Capacity Market Design With Renewable Capacity

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Goals:

- Assess the impact of renewable capacity definitions on market performance.
- Seek a market design that best supports optimal investment decisions.

Industry Renewable Capacity Definitions:

Current practices in renewable capacity credit towards resource adequacy:

CPUC/CAISO: Exceedance - Capacity sustained for 70% of the month (avg 3 yrs). Capacity adder adjusts farms to system.

entso: 50th and 10th percentile for seasonal adequacy by country.

ERCOT: Wind – Average output during top 20 load hours in two zones. Solar 100% to 200 MW. (avg. 10 yrs.)

IESO: Capacity Factor – Top 5 consecutive load hours. (median 10 yrs.)

ISO-NE: Median during 610 summer peak hrs. by farm. (avg. 5 years)

MISO: Wind - ELCC of system (avg. 10 yrs.) with adjustments to farms, up or down. Solar – 276 summer pk hours. (avg. 3 yrs.)

NYISO: Capacity factor of top 368 summer peak hrs. by farm (one year)

PJM: Capacity factor of top 368 summer peak hrs. by farm (avg 3 yrs.)

Applying Definitions:

Using ERCOT system load & wind data, wind capacity is calculated using the various definitions. **Large divergences** occur when applied to the same data set.

MISO ELCC: 33% coastal, 14% west

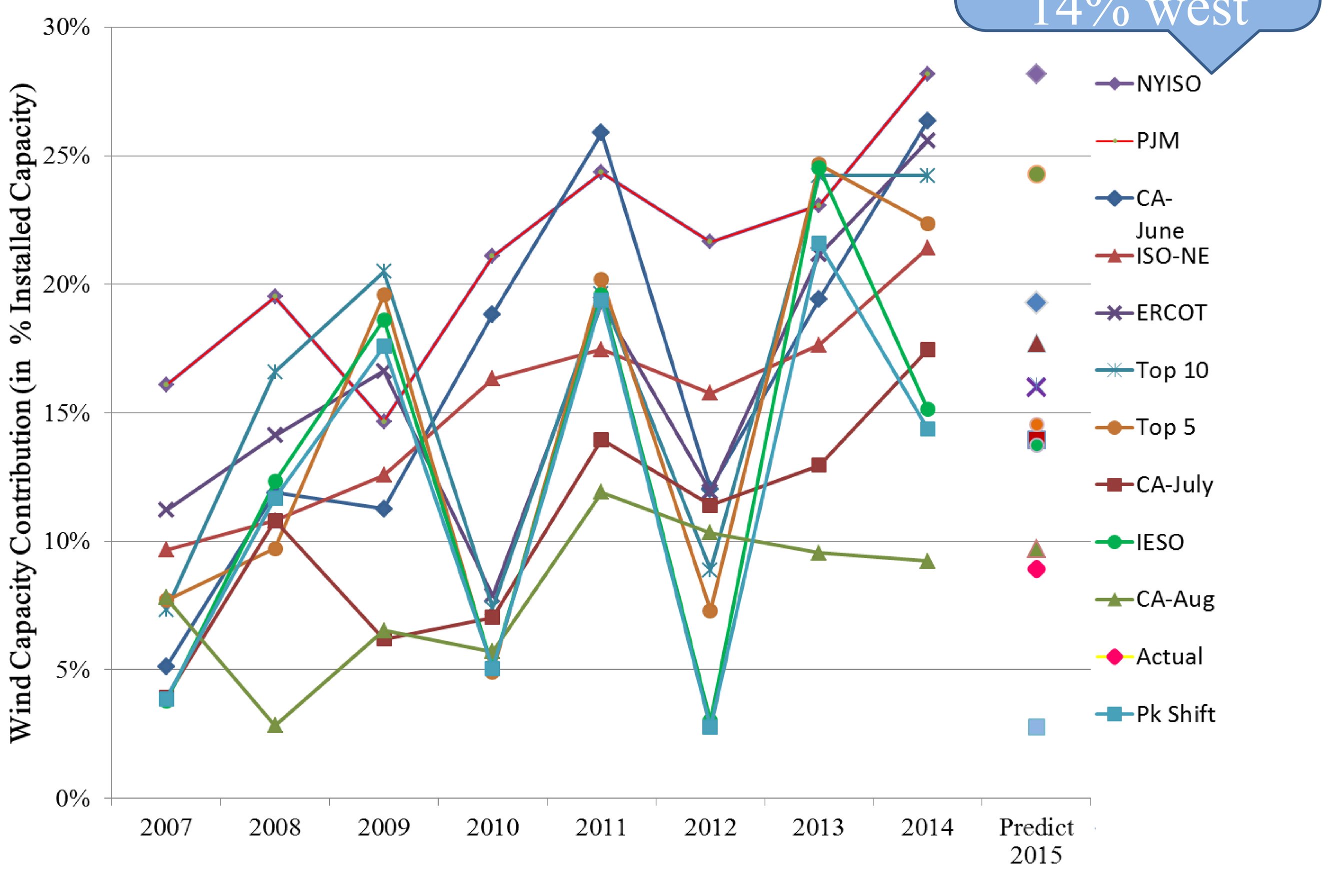


Fig. 1: Capacity Methods – Historical and Predicted ERCOT

Market Model Formulation:

