Rhode Island Renewable Energy Growth Program:

Research, Analysis, & Discussion in Support of Second Draft 2024 Program Year Ceiling Price and Incentive-Rate Adder Recommendations

October 24, 2023

Sustainable Energy Advantage, LLC
Mondre Energy, Inc.

Schedule for Analysis/Stakeholder Engagement Process Ahead of (Potential) Multi-Year Filing

- **Meeting #1: 1st Draft of Ceiling Prices for <=5 MW Renewable Energy Classes**
  - **Thursday, August 24, 2023**
  - ***Purpose of the Meeting*:** Share analysis/discuss with stakeholders first draft of Ceiling Prices for the Renewable Energy Classes **less than or equal to 5 MW** (read: the pre-new law categories) and all years of the program prior to that.
  - A copy of the presentation delivered at the meeting can be found **here**
- **Meeting #2: 1st Draft of Greater than 5 MW Class Prices & All Incentive-Rate Adders**
  - **Friday, September 22, 2023**
  - ***Purpose of the Meeting*:** Share analysis/discuss with stakeholders first draft of Ceiling Prices for the Renewable Energy Classes ***for Solar projects greater than 5 MW and potential incentive-rate adders (from recently-enacted law).***
  - A copy of the presentation delivered at the meeting can be found **here**
- **Meeting #3: 2nd Draft of All Proposed Prices and All Incentive-Rate Adders**
  - **Tuesday, October 24, 2023** (9:00-11:00 am ET)
  - ***Purpose of the Meeting*:** Share (and discuss with stakeholders) second draft of ***all REG ceiling prices and incentive-rate adders under consideration***.
  - **Click here** to register.

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Context Regarding Recent Changes in Rhode Island Distributed Generation Statutes

- On June 24, 2023, the companion bills **2023-S 684/2023-H 5853 – An Act Related to Public Utilities and Carriers – Net Metering** were signed into law
- Implications for REG program:
  - Permits OER and the DG Board to propose schedules of REG ceiling prices and capacity allocations for **no more than three program years in the future**, but allows OER and the Board to make adjustments to said prices
  - **Disqualifies projects sited on a "core forest" parcel** from REG program participation
  - **Creation of resource classes** for projects:
    - 5-9.99 MW
    - 10-14.99 MW
    - 15-38.99 MW, but only if eligible projects are sited on "preferred sites"
  - Allows OER and the Board to consider the **development of adders** for projects "requiring remediation"

Sustainable Energy Advantage, LLC

Second Draft 2024–26 Ceiling Prices, Categories and Modeling Parameters

Purpose

- To present stakeholder data responses, survey results, and supplemental research
- To *continue* the discussion that supports the development of
    - Ceiling Price inputs for resources for the 2024 Renewable Energy Growth (REG) Program (and possibly up to two (2) Program Years thereafter); and
    - Adders for projects "requiring remediation"
- To refine results presented today in an iterative, public process based on stakeholder feedback

Potential 2024–2026 PY Ceiling Price Categories

REG Program: Proposed Technology, Size & Tariff Length Parameters			
Eligible Technology	**System Size for CP Development (DC)**	**Eligible System Size Range (DC)**	**Tariff Length**
Small Solar I	5.8 kW	≤ 15 kW	15 Years
Small Solar II	25 kW	>15 to 25 kW	20 Years
Medium Solar	250 kW	>25 to 250 kW	20 Years
Commercial Solar I	500 kW	>250 to 500 kW	20 Years
Commercial Solar I – Community Remote DG (CRDG)	500 kW	>250 to 500 kW	20 Years
Commercial Solar II	1 MW	>500 kW to 1 MW	20 Years
Commercial Solar II – Community Remote DG (CRDG)	1 MW	>500 kW to 1 MW	20 Years
Large Solar	5 MW	>1 to 5 MW	20 Years
Large Solar - CRDG	5 MW	>1 to 5 MW	20 Years
Large Solar II	9.99 MW	5 to <10 MW	20 Years
Large Solar III	14.99 MW	10 to <15 MW	20 Years
Large Solar IV	20 MW	15 to <39 MW	20 Years
Wind	3 MW	≤ 5 MW	20 Years
Anaerobic Digestion	750 kW	≤ 5 MW	20 Years
Hydropower	500 kW	≤ 5 MW	20 Years

Summary Results, Potential 2024–2026 Solar Classes <=5 MW (¢/kWh)

NOTE: The 2024-2026 prices shown below are indicative only. As of the drafting of this presentation, no decision has yet been made regarding the length of a potential multi-year pricing schedule.

Technology	Tariff Term	Size Range kW (Modeled Size kW)	2023 CP (Approved}	2024 CP	Potential 2025 CP	Potential 2026 CP	% Change (2023➔ 2024)	% Change (2023➔ 2025)	% Change (2023➔ 2026)
Small Solar I	15	0-15 (5.8)	27.75	**36.45** [33.55]	**34.65** [31.85]	**33.95** [30.95]	**31%** [21%]	**25%** [13%]	**22%** [5%]
Small Solar II	20	>15-25 (25)	26.15	**33.15** [32.25]	**31.95** [31.05]	**31.35** [30.35]	**27%** [23%]	**22%** [16%]	**20%** [10%]
Medium Solar	20	>25-250 (250)	25.65	**34.35** [33.45]	**33.45** [32.55]	**33.25** [32.25]	**34%** [30%]	**30%** [26%]	**30%** [23%]
Commercial I	20	>250-500 (500)	22.05	**29.35** [29.85]	**28.55** [28.95]	**28.35** [28.55]	**33%** [35%]	**29%** [30%]	**29%** [26%]
Commercial I CRDG	20	>250-500 (500)	25.15	**32.25** [32.65]	**31.45** [31.75]	**31.25** [31.45]	**28%** [30%]	**25%** [25%]	**24%** [22%]
Commercial II	20	>500-1,000 (1,000)	19.05	**24.45** [23.85]	**23.75** [23.05]	**23.55** [22.75]	**28%** [25%]	**25%** [20%]	**24%** [16%]
Commercial II CRDG	20	>500-1,000 (1,000)	21.91*	**27.35** [26.65]	**26.65** [25.85]	**26.35** [25.55]	**25%** [22%]	**22%** [17%]	**20%** [13%]
Large Solar	20	>1,000-5,000 (5,000)	14.35	**18.65** [17.35]	**18.05** [16.75]	**17.85** [16.65]	**30%** [21%]	**26%** [15%]	**24%** [12%]
Large Solar-CRDG	20	>1,000-5,000 (5,000)	16.50*	**21.35** [19.95]	**20.75** [19.26]	**20.52*** [19.14]	**30%** [21%]	**26%** [15%]	**24%** [12%]

Values in **bold** represent current draft values, while those in [purple brackets] represent the previous draft values.

*This is the maximum CRDG Ceiling Price allowed by law. The calculated 2023 values are 22.95 for Commercial CRDG 251-500, 19.95 for Commercial CRDG 500-999 and 15.15 for Large CRDG. The calculated 2026 value for Large Solar is 20.55. Note, however, that this CP would allow cost-competitive projects (bidding below the CP) access to > a 15% premium compared to actual project costs.

