Evaluation of Rhode Island Distributed Generation Policies

Stakeholder Workshop #2: Key Objectives of Design Process and Overview of DG Policy and Program Design Elements

March 3, 2023

Sustainable Energy Advantage, LLC, on Behalf of the Rhode Island Office of Energy Resources

Schedule for Stakeholder Workshop #2

- **10:00-10:15:** “First Principles” and Introduction to of Key Objectives of DG Policy Design Process and Request for Comments
- **10:15-10:30:** Questions* Regarding “First Principles” and Introduction to of Key Objectives of DG Policy Design Process and Request for Comments
- **10:30-11:30:** DG Policy/Program Design Elements Overview and Request for Comments
  11:30-12:00: Questions* Regarding the DG Policy/Program Design Elements Overview and Request for Comments

**Please take note that, given the extensive content to be covered in the Overview, and the fact that written comments have been requested on the design elements, the time in these section will be reserved for <u>questions only (and ideally of a clarifying nature)</u>. This is to ensure all relevant questions can be answered.*

“First Principles” and Introduction to of Key Objectives of DG Policy Design Process

First Principles (1): Defining Distributed Generation (DG)

- The term “distributed generation” can have several different meanings and refer to several different types of renewable and non-renewable electricity generation resources.
- For the purposes of this process and analysis, we define distributed generation (DG) as:
  - Renewable energy generation sources (herein and hereafter referred to as “projects”) eligible for the current statutory net metering policies that are less than or equal to 10 MW_{AC} in size.
  - These include renewable energy projects that are 1) paired with an energy storage system (ESS), and 2) those that are not.

NOTE: There is a definition of distributed generation for the purposes of the REG program that limits such projects to 5 MW, but that is not being utilized for this analysis, given that the analysis concerns both the REG and Net Metering programs.

First Principles (2): What Does a DG Project's Revenue Requirement (or Levelized Cost of Energy) Consist Of?

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

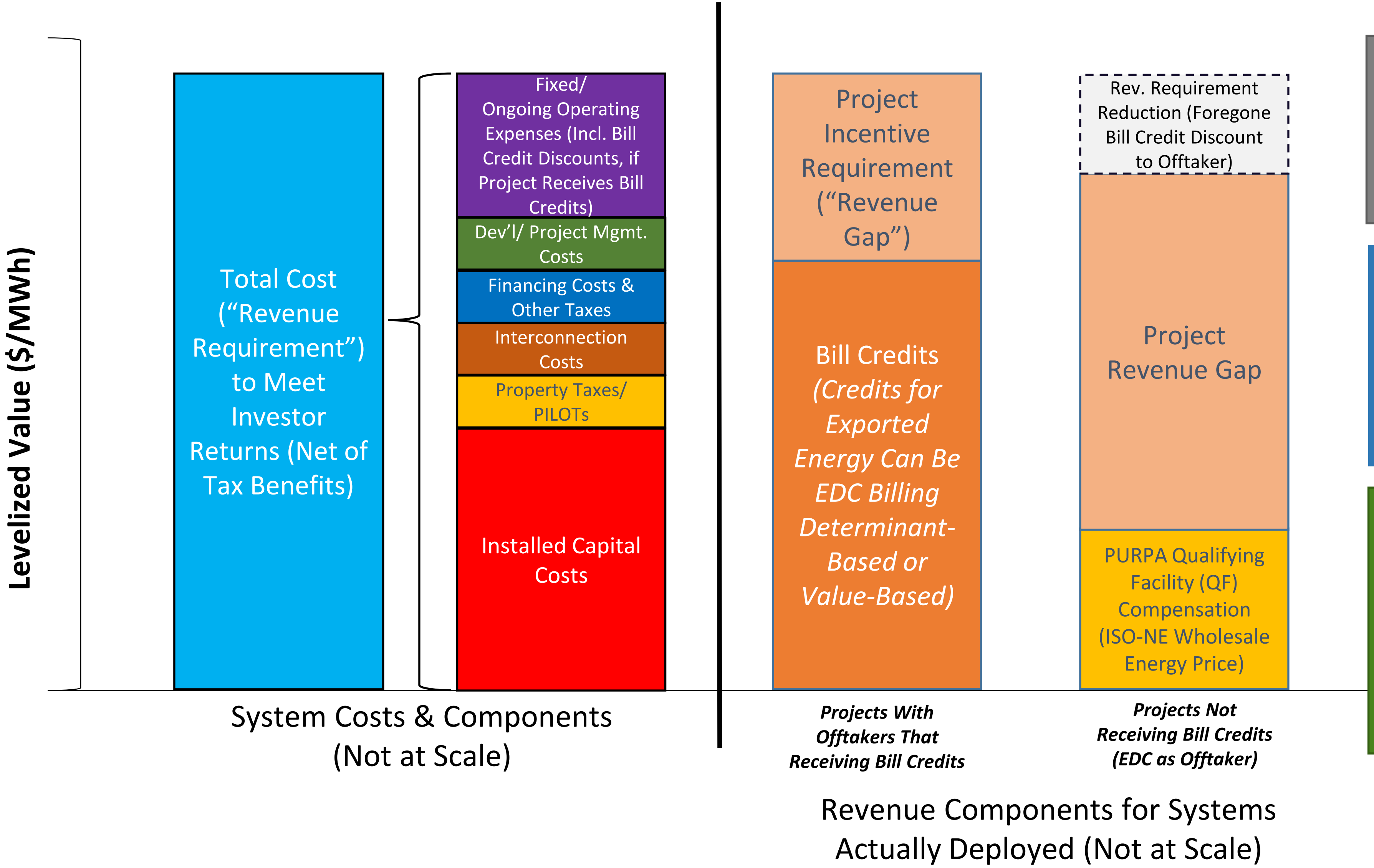
All Divided By…

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 (Total Amount Necessary to Earn in Order to Justify Investment) ($/MWh)

First Principles (3): What Role Does Project Revenue Play in Meeting Project Minimum DG Project Revenue Requirements?



