



# Final 2026 DER Forecast

*Distributed Generation Forecast Working Group*

Long Vu

LEAD DATA SCIENTIST

ADVANCED FORECASTING & ANALYTICS



# Acronyms

<b>BTM</b>	Behind-the-meter	<b>IOU</b>	Investor-owned utility
<b>CBI</b>	Capacity-based incentive	<b>ITC</b>	Investment tax credit
<b>CELT</b>	Capacity, Energy, Load, and Transmission report	<b>NEB</b>	Net energy billing (ME)
<b>C&amp;I</b>	Commercial and industrial	<b>NM, NEM</b>	Net metering, net energy metering
<b>DER</b>	Distributed energy resource	<b>NREL</b>	National Renewable Energy Laboratory
<b>DG</b>	Distributed generation	<b>NRES</b>	Non-residential Renewable Energy Solutions (CT)
<b>DGFWG</b>	Distributed Generation Forecast Working Group	<b>PP12</b>	ISO-NE Planning Procedure 12
<b>dGEN™</b>	Distributed Generation Market Demand Model	<b>PV</b>	Photovoltaic
<b>EOR</b>	Energy only resources	<b>REF</b>	Renewable Energy Fund (RI)
<b>FCM</b>	Forward Capacity Market	<b>REG</b>	Renewable Energy Growth program (RI)
<b>FITs</b>	Feed-in-tariffs	<b>RRES</b>	Residential Renewable Energy Solutions (CT)
<b>IBI</b>	Investment-based incentive	<b>SCEF</b>	Shared Clean Energy Facility program (CT)
<b>ICR</b>	Installed Capacity Requirement	<b>SMART</b>	Solar Massachusetts Renewable Target

# Outline

- [Introduction](#)
- [Final Draft 2026 DER Nameplate Forecast](#)
- [2026 DER Scenario Forecast](#)
- [Classification of DER Forecast – Results](#)
- [2026 BTM DER Energy Forecast](#)
- [2026 BTM DER Peak Demand Reductions](#)
- **Appendix:**
  - [Appendix I: County-level PV Forecast](#)
  - [Appendix II: County-level BESS Forecast](#)
  - [Appendix III: Classification of DER Forecast – Background and Methods](#)
  - [Appendix IV: BTM DER Energy Forecast – Background and Methods](#)
  - [Appendix V: Final 2026 PV Forecast Classification](#)



# Forecast Review Process



- The following materials were presented as part of the 2026 forecast cycle:
  - DER forecast enhancements – [Oct 2025](#)
  - DER forecast updates – [Dec 2025](#)
  - Draft 2026 DER forecast – [Feb 2026](#)
- No formal written comments were submitted on the 2026 draft DER forecast
- The ISO's updates to the draft 2026 PV forecast were based on feedback received during the February DGFWG meeting, and other planned updates to input variables

# INTRODUCTION



# Introduction

- A significant amount of state-sponsored distributed energy resource (DER) do not participate in wholesale markets, but have impacts on system load observed by the ISO
- The long-term DER forecast helps the ISO determine future system load characteristics that are important for the reliable planning and operation of the system
- The 2026 DER forecast includes DER battery energy storage systems (BESS) that are co-located with rooftop DER PV
- To properly account for DER PV in long-term planning, the finalized PV portion of the forecast will be categorized as follows:
  1. DER in the Forward Capacity Market (FCM)
  2. Non-FCM Energy Only Resources (EOR) and Generators
  3. Behind-the-meter (BTM)
- The scope of the DER BESS forecast focuses exclusively on systems co-located with rooftop PV that are < 1 MW in nameplate capacity
  - Intended to represent a small portion of overall DER BESS growth that does not participate in wholesale markets, and is categorized as BTM in the ISO's forecast

**Behind-the-meter PV is reconstituted into historical loads\***

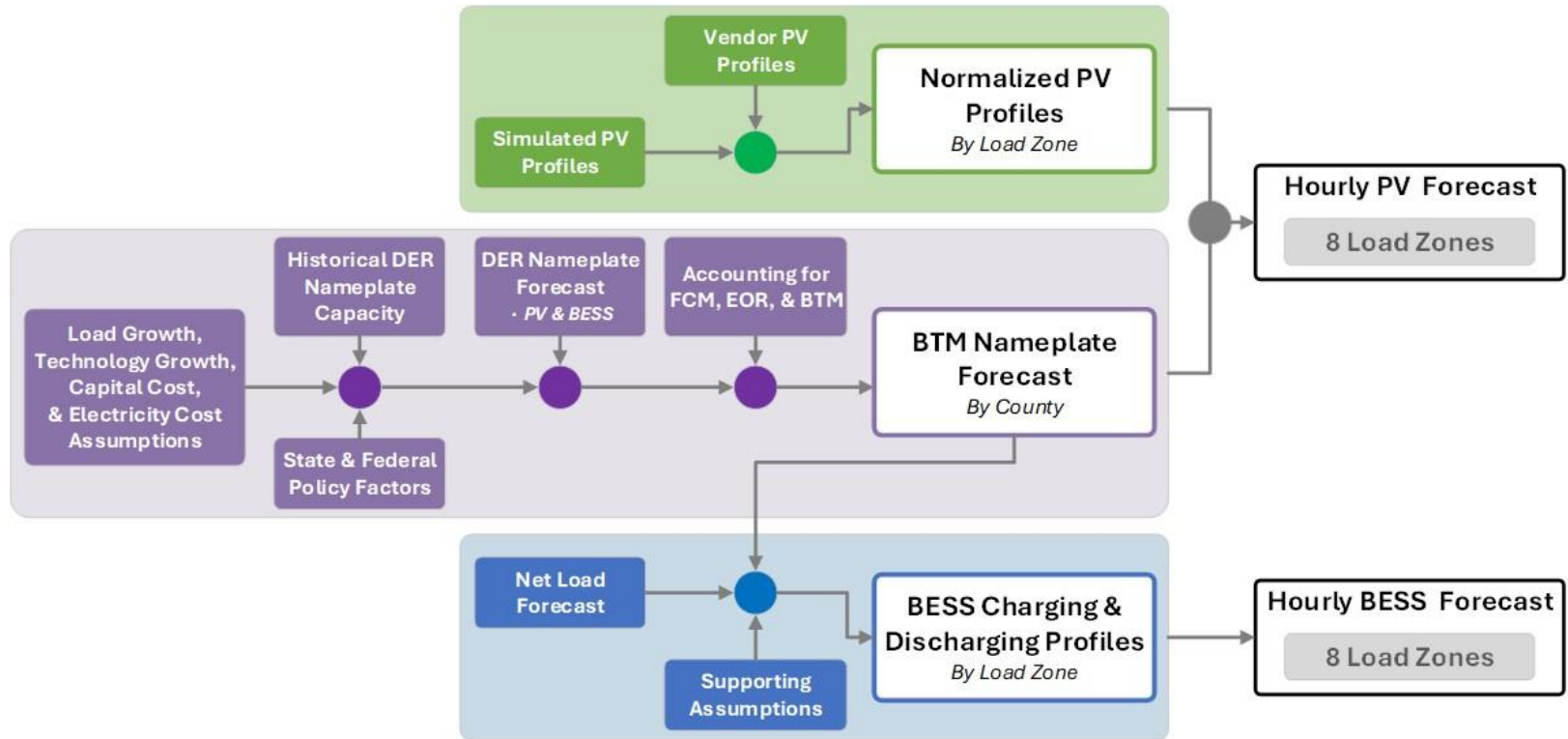
**The 2026 gross load forecast reflects loads without PV load reductions**

*\*Historical BTM PV reduces historical metered loads; historical loads reconstituted for BTMPV are used to model base load in developing the base load forecast. All historical BTM BESS impacts are reflected in historical loads.*

# DER Forecast Focuses on Distributed Generation

- The focus of the DGFWG is distributed generation (DG) 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.”
  - Note that the industry has evolved since the formation of the DGFWG, and today DG is often referred to as a distributed energy resource (DER)
    - Per the ISO’s [Planning Procedure 12](#), DER is defined as *any generator or energy storage facility located on the distribution system, any subsystem thereof, or behind a customer meter that is capable of providing energy injection, energy withdrawal, regulation or demand reduction*
      - DER does not include demand response, controllable loads, or other load modifiers
- While DER may include larger-scale DER projects greater than 5 MW in size, the forecast does not consider policy drivers and growth of larger-scale DER projects, since these projects are generally accounted for as part of the ISO’s interconnection process and participate in wholesale markets (i.e., they are not BTM)

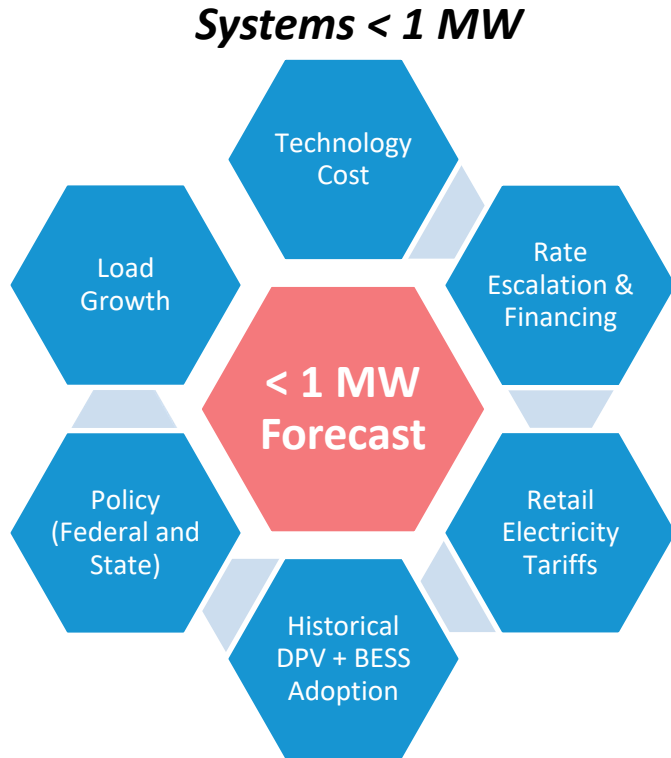
# CELT 2026 DER Forecast Process Flow



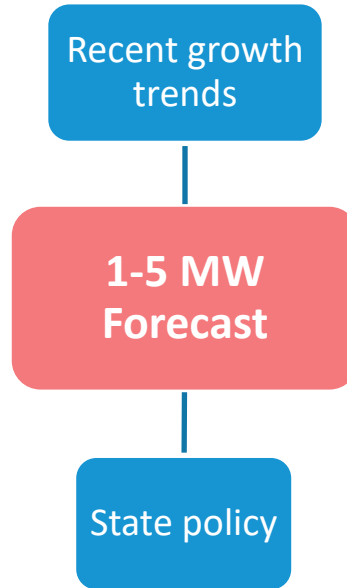
# DER Forecast Methodology

- The DER forecast is a projection of distributed energy resources to be used in ISO-NE System Planning studies
- Development of the DER forecast includes use of the Distributed Generation Market Demand Model (dGen™), an agent-based simulation platform developed and open-sourced by the National Renewable Energy Laboratory (NREL)
  - An overview of the dGen™ model was presented by the NREL team at the [October 2023 DGFWG meeting](#)
- The nameplate forecast is developed using the two following additive processes:
  1. For < 1 MW systems (both PV and BESS): Use residential and commercial dGen™ modeling
  2. For 1-5 MW systems (PV only): Use a policy-based approach
- The DER forecast is developed out through 2050

# DER Forecast Inputs



**Systems 1-5 MW  
(PV Only)**



# FINAL 2026 DER NAMEPLATE CAPACITY FORECAST

# Updates to 2026 DER Draft Forecast

- Updated VT MW-scale forecast to further reflect anticipated DER growth due to the increase in DG RES obligations for utilities in VT
- Updated VT DER BESS policy modeling to reflect higher resiliency values from the supporting programs to VT customers
- Increase near-term discount factors to reflect greater uncertainty associated with the impacts of the changes to the Federal Investment Tax Credit

# Discount Factors Used

Forecast Year	Draft 2026 Forecast	Final Draft 2026 Forecast
2026	2.5%	7.5%
2027	5%	10%
2028	7.5%	12.5%
2029	10%	15%
2030	12.5%	15%
2031	15%	15%
2032	15%	15%
2033	15%	15%
2034	15%	15%
2035 - 2050	15%	15%

Update since draft forecast

# Final 2026 DER PV Forecast – 10 Year Horizon

*Nameplate Capacity, MW<sub>ac</sub>*

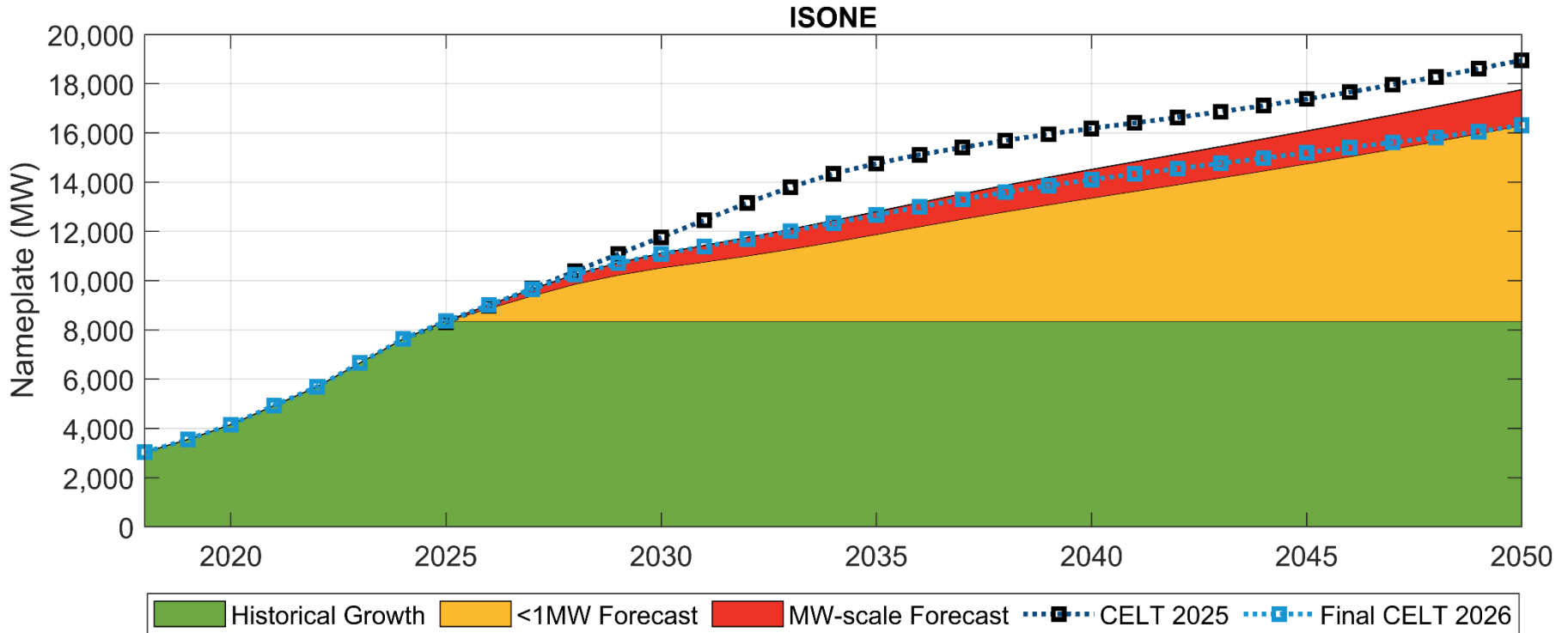
States	Annual Total MW (AC nameplate rating)											Totals
	Thru 2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	
CT	1,458	155	139	117	89	79	74	74	78	77	78	<b>2,419</b>
MA	4,286	312	325	310	233	162	100	97	107	111	116	<b>6,160</b>
ME	1,181	56	50	41	39	39	40	41	42	42	42	<b>1,615</b>
NH	333	33	35	34	30	27	26	27	30	32	34	<b>639</b>
RI	504	54	49	44	39	34	32	31	30	30	29	<b>876</b>
VT	597	45	43	39	37	37	33	33	32	31	32	<b>960</b>
<b>Regional - Cumulative (MW)</b>	<b>8,359</b>	<b>9,013</b>	<b>9,655</b>	<b>10,241</b>	<b>10,707</b>	<b>11,085</b>	<b>11,389</b>	<b>11,694</b>	<b>12,013</b>	<b>12,337</b>	<b>12,669</b>	<b>12,669</b>