Summary Results, Potential 2024–2026 Solar Classes <=5MW (¢/kWh)

NOTE: The 2024-2026 prices shown below are indicative only. As of the drafting of this presentation, no decision has yet been made regarding the length of a potential multi-year pricing schedule.

Technology	Tariff Term	Size Range kW (Modeled Size kW)	2024 1st Draft Potential CP	2025 1st Draft Potential CP	2026 1st Draft Potential CP
Large Solar II	20	5,000-<10,000 (9,999)	**18.55** [15.25]	**17.95** [14.75]	**17.75** [14.65]
Large Solar III	20	10,000-<15,000 (14,999)	**19.15** [14.15]	**18.65** [13.65]	**18.45** [13.55]
Large Solar IV*	20	15,000-<39,000 (20,000)	**18.85** [17.05]	**18.35** [16.65]	**18.15** [16.55]

Values in **bold** represent the current draft values, while those in [purple brackets] represent the previous draft values.

*In first draft pricing, SEA included the maximum adder for projects requiring remediation in the ceiling price for Large Solar IV, as these projects are required to be on a preferred site. Based on stakeholder feedback, the Large Solar IV CP no longer includes added costs relating to development on sites requiring remediation. However, SEA intends Large Solar IV to be able to qualify for such adders in the same way other resource classes can.

Note: The Ceiling Price increase for Large II, III, and IV are primarily driven by 1) removal of interconnection costs from the ITC basis (for all classes over 5 MW) and 2) removal of net metering post-tariff revenue (for all classes over 10 MW) and truncation of the post-tariff period – discussed in detail in later slides

Summary Results, Potential 2024-2026 Non-Solar Classes (¢/kWh)

NOTE: The 2024-2026 prices shown below are indicative only. As of the drafting of this presentation, no decision has yet been made regarding the length of a potential multi-year pricing schedule.

Technology	Tariff Term (Years)	Size Range kW (Modeled Size kW)	2023 Approved CP	2024 2nd Draft Potential CP	2025 2nd Draft Potential CP	2026 2nd Draft Potential CP	% Change (2023 → 2024)	% Change (2023 → 2025)	% Change (2023 → 2026)
Wind*	20	<=5,000 (3,000)	19.15	**20.1** [19.55]	**19.75** [19.25]	**19.75** [19.35]	**6%** [2%]	**4%** [1%]	**4%** [1%]
Wind – CRDG*	20	<=5,000 (3,000)	21.15	**21.95** [21.35]	**21.55** [21.15]	**21.55** [21.15]	**4%** [1%]	**2%** [0%]	**3%** [0%]
Hydroelectric	20	<=5,000 (500)	31.95	**34.15** [31.55]	**33.35** [31.05]	**33.45** [31.05]	**7%** [-1%]	**4%** [-3%]	**5%** [-3%]
Anaerobic Digestion (AD)	20	<=5,000 (750)	19.05	**19.25** [18.85**]	**18.95** [18.35**]	**19.05** [18.25**]	**1%** [-2%]	**-2%** [-4%**]	**1%** [-4%**]

Values in **bold** represent 2nd draft values, while those in [purple brackets] represent the previous 1st Draft values.
*Average of (1) 60-20% bonus depreciation and (2) no bonus depreciation
**The purple-bracketed values that were in the prior presentation for program years 2024-2026 were miscopied from SEA's models. The correct values for the previous draft are as shown in the purple brackets. The values as proposed for the current draft and rendered in bold are as calculated in the CREST model and are unaffected by the miscopy.

Overview of Key Stakeholder Feedback and Modeling Implications for Ceiling Prices

Interest Rates on Term Debt (1)

- **Starting (2023) Value: Interest Rate on Term Debt**
  - Despite several requests for financing information, stakeholders **did not submit new information** suggesting that SEA's current approach of taking applicable debt term values was incorrect
  - Furthermore, increases in the Federal Funds Rate by the Federal Open Market Committee (FOMC), as well as other market dynamics, **have caused 10- and 20-year Treasury rates to sharply increase in the past several months**
  - **M.I.: Revise 2023 starting value for interest rate on term debt to reflect recent market changes**

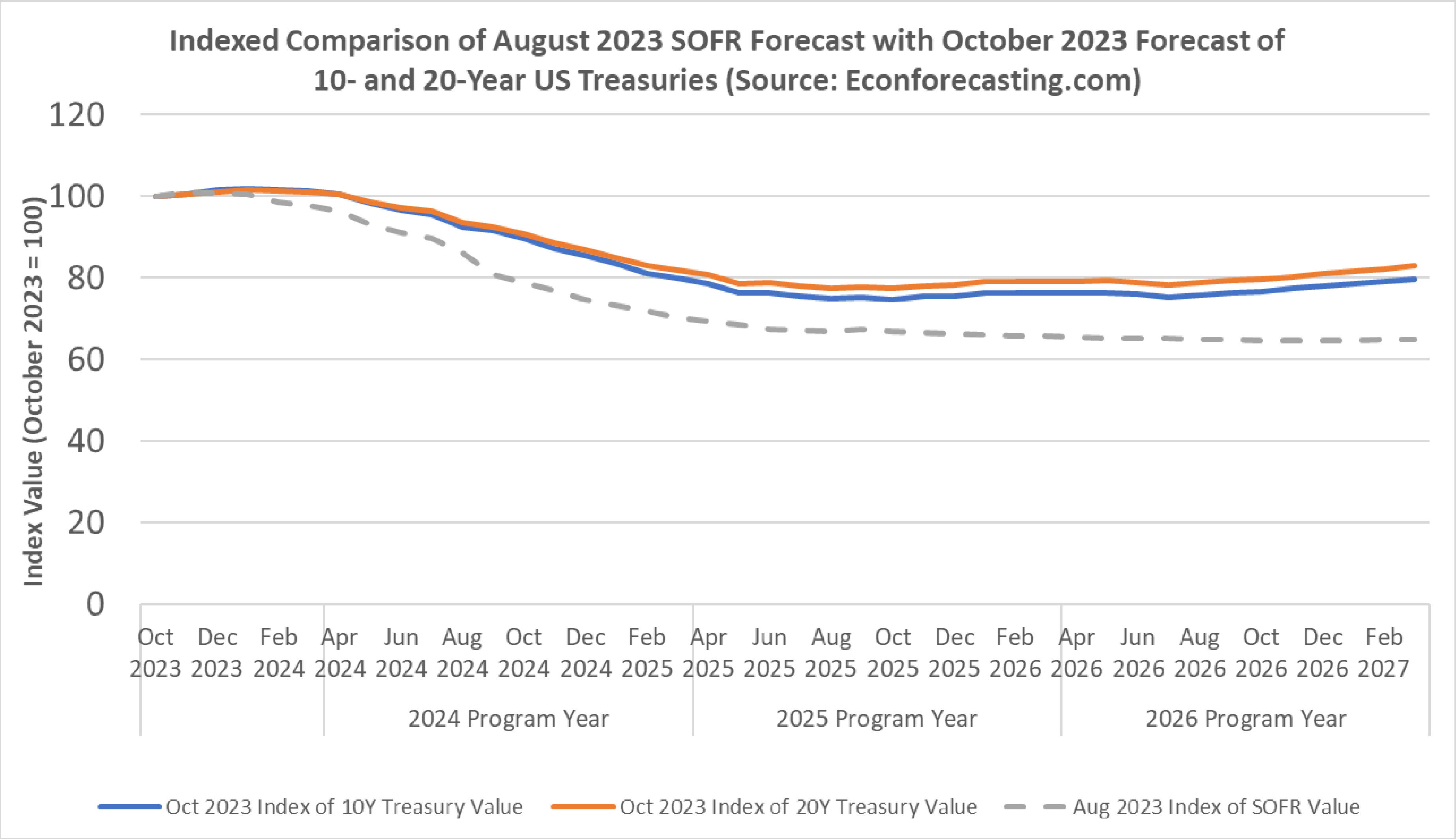
Renewable Energy Class	Small Solar I	Small Solar II	Medium Solar	Comm'l Solar/ Comm'l CRDG	Large Solar (All)/Lg. CRDG	Wind/ Wind CRDG	Anaerobic Digestion	Small-Scale Hydro
Previous Draft Interest Rate on Term Debt Assumption	**6.30%**	**7.00%**	**7.29%**	**7.29%**	**7.34%**	**7.59%**	**7.34%**	**7.59%**
Debt Term (Years)	13	10	13	13	15	15	15	20
UMass Five Credit Union (10 Years)	7.88%	7.88%	N/A	N/A	N/A	N/A	N/A	N/A
UMass Five Credit Union (15 Years)	8.13%	8.13%	N/A	N/A	N/A	N/A	N/A	N/A
10-Year Treasury Yield (10/11/2023)	N/A	N/A	4.64%	4.64%	4.64%	4.64%	4.64%	4.64%
20-Year Treasury Yield (10/11/2023)	N/A	N/A	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
Effective 13-Year Treasury Value (Risk-Free Basis)	N/A	N/A	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%
Effective 15-Year Treasury Value (Risk-Free Basis)	N/A	N/A	4.82%	4.82%	4.82%	4.82%	4.82%	4.82%
Effective 20-Year Treasury Value (Risk-Free Basis)	N/A	N/A	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
Applicable Treasury-Based Value	**N/A**	**N/A**	**4.75%**	**4.75%**	**4.82%**	**4.82%**	**4.82%**	**5.00%**
Risk Premium	**N/A**	**N/A**	**3.25%**	**3.25%**	**3.25%**	**3.50%***	**3.25%**	**3.50%***
Current Draft Interest Rate on Term Debt Assumption	**8.03%**	**7.88%**	**8.00%**	**8.00%**	**8.07%**	**8.32%**	**8.07%**	**8.50%**

