An Analysis of the Potential Cost of Increasing MA RPS Targets and RE Procurements

Sustainable Energy Advantage, LLC

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Purpose & Scope

- The purpose of this study is to analyze the potential cost of the current suite of MA (legislative) energy proposals to MA ratepayers. In particular, this analysis focuses on:
  - (a) RPS target increases,
  - (b) long-term contracting for offshore wind resources,
  - (c) long-term contracting for Class 1 resources, and
  - (d) long-term contracting for hydro resources.
- The results of this study represent an estimate of the *incremental* cost to MA ratepayers relative to current RPS and contracting obligations.

Summary of Approach

To fulfill this purpose and scope, Sustainable Energy Advantage:

- Relied on publically-available data sources, where available
- Developed projections of supply and demand for New England Class 1 renewables;
- Considered the impact of increases in MA RPS targets on the cost and availability of supply used to satisfy regional RPS demands;
- Calculated both spot market- and long-term contract-based REC premiums for Offshore Wind and other Class 1 resources;
- Estimated long-term hydro contract premium; and
- Estimated the incremental monthly bill impact for typical residential, commercial and industrial customers in MA based on increased targets and procurements.

Regional Analysis

This analysis recognizes that Massachusetts energy policy is implemented within the context of a broader marketplace (ISO-NE) that includes other states with similar RPS mandates. These states have overlapping eligibility criteria for renewable resources, and so they compete on the margin for adequate renewable energy supplies to meet their respective demands. This regional approach is taken into account in the analysis of supply, demand, and renewable energy credit (REC) price.

Case Definitions

	Reference Case (Business as Usual)	Proposed Policies Case
MA RPS Target Increases	Status Quo	MA annual RPS target increase changes to 2%/year starting in 2017
Additional Class 1 Procurements	None beyond existing authority	5.7 TWh/yr (30% of 18.9 TWh)*
Large Hydro Procurements	None	13.2 TWh/yr (70% of 18.9 TWh)*
Offshore Wind Procurements	None	2,000 MW*

** See "Key Assumptions" section for deployment timing.*

Approach: Overview

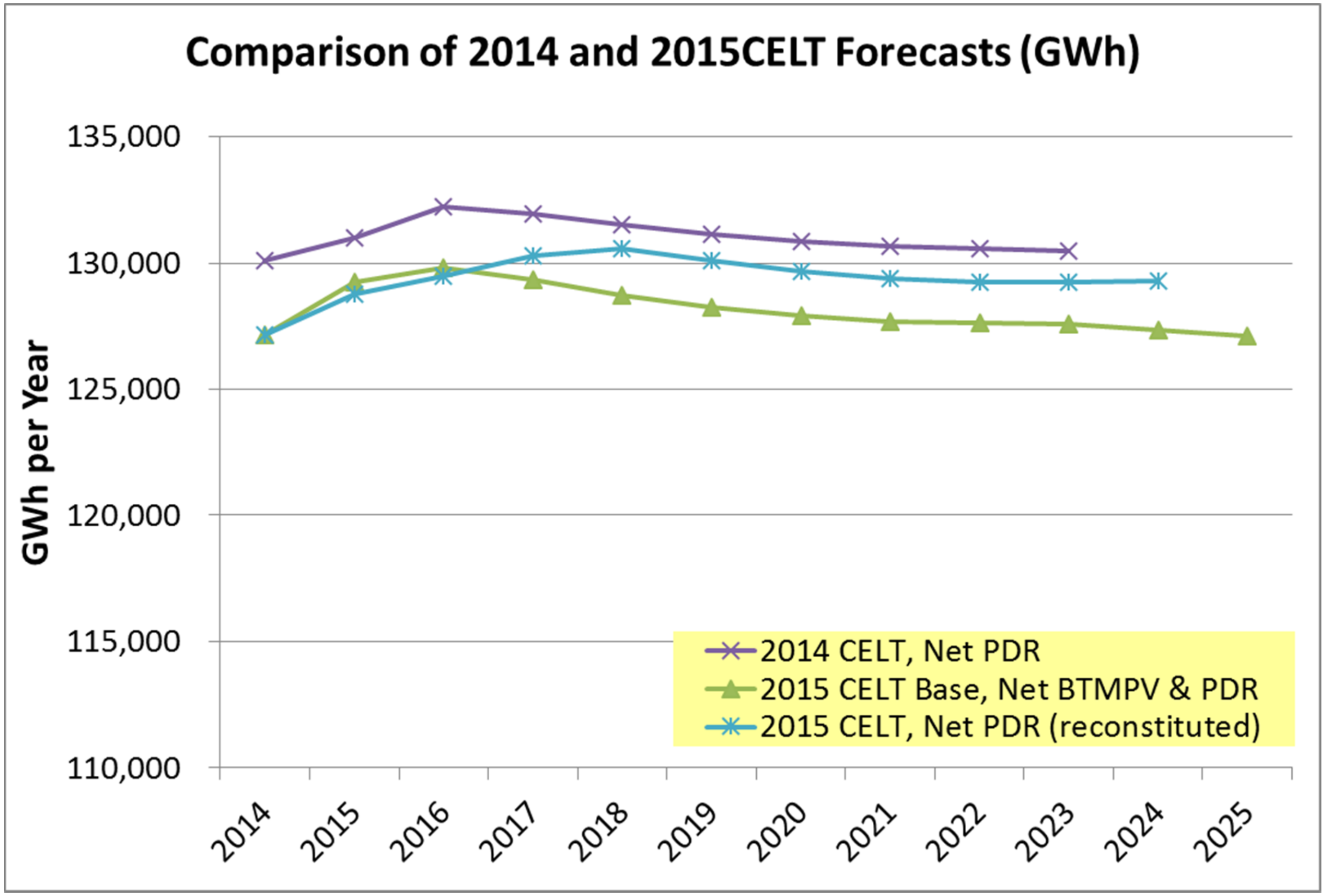
- Estimate supply of, and demand for, regional Class 1 RPS-eligible renewables under a reference case and an alternative policies case.
- Use supply/demand analysis to inform a spot REC price forecast, by case.
- Apply a resource potential/supply curve analysis to estimate the cost of Class 1 resources deployed to meet both contract and spot market demand.
- Estimate cost of energy and REC premium for long-term contracted offshore wind and hydro supply.
- Estimate market value of production and resulting REC premium for both spot and long-term contracts.
- Apply dispatch model to estimate natural gas usage and CO_2 emissions.
- Estimate typical customer usage and associated cost of RPS compliance, by case.
- Result Metrics:
  - Monthly bill impact for typical residential, commercial & industrial customers
  - Annual change in Natural Gas usage and CO_2 emissions

