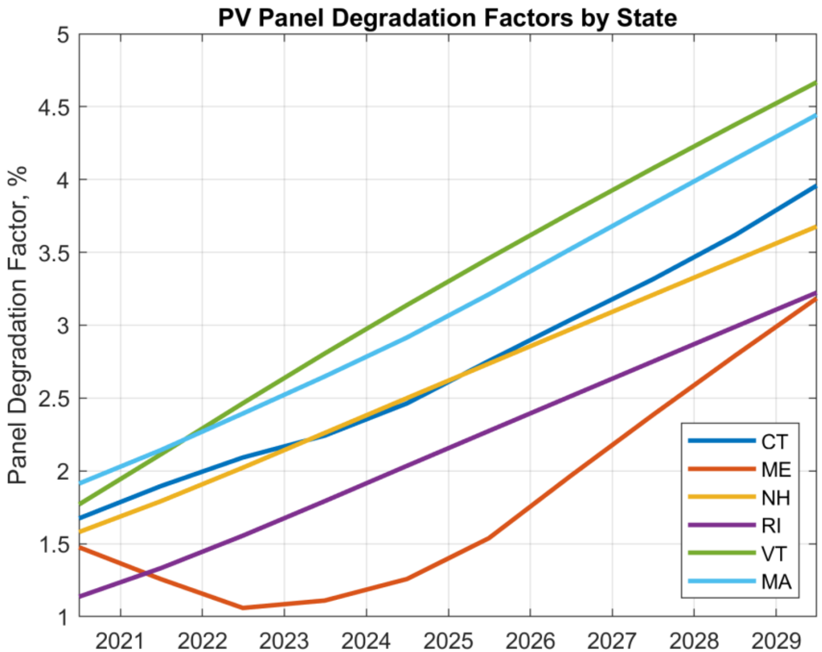
- No changes to the methodology to account for panel degradation were made since last year's forecast
- Forecasts of BTM PV energy and estimated summer peak load reductions include the effects of a 0.5%/year panel degradation rate to account for the expected declining conversion efficiency of solar panels 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 all 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 2020 PV Energy Forecast

All Forecast PV (FCM+EOR+BTM), GWh

States	Total Estimated Annual Energy (GWh)										
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
CT	681	821	945	1,089	1,266	1,411	1,507	1,605	1,703	1,785	1,836
MA	2,693	3,067	3,453	3,807	4,147	4,466	4,708	4,921	5,126	5,332	5,512
ME	68	83	142	260	390	520	597	611	625	640	653
NH	122	148	172	196	219	242	264	287	309	332	354
RI	181	247	311	372	429	486	541	596	652	708	761
VT	408	473	504	531	556	583	607	632	657	683	707
Regional - Annual Energy (GWh)	**4,154**	**4,838**	**5,528**	**6,255**	**7,008**	**7,708**	**8,224**	**8,652**	**9,072**	**9,481**	**9,823**

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% 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 is 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 14
  2. **Non-FCM EOR/Gen**
     - Determine the % share of non-FCM PV participating in energy market at the end of 2019
  3. **BTM**
     - Net the values from steps 1 and 2 from the annual state PV forecast according to assumptions detailed on the next slide; the remainder is the BTM PV

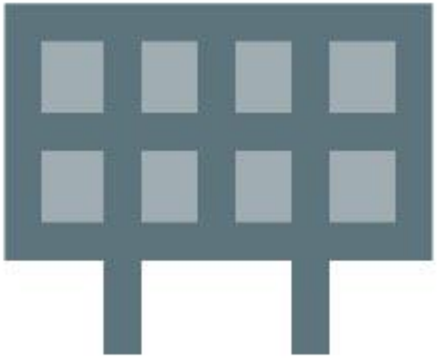
PV in ISO New England Markets

Data and Assumptions

- **FCM**
  - ISO identified all PV generators or demand resources (DR) that have Capacity Supply Obligations (CSO) in FCM up through FCA 14
    - Maintain separate accounting for FCM_{supply} and FCM_{DR}
  - Assume aggregate total PV in FCM as of FCA 14 remains constant from 2023-2028
- **Non-FCM Gen/EOR**
  - ISO identified total nameplate capacity of PV in each state registered in the energy market as of 12/31/19
  - Assume the ($EOR+FCM_{supply}$) share of total PV at the end of 2019 in each state *except Maine* remains constant throughout the forecast horizon
    - For Maine, assume ($EOR+FCM_{supply}$) share is 75% over the forecast horizon to reflect the fact that new policies prompting the majority of future PV growth require participation in wholesale markets
- Other assumptions:
  - FCM_{supply} 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

- Historical BTM PV production estimates are developed at the hourly level for reconstitution in the development of the long-term gross load forecast
  - Estimates cover the historical period starting January 1, 2012
- 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
- The method used to develop the historical BTM PV profiles is described in slides 18-28 of [this September 27, 2019 Load Forecast Committee presentation]



