PosiGen

**PosiGen Comments in Response to the Evaluation of Rhode Island's Distributed Generation Policies**

PosiGen appreciates the opportunity to provide these comments to the Rhode Island Office of Energy Resources as part of the evaluation of Rhode Island's distributed generation policies. The following comments are meant to address the residential market segment only unless otherwise indicated.

**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.**

1. Maximize likelihood of reaching 100% Renewable Energy Standard by 2033 and 2021 Act on Climate requirements
2. Enhance benefits for low income and/or disadvantaged communities
3. Maximize ratepayer and societal benefit/minimize ratepayer and societal cost
4. Encourage sustained distributed generation industry growth and market development
5. Maximize benefits/minimize costs, impacts and delays associated with interconnection to the transmission and distribution system

**2. Please explain the ranking provided in Question #1.**
In our view, achieving the 100% RES by 2033 is the overarching goal to which all other policies are progressing towards. In order for that goal to be achieved in a way that does not perpetuate the systemic inequities of our energy system, there must be a focus in every policy or program to benefit disadvantaged communities and environmental justice areas which is why that is our second priority principle. The focus on benefitting disadvantaged communities is one of the primary ways to achieve the right balance of maximizing societal and ratepayer benefits while minimizing the costs. Quantifying the societal and ratepayer benefits and costs, where possible, helps create more sustainable long-term distributed generation policies, which is what will allow for sustained industry growth and market development. Policies, programs, or tariffs that do not support a robust distributed generation industry will make achieving the 100% RES by 2033 very difficult, thus the impact on the industry must be considered. Finally, we should ensure that all of the resources that go into the policies, programs, and tariffs are fully utilized, help avoid distribution system upgrades where possible, and reduce ratepayer costs.

The four objectives that were omitted were not done so because they are not worthy considerations. We strongly believe that consumer protection (for all solar industry segments) must be considered in every program and, if done poorly, threatens the viability of the industry long-term. However, many consumer protection aspects are typically handled by other oversight agencies and are not directly built into the rate design or compensation structure of solar programs. We also believe that maximizing development on disturbed lands and the built environment helps preserve critical green space and that the higher costs of doing so are offset by societal benefits. We also believe the IRA provides several key “adders,” but given the substantial amount of uncertainty at this time we believe that should be a lower priority consideration.

**3. 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?**
For the residential segment, bill crediting should remain the primary mechanism for customer compensation. Bill crediting has the advantages of being understood by customers, allows for simpler processes by avoiding the need for customers to provide sensitive payment information, and avoids being considered taxable income for offtakers. It is also a flexible method of compensation that has a number of ways that can be adjusted through adders or non-bypassable charges, monetary crediting, and is compatible with time-of-use rates.

PosiGen also has experience participating in the Connecticut Residential Renewable Energy Solutions Program which allows customers the option of net metering (netting tariff) or a Buy-all/Sell-all tariff. While we primarily utilize the netting tariff, one of the main benefits of the Buy-All/Sell-All is that the direct payments to a non-utility customer is that it allows for new financing arrangements which can help reach underserved communities. For example, if the Buy-All/Sell-All Tariff payments are made to the solar company, then the contract with the customer can be more akin to a roof lease where the customer is *paid by the solar company* a certain amount each month. While this can provide the same or better savings outcome to traditional bill crediting for the customer, it lowers financing risk because the customer is not making payments to the financier and thus there is virtually no risk of customer default. Instead the revenue stream is coming from an investment-grade utility with the backing of a tariff which is extremely low risk. Such a financing arrangement could be more accessible for those with poor credit, incomes, or are otherwise viewed as riskier customers by traditional financing standards.

**4. 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?**
Aligning the compensation term with standard consumer financing terms of 20 or 25 years is ideal for providing customers with the necessary level of certainty to invest in a solar system for their home. Mismatched compensation and financing terms will lead to more expensive financing costs and raise consumer protection concerns due to the inability for reasonable savings estimates to be provided to customers.

We recommend 25 years as the preferred term to align with the standard manufacturer warranty for panels. In states where there are incentives that are paid out over time, the term for those incentive-specific payments can be for a shorter duration such as in SMART in Massachusetts (10 years for residential) or in the New Jersey Successor Solar Incentive Program (15 years).

