Distributed Generation Stakeholder Group

LD 936 Proposed Successor Program Framework

Public Comments

On November 23, 2022, the Distributed Generation Stakeholder Group released the LD 936 Proposed Successor Program Framework[1] for public comment. Public comments were requested by December 14, 2022. Members of the public were provided with an online form to submit comments and were also provided the option to submit comments directly by separate correspondence. This document contains all public comments submitted using the online form and by separate correspondence.

Note: page numbers in this table of contents can be found in the bottom right corner of each page.

[1] https://www.maine.gov/energy/sites/maine.gov.energy/files/inline-files/LD%20936%20proposed%20successor%20framework_for%20public%20comment.pdf

Your name	Kaitlin Hollinger
Your organization, if any (if commenting on your own behalf, please enter "self")	BlueWave
Please provide any input in response to page 31, "Proposed successor program framework: competitive procurement"	Holding a competitive procurement has trade-offs. Developers are unlikely to invest enough money to accurately assess project viability before having confidence that their project has secured capacity and a workable compensation rate in the program. One solution would be to require a minimum bid, effectively allowing the industry to realistically model compensation in order to evaluate whether or not projects are feasible under this program. Another solution would be to hold a single procurement to set the bid price and then flow the rest of available capacity into a declining block program, similar to what was done for the MA SMART program. While procurements theoretically provide the most economic pathway to deploying projects, the high barriers to entry coupled with low compensation encourages speculative and poorly sited projects. This dynamic drives maximum conflict over solar siting and encourages projects to apply whether or not they have a realistic idea of the infrastructure needs or costs that they may be facing. Furthermore, requiring permits as a barrier to entry places an undue burden on local AHJs and town officials who would need to evaluate speculative projects through permitting processes without knowing if the project has secured capacity or compensation in order to move forward. BlueWave suggests mitigating this concern by simply requiring a signed ISA and site control for entering a project into the procurement, rather than requiring permits to be in-hand.
Please provide any input in response to page 32, "Proposed successor program framework: community access"	While we understand that there is a limited market of subscribers given the population of Maine, it is unfortunate that many of the projects participating in this program will not be directly serving C&I and small business offtakers. To encourage enough projects to pursue the proposed community access tranche, compensation should realistically be larger than the value determined by selected bids within the procurement tranche of the program. These projects will be taking on added customer acquisition and management costs, as well as providing the customer discount, in order to maximize public benefits. BlueWave recommends that these projects be compensated at the 150th percentile rather than the suggested 20th percentile. Doing so would drive development to the stated policy goal of the distributed generation stakeholder group and the Governor’s Energy Office.

Please provide any input in response to page 33, "Proposed successor program framework: siting preferences aligned with federal funding"	BlueWave's immediate recommendation is to include sites contaminated by PFAs in this category of bid preference for brownfields. With regards to this section of the framework, BlueWave cautions against fully formulating the proposed mechanism without definitive guidance from Treasury about implementation of the IRA. Some projects may work if utilizing the ITC provisions within the IRA, but it is too soon to know if projects qualify without final Treasury guidance. The investment community is unable to model revenues under the "low-income bonus" tax credits proposed by the IRA, and thus it is difficult to provide specific feedback on this portion of the proposal at this time. Without official guidance from Treasury, the industry has no visibility into what will qualify a project's capacity (or portion of capacity) for the low-income bonus. Current definitions for low-income customers, low-income communities, and energy communities are too vague to begin enrolling qualified customers. As we are evaluating opportunities created by the IRA, we have many questions, including: - Will qualifying criteria be household or family-based, or can customers be qualified by their geographic location relative to neighborhood income data? - What documentation to demonstrate income eligibility will be required to screen low-income customers? - What project milestones must be met in order to secure capacity and funding, and how will the queueing and waitlist process work? - What compliance measures will project owners be responsible for throughout a project's life?
Please provide any input in response to page 34, "Proposed successor program framework: direct benefits to decrease energy burden aligned with federal funding"	It is imperative to guarantee that all projects participating in the solicitation or walk-up program are qualified (through their participation in the program) to receive the 20% ITC for providing direct benefits to the target population. BlueWave poses many questions about this section of the framework, and looks forward to continued discussion about how to reach the stated policy goals while ensuring that projects qualify for the ITC and remain economically viable. Firstly, we would like to understand how the Mills administration is planning to integrate this portion of the program into their overall strategy for reducing rate burdens. In general, BlueWave would caution against empowering the utilities to distribute financial benefits without clear accountability and enforcement mechanisms. Other questions and considerations include: - Does the first bullet on this slide 34 mean that the state is going to set up a program to distribute electricity bill relief to qualified customers? Or does it mean that projects participating will need to ensure that their projects will provide electricity bill relief to qualified customers? If it's the latter, projects will require more insight into the IRA program to be able to

	know whether the enrollment and compliance criteria for customers will require more funding to implement. - If the state is going to implement a program to distribute bill credits to eligible customers, then we will need to know how project sponsors can prove to the IRS that we will be eligible for the 20% tax credit bonus. Right now, the IRA tax credit bonuses are not bankable. We don't know enough information about them for a bank to include them in our underwriting. - BlueWave's experience developing community solar projects across various state incentive programs has indicated that these details will determine whether the policy goals set out in the IRA will be met, or whether participation will be too onerous to implement.
Please provide any input in response to page 35, "Proposed successor program framework: energy storage and grid optimization to maximize value"	BlueWave remains concerned that projects seeking to participate in the program are those most exposed to increased costs and timing risks due to their involvement in ASO studies. These challenges coupled with the decrease in compensation may render most projects infeasible, or may render any solicitation non-competitive. We recommend providing additional compensation (perhaps through a reduced % evaluation of bid price) for projects that demonstrate ASO risk. Although we share concerns that ratepayers should not pay an undue share of grid upgrades, there is almost no way for projects to be sited in Maine in such a way that avoids these insurmountable timing and cost barriers. Some amount of compensation is needed to make any projects feasible under the current interconnection reality. The framework as proposed does not directly encourage solar + storage or standalone storage. Co-located storage specifically can help to promote smaller AC system sizes and minimize the impact of distributed generation on the grid, helping to avoid some of the challenges with ASO studies described above. BlueWave recommends providing a bid preference to projects that meet the requirements for solar collocated with storage under this program. Storage should not be required to participate in this program, due to the uneven treatment across municipal jurisdictions for storage siting and permitting and the likelihood that storage will not be well-suited to pair with all solar configurations. Paired storage resources can provide many benefits, but cannot provide a suite of benefits all at once. We suggest designing the program (and thus individual projects) intentionally in order to meet a specific policy goal of the stakeholder group and the Governor's Energy Office. Potential paired use cases include (but are not limited to): - Maximizing solar output. Paired storage would be designed to capture clipped or curtailed solar energy and discharge that energy when the solar is not producing.

	- Minimizing load ramp. Paired storage would be designed to charge either from solar or from the grid and discharge energy when solar production wanes to reduce the so-called "duck curve." - Maximizing grid benefits. Paired storage would be designed to charge from either solar or from the grid and would discharge energy when it is most beneficial, regardless of correlation with solar generation. Any of the above options could provide benefits to Maine state policy and ratepayers, and we look forward to continued discussion within the stakeholder group and with the Governor's Energy Office to determine a path forward. Once a specific use case is determined for storage resources that are participating in this program, the industry can provide input on best practices and market experience for appropriate compensation for those specific services. The use case chosen will impact the magnitude of the bid preference needed, as well as the magnitude of the benefits provided to ratepayers.
Please provide any input in response to page 36, "Proposed successor program framework: additional recommendations to ensure robust competition"	There are specific challenges with competitive procurements for DG-scale projects. DG doesn't have the same economies of scale found on utility-scale projects, and costs are quite high across the board. Economics at this scale don't work without the 20% ITC adder for Low Income Economic Benefit projects (see below). Due to these challenges and the relatively low compensation rate predicted for this program, BlueWave cautions that there will likely be significant project attrition even if the full capacity target is awarded each year. The program proposal should include a mechanism for unused capacity to roll over into future procurements so that Maine is able to reach its clean energy deployment goals. In addition, BlueWave recommends that the procurement be overseen by the Governor's Energy Office to ensure robust competition and swift progress towards Maine's clean energy deployment goals. The GEO may need to hire additional staff or use an outside servicer (such as EnelX) to administer the program, and we would be supportive of including funding for those resources within the enabling legislation.
Please provide any additional input to the Distributed Generation Stakeholder Group	The proposed framework is silent on whether or not dual-use projects can participate and/or receive adequate compensation for the benefits they provide. Dual-use has been recognized as a policy goal by the Agricultural Solar Stakeholder Group as well as various conservation-centered organizations like Maine Audubon and Maine Farmland Trust. Dual-use projects between 1-5MW represent the best opportunity to achieve economies of scale and implement responsible solutions for Maine farmers. This proposal represents an opportunity to encourage such projects, but should recognize the additional costs required to make them feasible. We recommend evaluating dual-use projects at 80% of the bid price, although a range of evaluation options may be required depending on the stringency of program criteria. This bid preference should be able to be stacked with others (i.e. sited in energy communities) to allow single

	projects to achieve multiple policy goals. Providing additional compensation takes into consideration additional costs incurred by dual-use projects, such as tracker systems, vetted farm plans, raised panels, and other incremental costs. As a starting point, we encourage the program to adopt the definitions of dual-use and co-location agreed upon by the Agricultural Solar Stakeholder Group. These definitions may be a starting point to define different ranges of bid evaluation options for different types of arrays that incur different levels of incremental costs.

Your name	Chris Byers
Your organization, if any (if commenting on your own behalf, please enter "self")	Owner, Branch Renewable Energy LLC, North Yarmouth, ME
Please provide any input in response to page 31, "Proposed successor program framework: competitive procurement"	• The first attempt at a small-scale procurement process a few years ago required documentation that was not a part of the regular suite of permits and approvals required to develop and build a DG solar project. Some of these documents included, for example, Clearance Letters from Maine Department of Inland Fisheries and Wildlife, or a letter from a licensed soil scientist attesting that the project was not on prime farmland. I worked as a consultant during this procurement process and helped many clients obtain these documents in order for their submittals to comply with the procurement requirements. Our experience in talking with state agencies asked to produce these letters as well as state certified soil scientists was that this created a cumbersome and confusing process that did not involve their input or collaboration in exactly how to meet these requests. The state agencies and soil scientists (there are so few licensed soil scientists in Maine as is and that number is only shrinking) are already overburdened by permit applications from solar projects, so why make their job harder when these custom letters are not even required approvals that a project needs in the first place to be built? These letters do not add value to the solar project assessment process based on what is already rigorously required by in the first place. If the procurement process is revived, we would request that the Clearance Letters from agencies and Soil Scientist letters be removed from the list of documents that are either required for submittal into the successor NEB procurement program. Let's keep it simple and not add more layers of approval on top of the existing rigorous permitting process that has worked well. • The study commissioned by the Nature Conservancy indicated that a large amount of MWs are available on disturbed land, but it does not take into account one of the most critical parts of a solar development process: the landowner. Every project has to find a willing landowner to lease or sell their land. While many variables were accounted for in the study that filtered results, the willingness of a landowner to sign a long-term agreement to use their land is not a small step. We recognize that this subjective factor is not something that can be plugged into a GIS analysis, but the amount of MW's that can be developed according to the study should be viewed with some level of healthy skepticism given this subjective reality of finding a landowner that wants to play ball. Other subjective factors such as a town that is considering a moratorium at any moment, or a substation that has 10 projects in the queue also limit development and the interest of a developer to consider a piece of land that would have been otherwise green-lit in the study that was commissioned. I simply ask that the commission not oversimplify the opportunity and acknowledge that development is a nuanced process that

	can't be judged by an objective GIS exercise. Proper siting is a must, but the low hanging fruit has already been signed up. • The program also suggests that applications for permits would be "complete", but it needs to be more clear if the intent is for projects to have their permit applications formally deemed complete for processing, or if the intent is for the applications to be simply filled out. This should be clarified. • For projects that have obtained approvals on all non-ministerial permits, would the commission consider favoring these projects and perhaps evaluating them at 95% of the bid price in order to incentivize more due diligence and limit risk of less than desired projects (ex. Poorly sited projects) being submitted into the program? • If bids are anticipated to be anywhere from \$0.05 - \$0.09/kWh, then this uncertainty of pricing outcomes will create risk for developers that anticipate a 2-3 year development process from project inception to final completion. If the commission would consider a minimum clearing price whereby the price in year 1 (ex \$0.08) would help developers understand if project economics can bear this lowest sale price of energy and also look ahead at future years to ensure their project can remain viable. Predictability will yield long term interest for developers and attract a competitive pool of better sited projects. • Similar to what Massachusetts implemented for their revised NEB program, the commission could then set up a block program where XX MW's at fixed clearing prices would be established in each subsequent block after year 1. • Massachusetts also implemented a milestone of MW's built in the new program to trigger a review of the overall program and determine if the program's outcome was meeting its goals; it might be helpful to also have this feature built into the NEB successor program in general regardless of a block program so that the results of the program stay in line with its intent and so that stakeholder have another opportunity to share from their perspectives what is and is not working in the program up to that point.
Please provide any input in response to page 32, "Proposed successor program framework: community access"	• By only allocating 30% to projects not allocated through the bid process, this may not be a portion large enough to meet the demand for businesses and homes that would prefer a subscription or PPA financial benefit from solar. Many businesses feel compelled more than ever to "do their part", and some are even mandated by their own internal goals to tie their own energy usage with actual, tangible projects. Bath Iron Works and Hannaford are just two examples of companies that wanted real projects to point to around Maine that generate renewable energy to cover their energy loads. Additionally, many end users have signed up on waiting lists to subscribe to a solar project, so if they don't end up getting

	that benefit due to programmatic constraints and a lack of project capacity, then this would create mistrust in community solar projects and make it harder to convince people that community solar is worth it and they can actually benefit. • Would the commission consider a different ratio such as 50% procurement, 50% community solar so a larger amount of end users can more directly connect to actual community solar projects? • We have run a financial model using \$0.06/kWh (estimated 20th percentile) as the compensation for the community access block, and the only way to make it work is by maximizing the IRA's full tax credit value which is anything but certain at this point given the lack of guidance out of the Federal government. If maximized tax credits were not realized, and the project could only take a 30% tax credit, then this would put the project's viability at risk. In short, while the commission seeks a low kWh compensation rate they may also simultaneously constrict development by not having a competitive pool of well-sited and developed projects to choose from. • We suggest increasing this target compensation to the 50th percentile to allow more projects to participate and not cut corners in the development process in order to barely make the financial model work.
Please provide any input in response to page 33, "Proposed successor program framework: siting preferences aligned with federal funding"	• The entire solar industry is waiting on official guidance from the Federal government, so it's difficult to indicate exactly how this preference would be realized by the commission in the NEB successor program. Developers will most certainly seek out this tax credit advantage if they can, and they would likely be able to offer a more competitive bid knowing that they would be able to have upside on the tax credit. • The commission should also consider the massive impact of PFAS affected sites across Maine and include those in sites that can site solar as a means for making use of otherwise unusable land. PFAS testing thresholds would have to be implemented given that probably most of the land around Maine has some level of PFAS impact, so this comment is meant to be directed at the more sever cases of PFAS contamination. • We take issue with siting projects in "low income or disadvantaged communities" as the location of the project often does not dictate who benefits. Given that projects overwhelmingly qualify for tax exempt status when paying personal property tax, host communities often don't see a direct financial benefit from a solar project sited in their town except for the landowner themselves who receive payments to lease /sell their land. • We suggest eliminating this pricing advantage in terms of siting projects in low income communities and instead look to how the project is subscribed. If XX% of the subscribers qualify for low to moderate income levels, then this is a real financial benefit to these people's bottom line.

	For this topic of helping Mainers that need financial assistance, we should only incentivize projects that actually and directly help low/moderate income households.
Please provide any input in response to page 34, "Proposed successor program framework: direct benefits to decrease energy burden aligned with federal funding"	• While the Federal guidelines are still pending, we support this idea in concept. If there are direct benefits that can be realized by Mainers who face financial burdens, then adding value to the project economics and to the end users is a win-win.
Please provide any input in response to page 35, "Proposed successor program framework: energy storage and grid optimization to maximize value"	• The topic of storage in the solar industry is akin to the wild west. There are not a plethora of multi-year state programs that Maine could emulate with a high degree of confidence, so this is a topic that should continue to be monitored and potentially added into the successor program at a later date. Per our suggestions above, perhaps in 2 years the program would undergo an evaluation and then the clear incentive guidelines and market metrics of a battery storage program could more confidently be implemented. • If the commission wants to push for energy storage, then it should be incentivized with a bid preference. • While it's helpful to reiterate the clear benefits of battery storage in the framework document, it would also be helpful if the commission could provide more clarity around the ideas they suggest implementing so that more detailed responses can be provided.
Please provide any input in response to page 36, "Proposed successor program framework: additional recommendations to ensure robust competition"	• No additional comments.
Please provide any additional input to the Distributed Generation Stakeholder Group	n/a

Your name	Michael Judge
Your organization, if any (if commenting on your own behalf, please enter "self")	Coalition for Community Solar Access
Please provide any input in response to page 31, "Proposed successor program framework: competitive procurement"	It is CCSA's preference that any successor program assign all capacity allocations primarily through a first come, first served application process with strong project maturity requirements to ensure that only viable projects are able to obtain a capacity allocation. Under such an approach, rates could be set through an initial procurement to ensure they are set competitively. Such a process provides more predictability and certainty to project developers and helps avoid or minimize the stop/start cycle that may result from infrequent procurements. There are many successful examples of programs around the country that have adopted such an approach that could serve as models for Maine. However, should a significant percentage of the total program capacity be awarded through a procurement process, we recommend that procurements be conducted at regular intervals (e.g., 2-4 times per year). We also recommend that great care be taken to ensure that there are appropriate project maturity requirements to establish the viability of projects that bid. For example, projects should have executed interconnection agreements, proof of site control, and all non-ministerial permits in hand. Two other issues are worth noting at this time. The first relates to issues experienced with the interconnection process in Maine in recent years, where the utilities have made significant changes to executed ISAs after they have been signed. This situation is virtually unique to Maine and creates a significant amount of financial and project viability uncertainty for project developers because it amounts to the utilities being able to change signed contract terms with relative impunity. It is imperative for the state of Maine to ensure that going forward, ISAs are only executed after the utility has completed all necessary work to allow a facility to proceed. If the current state of affairs is allowed to persist and the utilities continue to routinely change costs, timelines, and other parameters for interconnecting a facility after an ISA has been signed, then an executed ISA is likely not a sufficient demonstration of project maturity and viability and it should be reconsidered as a requirement to participate in the procurement. The second issue relates to the potential misalignment of the interconnection queue with projects selected through the procurement process. For example, if a project is selected via the procurement process, but has another project that did not participate or was not selected in front of it in the interconnection queue, it is possible that the selected project may have difficulty interconnecting in a timely manner if the project in front of it does not move forward quickly but maintains its

	position in the queue. This may be able to be addressed through interconnection queue management procedures established by the utilities and the MPUC, but we raise it here as a potential challenge.
Please provide any input in response to page 32, "Proposed successor program framework: community access"	Because the competitive procurement results will dictate the level of compensation provided to other projects, it is crucial to ensure that they produce results that will drive development for projects that are not part of that process. As it currently stands, the proposed successor program framework is very light on details as to what types of projects will be eligible for this portion of the program. However, the reference to policy priority projects implies that this capacity will be available to projects that may not be able to as easily compete with projects in the procurement. If this is the case, CCSA notes that compensation set at the capacity weighted 20th percentile of selected bids is likely far too low. As structured, the procurement process is likely to yield responses from large (i.e., 5 MW) distributed solar projects sited on undeveloped land. That is because these projects are typically the most economic types of projects to develop and will be most competitive in the procurement process. Accordingly, providing projects in the "community access" bucket with compensation that is set at the capacity weighted 20th percentile of selected bids is almost certain to be insufficient for a significant number of projects to apply via the first-come, first-served approach for this portion of the program. This is because, when trying to promote projects that advance public policy priorities, project development costs increase. Public projects and projects sited on previously developed or blighted lands (e.g., landfills, brownfields, buildings, paved surfaces, etc.) typically cost more to develop. So, to assign them a value that is less than 80% of the projects selected through the procurement process is likely to produce an outcome that runs counter to Maine's efforts to get such projects built. Additionally, we note that there may need to be parameters established to ensure that projects selected through the procurement process cannot simply withdraw and then apply via the first-come, first-served process in order to obtain a higher compensation rate. For example, a procurement project in the 10th percentile of selected bid prices withdrawing and then reapplying to receive a compensation rate in the 20th percentile. CCSA argues that more clarity is needed around the types of projects that Maine wishes to prioritize so that the compensation value for such projects can be better calibrated. This would best be done by the state articulating its policy priorities more clearly and having further public process for the solar industry and other stakeholders to weigh in regarding where compensation levels need to be set to achieve Maine's stated goals.
Please provide any input in response to page 33, "Proposed successor program framework: siting	CCSA generally supports the proposed approach of preferentially weighting projects that qualify for certain location-based ITC adders under the Inflation Reduction Act. However, a better question might be whether the state of Maine wants to prioritize projects sited in these geographic areas? We note that such projects already have a financial advantage via

