Appendix A:

Task 3 - Analysis of Costs and Benefits: Key Assumptions

Massachusetts Net Metering Task Force

PEREGRINE ENERGY GROUP

Sustainable Energy Advantage, LLC

MEISTER CONSULTANTS GROUP

La Capra Associates

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A. OVERARCHING ASSUMPTIONS & SIMPLIFYING ASSUMPTIONS

& SIMPLIFYING ASSUMPTIONS

Key Assumptions

- Analysis performed, and metrics, in Nominal $
- Tax Rates
  - Massachusetts Tax Rates = 8%
  - Federal Tax Rates = 35%
- Nominal Discount rate = 5%
- Federal Investment Tax Credits (ITC) were not assumed to be extended beyond their current statutory timeframe.
- General inflation rate from EIA AEO 2014 GDP IDP
- Inflation rate for ACP from EIA AEO 2014 CPI All Urban Customers

MA DG Solar Avoids Electric Losses

Raw Data (Utility-specific average & peak loss factors)

			Average T&D	Peak T&D	Avg. excl. TX losses	Peak excl. TX losses
Wtd. Avg MA			5.15%	8.62%	4.35%	7.34%
		weight				
NSTAR		45.28%	4.70%	6.60%	3.77%	5.300%
WMECO		7.79%	5.00%	9.78%	4.45%	8.70%
NGRID - MECO		45.69%	5.60%	10.38%	4.90%	9.077%
NGRID - NEC		0.31%	5.60%	10.38%	4.90%	9.08%
FG&E		0.92%	5.60%	10.38%	4.90%	9.08%

Blue: provided by EDCs
Black: imputed based on similar relationships of peak to average data in blue
Red: used other EDC data as proxies

For Solar Impact ➔ Statewide Factors

Loss Level		Loss Factor
MA Avg. Peak T&D		8.62%
MA Avg. Peak D		7.34%
MA Avg. Production-Wtd Energy T&D		5.58%
MA Avg. Production-Wtd Energy D		4.72%

Production weighting reflects higher-than-average loss reduction due to peak coincidence
(developed using inferred square-function matching average and peak losses)

Key Considerations for Understanding Results:
Implications of Simplifying Assumptions (1)

1. **Retail Rate Structures Held Constant.** Assumed no change in retail rate structures from current, with respect to any shift from components billed on a per-kWh basis to fixed charges, customer charges, or the establishment of minimum bills. Task Force determined that rate design is important but best addressed before the DPU.
   - A future shift in rate structure away from kWh charges would reduce the avoided cost or revenue realized for behind-the-meter or net metered solar PV projects ➔ Would diminish economics, lead to a slower build-out and a potential shift among installation types unless solar incentives were increased to match (as might be the case under Paths A and B).
   - However, this analysis assumes that a subsector of the marketplace whose retail rate value is not hedged through fixed-price PPA or discount arrangements would derate expectations of future rate revenue to some degree to account for exposure to change of rate structure risk (i.e., host owned <= 25 kW systems under SREC or Path B)

2. **Distribution System Saturation Ignored.** Did not explicitly examine limitations on development caused by saturation of distribution feeders or resulting elevated interconnection costs. Considering such factors would slow the pace of development.(forecast of installations does consider interconnection timelines/constraints).

3. **Technical Potential Saturation Largely Ignored.** Did not explicitly constrain solar technical potential. However, modeling does consider land area, population density, number of residential customers and number of non-residential customers in regards to growth rates and relative potential among utilities. Paths A&B have low growth rates and are not likely to be constrained by technical potential, but are constrained by the policy mechanism itself. Path B is constrained economically. Separately, we have done research that did not find significant near term constraints on brownfield, landfills, or VNM low-moderate income housing sub-sectors.

Key Considerations for Understanding Results:
Implications of Simplifying Assumptions (2)

4. **Ignored Potential Differential Impacts of Installer Incentive Capture.** Did not explicitly assume or analyze installed cost inflation under the more 'generous' policy options (compared to less generous policies), an installer 'incentive capture' phenomenon cited by some analysts, or assume lower installed costs for Policy futures with less generous combined solar and NM incentives.

5. **Ignored Impact of ITC Qualification Peril at 1/1/17.** Did not reflect the likelihood that projects are unwilling to commit to projects with risk exposure to loss of ITC due to interconnection delay or labor shortages in 2016, which may in practice lead to a risk-aversion-driven drop-off in development. Simplified to assume a steadier rate of development influenced by economics and shifted some development back to earlier in the year as participants are well aware of the pending loss of ITC, the risk in being late and are starting development activity earlier.

6. **Assumed Municipal Light Plants Participate Like IOUs in Policy Paths A & B.** MLPs are assumed to participate in Policy Paths A&B the same way as do investor owned utilities (including allowing or not allowing virtual net metering in capped and uncapped scenarios). We treated all MLPs as having a single prototypical rate structure based on Taunton Municipal Lighting Plant rates.

7. **Assumed Future LSE Participation in SREC Floor Price Auctions.** LSEs will fully participate in auction and thus hold marginal SRECs during the auction out years. If LSEs continue to stay on sidelines, it causes extreme additional expenses for NPRs ➔ seems imprudent to assume that this practice would continue indefinitely.

Key Considerations for Understanding Results:
Implications of Simplifying Assumptions (3)

7. **Ignored Nantucket as a location for solar development.** Did not include Nantucket Electric in the primary analysis

8. **Reclassified SREC-I Projects into SREC-II Sectors.** In order to provide SREC-I results in a comparable manner to other policy paths, we have made best guesses of project reclassification to SREC-II subsectors. Assigning SREC-II subsectors provides a basis of computing and reporting build-out, revenue and cost and analysis.

9. **Treated All Towns as Served by Single Distribution Utility.** In order to assess potential for different project types, utility square miles were computed. Some Massachusetts towns are served by multiple utilities. We assigned each town a unique utility in order to simplify the calculation.

B. SOLAR PV MODELING

FOR DISPATCH ANALYSIS ANDS COST & BENEFIT ANALYSIS

Solar PV Production Modeling
Technical Assumptions (1)

- Analysis requires understanding:
  - How many MWh produced per DC MW PV installed?
    - # of SRECs (current policy) is less than this #
  - When production occurs?
    - Value of energy; Coincidence with applicable peaks
- 25-year economic Life of Solar PV Installations
- Key & Simplifying Assumptions:
  - Ignore technological advance and change in mix of fixed vs. tracking
    - Performance (profile and capacity factor) held constant for each installation type across analysis horizon and policy path
  - Degradation: 0.5% energy production per yr.
- AC vs. DC
  - PV rated @ Direct Current (DC)
  - Inverters convert to AC (Alternating Current)
  - Energy on the grid is AC
  - Solar Policy Goals are stated in DC
  - DC to AC conversion efficiency varies by installation type

- Annual Production:
  - Use "Proxy" profile representing simplified composite of different installation types
  - Installation composition may vary over time
  - PV Watts (NREL model estimating production @ specified location) used to estimate production volume and timing
  - PV Watts requires assumptions on tile, azimuth (degrees from due south), AC to DC ratio determinates, shading, etc.
  - MA CEC's Production Tracking System (PTS) provides performance details on current MA PV fleet
  - SEA studied PTS data on existing fleet, developed 'standard' installation characteristics for **composite project type**: Residential, C&I Rooftop, Ground Mount and Solar Canopy installations
  - SEA assumed fraction of each SREC-II subsector associated with each composite project type
  - For PV Watts, assumed single location (Worcester)
- Results: Year 1 for any installation for current SREC-II fleet
  - Capacity Factor (c.f.) (DC) = 14.3%
  - Annual energy: 1627 kWh per AC kW installed
  - Annual energy: 1253 kWh per DC kW installed

Solar PV Technical Assumptions
Application to Modeling of Solar Policy & Net Metering Impacts (2)

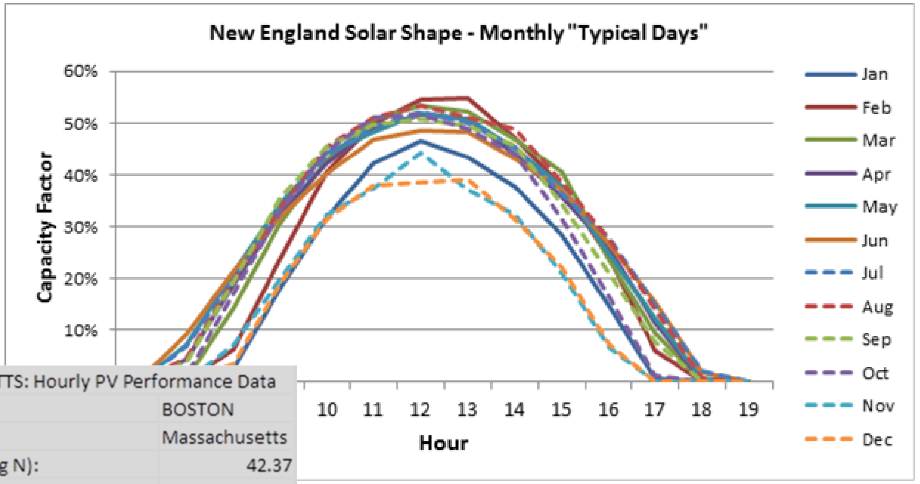
- Each SREC-II subsector has:
  - Composite proxy profile (constant c.f. and production profile over time)
  - Economics of each subsector vary under each policy path ➔ different quantity of PV installed for each subsector under each policy path
  - Policy-path-specific blend of composite profiles and installation proportions ➔ aggregate annual PV production in each year ➔ "Portfolio Annual Production"
    - c.f. was held constant over time and between policy paths as a simplification

- Area for potential future study:
  - Allow performance over time to vary with evolving blend of system types
  - More nuanced profile as weighted average of projects of varying technology, orientation, tilt, etc.
  - Consider technology advance
  - Would allow looking at possible benefits of encouraging more peak-value orientation, etc.

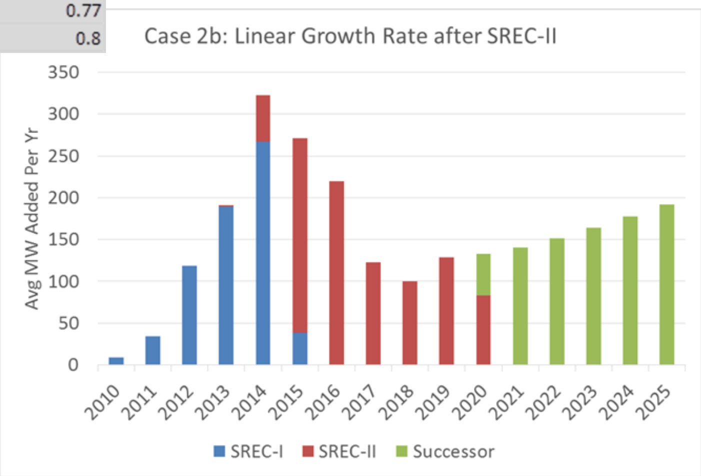
Residential System	Commercial Rooftop	Ground Mount	Solar Canopy
16%	18%	63%	3%

Solar PV Technical Assumptions
Application to Modeling - Production Modeling in Aurora (3)

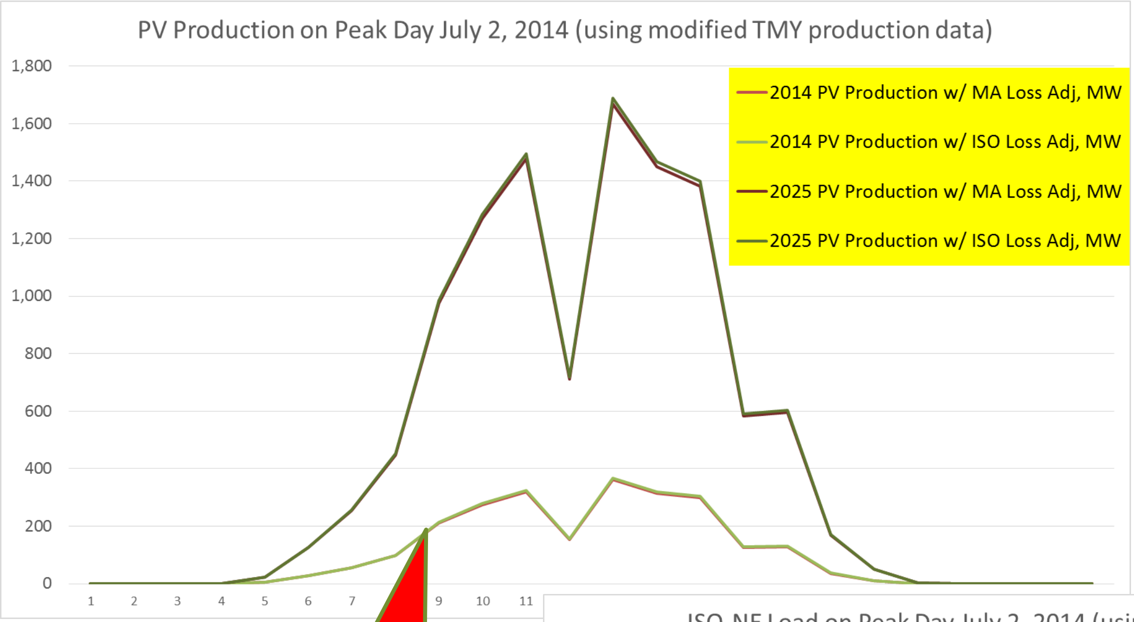
- Applies to: market value, energy market price impacts, emission impacts
- Uses a single standard proxy profile of average day per month based on PV Watts profile, 0.77 AC/DC (Boston) (see graph and table: 14% annual c.f. (DC); 1593 kWh per AC kW
    - Same as DOER 2013 Task 3B report
- MW targets in DC
- Modeling convention: Policy paths have similar solar PV build-out quantities
    - Small differences will not alter per-MWh values materially
- Results of a single Aurora build-out analysis (graph) → scaled to *projected* portfolio annual production in each case using per-MWh Aurora result values

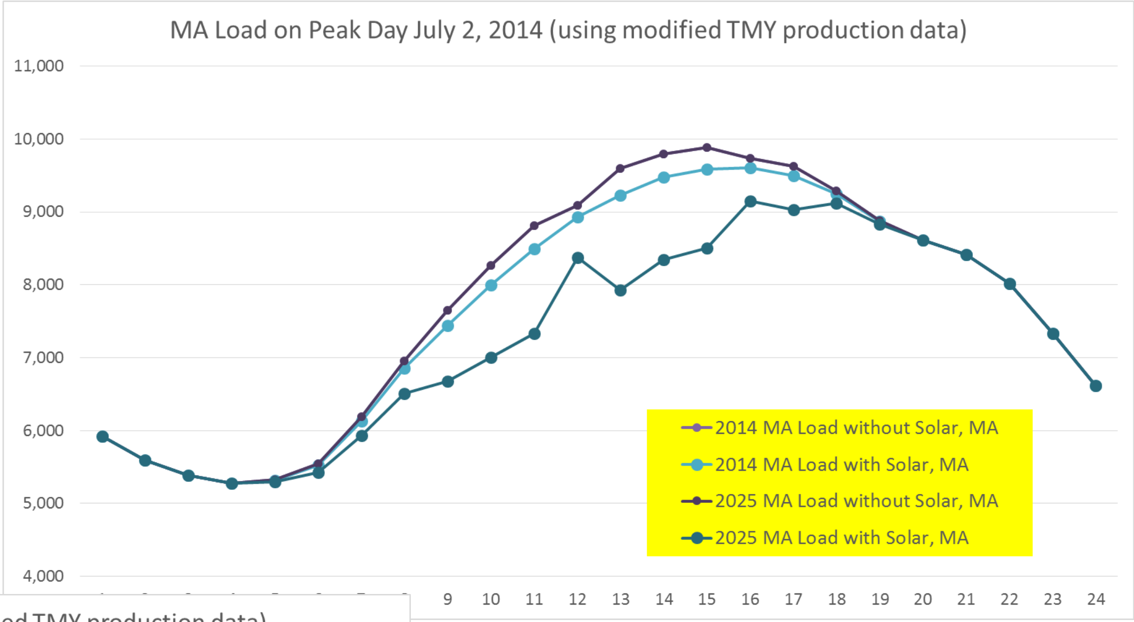


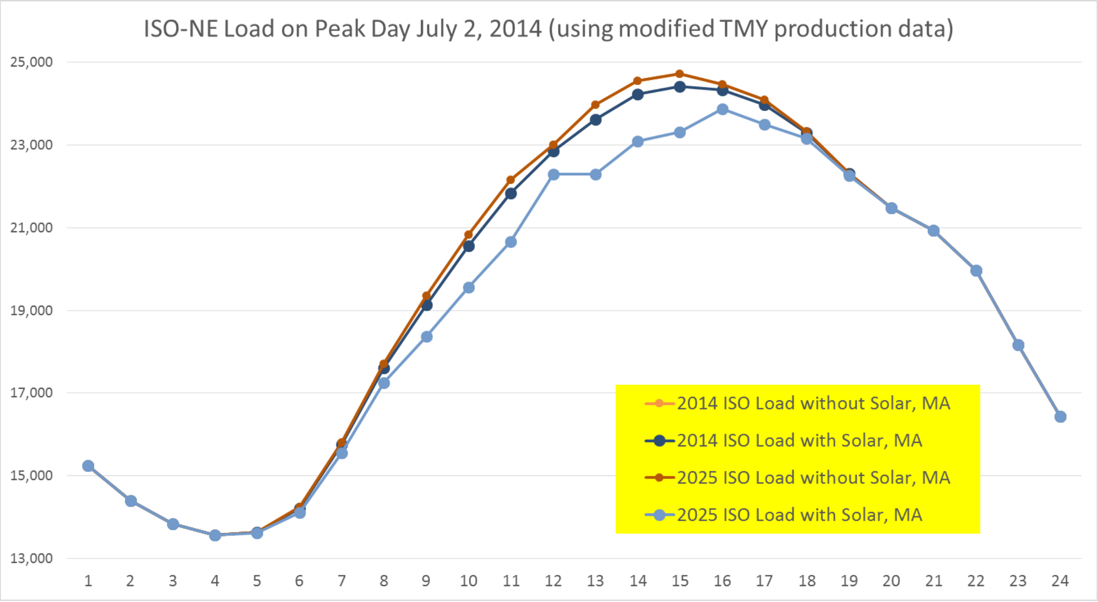
PVWATTS: Hourly PV Performance Data	
City:	BOSTON
State:	Massachusetts
Lat (deg N):	42.37
Long (deg W):	71.03
Elev (m):	5
Array Type:	"Fixed Tilt"
Array Tilt (deg):	42.4
Array Azimuth (deg):	180
DC Rating (kW):	1
DC to AC Derate Factor:	0.77
AC Rating (kW):	0.8



