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Draft 2015 Solar PV Forecast

Jon Black

SR. ENGINEER, SYSTEM PLANNING

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OVERVIEW

Summary: First Draft CELT 2015 PV Forecast

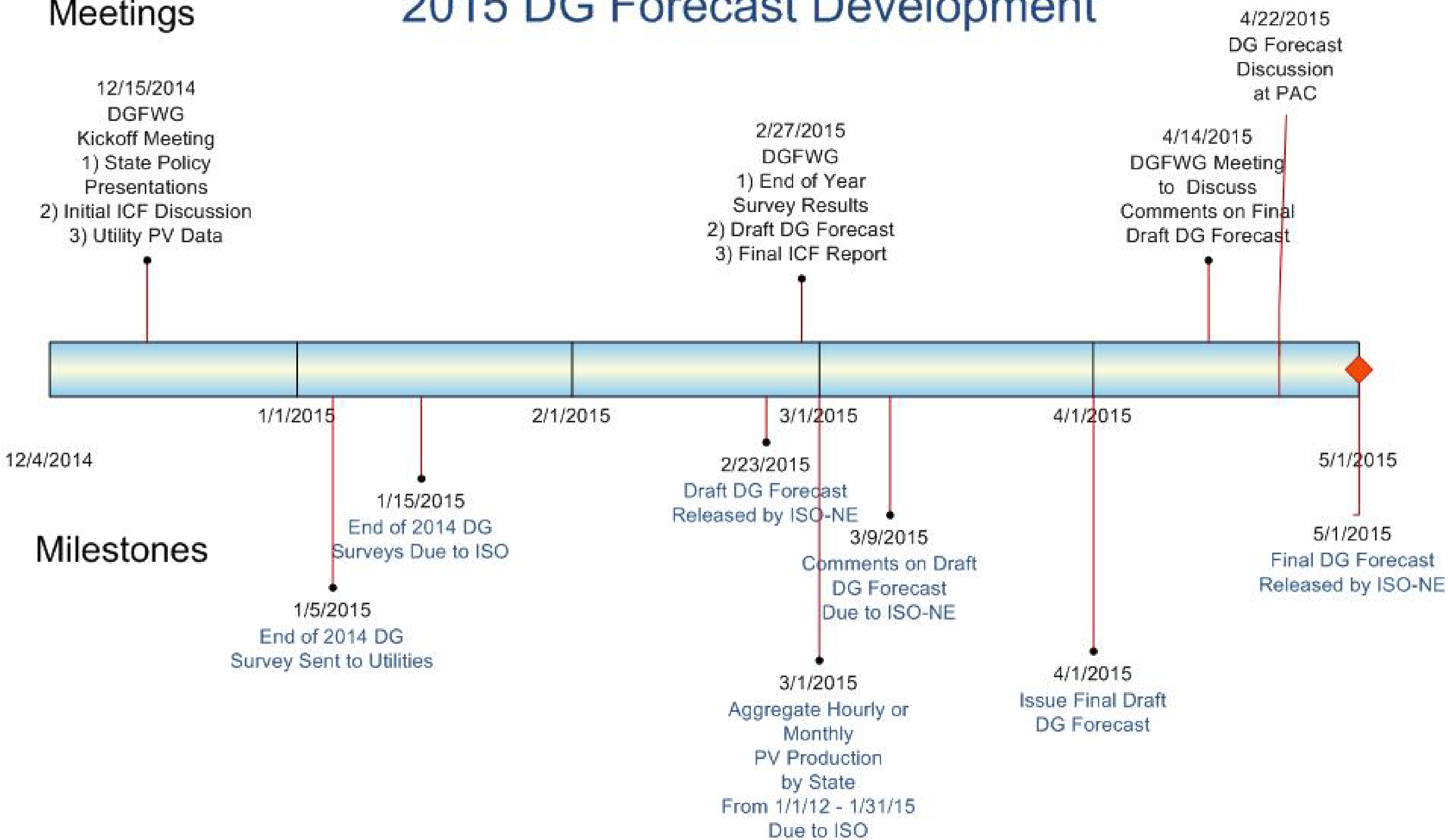
- PV development is happening more rapidly than projected in 2014
  - Based on discussions with stakeholders and data exchange with the New England states and Distribution Owners
  - The first draft 2015 PV forecast is higher and more “frontloaded” than the 2014 PV forecast
- The interrelated factors influencing the potential future development of PV resources are complex
  - The 2015 PV forecast reflects a qualitative approach, but with better information than was available to the ISO last year

What's New in the 2015 PV Forecast?

- Greater availability of historical data
  - Distribution owner survey of installations
  - Energy production information from the states (to be provided by March 2)
- Consideration of the anticipated economic drivers of PV over the forecast horizon
- Updates on state policies and programs influencing PV deployment in New England
- The ISO will break out PV resources by type for discussion at the April 14 DGFWG meeting
  - FCM resources with capacity supply obligations
  - Settlement only resources that are not FCM resources
  - Behind the meter resources that are already accounted for as part of the ISO load forecast*
  - Other behind the meter resources not accounted for as part of the ISO load forecast

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

2015 DG Forecast Development



BACKGROUND

Background

- The 2014 PV forecast represented the first multistate forecast
  - The forecast was primarily based on state policy goals
- 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)
    - Changes to federal Investment Tax Credit (ITC), post-2016;
  - 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
- The draft 2015 PV forecast methodology is similar to that of the 2014 forecast, with the improvements and updates noted on slide 5