preferences aligned with federal funding"	the additional 10% ITC that they will receive. Whether weighting them at 95% of the bid price is sufficient or necessary though is too difficult to say at this time though as guidance from US Treasury on precisely how the ITC adders will be implemented has yet to be released. Such guidance must be issued by no later than mid-February and we recommend that in the interim the proposed framework avoid such specifics and instead simply note that projects that qualify for certain ITC adders will be scored higher in any competitive bidding process that is part of the successor program. Details on exactly how much weight is given to these types of projects can then be specified at a later date, ideally through a rulemaking/regulatory process. Additionally, we encourage the state to determine if it wishes to prioritize other project types through a similar weighting scheme. For example, the IRA definition of a brownfield may not cover all lands that the state considers to be brownfields or otherwise more suitable for solar (e.g., landfills, previously developed lands, etc.). It may be worth considering whether other geographic areas that do not receive an adder under the IRA should receive preferential weight through a procurement process.
Please provide any input in response to page 34, "Proposed successor program framework: direct benefits to decrease energy burden aligned with federal funding"	While CCSA is supportive of providing bill credits to low- and moderate-income customers via community solar projects, it is unclear how this draft proposal would work in practice. As we understand it, the ability for project owners to provide bill credits directly to customers will be removed under the successor framework. That notwithstanding, the proposal states "net revenue from project contracts will be designated to provide electricity bill relief to qualified customers through a credit that complies with forthcoming guidance established by the U.S. Department of the Treasury to establish qualification for this tax credit." The mechanics of this are very unclear though as it is not certain what is meant by "net revenue." If this refers to the net revenue earned by the utilities from reselling electricity, capacity, and RECs, then it is entirely possible that such net revenue is never generated, as this is entirely dependent on the compensation levels that projects are awarded and the market value of electricity, capacity, and RECs. This is not to say that there are not net benefits to Maine ratepayers at large from building distributed solar projects though. The consultants retained by the DG Stakeholder Group have clearly demonstrated that benefits will significantly outweigh costs with the analysis that they have provided to the DG Stakeholder Group. However, not all of these will be directly measurable in a way that would permit them to be allocated to low-income customers in the manner that seems to be contemplated by the successor program proposal. This means that the proposed framework is likely incapable of delivering benefits directly to LMI customers in a manner that would permit projects to meet the eligibility requirements for the 20% ITC adders for projects serving LMI communities.

	If Maine were to permit the direct allocation of bill credits from project owners to LMI and other customers as is permitted via the NEB program today, this issue could be solved as the Inflation Reduction Act clearly contemplates this as a viable mechanism to deliver financial benefits to LMI communities. This would (1) create direct benefits for LMI communities through a reduction in their electricity expenses and (2) would allow projects to secure these valuable tax credit adders, which in turn may help reduce the level of support that Maine ratepayers would need to provide such projects to be developed otherwise. We urge a reconsideration of this part of the proposed framework to permit the direct allocation of credits to off-takers, which is proven to be an effective tool in delivering benefits to customers across dozens of jurisdictions in the US.
Please provide any input in response to page 35, "Proposed successor program framework: energy storage and grid optimization to maximize value"	CCSA is extremely supportive of including incentives for energy storage in the successor program. As has been clearly demonstrated by the consultants, the inclusion of energy storage dramatically improves the benefit-cost ratio of the program as a whole and maximizes efficiency and resiliency benefits. However, the proposed energy storage provisions include few details, which makes it difficult to provide a detailed comment on how effective they may or may not ultimately prove to be. Storage can provide a wide range of benefits that solar cannot provide on its own, allowing for greater dispatchability of solar resources, improved power quality, voltage control, and reliability. As solar penetration increases, it is critical to deploy it in tandem with storage in order to integrate more solar onto the grid. In developing an incentive framework for solar paired with storage, the key question for Maine policymakers is what Maine wants the storage resources to do. If the goal is to maximize solar generation delivered to the grid during peak hours by shifting output throughout the day, establishing a simplified dispatch schedule that is designed to align with peak periods would likely accomplish that goal. If paired storage facilities can simply receive their necessary revenue requirement to perform such a function, the program can likely achieve this outcome easily. In such a scenario, the storage could be fully compensated via a retail tariff with specific operating parameters. Maine could also let storage facility operators obtain their revenues primarily via the wholesale markets, however, much more work will likely need to be done on the regulatory front to achieve the same results. For example, it may be necessary to untangle rules regarding ownership rights of the energy and capacity for the solar that the facilities are paired with. This is because utilities would have rights to the energy and capacity of the solar facility, but not necessarily the storage resource with which it is paired. This makes it impossible for the storage owner to enroll the

	storage resource in the wholesale markets in many cases, necessitating the state's involvement in a process to clarify who owns what. Additionally, because there is a significant amount of merchant risk associated with earning sufficient revenue to finance the storage facility using wholesale market revenues, it may be necessary for the state to provide some financial backstop to help such facilities secure financing. This would not be the case if a retail level tariff was structured in such a manner to fully cover the financing costs of the storage facility, as it would be easily financeable in such a scenario. At this time, more details are needed before CCSA can fully comment on the structure of a storage incentive in a future program. We recommend that Maine policymakers put forward more details on the state's policy priorities so we can provide more substantive feedback. This could be done through a further iteration of this proposal put forward to the DG Stakeholder Group and/or a subsequent legislative/regulatory process that follows high level recommendations on program design put forward to the legislature.
Please provide any input in response to page 36, "Proposed successor program framework: additional recommendations to ensure robust competition"	CCSA has no objection to recommending that projects sized between one and two MW that are not co-located with load should be directed to the successor program.
Please provide any additional input to the Distributed Generation Stakeholder Group	Off-takers As noted above, CCSA is strongly opposed to the elimination of the ability to provide credits directly to off-takers, an approach which is inconsistent with the legislative intent to develop a successor program that "has identified residential, commercial and institutional customers." CCSA understands concerns about the assignment of bill credits in the current program and the cost impacts that may have resulted from this policy, however, as has been demonstrated by the consultants throughout this process, the value of bill credits under the successor program and its overall costs will both be dramatically lower than the current NEB program. In a successor program that is expected to have a BCR of between 1.5 and 3.0, CCSA argues that a greater concern should be the loss of the equity benefits that the assignment of bill credits provides. Allowing bill credits to be provided directly to customers has demonstrated benefits for customers that sign up with project owners to receive them. Removing the ability for customers that cannot install solar to realize direct benefits through the assignment of bill credits represents a serious equity concern. This is because customers that generally have greater means and own their own homes will still be able to install solar on

their own property and receive direct benefits. However, renters and other customers that may not be able to install solar on their own property will have no means by which to receive direct benefits. For these reasons, Maine should reconsider eliminating the ability to offer bill credits to customers.

Compensation (REC vs. Energy/Capacity)

While CCSA supports bundling energy, capacity, and REC values under a single compensation framework, it may be important to delineate the different values assigned to these distinct attributes, particularly the RECs. This is commonly done in other bundled long-term contracts and could be easily incorporated into the bidding process of a procurement style program or the administratively set price in a first-come, first-served program. To the extent that the ability to assign credits to third-party off-takers is retained in some manner, it will be important to delineate between RECs and energy/capacity value as the former would presumably be retained by the utility to be used for RPS compliance or resold to offset program costs and the latter would be assigned to customer accounts in the form of a bill credit. Further consideration should be given to delineating what portion of the total compensation each value stream comprises.

Size of Program

CCSA recognizes that the size of the successor program cannot be known with precise certainty at this time and that the legislature has limited the scope of the DG Stakeholder Group's work by directing the group to include a recommendation on the optimum total amount of DG for the program using 7% of total load based on operational capacity. However, in making recommendations to the legislature on the scale of the successor program, CCSA urges that the group recommend a more precise program capacity target as expressed in MW. Specifically, we recommend a target of 750 MW, which will permit approximately 150 MW of development to occur annually.

Interconnection and Grid Planning

CCSA would be remiss if we did not mention that the ability for any successor program to achieve targets for distributed solar and storage deployment is wholly dependent on the ability to interconnect facilities to the electric grid. As can be seen by the current state of affairs in Maine, the distribution system is woefully unprepared to integrate the current pipeline of distributed solar facilities. As such, it is imperative that the utilities and Maine policymakers and regulators work expeditiously to adopt new proactive planning processes so that the critically important work of upgrading Maine's distribution and transmission infrastructure can commence.

We are aware that the MPUC has commenced a grid planning proceeding (Docket No. 2022-00322), however, without immediate action, Maine runs the risk of critically delaying its efforts in not just the deployment of distributed solar and storage resources, but also beneficial electrification measures and larger transmission connected clean energy resources. It is CCSA's view that the most important action that Maine can take at this time is working with the utilities and other stakeholders to prepare its electric grid for the changes it is about to experience. Without effective integrated distribution planning and robust interconnection policies, Maine's entire decarbonization strategy is unlikely to proceed on the schedule that it needs for the state to achieve the ambitious but necessary requirements that it has set forth.

Program Administration

Lastly, CCSA advocates that whatever enabling legislation is passed to authorize a successor program not be overly prescriptive or limiting. The legislation should define policy objectives and program structure broadly and should delegate specific policymaking and program design authority to the Governor's Energy Office. For example, spelling out the precise mechanics of an RFP design in legislation may create unforeseen and problematic outcomes. Allowing an administrative agency to fine tune policy and program design details will allow for a robust public process to occur and will likely result in the best outcome for the state of Maine. While the MPUC has done some very good work in the area of DG solar policy, they are not a policymaking body and are not as well suited to design a program like this given their quasi-judicial adjudicatory role. To date, the majority of the most successful DG solar programs in the US have been primarily designed by state energy policy offices acting under broad legislative authority (e.g., MA, NY, IL, CA, etc.), with state utility commissions in each state responsible for reviewing the rules for the interaction between the utilities and program participants and ensuring that established rates and cost impacts are just and reasonable. We urge Maine to look to these states as examples and delegate specific rulemaking authority to the GEO, with final tariff/contract approval maintained by the MPUC.

Your name	Kenneth A. Colburn
Your organization, if any (if commenting on your own behalf, please enter "self")	Self
Please provide any input in response to page 31, "Proposed successor program framework: competitive procurement"	Please see my comments under Item 9. The work of the DGSG certainly represents laudable progress within Maine's existing utility/procurement framework. However, this is an opportunity to alter that framework in ways that better address the rapidly transforming power sector. In particular, the first two bulleted goals on page 30 are not addressed literally; they are constrained by adherence to the existing utility/procurement framework. In addition, the underlying benefit-cost analysis utilized is incomplete and inadequate. Please see related comments under Item 9.
Please provide any input in response to page 32, "Proposed successor program framework: community access"	I encourage set-asides and/or other measures/policies that encourage project development that retains greater benefits, including economic/investment benefits, in the State of Maine rather than providing them elsewhere. A set-aside for state, municipal, educational, or other such projects would seem to assist in creating this outcome.
Please provide any input in response to page 33, "Proposed successor program framework: siting preferences aligned with federal funding"	This element of the proposed framework seems appropriate.
Please provide any input in response to page 34, "Proposed successor program framework: direct benefits to decrease energy burden aligned with federal funding"	This element of the proposed framework seems appropriate.
Please provide any input in response to page 35, "Proposed successor program framework: energy storage and grid optimization to maximize value"	I applaud the DGSG's work in this direction, but urge that it go further in terms of explicitly including residential scale storage and enabling the aggregation thereof. The grid of our future will be balanced by managing demand rather than supply. Storage, electrification, and load flexibility will be vital to shaping load. Genuine grid optimization will hinge on a high-DER grid future and an open-access distribution network, as further described/recommended in Item 9 below.
Please provide any input in response to page 36, "Proposed	Pilot programs can be pursued for Item 9 below. Dramatic wholesale changes needn't be instituted all at once.

successor program framework: additional recommendations to ensure robust competition"	
Please provide any additional input to the Distributed Generation Stakeholder Group	1. The benefit-cost analysis (BCA) conducted by the DGSG is dated and excludes numerous easily quantified and appropriately included non-energy benefits. In particular, heath benefits can now be readily included as a result of US EPA's "Benefits-per-KWh" efforts (https://www.epa.gov/statelocalenergy/estimating-health-benefits-kilowatt-hour-energy-efficiency-and-renewable-energy). Synapse contributed greatly to this work at EPA, so is readily able to incorporate in this BCA for Maine -- unless inappropriately instructed NOT to do so. Another excellent source of information on this issue is RAP's "Layer Cake" paper (https://www.raponline.org/knowledge-center/recognizing-the-full-value-of-energy-efficiency/). 2. The efforts of the DGSG are laudable, but they start from a point that constrains distributed generation (DG) now and in the future. That is, the "procurement" underpinnings of the effort, as opposed to pursuing "market" or "open-access" underpinnings. Procurement necessarily maintains control/primacy by government operation (not just appropriate oversight) and utility implementation. The power industry is vital to society's economic, climate, and equity goals. It is rapidly evolving, and how it is enabled/encouraged to do so will either assist or hinder the achievement of those goals. The mandate of the DGSG hardly addresses the entirety of this evolution, but its conclusions will help perpetuate the status quo or help encourage its evolution. I would strongly recommend reviewing the testimony of Lorenzo Kristov in Minnesota PUC Docket E002/GR-21-630 (https://efiling.web.commerce.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={7056A383-0000-CE18-99DA-2C52E2B84E24}&documentTitle=202210-189513-03). Kristov's testimony details the evolution of a "high-DER future" grid and the "open access distribution network" it requires. I believe the future he envisions characterizes Maine as well as it does Minnesota: "A crucial question for policy and regulation then is whether to embrace the high-DER future and maximize its benefits, or try to suppress DER growth to maintain the legacy monopoly structure and its centralized operation, planning, investment and ownership. My thesis is that a high-DER future is essential for achieving a clean energy transition, with greater resilience to extreme disruptions, broadly inclusive energy justice, and affordable, just and reasonable rates. Adopting policies to discourage DER growth, or failing to act effectively to maximize the total benefits of DERs, will go against customer desires and the cost-effectiveness trends of DERs, will create incentives for financially capable customers to defect from the grid, and ultimately will compromise the state's goals for decarbonization, resilience

	and energy justice and the Commission’s mandates to ensure just and reasonable electric services and rates." (page 9)

Your name	Amanda Dwelley
Your organization, if any (if commenting on your own behalf, please enter "self")	self
Please provide any input in response to page 31, "Proposed successor program framework: competitive procurement"	n/a
Please provide any input in response to page 32, "Proposed successor program framework: community access"	n/a
Please provide any input in response to page 33, "Proposed successor program framework: siting preferences aligned with federal funding"	Regarding brownfield development: I realize that federal guidelines may prioritize brownfields, and Mainers wish to protect timber and agricultural land. I also wish to protect/preserve undeveloped land and prioritize brownfields. I encourage the DG group and regulators to consider carbon impacts of construction techniques and materials that may be needed to mount solar on brownfields. For example the Thomaston municipal solar project on former wastewater treatment land uses large concrete blocks for ballast, because it was not possible to dig/drill for a metal frame. If/where ballast mounting necessary, I encourage DG decision-makers/regulators to encourage or require less carbon-intensive materials (e.g., stone gabions - baskets of rocks). https://cleanpower.org/wp-content/uploads/2022/08/ACP_FactSheet_Brownfields_220830.pdf
Please provide any input in response to page 34, "Proposed successor program framework: direct benefits to decrease energy burden aligned with federal funding"	I agree with the general approach on slide 34 and the equity access principles on slide 24, and appreciate the DG Stakeholder Group's consultation of the MCC Equity Subcommittee, NYSERDA, and incorporation of public comments (e.g., Maine CAN, Ampion, Dr. Sharon Klein). Stakeholders seem to recognize that even with the best community outreach, technical assistance and financial incentives for (a) disadvantaged communities, and (b) low-income households and renters, they will likely not achieve DG benefits at the same pace or level as non-low-income people or communities. Combine this with LMI households and communities not weatherizing/insulating homes/businesses, enrolling in TOU rates or installing grid-responsive technologies at the same pace, and we have a recipe for low-income people and communities accessing and benefiting less from Maine's energy transition.

	In the full report, I would like to see specifics of how the PUC, other agencies (OPA, GEO?) and/or utilities (CMP, Versant) plan to incorporate equity and deliver equitable benefits to all Maine people, regardless of whether they adopt or access DG opportunities. For example, a plan for outreach, assistance, participation, benefits and evaluation for LMI customers and disadvantaged communities in: (a) DG siting and permitting (b) DG education, enrollment, requirements/incentives to enroll LMI households (e.g., community solar) (c) DG and TOU/time-varying rate design for LMI households - including options, impacts and a research/evaluation plan Our DG investments plus grid modernization will allow Maine to test/deploy TOU/time-varying rates or technology-dependent rates (EVs, heat pumps, etc.), providing an opportunities for customers to save money from load shifting. I am curious how LMI customers and small businesses are being considered and involved in rate design. I'm not quite clear whose responsibility this is - PUC? Other states are considering things like income-based fixed charges (e.g., lower fixed rate for LMI) and evaluating/monitoring participation and impacts among LMI customers. Personally I'm open to non-revenue-neutral charges or rates to perhaps allow some portion of DG and/or TOU charges to offset bills for LMI customers with lower access/participation and reduce energy burden. With respect to stakeholder process, I'm curious if the PUC has looked into other state models for community involved and/or equity in planning, and if they might consider a Just Transition or Equity Working Group? Washington State is an interesting model - per the Clean Energy Transformation Act, utilities are required to form Equity Advisory Groups and incorporate equity into their Clean Energy Implementation Plans. I am inspired by what the Washington utilities have done - see for example: Puget Sound Energy - https://www.cleanenergyplan.pse.com/ PacifiCorp - https://www.pacificorp.com/energy/washington-clean-energy-transformation-act-equity.html I believe there are parallel state processes to streamline and improve access to public proceedings and hearings (PUC, DEP), including intervenor funding. I believe that improving access and benefits among LMI, vulnerable and disadvantaged communities will be easier with their input in program design and implementation from the outset, and support any efforts to remove or reduce barriers to public participation.
Please provide any input in response to page 35, "Proposed successor program framework: energy storage and grid	n/a

optimization to maximize value"	
Please provide any input in response to page 36, "Proposed successor program framework: additional recommendations to ensure robust competition"	n/a
Please provide any additional input to the Distributed Generation Stakeholder Group	Thank you for taking this, convening a diverse group of stakeholders, and hosting a range of technical and equity discussions.

