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Onshore Wind Offer Review Trigger Price (ORTP) Model

Comments to ISO New England Markets Committee

Brett Kruse
December 6, 2016

CLEAN MODERN EFFICIENT FLEXIBLE POWER GENERATION

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Calpine supports the ISO's position of a 32% capacity factor as an input in the Generic Wind Model[1]

Summary

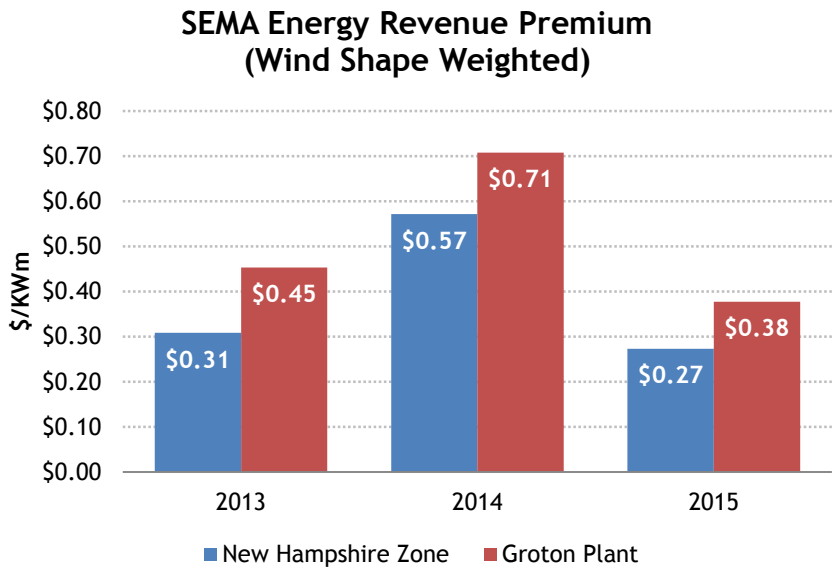
The methodology already gifts the Generic Wind Model with multiple favorable assumptions:

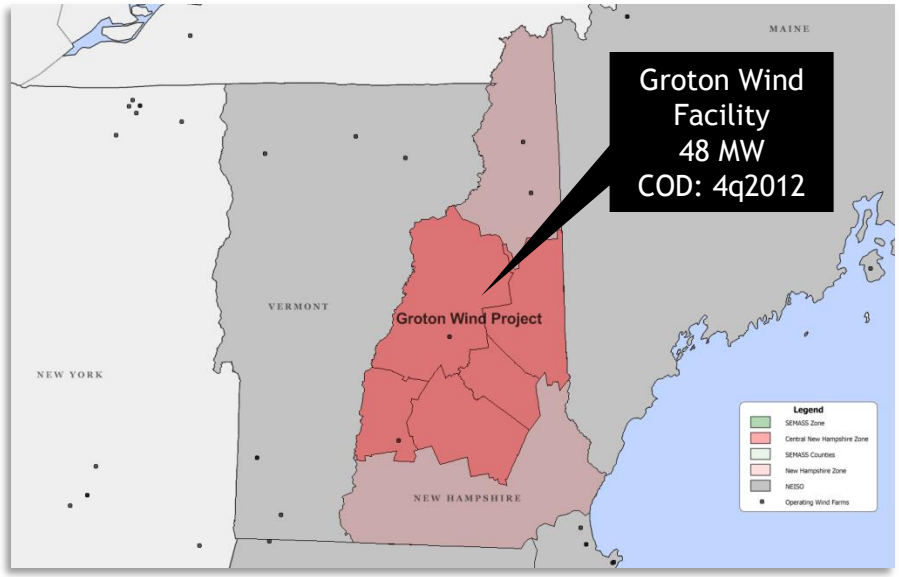
1. **Locational Basis Mismatch** - The model assumes the generic wind unit is located in Central New Hampshire, and receives all the cost benefits (i.e. land, taxes, and development cost) of central New Hampshire, but the energy revenue is derived from a premium Southeast Massachusetts (SEMA) price forecast.
2. **Production Tax Credit Qualification** - The model assumes the generic wind unit will receive the 2018 Production Tax Credit (PTC) without meeting the requirements of the capital spend test or the physical work test.
3. **Tax Attribute Monetization** - The model unrealistically assumes monetizing tax attributes at 100% of their notional value.
4. **Renewable Energy Credit Price Assumption** - The model does not link energy prices and Renewable Energy Credits (REC) thereby overstating the RECs value.
5. **Capacity Factor Assumption** – The model should use performance data for projects that closely analog the Generic Wind Project.

