



# Rhode Island Distributed Generation Standard Offer:

## *Preliminary Input Assumptions & Modeling Results for 2013 Ceiling Price Review*

November 7, 2012

**Sustainable Energy Advantage, LLC**  
(with support from Meister Consultants Group)





# 2013 Ceiling Prices to be established for 9 Classes...

- 4 Solar
- 3 Wind
- 1 Anaerobic Digestion
- 1 Hydro benchmark (*not official CP for 2013*)
- 'standard' installations will be modeled to inform setting of ceiling rates for each class


| Technology, sub class | Eligible Size Range | Standard Size for Modeling Ceiling Price |
|-----------------------|---------------------|--|
| Solar, Large          | 500 kW and above    | 1.5 MW                                   |
| Solar, Medium 2       | 251 – 499 kW        | 500 kW                                   |
| Solar, Medium 1       | 101 – 250 kW        | 250 kW                                   |
| Solar, Small          | 50 – 100 kW         | 100 kW                                   |
| Wind, Large           | 1.0 MW – 1.5 MW     | 1.5 MW                                   |
| Wind, Medium          | 200 kW – 999 kW     | 750 kW                                   |
| Wind, Small           | 90 – 100 kW         | 100 kW                                   |
| Anaerobic Digestion   | 400 – 500 kW        | 500 kW                                   |
| Hydroelectric         | 500 kW – 1.0 MW     | 1.0 MW                                   |



## Summary Comparison of 2011/2012 to Proposed 2013 Ceiling Prices

| Technology, sub-class | 2011/2012 Ceiling Price (¢/kWh) | 2013 Proposed Ceiling Price (¢/kWh) <u>w/PTC</u> | Net Change* btw previous and proposed Ceiling Prices | 2013 Proposed Ceiling Price (¢/kWh) <u>w/o PTC</u> |
|-----------------------|---------------------------------|--|--|--|
| Solar, 500 kW+        | 28.95                           | 24.95  | -14%   | N/A  |
| Solar, 251 – 499 kW   | 31.60                           | 28.40  | -10%   | N/A  |
| Solar, 101 – 250 kW   | 33.35 (for 150 kW)              | 28.80  | -14%   | N/A  |
| Solar, 50 – 100 kW    | 33.35 (for 150 kW)              | 29.95  | -10%   | N/A  |
| Wind, 1 – 1.5 MW      | 13.35                           | 16.80  | +26%   | 18.60  |
| Wind, 400 – 999 kW    | N/A                             | 18.15  | N/A  | 19.95  |
| Wind, 90 – 100 kW     | N/A                             | 24.65  | N/A  | N/A  |
| AD, 400 – 500 kW      | N/A                             | 18.55  | N/A  | 19.55  |
| Hydro, 500 kW – 1 MW  | N/A                             | 17.90  | N/A  | 18.85  |

\* See next slide



## Comparison of 2011/2012 to Proposed 2013 Ceiling Prices, Cont.

- A reduction in the market-based total installed cost of solar PV was the principle driver of the proposed reduction in Standard Offer prices for solar.
- The availability of actual cost data for 1.5 MW wind turbine generators installed in southeastern MA was the principle driver of the proposed increase in the Standard Offer price for 1.5 MW Wind.
- 2 additional factors played an important role in the analytical review of proposed 2013 CPs:
  1. The availability of **bonus depreciation** (100% in 2011, and 50% in 2012) is **scheduled to cease** for projects coming on-line beginning 1/1/2013. All else equal, the removal of 50% bonus depreciation would cause an increase in the cost of energy – estimated at 7% for 1.5 MW solar and 8% for 1.5 MW wind.
  2. The **expiration of the 1603 cash payment** in lieu of the ITC significantly reduces most investors' ability to fully monetize the Investment Tax Credit. This analysis estimates 90% ITC monetization. All else equal, reducing the ITC benefit by 10% would cause an increase in the cost of energy – estimated at 4% for 1.5 MW solar. For wind, reduced monetization plus the expiration of the ability to use the ITC (or 1603 payment) in lieu of the PTC could cause an increase in the cost of energy of up to 25%.

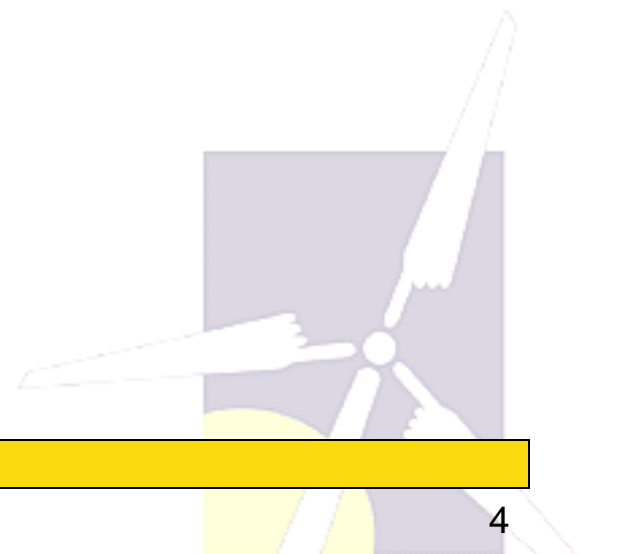
As a result, proposed CPs demonstrate a *net* reduction ranging between 10% and 14% for solar, and a *net* increase for wind of approximately 26%.

### Est. Impact of Changes in Federal Incentives on LCOE

|  | Solar, 1.5 MW       |            | Wind, 1.5 MW        |            |
|--|---------------------|------------|---------------------|------------|
|  | Impact of Fed. Inc. | Net Change | Impact of Fed. Inc. | Net Change |
| Sunset of (50%) Bonus Depreciation                     | + 7%                | - 14%      | +8%                 | + 26%      |
| 90% monetization;<br>+ Switch from ITC to PTC for Wind | + 4%                |            | + 2%<br>+ 14%       |            |



# SOLAR





## Est. of 15-year levelized contract: Solar

*In 2011, LCOE modeling was performed under two scenarios, and the ceiling price was established as the arithmetic average of the 2 cases. For 2013, we propose to use the same approach.*

| Scenario<br>(Modeling<br>Assumptions)  | Estimated Contract Price (cents/kWh) |                       |              |                     |
|--|--------------------------------------|-----------------------|--------------|---------------------|
|  | 50-100 kW                            | 101-250 kW            | 251-499 kW   | 500 kW<br>and above |
| Debt optimized to meet<br>both min + average<br>DSCR; Tax Benefits<br>utilized as generated              | 29.65                                | 28.55                 | 28.15        | 24.75               |
| Debt optimized to meet<br>both min + average<br>DSCR; NOL carried<br>forward and used only<br>by project | 30.25                                | 29.05                 | 28.65        | 25.15               |
| <b>Average = Proposed<br/>Ceiling Price</b>  | <b>29.95</b>                         | <b>28.80</b>          | <b>28.40</b> | <b>24.95</b>        |
| <b>2011 Ceiling Prices</b>   | <b>33.35 (150 kW)</b>                | <b>33.35 (150 kW)</b> | <b>31.60</b> | <b>28.95</b>        |



## Researched cost, O&M & financing inputs: Solar $\approx$ 100 kW dc (1)

### Input category\*

Expected Annual Average Net capacity factor, (%) DC

**Proposed Input = 14.39%**

**(rationale: 7 of 8 respondents had no comments on what was in 2011)**

2011 Input = 14.39%

Annual Production Degradation (%)

**Proposed Input = 0.5%**

2011 Input = 0.5%

Total installed cost (\$/kW<sub>DC</sub>), excluding Interconnection Cost

**Proposed Input = \$3,100 -> \$3,150/kW**

2011 Input = \$3,900

+ \$70/kW 20-yr inverter warranty

Interconnection cost (\$)

**Proposed Input = \$50/kW**

2011 Input = \$210/kW

O&M expenses (in \$/kW<sub>DC</sub>-year) in Year 1 of operations

**Proposed Input = \$20/kW-yr**

2011 Input = \$22/kW-yr



## Researched cost, O&M & financing inputs: Solar $\approx$ 100 kW dc (2)

### Input category\*

Insurance, Yr 1, (% of total project costs or \$/yr)

**Proposed Input = 0.3% of total proj. costs**

**2011 Input = 0.3%**

Project Management, Yr 1 (\$/yr)

**Proposed Input = \$1,400/yr**

**2011 Input= included in overall O&M**

Land Lease, Yr 1 (\$/yr)

**Proposed Input = \$2,500/yr**

**2011 Input = \$1,500 for 150 kW project**

Annual average escalation rate for O&M expenses (%)

**Proposed Input = 3%**

**2011 Input = 3%**

Royalties (% of Revenue, or \$/yr)

**Proposed Input = 0.0% (covered in lease)**

**2011 Input = 0.0%**

Property Taxes (\$ in Yr 1 and annual adjustment factor)

**Proposed Inputs: Cost basis = 95% of \$15/1000, basis declines by 5%/yr thereafter to floor of 30%**

**2011 Input = \$5,250 for 150 kW project,**

**annual adjustment factor = -10.0%**

\*There was no 100kW CP in 2011. The 2011 150 kW inputs are shown here for comparison.





## Researched cost, O&M & financing inputs: Solar $\approx$ 100 kW dc (3)

### Input category\*

Length of construction period (months)

**Proposed Input = included in installed costs;**

**2011 Input = included in installed costs**

Source (D/E) and Cost (e.g. interest rate) of construction financing

**Proposed Input = included in installed costs;**

**2011 Input = included in installed costs**

Debt-to-equity ratio

**Proposed Input = same (result = 48%)**

**2011 Input = debt optimized to cash flow**

Debt tenor (years)

**Proposed Input = 14 -> 13 yrs; 2011 Input = 12 years**

Interest rate on debt (%)

**Proposed Input = 6.5%; 2011 Input = 6.5%**

Lender's Fee (% of loan amt)

**Proposed Input = same; 2011 Input = included in cap. cost**

Avg. Debt Service Coverage Ratio

**Proposed Input = 1.40; 2011 Input = 1.45**

After Tax Return on Equity (e.g. IRR) (%)

**Proposed Input = 12%; 2011 Input = 13%**

Decommissioning Reserve?

**Proposed Input = same; 2011 Input = \$0 (= salvage value)**

\*There was no 100kW CP in 2011. The 2011 150 kW inputs are shown here for comparison.



## Researched cost, O&M & financing inputs: Solar $\approx$ 250 kW dc (1)

### Input category\*

Expected Annual Average Net capacity factor, (%) DC

**Proposed Input = 14.39%**

**(rationale: 7 of 8 respondents had no comments on what was in 2011)**

**2011 Input = 14.39%**

Annual Production Degradation (%)

**Proposed Input = 0.5%**

**2011 Input = 0.5%**

Total installed cost (\$/kW<sub>DC</sub>), excluding Interconnection Cost

**Proposed Input = \$2,750 -> \$2650/kW**

**2011 Input = \$3,900**

**(excl. Interconnection costs)**

**+ \$70/kW 20-yr inverter warranty**

Interconnection cost (\$)

**Proposed Input = \$40/kW**

**2011 Input = \$210/kW**

O&M expenses (in \$/kW<sub>DC</sub>-year) in Year 1 of operations

**Proposed Input = \$20/kW-yr**

**2011 Input = \$22.00/kW**

\*There was no 250kW CP in 2011. The 2011 150 kW inputs are shown here for comparison.