*Values reflect added 25 bps risk premium for the increased variability of wind and water as a fuel source relative to the sun.

Interest Rates on Term Debt (2)

- **Outlook for Interest Rates on Term Debt (Cont'd):**
  - With a shift (as in the Straw Proposal) towards an approach to identify changes in forecasted interest rates of a sufficient magnitude to change prices, **it is necessary to shift the basis for future expectations from SOFR to a more directly-applicable and calculable metric (forecasted 10- and 20-year Treasury yields)**
  - SEA understands this outlook will **almost certainly change over the potential 2024-2026 period** (especially with changes in economic outlook and resultant macroeconomic policy)
  - As shown on the next slide, however, the recent sharp increases in Treasury yields **have driven investors to expect that such yields will remain elevated for longer relative to initial expectations** (e.g. those at the time of the development of the previous draft financing assumptions)

Interest Rates on Term Debt (3)



Interest Rates on Term Debt (4)

- **Outlook for Interest Rates on Term Debt (Cont'd):**
  - **M.I.: Reduce current assumed interest rates on term debt based on trajectories of 10- and 20-year Treasuries, resulting in the following interest rates between 2024 and 2026 Program Year**
  - **Adjust debt percentages downward to ensure projects can meet minimum and average debt service coverage ratios (DSCRs), but maintain increases in debt shares through 2026 (where possible) to account for lower values over time (see Appendix A for more detail)**
  - **Continue monitoring Treasuries (and sources for solar loan quotes) for changes over time**

Resource Class	Current Year (2023) Value		2024 PY		2025 PY		2026 PY	
Draft	*Prev. Draft*	*Cur. Draft*	*Prev. Draft*	*Cur. Draft*	*Prev. Draft*	*Cur. Draft*	*Prev. Draft*	*Cur. Draft*
Small I	6.30%	**8.03%**	5.47%	**7.63%**	4.67%	**6.91%**	4.56%	**6.97%**
Small II	7.00%	**7.88%**	6.17%	**7.49%**	5.37%	**6.78%**	5.26%	**6.84%**
Medium	7.29%	**8.00%**	6.46%	**7.60%**	5.66%	**6.88%**	5.55%	**6.95%**
Commercial I	7.29%	**8.00%**	6.46%	**7.60%**	5.66%	**6.88%**	5.55%	**6.95%**
Commercial II	7.29%	**8.00%**	6.46%	**7.60%**	5.66%	**6.88%**	5.55%	**6.95%**
Large Solar	7.29%	**8.07%**	6.46%	**7.66%**	5.66%	**6.96%**	5.55%	**7.03%**
Wind	7.59%	**8.07%**	6.76%	**7.66%**	5.96%	**6.96%**	5.85%	**7.03%**
Hydro	7.59%	**8.50%**	6.76%	**8.05%**	5.96%	**7.32%**	5.85%	**7.40%**
Anaerobic Digestion	7.34%	**8.07%**	6.51%	**7.66%**	5.71%	**6.96%**	5.60%	**7.03%**

Other Financing Assumptions

- **Debt Term (Years)**
  - Ecogy Energy advocated that it be 10 years
  - **M.I.: No change for current draft, but SEA will consider changes in later rounds if documentary evidence provided.**
- **Lender's Fee (%) for Projects <25 kW**
  - Market participants indicated that, along with increased interest rates, typical solar loans now include substantially higher dealer fees (another word for Lender's Fee)
  - **M.I.: No change for current draft, but SEA will verify the increased dealer fee with UMass Five Credit Union, a lender utilized by Small Solar participants that publishes its solar loan terms online, and continue to research other solar loan offers available in Rhode Island**
- **Lender's Fee (%) for Projects >25 kW**
  - Ecogy Energy advocated an increase from 1% to 2-3.5% to better account for legal costs, commitment fees, audited financial statement fees, and other financing closing costs.
  - **M.I.: No change for current draft, but SEA will consider changes in later rounds if documentary evidence provided.**
- **Depreciation Approach for Solar Projects**
  - Ecogy Energy suggested owner-operator developers may not utilize 5-yr MACRS depreciation and may instead elect 12-yr ADS depreciation
  - **M.I.: No change. Aside from this comment, market participants have consistently indicated 5-year MACRS remains the standard depreciation schedule for the vast majority of solar PV project costs**

Accounting for Changes in Key Ceiling Price Inputs Over Time (1)