Your name	Peter Evans
Your organization, if any (if commenting on your own behalf, please enter "self")	self (my company is New Power Technologies, Inc., but these comments are my own)
Please provide any input in response to page 31, "Proposed successor program framework: competitive procurement"	Is the proposal that all of this capacity would be procured by the T&D utilities for the benefit of all of their customers, with no mechanism at all of allocation to individual or groups of customers through bill credits such as through community solar? If so, that should be more more clear to decisionmakers as it is such a departure from the present program. Maine Won't Wait speaks of transforming Maine's electric power sector through beneficial electrification and demand management. To accomplish this will require engagement of electricity end-use customers that goes well beyond what we have apparently achieved through retail competition and community solar. Perhaps a portion of the successor program should remain offtaker-centric but seek to overcome the shortcomings of our customer engagement experience so far.
Please provide any input in response to page 32, "Proposed successor program framework: community access"	n/a
Please provide any input in response to page 33, "Proposed successor program framework: siting preferences aligned with federal funding"	I think the successor program should explicitly prioritize Maine values and priorities. Maine Won't Wait (paraphrasing) talks about preserving natural and working lands from development and identifies siting incentives that minimize impacts to communities, fishing, and the environment, and avoid significant losses of key farmlands. The report out from the Land Use work session on pp 25 and 26 of the framework seem to prioritize rooftops, brownfield, and disturbed sites. In my view, projects located in developed areas and load centers are more likely to provide grid benefits. The IRA tax credits will make projects having federally-prioritized siting attributes more competitive in any case. Maine must promote Maine's priorities.
Please provide any input in response to page 34, "Proposed successor program framework: direct benefits to decrease energy burden aligned with federal funding"	As noted in the stakeholder discussion, we don't yet know what a direct benefit to LMI entails under the IRA. I think one of the great things about community solar is how it potentially expands access to direct participation in renewable energy for those who can't or don't want to build it on their own roof.
Please provide any input in response to page 35, "Proposed	I could not agree more.

successor program framework: energy storage and grid optimization to maximize value"	Regarding storage, the framework at this time should be inclusive of multiple technologies and business models. Storage might be co-located with PV, or it could be distributed and aggregated. It could be operated by a third party as a virtual power plant. Maine Won't Wait speaks of some of these models. Commissioner Bartlett rightly probed the Stakeholder Group on this point. Regarding siting for grid benefits, the class of projects targeted by this program, 1-5 MW, are likely to be connected at distribution voltage and have the greatest potential to provide these benefits. However, studies show this is very location specific; in fact, it may be at odds with idea of competitive procurement on a simple price per kWh basis -- there might be only one project in the right location with the right operating characteristics to defer a substation upgrade. T&D utilities could publish their grid needs coming out of local planning, along the lines of the California Distribution Investment Deferral Framework, and developers could complete to provide local grid relief as a compensated grid service. The successor program should enable such outcomes.
Please provide any input in response to page 36, "Proposed successor program framework: additional recommendations to ensure robust competition"	It could be that < 2 MW rooftop and parking lot PV projects with storage provide an attractive stack of benefits through renewable energy, locational and temporal capacity, load relief, IRA tax credits, minimal or no impacts on natural land and farmland. Yes these projects are more expensive, but if these benefits can be monetized they might still be cost-effective. The successor program should at least facilitate this possibility.
Please provide any additional input to the Distributed Generation Stakeholder Group	Thank you for the opportunity to provide input.

Your name	Geoff Sparrow
Your organization, if any (if commenting on your own behalf, please enter "self")	Green Lantern Development
Please provide any input in response to page 31, "Proposed successor program framework: competitive procurement"	A competitive procurement is appropriate. A 'Clearing Price' should be used to set the rate for all projects that submit bids to ensure fairness and competitiveness across all projects. Projects should be awarded regardless of the clearing price. It is Green Lantern Development's position that the \$.05-\$.09 price range is low and does not account for interconnection costs related to Transmission and Distribution upgrades, nor does it account for the current volatility and challenges in the EPC Markets and Supply Chain.
Please provide any input in response to page 32, "Proposed successor program framework: community access"	This proposed design is flawed. An appropriate and fair method is to do a Clearing Price for all bids. The remaining 30% of capacity should be available to 'walk up' projects at 90% of the Clearing Price. The Second Bullet is not appropriate. The remaining 30% capacity should not be set aside for a select group. It should be allocated to mature projects (all non-ministerial permits, interconnection approval, site control, etc.) and ready to be constructed.
Please provide any input in response to page 33, "Proposed successor program framework: siting preferences aligned with federal funding"	If there is a carveout, it should be specific to brownfield, landfill, and roof-mounted sites only. There are few if any federally designated energy communities in Maine. Brownfields, landfills, and rooftops cost more to build on and are better siting locations, and it makes sense to promote them. Projects located in Energy Communities are already receiving an ITC benefit, so there is no need to provide an additional advantage to those projects.
Please provide any input in response to page 34, "Proposed successor program framework: direct benefits to decrease energy burden aligned with federal funding"	This approach works as long as the PUC or Utilities are required to provide written guarantees to participating projects that all of the energy from the project is being used to offset LMI accounts. This will be a requirement from project financiers and accountants. The PUC/State will need to compile some type of LMI Database.
Please provide any input in response to page 35, "Proposed successor program framework: energy storage and grid optimization to maximize value"	There should be a Standalone Energy Storage option in addition to Solar + Storage. Battery Storage is often needed in locations where large solar developments are not possible (such as cities and high-density coastal areas). Will need to determine if storage gets a fixed adder or if it is competitively bid with a clearing price.
Please provide any input in response to page 36, "Proposed successor program	This new program should only apply to projects between 2MW and 5 MW. Otherwise, this may create an undue burden for projects currently under development.

framework: additional recommendations to ensure robust competition"	
Please provide any additional input to the Distributed Generation Stakeholder Group	Thank you all for your hard work!

Your name	Shelley Megquier
Your organization, if any (if commenting on your own behalf, please enter "self")	Maine Farmland Trust
Please provide any input in response to page 31, "Proposed successor program framework: competitive procurement"	We would like the addition of incentives for siting considerations and dual-use. To protect valuable natural resources in the state, we suggest evaluating the project's bid price at a reduced percentage if certain criteria are met in terms of siting (e.g. on agricultural land with documented PFAS contamination, successfully avoiding important agricultural soils). Dual-use projects that integrate solar with agricultural production should also be evaluated at a reduced percentage. A common definition of what dual-use entails should be established, to ensure that only projects that are truly dual-use benefit from the incentive.
Please provide any input in response to page 32, "Proposed successor program framework: community access"	n/a
Please provide any input in response to page 33, "Proposed successor program framework: siting preferences aligned with federal funding"	We would like to see the siting preferences expanded beyond alignment with federal funding to include severely PFAS-contaminated land (as documented by DACF) and avoidance of important agricultural resources as well as a preferential benefit for dual-use projects.
Please provide any input in response to page 34, "Proposed successor program framework: direct benefits to decrease energy burden aligned with federal funding"	n/a
Please provide any input in response to page 35, "Proposed successor program framework: energy storage and grid optimization to maximize value"	n/a
Please provide any input in response to page 36, "Proposed successor program	n/a

framework: additional recommendations to ensure robust competition"	
Please provide any additional input to the Distributed Generation Stakeholder Group	Thank you for the opportunity to provide input.

Your name	Neal Goldberg
Your organization, if any (if commenting on your own behalf, please enter "self")	Maine Municipal Association
Please provide any input in response to page 31, "Proposed successor program framework: competitive procurement"	Interconnection fees should be regulated by the PUC. Wait times and fees for interconnections for public projects should be capped, at least for a limited period of time.
Please provide any input in response to page 32, "Proposed successor program framework: community access"	Setting-aside exclusive capacity for public projects is advised. Ideally a minimum amount, maybe 10%, would be reserved for municipal projects. Since there are already development incentives in "energy communities" and "low income and disadvantaged communities," a smaller subsection of exclusive capacity could be reserved for community projects that do not meet the eligibility of IRA adders. For instance, communities that experienced the loss of a major employer or decline in heritage industry could be given priority under Maine's program, even though they are not classified as an energy or low income/disadvantaged community.
Please provide any input in response to page 33, "Proposed successor program framework: siting preferences aligned with federal funding"	While there is great benefit for aligning Maine's successor program with the federal designations forthcoming from the IRA, additional inspection of local needs should be undertaken. Broadly defined designations of "energy communities" and "low income or disadvantaged communities" will include municipalities that have significant development priorities, that may not immediately include renewable energy. These same communities are frequently defined by limited housing options or shrinking labor forces. There is municipal concern that incentivizing solar development in areas of a community that could otherwise yield a higher use exacerbate existing local issues like housing, employment, or tax base. The successor plan should also consider reimbursing municipalities for lost property tax revenue as a result of any solar development that is approved by state preemption, or permit-by-rule. While solar arrays are taxable, municipalities only receive partial payment as the state gives an exemption to renewable energy equipment. When this concern is raised by municipalities, opponents argue that development is always beneficial because it brings net increases in valuation. This argument ignores the desires of local communities that may prefer housing or commercial development over solar.
Please provide any input in response to page 34, "Proposed successor program framework: direct benefits to decrease	n/a

energy burden aligned with federal funding"	
Please provide any input in response to page 35, "Proposed successor program framework: energy storage and grid optimization to maximize value"	The advantages of energy storage system in tandem with distributed generation, either through co-location or intentional grid-planning, are desirable in the successor program. The benefits to ratepayers and load management are important considerations. However, the success program should not provide economic incentives to an industry that is flush with private capital and already on-pace to reap profits in the near term. More pointedly, the property tax, sales tax, and income tax exemptions that are frequently provided to burgeoning industries are not needed to encourage battery storage systems. Further, any program that depends on state or local subsidies is limiting its lifetime impact as eventually the exemptions and reimbursements will expire. Instead, a successor program that incorporates battery storage should be economically sufficient without relaying on municipal or state coffers.
Please provide any input in response to page 36, "Proposed successor program framework: additional recommendations to ensure robust competition"	n/a
Please provide any additional input to the Distributed Generation Stakeholder Group	Please reach out to Rebecca Lambert, rlambert@memun.org, for follow-up questions.

Your name	Rebecca Schultz
Your organization, if any (if commenting on your own behalf, please enter "self")	Natural Resources Council of Maine (NRCM)
Please provide any input in response to page 31, "Proposed successor program framework: competitive procurement"	n/a
Please provide any input in response to page 32, "Proposed successor program framework: community access"	Stakeholder discussions have suggested that the 30% walk-up reserve is intended to support participation by entities such as non-profits, schools, and municipalities for projects that may be community owned outright or have multiple off-takers. The program proposal should be explicit about equity and access being foundational goals for this component of the program and who the intended participants are. It should also consider whether the 20th percentile of selected bids offers a price point at which these kinds of projects are likely to be stimulated, and discuss ways of determining and/or adjusting the appropriate compensation level. The proposal should also include robust discussion of creating the institutional resources needed to support project development.
Please provide any input in response to page 33, "Proposed successor program framework: siting preferences aligned with federal funding"	Merely siting energy infrastructure in low income and disadvantaged communities will not necessarily confer local financial or renewable energy system benefits. A community benefits package developed between the municipality and the developer, for example, could provide meaningful benefits, but there may also be concerns around the timing of negotiating such an agreement vs. submitting a bid proposal that would make it infeasible for the PUC to take community agreements into consideration at the time of bid selection. Without being overly prescriptive or overly deferential to the pending federal guidance, GEO's program proposal could identify ways to make this provision workable and reflective of laws, conditions, and communities in Maine.
Please provide any input in response to page 34, "Proposed successor program framework: direct benefits to decrease energy burden aligned with federal funding"	Aligning with the federal incentives under the Inflation Reduction Act (IRA) is a powerful way to maximize these opportunities for Maine renewable energy development, and NRCM commends the Governor's Energy Office for putting IRA benefits front and center as a strategy to reduce overall program costs for Maine ratepayers. GEO proposes that projects developed through the successor program would be eligible as "low-income economic benefit projects" for an additional 20% investment tax credit under the IRA with net revenue directly credited to low-income ratepayers. This provision is apparently predicated on Maine's Public Utilities Commission overseeing compliance

	with the forthcoming rules by allocating project benefits to low-income ratepayers through bill credits. This approach would have the advantage of guaranteeing eligibility to all projects for the additional 20% investment tax credit without putting the hefty administrative onus on developers to identify and conscript low-income off-takers. Another substantial advantage would be that the financial credit would be applied equitably across all low-income ratepayers, instead of only those ratepayers who have the time and wherewithal to navigate community solar offerings to sign up for 15% savings under the current program. Tapping renewable energy revenue to offset energy burdened households directly could set a strong precedent for the kinds of embedded distributional mechanisms we will need to protect Maine's most vulnerable households from high electricity prices as we decarbonize the power grid. NRCM recommends that the proposal include greater detail on how this provision would work in practice, even if that detail is fleshed out in an discussion of potential options. In the Synapse-Sustainable Energy Association analysis, the wholesale power purchase agreement (PPA) outperformed other policy options modeled in part due to the fact that the benefits of renewable energy could more directly be applied to reduce rates, including particularly the REC revenue stream. The Commission would presumably be charged with determining project net revenue, but also potentially generating a portion of that revenue by monetizing the RECs. These are the kinds of details that would help legislators and interested parties better understand what is being proposed, related risks and complexity.
Please provide any input in response to page 35, "Proposed successor program framework: energy storage and grid optimization to maximize value"	n/a
Please provide any input in response to page 36, "Proposed successor program framework: additional recommendations to ensure robust competition"	n/a
Please provide any additional input to the	NRCM would encourage GEO to include a robust discussion of how the Maine cost-effectiveness test developed by Synapse could be incorporated in regulatory work of the Commission.

Your name	Jessica Robertson
Your organization, if any (if commenting on your own behalf, please enter "self")	New Leaf Energy
Please provide any input in response to page 31, "Proposed successor program framework: competitive procurement"	We have expressed at several points throughout the DG 2.0 Stakeholder process that while procurements are a useful mechanism to ensure that rates are set competitively, requiring participation in a competitive procurement in order to access a program can have a number of unwanted consequences. For example: smaller, Maine-based companies may be less equipped to participate in a bidding process; holding procurements only once a year may cause strain on permitting agencies if many projects are trying to reach the same deadlines; projects that are not selected in the competitive process may maintain their interconnection queue position while they wait for a subsequent procurement, potentially blocking selected projects from moving forward. For these reasons we believe that it is important to reserve some program capacity for a first come, first served application process. For both the competitive solicitation and any walk-up portion of the program, we strongly recommend high project maturity requirements. Specifically, the proposal lists completed applications for required non-ministerial permits; we recommend completed permit approvals, not just applications. For interconnection maturity, we agree with the comments filed by CCSA that under normal circumstances an executed ISA would be a sufficient standard, but that recent history in Maine has shown that that is not reliably the final word on a project's viability. Instead, we recommend that projects demonstrate that their proposed plan application has been approved by the Reliability Committee. High maturity standards with respect to interconnection are the most important tool available to reduce attrition among selected projects, as interconnection is the biggest driver of both technical and financial viability. Finally, we support an auction structure in which each bidder receives the price that project bid rather than a clearing price, but this structure should include a prohibition on applying for capacity in a walk-up program for any project that has been selected in the procurement, in order to prevent perverse incentives and unintended bidding behavior.
Please provide any input in response to page 32, "Proposed successor program framework: community access"	We agree with the comments submitted by CCSA that project types that have additional public policy benefits, such as brownfield, landfill, canopy, and public entity- or community-owned, are almost always more expensive to build than a basic greenfield ground-mounted project. For this reason, we doubt that these types of projects will be successfully incentivized by reserving program capacity at a compensation rate that is lower than the majority of competitively bid projects. Instead, we recommend a bid preference structure within the competitive process, wherein prioritized project types are evaluated at a percentage of the price bid, as suggested on page 33 of the proposal for projects aligning

	with additional federal tax benefits. However, many of these project types–especially those that don't qualify for additional federal benefits–may require a greater than 5% bid preference. Additional policy discussion is needed to determine the types of projects that should receive a preference, and further economic analysis is needed to determine the appropriate bid preference level. Overall, we recommend that neither the procurement nor the walk-up program be restricted to certain project types. Instead, we recommend that 50% of the program capacity be reserved through the procurement and 50% through a first-come, first-served reservation system, where prioritized project types receive a financial bid preference in the procurement, and that same adder is applied to the walk-up rates. For example, if municipally-owned projects receive a 10% bid preference in the procurement, the rates available to those projects in the walk-up program should be 10% higher than the standard rate.
Please provide any input in response to page 33, "Proposed successor program framework: siting preferences aligned with federal funding"	It is unclear if projects sited in "energy communities" or "low income/disadvantaged communities" in accordance with federal guidelines are proposed to receive a bid preference because projects sited in those locations are also aligned with Maine policy priorities, or if the goal is to maximize the cost-effectiveness of the projects selected through the DG 2.0 competitive solicitation by favoring those that can leverage the highest federal incentives. Assigning those projects a bid preference because they align with Maine policy priorities makes sense, but as argued above there are likely other project types that also merit bid preferences, and evaluating at 95% of bid price may not be sufficient to enable all priority project types. However, if the goal of the bid preference is to maximize the cost-effectiveness of selected projects, then a bid preference is redundant, since by definition these projects will already have a financial advantage. It might be more advantageous to give a bid preference to similar types of projects that do not fall within the specific definitions forthcoming from the IRS. For example, PFAS contaminated farmland could be a Maine priority but not qualify as a brownfield under the federal guidelines, or Maine may want to expand the federal category of areas suffering lost employment in fossil fuel industries to include lost employment in logging-related industries. Depending on how the federal guidelines are written, it may be a better use of state-level policy levers to incentivize projects that do not qualify for additional federal incentives rather than incentivize more deeply those that do.
Please provide any input in response to page 34, "Proposed successor program framework: direct benefits to decrease	We support enabling some portion of the DG 2.0 program capacity to qualify for the federal low-income benefit 20% ITC by assigning bill credits to low-income customers. However, this federal program is capacity-limited, and there are no details to date on how projects will reserve capacity to access the 20% ITC bonus. The fact that it is a competitive program complicates the administration of a competitive solicitation: depending on how the federal process is established, project maturity

energy burden aligned with federal funding"	milestones and procurement schedules on the state level may not line up with the timeline and maturity milestones for securing capacity for the bonus at the federal level. Potential scenarios could include a project bidding into the state procurement under the assumption that it would get the federal incentive, but then failing to secure it and being forced to withdraw at the price that was bid; a project bidding into the state procurement without an ITC bonus but later qualifying for it and receiving an unnecessary windfall; a project securing the federal incentive but then failing to be selected in the state procurement, etc. Due to the current uncertainty about the process and timeline for securing the 20% ITC bonus, we recommend that the DG 2.0 program development include a placeholder for this idea, but wait to define how it will work until federal guidelines have been released.
Please provide any input in response to page 35, "Proposed successor program framework: energy storage and grid optimization to maximize value"	We strongly support the requirement to include energy storage given the numerous benefits that storage can provide, and the limited deployment of storage to date in the absence of any program or policy to support it. We agree with the comments submitted by CCSA that the simplest program structure would be to develop a performance requirement for paired storage and incorporate the capital and operational costs of storage into a combined solar+storage bid price and compensation mechanism, rather than expecting projects to rely on wholesale market revenues. We further agree that more discussion is needed to determine the specific parameters that would make a storage requirement and operational structure successful. However, we do not support a location-specific storage benefit at this time. Experiences in other states (such as the Massachusetts Clean Peak Standard Distribution Circuit Multiplier) have shown that designing a storage incentive that attempts to pinpoint the locations on the grid where storage can be most beneficial is extremely difficult and requires very active administration and engagement from utilities as grid conditions are always changing. Furthermore, storage co-located with solar may not be as well-suited as standalone storage to provide the needed grid services, while at the same time many of the locations on the grid where storage could be helpful are in denser areas where there is insufficient land available for a co-located solar+storage project. Updating Maine's Non-Wires Alternative process or establishing a new standalone storage program may be better options for incentivizing storage specifically with the goal of addressing grid constraints. Yet as the cost-benefit analysis showed, pairing storage with solar provides dramatic additional benefits to ratepayers without restricting it to specific, highly-constrained areas of the grid. Shifting the time of day that solar energy is available maximizes the benefits of solar to ratepayers. Paired storage also enables a larger amount of solar energy to be delivered through a given amount of interconnection capacity, which is highly relevant in light of the severe interconnection challenges that are currently

	commonplace across Maine. We support a blanket requirement for paired storage along with additional discussion to determine the most appropriate performance requirements.
Please provide any input in response to page 36, "Proposed successor program framework: additional recommendations to ensure robust competition"	We do not object to making the successor program open to projects of 1-5 MW, while maintaining NEB for all projects up to 1MW plus behind-the-meter projects up to 2MW.
Please provide any additional input to the Distributed Generation Stakeholder Group	We strongly agree with the additional comments submitted by CCSA regarding interconnection and grid planning. Maine has no time to waste in establishing a new process for comprehensive, forward-looking grid planning; without it, all development of renewables will come to a standstill. We also strongly agree with the additional comments submitted by CCSA regarding program administration. There are many important aspects of the proposal that the DG 2.0 Stakeholder Group is unlikely to finalize in the remaining weeks before the final report is due. Many of these items may seem like minor details, but could have major impacts on the program's success. Establishing them in statute will not provide the flexibility to policymakers to iterate based on program results, so we agree with CCSA that the legislature should establish goals and delegate authority for detailed program design to the Governor's Energy Office.

