STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
Department of Administration
DIVISION OF LEGAL SERVICES
One Capitol Hill, 4th Floor
Providence, RI 02908-5890
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November 10, 2016

Via U.S. Mail & Email

Luly E. Massaro
Commission Clerk
Public Utilities Commission
89 Jefferson Blvd.
Warwick, RI 02888

Re: The Rhode Island Distributed Generation Board's Report and Recommendations Relating to the 2017 Renewable Energy Growth Classes, Ceiling Prices, and Capacity Targets

Dear Ms. Massaro:

In accordance with R.I. Gen. Laws §§ 39-26.2-5 and 39-26.6-4, the Rhode Island Office of Energy Resources ("OER") hereby files the Rhode Island Distributed Generation Board's ("Board's") report and recommendations relating to the 2017 renewable energy growth classes, ceiling prices, and capacity targets. Enclosed, please find an original and ten (10) copies of the Board's report and recommendations.

Pursuant to R.I. Gen. Laws § 39-26.2-5(b), the Rhode Island Public Utilities Commission shall open a docket to consider for approval the recommendations made by the Board.

If you have any questions or concerns, please do not hesitate to contact me.

Sincerely,

Andrew S. Marcaccio
Senior Legal Counsel
Department of Administration on behalf of the Office of Energy Resources and Distributed Generation Board

cc: Kenneth Payne, Chairperson, Rhode Island Distributed Generation Board
Christopher Kearns, Office of Energy Resources

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

IN RE: THE RHODE ISLAND DISTRIBUTED	:	
GENERATION BOARD'S REPORT AND	:	DOCKET NO. __________
RECOMMENDATIONS RELATING TO THE 2017	:	
RENEWABLE ENERGY GROWTH CLASSES,	:	
CEILING PRICES, AND CAPACITY TARGETS	:	

REPORT AND RECOMMENDATION
OF THE RHODE ISLAND DISTRIBUTED GENERATION BOARD

I. INTRODUCTION

The Distributed Generation Board ("Board") hereby submits its recommendations to the Public Utilities Commission ("Commission") regarding the 2017 ceiling prices and annual targets in accordance with R.I. Gen. Laws § 39-26.6-4(a)(1) and the applicable provisions of R.I. Gen. Laws § 39-26.2-4 and § 39-26.2-5. These recommendations were approved by the Board at its meetings on October 17, 2016, continued to November 1, 2016, to approve the ceiling prices for the community remote distributed generation ceiling price categories; the recommendations were endorsed by Office of Energy Resources ("OER") and are submitted as a package.

The Renewable Energy Growth ("REG") Program, R.I. Gen. Laws § 39-26.6-1 et seq. requires the Board to develop and recommend ceiling prices for tariffs under the REG Program to the Commission for review and approval. The Board had Sustainable Energy Advantage ("SEA") develop the recommended ceiling prices, which SEA has conducted for the Board for prior REG program year submittals to the Commission. The REG Program also requires the Board to develop and recommend to the Commission annual megawatt ("MW") targets for enrollments by specified renewable energy technology classes for the program year. This is the third year in which the Board has made submissions to the Commission under the REG Program.

This filing contains the Board's Report and Recommendations for the 2017 Renewable

Energy Growth Program Classes, Ceiling Prices, and Targets (hereafter "Report"). The Board's 2017 REG Program recommendations are summarized in **Exhibit B**, attached hereto and explained further in the Report.

II. 2016 REG PROGRAM RESULTS

The Rhode Island solar market continued its growth in 2016 as both national and local solar businesses have become more familiar with the REG Program. As of October, over 700 small solar tariffs have been awarded to homeowners across the State. The larger-scale solar market was also very strong in 2016, with full subscriptions in the commercial and large solar classes, including the largest solar project awarded under either the REG or Distributed Generation Standard Contracts Programs to date - a 5 megawatt ground mount solar project in Charlestown. The uptake for the medium solar class increased when compared to the 2015 REG Program. There were no anaerobic digestion or small-scale hydropower projects awarded in 2016, but the Board anticipates one small-scale hydropower project to submit a bid under the 2017 REG Program. No wind projects were submitted in 2016. As we have seen over the last several years, however, wind projects typically occur at intervals that reflect the permitting process, with gaps in between project installations. Overall, both the Board and OER are pleased with the REG Program's progress and National Grid's implementation.

III. PROGRAMMATIC EXPANSION IN 2017

The Rhode Island General Assembly amended the REG law and local taxation laws for renewable energy systems in June 2016. This section summarizes the policies enacted by the General Assembly and signed by Governor Raimondo:

1. *REG Program - Shared Solar Facilities:* Allows multiple solar installations for property owners that share the same room space, such as a

condominium, duplex or business facility where the property has multiple business tenants.

2. *REG Program - Community Remote Distributed Generation Systems:* Allows renewable energy systems greater than 250 kilowatts to have multiple recipients of the energy credits produced from the REG system.

3. *Local Taxation:* Renewable energy systems installed on residential and manufacturing properties are now exempt from local taxation.

4. *Statewide Commercial Renewable Energy System Tangible Tax Value:* OER through rules and regulations shall establish a statewide tangible tax value for commercial renewable energy systems, which municipalities will be required to use effective January 1, 2017. If a municipality is using ordinances or resolutions for collecting tangible taxes on renewable energy systems, then they will be required to use the tangible tax value adopted in OER rules and regulations.

IV. THE BASIC REQUIREMENTS OF THE REG PROGRAM

The applicable provisions of the REG law pertaining to the development of ceiling prices are as follows:

> *"Ceiling price" means the bidding price cap applicable to an enrollment for a given distributed-generation class that shall be approved annually for each renewable-energy class pursuant to the procedure established in this chapter. The ceiling price for each technology should be a price that would allow a private owner to invest in a given project at a reasonable rate of return, based on recently reported and forecast information on the cost of capital, and the cost of generation equipment. The calculation of the reasonable rate of return for a project shall include, where applicable, any state or federal incentives, including, but not limited to, tax incentives.* See R.I. Gen. Laws § 39-26.6-3(17)
>
> *The board shall use the same standards for setting ceiling prices as set forth in § 39-26.2-5. In setting the ceiling prices, the board may specifically consider:*

(1) Transactions for newly developed renewable energy resources, by technology and size, in the ISO-NE control area and the northeast corridor;

(2) Pricing from bids received during the previous program year;

(3) Environmental benefits, including, but not limited to, reducing carbon emissions;

(4) System benefits; and

(5) Cost effectiveness. See R.I. Gen. Laws § 39-26.6-5(d)

In addition, the Board is expected by R.I. Gen. Laws § 42-6.2-8 to exercise its powers in manner that addresses the purposes of the Resilient Rhode Island Act.

V. 2017 REG PROGRAM

A. Technology Classes and System Sizes

The anticipated outcomes for the 2017 REG Program are the following:

1. A diversified renewable energy program, in accordance with the purposes of R.I. Gen. Laws Ch. 39-26.6, with a portion of the MW capacity to support each sector.
2. As appropriate, continued decreases in ceiling prices in each technology – signaling increased program cost effectiveness.
3. Economic development in the renewable energy market.

The Board recommends the following classes and eligible system sizes for solar, wind, anaerobic digestion and small scale hydropower. The 2017 REG Program includes the same technology and classes that were filed and approved for the 2016 REG Program, and recommends reconstituting a class for small wind systems (which had been present as part of the 2011-2013 DG Standard Contracts Program):

Table I

Technology Class	Eligible System Sizes
Small Solar I – Host Owned	1 to10 kW DC
Small Solar I – Third Party Owned	1 to 10 kW DC
Small Solar II	11 to 25 kW DC
Medium Solar	26 to 250 kW DC
Commercial Solar	251 to 999 kW DC
Large Solar	1 to 5 MW DC
Small Wind	10 to 999 kW DC
Wind I	1.0 to 2.99 MW DC
Wind II	3.0 to 5.0 MW DC
Wind III	3.0 to 5.0 MW DC
Anaerobic Digestion I	150 to 500 kW DC
Anaerobic Digestion II	501 kW to 1 MW DC
Small Scale Hydropower I	10 to 250 kW DC
Small Scale Hydropower II	251 kW to 1 MW DC

In addition, and pursuant to the July 2016 legislation, the Board recommends the following community remote classes and eligible system sizes for solar and wind.

Table II

Technology	Eligible System Sizes
Community Remote – Commercial Solar	251 to 999 kW DC
Community Remote – Large Solar	1 to 5 MW DC
Community Remote – Wind I	1.0 to 2.99 MW DC
Community Remote – Wind II	3.0 to 5.0 MW DC
Community Remote – Wind III	3.0 to 5.0 MW DC

B. <u>Recommended Ceiling Prices</u>

The Board, with SEA and OER, considered the following data when developing the ceiling prices recommendations:

1. State or federal incentives including, but not limited to, tax incentives;
2. Transactions for newly developed renewable energy resources, by technology and size, in the ISO-NE region and the northeast corridor;
3. Pricing for DG Standard Contracts executed between 2011 and 2014 and first two years (2015 and 2016) of the REG Program;

4. Updated Property Tax Laws;
5. Rhode Island and Massachusetts Interconnection Costs;
6. Cost effectiveness for the eligible technology; and
7. Public Comments and Data received from stakeholders, including estimates of the cost and performance of their projects currently under development.

The Board developed ceiling price recommendations for each technology and size class listed in Tables I and II above. The Board recommends that all of the solar ceiling prices include the benefit of the thirty percent (30%) federal investment tax credit ("ITC"), as the full value of this credit is available for projects achieving commercial operation by December 31, 2019. A prescribed phasedown of the ITC commences thereafter. While the Production Tax Credit ("PTC") was also extended, the wind PTC (or ITC in lieu thereof) is subject to an earlier phasedown than the solar ITC. As a result, the Board recommends that the wind ceiling prices include a benefit equal to 80% of the (30%) full value of the ITC. The Board recommends ceiling prices for the anaerobic digestion and small-scale hydropower classes without the federal production tax credit (or ITC in lieu thereof) because this incentive is not currently available. Federal accelerated depreciation benefits – including bonus depreciation – are also assumed to be captured.

2017 Ceiling Price Development

SEA has previously advised the development of the 2011, 2012, 2013 and 2014 DGSC and the 2015 and 2016 REG ceiling prices. SEA used the Cost of Renewable Energy Spreadsheet Tool ("CREST") Model to evaluate potential 2017 ceiling prices. The CREST Model was published as a report of the National Renewable Energy Laboratory, a national laboratory of the U.S. Department of Energy, Office of Renewable Energy and Energy Efficiency.

To generate ceiling prices with the CREST Model, SEA collected data from similar renewable energy programs in Rhode Island, Massachusetts, Connecticut, Vermont, and New York. SEA also requested from National Grid the economic and interconnection data from the DGSC and REG applications submitted in 2011, 2012, 2013, 2014, 2015 and 2016 (to date). SEA, on behalf of the Board, also issued a survey to stakeholders at the beginning of the 2017 ceiling price development process (July 2016). SEA further requested data and comments from stakeholders to inform the development of a first, second, and final draft of the ceiling prices. SEA staff was made available to OER, Board members, and stakeholders during the development of the ceiling prices. SEA attended and participated in three (3) public meetings, including public discussion of the research conducted and data submitted, as well as meeting to discuss each of the draft ceiling price recommendations. In addition, SEA also attended the October 17th Board meeting, where the 2017 REG Program Report was unanimously approved.

Tables III and IV provide the Board's recommended 2017 ceiling prices:

Table III

Technology	Ceiling Prices (¢/kWh)
Small Solar I – Host Owned (15 Year Tariff)	34.75
Small Solar I – Host Owned (20 Year Tariff)	30.85
Small Solar I – Third Party Owned (15 Year Tariff)	27.05
Small Solar I – Third Party Owned (20 Year Tariff)	24.05
Small Solar II (11-25)	27.75
Medium Solar (26-250)	22.75
Commercial Solar	18.75
Large Solar	15.05
Small Wind	21.45
Wind I	19.45
Wind II	18.25
Wind III	17.35
Anaerobic Digestion I	20.15
Anaerobic Digestion II	20.15
Small Scale Hydropower I	22.45
Small Scale Hydropower II	22.45

Table IV – Community Remote Distributed Generation Classes

Technology	Ceiling Prices (¢/kWh)
Community Remote – Commercial Solar	20.65
Community Remote – Large Solar	16.85
Community Remote – Wind I	20.65
Community Remote – Wind II	19.35
Community Remote – Wind III	18.55

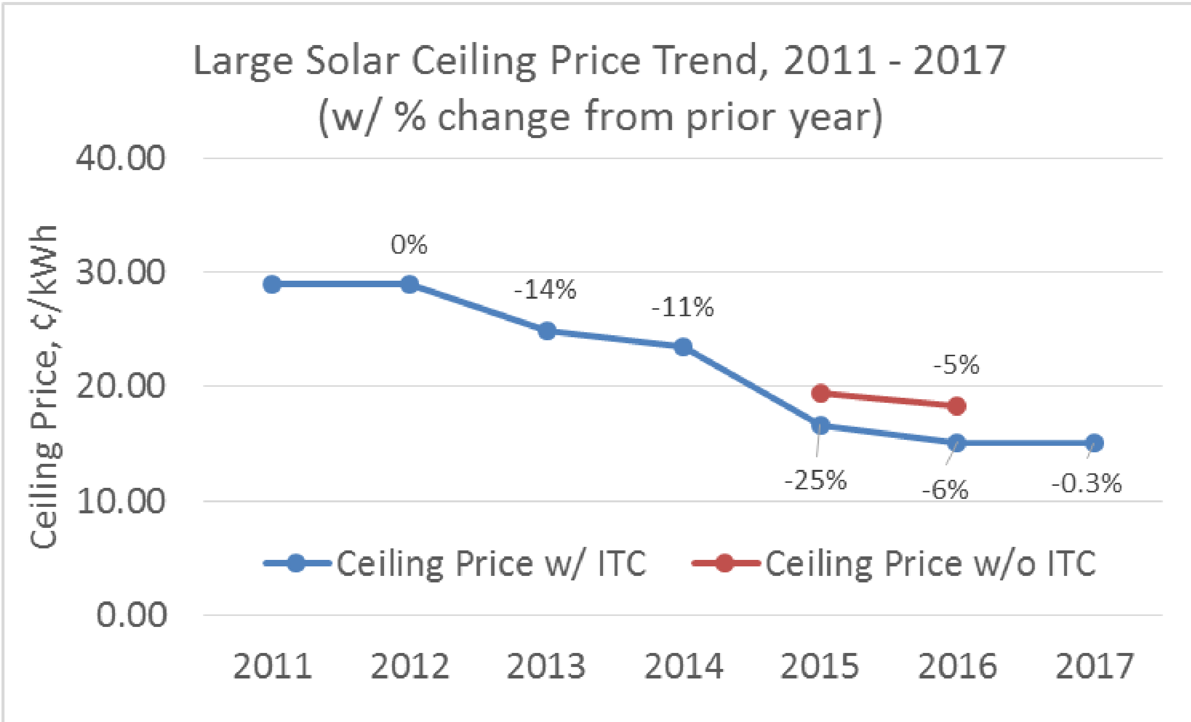
Solar (Modeling Inputs Sources)

The CREST modeling relied upon information provided by stakeholders, as well as data from the Rhode Island Renewable Energy Fund, past DGSC and REG enrollments, National Grid, the Massachusetts SREC Database, the Massachusetts Commonwealth Solar Program, NYSERDA (the New York Power Clerks Database), Lawrence Berkeley National Laboratories, and the Department of Energy to determine inputs used in modeling. Interconnection cost data were provided by National Grid and stakeholders. SEA also reviewed data from the Department of Energy's *Tracking the Sun* Program.

Solar (Comparison to 2016 REG Ceiling Prices)

Solar Ceiling Price Category	% Change between 2016 Actual and 2017 Proposed Ceiling Prices
Small Solar I (Host Owned)	15 year: -8%; 20 year: -8%
Small Solar I (Third Party Owned)	15 year: -5%; 20 year: -3%
Small Solar II	11%
Medium Solar	0.9%
Commercial Solar	-3.0%
Large Solar	-0.3%

The following chart summarizes the Ceiling Price trend for the Large Solar category from 2011 to 2017 (proposed), and includes the percentage change from year to year:



Changes in solar ceiling prices are based on updates to equipment (including interconnection), installation, and operating expenses, as well as tax and financing assumptions, where applicable.

Wind (Modeling Inputs Sources, and Comparison to Past DGSC Ceiling Prices)

The CREST modeling relied upon information provided by stakeholders, as well as data from the Massachusetts Clean Energy Center and the Lawrence Berkeley National Laboratory to determine inputs used in modeling. Historic interconnection cost data were provided by National Grid. Recent interconnection study cost data were provided by Wind Energy Development. A new Ceiling Price class is proposed for small wind (10 – 999 kW), with the expectation that it will lead to participation by the 100 kW turbine currently available in the market. Modest adjustments are recommended for the existing Ceiling Price classes Wind I, II & III The proposed ceiling prices would provide an 4 percent increase compared to 2016 for the Wind I technology class, a 1 percent increase for Wind II , and a 0.3 percent decrease for Wind III. The increase in ceiling prices for the Wind I and II technology classes is due to assumptions for increased interconnection cost and major capital expenditures during operations.

The Board and SEA recommend these proposed ceiling prices as necessary to support wind development in Rhode Island, taking into account the difficulty of wind project siting and permitting, and the significant cost of developing, financing, constructing and operating wind projects that cannot benefit from the economies of scale that support the cost reduction trend demonstrated in other parts of the country. These high cost conditions are further exacerbated by the fact that on-shore wind development in Rhode Island will likely take place inland, as opposed to in coastal areas, where wind regimes are weaker. This leads to a lower production per MW of capacity, and a higher cost per MWh than would be expected for most well-sited wind turbines in other areas.

Anaerobic Digestion (Comparison to Past DGSC Ceiling Prices)

In 2014, there was only one Anaerobic Digestion technology class (50kW - 1.0MW). For the 2017 REG Program, the same ceiling price is once again recommended for both Anaerobic Digestion I and II technology classes. This proposed ceiling price would provide a 0.25 percent decrease compared to 2016, due to (largely offsetting) changes in assumed fuel consumption, heat rate, financing terms and tipping fees[1].