Approach: Cost Estimation

- Spot REC prices
  - Cost = Based on supply/demand balance, and banking
  - Assume capital structure and cost consistent with absence of long-term contracts
- Additional Class I procurements
  - Cost = weighted average of LCOE of procured supply tranches (adjusted upwards by 50% of the difference between the block-specific premium and the premium of the marginal procured supply block)
  - This adjustment is intended to reflect the expectation that least-cost respondents will increase their bids to more closely reflect their estimation of the cost of marginal supply
- Offshore Wind procurements
  - Cost = LCOE shaped to an equivalent year-one price assuming 3.5% annual escalation
- Hydro procurements
  - Cost = Levelized premium consistent with Class I procurements *minus* REC revenue; then reshaped to year-one cost estimate, escalating with same shape as LT market value of production

ISO-NE Load Forecast (GWh)

Analysis Employs 2015 CELT, Net BTM PV & PDR



BTM PV = Behind the Meter Photovoltaics; PDR = Passive Demand Resources

Dispatch Modeling

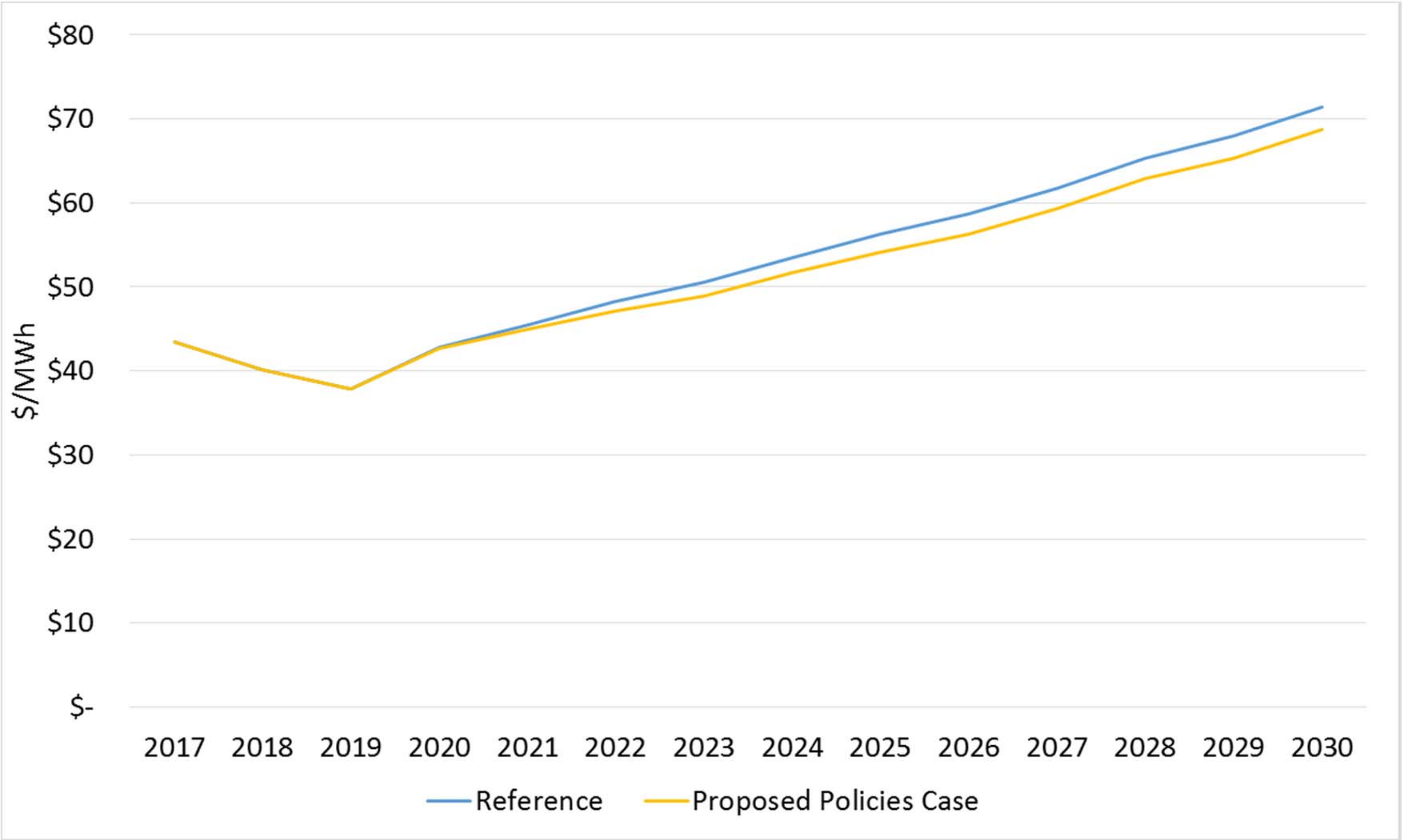
A plant-specific dispatch model was used to:

1. Derive electricity price forecast (next slide)
   i. Net imports/exports for adjacent control areas considered
   ii. Included estimated volume and timing additions and retirements
2. Determine the composition of total supply serving ISO-NE
   i. Under business as usual and proposed policies case
3. Estimate total CO_2, SO_2 and NO_x emissions.
   i. To derive difference between cases

Iterative analysis:

- Sustainable Energy Advantage provided estimates of incremental renewable energy deployment (including imports) to Daymark Energy Advisors. Daymark produced LMP forecasts, which were used as one component of SEA's estimation of spot market and long-term contract REC premiums.