What is a Billing Determinant?

A billing determinant is a component of services billed through retail rates, such as Last Resort Service, Transmission, Transition and Distribution

What is a Project’s “Revenue Gap”?

The project’s revenue gap is the difference (if any) between its revenue requirement (the minimum amount required to finance the project and the revenue it can expect to earn from bill credits or other compensation.

What is Value-Based Compensation?

Value-based compensation is based on the value of the resource to the utility system, and (often) to the broader society. There are a variety of potential methods for estimating these values under Rhode Island’s Docket 4600 principles for Benefit-Cost Analysis.

Statutory Requirements and Statements of Legislative Intent

- The state is <u>required by law</u> to:
    - Ensure Rhode Island Energy procures renewable energy certificates (RECs) equivalent to 100% new and existing renewable energy by 2033 and thereafter (Renewable Energy Standard (2022), R.I.G.L. § 39-26-4)
    - Effect a 45% reduction in greenhouse gas (GHG) emissions below 1990 levels by 2030, an 80% reduction in GHG emissions below 1990 levels by 2040, and reach net-zero emissions (as yet undefined) by 2050 (R.I.G.L. § 42-6.2-2)
- Net Metering (2011) (R.I.G.L. § 39-26.4-1)
    - *"Facilitate and promote installation of customer-sited, grid-connected generation of renewable energy; to support and encourage customer development of renewable generation systems; to reduce environmental impacts; to reduce carbon emissions that contribute to climate change by encouraging the local siting of renewable energy projects; to diversify the state's energy generation sources; to stimulate economic development; to improve distribution system resilience and reliability; and to reduce distribution system costs."*
- Renewable Energy Growth Program (2014) (R.I.G.L. § 39-26.6-1)
    - *"Facilitate and promote installation of grid-connected generation of renewable energy; support and encourage development of distributed renewable energy generation systems; reduce environmental impacts; reduce carbon emissions that contribute to climate change by encouraging the siting of renewable energy projects in the load zone of the electric distribution company; diversify the energy-generation sources within the load zone of the electric distribution company; stimulate economic development; improve distribution-system resilience and reliability within the load zone of the electric distribution company; and reduce distribution system costs"*

RI Public Utilities Commission Goals for Electric System (Adopted by PUC in Docket 4600A)

- *Provide reliable, safe, clean, and affordable energy to Rhode Island customers over the long term (this applies to all energy use, not just regulated fuels);*
- *Strengthen the Rhode Island economy, support economic competitiveness, retain and create jobs by optimizing the benefits of a modern grid and attaining appropriate rate design structures;*
- *Address the challenge of climate change and other forms of pollution;*
- *Prioritize and facilitate increasing customer investment in their facilities (efficiency, distributed generation, storage, responsive demand, and the electrification of vehicles and heating) where that investment provides recognizable net benefits;*
- *Appropriately compensate distributed energy resources for the value they provide to the electricity system, customers, and society;*
- *Appropriately charge customers for the cost they impose on the grid;*
- *Appropriately compensate the distribution utility for the services it provides; and*
- *Align distribution utility, customer, and policy objectives and interests through the regulatory framework, including rate design, cost recovery, and incentives*

Source: RI Public Utilities Commission's Guidance on Goals, Principles and Values for Matters Involving The Narragansett Electric Company (Docket 4600A)

Potential DG Policy Design Objectives for Stakeholder Comment (Presented in No Intended Order)

- Encourage sustained distributed generation industry growth and market development
- Maximize ratepayer and societal benefit/minimize ratepayer and societal cost
- Encourage solar development on disturbed land/minimizes reliance on green space
- Protect consumers from (intentionally or unintentionally) deceptive or abusive practices
- Leverage recently-adopted federal clean energy tax credits from the Inflation Reduction Act of 2022 (IRA)
- Enhance benefits for low income and/or disadvantaged communities
- Maximize benefits/minimize costs, impacts and delays associated with interconnection to the transmission and distribution system
- Maximize near- and long-term local jobs/economic development
- Maximize likelihood of reaching 100% Renewable Energy Standard by 2033 and 2021 Act on Climate requirements

Potential DG Policy Design Objectives: Request for Comments

1. Of the nine (9) DG policy design objectives on p. 9 of this slide deck, please select the five (5) that you (as an individual, advocate, business, public agency, legislator or other) should be prioritized in evaluating DG policy design options and rank them from #1 to #5. Alternatively, you may add one or more of your own principles, if you do not believe they are appropriately represented in the nine (9) principles.
2. Please explain the ranking provided in Question #1.