Small Scale Hydropower (Comparison to Past DGSC Ceiling Prices)

In 2014, there was only one Small Scale Hydropower technology class (50kW - 1.0MW). For the 2017 REG Program, the same ceiling price is once again recommended for Hydro I and Hydro II. Hydroelectric development generally requires longer lead-times and is subject to more site-specific cost variation than other renewable energy technologies. As a mature technology, where available resources have largely been developed over the last 100+ years, there are limited

[1] A tipping fee represents the revenue that the facility would receive for accepting food waste.

opportunities for incremental hydro development. The recommended ceiling prices represent the acquisition of additional data about the costs to develop and operate those Rhode Island sites that may provide opportunity to install additional hydro capacity. The recommended Ceiling Price would result in a 20 percent increase for Hydro I and a 29% increase for Hydro II.

Table V provides a comparison to the proposed 2017 ceiling prices to the ceiling prices that were approved for the 2016 REG Program:

Table V*

2017 Renewable Energy Growth Program Recommended Ceiling Prices v. 2016 REG Approved Ceiling Prices (¢/kWh)				
2015 Technology Class	2016		2017	
	Size	Price (c/kWh)	Size	Price (c/kWh)
Small Solar I - Host -15 year tariff	1 - 10 kW	37.65	1 - 10 kW	34.75
Small Solar I - Host – 20 year tariff	1 - 10 kW	33.45	1 - 10 kW	30.85
Small Solar I - 3rd Third Party Owned/Financed – 15 year tariff	1 – 10 kW	28.35	1 - 10 kW	27.05
Small Solar I - 3rd Third Party Owned/Financed – 20 year tariff	1 - 10 kW	24.70	1 - 10 kW	24.05
Small Solar II	10 - 25 kW	24.90	10-25 kW	27.75
Medium Solar	26 - 250 kW	22.55	26-250 kW	22.75
Commercial Solar	251 - 999 kW	19.30	251-999 kW	18.75
Large Solar	1 - 5 MW	15.10	1 – 5 MW	15.05
Small Wind		NA		21.45
Wind I	1500 - 2999 kW	18.75	1500 - 2999 kW	19.45
Wind II	3000 - 5000 kW	18.00	3000 - 5000 kW	18.25
Wind III	N/A	17.40	3000- 5000 kW	17.35
AD I	150 - 500 kW	20.00	150-500 kW	20.15
AD II	501 - 1000 kW	20.00	501-1000 kW	20.15
Hydro I	10 - 250 kW	18.65	10-250 kW	22.45
Hydro II	250 - 1000 MW	17.45	250-1000 kW	22.45

*No comparison is provided for the proposed 2017 ceiling prices for the community remote distributed generation classes because these classes are a new feature of the REG Program in 2017.

C. Recommended Allocation Plan

The 2017 REG Program will provide 40 MW of total nameplate capacity for fixed price and competitively bid projects. There will be 9.55 MW of capacity available for fixed priced projects and 30.45 MW available through a competitive bidding process.

The Board recommends the following allocation for 2017:

Table VI

<table>
<tr><th>Technology/Classes</th><th>Megawatt/Kilowatt Allocation</th></tr>
<tr><td>Small Solar I – Host Owned (15 Year Tariff)</td><td rowspan="5">6.55 MW DC</td></tr>
<tr><td>Small Solar I – Host Owned (20 Year Tariff)</td></tr>
<tr><td>Small Solar I – Third Party Owned (15 Year Tariff)</td></tr>
<tr><td>Small Solar I – Third Party Owned (20 Year Tariff)</td></tr>
<tr><td>Small Solar II (11-25)</td></tr>
<tr><td>Medium Solar (26-250)</td><td>3.0 MW DC</td></tr>
<tr><td>Commercial Solar</td><td>5.0 MW DC</td></tr>
<tr><td>Community Remote - Commercial Solar</td><td>3.0 MW DC</td></tr>
<tr><td>Large Solar</td><td>12.05 MW DC</td></tr>
<tr><td>Community Remote - Large Solar</td><td>3.0 MW DC</td></tr>
<tr><td>Small Wind</td><td>0.400 MW DC</td></tr>
<tr><td>Community Remote and Non-Community Remote Wind I, II and III</td><td>6.0 MW DC</td></tr>
<tr><td>Anaerobic Digestion I</td><td rowspan="4">1.0 MW DC</td></tr>
<tr><td>Anaerobic Digestion II</td></tr>
<tr><td>Small Scale Hydropower I</td></tr>
<tr><td>Small Scale Hydropower II</td></tr>
<tr><td>Total</td><td>40 MW DC</td></tr>
</table>

D. 2017 REG Enrollment Plan Recommendations

The Board recommends the following for the 2017 REG enrollments:

> Allow the MW rollover rule for anaerobic digestion, small scale hydropower and wind technologies to occur during the first and second enrollments in 2017. If there are no projects submitted in the third enrollment to National Grid for these technologies, then the MW capacity

can be redirected to where there is the greatest demand during the final enrollment. This process has been implemented by National Grid during the 2015 and 2016 REG Programs.

SolarWise Program

The REG law allows National Grid to establish a program that coordinates capacity from the REG Program with the state's annual energy efficiency program. This new program began in 2016. The Board unanimously endorsed that the SolarWise program be included as part of the 2017 REG Program and the Board will monitor the lift-off and full implementation of this program in 2017.

Continuous Open Enrollment for Small Solar Class

The Board is recommending again that the small solar class of the REG Program be available through open enrollment, year round. This is how the REG Program operated in 2015 and 2016, and will allow homeowners, businesses, and renewable energy developers the ability to submit their tariff applications on a rolling basis to National Grid, instead of limiting it to three open enrollment periods. This recommendation would allow small solar projects to participate when they are ready.

First Enrollment

The Board recommends the following for the first enrollment in June 2017:

Table VII

<table>
<tr><th>Technology/Classes</th><th>Kilowatt Allocation</th></tr>
<tr><td>Small Solar I – Host Owned (15 Year Tariff)</td><td rowspan="5">6.55 MW DC*</td></tr>
<tr><td>Small Solar I – Host Owned (20 Year Tariff)</td></tr>
<tr><td>Small Solar I – Third Party Owned (15 Year Tariff)</td></tr>
<tr><td>Small Solar I – Third Party Owned (20 Year Tariff)</td></tr>
<tr><td>Small Solar II (11-25)</td></tr>
<tr><td>Medium Solar (26-250)</td><td>3.0 MW DC</td></tr>
<tr><td>Commercial Solar</td><td>5.0 MW DC</td></tr>
</table>

Community Remote - Commercial Solar	3.0 MW DC
Large Solar	12.05 MW DC
Community Remote - Large Solar	3.0 MW DC
Small Wind	0.400 MW DC
Community Remote and Non-Community Remote Wind I, II and III	6.0 MW DC
Anaerobic Digestion I	1.0 MW DC
Anaerobic Digestion II	
Small Scale Hydropower I	
Small Scale Hydropower II	
Total	40 MW DC

*The continuous Small Solar Program is from March 2017 to March 2018.

<u>Second and Third Enrollments</u>

The second (August) and third (October) enrollment quantities will be dependent on the results of the first enrollment.

VI. <u>CONCLUSION</u>

After an extensive and transparent development process, the Board voted unanimously at its October 17, 2016 to approve the recommendations, except those pertaining to the ceiling prices for the community remote distributed generation categories and support for the SolarWise program, which were approved at its meeting on November 1, 2017 made in this Report including the: 2017 REG ceiling prices; 2017 Allocation Plan; and National Grid's SolarWise Program. The Board and OER respectfully request the Commission to approve the recommendations contained in this Report.

LIST OF EXHIBITS

Exhibit A - Distributed Generation Board Members

Exhibit B – Summary of 2017 REG Recommendations:

- Rhode Island Distributed Generation Board Recommended Target Classes, Ceiling Prices, and Targets for the 2017 Renewable Energy Growth Program;
- Rhode Island Distributed Generation Board Recommended 2017 Technology Classes and Allocation Targets; and
- Rhode Island Distributed Generation Board Recommended 2017 Ceiling Prices (¢/kWh), by Technology Class

Exhibit C - Sustainable Energy Advantage Documents:

- Rhode Island Renewable Energy Growth Program: Research & Discussion in Support of 2017 Ceiling Price Recommendations, July 27, 2016, Sustainable Energy Advantage, LLC; Meister Consultants Group, Inc.; Mondre Energy, Inc.;
- Rhode Island Renewable Energy Growth Program: 2017 1st Draft Ceiling Price Recommendations, August 2016, Sustainable Energy Advantage, LLC; Meister Consultants Group, Inc.; Mondre Energy, Inc.;
- Rhode Island Renewable Energy Growth Program: 2017 2nd Draft Ceiling Price Recommendations, September 2016, Sustainable Energy Advantage, LLC; Meister Consultants Group, Inc.; Mondre Energy, Inc.;
- Rhode Island Renewable Energy Growth Program: 2017 Ceiling Price Recommendations, October 2016, Sustainable Energy Advantage, LLC; Meister Consultants Group, Inc.; Mondre Energy, Inc.; and
- Rhode Island Renewable Energy Growth Program: 2017 CRDG Ceiling Price Recommendations, October 2016, Sustainable Energy Advantage, LLC; Meister Consultants Group, Inc.; Mondre Energy, Inc.

EXHIBIT A

Distributed Generation Board Members

Name	**Representing**	**Voting or Non-Voting Member**
Carol Grant	Office of Energy Resources	Non-Voting
Ian Springsteel	National Grid	Non-Voting
Kenneth Payne (Chair)	Energy Regulation and Law	Voting
Vacant*	Construction of Renewable Generation	Voting
William Ferguson	Large Commercial/Industrial Users	Voting
Sam Bradner	Small Commercial/Industrial Users	Voting
Kari Lang	Residential Users	Voting
Sharon Conard-Wells	Low Income Users	Voting
Sheila Dormody	Environmental Issues Pertaining to Energy	Voting

*Sue Anderbois stepped down in June 2016.

EXHIBIT B

Rhode Island Distributed Generation Board
Recommended Target Classes, Ceiling Prices, and Targets for the
2017 Renewable Energy Growth Program

The Board recommends that National Grid conduct three open enrollments and the continuous small solar program in 2017, with the goal of 40 MW of projects being awarded tariffs.

Rhode Island Distributed Generation Board
Recommended 2017 Technology Classes and Allocation Targets

Technology/Classes	Megawatt/Kilowatt Allocation
Small Solar I – Host Owned (15 Year Tariff)	6.55 MW DC
Small Solar I – Host Owned (20 Year Tariff)	
Small Solar I – Third Party Owned (15 Year Tariff)	
Small Solar I – Third Party Owned (20 Year Tariff)	
Small Solar II (11-25)	
Medium Solar (26-250)	3.0 MW DC
Commercial Solar	5.0 MW DC
Community Remote - Commercial Solar	3.0 MW DC
Large Solar	12.05 MW DC
Community Remote - Large Solar	3.0 MW DC
Small Wind	0.400 MW DC
Community Remote and Non-Community Remote Wind I, II and III	6.0 MW DC
Anaerobic Digestion I	1.0 MW DC
Anaerobic Digestion II	
Small Scale Hydropower I	
Small Scale Hydropower II	
Total	40 MW DC

Rhode Island Distributed Generation Board
Recommended 2017 Ceiling Prices (¢/kWh), by Technology Class

Technology and Eligible Class	**Ceiling Price**
Small Solar I – Host Owned (15 Year Tariff)	34.75
Small Solar I – Host Owned (20 Year Tariff)	30.85
Small Solar I – Third Party Owned (15 Year Tariff)	27.05
Small Solar I – Third Party Owned (20 Year Tariff)	24.05
Small Solar II	27.75
Medium Solar	22.75
Commercial Solar	18.75
Community Remote – Commercial Solar	20.65
Large Solar	15.05
Community Remote – Large Solar	16.85
Small Wind	21.45
Wind I	19.45
Community Remote – Wind I	20.65
Wind II	18.25
Community Remote – Wind II	19.35
Wind III	17.35
Community Remote – Wind III	18.55
Anaerobic Digestion I	20.15
Anaerobic Digestion II	20.15
Small Scale Hydropower I	22.45
Small Scale Hydropower II	22.45

EXHIBIT C

Sustainable Energy Advantage Documents

Rhode Island
Renewable Energy Growth Program:

Research & Discussion in Support of 2017 Ceiling Price Recommendations

July 27, 2016

Sustainable Energy Advantage, LLC
Meister Consultants Group, Inc.
Mondre Energy, Inc.

Purpose

- To present stakeholder data responses, survey results, and supplemental research,
- To *begin* the discussion that supports the development of Ceiling Price inputs and recommendations for the 2017 Renewable Energy Growth (REG) Program.
- To develop Ceiling Price recommendations through an iterative, public process.

Overview: Ceiling Price Categories

2017 REG Program: Proposed Technology, Size & Tariff Length Parameters			
For the 2017 REG Program, the DG Board and OER seek comment on the following Ceiling Price technology, system size and tariff length parameters.			
Eligible Technology	**System Size for CP Development**	**Eligible System Size Range**	**Tariff Length**
Small Solar I	5 kW	1 to 10 kW	15 and 20 Years Options
Small Solar II	25 kW	11 to 25 kW	20 Years
Medium Solar	140 kW	26 to 250 kW	20 Years
Commercial Solar	500 kW	251 to 999 kW	20 Years
Large Solar	1.5 MW	1 to 5 MW	20 Years
Wind I	1.65 MW	1 to 2.99 MW	20 Years
Wind II	3.3 MW	3 to 5 MW	20 Years
Wind III	*4.95 MW*	*3 to 5 MW*	*20 Years*
Anaerobic Digestion I	325 kW	150 to 500 kW	20 Years
Anaerobic Digestion II	750 kW	501 kW to 5 MW ☆	20 Years
Small Scale Hydropower I	150 kW	10 to 250 kW	20 Years
Small Scale Hydropower II	500 kW	251 to 5 MW ☆	20 Years

☆ *Eligible up to 5 MW. Expected to be 1 MW or less.*

New Categories

- Shared Solar Facilities
  - Small or medium scale
  - Shared solar facilities will receive the same ceiling price and enroll from the same classes of other projects of the same size and ownership as established by the board for a given program year.
  - Allocates bill credits to between 2 and 50 accounts in the same customer class and on the same or adjacent parcels of land (public entities may allocate bill credits without regard to physical location within the municipality)
  - Allocated credits must not exceed the prior 3 years' average annual usage
- Community Remote Distributed Generation Systems, "shall not":
  - Comprise more than thirty percent (30%) of the annual total of capacity available under the renewable energy growth program in each year;
  - Be subject to a ceiling price that is more than fifteen percent (15%) higher than the then in effect ceiling price for the same technology of the same size as recommended by the board and approved by the commission; or
  - Transfer credits to any account in an amount that in kWh exceeds the prior three (3) year annual average usage.

Overview of Research to Inform CP Inputs

- Direct stakeholder input
  - Through *Data Request* <u>and</u> *Survey*
- Supplemental research
  - Primary research:
    - Interviews
    - Program data (bids, executed contracts)
    - Additional data from National Grid (Actual interconnection costs)
  - Secondary research:
    - Northeast regional cost databases
    - Northeast data from national reports
    - Technology-specific, competitively bid long-term contract pricing data (VT)
- DG Standard Contracts bid data (2011 – 2014)
- REG bid data (2015 & early 2016)

Summary of Data/Survey Response

Ceiling Price Category	# of Data Points Received (Data Request / Survey)
Small Solar	5 / 3
Medium Solar	2 / 1
Commercial Solar	5 / 3
Large Solar	5 / 2
Wind	5 / 0
Anaerobic Digestion	2 / 1
Hydro	6* / 1

Detailed data provided in Appendix.

** Through supplemental research and data provided through other than the formal data request template.*

Small Solar I, Installed Costs, Res.

Requires further review for presence of FMV-reported data.

Datasets: MA SREC, NY , CT RSIP

State	Bin	Sector	Year	Avg Cost Per kW	25th percentile	75th percentile
MA	1_10	Res	2015	4,397	3,621	4,972
MA	1_10	Res	2016	4,100	3,430	4,547
NY	1_10	Res	2015	4,675	3,920	5,600
NY	1_10	Res	2016	4,388	3,447	5,600
CT	1_10	Res	2015	4,423	3,730	5,250
CT	1_10	Res	2016	4,401	3,463	5,250

Dataset: NREL, Tracking The Sun, 2015

State	Bin	Sector	Year	Avg. Cost Per kW	20th percentile	80th percentile
CT	1_10	Res	2015	$3,818	$3,366	$4,186
DE	1_10	Res	2015	$4,266	$3,495	$4,991
MA	1_10	Res	2015	$4,430	$3,472	$5,230
MD	1_10	Res	2015	$4,485	$3,326	$5,336
NH	1_10	Res	2015	$3,964	$3,365	$4,463
NJ	1_10	Res	2015	$3,660	$3,173	$3,977
NY	1_10	Res	2015	$4,386	$3,582	$5,270
RI	1_10	Res	2015	$4,019	$3,643	$4,406
VT	1_10	Res	2015	$4,343	$3,696	$4,861

Small Solar I, Installed Costs, non-Res.

Requires further review for presence of FMV-reported data.