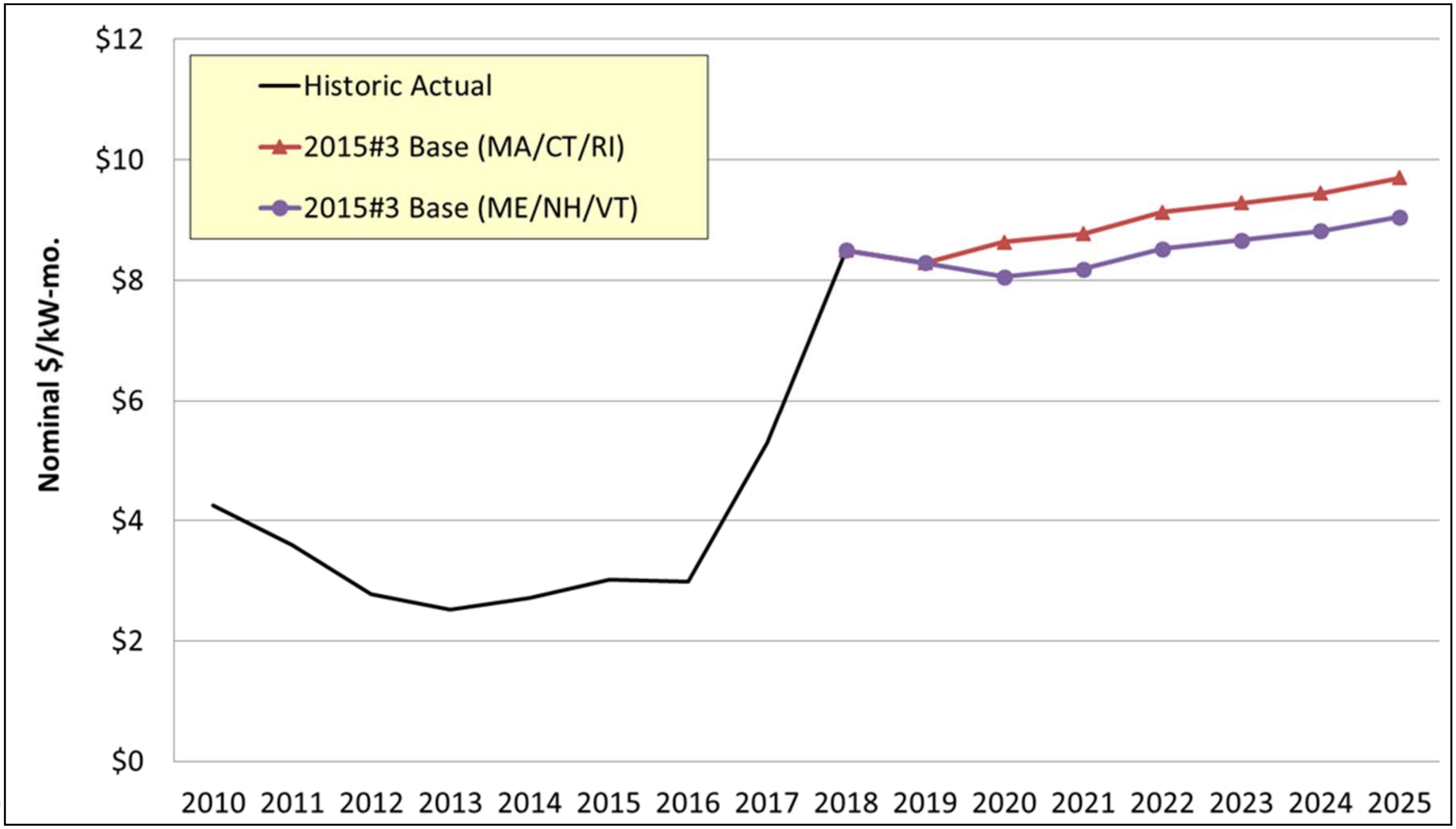
Energy Price Forecast* ($/MWh)