Due Date for Written Comments Related to this Workshop

- Please submit any written comments to this process discussed at this workshop **no later than March 14, 2023 at 11:59 pm Eastern Time (ET)**
- Please send written comments **in a PDF attachment** (preferably on organizational letterhead if applicable) to Cal Brown (cbrown@seadvantage.com), copying me (jkennerly@seadvantage.com) and Karen Bradbury (karen.bradbury@energy.ri.gov)

Sustainable Energy Advantage, LLC

Review of Potential DG Policy Design Elements & Options

List of Key DG Policy Design Elements and Options

1. Compensation Mechanism
2. Compensation Term
3. Transferred Attributes
4. Ratepayer Impacts and Crediting
5. Price-Setting Mechanism
6. Structure of Bill Credit Compensation to Projects Receiving Bill Credits
7. Eligible Project Sizing to Load
8. Eligible Accounts and Associated Capacity
9. Credit Offtaker Enrollment
10. Incentivizing Beneficial Siting
11. Disincentives for/Prohibitions on Siting on Certain Greenfield Parcels
12. Behind-the-Meter Time-Varying Rate (TVR) Integration
13. Paired Energy Storage Dispatch/Revenue

Design Element: Compensation Mechanism (1)

- Description
  - The mechanism used to compensate DG projects to the point of ensuring their ability to attract investment capital
- Primary Options in Rhode Island Context (Examples in Rhode Island and Northeast Region)
  - **Bill Crediting** (NEM/VNM status quo)
    - *Example: Everywhere with net metering, RI Net Metering and Virtual Net Metering, Massachusetts Net Metering*
  - **No Specific Customer Offtaker** (sometimes known as "buy-all/sell-all")
    - **NOTE:** Such projects could include the use of both tariffs (such as in the REG program) or purchased power agreements (PPAs), which are contracts
    - *Examples*: *RI Renewable Energy Growth Program (REG)*, *VT Standard Offer Program* (though program will have no further solicitations)
  - **Combination of projects with bill crediting and no specific offtaker** (buy-all/sell-all)
    - **NOTE:** Such projects could include the use of both tariffs (such as in the REG program) or purchased power agreements (PPAs), which are contracts
    - Examples. *Massachusetts SMART*, *Connecticut Non-Residential Renewable Energy Solutions (NRES) program*, *Combination of NY-Sun and NY-Value of Distributed Energy Resources (VDER)*

Design Element: Compensation Mechanism (2)

- Primary Modeling Implications
  - On one hand, NEM and other bill credit-based compensation approaches can lead to the shifting of certain costs to non-participating customers to an undesirable degree if left unmitigated
  - On the other hand, such cost shifts **can be mitigated to a point of <u>relative</u> indifference** by:
    - Providing **significant benefits to low-income** customers
    - Utilizing **monetary credits** (based on their value in the period they are generated) **rather than volumetric credits** (which are based on the period in which they are ultimately used)
    - **Limiting sizing of projects/shares of projects to load**, and/or
    - Designing or implementing **alternative bill credits** that are not equivalent to the full (or near-full) retail rate (plus sufficient additional compensation to provide for a project's capital and operating costs, plus a reasonable rate of return)
  - Projects without specific participating customer offtakers do not need to provide discounts to such customers, and thus would not require added costs to provide such discounts

Design Element: Compensation Term (1)

- Description
  - The term (in years) over which the compensation value in question is available to the project
- Primary Options in Rhode Island Context (Examples in Rhode Island and Northeast Region)
  - Unlimited
    - *Examples: RI Net Metering and Virtual Net Metering*
  - 25 years
    - *Examples: Massachusetts Net Metering, NY-VDER*
  - 20 years
    - *Examples: MA SMART Alternative On-Bill Credits (AOBCs), ME Net Energy Billing (NEB), Connecticut Non-Residential Renewable Energy Solutions (NRES) program*
  - 15-20 years
    - *Examples: MA SMART and RI REG*
- Primary Modeling Implications for Net Metering/Billing Determinant-Based Approaches
  - If compensation is set solely based on billing determinants, the cost of bill credits associated with such resources to ratepayers **will mirror the billing determinants in question**
  - Thus, **a longer term under this approach is associated with greater ratepayer cost and potential cost shifting than a shorter term**
  - Modeling should consider the compensation terms necessary to ensure typical projects are economical and **potential revenues after incentive term (if available, and reliably forecasted)**

Design Element: Compensation Term (2)

- Primary Modeling Implications for Programs with Cost-Based Compensation
    - If compensation is tied to an estimated project cost, a longer incentive term **reduces the required incentive rate**
    - Lower payments spread over a longer period of time **generally tend to yield higher net present value when conducting benefit-cost analysis**
    - Modeling should consider **potential revenues after incentive term (if available, and reliably forecasted)**
- Primary Modeling Implications for Programs with Value-Based Compensation
    - If compensation is strictly based on avoided costs and/or benefits of said resources, **cost of said bill credits/resources is calibrated to their benefits to ratepayers and society**
    - Thus, the term of compensation **should, by design, be less relevant to the benefits and costs of such an approach**, but the ultimate degree of costs shifted to non-participants is associated with the value in question

Design Element: Transferred Attributes (1)