Datasets: MA SREC, NY

State	Bin	Sector	Year	Avg Cost Per kW	25th percentile	75th percentile
MA	1_10	Non Res	2015	4,380	3,500	5,137
MA	1_10	Non Res	2016	4,460	3,511	4,832
NY	1_10	Non Res	2015	4,828	3,727	5,423
NY	1_10	Non Res	2016	4,027	2,744	4,631

Dataset: NREL, Tracking The Sun, 2015

State	Bin	Sector	Year	Avg. Cost Per kW	20th percentile	80th percentile
CT	1_10	Non Res	2015			
DE	1_10	Non Res	2015	$3,652	$3,652	$3,652
MA	1_10	Non Res	2015	$4,204	$3,947	$4,476
MD	1_10	Non Res	2015			
NH	1_10	Non Res	2015	$3,967	$3,446	$4,022
NJ	1_10	Non Res	2015	$3,706	$3,512	$3,805
NY	1_10	Non Res	2015	$4,678	$3,405	$5,578
RI	1_10	Non Res	2015			
VT	1_10	Non Res	2015	$3,748	$3,672	$3,824

Small Solar II, Installed Costs

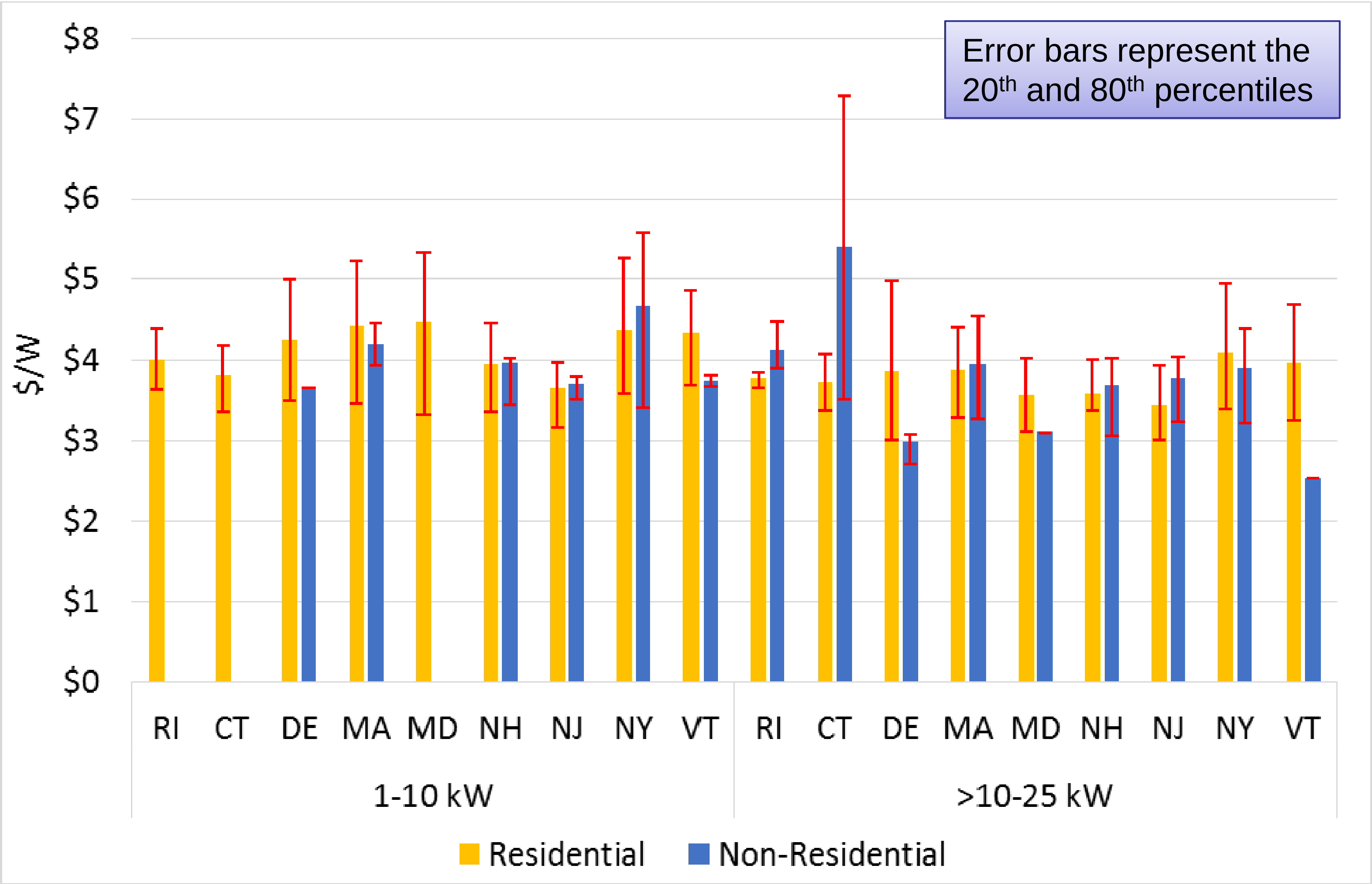
Datasets: MA SREC, NY

State	Bin	Sector	Year	Avg Cost Per kW	25th percentile	75th percentile
MA	10_25	Non Res	2015	3,929	3,327	4,241
MA	10_25	Non Res	2016	3,992	3,547	4,463
NY	10_25	Non Res	2015	3,895	3,285	4,161
NY	10_25	Non Res	2016	3,581	2,805	3,945

Dataset: NREL, Tracking The Sun, 2015

State	Bin	Sector	Year	Avg. Cost Per kW	20th percentile	80th percentile
CT	11_25	Non Res	2015	$5,402	$3,517	$7,288
DE	11_25	Non Res	2015	$2,993	$2,706	$3,073
MA	11_25	Non Res	2015	$3,963	$3,272	$4,559
MD	11_25	Non Res	2015	$3,110	$3,097	$3,101
NH	11_25	Non Res	2015	$3,695	$3,060	$4,030
NJ	11_25	Non Res	2015	$3,774	$3,236	$4,045
NY	11_25	Non Res	2015	$3,904	$3,226	$4,391
RI	11_25	Non Res	2015	$4,139	$3,903	$4,486
VT	11_25	Non Res	2015	$2,537	$2,537	$2,537

Small Solar I+II Cost Comparison



* Figures drawn from LBNL's 2015 Tracking the Sun Data, disaggregated into residential and non-residential. States with no data in a particular size category had no installations in the size class in 2015.

Medium Solar Installed Costs

Datasets: MA SREC, NY

State	Bin	Sector	Year	Avg Cost Per kW	25th percentile	75th percentile
MA	25_250	Non Res	2015	3,170	2,734	3,489
MA	25_250	Non Res	2016	3,069	2,568	3,685
NY	25_250	Non Res	2015	3,624	3,020	3,950
NY	25_250	Non Res	2016	3,460	2,903	4,001

Dataset: NREL, Tracking The Sun, 2015

State	Bin	Sector	Year	Avg. Cost Per kW	20th percentile	80th percentile
CT	26_250	Non Res	2015	$3,518	$2,884	$4,203
DE	26_250	Non Res	2015	$2,983	$2,769	$3,088
MA	26_250	Non Res	2015	$3,190	$2,643	$3,543
MD	26_250	Non Res	2015	$2,822	$2,337	$3,504
NH	26_250	Non Res	2015	$3,214	$2,888	$3,455
NJ	26_250	Non Res	2015	$3,089	$2,560	$3,593
NY	26_250	Non Res	2015	$3,632	$2,957	$4,025
RI	26_250	Non Res	2015	$3,669	$3,140	$4,009
VT	26_250	Non Res	2015	$2,529	$2,529	$2,529

Commercial Solar Installed Costs

Datasets: MA SREC, NY

State	Bin	Sector	Year	Avg Cost Per kW	25th percentile	75th percentile
MA	**250_1000**	**Non Res**	**2015**	**2,725**	2,276	3,020
MA	**250_1000**	**Non Res**	**2016**	**2,683**	2,397	2,938
NY	**250_1000**	**Non Res**	**2015**	**2,464**	2,346	2,585
NY	**250_1000**	**Non Res**	**2016**	**3,100**	3,100	3,100

Dataset: NREL, Tracking The Sun, 2015

State	Bin	Sector	Year	Avg. Cost Per kW	20th percentile	80th percentile
CT	251_999	Non Res	2015	$2,714	$2,645	$2,789
DE	251_999	Non Res	2015			
MA	251_999	Non Res	2015	$2,707	$2,151	$3,274
MD	251_999	Non Res	2015			
NH	251_999	Non Res	2015	$2,444	$2,644	$2,644
NJ	251_999	Non Res	2015	$2,898	$2,216	$3,151
NY	251_999	Non Res	2015	$2,472	$2,339	$2,584
RI	251_999	Non Res	2015			
VT	251_999	Non Res	2015			

Large Solar Installed Costs

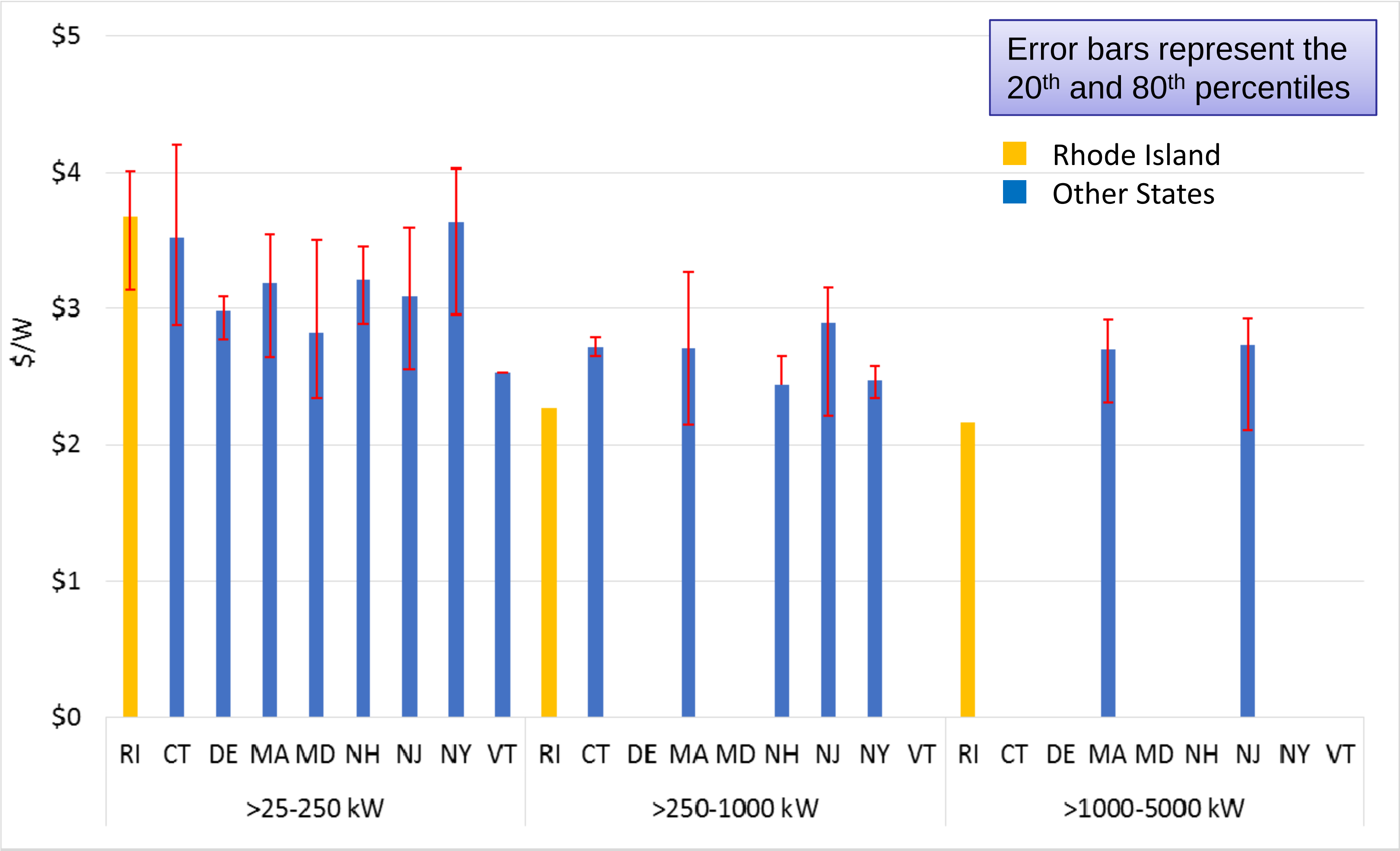
Datasets: MA SREC

State	Bin	Sector	Year	Avg Cost Per kW	25th percentile	75th percentile
MA	1000_6000	Non Res	2015	2,691	2,430	2,891
MA	1000_6000	Non Res	2016	2,277	1,800	2,554

Dataset: NREL, Tracking The Sun, 2015

State	Bin	Sector	Year	Avg. Cost Per kW	20th percentile	80th percentile
CT	1000_5000	Non Res	2015			
DE	1000_5000	Non Res	2015			
MA	1000_5000	Non Res	2015	$2,694	$2,308	$2,923
MD	1000_5000	Non Res	2015			
NH	1000_5000	Non Res	2015			
NJ	1000_5000	Non Res	2015	$2,728	$2,107	$2,931
NY	1000_5000	Non Res	2015			
RI	1000_5000	Non Res	2015			
VT	1000_5000	Non Res	2015			

Installed Cost Trends – Larger Size Categories*



*Including Interconnection Costs
*Draws from 2015 RI REG Program Data and LBNL's Tracking the Sun Data

REG Bid Data

- Medium Solar
  - 2015: $2,900 - $3,200
  - 2016: $2,500 - $3,500
- Commercial Solar
  - 2016: $2,000 – $2,200
  - 2015: $2,000 – $2,700
- Large Solar
  - 2016: ~$2,100
  - 2015: ~$2,100

Interconnection Cost Analysis (1)

Massachusetts and Rhode Island Solar Interconnection Costs		
	Number of Projects	Wtd. Average Cost ($/kW DC)
Small Solar I <=10	0	N/A
Small Solar II <=25	0	N/A
Medium Solar	200	$11
Commercial Solar	149	$84
Large Solar	48	$105
Wind I	5	$76
Wind II/III	2	$77
Anaerobic Digestion I	0	N/A
Anaerobic Digestion II	0	N/A

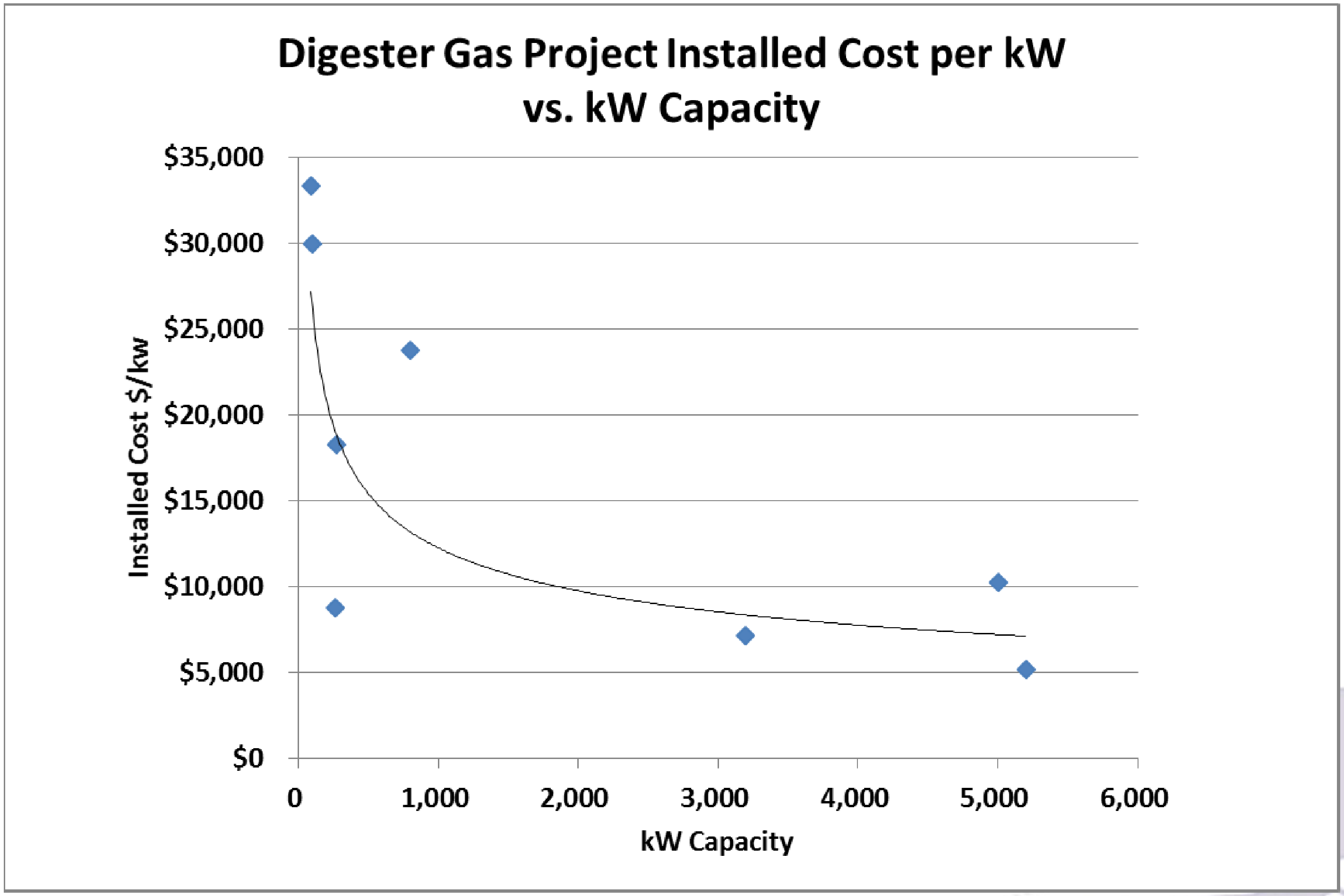
**Based on National Grid Data, <u>excludes</u> projects assumed to require safety equipment related to islanding (i.e. DTT, 3Vo, etc.)*

Interconnection Cost Analysis (2)