Your name	Fortunat Mueller
Your organization, if any (if commenting on your own behalf, please enter "self")	ReVision Energy
Please provide any input in response to page 31, "Proposed successor program framework: competitive procurement"	• I am supportive of the program framework overall with the majority of the capacity allocated in annual competitive procurements. • I am strongly supportive of allocating the benefits of those procurements in a targeted way to LMI households through automatic enrollment and bill crediting (no offtake requirement for bidders) • Though I recognize that most lawyers don't seem to understand the economic benefits of single clearing price auctions, I think there is strong evidence that they result in a lower overall prices and are more appropriate for this kind of procurement. • I am not fully convinced that SEA assumption that 'fully hedged' (Energy + RECs + Capacity) procurement results in lowest cost is actually accurate. This assumes that developers and PUC always have the same forward price assumptions for RECs and Capacity and the only difference is in developer cost of capital reflecting lower risk. In practice, I think there are lots of examples where developers/asset owners make more aggressive forward price assumptions about RECs than the PUC may be willing to do, and as a result can offer lower cost energy only PPA. It may be possible to structure a procurement in a way that is flexible enough to allow for both. • Given the delays and uncertainty we're seeing in projects procured in the RPS Auction pursuant to LD1494, I think these auction need to have a high bar for project maturity to bid, and just as importantly, a robust process for holding projects to milestones and 'recycling' capacity into a future auction if a winning project fails to materialize. • I believe the successor program should apply a 2 MW lower size limit consistent with PL 2001 CH 390. Lowering that lower bound to 1 MW effectively creates a market hole in the 1-2 MW project size (1 MW projects will not bid successfully in a competitive procurement against projects with 5x the scale). • Procurement should be for a first year initial price per kwhr, with 20 year escalator defined by RFP. This better aligns costs with benefits compared to a 20 year fixed price contract (and reduces guessing and gamesmanship compared to asking each sponsor to bid both initial price and escalator seperately).
Please provide any input in response to page 32, "Proposed successor program framework: community access"	• My understanding of the goal of the 'community access' portion of the program was to continue to provide an opportunity for community groups (homeowners), municipalities, non profits and local business to invest in solar to offset their electric load. • I don't think the 'walk up' program as described on slide 32 meets that goal and I don't think there is an easy way to meet that goal within the overall framework where offtake/beneficiaries of the solar projects are LMI customers managed by the utilities not by project sponsors. Even if the goal is just to diversify ownership (without diversifying

	benefit/offtake), community groups (whether groups of individuals or municipalities) cannot develop and finance solar projects in a way that is competitive, let alone cheaper than 80% of projects (even post IRA, the economics favor corporate project investors). So I don't think this walkup portion is work the complexity it introduces. • One way to solve this issue is to eliminate the 'walk up' portion of this successor program entirely, but to allow some carveouts in the 2MW (or 1 MW) size limitation for projects to continue to participate in NEB 1.0 for projects that meet certain local ownership/benefit requirements. This might be in addition to a similar carveout for projects co-located with load, which should also continue to be allowed to offset load, rather than participate in a wholesale PPA.
Please provide any input in response to page 33, "Proposed successor program framework: siting preferences aligned with federal funding"	• I support the bid preference for projects being built in 'energy communities' or brownfield sites. I think it may even need to be 90% rather than 95%. • I don't support bid preference for projects built in low income communities. Those projects may already get an ITC benefit, but they shouldn't cost any more to build than any other project and don't necessarily have any extra benefit for Maine and so I don't think there is any reason to include a bid preference for them. If anything, forcing solar development into low income communities may be seen as a negative, rather than a positive, from the perspective of equity.
Please provide any input in response to page 34, "Proposed successor program framework: direct benefits to decrease energy burden aligned with federal funding"	• Strongly support this proposal, though recognize that its success depends on tbd rules from Treasury about meaning of 'direct LMI benefit' and allocation of those credits. • Ideally the PUC/utilities can use existing programs to identify eligible ratepayers to avoid extra cost and complexity. • The bill credit provided to low income customers can either be the difference between the value of the solar (as administratively determined) and the price paid to sponsor. Or can be some fixed amount per kwhr (2 cents, for example).
Please provide any input in response to page 35, "Proposed successor program framework: energy storage and grid optimization to maximize value"	• It is clear that energy storage adds value to these projects even in the absence of location specific value. Energy storage should be included automatically in all procurements. • If it is possible to coordinate with NWA efforts, additional locational value could be included.
Please provide any input in response to page 36, "Proposed successor program framework: additional recommendations to ensure robust competition"	• I agree that expecting projects that can participate in NEB 1.0 to participate in the successor is unrealistic and distortive. Projects should clearly belong in one program or the other. As noted above, I believe that dividing line should continue to be 2MW AC.

Please provide any additional input to the Distributed Generation Stakeholder Group	As you note in your slide 11, the RE Goals and Market Assessment that GEO did in 2021 included about 500 MW of DG solar from the DG procurement from LD1711, none of which is being built. That slide also shows about 1,500 Gwhr of 2022 generation from the Class 1A procurement in 2020 and 2021, of which (as far as I know) none is built or even in construction yet and only a very small portion is due to come on line in the next 12-24 months. The NEB 1.0 program may still get 700-800 MW built eventually, but only about 200 MW has been built so far, and most of it will get a haircut per LD634. All that is to say that any narrative that Maine is building solar too aggressively is grossly disconnected with the reality of what Maine needs to do to accomplish our climate and energy goals. Maine needs close to 7,500 MW of solar by 2050 and roughly half that (3,750 MW) needs to be built by 2030. Under current policy, we're on track to build only about half that amount. Also worth noting for those who are focused on costs of NEB 1.0, that as a result of LD634 only a couple hundred MW of projects will get full price. 80% of the projects in the queue get the fixed future payments (if they get built at all) and though that program is more costly than the new options explored in the stakeholder group, Synapse/SEA analysis showed that even that program has a B/C > 1.3 and a very modest (1.5%) long term average rate impact. In other words, most of the chicken-little hysterics about NEB 1.0 that continue to dominate the conversation in some quarters are not grounded in facts or analysis. • I am sure you will manage this expertly, but even among stakeholders there has been significant confusion about what was modeled (resource blocks, storage dispatch choices) vs what is a future program design choice. I think its important to be very clear that the modeling reflects one possible view of the kinds of projects that might get selected by a program (and thus the economics of the program overall), but that the resource blocks are a modeling choice, not a program design choice. • On that point, it is probably too late to modify the model, but I think the inclusion of the 1 MW BTM roof mounted block is confusing in light of the program framework being advanced. Those projects would continue to be in an NEB 1.0 framework and thus don't belong in this analysis at all.

Your name	Pat Jackson
Your organization, if any (if commenting on your own behalf, please enter "self")	Rewild Renewables
Please provide any input in response to page 31, "Proposed successor program framework: competitive procurement"	We agree with CCSA's comments to this question and emphasize the need for several procurements a year that are far more efficiently run than the DG Procurement process was a couple years ago. Additionally, a few points: (1) please keep in mind that RECs account for between 4-5 cents/kWh of revenue that the proposed program states the projects will not get to keep, therefore I would temper expectations getting many bids in the 5-9 cents/kWh. Also, if procurement rates are flat (ie no escalator) that will impact the year one bid price to make the lifetime economics work; (2) the interconnection issues in Maine are massive impediments that don't appear to be getting better. The i39 transmission system studies are years behind and doesn't seem to be providing viable pathways forward for nearly all projects. On the distribution side most substations require multi million dollar upgrades that take years, and CMP has an egregious history of grossly increasing upgrade costs well after the signed interconnection agreements. Together, these interconnection issues may prevent both distributed generation and grid scale renewables in Maine from getting deployed for many years until the transmission system is upgraded and costs are both reasonable and fixed. This will have an impact on the viability of projects in the procurement; lastly (3), the level 2 leapfrog queue issue needs to be solved immediately or else all projects that go through the major development risk to enter a bid to the procurement program will be subject to leapfrogging which undermines the "maturity of all projects and the viability of any bid. Please see the Petitions to the PUC on this very flawed level 2 leapfrog Order.
Please provide any input in response to page 32, "Proposed successor program framework: community access"	We agree with the response submitted by CCSA.
Please provide any input in response to page 33, "Proposed successor program framework: siting preferences aligned with federal funding"	We agree with the response submitted by CCSA.
Please provide any input in response to page 34, "Proposed successor program framework: direct	This net revenue concept is not clear at all so it's hard to directly respond. Given this we will offer some related suggestions. Net crediting is a very rate-intelligent design to (1) create direct benefits for LMI communities through a reduction in their electricity expenses (2) remove all invoicing and collection risks of a customer which are amplified with LMI

benefits to decrease energy burden aligned with federal funding"	communities thereby allowing projects to bid in much more competitive low rates, and (3) would allow projects to secure these valuable tax credit adders, which in turn may help reduce the level of support that Maine ratepayers would need to provide such projects to be developed otherwise. Net crediting is the concept whereby (i) the utility or state pays the solar projects the net revenue per kWh credit that they keep and (ii) the utility/state simply issues a credit (or rebate or coupon, they can all act the same way) to the LMI customer. Net crediting is by far and away the best way to widely access and provide benefits to LMI communities while reducing the revenue rates solar projects need to be financed.
Please provide any input in response to page 35, "Proposed successor program framework: energy storage and grid optimization to maximize value"	We agree with the response submitted by CCSA.
Please provide any input in response to page 36, "Proposed successor program framework: additional recommendations to ensure robust competition"	We agree with the proposed suggestions so long as "future project" means a project that submits for interconnection application after the date of the proposed program being voted into law. There are projects that were submitted up to two years ago that are still waiting for interconnection approval at either the distribution or transmission (i39) approval, in many cases due to recent level 2 leap frogging.
Please provide any additional input to the Distributed Generation Stakeholder Group	Size of Program: we agree with CCSA's comments on Size of Program. "CCSA recognizes that the size of the successor program cannot be known with precise certainty at this time and that the legislature has limited the scope of the DG Stakeholder Group's work by directing the group to include a recommendation on the optimum total amount of DG for the program using 7% of total load based on operational capacity. However, in making recommendations to the legislature on the scale of the successor program, CCSA urges that the group recommend a more precise program capacity target as expressed in MW. Specifically, we recommend a target of 750 MW, which will permit approximately 150 MW of development to occur annually." Interconnection and Grid Planning: in addition to our level 2 comments above, we agree with CCSA's comments on interconnection and grid planning: "CCSA would be remiss if we did not mention that the ability for any successor program to achieve targets for distributed solar and storage deployment is wholly dependent on the ability to interconnect facilities to the electric grid. As can be seen by the current state of affairs in Maine, the distribution system is woefully unprepared to integrate the current pipeline of distributed solar facilities. As such, it is imperative that the utilities and Maine policymakers and regulators work expeditiously to adopt new proactive planning processes so that the critically important

	work of upgrading Maine's distribution and transmission infrastructure can commence. We are aware that the MPUC has commenced a grid planning proceeding (Docket No. 2022-00322), however, without immediate action, Maine runs the risk of critically delaying its efforts in not just the deployment of distributed solar and storage resources, but also beneficial electrification measures and larger transmission connected clean energy resources. It is CCSA's view that the most important action that Maine can take at this time is working with the utilities and other stakeholders to prepare its electric grid for the changes it is about to experience. Without effective integrated distribution planning and robust interconnection policies, Maine's entire decarbonization strategy is unlikely to proceed on the schedule that it needs to in order for the state to achieve the ambitious but necessary requirements that it has set forth." Program Administration: we recommend we delegate specific rulemaking authority to the GEO, with final tariff/contract approval maintained by the MPUC.

Your name	Matt Cannon
Your organization, if any (if commenting on your own behalf, please enter "self")	Sierra Club Maine
Please provide any input in response to page 31, "Proposed successor program framework: competitive procurement"	Power Purchase Agreements (PPA) central to successor program. We agree with the Group's apparent focus on PPAs as the mechanism to move Maine's adoption of solar energy forward. The analysis of the consultants presented to the Group on December 6 reveals this as the most beneficial path forward, and such an approach has been shown to be successful in other states. An intangible benefit of this path is its simplicity relative to the previous program, and we believe a program that is clear and simple is likely to receive better public and media acceptance as well as being easier to administer and monitor.
Please provide any input in response to page 32, "Proposed successor program framework: community access"	Set-aside for true community solar. The proposed 30% set-aside for projects not within the normal bidding pool would allow for true ownership of generation facilities by aggregated individuals who could not, or would not, choose to install solar equipment on their own property. We believe that municipalities, schools, and other community-based entities can provide indirect ownership benefits under such arrangements. We question though why the Group has suggested that bids from the 30% set-aside sector should be capped at the 20th percentile of the bids of the 70% sector. Why not the 50th percentile; what's the rationale?
Please provide any input in response to page 33, "Proposed successor program framework: siting preferences aligned with federal funding"	Solar incentives on disturbed lands. The report prepared by Sustainable Energy Advantage for The Nature Conservancy of Maine treated the suitability of disturbed lands for solar development and was presented to the Group on October 19. We believe that incentivizing the use of such lands should be done with a discount on bids made with siting on such lands. Such discounts are offset by increased local taxes, by turning eyesores into beneficial facilities, and by preventing the use of other, less desirable sitings such as on farmland or forest lands. We also recommend that further analysis be done to include "disturbed" lands not in the original SEA study, such as parking lots.
Please provide any input in response to page 34, "Proposed successor program framework: direct benefits to decrease energy burden aligned with federal funding"	Utility bill relief for low-moderate income (LMI) ratepayers. The "December 2022 Highlights" released December 7 by the Office of Public Advocate is a stern reminder that we must transition to renewable energy as fast as feasible. It indicates possible residential rates for electricity going to over \$0.25/kWh, unprecedented in Maine. This high rate will be felt most onerously by low-income and even middle-income ratepayers. We understand that a program based on PPAs will control and lower rates for all ratepayers. However, this is not a solution for those ratepayers at the economic bottom; and we favor, as a means of keeping matters simple, that relief for high utility bills should come from the Maine Efficiency Trust or whatever additional public and private programs exist to address this. The Public Advocate calls for increasing the state funding for utility-bill assistance from \$17M to \$60M, and this may not be enough. Another possibility to increase those funds lies with the IRA federal funds.

	We understand this Act will grant tax credits to entities that develop solar generation for which a certain proportion of subscribers are LMI ratepayers. Rather than lowering the LMI bills, could the developers simply be part of the PPA program and set aside an amount equal to the tax credit and contribute that to the public utility-bill assistance program? Additionally, focusing on weatherization and electrification coupled with more renewables (especially if regulated so as to not benefit investors), should lower the need for intervention for LMI folks.
Please provide any input in response to page 35, "Proposed successor program framework: energy storage and grid optimization to maximize value"	Battery storage. The analysis presented at the December 6 meeting of the Group clearly shows that a sizable component of battery storage in solar generation facilities will have overall benefits and will reduce electricity rates. This analysis aligns with that found in various industry and agency sources and it reinforces the GEO study "Maine Energy Storage Market Assessment" of March 2022. We favor the inclusion of a specific goal for battery-storage energy capacity relative to the overall solar capacity in setting the goals for the successor program. The exact amount of this battery-storage goal can be determined by some fine tuning of the modeling presented at the December 6 meeting of the Group.
Please provide any input in response to page 36, "Proposed successor program framework: additional recommendations to ensure robust competition"	Distributed generation less than 1 MW capacity. The Proposed Framework on p. 9 states: "For the purpose of this straw proposal, the Distributed Generation Stakeholder Group considers applicable distributed generation to mean a distributed generation resource between one and five megawatts." We strongly wish to see small rooftop projects still included in the goals for solar generation. We consider projects of less than 1 MW, including rooftop solar projects, to be important to the overall adoption of solar energy and to provide benefits to the customer base at large. The federal government's tax credit of 30% of costs remains a strong incentive to homeowners to install rooftop solar. The analysis presented on December 6 to the Group includes this component in a hybrid model with PPAs as the major component, and therefore we support the hybrid model.
Please provide any additional input to the Distributed Generation Stakeholder Group	Relating to growing Maine's clean energy economy on p. 13: More workforce development for projects under the Successor Program. We already know that a lack of skilled workers has slowed the needed pace of renewable energy development in Maine. However the successor program is finally enacted, it should be accompanied by a strong state program to make sure a workforce is trained to implement the successor program in a we have an adequately sized, capable workforce meeting the demands of our clean energy transition. This should be focused on ensuring there is a just transition: workers in the fossil fuel industry should be prioritized. Additionally, any development incentives should also encourage a living wage and democratized ownership or power structures, consistent with the language in LD 1969.

Your name	Shannon Meyer-Johanson
Your organization, if any (if commenting on your own behalf, please enter "self")	Sol Systems
Please provide any input in response to page 31, "Proposed successor program framework: competitive procurement"	While a competitive solicitation can help achieve cost-effectiveness, we do not believe that it is the most efficient way for Maine to achieve its distributed generation goals as outlined in LD 936. We have two main concerns with the proposed framework. First, the framework favors large developers who have high amounts of capital on hand to develop projects before incentives are finalized. Such developers can take on more risk and make the most cost-competitive assumptions and therefore bids. Second, this framework would specifically favor ground-mount projects developed on greenfield sites as these projects tend to have the lowest development costs. Favoring greenfield projects goes directly against the language in LD 936 asking for recommendations regarding "5) Identifying mechanisms that prioritize distributed generation that are sited to: (a) Limit impacts by being located on previously developed or impacted land, including areas covered by impervious surfaces, reclaimed gravel pits, capped landfills or brownfield sites as defined by the Department of Environmental Protection; (b) Serve load within a low-income to moderate-income community; (c) Directly serve customer load; or (d) Optimize grid performance or serve a nonwires alternative function." The proposed competitive procurement framework favors ground-mount projects and does not promote on-site solar on rooftops, carports, brownfields, or in LMI communities. In order for Maine to incentivize project diversity conducive to the goals stated in LD 936, we strongly urge the stakeholder group to consider a fixed, declining block-style incentive program similar to the Adjustable Block Program in Illinois. Such a framework would provide structure and certainty around pricing and timing while also providing higher incentive levels for non-greenfield projects which are more costly to develop. Furthermore, this structure would also be cost-effective as block prices decline over time (i.e., once a block is full, the next will have lower incentive levels).
Please provide any input in response to page 32, "Proposed successor program framework: community access"	Per LD 936, the goal of the stakeholder group is to "[consider] all types of distributed generation, including, but not limited to, net energy billing arrangements paired with energy storage." The successor program proposal however seems to primarily focus on cost-competitive "community-scale" renewable energy projects, which presumably implies ground-mount solar. Moreover, slides 30 and 7 mention that "siting on large rooftops and brownfield sites [is] favored" but the proposal does not provide a framework that would implement that goal. Based on the current competitive procurement framework, siting on large rooftops and brownfield sites would actually be discouraged. Since these project types typically have higher development costs compared to ground-mount projects, they will not be able to win cost-competitive bids. If all types of distributed generation, including large rooftops and brownfield sites, are to be incentivized, the competitive solicitation would have to be separated

	by project type with pre-determined capacity amounts set aside for each category. For example, if the program wanted to incentivize a specific amount of rooftop solar, there would need to be a procurement for only rooftop projects (i.e., rooftop projects compete against rooftop projects, brownfields compete against brownfields).
Please provide any input in response to page 33, "Proposed successor program framework: siting preferences aligned with federal funding"	We agree that the successor program should align with opportunities within the Inflation Reduction Act. However, given the lack of clear guidance around how Energy Communities will be defined, we urge the stakeholder group to be flexible to accommodate forthcoming IRS guidance.
Please provide any input in response to page 34, "Proposed successor program framework: direct benefits to decrease energy burden aligned with federal funding"	n/a
Please provide any input in response to page 35, "Proposed successor program framework: energy storage and grid optimization to maximize value"	n/a
Please provide any input in response to page 36, "Proposed successor program framework: additional recommendations to ensure robust competition"	n/a
Please provide any additional input to the Distributed Generation Stakeholder Group	Thank you for all the work you've done!