COMPARISON OF DISTRIBUTION OWNER SURVEY WITH THE 2014 PV FORECAST

Continued Data Quality Improvements Needed

Uncertainty Regarding PV Installations at the End of 2013

- Most recent Distribution Owner data suggests that more PV was likely in-service at the end of 2013 than indicated by information collected last year
  - Reflects better quality data submitted to ISO
  - Raises some uncertainty regarding MW growth of 2014 PV installations
- In-service dates for some PV either remain unknown to the ISO (especially in MA and ME) or may be unreliable

State	Installed PV as of 12/31/13 *(MW_{AC})*		Difference
	March 2014 Survey	January 2015 Survey	
CT	73.8	73.2	-0.6
MA*	361.6	397.9	+36.3
ME*	8.1	2.3	-5.8
NH	8.2	8.6	+0.4
RI	10.9	12.6	+1.7
VT	36.1	42.7	+6.6
Region	498.7	537.4	+38.7

<u>Notes:</u> * As of 12/31/14, in-service dates for approximately 40 MW of PV in MA and 4 MW of PV in ME are unknown

Recent Survey Results Compared with 2014 PV Forecast

- Tabulated below is a comparison of the forecasted incremental PV growth (MW_{AC}) and the observed growth for 2014
  - Growth was as expected in CT, ME, NH, and RI
  - Greater than expected growth was observed in MA and VT
- Some of differences are likely attributable to improved data quality in the last year and are not due to differences in forecasted vs. actual growth

State	2014 Forecasted Growth	Actual Growth	Difference
CT	46.2	45	-1.2
MA	168.5	305.2	+136.7
ME	2.0	2.3	+0.3
NH	2.5	4.5	+2.0
RI	7.3	7.3	0
VT	20.1	45.4	+25.3
Region	246.5	410.0	+163.5

FORECAST ASSUMPTIONS AND INPUTS

Introduction

- The PV forecast acknowledges the significant trend in PV development and its potential impact on the New England process
- All state-by-state assumptions and inputs to the PV forecast are listed on the following slides

Forecast Methodology
MA Assumptions

- MA DPU's 12/15/14 DGFWG presentation serves as primary source for MA policy information
- A DC-to-AC derate ratio of 83% is applied to the MA SREC goal to determine AC nameplate of state goal
  - PV system designers/developers typically choose to oversize their solar panel array with respect to their inverter(s) by a factor of 1.2**
  - DC nameplate capacity is determined by the sum of the DC ratings of all the panels that make up the solar array, and AC nameplate capacity is determined by the (sum of the) inverter(s) rating(s).
    - E.g., a 120 kW_{DC} solar panel array is connected to 100 kW_{AC} inverter
  - This factor is called any of the following:
    - Array-to-inverter ratio, oversizing ratio, overloading ratio, DC-to-AC ratio
  - 1/1.2 = **83%**
  - Converted MA 2020 goals: 1,600 MW_{DC} = **1,358 MW_{AC}**

**Source: J. Fiorelli and M.Z. Martinson, *How oversizing your array-to-inverter ratio can improve solar-power system performance,* Solar Power World, July 2013, available at: http://www.solren.com/articles/Solectria_Oversizing_Your_Array_July2013.pdf

Forecast Methodology
MA Assumptions, cont'd

- MA SREC I/II programs successfully achieve 2020 state goal
- Remaining MWs needed to reach state goal are applied from 2015-2020 according to the following anticipated factors:
  - Planned reduction of federal ITC in 2016 will promote increased development through 2016
  - Program stabilizes from 2017-2020 until goal is achieved
- Post-SREC (after 2020) forecast values are kept at 2020 growth level, but are more significantly discounted (refer to slide 28)

Forecast Methodology
CT Assumptions

- CT DEEP's 9/30/13 DGFWG presentation serves as primary source for CT policy information
  - Policy updates were provided verbally during the 12/15/14 DGFWG meeting
- ZREC program will be satisfied entirely with PV
  - 210 MW CL&P + 42 MW UI = 252 MW total
  - Year 4 competitive solicitation scheduled for April 2015
  - Assumed 37 MW of ZREC projects in service by 12/31/14
    - Remaining 215 MW were divided and applied evenly during 5-year program duration, from 2015-2019
  - Program review in year four will find technology costs have decreased and extend program for its last two years (refer to PA 11-80, Section 107(c)(2))

Preliminary Forecast Methodology
CT Assumptions, cont'd

- CT Green Bank's Residential Solar Investment Program
  - 20.75 MW_{AC}/year (25 MW_{DC}) for 2015, based on recent project approvals and those anticipated this year
- Discrete utility-scale project
  - 20 MW project in Sprague/Lisbon assumed to be commissioned in 2016
- Existing PV by end-of-2014 is based on Distribution Owner survey results
  - Includes approximately 30 MW of "legacy" PV that pre-existed aforementioned programs
- Post-ZREC (after 2019) forecast values are kept at 2018 growth level, but are more significantly discounted (refer to slide 28)