1. The Generic Wind Model is the model used for the Onshore ORTP wind calculation.

The Model assumes the Generic Wind Unit is located in New Hampshire yet receives energy revenue from SEMA

Issue #1





The locational mismatch causes an understatement in the onshore wind ORTP of $0.90- $2.35/KW-mth

Note: Basis differentials are based on real time prices and evaluated against the Generic Wind Model shape. Onshore Wind ORTP adders are created by taking 3.33 x Differential .
Sources: Real time prices from the ISO New England via LIM, Groton statistic from ABB – Energy Velocity

Overstatement of the true economic value of the Production Tax Credit

Issue #2

- The Generic Wind Model assumes the project will receive the 2018 Production Tax Credit.
- To qualify for the 2018 PTC one of two conditions must be met ***in*** 2018:
  1. Physical Work Test – Physical work of a significant nature[1]
  2. Safe Harbor Test - Demonstrate that 5% or more of the total cost of the facility was paid or incurred in 2018.
- The Model assumes that construction starts in 2019 and makes no provision for any construction costs in 2018. Thus, under current PTC rules, the Generic wind unit would *not* qualify for the 2018 PTC.
  - By correcting the PTC to represent the 2019 attributes, the Onshore Wind ORTP would increase by $3.89/KW-mth bringing it to $14.91/KW-mth.
  - By including 5% of the project's costs, in 2018 the Onshore wind ORTP increases ~$0.20/KW-mth.

Refinement of the Production Tax Credit assumption would increase the Onshore Wind ORTP by $0.20-$3.89/KW-mth.

1. The DOE gives the following as an example of Physical Work of a significant nature -
For a facility that produces electricity from a wind turbine, the beginning of the excavation for the foundation, the setting of anchor bolts into the ground, or the pouring of the concrete pads of the foundation.

The Generic Wind Model unrealistically assumes that tax attributes are monetized at 100%

Issue #3

Tax attribute monetization methods:

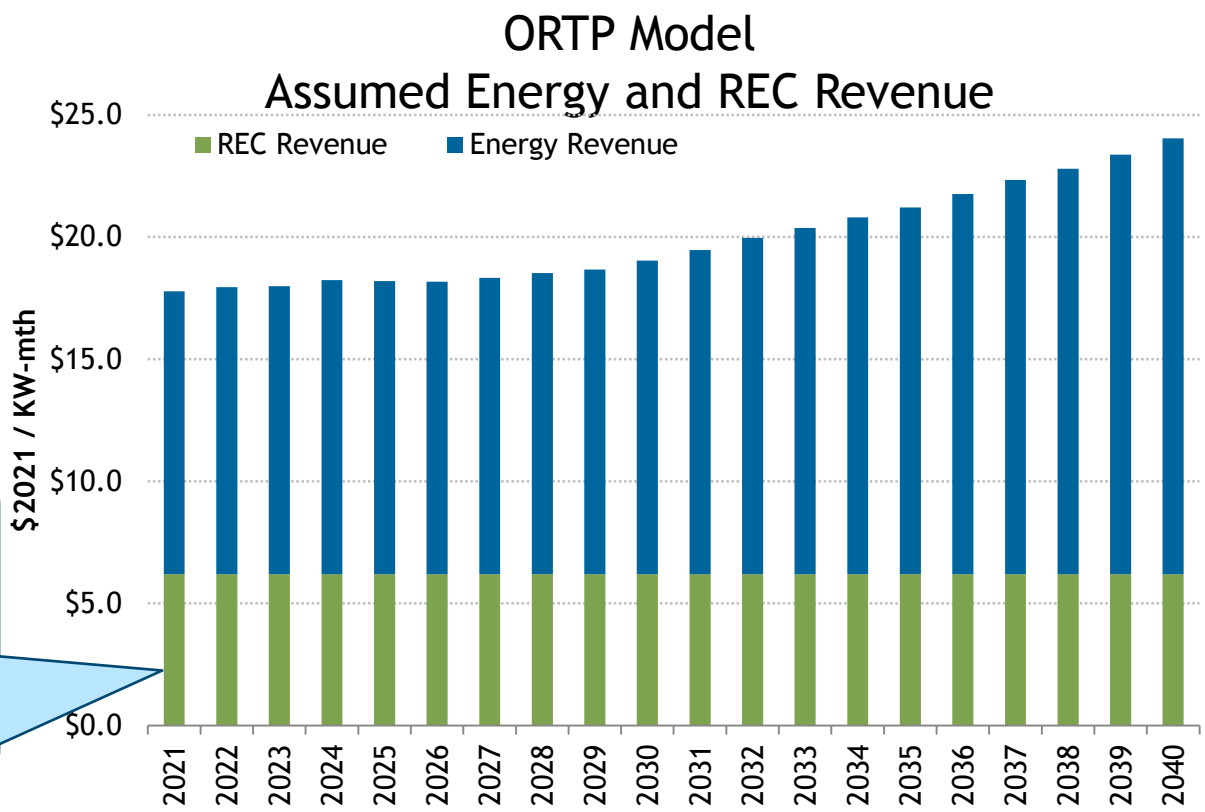
1. The Project has sufficient income to use all tax attributes
   - ✗ The five year MACRS depreciation schedule creates negative cash flows for the project's first five years of operation. Thus, tax attributes are deferred and cannot be monetized at 100%.
2. Project's owner (i.e. corporate parent) has sufficient tax liability to use 100% of tax attributes
   - ✗ Inconsistent with tariff's provision for Calculation of Offer Review Trigger Price[1]
3. Monetization through a third party
   - ✗ Third party requires a return (typically approximately 7-10%)