## Researched cost, O&M & financing inputs: Solar ≈ 250 kW dc (2)

### Input category\*

Insurance, Yr 1, (% of total project costs or \$/yr)

**Proposed Input = 0.3% of total proj. costs**

**2011 Input = 0.3%**

Project Management, Yr 1 (\$/yr)

**Proposed Input = \$3,500/yr**

**2011 Input= included in overall O&M**

Land Lease, Yr 1 (\$/yr)

**Proposed Input = \$10,000/yr**

**2011 Input = \$1,500/yr for 150 kW project**

Annual average escalation rate for O&M expenses (%)

**Proposed Input = 3%**

**2011 Input = 3%**

Royalties (% of Revenue, or \$/yr)

**Proposed Input = 0.0% (covered in lease)**

**2011 Input = 0.0%**

Property Taxes (\$ in Yr 1 and annual adjustment factor)

**Proposed Inputs: Cost basis = 95% of \$15/1000, basis declines by 5%/yr thereafter to floor of 30%**

**2011 Input = \$5,250 for 150 kW project, annual adjustment factor = -10.0%**

Length of construction period (months)

**Proposed Input = included in installed costs;**

**2011 Input = included in installed costs**

\*There was no 250kW CP in 2011. The 2011 150 kW inputs are shown here for comparison.



## Researched cost, O&M & financing inputs: Solar ≈ 250 kW dc (3)

### Input category\*

Source (D/E) and Cost (e.g. interest rate) of construc. financing

**Proposed Input = included in installed costs;**

**2011 Input = included in installed costs**

Debt-to-equity ratio

**Proposed Input = same (result = 48.75%)**

**2011 Input = debt optimized to cash flow**

Debt tenor (years)

**Proposed Input = 14 -> 13 yrs; 2011 Input = 12 years**

Interest rate on debt (%)

**Proposed Input = 6.5%; 2011 Input = 6.5%**

Lender's Fee (% of loan amt)

**Proposed Input = same; 2011 Input = included in cap. cost**

Avg. Debt Service Coverage Ratio

**Proposed Input = 1.35; 2011 Input = 1.45**

After Tax Return on Equity (e.g. IRR) (%)

**Proposed Input = 11.5%; 2011 Input = 13%**

Decommissioning Reserve?

**Proposed Input = same; 2011 Input = \$0 (= salvage value)**

\*There was no 250kW CP in 2011. The 2011 150 kW inputs are shown here for comparison.



## Researched cost, O&M and financing inputs: Solar $\approx$ 450 kW dc (1)

### Input category

Expected Annual Avg. Net c.f. (%)

**Proposed Input = 14.56%**

**(rationale: 7 of 8 respondents had no comments)**

**2011 Input = 14.56%**

Annual Production Degradation (%)

**Proposed Input = .5%**

**2011 Input = 0.5%**

Total installed cost (\$/kW<sub>DC</sub>), excluding Interconnection Cost

**Proposed Input = \$2,500 -> \$2,650/kW**

**2011 Input = \$3,700**

**(excl. Interconnection costs)**

**+\$60/kW 20-yr inverter warranty**

Interconnection cost (\$)

**Proposed Input = \$300/kW**

**2011 Input = \$185/kW**

O&M expenses (in \$/kW<sub>DC</sub>-year) in Year 1 of operations

**Proposed Input = \$20/kW-yr**

**2011 Input = \$22/kW**

Insurance, Yr 1, (% of total project costs or \$/yr)

**Proposed Input = 0.3% of total proj. costs**

**2011 Input = 0.3%**





## Researched cost, O&M and financing inputs: Solar $\approx$ 450 kW dc (2)

### Input category

Project Management, Yr 1 (\$/yr)

**Proposed Input = \$6,500/yr**

**2011 Input= included in overall O&M**

Land Lease, Yr 1 (\$/yr)

**Proposed Input = \$15,000**

**2011 Input = \$7,500**

Annual avg. escalation rate for O&M expenses (%)

**Proposed Input = 3%**

**2011 Input = 3%**

Royalties (% of Revenue, or \$/yr)

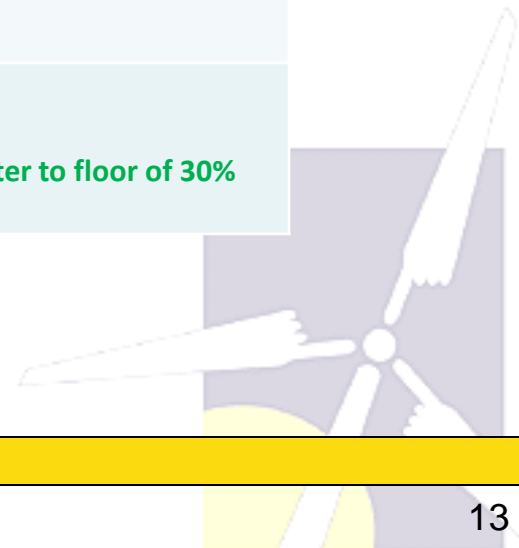
**Proposed Input = 0.0% (covered in lease)**

**2011 Input = 0%**

Property Taxes (\$ in Yr 1 and annual adjustment factor)

**Proposed Inputs: Cost basis = 95% of \$15/1000, basis declines by 5%/yr thereafter to floor of 30%**

**2011 Input = \$17,500 annual adjustment factor = -10.0%**





## Researched cost, O&M and financing inputs: Solar $\approx$ 450 kW dc (3)

### Input category

Length of construction period (months)

**Proposed Input = included in installed costs;**

**2011 Input = included in installed costs**

Source (D/E) and Cost (e.g. int. rate) of constr. financing

**Proposed Input = included in installed costs;**

**2011 Input = included in installed costs**

Debt-to-equity ratio

**Proposed Input = same (result = 51.5%)**

**2011 Input = debt optimized to cash flow**

Debt tenor (years)

**Proposed Input = 14 -> 13 yrs**

**2011 Input = 12 years**

Interest rate on debt (%)

**Proposed Input = 6.0%**

**2011 Input = 6.5%**



## Researched cost, O&M and financing inputs: Solar $\approx$ 1,500 kW dc (1)

### Input category

Expected Annual Avg. Net capacity factor, (%)

**Proposed Input = 14.65%**

**(rationale: 7 of 8 respondents had no comments)**

**2011 Input = 14.65%**

Annual Production Degradation (%)

**Proposed Input = .5%**

**2011 Input = 0.5%**

Total installed cost (\$/kW<sub>DC</sub>), excluding Interconnection Cost

**Proposed Input = \$2,400 -> \$2,550/kW**

**2011 Input = \$3,400 (excl. Interconnection costs) + \$50/kW 20-yr inverter warranty**

Interconnection cost (\$)

**Proposed Input = \$150/kW**

**2011 Input = \$132/kW**

O&M expenses (in \$/kW<sub>DC</sub>-year) in Year 1 of operations

**Proposed Input = \$15/kW-yr**

**2011 Input = \$24/kW**

Insurance, Yr 1, (% of total project costs or \$/yr)

**Proposed Input = 0.25%**

**2011 Input = 0.2%**







## Researched cost, O&M and financing inputs: Solar $\approx$ 1,500 kW dc (2)

### Input category

Project Management, Yr 1 (\$/yr)

**Proposed Input = \$10,000**

**2011 Input= included in overall O&M**

Land Lease, Yr 1 (\$/yr)

**Proposed Input = \$30,000 -> \$34,500 to reflect tax on underlying land**

**2011 Input = \$33,000**

Annual average escalation rate for O&M expenses (%)

**Proposed Input = 3%**

**2011 Input = 2.5%**

Royalties (% of Revenue, or \$/yr)

**Proposed Input = 0.0% (covered in lease)**

**2011 Input = 0.0%**

Property Taxes (\$ in Yr 1 and annual adjustment factor)

**Proposed Inputs: Cost basis = 95% of \$15/1000, basis declines by 5%/yr thereafter to floor of 30%**

**2011 Input = \$52,500, annual adjustment: -10%**

Length of construction period (months)

**Proposed Input = included in installed costs;**

**2011 Input = included in installed costs**

Source (D/E) and Cost (e.g. interest rate) of construction financing

**Proposed Input = included in installed costs;**

**2011 Input = included in installed costs**



## Researched cost, O&M and financing inputs: Solar $\approx$ 1,500 kW dc (3)

### Input category

Debt-to-equity ratio

**Proposed Input = same (result = 51.25%)**

**2011 Input = debt optimized to cash flow**

Debt tenor (years)

**Proposed Input = 14 -> 13 yrs**

**2011 Input = 12 yrs**

Interest rate on debt (%)

**Proposed Input = 5.5%**

**2011 Input = 6%**

Lender's Fee (% of loan amt)

**Proposed Input = same;**

**2011 Input = included in cap. cost**

Avg. Debt Service Coverage Ratio

**Proposed Input = 1.35**

**2011 Input = 1.45**

After Tax Return on Equity (e.g. IRR) (%)

**Proposed Input = 12%**

**2011 Input = 13%**

Decommissioning Reserve?