Your name	Trevor Laughlin
Your organization, if any (if commenting on your own behalf, please enter "self")	Standard Solar Inc.
Please provide any input in response to page 31, "Proposed successor program framework: competitive procurement"	n/a
Please provide any input in response to page 32, "Proposed successor program framework: community access"	n/a
Please provide any input in response to page 33, "Proposed successor program framework: siting preferences aligned with federal funding"	n/a
Please provide any input in response to page 34, "Proposed successor program framework: direct benefits to decrease energy burden aligned with federal funding"	n/a
Please provide any input in response to page 35, "Proposed successor program framework: energy storage and grid optimization to maximize value"	SSI opposes requiring energy storage with vague criteria, such as "where beneficial." In the event energy storage remains required "where beneficial," SSI requests that the Maine Governor's Energy Office (GEO) clearly defines the benefits and beneficiary. E.g., do benefits apply to the utility, customers, or developer? SSI asks the Maine GEO to incentivize energy storage through adders that promote development where energy storage makes sense economically rather than by mandate. Requiring energy storage "where beneficial" without commensurate compensation will limit development if the additional costs of energy storage make a project economically unviable.
Please provide any input in response to page 36, "Proposed successor program	n/a

framework: additional recommendations to ensure robust competition"	
Please provide any additional input to the Distributed Generation Stakeholder Group	To support the Maine GEO and Department of Agriculture's efforts to promote development of agrivoltiacs, SSI recommends offering additional incentives to offset the increased costs for developers. SSI recommends that multiple systems collocated at a site should be able to be interconnected behind the same meter, regardless of their type e.g., ground mount, canopy, rooftop, or a combination, subject to relevant individual project program sizing limits (for example, the discrete electric generating facilities standard or any successor standard).

Your name	Rob Wood
Your organization, if any (if commenting on your own behalf, please enter "self")	The Nature Conservancy in Maine (TNC)
Please provide any input in response to page 31, "Proposed successor program framework: competitive procurement"	n/a
Please provide any input in response to page 32, "Proposed successor program framework: community access"	n/a
Please provide any input in response to page 33, "Proposed successor program framework: siting preferences aligned with federal funding"	TNC Maine appreciates and supports the inclusion of a bid enhancement mechanism in the successor program framework. The inclusion of this mechanism is consistent with comments TNC and other groups and individuals offered during and after the land use work session. We thank the Stakeholder Group for incorporating this suggestion. We also believe that the bid enhancement mechanism could be further strengthened in two important ways. First, we recommend that projects that are eligible for the bid enhancement should be evaluated at 90% of their offered rate (or less, e.g., 80% or 85%), rather than 95% as currently proposed. This slightly stronger preference would increase the efficacy of the bid enhancement mechanism, and this would also be consistent with the bid enhancement mechanism included in the original DG procurement program authorized by the Legislature in LD 1711 (in which projects located on previously developed or impacted land were eligible to be evaluated at 90% of their offered rate). Second, we recommend that eligibility for the bid enhancement in the successor program should be extended beyond brownfields to other types of degraded or developed land—for example, capped landfills, closed gravel pits, buildings and impervious surfaces (as well as PFAS contaminated sites to the extent these sites do not meet the strict definition of brownfields). While TNC appreciates and understands the emphasis on alignment with federal tax incentive programs, we see little downside to utilizing a more expansive definition in a competitive bidding process. In short, ratepayers will still be protected, because even if all types of degraded or developed land are eligible for the bid enhancement, a brownfield project will still be selected before a project located on another type of degraded or developed land, if the brownfield project is in fact less expensive to build. This approach would simply place all projects

	located on degraded or developed land on equal footing in the bidding process. Thank you for your consideration of our comments.
Please provide any input in response to page 34, "Proposed successor program framework: direct benefits to decrease energy burden aligned with federal funding"	n/a
Please provide any input in response to page 35, "Proposed successor program framework: energy storage and grid optimization to maximize value"	n/a
Please provide any input in response to page 36, "Proposed successor program framework: additional recommendations to ensure robust competition"	n/a
Please provide any additional input to the Distributed Generation Stakeholder Group	n/a

Your name	Ross Abbey
Your organization, if any (if commenting on your own behalf, please enter "self")	US Solar
Please provide any input in response to page 31, "Proposed successor program framework: competitive procurement"	The program administrator (e.g., state energy office or PUC) should be given the authority to consider and adopt bid preferences for project applications that include extra optional elements (e.g., sited on disturbed lands or in certain load zones, or committing to dual-use aka agrivoltaics practices such as sheep grazing, etc.) as done in other states.
Please provide any input in response to page 32, "Proposed successor program framework: community access"	Thirty (30) percent seems like a fairly big set-aside, especially given the low compensation rate (20th percentile of selected bids) envisioned for these MW. For these reasons, the program framework should also include a mechanism to re-allocate any that capacity that goes unawarded to the bid process in subsequent years. If the framework does limit a portion of the annual capacity to use only by "state-, municipal- or school-sponsored projects", then the size of the set-aside should be pegged to the relative annual kWh use of those entity types (as a class) verses the state's overall annual kWh use.
Please provide any input in response to page 33, "Proposed successor program framework: siting preferences aligned with federal funding"	We're not against the use of reasonable bid preferences (see # 3, above), but it would be better to give the PUC the flexibility to adopt (and tailor) program preferences on an annual or bi-annual basis, based on program learnings to date, rather than "lock in" one or more preferences in statute prior to the rule-making and/or implementation stage. For example, the preference proposed on page 33 might well end up being unnecessary or counter-productive, e.g., if the federal incentive standing alone ends up being sufficient to drive preferable siting, etc. practices. Finally, the U.S. Treasury Department hasn't yet issued detailed guidance on the IRA's energy community bonus, so its hard to provide more detailed feedback at this time.
Please provide any input in response to page 34, "Proposed successor program framework: direct benefits to decrease energy burden aligned with federal funding"	This slide accurately conveys that the 20% ITC bonus credit for providing direct benefits to low-income customers will only be available in states that implement (or already have) a qualifying bill-credit mechanism such as community solar or virtual net energy billing. For that reason, the current NEB program (and/or any successors) should be made compatible with the 20% federal credit (i.e., once the U.S. Treasury published detailed guidance on this new federal incentive).
Please provide any input in response to page 35, "Proposed successor program framework: energy storage and grid	We support the inclusion of an energy storage component to maximize value. But while making interconnection capacity available to storage is necessary, it is not by itself sufficient to enable actual project development. To enable actual storage projects, the framework should also specify how storage will be valued for purposes of project compensation aka revenue.

optimization to maximize value"	
Please provide any input in response to page 36, "Proposed successor program framework: additional recommendations to ensure robust competition"	No feedback at this time.
Please provide any additional input to the Distributed Generation Stakeholder Group	The framework report should include an example implementation timeline, so legislative readers can be informed of when (approximately) the program would open & projects would start coming online if they adopt the report's proposal into statute. For example, the report could say something like "if the legislature adopts this proposal in 2023, the first RFP window may open by Q3 2024, with awarded project becoming operational by Q3 2026 or later" — or whatever the rough timeline would be under the final report's proposal. In our experience for a 1-5 MW project, it typically takes 24 months from IA execution to commercial operation – especially for a northern state like Maine where construction is more difficult in the winter months. Page 29 notes that P.L. 2021 chapter 390 includes a legislative finding that the optimum amount of DG (i.e., the "program target") is 7% of total statewide load after subtracting the current awarded pipeline of 2-5 MW DG. But given passage of the federal Inflation Reduction Act in late 2022, which includes mechanisms to lower the cost of DG solar and storage going forward, the legislature may at some point want to re-evaluate its 7% load target to re-optimize for the lowest cost reliable electricity system going forward.

Your name	Joseph Moss
Your organization, if any (if commenting on your own behalf, please enter "self")	Verogy
Please provide any input in response to page 31, "Proposed successor program framework: competitive procurement"	a. The competitive solicitation should be for 100% of annual capacity, with any excess or unallocated capacity rolling forward into the next year's auction. This will ensure that only the most competitive projects are awarded & simplify the overall program design, bidding process and administration. b. Rather than requiring fully executed interconnection service applications, projects should be required to pay a bid fee or post a form of refundable performance/development period security. This suggestion is in light of the lengthy interconnection approval and execution timelines common with ME EDCs which regularly approach or exceed one year. Project developers will be hesitant to commit the resources required to execute an interconnection agreement with the EDCs if they do not know whether or not they will be awarded a revenue contract – detracting from the competitiveness of the procurement. Further, if bidders are required to post some form of performance assurance, they will be incentivized to ensure the project they bid enters operation as planned, else they risk losing the performance assurance posted. c. The first year of the successor program should not include a price cap for bids. The renewable energy market has undergone significant changes in the past year, with many seemingly offsetting factors such as increased equipment and labor costs, extended federal support, tariffs…etc. The many changes in the market will make it very difficult to administratively determine an appropriate bid cap with retrospective analysis. Bidders will already be incentivized to bid as low as possible given the competitive nature of the solicitation and the limited capacity available. If a bid price cap is instituted, bids should be allowed to bid over the price cap as long as their evaluated bid prices are under the price cap after taking into account any bid preferences or bonuses.
Please provide any input in response to page 32, "Proposed successor program framework: community access"	a. Remove the 30% capacity first-come, first-served set-aside. This will improve solicitation competitiveness & simplify overall program administration & bidding process. b. If any amount of capacity is reserved for a first-come first-served allocation, compensation level should be set at the median rate of selected competitive bids rather than the 20th percentile. Setting the compensation rate at the 20th percentile would mean that most projects would not be viable, as the most competitive projects are already incentivized to bid into the competitive solicitation, since they will have the highest chance of securing an award in the competitive solicitation rather than the first-come first-served set-aside.

Please provide any input in response to page 33, "Proposed successor program framework: siting preferences aligned with federal funding"	a. Bid preference rates for Energy Communities, Low Income Areas or Low Income Offtake should be increased to align with federal ITC levels – that is 10%, 10% & 20% respectively. This would incentivize bidders to align bids with federal funding and further reduce costs to the ME ratepayer, whereas a 5% bid preference is likely not enough to overcome the additional capex associated with siting projects in preferential areas. i. If not provided by federal government, state of ME should provide map or list of zip codes / areas which would qualify for E.C. or L.I. ITC bonuses. b. Add a bid preference for canopy-mounted PV projects. For reference, CT programs utilize a canopy bid preference of 20% (NRES) to 40% (SCEF), MA is $0.06/kWh. Providing a preference for canopy mounted projects will direct development away from prime woodlands or wilderness and to previously disturbed areas, usually closer to load/population centers. c. Verogy suggests adding a bid preference for projects co-located with enough load to offtake 100% of annual generation. This will help provide grid benefits by removing load from the grid and decreasing grid congestion.
Please provide any input in response to page 34, "Proposed successor program framework: direct benefits to decrease energy burden aligned with federal funding"	a. Ensure the low income offtake incentive is a bid bonus/bid preference rather than a requirement, if it is actually being proposed as a requirement. ME has many remote areas that may be quite suitable for PV development in many ways but lack local population to offtake energy of a large PV array.
Please provide any input in response to page 35, "Proposed successor program framework: energy storage and grid optimization to maximize value"	a. Make paired storage eligible for a bid bonus or bid preference rather than a requirement for projects. Make storage preferences / bonuses tied to PV production to improve "financabitliy" or predictability of contracted revenue. Financiers are much more comfortable with contracted or easily predicted revenue such as that from solar PV with a long term fixed price revenue contract rather than energy storage relying on uncontracted merchant revenues such as energy/capacity arbitrage. For example, a PV project paired with storage should be evaluated at 70% of its bid price, or receive an additional $0.04/kwh for PV generation, provided that storage performance meets certain criteria (charging/discharging at certain times, participating in EDC demand response programs…etc). If the proposed procurement is for a fixed $/kWh contract, bidders have zero incentive to pair storage with generation, as the value of energy / capacity arbitrage could not be recognized. i. MA has "SMART Storage Adder" for reference, tied to PV generation.

	ii. Ensure capacity rights & other rights are retained by bidder for storage for monetization, the value of which can be used to bring down PV bid prices & lower program costs. b. MPUC should publish map or list of substations or other locations where distributed PV projects would benefit local grid conditions. Projects sited at these locations should be eligible for a bid preference or bid bonus. This will allow for a competitive market to determine the most cost-effective locations (locations with easy access to infrastructure / grid and lower build cost/bid price, or remote locations with limited grid access and higher build cost/bid price, but with an appropriate preference/bonus)
Please provide any input in response to page 36, "Proposed successor program framework: additional recommendations to ensure robust competition"	a. The requirement of having an executed interconnection service agreement to bid should be removed. This is a significant hurdle for project developers & will hinder competition and MW deployments, as many bidders will not want to spend the necessary time and money to secure an interconnection service agreement without knowing if their project will have a revenue contract or not.
Please provide any additional input to the Distributed Generation Stakeholder Group	a. Projects with interconnection/NEB applications submitted by 12/31/2023 should be grandfathered into the current NEB program. b. Clarify if capacity rights will be transferred to EDCs as part of program – if so, clearly define value that developers can buy them back for. c. The proposed NEB successor program seems to be aimed at "grid-feed" projects over 1 MW AC not co-located with load. Verogy suggests that there should be some sort of parallel successor program similar to the current NEB program that allows for electricity to be consumed on-site or for bill credits to be transferred across multiple meters on the same project site or owned by the same utility customer in the same utility territory for projects up to 2 MW AC – the current NEB size cap. i. The proposed program design does very little to protect participants from increasing utility rates if all energy is exported to the grid at a fixed rate, negating one of the most significant benefits of distributed generation – utility rate hedging. A successor program that allows for electricity to be consumed on-site or that is tied to utility rates would allow for solar PV offtakers to protect themselves from rising utility rates, a feature that appears to be lacking from the proposed program design, and one that is front of mind for all utility customers in the current economic environment. ii. A successor program similar to the current NEB Tariff program that allows for credits tied to utility rates to be transferred across multiple meters would allow for the optimal siting of solar PV projects. For example, a property with multiple meters on-site should be able to tie into only one meter, but transfer credits across all meters on site, or all meters

	owned by the same utility customer in the same utility territory. This would optimize solar PV siting and reduce install costs. iii. A parallel program could be developed targeted only at procuring only RECs or “environmental attributes” generated by solar PV arrays – similar to the legacy CT L/ZREC program – while the electricity generated by a solar PV array is consumed on-site or transferred to a different meter on-site or owned by the same utility customer in the same utility territory via bill credits.

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L.D. 936 PROPOSED FRAMEWORK FOR DISTRIBUTED GENERATION SUCCESSOR PROGRAM: DRAFT REPORT
DISTRIBUTED GENERATION STAKEHOLDER GROUP

COMMENTS OF AARP MAINE
December 14, 2022

AARP is a non-profit, non-partisan social mission organization with more than 200,000 members across the state. AARP works on a range of energy issues at the state level. Among AARP's core principles is to seek to ensure service affordability for all — utility rates should be based on prudent use of ratepayer money. Costs and savings should be distributed fairly among consumers. Households with lower incomes should be taken into account. And, regulators and policymakers should make sure that public utilities provide a high-quality, reliable service. These policies are particularly important for fixed income Mainers for whom even a small increase in their bill for essential electricity service is a significant hardship. Like healthcare and broadband, accessibility is actually about affordability.

AARP Maine has followed the development of this Distributed Generation Successor Program. This study and recommendations are the product of a Legislative directive in L.D. 936. This directive required the Stakeholders consider and address the following matters in this "final" report:

> By January 1, 2023, the Governor's Energy Office shall submit a final report to the joint standing committee of the Legislature having jurisdiction over energy and utility matters that includes, subject to available resources, the following:
>
> > A. Identification of the recommended optimum total amount of distributed generation for the program period represented as a percentage of total load;

AARP COMMENTS: The Draft Final Report does not contain any analysis of what the "optimum" amount of distributed generation should be implemented in Maine as a percentage of the total load. There is no analysis of *how much* distributed generation is necessary or cost effective in terms of Maine's generation profile compared to ISO New England. This type of analysis is particularly important in light of the high subscription level of the current distributed generation program as documented in this draft report. In other words, how much is enough?

Rather, the draft final report purports to rely on the provision of L.D. 936 that included a provision for the **interim** report that required recommendations, one of which was "The optimum total amount of distributed generation for the program period calculated using 7% of total load based on operational capacity." However, the final report requires a **"recommended optimum**" distributed generation target as a percentage of total load." This final report should identify the criteria and recommendations for adopting a distributed generation target that takes into account Maine's total load, the percentage of distributed generation that is already under contract and the amount in the queue that is likely to be implemented prior to 2024.

> B. An estimation of the net ratepayer impacts, including all on-bill benefits and costs, expected as a result of the development of distributed generation resources under the Maine Revised Statutes, Title 35-A, section 3209-A, subsection 7 and Title 35-A, section 3209-B, subsection 7, accounting for projects that have reached or are expected to reach full maturity and load growth trends;

AARP COMMENTS: This Report does not identify the ratepayer impacts, including on bill benefits and costs, associated with the current Net Energy Billing programs. Rather, the Report merely provides information on the number and MWs of projects approved and those in the queue under the current program rules and tariffs. **The Synapse Energy Economics consultants submitted its analysis of the current program and various future programs to the Stakeholders on December 6, 2022. This analysis calculated that the current tariff program has a cost/benefit ratio of 0.39 meaning that the benefits only "cover" 39% of the costs of the program over the program period.**[1] This information is not included in the Draft Final Report and should be rectified by including this information in the final report, as well as the ratepayer or bill impacts associated with the current program. It is not reasonable to consider the costs associated with expanding a "successor" program without an identification of the ratepayer impacts of the current program that will occur over the 20 year period of the Net Energy Billing contracts under current law, the growth in distributed generation that has and will occur with the current program, and how ratepayer bill impacts might be ameliorated with program reforms.

> E. Consideration of the feasibility of implementing innovations to increase the net ratepayer value of distributed generation, including, but not limited to, time differentiated rates and 2-way energy flows;

AARP COMMENTS: This report does not address this issue. Rather, the Report focuses on the development of a program that is acquired in a manner that will, assuming that the assumptions about future costs and benefits are correct, provide benefits in excess of costs. AARP appreciates the development of more cost-effective programs, but whether those additional costs that must be added to the ratepayer impacts of the current program are reasonable, affordable or cost effective as a whole is not discussed or identified.

[1] https://www.maine.gov/energy/sites/maine.gov.energy/files/inline-files/Dec%206%20Presentation-FINAL.pdf

F. Consideration of the use of declining net energy billing arrangement bill credit rates, including the use of reduced bill credit rates for distributed generation that is not located on one of the prioritized sites identified in the interim report pursuant to subsection 2, paragraph C, subparagraph (5); and

AARP COMMENTS: This proposed final report does not address this issue of “declining net energy billing arrangement bill credit rates” for projects not located on “prioritized sites.”

G. Consideration of the feasibility of standardizing the classification of distributed generation as load reducers, regardless of whether the bill credit is in the form of kilowatt-hour credits or monetary credits.

AARP COMMENTS: This Report does not address this issue.

CONCLUSION: Overall, AARP supports the main recommendation of the Draft Report to rely on competitive procurements for future distributed generation projects over 1 megawatt and to deliver the costs and benefits of the value of least cost solar generation to all customers. We suggest that any deviation from a competitive bidding process relying on lowest cost criteria to acquire future solar generation that is being paid for Maine distribution ratepayers be adopted only in narrow circumstances and with a documentation that the excess costs be compensated by state or federal taxpayers, and not electric ratepayers. For example, any program designed to target benefits to low income customers should fund the excess costs that might result (compared to competitive bids that benefit all ratepayers) by federal or state grants or taxpayers and implemented in the most efficient manner possible through, for example, increasing the benefit for the existing Low Income Assistance Program (LIAP).