CLASSIFICATION OF FINAL 2020 PV FORECAST

Final 2020 PV Forecast

Cumulative Nameplate, MW_{ac}

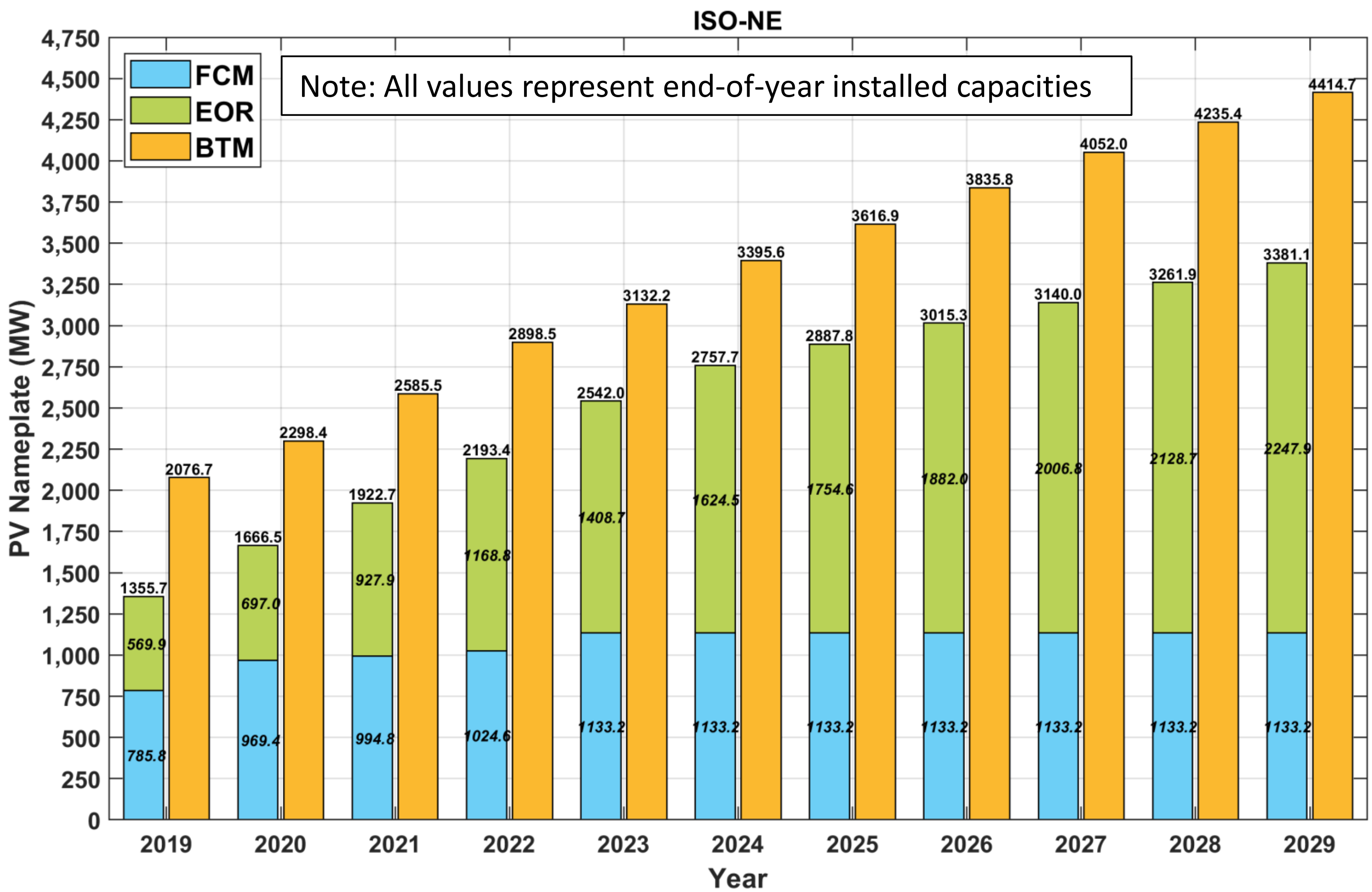
States	Cumulative Total MW (AC nameplate rating)										
	Thru 2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
CT	566.5	666.3	756.1	890.2	1,024.3	1,101.9	1,179.5	1,257.1	1,334.8	1,381.9	1,427.6
MA	2,180.4	2,500.1	2,783.6	3,051.3	3,319.1	3,540.2	3,718.7	3,891.9	4,059.9	4,222.7	4,380.2
ME	56.3	70.5	151.4	249.1	346.8	444.5	457.2	469.8	482.5	495.2	507.9
NH	105.2	125.6	144.8	163.0	181.2	199.4	217.6	235.8	254.0	272.1	290.3
RI	159.7	208.8	255.3	299.3	341.7	384.1	426.5	468.9	511.3	553.7	596.1
VT	364.1	393.6	417.0	439.1	461.2	483.3	505.4	527.5	549.6	571.7	593.8
Regional - Cumulative (MW)	**3,432.4**	**3,964.9**	**4,508.2**	**5,092.0**	**5,674.2**	**6,153.3**	**6,504.8**	**6,851.0**	**7,192.0**	**7,497.3**	**7,795.8**