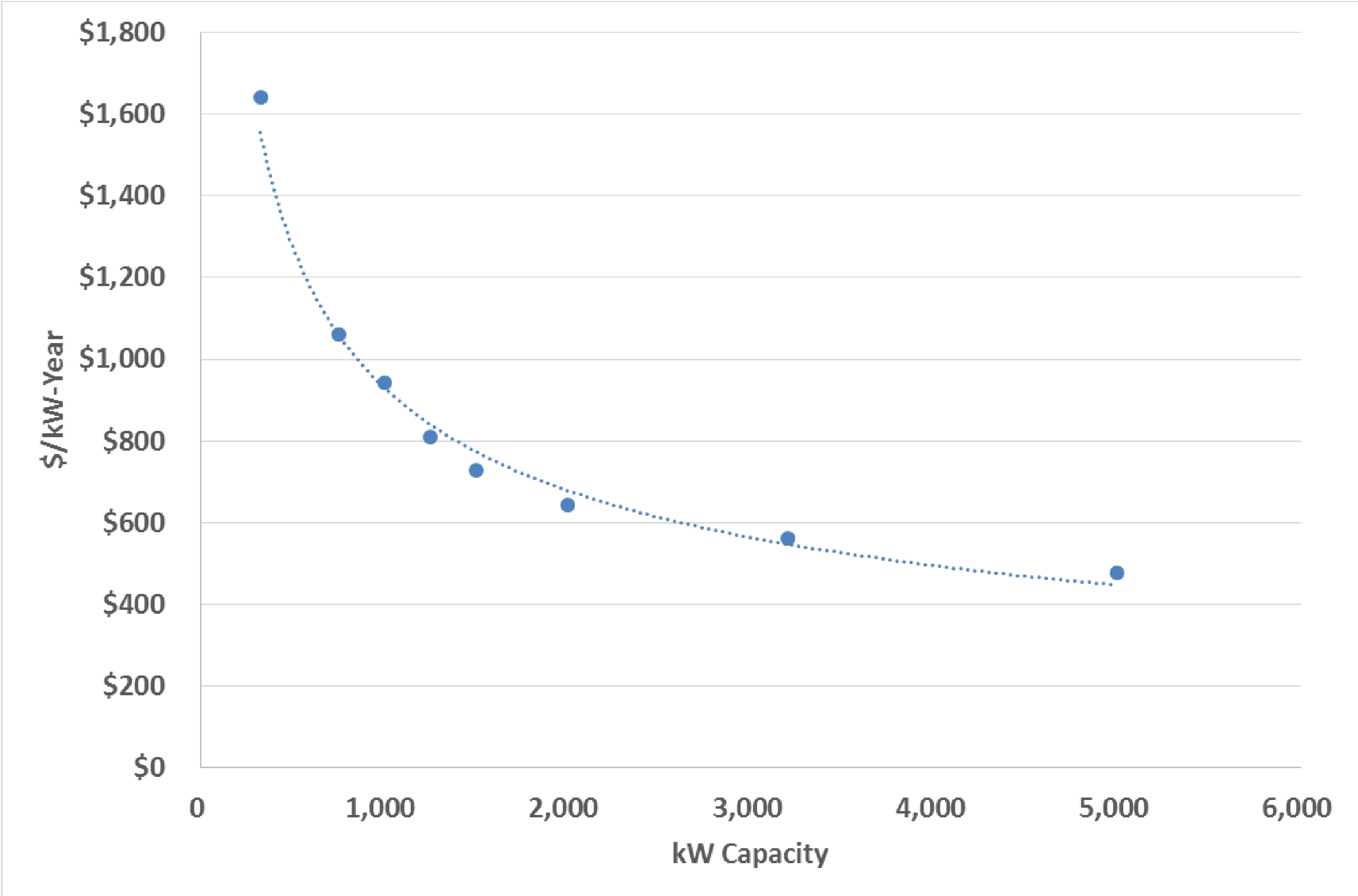
Rhode Island Solar Interconnection Costs		
	Number of Projects	Wtd. Average Cost ($/kW DC)
Small Solar I <=10	0	N/A
Small Solar II <=25	0	N/A
Medium Solar	10	$54
Commercial Solar	15	$97
Large Solar	4	$91
Wind I	1	$102
Wind II/III	1	$100
Anaerobic Digestion I	0	N/A
Anaerobic Digestion II	0	N/A

**Based on National Grid Data, <u>excludes</u> projects assumed to require safety equipment related to islanding (i.e. DTT, 3Vo, etc.)*

AD (Food Waste) Installed Cost Curve



AD (Food Waste) O&M Expense Curve



AD: Additional Data

- Tipping Fees
  - 2016 CP: $22.50
  - Supplemental Research data Points
    - $35/ton
    - $10-$40/ton
    - $60/ton
- Parasitic Load (Station Service)
  - 12.5%
  - 13.8%
- Capacity Factor
  - 95%

REGIONAL BENCHMARKING & DG SC BID DATA

VT Standard Offer 2016 Bid Prices: SOLAR

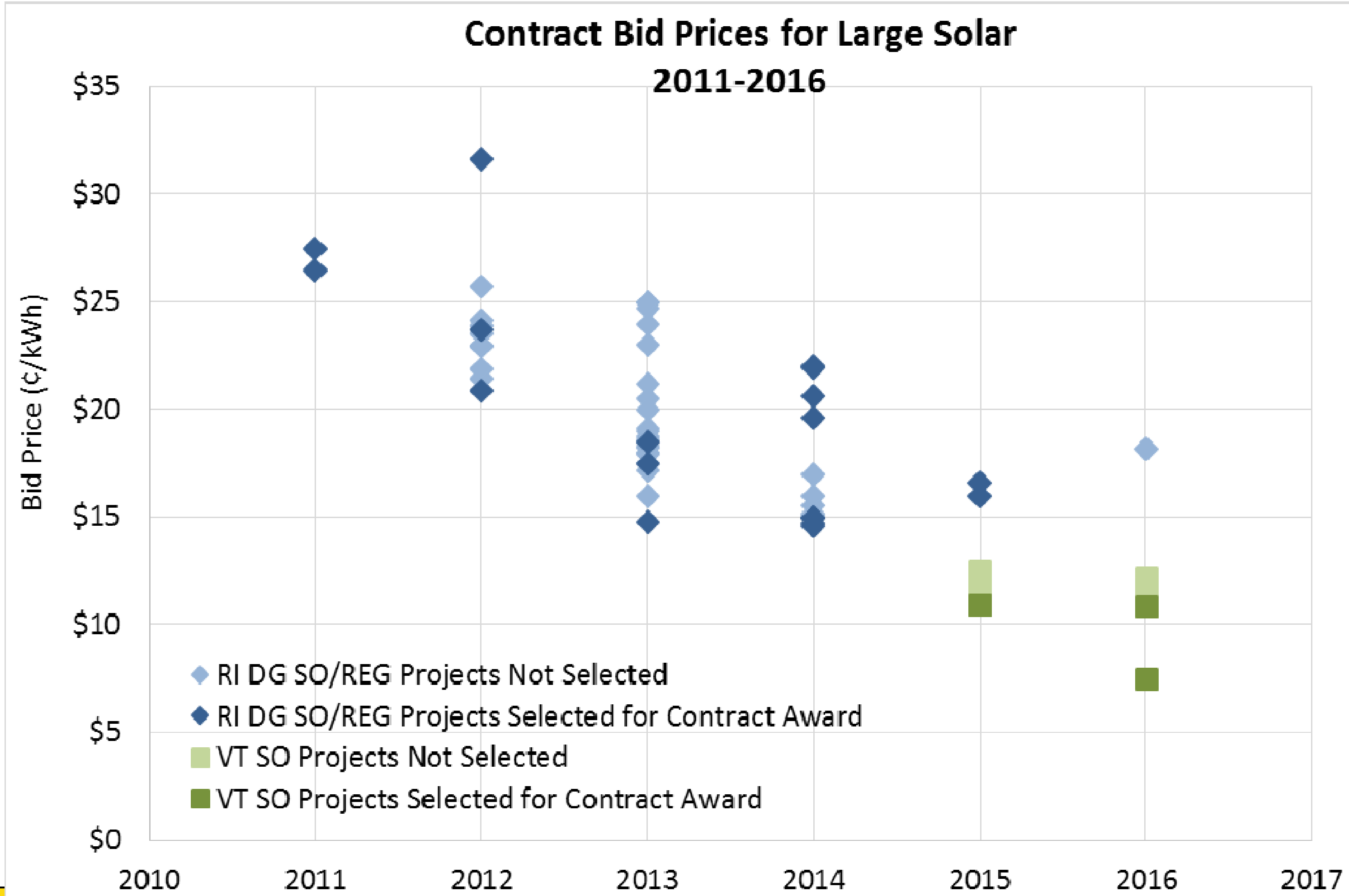
Project Name	Project Size (kW)	Bid Price* ($/kWh)
Checkerberry Solar Park	2,160	$0.075
Pit Site	2,050	$0.1087
Cornfield Site	2,200	$0.1088
Missisquoi Valley Solar	2,200	$0.1108
Time L Tell Solar	2,200	$0.1168
Gilman Landfill Solar	2,100	$0.1094
Otter Creek 1 Solar	2,200	$0.1089
Otter Creek 2 Solar	2,200	$0.1137
Otter Creek 3 Solar	2,200	$0.1176
Weybridge 1 Solar	2,200	$0.1210
Weybridge 2 Solar	2,200	$0.1220
Sunderland 1 Solar	2,200	$0.1181
Sunderland 2 Solar	2,200	$0.1184
Sunderland 3 Solar	2,200	$0.1190
Battle Creek 1 Solar	2,200	$0.1087
Battle Creek 2 Solar	2,200	$0.1129
Battle Creek 3 Solar	2,200	$0.1171

Highlighted Orange= Projects awarded a contract

Highlighted Green = Projects selected for “Reserve Group” – these projects will be contracted if a project in the “Award Group” is withdrawn following selection

* Note that the VT SO Program offers 25-year fixed price contracts, compared to 20 years in RI.

RI DG Standard Contract/REG Bid Price History & Comparison to VT Standard Offer Bid Prices



* *Note that the VT SO Program offers 25-year fixed price contracts, compared to 20 years in RI.*

VT Standard Offer 2016 Bid Prices: NON-SOLAR

Food Waste

Project Name	Project Size (kW)	Bid Price (/kWh)
Blue Sphere AD Project	2,200	$0.180

Wind

Project Name	Project Size (kW)	Bid Price (/kWh)
Dairy Air Wind	2,200	$0.1160
Tomlinson Wind A	100	$0.251
Tomlinson Wind B	50	$0.251
FELLCO 78A	100	$0.251
FELLCO 78A	50	$0.251

VT Standard Offer 2015 Bid Prices (NON-SOLAR)

Food Waste

Project Name	Project Size (kW)	Bid Price (/kWh)
Brattleboro Organic Energy	300	$0.2080

Wind

Project Name	Project Size (kW)	Bid Price (/kWh)
Highgate Wind 1 Project	100	$0.2520
Highgate Wind 2 Project	100	$0.2520
Highgate Wind 3 Project	100	$0.2520
Highgate Wind 4 Project	100	$0.2520
Tesla Wind	36	$0.2530
Baily Hill Wind	24	$0.2530
Danby Wind Farm	96	$0.2530
Hedgehog Hill Wind B	96	$0.2530

Hydro

Project Name	Project Size (kW)	Bid Price (/kWh)
Pownal Tannery	1,100	$0.1226

Property Taxes

- Methodology Supporting 2016 Ceiling Price
  - Start at 80% of cost basis
  - Reduce by 5% per year to floor of 30%
  - Multiply by Mill rate.
  - Effect: Tax expense starts high, decreases over time
- Methodology supporting 2017 Ceiling Price
  - Fixed rate
  - Starting point = $5.00 per kWac installed
  - Effect: Tax expense is fixed and flat

Incentives: Tax Credits

- Solar:
  - 30% ITC for projects commencing construction on or before 12/31/2019.
  - Assumed to apply to all projects selected in 2017 solicitations.
  - No monetization “haircut” assumed.

- Wind
  - For facilities commencing construction in 2017, PTC/ITC value is reduced by 20%
  - For facilities commencing construction in 2018, PTC/ITC value is reduced by 40%
  - No monetization “haircut” assumed.

- AD & Hydro
  - No PTC (or ITC in lieu thereof) for facilities commencing construction after 12/31/2016.
  - Given REG eligibility criteria that facilities not be under construction, PTC/ITC assumed not available to facilities participating in 2017 solicitations.

- RI State Investment Tax Credit
  - Modeled as a one-time, year-one benefit of $3,750 for small, third-party owned solar

Incentives: NOL Carryforward

- MACRS depreciation creates deduction benefit by reducing taxable income.
- Where depreciation expense is > operating income, the project will most likely experience a net operating loss (NOL) for the specified year.
- This NOL is passed through to the facility owner, creating a benefit by reducing that entity's eligible taxable income.
- NOL benefits are assumed to be applied "as generated" to both state and federal tax liabilities
- No federal, state, local or other grants assumed.
- Policy Objective: Encourage projects able to make most effective use of tax benefits

Post-Tariff Market Value of Production

- Applied after tariff expires, for remainder of modeled useful life, if applicable.
  - Solar (years 21 through 25)
  - Hydro (years 21 through 30)
  - Does not apply to wind and AD, modeled as 20-year useful life
- Purpose = to take full useful life and market revenues into account when recommending ceiling price
- Methodology
  - Wholesale energy revenue +
    - Production-weighted for solar
    - All-hours for hydro
  - Capacity revenue +
  - (Nominal) REC revenue ($5)
- Values will be provided with draft Ceiling Prices

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Rhode Island Renewable Energy Growth Program:

2017 1st Draft Ceiling Price Recommendations

August 2016

Sustainable Energy Advantage, LLC
Meister Consultants Group, Inc.
Mondre Energy, Inc.

SUMMARY RESULTS

Draft Proposed Ceiling Prices, 2017 REG Program (1)

(cents/kWh)

Technology	Size Range (Modeled Size)	2016 Approved CP 15 year Tariff Duration	2017 *Proposed* CP 15 year Tariff Duration	2016 Approved CP 20 year Tariff Duration	2017 *Proposed* CP 20 year Tariff Duration
Small Solar I, Host Owned, Non-Res./Non-Mfg.*	1 to 10 kW (5)	**37.65****	**28.65 (-24%)**	**33.45****	**25.85 (-23%)**
Small Solar I, Host Owned, Res./Mfg.*	1 to 10 kW (5)		**28.15**		**25.45**
Small Solar I, TPO, Non-Res./Non-Mfg.*	1 to 10 kW (5)	**28.35****	**26.75 (-6%)**	**24.70****	**23.75 (-4%)**
Small Solar I, TPO, Res./Mfg.*	1 to 10 kW (5)		**26.25**		**24.55**

** "Non-Res./Non-Mfg." denotes projects on which property taxes are assessed. "Res./Mfg. denotes projects exempt from property taxes.*

*** Because property taxes were applied, 2016 CPs most closely align with this 2017 category.*

Draft Proposed Ceiling Prices, 2017 REG Program (2)
(cents/kWh)

Technology	Size Range (Modeled Size)	2016 Approved CP	2017 *Proposed* CP
Small Solar II	11 to 25 kW (25)	24.90	23.65 (-5%)
Small Solar II, Mfg.	11 to 25 kW (25)		23.25
Medium Solar	26 to 250 kW (140)	22.55	22.25 (-1%)
Medium Solar, Mfg.	26 to 250 kW (140)		21.85
Commercial Solar	251 to 999 kW (500)	19.30	18.35 (-5%)
Commercial Solar, Community Remote DG	251 to 999 kW (500)		18.45*
Commercial Solar, Mfg.	251 to 999 kW (500)		17.95
Large Solar	1 to 5 MW (2)	15.10	14.95 (-1%)
Large Solar, Mfg.	1 to 5 MW (2)		14.55

** Assumes $10,000 in customer acquisition costs for a 500 kW project. Source = MA DOER Post-1600 analysis.*

Draft Proposed Ceiling Prices, 2017 REG Program (3)

Technology	Size Range (Modeled Size)	2016 Approved CP	2017 *Proposed* CP	Notes
Small Wind, 80% ITC	1 – 999 kW (100 kW)	NA	20.95*	2017 safe harbor
Small Wind, 60% ITC			22.75*	2018 safe harbor
Small Wind, 80% ITC, Mfg.			20.65*	2017 safe harbor
Small Wind, 60% ITC, Mfg.			22.55*	2018 safe harbor
Wind I, 80% ITC	1 – 3 MW (1.65 MW)	18.75**	17.55 (-6%)	2017 safe harbor
Wind I, 60% ITC			19.05	2018 safe harbor
Wind I, 80% ITC, Mfg.			17.25	2017 safe harbor
Wind I, 60% ITC, Mfg.			18.75	2018 safe harbor

** The DG Board will also need to recommend whether the Small Wind CP is fixed or competitively bid. Given the expectation that turbines in this category will be 100 kW, it may be appropriate to fix the tariff rate, as is done with solar projects of this size.*

*** 2016 Wind I CPs were modeled with 75% ITC monetization; 2017 Wind I CPs are modeled with 100% monetization of 80% and 60% ITC availability, respectively.*

Draft Proposed Ceiling Prices, 2017 REG Program (4)

Technology	**Size Range** (Modeled Size)	2016 Approved CP	2017 *Proposed* CP	Notes
Wind II, 80% ITC	3 – 5 MW (3.3 MW)	**18.00**	**16.85 (-6%)**	2017 safe harbor
Wind II, 60% ITC			**18.25**	2018 safe harbor
Wind II, 80% ITC, Mfg.			**16.65**	2017 safe harbor
Wind II, 60% ITC, Mfg.			**16.95**	2018 safe harbor
Wind III, 80% ITC	3 – 5 MW (4.95 MW)	**17.40**	**16.25 (-7%)**	2017 safe harbor
Wind III, 60% ITC			**17.55**	2018 safe harbor
Wind III, 80% ITC, Mfg.			**15.95**	2017 safe harbor
Wind III, 60% ITC, Mfg.			**17.35**	2018 safe harbor

** 2016 Wind I CPs were modeled with 75% ITC monetization; 2017 Wind I CPs are modeled with 100% monetization of 80% and 60% ITC availability, respectively.*

Draft Proposed Ceiling Prices, 2017 REG Program (5)

Technology	Size Range (Modeled Size)	2016 Approved CP	2017 *Proposed* CP	Notes
Hydro I	10 – 250 kW (150 kW)	18.65	22.15 (19%)	For both Hydro & AD, PTCs are no longer after 12/31/2016. 2016 CPs included PTCs, 2017 proposed CPs do not.
Hydro II	251 kW – 5 MW (500 kW)	17.45	20.75 (19%)	
AD I	150 – 500 kW (325 kW)	20.20	19.45 (-4%)	
AD I, Mfg.			19.35	
AD II	501 kW – 5 MW (750 kW)	20.20	20.15 (-0.25%)	
AD II, Mfg.			20.05	

MODELED PARAMETERS: SOLAR

SOLAR: Cost & Production Inputs

Modeled Parameters

		Small Solar I Resi (1-10 kW)	Small Solar I Comm (1-10 kW)	Small Solar II (11-25 kW)	Medium Solar (26-250 kW)	Commercial Solar (251-1,000 kW)	Large Solar (1-5 MW)
Nameplate Capacity	kW	5		25	140	500	2,000
Capacity Factor		13.49%	13.49%	13.49%	14.00% [13.45%]	14.40% [13.59%]	15.30% [14.18%]
Annual Degradation	%	0.5%					
Cost, Less Interconnection	$/kW	$3,800 (+ $161 inverter warrantee) [$3,839 + $161 inverter warrantee]		$3,541 [$3,680]	$2,724 [$2,799]	$2,293 [$1,939]	$2,150 [$1,784]
Interconnection	$/kW	$0			$129 [$128]	$97 [$513]	$91 [$237]
Total Cost	$/kW	$3,961 [$4,000]		$3,541 [$3,680]	$2,853 [$2,927]	$2,390 [$2,452]	$2,241 [$2,021]

Blue = change from 2016 value.