Solar Peak Impact

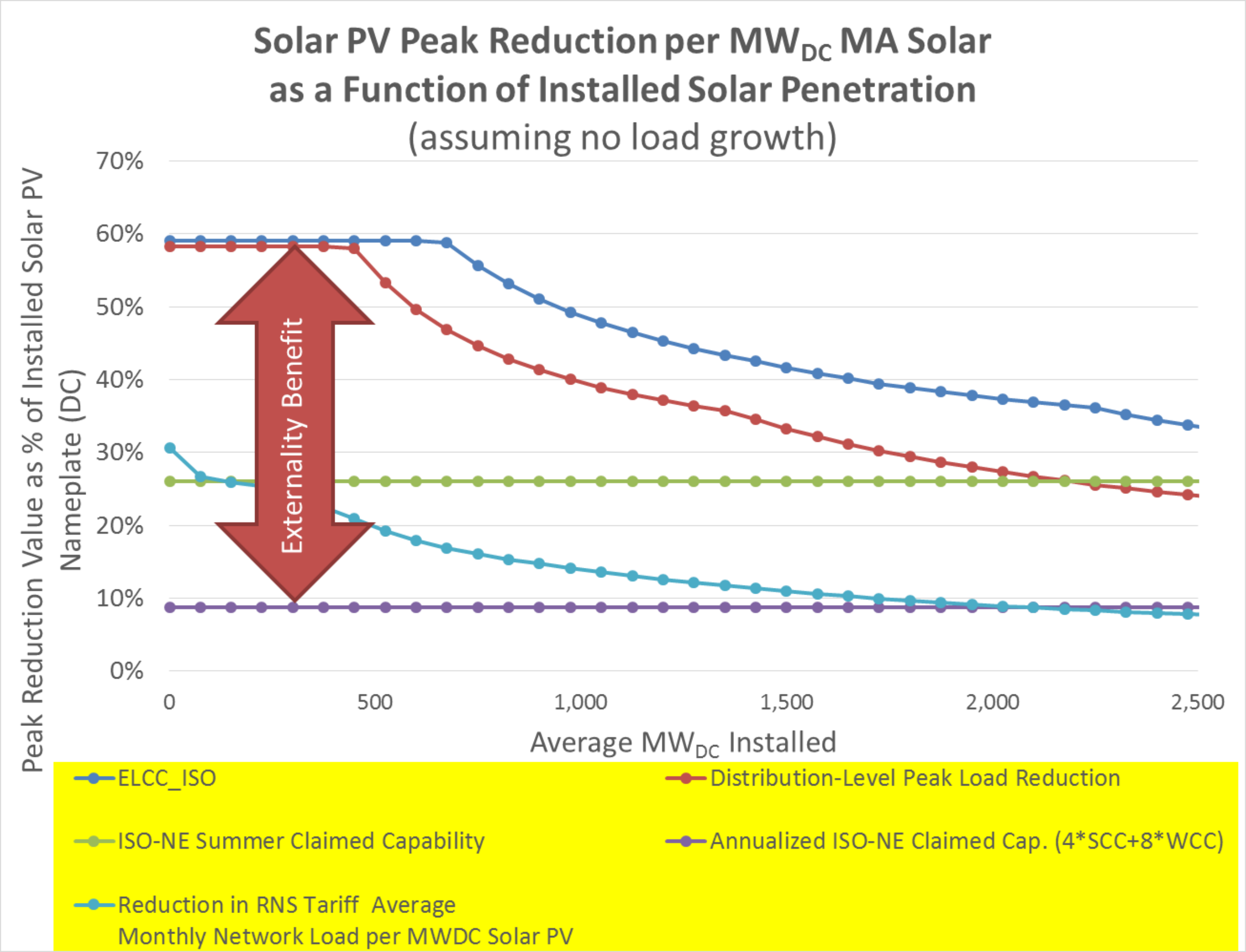






Single site proxy (note the passing cloud)… in reality, many sites smooth the aggregate curve

Solar PV Impact on Avoiding G, T & D Capacity



- ISO-NE FCM value (purple):
  - Doesn't vary with PV MW
  - Well below impact on reducing peaks until PV penetrations >> 2500 MW
- Actual PV impact on peaks declines with penetration
  - PV has high peak coincidence
  - But starting to shift time of peak
  - Eventually: the CA 'Duck Diagram'
- G&T peak reduction value (blue) somewhat higher than Distribution value due to different timing of peaks
- Difference between *actual* impact (e.g. lower ISO ICR) and value in FCM market is a *benefit* to all citizens of MA
- FCM value not monetized by generators also a *benefit* to all citizens of MA

C. WHOLESALE MARKETS & PRODUCTION DISPATCH MODELING ASSUMPTIONS

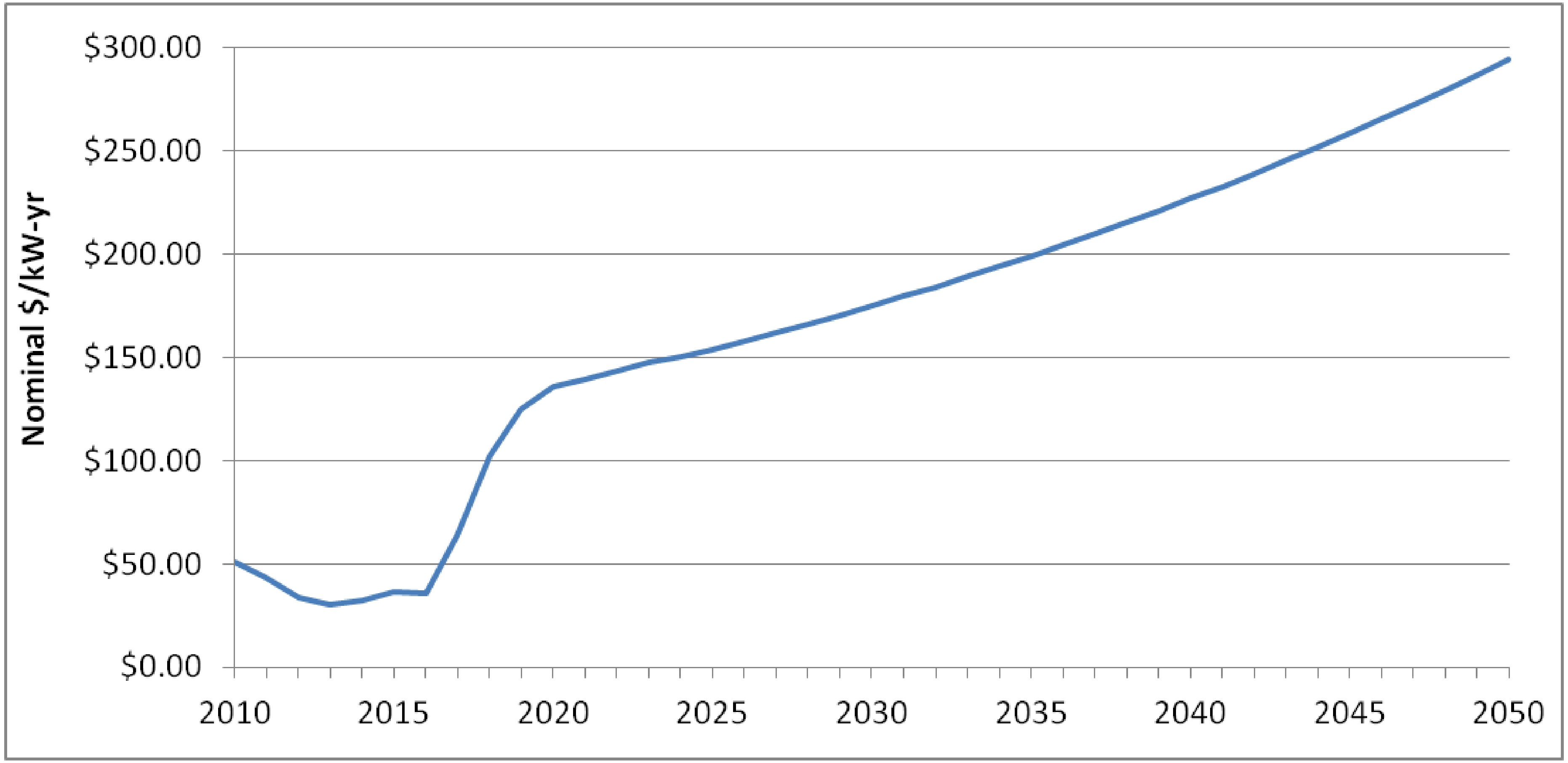
DISPATCH MODELING & COST/BENEFIT ASSUMPTIONS

Wholesale Market Assumptions

- ISO-NE Transmission Tariff:
  - 2014 RNS Tariff Rate = $89.80/kW-yr
  - 2014 RNS MA Load Ratio Share = 43.59%
- Installed Capacity Reserve Margin
  - Per ME VOS study, for the year 2017/18, the ISO New England reserve margin was 13.6% based on Net ICR

Capacity Market Assumptions

- Capacity market prices = Historic actuals, projected values taken from CT 2014 IRP, adjusted to nominal using AEO 2014 GDP deflator, and converted to calendar year

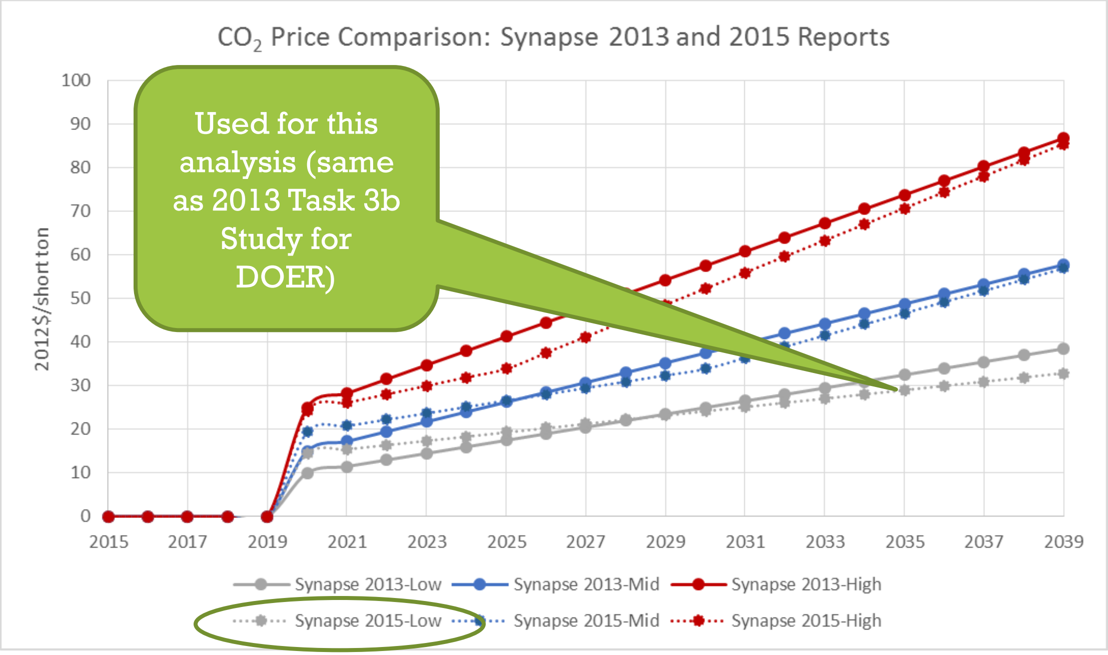


Capacity Value of Intermittent Resources

- Intermittent Resources per : ISO-NE Commercialization and Audit/CCA Establish Procedures for FCM resource (ISO-NE, Apr. 17, 2014)
  - Intermittent reliability hours
  - http://iso-ne.com/static-assets/documents/committees/comm_wkgrps/othr/vrwg/mtrls/a4_commercialization_and_audit.pdf
  - Comparative benchmark for SCC: See slide 20 of this:
    - http://www.iso-ne.com/static-assets/documents/2014/08/2014_final_solar_forecast.pdf
    - 35% SCC used by ISO for estimate

Internalized (Market) CO_2 Price Assumptions
Used in Dispatch Modeling

Potential Future Carbon Pricing or Equivalent LMP Impact of GHG Regs

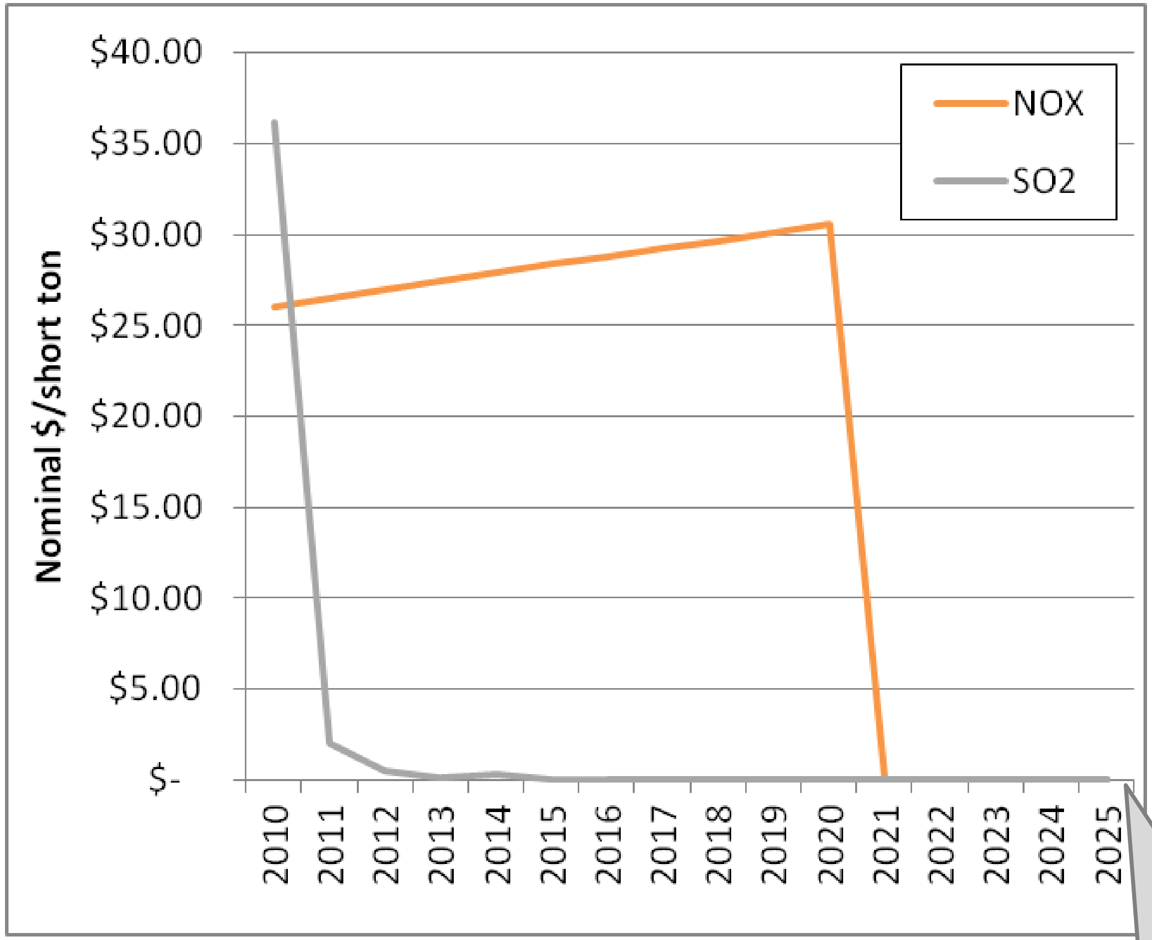


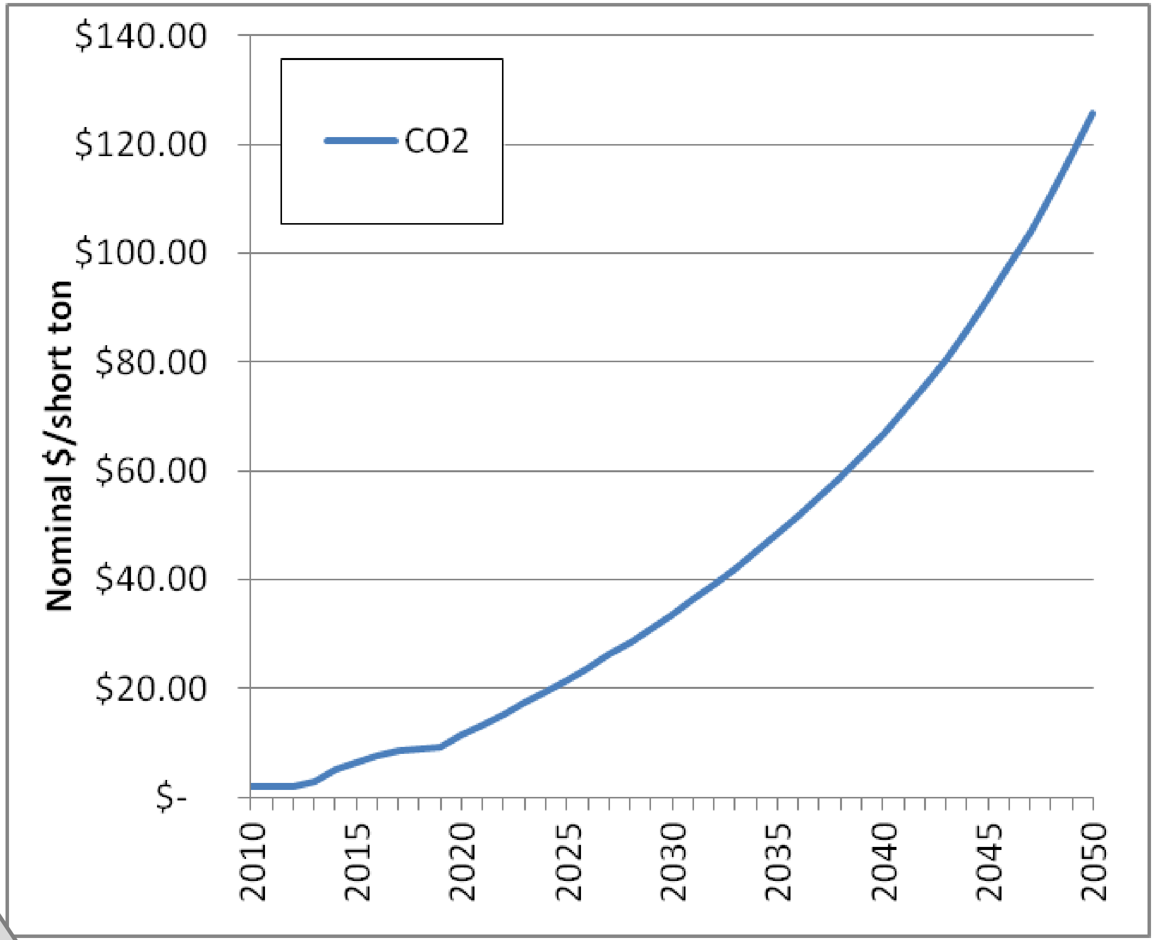
Note: Potential sensitivity of interest for further study: higher carbon price future

Used as a PROXY

- Start with: Regional Greenhouse Gas Initiative (RGGI) past and projected pricing (projections by ICF for RGGI)
- Transition after 2019 to Synapse Low as a proxy for some combination of future:
  - Federal cap & trade
  - Federal Clean Power Plan impact on energy costs
  - MA Global Warming Solutions Act (and other regional state carbon regs) impact on energy prices

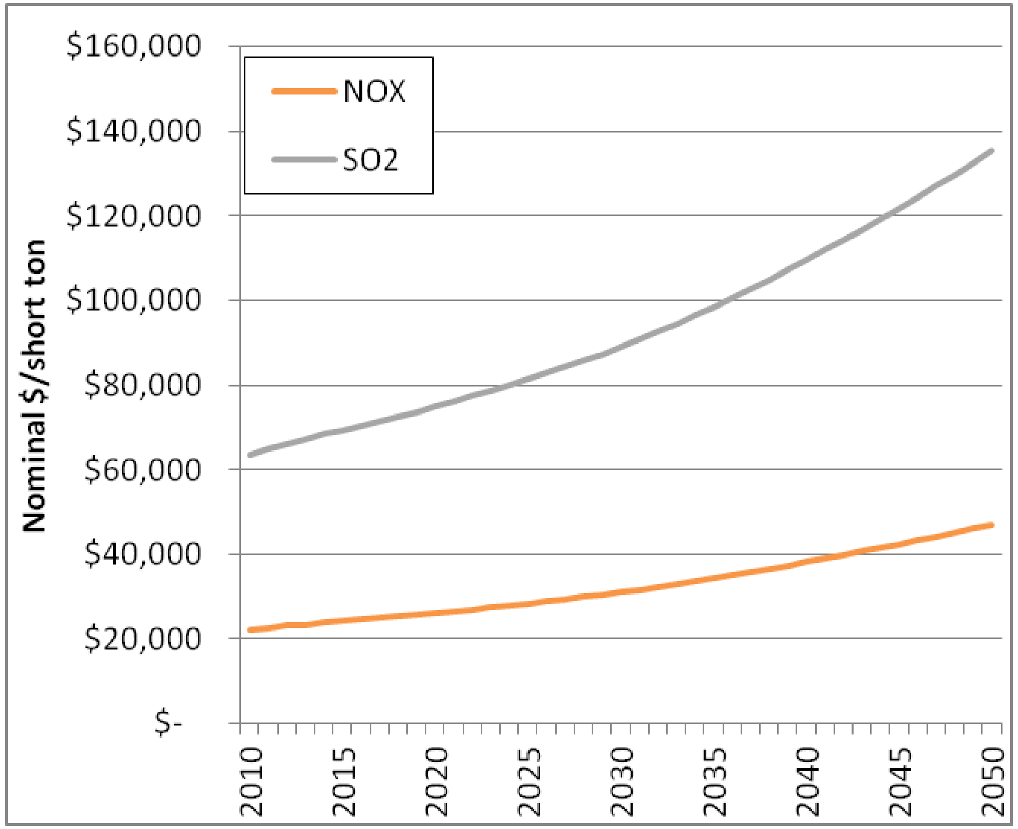
Emission Pricing Assumptions for Dispatch Modeling