Forecast Methodology
VT Assumptions

- VT DPS' 12/15/14 DGFWG presentation serves as primary source for CT policy information
- PV comprises 110 MW of Standard Offer Program goal of 127.5 MW goal is reached by 2022
  - Assume 34 MW of SOP projects in-service by end of 2014, remaining MWs applied evenly over years 2015-2023
- Assume net metering projects will promote 135 MW of PV until 15% cap is reached
  - Planned reduction of federal ITC in 2016 will promote increased development through 2016, with residual impact continuing through 2017
- Assume 75% of existing PPA projects reported by DPS go into service
  - 2014: 3.7 MW, 2015: 2.95 MW, 2016: 2.95 MW
- Overall timing and total capacity of annual installed PV are generally consistent with VT DPS's 9/30/13 presentation to DGFWG
- Annual forecast value from 2023 kept constant for 2024 (post-policy), but is more significantly discounted (refer to slide 28)

Forecast Methodology
RI Assumptions

- RI OER's 12/15/14 DGFWG presentation serves as primary source for RI policy information
- Consistent with DG Standard Contract program data to date
  - A total of 30 MW of DG Standards Contract projects will be PV
- Renewable Energy Growth Program, 2015-2019
  - Total of 144 MW PV (90% of goal) anticipated, applied from 2016-2020 in proportion to phased-in timeline with one year commercialization period assumed
- Renewable Energy Fund & Net Metering
  - Combined influence results in 2.7 MW/year over the forecast horizon
- Post-2021 (after REGP ends), annual forecast values are kept constant, but are more significantly discounted (refer to slide 28)

Forecast Methodology
NH & ME Assumptions/Inputs

- NH
  - NH PUC's 12/15/14 DGFWG presentation serves as primary source for NH policy information
  - Based on Distribution Owner survey results, net metering and other state grants/incentives resulted in 4.5 MW of PV growth in 2014
    - Growth carried forward at constant rate throughout forecast period
  - Assume 50 MW net metering cap reached by 2020
  - Post-2020, annual forecast values are kept constant, but are more significantly discounted (refer to slide 28)
- ME
  - ME PUC's 9/30/13 DGFWG presentation serves as primary source for ME policy information
  - Based on Distribution Owner survey results, net metering and other state grants/incentives resulted in 2.7 MW of PV growth in 2014
    - Growth carried forward at constant rate throughout forecast period

RESULTS OF ICF’S ECONOMIC DRIVERS STUDY

What the ICF Study Is

- ICF was contracted by ISO-NE to deconstruct PV economics into individual drivers to help inform ISO-NE's 2015 PV forecast process in response to stakeholder feedback that PV economics need to be considered as part of the forecast process
- The study helps illustrate the complex interplay of public and private investment and business models commonly involved in PV commercialization
- It characterizes the relative importance of economic drivers under standardized assumptions across states & customer types
- The study assesses how economic drivers may change over time due to changes in technology cost and performance, electricity rates, federal & state incentives, etc.

What the ICF Study Is Not

- The study does NOT analyze the cost-effectiveness of federal, state, or utility PV policies nor make value judgments about the need for, or appropriateness of, such policies.
- Not a review of the “value of solar” nor the grid integration of renewable energy
- Not a forecast of PV capacity deployment, electricity production, nor incentive levels in the region
- Does not suggest how the ISO should use the results

Interpretation of ICF Results

- The ISO proposes that the results of the ICF study are useful in the determination of suitable discount factors applied over the forecast horizon
- To this end, values for the "Fully Supported PV Economics" summary measure were compared across all project start years and customer types in each state to aid in understanding the ICF results
  - Fully Supported PV Economics represent the "best-case" scenario for PV projects, in which the benefits of all federal and state incentives are captured
- These results were then normalized to the 2015 base year, to show relative changes in the results in 2019 and 2024
- Given that the overall PV economics in 2015 are similar to 2014, normalizing the results to the 2015 base year helps to compare the PV economics over time to the recent PV economics within which recent PV growth trends occurred in each state
  - This comparison is based on the numerous assumptions and inputs, as well as the financial modeling methodology used by ICF
- The resulting plots are shown on the Appendix
  - The plots are meant to illustrate general trends, but not as precise values for PV economics
  - Because the plots (and the study reference periods) begin in 2015, the plots do not display past improvements in PV economics

ISO's Main Takeaways From ICF Study

- There are a number of interrelated federal and state policies, financing options, and ownership models that should be considered when evaluating the viability of current and future PV investments
  - Evaluating existing and future PV economics is a complex task!
  - Frequently, there are a dozen individual drivers that increase or decrease PV economics by $.01/kWh or more on a levelized basis for PV projects
- The largest economic drivers of PV tend to be:
  1. System installed cost (i.e., first cost)
  2. Physical power revenue (wholesale, offsetting on-site electricity loads, net metering)
  3. Renewable energy credit (REC) revenue
  4. Federal investment tax credit
  5. Federal depreciation

  (The order of importance (1-5) of these largest economic drivers can vary between state, customer type, and project start year)
- Future trends with respect to all of these drivers are uncertain
- Physical power revenues become increasingly important over time, while REC revenues and total federal support tend to decline over time