[Bracketed] values show 2016 CP inputs, where different

Ongoing Cost Assumptions

Modeled Parameters

		Small Solar I Resi (1-10 kW)	Small Solar I Comm (1-10 kW)	Small Solar II (11-25 kW)	Medium Solar (26-250 kW)	Commercial Solar (251-1,000 kW)	Large Solar (1-5 MW)
Fixed O&M Expense, Yr 1	$/kW-yr	$50 **[$15]**	$50 **[$15]**	$50 **[$15]**	$34 **[$15]**	$24 **[$15]**	$15
O&M Cost Inflation	%	2%					
Insurance, Yr 1 (% of Total Cost)	%	0.00%			0.27% **[0.25%]**		
Management Yr 1	$/yr	Included in O&M. **[$150]**			$750 **[$500]**	$3,000 **[$3,300]**	$7,700 **[$10,000]**
Land Lease	$/yr	$0			$3,500 **[$0]**	$12,500 **[$6,000]**	$50,000 **[$24,000]**

Blue = change from 2016 value.

[Bracketed] values show 2016 CP inputs, where different

Financing Assumptions

Modeled Parameters

		Small Solar I Resi (1-10 kW)	Small Solar I TPO (1-10 kW)	Small Solar II (11-25 kW)	Medium Solar (26-250 kW)	Commercial Solar (251-1,000 kW)	Large Solar (1-5 MW)
% Debt	%	100% [0%]	50%	45% [50%]	45% [50%]	40% [50%]	40% [50%]
Debt Term	yrs	10 [N/A]	12/15 [13/18]	12 [18, 10, 15]			15
Interest Rate on Term Debt	%	5.5% [N/A]	5.5% / 5.75% [6.5%]	5.5% [6.5%, 6.5%, 6.0%]			5.75% [6.0%]
Lender's Fee (% of total borrowing)	%	2.0% [2.25%, N/A for Small Solar I Resi (1-10 kW)]					
Required Minimum Annual DSCR		1.00					
Required Average DSCR		1.35					
Target After-Tax Equity IRR	%	5.5% [5.0%]	8.0% [8.0%, 8.0%, 7.5%, 7.0%, 7.0%]				

Blue = change from 2016 value. **[Bracketed]** values show 2016 CP inputs, where different

MODELED PARAMETERS: WIND

Production and Capital Cost Assumptions

Modeled Parameters

		Small Wind	Wind I	Wind II	Wind III
Nameplate Capacity	kW	**100**	1,650	3,300	4,950
Capacity Factor	%	**21%**	21%		
Annual Degradation	%	**0.0%**	0.0%		
Generation Equipment	$/kW	**$4,000**	$3,200	**$3,025** **[$3,100]**	**$2,850** **[$3,000]**
Interconnection	$/kW	**$54**	**$102** **[$241]**	**$100** **[$181]**	**$100** **[$160]**

Blue = change from 2016 value.

[Bracketed] values show 2016 CP inputs, where different

Ongoing Cost Assumptions

Modeled Parameters

		Small Wind	Wind I	Wind II	Wind III
Fixed O&M Expense, Yr 1	$/kW-yr	$30.00	$45.00 [$25.00]		
O&M Cost Inflation	%	2%	2%		
Insurance, Yr 1 (% of Total Cost)	%	0.25%	0.45% [0.60%]		
Management Yr 1	$/yr	Incl.	Included in O&M		
Land Lease	$/yr	$5,000	$54K [$52.5K]	$108K [$105K]	$162K [$157.5K]

Blue = change from 2016 value.

[Bracketed] values show 2016 CP inputs, where different

Financing Assumptions

Modeled Parameters

		Small Wind	Wind I	Wind II	Wind III
% Debt	%	45%	60% [70%]		
Debt Term	yrs	15	15 [18]		
Interest Rate on Term Debt	%	6.25%	6.25% [6.50%]		
Lender's Fee (% of total borrowing)	%	2.00%	2.00% [2.25%]		
Required Minimum Annual DSCR		1.00	1.00		
Required Average DSCR		1.45	1.45		
Target After-Tax Equity IRR	%	10%	10%		
Reserve Requirement	$	Incl.	6 mos of debt service		
Major Equipment Replacements		Incl.	Yrs 12, 15, 18, 19, $30/kW [$0/kW]		

Blue = change from 2016 value.

[Bracketed] values show 2016 CP inputs, where different

MODELED PARAMETERS: ANAEROBIC DIGESTION

PROJECT PERFORMANCE ASSUMPTIONS

Modeled Parameters

		Anaerobic Digestion I	Anaerobic Digestion II
Generator Nameplate Capacity	*kW*	**325**	**725**
Biogas Consumption per Day	*cubic feet/day*	**157,911** **[120,066]**	**293,856** **[267,840]**
Energy Content per Cubic Foot	*BTU/cubic foot*	**550** **[600]**	
Heat Rate	*BTU/kWh*	**10,339** **[8,928]**	**8,979** **[8,928]**
Availability	*%*	**92%**	
Station Service (Parasitic Load)	*%*	**20%**	
Annual Production Degradation	*%*	**0%**	
Project Useful Life	*years*	**20**	

Blue = change from 2016 value.

[Bracketed] values show 2016 CP inputs, where different

CAPITAL, INTERCONNECTION AND O&M COSTS

Modeled Parameters

		Anaerobic Digestion I	Anaerobic Digestion II
Generation Equipment	*$/kW*	**$10,000**	**$10,000**
Interconnection Costs	*$/kW*	**$150**	
Fixed O&M Expense	*$/kW-yr*	**$600**	
Variable O&M Expense	*¢/kWh*	**2.00**	
O&M Cost Inflation	*%*	**2%**	

Blue = change from 2016 value.

[Bracketed] values show 2016 CP inputs, where different

ONGOING EXPENSE ASSUMPTIONS

Modeled Parameters

		Anaerobic Digestion I	Anaerobic Digestion II
Insurance, Yr 1 (% of Total Cost)	*%*	**1.0%**	
Project Management Yr 1	*$/yr*	**$33,621**	**$75,000**
Water & Sewer Expenses	*$/yr*	**$0**	
Digestate Disposal Cost (if handled as an expense)	*$/ton*	**$0.00**	
Land Lease	*$/yr*	**$15,690**	**$35,000**

Blue = change from 2016 value.

[Bracketed] values show 2016 CP inputs, where different

FINANCING ASSUMPTIONS

Modeled Parameters

		Anaerobic Digestion I	Anaerobic Digestion II
% Debt (% of hard costs) (mortgage-style amort.)	*%*	**60%**	
Debt Term	*years*	**15** **[18]**	
Interest Rate on Term Debt	*%*	**6.25%** **[6.50%]**	
Lender's Fee (% of total borrowing)	*%*	**0%**	
Required Minimum Annual DSCR	*Ratio*	**1.00**	
Required Average DSCR	*Ratio*	**1.50**	
Target After-Tax Equity IRR	*%*	**10%**	
Other Closing Costs	*$*	**$0**	
Reserve Requirement	*$*	**$0**	

Blue = change from 2016 value.

[Bracketed] values show 2016 CP inputs, where different

SUPPLEMENTAL REVENUE ASSUMPTIONS

Modeled Parameters

		Anaerobic Digestion I	Anaerobic Digestion II
Tipping Fee	*$/ton*	**$25.00** **[$22.50]**	
Quantity Received Each Year	*tons per year*	**10,000**	**22,308**
Digestate (if merchantable for additional revenue)	*$/gallon*	**$0**	

Blue = change from 2016 value.

[Bracketed] values show 2016 CP inputs, where different

MODELED PARAMETERS: HYDRO

Production and Capital Cost Assumptions

Modeled Parameters

		Hydro I	Hydro II
Nameplate Capacity	kW	**150**	**500**
Capacity Factor	%	**40%**	
Annual Degradation	%	**0.0%**	
Cost Excluding Interconnection	$/kW	**$6,000** **[$4,500, $4,200]**	
Interconnection	$/kW	**$100**	

Blue = change from 2016 value.

[Bracketed] values show 2016 CP inputs, where different

Modeled Parameters

		Hydro I	Hydro II
Variable O&M Expense, Yr 1	¢/kWh	**2.00**	
O&M Cost Inflation	%	**2.00%** **[3.00%]**	
Insurance, Yr 1 (% of Total Cost)	%	**0.50%**	
Management Yr 1	$/yr	**$10,000** **[$5,000]**	**$15,000**
Land Lease	$/yr	**$3,750** **[$3,000]**	**$12,500** **[$10,000]**

Blue = change from 2016 value.

[Bracketed] values show 2016 CP inputs, where different

Modeled Parameters

		Hydro I	Hydro II
% Debt	%	60% [50%]	
Debt Term	yrs	15 [18]	
Interest Rate on Term Debt	%	6.25% [6.50%]	
Lender's Fee (% of total borrowing)	%	2.00% [2.25%]	
Required Minimum Annual DSCR		1.00	
Required Average DSCR		1.45	
Target After-Tax Equity IRR	%	10%	
Reserve Requirement	$	$0	

Blue = change from 2016 value.

[Bracketed] values show 2016 CP inputs, where different

MODELED PARAMETERS: ADDITIONAL ASSUMPTIONS, ALL TECHNOLOGIES

Property Taxes

- Methodology Supporting 2016 Ceiling Price
  - Start at 80% of cost basis
  - Reduce by 5% per year to floor of 30%
  - Multiply by Mill rate.
  - Effect: Tax expense starts high, decreases over time
- Methodology supporting 2017 Ceiling Price
  - Fixed rate, $5.00 per kWac installed
    - Rate ultimately subject to regulatory approval
  - Effect: Tax expense is fixed and flat
  - Hydroelectric facilities are exempt from property tax per Title 44, § 44-3-3

Incentives: Tax Credits

- Solar:
  - 30% ITC for projects commencing construction on or before 12/31/2019.
  - Assumed to apply to all projects selected in 2017 solicitations.
  - No monetization “haircut” assumed.

- Wind
  - For facilities commencing construction in 2017, PTC/ITC value is reduced by 20%
  - For facilities commencing construction in 2018, PTC/ITC value is reduced by 40%
  - No additional monetization “haircut” assumed.

- AD & Hydro
  - No PTC (or ITC in lieu thereof) for facilities commencing construction after 12/31/2016.
  - Given REG eligibility criteria that facilities not be under construction, PTC/ITC assumed not available to facilities participating in 2017 solicitations.

Incentives: NOL Carryforward

- MACRS depreciation creates deduction benefit by reducing taxable income.
- Where depreciation expense is > operating income, the project will most likely experience a net operating loss (NOL) for the specified year.
- This NOL is passed through to the facility owner, creating a benefit by reducing that entity's eligible taxable income.
- NOL benefits are assumed to be applied "as generated" to both state and federal tax liabilities
- No federal, state, local or other grants assumed.
- Policy Objective: Encourage projects able to make most effective use of tax benefits

Additional Assumptions:
Forecast of Market Value of Production

Project Year	Calendar Year	Market Value of Production (incl. energy, capacity & RECs) (cents/kWh)	
		Solar	**Hydro**
21	2037	11.96	11.30
22	2038	12.57	11.88
23	2039	13.22	12.49
24	2040	13.90	13.14
25	2041	14.61	13.81
26	2042		14.52
27	2043		15.27
28	2044		16.05
29	2045		16.87
30	2046		17.74

APPENDIX A:
SENSITIVITY ANALYSIS

Sensitivity Analysis: Methodology

• Somewhat comparable to a step-wise regression, which models the correlation of one variable to the result

• Specific Cost Inputs are "**Zeroed Out**" (i.e. set at $0.00, 0%, etc.)

• Ceiling Prices are then recalculated, with all other inputs held constant

•The "Zeroed Out" Ceiling Price is then compared to the Original Ceiling price, to determine how much of the ceiling price is affected by that input

• ***Note***: This is not a pure regression, as the results are somewhat based on the magnitude of the original cost. The results are useful, however, to understanding the relative importance of certain inputs.

Sensitivity Analysis: Results, Solar & Wind

% of Proposed Ceiling Price attributable to specified Input

Input:	Installed Cost	Interconnection Cost	Fixed O&M	Property Tax
Small Solar I, Host-Owned, 15	73%	N/A	25%	2%
Small Solar II	74%	N/A	24%	2%
Medium Solar	77%	4%	17%	2%
Commercial Solar	82%	2%	14%	2%
Large Solar	85%	2%	10%	3%
Small Wind	88%	1%	10%	1%
Wind I	79%	3%	16%	2%
Wind II	78%	4%	17%	1%
Wind III	77%	4%	17%	2%

** Not available. Interconnection costs are not separated from total costs for Solar I and Solar II.*

Sensitivity Analysis: Results, AD & Hydro

% of Proposed Ceiling Price attributable to specified Input

Input:	Installed Cost	Interconnection Cost	Fixed O&M	Property Tax
Anaerobic Digestion I	34%	2%	63%	1%
Anaerobic Digestion II	34%	2%	63%	1%
Hydroelectric I	86%	2%	12%	0%
Hydroelectric II	86%	1%	13%	0%

APPENDIX B:
SURVEY RESPONSES

Question #1: Size Ranges & Representative kW

- **Solar (1)**: The Commercial Solar category is best represented by a 650 kW (DC) project size. [Current = 500 kW]
- **Solar (2)**: The Small Solar I category should be changed to 1-15kW [current is 1-10 kW] to align with the simplified interconnection process size restrictions and due to increases in panel efficiency. The current structure de-incentivizes 11-15kW systems. A 10kW system would generate more income than a 14kW installation. The representative size for the Small Solar I and II categories should be in the middle of the size range for that category, 5kW for small solar I and 17 kW for small solar II.
- **Solar (3)**: Proposes the sizing bins for Small Scale Solar (I – III): 0-10.99 kW, 11 – 15.99 kW, 16 – 25 kW. Ideally, a sliding scale for all systems of 0-25kW would exist. Presently, in general, clients select a smaller system of just under 11 kW for profitability reasons over sizing a system that would produce closer to 100% of their electricity and pay a lower per kWh compensation.

- **AD (1)**: Current size range is reasonable.

Question #2: Pros & Cons of offering both 15 and 20 Yr Tariff for Small Solar

- **Solar (1):** Given large capital expenditures being underwritten against contracted revenue, longer contract terms provide more certainty for investors, reduce capital costs, and thereby reduce policy costs per MW deployed.
- **Solar (2):** The 15 year option is preferred by most homeowners based on its accelerated payback period. The 20 year option is not as financially advantageous.
- **Solar (3):** Preference for the 15-year term because residential home owners focus on payback as they often have a much shorter tenure in their property.

- **Hydro (1):** Request the term of the REG contracts for hydro be extended to 40 years to more align the development lead times (~3 to 8 years) and capital life of equipment (~40-100 years) with the contract period annually adjusted for inflation though the length of the contract.

Question #3: Installed Cost Source Data

- The following most closely answered this question. Quantitative responses are summarized in the Data Request section.

- **Solar (1):** The primary variable between solar projects in RI and other Northeast markets is labor.

- **Solar (2):** Installation costs are approximately 10-15% higher than surrounding states due to a unique state labor requirements, generally higher labor rates, and the availability of licensed RI contractors.

Question #4: CapEx Replacement Inputs

- **Solar (1):** Some create an equipment replacement reserve funded through life of the project, while others “pad” O&M assumptions to include an equipment replacement reserve. Modules and racking are assumed (and warrantied) for a projects’ lifetime. Inverters rarely need replacement.
- **Solar (2):** Solar modules and racking equipment are under warranty for the duration of the project useful life. Inverters are under warranty for 10-15 years, and the costs of such warranties or extended warranties are considered in the project cost.
- **Solar (3):** Replacement of inverter after the 12-year warranty period, with the cost absorbed by the client; labor cost for removal and installation not included.

- **Hydro (1):** Equipment will have manufacturer’s warrantees with designed with a 30 year life. A system/dam reserve per year watt of $0.075 escalating with inflation.

Question #5: Consideration of IC Data in CP

- **Solar (1):** The upfront estimates of IC from the utility are a program strength. Timelines for deposits should align with two-year development cycle.
- **Solar (2):** IC data are highly variable depending upon project location. Current IC are conservative with costs at the mid/high range of market experience. Supports the conservative approach.
- **Solar (3):** IC should be known at time of bid within +/- 20% of final IC. If the final IC costs increase by more than 20% of estimate, developer should be entitled to a $0.005 to $0.01/kWh “adder” to the tariff.
- **Solar (4):** IC vary by location and project. The current CP for Commercial and Large Solar is too low to attract significant solar development given the high cost of land lease/acquisition, property taxes, IC, development fees, permitting and site costs.

- **Hydro (1):** IC data should be considered part of project costing and tariffs should be adjusted based on known project costs. IC are very small compared to the cost of permitting, civil construction, and equipment costs.