- Both the DPUC and Rhode Island Energy (RIE) expressed two main concerns regarding the 1st Draft proposed prices:
  - That the assumed Ceiling Price increases could be burdensome for non-participating ratepayers (more so in administratively set categories)
  - That there was no specific means to consider changes in prices over time based on differences from forecasted market conditions over the potential three-year period for the prices
- While these concerns regarding the potential rate impacts is valid, proposing Ceiling Prices based on factors not grounded in observed cost, performance and financing assumptions observable in Northeast DG markets would:
  - Be **inconsistent with REG statute**; and
  - **(Could) fail to account for recent under-procurements** in the past five REG Open Enrollments
- Furthermore, the purpose of recently-enacted legislation authorizing a multi-year ceiling price schedule is to **provide developers and investors with an enhanced degree of certainty** and transparency regarding future program incentives

Accounting for Changes in Key Ceiling Price Inputs Over Time (2)

- Nevertheless, adopting a forward-looking schedule of Ceiling Prices and capacity allocations by class with no means for revision **carries both upside and downside risks**, including:
  - The **risk that Ceiling Prices are insufficient** relative to future cost~~s~~ increases, leading to further under-procurements
  - The risk that **Ceiling Prices could be inappropriately high and not produce efficient market outcomes if costs fall** relative to forecasted values
- Therefore, SEA has developed <u>**a straw proposal**</u> providing a series of proposed thresholds for changes in at which either upward or downward Ceiling Price adjustments would be made (as appropriate)

Straw Proposal: Thresholds for Potential 2024-2026 Ceiling Price Changes

During the two- to three-Program Year period under consideration, OER and the DG Board propose to revise the Ceiling Price for a given renewable energy class for the next Program Year **if**:

1. (*As measured between October 1 and December 31 of the calendar year prior to the Program Year in question*) SEA determines there is a **fifty (50) basis point (bps) deviation** (above or below) SEA's forecasted estimate of interest rate inputs (which are based on 10-year and 20-year Treasury bond values measured at the time of the analysis, plus a 325 bps risk premium, and averages thereof); **OR**
2. (*As measured based on information reported to various Northeastern state government and other databases over the 12 months prior to October 1st of the calendar year prior to the next Program Year*) SEA determines there is a **ten percent (10%) deviation** above or below expected total project costs, based on average of the 50th and 75th percentile of a regional analysis of:
   - Reported total project costs (as installed); and
   - Revealed pricing from:
     - Accepted bids from the previous two Renewable Energy Growth (REG) Open Enrollments;
     - Information on estimated total project costs for accepted bids from other private databases (such as EnergySage); **OR**
3. (*At any time prior to PUC approval of Program Year prices*) SEA determines that there have been **changes in state or federal law and/or regulations with a direct, material, and mandatory impact** on either program design or cost, performance and financing assumptions, or any other factor that would change the expected rate of return for said projects.

Interconnection Cost Assumptions for All Projects

- In SEA's first presentation, we noted that, based on developer quotes, SEA understands interconnection costs for **Large Solar (>1 MW)** in the range of $300-600/kW are expected absent revisions to cost allocation procedures
- Stakeholders provided the following comments regarding interconnection costs:
    - Solect noted that increased ceiling prices were necessary to address anticipated interconnection costs
    - RIE requested that SEA clarify if the scope of interconnection costs included in inputs include just distribution system modifications or if they also include site-specific upgrades
    - RIE also questioned the interconnection cost assumptions used for Large Solar II-IV
- The most appropriate and REG statute-reflective means to calculating interconnection costs is to take a regional approach reflecting the states (like RI) with both
    - Relatively high levels of DG penetration and
    - (Where possible) known and measurable interconnection costs that reflect the results of completed transmission and distribution studies

Interconnection Cost Assumptions for All Projects

- M.I.: Average data from RIE with the estimated total non-socialized costs from the regional interconnection studies. Specifically, SEA computed its revised interconnection cost estimate as an average of:
  - $750/kW – The average interconnection cost resulting from Massachusetts's provisional cost allocation program, *assuming no portion of costs are socialized* (as is the case in RI)
  - $500/kW – SEA's assumed interconnection cost for future large DG interconnecting in Maine, based on synthesis of surveyed developers and initial group study results
  - $230/kW – The average interconnection cost for Solar over 1 MW in RI (2022-2023)
- ➔ Assume $490/kW interconnection costs in CapEx estimates for <u>all</u> Solar and Non-Solar projects >1 MW ➔ Apply additional $260/kW to installed cost inputs (model assumes $260/kW on top of $230/kW estimate from RIE dataset)

Interconnection Cost Considerations for Projects >5 MW

- In SEA’s second presentation, we noted that interconnection costs for Large Solar III and IV were informed by assumed IC costs for transmission-connected facilities (based on an analysis of NY TX IC costs)
- However, in its comments on second-draft ceiling prices, RIE noted that REG program rules require all facilities to be distribution connected
- **M.I.: Following consultation of statute, SEA has revised it’s adopted distribution interconnection cost assumptions all Large Solar projects**
  - **➔ Assume $490/kW interconnection costs for all Solar >1 MW**

Installed Cost Assumptions for Solar Projects <=5 MW

- CapEx assumptions for projects under 5 MW are derived based on an analysis of regional installed cost databases and REG bids
  - Since publishing 1st Draft Ceiling Prices, SEA discovered recent installed cost data from selected CT Non-Residential Renewable Energy Solutions (NRES) projects
  - **M.I.: Incorporate *average of median and 75th percentile* costs from CT NRES cost data into regional installed cost analysis (see appendix for specific figures) for projects over 25 kW**

Installed Cost Assumptions for Solar Projects >5 MW (1)

- CapEx assumptions for projects over 5 MW are derived based on bottom-up analysis
  - Initial inputs were derived from NREL's Detailed Cost Analysis Model (DCAM),
- SEA vetted NREL component-level cost estimates with industry participants, who provided feedback to the consulting team
- SEA has benchmarked the resulting values against region-specific datapoints provided in Lawrence Berkley National Lab's (LBNL's) 2023 Utility Scale Solar report, which validate their reasonableness
- **M.I.: Adopt following cost inputs (see next slide) representing NREL input categories with adjustments based on participant feedback**
  - **Based on industry feedback, SEA added an additional cost component to cover civil work (e.g., site prep, road construction)**

Installed Cost Assumptions for Solar Projects >5 MW (2)