** NEPOOL Hub All-Hours LMP Forecast, including impact of potential future carbon regulation.*

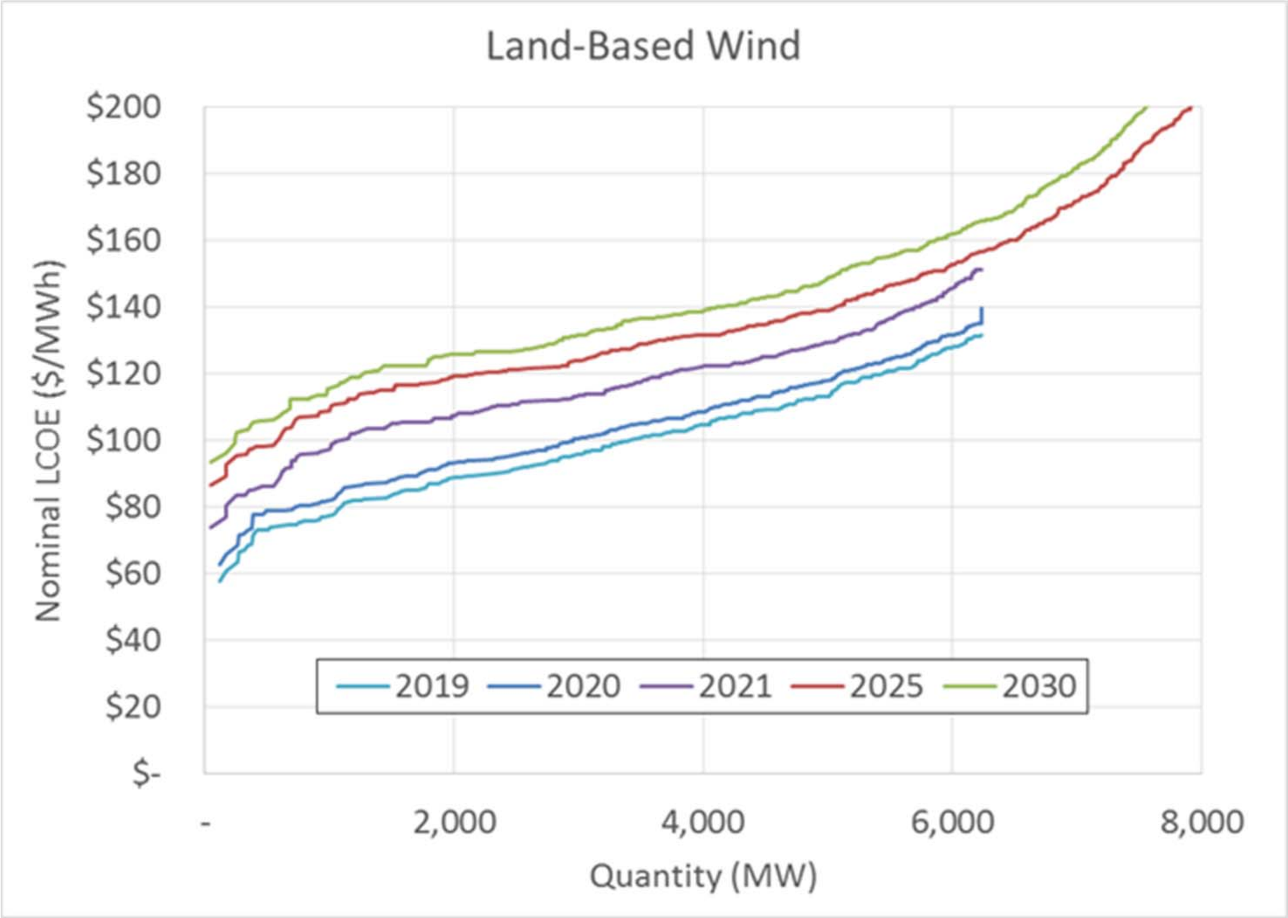
Source: Daymark Energy Advisors

Capacity Market Forecast ($/kW-mo)



Source: RGGI & Synapse Energy Economics, April 2015

Supply Curve Sample, Land-Based Wind

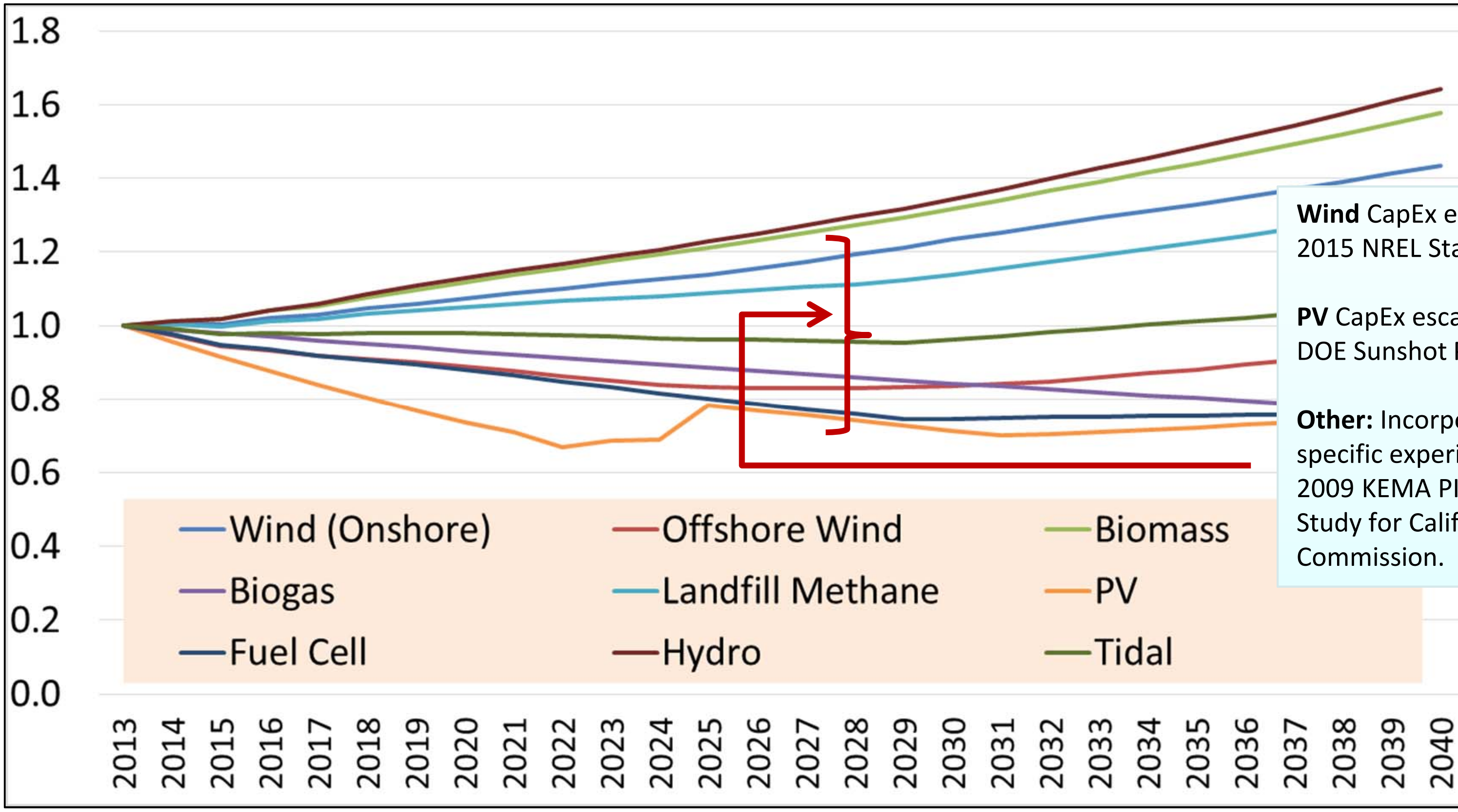


The figure above shows the quantity (MW) and cost ($/MWh LCOE) of New England land-based wind available to meet demand in 2019-2021 and in 'outer years' 2025 and 2030