**Proposed Input = \$200,000**

**2011 Input = \$0 (= salvage value)**





# Incentives

- Federal Investment Tax Credit (ITC) assumed available at time of initial operation (2013/2014)
  - Monetization assumption reduced to 90% to reflect the difficulty and cost of securing tax equity as well as the associated transaction costs.
- Assume Bonus Depreciation no longer available
- Proposed CPs are an average of two modeling runs – one which assumes state tax benefits are used as generated, and a second which assumes the Net Operating Loss is carried forward until it can be used by the project.
- No federal, state, local or other grants assumed



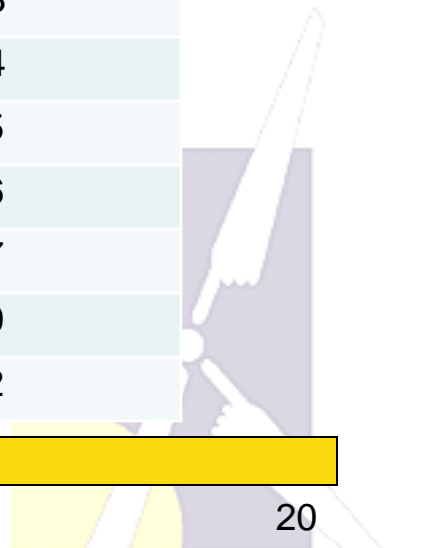
# Additional Assumptions

- COD achieved in 2013
- Project Useful Life: 25 years
- 0.5%/yr production degradation
- Debt Service Coverage Ratio:
  - Min = 1.20X
  - Avg. varies by case
- Interconn. Costs depreciated on 15-year MACRS schedule
- All other project costs:
  - 96% depreciated on 5-year MACRS
  - 2% depreciated on 15-year MACRS
  - 2% not depreciable
- Fed. Income Tax rate 35%;  
State rate 9%
- All tax benefit utilized in period generated, unless otherwise noted
- *Assumed NEPOOL Membership costs either covered by NGRID as lead participant, or spread over many installations and therefore negligible*
- Market value of production (assumed revenue) post-contract = 90 -> 75% of sum of **solar-weighted** energy and capacity price forecasts from 2011 Avoided Energy Supply Cost Study and \$5/REC (next slide)



## Additional Assumptions: Forecast of Market Value of Production

| <u>Project Year</u> | <u>Calendar Year</u> | Time-of-Production<br>Weighted Market Value<br>of Production<br>(incl. energy, capacity<br>& RECs) (cents/kWh) |
|---------------------|----------------------|--|
| 16                  | 2029                 | 10.04  |
| 17                  | 2030                 | 10.24  |
| 18                  | 2031                 | 10.43  |
| 19                  | 2032                 | 10.63  |
| 20                  | 2033                 | 10.84  |
| 21                  | 2034                 | 11.05  |
| 22                  | 2035                 | 11.26  |
| 23                  | 2036                 | 11.47  |
| 24                  | 2037                 | 11.70  |
| 25                  | 2038                 | 11.92  |





# Benchmarking to CT ZREC Program

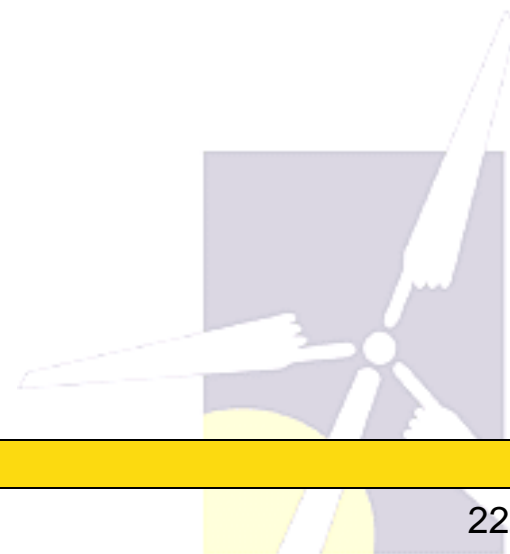
October 2012 Results

| <b>Large ZREC: 250kW – 1 MW</b><br><b>Medium ZREC: &gt;100 kW &lt;250 kW</b><br><b>Small ZREC: ≤ 100 kW</b><br><i><b>(All Behind the Meter)</b></i> | <b>UI Large ZREC (\$/REC)</b>                | <b>CL&amp;P Large ZREC (\$/REC)</b> | <b>UI Medium ZREC (\$/REC)</b>  | <b>CL&amp;P Medium ZREC (\$/REC)</b> |
|---|--|-------------------------------------|---------------------------------|--------------------------------------|
| <b>Weighted <u>Average</u> Bid Price of Accepted Bids</b>   | \$117.27                                     | \$101.36                            | \$135.36                        | \$149.29                             |
|   | 6 accepted bids:<br>All but 1 winner <500 kW | Winners span whole size range.      | Winners range from 132 – 250 kW | Winners range from 101 – 250 kW      |
| <b>Approx. Value of Retail Electricity Purchases Avoided, <b>Levelized*</b></b>   | \$166-191                                    |                                     | \$166-191                       |                                      |
| <b>Est. Value Under 3<sup>rd</sup>-Party Net Metering (Assumed 10-15% discount, common in MA)</b>   | \$113-138                                    |                                     | \$113-138                       |                                      |
| <b>Est. Equivalent to Calculated LCOE</b>   | \$258-289                                    |                                     | \$276-307                       |                                      |

\* Levelization assumes 4% annual rate escalation and 10% discount rate.



# WIND





# Est. of 15-year levelized contract: **Wind**

*In 2011, LCOE modeling was performed under two scenarios, and the ceiling price was established as the arithmetic average of the 2 cases. For 2013, we propose to use the same approach.*

| Scenario<br>(Modeling Assumptions)   | Estimated Contract Price (cents/kWh) |              |              |              |              |
|--|--------------------------------------|--------------|--------------|--------------|--------------|
|  | 1.5 MW                               |              | 750 kW       |              | 100<br>kW    |
|  | w/PTC                                | w/o<br>PTC   | w/PTC        | w/o<br>PTC   |              |
| Debt optimized to meet both min + average DSCR; Tax Benefits utilized as generated           | 16.65                                | 18.45        | 17.95        | 19.85        | 24.35        |
| Debt optimized to meet both min + average DSCR; NOL carried forward and used only by project | 16.95                                | 18.75        | 18.35        | 20.05        | 24.95        |
| <b>Average = Proposed Ceiling Price</b>  | <b>16.80</b>                         | <b>18.60</b> | <b>18.15</b> | <b>19.95</b> | <b>24.65</b> |
| <b>2011 Ceiling Price</b>  | <b>13.35</b>                         | <b>N/A</b>   | <b>N/A</b>   | <b>N/A</b>   | <b>N/A</b>   |





## Researched cost, O&M and financing inputs: Wind 1,500 kW (1)

### Input category

Expected Annual Average Net capacity factor, (%)

**Proposed Input = 27.5% (to account for new turbine optimization to low wind regimes)**

**2011 Input = 25%**

Annual Production Degradation

**Proposed Input = 0.5%**

**2011 Input = 0.5%**

Total installed cost (\$/kW), **excluding** Interconnection Cost

**Proposed Input = \$3,200/kW**

**2011 Input = \$2,750/kW (excl. interconnection costs)**

Typical Interconnection cost (\$/kW)

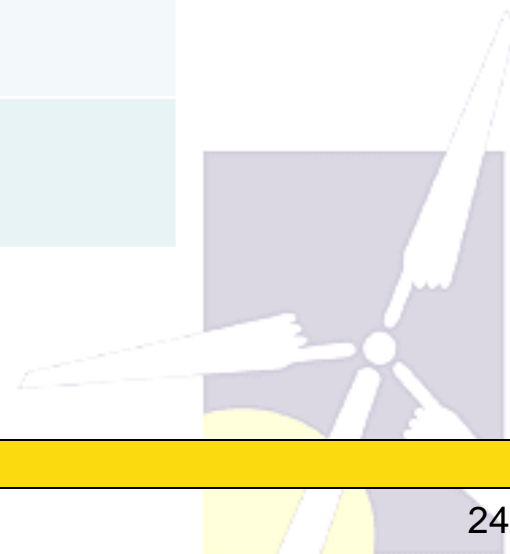
**Proposed Input = \$100/kW**

**2011 Input = \$117/kW**

O&M expenses in Year 1 of operations

**Proposed Input = \$30/kW-yr**

**2011 Input = \$55/kW-year**





## Researched cost, O&M and financing inputs: Wind 1,500 kW (2)

### Input category

Insurance Expense (as % of total proj. cost, or in \$/yr)

**Proposed Input = 0.3% of total project cost**

**2011 Input = included in O&M**

Project Management

**Proposed Input = \$15,000/yr**

**2011 Input = included in O&M**

Land Lease, Year 1 (\$/year)

**Proposed Input = \$20,000/yr**

**2011 Input = included in O&M**

Annual avg. escalation rate for O&M expenses (%)

**Proposed Input = 2.5%**

**2011 Input = 2%**

Royalties

**Proposed Input = included in lease exp.**

**2011 Input = included in O&M**

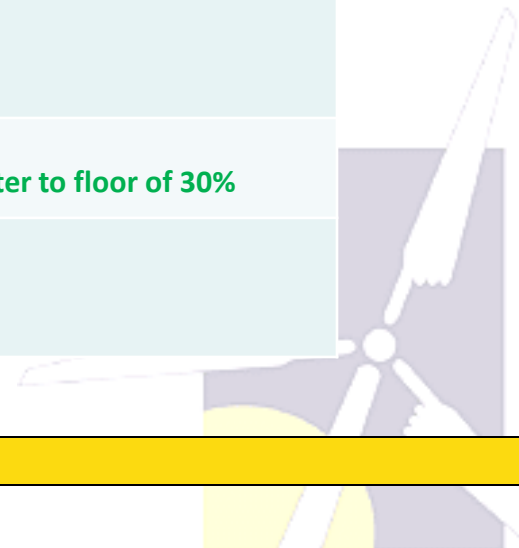
Property Taxes (\$ in Yr 1 and annual adjustment factor)

**Proposed Inputs: Cost basis = 95% of \$15/1000, basis declines by 5%/yr thereafter to floor of 30%**

Length of construction period (months)

**Proposed Input = included in installed costs;**

**2011 Input = included in installed costs**





## Researched cost, O&M and financing inputs: Wind 1,500 kW (3)

### Input category

Source and Cost of Construction Financing

**Proposed Input = included in installed costs;**

**2011 Input = included in installed costs**

Debt-to-equity ratio

**Proposed Input = same (56.25%)**

**2011 Input = debt optimized to cash flow**

Debt tenor (years)

**Proposed Input = 15 yrs**

**2011 Input = 12 Yrs.**

Interest rate on debt (%)

**Proposed Input = 5.5%**

**2011 Input = 6.5%**

Lender's Fee

**Proposed Input = same;**

**2011 Input = included in cap. cost**

After Tax Return on Equity (e.g. IRR) (%)

**Proposed Input = 11% -> 12%**

**2011 Input = 13%**

Decommissioning Reserve

**Proposed Input = \$0 (= salvage value)**

**2011 Input = \$0 (= salvage value)**





## Researched cost, O&M and financing inputs: Wind 750 kW (1)

### Input category

Expected Annual Average Net capacity factor, (%)

**Proposed Input = 24%**

Annual Production Degradation

**Proposed Input = 0.5%**

Total installed cost (\$/kW), excluding Interconnection Cost

**Proposed Input = \$2,800**

Typical Interconnection cost (\$/kW)

**Proposed Input = \$137/kW**

O&M expenses (in ¢/kWh) in Year 1 of operations

**Proposed Input = \$30/kW-yr**

Insurance Expense (as % of total project cost, or in \$/yr)