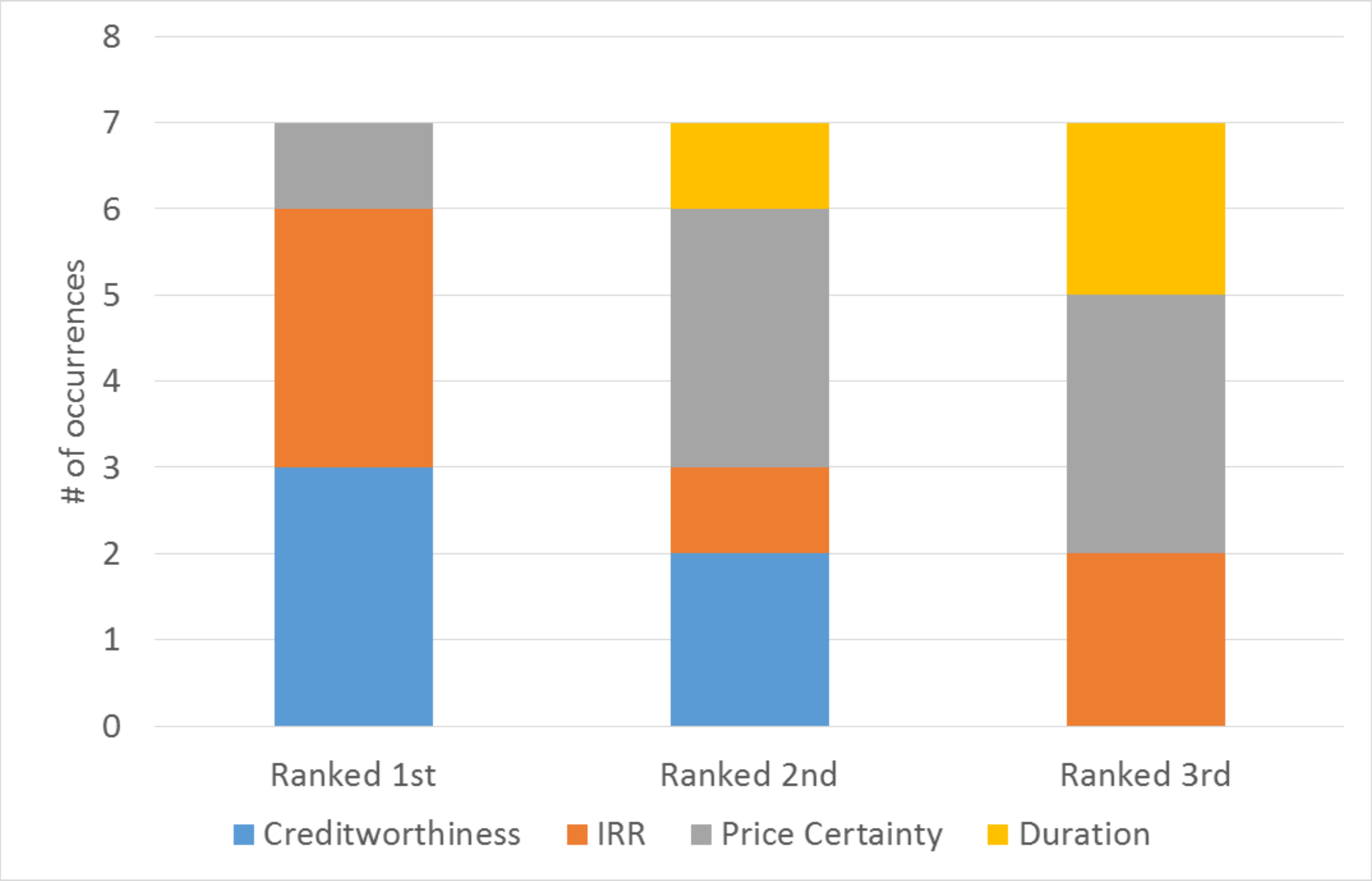
Question #6: Describe Financing Approach

- **Solar (1):** Seller of projects to energy companies, banks, and utility companies, who own the asset long-term as a balance sheet asset. If leverage exists, it is at the corporate level with the buyer.
- **Solar (2):** (a) 50-55% debt from a regional lender, (b) 25-30% from a tax equity partner (ITC), (c) 15-25% from equity contributions
- **Solar (3):** Customers provide their own financing. Many of customers use banks for financing.
- **Solar (4):** Residential clients use their own capital or a loan secured by the solar installation (20 year terms at rates of 6.5%-8.0% with fees ~5% of financed amount)
- **Solar and Wind (1):** Significant equity allocation from private equity. Tax Equity and debt is provided from several large national and global banking institutions. Many commercial businesses finance systems with own equity, and a local bank or credit line.
- **Hydro (1):** Most banks are not interested in financing hydropower, mostly financed privately.

Question #7: Applying TPO to REG

- **Solar (1):** TPO is successful in bringing investment capital into the state. Returns must be higher for commercial projects (8.5% - 9%) as opposed to large solar projects.
- **Solar (2):** Many non-local companies will aggressively push TPO solar onto customers, providing little benefit to the owners for uneducated customers. Potential customers will be turned away by these non-advantageous proposals.
- **Solar (3):** Advocate opening the 3rd party ownership market to large commercial accounts with benefits: energy savings/cost reductions, reduced grid dependency, environmental benefits, and battery/storage options are emerging
- **Solar (4):** For Commercial, the ceiling price is too low to attract significant developer interest

Question #8: Rank Investor Contract Criteria



Question #9: Limitations Imposed by Investors

- **Solar (1):** Financing costs (approx. $100/kW) for smaller-scale projects. Investor limitations include:
  - debt tenor shall never be equal to contract length
  - DSCR must be 1.25 or greater in any loan year

Question #10: IRR for RI Projects

- **Solar (1):** [REG] Returns are comparable to the marketplace over past 5+ yrs.
- **Solar (2):** Labor and real estate costs are significantly more in RI compared to VT
- **Solar (3):** Commercial building owners are concerned about predictability and long term stability of electricity price. Thus lower IRR is acceptable. Residential home owners' main concerns include expected capital payback term, upfront cost, future tenure in their property, roof longevity, property value reduction due to aesthetic concerns, and compliance cost in relation to taxable income. Compared to S&P 500 return (~6.7% since inception CPI adjusted), a 5% IRR for small scale residential solar installations does not appropriately compensated for risks.

Question #11: Use of Federal Incentives

- **Solar (1):** [The Program] only works with investors who are able to monetize 100% of the ITC and MACRS, representing more than half of the capital stack for a project. Noted the usage of bonus depreciation is very low, due to its extensive use on all capital investments in the economy.
- **Solar (2):** The federal incentive is often funded by the financier for a term of 16 months, paid by month 16 as a lump sum against the principal of the loan. The loan is then re-amortizes.
- **Solar (3):** Relies upon the ITC for its financing structures and leverages tax equity partnerships to utilize the various tax benefits.
- **Solar (4):** 95% of our customers are tax paying corporations that use the ITC to offset taxable income.

- **AD (1):** Federal tax incentives have been monetized for past projects. Federal ITC for new AD projects will end after 2016.

Additional Comments: Solar

- **Net Zero Homes**
  - Have seen some customers with 16000-17000 kWh load (geothermal heat pump, all electric, 100% renewable) design go with only an 11kW system because the larger system size tariff is not financially favorable
- **Net metering**
  - “50% of people are doing net metering; 50% are using the tariff.”
- **Customer time horizon**
  - Most homeowners have a very short (3-5 year) payback horizon. Hope the 15 year option stays around as it is more attractive than the 20 year option
- **Impact of MA market**
  - MA construction surge is reducing availability of electricians for solar projects in RI, increasing labor costs from .30 $/W to .50 $/W… surge will likely die down by 2018, but in the meantime electricians will be the limiting factor….
- **Permitting**
  - has gotten more challenging as market has matured

Additional Comments: Wind

- **PTC vs. ITC**
  - With a lower capacity factor, under ~35% (depending on project size), go with the ITC; with higher capacity factor or large project sizes, the PTC works better

- **Larger scale competition**
  - Problem for a single or few turbine project in RI is the competition for turbines vs a 100MW windfarm in Maine.
  - For a 1 turbine project, 11.5 cents/kWh including RECs is reasonable, with utilities willing to pay 7-8 cents for energy only.

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TOPICS FOR DISCUSSION:
STAKEHOLDER MEETING, 9/7/2016

Ceiling Price Additions

- **The following categories will be added for the next round of draft Ceiling prices:**
  - **Large Solar, Community Remote DG (up to 5 MW)**
  - **Small Wind, Community Remote DG (100 kW)**
  - **Wind I, Community Remote DG (1.65 MW)**

Topics for Discussion

- **Applicable to all CP categories:**
  - The necessity of property tax-driven CP variants (e.g. for res. / mfg.)
  - Equity return targets: pre-tax v. after-tax
  - Community Remote DG: cost + shared savings and incentive to enroll
  - Differentiation of CRDG in the MW Allocation Plan.
- **Solar:**
  - Small Solar Financing
    - Choice of 100% debt; other financing options
    - How is equity input used in a 100% debt financing case?
  - Capacity factors
- **Wind:**
  - Wind CP category naming conventions
  - Complexity associated with ITC safe harbor (for wind)
  - Small Wind: Fixed price or competitive bid?
  - Small Wind: Necessity of land lease payment

Rhode Island
Renewable Energy Growth Program:

2017 2nd Draft
Ceiling Price Recommendations

September 2016

Sustainable Energy Advantage, LLC
Meister Consultants Group, Inc.
Mondre Energy, Inc.

DISCUSSION TOPIC: CRDG

Community Remote DG, initial comments

- Ceiling Prices for Community Remote Distributed Generation (CRDG) facilities are proposed at a 15% premium to projects of the otherwise same technology and size category.
- The following provide support for this recommendation:
  - Many consumers either rent or do not have facilities suitable for on-site generation
  - The REG policy intends to reach these consumers through CRDG
  - Educating, signing up, and retaining these customers requires substantial effort on the part of new market entrants
  - Some projects may require the acquisition of hundreds of customers
  - Billing and customer service functions must also be established, operated and maintained
  - The "community shared" renewables business model is in its infancy, but holds promise for delivering benefits to Rhode Island consumers. As with the other RI REG categories, it is expected that the cost to provide these benefits will reduce as the market matures.

- Reply comments state that this support is largely anecdotal.
  - Such comments are not unreasonable; CRDG is a nascent market.
- SEA has requested customer acquisition cost data for CRDG systems.
- In response, CSS developers have provided additional, quantitative, feedback.
  - (Next slide)

Community Remote DG, data response

	Range Reported by Stakeholders	Value Deployed in Modeling
Customer Acquisition Cost[1,2] (¢/Watt, one-time)	R1: 20 – 30 ¢ R2: 20 – 25 ¢[3,4] R3: 20 – 50 ¢	25 ¢/Watt
Customer Replacement Cost[5] (¢/Watt/year)	R1: 2 ¢ R2: 2 ¢	2 ¢/Watt
Customer Management & Billing Cost (¢/Watt/year)	R1: 2 ¢ R2: 2 ¢ "or maybe less"	1 ¢/Watt

Supplemental Comments:
1. Most developers hire a 3rd-party for lead generation.
2. Conversion rate on prospects is 5 to 10%
3. "It is very difficult to convert leads for less [than amounts quoted]"
4. "The market is immature; participation needs to be driven in order to reduce cost."
5. ~7% of households move each year; this leads to annual replacement costs (ongoing acquisition costs for a portion of participants each year.

Community Remote DG, CP analysis

- Based on feedback provided to date, modeled CRDG CPs using quantitative values provided by market participants result in CPs above the 15% premium.

- Data were not provided that differentiate solar and wind customer acquisition and management costs.

(¢/kWh)	2nd Draft CP @ 15% Premium (Cap)	2nd Draft CP Adj. to Survey Feedback
Commercial Solar, CRDG	20.50	22.25
Large Solar, CRDG	16.60	18.65
Wind I, CRDG	20.20	20.25
Wind II, CRDG	19.40	19.65
Wind III, CRDG	18.70	19.05

SUMMARY RESULTS

Draft Proposed Ceiling Prices, 2017 REG Program (1)
(cents/kWh)

Technology	Size Range (Modeled Size)	Analysis Run	15 year Tariff Duration	20 year Tariff Duration
Small Solar I, Host Owned, Residential	1 to 10 kW (5)	2016 Final CP 2017 1st Draft 2017 2nd Draft	37.65 28.15 (-25%) 29.65 (-21%)	33.45 25.45 (-24%) 27.65 (-16%)
Small Solar I, Host Owned, Non-Residential	1 to 10 kW (5)	2016 Final CP 2017 1st Draft 2017 2nd Draft	NA 28.65 29.15	NA 25.85 26.85
Small Solar I, TPO, Residential	1 to 10 kW (5)	2016 Final CP 2017 1st Draft 2017 2nd Draft	28.35 26.25 (-7%) 27.65 (-2%)	24.70 24.55 (-1%) 24.55 (-1%)
Small Solar I, TPO, Non-Residential	1 to 10 kW (5)	2016 Final CP 2017 1st Draft 2017 2nd Draft	NA 26.75 27.05	NA 23.75 24.25

When comparing Ceiling Prices, please note that property taxes were applied to residential projects for 2016 CPs and are not applied to residential projects for 2017 CPs.

Draft Proposed Ceiling Prices, 2017 REG Program (2)

(cents/kWh)

Technology	Size Range	Analysis Run	20-Yr Tariff
Small Solar II, Residential	11 to 25 kW (25)	**2016 Final CP** **2017 1st Draft** **2017 2nd Draft**	**24.90** **23.65 (-5%)** **24.65 (-1%)**
Small Solar II, Non-Residential	11 to 25 kW (25)	**2016 Final CP** **2017 1st Draft** **2017 2nd Draft**	**NA** **23.25** **23.95**
Medium Solar	26 to 250 kW (140)	**2016 Final CP** **2017 1st Draft** **2017 2nd Draft**	**22.55** **22.25 (-1%)** **22.25 (-1%)**
Commercial Solar	251 to 999 kW (500)	**2016 Final CP** **2017 1st Draft** **2017 2nd Draft**	**19.30** **18.35 (-5%)** **17.85 (-8%)**
Commercial Solar, Community Remote DG	251 to 999 kW (500)	**2016 Final CP** **2017 1st Draft** **2017 2nd Draft**	**NA** **18.45** **20.50**
Large Solar	1 to 5 MW (2)	**2016 Final CP** **2017 1st Draft** **2017 2nd Draft**	**15.10** **14.95 (-1%)** **14.45 (-4%)**
Large Solar, Community Remote DG	1 to 5 MW (2)	**2016 Final CP** **2017 1st Draft** **2017 2nd Draft**	**NA** **NA** **16.60**

Draft Proposed Ceiling Prices, 2017 REG Program (3)

(cents/kWh)

Technology	Size Range	Analysis Run	20-Yr Tariff
Small Wind	1 – 999 kW (100 kW)	**2016 Final CP** **2017 1st Draft** **2017 2nd Draft**	**NA** **20.95** **20.95**
Wind I	1 – 3 MW (1.65 MW	**2016 Final CP** **2017 1st Draft** **2017 2nd Draft**	**18.75** **17.55 (-6%)** **17.55 (-6%)**
Wind I, Community Remote DG	1 – 3 MW (1.65 MW	**2016 Final CP** **2017 1st Draft** **2017 2nd Draft**	**NA** **NA** **20.20**
Wind II	3 – 5 MW (3.3 MW)	**2016 Final CP** **2017 1st Draft** **2017 2nd Draft**	**18.00** **16.85 (-6%)** **16.85 (-6%)**
Wind II, Community Remote DG	3 – 5 MW (3.3 MW)	**2016 Final CP** **2017 1st Draft** **2017 2nd Draft**	**NA** **NA** **19.40**
Wind III	3 – 5 MW (4.95 MW)	**2016 Final CP** **2017 1st Draft** **2017 2nd Draft**	**17.40** **16.25 (-7%)** **16.25 (-7%)**
Wind III, Community Remote DG	3 – 5 MW (4.95 MW)	**2016 Final CP** **2017 1st Draft** **2017 2nd Draft**	**NA** **NA** **18.70**

The analysis assumes that wind projects qualify for 80% of the full ITC value.

Draft Proposed Ceiling Prices, 2017 REG Program (4)

(cents/kWh)

Technology	Size Range	Analysis Run	20-Yr Tariff
Hydro I	10 – 250 kW (150 kW)	**2016 Final CP** **2017 1st Draft** **2017 2nd Draft**	18.65 22.15 (19%) 22.15 (19%)
Hydro II	251 kW – 5 MW (500 kW)	**2016 Final CP** **2017 1st Draft** **2017 2nd Draft**	17.45 20.75 (19%) 20.75 (19%)
AD I	150 – 500 kW (325 kW)	**2016 Final CP** **2017 1st Draft** **2017 2nd Draft**	20.20 19.45 (-4%) 20.15 (-0.25%)
AD II	501 kW – 5 MW (750 kW)	**2016 Final CP** **2017 1st Draft** **2017 2nd Draft**	20.20 20.15 (-0.25%) 20.15 (-0.25%)

The Production Tax Credit has expired for both hydroelectric and anaerobic digester facilities. As a result, 2016 CPs included PTCs, 2017 proposed CPs do not.

MODELED PARAMETERS:
SOLAR

SOLAR: Cost & Production Inputs

Modeled Parameters

No changes to this set of inputs.

		Small Solar I Resi (1-10 kW)	Small Solar I Comm (1-10 kW)	Small Solar II (11-25 kW)	Medium Solar (26-250 kW)	Commercial Solar (251-1,000 kW)	Large Solar (1-5 MW)
Nameplate Capacity	kW	5		25	140	500	2,000
Capacity Factor		13.49%	13.49%	13.49%	14.00% [13.45%]	14.40% [13.59%]	15.30% [14.18%]
Annual Degradation	%	0.5%					
Cost, Less Interconnection	$/kW	$3,800 (+ $161 inverter warrantee) [$3,839 + $161 inverter warrantee]		$3,541 [$3,680]	$2,724 [$2,799]	$2,293 [$1,939]	$2,150 [$1,784]
Interconnection	$/kW	$0			$129 [$128]	$97 [$513]	$91 [$237]
Total Cost	$/kW	$3,961 [$4,000]		$3,541 [$3,680]	$2,853 [$2,927]	$2,390 [$2,452]	$2,241 [$2,021]

Blue = change from 2016 value.

