Maine Distributed Generation Successor Program Study:

DRAFT Solar PV Project Revenue Requirement Modeling Results (Policy Cases 1-4 and Straw Proposal Case)

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Methodology for Modeling Resource Cost Values for Benefit-Cost Analysis

Modeling Process Overview

- The consulting team utilized ME-customized Cost of Renewable Energy Spreadsheet Tool (CREST) Model (a tool Sustainable Energy Advantage, LLC developed for the National Renewable Energy Laboratory (NREL))
- Purpose of ME CREST: Establish revenue requirement (on a levelized cost of energy basis) for hypothetical ME solar project resource blocks closing financing from 2024 through 2028
  - NOTE: components of revenue requirement shown on next slide
- Standard (and customized) modeled inputs in ME CREST include
  - Capacity Factor and Production Degradation (by project type)
  - Installed Costs
  - Financing Costs (interest on term debt, debt tenor, % of debt, after-tax equity IRR, development and fees (if not captured in equity return))
  - O&M Costs
  - Project Management Costs
  - Land Lease
  - Incremental operating and CapEx costs for certain project types (e.g., brownfield, roof mounted, LMI, community solar, carport)

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Simplified Representation of CREST Calculation of Project Revenue Requirement

Net Present Value (NPV)/ Discounted Cash Flows Resulting From:

PV Total Capital and Operating Costs (Various)

Compounded/Grossed-Up by…

Risk-Adjusted Financing Costs & Taxes (Various Terms)

LESS…

Expected Federal Tax & Depreciation Benefits During and After Incentive Term

All Divided By…

PV Performance over Useful Life (MWh) derived from Degradation-Adjusted Capacity Factor

Put it all together and you get…

Revenue Requirement/ LCOE by Resource Block ($/MWh)

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Resource Blocks

- Resource blocks are chosen to create some diversity in the technologies, locations, and the types of offtakers.
  - **Please note that these are not intended to be interpreted as the actual resources expected or preferred in the successor program**
- For the initial analysis (Cases 1-4), our team proposed six types of resource blocks, representing combinations that result in low costs but also achieve certain policy goals, e.g., LMI customer participation.
  - These six blocks were presented in discussed at the October 4 workshop and are described in more detail below.
- SEA estimated the costs of each resource block, for each of the programs as described
- For the hybrid case, we proposed 5 of those 6 blocks (excluding the LMI case that only received a 30% ITC)

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Supply Blocks (Cases 1-4)

	Technology	Location	Offtakers	IRA Bonus Credit	Capacity
Program Options 1, 2, and 3	Roof PV (1 MW)	BTM: Host customer	Host customer	none	93 MW
	Ground PV (5 MW)	FTM: anywhere	50% Res, 50% C&I	none	93 MW
	Ground PV (5 MW)	FTM: anywhere	50% LMI, 25% Res, 25% C&I	10%	93 MW
	Ground PV (5 MW)	FTM: Brownfield & LMI neighborhood	50% Res, 50% C&I	10%	93 MW
	Ground PV (5 MW)	FTM: “Low Income Community”	50% Res, 50% C&I	10%	93 MW
	Ground PV (5 MW)	FTM: LMI benefit	50% LMI, 25% Res, 25% C&I	20%	93 MW
	Totals	-----	-----	-----	558 MW

	Technology	Location	Offtakers	IRA Bonus Credit	Capacity
Program Option 4	Roof PV (1 MW)	BTM: Host customer	All customers	none	141 MW
	Ground PV (5 MW)	FTM: anywhere	All customers	none	141 MW
	~~Ground PV (5 MW)~~	~~FTM: anywhere~~	~~All customers~~	~~10%~~	not included
	Ground PV (5 MW)	FTM: Brownfield & LMI neighborhood	All customers	10%	141 MW
	Ground PV (5 MW)	FTM: “Low Income Community”	All customers	10%	141 MW
	~~Ground PV (5 MW)~~	~~FTM: LMI benefit~~	~~All customers~~	~~20%~~	not included
	Totals	-----	-----		564 MW

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Important Note Regarding CREST-Modeled vs. BCA-Utilized Values