ISO's Main Takeaways From ICF Study, cont'd

- PV projects should continue to offer strong investment returns in the next couple of years if all incentives can be monetized
  - Recent trends in PV deployment should continue through 2016, and may accelerate near the planned decline of the federal Investment Tax Credit (ITC)
  - ISO suggests that the following trends will likely result:
    - Policy drivers that do not significantly constrain the timing of PV development (SRECs, net metered project growth below caps) will likely facilitate accelerated deployment until the slated ITC reduction
    - Policies that involve periodic procurement or solicitation (CT ZREC, RI Renewable Energy Growth, VT Standard Offer) will likely facilitate more consistent, incremental growth
- The planned decline of the federal ITC beginning in 2017, together with the planned reduction of some state PV policy support, creates more challenging overall PV economics in 2019 and 2024, as compared to 2015
  - Much more uncertainty regarding PV deployment in the region from 2017 onward
- By the 2024 timeframe, the overall economics of PV investment does not entirely recover from the ITC reduction, despite the following assumptions:
  - Modest reductions in installed costs (in real dollars)
  - Improvements in system performance
  - Increases in wholesale/retail electricity rates
  - Existing net metering policies remain intact, and existing net metering caps would not be constraints on future PV investment

Discount Factors

- Notwithstanding the recent success of state programs, discount factors were developed and incorporated into the forecast, and are meant to reflect a degree of uncertainty in future PV commercialization
- The results of the ICF study have been considered as part of developing the discount factors
- Discount factors were developed for two types of future PV inputs to the forecast:
  1. Policy-based – PV that results from state policy
     - Discounted by values that increase annually up to a maximum value of 50%
  2. Post-policy – PV that may be installed after existing state policies end
     - Discounted by 75% due to the much higher 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
- All discount factors are applied equally in all states

Discount Factors, cont'd

- Annual discount factors for policy-based solar PV are tabulated below

Anticipated federal ITC reduction

Thru 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
0%	5%	10%	35%	40%	45%	50%	50%	50%	50%	50%

- In general, discount factors are lower for 2015-2016, and higher for years beginning 2017 when compared to those developed for the 2014 PV forecast

- All post-policy MWs are discounted at 75%, consistent with last year's forecast approach

PV's Summer Seasonal Claimed Capability

- In accordance with Market Rule 1, Section III.1.7.11, ISO uses Seasonal Claimed Capability (SCC) as a measure of a resource's capability to perform under specified summer and winter conditions
  - As an Intermittent Resource, PV's SCC is determined using the median of net output during Intermittent Reliability Hours, which are defined as follows:
    - Summer : June-September, 14:00 through 18:00 (Hours Ending 14 – 18)
    - Winter : October-May, 18:00 and 19:00 (Hours Ending 18 – 19)

- In order to illustrate PV's intermittent nature and how it complicates efforts to determine how best to use the PV forecast in planning studies, ISO developed an estimated summer SCC for PV:
  - Estimate was based on analysis of different sources of PV production data
    - Discussion of analysis was shared with DGFWG on December 16, 2013: http://www.iso-ne.com/committees/comm_wkgrps/othr/distributed_generation_frcst/2013mtrls/dec162013/dg_forecast.pdf (slides 11-29)
    - The results of a similar previous analysis was shared with PAC on June 19, 2013: http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2013/jun192013/a7_solar_dg_update.pdf (slides 20-30)
  - Results suggest PV's summer SCC is approximately 35% of its AC nameplate (PV's winter SCC is zero)

- **It should be cautioned that**:
  1. PV performance often differs from its summer SCC during the variety of peak load conditions that occur
  2. PV's summer SCC will tend to vary from year-to-year, due to variations in the weather influencing its power output
  3. As PV penetrations grow across the region, PV will tend to shift peak net loads to later in the afternoon, when PV output is diminishing due to the lowering solar altitude angle as the sun begins to set, thereby decreasing PV's incremental contribution to serving peak loads

- For these reasons, values that differ from the 35% summer SCC estimate may be more suitable for various planning studies, based on the assumptions (e.g., load level) and intent of each study in question

Summary of State-by-State 2015 Draft Forecast Inputs

Pre-Discounted Nameplate Values

States	Pre-Discount Annual Total MW (AC nameplate rating)											Totals
	Thru 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	
CT	118.8	63.8	83.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	**776.3**
MA	666.8	241.9	241.9	51.8	51.8	51.8	51.8	51.8	51.8	51.8	51.8	**1,565.4**
ME	10.4	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	**33.4**
NH	12.7	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	**57.7**
RI	18.2	10.2	32.7	38.7	38.7	38.7	16.2	16.2	16.2	16.2	16.2	**258.2**
VT	81.9	42.5	42.5	26.2	17.3	8.5	8.5	8.5	8.5	8.5	8.5	**261.1**
Pre-Discount Annual Policy-Based MWs	**908.8**	**365.1**	**407.6**	**166.6**	**157.7**	**148.8**	**83.3**	**13.5**	**13.5**	**13.5**	**5.0**	**2,283.2**
Pre-Discount Annual Post-Policy MWs	**0.0**	**0.0**	**0.0**	**20.8**	**20.8**	**20.8**	**63.8**	**133.6**	**133.6**	**133.6**	**142.0**	**668.8**
Pre-Discount Annual Total (MW)	**908.8**	**365.1**	**407.6**	**187.3**	**178.4**	**169.5**	**147.0**	**147.0**	**147.0**	**147.0**	**147.0**	**2,952.0**
Pre-Discount Cumulative Total (MW)	**908.8**	**1,273.9**	**1,681.6**	**1,868.9**	**2,047.3**	**2,216.8**	**2,363.9**	**2,510.9**	**2,658.0**	**2,805.0**	**2,952.0**	**2,952.0**

Notes:

(1) The above values **are not the forecast**, but rather pre-discounted inputs to the forecast (see slides 11-17 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 load reducing PV resources
(4) All values represent end-of-year installed capacities