CapEx Inputs (All Units $/kW)	Large Solar II (10 MW Modeled Size)		Large Solar III (15 MW Modeled Size)		Large IV (20 MW Modeled Size)	
Draft	*1st Draft*	*2nd Draft*	*1st Draft*	*2nd Draft*	*1st Draft*	*2nd Draft*
EPC/Developer Net Profit	$195	**$131**	$192	**$131**	$186	**$131**
Contingency	$50	$50	$50	$50	$50	$50
Developer Overhead	$66	$66	$51	$51	$29	$29
Transmission Line	$10	**$0**	$10	**$0**	$10	**$0**
Permitting Fee	$50	**$38**	$40	**$21**	$30	**$15**
Interconnection Fee	$500	**$490**	$340	**$490**	$260	**$490**
EPC Overhead	$81	$81	$80	$80	$76	$76
Installation Labor/Equipment	$250	**$243**	$250	**$189**	$250	**$186**
Electrical BOS	$200	**$252**	$200	**$245**	$200	**$245**
Structural BOS	$300	**$245**	$300	**$245**	$300	**$240**
Inverter	$26	**$60**	$26	**$60**	$26	**$60**
Module	$353	**$370**	$353	**$370**	$353	**$370**
Civil Engineering (e.g., roads/access, other site work)	$0	**$190**	$0	**$190**	$0	**$190**
Total CapEx ($/kW)	**$2,082**	**$2,210**	**$1,893**	**$2,118**	**$1,770**	**$2,068**

Year-on-Year (YoY) Capital Cost Changes

- Ecogy Energy suggested that the "Conservative" cost trajectory (of ~1%/year) in the National Renewable Energy Laboratory's YOY declines is too aggressive considering that costs have increased in the near term
- **M.I.: No change from current proposed approach (as potentially revised, over time, by the Straw Proposal described herein)**
  - **Though we agree with Ecogy that the costs included in the NREL Annual Technology Baseline are functionally "learning curve" values, and are not a reasonable forecast of what will occur with installed costs, we account for the changes observable in the market in a variety of other ways**
  - **Furthermore, the straw proposal included in this draft should better address the potential for system costs (and financing costs) to deviate from expectations**
  - **Finally, as discussed in several prior processes, the DPUC and PUC have functionally made a degree of forward-looking cost reductions a condition of the Ceiling Prices' approval**
    - **Thus, this has been the approach utilized by SEA for many years**

Medium Solar Costs

- The DPUC expressed concern that the modeled ceiling price for Medium Solar exceeded that of Small Solar II class, given economies of scale would suggest larger facilities would require a reduced incentive
    - **M.I.: No change. Although SEA is open to changing individual inputs informing the resulting ceiling price for any given resource class in response to compelling evidence, we do not find these results to be concerning.**
        - **Because the modeled results for Medium Solar and larger resource classes inform a *ceiling price*, SEA takes an average of median and 75th percentile installed cost values from state databases when calculating its inputs to provide appropriate headroom to support healthy competition (vs Small Solar I and II based on only the median costs)**
        - **Land lease costs are more significant for Medium Solar given that:**
            - **Medium Solar is primarily third-party owned; and**
            - **REG is a FTM, buy-all/sell-all program, and thus lease payments are the primary financial benefit for site-owners**
        - **In addition, other costs are applicable to Medium solar that are not incurred by Small Solar I and II (e.g., project mgmt., insurance)**

Other Capital Cost Assumptions

- **Meter Reconfiguration Costs**
  - In SEA's first presentation we noted that that Rhode Island Energy's Electric System Bulletin now contains requirements that customers upgrading their service must re-locate their meter outside of the building in question at the customer's expense
    - **➔ Apply $30,000 additional upfront costs to Medium and Commercial I Solar**
  - Ecogy argued that the adopted costs are too low relative to the costs they have experienced, siting specific project's costs
    - **M.I., No change. SEA has collected additional cost estimates from other market participants that substantiate the $30,000 assumption (including estimates below this figure). Given that these costs are highly variable and site-specific, SEA is cautious to adopt cost that may represent atypically high costs.**
- **Site Control Expenses**
  - Solect recommended that SEA include the cost of site control pre-COD in its modeling, arguing that long interconnection timelines result in significant site control expenses pre-COD
    - **M.I., No change for this draft, but SEA intends to engage Solect and other market participants to better understand the nature and magnitude of such costs**

Operating Expense Assumptions

- **YoY changes to Solar Operating Expenses**
  - Ecogy argued that certain O&M expenses are uncontracted, and are likely to vary based on the COD year, meaning that Year 1 O&M costs should not be held constant across the program-year inputs in consideration (2024-2026)
  - **M.I.: No change for this draft. Although it is reasonable to expect that O&M expenses may deviate from SEA's current assumptions over time, SEA is not aware of any analysis regarding the direction or magnitude of such change. SEA welcomes evidence regarding the trending of O&M costs to inform its final recommendations.**

Post-Tariff Revenue (1)

- In SEA's first presentation, we noted that recent change in law provides for virtual net metering credits at 80% of the full net metering rate and discounted our net metering forecast used to calculate post-tariff revenue by 20%
    - This revenue stream is then discounted by a further 40% (as is SEAs practice in prior years) to reflect uncertainty regarding changes to policy and rates impacting post tariff revenue
- The DPUC argued that SEA should not adopt a 20% discount due to the change in law, arguing that the 40% reduction already covers the risk of policy change
- **M.I., No change. The 40% discount is intended to capture uncertainty relative to the *current* post-tariff outlook (which now, by law, includes a 20% haircut except for projects having submitted an interconnection or permitting application by April 15, 2023)**
    - **As noted in prior Ceiling Price development processes, our view is informed by the fact that not applying the 20% haircut associated with the statutory reduction in VNM compensation would effectively result in an "uncertainty" discount of 20%, which SEA views as insufficient given the potential for significant revisions to retail rate outlooks and solar incentive policy 20+ years into the future**

Post-Tariff Revenue (2)

- In first draft ceiling prices, SEA applied discounted net metering revenue post-tariff for all resource classes
- This application for resources over 10 MW (Large Solar III and IV) is not consistent with current law (which requires that VNM project be under 10 MW)
- **M.I., Do not model post-tariff revenue for Large Solar III and IV and constrain analysis period to tariff duration**
  - **SEA tested the application of wholesale energy + REC revenue post-tariff, but this revenue stream was insufficient to cover operating expenses post-tariff ➔ extending analysis period to include post tariff increased the modeled ceiling price**
  - **Consistent with SEA's first draft, post tariff revenue is also not modeled for Medium Solar for the same reason**

Non-Solar Assumptions

- **Anaerobic Digestion Proxy Size**
  - RIE recommended consideration of a larger proxy size when modeling AD projects
  - **M.I.: No change for current draft. As noted later in this presentation, the REG program to date has not received any AD project bids → increasing the proxy size to capture economies of scale is unlikely to result in significant ratepayer savings and could dissuade participation from an already thin market segment.**

Technical Adjustments/Fixes to CREST Model

- SEA identified and fixed three technical modeling errors that impacted the Large Solar ceiling prices as follows
  - Large Solar II-IV projects >5 MW were unintentionally being treated as being able to claim the cost of their interconnection system modifications in the basis for claiming the ITC
    - The Inflation Reduction Act of 2022 only allows interconnection to be counted in the project's basis if it is less than 5 MW_{AC}
    - ➔ ~2 cent/kWh increase in Large Solar II-IV CPs for all three years due to reduction in total eligible ITC value
  - Large Solar was erroneously assigned the interest rate applicable to Hydro projects
    - ➔ slight (relative) reduction in Large Solar CP due to slightly lower interest rate
  - Large Solar was missing the last two years of post tariff revenue for the 2026 ceiling price calculations, and the last year of post tariff revenue for the 2025 ceiling price
    - ➔ slight reduction in CP due to additional post tariff revenue