- Description
  - Every incentive program must define which project production attributes are **purchased by the electric distribution company (EDC)**, and which are **retained to be monetized by project owner;** EDC purchase of more attributes generally requires higher compensation/incentive rate, though this higher compensation/incentive rate can be at least partially offset by revenue from sale of purchased attributes
- Primary Attributes
  - **Energy** – Value of energy, and right to sell into ISO-NE energy markets
  - **Capacity –** Value of capacity, and right to sell into ISO-NE Forward Capacity Market (FCM)
  - **RECs –** Environmental attributes, including the right to sell to other entities, or to retain to claim use of "green" electricity
- Primary EDC Attribute Purchase Options (Examples in Rhode Island and Northeast Region)
  - **Energy only**
    - *(Examples: RI Net Metering and Virtual Net Metering, ME NEB)*
  - **Energy + RECs**
    - *(Examples: Most other Northeast DG incentive programs, save for MA SMART and RI REG)*
  - **Energy + Capacity + RECs**
    - *(Examples RI REG, NY-VDER)*
  - **Energy + Capacity + RECs, w/capacity subject to project owner buyback**
    - *(Examples: MA SMART (for solar (not storage) above 60 kW)*

Design Element: Transferred Attributes (2)

- Modeling Implications for Program Designs with <u>Limited</u> Attribute Transfer to EDCs
  - Though project owners would be able to **privately monetize the gains** from the sale of attributes, project owners also **bear the risk** of monetizing these attributes
  - Though EDCs would be able to avoid the financial risks (and administrative costs) associated with monetizing as many attributes, EDCs would also be **unable to utilize the gains from the sale of attributes to offset the cost of the program to their ratepayers** (particularly during **periods of high rates**)
    - In other words, **such designs lack "hedge value"**
- Modeling Implications for Program Designs with <u>Broad</u> Attribute Purchase
  - Though project owners would lose the ability to privately monetize the gains from the sale of attributes, **project owners would also incur fewer risks associated with that monetization** by selling their attributes to the EDCs (resulting in **lower financing costs** for eligible resources)
  - Though ratepayers would instead indirectly bear more financial risks (and EDC administrative costs) associated with monetizing the gains from attribute sales on behalf of their ratepayers, **EDCs would gain an enhanced ability to offset the cost of a DG/DER program to their ratepayers** (particularly during **periods of high rates, thereby gaining a degree of "hedge value")**

Design Element: Transferred Attributes (3)

- Further Considerations
  - Unlike for energy and RECs, which are sold into relatively well-understood markets not currently undergoing rapid and fundamental change, many EDCs are uncomfortable with being given title to capacity rights associated with resources that are variable in nature to monetize in the ISO-NE Forward Capacity Market, given the requirement to assume a capacity supply obligation (CSO) or take other risks associated with non-performance

Design Element: Ratepayer Impacts and Crediting

- Description
  - When EDCs must purchase attributes from market participants, they must share the gains with ratepayers
  - It is notionally possible, via the utility ratemaking process, to share these gains disproportionately with certain customer classes that have been shown to be struggling financially.
- Primary Options in Rhode Island Context (Examples in Rhode Island and Northeast Region)
  - **Shared with all distribution customers** based on load share and other traditional cost allocation principles
    - ***Example:*** *All known regional DG incentive and net metering programs involving the transfer of attributes*
  - **Disproportionately credited to low-income (Rate A-60) customers**
    - ***Example:*** *None at present, but has been discussed or proposed by program administrators in Maine*
  - **Entirely credited to low-income (Rate A-60) customers**
- Modeling Implications
  - There are **no specific BCA modeling implications for this approach, given that the impact is in the distribution of benefits and gains**, rather than the overall benefits and gains themselves
  - However, sharing such revenue disproportionately (or fully) with certain customers **can mitigate cost shifts (or rate increases) that may more significantly affect non-participant low-income customers**

Design Element: Price-Setting Mechanism (1)

- Description
  - The mechanism used to establish initial incentive rate or price cap
- Primary Options in Rhode Island Context (Examples in Rhode Island and Northeast Region)
  - Bill crediting based on EDC billing determinants (NEM/VNM status quo)
  - Cost-Based Options
    - Initial Competitive Procurement (followed by standard offer subject to price adjustments)
      - ***Example:*** *Massachusetts SMART program*
    - Competitive Procurement (for QFs/projects with no offtakers of a Certain Size Only)
      - ***Example:*** *RI Renewable Energy Growth Program (REG)*
    - Competitive Procurement (for All Projects (including ones with offtakers) Over a Certain Size)
      - ***Example:*** *RI Renewable Energy Growth Program (REG)*
    - Standard Offer Without Competitive Procurement (Indexed to cost-based value)
      - ***Example:*** *IL Adjustable Block Program*
  - Value-based (based on AESC, for modeling purposes/example)
    - VDER/value stack
      - VDER "mixture" (with specific added PBIs/upfront)
        - ***Example:*** *NY-Sun + NY-VDER compensation approach*
      - "True" VDER (no specific added PBIs/upfront)

Design Element: Price-Setting Mechanism (2)