DRAFT 2015 PV FORECAST

2014 PV Forecast

States	Annual Total MW (AC nameplate rating)											Totals
	Through 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	
CT	73.8	46.2	39.3	53.0	34.7	34.7	13.1	13.1	13.1	13.1	11.6	**345.4**
MA	361.6	168.5	117.4	110.5	103.6	98.7	98.7	98.7	32.9	32.9	32.9	**1,256.4**
ME	8.1	2.0	1.9	1.8	1.6	1.6	1.6	1.6	1.6	1.6	1.6	**25.2**
NH	8.2	2.5	2.3	2.2	2.0	2.0	2.0	2.0	2.0	0.7	0.7	**26.7**
RI	10.9	7.3	5.4	3.7	1.2	1.2	1.2	1.2	1.2	1.2	1.2	**35.5**
VT	36.1	20.1	13.4	7.0	6.5	6.5	6.5	6.5	6.5	6.5	1.7	**117.3**
Regional - Annual (MW)	**498.7**	**246.5**	**179.6**	**178.1**	**149.6**	**144.8**	**123.1**	**123.1**	**57.3**	**56.0**	**49.7**	**1,806.5**
Regional - Cumulative (MW)	**498.7**	**745.2**	**924.8**	**1102.9**	**1252.5**	**1397.3**	**1520.4**	**1643.6**	**1700.9**	**1756.9**	**1806.5**	**1,806.5**

Notes:

(1) Forecast values include FCM Resources, non-FCM Settlement Only Generators, and load reducing PV resources
(2) The forecast reflects discount factors described on slides 18-19
(3) All values represent end-of-year installed capacities
(4) ISO is working with stakeholders to determine the appropriate use of the forecast

Draft 2015 PV Forecast

States	Annual Total MW (AC nameplate rating)											Totals
	Thru 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	
CT	118.8	60.6	75.4	33.1	31.0	28.8	15.9	15.9	15.9	15.9	15.9	**427.4**
MA	666.8	229.8	217.7	33.7	31.1	28.5	25.9	13.0	13.0	13.0	13.0	**1,285.4**
ME	10.4	2.2	2.1	1.5	1.4	1.3	1.2	1.2	1.2	1.2	1.2	**24.5**
NH	12.7	4.3	4.1	2.9	2.7	2.5	2.3	1.1	1.1	1.1	1.1	**35.9**
RI	18.2	9.7	29.4	25.2	23.2	21.3	8.1	4.7	4.7	4.7	4.7	**154.0**
VT	81.9	40.4	38.2	17.0	10.4	4.6	4.2	4.2	4.2	4.2	2.1	**211.6**
Regional - Annual (MW)	**908.8**	**346.9**	**366.9**	**113.4**	**99.8**	**87.0**	**57.6**	**40.1**	**40.1**	**40.1**	**38.0**	**2,138.8**
Regional - Cumulative (MW)	**908.8**	**1255.7**	**1622.5**	**1736.0**	**1835.8**	**1922.8**	**1980.4**	**2020.5**	**2060.6**	**2100.8**	**2138.8**	**2,138.8**

Notes:

(1) Forecast values include FCM Resources, non-FCM Settlement Only Generators, and load reducing PV resources
(2) The forecast reflects discount factors described on slides 18-19
(3) All values represent end-of-year installed capacities
(4) ISO is working with stakeholders to determine the appropriate use of the forecast

2014 PV FORECAST

Estimated Summer Seasonal Claimed Capability of PV Forecast

Based on 35% of Forecasted AC Nameplate Capacity

States	Estimated Summer SCC (MW)											Totals
	Through 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	
CT	25.8	16.2	13.8	18.5	12.1	12.1	4.6	4.6	4.6	4.6	4.0	**120.9**
MA	126.6	59.0	41.1	38.7	36.3	34.5	34.5	34.5	11.5	11.5	11.5	**439.7**
ME	2.8	0.7	0.7	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	**8.8**
NH	2.9	0.9	0.8	0.8	0.7	0.7	0.7	0.7	0.7	0.2	0.2	**9.4**
RI	3.8	2.6	1.9	1.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	**12.4**
VT	12.6	7.0	4.7	2.4	2.3	2.3	2.3	2.3	2.3	2.3	0.6	**41.1**
Regional - Annual Summer SCC (MW)	**174.5**	**86.3**	**62.9**	**62.3**	**52.4**	**50.7**	**43.1**	**43.1**	**20.1**	**19.6**	**17.4**	**632.3**
Regional - Cumulative Summer SCC (MW)	**174.5**	**260.8**	**323.7**	**386.0**	**438.4**	**489.0**	**532.1**	**575.2**	**595.3**	**614.9**	**632.3**	**632.3**

Notes:

(1) ISO's methodology for determining SCC for Intermittent Resources is defined in Market Rule 1, Section III.1.7.11
(2) Estimated SCC values include FCM Resources, non-FCM Settlement Only Generators, and load reducing PV resources
(3) Summer SCC values are based on the assumption that all end-of-year resources are in operation during the summer period
(4) PV's winter SCC is assumed to be zero
(5) Different planning studies may use values different from the estimated SCC based on the intent of the study