The deferral of the tax credits until there is income would make the Onshore Wind ORTP increase to ~$21.00/KW-mth.

1. *Market Rule 1,* Section III.A.21.1.2 Calculation of the Offer Review Trigger Price – calculation of the Offer Review Trigger Price requires a project to be evaluated on a stand alone basis

REC price forecast are inconsistent with energy prices and renewable development cost outlook

Issue #4



Declining wind and solar capex suggest declining REC revenue

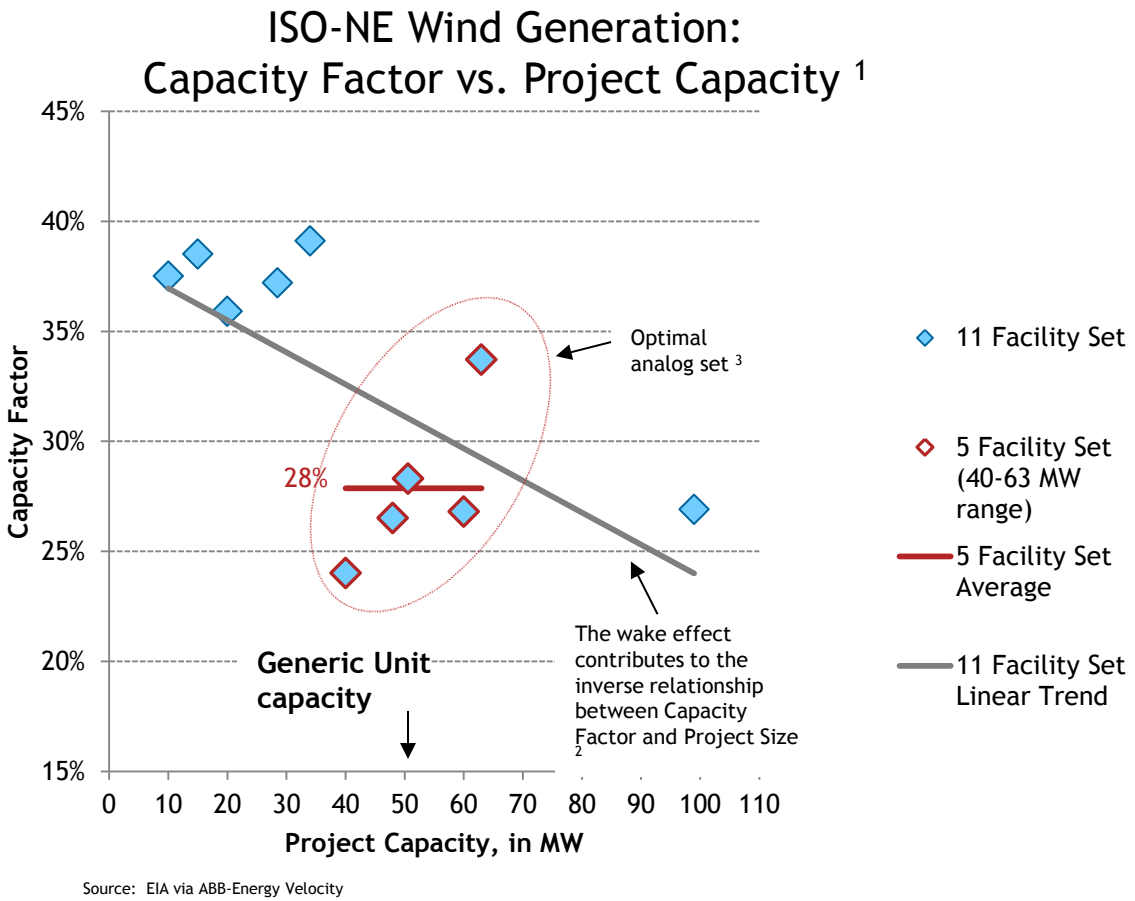
Flat assumed REC revenue is inconsistent with increasing energy revenue