## 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

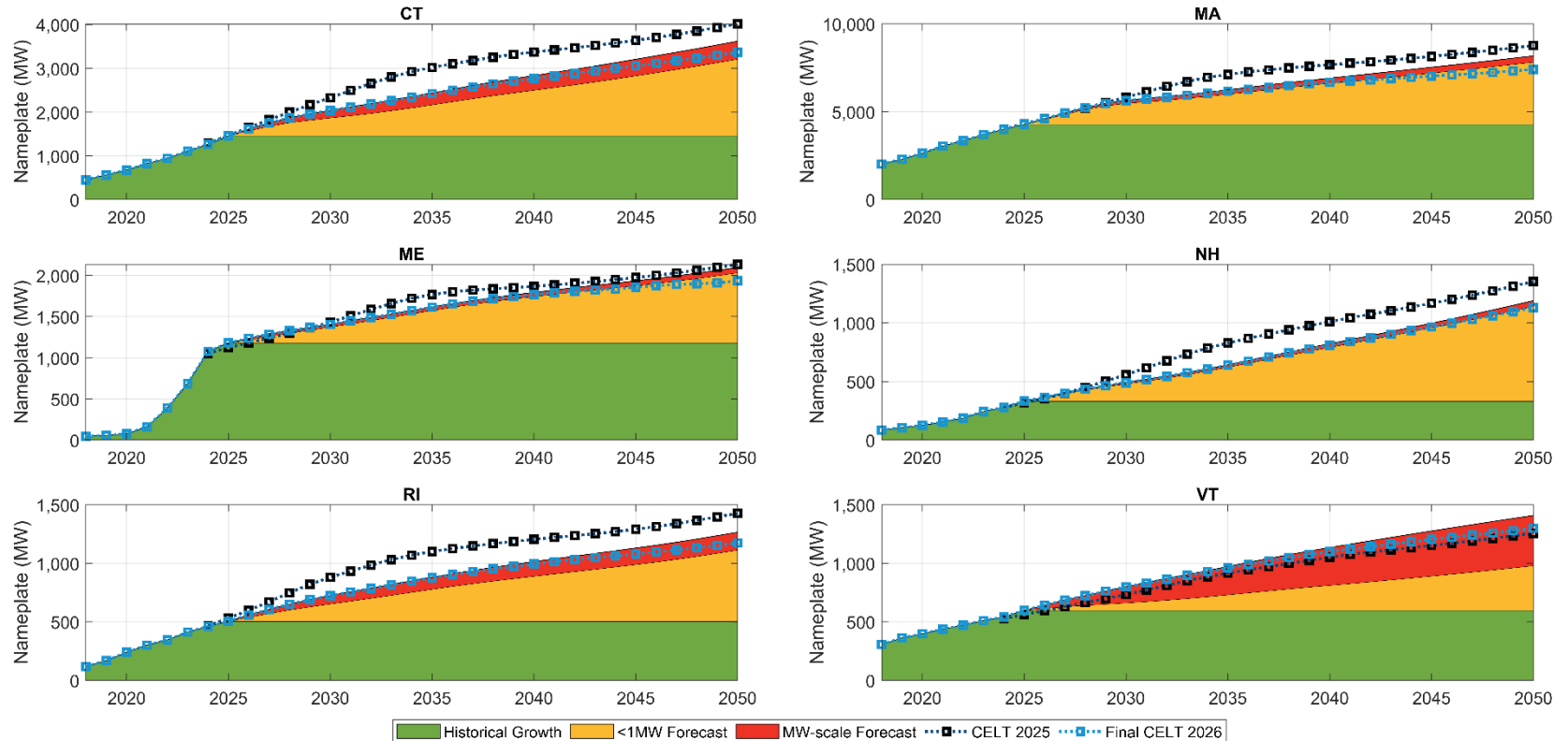
# Regional PV Nameplate Capacity Growth

*Historical vs. Forecast*



# State PV Nameplate Capacity Growth

## Historical and Forecast



# Final 2026 DER BESS Forecast – 10-Year Horizon

*Nameplate Capacity, MW<sub>ac</sub>*

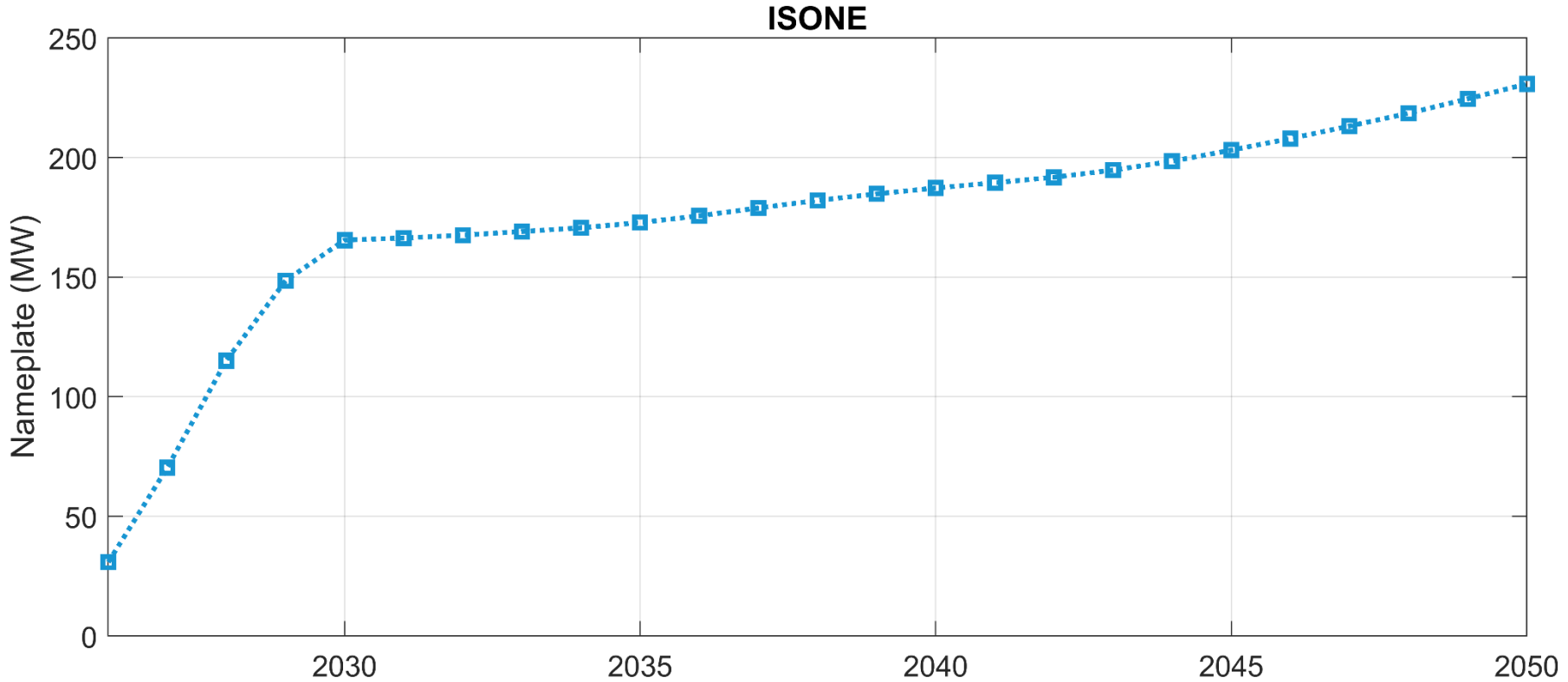
States	Annual Total MW (AC nameplate rating)										Totals
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	
CT	6.0	6.4	6.3	4.2	2.1	0.0	0.0	0.0	0.0	0.5	<b>25.4</b>
MA	20.3	28.8	34.2	26.2	13.1	0.2	0.5	0.8	0.9	1.1	<b>126.1</b>
ME	1.4	1.5	1.5	1.0	0.5	0.1	0.2	0.2	0.1	0.1	<b>6.4</b>
NH	0.7	0.9	0.9	0.6	0.3	0.0	0.0	0.1	0.1	0.2	<b>3.7</b>
RI	0.3	0.4	0.8	0.7	0.4	0.0	0.0	0.0	0.0	0.0	<b>2.6</b>
VT	2.2	1.7	1.2	0.7	0.6	0.5	0.5	0.4	0.4	0.4	<b>8.5</b>
Regional - Cumulative (MW)	<b>30.8</b>	<b>70.3</b>	<b>115.2</b>	<b>148.5</b>	<b>165.5</b>	<b>166.3</b>	<b>167.5</b>	<b>169.0</b>	<b>170.6</b>	<b>172.8</b>	<b>172.8</b>

**Notes:**

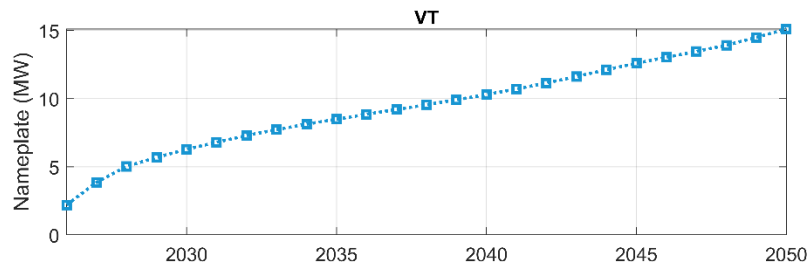
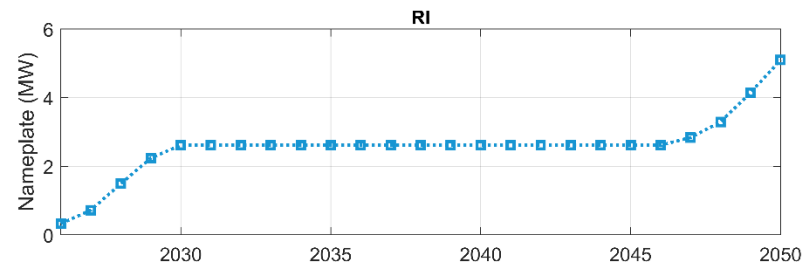
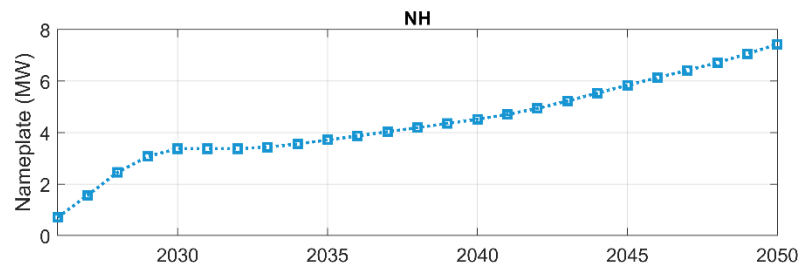
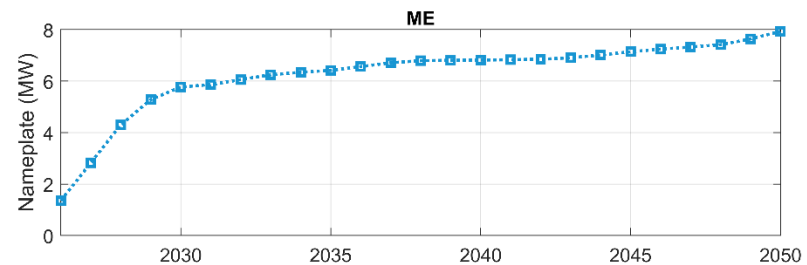
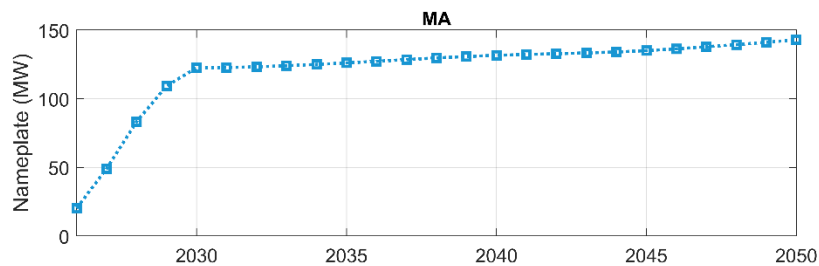
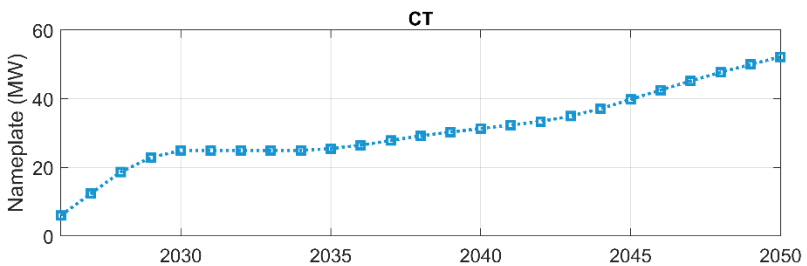
- (1) The forecast values are net of discount factors
- (2) All values represent end-of-year installed capacities



# Regional BESS Nameplate Capacity Growth Forecast



# State BESS Nameplate Capacity Growth Forecast



# Development of County-Level Forecasts

- County-level DER forecast for systems with nameplate capacity less than 1 MW is generated by dGen™
- County-level allocations of forecast for MW-scale systems (PV only) are developed based on:
  - Historical share of MW-scale system in each county
  - Land availability (using county population density as proxy)
  - Land value (using county median income as proxy)
  - Remaining area hosting capacity (estimated using substation electricity demand data)
- County-level forecast results are included in the [Appendix I](#) and [Appendix II](#)

# DER SCENARIO FORECAST



# DER Scenario Forecast

- Scenario forecasts are developed under different assumptions that help quantify the range of potential future DER growth
- Final CELT 2026 forecast will reflect the **Baseline Growth Scenario (S2)**
  - Denoted in visuals by a **dashed blue line**
- **High & Low Growth Scenarios (S1/S3)** illustrate the possible forecast uncertainty that may exist in key assumptions
  - Denoted in visuals by a **dashed red line**

## High Growth Scenario

- Optimistic ITC: Returns from 2030 – 2035 at 15%
- Low ATB cost
- Increased NEM rate (110%)

S1

## Baseline Growth Scenario

- ITC reflective of 2025 policy change
- Moderate ATB cost
- Moderate NEM rate (100%)

S2

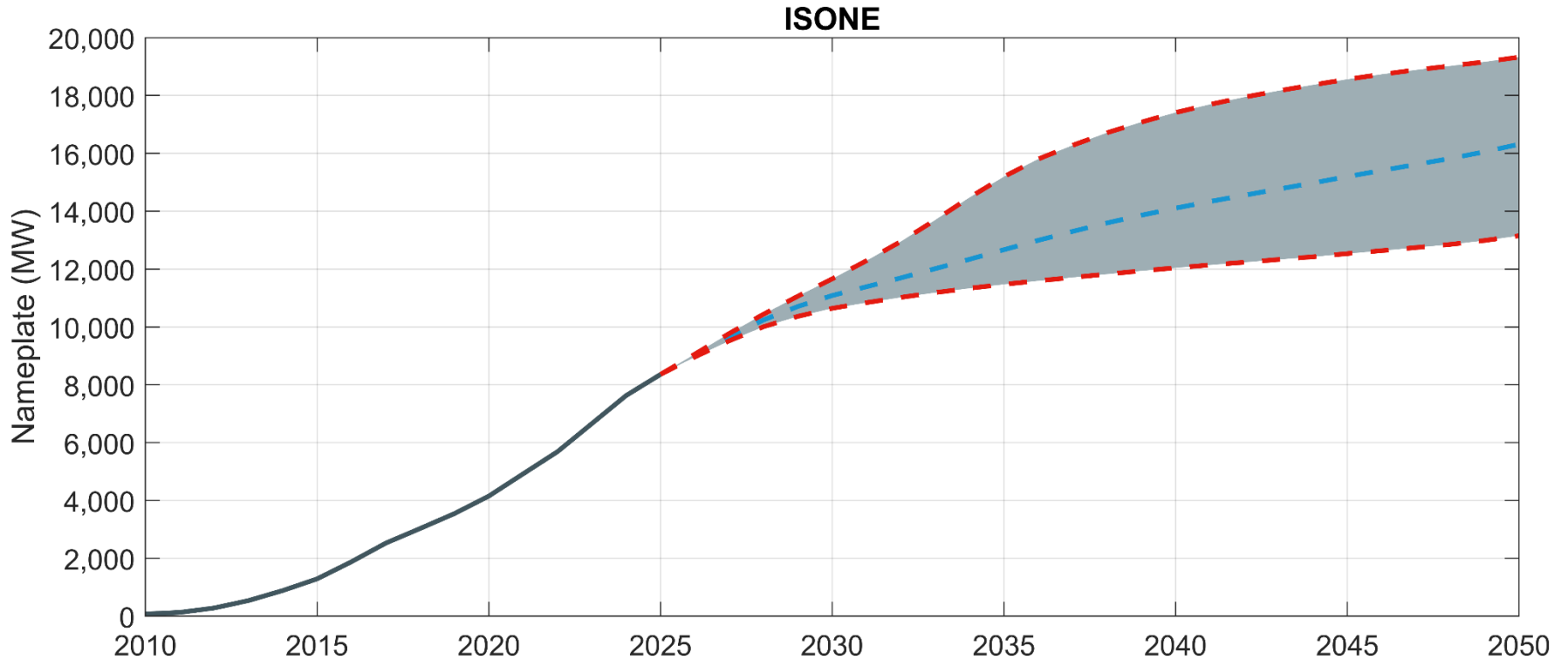
## Low Growth Scenario

- ITC reflective of 2025 policy change
- High ATB cost
- Reduced NEM rate (80%)