- All policy cases assume (regardless if the state were to adopt an annual procurement approach or a declining- or adjustable-block incentive) that **a competitive procurement would be used to set <u>at least</u> the initial compensation rates**
- Under such an initial (or ongoing) procurement, the team assumes:
  - **A maximum bid cap/ceiling price (either overall, or by category)**, below which bidders can engage in (what would hopefully be) a degree of sufficiently healthy competition to get to a price that would sustain projects and not lead to widespread program attrition; and
  - The above-mentioned ceiling price is intended to be **inclusive of "typical" project costs on a regional basis** (with any necessary **Maine-specific adjustments to cost and performance assumptions**)
  - Bidders would **receive their accepted as-bid price** as compensation

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Important Note Regarding CREST-Modeled vs. BCA-Utilized Values (Cont'd)

- In the Rhode Island Renewable Energy Growth (REG) program, as-bid prices for projects >=1 MW_{DC} have historically been around **9.5% below the established ceiling price**
- Therefore, in order to represent the impact of competition under such an initial (or annual) procurement, the modeling results shown herein are equivalent to:
  - The (CREST-modeled) **functional "ceiling price" value/MWh** (modeled to be inclusive of "typical" total development costs on a regional basis); **LESS**
  - **9.5%** (the as-bid RI REG historical average)
- Our team is confident this approach is likely to result in **the lowest reasonable costs to ratepayers of projects that can <u>reasonably be expected to reach commercial operation</u>**

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Highlights of Draft PV Cost/Performance Assumptions

- Installed cost estimates (based on regional solar projects) were set based on:
  - **For 1 MW_{AC} Projects: Averages of median and 25th percentile values** from state databases in the Northeast region and actual as-bid values for projects submitting bids in 2022 Rhode Island Renewable Energy Growth (REG) Open Enrollments
  - **For 5 MW_{AC} Projects:** An **average of the average and median value** of several different Northeast regional statewide databases
- Installed costs assumed to decline in all cases through 2030 based on an average of the NREL Annual Technology Baseline (ATB) 2022 Moderate and Conservative cases **(~3%/yr)**
- Project performance based on assumed **location in Bangor, ME** (near the latitudinal center of the state), **as adjusted by regional real-world observed project performance**

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Highlights of Draft PV Cost/Performance Assumptions (Cont'd)

- For Policy Cases 1-3, **all projects assumed to have non-utility offtakers** (residential, commercial and/or industrial), per LD 936
  - Therefore, 1 MW_{AC} C&I rooftop projects would assume a 10% discount to a commercial customer relative to their retail rate, while 5 MW_{AC} projects would assume discounts ranging from 5%-10% relative to their retail rate
  - All 5 MW_{AC} projects under Cases 1-3 are assumed to be shared solar projects, and thus require upfront customer acquisition costs (treated in modeling like CapEx) and ongoing customer care and management cost (treated in modeling like OpEx)
- For Policy Case 4, **all projects are assumed to sell directly to the utility**, and would thus have no residential, commercial or industrial offtakers (and thus require no offtaker discounts or added CapEx or OpEx)

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Highlights of Draft PV Cost/Performance Assumptions (Cont'd)

- All projects assumed to include added cost of meeting Inflation Reduction Act (IRA) prevailing wage requirements (**starting at \$57.50/kW$_{DC}$**), and rising at EIA Annual Energy Outlook 2022 Chain-Type CPI rate
- 1% incremental annual improvement over time in Year 1 capacity factor
  - E.g., if assumption for 2024 qualified projects = 13.8%, 2025 qualified projects = 14.0%
- Annual degradation assumed at **0.8% for 1 MW$_{AC}$** projects, and **0.5% for 5 MW$_{AC}$** projects
- **Assumed DC-AC ratio of 1.3** (corresponding to a 1.3 MW$_{DC}$ and 6.5 MW$_{DC}$ modeled project, to produce 1 MW$_{AC}$ and 5 MW$_{AC}$ results)

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Highlights of Draft PV Cost/Performance Assumptions (Cont'd)