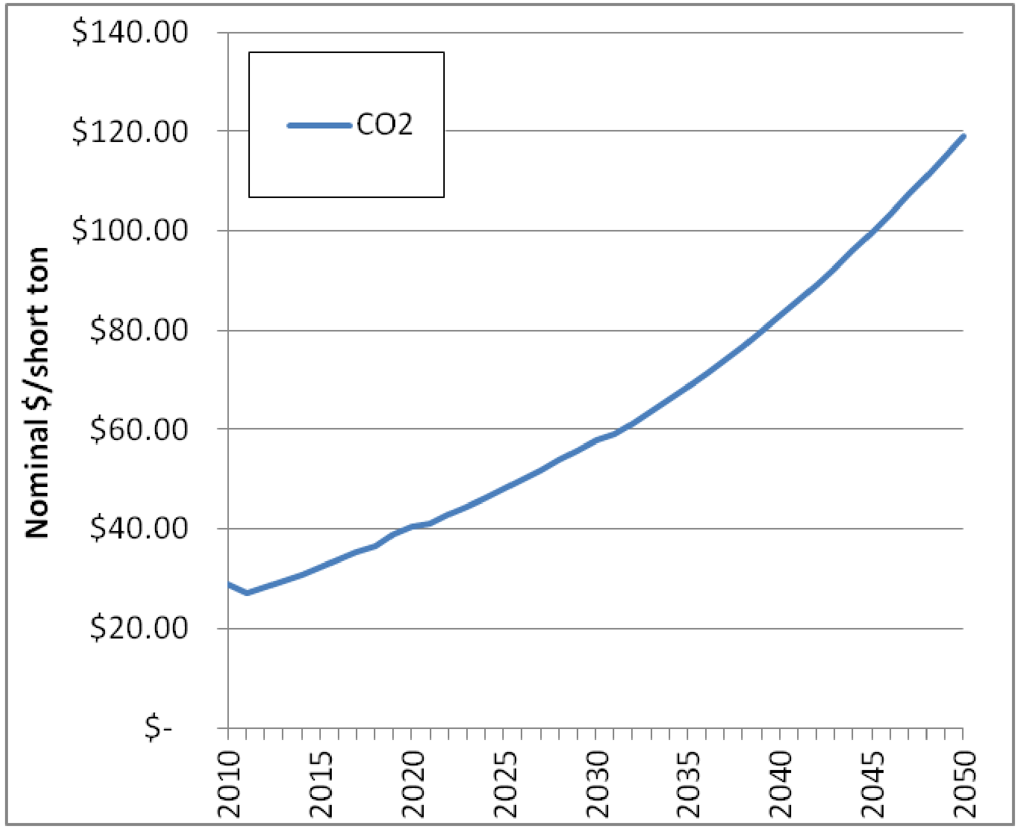




Remains $0 from 2025 onward

Gross Social Costs of Emissions





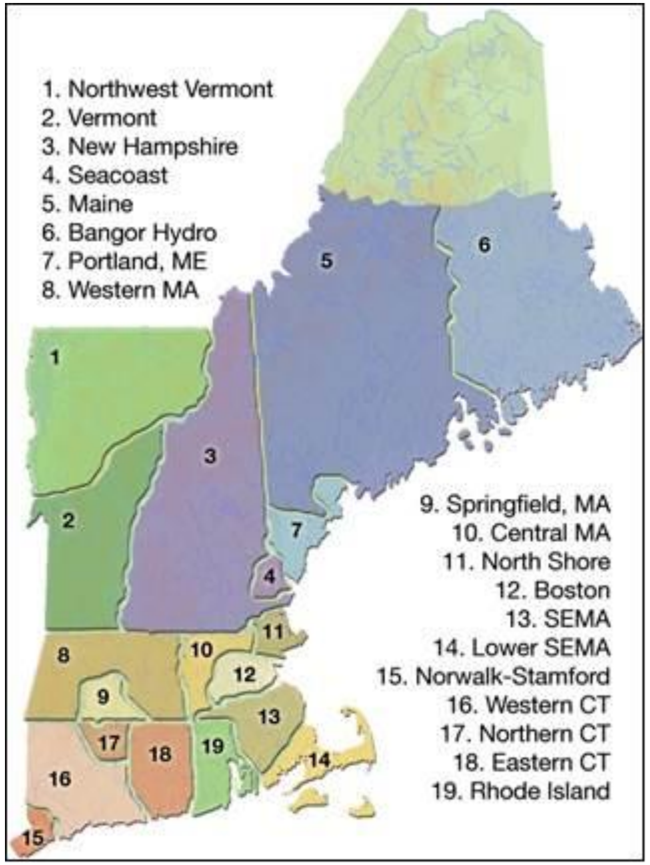
- Social costs of NO_X and SO_2 are taken from Table 4-7 of the 2014 EPA "*Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants*" report
- Social costs of CO_2 are taken from Table A-1 of the 2013 "*Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis*" prepared by U.S. Interagency Working Group on Social Cost of Carbon under Executive Order 12866

Production Modeling of Impacts (1)

- Case 1a: no policy: remove SREC-I & SREC-II production (keep pre-carve-out PV), assume Class I RPS is met by adding a commensurate amount of wind or (if fall short) natural gas
  - In past, before 1/1/2015 not modeled. Instead:
    - solar not replaced by other supply (onshore wind) but rather all the wind that could be built, was, so RPS supply came up shorter by the amount of SRECs projected, and replaced to the extent supply needed by natural gas
    - Fuel use and emissions changes not modeled; rather, calculated at marginal values
    - Was negligible congestion historically ➔ assume same marginal units (modeled as hypothetical NG unit at composite marginal heat rate
    - Assume no material change in LMPs
  - In future: through 2017 assume no more wind could be built, so substituted by falling short of RPS, met be marginal natural gas; 2018 & thereafter, assume PV substituting with land-based wind
- Case 1b: Assume RPS shortfall made up by natural gas
- Case 2a: 1600 MW by 2020
  - Buildout: Historic (from DOER) + projected (SEA MA-SMS in consultation w/ DOER)
- Case 2b: 1600 MW by 2020 continuing to 2500 MW by 2025
  - Buildout: Extrapolate normalized build per yr and round up to allow for a bit of growth
- Impacts calculated as differences:
  - SREC-I & SREC-II from difference between Case 1 & Case 2a
  - SREC-I, SREC-II & (projected) SREC-III from difference between Case 1 & Case 2b

Production Cost Modeling (2)

- Geographic distribution assumed to be same as current cumulative build
  - BOSTN = 11 North Shore + 12 Boston
  - CMA = 10 Central MA
  - WMA = 8 Western MA + 9 Springfield
  - SEMA = 13 SEMA + 14 Lower SEMA



- Note: the Aurora modeling was done using a slightly older SEA forecast (vintage Dec. 2014) of SREC Carve-out (current policy) than used for Policy Path A & B.
- SEA's March 2015 Solar Market Study model is better able to address the differential economics of alternative policy paths.
- March 2015 model projects hitting 1600 MW under current policy at a somewhat different pace.
- Use of per-MWH Aurora results scaled to SMS MWH projections used to correct for this difference.

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MA DOER Net Metering

Modeling Assumptions

Presented by: *La Capra Associates, Inc.*

Presented to: **Sustainable Energy Advantage, LLC**

April 21, 2015

Introduction: Modelling Overview

- The La Capra Associates NMM uses an hourly chronologic electric energy market simulation model based on the AURORAxmp® software platform (AURORA). The model provides a zonal representation of the electrical system of New England and the neighboring regions. For New England, the zones and corresponding transfer capabilities represented in the model conform to the information provided in ISO New England’s Regional System Plan.

- AURORA is a well-established, industry-standard simulation model that uses and captures the effects of multi-area, transmission-constrained dispatch logic to simulate real market conditions. AURORA realistically approximates the formation of hourly energy market clearing prices on a zonal basis using all key market drivers, including fuel and emissions prices, loads, DSM, generation unit operating characteristics, unit additions and retirements, and transmission congestion and losses to capture the dynamics and economics of electricity markets.

- The NMM utilizes a comprehensive database representing the entire Eastern Interconnect, including representations of power generation units, zonal electrical demand, and transmission configurations. EPIS, the developer of AURORA, provides a default database, which La Capra Associates supplements with updates to key inputs for the New England market.

Modeling Assumptions

- Case assumptions
- Environmental Policies
- Regional Demand and DSM
- Regional Generation
- Transmission
- Natural Gas

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Four cases run in Aurora

Case 1: No SREC Carve-out (removes MA SREC I and II) and replaces solar with wind resources beginning in 2018

Case 1b: No SREC Carve-out (removes MA SREC I and II)

Case 2a: 1600 MW of solar by 2020 (Current Policy)

Case 2b: 1600 MW of solar by 2020 and continuing to 2500 MW by 2025 with linear growth

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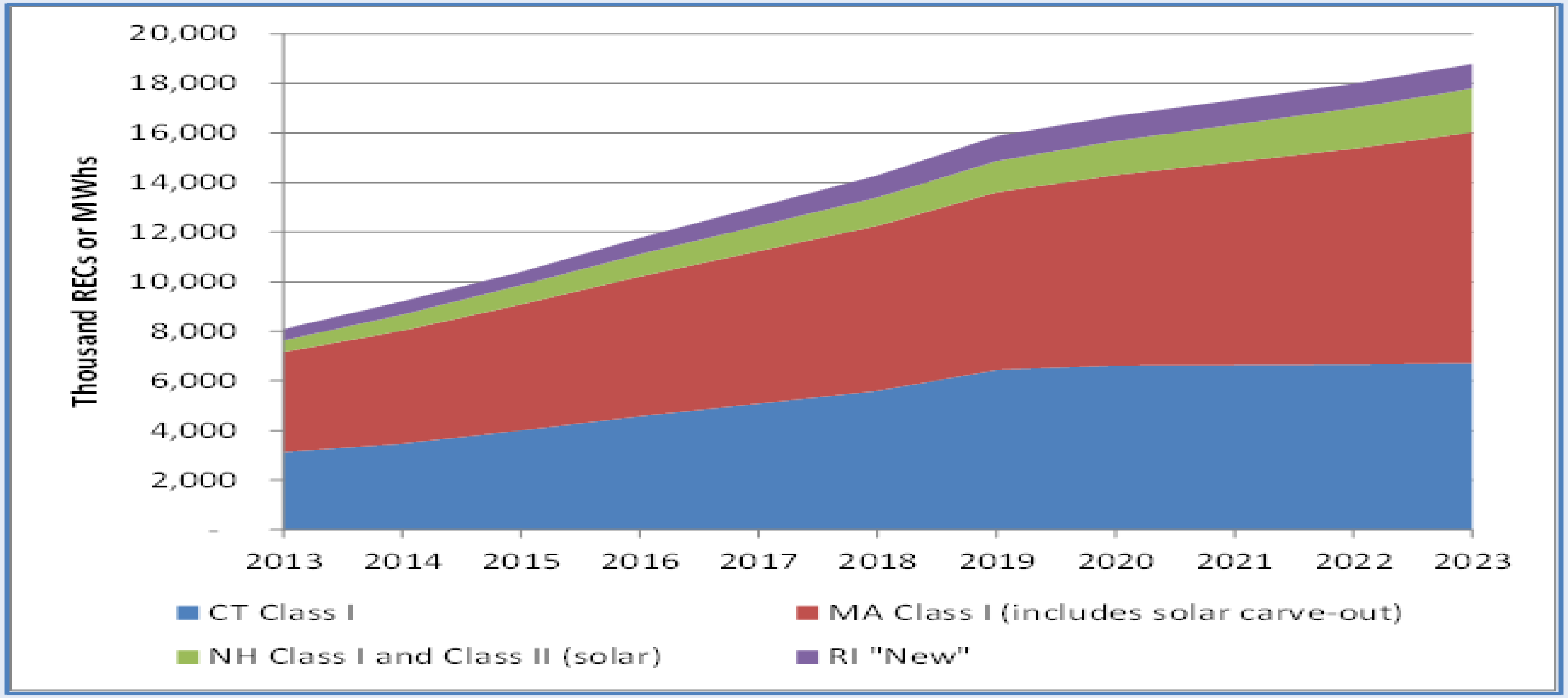
Environmental Policies

- There are two major policy issues affecting the regional market outlooks.
- The two programs particularly impact decisions on generation resource continued operation and new supply choices.

1. The continued strong support for Renewable Portfolio Standards
2. The existing and developing GHG regulations

Renewable Energy - Premium Markets RPS

	2014	2015	2016	2017	2018	2019	2020	2021-2023
CT Class 1	11.0%	12.5%	14%	15.5%	17%	19.5%	20.0%	20.0%
MA Class 1	9%	10%	11%	12%	13%	14%	15%	16%+
NH Class 1	5.0%	6.0%	6.9%	7.8%	8.7%	9.6%	10.5%	11.4%+[1]
NH Class 2	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%
RI New	6.5%	6.5%	8.0%	9.5%	11.0%	12.5%	12.5%[2]	12.5%
Load-Weighted Average	9.0%	10.1%	11.2%	12.4%	13.6%	15.1%	15.9%	16.5%+



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Greenhouse Gas Regulations

RGGI

All New England states participate in RGGI, a cap-and-trade program aimed at reducing CO_2 emissions from the power sector. Pricing carbon emissions through a cap-and-trade program affects New England electric energy prices by increasing the variable costs of fossil fuel-fired generators that are almost always on the margin. RGGI allowance prices have been minimal since the program began in 2009 because actual CO_2 emission levels have fallen well below the initial program caps. On February 7, 2013 the RGGI states committed to an Updated Model Rule that would tighten the caps significantly in 2014. A RGGI-commissioned study of the Updated Model Rule projects that emission allowance prices will rise from about $4 (2010$) per ton in 2014 to over $10 (2010$) per ton by 2020.RGGI auction results to-date have benchmarked well to the Updated Model Rule forecast. After 2020, the reference case assumes that a national CO_2 pricing program is implemented and that prices will reflect the “Low” case of Synapse Energy Economics, Inc.’s 2012 Carbon Dioxide Price Forecast.

Federal Policy

EPA released its Clean Power Plan proposal, which aims to cut carbon emissions from existing power plants and enable the US to reduce carbon emissions from the power sector by 30% below 2005 levels. EPA has proposed each state or multi-state collaboration would develop a plan to meet an individual carbon intensity reduction target through any combination of plant efficiency improvements, shifting generation from higher to lower-emitting resources, maintaining and expanding nuclear and renewable generation, and energy efficiency. New England has already implemented programs and policies that would likely generate more carbon dioxide reductions than required under the EPA’s proposal, but the federal proposal would backstop these efforts.

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Regional Electric Demand – Gross Outlook Pre - EE

ISO-NE Peak Demand Outlook

▪ 2013 Normalized Demand		Actual 27,941	MW
▪ 2014 Forecasted Demand		28,290	MW
▪ 2023 Forecasted Demand		31,878	MW
▪ 10 Year CAGR			1.4 %
▪ 10 Year Increase	3,937 MW	11% of 2023 Demand	

ISO-NE Energy Requirements Outlook

▪ 2013 Energy		*est. 135,000*	GWh
▪ 2014 Forecasted Energy		138,910	GWh
▪ 2023 Forecasted Energy		152,347	GWh
▪ 10 Year CAGR			0.7%
▪ 10 Year Increase	3,006 GWh	10% of 2023 Energy	

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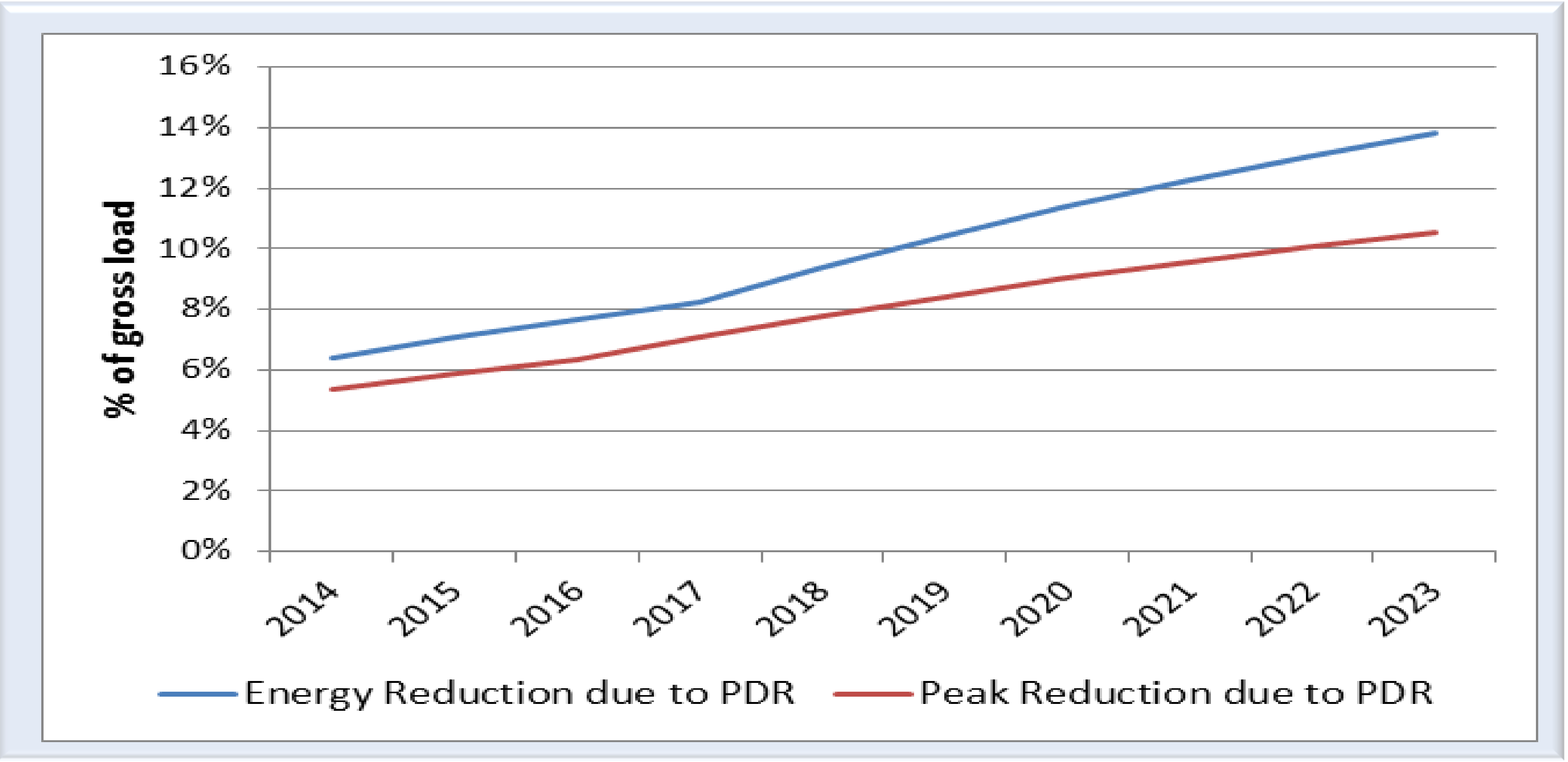
Energy Efficiency Resources



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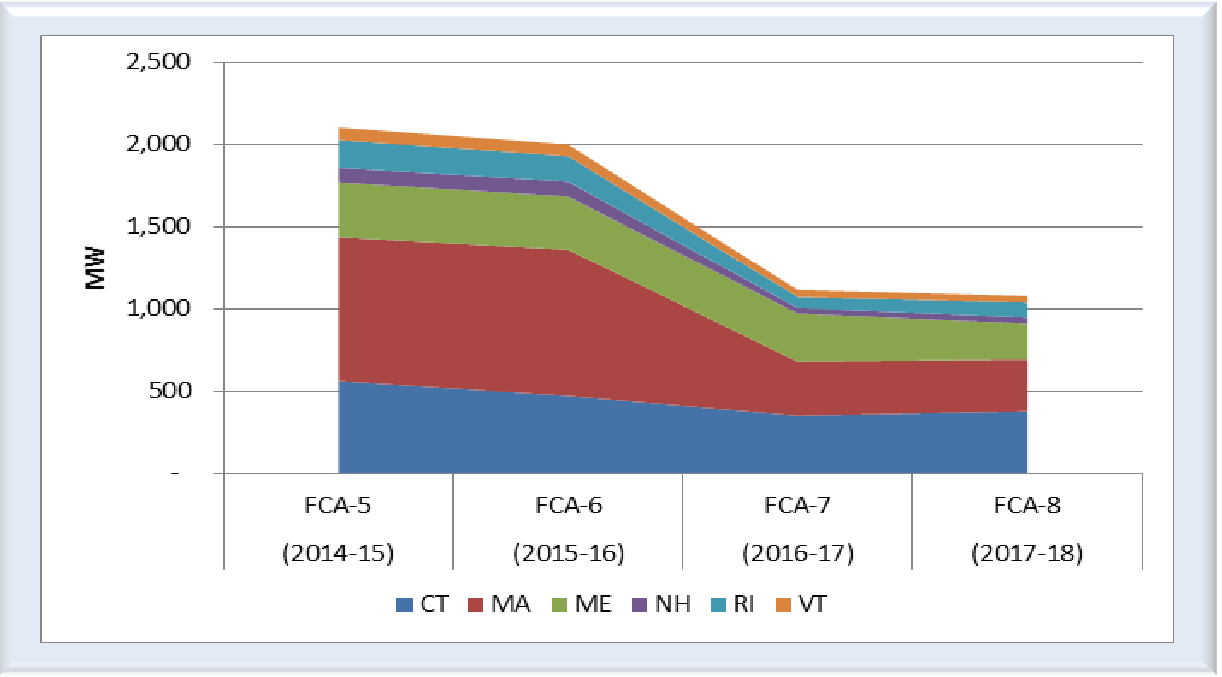
Active Demand Response Resources