Sustainable Energy Advantage, LLC

Second Draft Incentive-Rate Adder Values for >1 MW Projects Sited on Parcels Requiring Remediation

Case Definitions and Research Approach (1)

- As discussed above, **2023-S 684/2023-H 5853 – An Act Related to Public Utilities and Carriers – Net Metering** Allows OER and the Board to consider the **development of adders** for projects sited on parcels "requiring remediation"
  - SEA interprets "requiring remediation" to focus on parcels that involve environmental cleanup to be suitable for development ➔ focus on brownfields and landfills
    - However, SEA does not assume that remediation would include the initial capping of landfills, as such activity is a cost the landfill owner would inevitably incur in the regular course of business
  - Stakeholders have requested clarity regarding how Superfund sites will be treated under the proposed adders, as Superfund sites may require remediation
    - SEA assumes that the incremental costs of siting on Superfund sites will be very similar to that of brownfields, and thus the resulting adder applicable to brownfields could be applied to Superfund sites

Case Definitions and Research Approach (2)

- To derive an appropriate adder for such projects, SEA relied on regional data collected through prior engagements to derive initial proposed input values
  - Such inputs have since undergone two rounds of feedback from market participant via targeted outreach from the consultant team to solicit additional feedback specific to Rhode Island
  - Overall, market participant feedback was in line with SEA's initial proposed inputs, suggesting that proposed inputs are robust
- Given that most development on parcels requiring remediation is likely to be over 1 MW, SEA's modeling focused on Large Solar Classes
  - This modeling decision does not necessarily preclude smaller resource classes from qualifying for an adder, if such an adder is ultimately adopted
- In Draft 1 results, SEA applied the maximum adder value for Large Solar IV to the ceiling price, reasoning that this class is required to be cited on preferred sites which will involve incremental costs
  - Stakeholders expressed concern that adopting this approach would enable projects to bid at values higher than their costs reflect (e.g., bidding at a landfill equivalent incentive rate for a gravel pit project)
  - **M.I., Large Solar IV's CP will only reflect base costs, and will be eligible to qualify for remediation adders similar to other resource classes**

Incremental Cost Assumptions (1)

- In response to First Draft inputs which showed no change from greenfield land-lease costs, the DPUC suggested that SEA consider a negative cost delta for projects sited on land requiring remediation (e.g., lower costs), arguing that greenfield land lease costs may exceed preferred site costs
- **M.I.: No change for this draft. However, SEA intends to conduct additional research regarding site leases to better understand how costs may compare to parcels not requiring remediation**

Incremental Cost Assumptions (2)

- **M.I.: Adopt SEA's proposed inputs, adjusted to account for incremental market participant feedback, provided below:**

Input	Unit	Landfill			Brownfield		
		Initial Input	1st Draft	2nd Draft	Adopted Input	1st Draft	2nd Draft
Upfront Capital Cost	Inc. $/kW vs. Greenfield	$350	$392	$391	$330	$365	$372
Upfront Permitting Costs (incremental to above $/kW input)	Inc. $ vs. Greenfield	$175,000	$230,000	$216,071	$0	$240,000	$190,833
Year 1 DC CF	% Change vs. Greenfield	-5.0%	-5.0%	-5.0%	0%	-2.5%	-2.5%
O&M	"	15%	15%	15%	16%	16%	16%
Project Mgmt.	"	10%	10%	10%	7%	7%	7%
Insurance	"	10%	10%	10%	15%	15%	15%
Land/Site Lease	"	0%	0%	0%	0%	0%	0%

Summary of Resulting Adder Values

- A summary of the resulting adders, by resource class and parcel type, is provided below
  - **Results are in line with adders in Massachusetts for landfills/brownfields, which are approximately 3-4 cents/kWh**

Resource Class	Landfill Adder (¢/kWh)		Brownfield Adder (¢/kWh)	
Draft	***1st Draft***	***2nd Draft***	***1st Draft***	***2nd Draft***
Non-Large Solar (<1 MW)	4.20	**4.30**	3.50	**3.60**
Large Solar (1-<5 MW)	4.20	**4.30**	3.50	**3.60**
Large Solar II (5-<10 MW)	3.80	**3.60**	3.20	**2.90**
Large Solar III (10-<15 MW)	3.70	**3.40**	3.10	**2.80**
Large Solar IV (15-<39 MW)	3.60	**3.30**	3.00	**2.70**

SEA proposes to set the adder value for resources under 1 MW equal to the Large Solar Adder Value.

Note: The proposal is to apply the above values for the duration of the two- to three-year period under consideration

Adder Implementation Recommendations in Response to Stakeholder Comments (1)

- **Verification/Proof of Incremental Costs**
  - DPUC requested clarity on how RIE would verify the incremental costs of Landfill and Brownfield projects eligible for these adders
  - While SEA supports verification, we would recommend that such verification extend to <u>all eligible projects in Open Enrollments</u>
  - **Recommendation: OER/the Board, RIE, DPUC and interested market participants should develop requirements for submission of total development cost estimates**
- **Incentive Values for Partial Sites**
  - DPUC expressed some concern that it was unclear how RIE (or others) would verify the proportion of the project would be sited on a parcel designated as a brownfield or landfill, and whether it was appropriate for such sites to be paid the full value of the adder
  - We believe the DPUC's suggestion that the full adder value should not be applied to a project is a valid concern
  - **Recommendation: OER/the Board, RIE, DPUC and interested market participants should collaborate to developing an approach to pro-rating for the Landfill and Brownfield adders similar to the approach employed for Carport adder pilot projects**

Adder Implementation Recommendations in Response to Stakeholder Comments (2)

- **Consideration of Anaerobic Digestion (AD) Adders**
  - RIE recommended consideration of an adder for AD projects on brownfield parcels
  - While SEA does not object to such an adder on principle, there are several obstacles to developing one, including (but not limited to):
    - The fact that there have been (to our knowledge) no AD project bids received during the life of the REG program;
    - There are not (to SEA's knowledge) reliable public estimates or databases of Northeast regional cost, performance and financing assumptions for AD projects;
    - AD stakeholders have not responded to our Data Requests and Surveys in at least 4-5 years, or reached out to us during the stakeholder process to provide us with cost, performance or financing data
  - **Recommendation: If broader stakeholder/institutional consensus builds around encouraging AD via REG program, we would recommend starting with a more intensive effort to understand the more basic costs of greenfield projects**

Key Remaining Incentive-Rate Adder Eligibility and Implementation Questions Raised by Stakeholders

- Should Superfund sites be deemed to be eligible for the "Brownfield" adder?
- As part of the REG Open Enrollment and bid evaluation processes:
  - As part of the REG Open Enrollment and bid evaluation processes:
    - What additional information, if any, must bidders present during the bid process to substantiate the incremental capital and operating costs necessary to develop a project on a adder-eligible site.
      - What steps should Rhode Island Energy (or another entity) take to verify the incremental cost.
    - Should an entity other than Rhode Island Energy be responsible for verifying a determination by the Department of Environmental Management (DEM) that a particular Large Solar IV project is sited on a "preferred site", as required by R.I.G.L. § 39-26.6-22?
    - Should an entity other than Rhode Island Energy be responsible for verifying a determination by DEM that a particular Landfill or Brownfield project "require(s) remediation"?
    - Should adder eligibility criteria require that the entire project be located within the land area designated as "requir(ing) remediation" to be eligible for an adder?
      - If not, what requirements should be adopted regarding adder eligibility for projects partially located on land designated as "requir(ing) remediation"?