Carbon Compliance

- Current carbon cap & trade or other policy to price carbon will increase locational marginal energy prices by increasing the operating costs of marginal (price-setting) fossil fuel generators
- The higher the allowance price, the lower the REC Premium required to clear the market in equilibrium (and vice versa)
- For a buyer, increased risk if buy energy and RECs separately; buying together (bundled) hedges the risk
- Calculate *incremental* impact above current GHG policy based on NEPOOL marginal carbon intensity ➔ Model as carbon price adder to energy price forecast
- Base carbon price forecast used = RGGI 91 Cap transitions to Average of 2015 Synapse carbon price forecast (Low) and RGGI 91 cap in 2024 and thereafter

Renewable Energy CAPEX Trajectories

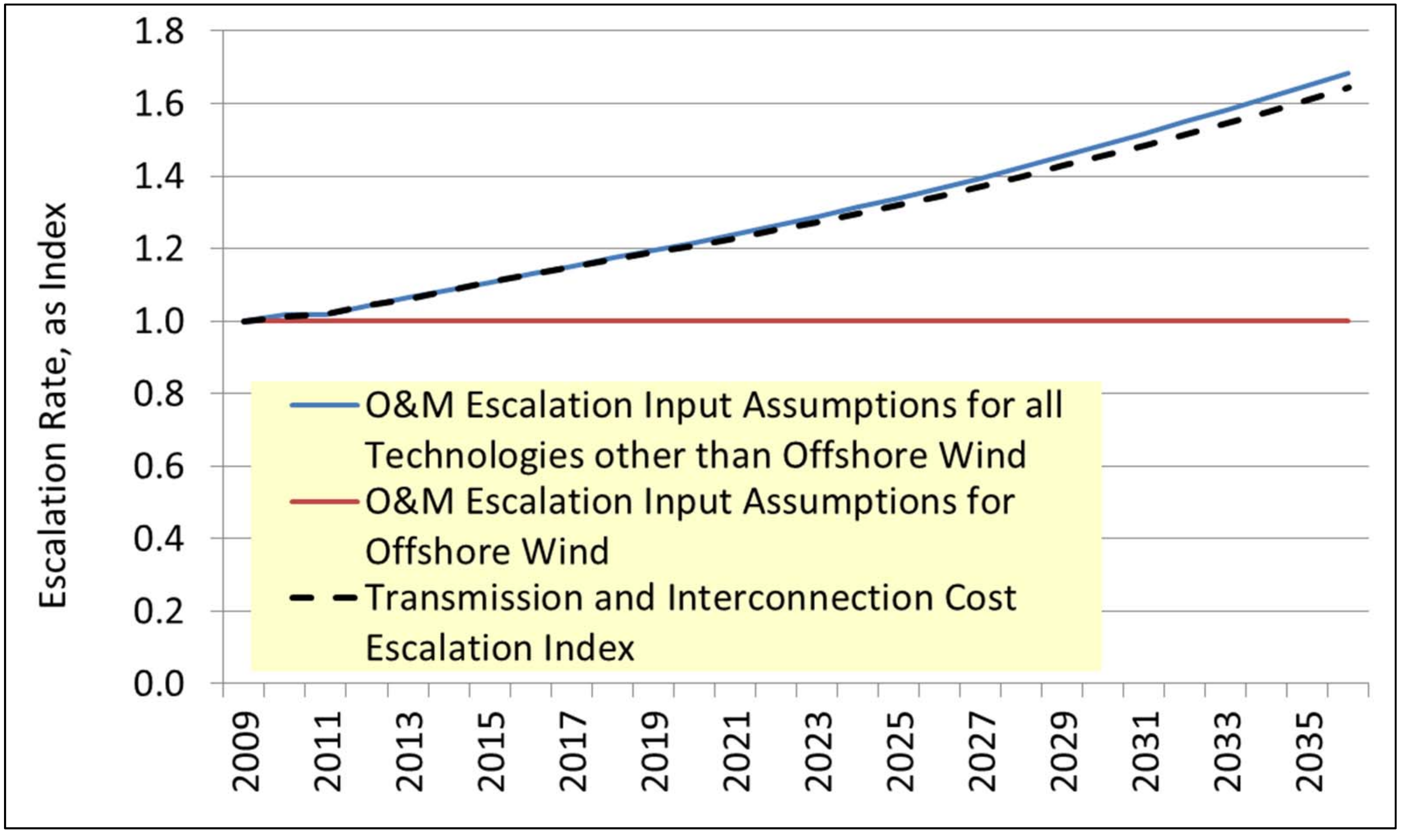


Wind CapEx escalation updated per 2015 NREL Standard Scenarios

PV CapEx escalation updated per 2014 DOE Sunshot Pricing Trends

Other: Incorporates Technology-specific experience curves from Aug. 2009 KEMA PIER Cost of Generation Study for California Energy Commission.

O&M & Transmission Escalation Index Assumptions
(Escalation of Nominal $)



Capacity Factor Estimates

<table>
<tr><th>Technology</th><th>2025 (min/max)</th><th>2030 (min/max)</th></tr>
<tr><td>Land-Based Wind*</td><td>26% / 46%</td><td>27% / 47%</td></tr>
<tr><td>Offshore Wind</td><td>45.3%</td><td>46.7%</td></tr>
<tr><td>Biomass Co-Firing</td><td colspan="2">80%</td></tr>
<tr><td>Biomass Stoker</td><td colspan="2">89%</td></tr>
<tr><td>Biomass Repower</td><td colspan="2">84%</td></tr>
<tr><td>Biogas</td><td colspan="2">82%</td></tr>
<tr><td>Hydro Upgrades</td><td colspan="2">21% / 49%</td></tr>
<tr><td>LFG</td><td colspan="2">79%</td></tr>
<tr><td>Utility-Scale Solar</td><td colspan="2">12.7% / 15.2%</td></tr>
<tr><td>Tidal</td><td colspan="2">40%</td></tr>
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**Land-Based Wind CFs are site specific, resulting in a large range; CF estimates shown are sample of range of cleared LBW supply blocks*

Source: Sustainable Energy Analysis research & analysis

Long-Term Procurements: Class 1

Cumulative aMW	2019	2020	2021	2022	2023	2024	2025	2026
Reference	-	-	-	-	-	-	-	-
Proposed Policies Case	-	65	129	227	324	421	518	647

Cumulative GWh	2019	2020	2021	2022	2023	2024	2025	2026
Reference	-	-	-	-	-	-	-	-
Proposed Policies Case	-	567	1,134	1,984	2,834	3,684	4,534	5,668

Modeled as single procurement phased in over time to represent combined impact of several staggered procurements, attrition of some projects, and their replacement in subsequent procurements.