Thank you very much for this opportunity to provide comments on the draft final report.

Noël Bonam
State Director, AARP Maine

L.D. 936 Distributed Generation Stakeholder Group

Comments of Central Maine Power

Central Maine Power Company ("CMP" or the "Company") offers these comments on the proposed final report of the Distributed Generation ("DG") Stakeholder Group. The Company actively participated in the DG Stakeholder Group and offers these comments to clarify the utility's position and offer final comment on certain areas.

CMP is committed to supporting Maine's clean energy initiatives and working towards building a resilient grid to help achieve those efforts. We welcome the opportunity to participate in the DG Stakeholder Group and will continue to work collaboratively with all stakeholders into the future as we work to reduce the state and region's reliance on fossil fuels.

In 2019, the Maine Legislature passed LD 1711, "An Act to Promote Solar Energy Projects and Distributed Generation Resources in Maine". Since that time, Maine has seen an exponential growth in solar projects being proposed and build in the CMP and Versant service territories. While the increase in solar capacity helps to achieve the goal of shifting away from fossil use and the switch to clean sources of electricity, the utilities agree that the existing Net Energy Billing programs in Maine are not a sustainable option given the significant stranded costs that have resulted in the program.

A number of proposals have been discussed since the working group was formed. The utilities offer up the following comments.

(1) Bidding Process for Future DG Projects: In regards to a bidding process to select future DG projects, the Company does not support a bid structure whereby a ceiling price is known beforehand. Bidders may be inclined to bid just at or below the ceiling and thus truly competitive bids would not be submitted, raising stranded costs for utility customers. In addition to achieving climate goals, the final recommendation should take into consideration the impact to customers when designing the future of Distributed Generation. The RPS Legislation which resulted in the Commission seeking bids for DG projects is a prime example of achieving the clean energy goals and reducing stranded costs. Many of the projects awarded bids through that bid process are at fixed prices that do not negatively impact utility rates. If the utilities sign 20-year long term contracts with a DG project a truly competitive bidding process would need to be developed to help ensure that customers do not unnecessarily incur additional stranded costs. As discussed below, CMP currently receive the ISO-NE hourly locational marginal price for the energy associated with long-term contracts. Given the uncertainty surrounding the hourly market prices and the influx of new generation being built in the region, there is no way to reasonable predict the value that will be achieved on behalf of customers from the resale of energy into the market, or through some other mechanism. The difference between fixed priced contracts and the resale value flows through the utilities annual stranded costs files, which can result in significant price volatility for customers.

(2) Increased Participation for Low Income Customers While the Company supports participation of low-income Mainers into Community Energy Programs, CMP does not support the recommended proposal which would result in a fixed price contract being paid to project developers and then a financial bill credit being applied to low income customers. The proposal would result in increased stranded costs to all other customers which are already bearing the cost responsibility for the existing Net Energy Billing programs. CMP proposes that low income customers should be offered the opportunity to willingly sign up for any program. The utilities provide funding for a number of low income assistance and Efficiency Maine programs. Efficiency Maine Trust and other State Agencies should help low-income Mainer's learn about the opportunities to participate and provide information on how customers can sign up.

(3) Siting of Future DG Projects: The Company supports siting new projects on brownfield sites. The Company also supports siting new facilities in areas where generation is needed. With the large influx in solar in Maine, CMP cannot guarantee that proposed projects will avoid cluster studies as there a very few- if any- locations in Maine with open capacity to accept a new project without trigging major grid impacts. CMP is committed to working with projects to ensure that Maine meets the State's Climate goal and will continue to maintain Heat Maps and other information that can provide input into the process.

(4) Forward Capacity and Other Market Products: The Company rejects any proposal that would place utilities in the position of qualifying resource in the ISO-NE Forward Capacity Market, as utilities are not the owners, nor do they control the facility operations or maintenance. The utilities would only be assigned capacity rights if the project qualifies the facility in the ISO Market. Under the current Net Energy Billing Agreements, the Commission inserted language that allows a project sponsor to qualify their resource in the FCM and propose a revenue sharing mechanism to share the benefits with customers. The ISO requires financial security to be posted when bidding resources into the forward capacity market. These costs and risks should not be borne by utility customers. Whether or not the facility had any obligation to qualify the resource would be at the direction of the contract that the Commission directs the utility and resource to sign. Under the existing Net Energy Billing program, the Renewable Energy Credits (RECs) stay with the project sponsor. The utilities are required to register the RECs in the ISO-NE GIS and obtain Maine certification. If the RECs flow to the utilities and we then need to maximize the value of those for customers and potentially qualify these in other states in order to maximize rate payer value, additional staffing and costs will be required. Due to the statutory prohibitions on utilities owning generation and serving load, utilities are not staffed to perform functions such as qualifying resources in the FCM and buying and selling generation or qualifying and selling RECs. Prior to electric industry restructuring, the utilities had an energy trading floor which was fully staffed with

knowledgeable traders along with mid- and back-office support staff which is required under industry risk management standards. CMP is currently not staffed to perform these functions and there would be significant costs to hire experienced energy marketing personal to perform this function.

STATE OF MAINE
GOVERNOR'S ENERGY OFFICE
DISTRUBUTED GENERATION
STAKEHOLDER GROUP

December 14, 2022

Dirigo Solar LLC ("Dirigo") submits these comments in response to the "Proposed Framework for Distributed Generation Successor Program" released to the Distributed Generation Stakeholder Group ("NEB Working Group") on November 23, 2022. Dirigo is a member of the Group and also a developer of "utility scale" as well as projects that meet the definition of "distributed generation" pursuant to 35-A MRSA 3481.

The legislation enabling the NEB Working Group asked the Governor's Energy Office to "***consider*** various distributed project programs to be implemented between 2024 and 2028.*"* There is no mandate to create a similar or successor form of Net Energy Billing ("NEB") and Procurement Program created by the Legislature in 2019. While NEB procurement has been a resounding success in deploying solar projects throughout the state, it is no longer needed to incentivize future deployment. Accordingly our recommendation is that, for new projects above 1 MW, the NEB procurement program be replaced with simplified competitive solicitations and that *all* distributed generation ("DG") projects compete for long term contracts.

Along with our partners at BNRG Renewables Ltd., Dirigo has successfully developed Maine solar projects with long-term contracts awarded in Docket No. 2015-00026, with a beginning contract price of $34/MWh. The currently operating projects constitute 67 MW and are located in Milo, Oxford, Fairfield, Winslow, Hancock, Palmyra, and Augusta.[1] According to CMP and Versant stranded cost filings, six of those projects will result in nearly $5 million in estimated ratepayer savings from one year of operation alone (or a partial year, for the projects that commenced operation after March 2022).[2] With the exception of Milo, which is on the "sub-transmission" level, all of these projects are on the "distribution network." They range in size from 4.99MW to 26MW. They all provide the same "distribution benefits" of smaller projects now built under the NEB program, and they are doing so for a fraction of the cost.

Dirigo appreciates the work of the GEO and the NEB Working Group. It has been a highly professional and much needed exercise. The fundamental problem with our work and the engagement of outside consultants is that our inquiry is limited to the 5MW definition of "distributed generation," a concept created by the Legislature in LD 1711, presumably to cap the size of projects that could qualify for NEB benefits. To the extent that "smaller" projects are worthy of being built even if "more expensive," it is up to the Maine Legislature to decide whether the State should be promoting *any* above market solar projects at a time of meteoric energy costs and historic inflation. If the question is "what program is the most cost-effective means of developing distribution level capacity," the answer is unequivocally competitive procurements.

[1] An additional project of approximately 10 MW in Auburn is delayed for a CMP cluster study.

[2] *Central Maine Power Company*, *Request for Approval of Rate Change Regarding Annual Reconciliation of Stranded Cost Revenue and Costs*, Docket No. 2022-00042, Stranded Costs June Update Filing (June 7, 2022), at Attachment E3 (summing revenues net of payments for BD Solar projects); *Versant Power*, *Request for Approval of Standard Cost Rate Change*, Docket No. 2022-00102, Updated Revenue Requirement Filing (May 16, 2022), at Attachment B2 (summing Milo, Hancock 1, and Hancock 2 revenues net of payments).

A. <u>The Current NEB Program: Fewer Opportunities, Increased Costs, and Increasingly Uneconomic Compared to PUC Solicitations</u>

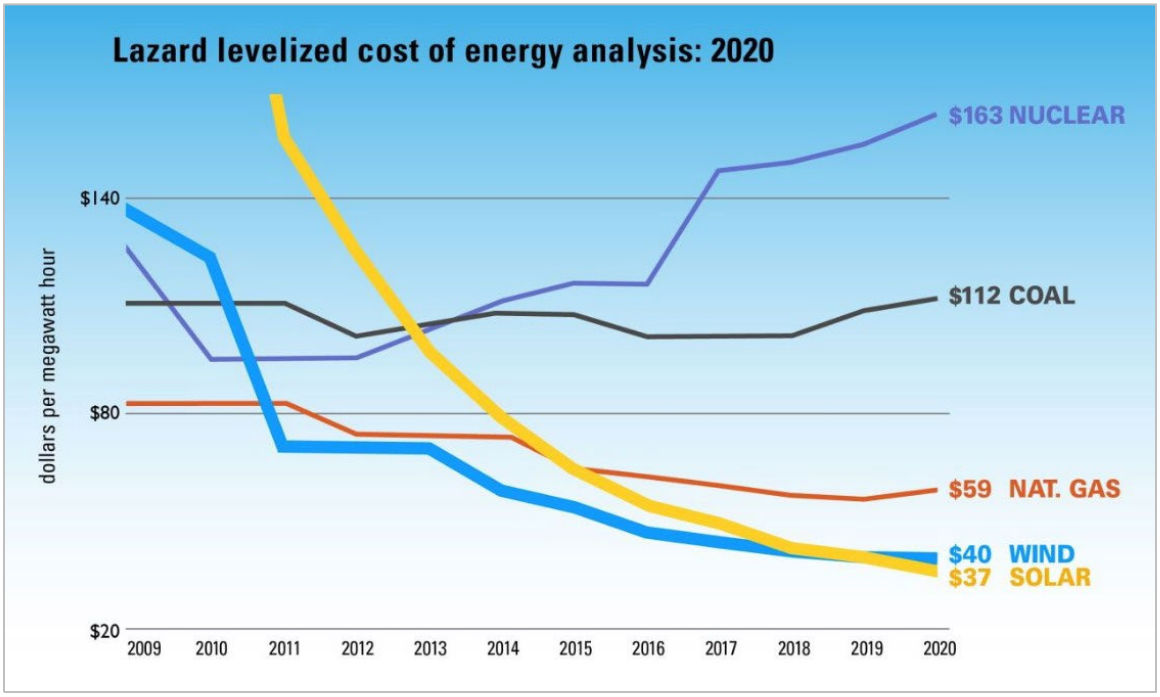
Launched in 2019, the current NEB Program has been a resounding success for growing Maine's clean energy economy and deploying solar technology throughout the state. As noted in the GEO's straw proposal, Maine is on track to meet clean energy workforce goals and renewable targets. In fact, the program has been so successful that it's a victim of its own success. As explained below, compared to when the program began in 2019, there are far fewer opportunities now to cost effectively connect sub-5MW projects to the grid, assuming such opportunities are even available.

Since the beginning of 2019, there have been more than 750 level 4 interconnection applications submitted in Central Maine Power ("CMP") territory and nearly 300 applications submitted in Versant Power ("Versant") territory. Due to project attrition, CMP currently has approximately 500 active projects in its level 4 interconnection queue, while Versant has approximately 180 active projects. The vast majority of these applications are for sub-5 MWac projects, so they presumably intend to take advantage of the NEB Program. This influx of applications has quickly filled Maine's distribution grid capacity, and the Investor-Owned Utilities and ISO-New England have frequently shared that the total capacity of these DG interconnection applications exceed the grid's peak load; the grid wasn't built to handle the unprecedented number of DG projects. The impacts of the DG interconnection queue are being seen on both the distribution and transmission systems in CMP territory, as evidenced by ongoing cluster study delays and required network upgrades, which will cost hundreds of millions of dollars and are expected to take years if not decades to complete.

Dirigo Solar's earliest level 4 interconnection applications were submitted in 2018 and secured some of the earliest queue positions in both CMP and Versant territory. Our company has been fortunate to have additional level 4 interconnection application opportunities since that time, including some as recently as 2022. From our experience across all of our interconnection applications, it is clear that the amount of Chapter 324, distribution upgrades required per project, and their associated costs, are far higher for later queued projects than the earlier applications.

Compounding the increasing costs of interconnecting to the distribution system are the transmission network upgrades that will be required for future DG projects in CMP territory. All projects above 1 MWac require an I.3.9 review which is independent of the Chapter 324 process. The threshold that triggers a cluster study is when there is more than 20 MW of DG capacity in aggregate at a 115 kV substation or electrically close 115 kV substations. Due to the amount of projects in the interconnection queue, CMP began requiring Level 3 Aggregate Studies ("Cluster Studies") for all new projects in 2021. CMP commenced its work on Cluster Studies in 2020 and to-date has completed four studies that have their I.3.9 approval. Despite this, some of the projects in these approved clusters are encumbered by prohibitive cost allocations for transmission network upgrades. CMP currently has 15 additional clusters of DG projects which include 118 projects, and collectively 418 MW, greater than 1 MWac. The majority of the Cluster Studies that have received initial results from CMP are facing prohibitive network upgrades that can involve cost allocations in the millions of dollars for individual projects, which will likely result in significant project attrition and, potentially, entire clusters collapsing.

Given dwindling and increasingly costly NEB opportunities, why should the NEB Working Group focus on *any* successor program limited to 5MW and smaller, particularly when solar projects at scale continue to offer the potential of considerable benefits for ratepayers? Over the last five years alone, the price of solar panels has dropped by close to 50%, enabling developers to deliver solar at prices in the range of $35 – 50/MWh.



To give the GEO a sense of the ratepayer benefits of competitive procurements unencumbered by arbitrary size restrictions, we urge the GEO to consider the results of recent PUC solicitations, and also where the economics of solar are currently.

In response to 35-A M.R.S. § 3210-G, the Commission has undertaken a number of competive solicitations. The weighted average of contracts awarded for the Tranche 1 projects was $35.00/MWh.[3] The weighted average for the Tranche 2 projects was $31.00/MWh. While the industry has experienced higher capital costs and overall contractor expenses since the award of

[3] *Maine Public Utilities Commission*, *Request for Proposals for the Sale of Energy or Renewable Energy Credits from Qualifying Renewable Resources Pertaining to Versant Power and Central Maine Power Company (Tranche 1)*, Docket No. 2020-00033, Order Approving Term Sheets, at 3 (September 23, 2020). A single existing facility award (ReEnergy Livermore Falls, LLC) was $53.00/MWh.

those bids, the economics are instructive and should inform the GEO regarding any successor program.

Current EPC costs are approximately 70% higher than the forecasted EPC costs from bids submitted to the PUC even 24 months ago. Drivers of the increased cost include inflationary and supply chain costs (like shipping), as well as various national and global factors driving up equipment prices and intense local competition for qualified labor. For national and global factors, in 2022, the Biden Administration extended solar panel tariffs initially implemented by the Trump Administration, applying a 15-30% tariff on imported solar panels.[4] An anticircumvention and anti-dumping investigation by Department of Commerce opened earlier this year clogged solar module supply chains, even after the Biden Administration delayed any additional tariffs as a result of that investigation until 2024. Solar supply chains were further constrained when Customs and Border Patrol held shipments of solar equipment at the border due to enforcement of the Uyghur Forced Labor Prevention Act ("UFLPA"), requiring strict documentation of the sourcing of materials for polysilicon used in solar modules.[5] These developments, along with general supply chain constraints and dramatic increases in prices of raw materials used to make solar modules, have substantially increased the equipment costs for the solar projects nationally. Locally, solar construction costs in Maine have faced significantly steeper increases over national solar cost

[4] The White House, "A Proclamation to Continue Facilitating Positive Adjustment to Competition From Imports of Certain Crystalline Silicon Photovoltaic Cells (Whether or Not Partially or Fully Assembled Into Other Products)," February 4, 2022, available at https://www.whitehouse.gov/briefing-room/presidential-actions/2022/02/04/a-proclamation-to-continue-facilitating-positive-adjustment-to-competition-from-imports-of-certain-crystalline-silicon-photovoltaic-cells-whether-or-not-partially-or-fully-assembled-into-other-produc/

[5] *See* "More than 3 GW of solar panels held by US customs under forced labor law," PV Magazine (August 16, 2022), available at https://www.pv-magazine.com/2022/08/16/more-than-3-gw-of-solar-panels-held-by-us-customs-under-forced-labor-law/

increases due to the shortage of labor and contractors needed to install the large volume of solar projects under construction in the state.

A major component of project funding for utility-scale solar is debt financing issued by financial institutions. Global efforts to curb levels of inflation not seen in several decades have added roughly 4% to interest rates in the last two years, with further increases expected from the Federal Reserve. From a project finance perspective, the increase in interest rates means that the Projects will be able to raise less debt from their respective cashflows to fund construction. Typically, a project sponsor would expect to fund approximately 50% of the build costs through bank debt. Given the increase in interest rates, it may not be possible to raise more than 25% of project funding through bank debt due to a combination of EPC costs and federal interest rate hikes. Aside from bank debt, the other primary source of non-sponsor capital to build a project comes from tax equity investors. There are different elements that dictate the size of tax equity funding, but generally tax equity would account for approximately 30-35% of the capital stack for projects. To be sure, the recently enacted Inflation Reduction Act of 2022 enhanced various tax credits that will partially mitigate the higher project finance and other costs. Provided that projects meet certain labor and apprenticeship requirements, the ITC rate will increase to 30% due to the federal legislation. For projects that meet other features of the IRA, a "bonus" ranging from 10% to 20% may be available.

In light of the above, we project that current market conditions will allow projects to be financed in the $0.05 to $0.07 range, and for a variety of sized projects including "distribution projects" broadly defined. We are doubtful that a successor program—whether through a competitive solicitation or a 30% "set aside"—will result in prices at these levels.

B. **<u>Dirigo's Recommendations</u>**

1. Perpetuating a sub-5MW program that is dramatically shrinking and increasingly uneconomic is misplaced, particularly in light of the alarming increase in electricity rates.[6] As a company, we believe (and have proven) that solar can result in a *reduction* in rates and a hedge against regional and national trends beyond our control. If a proposed structure cannot be assured to offer the same or better rates than a competitive solicitation not limited to 5MW, then it should be scrapped.

2. The GEO should recommend to the Legislature that the definition of "distributed generation" be *any* size project located on the distribution network and that future distribution level projects above 1MW participate in a competive solicitation.

3. The GEO should evaluate to determine whether existing regulatory barriers stand in the way of maximizing the development potential of a distributed generation project that can cost-effectively built as the result of a competive auction. One example is the so-called "discrete generating facility" rule. When the legislature enacted "An Act to Promote Solar Energy Projects and Distributed Generation Resources in Maine" in 2019, it charged the Public Utilities Commission with implementing the expanded program. In implementing the Act, the PUC has taken seriously the responsibility of ensuring "that qualifying facilities are, in fact, less than 5 MW, rather than part of another, larger facility." Chapter 313 was amended to read:

"'Discrete electric generating facility' means a facility that is not co-located with or otherwise in geographic proximity to (i) another eligible facility or (ii) a distributed

[6] In 2021, the Standard Offer rate for residential/small commercial class customers in CMP's territory was $0.064/kWh; in 2022 it is $0.118/kWh; and in 2023 it will be $0.1763/kWh. From Spring 2021 to Spring 2022 alone, the average real-time energy price at the ISO New England hub increased approximately $39/MWhISO New England, Spring Quarterly Markets Report, at 23-24 (August 19, 2022), available at https://www.iso-ne.com/static-assets/documents/2022/08/2022-spring-quarterly-markets-report.pdf.

generation resource as defined in Chapter 312 of the Commission's rules in which there is a common financial or other interest that is contrary to the purpose of Title 35-A, sections 3209-A, 3209-B, chapter 34-C."