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

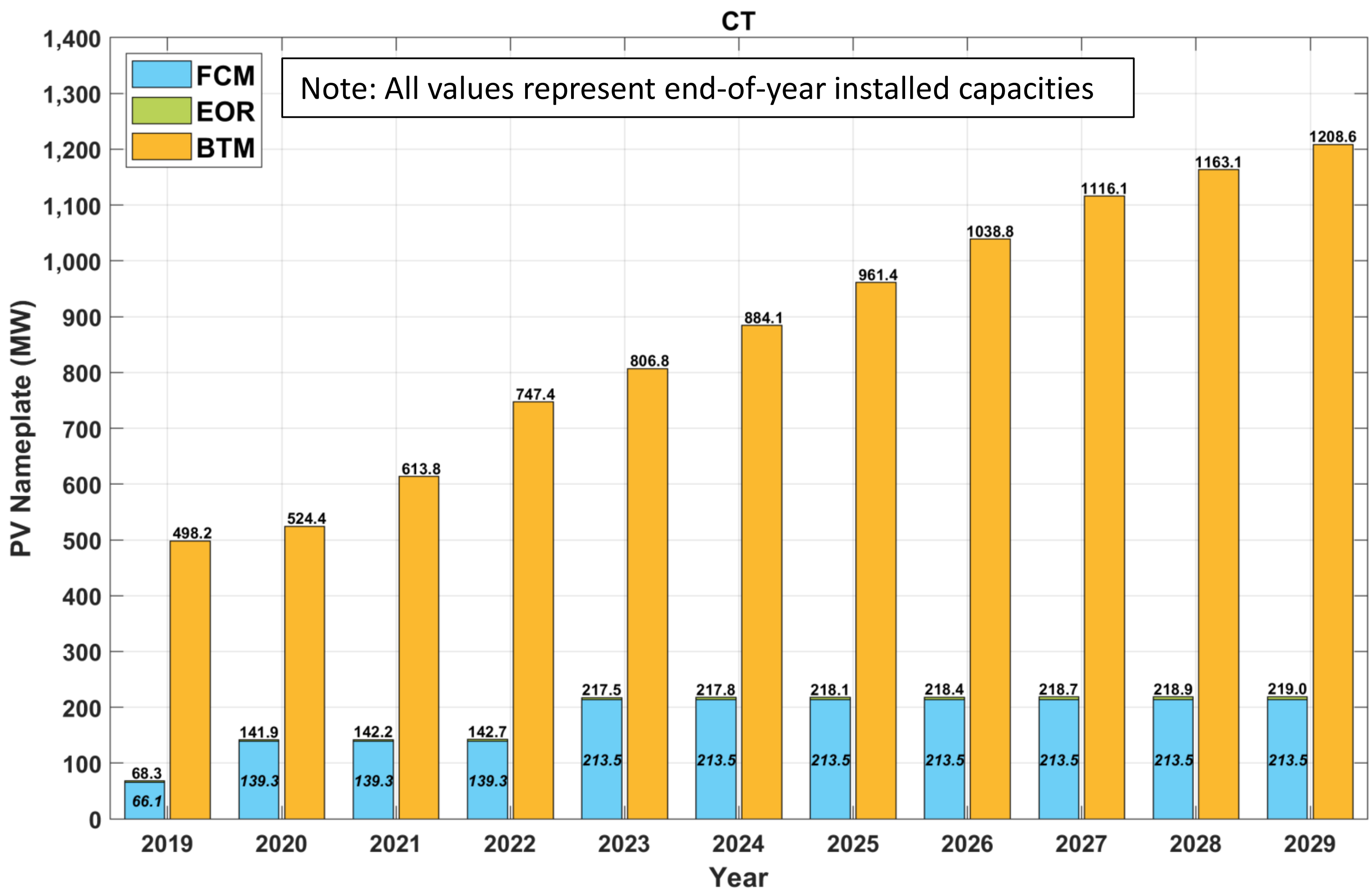
Final 2020 PV Forecast – New England

Cumulative Nameplate by Category, MW_{ac}



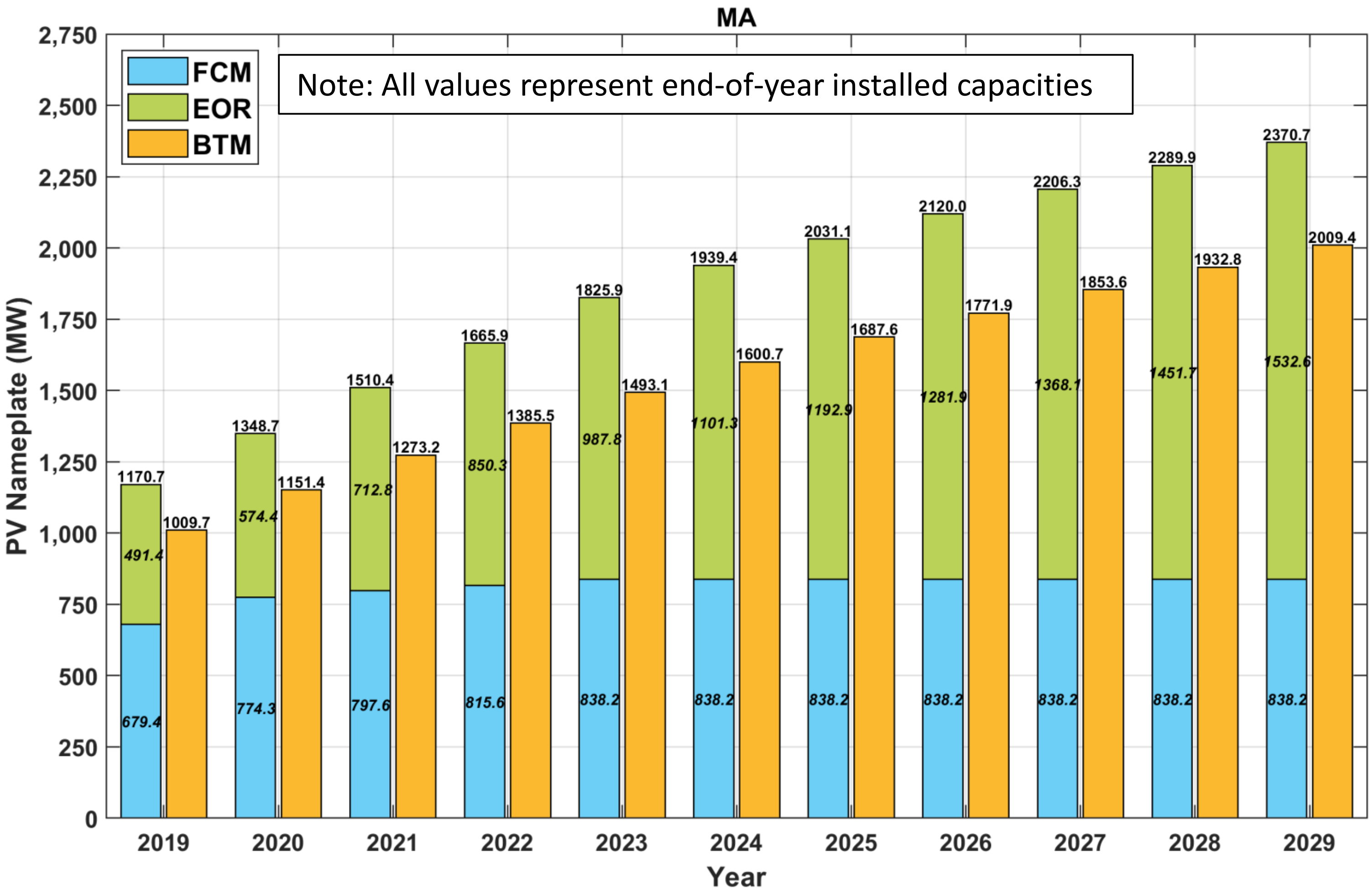
Final 2020 PV Forecast – Connecticut

Cumulative Nameplate by Category, MW_{ac}



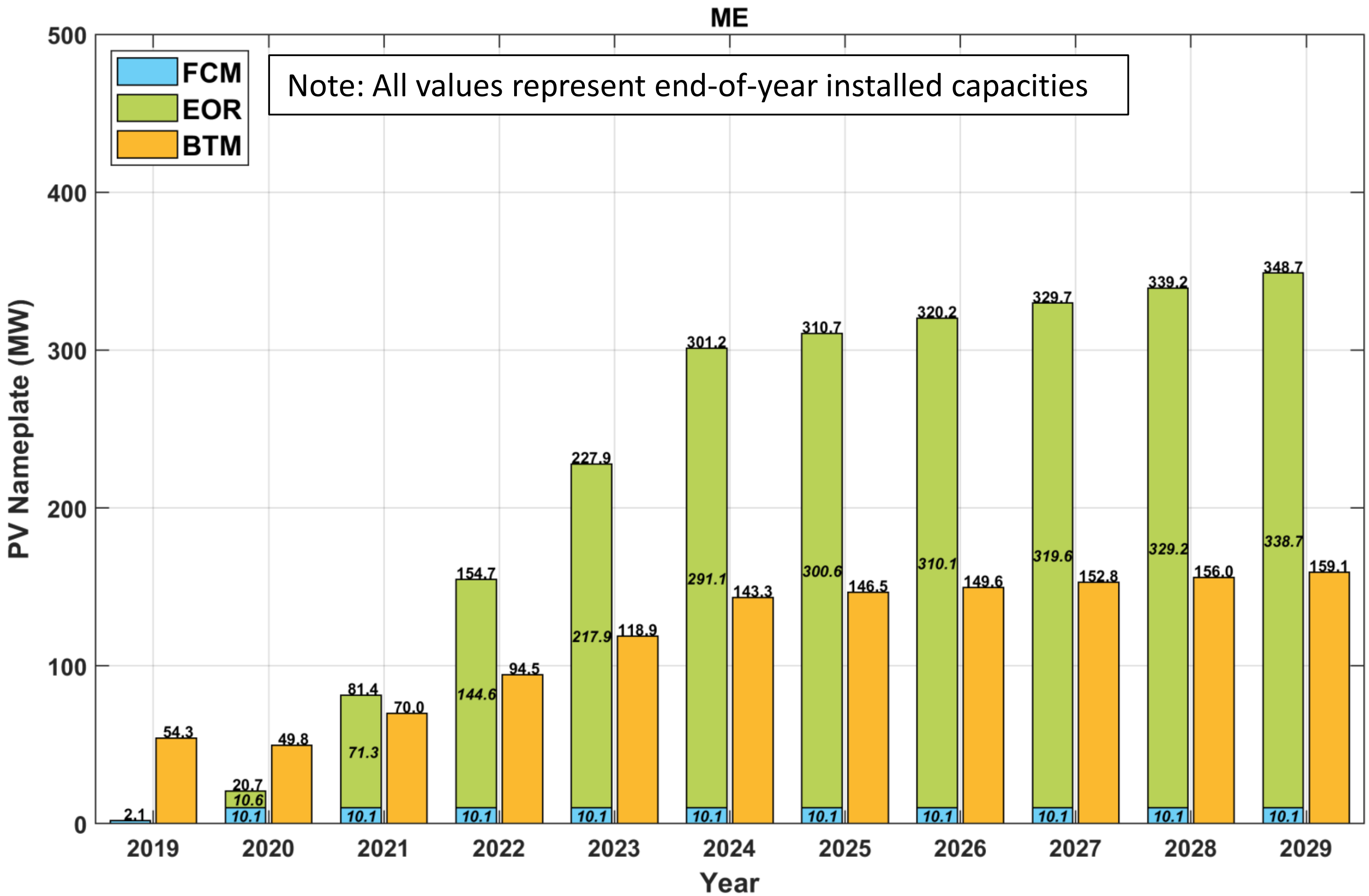
Final 2020 PV Forecast – Massachusetts

Cumulative Nameplate by Category, MW_{ac}



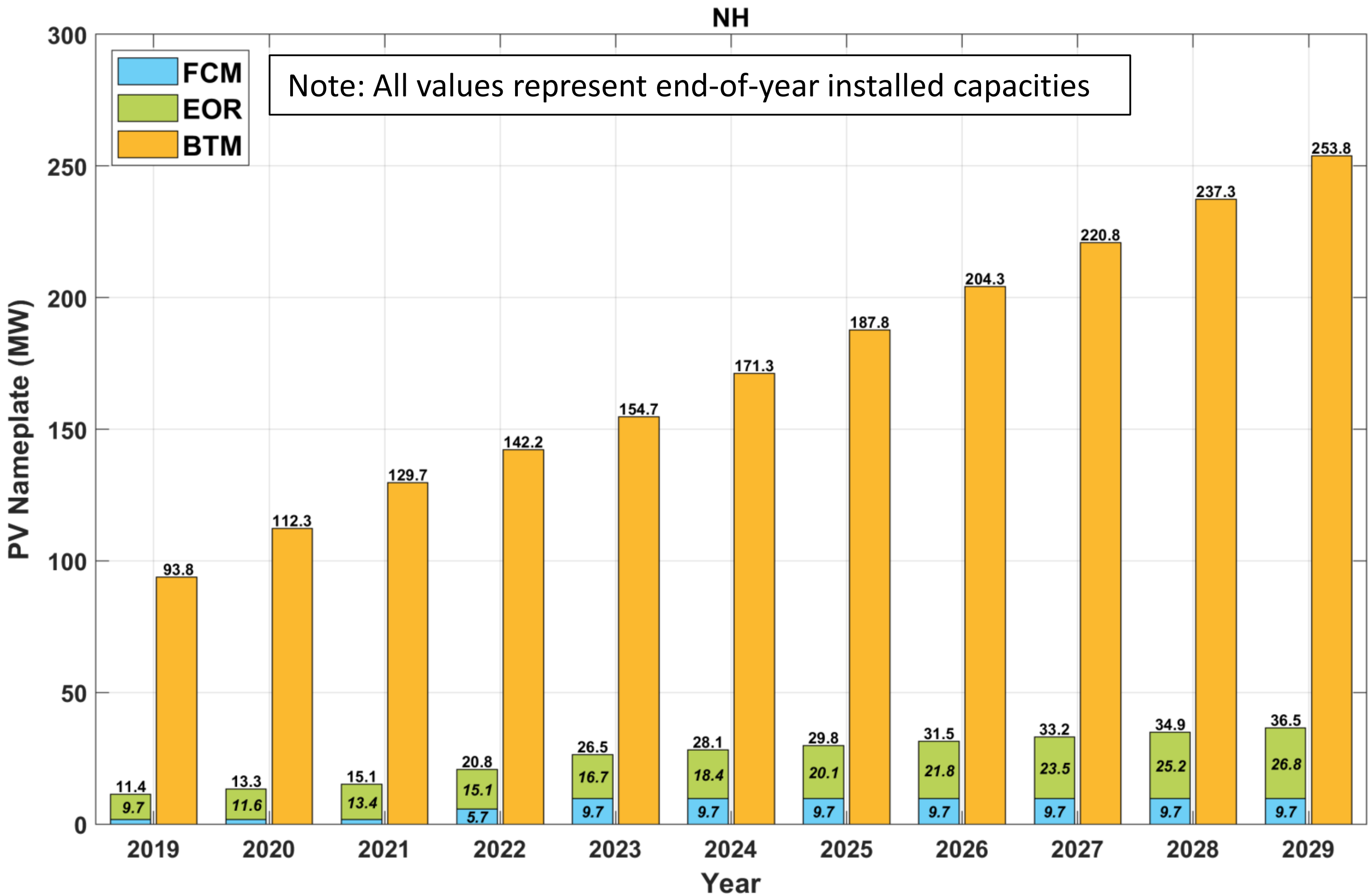
Final 2020 PV Forecast – Maine

Cumulative Nameplate by Category, MW_{ac}



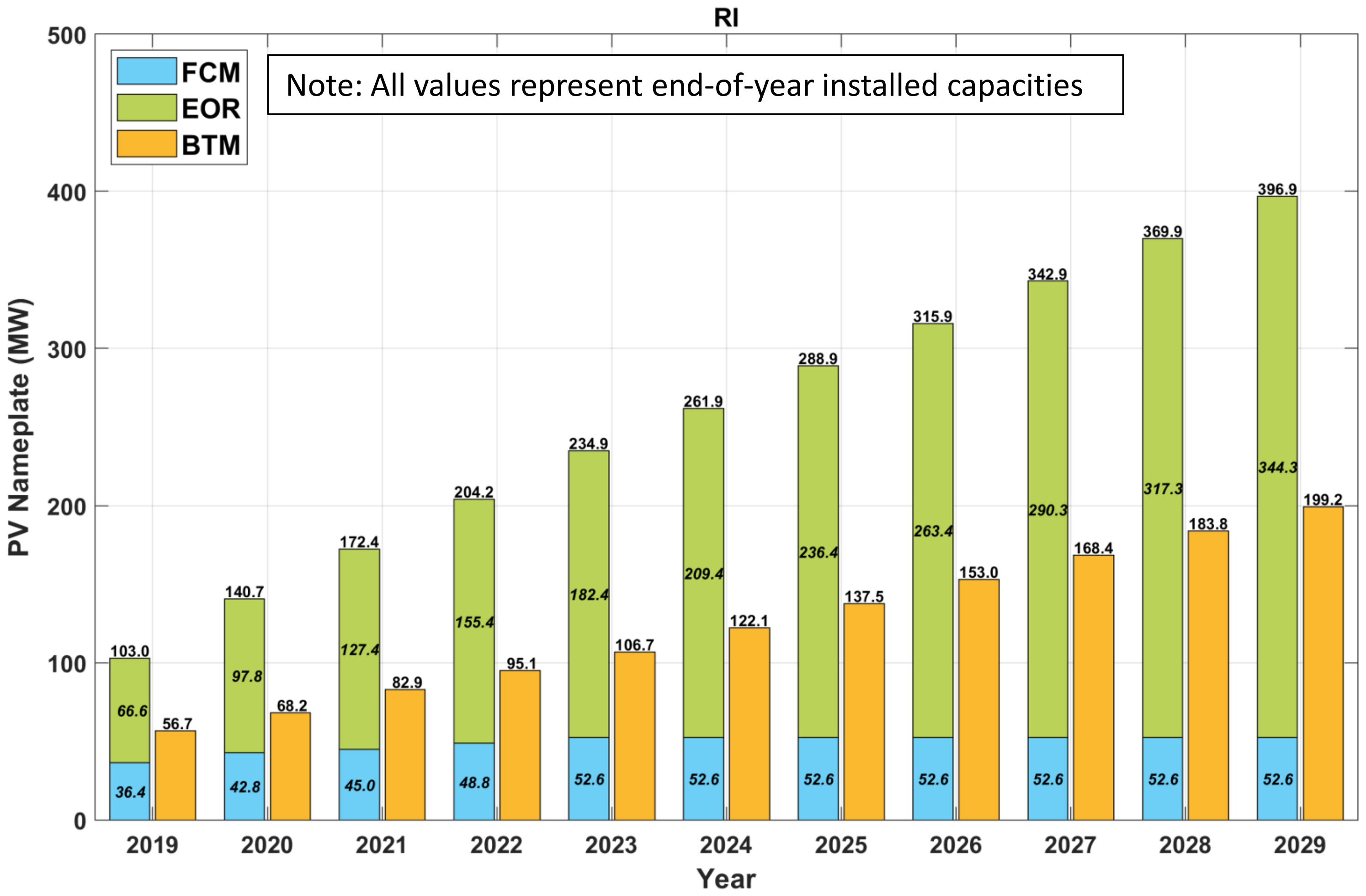
Final 2020 PV Forecast – New Hampshire

Cumulative Nameplate by Category, MW_{ac}



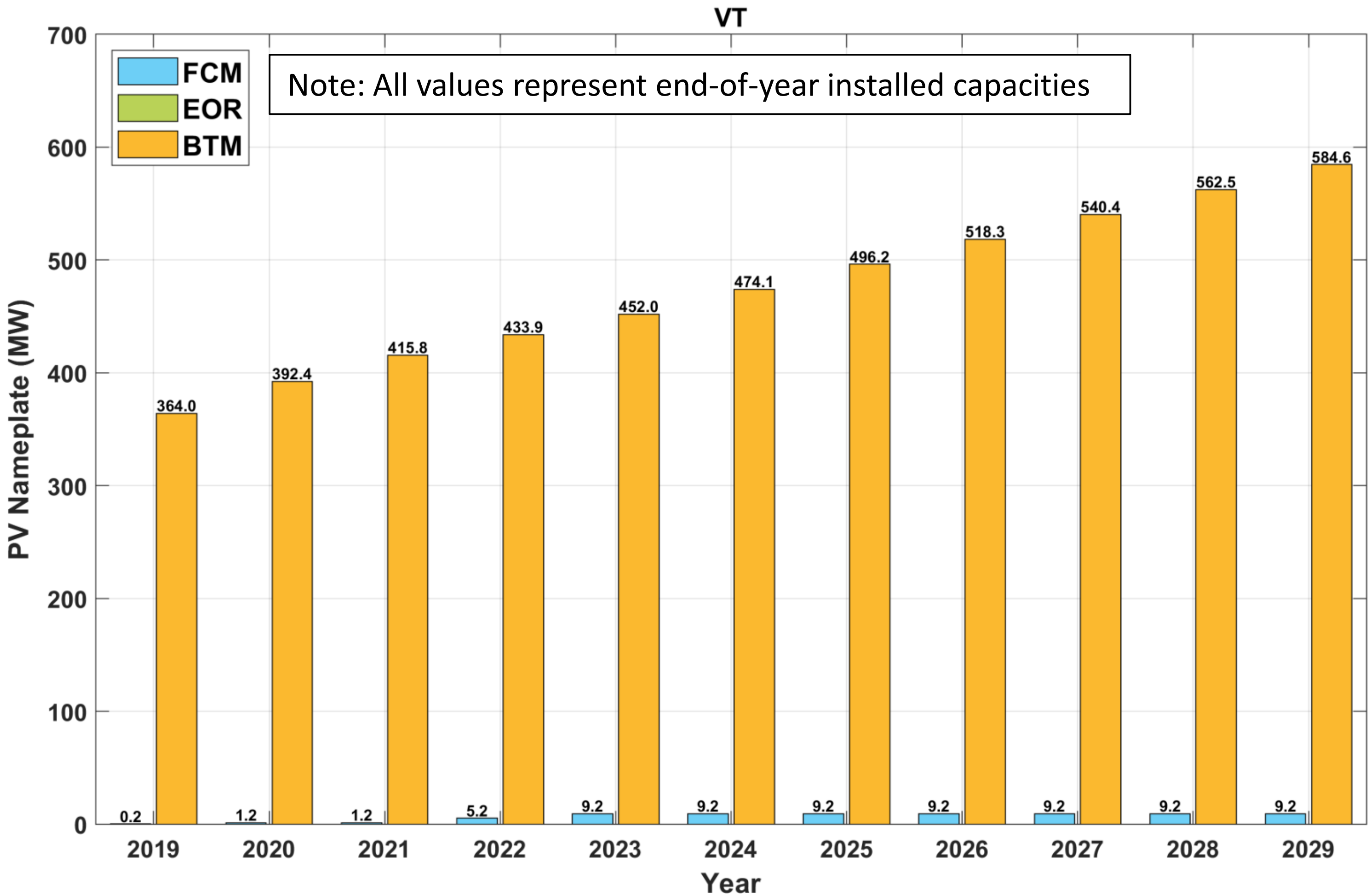
Final 2020 PV Forecast – Rhode Island

Cumulative Nameplate by Category, MW_{ac}