S3

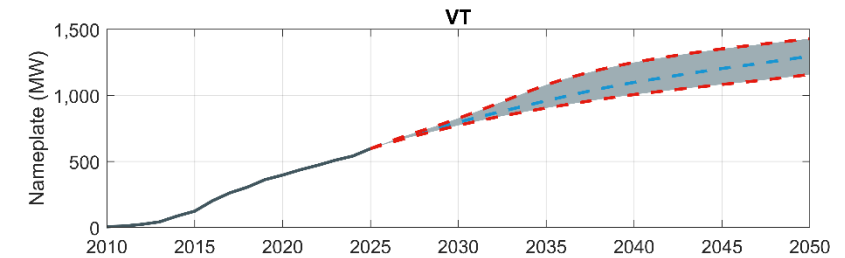
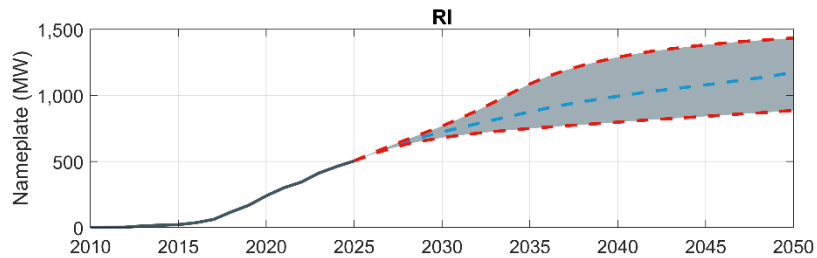
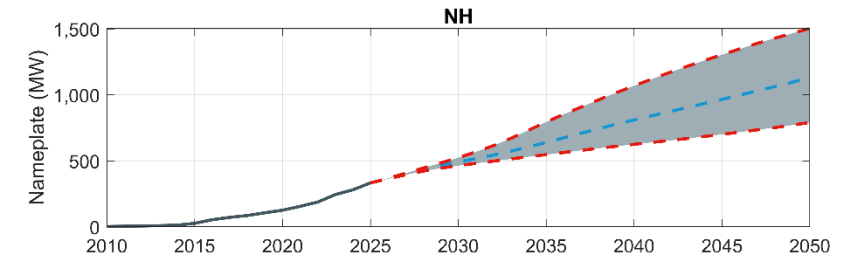
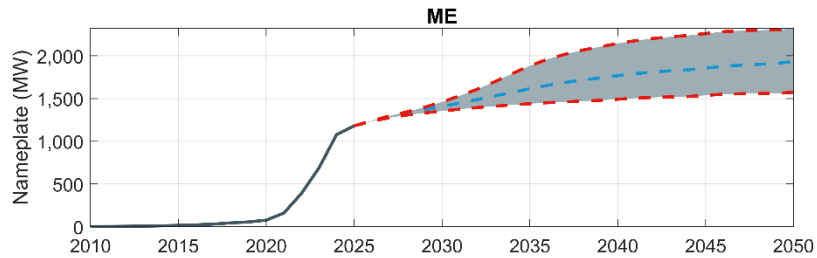
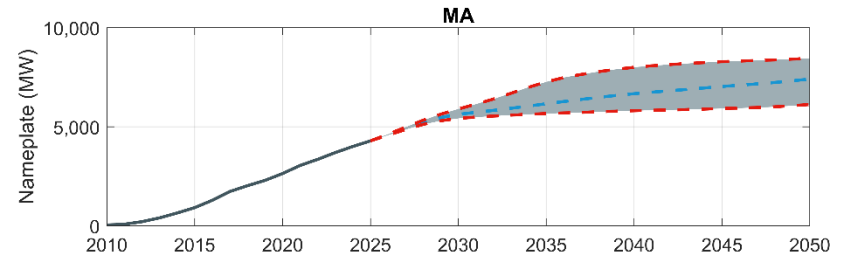
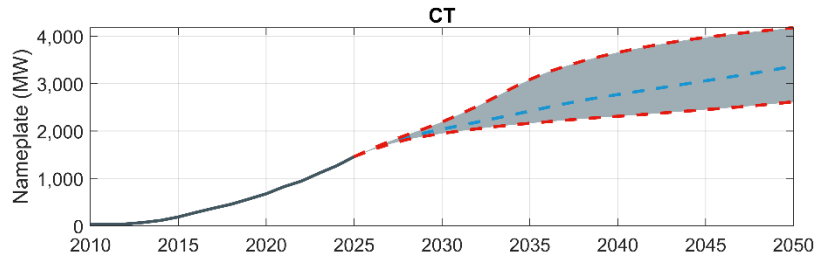
# Regional PV Nameplate Capacity Growth

*Forecast for all scenarios*



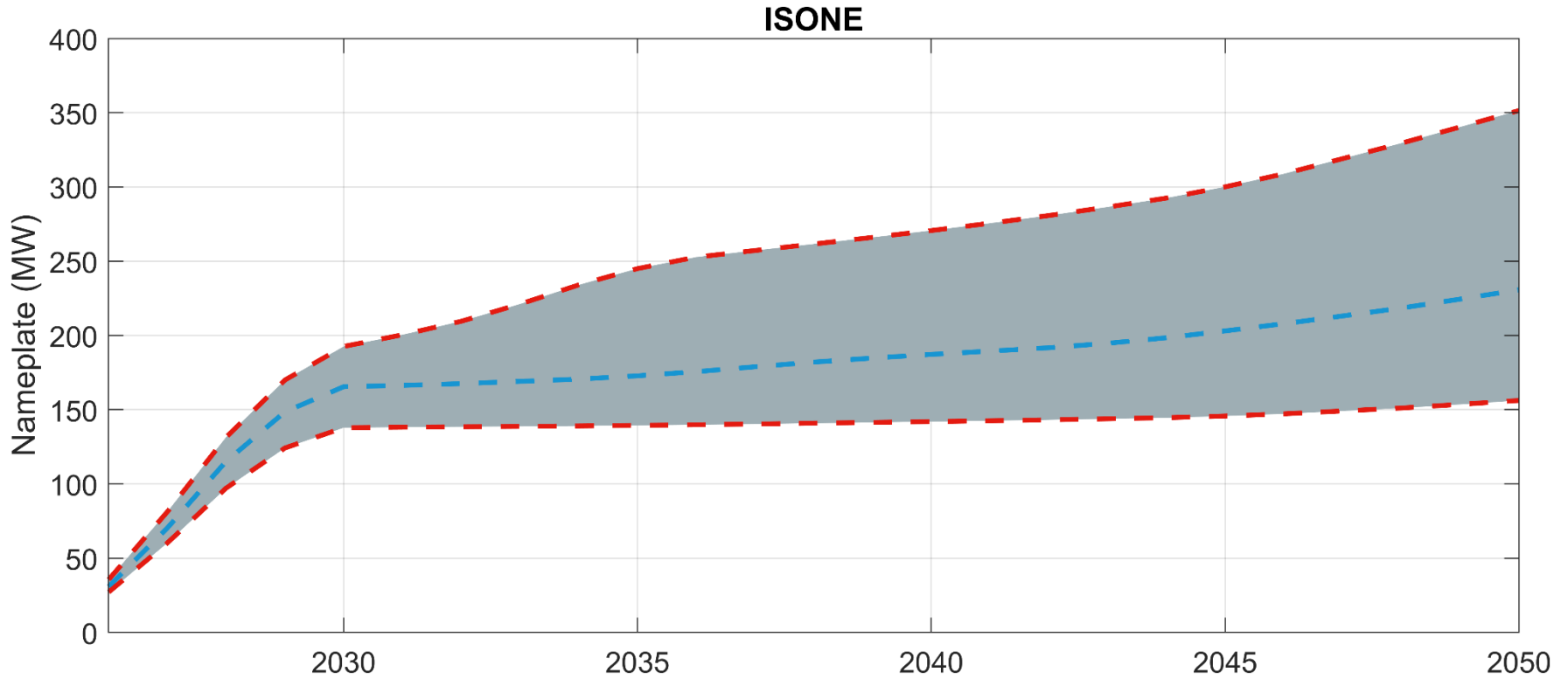
# State PV Nameplate Capacity Growth

*Forecast for all scenarios*



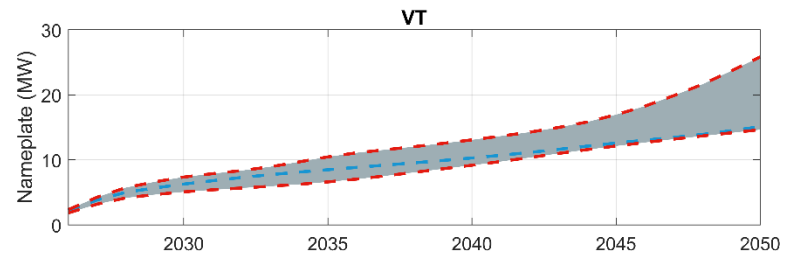
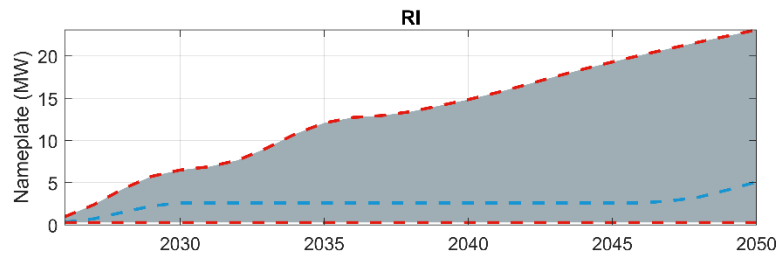
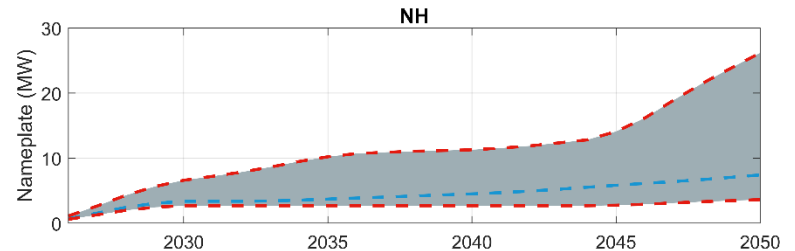
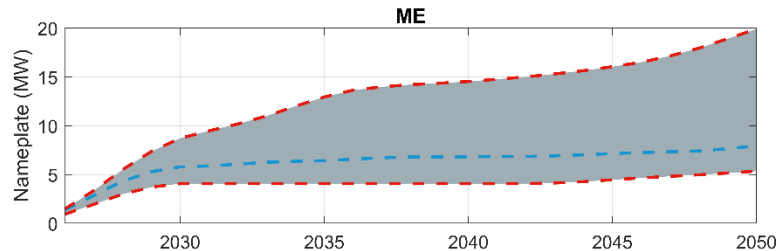
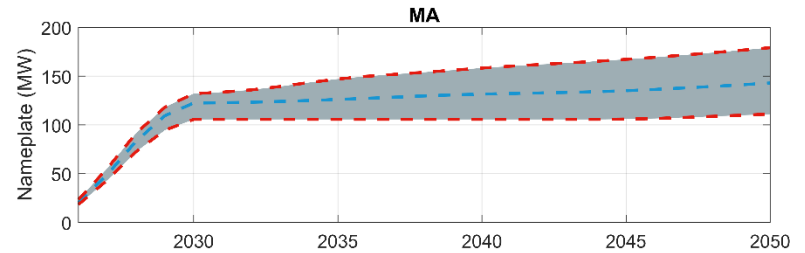
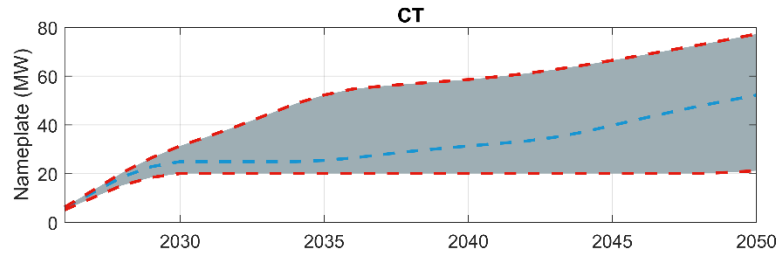
# Regional BESS Nameplate Capacity Growth

*Forecast for all scenarios*



# State BESS Nameplate Capacity Growth

*Forecast for all scenarios*



# CLASSIFICATION OF DER FORECAST

*Results*

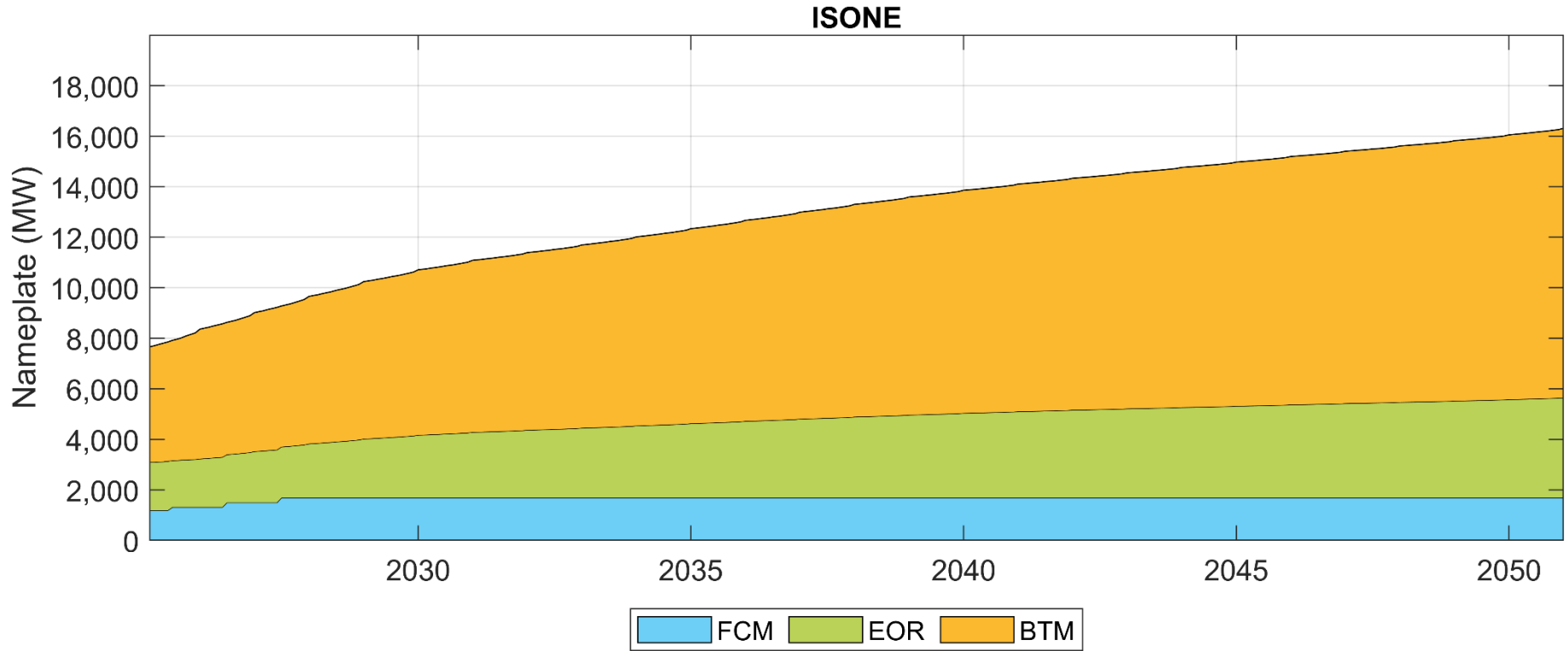


# Classification Needed to Determine BTM DER

- Ultimately, the ISO needs to determine the amount of DER that is not expected to participate in wholesale markets, and instead reduces load
  - This is the amount of BTM DER that is reflected in the long-term load forecast
- To properly account for existing and future DER in planning studies and avoid double counting, ISO classifies all DER PV and BESS included in the 2026 DER forecast as the following:
  - All DER PV are classified into three distinct categories related to its assumed market participation/non-participation
  - All DER BESS are classified as BTM
- Accounting for these market distinctions is performed for both installed nameplate capacity and estimates of hourly energy production (historical and forecast), and is important for the ISO's use of the DER forecast in planning studies
- Details of classification methods are included in [Appendix III](#)