- There has been a major reduction in the amount of active DR available to ISO-NE by 201-18
- Total reductions are approximately 1,000 MW
- Proportionately largest reduction in Massachusetts
- This is primarily a result of the new rules requiring DR participation in energy markets
- Further operational requirements on DR could virtually eliminate DR as an FCA resource



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Regional Electric Demand – Net Outlook after EE Effects

ISO-NE Peak Demand Outlook

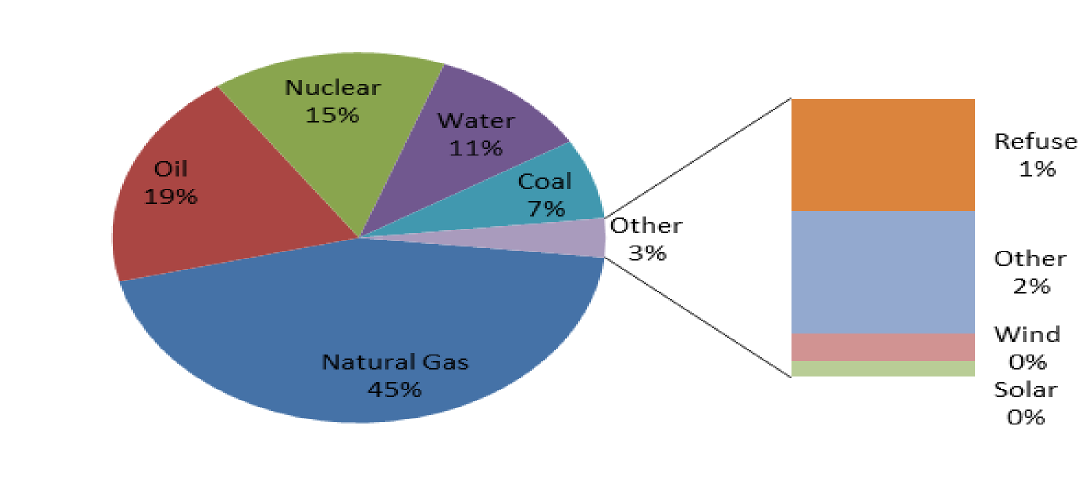
2013 Normalized Demand	*est 26,000*	MW
2014 Forecasted Demand	26,929	MW
2023 Forecasted Demand	29,206	MW
10 Year CAGR		0.7 %
10 Year Increase	3,006	MW

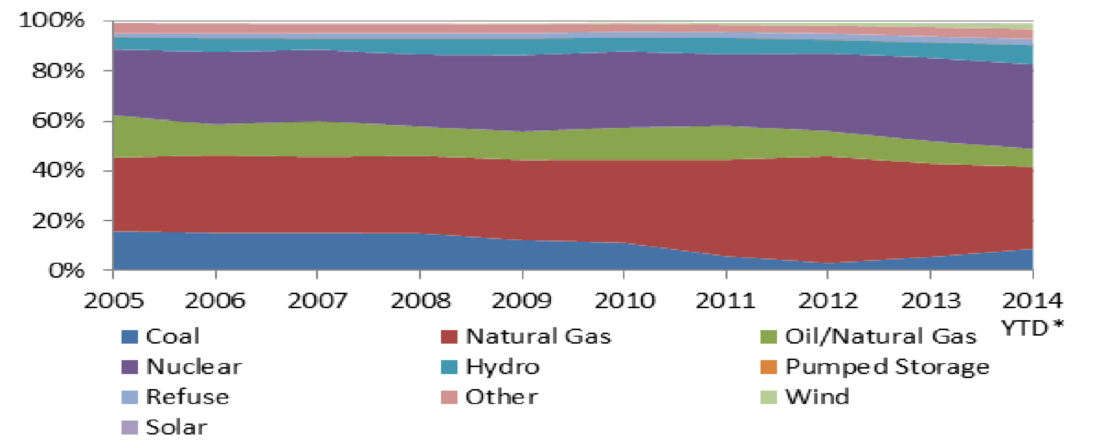
ISO-NE Energy Requirements Outlook

2013 Energy	*est. 134,000*	GWh
2014 Forecasted Energy	131,037	GWh
2023 Forecasted Energy	134,786	GWh
10 Year CAGR		0.1 %
10 Year Increase	786	GWh

Generation Mix

- New England remains a natural gas fueled dependent region
- Renewables have not yet been established as a major component of generation mix
- Natural Gas share of energy increased every year until its highest in 2012, before regional constraints began to push natural gas prices upward





*Includes data through May 2014

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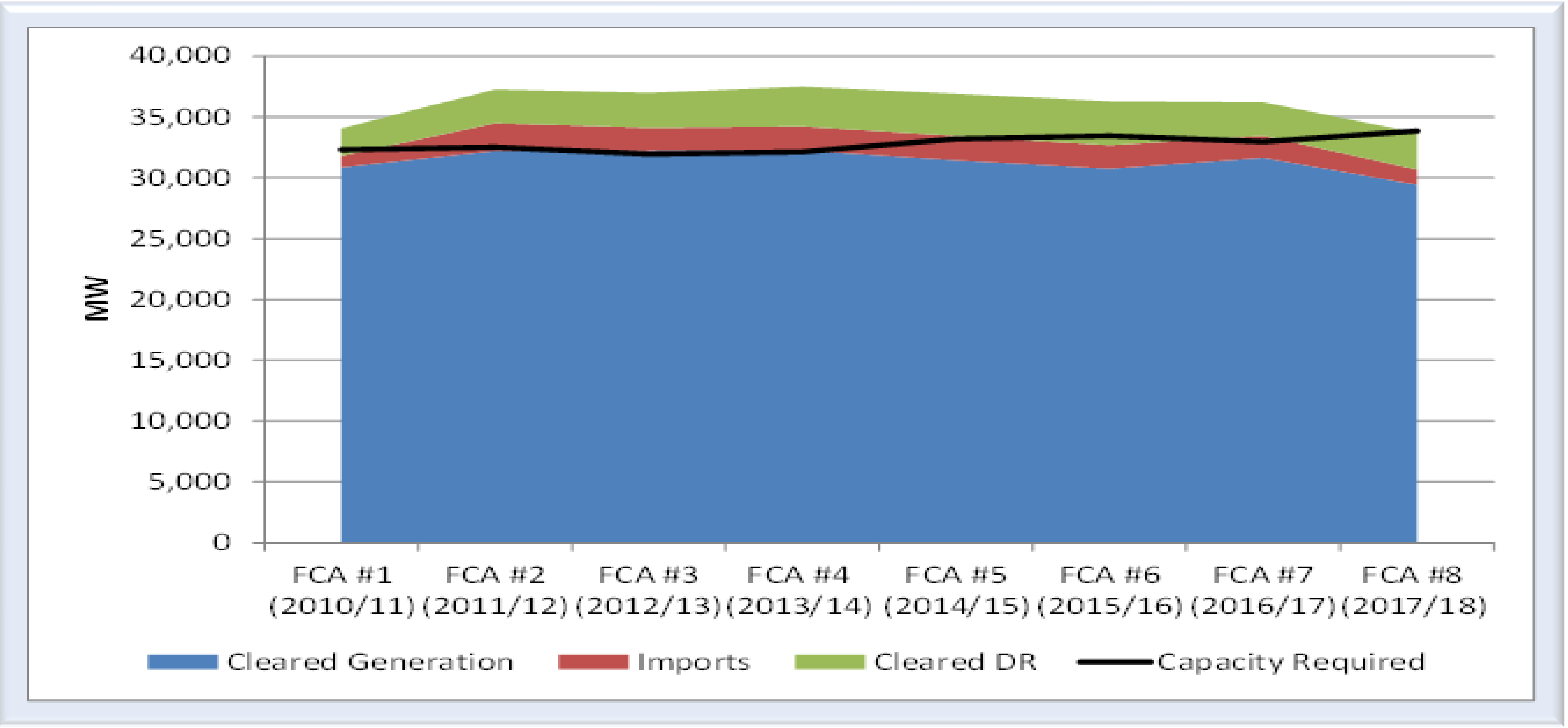
Generation Resource Retirements

Name	Capacity (MW)	Location	Fuel Type	Status	Planned or Actual Shutdown
Vermont Yankee	600	Vernon, VT	Nuclear	Shutdown Announced	End of 2014
Brayton Point (Units 1-4)	1,500	Somerset, MA	Coal/Oil	Shutdown Announced	2017
Salem Harbor (Units 1-4)	750	Salem, MA	Coal/Oil	Closed	2011-2014
AES Thames	450	Montville, CT	Coal	Demolition	2011
Mt. Tom	150	Holyoke, MA	Coal	Shutdown Announced	2014
Bridgeport Harbor 2	130	Bridgeport Harbor, CT	Oil	Shutdown Announced	2017
Norwalk Harbor (Units 1, 2, 10)	350	Norwalk, CT	Oil	Deactivated	2013

Regional Capacity Outlook

ISO-NE FCA Results showing slight shortfall in 2017/18



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Regional Transmission Developments

There are several other transmission projects currently planned or under construction in New England:

- **Maine Power Reliability Program:** six new substations, upgrades to numerous existing substations, and the installation or rebuilding of 440 miles of transmission line in the communities from Eliot to Orrington in Maine. Expected in service date is 2015.
- **New England East-West Solution:** a group of related transmission projects addressing reliability needs in New England, including:
  - **The Greater Springfield Reliability Project:** upgrades to 39 miles of transmission lines between Ludlow, MA and Bloomfield, CT. Now fully in service.
  - **The Interstate Reliability Project:** transmission upgrades spanning three states on a line from Millbury, MA to Card Street Substation in Lebanon, CT. Expected in service date is December 2015.
  - **Central Connecticut Reliability Project:** a project currently in development to remedy reliability concerns in the central Connecticut area**.**
  - **Rhode Island Reliability Project:** includes several transmission upgrades in Rhode Island, including a new 345 kV line from West Farnum to Kent County. Now in service.
- **Boston Upgrades:** transmission upgrades due to the retirement of Salem Harbor and advanced NEMA/B**oston upgrades increasing Boston import capability in 2014.**

Natural Gas Pricing Methodology

- *Henry Hub:* Prices are a blend of EIA's December 2014 Short-Term Energy Outlook (2013-2015) and EIA's 2014 Annual Energy Outlook (AEO) (2015 and after). In the early years, we rely on the Short-Term Energy Outlook. For years 2017 and 2021, we smooth our forecast by assuming that the price rises at a constant rate. In 2021 and beyond, our forecast follows the AEO2014 exactly.
- *New England Basis Differential:* We developed our near-term basis differential outlook using the average across a recent one year period (1/6/14 – 1/5/15) of daily closing quotes for February 2015 to January 2016 Algonquin City-gates basis swaps. In 2018 and beyond, we revert to a basis that results in a delivered natural gas price equal to the AEO2014 Reference Case forecast for delivered prices to the New England electric industry. We make a straight-line interpolation for basis differential values between 2015 and 2018.

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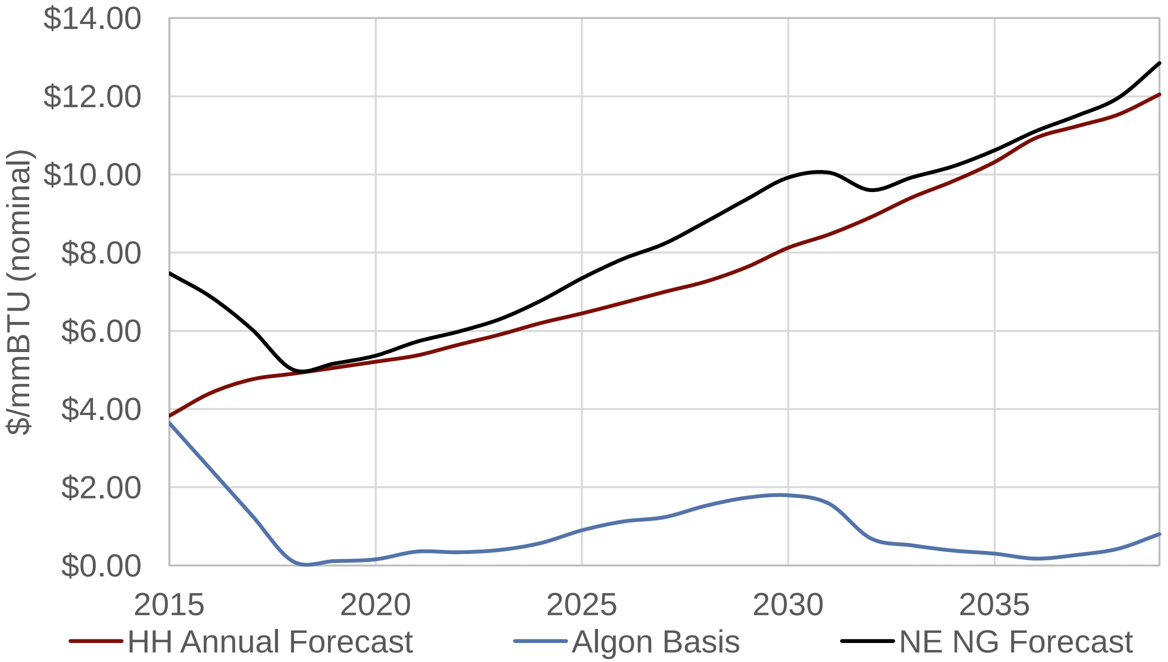
Natural gas price inputs in nominal dollars



Year	HH Annual Forecast	Algon Basis	NE NG Forecast
2015	$3.83	$3.64	$7.47
2016	$4.41	$2.46	$6.87
2017	$4.76	$1.28	$6.04
2018	$4.91	$0.10	$5.01
2019	$5.06	$0.11	$5.17
2020	$5.21	$0.15	$5.37
2021	$5.37	$0.35	$5.72
2022	$5.64	$0.34	$5.98
2023	$5.90	$0.39	$6.30
2024	$6.20	$0.57	$6.77
2025	$6.45	$0.90	$7.34
2026	$6.72	$1.12	$7.84
2027	$7.00	$1.23	$8.23
2028	$7.26	$1.53	$8.79
2029	$7.63	$1.73	$9.37
2030	$8.12	$1.79	$9.92
2031	$8.47	$1.57	$10.04
2032	$8.91	$0.69	$9.60
2033	$9.41	$0.51	$9.92
2034	$9.83	$0.38	$10.21
2035	$10.31	$0.30	$10.61
2036	$10.93	$0.17	$11.10
2037	$11.23	$0.27	$11.50
2038	$11.53	$0.43	$11.96
2039	$12.04	$0.80	$12.84

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End of Presentation

Additional Discussion or Questions ?

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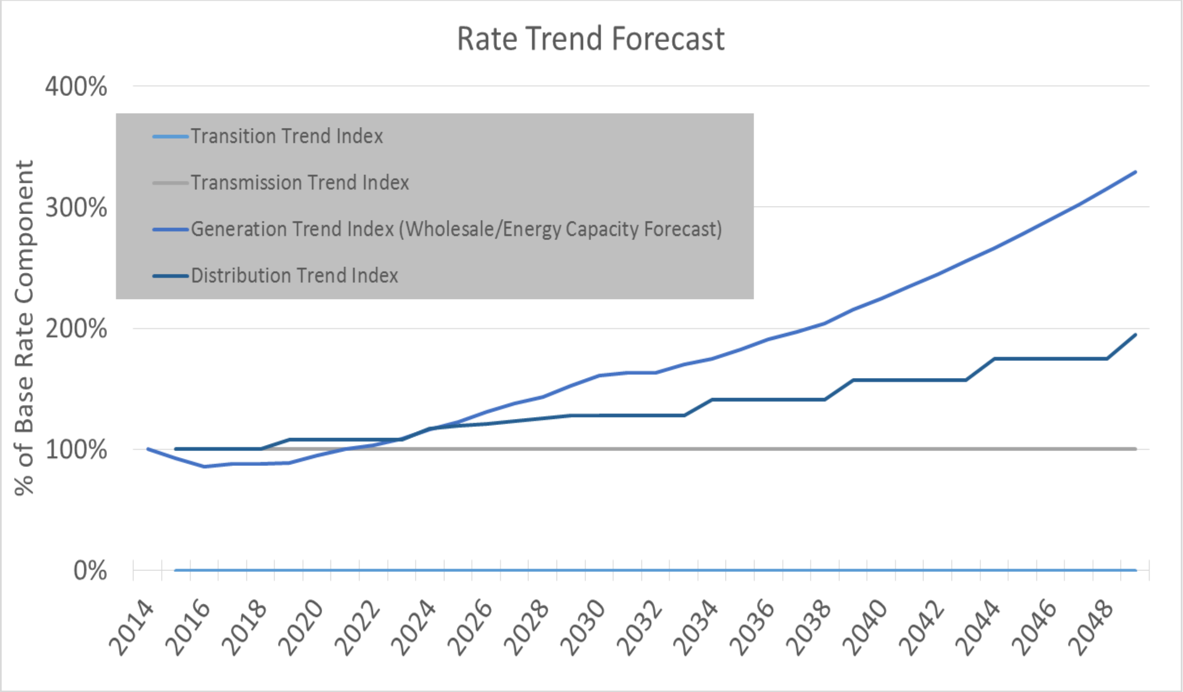
D. AVOIDED RETAIL RATES AND NET METERING REVENUES

AND RELATED ASSUMPTIONS

Rate Trend Forecast:
Assume no fundamental change in rate structures over time

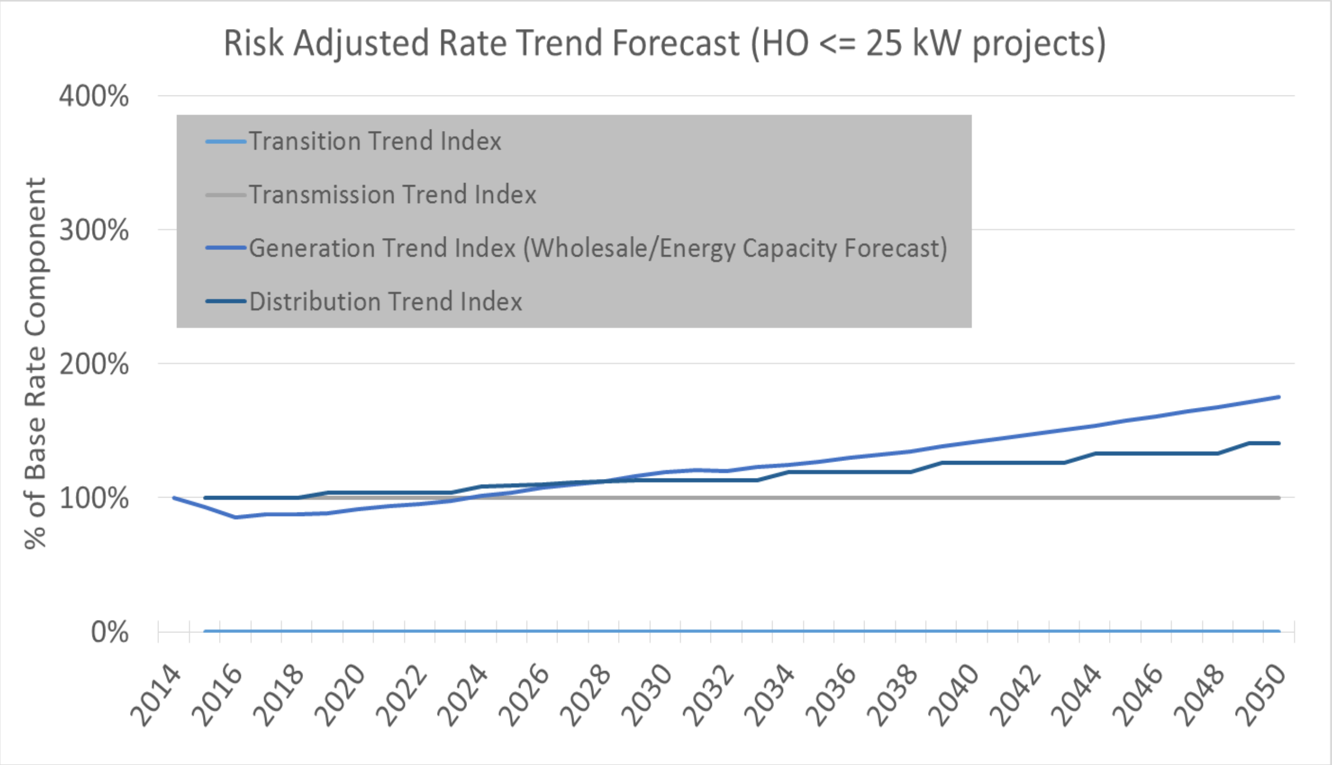
- **Transition** assumed to be 0% escalation after 2015, per EDCs
- **Transmission** assumed to be fixed (0% escalation), per EDCs
- **Distribution** assumed to increase by inflation in steps (corresponding to rate cases) every 5 years, per EDCs
- **Generation** assumed to escalate at index of wholesale blended energy (75%)/capacity (25%)* trend forecast
- **Other Rate Components**: Increase with Inflation, per EDCs
- Recent difference between wholesale energy prices and Basic Service generation rates applied to factor in impact of capacity, reserves, losses, etc.
  - Average of 2014 basic service rates (two procurements) used as the base for forecasting generation charge to avoid overstatement due to unusually high 2015 winter basic service rates