**5. 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?**
For residential projects, combining the sale of energy and RECs in a low-friction way is preferable to ensure that compliance with the state's 100% Renewable Energy Standard by 2033 can be met. Typically residential customers do not want to navigate the added work, costs, and complexity of enrolling with REC aggregators who report, verify, and sell RECs. The REG, SMART program, and Connecticut RRES program all include the sale of RECs which helps maximize ratepayer value.

For non-residential projects there are different considerations on whether RECs should be required to be transferred as part of distributed generation policy. This topic recently been raised in Connecticut's NRES program where businesses want to install solar projects on their facilities but also want to keep and retire the RECs to meet corporate sustainability goals. NRES currently do not allow that to occur which has led some projects to be placed on hold.

The transfer of capacity rights for residential solar systems is a more complicated issue. In Massachusetts projects under 60 kW retain their capacity rights while in Connecticut the capacity rights are technically transferred to the utilities despite the state statute creating the RRES program specifically referring only to energy and RECs as part of the tariff. Some residential solar companies are currently pursuing the ability for system owners to retain capacity rights. The Connecticut Energy Storage Solutions program allows system owners to retain their capacity rights, but they are unable to bid them into the FCM.

While current residential solar participation in the ISO-NE Forward Capacity Market has been limited, there are some companies who are doing. Presumably as ISO-NE implements FERC O.2222 and we see broader access for DER aggregations, the desire to retain capacity rights will increase. Massachusetts originally allowed the utilities to claim capacity rights for small-scale solar, but then the utilities did not actually bid that capacity in the FCM which is one reason why that was changed by the Department of Public Utilities.

**6. 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?**
We believe that the crediting gains from the sales of attributes should be disproportionately credited to low-income customers, though some value should be provided to all distribution customers.

**7. 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?**

The price-setting mechanism is one area where the 5 priority principles identified above can conflict and where a balance between them must be achieved. No price-setting mechanism is without flaws and some are better than others at being responsive to maintaining a distributed generation industry. Generally, for residential customers, a competitive procurement mechanism to set prices is the least conducive to how projects are developed. Residential projects need a reasonable level of certainty so that residents can make informed decisions on whether the investment will make sense for them. It is also important that all residential customers, who are supporting the DG program(s), have access to it which may not be the case in a competitive procurement.

At current penetration levels in Rhode Island, we believe that the bill crediting based on EDC billing determinants is acceptable. Even New York, which has developed a robust VDER approach, has opted to maintain a NEM structure with more incremental changes for residential and small commercial customers.

Theoretically, a value-based approach is the ideal long-term structure which can then include any applicable adders to achieve public policy objectives such as an equitable distribution of deployment and benefits. Moving to such a structure is easier said than done and will also require a more holistic view on the value of DERs, the types of DERs that can participate, and other revenue streams from other sources to ensure there are the right price signals to avoid the double counting of benefits and compensation.

Ultimately a value-based approach alone may not lead to the level of DG deployment needed to meet the state's goals. The REG and Connecticut RRES programs undergo annual review processes to set the tariff rates so that projects are viable while also not being overly lucrative for customers. While this approach can be successful in maintaining a healthy distributed generation industry, it too has some drawbacks. An annual (or every few years) review reflecting an "average" system runs the risk of setting the compensation rate too high or too low based on a limited number of variables. This may not reflect key changes to the product or market and also can run the risk of over (or under) reacting to market conditions. An annual review process also does not necessarily provide a long runway for developers and are a source of risk that businesses have to take into account. Clearly, based on the experience of the REG and Connecticut RRES programs, the annual review process can work. However, we have also seen it lead to poor results in other states such as New Jersey where the process ultimately led to too low REC incentive values for certain market segments, resulting in little deployment in the last year.

**9. 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?**

The sized-to-load provision currently in in statute, and it's enforcement by Rhode Island Energy over the years, has been frustrating to residential customers and developers alike. Ignoring site-specific factors, primarily shading, has resulted in many projects being unnecessarily undersized. It is also incompatible with policies and goals in place to decarbonize home heating and transportation, which necessarily leads to increased future electricity usage. Customers should be able to size their systems to not only meet their actual electricity needs today, but also for their future needs if they so choose. Addressing the potential for the oversizing of systems through how much those “excess” credits are worth is a better approach.

**10. 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?**
We believe that annual deployment targets that align with the broader state goal of achieving 100% renewable energy by 2033 are important. However, we strongly recommend against have hard caps on participation for the residential segment. Given the structure of the residential solar market segment with shorter development cycles, customer expectations, and need to install projects on a continuous basis, having a hard annual capacity limit would be incompatible. While the REG does have an annual capacity limit, there is always the option of net metering which makes it unique.