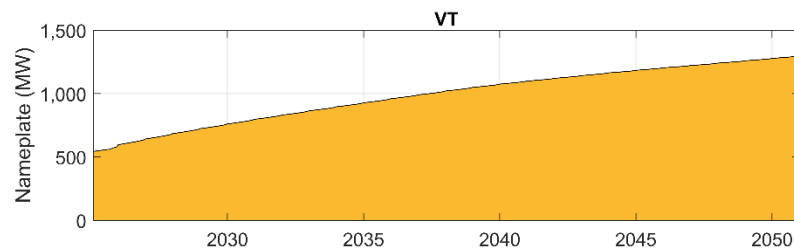
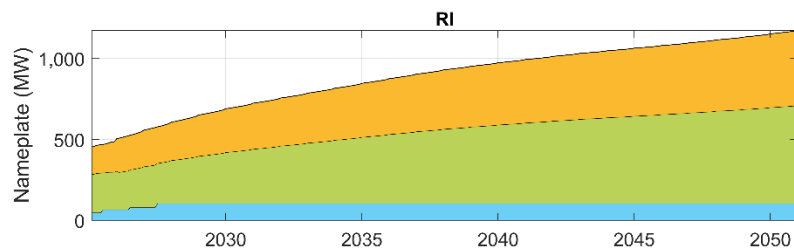
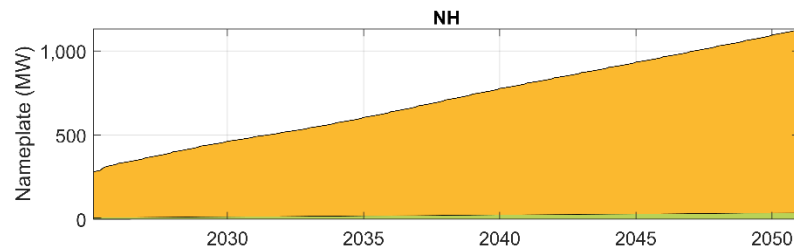
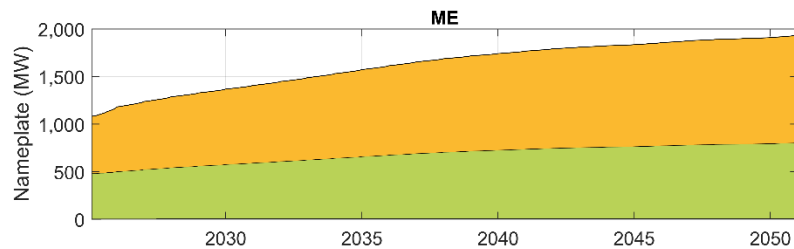
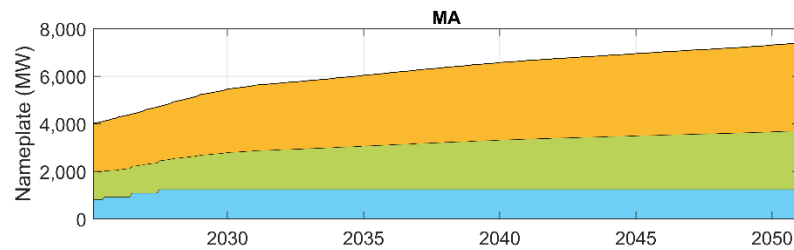
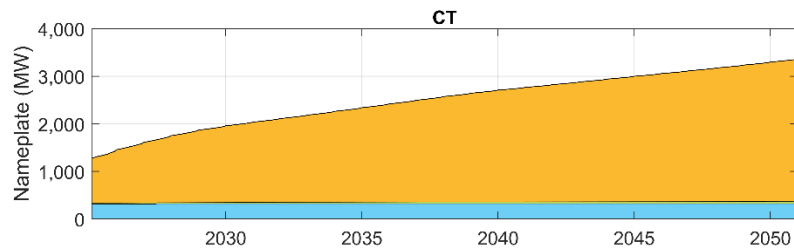
# Final 2026 Regional PV Forecast

*Cumulative Nameplate by Category, MW<sub>ac</sub>*



# Final 2026 State PV Forecast

## Cumulative Nameplate by Category, MW<sub>ac</sub>



FCM EOR BTM

ISO-NE PUBLIC

# 2026 BTM DER ENERGY FORECAST

# BTM DER Energy Forecast

- Monthly energy forecasts are the averages of the 70 monthly energy values of simulations performed for each forecast year
  - For example, January energy forecast is the average of all 70 January energy values withing the 70-year simulation period for a given forecast year
- Annual energy forecast is calculated as the sum of monthly energy forecasts for each forecast year
- Details of the development of the BTM DER energy forecast are included in [Appendix IV](#)

# Final 2026 BTM PV Energy Forecast – 10 Year Horizon

*BTM PV, GWh*

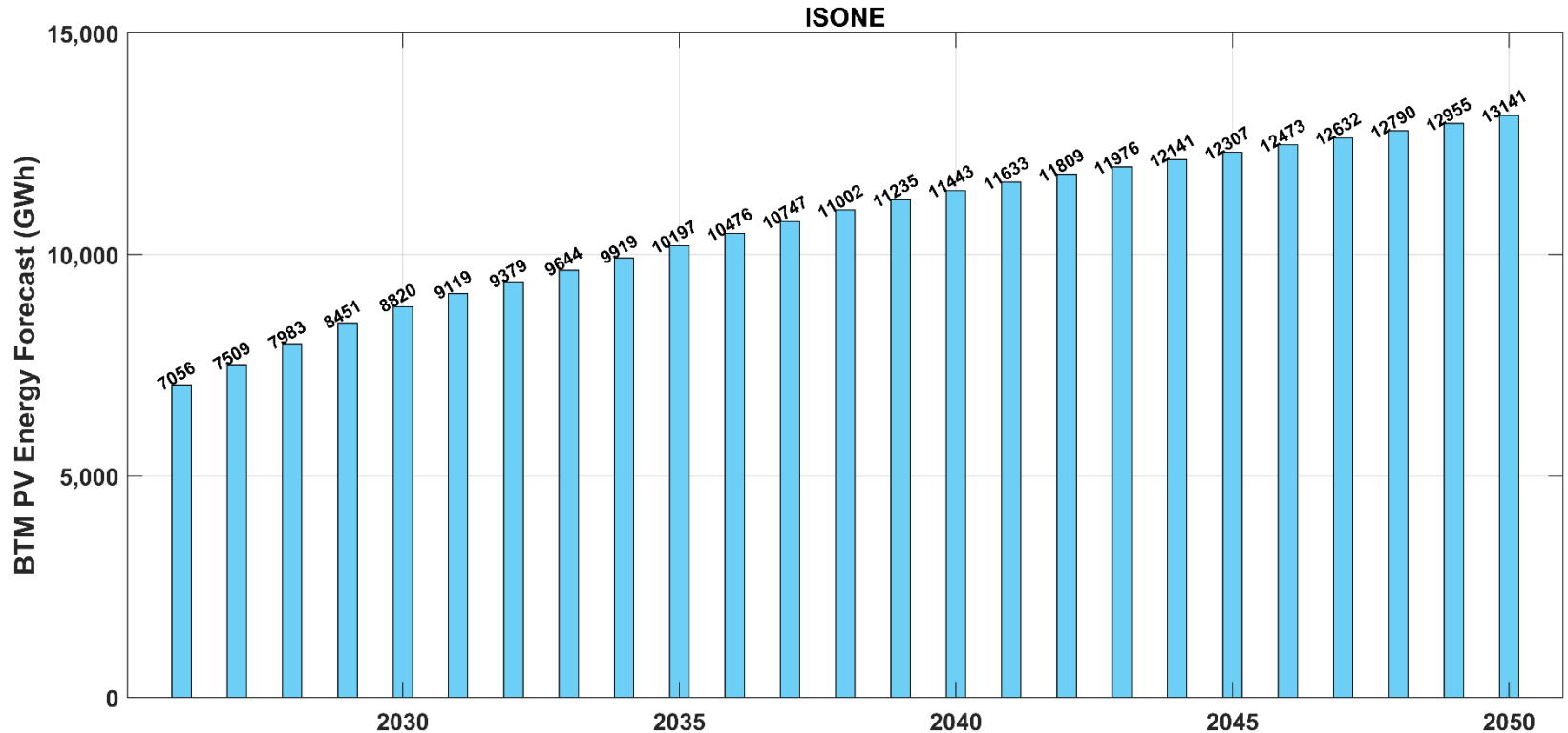
States										
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
CT	1,616	1,813	1,983	2,123	2,231	2,328	2,420	2,514	2,610	2,706
MA	3,015	3,119	3,280	3,473	3,610	3,696	3,752	3,809	3,871	3,937
ME	927	966	999	1,027	1,054	1,081	1,108	1,137	1,165	1,194
NH	433	474	516	555	590	621	651	684	720	758
RI	304	323	342	365	385	402	418	434	449	465
VT	761	814	863	907	950	992	1,029	1,067	1,102	1,137
<b>Regional - Annual Energy (GWh)</b>	<b>7,056</b>	<b>7,509</b>	<b>7,983</b>	<b>8,451</b>	<b>8,820</b>	<b>9,119</b>	<b>9,379</b>	<b>9,644</b>	<b>9,919</b>	<b>10,197</b>

**Notes:**

- (1) Forecast values include energy 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

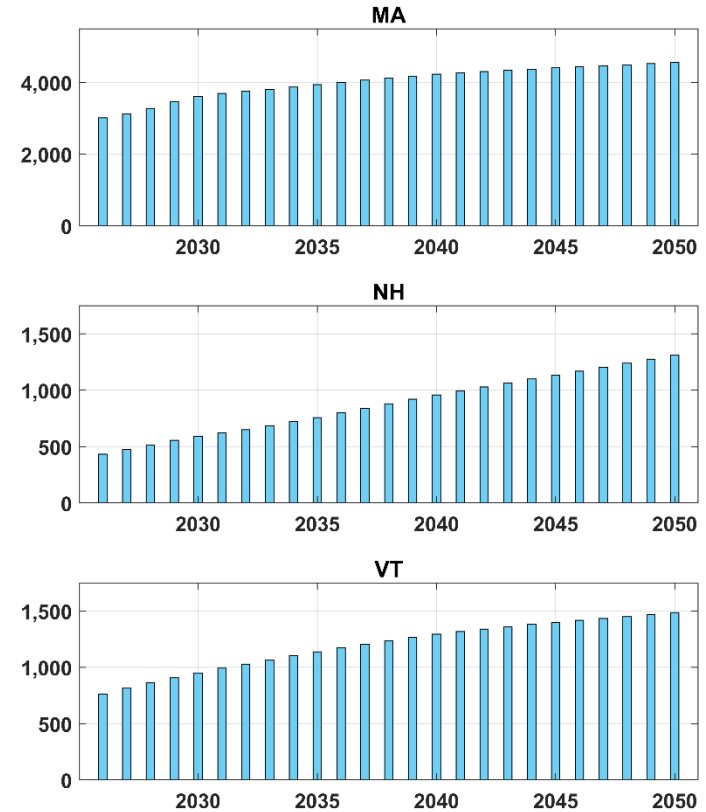
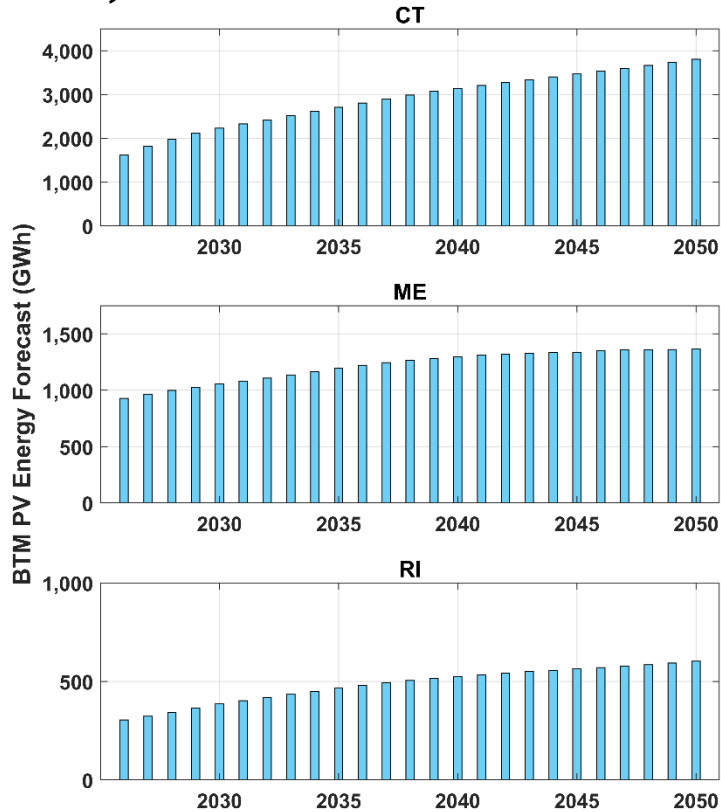
# Final 2026 BTM PV Energy Forecast – New England

*BTM PV, GWh*



# Final 2026 BTM PV Energy Forecast – State Level

*BTM PV, GWh*



# 2026 BTM DER PEAK DEMAND REDUCTIONS



# BTM DER Forecast Used in CELT Net Load Forecast

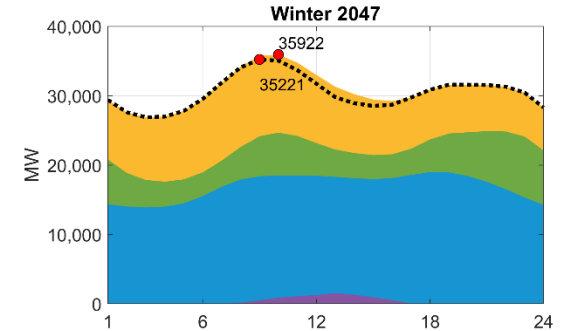
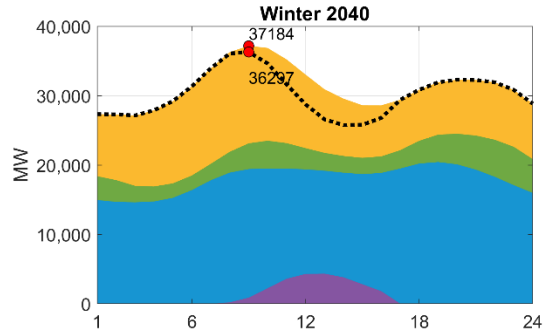
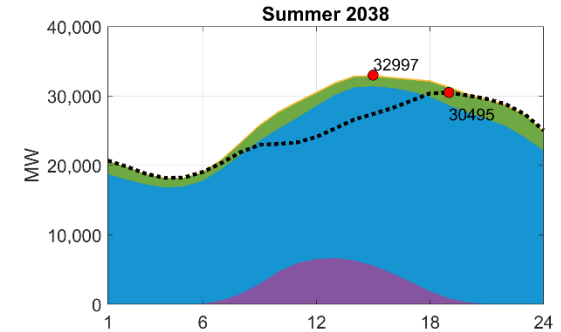
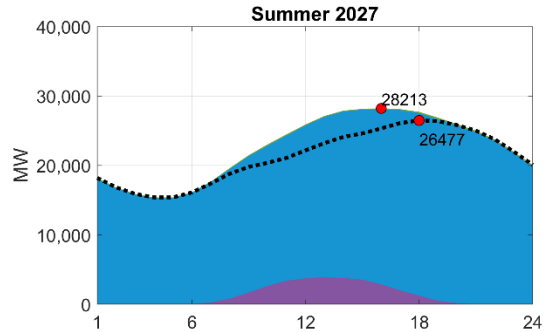
- The 2026 CELT net load forecast will reflect deductions associated with the BTM DER portion of the DER forecast
- Summer and winter peak load reductions associated with BTM DER (both PV and BESS) over the forecast horizon are calculated using the waterfall approach described in slide 14 of the [February 21<sup>st</sup> 2025 LFC presentation](#)