- Primary Benefit/Cost Modeling Implications for Value and Billing Determinant-Based Compensation (e.g., VDER or NEM/VNM)
  - By definition, pegging compensation to projects to certain billing determinants (even at values substantially less than retail rates) subjects DG market development to these billing determinants, regardless of whether it is sufficient compensation
  - Therefore, **billing determinant- and value-based approaches require additional verification that they can provide sufficient compensation** to cover typical costs in the market plus a reasonable return to investors
- Primary Benefit/Cost Modeling Implications for Cost-Based Compensation
  - Competitive and administratively-set approaches **should result in a comparable payment rate, so they will not be distinct** in our modeling
  - If future pricing is pegged to initial price (e.g., set reductions from initial price based on achieving MW deployment levels), **it may result in more predictable program cost**
  - However, a cost-based approach **may also yield payments that are higher than necessary or too low to stimulate development if there are large changes to underlying revenue requirements** that are not considered at the time prices are set (e.g., change to investment tax credit or increases in capital cost observed since start of COVID-19 pandemic)

Design Element: Structure of Bill Credit Compensation to Projects Receiving Bill Credits (1)

- Description
  - If projects are assumed to have bill credit offtakers, **the bill credit is the amount provided to the project owner by the EDC for distribution to the offtaker via the offtaker's bill for services** (for a fee to the project owner, or automatically netted against a fee to the project owner).
- Primary Options in Rhode Island Context for Non-Cost Based Compensation Approaches (**Without** Additional Payment (if necessary) to Meet Costs + Market Rate Return)
  - **Last Resort Service (LRS) + Transmission + Transition + Distribution until 2050 (then public entities lose Distribution for 2050 and after)**
    - *Example: Current Rhode Island Net Metering/Virtual Net Metering practice*
  - **LRS + Transmission + Transition credits**
  - **LRS + Transmission credits**
  - **LRS credits only**
  - **ISO-NE Wholesale Energy + RECs only**
  - **Value-Based compensation**

Design Element: Structure of Bill Credit Compensation to Projects Receiving Bill Credits (2)

- Primary Options for Projects Receiving Cost-Based Compensation (**With** Additional Payment (If Necessary) to Meet Costs + market rate of return
  - **Last Resort Service (LRS) + Transmission + Transition + Distribution credits until 2050 (then public entities lose Distribution for 2050 and after)**
    - ***Example:*** *Current RI NEM and VNM approach*
  - **LRS + Transmission + Transition credits**
  - **LRS + Transmission credits**
  - **LRS credits only**
    - ***Example:*** *Massachusetts SMART program (Alternative On-Bill Credits (AOBCs) valued at MA equivalent to LRS rate)*
  - **Energy + RECs only**
    - ***Example:*** *Connecticut Non-Residential Renewable Energy Solutions (NRES) program "netting" option*
  - **Value-Based Compensation**
    - ***Example:*** *NY VDER Value Stack + Additional NY-Sun Compensation*

Design Element: Structure of Bill Credit Compensation to Projects Receiving Bill Credits (3)

- Primary Modeling Implications for Non-Cost Based Compensation Approaches
  - Financing costs (which mirror the risks being taken by the project owners) for DG projects tend to be driven most significantly by:
    - The **credit quality** of the offtaker;
    - The **extent of the attributes being transferred** to the EDC; and
    - The **risk the project cannot receive sufficient revenue** (or hedge sufficient revenue with long-term revenue streams)
  - Therefore, compensation approaches like net metering that are not calibrated to the cost of the resource will carry higher risks, and thus have increased financing costs (and therefore higher project costs/revenue requirements)
  - It will be necessary for SEA to model the specific project economics associated with such projects to ensure that such changes provide sufficient revenue for projects to be financeable

Design Element: Structure of Bill Credit Compensation to Projects Receiving Bill Credits (4)

- Primary Modeling Implications for Cost-Based Compensation Approaches
  - The same considerations regarding financing cost for non-cost based approaches (attribute transfer, credit quality and degree of long-term revenue certainty) also apply for cost-based approaches
  - Functionally, this means that, so long as the ultimate value of the compensation to projects is sufficient to cover their capital and operating costs plus a reasonable return, **there are very few significant differences from a benefit/cost perspective between a compensation approach that assumes buy-all/sell-all (akin to the REG program) vs. one in which compensation is intended to be indexed to the cost of the resource** (akin to the MA SMART or CT NRES program "netting option")
    - However, **there is some degree of cost shifting associated with a bill crediting approach (including the bill crediting option available in the REG program**, under which participants can elect to receive bill credits to be credited against their full requirements service each month)
  - Furthermore, adopting cost-based incentives **reduces the risk that said incentives would provide insufficient compensation to projects to make them financeable**, so long as close surveillance of market conditions takes place and appropriate adjustments can be made

Design Element: Maximum Size/Eligible Project Sizing to Load (1)

- Description
  - The maximum size of projects relative to the on-site load they are intended to serve
- Primary Options in Rhode Island Context
  - **10 MW maximum size, Last Resort Service (LRS) + Transmission (T) + Transition (T) + Distribution (D) sized to 100% of 3-year average load, LRS paid for 100% to 125%**
    - *Example: RI Net Metering and Virtual Net Metering*
  - **10 MW maximum size, Sized to 100% of 3-year average load, for which participant can receive cash payment or bill credits**
    - *Example: RI Renewable Energy Growth Program (REG)*
  - **10 MW maximum size, No sizing to load requirements, but excess paid at actual ISO-NE energy rate**
    - *Example: HB 5033 – An Act Relating to Public Utilities and Carriers – Net Metering (Proposed)*
  - **10 MW maximum size, No sizing to load, but excess paid at actual ISO-NE energy rate + RECs at purchased value**
    - *Example: CT Non-Residential Renewable Energy Solutions (NRES) “Netting” Option*