* Portion of spread to trend @ Energy vs. capacity escalator

Rate Trend Forecast:
For Modeling Project Threshold Return Requirements

- Generators cannot take the uncertain projected retail revenue stream, dependent on long-term factors like carbon pricing, natural gas pricing and capacity market prices, which cannot be relied upon, to the bank
- For 3rd-party owned projects, this risk can and often is hedged (i.e., passed along to the host or NMC off-taker through a fixed-price transaction). We assume going forward that this risk is hedged in such a manner for all 3rd-party owned systems
- For host-owned small projects (<= 25 kW) under SREC and Policy Path B, we assume project owner is exposed to future retail price risk, and makes choices based on a more conservative outlook of future retail rates
- Modeled more conservative future by halving the year-to-year growth in prior slide of **generation** and **distribution** rates after 2018
- Otherwise, under PBIs as studied in Paths A and B, the combined incentive structure serves to hedge this risk



‘Generic” Municipal Light Plant Modeling

- Municipal light territories are modeled in aggregate
- Net metering credit assumed to be load-weighted average of a sample of 10 MLP NMC values (Taunton rates were used as proxy to differentiate G rate from other charges)
  - NMC escalated at wholesale/energy capacity forecast index
- Residential and commercial retail rates calculated as the ratio of EIA “loaded” $/MWh (includes non-kWh charges) of IOUs to MLPs applied to the actual “unloaded” IOU retail rates
  - 40% of MLP retail rate escalated by wholesale/energy capacity forecast index
  - 60% of MLP retail rate escalated by CPI
- Assume 13% of installations in 2015 are in MLPs - based on historic installation trends
- For calculating rate component value, assume MLP rates are made up of basic service (40%), distribution (40%), and transmission(20%)

Errata Note: rates used were 20% higher than avg. MLP. This was an error discovered too late in the analysis for revision. Correction of this error would modify results in the following manner: overall growth in installations in the MLP sector would slow moderately, and the overall cost of solar incentives would be slightly higher. This does not alter the nature of overall conclusions in a material manner.

Applicable Rate Class & Net Metering Class Assumptions

Description	Rate Class	% NM Beyond Billing Month/VNM	% BTM Production w/in Billing Month	Net Metering Class Assumed		
				3rd Party	Host Owned	Public Owned
Residential Roof Mount	R-1	10%	90%	Class 1		
Small Commercial Roof Mount	G-1	5%	95%	Class 1		
Solar Canopy	G-1	5%	95%	Class 2		
Commercial Emergency Power	G-1	5%	95%	Class 1		
Community Shared Solar	G-1	100%	0%	Class 2		
On-Site LIH	G-2	5%	95%	Class 2		
VNM LIH	G-1	100%	0%	Class 2		
Building Mounted	G-2	5%	95%	Class 2		
Small/Medium Ground Mount BTM	G-2	5%	95%	Class 2		
Large Ground Mount BTM	G-2	5%	95%	Class 3		Class 2
Small/Medium Landfill	G-1	100%	0%	Class 2		
Large Landfill	G-1	100%	0%	Class 3		Class 2
Small/Medium Brownfield	G-1	100%	0%	Class 2		
Large Brownfield	G-1	100%	0%	Class 3		Class 2
Medium Ground Mount VNM	G-1	100%	0%	Class 2		
Medium MG	G-1	100%	0%	Class 2		
Large MG	G-1	100%	0%	Class 3		Class 2

Net Metering Credit Rates

- Net meter credits are equal to the following components based on the project type net metering class:

Net Metering Class	Components
Class 1	Generation + Distribution + Transition + Transmission
Class 2	Generation + Distribution + Transition + Transmission
Class 3	Generation + Transition + Transmission

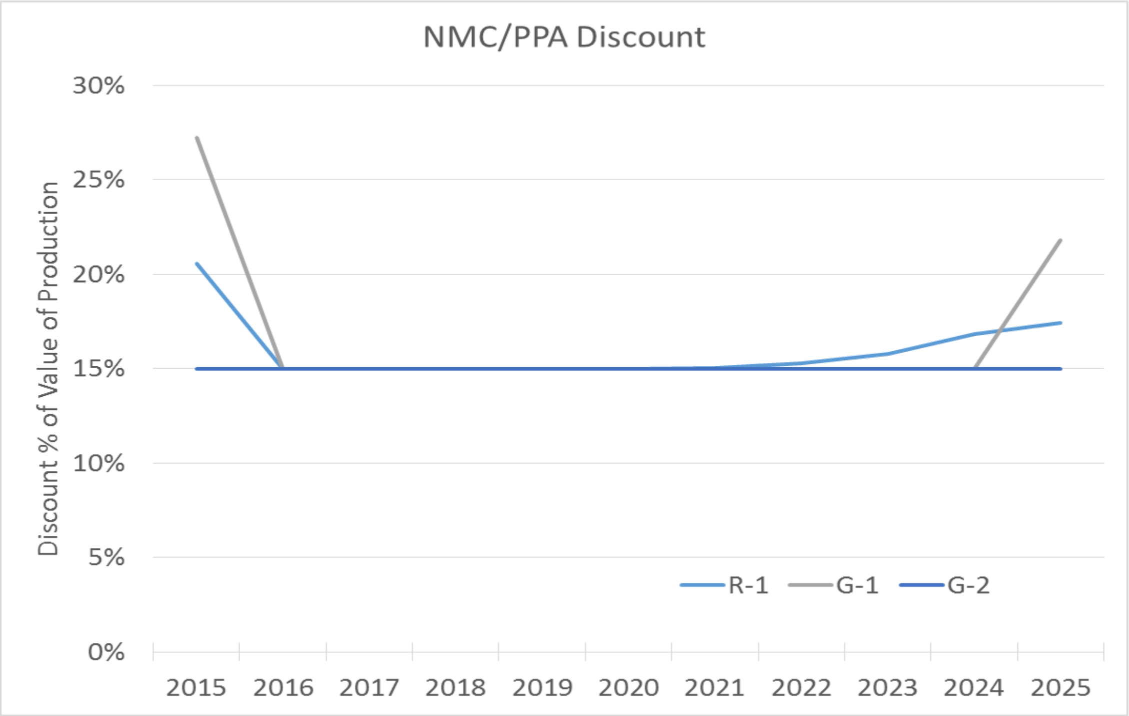
- Small (<= 25 kW) projects always receive net metering (whether uncapped or capped scenario)
- In **Policy Path A** net metering credits are equal to the generation component only

Net Metering For MLPs

- Assume MLPs are able to VNM when net metering is uncapped for all
- Assume no VNM for MLPs when net metering is capped for all:
  - VNM low-income housing, CSS, and large ground mount projects cannot be built

NMC/PPA Discount

- NMC/PPA discount is applied to the net metering credit and retail rate value of production for 3rd party owned projects
  - Discount is calculated for each year using the average forecasted net metering credit rate over all utilities for each rate class. Depending on how much greater than a base rate of 12 cents/kWh the net metering credit rate is the discount will be higher. The minimum discount is 15%.
- Assume NMC/PPA discount 2010-2014 is 15%



E. PV SYSTEM COSTS

INSTALLED AND OPERATING COSTS

Project Output Assumptions

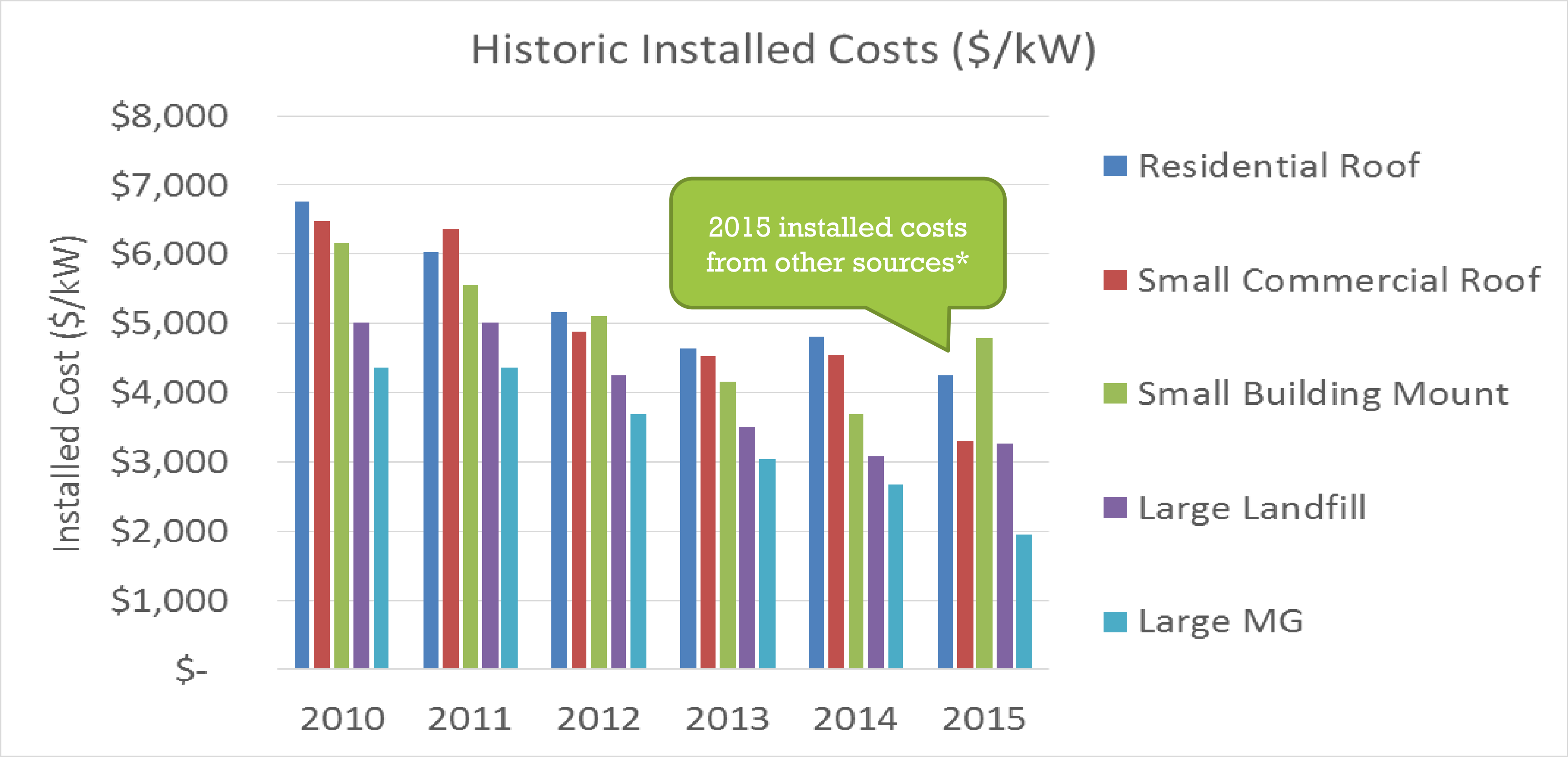
- Capacity factor by project size constant across EDCs and over time

Project Size (kW)	Capacity Factor
5	13.49%
10	13.49%
15	13.49%
100	13.52%
500	13.52%
1,000	14.18%
2,000	14.18%
4,000	14.18%

- Assumed annual project degradation of 0.50%

Historic Installed Costs

- Use DOER SREC-I and SREC-II SQA installed cost data to find the average annual residential installed costs and non-residential by size block for 2010 to 2014

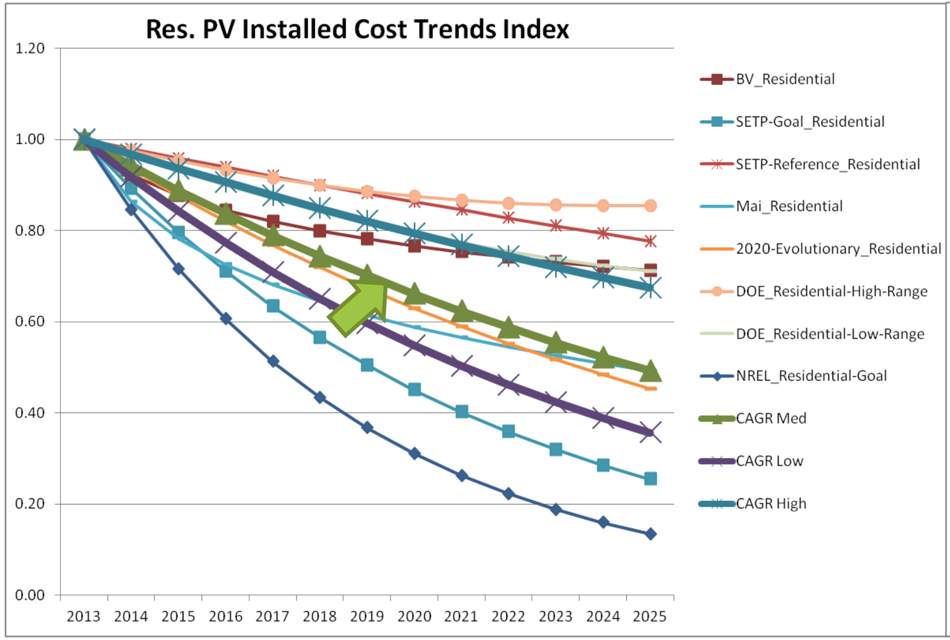


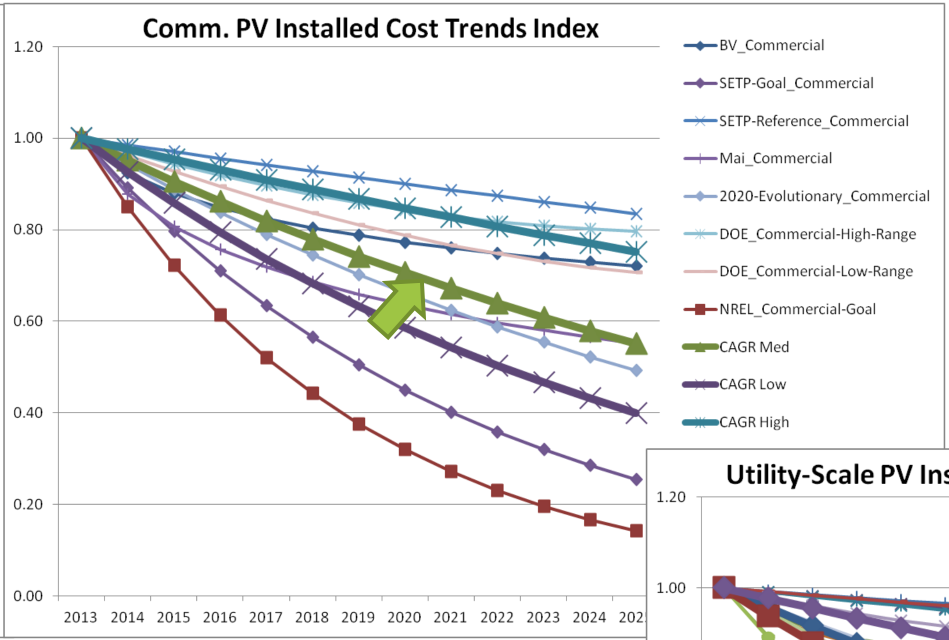
* Discussed in detail PV System Costs section of Appendix

Historic:
Other PV System Costs & Rates

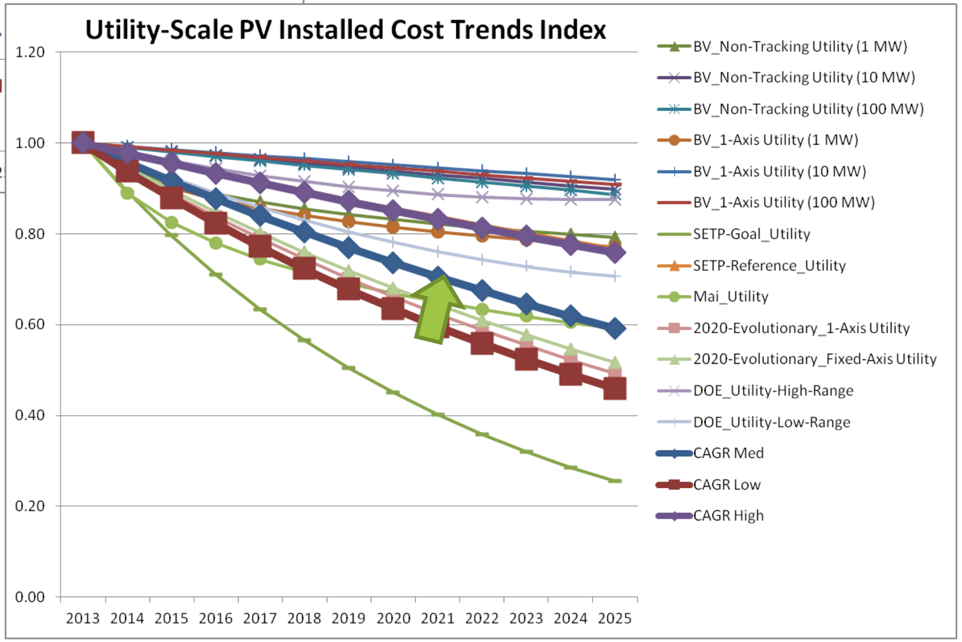
- O&M, customer acquisition, and interconnection costs were backcasted by extrapolating the CPI to 2010 and applying the index to 2015 costs
- Fixed costs (lease payments & PILOT/property taxes) assumed to be fixed back to 2010
- Actual 2010 to 2014 rates for each utility were used to calculate net metering and retail value of production

Installed Cost Forecasts: Trends





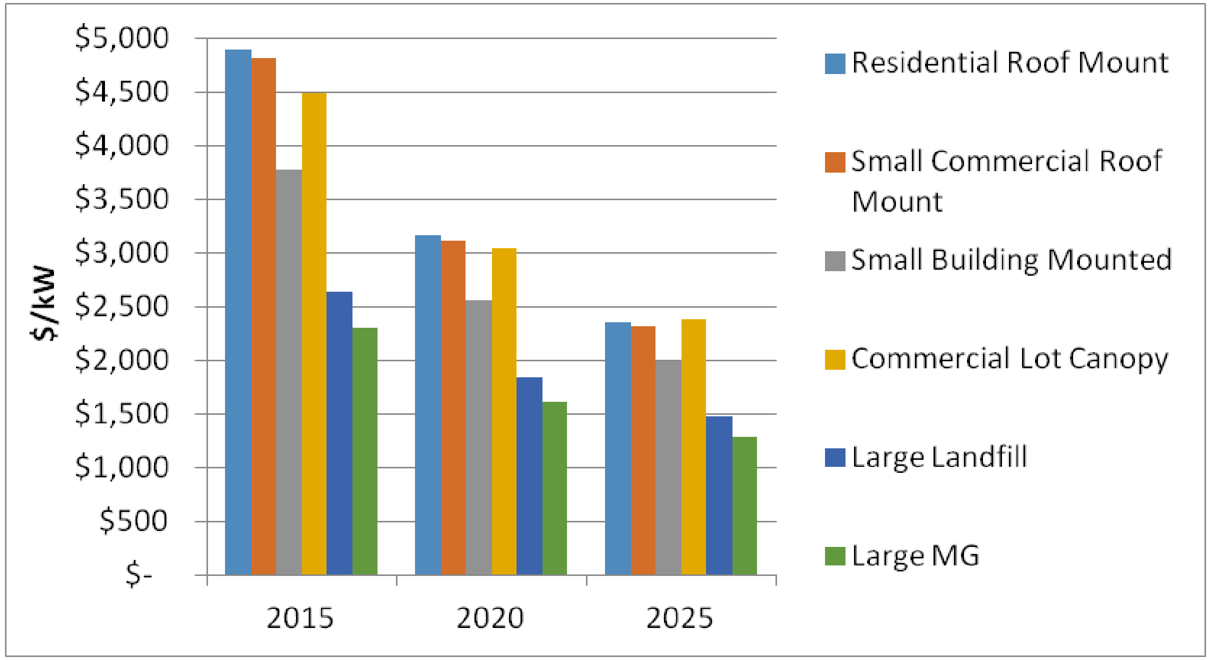
Note: No explicit adjustments made for impact of import duties; Overall impact on module price ~ 8¢/W (per SEAI), portion in effect during 2014 already embedded in forecast