# Seasonal Demand Impacts of BTM PV

- Example plots are shown for two summer and winter days to illustrate how BTM PV demand impacts are calculated for specific days
  - For each forecast year, probabilistic forecasts are based on the hourly results from 70 seasonal peak days
- New forecast components (BTM BESS and large loads) not yet shown
- Calculations are tabulated below

## Calculations From Plots

Example Day	Gross Peak	Net Peak	Peak Load Reduction
Summer 2027	28,213	26,477	1,736
Summer 2038	32,997	30,495	2,502
Winter 2040	37,184	36,297	887
Winter 2047	35,922	35,221	701



Base Load EV HP BTM PV Net Load

# Final 2026 BTM PV Forecast – Summer

## *Coincident “50-50” Summer Peak Load Reductions*

Category	States	Cumulative Total MW - "50-50" Summer Seasonal Peak Load Reduction									
		2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Behind-the-Meter PV	CT	401	438	461	480	496	508	517	523	526	524
	NEMA	191	198	204	209	213	214	213	210	207	203
	SEMA	284	284	293	304	312	314	313	310	306	300
	WCMA	287	287	292	298	302	303	301	296	290	284
	ME	217	221	220	218	218	219	220	219	218	217
	NH	110	117	123	128	132	136	140	143	146	149
	RI	75	77	79	82	85	88	89	90	90	90
	VT	194	202	207	209	209	213	216	219	220	220
	<b>ISONE</b>	<b>1,759</b>	<b>1,824</b>	<b>1,880</b>	<b>1,928</b>	<b>1,966</b>	<b>1,994</b>	<b>2,009</b>	<b>2,011</b>	<b>2,003</b>	<b>1,986</b>

**Notes:**

- (1) Forecast values include energy 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 8% to reflect avoided transmission and distribution losses

# Final 2026 BTM PV Forecast – Winter

## *Coincident “50-50” Winter Peak Load Reductions*

Category	States	Cumulative Total MW - "50-50" Winter Seasonal Peak Load Reduction									
		2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Behind-the-Meter PV	CT	0	0	0	0	1	15	32	51	71	92
	NEMA	0	0	0	0	0	5	11	18	25	32
	SEMA	0	0	0	0	1	8	17	27	37	48
	WCMA	0	0	0	0	1	8	16	26	35	45
	ME	0	0	0	0	0	5	11	18	25	33
	NH	0	0	0	0	0	3	7	12	16	22
	RI	0	0	0	0	0	3	6	10	13	17
	VT	0	0	0	0	0	5	10	15	21	27
	<b>ISONE</b>	0	0	0	0	4	53	110	176	243	316

**Notes:**

- (1) Forecast values include energy 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 8% to reflect avoided transmission and distribution losses

# Final 2026 BTM BESS Forecast – Summer

## *Coincident “50-50” Summer Peak Load Reductions*

Category	States	Cumulative Total MW - "50-50" Summer Seasonal Peak Load Reduction									
		2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Behind-the-Meter BESS	CT	2.1	6.5	11.1	14.9	17.2	18.0	18.0	18.0	18.0	18.1
	NEMA	2.1	7.3	13.4	18.8	22.4	23.6	23.8	24.3	24.8	25.4
	SEMA	3.2	11.1	21.7	32.1	39.0	41.4	41.4	41.4	41.4	41.4
	WCMA	1.7	6.0	11.9	18.0	21.9	23.3	23.3	23.3	23.4	23.6
	ME	0.5	1.5	2.5	3.4	4.0	4.2	4.3	4.4	4.5	4.6
	NH	0.2	0.8	1.4	2.0	2.3	2.4	2.4	2.5	2.5	2.6
	RI	0.1	0.4	0.8	1.3	1.7	1.9	1.9	1.9	1.9	1.9
	VT	0.8	2.1	3.2	3.8	4.3	4.7	5.1	5.4	5.7	6.0
	<b>ISONE</b>	10.6	35.8	66.1	94.4	112.8	119.4	120.2	121.1	122.2	123.6

**Notes:**

(1) All values are grossed up by 8% to reflect avoided transmission and distribution losses

# Final 2026 BTM BESS Forecast – Winter

## *Coincident “50-50” Winter Peak Load Reductions*

Category	States	Cumulative Total MW - "50-50" Winter Seasonal Peak Load Reduction									
		2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Behind-the-Meter BESS	CT	4.9	9.2	12.9	14.5	12.9	8.8	4.1	0.9	0.0	0.0
	NEMA	5.1	11.0	16.0	18.7	16.9	11.5	5.4	1.2	0.0	0.0
	SEMA	7.7	16.9	26.8	32.5	29.7	20.2	9.4	2.0	0.0	0.0
	WCMA	4.2	9.2	14.9	18.3	16.7	11.4	5.3	1.1	0.0	0.0
	ME	1.1	2.1	3.0	3.4	3.0	2.1	1.0	0.2	0.0	0.0
	NH	0.6	1.2	1.7	1.9	1.7	1.2	0.6	0.1	0.0	0.0
	RI	0.3	0.6	1.0	1.4	1.4	0.9	0.4	0.1	0.0	0.0
	VT	1.8	2.8	3.4	3.6	3.3	2.4	1.2	0.3	0.0	0.0
	<b>ISONE</b>	25.6	53.0	79.7	94.4	85.6	58.5	27.3	6.0	0.0	0.0

**Notes:**

(1) All values are grossed up by 8% to reflect avoided transmission and distribution losses

# SUMMARY AND NEXT STEPS



# Next Steps

- The 2026 DER forecast has been finalized
  - The ISO has developed the associated energy and seasonal peak reduction forecasts
- The final DER forecast will appear in the 2026 CELT, which will be published by May 1, 2026

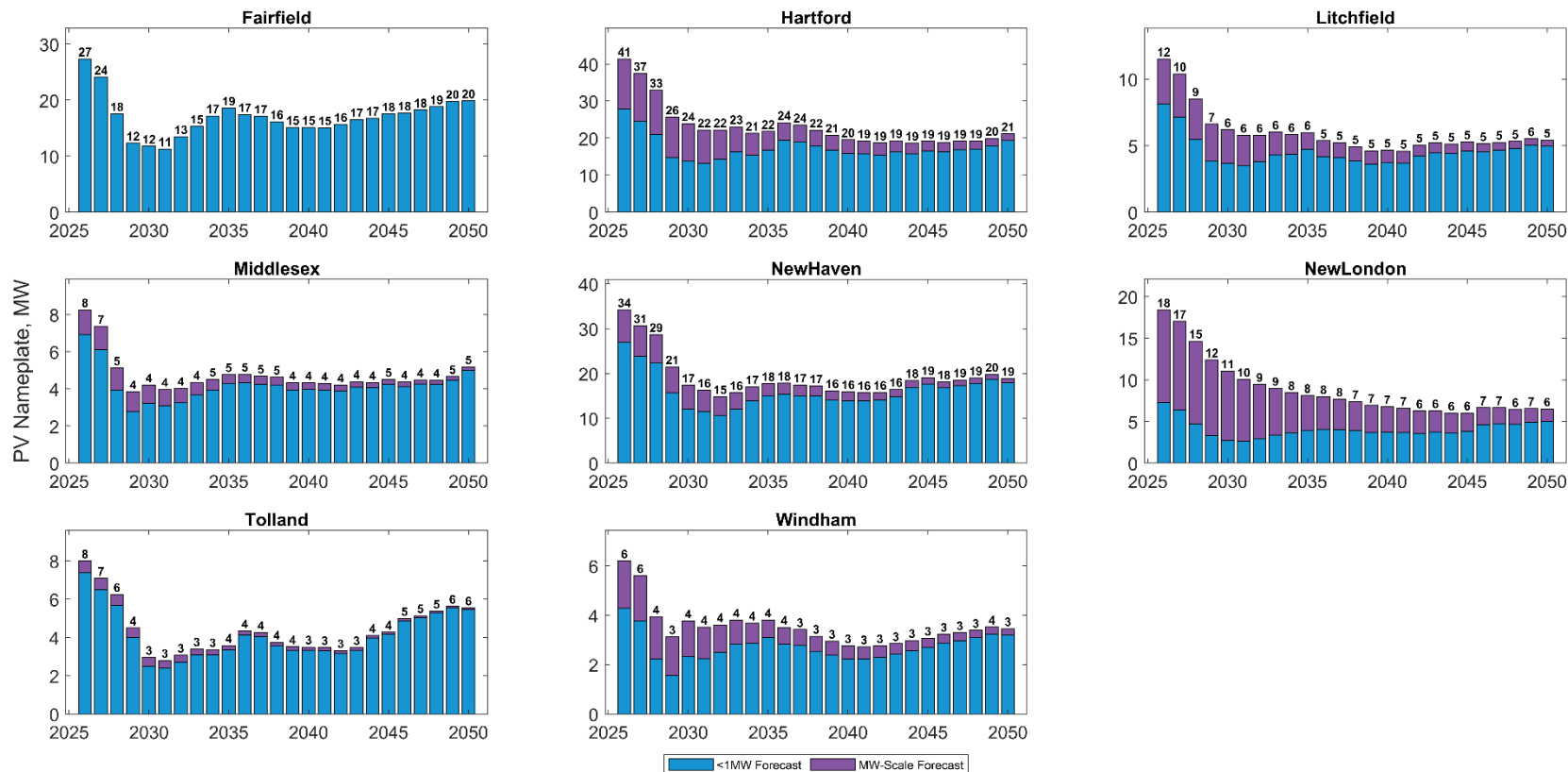
# Questions



# APPENDIX I

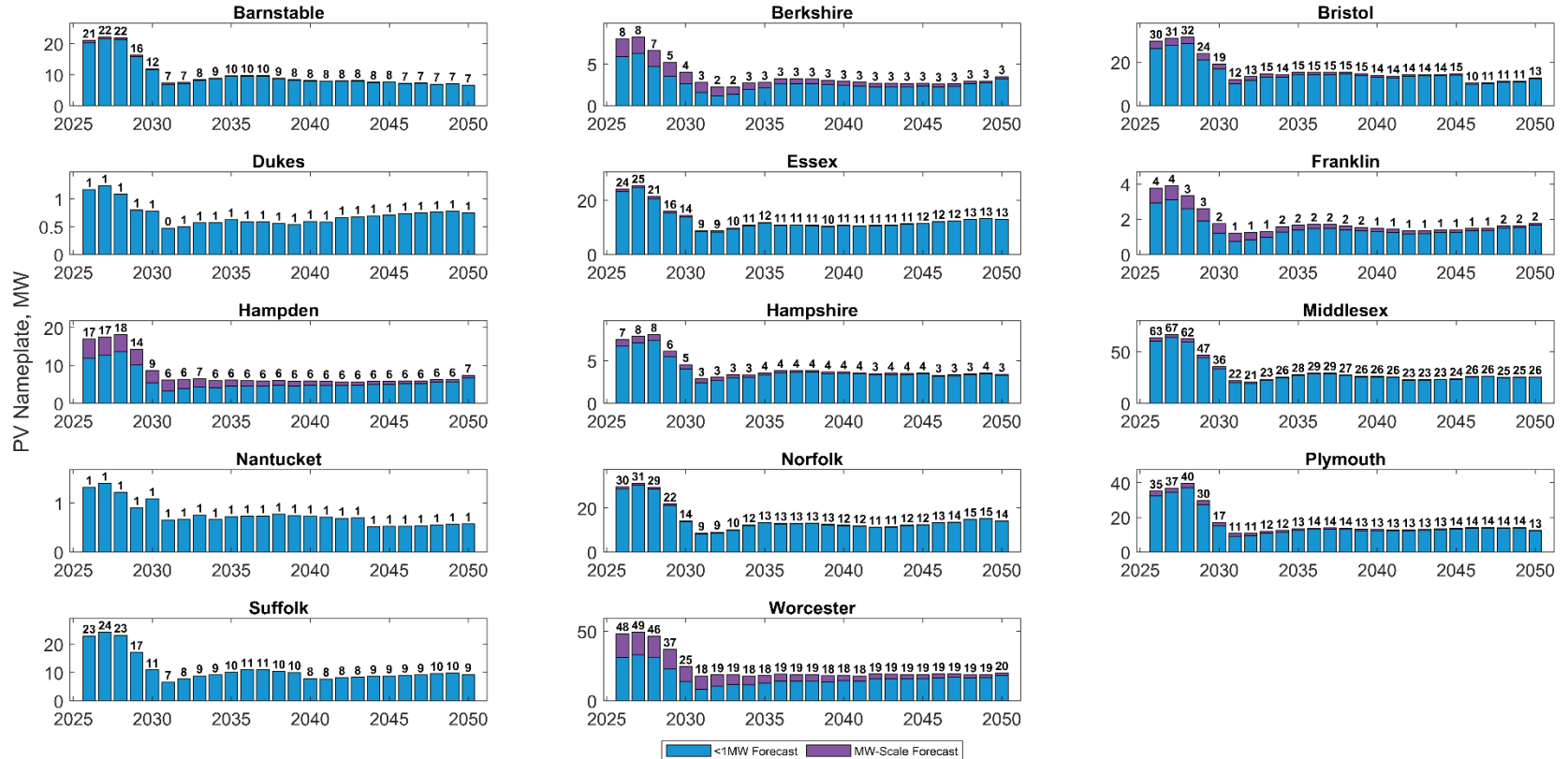
## *2026 DER PV County-level Forecast*

# Final 2026 County PV Forecast – Connecticut

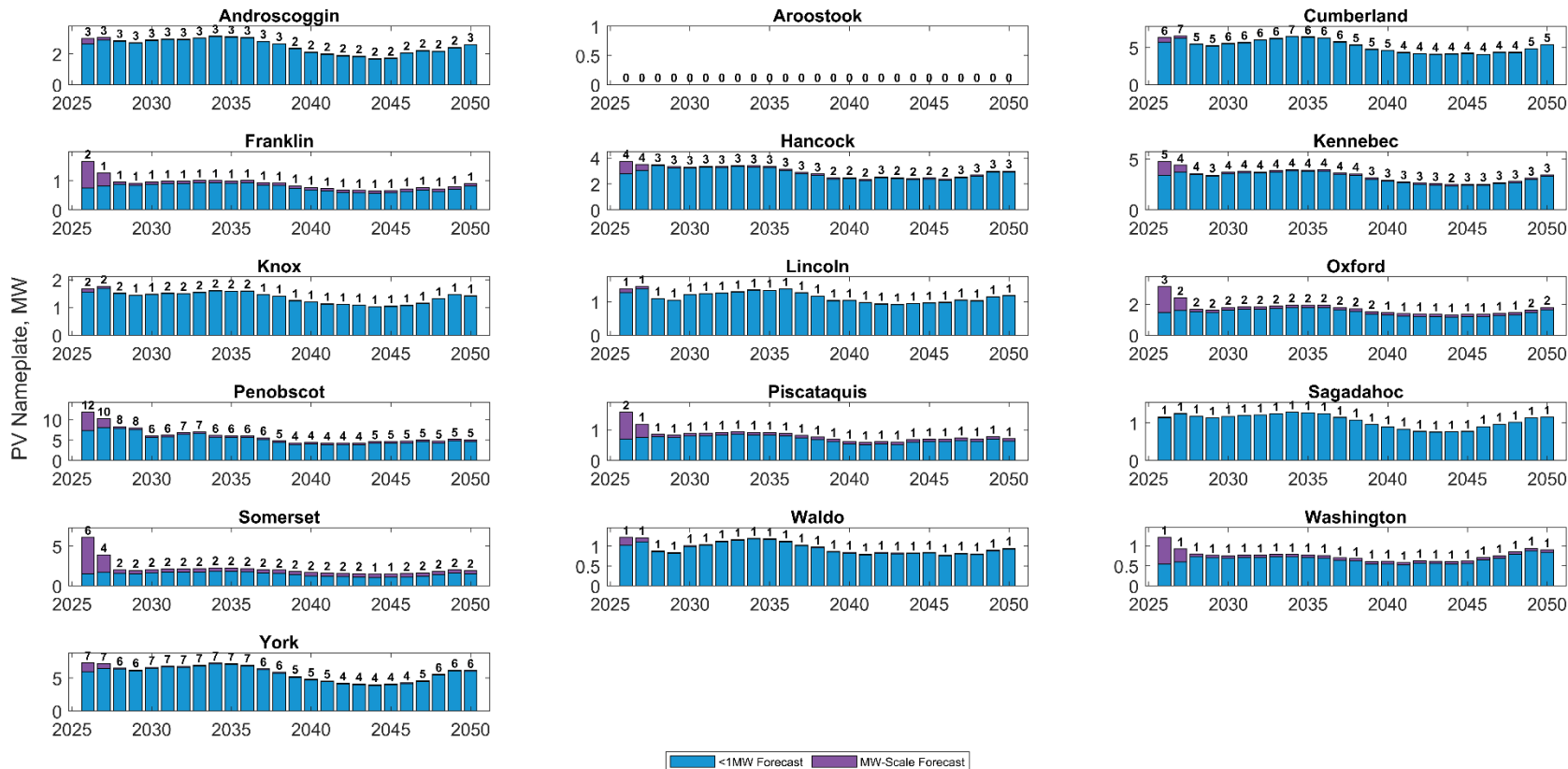


Legend: <1MW Forecast (Blue), MW-Scale Forecast (Purple)