Design Element: Eligible Project Sizing to Load (2)

- Primary Modeling Implications
  - Disincentivizing projects from over-sizing to load (relative to current practice) **would limit cost shifting (and the overall risk to ratepayer/participants)**
  - **Could also cause market participants to propose smaller projects with higher unit ($/kW) costs** (also relative to current practice)
  - Projects with higher unit ($/kW) costs **have higher average revenue requirements** per kWh of expected production

Design Element: Eligible Accounts and Associated Capacity (1)

- Description
  - The types of accounts eligible to benefit from net metering from on-site and off-site projects, and the degree to which capacity serving said accounts is limited ("capped") or unlimited ("uncapped")
- Primary Options for Customer Accounts with On-Site Generation in Rhode Island Context
  - **All accounts eligible, with no capacity caps**
    - *Examples: RI Net Metering, MA Net Metering, VT NEM, ME NEB*
  - **State and municipal (or other MUSH) accounts eligible, with no capacity caps, but with bill credit rate limited by project size or other means**
    - *Examples: NH NEM projects >1 MW)*
  - **All accounts eligible and capacity uncapped, but with value-based bill credit**
    - *Examples: NY VDER*
  - **No standard offer net metering**, with only procured projects provided bill credits or buy-all/sell-all compensation
    - *Examples: RI REG, CT NRES and CT SCEF*

Design Element: Eligible Accounts and Associated Capacity (2)

- Primary Options for Customer Accounts Benefiting from Off-Site Generation in Rhode Island Context
  - **Projects serving Municipalities, universities, schools, and hospitals (MUSH), other public entities, and agricultural customers uncapped, others capped or otherwise ineligible**
    - *Examples: RI Virtual Net Metering and Community Remote Net Metering (CRNM))*
  - **All accounts eligible, but project capacity serving said accounts capped by annual program capacity allocation**
    - *Examples: RI Renewable Energy Growth Community Remote Distributed Generation (CRDG), CT Shared Clean Energy Facilities (SCEF) program*
  - **Project capacity serving MUSH, other public entities and agricultural customers uncapped, others capped or otherwise ineligible**
    - *Examples: CT Non-Residential Renewable Energy Solutions (NRES) State and Municipal tier*
  - **All accounts eligible and project capacity uncapped, but bill credit rate limited for non-state/municipal government projects**
    - Examples: Combination of *Massachusetts Net Metering* and *Massachusetts SMART program*
  - **All accounts eligible and project capacity uncapped, with compensation rate based on value-based amount**
    - Example: *NY Community Distributed Generation (CDG)*
  - **All accounts eligible and project capacity uncapped, but with excess generation compensation rate limited** (likely to REG/cost-based amount)

Design Element: Eligible Accounts and Associated Capacity (3)

- Primary Modeling Implications
  - In general, limiting eligible accounts has limited BCA-specific impacts, given that BCAs pursuant to Docket 4600 tend to model the impact of the deployment of certain kinds of projects (or measures) over time
  - However, **limiting capacity eligible to serve certain types of accounts can have significant market impacts**, because it can mean that an unknown degree of certain types of projects would be economically unable to be developed without eligibility for the program in question (e.g., net metering or REG)

Design Element: Credit Offtaker Enrollment (1)

- Description
  - Customer purchasing credits produced by project (if applicable – not applicable for buy all, sell all designs)
- Primary Options in Rhode Island Context (Examples in Rhode Island and Northeast Region)
  - **Customers recruited/enrolled by project owner**
    - ***Examples:*** *RI Net Metering and Virtual Net Metering, as well as most other net metering/excess generation and incentive programs in the region*
  - **Customers recruited/enrolled by EDC (or other central entity) on an opt-in basis**
    - ***Examples:*** *Connecticut SCEF, NY-Sun Solar for All*
  - **Customers enrolled by EDC (or other central entity) on an opt-out basis**
    - ***Examples:*** *None at present, but has been discussed or proposed by program administrators in Maine, Vermont, and New York*

Design Element: Credit Offtaker Enrollment (2)

- Primary Modeling Implications
  - Recruiting offtakers, managing billing processes, etc. **represent incremental (and sometimes significant) administrative costs ultimately passed on to ratepayers**
  - (If project owners are required to enroll customers) Removing credit checks for residential low-income and non-low-income customers **can further increase administrative costs for project owners** (since they can lead to more defaults and customer turnover)
    - When project owners are required to recruit credit offtakers, they may include credit score requirements to minimize defaults, which can result in less access for lower income customers.
  - Opt-out, EDC enrollment **can, if executed properly, reduce the unit costs of upfront customer acquisition** (and thus reduce project revenue requirements)
- Other Considerations
  - An additional important consideration is **how project owners are paid for credits by credit offtakers**
    - Possibility for EDC to offer consolidated billing, reducing administrative burden?
  - EDC enrollment **could be on opt-in or opt-out basis**

Design Element: Incentivizing Beneficial Siting (1)