**Proposed Input = 0.3% of total proj. costs**

Project Management

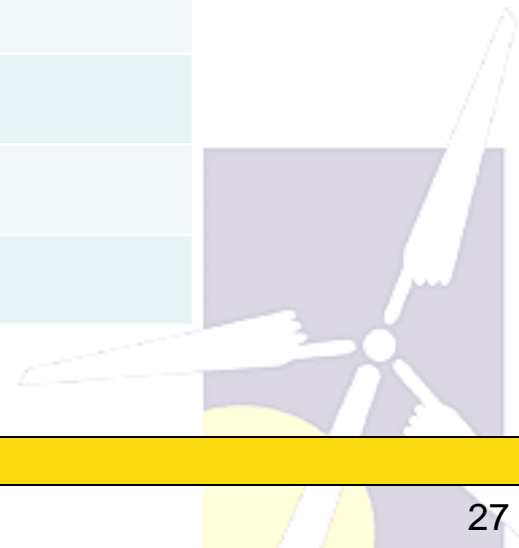
**Proposed Input = \$15,000**

Land Lease, Year 1 (\$/year)

**Proposed Input = \$10,000**

Annual avg. escalation rate for O&M expenses (%)

**Proposed Input = 2.5%**





## Researched cost, O&M and financing inputs: Wind 750 kW (2)

### Input category

Royalties

**Proposed Input = included in lease exp.**

Property Taxes (\$ in Yr 1 and annual adjustment factor)

**Proposed Inputs: Cost basis = 95% of \$15/1000, basis declines by 5%/yr thereafter to floor of 30%**

Length of construction period (months)

**Proposed Input = included in installed costs;**

Source and Cost of Construction Financing

**Proposed Input = included in installed costs;**

Debt-to-equity ratio

**Proposed Input = debt optimized to cash flow (result = 66%)**

Debt tenor (years)

**Proposed Input = 15 yrs**

Interest rate on debt (%)

**Proposed Input = 6%**

Lender's Fee

**Proposed Input = included in cap. cost**

After Tax Return on Equity (e.g. IRR) (%)

**Proposed Input = 12%**

Decommissioning Reserve

**Proposed Input = \$0 (salvage value)**





## Researched cost, O&M and financing inputs: Wind 100kW (1)

### Input category

Expected Annual Average Net capacity factor, (%)

**Proposed Input = 23%**

Annual Production Degradation

**Proposed Input = 0.5%**

Total installed cost (\$/kW), excluding Interconnection Cost

**Proposed Input = \$5,600/kW**

Typical Interconnection cost (\$/kW)

**Proposed Input = \$200/kW**

O&M expenses (in \$/kW-year) in Year 1 of operations

**Proposed Input = \$20/kW-yr**

Insurance Expense (as % of total project cost, or in \$/yr)

**Proposed Input = 0.3% of total proj. costs**

Project Management

**Proposed Input = \$2,000**

Land Lease, Year 1 (\$/year)

**Proposed Input = \$2000/year**

Annual avg. escalation rate for O&M expenses (%)

**Proposed Input = 2.5%**

Royalties

**Proposed Input = included in lease exp.**





## Researched cost, O&M and financing inputs: Wind 100kW (2)

### Input category

Property Taxes

**Proposed Input = assumed exempt**

Length of construction period (months)

**Proposed Input = included in installed costs;**

Source and Cost of Construction Financing

**Proposed Input = included in installed costs;**

Debt-to-equity ratio

**Proposed Input = debt optimized to cash flow (result = 50.25%)**

Debt tenor (years)

**Proposed Input = 15 yrs**

Interest rate on debt (%)

**Proposed Input = 6%**

Lender's Fee

**Proposed Input = included in cap. cost**

After Tax Return on Equity (e.g. IRR) (%)

**Proposed Input = 12%**

Decommissioning Reserve

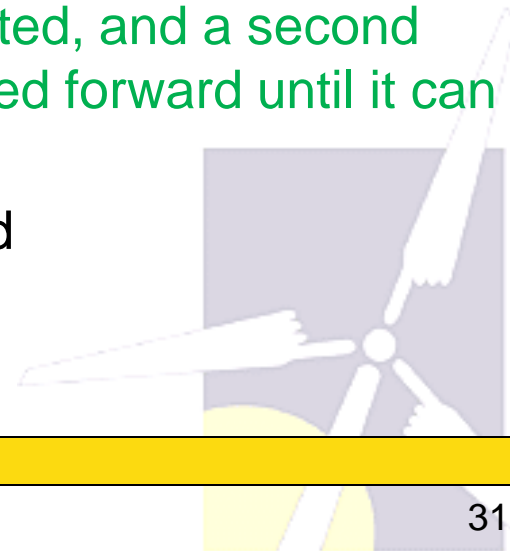
**Proposed Input = \$0 (salvage value)**





# Incentives

- Current Production Tax Credit (PTC) expires as of 12/31/2012.
  - For 750 kW and 1500 kW wind, ceiling prices calculated both with and without PTC extension.
    - For these categories, monetization assumption reduced to 90% to reflect the difficulty and cost of securing tax equity as well as the associated transaction costs.
  - For 100 kW wind, assume ITC available and fully monetized through 2016.
- Assume Bonus Depreciation no longer available
- Proposed CPs are an average of two modeling runs – one which assumes state tax benefits are used as generated, and a second which assumes the Net Operating Loss is carried forward until it can be used by the project.
- No federal, state, local or other grants assumed







# Additional Assumptions

- Commercial operation achieved in 2013
- Project Useful Life: 20 years
- Minimum Debt Service Coverage Ratio: 1.20X
- Average Debt Service Coverage Ratio: 1.35X
- Interconnection Costs depreciated on 15-year MACRS schedule
- All other project costs:
  - 96% depreciated on 5-year MACRS
  - 2% depreciated on 15-year MACRS
  - 2% not depreciable
- Federal Income Tax rate 35%; State rate 9%
- All tax benefit utilized in period generated, unless otherwise noted
- Market value of production (assumed revenue) post-contract = 90 -> 75% of sum of **wind-weighted** energy and capacity price forecasts from 2011 Avoided Energy Supply Cost Study and \$5/REC (see next slide)

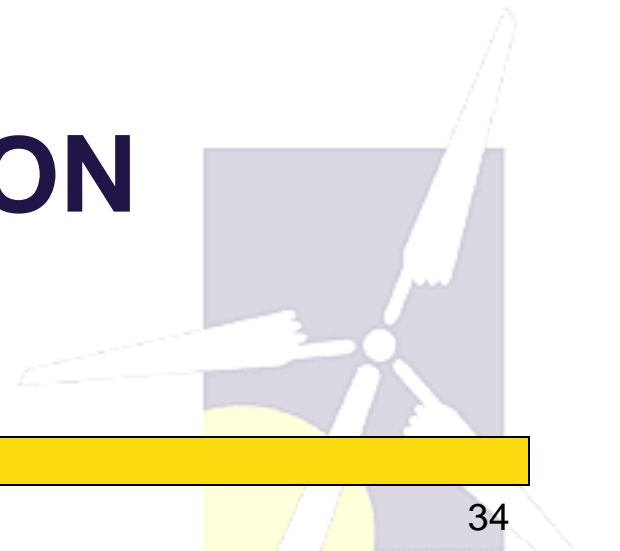


## **Additional Assumptions: Forecast of Market Value of Production**

| <b>Project Year</b> | <b>Calendar Year</b> | <b>Time-of-Production<br/>Weighted Market<br/>Value of Production<br/>(incl. energy, capacity<br/>&amp; RECs) (cents/kWh)</b> |
|---------------------|----------------------|---|
| 16                  | 2029                 | 9.63  |
| 17                  | 2030                 | 9.82  |
| 18                  | 2031                 | 10.01   |
| 19                  | 2032                 | 10.20   |
| 20                  | 2033                 | 10.39   |



# ANAEROBIC DIGESTION






## Est. of 15-year levelized contract: Anaerobic Digestion

| Scenario<br>(Modeling Assumptions)   | Estimated Contract Price<br>(cents/kWh) |              |
|--|---|--------------|
|  | 500 kW                                  |              |
|  | w/PTC                                   | w/o PTC      |
| Debt optimized to meet both min + average DSCR; Tax Benefits utilized as generated           | 18.35                                   | 19.35        |
| Debt optimized to meet both min + average DSCR; NOL carried forward and used only by project | 18.75                                   | 19.75        |
| Average = Proposed Ceiling Price   | <b>18.55</b>                            | <b>19.55</b> |



# Anaerobic Digestion - Overview

- The most common opportunity for AD in RI is *assumed* to be for food waste digesters. Sludge or manure-based applications are also possible.
- Feed stocks are expected to be derived from food manufacturing, restaurant and grocery waste. *No manure or WWTP sludge are assumed – although such projects may be possible in RI.*
- *The VT Standard Offer program established a farm digester price which esc. from 13.6 to 15.0 cents/kWh over a 20 year contract. The VT Standard Offer contract allows the generator to keep and sell all RECs – and retain associated revenue.*
- This approach means that there are *no fuel costs*. Fuel deliveries will generate a *tipping fee*, and are assumed to arrive clean, with no cost to dispose of packaging.
- ~~Further, it is assumed that digestate will be sold, generating additional revenue for the facility.~~



## Researched cost, O&M and financing inputs: Anaerobic Digestion, ~500 kW (1)

### Input category

Biogas consumption/day (ft<sup>3</sup>/day)

**Proposed Input = 150,000**

Energy content/cubic foot (BTU/cubic ft)

**Proposed Input = 650** BTU/cubic ft

Heat Rate (BTU/kWh)

**Proposed Input = 9,000** BTU/kWh

Availability Factor

**Proposed Input = 92%**

Station Service/Parasitic Load

**Proposed Input = 10%**

Annual Production Degradation (%)

**Proposed Input = 0%**

Total installed cost (\$/kW), excl. Interconnection Cost

**Proposed Input = \$9,500 -> \$10,000/kW -- additional \$500/kW takes into account ownership of land**

Typical Interconnection cost (\$)

**Proposed Input = \$150,000**



## Researched cost, O&M and financing inputs: Anaerobic Digestion, ~500 kW (2)

### Input category

O&M expenses (\$/kW-yr), Yr 1 (excluding those listed below)

**Proposed Input** = \$300/kW-yr

Variable O&M (¢/kWh), Yr 1 (excluding those listed below)

**Proposed Input** = 2¢/kWh

Insurance, Yr 1, (provide as % of total project cost, or in \$/yr)

**Proposed Input** = 0.4%

Project Management, Yr 1 (\$/yr)

**Proposed Input** = \$30,000/yr

Land Lease, Yr 1 (\$/yr)

**Proposed Input** = \$5,000 -> \$0/yr (land assumed purchased by the project @ equivalent of \$500/kW)

Annual average escalation rate for O&M expenses (%)

**Proposed Input** = 2 %


Royalties (% of revenue, or \$/yr)

**Proposed Input** = 0%

Property Taxes (\$ in Yr 1 and annual adjustment factor)

**Proposed Inputs: Cost basis** = 95% of \$15/1000, basis declines by 5%/yr thereafter to floor of 30%





## Researched cost, O&M and financing inputs: Anaerobic Digestion, ~500 kW (3)

### Input category

Length of construction period (months)