# Final 2026 County PV Forecast – Massachusetts

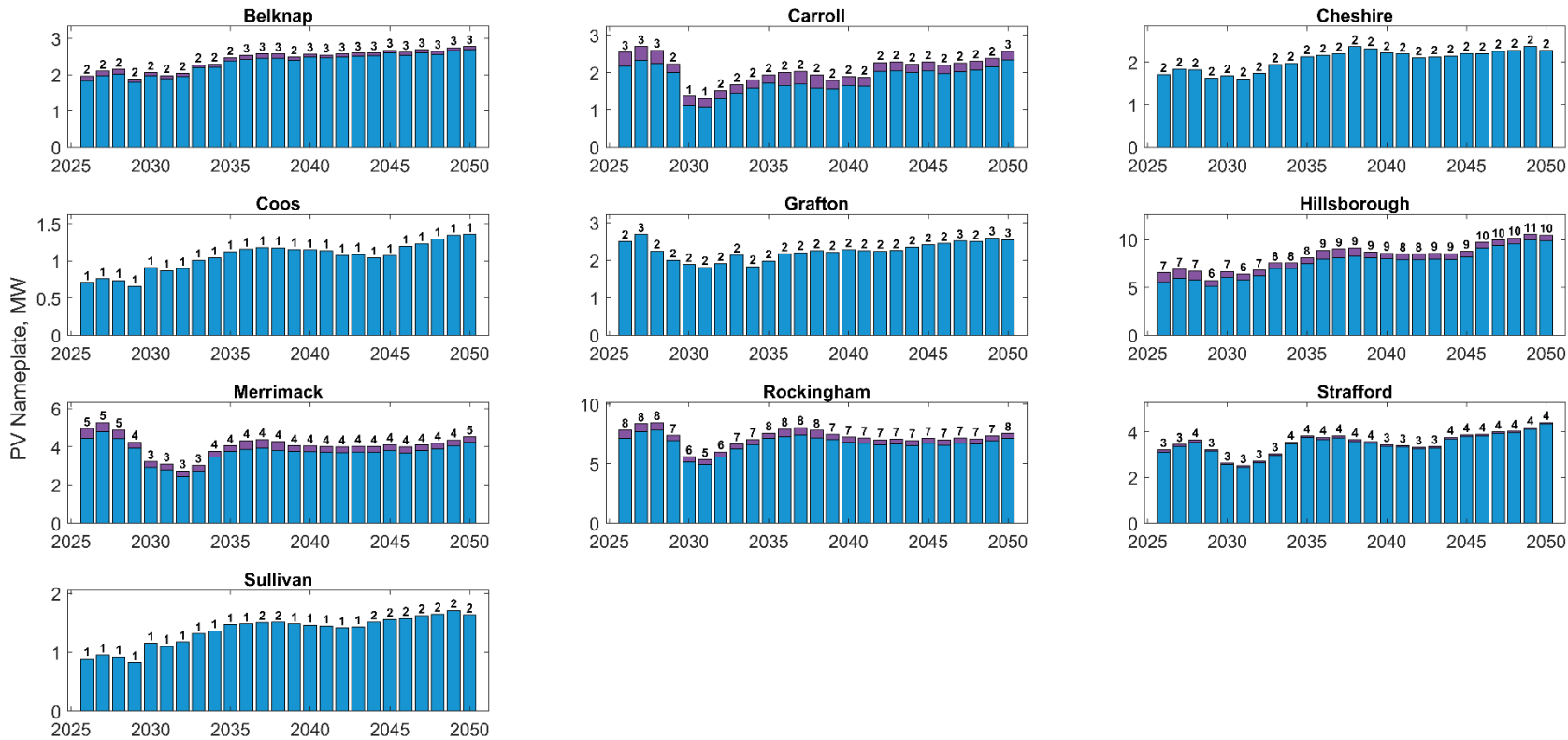


# Final 2026 County PV Forecast – Maine



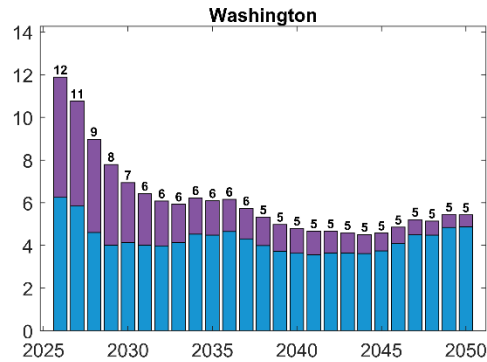
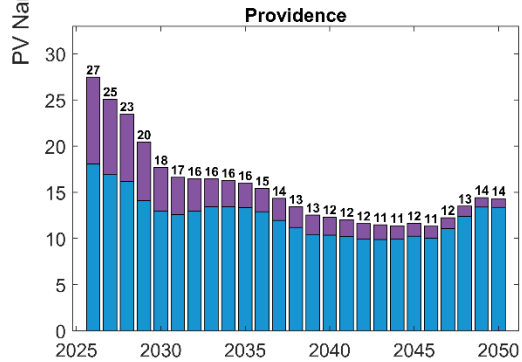
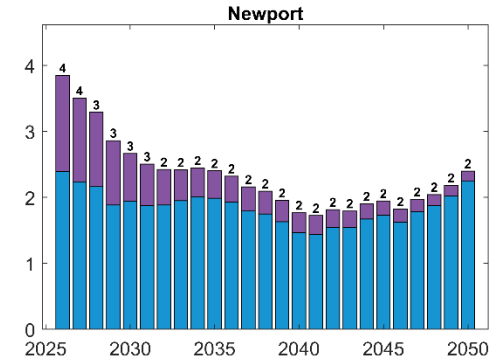
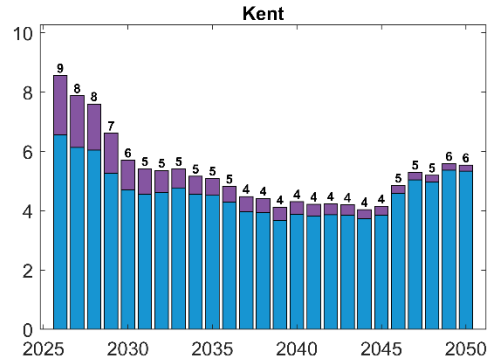
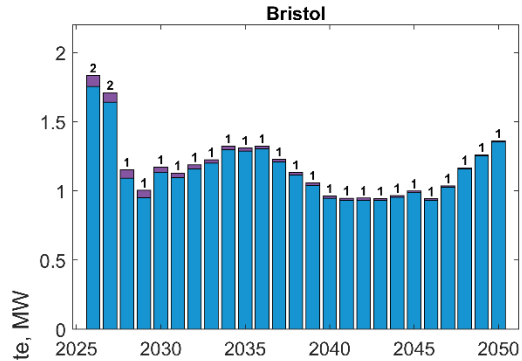
Legend: <1MW Forecast (blue), MW-Scale Forecast (purple)

# Final 2026 County PV Forecast – New Hampshire



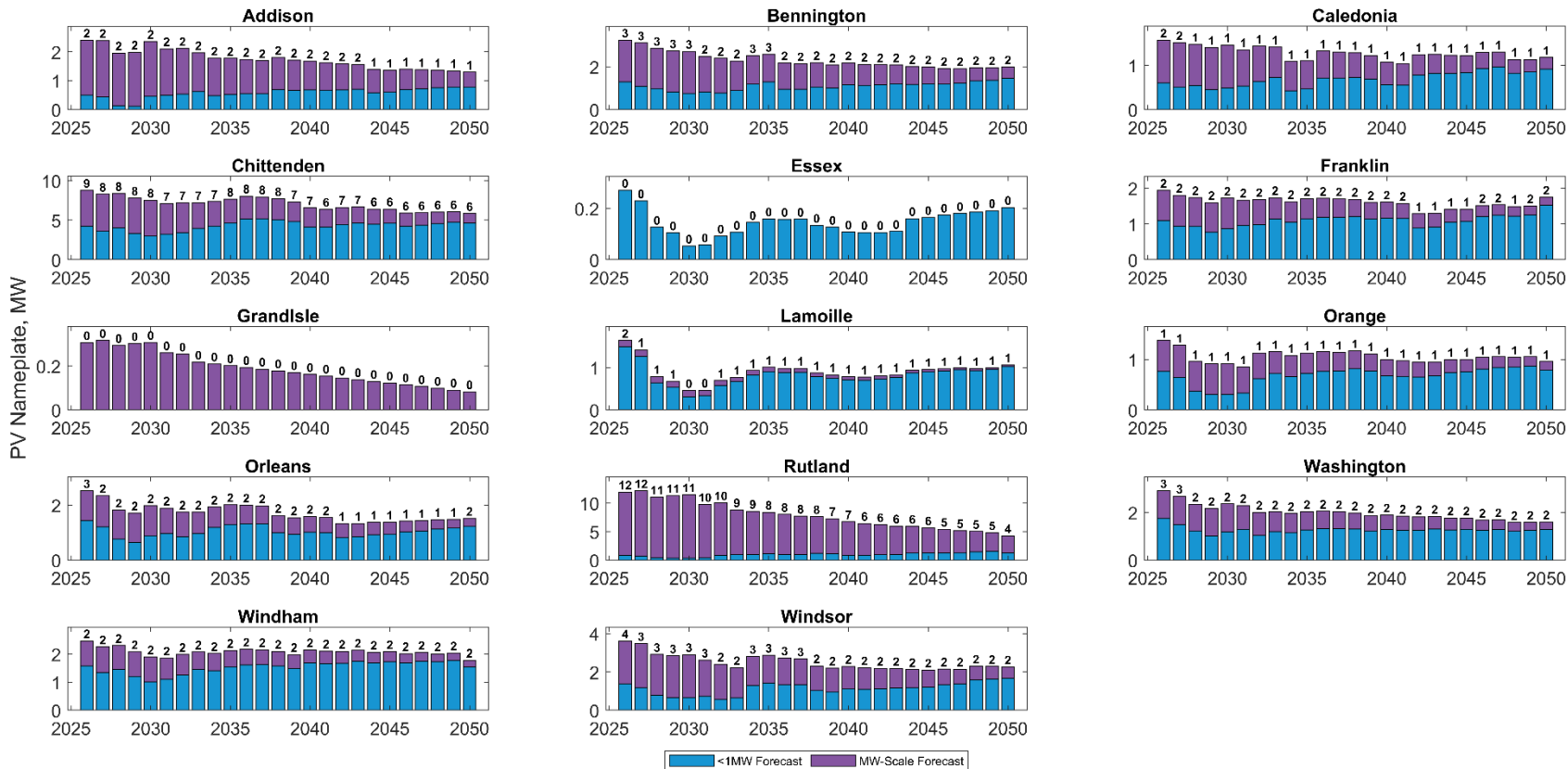
Legend: <1MW Forecast (blue), MW-Scale Forecast (purple)

# Final 2026 County PV Forecast – Rhode Island



Legend: <1MW Forecast (blue), MW-Scale Forecast (purple)

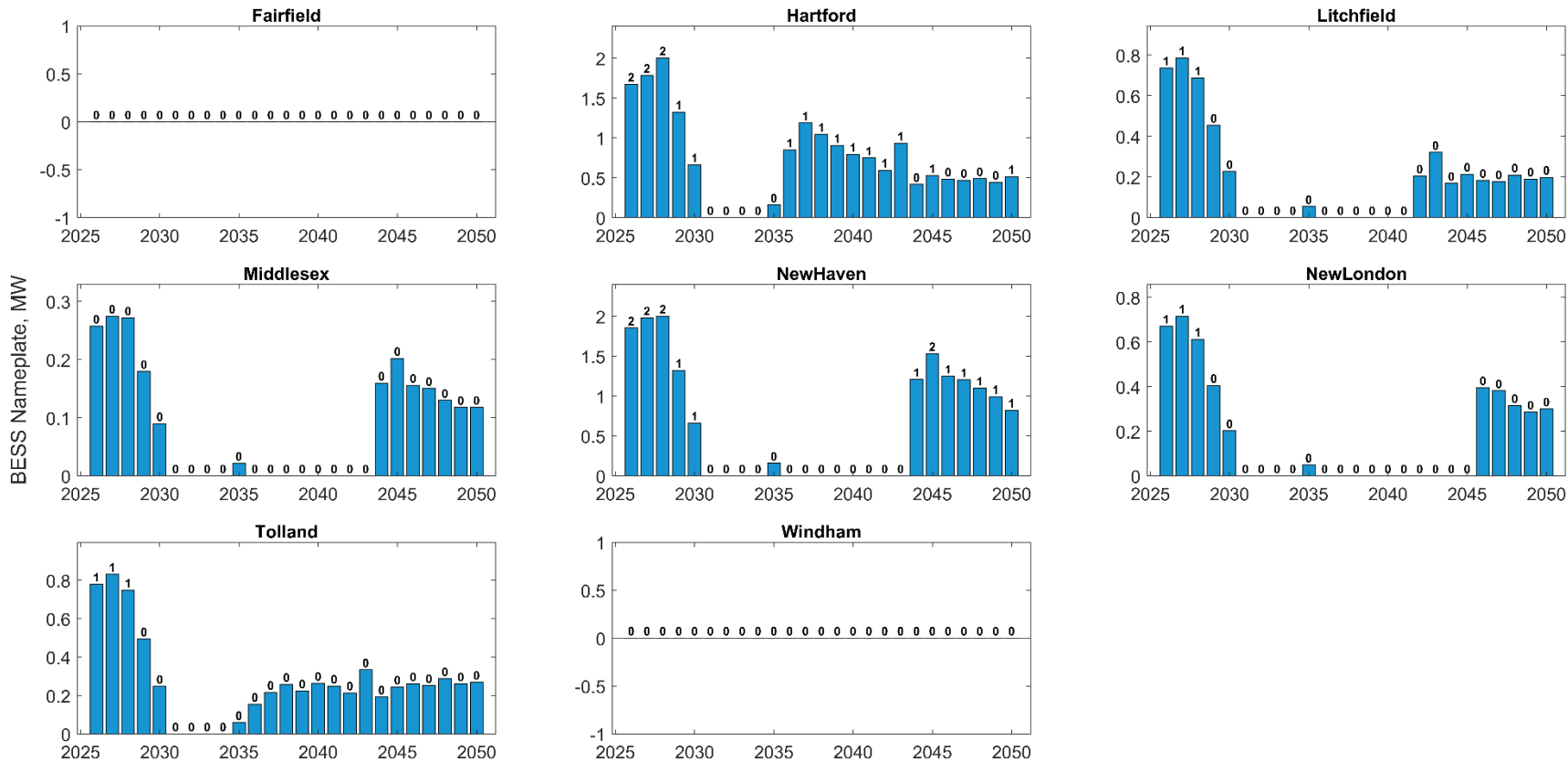
# Final 2026 County PV Forecast – Vermont