The PUC has been correct to identify the co-location of distributed generation resources as an important issue that requires regulatory oversight, but it has erred by ruling that "discreteness" applies to solar projects regardless of whether they participate in Net Energy Billing. There is no reason to disqualify a project which is otherwise eligible for NEB because it is located less than 1 mile from a second project owned by the same developer which is not participating in NEB (provided the developer can show no "common scheme of development"). Doing this deprives ratepayers of the cost-savings derived from non-NEB projects and results in otherwise viable, well-sited projects from being built.

4. Finally, the GEO should recommend that the Legislature review the authority of the Public Utilities Commission to assure that future solicitations are conducted with enough frequency, simplicity and size to capture the full benefits of low-cost solar deployment at rates that are at or below all other forms of electricity.

Industrial Energy Consumer Group (IECG) Initial Comments on LD 936 Proposed Framework for Distributed Generation "Successor Program" (Successor Program)

IECG welcomes the opportunity to offer initial comments on the Successor Program proposal created in partial response to LD 936. IECG's comments will also address the command of LD 936 that the Distributed Generation Stakeholder Group (Group) report summarize the lessons learned from the existing Net Energy Billing (NEB) program. IECG combines these topics because prudence dictates understanding the failures of existing NEB before creating another NEB program. That has not been attempted by the Group, so true to ancient wisdom, we risk repeating, in part, the most destructive climate and energy mistake in Maine history.

IECG understands and respects that the Successor Program is a good faith attempt to fulfill the Legislature's request in LD 936 for design of an NEB program more limited in project size and nature than the existing NEB program. As The Successor Program states the Proposal is not any entity's current recommendation, and clearly is not IECG's. The Successor Program allows the basic concepts underlying NEB to be further tested for usefulness. Without the test proposal, some would contend that the flaws in existing NEB would be corrected by certain constraining limitations, such as "smaller" projects.

The dynamics of the Successor Program, however, clearly reveal that the very same flaws that impair existing NEB lie at the heart of NEB itself. The only possible material difference is a —possible— reduction in the total cost of the mistake to ratepayers.

The public interest in more effective climate mitigation and lower electricity costs is not advanced by another NEB mistake, even if it possibly will be a smaller mistake than the mistake of existing NEB. Instead, the public interest is best served by rigorously pursuing cost-effective beneficial electrification and promoting the cost-effective "greening" of the entire grid though renewable energy projects at scale the "biggest bang for the buck". Many cost-superior opportunities are available to Maine. While Maine is making progress in climate mitigation, Maine cannot waste energy investment; Maine has far more mitigation miles yet to travel.

The flaws of greatest significance in existing NEB deserve brief explication:

1. Existing NEB was created entirely by the Legislature with no material input by MPUC or the OPA, and after minimal explanation and public hearing discussion. This dynamic minimized consideration of ratepayer impacts and ratepayer perspectives.

2. The Legislature set the compensation mechanism, or payment rate, based on the current rate that small commercial ratepayers pay for utility delivery service, a cost unrelated to the cost of building and operating NEB of 5 MW or smaller, added to 75% of the current standard offer retail rate, another cost unrelated to the cost of building and operating NEB. As those costs escalate, so does the NEB payment rate. For example, NEB payment rates that began at 12 cents/kWh and 15 cents/kWh for CMP and Versant, in 2021 will be as much as 25 cents/kWh in 2023. These increases also are unrelated to the cost of building and operating NEB.

3. The Legislature also set no binding limitation on the total number of NEB projects or the total MW of the program, thereby setting no limit on the total cost to be borne by ratepayers. In effect , The Legislature created an "entitlement program" for solar developers and financiers at the expense of Maine ratepayers.

4. The Legislature gave MPUC no authority to limit the payment rate for NEB, the total number of projects or contracted MW, or the total cost to ratepayers. No other energy purchase program ever created by the Legislature has failed to give MPUC such essential powers.

5. Despite multiple subsequent opportunities to limit the amount of NEB and the payment rates for NEB, the Legislature did not act to impose binding limits on NEB MW purchases or to freeze or reduce the original payment rates for NEB. Today, the payment rate continues to escalate without regard to the cost of building and operating NEB and the total MW of NEB projects 2 MW or smaller remains entirely unlimited. Further, the Legislature's "goal "of a 750 MW limit on projects up to 5 MW in size, based on NEB advocate assertions, appears to likely to be at least doubled to 1500 MW for NEB in service by 2025.

6. The Legislature required no competitive bidding in any form to obtain an NEB contract. The nearly simultaneous competitive bidding conducted by MPUC pursuant to other renewables legislation produced solar projects with greater societal benefits (environmental, employment, and grid-supporting) than NEB, but at only at 3-5 cents/kWh for twenty years. This represents payment rates at 25% of the cost of NEB, or even less.

7. The consequences of existing NEB to ratepayers appear increasingly certain. Based on monthly updated reports of NEB activity from CMP and Versant, if all currently active NEB projects come on-line as required by 2025, CMP ratepayers will shoulder additional costs above current rates of $243 million per year, or a total of $5 billion over the twenty- year NEB contracts (See Attachment A). Versant ratepayers will shoulder additional costs of $100 million annually and a total of $2 billion over the twenty- year contracts (See Attachment B). These amounts in only one of many state energy programs approximately equal the entire present cost of delivering service to the ratepayers of each utility.

8. The significant difference between the cost of NEB and solar projects competitively bid by MPUC consumes money ratepayers might prefer to keep to pay their bills, or which could be used to greatly increase the speed of Maine's pursuit of beneficial electrification and thus climate mitigation. For example, the Efficiency Maine Trust has invested in the installation of more than 80,000 heat pumps. Every heat pump frees a Maine family of material reliance on heating oil, propane, or kerosene – all price-volatile, expensive and carbon-rich fuels. Maine's reliance on oil for heat remains at near 60% of all households, the highest in the nation after Alaska. The human and climate toll of this reliance puts in full context the moral error of unnecessary expenditures on NEB.

Examination of the Proposed Successor Program reveals cost-increasing factors similar or identical to certain of those which have made existing NEB exorbitantly expensive:

1. The Successor Program would be designed once again entirely by the Legislature, with no ability of MPUC to determine the size or total number of projects, rates to be paid, total ratepayer cost or to fix discovered malfunctions.

2. The Successor Program would allow only narrowly limited competition, with bidding among those smaller eligible projects meeting only 70% of the target acquisition. The other 30% would receive a fixed price without any competition to further lower the cost. This absence of a rigorous competition mechanism ignores the fact that in a similarly limited previous DG competition, the Commission voided the results because of possible anticompetitive bidder behavior. This is always a risk, and especially in artificially limited competitions.

3. Most importantly, by creating another unjustified size limitation on competition, the Successor Program will cost ratepayers at least twice as much for project output as would be paid by allowing competition without regard to size. There will be no societal benefits that could not be obtained from larger, less expensive projects. In other words, there is no need for, and no public policy justification for, the increased costs. In the alternative, MPUC has existing authority to acquire solar through full competition, which would acquire at least twice as much solar energy for the same total cost as would the Successor Program, also with twice as much delivered societal non-cost benefits.

4. The Successor Program contains untested complexities to achieve societal goals of aiding low-income persons and rewarding locations on brownfield sites, without any MPUC authority to modify the goals, the cost-increasing mechanisms, or otherwise protect ratepayers. Moreover, as the proposal draft acknowledges, these incentives are redundant of large new federal tax incentives enacted in the Inflation Reduction Act to achieve exactly the same objectives. Thus, the only purpose of these incentives is to increase the ratepayer cost by around 10% as a reward for the developer receiving large federal tax benefits of some 20%. This is a classic example of an industry camouflaging its financial benefits. Ratepayer costs would increase by 10% because the developer has received a 10-20% or more in federally subsidized reduction in its costs. This makes no sense. The federal incentives are both efficient and adequate.

5. The Successor Program acknowledges that it is not integrated with existing NEB, including the ongoing and quantitatively unconstrained 2 MW and smaller project NEB incentives. Careful, intelligent integration of any new program is ignored at ratepayer peril and to the glee of developers. For example, some developers are pursuing fuel cell NEB under the existing program for projects of 2MW or less—with the fuel cells powered by natural gas. (Yes, natural gas; read the definitions of Title 35-A carefully). Fuel cells operate above 90% capacity, meaning that a 2 MW fuel cell produces six times the output of a 2 MW solar project, resulting in six times the total cost to ratepayers, while actually increasing Maine's GHG emissions. There is no limit in the number of projects or total ratepayer cost of NEB of

this size. This is the risk to ratepayers created by the Legislature supplanting the MPUC's judgement and fulsome consideration of complex matters.

6. The Successor Program does nothing to change the inequities imposed on the vast majority of ratepayers created by existing cost allocation mechanisms. Currently, as well as under the Successor Program, the cost of energy purchased at above market rates would becomes stranded costs and, apparently, be allocated among all ratepayers. This continues the existing imbalance between project participants, who are subsidized to engage in NEB and thus who save money and all other ratepayers who share equally in the cost. This failure in energy equity becomes glaringly apparent when the proposed program, for example, is compared to solar, purchased at less than half the cost through full competition with no limits on size. This cost-efficient alternative produces little or no stranded costs, and perhaps actually offsets high market costs, and delivers at least twice the societal benefits at such lower cost.

7. Similarly, the Successor Program makes no change to the additional inequity of forcing other ratepayers to pay higher rates to make up for the decreased revenue contributions to the electric utility of the NEB participants. As IECG analysis shows in Attachments A and B, based on MPUC reports, this specific inequity will raise the rates of remaining utility ratepayers by $125 million annually for existing NEB. The Successor Program increases the injustice. No estimate of these ratepayer harms from the Successor Program has apparently been attempted.

Once again, IECG respects that GEO is obligated to prepare the report requested by LD 936 and has done so with highly significant effort and consultant assistance. GEO's administration has been thorough, efficient and diplomatic.

IECG observes, however, the striking continuation of limited interest, at best, in the financial consequences to ratepayers and to Maine's critical climate initiatives of existing NEB at all moments of legislative and governmental consideration. Perhaps the harm is so huge, so awful that we cannot bear to discuss it, much as we look away from a horrible accident.

IECG warned at the creation of NEB of the consequences, but IECG gets no comfort in having predicted the result. Instead, IECG regrets that the monies which will be spent involuntarily by all ratepayers on NEB renewables(that should have cost 25% of the estimated 7 billion NEB will cost) will not be available to be spent where needed most: to take 300,000 Maine households off heating oil and propane with heat pumps, to weatherize the nation's oldest housing stock, to incentivize electric vehicles in the state with the most significant commutes by vehicle and to otherwise aggressively pursue beneficial electrification. Time is not on Maine's side, or the planet's.

Existing NEB is by far the largest climate mistake in Maine history. It demonstrates the cost of politics and fear triumphing over critical thought. Understanding the causes and scope of the mistake is essential to mitigating the mistake and avoiding its repetition. Here, due to LD 936, the DG Stakeholder Group and GEO are obligated to present the framework of a successor program. Ethan Tremblay and GEO and its consultants have done their best; the DG Stakeholder Group will offer useful comment, as IECG attempts here. But there is a reality that time has taught and that we must acknowledge.

NEB was and remains a terrible mistake. The proposed Successor Program implicitly acknowledges this reality by offering a program with smaller projects, some limited competition and other constraints. Yet the truth is the proposed Successor Program also is a mistake, one whose only virtue is that it is a smaller mistake.

Maine cannot afford any further climate mistakes. If Maine needs more DG, MPUC has existing authority to acquire it on a fully competitive basis, and therefore at lowest cost and most efficiently acquired social benefits.

IECG recommends that the only Successor Program which should be enacted would be to vest in MPUC authority to acquire the resources and cause the funding necessary to accomplish beneficial electrification at the lowest cost to Maine ratepayers. This would be consistent with the recent legislative addition of climate mitigation to the Commission's virtual charter. The Legislature in 1913 created the Commission to oversee the complex world of utility development and regulation. A century and more later, history teaches another timely lesson.

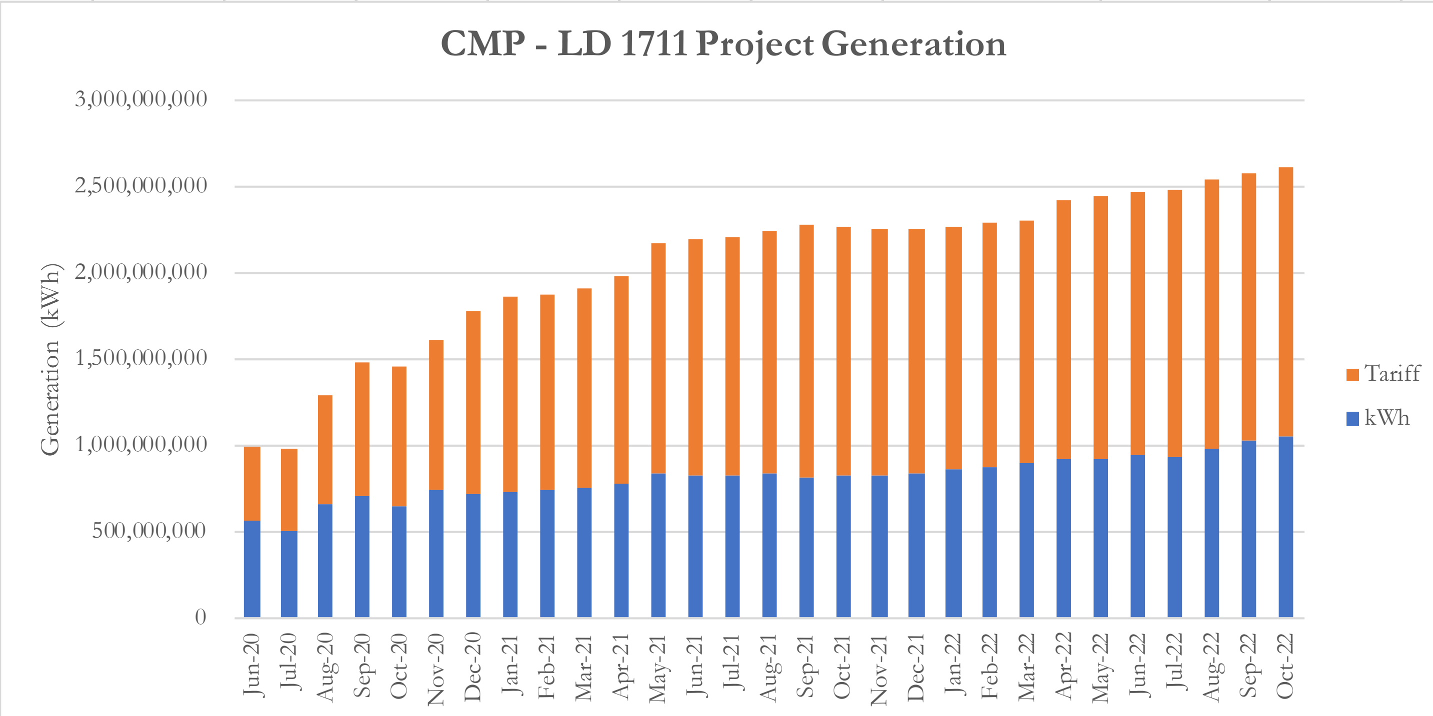
Respectfully submitted,

Anthony W. Buxton

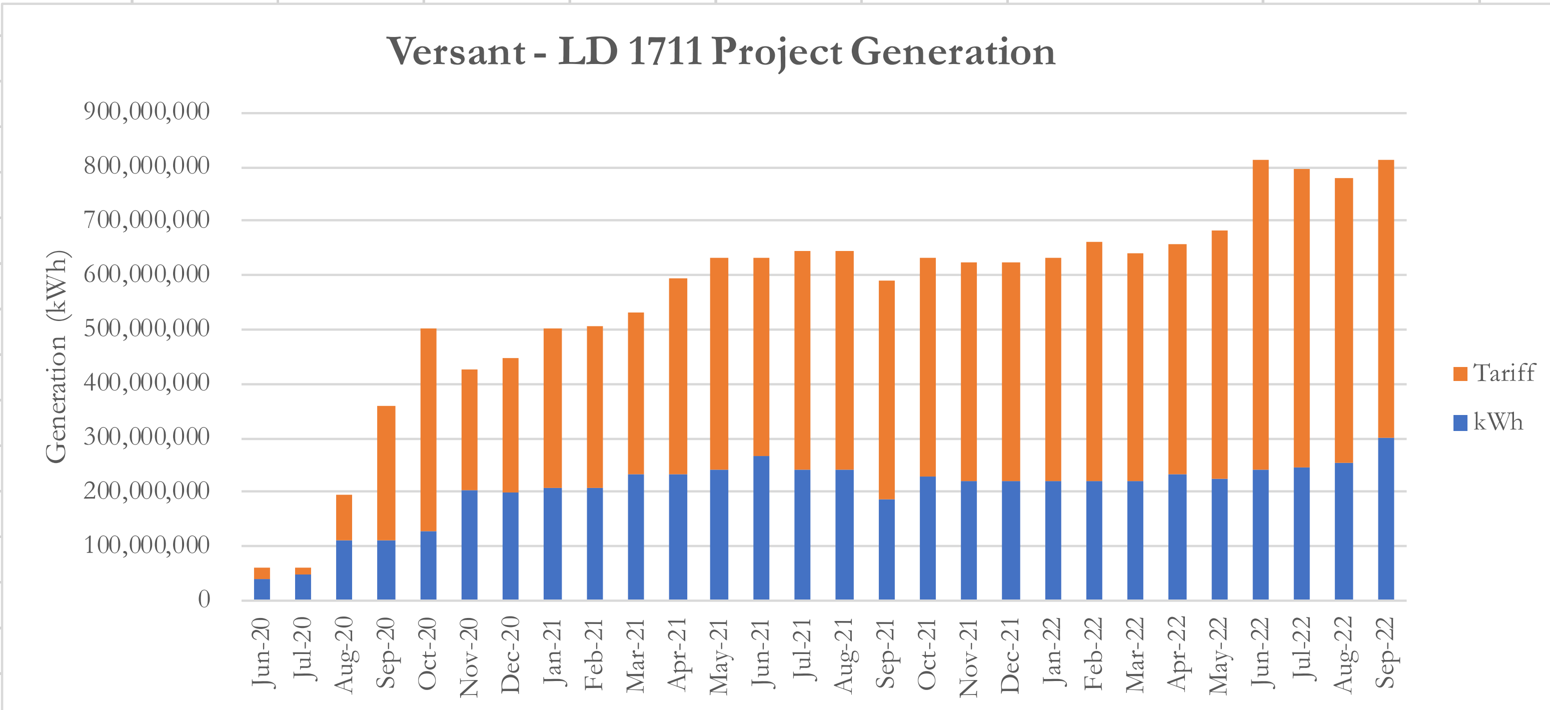
Anthony W. Buxton
Preti Flaherty
Counsel to Industrial Energy Consumer Group

Attachment A – CMP

Attachment B - Versant



As of End of October 2022 - Assuming all Projects Get Built		**$/MWh**
Estimated Value of Lost Sales - kWh Program	$92,442,638	$87.75
Estimated Tariff Program Gross Costs	$293,719,480	$188.94
Less Estimated Value of Energy	$143,208,787	$96.82
Estimated Net Cost of Tariff Program	$150,510,694	$92.12
Estimated Total Cost of Net Energy Billing	$242,953,332	
Total CMP Load - MWh	9,000,000	
Cost per MWh	$26.99	



As of End of September 2022 - Assuming all projects Get Built		**$/MWh**
Estimated Value of Lost Sales - kWh Program	$34,680,232	$98.46
Estimated Tariff Program Gross Costs	$105,813,643	$204.26
Less Estimated Value of Energy	$39,666,647	$127.69
Estimated Net Cost of Tariff Program	$66,146,996	$76.57
Estimated Total Cost of Net Energy Billing	$100,827,228	
Total Versant Load - MWh	1,900,000	
Cost per MWh	$53.07	

Tremblay, Ethan

From: Sharon Klein <sharon.klein@maine.edu>
Sent: Wednesday, December 14, 2022 8:06 AM
To: Tremblay, Ethan
Subject: Comments on Proposed Framework DG stakeholder working group

Hi Ethan,

I want to provide some comments on the proposed framework. I am not sure if it is better from your perspective for me to email them directly or fill out the public comment form. I suspect you want stakeholder group members separate from public comment, so I am emailing them, but let me know if you want me to fill out the form instead.