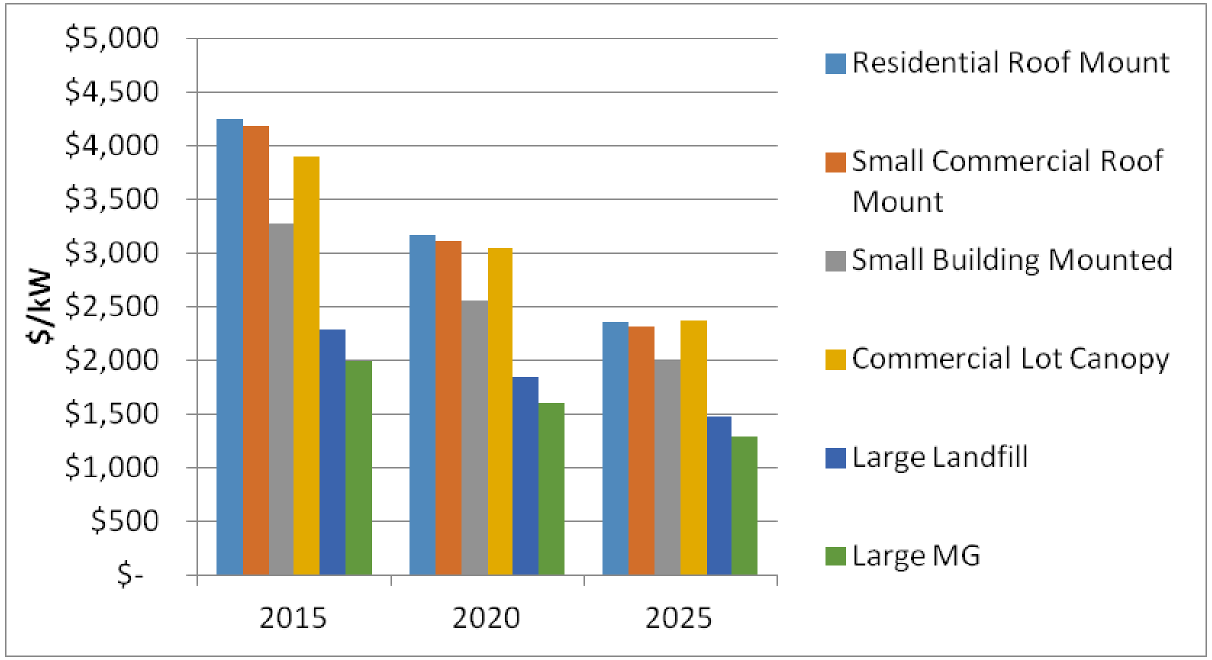
- Survey of available public sources as of late 2014 considered
- Developed trajectory as an index, applied over analysis period to applicable recent historic installed cost data
- 'Medium' used as base case for this analysis

Installed Costs

Host Owned and Public Owned



Third-Party Owned



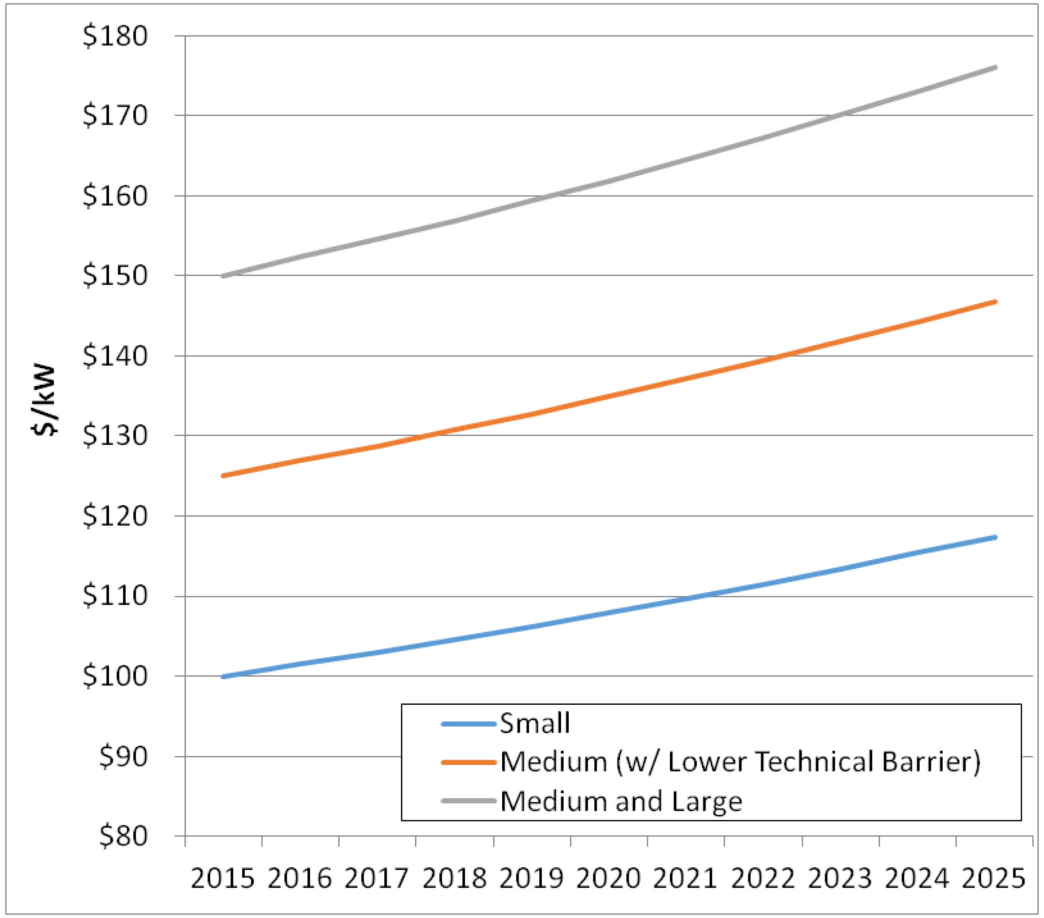
- The following blocks were also modeled: Campus Lot Canopy, Commercial Emergency Power, Community Shared Solar, On-Site LIH, VNM LIH, Medium Building Mounted, Large Building Mounted, Medium Ground Mount BTM, Large Ground Mount BTM, Small Landfill, Medium Landfill, Small Brownfield, Medium Brownfield, Large Brownfield, Medium Ground Mount VNM, Medium MG
- Blocks of high and low cost systems were also modeled (the above figures represent average cost systems)

Interconnection Cost Assumptions

- Based on historical data from public sources and supplemental research
- Assumed interconnections costs vary by project size and technical barrier to interconnect
- Year 1 Interconnection Costs:

Project Size	Modeled Blocks	Year 1 Cost
Small	Residential Roof Mount, Small Commercial Roof Mount, Commercial Lot Canopy, Commercial Emergency Power, On-Site LIH, Small Building Mounted	$100/kW
Medium (with Lower Technical Barrier)	Medium Building Mounted, Medium Ground Mount BTM	$125/kW
Medium and Large	Campus Lot Canopy, Community Shared Solar, VNM LIH, Large Building Mounted, Large Ground Mount BTM, Small Landfill, Medium Landfill, Large Landfill, Small Brownfield, Medium Brownfield, Large Brownfield, Medium Ground Mount VNM, Medium MG, Large MG	$150/kW

- Escalated annually by CPI
- Assumed same interconnection costs across ownership models

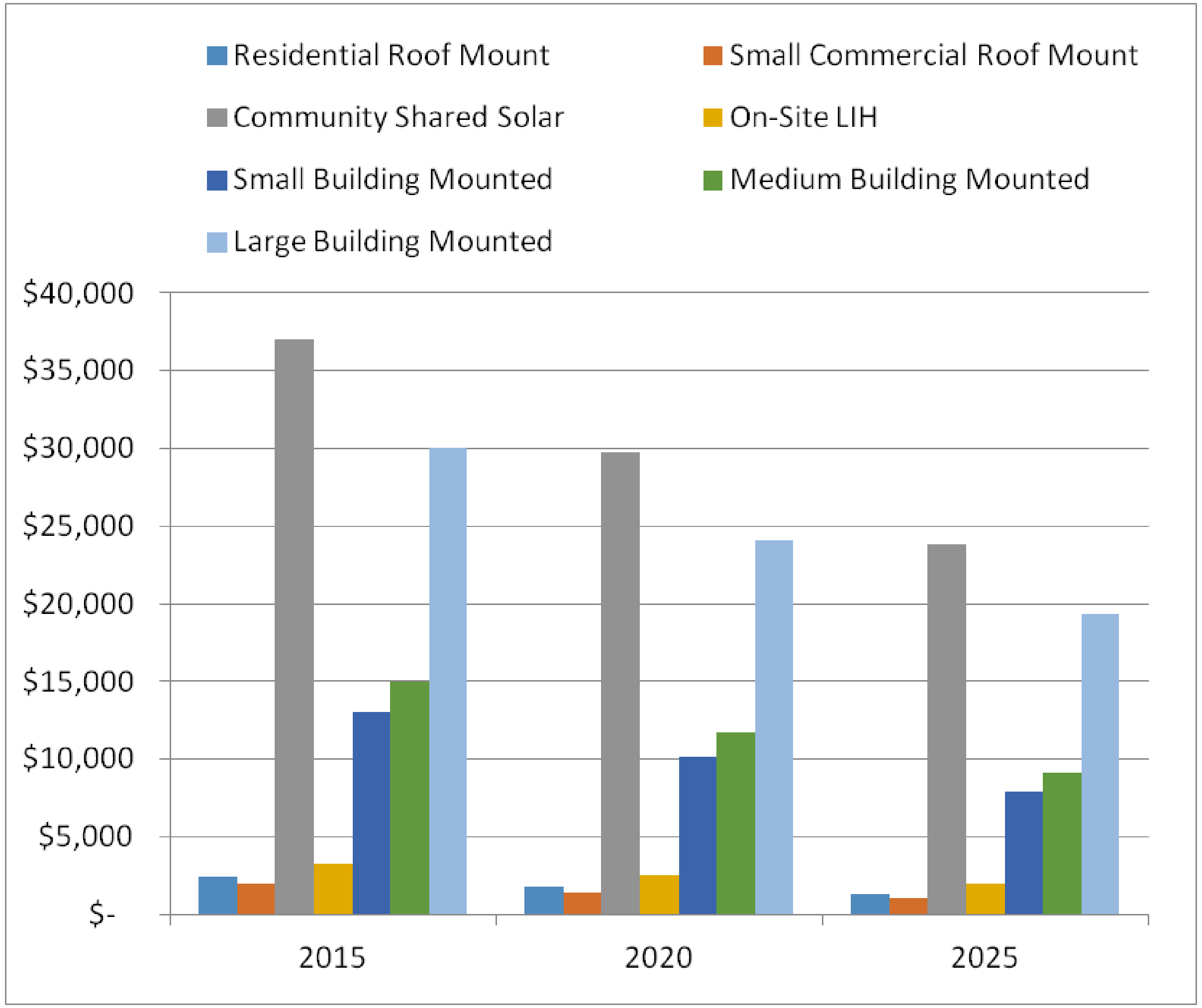


Customer Acquisition Cost Assumptions

- Based on NREL SunShot soft cost estimates
- Year 1 Customer Acquisition Costs:

Project Type	Year 1 Cost ($/kW)
Residential	$480
Small Commercial	$130
Large Commercial	$30

- Escalated annually using Installed Cost Forecast
- Only applied to third-party owned projects
- Assumed no Customer Acquisition Costs for Canopy, VNM LIH, and Ground Mounted projects

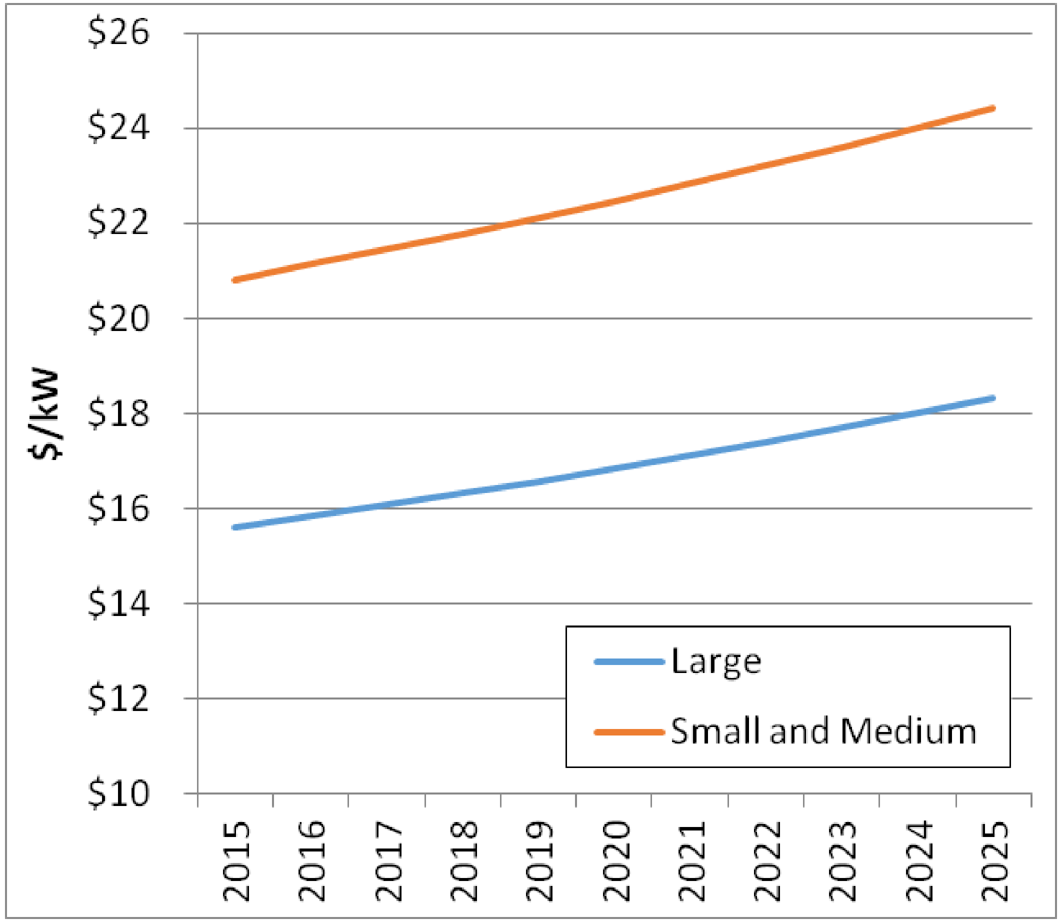


O&M Cost Assumptions

- Based on historical data from public sources and supplemental research
- Assumed O&M costs "fixed" based on system size not performance
- Assumed O&M costs vary by project size ➔ larger projects will have lower $/kW O&M costs
-

Project Size	Modeled Blocks	Year 1 Cost
Large	Community Shared Solar, VNM LIH, Large Ground Mount BTM, Medium Landfill, Large Landfill, Medium Brownfield, Large Brownfield, Medium MG, Large MG	$16/kW
Small and Medium	Residential Roof Mount, Small Commercial Roof Mount, Commercial Lot Canopy, Campus Lot Canopy, Commercial Emergency Power, On-Site LIH, Small Building Mounted, Medium Building Mounted, Large Building Mounted Medium Ground Mount BTM, Small Landfill, Small Brownfield, Medium Ground Mount VNM	$21/kW

- Escalated annually by CPI
- Assumed same O&M costs across ownership models



Property Tax (PILOT) and Land Lease Cost Assumptions

- Assumptions developed through market analysis and benchmarking
- PILOT Costs
  - Base Case assumed $10/kW per year, fixed over time
  - Assumed constant across all ownership models
  - Only applied to Ground Mount (incl. Landfill and Brownfield) projects
- Land Lease Costs
  - Base Case assumed $13/kW per year, fixed over time
  - Assumed constant across all ownership models
  - Not applied to Roof Mount projects

Financing Assumptions:
Related to Risk under each Policy

- For modeling, use simplified capital structure
- Debt:
    - Host & 3rd-party owned systems: on commercial terms
    - Publicly-owned projects: Based on long-term municipal bonds
- Equity
    - Initial developer/sponsor: cash + sweat equity
    - Tax equity to fully monetize tax benefits as generated
    - Where long-term contracts provide stable revenue, YieldCos emerge as another viable source of capital
- Cost & availability of capital is assumed sensitive to:
    - Contract quantity and duration
    - Type, duration & magnitude of incentive
        - Greater revenue certainty ➔ lower cost of capital
        - Fixed PBI is likely to generate interest from more capital, at a lower cost, than a downward sloping soft price floor

- Modeling reflects:
    - Increasing competition among equity providers, including availability and applicability of YieldCo & similar investment vehicles
        - Downward pressure on cost of capital over time
    - Impact of transition from 30% to 10% ITC on capital structure and cost of capital
    - Expiration of ITC for residential host-owned
    - Impact of MA residential solar loan program for small portion of residential installations
        - Implemented as slight interest rate reduction to all residential host-owned projects
    - Considering the degree to which cost of capital advantage of fixed price PBI vs. SREC floor price shrinks as proportion of uncertain revenue shrinks
        - At the limit, if discount to floor is sufficient to finance, cost of capital advantage vanishes

Financing Assumptions:
Derivation & Application of Key Inputs

	Private, 3rd-Party	Private, Host-Owned	Public, Host-Owned
% Debt	Based on maximum sustainable debt, subject to DSCR (average = 1.35); > rev. certainty (PBI) means > leverage; Debt % also ↑ as ITC % ↓	Estimate of corporate financing structure for major capital investments	Assumed to finance 100% of cost through municipal bonds
Debt Term	Est. of commercial terms. Shorter for SREC structure, longer for PBI	Est. of corporate financing, with guarantee. Term longer for PBI than SREC	20 year bond, all market structures
Int. Rate	Term-specific risk free rate plus market-based premium; assumes volume discount compared to one-off project	Term-specific risk free rate plus market-based premium; rates higher than Private, 3rd-Party due to one-off nature	20-year municipal bond market
Loan Fee	An origination fee, paid to the lender. Set at a level which approximates the market-based premium above the base debt interest rate. For Private, Host-Owned the Loan Fee is assumed built into the term debt interest rate.		
% Equity	All remaining funds required after maximum sustainable debt; a blend of cash, tax and YieldCo equity; blend changes as ITC is reduced	Est. of corporate financing, with guarantee.	Not applicable. Projects financed 100% with municipal bonds.
AT Wtd Cost of Equity	A weighted average of cash, tax and YieldCo equity; subject to downward (competitive) pressure over time	Est. of corporate opportunity cost of other capital investments	Not applicable
WACC	= (%e * Ke) + (%d*Kd*(1-Tax Rate)) The project-specific WACC is used to convert the PBI into an equivalent EPBI (rebate).		Not applicable