Draft 2015 Forecast

Estimated Summer Seasonal Claimed Capability of PV Forecast

Based on 35% of Forecasted AC Nameplate Capacity

States	Estimated Summer SCC (MW)											Totals
	Thru 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	
CT	41.6	21.2	26.4	11.6	10.8	10.1	5.6	5.6	5.6	5.6	5.6	**149.6**
MA	233.4	80.4	76.2	11.8	10.9	10.0	9.1	4.5	4.5	4.5	4.5	**449.9**
ME	3.6	0.8	0.7	0.5	0.5	0.4	0.4	0.4	0.4	0.4	0.4	**8.6**
NH	4.4	1.5	1.4	1.0	0.9	0.9	0.8	0.4	0.4	0.4	0.4	**12.6**
RI	6.4	3.4	10.3	8.8	8.1	7.4	2.8	1.7	1.7	1.7	1.7	**53.9**
VT	28.6	14.1	13.4	6.0	3.6	1.6	1.5	1.5	1.5	1.5	0.7	**74.0**
Regional - Annual Summer SCC (MW)	**318.1**	**121.4**	**128.4**	**39.7**	**34.9**	**30.5**	**20.2**	**14.0**	**14.0**	**14.0**	**13.3**	**748.6**
Regional - Cumulative Summer SCC (MW)	**318.1**	**439.5**	**567.9**	**607.6**	**642.5**	**673.0**	**693.1**	**707.2**	**721.2**	**735.3**	**748.6**	**748.6**

Notes:

(1) ISO's methodology for determining SCC for Intermittent Resources is defined in Market Rule 1, Section III.1.7.11
(2) Estimated SCC values include FCM Resources, non-FCM Settlement Only Generators, and load reducing PV resources
(3) Summer SCC values are based on the assumption that all end-of-year resources are in operation during the summer period
(4) PV's winter SCC is assumed to be zero
(5) Different planning studies may use values different from the estimated SCC based on the intent of the study

PV Energy Forecast

- Once the PV forecast is finalized, ISO will provide an estimate of the energy production associated with the forecast, as discussed during the September 15, 2014 DGFWG meeting
- The illustrative estimated energy forecast associated with the 2014 PV forecast that was shared at that meeting is included below

States	Annual PV Energy Forecast (GWh)									
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
CT	59	118	183	244	293	326	345	363	381	399
MA	288	481	635	779	916	1,049	1,182	1,271	1,315	1,359
ME	6	8	11	13	15	17	19	22	24	26
NH	6	9	12	15	17	20	23	25	27	28
RI	12	20	26	30	31	33	35	36	38	39
VT	26	47	59	67	75	83	91	99	107	112
Total Regional PV GWh	**396**	**684**	**926**	**1,148**	**1,348**	**1,529**	**1,695**	**1,816**	**1,892**	**1,964**

BREAKDOWN OF PV FORECAST BY MARKET PARTICIPATION CATEGORY

Market Participation Categories

- PV as a capacity resource in the Forward Capacity Market (FCM)
  - Qualified for the FCM
  - Have capacity supply obligations
  - Size and location identified and visible to the ISO
  - May be supply or demand-side resources
  - May also be Settlement Only Resources (see below)
- Non-FCM Settlement only Resources (SORs) and Generators (per OP-14)
  - Registered in CAMS
  - ISO collects energy output
  - Participate only in the energy market
- Behind the Meter PV (BTM)
  - Reduces system load
  - Not registered in CAMs
  - ISO has an incomplete set of information on generator characteristics
  - ISO does not collect energy output data → <u>ISO needs data to know the BTM energy production</u>
  - Can be further divided into two categories:
    - Behind the Meter PV Embedded in Load (BTMEL)
      - The portion of BTM that is captured in the historical load forecast
      - Can be estimated via reconstitution
    - Behind the Meter PV not Embedded in Load (BTMNEL)
      - The portion of BTM that is not captured in the historical load forecast (i.e., not embedded)

Determining Market Participation By State

- Relative market participation varies significantly by state
  - Can be influenced by state regulation (e.g., net metering requirements)
- Estimated breakdown of market participation in each state are provided on subsequent slides
  - ***These are for discussion purposes only***
- ISO needs energy production data from all PV resources in each state to determine the amount of PV generation that is behind-the-meter
- These distinctions will become important as the ISO looks to use the PV forecast in a wider range of studies
  - Further and more detailed discussions will take place in other stakeholder meetings