**Proposed Input = included in installed costs;**

Source and Cost of Construction Financing

**Proposed Input = included in installed costs;**

Debt-to-equity ratio

**Proposed Input = debt optimized to cash flow**

Debt tenor (years)

**Proposed Input = 13 years**

Interest rate on debt (%)

**Proposed Input = 7 %**

Lender's Fee

**Proposed Input = included in cap. cost**

Avg. Debt Service Coverage Ratio

**Proposed Input = 1.5**

After Tax Return on Equity (e.g. IRR) (%)

**Proposed Input = 12 %**

Decommissioning Reserve

**Proposed Input = \$0**

Tipping Fees/Digestate Revenue, If Applicable: \$/ton, and tons per year

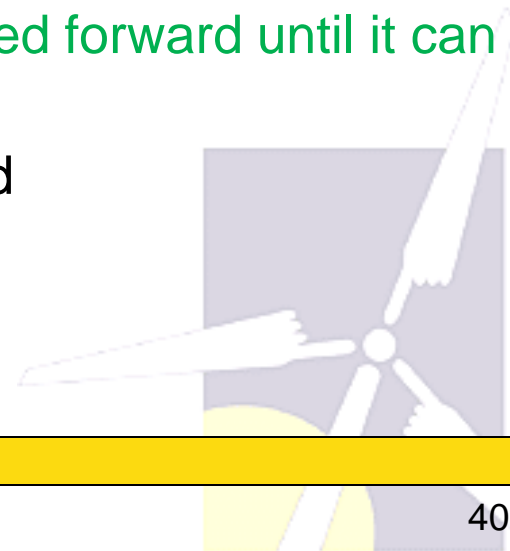
**Proposed Input = Tipping Fee: \$10 -> \$30/ton ; Digestate: 7¢ -> 0¢/gal.**





# Incentives

- Current Production Tax Credit (PTC) expires as of 12/31/2012.
  - Anaerobic digesters eligible for 50% of face value
  - Ceiling prices calculated both with and without PTC extension.
  - Monetization assumption reduced to 90% to reflect the difficulty and cost of securing tax equity as well as the associated transaction costs.
- Assume Bonus Depreciation no longer available
- Proposed CPs are an average of two modeling runs – one which assumes state tax benefits are used as generated, and a second which assumes the Net Operating Loss is carried forward until it can be used by the project.
- No federal, state, local or other grants assumed





# Additional Assumptions

- Commercial operation achieved in 2013
- Project Useful Life: 20 years
- Minimum Debt Service Coverage Ratio: 1.20X
- Average Debt Service Coverage Ratio: 1.50X
- Interconnection Costs depreciated on 15-year MACRS schedule
- All other project costs:
  - 96% depreciated on 5-year MACRS
  - 2% depreciated on 15-year MACRS
  - 2% not depreciable
- Federal Income Tax rate 35%; State rate 9%
- All tax benefit utilized in period generated, unless otherwise noted
- Market value of production (assumed revenue) post-contract = 90 -> 75% of sum of energy and capacity price forecasts from 2011 Avoided Energy Supply Cost Study and \$5/REC (see next slide)

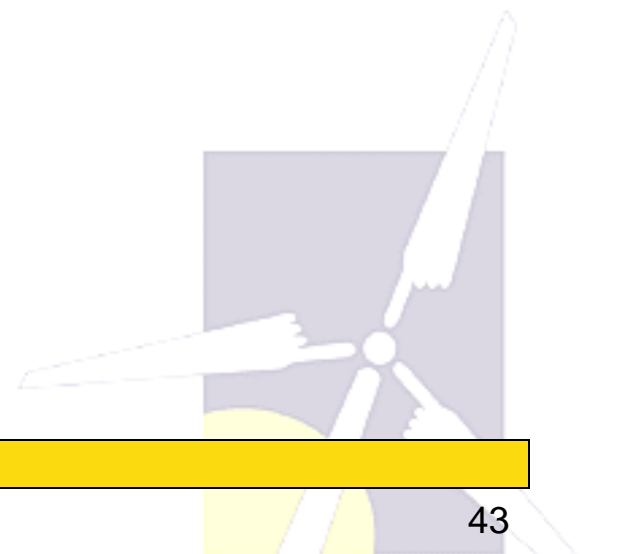



## **Additional Assumptions: Forecast of Market Value of Production**

| <b>Project Year</b> | <b>Calendar Year</b> | <b>Market Value of<br/>Production<br/>(incl. energy, capacity<br/>&amp; RECs) (cents/kWh)</b> |
|---------------------|----------------------|---|
| 16                  | 2029                 | 9.70  |
| 17                  | 2030                 | 9.89  |
| 18                  | 2031                 | 10.08   |
| 19                  | 2032                 | 10.27   |
| 20                  | 2033                 | 10.46   |



# HYDRO





## Est. of 15-year levelized contract: Hydro

| Scenario<br>(Modeling Assumptions)   | Estimated Contract Price<br>(cents/kWh) |              |
|--|---|--------------|
|  | 1,000 kW                                |              |
|  | w/PTC                                   | w/o PTC      |
| Debt optimized to meet both min + average DSCR; Tax Benefits utilized as generated           | 17.75                                   | 18.75        |
| Debt optimized to meet both min + average DSCR; NOL carried forward and used only by project | 18.05                                   | 18.95        |
| <b>Average = Proposed Ceiling Price</b>  | <b>17.90</b>                            | <b>18.85</b> |



## Researched cost, O&M and financing inputs: Hydro 500-1000kW

### Input category

Expected Annual Average Net capacity factor, (%)

**Proposed Input = 40%**

Total installed cost (\$/kW), excluding Interconnection Cost

**Proposed Input = \$4,000/kW (excl. interconnection costs)**

Typical Interconnection cost (\$/kW)

**Proposed Input = \$100/kW**

O&M expenses (in \$/kW-year) in Year 1 of operations

**Proposed Input = \$13/kW-year**

Variable O&M (¢/kWh), Yr 1 (excluding those listed below)

**Proposed Input = 2.00 ¢/kWh**

Insurance Expense (as % of total project cost, or in \$/yr)

**Proposed Input = 0.5%**

Project Management

**Proposed Input = \$30,000/year**





## Researched cost, O&M and financing inputs: Hydro 500-1000kW

### Input category

Land Lease, Year 1 (\$/year)

**Proposed Input = (see royalties)**

Annual avg. escalation rate for O&M expenses (%)

**Proposed Input = 2.5%**

Royalties

**Proposed Input = 3.5%**

Property Taxes (\$ in Yr 1 and annual adjustment factor)

**Proposed Inputs: Cost basis = 95% of \$15/1000, basis declines by 5%/yr thereafter to floor of 30%**

Length of construction period (months)

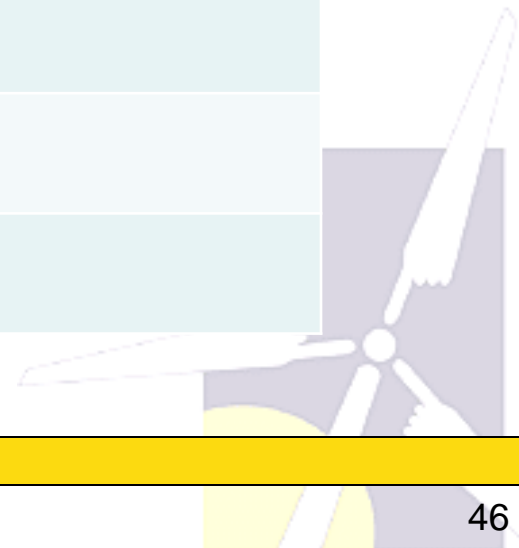
**Proposed Input = included in installed costs**

Source and Cost of Construction Financing

**Proposed Input = included in installed costs**

Debt-to-equity ratio

**Proposed Input = debt optimized to cash flow**





## Researched cost, O&M and financing inputs: Hydro 500-1000kW

### Input category

Debt tenor (years)

**Proposed Input = 14 Yrs.**

Interest rate on debt (%)

**Proposed Input = 6.75%**

Lender's Fee

**Proposed Input = included in cap. cost**

Avg. Debt Service Coverage Ratio

**Proposed Input = 1.45**

After Tax Return on Equity (e.g. IRR) (%)

**Proposed Input = 12%**

Decommissioning Reserve

**Proposed Input = \$0**

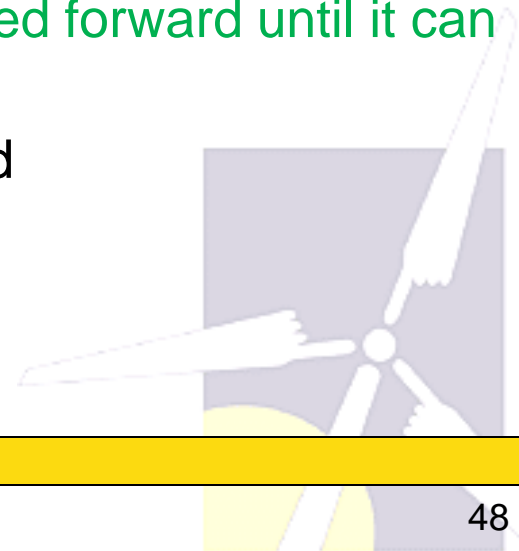






# Incentives

- Current Production Tax Credit (PTC) expires as of 12/31/2012.
  - Hydro is eligible for 50% of face value
  - Ceiling prices calculated both with and without PTC extension.
  - Monetization assumption reduced to 90% to reflect the difficulty and cost of securing tax equity as well as the associated transaction costs.
- Assume Bonus Depreciation no longer available
- Proposed CPs are an average of two modeling runs – one which assumes state tax benefits are used as generated, and a second which assumes the Net Operating Loss is carried forward until it can be used by the project.
- No federal, state, local or other grants assumed





# Additional Assumptions

- Commercial operation achieved in 2013
- Project Useful Life: 30 years
- Minimum Debt Service Coverage Ratio: 1.20X
- Average Debt Service Coverage Ratio: 1.45X
- Interconnection Costs depreciated on 15-year MACRS schedule
- All other project costs:
  - 96% depreciated on 5-year MACRS
  - 2% depreciated on 15-year MACRS
  - 2% not depreciable
- Federal Income Tax rate 35%; State rate 9%
- All tax benefit utilized in period generated, unless otherwise noted
- Market value of production (assumed revenue) post-contract = 75% of sum of energy and capacity price forecasts from 2011 Avoided Energy Supply Cost Study and \$5/REC (see next slide)



# Additional Assumptions:

## Forecast of Market Value of Production

| Project Year | Calendar Year | Market Value of Production<br>(incl. energy, capacity & RECs) (cents/kWh) |
|--------------|---------------|---|
| 16           | 2029          | 9.70  |
| 17           | 2030          | 9.89  |
| 18           | 2031          | 10.08   |
| 19           | 2032          | 10.27   |
| 20           | 2033          | 10.46   |
| 21           | 2034          | 10.66   |
| 22           | 2035          | 10.87   |
| 23           | 2036          | 11.08   |
| 24           | 2037          | 11.29   |
| 25           | 2038          | 11.51   |
| 26           | 2039          | 11.73   |
| 27           | 2040          | 11.95   |
| 28           | 2041          | 12.18   |
| 29           | 2042          | 12.37   |
| 30           | 2043          | 12.56   |