Financing Assumptions: SREC

Private, 3rd-Party Ownership

kW	< 25			100			500			1,000			2,000+		
	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25
% Debt	40%	50%	50%	40%	50%	50%	40%	50%	50%	40%	55%	55%	40%	55%	55%
Debt Term	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Int. Rate	5.50%	5.75%	6.00%	5.50%	5.75%	6.00%	5.50%	5.75%	6.00%	5.50%	5.75%	6.00%	5.50%	5.75%	6.00%
Loan Fee	2.00%	2.00%	2.25%	2.00%	2.00%	2.25%	2.00%	2.00%	2.25%	2.00%	2.00%	2.25%	2.00%	2.00%	2.25%
% Equity	60%	50%	50%	60%	50%	50%	60%	50%	50%	60%	45%	45%	60%	45%	45%
AT Wtd Cost of Equity	9.5%	8.4%	8.1%	9.5%	8.4%	8.1%	8.9%	8.4%	8.1%	8.9%	7.8%	7.6%	8.9%	7.8%	7.6%
WACC	7.0%	5.9%	5.8%	7.0%	5.9%	5.8%	6.9%	5.9%	5.8%	6.7%	5.4%	5.4%	6.7%	5.4%	5.4%

Financing Assumptions: SREC

Private Host Ownership

kW	**< 25**			**100**			**500**			**1,000**			**2,000+**		
	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25
% Debt	50%	50%	50%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%
Debt Term	15	15	15	12	12	12	12	12	12	12	12	12	12	12	12
Int. Rate	6.50%	6.75%	7.00%	6.50%	6.75%	7.00%	6.00%	6.25%	6.50%	6.00%	6.25%	6.50%	6.00%	6.25%	6.50%
Loan Fee	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
% Equity	50%	50%	50%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%
AT Wtd Cost of Equity	8.0%	8.0%	8.0%	12.0%	10.5%	9.0%	12.0%	10.5%	9.0%	12.0%	10.5%	9.0%	12.0%	10.5%	9.0%
WACC	5.9%	6.0%	6.1%	9.6%	8.6%	7.6%	9.5%	8.5%	7.5%	9.5%	8.5%	7.5%	9.5%	8.5%	7.5%

Financing Assumptions: SREC
Public host Ownership

kW	< 25			100			500			1,000			2,000+		
	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25
% Debt	-	-	-	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Debt Term	-	-	-	20	20	20	20	20	20	20	20	20	20	20	20
Int. Rate	-	-	-	3.5%	3.75%	4.00%	3.5%	3.75%	4.00%	3.5%	3.75%	4.00%	3.5%	3.75%	4.00%
Loan Fee	-	-	-	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
% Equity	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0
AT Wtd Cost of Equity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WACC	-	-	-	3.5%	3.75%	4.00%	3.5%	3.75%	4.00%	3.5%	3.75%	4.00%	3.5%	3.75%	4.00%

Financing Assumptions: PBI
Private, 3rd-Party Ownership

kW	< 25			100			500			1,000			2,000+		
	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25
% Debt	50%	60%	60%	50%	60%	60%	50%	60%	60%	50%	65%	65%	50%	65%	65%
Debt Term	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
Int. Rate	6.00%	6.25%	6.50%	6.00%	6.25%	6.50%	6.00%	6.25%	6.50%	6.00%	6.25%	6.50%	6.00%	6.25%	6.50%
Loan Fee	2.00%	2.00%	2.25%	2.00%	2.00%	2.25%	2.00%	2.00%	2.25%	2.00%	2.00%	2.25%	2.00%	2.00%	2.25%
% Equity	50%	40%	40%	50%	40%	40%	50%	40%	40%	50%	35%	35%	50%	35%	35%
AT Wtd Cost of Equity	7.6%	7.1%	7.2%	7.6%	7.1%	7.2%	7.1%	6.7%	6.9%	7.3%	6.8%	7.0%	7.3%	6.8%	7.0%
WACC	5.6%	5.1%	5.2%	5.6%	5.1%	5.2%	5.3%	4.9%	5.1%	5.5%	4.8%	5.0%	5.5%	4.8%	5.0%

Financing Assumptions: PBI

Private Host Ownership

kW	< 25			100			500			1,000			2,000+		
	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25
% Debt	50%	60%	60%	50%	60%	60%	50%	60%	60%	50%	65%	65%	50%	65%	65%
Debt Term	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
Int. Rate	6.50%	6.75%	7.00%	6.50%	6.75%	7.00%	6.00%	6.25%	6.50%	6.00%	6.25%	6.50%	6.00%	6.25%	6.50%
Loan Fee	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
% Equity	50%	40%	40%	50%	40%	40%	50%	40%	40%	50%	35%	35%	50%	35%	35%
AT Wtd Cost of Equity	7.0%	7.0%	7.0%	10.0%	10.0%	9.0%	10.0%	10.0%	9.0%	10.0%	10.0%	9.0%	10.0%	10.0%	9.0%
WACC	5.4%	5.2%	5.3%	6.9%	6.4%	6.1%	6.8%	6.2%	5.9%	6.8%	5.9%	5.7%	6.8%	5.9%	5.7%

Financing Assumptions: PBI
Public host Ownership

kW	< 25			100			500			1,000			2,000+		
	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25
% Debt	-	-	-	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Debt Term	-	-	-	20	20	20	20	20	20	20	20	20	20	20	20
Int. Rate	-	-	-	3.5%	3.75%	4.00%	3.5%	3.75%	4.00%	3.5%	3.75%	4.00%	3.5%	3.75%	4.00%
Loan Fee	-	-	-	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
% Equity	-	-	-	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
AT Wtd Cost of Equity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WACC	-	-	-	3.5%	3.75%	4.00%	3.5%	3.75%	4.00%	3.5%	3.75%	4.00%	3.5%	3.75%	4.00%

F. SREC POLICY ASSUMPTIONS

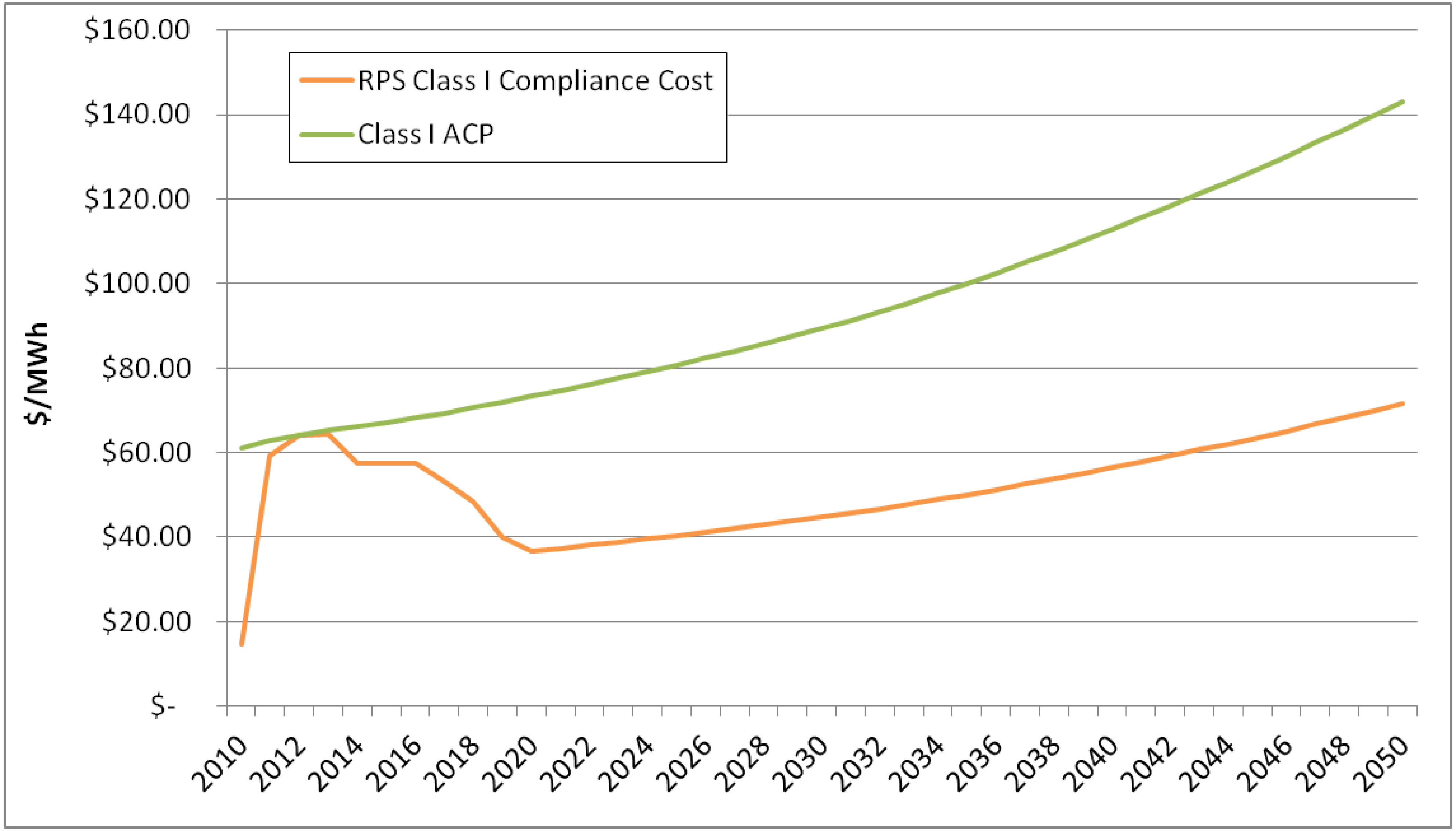
SREC-I, II AND III

Modeling Extension of Current Policy: SREC-III

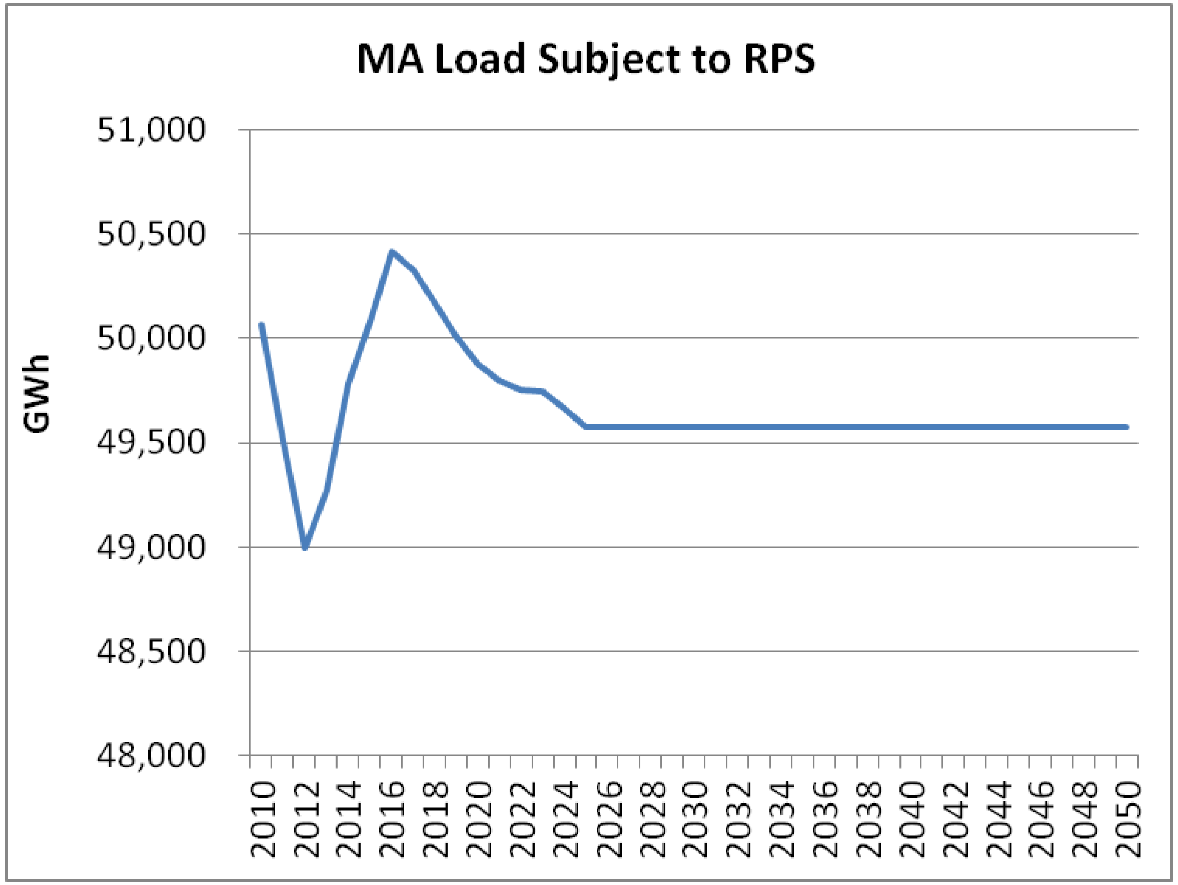
- Treated SREC-III from 1601 MW to 2500 MW dc as a separate tier, so as to not impact SREC-II expected prices and dynamics
- Extended the trend of SACP and floor price declines from those built into SREC-II policy
- Set and used annual MW targets with the objective of getting to 2500 MW by 2025, starting at the market size in last year of SREC-II with small escalator, in an analogous manner to SREC-II
- Modified SEA's proprietary Massachusetts Solar Market Study model of SREC-II with the above changes, using projected system costs and rates, to produce forecasted market buildout and prices.
- *Note: in modeling, SREC-III did not follow the targets, as sectors that were not 'managed' outstripped their targets and led to reaching 2500 MW well before 2025*

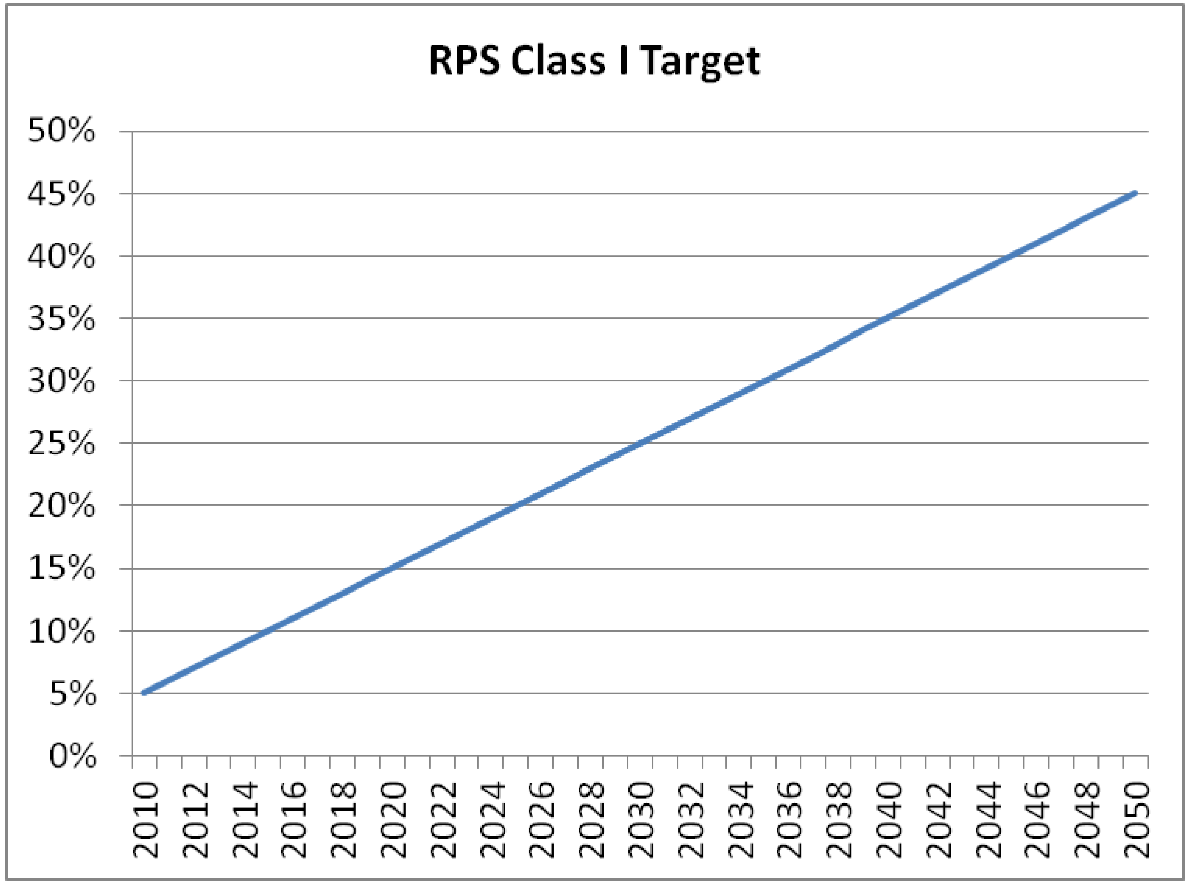
G. CLASS I RPS

ACP and Avoided Class I RPS Compliance Costs



MA RPS Load, RPS Exemptions and Class I Targets





- RPS Exemptions = 17.27% of annual load

H. SUPPLY CURVE

APPROACH AND ASSUMPTIONS

SREC, Policy Paths A & B:
Overarching Supply Curve Granularity

- The Foundation of the Path A & B Models is a Supply Curve comprised of 612 Production Blocks
- Each Production Block is a Unique Combination of:
  - Project Type (i.e., Residential Roofmount, Medium Landfill, CSS) – 22 Types
  - Utility District (i.e., Munis, NGRID, Nstar BeCO, etc.) – 6 Districts
  - Ownership Type (i.e.. Third Party Owned, Host Owned, Public Owned) - 3 Types
  - Cost Type (High, Medium, Low Cost) - 3 Types (only 6 projects type are further disaggregated by Cost Type)
- MW Installs, MWh Production, Technical Potential, CoE, and Incentives are tracked on a quarterly basis for each of the 612 Production Blocks.

I. POLICY PATHS A & B

MODELING APPROACH AND ASSUMPTIONS

Path A & B: Aggregate Program Targets

- Overall Annual Program Targets were set to achieve 2500 MW (including SREC-I & SREC-II) by 2500, with less than 2% increase in targets annually
  - This was done to minimize installation volatility.
- For Capped Scenarios, Initial 2017 Program Aggregate Targets were set at 120 MW, increasing by 2.5 MW, to a Target of 140 MW in 2025.
- For Uncapped Scenarios, Initial 2017 Program Aggregate Targets were set at 120 MW, increasing by 2.0 MW, to a Target of 136 MW in 2025.
  - Increase was set lower than Capped because more MW were installed under SREC-II Uncapped than SREC-II Capped.
- Total Program Targets were set to exceed 2500 MW by 8.8 MW (Capped) and 13 MW (Uncapped) to Ensure 2500 MW target was Hit
  - Overbuild in final quarter of installations was pro-rated to ensure that C/B analysis only modeled costs/benefits for 2500 MW of installations.

Path A & B: Sector Specific Program Targets

- For Path A and Path B Uncapped, the following Target % were set for each Sector:
  - Sector A Small-Residential: 13.33%
  - Sector A Small-Non-Residential: 1%
  - Of the total % not devoted to Small Residential & Small Non-Residential:
    - Sector A Large: 25%
    - Sector B: 25%
    - Sector C: 25%
    - Sector D (MG): 25%
- For Path A and Path B Uncapped, the following Target % were set for each Sector:
  - Sector A Small-Residential: 13.33%
  - Sector A Small-Non-Residential: 1%
  - Of the total % not devoted to Small Residential & Small Non-Residential:
    - Sector A Large: 10%
    - Sector B: 30%
    - Sector C: 30%
    - Sector MG: 30%
- Sector A Large, Path A & Path B is set at 10% under the Capped Scenario because, as CSS and VNM LIH cannot exist in a NM Capped Scenario, the Sector lacks Resource Potential to hit a 25% Target; the 15% that was not allocated to Sector A Large was evenly distributed between Sector B, C and MG.
- Sector Specific Program Targets directly effect total installs by Path A Large Sectors, as Quarterly Base Solicitation Targets are set equal to one-fourth of Annual Targets.
- Sector Specific Program Targets affect Path A & Path B DBI/PBI & EPBI as Initially Block sizes are set at ½ of the annual 2017 target.

Path A & B: Starting Resource Potential –Utility Distribution

- Projected 2015-2016 Annual Installs were used as a Base Starting Resource Potential each Project Type (i.e., Residential Roofmount, CSS, Medium MG)
- Base Starting Resource Potential was then divided between each utility for each project type based on whether the Project was Residential, Non-Residential, Land Use Constrained, or Landfill/Brownfield:
    - Residential: Base Starting Potential was divided between each utility based on total % of Residential Customers (i.e. if Residential Roofmount project type has 10 MW of Base Starting Potential, and 10% of Residential customers are in Utility X, Utility X's -Residential Roofmount has 1MW of Resource Potential)
- Non-Residential: Base Starting Potential was divided between each utility based on total % of Non-Residential Customers
- Land-Use Constrained: Base Starting Potential was divided between each utility based on a weighting of open space potential in the utility district (2x Weight), and % Non-Residential Customers in each utility (1x Weight).
    - Open Space Potential is an analytically derived metric based on: 1.) Total Acreage in each Utility; and 2.) Population density in each utility.
- Landfill/Brownfield: Base Starting Potential was divided between each utility based on a weighting of open space potential in the utility district (1x Weight), and % Non-Residential Customers in each utility (2x Weight).