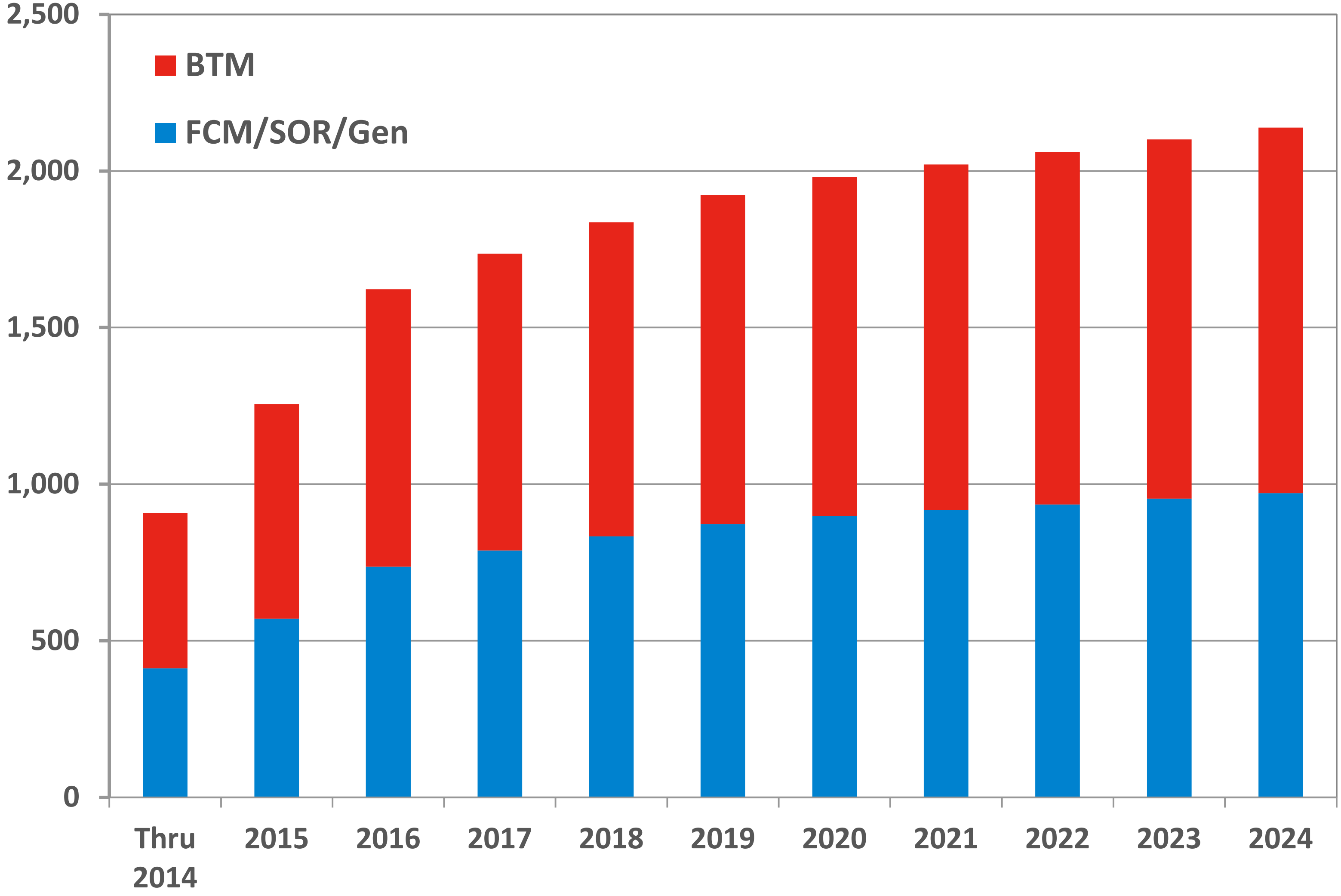
Estimated Market Participation Breakdown

<u>Note</u>: Values listed below are estimates and are provided for discussion purposes only. These values will be updated based on PV energy production data provided by the states

State	Existing Nameplate (MW_{AC})	% share of total	
		FCM/Gen/SOR	BTM
CT	118.8	0	100%
MA	666.8	60%	40%
ME	10.4	0%	100%
NH	12.7	5%	95%
RI	18.2	65%	35%
VT	81.9	0%	100%
Regional	**908.8**	**45%**	**55%**