## **Sustainable Energy Advantage, LLC**

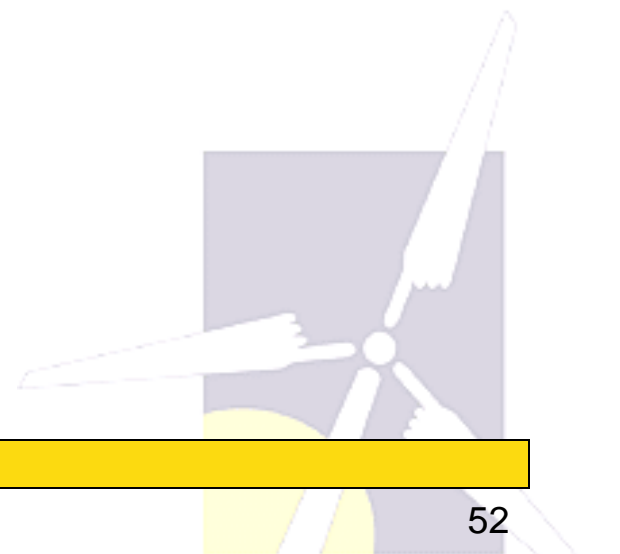
**10 Speen Street  
Framingham, MA 01701  
508.665.5850**

**[www.seadvantage.com](http://www.seadvantage.com)**

**Bob Grace  
tel. 508.665.5855  
[bgrace@seadvantage.com](mailto:bgrace@seadvantage.com)**



# APPENDIX A - SOLAR





# Capital Cost, Installed: Details, Sources

(Includes soft costs & construction financing; excludes Interconnection)

- Stakeholder Data Request
  - Responses received from stakeholders: solar (12), wind (9), anaerobic digestion (5) and hydro (5)
- Follow up Interviews; Data available to SEA through other recent engagements
- Industry Databases Polled

**Usable data extracted from:**

- MA SREC Database [installed cost data analyzed from projects installed within the last 3, 6, and 9 months]
- NREL July 2012 distributed generation cost estimates

**Database reviewed; data of limited direct usefulness, from:**

- NYSERDA PowerClerks Database (Only systems <100 kW; access to raw data not available)
- California Solar Initiative Database (Data concerns, inconsistency with more relevant databases)
- Mass CEC Commonwealth Solar Database (Not updated since 3/12; likely redundant with SREC Database)
- Delaware SREC Long-term Contract Auction Results (No installed cost data available, only auction results)
- New Jersey EDC Long-term Contract Auction Results (No installed cost data available, only auction results, last auction was in 2011)

**Costs embedded in total installed cost estimates include:**

**Soft Costs:** development, permitting, engineering costs, as well as interest incurred during construction, the initial funding of all required reserve accounts, financing closing costs, and lender fees (if applicable)

**Inverter warranty:** The solar CREST model has the ability to incorporate two capital expenditures during operations, which could be used to model inverter replacements. In response to recent data and stakeholder feedback, however, this analysis assumes that a 20-year inverter warranty is included in the total installed cost estimate. No additional inverter replacement costs are modeled.



# Mass SREC Database

## (Sept 2011-August 2012)

Mass SREC Database - Average Installed Cost by Bin Quarter (\$/Watt)

| Size Bin (kW) | Sept-Nov 2011 | Dec-Feb | March-May 2012 | June-August |
|---------------|---------------|---------|----------------|-------------|
| 50-100        | \$5.97        | \$5.59  | \$4.75         | \$4.85      |
| 101-250       | \$5.14        | \$5.48  | \$4.76         | \$4.33      |
| 251-500       | \$4.75        | \$4.78  | \$3.98         | \$4.00      |
| 500+          | \$3.82        | \$5.25  | \$4.11         | \$4.10      |

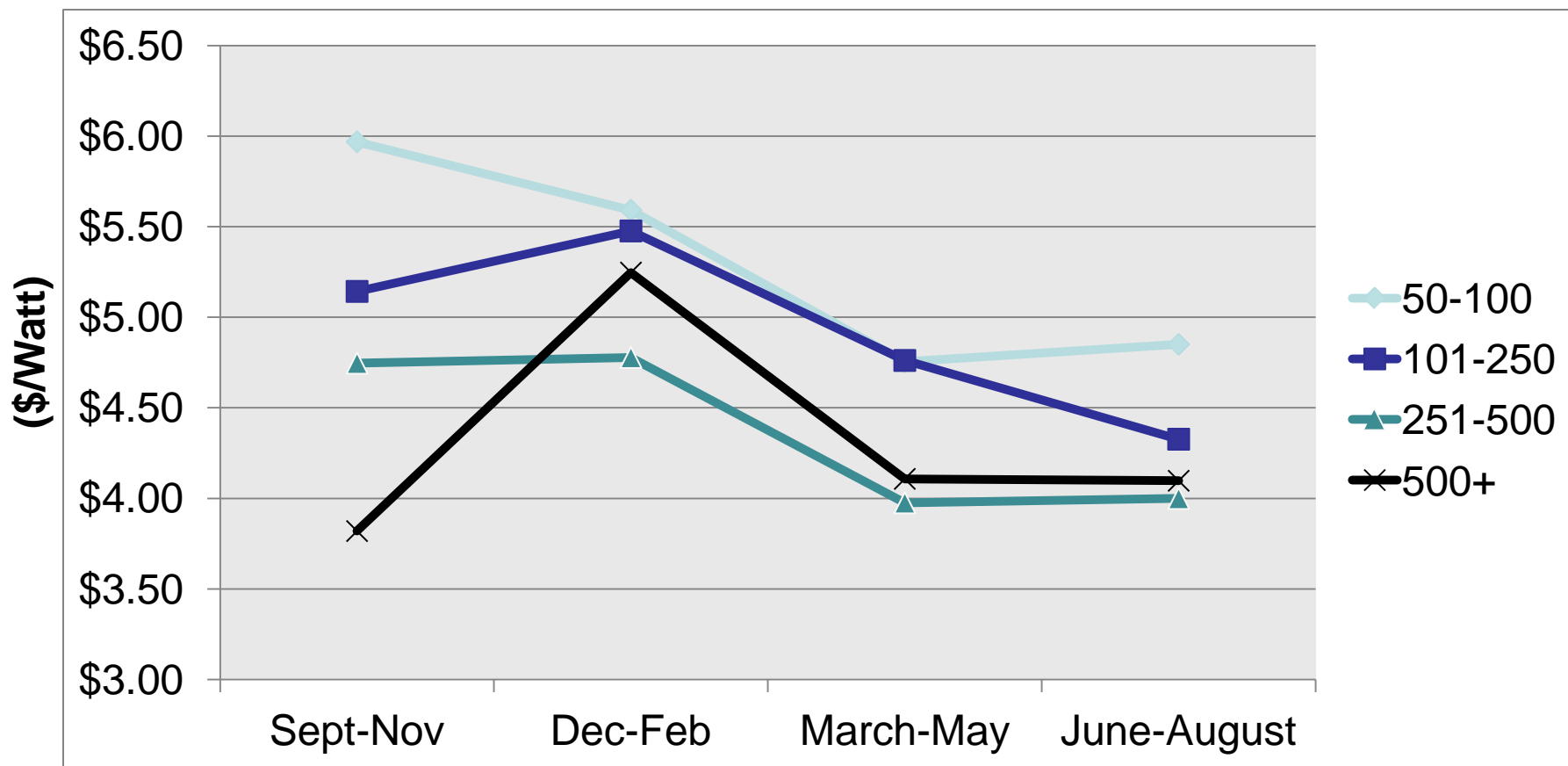
Mass SREC Database - Average Installed Cost for Target Sizes by Quarter (\$/Watt)

| Size Bin (kW) | Sept-Nov 2011 | Dec-Feb | March-May 2012 | June-August |
|---------------|---------------|---------|----------------|-------------|
| 350-650       | \$5.05        | \$4.88  | \$4.35         | \$3.84      |
| 1000-2500     |               | \$5.75  | \$4.33         | \$3.98      |

Note: MA SREC data are backward looking, and generally represent the downward trending market. Where comparable, 2013 costs are expected to be lower.



## Mass SREC Database Trend: Average Cost (Sept 2011-August 2012)







## Mass SREC Database: Avg. - 1 Std. Deviation (Sept 2011 – August 2012)

Mass SREC Database – Avg. Installed Cost minus 1 Std Dev by Qtr. (\$/Watt)

| Size Bin (kw) | Sept-Nov 2011 | Dec-Feb | March-May 2012 | June-August |
|---------------|---------------|---------|----------------|-------------|
| 50-100        | \$4.49        | \$4.32  | \$4.02         | \$4.07      |
| 101-250       | \$4.62        | \$3.82  | \$3.64         | \$3.53      |
| 251-500       | \$4.20        | \$3.76  | \$3.19         | \$3.46      |
| 500+          |               | \$3.67  | \$3.70         | \$3.20      |