[Bracketed] values show 2016 CP inputs, where different

Ongoing Cost Assumptions

No changes to this set of inputs.

Modeled Parameters

		Small Solar I Resi (1-10 kW)	Small Solar I Comm (1-10 kW)	Small Solar II (11-25 kW)	Medium Solar (26-250 kW)	Commercial Solar (251-1,000 kW)	Large Solar (1-5 MW)
Fixed O&M Expense, Yr 1	$/kW-yr	$50 [$15]	$50 [$15]	$50 [$15]	$34 [$15]	$24 [$15]	$15
O&M Cost Inflation	%	2%					
Insurance, Yr 1 (% of Total Cost)	%	0.00%			0.27% [0.25%]		
Management Yr 1	$/yr	Included in O&M. [$150]			$750 [$500]	$3,000 [$3,300]	$7,700 [$10,000]
Land Lease	$/yr	$0			$3,500 [$0]	$12,500 [$6,000]	$50,000 [$24,000]

Blue = change from 2016 value.

[Bracketed] values show 2016 CP inputs, where different

Financing Assumptions

Modeled Parameters

		Small Solar I, Host, Residential (1-10 kW) (15 / 20 yrs)	Small Solar I, Host, Non-Residential (1-10 kW) (15 / 20 yrs)	Small Solar I, TPO, Residential (1-10 kW) (15 / 20 yrs)	Small Solar I, TPO, Non-Res. (1-10 kW) (15 / 20 yrs)
% Debt	%	**100%** **[0%]**	**45%**	50%	**55%**
Debt Term	yrs	**10/15** **[N/A]**	**10**	**12/15** **[13/18]**	**10/12**
Interest Rate on Term Debt	%	**6.5%/70%** **5.5%** **[N/A]**	**6.5%**	**6.5%/7.0%** **5.5%/5.75%** **[6.5%]**	**5.5%/5.75%**
Lender's Fee (% of total borrowing)	%	**2.0%** **[2.25%, N/A for Small Solar I Resi (1-10 kW)]**			
Required Minimum Annual DSCR		1.00			
Required Average DSCR		1.35			
Target After-Tax Equity IRR	%	**5.0%** **5.5%** **[5.0%]**	**8.0%**	**8.0%**	**8.0%**

Green = change from 1st draft **Blue** = change from 2016 value. **[Bracketed]** values show 2016 CP inputs, where different

Financing Assumptions

Modeled Parameters

		Small Solar II, Residential (11-25 kW)	Small Solar II, Non-Res. (11-25 kW)	Medium Solar (26-250 kW)	Commercial Solar (251-1,000 kW)	Large Solar (1-5 MW)
% Debt	%	**100%**	**45%** **[50%]**	**45% [50%]**	**40%** **[50%]**	**40%** **[50%]**
Debt Term	yrs	**10**	**12** **[18, 10, 15]**			15
Interest Rate on Term Debt	%	**6.5%**	**6.0%, 6.0%, 5.75%** **5.5%** **[6.5%, 6.5%, 6.0%]**			**5.75%** **[6.0%]**
Lender's Fee (% of total borrowing)	%	**2.0%** **[2.25%, N/A for Small Solar I Resi (1-10 kW)]**				
Required Minimum Annual DSCR		1.00				
Required Average DSCR		1.35				
Target After-Tax Equity IRR	%	**5.0%, 8.0%. 7.5%, 7.0%, 7.0%** **8.0%** **[5.0%, 8.0%, 7.5%, 7.0%, 7.0%]**				

Green = change from 1st draft **Blue** = change from 2016 value. **[Bracketed]** values show 2016 CP inputs, where different

MODELED PARAMETERS: WIND

Production and Capital Cost Assumptions

No changes to this set of inputs.

Modeled Parameters

		Small Wind	Wind I	Wind II	Wind III
Nameplate Capacity	kW	100	1,650	3,300	4,950
Capacity Factor	%	21%	21%		
Annual Degradation	%	0.0%	0.0%		
Generation Equipment	$/kW	$4,000	$3,200	$3,025 [$3,100]	$2,850 [$3,000]
Interconnection	$/kW	$54	$102 [$241]	$100 [$181]	$100 [$160]

Blue = change from 2016 value.

[Bracketed] values show 2016 CP inputs, where different

Ongoing Cost Assumptions

No changes to this set of inputs.

Modeled Parameters

		Small Wind	Wind I	Wind II	Wind III
Fixed O&M Expense, Yr 1	$/kW-yr	**$30.00**	**$45.00** [$25.00]		
O&M Cost Inflation	%	**2%**	2%		
Insurance, Yr 1 (% of Total Cost)	%	**0.25%**	**0.45%** [0.60%]		
Management Yr 1	$/yr	**Incl.**	Included in O&M		
Land Lease	$/yr	**$5,000**	**$54K** [$52.5K]	**$108K** [$105K]	**$162K** [$157.5K]

Blue = change from 2016 value.

[Bracketed] values show 2016 CP inputs, where different

Financing Assumptions

Modeled Parameters

No changes to this set of inputs.

		Small Wind	Wind I	Wind II	Wind III
% Debt	%	45%	60% [70%]		
Debt Term	yrs	15	15 [18]		
Interest Rate on Term Debt	%	6.25%	6.25% [6.50%]		
Lender's Fee (% of total borrowing)	%	2.00%	2.00% [2.25%]		
Required Minimum Annual DSCR		1.00	1.00		
Required Average DSCR		1.45	1.45		
Target After-Tax Equity IRR	%	10%	10%		
Reserve Requirement	$	Incl.	6 mos of debt service		
Major Equipment Replacements		Incl.	Yrs 12, 15, 18, 19, $30/kW [$0/kW]		

Blue = change from 2016 value.

[Bracketed] values show 2016 CP inputs, where different

MODELED PARAMETERS: ANAEROBIC DIGESTION

PROJECT PERFORMANCE ASSUMPTIONS

No changes to this set of inputs.

Modeled Parameters

		Anaerobic Digestion I	Anaerobic Digestion II
Generator Nameplate Capacity	*kW*	**325**	**725**
Biogas Consumption per Day	*cubic feet/day*	**131,729** **157,911** **[120,066]**	**293,856** **[267,840]**
Energy Content per Cubic Foot	*BTU/cubic foot*	**550** **[600]**	
Heat Rate	*BTU/kWh*	**8,979** **10,339** **[8,928]**	**8,979** **[8,928]**
Availability	*%*	**92%**	
Station Service (Parasitic Load)	*%*	**20%**	
Annual Production Degradation	*%*	**0%**	
Project Useful Life	*years*	**20**	

Blue = change from 2016 value.

[Bracketed] values show 2016 CP inputs, where different

CAPITAL, INTERCONNECTION AND O&M COSTS

No changes to this set of inputs.

Modeled Parameters

		Anaerobic Digestion I	Anaerobic Digestion II
Generation Equipment	*$/kW*	**$10,000**	**$10,000**
Interconnection Costs	*$/kW*	**$150**	
Fixed O&M Expense	*$/kW-yr*	**$600**	
Variable O&M Expense	*¢/kWh*	**2.00**	
O&M Cost Inflation	*%*	**2%**	

Blue = change from 2016 value.

[Bracketed] values show 2016 CP inputs, where different

ONGOING EXPENSE ASSUMPTIONS

No changes to this set of inputs.

Modeled Parameters

		Anaerobic Digestion I	Anaerobic Digestion II
Insurance, Yr 1 (% of Total Cost)	*%*	**1.0%**	
Project Management Yr 1	*$/yr*	**$33,621**	**$75,000**
Water & Sewer Expenses	*$/yr*	**$0**	
Digestate Disposal Cost (if handled as an expense)	*$/ton*	**$0.00**	
Land Lease	*$/yr*	**$15,690**	**$35,000**

Blue = change from 2016 value.

[Bracketed] values show 2016 CP inputs, where different

FINANCING ASSUMPTIONS

Modeled Parameters

No changes to this set of inputs.

		Anaerobic Digestion I	Anaerobic Digestion II
% Debt (% of hard costs) (mortgage-style amort.)	%	**60%**	
Debt Term	years	**15** [18]	
Interest Rate on Term Debt	%	**6.25%** [6.50%]	
Lender's Fee (% of total borrowing)	%	**0%**	
Required Minimum Annual DSCR	Ratio	**1.00**	
Required Average DSCR	Ratio	**1.50**	
Target After-Tax Equity IRR	%	**10%**	
Other Closing Costs	$	**$0**	
Reserve Requirement	$	**$0**	

Blue = change from 2016 value.

[Bracketed] values show 2016 CP inputs, where different

SUPPLEMENTAL REVENUE ASSUMPTIONS

No changes to this set of inputs.

Modeled Parameters

		Anaerobic Digestion I	Anaerobic Digestion II
Tipping Fee	*$/ton*	**$25.00** [$22.50]	
Quantity Received Each Year	*tons per year*	**10,000**	**22,308**
Digestate (if merchantable for additional revenue)	*$/gallon*	**$0**	

Blue = change from 2016 value.

[Bracketed] values show 2016 CP inputs, where different

MODELED PARAMETERS:
HYDRO

Production and Capital Cost Assumptions

No changes to this set of inputs.

Modeled Parameters

		Hydro I	Hydro II
Nameplate Capacity	kW	**150**	**500**
Capacity Factor	%	**40%**	
Annual Degradation	%	**0.0%**	
Cost Excluding Interconnection	$/kW	**$6,000** [$4,500, $4,200]	
Interconnection	$/kW	**$100**	

Blue = change from 2016 value.

[Bracketed] values show 2016 CP inputs, where different

ONGOING EXPENSES

No changes to this set of inputs.

Modeled Parameters

		Hydro I	Hydro II
Variable O&M Expense, Yr 1	¢/kWh	2.00	
O&M Cost Inflation	%	2.00% [3.00%]	
Insurance, Yr 1 (% of Total Cost)	%	0.50%	
Management Yr 1	$/yr	$10,000 [$5,000]	$15,000
Land Lease	$/yr	$3,750 [$3,000]	$12,500 [$10,000]

Blue = change from 2016 value.

[Bracketed] values show 2016 CP inputs, where different

FINANCING ASSUMPTIONS

No changes to this set of inputs.

Modeled Parameters

		Hydro I	Hydro II
% Debt	%	60% [50%]	
Debt Term	yrs	15 [18]	
Interest Rate on Term Debt	%	6.25% [6.50%]	
Lender's Fee (% of total borrowing)	%	2.00% [2.25%]	
Required Minimum Annual DSCR		1.00	
Required Average DSCR		1.45	
Target After-Tax Equity IRR	%	10%	
Reserve Requirement	$	$0	

Blue = change from 2016 value.

[Bracketed] values show 2016 CP inputs, where different

MODELED PARAMETERS: ADDITIONAL ASSUMPTIONS, ALL TECHNOLOGIES

Property Taxes

- Methodology Supporting 2016 Ceiling Price
  - Start at 80% of cost basis
  - Reduce by 5% per year to floor of 30%
  - Multiply by Mill rate.
  - Effect: Tax expense starts high, decreases over time
- Methodology supporting 2017 Ceiling Price
  - Fixed rate, $5.00 per kWac installed
    - Rate ultimately subject to regulatory approval
  - Effect: Tax expense is fixed and flat
  - Hydroelectric facilities are exempt from property tax per Title 44, § 44-3-3

Incentives: Tax Credits

- Solar:
  - 30% ITC for projects commencing construction on or before 12/31/2019.
  - Assumed to apply to all projects selected in 2017 solicitations.
  - No monetization "haircut" assumed. "Discount" on ITC taken into account in equity rate of return.

- Wind
  - Wind facilities participating in the 2017 REG Program are assumed to qualify for 80% of the

- AD & Hydro
  - No PTC (or ITC in lieu thereof) for facilities commencing construction after 12/31/2016.
  - Given REG eligibility criteria that facilities not be under construction, PTC/ITC assumed not available to facilities participating in 2017 solicitations.

Incentives: NOL Carryforward

- MACRS depreciation creates deduction benefit by reducing taxable income.
- Where depreciation expense is > operating income, the project will most likely experience a net operating loss (NOL) for the specified year.
- This NOL is passed through to the facility owner, creating a benefit by reducing that entity's eligible taxable income.
- NOL benefits are assumed to be applied "as generated" to both state and federal tax liabilities

- No federal, state, local or other grants assumed.

- Policy Objective: Encourage projects able to make most effective use of tax benefits

Additional Assumptions:
Forecast of Market Value of Production

Project Year	Calendar Year	Market Value of Production (incl. energy, capacity & RECs) (cents/kWh)	
		Solar	Hydro
21	2037	11.96	11.30
22	2038	12.57	11.88
23	2039	13.22	12.49
24	2040	13.90	13.14
25	2041	14.61	13.81
26	2042		14.52
27	2043		15.27
28	2044		16.05
29	2045		16.87
30	2046		17.74

Rhode Island
Renewable Energy Growth Program:

2017 Ceiling Price Recommendations

October 2016

Sustainable Energy Advantage, LLC
Meister Consultants Group, Inc.
Mondre Energy, Inc.

Changes from prior analyses, and supporting comments, marked in green text.

SUMMARY RESULTS

Final Draft Proposed Ceiling Prices, 2017 REG Program (1)

(cents/kWh)

Technology	Size Range (Modeled Size)	Analysis Run	15 year Tariff Duration	20 year Tariff Duration
Small Solar I, Host Owned, Residential	1 to 10 kW (5)	**2016 Final CP** **2017 1st Draft** **2017 2nd Draft** **2017 Final Draft**	**37.65** **28.15 (-25%)** **29.65 (-21%)** **34.75 (-8%)**	**33.45** **25.45 (-24%)** **27.65 (-16%)** **30.85 (-8%)**
Small Solar I, Host Owned, Non-Residential	1 to 10 kW (5)	**2016 Final CP** **2017 1st Draft** **2017 2nd Draft** **2017 Final Draft**	**NA** **28.65** **29.15** **34.75**	**NA** **25.85** **26.85** **30.85**
Small Solar I, TPO, Residential	1 to 10 kW (5)	**2016 Final CP** **2017 1st Draft** **2017 2nd Draft** **2017 Final Draft**	**28.35** **26.25 (-7%)** **27.65 (-2%)** **27.05 (-5%)**	**24.70** **24.55 (-1%)** **24.55 (-1%)** **24.05 (-3%)**
Small Solar I, TPO, Non-Residential	1 to 10 kW (5)	**2016 Final CP** **2017 1st Draft** **2017 2nd Draft** **2017 Final Draft**	**NA** **26.75** **27.05** **27.05**	**NA** **23.75** **24.25** **24.05**

When comparing Ceiling Prices, please note that property taxes were applied to residential projects for 2016 CPs and are not applied to residential projects for 2017 CPs.

Final Draft Proposed Ceiling Prices, 2017 REG Program (2)

(cents/kWh)

Technology	Size Range	Analysis Run	20-Yr Tariff
Small Solar II, Residential	11 to 25 kW (25)	2016 Final CP 2017 1st Draft 2017 2nd Draft 2017 Final Draft	24.90 23.65 (-5%) 24.65 (-1%) 27.75 (11%)
Small Solar II, Non-Residential	11 to 25 kW (25)	2017 1st Draft 2017 2nd Draft 2017 Final Draft	23.25 23.95 27.75
Medium Solar	26 to 250 kW (140)	2016 Final CP 2017 1st Draft 2017 2nd Draft 2017 Final Draft	22.55 22.25 (-1%) 22.25 (-1%) 22.75 (1%)
Commercial Solar	251 to 999 kW (500)	2016 Final CP 2017 1st Draft 2017 2nd Draft 2017 Final Draft	19.30 18.35 (-5%) 17.85 (-8%) 18.75 (-3%)
Commercial Solar, Community Remote DG	251 to 999 kW (500)	2017 1st Draft 2017 2nd Draft 2017 Final Draft	18.45 20.50 21.60
Large Solar	1 to 5 MW (2)	2016 Final CP 2017 1st Draft 2017 2nd Draft 2017 Final Draft	15.10 14.95 (-1%) 14.45 (-4%) 15.05 (-0.3%)
Large Solar, Community Remote DG	1 to 5 MW (2)	2017 2nd Draft 2017 Final Draft	16.60 17.30

Final Draft Proposed Ceiling Prices, 2017 REG Program (3)
(cents/kWh)

Technology	Size Range	Analysis Run	20-Yr Tariff
Small Wind	1 – 999 kW (100 kW)	2017 1st Draft 2017 2nd Draft 2017 Final Draft	20.95 20.95 21.45
Wind I	1 – 3 MW (1.65 MW	2016 Final CP 2017 1st Draft 2017 2nd Draft 2017 Final Draft	18.75 17.55 (-6%) 17.55 (-6%) 19.45 (4%)
Wind I, Community Remote DG	1 – 3 MW (1.65 MW	2017 2nd Draft 2017 Final Draft	20.20 22.40
Wind II	3 – 5 MW (3.3 MW)	2016 Final CP 2017 1st Draft 2017 2nd Draft 2017 Final Draft	18.00 16.85 (-6%) 16.85 (-6%) 18.25 (1%)
Wind II, Community Remote DG	3 – 5 MW (3.3 MW)	2017 2nd Draft	19.40 21.00
Wind III	3 – 5 MW (4.95 MW)	2016 Final CP 2017 1st Draft 2017 2nd Draft 2017 Final Draft	17.40 16.25 (-7%) 16.25 (-7%) 17.35 (-0.3%)
Wind III, Community Remote DG	3 – 5 MW (4.95 MW)	2017 2nd Draft 2017 Final Draft	18.70 20.00

The analysis assumes that wind projects qualify for 80% of the full ITC value.