Final 2020 PV Forecast – Vermont

Cumulative Nameplate by Category, MW_{ac}



BTM PV Forecast Used in CELT Net Load Forecast

- The 2020 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 2020 CELT
  - PV does not reduce winter peak loads, which occur after sunset
- ISO incorporated the results of the recently updated analysis for estimating summer peak load reduction associated with BTM PV over the forecast horizon
  - Details of this analysis are available at: http://www.iso-ne.com/static-assets/documents/2020/04/final_btm_pv_peak_reduction.pdf

Final 2020 BTM PV Energy Forecast

GWh

Category	States	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
		Estimated Annual Energy (GWh)										
Behind-the-Meter PV	CT	597	682	755	899	1,005	1,121	1,218	1,317	1,415	1,497	1,550
	MA	1,185	1,412	1,578	1,729	1,867	2,014	2,132	2,236	2,337	2,437	2,526
	ME	66	73	78	108	140	173	192	195	199	202	205
	NH	116	132	154	172	188	207	228	248	268	289	309
	RI	55	87	100	118	134	153	173	193	213	234	253
	VT	406	473	503	526	546	571	596	621	646	672	696
Behind-the Meter Total		**2,424**	**2,858**	**3,168**	**3,552**	**3,880**	**4,239**	**4,538**	**4,810**	**5,078**	**5,332**	**5,538**

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% to reflect avoided transmission and distribution losses

Final 2020 BTM PV Forecast

July 1st Estimated Summer Peak Load Reductions

		Cumulative Total MW - Estimated Summer Seasonal Peak Load Reduction										
Category	**States**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Behind-the-Meter PV	CT	165.7	184.8	193.0	216.7	222.2	243.3	255.2	267.9	279.4	288.3	292.1