Path A & B: Starting Resource Potential –Ownership/Cost Distribution

- After dividing Resource Potential between each utility, Resource Potential was then divided between project ownership types (Host Owned, Third Party Owned, Public Owned) based on 2015-2016 SREC-II projections.
  - E.G., Residential Roofmount had roughly a 51-49% relative split between Third Party Owned and Host Owned Projects, thus 51% of technical potential was distributed to 3PO, and 49% to HO projects.

- Finally, after dividing Resource Potential between utilities and ownership type, Resource potential was further divided based on whether the Project Type was segmented by High/Medium/Low Cost.
  - 50% to Medium Cost
  - 25% to Low Cost
  - 25% to High Cost
  - If a project type was not segmented by Cost, naturally no division occurred.

Path A & B: Ongoing Resource Potential & Growth Rates

- Production Block Resource Potential in each Sector grow at a fixed rate annually, which is equal to MW installed in the previous year multiplied by a Growth Factor.
  - e.g., If a Production Block installs 20 MW in a year, and the Growth factor is 105%, the Production Block will have a technical potential of 21 MW in the subsequent year.
  - Growth Rates set conservatively at 105%-116% for all Sectors.
- Growth/Resource Potential forecasted on an annual basis; as the Model runs quarterly, annual Resource Potential was divided by four (4) to establish quarterly potential.
- Resurrection Rates: In the event a modeled Production Block installs no MW in a year, but Cost ofentry declines to such a degree that said Block could install in subsequent year, Resource Potential is set at ½ of Starting Potential (i.e., Resource Potential in 2017) for installs in the subsequent.

Path A Large: Competitive Solicitation, Modeling Assumptions

- Solicitations modeled to take place every Quarter.
- Base Quarterly Solicitation Targets equal to ¼ of Annual Sector Targets.
- "Price is Right" Type Solicitation Modeling: Each Quarter, Production Blocks are modeled to be successful until the cumulative MW including the next potential successful marginal Production Block's Resource Capacity is greater than Solicitation Targets (i.e. closest without going over).
    - This means that each solicitation, some % of the MW Target is not fulfilled (unless by chance, Cumulative MW installed for the Marginal Production Block exactly equals the Target);
    - The % of MW target not hit is rolled to the next solicitation as a Remainder.
- Further, a **10% Failure Rate** (i.e. 10% of selected projects fail to reach commercial operation) is assumed; all successful Production Blocks are prorated by 10%, and "Failed MW" are rolled into a solicitation exactly one year in the future.
- Quarterly Targets are equal to: Base Quarterly Target + Remainder & Failed MW carried to that solicitation.
- The combination of Remainder MW and Failure Rates means that MW solicited in each quarterly solicitation increase at a higher rate than initially set Annual Target percentages, and, likewise, that less MW is installed in early years than targeted.
- No Failure Rate assumed in 2025, so that the Model can hit Program Targets.

Path A Large: Competitive Solicitation, Incentive Assumptions

- Assumed that Production Blocks cannot bid below the value of Electric/NM Rates received from their utility.
- Production Block modeled to bid a Combined Incentive Bid (equal to their needed PBI Incentive + Levelized 15-yr Value of Electric/NM Rates).
- It is assumed that Bidders will strategically bid in such a way as to converge their bids with the marginal bid; thus, in calculating incentives for C/B Analysis, the **calculated Combined Incentive Bid for a successful bidder is equal to the average of the Marginal Bid and the bidders Cost of Entry Bid**.
- PBI Incentive are calculated for C/B analysis by netting out the 15-yr Levelized Value of Electric/NM Rates from the Combined Incentive Bid.

Path A & B: DBI/PBI, Modeling Assumptions

- Modeled on a Quarterly basis;
- Initial DBI Block sizes set equal to ½ of 2017 Annual Targets;
- All Production Blocks across a Sector compete for the same DBI/PBI Block (however, DBI/PBI incentives vary by utility)
- Model only allows at most two (2) DBI Blocks to fill per quarter;
  - Therefore, total MW that can be installed in a quarter is equal to: total MW remaining in a DBI Block that was partially filled in the previous quarter + the DBI Block Size.
- Model functions by looking at the PBI Incentive Level that each utility is offering, and allowing a Production Block to install in that quarter if PBI is greater than Cost of Entry.

Path A& B: DBI/PBI, Incentive Assumptions

- Initial DBI/PBI Incentives are set for utility in each Sector, in reference to an Initial Benchmark "Combined Incentive."
- Initial Combined Incentives are calculated by:
  - Selecting a Benchmark Production Block (e.g., Commercial Solar Canopy-NGIRD-Third Party Owned);
  - Determining the Levelized 15-yr Value of Electric/NM Rates for the Benchmark Production Block;
  - Adding this Levelized 15-yr Rate Value to an Optimized DBI/PBI Starting $/MWh incentive (Optimization process discussed in subsequent slide);
- DBI/PBI incentives are then set for each utility by netting out the Levelized 15-yr Rate Value specific to the comparable Benchmark Production Block in that utility from the Combined Incentive.
  - E.g., if the Benchmark Production Block is Commercial Solar Canopy-NGIRD-Third Party Owned, the Levelized 15-yr Rate Value for Commercial Solar Canopy-WMECO-Third Party Owned is netted from the Combined Incentive to determine the initial WMECO DBI/PBI .
- All Utility DBI/PBI incentives in a sector decline by the same specific fixed $/MWh rate:
  - Fixed $/MWh decline used because a % based decline will never "zero-out"
  - Further, analysis showed that program volatility can be better managed with $/MWh than % based DBI/PBI declines.

Path B: DBI/EPBI Modeling/Incentive Assumptions

- Path B DBI/EPBI was modeled using exactly the same process as DBI/PBI, with the exception that DBI/PBI and Initial Combined Incentives were calculated in $/kW rather than $/MWh; **and**

- The Levelized 15-yr Value of Electric/NM Rates was calculated by discounting the 15-year calculated PBI using the Production Block's weighted average cost of capital (WACC) as a discount rate, rather than Target Equity IRR.

Path A & B: DBI/PBI & EPBI Incentive Optimization Process

- **Setting DBI/PBI Incentives involves a balancing of several factors:** 2017 install Rates, and level of industry constriction versus 2016; level, constant growth versus volatile growth; setting minimum incentive levels to achieve 2025 targets at lowest cost.
- Because of this, Initial DBI/PBI/EPBI incentives (and decline rates) were set to meet the following policy objectives as closely as possible:
  - 2017 annual installs in each sector being as close to 2017 targets as possible;
  - Sectors hitting their targets (and the Program Hitting 2500 MW) as close to QT. 4, 2025 as possible;
  - Minimize volatility in annual installs from 2017-2025;
  - Incentive levels as low as possible, while still meeting the above objectives, to minimize costs;
- There is more than one solution set (i.e. Initial DBI/PBI or EPBI Incentive Levels **and** $/MWh or $/kW decline rate) that can meet the above parameters;
  - However, more than 100 combinations were tested for each Sector (under each Policy Path and Scenario), and any parallel solution set would be, at best, only marginally better.
- As Path A, Large does not use an open-enrollment system, and incentives are set by bidding rather than centrally planned, no optimization process was necessary.

J. CALCULATION OF OTHER COST & BENEFIT COMPONENTS

MISC. OTHER ASSUMPTIONS

‘Parametric Analysis’ Components

- Where data availability is limited or estimate would require extensive analysis infeasible within scope/timeline, we will make a parametric assumption
  - Example: “x% of cost item retained in-state”
- Consulting team will make an ‘anchor’ estimate
  - Based on brief literature, review, TF member input, or team judgment.
- When parametric assumption is applied to a model result (i.e. in $ or $/yr), a 10% sensitivity is possible.
  - Example: if anchor parameter is 50%, result will also be calculated as 60%
  - The sensitivity to changes of 10% from the key assumption is easily scaled to give magnitude of sensitivity over a broad range
- When parametric assumption is applied as an input to a complex model, analysis of sensitivities are beyond scope.

Parametric Values Assumptions:
Base Case Values used for All Presented Results; Sensitivity #s used for Sensitivity Analyses

		Parameter	Selected Parameter	Selected Value	Base	Sensitivity	Description
System Installed Costs	CB1.1	A	Base	42%	42%	52.0%*	% of System Installed Cost Expenditures Retained In-State
Ongoing O&M + Insurance Costs	CB1.2	A	Base	64%	64%	74.0%*	% of Ongoing O&M & Insurance Cost Expenditures Retained In-State
ROI (Aggregate Return to Debt & Equity)	CB1.5	A	Base	30%	30%	40.0%*	% of Return to Debt & Equity Investors Retained In-State
Federal Incentives (ITC)	CB1.7a	A	Base	15%	15%	25.0%*	% of Federal ITC retained in-state (assume same as CB1.1-A)
Avoided Generation Capacity Costs	CB5.3	A	Base	28.8%	28.8%	38.8%*	Fraction of solar PV monetizing its value in the FCM; [56 MW of DR PV with CSOs + 85 MW of PV with included on the load side for the FCA9 ICR calculation] divided by 489 MW total forecast = 28.8%
Avoided Trans. Investment - Remote Wind	CB6.1	A	Base	$ 27.50	$ 27.50	$ 35.00	$/MWh Incremental TX cost for Northern New England wind avoided by supplanting need for Class I wind with MA Solar PV
Avoided Trans. Investment - Remote Wind	CB6.1	B	Base	55%	55%	80%	% of incremental TX cost for Northern New England Wind assumed allocated to load
Avoided Transmission Investment - Local	CB6.2	A	Base	30%	30.0%	40%*	% of load on feeders with growth
Avoided Transmission Investment - Local	CB6.2	B	Base	80%	80.0%	90%*	Scalar Adjustment Factor for technical issues (reduces gross value to account for a variety of technical issues preventing solar PV from avoiding investment deferral
Avoided Distribution Investment	CB6.3	A	Base	30%	30.0%	40%*	% of load on feeders with growth
Avoided Distribution Investment	CB6.3	B	Base	50%	50.0%	60%*	Scalar Adjustment Factor for technical issues (reduces gross value to account for a variety of technical issues preventing solar PV from avoiding investment deferral
Avoided Distribution Investment	CB6.3	C	Base	50%	50.0%	60%*	Scalar derating factor applied to distribution level energy losses avoided by solar PV, to reflect that the D investment is at varying locations often close to load, while aggregate D losses measured at D system injection; also reflects that some of literature review sources were already loss adjusted

System Installed Costs Retained in State (Inputs)

	Residential			Small Commercial (Roof-top)			Small Commercial (Ground-mount)		
	Cost ($/kW)	% of Total Cost*	% Local Share	Cost ($/kW)	% of Total Cost*	% Local Share	Cost ($/kW)	% of Total Cost*	% Local Share
System Installation Costs									
Installation Costs									
Materials & Equipment									
Mounting (rails, clamps, fittings, etc.)	$168.10	3.4%	50%	$165.52	3.4%	40%	$90.71	3.4%	25%
Modules	$1,637.13	33.4%	0%	$1,612.05	33.4%	0%	$883.43	33.4%	0%
Electrical (wire, connectors, breakers, etc.)	$108.16	2.2%	50%	$106.51	2.2%	40%	$58.37	2.2%	25%
Inverter	$243.37	5.0%	50%	$239.64	5.0%	40%	$131.33	5.0%	25%
Labor									
Installation	$350.68	7.2%	95%	$345.30	7.2%	90%	$189.23	7.2%	70%
Other Costs									
Permitting	$651.64	13.3%	95%	$641.66	13.3%	95%	$351.64	13.3%	95%
Other Costs	$293.02	6.0%	63%	$288.53	6.0%	56%	$158.12	6.0%	56%
Business Overhead	$1,446.19	29.5%	63%	$1,424.04	29.5%	56%	$780.40	29.5%	56%
Sales Tax (Materials & Equipment Purchases)	$0.00	0%	0%	$0.00	0%	0%	$0.00	0%	0%
Total	$4,896.00	100.0%	47%	$4,821.00	100.0%	43%	$2,642.00	100.0%	40%

- % of Total Cost comes from NREL JEDI model default data for Massachusetts
- % Local Share developed from DOER 2013 Task 4 Consultant Report: “*Comparative Regional Economic Impacts of Solar Ownership/Financing Alternatives*” and supplemental research
- Used approx. weighted average of 42%. Based on analysis of annual weighted avg. blend of res, commercial rooftop and ground mount over time. #s were not highly sensitive to evolving blend, varying between 41% and 43%.

System O&M Costs Retained in State (Inputs)

	Residential			Small Commercial (Roof-top)			Small Commercial (Ground-mount)		
	Cost ($/kW)	% of Total Cost*	% Local Share	Cost ($/kW)	% of Total Cost*	% Local Share	Cost ($/kW)	% of Total Cost*	% Local Share
Ongoing O&M Costs									
Labor									
Technicians	$11.46	54.6%	100%	$11.46	54.6%	90%	$8.73	54.6%	90%
Materials and Services									
Materials & Equipment	$9.55	45.5%	50%	$9.55	45.5%	40%	$7.28	45.5%	25%
Services	$0.00	0.0%	100%	$0.00	0.0%	56%	$0.00	0.0%	58%
Sales Tax (Materials & Equipment Purchases)	$0.00	0%	0%	$0.00	0%	0%	$0.00	0%	0%
Total	$21.00	100.0%	77%	$21.00	100.0%	67%	$16.00	100.0%	60%

- % of Total Cost comes from NREL JEDI model default data for Massachusetts
- % Local Share developed from DOER 2013 Task 4 Consultant Report: "*Comparative Regional Economic Impacts of Solar Ownership/Financing Alternatives*" and supplemental research
- Used 64%. Based on analysis of annual weighted avg. blend of res, commercial rooftop and ground mount over time. #s were not highly sensitive to evolving blend, varying between 63% and 68%

Wholesale Market Price Impacts

- Wholesale energy market price effects are not in perpetuity
  - Effect of installation in year X assumed to dissipate based on energy DRIPE 2014 dissipation schedule from AESC 2013
- Wholesale energy market price effects only impact purchases from spot market or short-term transactions influenced by spot market. Energy transacted under multi-year energy hedges are not impacted
  - Effect of installation in year X assumed to phase in according to 2014 energy DRIPE hedged energy schedule from AESC 2013

Table 4. Energy Market Effect Adjustments

Production Year(s)	Dissipation %	Load Subject to Solar Market Effects
1	13%	18%
2	18%	72%
3	21%	81%
4	28%	90%
5	34%	90%
6	47%	90%
7	59%	91%
8	70%	91%
9	81%	91%
10	91%	92%
11-end of study period	100%	92%

Estimating EDC Incremental Admin Costs for Policy Paths A & B

- Assumed all EDC labor costs were incremental (whether or not EDC would have sought additional rate recover for these types of costs as core vs. incremental staff in the past)
- Cost estimates by SEA based SEA interpretation of interviews with EDC procurement staff
  - Results not reviewed or endorsed by EDCs
- Categories:
  - One-tome Setup Costs, New Policies (Staffing: EDC staff, legal); systems; tariff design, approvals, training)
    - Small: 2 FTEs, split 75% in 2016, 25% in 2017
    - Large: 2 FTEs, split 75% in 2016, 25% in 2017
    - Same for Paths A & B
  - Solicitation Costs (thru 2025) – Policy Path A (large) only
    - Including core staff, assume 25% of $500K. Assume this is per solicitation round based on LREC/ZREC 1 round/yr. If move to 3 rounds per year, assume some scale economies ==> assume 2.5x the cost of one solicitation
    - Escalate at 4%/yr
  - Ongoing Admin. Costs from 2017 on (Ongoing admin costs (meter reading, hand holding, accounting, payments, recovery filings… (applying from startup to completion, thru 2050)
    - Assume 1.25 FTEs initially for small and 2 for large
    - Costs assumed to escalate annually by 20% of increase in target procurement volume to reflect some increase in labor costs with increased transcaction volume but strong scale economies
  - Transaction Costs for reselling RECs on a $/MWh (Broker Fees Associated with the Sale of RECs if performed through a broker)
    - Assume $1/MWh, applying to 50% of all distribution load (reflecting 1 – today's basic service %)
    - Note: Under SREC, Assume EDCs only purchase for own needs, don't need to resell; SREC Policy 'transactional friction" modeled as part of SREC market mdoel as $2.50 per SREC purchased by LSEs outside of small quantity of direct hedge transactions entered into with generators up-front to support financing
    - Note: corresponding market participant costs for SREC policies embedded in SREC market model, captured there
- Utility staff Average FTE cost used in model: $162,500 fully-loaded, based on input from 2 EDCs

Solar Policy Incr. Admin. & Transaction Costs	CB2.4

Policy Path A additional developer overhead due to the need to sell both winning and losing bids:

Cust Aq. Cost * (sales/contract under solicitation – sale/contract under open program)

Commercial PV Customer Acquisition Cost ($/kW) (from NREL studies)			
Project Type	Med/Small	Med/Small	Large
Project Size	Not Specified	<250 kW	>250kW
Note	2010 Median	2012 Median	2012 Median
System Design	$0.10	$0.04	$0.01
Marketing/Advertising	$0.01	-	-
Other	$0.08	$0.09	$0.02
Total	$0.19	$0.13	$0.03

Assume $0.05/W as approx. fleet wtd. Avg.

*

Assume 2.5 bids/winning bid

➔ $0.05/W*(2.5-1) = $0.075/W

		# of Projects								
		Round 1			Round 2			Round 3		
		Total	Accepted	Ratio	Total	Accepted	Ratio	Total	Accepted	Ratio
Large ZREC	CL&P	140	21	6.67	52	19	2.74	78	32	2.44
	UI	22	6	3.67	12	4	3.00	8	8	1.00
	Total	162	27	6.00	64	23	2.78	86	40	2.15
Medium ZREC	CL&P	113	47	2.40	157	70	2.24	113	95	1.19
	UI	37	13	2.85	35	24	1.46	50	27	1.85
	Total	150	60	2.50	192	94	2.04	163	122	1.34
		Capacity (MW)								
		Round 1			Round 2			Round 3		
		Total	Accepted	Ratio	Total	Accepted	Ratio	Total	Accepted	Ratio
Large ZREC	CL&P	94.3	12.2	7.73	34.2	12.2	2.80	65.3	27.6	2.37
	UI	12.1	2.6	4.65	7.2	2.4	3.00	5.9	5.9	1.00
	Total	106.4	14.8	7.19	41.4	14.6	2.84	71.2	33.5	2.13
Medium ZREC	CL&P	21.5	8.8	2.44	30.2	14.2	2.13	24.5	18.1	1.35
	UI	7.1	2.5	2.84	6.4	4.4	1.45	9.7	5.1	1.90
	Total	28.6	11.3	2.53	36.6	18.6	1.97	34.2	23.2	1.47

MA Income Taxes	CB1.6.b	Federal Income Taxes	CB1.7b

Estimate of Taxable Discounts & Lease Revenue

Used for estimating income tax impact of these benefits on NOPs

% of Discount Payments Assumed Taxable

Scenario	2015	2020	2025
SREC Capped-1600	35%	80%	80%
SREC Uncapped-1600	35%	80%	80%
SREC Capped-2500	35%	80%	80%
Policy A Capped-1600	35%	80%	80%
Policy A Capped-2500	35%	80%	80%
Policy A Uncapped-1600	35%	80%	80%
Policy A Uncapped-2500	35%	35%	35%
Policy B Capped-1600	35%	80%	80%
Policy B Capped-2500	35%	80%	80%
Policy B Uncapped-1600	35%	80%	80%
Policy B Uncapped-2500	35%	35%	35%

% of Lease Payments Assumed Taxable

Scenario	2015	2020	2025
SREC Capped-1600	75%	80%	80%
SREC Uncapped-1600	75%	80%	80%
SREC Capped-2500	75%	80%	80%
Policy A Capped-1600	75%	80%	80%
Policy A Capped-2500	75%	80%	80%
Policy A Uncapped-1600	75%	80%	80%
Policy A Uncapped-2500	75%	75%	75%
Policy B Capped-1600	75%	80%	80%
Policy B Capped-2500	75%	80%	80%
Policy B Uncapped-1600	75%	80%	80%
Policy B Uncapped-2500	75%	75%	75%

Assumptions made based on SEA side-analysis to estimate evolving mix of taxable and non-taxable lease and PPA/NMC off-takers