Estimated Breakdown of PV Nameplate by Market Participation

Based on 2015 Draft PV Forecast and Estimated Market Participation



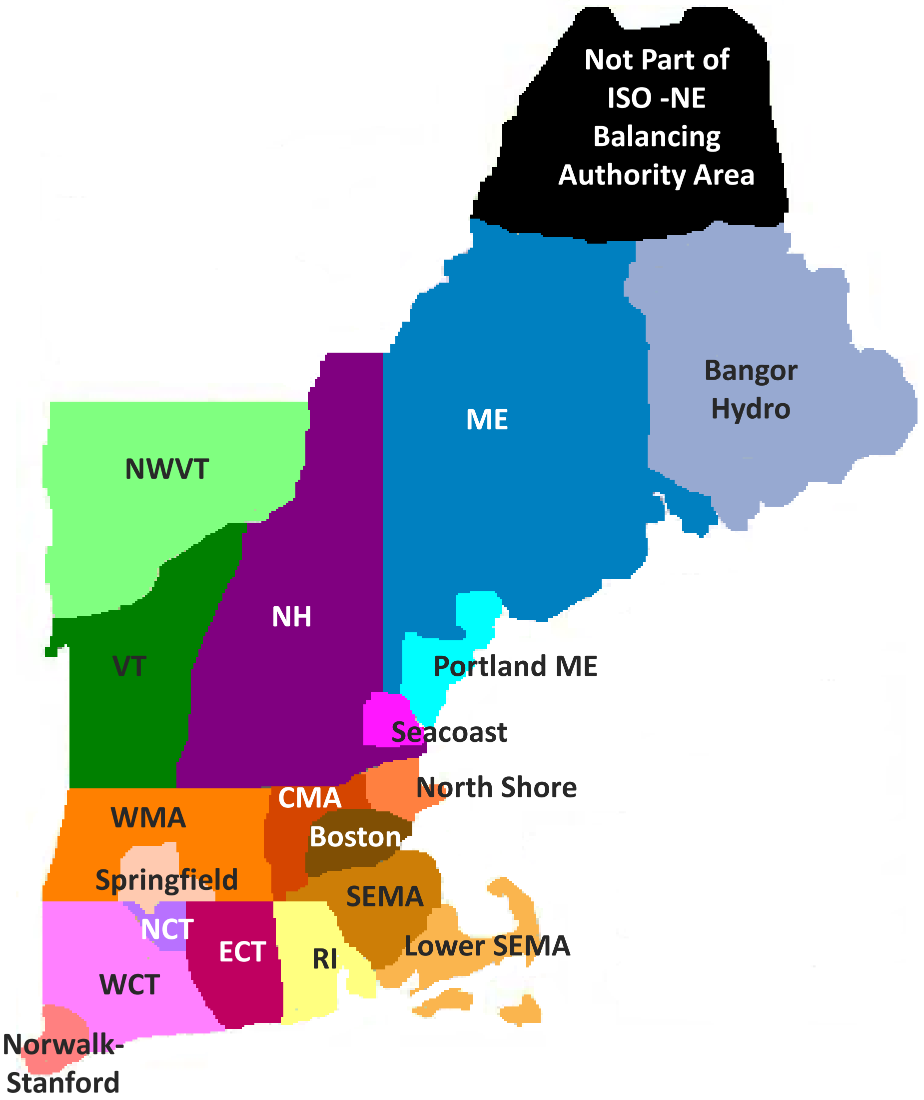
GEOGRAPHIC DISTRIBUTION OF PV FORECAST

Background

- A reasonable representation of the locations of existing and future PV resources is required for appropriate modeling
- The locations of future PV resources are ultimately unknown, but mitigation of some of this uncertainty (especially for near-term development) is likely possible via analysis of available data
- Distribution queue data has been collected by regional utilities and may prove helpful
- Where available, state PV program data may be able to be used in tandem with utility queue data

ISO-NE Dispatch Zones

- ISO developed the Dispatch Zones for the active Demand Response program
- Dispatch 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



Proposed 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:
  - If possible, use distribution queue or state program data to apply MWs by Dispatch Zone (for first 1-2 years of forecast)
    - In the absence of the capability of using such data, assume the same distribution as existing MWs
  - For longer-term forecast, assume the same distribution as existing MWs

Questions

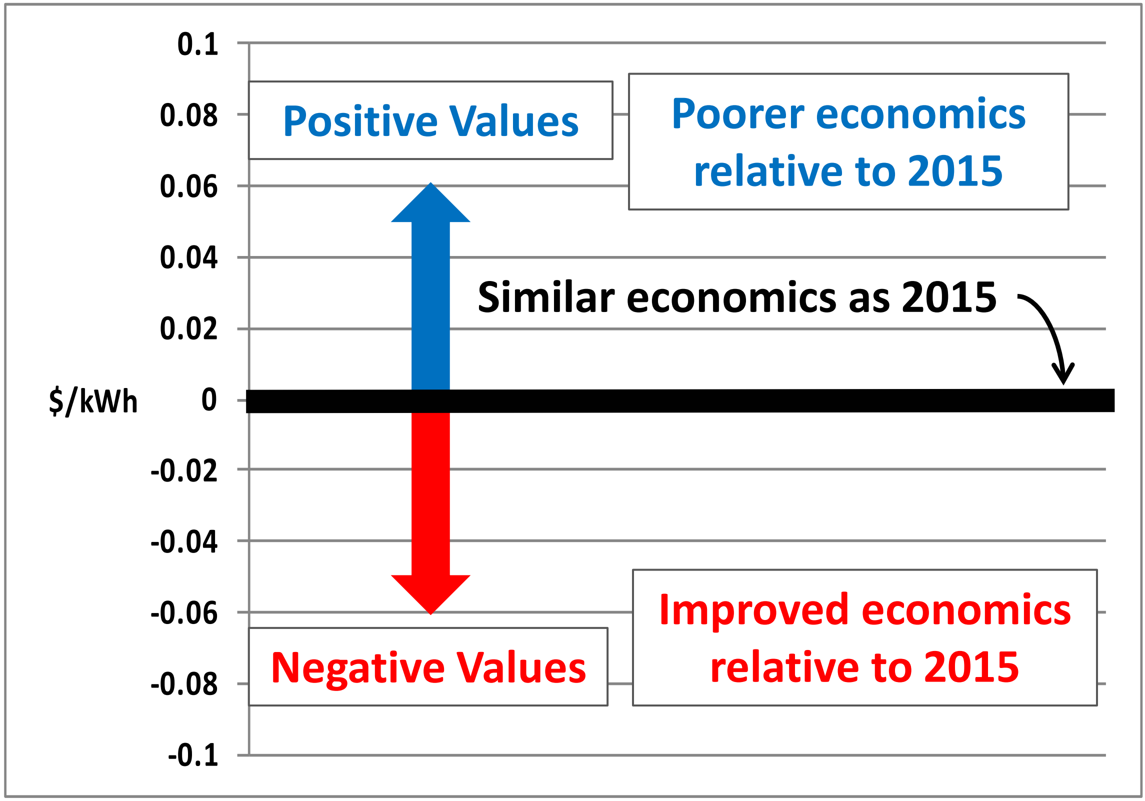
APPENDIX

Comparing Fully-Supported Economics, 2015-2024

Fully Supported PV Economics

Interpreting ICF Results

- Subtracting 2015 results from 2019 and 2024 results normalizes the results relative to 2015 base year
- The resulting normalized values for 2019 and 2024 can be interpreted as summarized in the figure to the right
- This allows results from the three project years to be compared across customer types in each state



Fully Supported PV Economics (levelized $/kWh)

Project Starts 2019 and 2024, Normalized to 2015 Base Year