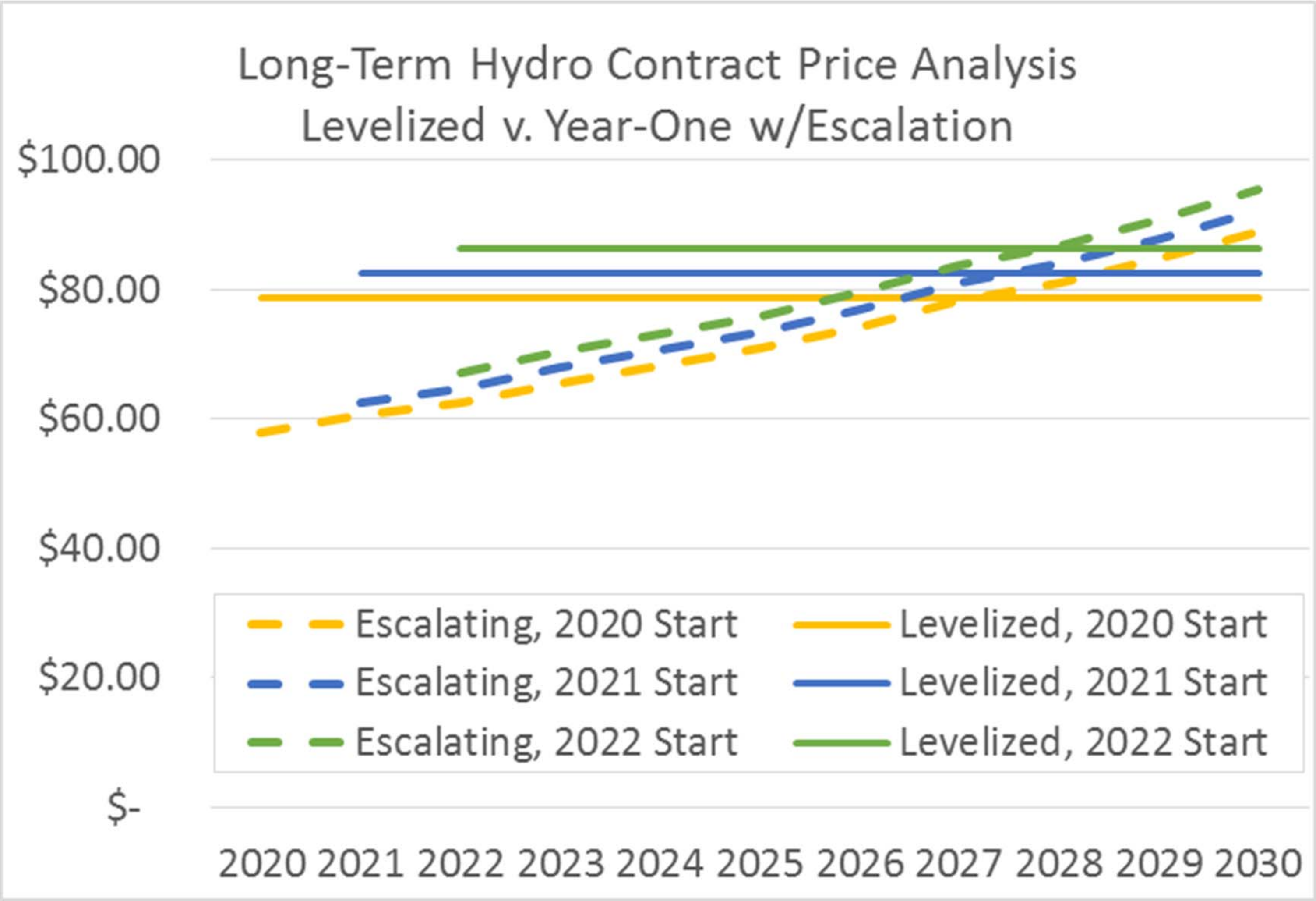
Long-Term Procurements: Hydro

Cumulative MW	2019	2020	2021	2022	2023	2024	2025
Reference	-	-	-	-	-	-	-
Proposed Policies Case	-	-	529	1,059	1,590	1,590	1,590

Cumulative GWh	2019	2020	2021	2022	2023	2024	2025
Reference	-	-	-	-	-	-	-
Proposed Policies Case	-	-	4,406	8,811	13,230	13,230	13,230

Wtd-Avg. LTC Price $/MWh	2019	2020	2021	2022	2023	2024	2025
Reference	-	-	-	-	-	-	-
Proposed Policies Case	-	-	$58	$62	$65	$68	$71