Supply Block	Modeled Size kW_{AC} (kW_{DC})	Tariff Term (Years)	Estimated 2024 Yr 1 Capacity Factor	Total Installed Cost by Selection Year ($/$kW_{DC}$, Inclusive of Interconnection)	
				2024 (Cases 1-3)	2024 (Case 4)
Large Commercial Roof Mounted	1 MW_{AC} (1.3 MW_{DC})	20	12.2%	$2,218	$2,218
Large Ground Mount	5 MW_{AC} (6.5 MW_{DC})	20	13.8%	$2,014	$1,914
Large Ground Mount (LMI)	5 MW_{AC} (6.5 MW_{DC})	20	13.8%	$2,064	$1,914
Large Ground Mount (Brownfield/Other Energy Community)	5 MW_{AC} (6.5 MW_{DC})	20	13.6%	$2,154	$2,054
Large Ground Mount (LMI Located in LMI Community)	5 MW_{AC} (6.5 MW_{DC})	20	13.8%	$2,064	$1,914
Large Ground Mount (LMI + Low Income Benefit Project)	5 MW_{AC} (6.5 MW_{DC})	20	13.8%	$2,064	$1,914

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Highlights of Financing/Tax Assumptions

- All projects assumed to be owned by third party corporations, and thus pay state and federal corporate tax (given vast majority of DG projects at this scale are not host customer-owned)
- **Projects included in supply blocks assumed eligible under federal tax code provisions** related to the Investment Tax Credit (ITC) for projects that either begin construction prior to 12/31/2024, as well as the availability of the successor Clean Energy Investment Credit (CEIC) for projects that are placed in service no earlier than January 1, 2025 (therefore rendering "safe harboring" irrelevant to this analysis)

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Highlights of Financing/Tax Assumptions (Cont'd)

- The two tax credits have **functionally identical statutory provisions**, including:
  - A full tax credit value of 30%
  - Bonus credits ranging from 10% (for projects sited on brownfields or other "energy communities" or in "low income or disadvantaged communities") to 20% (for projects serving low-income offtakers)
  - The ability to include the cost of transmission and/or distribution system modifications in the project's basis for calculating the value of either type of investment credit
  - The ability to transfer tax credits
- Given increasing project delays (which make it impossible to claim bonus depreciation under existing Tax Cuts and Jobs Act of 2017 provisions phasing out bonus depreciation for projects <u>placed in service</u> no later than the end of 2026) **we assume projects can only monetize 5-year MACRS depreciation (and cannot monetize bonus depreciation)**

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Highlights of Financing/Tax Assumptions (Cont'd)

- Debt shares held constant over analysis term, and sized to meet an average debt service coverage ratio (DSCR) of 1.25
- Debt terms vary based on the degree of hedged revenue (ranging from **10 years for least hedged policy cases, to 15 for most hedged cases**)
- Interest rates calculated based on **10- and 20-year Treasury note values on October 10, 2022, plus a risk premium of 325 basis points** (resulting in interest rates that are +10 bps higher in policy cases assuming more hedged revenue)
- Tax equity investors continue to be assumed to take the most valuable share of the project's net present value, and thus are **assumed to constitute a larger share of the project's capital stack**
  - **Projects with bonus 40% or 50% ITC/CEIC values include larger tax equity shares of total equity** than projects eligible for 30% credits
- **No other energy, capacity, REC or bill credit revenue directly assumed in modeling, either post-tariff or during the tariff term** (given that such revenues will be accounted for in the benefit cost analysis separately)
- **All applicable Maine tax rates** are assumed

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Table of Financing/Tax Credit Inputs