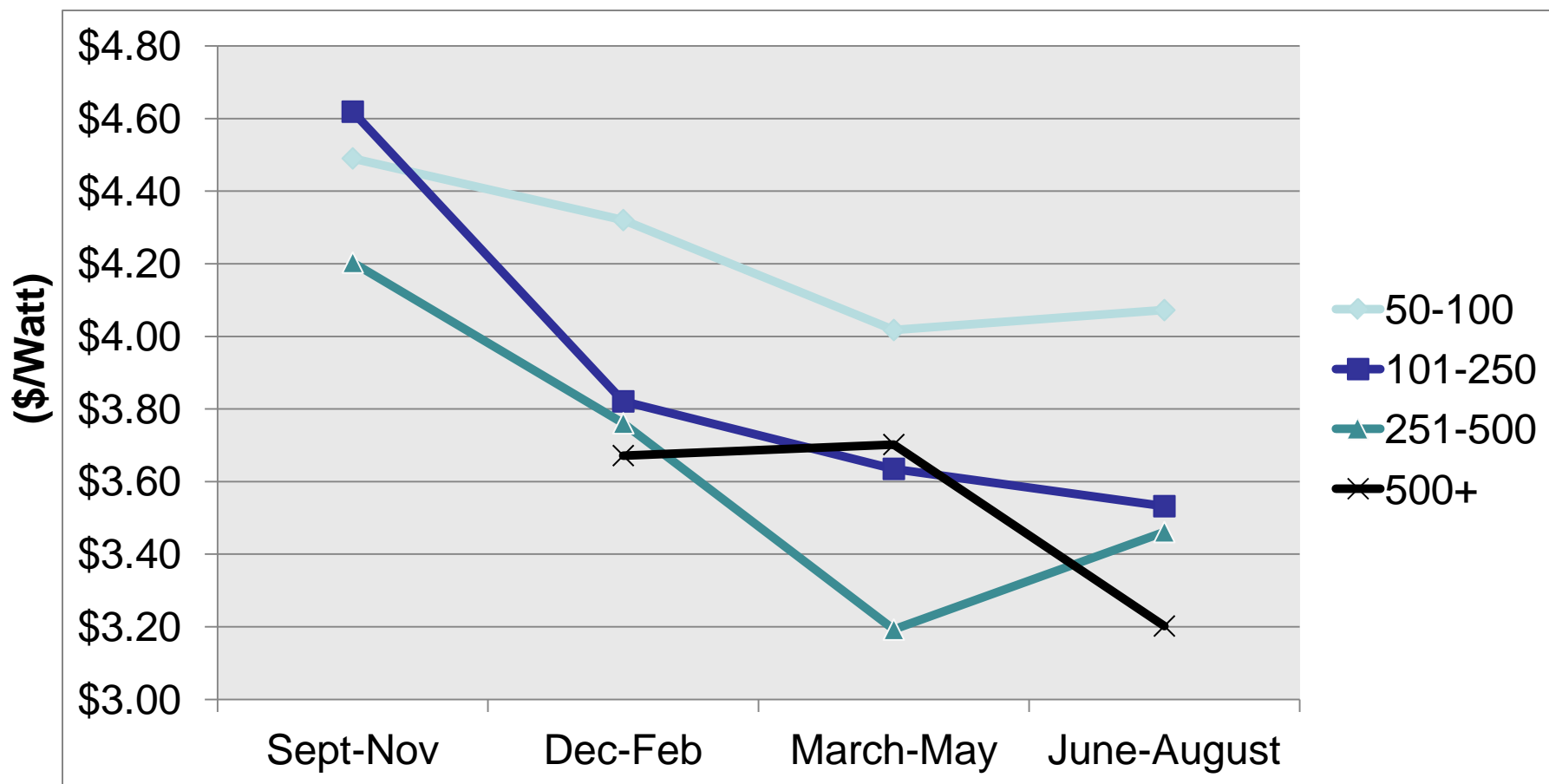
Mass SREC Database – Avg. Inst. Cost minus 1 Std Dev for Target Sizes by Qtr. (\$/Watt)

| Size Bin (kw) | Sept-Nov 2011 | Dec-Feb | March-May 2012 | June-August |
|---------------|---------------|---------|----------------|-------------|
| 350-650       | \$4.06        | \$3.99  | \$3.79         | \$2.88*     |
| 1000-2500     |               | \$4.08  | \$4.07         | \$3.13      |

\* StdDev not meaningful due to small sample size.



## Mass SREC Database Minus 1 Standard Deviation (Sept 2011-August 2012)

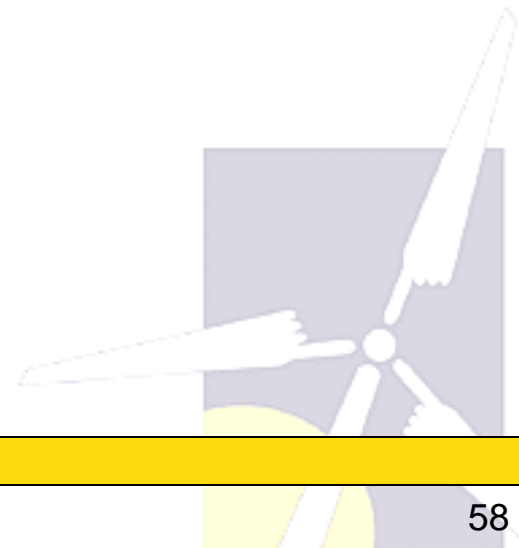




## Mass SREC Database: Minimum Installed Cost in Each Bin

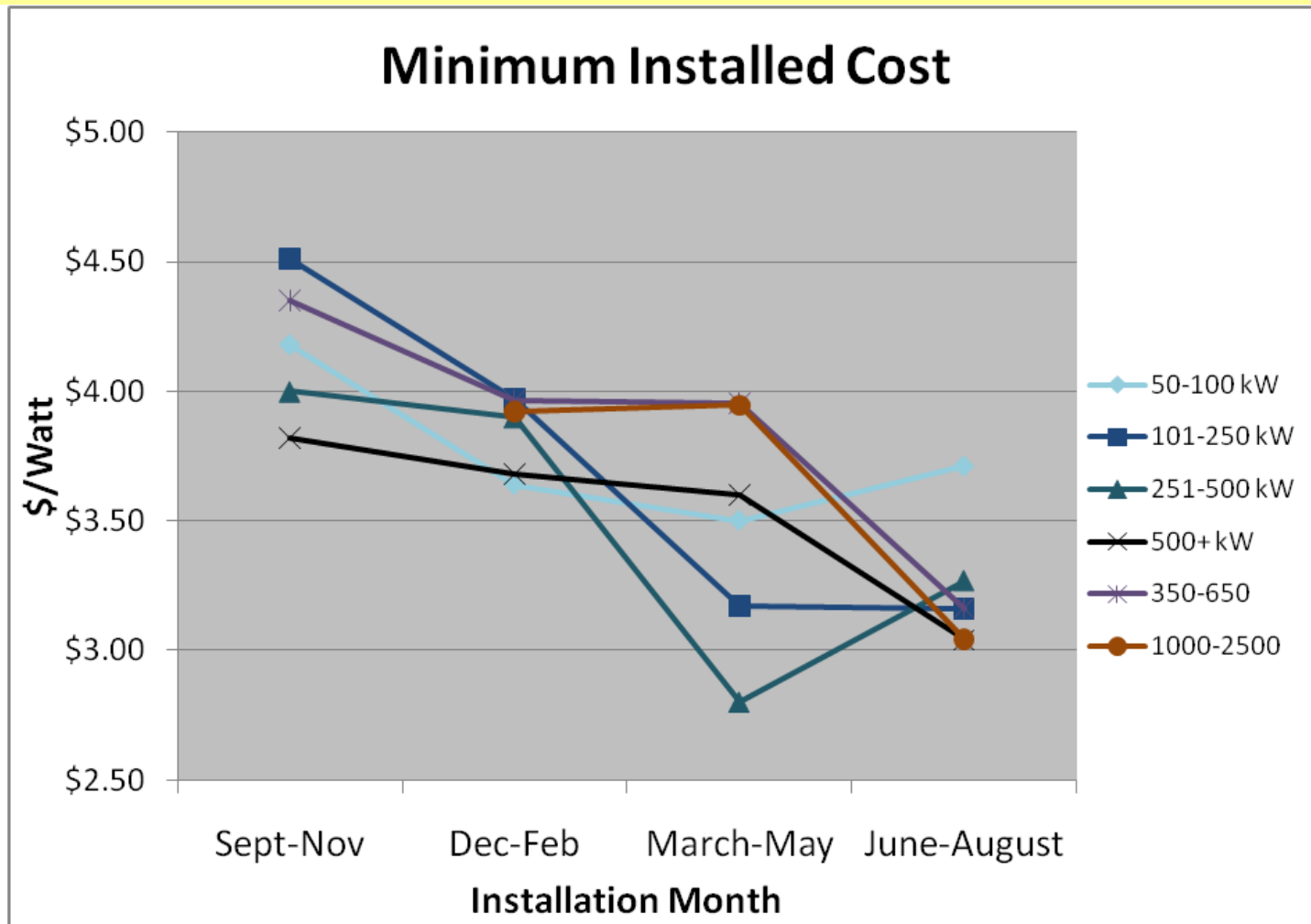
| Bin     | Installation Month (Range) | Min Installed Cost (\$/Watt) |
|---------|----------------------------|------------------------------|
| 50-100  | Sept-Nov                   | \$4.18                       |
|         | Dec-Feb                    | \$3.64                       |
|         | March-May                  | \$3.50                       |
|         | June-August                | \$3.71                       |
| 101-250 | Sept-Nov                   | \$4.51                       |
|         | Dec-Feb                    | \$3.97                       |
|         | March-May                  | \$3.17                       |
|         | June-August                | \$3.16                       |
| 251-500 | Sept-Nov                   | \$4.00                       |
|         | Dec-Feb                    | \$3.90                       |
|         | March-May                  | \$2.80                       |
|         | June-August                | \$3.27                       |
| 500+    | Sept-Nov                   | \$3.82                       |
|         | Dec-Feb                    | \$3.68                       |
|         | March-May                  | \$3.60                       |
|         | June-August                | \$3.04                       |

| Target Size | Installation Month (Range) | Min Installed Cost (\$/Watt) |
|-------------|----------------------------|------------------------------|
| 350-650     | Sept-Nov                   | \$4.35                       |
|             | Dec-Feb                    | \$3.96                       |
|             | March-May                  | \$3.95                       |
|             | June-August                | \$3.16                       |
| 1000-2500   | Sept-Nov                   |                              |
|             | Dec-Feb                    | \$3.92                       |
|             | March-May                  | \$3.95                       |
|             | June-August                | \$3.04                       |





## Mass SREC Database: Minimum Installed Cost in Each Bin





# NREL National PV Cost Estimates

|          | Mean Costs<br>(\$/Watt) | St Dev | Mean – 1 St Dev |
|----------|-------------------------|--------|-----------------|
| <10 kW   | \$4.78                  | \$0.82 | \$3.96          |
| 10-100   | \$4.43                  | \$0.54 | \$3.89          |
| 100-1000 | \$3.67                  | \$0.67 | \$3.00          |
| 1-10MW   | \$3.38                  | \$0.61 | \$2.77          |

Data from: *Distributed Generation Renewable Energy Estimate of Costs*  
National Renewable Energy Laboratory, July 2012

[http://www.nrel.gov/analysis/pdfs/2012\\_dg\\_icoe\\_data.pdf](http://www.nrel.gov/analysis/pdfs/2012_dg_icoe_data.pdf)





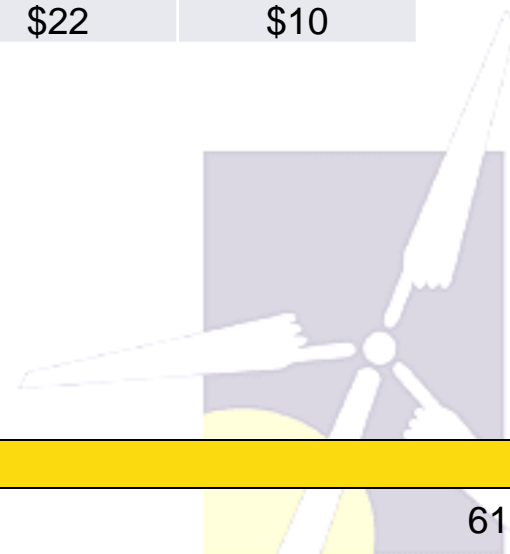
# Operation & Maintenance (O&M) Cost

## Sources

- NREL National PV Cost Estimates

| Project Size | Fixed O&M (\$/kW-year) | O&M Std Dev |
|--------------|------------------------|-------------|
| <10 kW       | \$29                   | \$20        |
| 10-100 kW    | \$26                   | \$19        |
| 100-1000 kW  | \$24                   | \$13        |
| 1-10 MW      | \$22                   | \$10        |