- Description
  - Any and all additional incentives or price signaling for projects sited on disturbed or other non-greenfield parcels of land
- Primary Options in Rhode Island Context If Projects Are Not Competitively Procured
  - **No explicit adders or other incentives for beneficial siting**
    - ***Example:*** Current RI DG program practice
  - **Adders for certain projects/projects sited on certain desired parcels** (e.g. gravel pits, brownfields, landfills, agrivoltaics, carports)
    - ***Example:*** *Massachusetts SMART program adders for landfill, brownfield, and canopy projects*
  - **Adders only for projects not incented by IRA** (e.g., non-brownfields)
- Primary Options in Rhode Island Context If Projects Are Competitively Procured
  - **Bid preferences for certain projects/projects sited on certain desired parcels** (e.g. gravel pits, brownfields, landfills, agrivoltaics, carports)
    - ***Example:*** *Connecticut Non-Residential Renewable Energy Solutions (NRES) and Shared Clean Energy Facilities (SCEF)*
  - **Bid preferences only for projects not incented by IRA** (e.g., non-brownfields)

Design Element: Incentivizing Beneficial Siting (2)

- Primary Modeling Implications
  - Functionally all projects sited on a disturbed parcel (often referred to as “beneficially sited” projects) **require some degree of added cost for remediation or other added site work** to ensure the project can be sited in compliance with federal, state and local rules
  - As a result, all said projects have incremental costs, and the added performance-based incentive **tends to increase costs to customers** (and depending on program design, a degree of cost shifting)
  - However:
    - From a BCA perspective, said projects also have **certain avoided costs associated with preservation of land and other land uses**; and
    - The IRA provides **specific 10 percentage point bonus federal Investment tax credits for brownfield projects**

Design Element: Disincentives for/Prohibitions on Siting on Certain Greenfield Parcels (1)

- Description
  - Any/all additional disincentives, price signaling or prohibitions for projects sited on disturbed or other non-greenfield parcels of land
- Primary Options in Rhode Island Context
  - **No explicit siting disincentives available**
    - ***Example:*** *Current RI practice in both REG and Net Metering programs*
  - **Subtractors (or limitation on available billing determinants) based on siting on certain greenfield parcels**
    - ***Examples:*** *Massachusetts SMART Program*, *Vermont Net Metering post-July 1, 2017*
  - **Restrictions/prohibitions on siting on certain parcels (core forest, prime farmland)**
    - ***Example:*** *Massachusetts SMART Program*, *Connecticut* *Public Act 17-218* *(applicable to renewable energy projects over 2 MW,* without explicit state agency siting approval*)*

Design Element: Disincentives for/Prohibitions on Siting on Certain Greenfield Parcels (2)

- Primary Modeling Implications
  - Blanket prohibitions of siting on certain parcels or broad types of parcels (whether with or without explicit approval in the cases of explicit state agency approval) **can limit the cost to society and/or certain sensitive ecosystems**, but **could have unknown and difficult-to-quantify impacts on solar potential**
  - If solar potential for certain market segments is broadly limited via restrictions, it **becomes much more difficult to estimate the amount of capacity that can reach commercial operation without extensive (and potentially untenable) assumptions**
    - This is also an issue that impacts market participants, particularly if significant GIS mapping is required to establish exactly which parcels are permissible and impermissible for development
  - Thus, **discrete, measurable financial disincentives are substantially easier to model the impact of**, because they simplify 1) the assessment of the effectiveness of such a disincentive for potential project owners and 2) the determination of an eventual rate by which certain projects reach commercial operation

Design Element: Behind-the-Meter Time-Varying Rate (TVR) Integration

- Description
  - The degree to which time-varying rate designs could be integrated into future DG compensation and compensation approaches
- Primary Options in Rhode Island Context
  - **No required integration**
    - ***Example:*** Current RI DG program status quo
  - **Required for on-site projects (Existing customers as of a date certain grandfathered)**
  - **Required for on-site projects (No grandfathering)**
- Primary Modeling Implications
  - Implementation of TVR for projects after a certain date **could serve to reduce the degree of shifted costs to non-participants**, and would **likely improve the economics and capacity value of projects paired with energy storage**
  - However, TVR **would likely reduce compensation to owners of PV projects not paired with energy storage**, which would need to be accounted for in any cost-based incentives
  - Not grandfathering certain projects **could also affect the economics of existing systems** (though currently-operating systems are beyond the scope of this specific analysis)

Design Element: Paired Energy Storage Dispatch/Revenue (1)

- Description
  - Compensation for pairing storage with DG may be designed numerous ways
  - In general, however, the design of compensation for energy storage is generally tied to obligations with regard to storage dispatch
- Primary Options for Paired Storage Incentive Design (Examples in Rhode Island and Northeast Region)
  - **Energy Storage Upfront Incentive:** Upfront payments, usually paired with dispatch/performance requirements during key periods
    - Example: CT Green Bank Energy Storage Solutions program
  - **Energy Storage Performance-Based Incentive** – payment based on discharging during specified periods
    - Example: ConnectedSolutions (Rhode Island Energy)
  - **Renewable Energy Incentive Adder** – incentive tied to production from paired RE system (may be tied to dispatch requirements)
    - Example: Massachusetts SMART Energy Storage adder

Design Element: Paired Energy Storage Dispatch/Revenue (2)