Alternative capacity definitions were applied to a capacity/energy market model (10 years) using actual normalized ERCOT load, wind and solar data →equilibrium investment/generation/unserved energy:

Objective Function:

$$MIN \quad \sum_{g\in G} FC_g * x_g + \sum_{h\in H, g\in F} VC_g * e_{h,g} + \sum_{h\in H} ue_h * PC - \sum_{h\in H, g\in W} WS * ce_{h,g} \qquad (1)$$

s.t.

Market Clearing Constraints:

$$\sum_{g\in G} e_{h,g} + ue_h = DM_h \qquad \forall h\in H \qquad (2)$$

$$\sum_{g\in F} x_g *(1\text{-}FOR_g) + \sum_{g\in W} x_g * WCC_g + \sum_{g\in S} x_g * SCC_g \geq PD * (1 + RM) \qquad (3)$$

$$\sum_{h\in H,\, g\in(W,S)} e_{h,g} \geq \sum_h DM_h * RPS \qquad (4)$$

Minimum Thermal On-line Constraint:

$$\sum_{g\in F} e_{g,h} \geq DM_h * MG \qquad \forall h\in H \qquad (5)$$

Generator Constraints:

$$e_{h,g} \leq x_g *(1\text{-}FOR_g) \qquad \forall g\in F; h\in H \qquad (6)$$

$$e_{h,g} \leq x_g * AVAIL_{h,g} \qquad \forall g\in W,S; h\in H \qquad (7)$$

$$x_{Coal} \leq PD * 0.45 \qquad (8)$$

$$\sum_{h\in H} e_{g,h} \leq x_g * AF_g \qquad \forall g\in F \qquad (9)$$

Model Designs Simulated

- Four sets of renewable credits in capacity markets:
  - 0%(Wind), 0%(Solar) - 15%(W), 75%(S)
  - 25%(W), 100%(Solar) - marginal contribution
- Two RPS levels: 0% vs. 40%.
- Price caps: Optimal* ($10,000/MWh VOLL, no reserve margin) vs. Low Cap ($1,200/MWh with reserve margin adjusted to match EUE in Optimal)

Calculation of Producer Marginal Capacity Credits:

$$pc_g = (EUE^* - EUE)/EUEH$$

Reserve Margin:

$$RM = [\textstyle\sum_{g\in G} x_g * pc_g]/PD - 1$$

Conclusions:

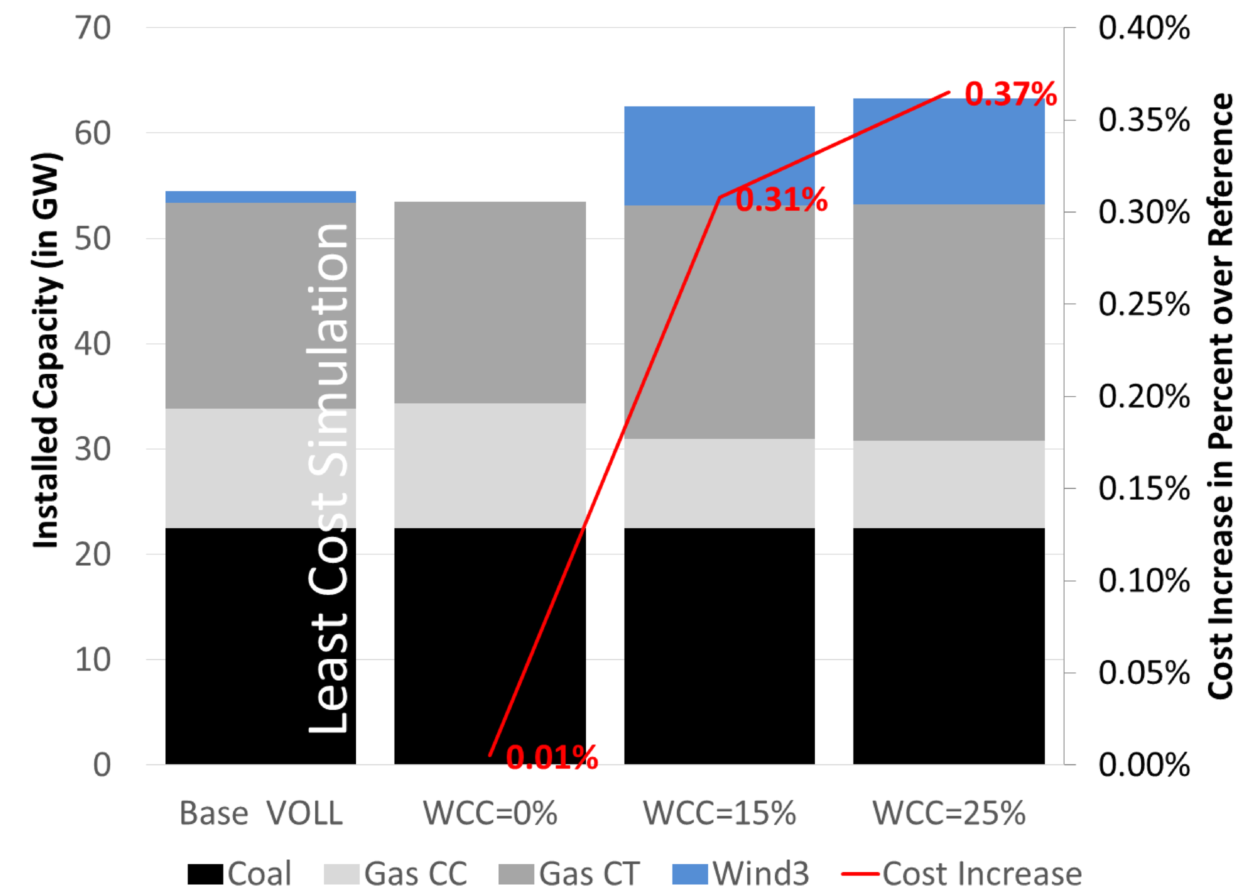
Capacity market payments are optimal if based on thermal unit forced outage rates and intermittent renewable resource's relative marginal ability to decrease unserved energy (locationally differentiated)

Future Work:

- Assess non-dominated solar profiles
- Refine operational constraints
- Add transmission constraints
- Investigate length of data series needed to avoid sample error-based distortions of price & resource mix

Results:

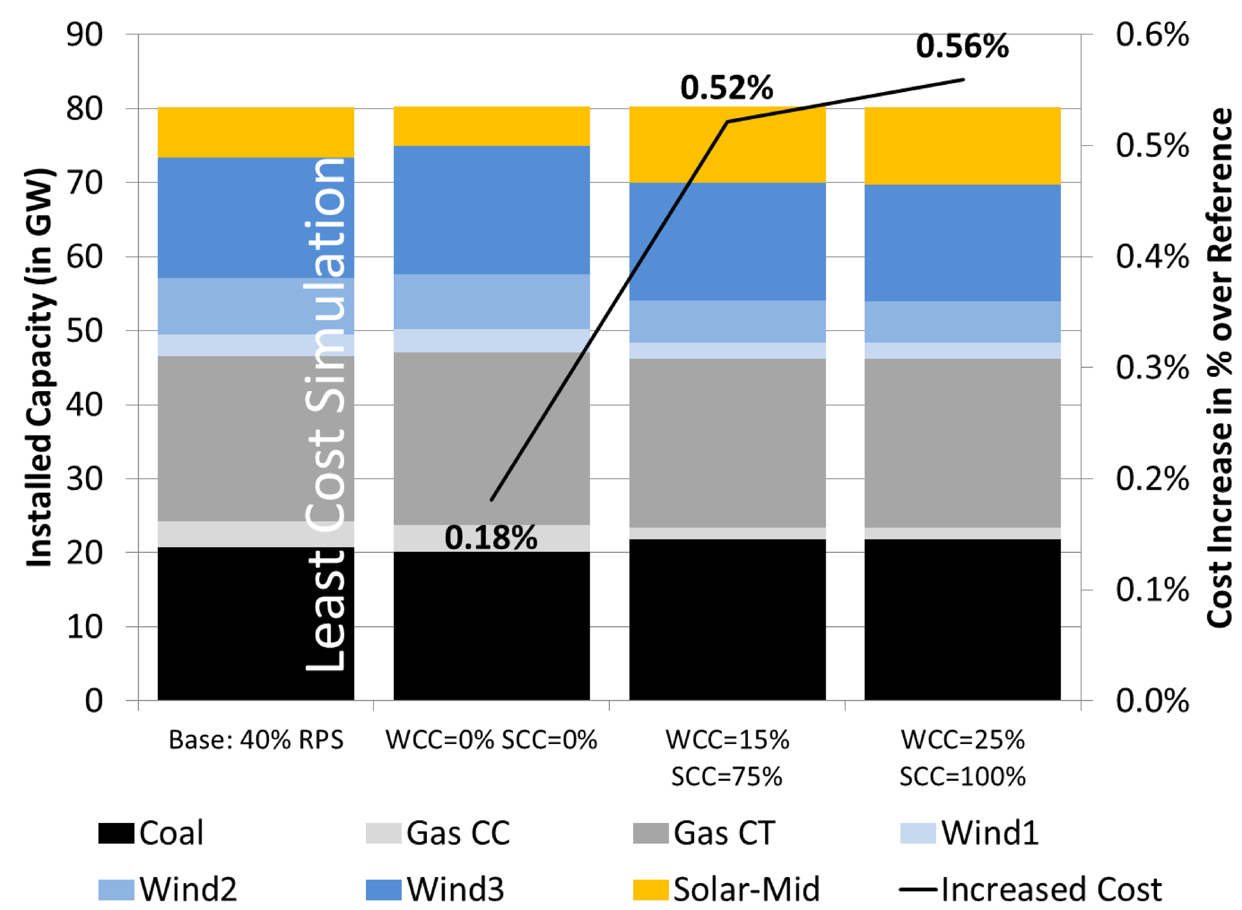
Fig. 2: Changing resource mix and cost with no RPS



Optimal system wind capacity credit = 7.6%

Distortions occur when renewable credit is too high or too low,, or not differentiated based on facility location

Fig. 3: Changing resource mix and cost with 40% RPS



When capacity contribution is ignored, renewables are optimized based on energy only – missing critical system benefits.

Table 1: Optimal Renewable Producer Capacity Credits with 40% RPS

	Capacity Credit, pc_g	Annual Capacity Factor	Installed Capacity (MW), x	% Annual Energy Supplied	Reserve Margin, RM
Wind1	8.56%	36.66%	2916	2.39%	-7.50%
Wind2	12.49%	34.53%	7589	7.91%	
Wind3	3.97%	42.32%	16239	23.03%	
Solar MID	28.15%	27.63%	6779	6.66%	
Aggregate Wind	6.89%	39.50%	26744	33.34%	-7.50%

Aggregating by resource provides a distorted investment signal.

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