Request for Comments and Other Next Steps

Supplemental Data Request and Survey/Request for Written Comments Related to this Meeting

- Comments on the ceiling prices (and inputs to said prices) contained in this presentation will be due no later than 11:59 am ET on **October 25, 2023**
- In addition, SEA is requesting comments on the "Request for Comments on Straw Proposal for Potential Triggers for Changes to 2024-2026 Ceiling Prices" and "Request for Comments on Rhode Island Renewable Energy Growth (REG) Incentive-Rate Adders and Siting Considerations for Potential 2024-2026 Program Year Period" **no later than 11:59 pm ET on October 31, 2023** 🎃👻
- Please send written comments **in a PDF attachment** (preferably on organizational letterhead if applicable) to Cal Brown (cbrown@seadvantage.com), copying Jim Kennerly (jkennerly@seadvantage.com), Toby Armstrong (tarmstrong@seadvantage.com), Shauna Beland (shauna.beland@energy.ri.gov), and Karen Bradbury (karen.bradbury@energy.ri.gov)

Sustainable Energy Advantage, LLC

Appendix A: Detailed Cost, Performance and Financing Assumptions

Summary: Solar <=25 kW Financing Assumptions

	Small I (1-15 kW)		Small II (15-25 kW)	
	2023 Final	*2024-2026*	*2023 Final*	*2024-2026*
Federal Investment Tax Credit (%)	30%	**30%**	30%	**30%**
% Debt	52.5%	See Slide "Multi-Year Debt % Assumptions"	45%	See Slide "Multi-Year Debt % Assumptions"
Debt Term (years)	13	**13**	10	**10**
Interest Rate on Term Debt	6.3%	See Slide "Interest Rate on Term Debt"	7.0%	See Slide "Interest Rate on Term Debt"
Lender's Fee (% of total borrowing)	4.25%	**4.25%**	2.3%	**2.3%**
Target After-Tax Equity IRR	7%	**7%**	12.5%	**12.5%**

Summary: Solar >25 kW Financing Assumptions

	Medium (>25-250 kW)		Comm'l & Comm'l CRDG (>250-1 MW)		Large & Large CRDG (>1 MW-5 MW)	
Assumption Set	***2023 Final***	***2024-2026***	***2023 Final***	***2024-2026***	***2023 Final***	***2024-2026***
Federal Investment Tax Credit (%)	30%	30%	30%	30%	30%	30%
% Debt	50%	See Slide "Multi-Year Debt % Assumptions"	48%	See Slide "Multi-Year Debt % Assumptions"	45%	See Slide "Multi-Year Debt % Assumptions"
Debt Term (years)	13	13	13	13	15	15
Interest Rate on Term Debt	7.29%	See Slide "Interest Rate on Term Debt"	7.29%	See Slide "Interest Rate on Term Debt"	7.34%	See Slide "Interest Rate on Term Debt"
Lender's Fee (% of total borrowing)	1.0%	1.0%	1.0%	1.0%	2.0%	2.0%
% Equity Share of Sponsor Equity	30%	32%	33.3%	32%	35%	35%
Target After-Tax Equity IRR (Sponsor Equity, Levered Return)	12.5%	12.5%	12.0%	12.0%	11.0%	11.0%
% Equity Share of Tax Equity	70%	68%	66.7%	68%	65%	65%
Target After-Tax Equity IRR (Tax Equity, Levered Return)	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%
Depreciation Approach	5-Year MACRS	5-Year MACRS	5-Year MACRS	5-Year MACRS	5-Year MACRS	5-Year MACRS

Summary: Solar >5 MW Financing Assumptions

	Large II	Large III	Large IV
Federal Investment Tax Credit (%)	30%	30%	30%
% Debt	See Slide “Multi-Year Debt % Assumptions”	See Slide “Multi-Year Debt % Assumptions”	See Slide “Multi-Year Debt % Assumptions”
Debt Term (years)	15	15	15
Interest Rate on Term Debt	See Slide “Interest Rate on Term Debt”	See Slide “Interest Rate on Term Debt”	See Slide “Interest Rate on Term Debt”
Lender's Fee (% of total borrowing)	2.0%	2.0%	2.0%
% Equity Share of Sponsor Equity	35%	35%	35%
Target After-Tax Equity IRR (Sponsor Equity, Levered Return)	11.0%	11.0%	11.0%
% Equity Share of Tax Equity	65%	65%	65%
Target After-Tax Equity IRR (Tax Equity, Levered Return)	9.5%	9.5%	9.5%
Depreciation Approach	5-Year MACRS	5-Year MACRS	5-Year MACRS

Summary: Non-Solar Financing Assumptions

	Wind & Wind CRDG		Hydroelectric		Anaerobic Digestion	
Assumption Set	*2023 Final*	*2024-2026*	*2023 Final*	*2024-2026*	*2023 Final*	*2024-2026*
Federal Investment Tax Credit	30%	30%	30%	30%	30%	30%
% Debt	44%	See Slide "Multi-Year Debt % Assumptions"	48%	See Slide "Multi-Year Debt % Assumptions"	42%	See Slide "Multi-Year Debt % Assumptions"
Debt Term (years)	15	15	20	20	15	15
Interest Rate on Term Debt	7.59%	See Slide "Interest Rate on Term Debt"	7.59%	See Slide "Interest Rate on Term Debt"	7.34%	See Slide "Interest Rate on Term Debt"
Lender's Fee (% of total borrowing)	1.0%	1.0%	1.88%	1.88%	1.5%	1.5%
% Equity Share of Sponsor Equity	25%	25%	25%	25%	25%	25%
Target After-Tax Equity IRR (Sponsor Equity, Levered Return)	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%
% Equity Share of Tax Equity	75%	75%	75%	75%	75%	75%
Target After-Tax Equity IRR (Tax Equity, Levered Return)	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%
Depreciation	5-Year MACRS	5-Year MACRS	5-year MACRS	5-year MACRS	5-year MACRS	5-year MACRS