Hydro Procurement Cost Assumptions: Proposed Policies Case

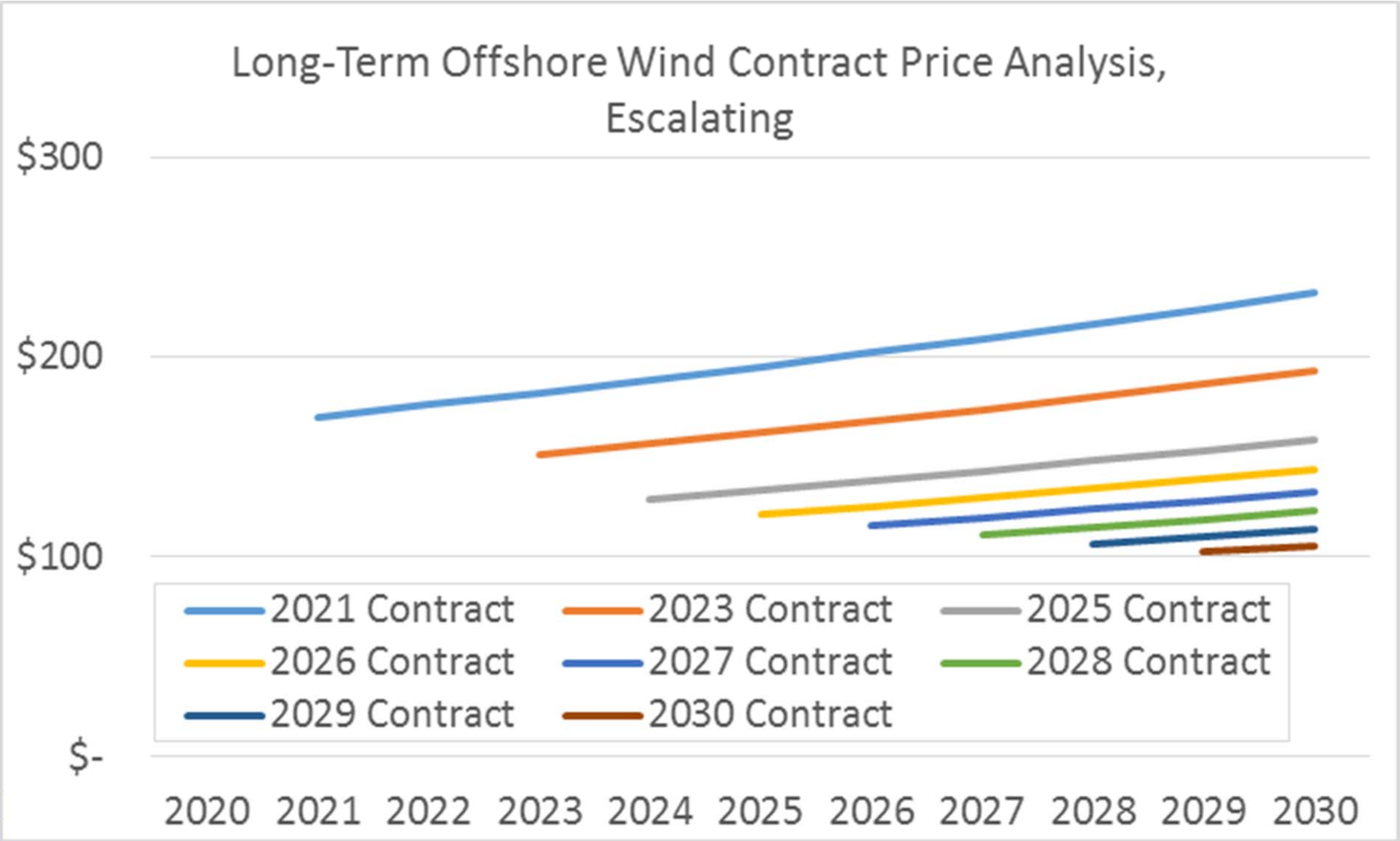


Long-Term Procurements: OSW

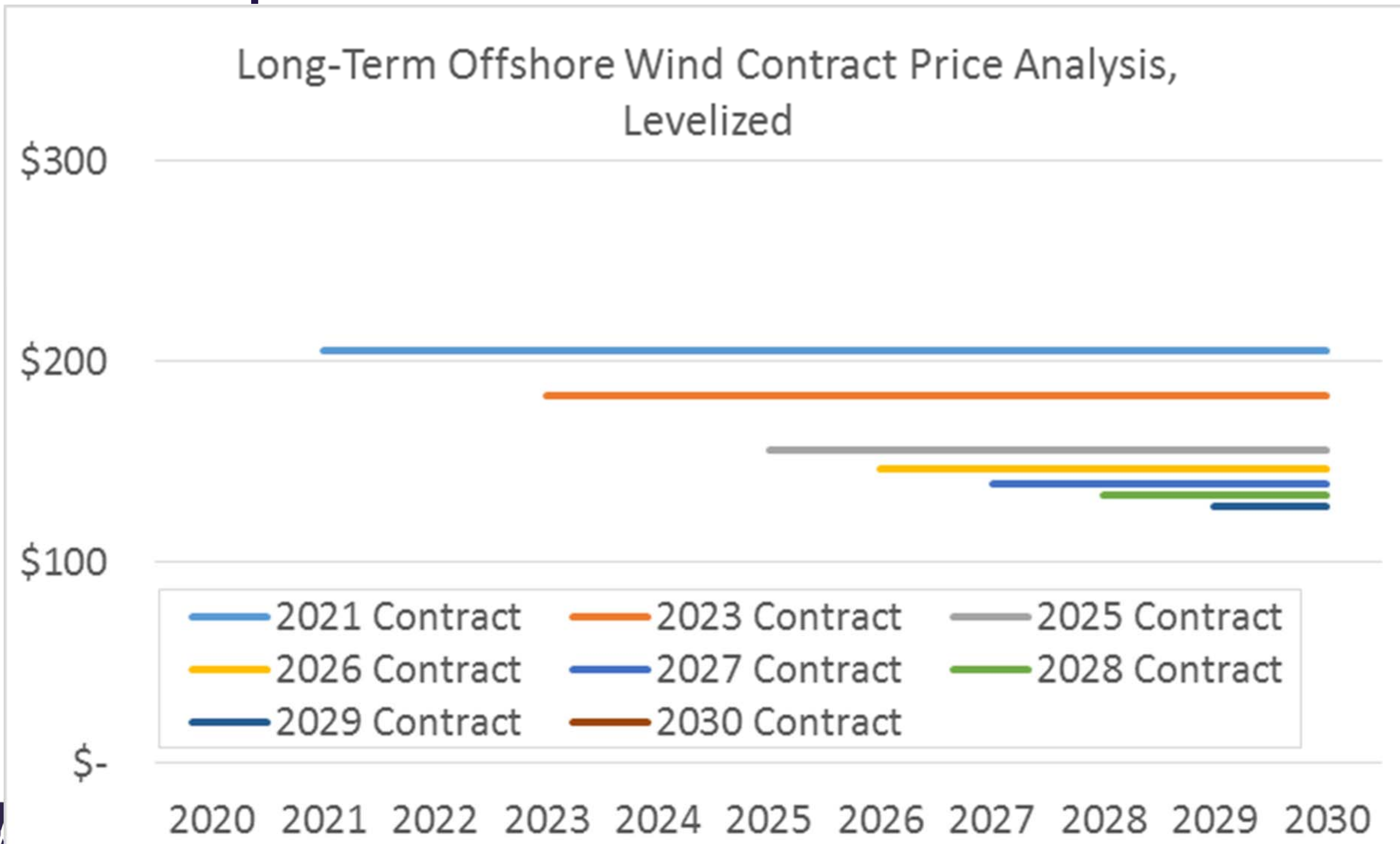
Cumulative MW (mid-year)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Reference	-	-	-	-	-	-	-	-	-	-
Proposed Policies Case	200	200	400	400	650	900	1,150	1,400	1,700	2,000