Connecticut has annual targets that can help guide it’s decisions, but does not have a hard cap on residential installations. New Jersey set a capacity limit by market segment for it’s incentive program (net metering does not have an annual cap) which has been a source of significant uncertainty and risk. The capacity limit was set too low and in the current energy year (June through May) the residential segment was set to hit that cap in January. To avoid a disastrous lapse in the program, the Board of Public Utilities re-allocated capacity from under-utilized market segments to residential to get through the energy year. Had the BPU not taken emergency action, the industry would have come to a halt which would have led to furloughs or layoffs and would have damaged the market’s confidence in the program.

The purpose or value of an annual cap that cannot actually be hit without having major negative consequences on the industry (which is known by both the industry and policymakers) is not clear. It adds a significant, and unnecessary, amount of risk to the market and sets up policymakers to be in a position of potentially need to take emergency action each year. An annual cap also stifles new market entrants and growth, particularly if the market runs close to (or hits) the annual cap each year. This in turn can make it harder to actually hit the annual deployment levels needed to hit the state’s target as companies.

**11. 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?**
We support the option that all residential customers are eligible, with no capacity caps, to benefit from on-site generation.

**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?**
We believe that time-varying rates will be an important part of an electrified, zero-carbon grid. Developing a TVR that is understandable and actionable for utility customers is the first step in gaining broader acceptance. Generally, we believe that TVR should begin on an opt-in basis for customers who are interested in shifting their energy consumption or have electric vehicles, solar+storage, or other load shifting options. At this time we do not believe solar customers should be required to go on a TVR rate unless that requirement is applied to all residential customers. It is difficult to determine whether there should be any grandfathering for existing solar-only customers without knowing what the TVR would look like and thus the impact on the customer value. If a TVR rate is developed and would have a significant negative impact on existing solar customers, they should be grandfathered or at least be able to opt-out. Undermining the value for solar customers would be a significant disruption because it would make it very difficult for new or prospective solar customers to trust that installing solar, with or without energy storage, will not be undermined in the future.

**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?**
In our view, an adder tied to the production of a solar system or an upfront rebate are primarily *deployment* incentives that are meant to scale up the technology, while the pay-for-performance programs (which are paying for real value and thus are not necessarily incentives) are *optimization* policies to ensure the resources are being used in grid-beneficial ways. While SMART and the Connecticut ESS programs have tied some performance requirements to the deployment incentives (though in the case of SMART the requirement is very simple and is not required if a system participates in ConnectedSolutions instead), we typically don't believe the structure is ideal because it requires ongoing verification and the potential for clawbacks. These are difficult to monitor and administer, particularly for customer-owned systems rather than third-party owned systems.

Where optimization mechanisms exist, whether ConnectedSolutions or TVR or DER aggregations, it is better to have those dictate the operation of the system rather than static requirements associated with a rebate. Deployment incentives should have the goal of normalizing the new technology for consumers, help bring down the cost through scale, and overcome barriers that come with new technologies such as permitting, interconnection, and recycling. Deployment incentives should scale down over time in a predictable manner. At the same time as the deployment incentives are scaling down, robust optimization policies should be established and scaled.

Many of the top solar+storage markets have taken this approach including Massachusetts with the SMART adder and ConnectedSolutions, Connecticut's ESS program which has both a rebate and performance payments (which take priority over the "set it and forget it" dispatch associated with the upfront rebate), California's SGIP rebates and TVR rates, and Hawaii's Battery Bonus program which uses both upfront incentives and bill credits based on performance. New York and New Jersey are also in the process of developing storage programs for residential customers, with New Jersey looking at the combination of fixed annual payments (over 10-15 years) as well as a ConnectedSolutions-type performance payment.

**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?**

For residential customers we believe that Defined Periods or Event-Based dispatch are the most practical dispatch options. A Defined Periods approach is the simplest for customers to understand and plan for and is best suited for use with a TVR. Event-based dispatch is more targeted and therefore can provide greater ratepayer benefit but does require a higher degree of engagement from the customer, installer, OEM, or aggregator to respond to event calls. This is technically more challenging, particularly for customer-owned systems, but has been proven to work.

Please feel free to contact me with any questions regarding these comments.

Respectfully,

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