Summary: Solar <1 MW Cost & Production Assumptions

	Small I	Small II	Medium	Comm'l I	Comm'l I (CRDG)	Comm'l II	Comm'l II (CRDG)
Nameplate Capacity (kW)	5.8	25	250	500	500	1,000	1,000
Capacity Factor	13.4%	13.4%	14.5%	14.6%	14.6%	14.6%	14.6%
Annual Degradation	1.0%	1.0%	0.8%	0.8%	0.8%	0.8%	0.8%
Useful Life (Years)	25	25	25	25	25	25	25
Total Capital Cost ^ ($/kW)	$4,449 [$3,566]	$3,946 [$3,058]	$3,060 [$3,111] [$2,485]	$2,863 [$3,051] [$2,352]	$2,963 [$3,151] [$2,452]	$2,665 [$2,673] [$2,218]	$2,765 [$2,773] [$2,318]
Additional Meter Relocation Cost ($)	$0	$0	$30,000 [$0]	$30,000 [$0]	$30,000 [$0]	$0	$0
Fixed O&M ($/kW-yr)	$29	$24	$14.57	$12.03	$34.03	$12.03	$34.03
O&M Escalation Factor	2.0%	2.0%	3.0%	3.0%	3.0%	3.0%	3.0%
Non-O&M Escalation %	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
Insurance (% of Cost)	0.0%	0.0%	0.34%	0.57%	0.57%	0.57%	0.57%
Project Management ($/yr)	$0	$0	$3,000	$4,000	$4,000	$4,000	$4,000
Site Lease ($/yr)	$0	$0	$30,753 [$18,090]	$41,650 [$24,500]	$41,650 [$24,500]	$55,178 [$32,458]	$55,178 [$32,458]

Values in [Purple Brackets] represent 2023 ceiling price inputs. Value in [Blue Brackets] represent first draft inputs.

Summary: Large Solar Cost & Production Assumptions

	Large I				Large II			Large III			Large IV		
Use Case	***Base***	***CRDG***	***Brownfield***	***Landfill***	***Base***	***Brownfield***	***Landfill***	***Base***	***Brownfield***	***Landfill***	***Base***	***Brownfield***	***Landfill***
Nameplate Capacity (kW_{DC})	5,000	5,000	5,000	5,000	9,999	9,999	9,999	14,999	14,999	14,999	20,000	20,000	20,000
Capacity Factor	15.10%	15.10%	14.72%	14.37%	15.10%	14.72%	14.37%	15.10%	14.72%	14.37%	15.10%	14.72%	14.37%
Annual Degradation	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
Useful Life (Years)	30	30	30	30	30	30	30	30	30	30	30	30	30
Total Capital Cost ^ ($/$kW_{DC}$)	$2,450 [$2,309] [$1,964]	$2,550 [$2,409] [$2,064]	$2,813 [$2,719]	$2,837 [$2,743]	$2,176 [$2,049]	$2,586 [$2,438]	$2,610 [$2,464]	$2,085 [$1,863]	$2,495 [$2,244]	$2,519 [$2,271]	$2,036 [$1,743]	$2,446 [$2,120]	$2,470 [$2,146]
Fixed O&M ($/$kW_{DC}$-yr)	$11.00	$33.00	$12.76	$12.65	$9.00	$10.35	$10.44	$9.00	$10.35	$10.44	$9.00	$10.35	$10.44
O&M Escalation Factor	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
Non-O&M Escalation %	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
Insurance (% of Cost)	0.57%	0.57%	0.66%	0.63%	0.57%	0.66%	0.63%	0.57%	0.66%	0.63%	0.57%	0.66%	0.63%
Project Management ($/yr)	$20,000	$20,000	$21,400	$22,000	$20,000	$21,400	$22,000	$20,000	$21,400	$22,000	$20,000	$21,400	$22,000
Site Lease ($/yr)	$160,701 [$94,530]	$160,701 [$94,530]	$160,701	$160,701	$321,370	$321,370	$321,370	$321,370	$321,370	$321,370	$642,804	$642,804	$642,804

Values in [Purple Brackets] represent 2023 ceiling price inputs. Value in [Blue Brackets] represent first draft inputs.

^ Total cost includes interconnection cost. For Large I cases, value includes and estimated $47.92/kW added cost for meeting IRA and state prevailing wage requirements

Summary: Non-Solar Cost & Production Assumptions

	Wind	Wind - CRDG	Hydroelectric	Anaerobic Digestion
Nameplate Capacity (kW)	3,000	3,000	500	725
Capacity Factor	21.00%	21.00%	55.00%	92%[1]
Annual Degradation	0.5%	0.5%	0.0%	0.0%
Total Cost ($/kW)	$3,548 [$3,558] [$3,288]	$3,648 [$3,658] [$3,388]	$12,179 [$12,189] [$11,918]	$11,518 [$11,408]
Fixed O&M ($/kW-yr)	$26.50	$48.50	$269.50 [$245]	$600
O&M Inflation	2.0%	2.0%	0%	2.0%
Insurance (% of Cost)	0.29%	0.29%	3.51% [3.19%]	1.5%
Project Management ($/yr)	$18,000	$18,000	$24,000	$75,000
Property Tax ($/kW)	$5	$5	$5	$5
Site Lease ($/yr)	$162,000	$162,000	$8,750	$35,000

1. *Note: For Anaerobic Digestion we use an Availability Factor*
2. Values in [Purple Brackets] represent 2023 ceiling price inputs. Values in [Blue Brackets] represent first draft 2024 inputs.

Multi-Year Installed Cost Inputs ($/kW)

Resource Class	2023 Costs (baseline)	2024	2025	2026
Small I	$4,535	$4,449	$4,361	$4,275
Small II	$4,022	$3,946	$3,868	$3,792
Medium	$3,105	$3,060	$3,016	$2,971
Commercial I	$2,904	$2,863	$2,821	$2,779
Commercial II	$2,704	$2,665	$2,627	$2,588
Large	$2,440	$2,402	$2,365	$2,328
Large II	$2,210	$2,176	$2,141	$2,109
Large III	$2,118	$2,085	$2,052	$2,021
Large IV	$2,068	$2,036	$2,004	$1,973

Interest Rate on Term Debt : Multi-Year Assumptions

Resource Class	2023 Approved	2024	2025	2026
Small I	8.03%	7.63%	6.91%	6.97%
Small II	7.88%	7.49%	6.78%	6.84%
Medium	8.00%	7.60%	6.88%	6.95%
Commercial I	8.00%	7.60%	6.88%	6.95%
Commercial II	8.00%	7.60%	6.88%	6.95%
Large Solar	8.07%	7.66%	6.96%	7.03%
Large II	N/A	7.66%	6.96%	7.03%
Large III	N/A	7.66%	6.96%	7.03%
Large IV	N/A	7.66%	6.96%	7.03%
Wind	8.07%	7.66%	6.96%	7.03%
Hydro	8.50%	8.05%	7.32%	7.40%
Anaerobic Digestion	8.07%	7.66%	6.96%	7.03%

Multi Year Debt % Assumptions

Resource Class	2024	2025	2026
Small I	51.00%	51.00%	51.00%
Small II	45.50%	45.50%	45.75%
Medium	47.00%	48.00%	48.00%
Commercial I	47.00%	47.50%	47.50%
Commercial II	46.00%	46.50%	46.50%
Large Solar	45.00%	45.25%	45.25%
Large II	44.00%	44.50%	44.50%
Large III	44.00%	44.25%	44.25%
Large IV	44.00%	44.00%	44.00%
Wind	42.00%	42.75%	42.75%
Hydro	48.00%	48.50%	48.50%
Anaerobic Digestion	51.00%	51.00%	51.00%

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