Final Draft Proposed Ceiling Prices, 2017 REG Program (4)

(cents/kWh)

Technology	Size Range	Analysis Run	20-Yr Tariff
Hydro I	10 – 250 kW (150 kW)	2016 Final CP 2017 1st Draft 2017 2nd Draft 2017 Final Draft	18.65 22.15 (19%) 22.15 (19%) 22.45 (20%)
Hydro II	251 kW – 5 MW (500 kW)	2016 Final CP 2017 1st Draft 2017 2nd Draft 2017 Final Draft	17.45 20.75 (19%) 20.75 (19%) 22.45 (29%)
AD I	150 – 500 kW (325 kW)	2016 Final CP 2017 1st Draft 2017 2nd Draft 2017 Final Draft	20.20 19.45 (-4%) 20.15 (-0.25%) 20.15 (-0.25%)
AD II	501 kW – 5 MW (750 kW)	2016 Final CP 2017 1st Draft 2017 2nd Draft 2017 Final Draft	20.20 20.15 (-0.25%) 20.15 (-0.25%) 20.15 (-0.25%)

Summary of Changes & Recommendations: Solar

- Inputs (detailed in next section) updated based on data from stakeholders
  - Interconnection costs assumed to increase compared to historic actuals.
- Modeling already aligned with stakeholder comment that ITC/5-year MACRS based on ~90% of project costs (current modeling ~89.5%); rest of cost basis depreciation as 15-year SL
- % of Total Tariff Value Assumed Taxable increased from 45% to 65%
- With respect to cost of capital, stakeholders recommended input increases. Stakeholders also commented that projects/portfolios are often back-levered after initial development, effectively reducing the cost of capital and liberating capital for future investment.
- Stakeholders recommended removing the non-res. small solar categories.
- CPs for both Res. and Non-Res. Host-Owned recommended at same value (Solar I & II).
- CPs for both Res. and Non-Res. 3rd-Party-Owned recommended at same value.

Summary of Changes & Recommendations: Solar CRDG

- 15% CP premium recommended;
- Stakeholders comment that this is insufficient; that actual premium is ~25%

- Taking "Large Solar" as an example, with weighted-average Round 2 project bids at 12.58 ¢/kWh, a CRDG project priced at the CRDG CP would be afforded a 37% premium over the "core" cost of solar at that scale.
  - Suggests that CRDG may be possible when paired with cost-effective projects.

- Taking "Commercial Solar" as an example, with weighted-average Round 2 project bids at 17.59 ¢/kWh, a CRDG project priced at the CRDG CP would be afforded a 27% premium over the "core" cost of solar at that scale.
  - Suggests that CRDG may be possible when paired with cost-effective projects.

Summary of Changes & Recommendations: Wind & Hydro

- Wind
  - Turbine size adjusted from 1,650 to 1,500 for Wind I, II & III.
  - Interconnection costs: updates based on NGrid estimate for proposed wind project in RI
  - Other cost data based on data from stakeholders and comparison to other markets
    - O&M costs disaggregated
    - Major equipment repairs and replacements added
  - Changes detailed in next section

- Hydro
  - Cost and performance assumptions updated based on additional stakeholder feedback
  - Dam maintenance expense added
  - CP intended to provide price-signal to long lead-time projects
  - Stakeholder recommends removing Hydro I category

MODELED PARAMETERS:
SOLAR

SOLAR: Cost & Production Inputs

Modeled Parameters

		Small Solar I Resi (1-10 kW)	Small Solar I Comm (1-10 kW)	Small Solar II (11-25 kW)	Medium Solar (26-250 kW)	Commercial Solar (251-1,000 kW)	Large Solar (1-5 MW)
Nameplate Capacity	kW	5		25	140	500	2,000
Capacity Factor		13.49%	13.49%	13.49%	14.00% [13.45%]	14.40% [13.59%]	15.30% [14.18%]
Annual Degradation	%	0.5%					
Cost, Less Interconnection	$/kW	$3,800 (+ $161 inverter warrantee) [$3,839 + $161 inverter warrantee]		$3,541 [$3,680]	$2,724 [$2,799]	$2,240* $2,293 [$1,939]	$2,091* $2,150 [$1,784]
Interconnection	$/kW	$0			$129 [$128]	$150* $97 [$513]	$150* $91 [$237]
Total Cost	$/kW	$3,961 [$4,000]		$3,541 [$3,680]	$2,853 [$2,927]	$2,390 [$2,452]	$2,241 [$2,021]

** This is a reallocation of costs among categories, per stakeholder recommendation.*

Green = change from 1st draft **Blue** = change from 2016 value. **[Bracketed]** values show 2016 CP inputs, where different

Ongoing Cost Assumptions

Modeled Parameters

		Small Solar I Resi (1-10 kW)	Small Solar I Comm (1-10 kW)	Small Solar II (11-25 kW)	Medium Solar (26-250 kW)	Commercial Solar (251-1,000 kW)	Large Solar (1-5 MW)
Fixed O&M Expense, Yr 1	$/kW-yr	$50 [$15]	$50 [$15]	$50 [$15]	$34 [$15]	$24 [$15]	$15
O&M Cost Inflation	%	2%					
Insurance, Yr 1 (% of Total Cost)	%	0.00%			0.27% [0.25%]		
Management Yr 1	$/yr	Included in O&M. [$150]			$750 [$500]	$3,000 [$3,300]	$7,700 [$10,000]
Land Lease	$/yr	$0			$3,500 [$0]	$12,500 [$6,000]	$50,000 [$24,000]
Inverter Replacement, in year 13	$/kW	Covered by warranty; see previous slide			$150	$150	$100

Green = change from 1st draft **Blue** = change from 2016 value. **[Bracketed]** values show 2016 CP inputs, where different

Financing Assumptions

Modeled Parameters

		Small Solar I, Host, Residential (1-10 kW) (15 / 20 yrs)	Small Solar I, Host, Non-Residential (1-10 kW) (15 / 20 yrs)	Small Solar I, TPO, Residential (1-10 kW) (15 / 20 yrs)	Small Solar I, TPO, Non-Res. (1-10 kW) (15 / 20 yrs)
% Debt	%	0% 100% [0%]	0%	55% 50%	55%
Debt Term	yrs	[N/A]	[N/A]	12/15 [13/18]	10/12
Interest Rate on Term Debt	%	[N/A]	[N/A]	6.0%/6.25% 5.5%/5.75% [6.5%]	5.5%/5.75%
Lender's Fee (% of total borrowing)	%	2.0% [2.25%, N/A for Small Solar I Resi (1-10 kW)]			
Required Minimum Annual DSCR		1.00			
Required Average DSCR		1.35			
Target After-Tax Equity IRR	%	5.0% [5.0%]	7.5%	8.0%	8.0%

Green = change from 1st draft Blue = change from 2016 value. **[Bracketed]** values show 2016 CP inputs, where different

Financing Assumptions

Modeled Parameters

		Small Solar II, Residential (11-25 kW)	Small Solar II, Non-Res. (11-25 kW)	Medium Solar (26-250 kW)	Commercial Solar (251-1,000 kW)	Large Solar (1-5 MW)
% Debt	%	0% 100%	0% 45% [50%]	50% 45% [50%]	50% 40% [50%]	40% [50%]
Debt Term	yrs	[N/A]	N/A, 12, 12 [18, 10, 15]			15
Interest Rate on Term Debt	%	[N/A]	N/A, 6.5%, 6.5% 5.5% [6.5%, 6.5%, 6.0%]			5.75% [6.0%]
Lender's Fee (% of total borrowing)	%	2.0% [2.25%, N/A for Small Solar I Resi (1-10 kW)]				
Required Minimum Annual DSCR		1.00				
Required Average DSCR		1.35				
Target After-Tax Equity IRR	%	5.0%, 7.5%. 7.5%, 7.5%, 7.0% 8.0% [5.0%, 8.0%, 7.5%, 7.0%, 7.0%]				

Green = change from 1st draft **Blue** = change from 2016 value. **[Bracketed]** values show 2016 CP inputs, where different

MODELED PARAMETERS: WIND

Production and Capital Cost Assumptions

Modeled Parameters

		Small Wind	Wind I	Wind II	Wind III
Nameplate Capacity	kW	**100**	**1,500** 1,650	**3,000** 3,300	**4,500** 4,950
Capacity Factor	%	**21%**	21%		
Annual Degradation	%	**0.0%**	0.0%		
Generation Equipment	$/kW	**$4,000**	**$3,500** $3,200	**$3,325** **$3,025** **[$3,100]**	**$3,159** **$2,850** **[$3,000]**
Interconnection	$/kW	**$54**	**$292** **$102** **[$241]**	**$240** **$100** **[$181]**	**$213** **$100** **[$160]**

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Ongoing Cost Assumptions

Modeled Parameters

		Small Wind	Wind I	Wind II	Wind III
Fixed O&M Expense, Yr 1	$/kW-yr	$30.00	$23.00* $45.00 [$25.00]		
O&M Cost Inflation	%	2%	2%		
Insurance, Yr 1 (% of Total Cost)	%	0.25%	0.43%* 0.45% [0.60%]		
Management Yr 1	$/yr	Incl.	$15,000 Included in O&M		
Land Lease	$/yr	$5,000	$54K [$52.5K]	$108K [$105K]	$162K [$157.5K]

*** Per stakeholder data response; O&M now disaggregated.***

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Financing Assumptions

Modeled Parameters

		Small Wind	Wind I	Wind II	Wind III
% Debt	%	45%	60% [70%]		
Debt Term	yrs	15	15 [18]		
Interest Rate on Term Debt	%	6.25%	6.25% [6.50%]		
Lender's Fee (% of total borrowing)	%	2.00%	2.00% [2.25%]		
Required Minimum Annual DSCR		1.00	1.00		
Required Average DSCR		1.45	1.45		
Target After-Tax Equity IRR	%	10%	10%		
Reserve Requirement	$	Incl.	6 mos of debt service		
Major Equipment Replacements*		Incl.	Yr 15 = $45K Yr 19 = $45K	Yr 15 = $90K Yr 19 = $90K	Yr 15 = $135K Yr 19 = $135K
			Yrs 12, 15, 18, 19, $30/kW [$0/kW]		

**** Per stakeholder data response; O&M now disaggregated.***

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MODELED PARAMETERS: ANAEROBIC DIGESTION

PROJECT PERFORMANCE ASSUMPTIONS

No changes to this set of inputs.

Modeled Parameters

		Anaerobic Digestion I	Anaerobic Digestion II
Generator Nameplate Capacity	*kW*	**325**	**725**
Biogas Consumption per Day	*cubic feet/day*	**131,729** **157,911** **[120,066]**	**293,856** **[267,840]**
Energy Content per Cubic Foot	*BTU/cubic foot*	**550** **[600]**	
Heat Rate	*BTU/kWh*	**8,979** **10,339** **[8,928]**	**8,979** **[8,928]**
Availability	*%*	**92%**	
Station Service (Parasitic Load)	*%*	**20%**	
Annual Production Degradation	*%*	**0%**	
Project Useful Life	*years*	**20**	

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CAPITAL, INTERCONNECTION AND O&M COSTS

No changes to this set of inputs.

Modeled Parameters

		Anaerobic Digestion I	Anaerobic Digestion II
Generation Equipment	*$/kW*	**$10,000**	**$10,000**
Interconnection Costs	*$/kW*	**$150**	
Fixed O&M Expense	*$/kW-yr*	**$600**	
Variable O&M Expense	*¢/kWh*	**2.00**	
O&M Cost Inflation	*%*	**2%**	

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No changes to this set of inputs.

Modeled Parameters

		Anaerobic Digestion I	Anaerobic Digestion II
Insurance, Yr 1 (% of Total Cost)	*%*	**1.0%**	
Project Management Yr 1	*$/yr*	**$33,621**	**$75,000**
Water & Sewer Expenses	*$/yr*	**$0**	
Digestate Disposal Cost (if handled as an expense)	*$/ton*	**$0.00**	
Land Lease	*$/yr*	**$15,690**	**$35,000**

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FINANCING ASSUMPTIONS

Modeled Parameters

No changes to this set of inputs.

		Anaerobic Digestion I	Anaerobic Digestion II
% Debt (% of hard costs) (mortgage-style amort.)	*%*	**60%**	
Debt Term	*years*	**15 [18]**	
Interest Rate on Term Debt	*%*	**6.25% [6.50%]**	
Lender's Fee (% of total borrowing)	*%*	**0%**	
Required Minimum Annual DSCR	*Ratio*	**1.00**	
Required Average DSCR	*Ratio*	**1.50**	
Target After-Tax Equity IRR	*%*	**10%**	
Other Closing Costs	*$*	**$0**	
Reserve Requirement	*$*	**$0**	

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SUPPLEMENTAL REVENUE ASSUMPTIONS

No changes to this set of inputs.

Modeled Parameters

		Anaerobic Digestion I	Anaerobic Digestion II
Tipping Fee	*$/ton*	**$25.00 [$22.50]**	
Quantity Received Each Year	*tons per year*	**10,000**	**22,308**
Digestate (if merchantable for additional revenue)	*$/gallon*	**$0**	

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MODELED PARAMETERS: HYDRO

Production and Capital Cost Assumptions

Modeled Parameters

		Hydro I	Hydro II
Nameplate Capacity	kW	**150**	**500**
Capacity Factor	%	**55%** **40%**	
Annual Degradation	%	**0.0%**	
Cost Excluding Interconnection	$/kW	**$8,750** **$6,000** **[$4,500, $4,200]**	
Interconnection	$/kW	**$500** **$100**	

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ONGOING EXPENSES

Modeled Parameters

		Hydro I	Hydro II
Variable O&M – Power Generation Expense, Yr 1	¢/kWh	**2.00**	
Variable O&M – Dam Maintenance Expense, Yr 1	¢/kWh	**2.00**	
O&M Cost Inflation	%	**2.00%** **[3.00%]**	
Insurance, Yr 1 (% of Total Cost)	%	**0.50%**	
Management Yr 1	$/yr	**$15,000** **$10,000** **[$5,000]**	**$15,000**
Land Lease	$/yr	**$3,750** **[$3,000]**	**$12,500** **[$10,000]**

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FINANCING ASSUMPTIONS

Modeled Parameters

		Hydro I	Hydro II
% Debt	%	65% 60% [50%]	
Debt Term	yrs	20 15 [18]	
Interest Rate on Term Debt	%	6.25% [6.50%]	
Lender's Fee (% of total borrowing)	%	2.00% [2.25%]	
Required Minimum Annual DSCR		1.00	
Required Average DSCR		1.45	
Target After-Tax Equity IRR	%	10%	
Reserve Requirement	$	$0	

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MODELED PARAMETERS: ADDITIONAL ASSUMPTIONS, ALL TECHNOLOGIES

Property Taxes

- Methodology Supporting 2016 Ceiling Price
  - Start at 80% of cost basis
  - Reduce by 5% per year to floor of 30%
  - Multiply by Mill rate.
  - Effect: Tax expense starts high, decreases over time

- Methodology supporting 2017 Ceiling Price
  - Fixed rate, $5.00 per kWac installed
    - Rate ultimately subject to regulatory approval
  - Effect: Tax expense is fixed and flat
  - Installations on residential and manufacturing facilities are exempt
  - Hydroelectric facilities are exempt from property tax per Title 44, § 44-3-3

Incentives: Tax Credits

- Solar:
  - 30% ITC for projects commencing construction on or before 12/31/2019.
  - Assumed to apply to all projects selected in 2017 solicitations.
  - “Discount” on ITC of 7.5% taken into account to ensure reasonable equity rate of return. [7.5% based on stakeholder input that a 5% to 10% discount is appropriate.]

- Wind
  - Wind facilities participating in the 2017 REG Program are assumed to qualify for 80% of the face value of the ITC.
  - “Discount” on ITC of 7.5% taken into account to ensure reasonable equity rate of return. [7.5% based on stakeholder input that a 5% to 10% discount is appropriate.]

- AD & Hydro
  - No PTC (or ITC in lieu thereof) for facilities commencing construction after 12/31/2016.
  - Given REG eligibility criteria that facilities not be under construction, PTC/ITC assumed not available to facilities participating in 2017 solicitations.

Incentives: NOL Carryforward

- MACRS depreciation creates deduction benefit by reducing taxable income.
- Where depreciation expense is > operating income, the project will most likely experience a net operating loss (NOL) for the specified year.
- This NOL is passed through to the facility owner, creating a benefit by reducing that entity's eligible taxable income.
- NOL benefits are assumed to be applied "as generated" to both state and federal tax liabilities

- No federal, state, local or other grants assumed.

- Policy Objective: Encourage projects able to make most effective use of tax benefits

Additional Assumptions:
Forecast of Market Value of Production

Project Year	Calendar Year	Market Value of Production (incl. energy, capacity & RECs) (cents/kWh)	
		Solar	**Hydro**
21	2037	11.96	11.30
22	2038	12.57	11.88
23	2039	13.22	12.49
24	2040	13.90	13.14
25	2041	14.61	13.81
26	2042		14.52
27	2043		15.27
28	2044		16.05
29	2045		16.87
30	2046		17.74

Rhode Island Renewable Energy Growth Program:

2017 CRDG Ceiling Price Recommendations

October 2016

Sustainable Energy Advantage, LLC
Meister Consultants Group, Inc.
Mondre Energy, Inc.

Changes from prior analyses, and supporting comments, marked in green text.

Final Proposed CRDG Ceiling Prices, 2017 REG Program

(cents/kWh)

Technology	Size Range	Analysis Run	20-Yr Tariff
Commercial Solar, Community Remote DG	251 to 999 kW (500)	**2017 1st Draft** **2017 2nd Draft** **2017 3rd Draft** **2017 Final Draft**	**18.45** **20.50** **21.60** **20.65**
Large Solar, Community Remote DG	1 to 5 MW (2)	**2017 2nd Draft** **2017 3rd Draft** **2017 Final Draft**	**16.60** **17.30** **16.85**
Wind I, Community Remote DG	1 – 3 MW (1.65 MW	**2017 2nd Draft** **2017 3rd Draft** **2017 Final Draft**	**20.20** **22.40** **20.65**
Wind II, Community Remote DG	3 – 5 MW (3.3 MW)	**2017 2nd Draft** **2017 3rd Draft** **2017 Final Draft**	**19.40** **21.00** **19.35**
Wind III, Community Remote DG	3 – 5 MW (4.95 MW)	**2017 2nd Draft** **2017 3rd Draft** **2017 Final Draft**	**18.70** **20.00** **18.55**