Year	2024	2025	2026	2027	2028
Statutory ITC/ CEIC Value (%)*	• Large Rooftop/Carport/Ground Mount (No Project Offtaker/Siting Bonus from IRA): **30% ITC/CEIC** • Large Carport or Ground Mount (Brownfield/Energy Community or Sited in LI/Disad. Comm.): **40% ITC/CEIC** • Large Ground Mount (LI Benefit Projects): **50% ITC/CEIC**				
Debt %^	• Projects Monetizing 30% ITC/: **47%-52%** • Projects Monetizing 40% Investment Credit: **40%-44%** • Projects Monetizing 50% Investment Credit: **34%-36%**				
Debt Tenor^	For All Projects: **10-15 years**				
Interest Rate on Term Debt %†	**6.7%-6.8%**	**6.1%-6.2%**	**5.5%-5.6%**	**5.5%-5.6%**	**5.5%-5.6%**
Lender's Fee*	For All Projects: **2%**				
Sponsor/Tax Equity Split*	• Projects Monetizing 30% ITC/CEIC: **25%/75%** • Projects Monetizing 40% ITC/CEIC: **17.5%/82.5%** • Projects Monetizing 50% ITC/CEIC: **10%/90%**				
Sponsor/Tax Equity After-Tax IRRs (Levered)*	• Tax Equity IRR (All Projects): **9.5%** • Sponsor Equity IRR (All Projects): **11%**				
Consolidated After-Tax Equity IRR (Levered)^	• Projects Monetizing 30% ITC/CEIC: **9.88%-10.88%** • Projects Monetizing 40% ITC/CEIC: **9.77%-10.77%** • Projects Monetizing 50% ITC/CEIC: **9.65%-10.65%**				
Depreciation	For all Projects: **5-Year MACRS (no bonus depreciation)**				

*Value held constant across all years.
^Value held constant across all years. The lowest end values represent policy cases with low/no hedged attribute revenue expectations, with values increasing as more revenue is hedged.
†The lowest end values represent policy cases with low/no hedged attribute revenue expectations (and shorter debt terms), with values increasing as more revenue is hedged (and longer debt terms are assumed). The assumed trajectory of interest rates is informed by federal funds rate expectations over the medium- and long-term, which drive pricing of 10- and 20-year Treasury note values.

CREST Modeling Results Across Resource Blocks

- First, we present the revenue requirements for all Policy Options to highlight the difference in revenue requirements across resource blocks

20-yr Revenue Requirements by Resource Block and Selection Year ($/MWh, Case 2 (Fixed Future Payments))

	2024	2025	2026	2027	2028
Large Commercial Roof Mounted	194.00	184.65	176.00	170.00	165.15
Large Ground Mount	166.15	158.00	151.95	147.45	143.00
Large Ground Mount (LMI)	182.00	174.55	167.00	163.15	158.00
Large Ground Mount (Brownfield/Other Energy Community)	166.75	159.55	153.45	149.00	145.15
Large Ground Mount (Located in a Low Income/Disadvantaged Community)	157.55	150.45	144.65	140.00	136.85
Large Ground Mount (LMI + Low Income Benefit Project)	149.00	143.00	138.35	134.00	131.00

NOTE: *Procured values are equivalent to modeled CREST value less 9.5% discount to account for "as-bid" pricing*

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CREST Modeling Results Across Resource Blocks (Cont'd)

20-yr Revenue Requirements by Resource Block and Selection Year ($/MWh, Case 3 (Moderate Hedge))

	2024	2025	2026	2027	2028
Large Commercial Roof Mounted	186.65	176.00	168.25	162.95	157.65
Large Ground Mount	159.85	151.95	145.55	141.35	137.00
Large Ground Mount (LMI)	176.00	167.00	161.00	156.85	152.00
Large Ground Mount (Brownfield/Other Energy Community)	161.00	153.95	147.95	143.00	140.00
Large Ground Mount (Located in a Low Income/Disadvantaged Community)	152.00	145.55	139.75	136.05	132.35
Large Ground Mount (LMI + Low Income Benefit Project)	146.00	140.00	135.15	131.00	128.00

NOTE: *Procured values are assumed equivalent to modeled CREST value less 9.5% discount to account for "as-bid" pricing*

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CREST Modeling Results Across Resource Blocks (Cont'd)

20-yr Revenue Requirements by Resource Block and Selection Year ($/MWh, Case 4 (Wholesale PPA))