	MA	351.0	384.6	409.5	423.5	431.7	444.3	454.2	462.4	468.7	476.0	482.7
	ME	18.8	20.3	19.9	26.0	32.1	37.6	40.6	40.1	39.6	39.2	38.9
	NH	31.5	36.9	41.2	43.1	44.4	46.9	49.6	52.5	55.1	57.8	60.4
	RI	16.3	23.3	25.2	27.9	30.0	32.9	36.0	39.0	41.8	44.6	47.3
	VT	121.6	136.7	138.4	136.3	133.8	133.1	133.8	135.4	136.6	138.4	140.1
Total	**Cumulative**	704.8	786.5	827.3	873.5	894.2	938.1	969.5	997.4	1,021.2	1,044.4	1,061.6

% of BTM AC nameplate	35.9%	34.3%	32.6%	30.8%	29.1%	27.6%	26.6%	25.8%	25.0%	24.4%	23.8%

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; details of the methodology used to determine the estimated peak demand reductions are available at: http://www.iso-ne.com/static-assets/documents/2020/04/final_btm_pv_peak_reduction.pdf

(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

Overview

- 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 is possible via analysis of available data
- ISO geographically distributes forecasted PV according to existing geographical distribution at the end of the last historical year of data provided by Distribution Owners for the following sub-regions:
  - Load Zones
  - Dispatch Zones
  - RSP Subareas
- The breakdown of total PV reflected in Distribution Owner data submittals as of 12/31/2019 by Dispatch Zone is included on the next slide
- Beginning with the 2020 forecast, all classification of PV (FCM, EOR, and BTM) is performed uniquely for each sub-region to ensure proper accounting for various system planning studies