Energy prices and RECs should be negatively correlated assuming no changes to RPS policy.

Source: ISO-NE Market Committee, 2016-11-09 MC AO7 Offer Review Trigger Price (ORTP) Model.xls

Using actual performance data for projects that closely analog the Generic Wind Project suggest using a 28% capacity factor

Issue #5



Source: EIA via ABB-Energy Velocity

Small projects should be excluded from Generic Unit analog

1. Capacity factors based on EIA 923 data -
2. The wake effect is the aggregated influence on the energy production of the wind farm, which results from the changes in wind speed caused by the impact of the turbines on each other. It is important to consider wake effects from neighboring wind farms and the possible impact of wind farms which will be built in the future. http://www.wind-energy-the-facts.org/wake-effect.html
3. Optimal analog set includes: Sheffield, Groton, Record Hill, Rollins Mountains, and Kingdom Community

Appendix

Onshore Wind ORTP revenue sources

Appendix

Onshore Wind ORTP Levelized Revenue Sources ($2021/KW-mth)			
Category	ISO Case (32% Capacity Factor)	RENEW Case (35% Capacity Factor)	Assumptions
Energy	$13.24	$14.62	Concentric Energy Advisors SEMA energy price forecast
Renewable Energy Credits	$6.19	$6.77	Based on $26.50/MWh ($2021)
Pay for Performance	$0.09	$0.09	ISO performed calculation
Capacity	$3.31	$1.35	$11.025 x 0.30 or $4.50x0.30[1]
	22.83	22.83	

For generic wind, since the Qualified Capacity is 30% of the nameplate capacity, any change in energy revenue, REC revenue, and/or PFP revenue gets multiplied by 3.33 (i.e. 1÷.30).

1. 30% is the quantity of qualified capacity. Note above Energy & REC revenue changed by $1.96 so the unforced capacity (UCAP) changed $6.53/KWm ($11.03 – $4.50 = 6.53).

ISO New England On Shore Wind Generation Projects

Appendix

Plant	2013	2014	2015	Nameplate (MW)	Average Capacity Factor*	Zone
Stetson Wind I	139,696	136,411	151,378	57	28.5%	Maine
Stetson Wind II	53,938	55,704	60,895	26	25.0%	Maine
Kibby Wind	268,986	307,567	341,546	132	26.5%	Maine
Rollins Mountains	134,228	137,138	151,886	60	26.8%	Maine
Spruce Mountain	59,387	63,184	66,323	20	35.9%	Maine
Record Hill	126,557	124,221	125,865	50.6	28.3%	Maine
Bull Hill Wind	106,923	117,098	115,845	34	39.1%	Maine
Lempster Wind	69,583	66,643	68,113	24	32.4%	New Hampshire
Granite Reliable	222,031	236,526	240,701	99	26.9%	New Hampshire
Groton Wind Farm	97,570	108,413	114,765	48	26.5%	New Hampshire
Sheffield	83,582	88,833	87,516	40	24.7%	Vermont
Kingdom Community	114,861	179,030	192,481	63	33.7%	Vermont
Georgia Mountain	25,395	32,511	33,147	10	37.5%	Vermont
Berkshire Wind	51,699	51,206	48,920	15	38.5%	WCMASS
New England Wind (Hoosac Wind)	99,905	95,197	90,308	28.5	37.2%	WCMASS

* Capacity factor calculated 2013-2015 realized EIA energy production except for: Bull Hill Wind, Groton Wind Farm, Kingdom Community, Georgia, Hoosac Wind which were calculated based of 2014 – 2015 EIA energy production.

Note: Includes all wind farms registered as full generators and excludes SOGS and distributed generators consistent with RENEW.
Source: EIA via ABB-Energy Velocity