	2024	2025	2026	2027	2028
Large Commercial Roof Mounted	173.00	163.75	155.00	150.35	145.05
Large Ground Mount	126.65	119.00	113.00	109.75	105.85
Large Ground Mount (LMI)	176.00	167.00	161.00	156.85	152.00
Large Ground Mount (Brownfield/Other Energy Community)	125.00	118.45	112.95	109.35	105.75
Large Ground Mount (Located in a Low Income/Disadvantaged Community)	113.00	107.00	101.00	98.00	95.00
Large Ground Mount (LMI + Low Income Benefit Project)	99.65	94.55	90.05	87.05	84.15

Note that, though Policy Option 4 (Wholesale PPA) would not allow for direct LMI offtake, costs for resource blocks that require LMI offtake (including to qualify for ITC bonuses) are still shown. It is unclear if they are eligible under either this case or the IRA

NOTE: *Procured values are assumed equivalent to modeled CREST value less 9.5% discount to account for "as-bid" pricing*

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Hybrid of Case 3 (Hedged Energy and RECs) and Case 4 (Wholesale PPA)

Supply Block Composition of Hybrid Program Case

	Technology	Location	Offtakers	IRA Bonus Credit	Capacity
Straw Proposal (Hybrid of Programs 3 & 4)	Roof PV (1 MW)	BTM: Host customer	Host customer	none	84 MW
	Ground PV (5 MW)	FTM: anywhere	None (wholesale PPA)	none	131 MW
	~~**Ground PV (5 MW)**~~	~~**FTM: anywhere**~~	~~**50% LMI, 25% Res, 25% C&I**~~	~~**10%**~~	Not included
	Ground PV (5 MW)	FTM: Brownfield & “Energy Community”	None (wholesale PPA)	10%	131 MW
	Ground PV (5 MW)	FTM: “Low Income Community”	None (wholesale PPA)	10%	131 MW
	Ground PV (5 MW)	FTM: “Low Income Benefit”	50% LMI, 25% Res, 25% C&I	20%	84 MW
	Totals	-----	-----	-----	560 MW

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Procured Values for Hybrid Program Case ($/MWh)

	Technology	Location	Offtaker?	2024 (2027 COD)	2025 (2028 COD)	2026 (2029 COD)	2027 (2030 COD)	2028 (2031 COD)
Straw Proposal (Hybrid of Programs 3 & 4)	Roof PV (1 MW)	BTM: Host customer	Yes	186.65	176.00	168.25	162.95	157.65
	Ground PV (5 MW)	FTM: anywhere	No	126.65	119.00	113.00	109.75	105.85
	Ground PV (5 MW)	FTM: Brownfield & "Energy Community"	No	125.00	118.45	112.95	109.35	105.75
	Ground PV (5 MW)	FTM: "Low Income Community"	No	113.00	107.00	102.15	98.00	95.00
	Ground PV (5 MW)	FTM: "Low Income Benefit"	Yes	146.00	140.00	135.15	131.00	128.00

NOTE: *Procured values are assumed equivalent to modeled CREST value less 9.5% discount to account for "as-bid" pricing*

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Comparison of Weighted Average $/MWh (Hybrid Case vs. Cases 2-4)

	2024	2025	2026	2027	2028
Case 2: Hedged Energy	169.24	161.70	155.23	150.60	146.53
Case 3: Hedged Energy & RECs	163.58	155.71	149.58	145.17	141.13
Case 4: Wholesale PPA	127.44	120.50	114.38	110.75	107.04
Hybrid of Case 3 & 4	139.46	132.09	126.07	122.21	118.45

NOTE: *Procured values are assumed equivalent to modeled CREST value less 9.5% discount to account for "as-bid" pricing*

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Synapse/SEA Next Steps in Resource Cost Analysis

- **Late November 2022:** Internal development of paired solar plus storage resource values, plus adjustments to initial CREST inputs based on stakeholder feedback
  - Market participant feedback on storage cost indue **no later than November 22, 2022** to SEA
- **December 2022:** Development of sensitivity analyses in conjunction with Synapse and additional development/revision of Straw Proposal

Appendix: Stakeholder Feedback to Draft LCOE Modeling Inputs & SEA Modeling Implications