Dispatch Zone Distribution of PV

Based on December 31, 2019 Distribution Owner Data Submittals

State	Load Zone	Dispatch Zone	% of State
CT	CT	EasternCT	18.3%
	CT	NorthernCT	19.0%
	CT	Norwalk_Stamford	7.4%
	CT	WesternCT	55.3%
ME	ME	BangorHydro	13.3%
	ME	Maine	48.9%
	ME	PortlandMaine	37.8%
MA	NEMA	Boston	11.2%
	NEMA	NorthShore	5.4%
	SEMA	LowerSEMA	14.8%
	SEMA	SEMA	20.4%
	WCMA	CentralMA	13.8%
	WCMA	SpringfieldMA	8.5%
	WCMA	WesternMA	25.8%
NH	NH	NewHampshire	87.1%
	NH	Seacoast	12.9%
RI	RI	RhodeIsland	100.0%
VT	VT	NorthwestVermont	63.1%
	VT	Vermont	36.9%

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 2020

Description of Example Calculation Steps & Inputs

Massachusetts BTM PV July 2020 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 52
   - Input uses the conversion of cumulative end-of-year state nameplate forecast (slide 49) into monthly forecast using monthly capacity growth rates (slide 37)
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 40

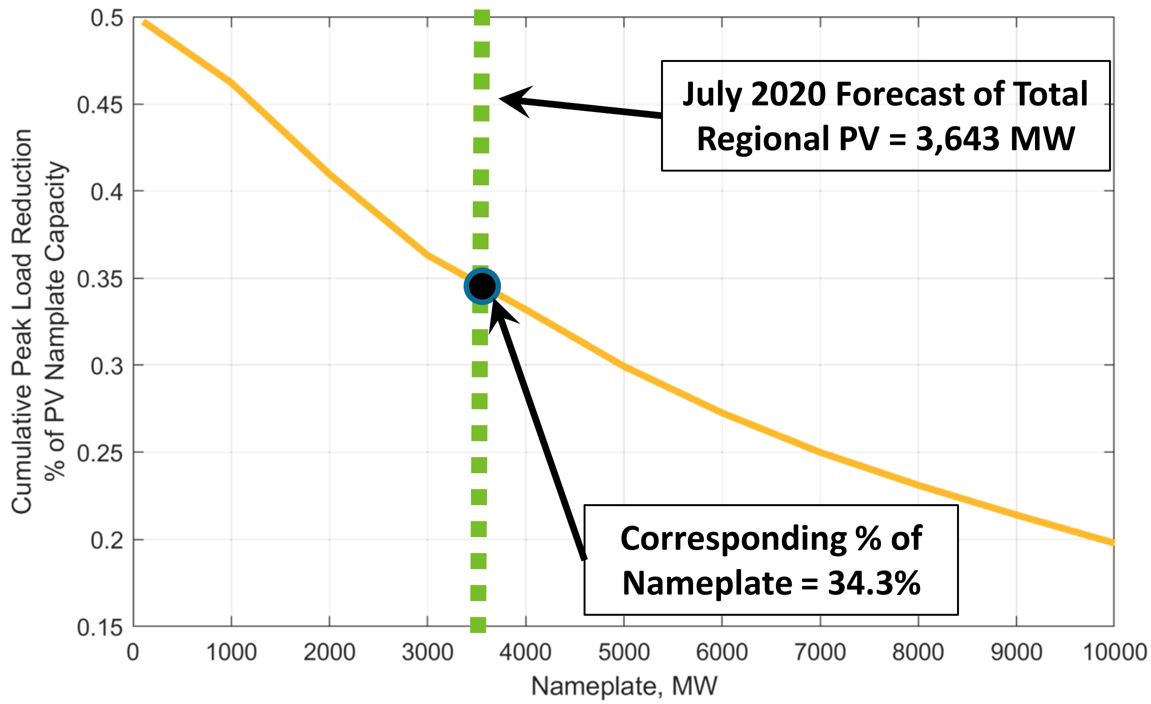
$$DegradeMultiplier = (1 - ADR)^{CA}$$

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

Estimated Summer Peak Load Reductions

July 2020 Example

- The orange line is the load-weighted peak load reduction as a percent of PV nameplate capacity
- These percent values are used to calculate BTM PV peak load reductions according to the equation below
- Details of underlying analysis used to develop the orange line is available at: http://www.iso-ne.com/static-assets/documents/2020/04/final_btm_pv_peak_reduction.pdf



- Equation to estimate BTM PV summer peak load reductions (in MW) is as follows:

BTM PV Peak Load Reduction, MW = (BTM PV Installed Capacity) * (% PV Nameplate)

Final Calculation

Massachusetts BTM PV July 2020 Summer Peak Load Reduction

Calculation Line Item	Relevant Region	
July 2020 Total Nameplate PV Forecast (MW)	ISO-NE	3642.6
July 2020 BTM PV Nameplate Forecast (MW)	MA	1059.3
% of Nameplate (from previous slide)	ISO-NE	0.343
Panel Degradation Multiplier	MA	0.98
Peak Gross Up Factor	ISO-NE	1.08
Final BTM PV Summer Peak Load Reduction (MW)	MA	**384.6**

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