- Primary Options for Paired Storage Dispatch Strategy (Examples in Rhode Island and Northeast Region)
  - **Defined Periods:** Regular discharge required or incentivized during defined periods.
    - *Example: MA Clean Peak Standard*
  - **Event-based dispatch:** Discharge required or incentivized in response to events called by program administrator, often with notification the night before.
    - *Example: ConnectedSolutions (Rhode Island Energy)*
  - **EDC Control:** EDC retains full control of battery (owner may use during outages). Sometimes called tolling agreement. Some similarities to NWA.
    - *Example: Green Mountain Power (VT) Bring Your Own Device (BYOD) program*
- Primary Modeling Implications
  - Benefits of performance-based incentives are easier to model
  - Challenging to quantify benefits of storage to distribution system – depends on operation of the battery, project location, and utility treatment of storage in distribution modeling.
  - Granting EDCs control of storage assets may increase realized distribution benefits, but value would be dependent on specifics of design (and modeling assumptions)

Request for Stakeholder Comments on Policy Design Elements

Sustainable Energy Advantage, LLC

Policy Design Elements: Request for Stakeholder Comment

1. **Compensation Mechanisms:** Of the options for DG Compensation Mechanisms on slide 11, which of the potential options presented (or an option not named therein that you recommend) is most appropriate for compensating DG projects, and why?
2. **Compensation Term:** Of the options for the potential compensation term for DG projects on slide 13, which of the potential options presented (or an option not named therein that you recommend) is most appropriate for compensating DG projects, and why?
3. **Transferred Attributes:** Of the options for attributes to be transferred from DG project owners to the EDC on slide 15, which of the potential options presented (or an option not named therein that you recommend) is most appropriate for compensating DG projects, and why?
4. **Ratepayer Crediting of Gains from Attribute Sales:** Of the options for crediting gains from the sales of attributes from eligible DG projects to the EDC on slide 18, which of the potential options presented (or an option not named therein that you recommend) is most appropriate for compensating DG projects, and why?

Policy Design Elements: Request for Stakeholder Comment

5. **Price-Setting Mechanism:** Of the options for DG Price-Setting Mechanisms on slide 19, which of the potential mechanisms presented (or an option not named therein that you recommend) is most appropriate for DG projects, and why?
6. **Structure of Bill Credit Compensation to Projects <=25 kW_{AC} Receiving Bill Credits:** Of the options for the structure of bill credits allocated to DG project owners (and then to offtakers, if different) on slides 21 and 22, which of the potential options presented (or an option not named therein that you recommend) is most appropriate for DG projects that are less than or equal to 25 kW_{AC}, and why?
7. **Structure of Bill Credit Compensation to Projects >25 kW_{AC} Receiving Bill Credits:** Of the options for the structure of bill credits allocated to DG project owners (and then to offtakers, if different) on slides 21 and 22, which of the potential options presented (or an option not named therein that you recommend) is most appropriate for DG projects that are greater than 25 kW_{AC}, and why?
8. **Eligible Project Sizing to Load:** Of the options for requiring projects (or project capacity allocations from off-site projects) to be sized to load on slide 25, which of the potential options presented (or an option not named therein that you recommend) is most appropriate for DG projects, and why?

Policy Design Elements: Request for Stakeholder Comment

9. **Eligible Accounts and Associated Capacity (Projects Serving On-Site Load):** Of the options for Eligible Accounts and Associated DG Capacity shown on slide 27, which of the potential mechanisms presented (or an option not named therein that you recommend) is most appropriate for DG projects, and why?
10. **Eligible Accounts and Associated Capacity (Projects Serving On-Site Load):** Of the options for Eligible Accounts and Associated DG Capacity shown on slide 28, which of the potential mechanisms presented (or an option not named therein that you recommend) is most appropriate for DG projects, and why?
11. **Credit Offtaker Enrollment:** Of the options for Credit Offtaker Enrollment shown on slide 30, which of the potential options presented (or an option not named therein that you recommend) is most appropriate for DG projects, and why?
12. **Incentivizing Beneficial Siting:** Of the options for Incentivizing Beneficial Siting shown on slide 32 (including for those associated with competitive procurements and those not associated with competitive procurements), which of the potential options presented (or an option not named therein that you recommend) is most appropriate for DG projects, and why?

Policy Design Elements: Request for Stakeholder Comment

13. **Disincentives for/Prohibitions on Siting on Certain Greenfield Parcels:** Of the options for disincentivizing or prohibiting siting projects on certain greenfield parcels of land shown on slide 34, which of the potential options presented (or an option not named therein that you recommend) is most appropriate for DG projects, and why?
14. **Behind-the-Meter Time-Varying Rate (TVR) Integration:** Of the options for integrating time-varying rates into behind-the-meter DG compensation shown on slide 36, which of the potential mechanisms presented (or an option not named therein that you recommend) is most appropriate for DG projects, and why?
15. **Paired Energy Storage Incentive Design:** Of the options for compensating paired energy storage systems shown on slide 37, which of the potential options presented (or an option not named therein that you recommend) is most appropriate for DG projects, and why?
16. **Paired Energy Storage Incentive Design:** Of the options for dispatching paired energy storage systems shown on slide 38, which of the potential options presented (or an option not named therein that you recommend) is most appropriate for DG projects, and why?

Due Date for Written Comments Related to this Workshop

- Please submit any written comments to this process discussed at this workshop **no later than March 14, 2023 at 11:59 pm Eastern Time (ET)**
- Please send written comments **in a PDF attachment** (preferably on organizational letterhead if applicable) to Cal Brown (cbrown@seadvantage.com), copying me (jkennerly@seadvantage.com) and Karen Bradbury (karen.bradbury@energy.ri.gov)

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