Stakeholder feedback/SEA modeling implications

- SEA received feedback from eight stakeholders in response to draft cost and performance inputs circulated for use in its LCOE modeling
- General themes in stakeholder comments, and SEA's response (and associated modeling implications in **red**) are described on the slides that follow within this section

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Stakeholder feedback/SEA modeling implications (Cont'd)

- Stakeholders requested that SEA clarify the share of installed cost representing interconnection costs, and argued that interconnection costs around $400/kW are expected for future projects
  - An analysis of CMP interconnection data conducted by SEA suggests costs in excess of $300/kW are becoming the norm. However, historic costs will not contain added transmission-level costs that are expected for future projects as a result of ongoing cluster studies.
  - **Modeling Implication (M.I.): SEA believes $400/kW to be a reasonable estimate and intends to revise its installed cost figures to assume such interconnection costs for further BCA iterations**
- Stakeholders recommended that SEA adopt higher assumed land lease costs
  - **M.I.: Given a lack of Maine-specific data forming its initial assumptions, and the consensus in stakeholder feedback SEA intends to increase its assumed land lease costs**

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Stakeholder feedback/SEA modeling implications (Cont'd)

- Stakeholders recommended that SEA adopt higher incremental brownfield installed costs
  - **M.I.: SEA intends to revise its estimates for future BCA iterations based on stakeholder feedback and prior market research**
- Stakeholders recommended a range of inputs for O&M, community solar offtake acquisition and management, project management, and insurance costs (both above and below those proposed by SEA)
  - **M.I.: SEA intends to maintain its inputs as originally proposed for future BCA iterations, as certain suggestions from stakeholders are likely the product of categorizing incremental CSS costs differently (e.g., O&M vs project management)**

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Stakeholder feedback/SEA modeling implications (Cont'd)

- Some stakeholders suggested their experience of certain cost inputs (both OpEx and CapEx) were lower than the values utilized, thus making SEA's costs "inflated" (according to one stakeholder)
  - **M.I.: No change. As noted previously, our team's estimates are intended to reflect what is "typical" in the market (for the purpose of setting a maximum bid value) that incorporate other factors (e.g., developer fees, other upfront costs) in order to ensure bids that reflect healthy price competition are received**
    - **However, if stakeholders wish to provide a documented all-in "total development cost" estimate to our team, <u>we will consider utilizing it in future BCA iterations</u>**
- Stakeholders also expressed conflicting outlooks regarding the impact of prevailing wage requirements on project pricing
  - Some suggested that incremental costs in excess of $100/kW are expected (vs $58/kW proposed by SEA), while some suggested that projects already pay prevailing wage resulting in little to no impact
  - **M.I: Given the range of suggestions and SEA's prior market research on this issue, SEA intends to maintain its input as originally proposed for future BCA iterations.**

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Stakeholder feedback/SEA modeling implications (Cont'd)

- Some stakeholders suggested assuming some degree of property taxes, despite the current property tax exemption for renewable energy projects under Maine law
  - **M.I.: No change, but our team is open to considering it in a sensitivity**
- Other stakeholder suggested that compensation could be set to escalate over time, thus potentially enabling a greater degree of short-term program cost effectiveness
  - **M.I.: While our team is not opposed to such an approach for any eventual program design, we have modeled the policy cases to have a flat lifetime LCOE in order to facilitate comparison between cases.**
    - **We recommend, however, that if such an approach is adopted, that a single rate of future increase be assumed for bidding, to ensure simplified and appropriate bid comparisons.**

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Stakeholder feedback/SEA modeling implications (Cont'd)

- A stakeholder suggested that the term of the analysis should be fixed to the tariff duration, and that post-tariff revenue should not be assumed given the uncertainties regarding its availability and value
  - **M.I.: No change. SEA intends to only model the term of the tariff, so no post-tariff revenue will be assumed in modeling**
- Several stakeholders indicated that discounts equivalent to 5%-10% of retail rates were too low to incent participation
  - **M.I.: SEA plans to adjust its discount to be equivalent to 10%-15% of project Year 1 retail rates, but clarifies that we assume a minimum <u>fixed</u> discount (rather than a value that moves with retail rates)**

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