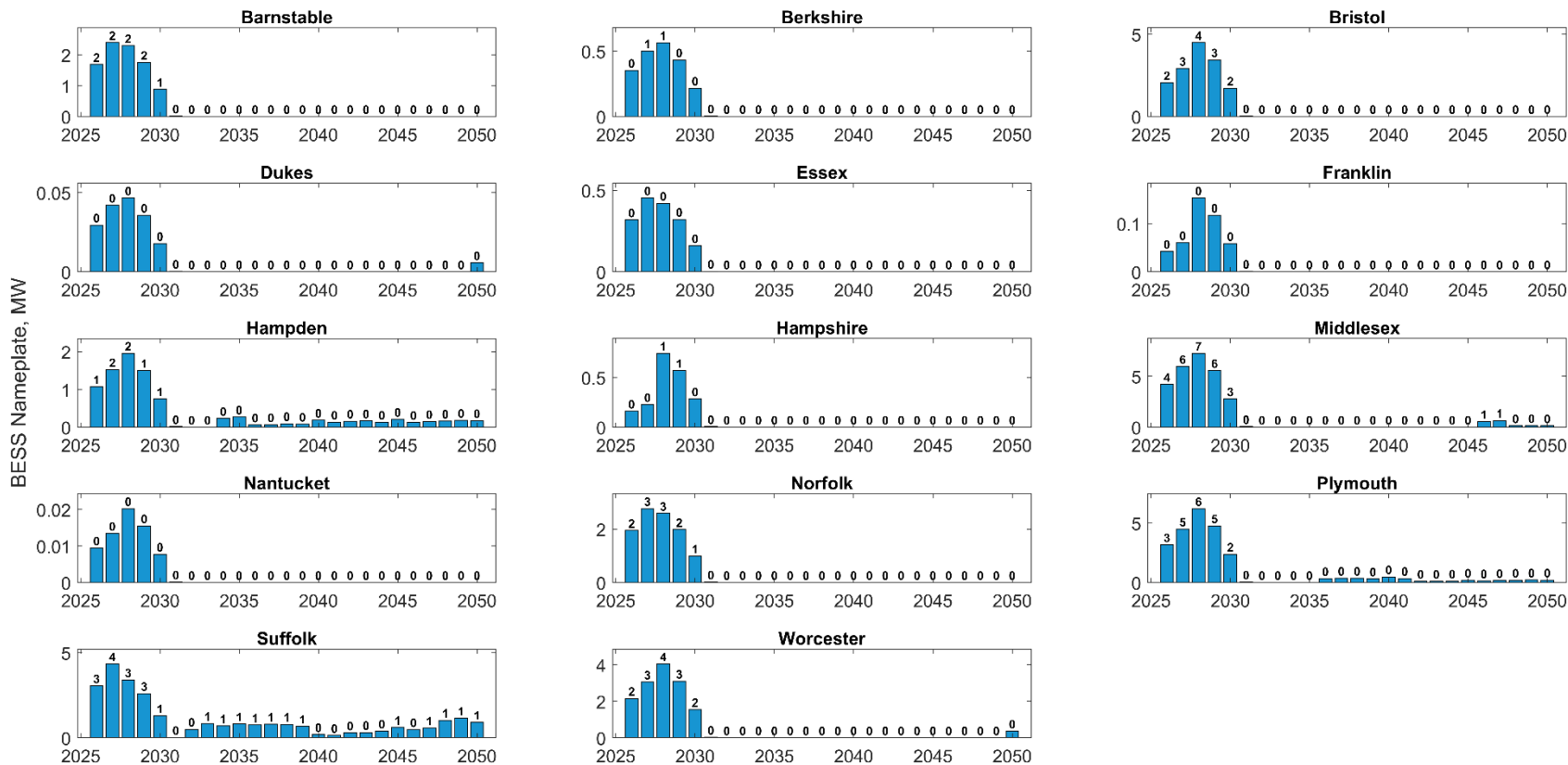
# APPENDIX II

## *2026 DER BESS County-level Forecast*

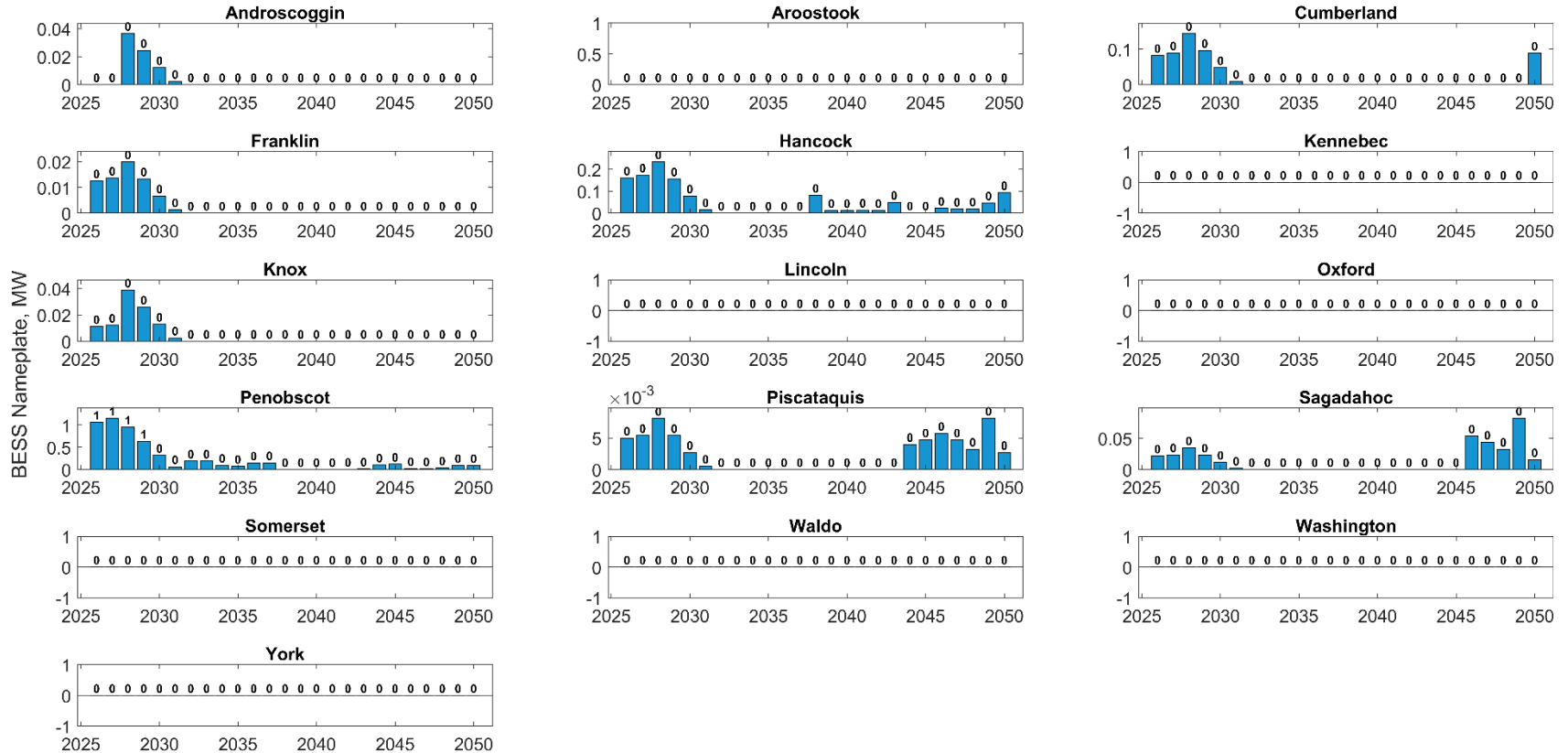
# Final 2026 County BESS Forecast – Connecticut



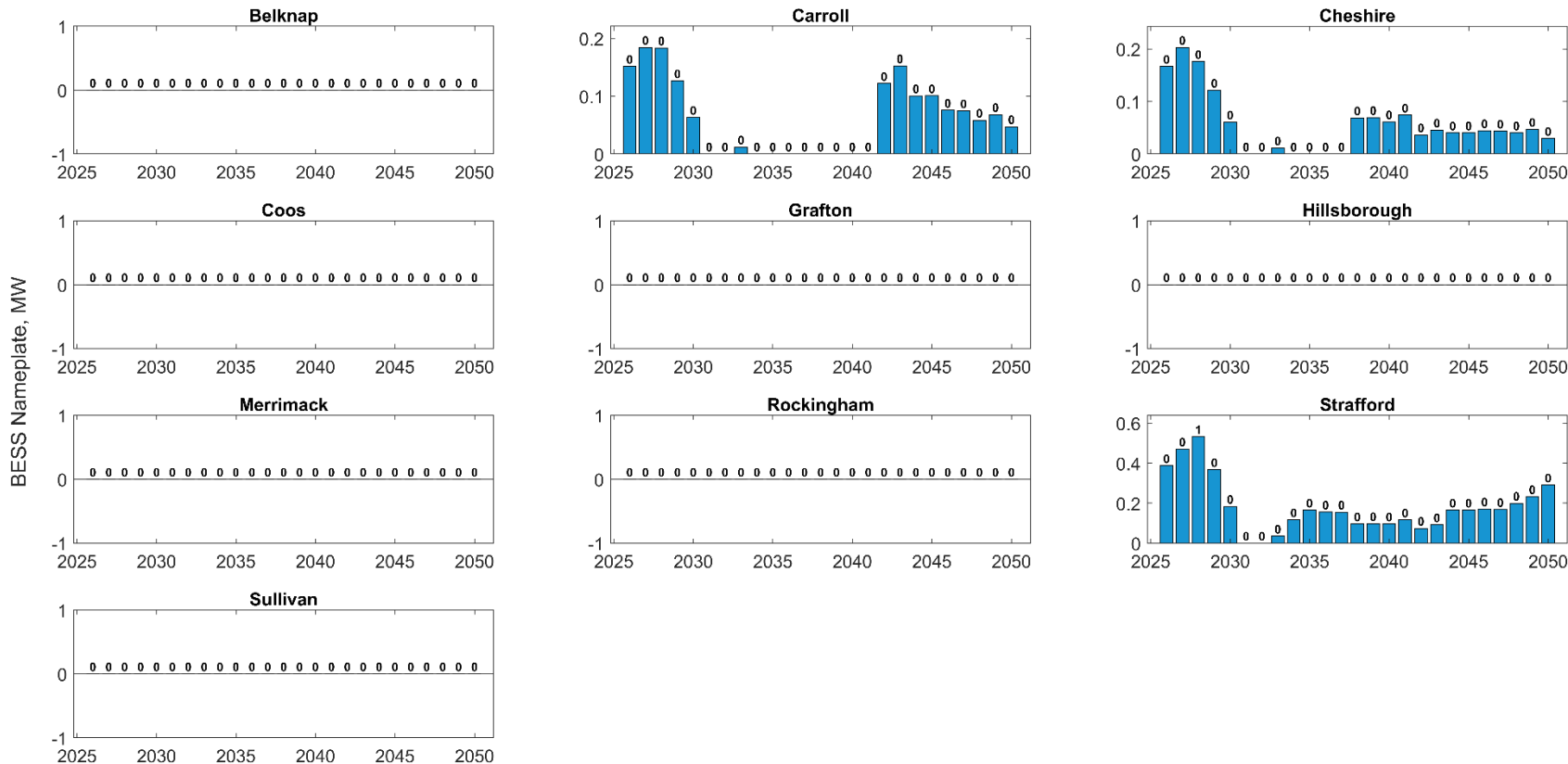
# Final 2026 County BESS Forecast – Massachusetts



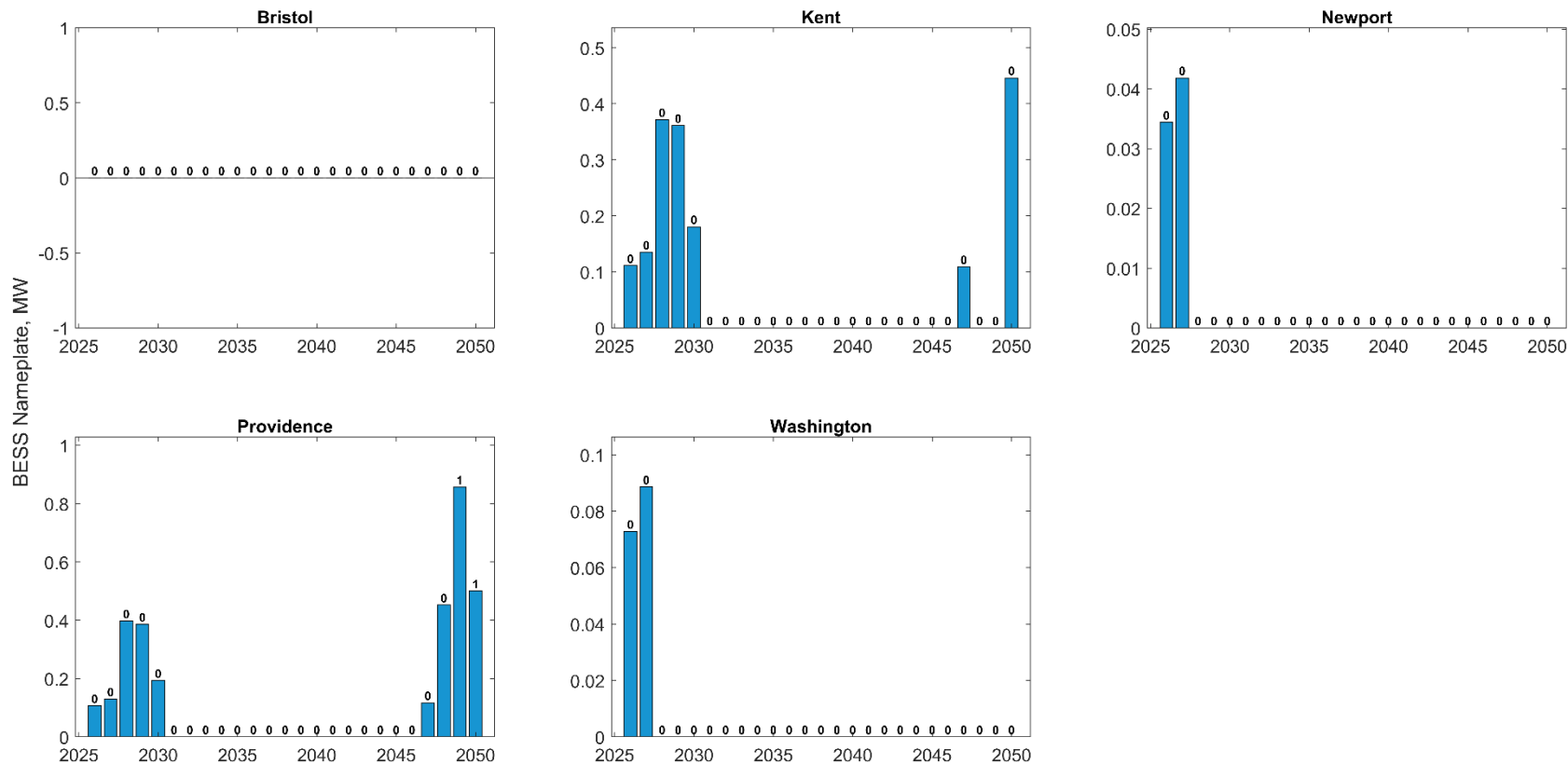
# Final 2026 County BESS Forecast – Maine