- MCG experience
- SEA experience
- Stakeholder DR



# Mass SREC Database Descriptive Stats

| Bin       | Months      | No. | Mean (\$/Watt) | StdDev | Max    | Min    |
|-----------|-------------|-----|----------------|--------|--------|--------|
| 50-100    | Sept-Nov    | 6   | \$5.97         | \$1.48 | \$8.30 | \$4.18 |
|           | Dec-Feb     | 16  | \$5.59         | \$1.27 | \$7.83 | \$3.64 |
|           | March-May   | 9   | \$4.75         | \$0.74 | \$5.98 | \$3.50 |
|           | June-August | 8   | \$4.85         | \$0.78 | \$5.97 | \$3.71 |
| 101-250   | Sept-Nov    | 8   | \$5.14         | \$0.52 | \$5.75 | \$4.51 |
|           | Dec-Feb     | 22  | \$5.48         | \$1.66 | \$9.60 | \$3.97 |
|           | March-May   | 12  | \$4.76         | \$1.13 | \$7.07 | \$3.17 |
|           | June-August | 8   | \$4.33         | \$0.79 | \$5.47 | \$3.16 |
| 251-500   | Sept-Nov    | 7   | \$4.75         | \$0.54 | \$5.75 | \$4.00 |
|           | Dec-Feb     | 8   | \$4.78         | \$1.02 | \$6.78 | \$3.90 |
|           | March-May   | 5   | \$3.98         | \$0.78 | \$4.75 | \$2.80 |
|           | June-August | 4   | \$4.00         | \$0.54 | \$4.52 | \$3.27 |
| 500+      | Sept-Nov    | 1   | \$3.82         | \$0.00 | \$3.82 | \$3.82 |
|           | Dec-Feb     | 8   | \$5.25         | \$1.58 | \$7.80 | \$3.68 |
|           | March-May   | 6   | \$4.11         | \$0.41 | \$4.49 | \$3.60 |
|           | June-August | 9   | \$4.10         | \$0.89 | \$5.76 | \$3.04 |
| 1000-2500 | Sept-Nov    | 0   |                |        |        |        |
|           | Dec-Feb     | 5   | \$5.75         | \$1.67 | \$7.80 | \$3.92 |
|           | March-May   | 4   | \$4.33         | \$0.26 | \$4.49 | \$3.95 |
|           | June-August | 4   | \$3.98         | \$0.85 | \$5.05 | \$3.04 |



# Interconnection

## Details, Sources

- National Grid:
  - data from Standard Offer bids, plus
  - random sample of 21 MA & RI projects
- Stakeholder DR





# Finance Structure & Costs of Debt and Equity

## Details, Sources

- Stakeholder Data Request
- SEA Experience
- Model optimized based on avail cash flows

## NOTE:

- Available data suggest a wider range of equity returns than returned in response to the data request, with much lower costs on the low-end of the range possible. Scale and ability to replicate are important factors.
- NREL Renewable Energy Finance Tracking Initiative, 2011:
  - Avg. equity return for solar < 1 MW (Q4'09-2011): developer equity ~12%; tax equity ~11%
    - Tax equity: 1<sup>st</sup> half 2011 ~7.8%; 2<sup>nd</sup> half 2011 ~10%
  - Solar developer return variance within 200 bps; tax equity w/in 70 bps
  - Trend is generally downward for both cash and tax equity.



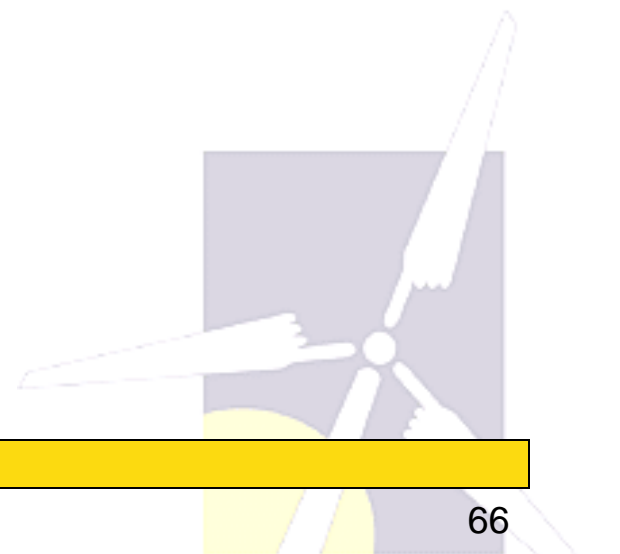
# Performance

## Details, Sources

- PV Watts assumes no tracking, idealized orientation & tilt
- Stakeholder Data Request
- Inverter conversion factor based on data request and manufacturer input
- MA CEC PTS: actual historic production
- Same adjustments as made in 2011.



# APPENDIX B - WIND





# Additional Comments

## Turbine Capacity Limit:

- Employing a capacity limit of ~2.0 MW would better reflect market conditions. During the last several years, the availability of 1,500 kW turbines has decreased in favor of machines in the 1.6, 1.65, 1.8 and 2 MW range.

## Transaction Costs:

- Legal expenses are highly variable, and an important factor until all project processes and documents can be standardized. Legal fees for a project in SEMA were \$400,000.

## Financing Assumptions Post-PTC:

*“We’ve not seen small [wind] projects pencil out without PTC for any reasonable return”*

## Behind the Meter

- *Thus far, 100 kW projects have been developed behind the retail meter, where the economics are more attractive due to net metering.*
- *Additional state-level grants have also played an important role for these projects.*



# Capital Cost, Installed

(Includes soft costs & construction financing;  
excludes Interconnection)

## Details, Sources

- Stakeholder DR
- SEA Experience
- Interviews

### Costs embedded in total installed cost estimates include:

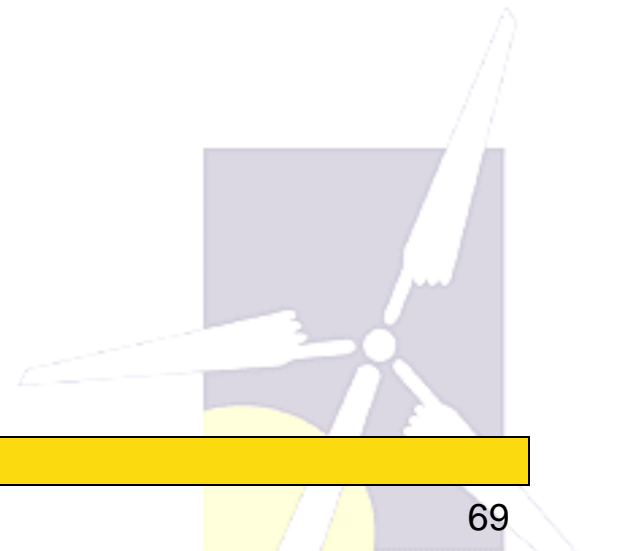
**Soft Costs:** development, permitting, engineering costs, as well as interest incurred during construction, the initial funding of all required reserve accounts, financing closing costs, and lender fees (if applicable)



# O&M Cost

## Details, Sources

- Stakeholder DR
- Interviews
- SEA Experience





# Interconnection

## Details, Sources

- Stakeholder DR
- National Grid: random sample of projects in RI & MA



# Finance Structure & Costs of Debt and Equity

## Details, Sources

- Stakeholder DR
- Interviews
- SEA Experience
- Model optimized based on available cash flows

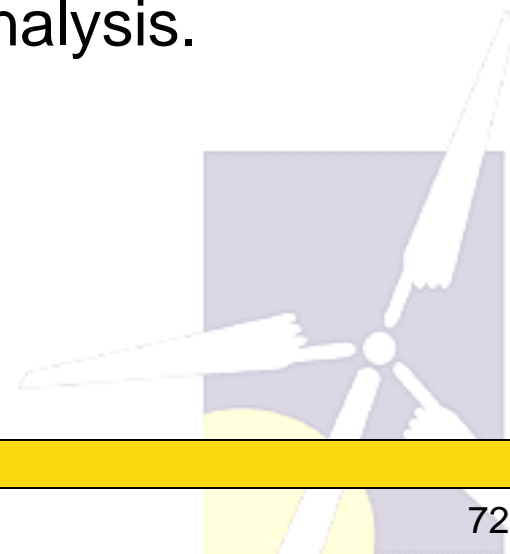




# Performance

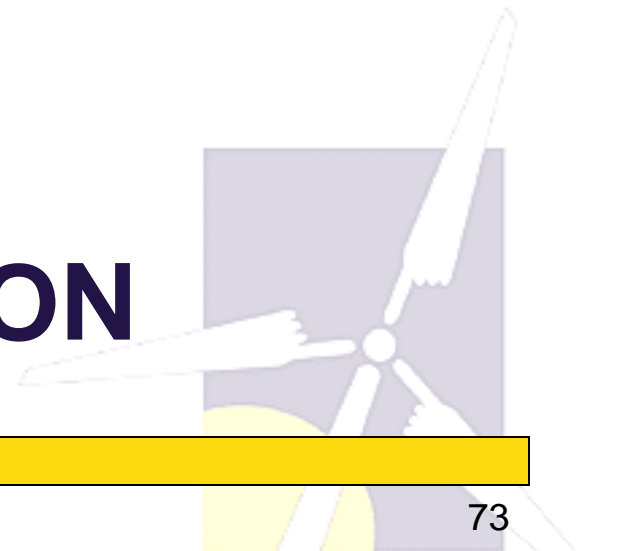
## Details, Sources

- Stakeholder DR
- SEA Experience
- MA CEC PTS
- Adjustment made for recent improvements in low wind-speed turbine performance, per SEA analysis.





# **APPENDIX C – ANAEROBIC DIGESTION**





# Details, Sources

## **Capital Cost, Installed** (Includes soft costs & construction financing; excludes Interconnection)

- Stakeholder DR
- Interviews

Costs embedded in total installed cost estimates include:

**Soft Costs:** *development, permitting, engineering costs, as well as interest incurred during construction, the initial funding of all required reserve accounts, financing closing costs, and lender fees (if applicable)*

## **O&M**

- Stakeholder DR

## **Interconnection**

- Stakeholder DR

## **Finance Structure and Cost of Debt & Equity**

- Stakeholder DR
- Model optimized based on available cash flows

## **Performance**

- Stakeholder DR



## Other Comments

- Costs and revenues (tipping fees) are highly variable and should be assessed on a per-project basis, especially related to digestate management.
- Also, there may be significant economies of scale. Inputs should be sought for each project.