Cumulative GWh	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Reference	-	-	-	-	-	-	-	-	-	-
Proposed Policies Case	387	774	1,166	1,558	2,054	3,049	4,051	5,058	6,174	7,398

OSW Procurement Cost Assumptions: Proposed Policies Case, Escalating



OSW Procurement Cost Assumptions Proposed Policies Case, Levelized



Offshore Wind Assumptions

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Capacity Factor	44.2%	44.5%	44.7%	45.0%	45.3%	45.6%	45.9%	46.2%	46.4%	46.7%
CAPEX (2013 $/kW)	$5,323	$5,189	$5,055	$4,744	$4,469	$4,232	$4,030	$3,865	$3,682	$3,572
Levelized OPEX (2013 $/kW)	$246	$187	$161	$144	$133	$124	$118	$112	$107	$100
Carrying Charge (With PTC/ITC)	10.0%	9.9%	9.8%	9.5%	9.3%	9.0%	8.9%	8.7%	8.7%	8.6%
Carrying Charge (Without PTC/ITC)	9.0%	8.8%	8.7%	8.5%	8.3%	8.1%	8.0%	7.9%	7.8%	7.7%

Source: Derived from research & analysis of the University of Delaware Special Initiative on Offshore Wind and Sustainable Energy Advantage.

Cost of Representative Generators

Sample of Key Assumptions (w/ PTC & LT Contracts*)

2013$	Biomass Stoker	Wind Small (10MW) (<5 miles from Tx)	Wind Medium (60MW) (<5 miles from Tx)	Wind Large (125 MW) (<5 miles from Tx)	Offshore Wind	Utility-scale solar (20MW)
Carrying Charge (avg for all applicable blocks)	14.16%	10.62%	10.23%	10.02%	8.6% - 10.6%****	11.73%
Economic Life	20 Years	20 Years	20 Years	20 Years	20 Years	25 Years
Tax Depreciation	20Yr, 1.5DB	5Yr MACRS	5Yr MACRS	5Yr MACRS	5Yr MACRS	5Yr MACRS
Debt Cost	8.0%	6.25%	6.25%	6.25%	7.00% - 6.25%****	6.25%
Debt Term	14 Years	18 Years	18 Years	18 Years	18 Years	15 Years
Equity Cost (w/PTC)	12.00%	12.11%	11.36%	10.86%	12.75% - 10.86%****	11.50%
Debt:Equity (w/PTC)	65:35	55:45	55:45	55:45	65:35 – 72:28****	35:65
Capital Cost ($/KW) (2013$)	$4,859	$2,673	$2,365	$2,097	$5,323 - $3,572****	$1,645
Transmission/Interconnection Cost Adder ($/kW)		$193	$110	$133	$1487 - $986****	
Capacity Factor	90%	Varies**	Varies**	Varies**	44.2% - 46.7%****	13% - 15.5%***
Fixed O&M ($/KW-Yr)	$132.92	$67.59	$67.59	$67.59	$246 - $100****	$31.61
Net Heat Rate (Btu/kWh)	13,000					

Financing assumptions vary by case

****Wide range of wind speeds modeled, which evolve over time*

****Varies by state and tracker types; only modeled fixed axis systems*

*****Varies over time*

Source: SEA research & analysis

Federal Tax Incentives, All Cases

- PTC:
  - o Full face value (2.3 ¢/kWh) thru 12/31/16 for all eligible technologies
  - o Additional phase-out for wind: 80% in'17; 60% in'18; 40% in'19; 0% in '20+
  - o Eligibility (and rate) based on commencement of construction (safe harbor)
  - o ITC may be (irrevocably) elected in lieu of PTC

- Solar Business ITC:
  - o 30% thru 12/31/19; 26% in '20; 22% in '21; 10% in '22+ (0% for res.)
  - o Eligibility based on commencement of construction thru 2021 (provided that construction complete by 12/31/2023; eligibility for 10% ITC thereafter is based on "placed-in-service"

Other Modeling Assumptions (1)

- Assume NY adopts a policy to retain legacy renewables in state, but that some imports come in initially prior to adoption
- 250 MW of incremental NY imports in response to 3-state regional procurement over existing ties (with COD 1/1/2019)
- No incremental Class 1 imports from Quebec or New Brunswick
- MA Solar Policy: 3,460 MW_{dc} MA DG* PV by 2025
  - 1,860 MW_{dc} post-SREC policy
- Biomass plants operating at c.f. of < 15% for 3 consecutive years are assumed to shut down permanently
- New transmission within NE phased in 2020 – 2022
  - Portion of the cost borne by developers and portion assumed to be socialized

** MA DG assumed ≤ 6 MW*

Other Modeling Assumptions (2)

- Typical Customer Consumption

	Res.	Comm.	Ind.
Consumption @ Retail	597	5,613	57,520
Grossed up for Losses, est. @ 8%	644	6,062	62,122

  - Based on EIA Form 861 from 2014
  - Held constant for analysis period
- Price suppression:
  - RE deployment causes reduction in generation service price (offsets REC premium).
  - Zonal pricing calculated on load and customer profile wtd basis for reference and alternate case; difference between alternate and reference case is applied to monthly usage to calculate monthly benefit
  - Assumes supply hedging, with benefits dissipating over time
- Pilgrim assumed retired in May of 2018

** MA DG assumed ≤ 6 MW*

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