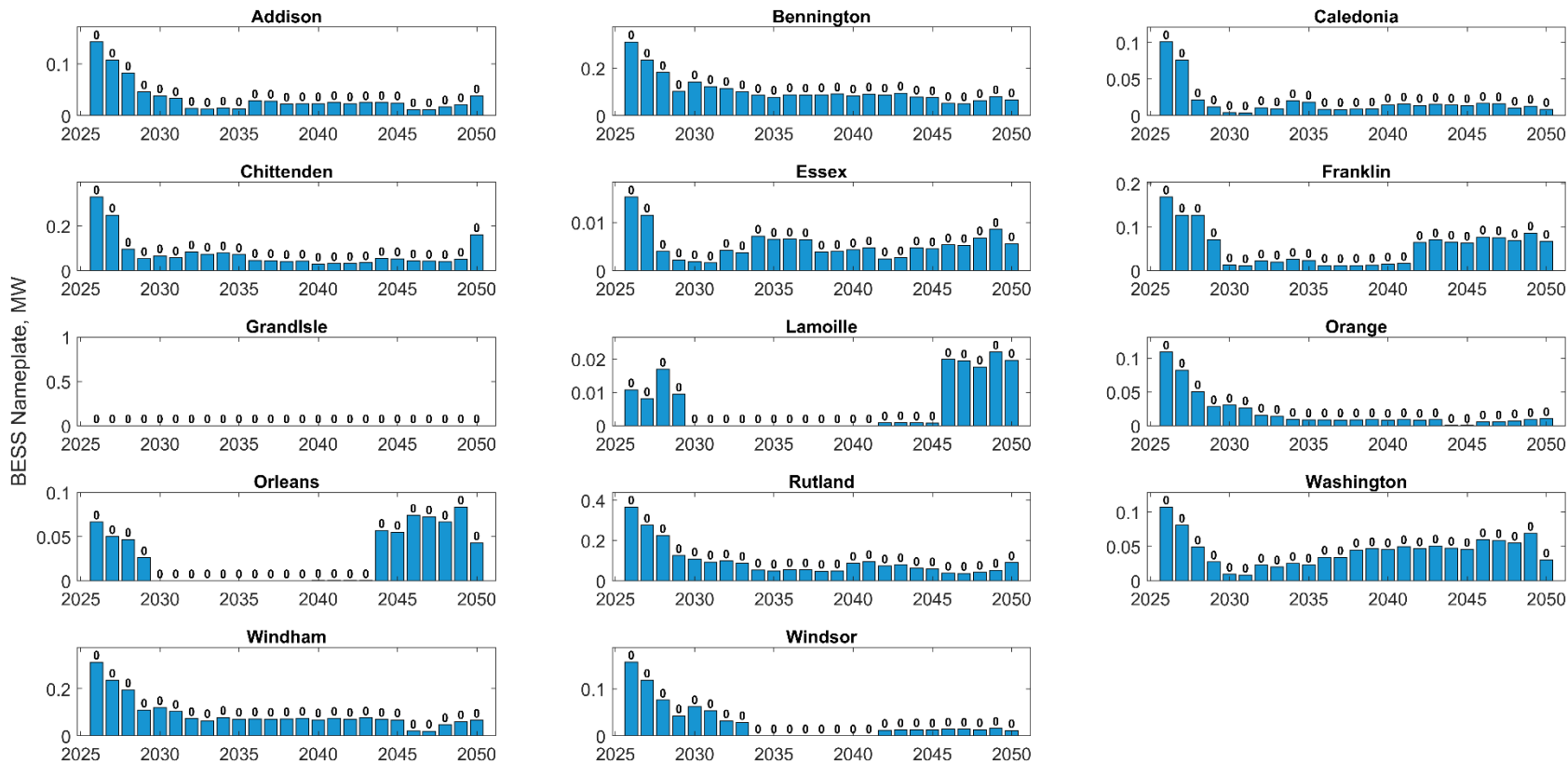
# Final 2026 County BESS Forecast – New Hampshire



# Final 2026 County BESS Forecast – Rhode Island



# Final 2026 County BESS Forecast – Vermont



# APPENDIX III

## *Classification of DER Forecast – Background and Methods*

# DER PV Classification

All DER PV are classified into the three following 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

# DER PV Nameplate Classification By State



- Classification varies by state
  - Market disposition of PV projects can be influenced by 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 18
  2. Non-FCM EOR/Gen
    - Determine the % share of non-FCM PV participating in energy market at the end of 2024
  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

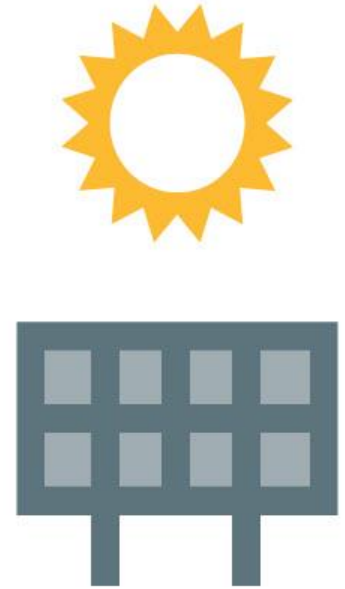
# DER PV in ISO New England Markets

## Data and Assumptions

- FCM
  - ISO identified all PV generators or demand resources (DR) that have Capacity Supply Obligations (CSO) in FCM up through FCA 18
    - Maintain separate accounting for  $FCM_{supply}$  and  $FCM_{DR}$
  - Assume aggregate total PV in FCM as of FCA 18 remains constant from 2027-2050
- Non-FCM Gen/EOR
  - ISO identified total nameplate capacity of PV in each state registered in the energy market as of 12/31/24
  - Assume the  $(EOR+FCM_{supply})$  share of total PV at the end of 2024 in each state except Maine remains constant throughout the forecast horizon
    - For Maine, assume  $(EOR+FCM_{supply})$  share is 40% over the forecast horizon to reflect how updated assumptions about NEB programs no longer reflect as much future MW-scale, resulting in less participation in wholesale markets than assumed in the 2024 forecast
- 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 DER For Reconstitution

- Historical BTM PV production estimates are developed at the hourly level for reconstitution in the development of the long-term load forecast
  - Estimates cover the historical period starting January 1, 2012
- The ISO estimates historical hourly BTM PV using:
  - Historical BTM PV performance data
  - Installed capacity data submitted by utilities
  - Historical energy production of market-facing PV
- BTM PV data and supporting documentation are available [here on the ISO New England website](#)
- Historical BTM BESS charging/discharging is assumed to be included in the historical load



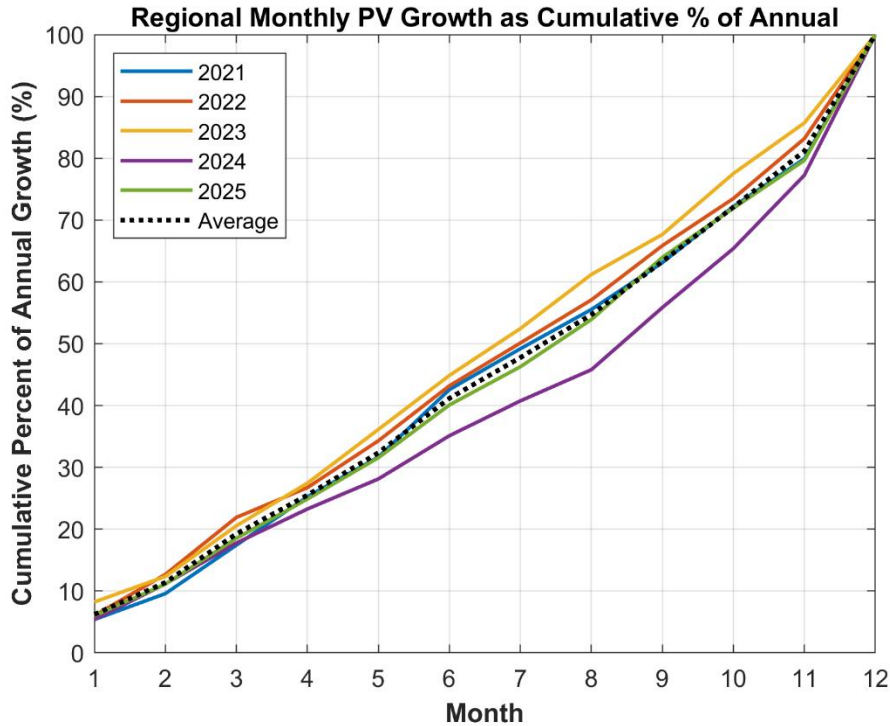
# APPENDIX IV

## *BTM DER Energy Forecast – Background and Methods*

# Development of BTM PV Energy Forecast

- The BTM PV nameplate forecast reflects end-of-year values
- Energy estimates in the BTM PV forecast are inclusive of incremental growth during a given year
- ISO assumes historical BTM PV growth trends across the region are indicative of future intra-annual growth rates
  - Growth trends between 2020 and 2024 were used to estimate intra-annual incremental growth over the forecast horizon (see next slide)
- For CELT 2026, monthly derated nameplate forecasts are used with historical hourly capacity factor profiles to generate the 70 years (1/1/1953 – 10/31/2023) of hourly forecasts, for each load zone and forecast year

# Historical Monthly PV Growth Trends, 2021-2025



*Average Monthly Growth Rates, % of Annual*

Month	Monthly PV Growth (% of Annual)	Monthly PV Growth (Cumulative % of Annual)
1	6%	6%
2	5%	11%
3	8%	19%
4	7%	26%
5	6%	32%
6	9%	41%
7	7%	48%
8	7%	55%
9	8%	63%
10	9%	72%
11	9%	81%
12	19%	100%

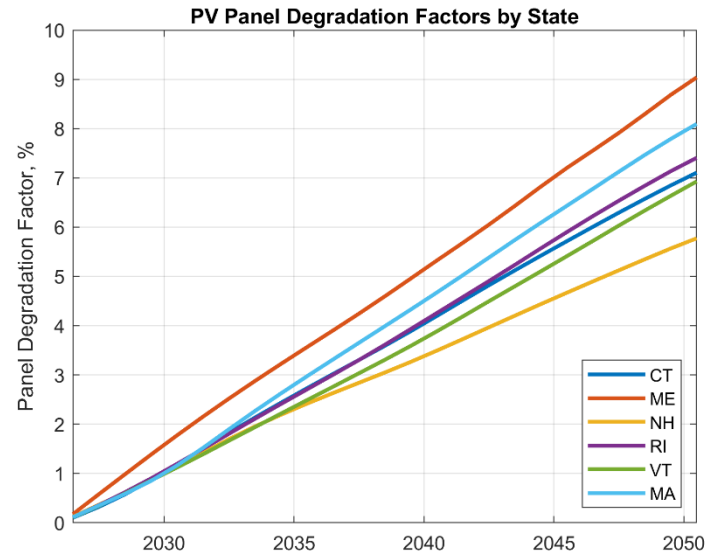
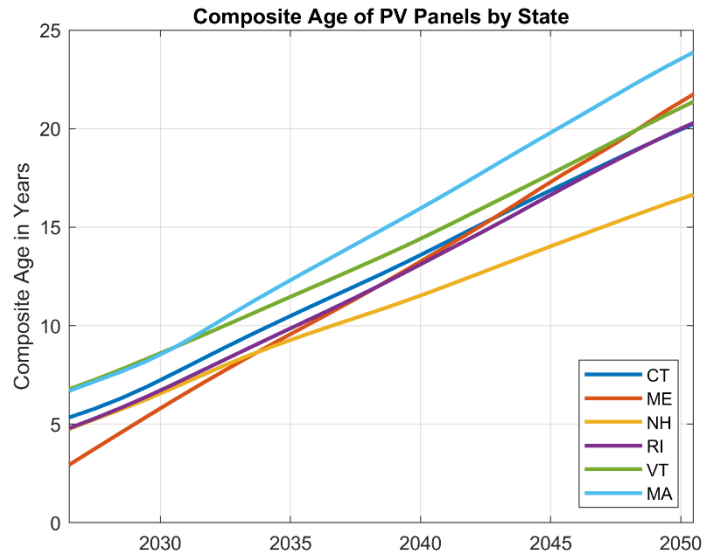
# PV Panel Degradation Factors

- No changes to the methodology to account for panel degradation were made since last year's forecast
- Forecast of BTM PV energy and summer peak load reductions include the effects of a 0.5% per 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 NREL, the median rate of degradation is 0.5% per 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 assumed the percent reduction of PV performance over time that reflects the anticipated degradation of PV panels



# APPENDIX V

## *Final 2026 PV Forecast Classification*

# Final 2026 PV Forecast Classification

Category	Sub_Category	States	y2025	y2026	y2027	y2028	y2029	y2030	y2031	y2032	y2033	y2034	y2035	Totals	
PV in Markets	FCM PV	CT	317.6	0.8	7.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	325.4	
		MA	925.4	165.8	155.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1246.6	
		ME	4.5	0.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.5	
		NH	0.0	0.5	2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.5	
		RI	66.8	13.1	24.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	104.1	
		VT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	Total	Annual		1314.4	180.3	191.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,686.2
		Cumulative		1314.4	1494.6	1686.2	1686.2	1686.2	1686.2	1686.2	1686.2	1686.2	1686.2	1686.2	1,686.2
	Non-FCM PV	CT		22.9	1.7	0.2	1.8	1.4	1.2	1.2	1.2	1.2	1.2	1.2	35.2
		MA		1145.2	71.0	81.9	146.3	110.0	76.2	47.0	45.9	50.6	52.4	54.7	1,881.2
		ME		496.7	22.7	17.3	16.6	15.9	15.8	16.2	16.6	17.0	17.1	16.8	668.8
		NH		11.5	0.7	-0.8	1.2	1.0	0.9	0.9	0.9	1.0	1.1	1.2	19.7
		RI		237.3	14.9	14.1	26.6	23.1	20.4	19.1	18.5	18.0	18.1	17.6	427.6
		VT		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	Annual		1913.6	111.0	112.6	192.5	151.4	114.6	84.4	83.1	87.9	89.9	91.6	3,032.6	
	Cumulative		1913.6	2024.6	2137.2	2329.7	2481.1	2595.7	2680.0	2763.1	2851.1	2941.0	3032.6	3,032.6	
<b>Markets Total</b>			<b>Annual</b>	<b>3227.9</b>	<b>291.3</b>	<b>304.2</b>	<b>192.5</b>	<b>151.4</b>	<b>114.6</b>	<b>84.4</b>	<b>83.1</b>	<b>87.9</b>	<b>89.9</b>	<b>91.6</b>	<b>4,718.7</b>
			<b>Cumulative</b>	<b>3227.9</b>	<b>3519.2</b>	<b>3823.4</b>	<b>4015.9</b>	<b>4167.3</b>	<b>4281.8</b>	<b>4366.2</b>	<b>4449.3</b>	<b>4537.2</b>	<b>4627.2</b>	<b>4718.7</b>	<b>4,718.7</b>

# Final 2026 PV Forecast Classification (cont.)

Behind-the-Meter PV	CT	1117.5	152.7	132.2	115.2	87.6	77.7	72.7	73.0	76.5	76.2	77.0	2,058.4
	MA	2215.6	74.8	87.5	164.2	123.4	85.5	52.7	51.4	56.8	58.8	61.4	3,032.1
	ME	679.9	33.5	30.0	24.5	23.4	23.4	24.0	24.5	25.1	25.3	24.8	938.4
	NH	321.0	31.5	33.8	32.9	28.7	25.9	24.6	26.1	29.2	30.5	32.5	616.8
	RI	200.0	25.5	10.7	17.8	15.5	13.6	12.7	12.4	12.1	12.1	11.8	344.2
	VT	597.3	44.9	43.1	38.6	36.8	37.1	33.2	33.4	32.0	31.3	32.1	959.9
Behind-the Meter Total	Annual	5131.4	362.9	337.2	393.2	315.3	263.3	220.1	220.9	231.8	234.3	239.6	7,949.9
	Cumulative	5131.4	5494.2	5831.4	6224.6	6540.0	6803.2	7023.3	7244.2	7476.0	7710.3	7949.9	7,949.9
<b>Annual total (all PV categories)</b>													
Annual total (all PV categories)	CT	1458.0	155.1	139.5	117.1	89.0	79.0	73.9	74.2	77.8	77.4	78.2	2,419.1
	MA	4286.3	311.6	324.7	310.5	233.3	161.7	99.8	97.3	107.4	111.2	116.2	6,159.8
	ME	1181.1	56.2	50.2	41.2	39.3	39.2	40.2	41.1	42.2	42.4	41.6	1,614.7
	NH	332.6	32.8	35.0	34.1	29.7	26.8	25.5	27.0	30.2	31.6	33.6	639.1
	RI	504.2	53.6	48.9	44.3	38.6	34.0	31.8	30.9	30.1	30.2	29.4	875.9
	VT	597.3	44.9	43.1	38.6	36.8	37.1	33.2	33.4	32.0	31.3	32.1	959.9
All PV Categories Total	Annual	8359.3	654.1	641.4	585.7	466.7	377.9	304.4	304.0	319.7	324.2	331.2	12,668.6
<b>Cumulative total (all PV categories)</b>													
Cumulative total (all PV categories)	CT	1458.0	1613.1	1752.5	1869.6	1958.6	2037.6	2111.5	2185.7	2263.4	2340.9	2419.1	2,419.1
	MA	4286.3	4597.8	4922.5	5233.0	5466.3	5628.0	5727.7	5825.0	5932.4	6043.7	6159.8	6,159.8
	ME	1181.1	1237.2	1287.5	1328.6	1367.9	1407.2	1447.4	1488.5	1530.7	1573.1	1614.7	1,614.7
	NH	332.6	365.4	400.4	434.5	464.2	491.0	516.5	543.6	573.8	605.5	639.1	639.1
	RI	504.2	557.7	606.7	651.0	689.5	723.6	755.4	786.3	816.4	846.5	875.9	875.9
	VT	597.3	642.2	685.2	723.8	760.6	797.8	831.0	864.4	896.4	927.8	959.9	959.9
All PV Categories Total	Cumulative	8359.3	9013.4	9654.8	10240.5	10707.2	11085.1	11389.5	11693.5	12013.2	12337.4	12668.6	12,668.6