Overall, I think the competitive procurement approach is sound for the 70%. I think this part needs work, however: "Projects sited in "low income or disadvantaged communities" and that demonstrate meaningful benefits to the community will be evaluated at 95% of bid price". Siting of projects should not be encouraged in low-income or disadvantaged communities unless the communities are true partners in project development from the very beginning and unless the project includes partial or full ownership by the community. Without those conditions, "meaningful benefits" is too vague of a phrase that could mean anything depending on the perspective and could lead to more energy development like the past in which disadvantaged communities get saddled with development they don't want and isn't good for them, contributing to energy inequities, rather than mitigating them.

Also, projects sited on brownfields, rooftops and/or that include an agrivoltaic component co-developed with farmers should be evaluated at 80% of the bid price - it sends a stronger incentive to avoid clear-cutting forests or taking over farmland. I don't think the brownfields requirement necessarily has to match the IRA - we should include what works best for our state. As I understand it, the "energy communities" portion of the IRA is more geared toward coal and natural gas communities, which don't relate much to us. But, we do have old mills, military spaces, landfills, and other sites that may not fit a federal "energy communities" brownfields definition but would be better for solar development than forests or farmlands.

I think the 30% community access portion needs a lot of work. Based on our discussions and the phrase "community access", I interpret this section to be the place in the proposal that is attempting to set aside some procurement capacity for community ownership. If that is the case, I agree there should be some portion set aside and dedicated to community ownership. I think this approach fits nicely with growing momentum for community-initiated energy solutions in GOPIF's Community Resilience Partnership. It also responds to concerns from Mainers all over the state that post-2019 legislation, solar development in Maine is following similar developer-led growth and ownership patterns as other energy options have, leaving most of the rewards to be gained by large companies often outside of the state rather than directly to communities within the state. Setting aside some capacity for community ownership will help retain a certain measure of the economic value of medium-size solar projects within the state and directly benefit Mainers over the long-term.

Community owned projects need support, however. Currently, each community owned project across the country is recreating the wheel every time. It is a much less standardized approach than utility-scale, large commercial, or developer-led community solar. Communities need guidance to even know it is a possibility, information-sharing to understand best practices, and will likely have unique issues that need to be resolved for projects to get off the ground. This uniqueness, at least at the beginning until learning can lead to more standardization may initially be more costly than a developer-led community solar farm for example. But, the long-term benefits to Mainers of community-owned solar are greater than developer-led solar. Financially, communities retain more of the economic value over the long-term. And, communities will likely site projects in a way that is more beneficial to their specific communities (and likely to Maine as a whole) - i.e., using available rooftop, municipal, landfill, or brownfield space and/or potentially including an educational component which helps advance renewable energy more broadly.

Because of these nuances, the current walk-up approach is not the correct approach for a goal of true community access if community access includes community ownership. Annual procurement bidding processes will likely be too complicated for the target population. The 20th percentile price point is likely too low, and a $/kWh incentive may not be the most appropriate in general. What community projects need the most is upfront capital to install the projects. Rather than providing a set $/kWh payment, I would recommend an upfront payment of all or most of the installation costs in the form of a grant or other direct one-time subsidy. Efficiency Maine used to administer a solar rebate program. They could be directed by the legislature to implement a grant program like this or GOPIF could include it as part of their Community Resilience Partnership program - a special sub-category of bi-annual Community Action Grants.

Years back, Maine had a community energy pilot program. Back then none of the projects were solar because the price of solar hadn't yet dropped. The "community access" program should build on learnings from that program and from the more recent Community Resilience Partnership. This would be a completely different approach from the 70% competitive procurement or the proposed walk-up. The community access program should include specific criteria the projects need to meet: positive net present value, benefit-cost ratio greater than 1, electricity bill savings for offtakers of at least 30%, 50-100% low-income offtakers or the community itself has a certain median income or % in poverty or is high on the social vulnerability index, siting on brownfields or other previously developed land, landfills, or rooftops, an educational component, etc. I would recommend leaving the number of or existence of offtakers flexible. We don't want to prescribe that these projects take on a community solar approach but leave that option open if that is what communities need/want. These criteria should be developed and refined through a process of targeted focus groups with communities high on the state social vulnerability index, in which they are compensated for their time.

A community access program like this should require that the applicants are municipal or tribal governments, schools, or any other community-serving organization. I found this definition of "community-based organizations" helpful in this context - however, I like the term "community-serving" better:

"CBOs are representative of a community or significant segments of a community, defined by place or population, and provide financial, educational, cultural, and/or other resources aimed at enhancing health, wealth, and overall community well-being. For-profit entities and large nonprofits with a particular area of focus beyond the local level are typically excluded from this definition. Ideally, CBOs are physically based in the communities they serve, though in some cases CBOs can be effective even without a physical presence. CBOs range from formal organizations with legal non-profit status (501c3, c4, etc.) to informal, grassroots community groups that are mission-driven and headed by respected community leaders. (Definition adapted from the Just Transition PowerForce)" from this website

It is important to provide flexibility in the interpretation of CBOs beyond established local governments because sometimes local governments are hindered by bureaucracy, limited understanding/awareness, and are not always trusted by their constituents. Sometimes schools and community groups can get more done quickly with less red tape.

I think there will still be enough incentive for developer-led community solar across these 2 programs because there is nothing preventing community solar developers from bidding into the procurement - there is nothing prohibiting offtakers, right? And, community solar developers could partner with communities on co-developing proposals for the community access program.

I also think for long-term sustainability, all projects (the 70% procurement and 30% community access) should include storage.

Other recommendations I would like to see included:

1. There has been a lot of talk in this working group and in the offshore wind working group about the need for a more transparent and publicly available model of the transmission and distribution grid to more easily identify potential sites where DG would be beneficial or problematic. With the current interconnection bottlenecks we are seeing, I think this group should make some recommendations about this. We don't want this procurement or community access program to get developed and then have projects waiting in an interconnection queue for years like they currently are. Ideally there would be some publicly available map of sites that are pre-approved for interconnection up to a certain capacity. Closely related to that, there needs to be some study of what grid upgrades need to happen regardless of increased DG development (i.e., based on beneficial electrification projections and normal grid expansion), how those will be paid for, and how to not pass those on to individual DG projects as part of interconnection agreements when they are something that would be needed anyway as part of upgrading an aging grid.

2. The Electric Ratepayer Council is working now and for the next 3 years on strategies to reduce electricity costs to ratepayers. There should be some mention of that group in this framework as a potential way to carry forward or collaborate on some of the recommendations. For example, the part about the IRA 20% that says "net revenue from project contracts will be designated to provide electricity bill relief to qualified customers through a credit that complies with forthcoming guidance established by the U.S. Department of the Treasury to establish qualification for this tax credit" relates directly to work the Electric Ratepayer Council is doing to study and make recommendations about streamlining benefits (i.e., bill credits) for low-income customers to make it easier for them to pay their bills if they can and access assistance if they can't. There has been much discussion in that group about how low-income Mainers can't actually access the benefits of traditional developer-led community solar because of the way existing benefits/assistance programs work. So, the work that group is doing to make assistance easier and more efficient for low-income Mainers should also align with future solar DG programs that could provide direct benefits to the same population.

Thank you for your leadership in this effort! Let me know if you have any questions about any of this.

Cheers,

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The University of Maine is located on Marsh Island, the homeland of the Penobscot Nation.
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Janet T. Mills
GOVERNOR

William S. Harwood
PUBLIC ADVOCATE

December 15, 2022

L.D. 936 Distributed Generation Stakeholder Group

Comments of the Office of the Public Advocate on Final Report to the Legislature

The Office of the Public Advocate (OPA) offers these comments on the proposed final report of the Distributed Generation (DG) Stakeholder Group. OPA represents the interests of Maine's utility customers and is a designated participant in the DG Stakeholder Group.

Maine has adopted ambitious targets for renewable energy, including requirements that 80% of retail sales of electricity come from renewable sources by 2030, and 100% by 2050.[1] There is no question that Maine must shift away from fossil fuels to clean sources of energy. But to achieve this necessary transition, it must be done in a way that contains costs to utility ratepayers. Controlling the rising cost of electricity is not only important for Mainers who are struggling with record high energy prices,[2] but it is also critical to electrifying Maine's heat and transportation sectors. As electricity prices rise, the incentive to switch to an electric vehicle or install heat pumps, all else equal, is reduced. Cost must therefore be the primary consideration for a successor DG program.

Maine's net energy billing (NEB) programs have failed to contain costs or deliver benefits to most of Maine's electric ratepayers. Reforming these programs is critical to ensuring that Maine can continue to accelerate the clean energy transition without making electricity unaffordable.

OPA supports four fundamental recommendations to reduce the cost of DG, eliminate the drawbacks of NEB, and maximize the benefits delivered to all ratepayers:

(1) Using a competitive procurement process for DG results in the lowest costs per MWh of renewable energy delivered to the grid. Competitive procurements should replace

[1] 35-A M.R.S. § 3210.
[2] *See* Synapse Energy Economics, Inc., Maine Low-Income Home Energy Burden Study, Final Report at 17-18, available at https://www.maine.gov/meopa/sites/maine.gov.meopa/files/inline-files/Maine%20Low%20Income%20Energy%20Burden%20Study%20June%202019.pdf (June 3, 2019) (finding that "low-income households in Maine have high energy burdens"). This report was prepared prior to the significant increases in electricity supply prices in 2022 and 2023, which likely exacerbated the energy burden for low-income Mainers.

existing NEB programs and NEB should be limited to projects less than 1 MW in size that are either located behind-the-meter or in close proximity to all offtakers.

(2) Shifting the DG compensation model from a bill credit approach to a wholesale power purchase agreement (PPA) approach[3] will simplify the program for customers, reduce administrative expenses, capture the value of renewable energy credits (RECs), and eliminate equity concerns created by NEB.

(3) Replacing NEB programs with competitive procurements and limiting NEB to projects less than 1 MW in size that are either located behind-the-meter or in close proximity to all offtakers strikes an appropriate balance between reducing the costs of NEB while still allowing for rooftop and community solar projects.

(4) Including energy storage can add value to DG projects but there remain significant questions surrounding how storage will be compensated under a wholesale PPA model.

The remainder of these comments will elaborate on these four points.

1. **Using a competitive procurement process for DG results in the lowest prices per MWh of renewable energy delivered to the grid.**

   a. <u>NEB programs are an extremely expensive way to encourage DG development.</u>

The costs of the current NEB programs are astronomical and unsustainable. According to a 2020 report prepared by the Maine Public Utilities Commission (Commission) for the legislature, the net costs to ratepayers of the current NEB programs is conservatively estimated to be $161 million annually.[4] That is the equivalent of more than $280/year in increased costs for every household in Maine.[5] According to Synapse, the current tariff rate NEB program has a benefit-cost ratio of just 0.39, meaning that for every dollar spent, the program returns just 39 cents in benefits.[6]

While some reports[7] claim that calculations of the net cost of NEB ignore important categories of benefits provided by solar energy, such as environmental and economic benefits, these types

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[3] OPA recognizes that L.D. 936 refers to bill credits and offtakers. However, the entirety of L.D. 936 makes clear that the legislature did not intend to limit the focus of the Stakeholder Group to evaluating DG models that only include offtakers. Instead, the legislature tasked this group with evaluating all reasonable options and providing recommendations regarding DG in general.

[4] Maine Public Utilities Commission, Report on Effectiveness of Net Energy Billing in Achieving State Policy Goals and Providing Benefits to Ratepayers, at 10 Figure 2, Nov. 10, 2020, available at https://www.maine.gov/mpuc/legislative/reports.

[5] U.S. Census Bureau, QuickFacts Maine, https://www.census.gov/quickfacts/fact/table/ME/HSD410221#HSD410221 (571,064 households in Maine).

[6] Synapse Energy Economics & Sustainable Energy Advantage, Final Benefit-Cost Analysis Results and Sensitivity Analyses, at 15, December 6, 2022. All of the stakeholder consultant documents referenced in these comments are available at https://www.maine.gov/energy/studies-reports-working-groups/current-studies-working-groups/dg-stakeholder-group.

[7] Daymark Energy Advisors, Costs and Benefits of Maine's Net Energy Billing Program (Mar. 11, 2021), available at https://www.renewablemaine.org/docs/Costs_and_Benefits_of_Net_Energy.pdf.

of analyses are largely beside the point because any solar project is going to provide similar benefits.[8] The fact that solar may have a high value is not a reason to pay more than necessary for it. The legislature should focus on the relative cost of proposed DG programs because the benefits are likely to be similar.

The final report should emphasize the magnitude of the costs of the current NEB programs so that the legislature can fairly evaluate the benefits of alternative approaches.

b. Competitive procurements result in the lowest reasonable cost to ratepayers.

Fortunately, the analyses produced by GEO's consultants as part of this stakeholder group have shown that there is a more cost-effective approach to distributed generation: competitive procurements. The analysis prepared by Synapse Energy Economics (Synapse) and Sustainable Energy Advantage (SEA) concludes that the competitive procurement approach "is likely to result in the **lowest reasonable costs to ratepayers of projects that can reasonably be expected to reach commercial operation**."[9] This conclusion is supported by real-world results in other jurisdictions, such as Rhode Island.[10] Maine's own experience with procurements for grid scale renewable energy has produced impressive results, yielding average prices of approximately \$35/MWh[11] and \$31/MWh[12] for new projects across two procurements.

OPA supports a simple, competitive procurement for DG that would be administered by the Commission for the total amount of targeted capacity. The procurement process should not include burdensome requirements related to providing in-state economic benefits or other conditions on proposed projects. Such conditions will only increase prices. There should be no capacity set aside for projects outside of the procurement. While the goals of such set-asides are laudable, they will only complicate the program, which leads to higher costs.

The Commission, in consultation with the utilities, should identify areas of the grid where DG would provide the greatest benefits and then issue a request for bids for projects located in those areas. This will ensure that DG is sited in areas where it will provide the greatest benefits and require the fewest distribution system upgrades, ultimately leading to lower prices.

To the extent there are opportunities for government grants or tax credits, those could be pursued by setting aside specific projects to benefit a particular subset of customers. For example, a specific project could be designated to benefit low-income customers by using project revenues to fund an expansion of the utilities' low-income assistance programs.[13]

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[8] Synapse Energy Economics & Sustainable Energy Advantage, Workshop #4: Draft Results of Economic Evaluation, at 18-20, November 17, 2022 (finding similar benefits for all DG program options).
[9] Synapse Energy Economics & Sustainable Energy Advantage, Solar PV Project Revenue Requirement Modeling Results, at 8, Nov. 22, 2022.
[10] *Id.*
[11] *Public Utilities Commission*, Request for Proposals for the Sale of Energy or Renewable Energy Credits from Qualifying Facilities, No. 2020-00033 Order Approving Term Sheets, at 3 (Me. P.U.C. Sept. 23, 2020).
[12] *Public Utilities Commission*, Request for Proposals for the Sale of Energy or Renewable Energy Credits from Qualifying Facilities, No. 2021-00004 Order Approving Term Sheets, at 3 (Me. P.U.C. June 29, 2021).
[13] *See generally* Maine Office of the Public Advocate, Electric Ratepayer Advisory Council, Initial Annual

Discretion could be vested in the Commission to capitalize on these opportunities, if available, as part of a planned procurement.

2. **Shifting the DG compensation model from a bill credit approach to a wholesale PPA approach will simplify the program for customers, reduce administrative expenses, capture the value of RECs, and eliminate equity concerns created by NEB.**

   a. NEB has many drawbacks beyond its high cost.

Beyond their sheer cost, the existing NEB programs are confusing for customers, add significant administrative burden on utilities, fail to monetize the value of renewable energy to offset the cost of the programs, and create equity concerns due to cost shifts between ratepayers.

OPA routinely receives calls from customers with questions about solar NEB programs. Many customers have been on project waiting lists for years; others have received inaccurate or confusing bills from project sponsors. Despite recent legislation designed to protect customers,[14] Mainers have been subjected to aggressive and deceptive sales tactics from marketers that make misleading promises of guaranteed savings and inaccurate claims regarding the use of renewable energy.[15]

NEB not only creates challenges for customers, it also affects utilities. Utility billing systems were not designed to apply bill credits generated by a single project to hundreds of customer bills. Inevitably, NEB creates billing issues and customers contact their utility with questions about and requests related to NEB. Responding to these inquiries and working through billing issues requires significant additional work on the part of the utility, the cost of which is ultimately passed on to ratepayers.

Another major drawback to NEB programs is that they fail to capture the value of the renewable nature of the energy generated because there is no requirement that project sponsors deliver renewable energy to their subscribers. Under NEB, project sponsors retain the RECs generated by a facility.[16] These RECs can be sold in out-of-state REC markets to create an additional revenue stream for the project sponsor.[17] As a result, and likely unbeknownst to many participants in these programs, there is no guarantee that the energy consumed by NEB participants is renewable. Because NEB project sponsors are not subject

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Report (December 1, 2022), available at https://www.maine.gov/meopa/reports-and-testimony/council (describing Maine's low-income assistance programs and the need for greater funding).

[14] 35-A M.R.S. § 3209-A(5).

[15] *See* 16 C.F.R. § 260.15(c) ("If a marketer generates renewable electricity but sells renewable energy certificates for all of that electricity, it would be deceptive for the marketer to represent, directly or by implication, that it uses renewable energy.").

[16] Commission Rules Chapter 313 § K(6). In the case of a facility enrolled in the kWh credit program, the facility acts as a load reducer and no energy or renewable energy credits are transferred to the utility.

[17] *See* https://www.poweradvisoryllc.com/reports/recs-and-srecs-still-playing-an-important-role-in-east-coast-renewable-energy-project-economics (showing historic REC prices in New England states).

to Maine's RPS requirements,[18] they are under no obligation to retire any of the RECs associated with project generation. This is a major oversight of the current NEB programs. Not only are ratepayers paying far too much for energy generated under NEB, the rules do not require that RECs be transferred to subscribing customers or monetized on behalf of all ratepayers. The OPA is interested in exploring a program whereby RECs that are not transferred to an offtaker, would be transferred to the utility to be sold, and the proceeds would be dedicated to expanding funding for utility low-income assistance programs.[19]

Finally, NEB creates major equity concerns because, by design, it shifts costs from program participants to non-participants. Thus, while the costs of NEB are broadly shared by ratepayers, the benefits accrue only to a select few who participate in the programs. While OPA is not aware of any analysis of the demographics of NEB participation, it is reasonable to assume that low-income customers are likely underrepresented as they often face obstacles to participating in such programs.[20]

b. A wholesale PPA approach to DG procurement eliminates the drawbacks of NEB.

A wholesale PPA model corrects the deficiencies of NEB. Using a competitive procurement process described above, a winning bidder would be selected to enter into a PPA with the appropriate utility at a fixed price per unit of energy generated and delivered to the grid over the term of the contract. The utility would be tasked with selling the energy generated by the project in the wholesale market (or as otherwise ordered by the Commission). The net costs or benefits of the contract would then be included in the utility's stranded cost revenue requirement. There would be no offtakers and no bill credits; benefits would instead accrue to all ratepayers.[21] This eliminates the undesirable cost-shifting inherent in NEB programs.

According to Synapse and SEA, the wholesale PPA model is the least expensive option under any of the scenarios modeled.[22] It provides the most benefits of any program type, including the greatest overall reduction in rates.[23]

A PPA is much simpler for utilities to administer compared to NEB. Because there are no bill credits involved, nothing is required from the utilities' customer billing systems. Maine's two investor-owned utilities already have experience acting as counterparties to long-term energy

[18] *See Public Utilities Commission*, Amendments to Portfolio Requirement Rule, No. 2021-00213 Order at 4 (Me. P.U.C. Nov. 4, 2021) (noting that a significant portion of Maine's retail metered electric load will not be subject to RPS requirements as NEB grows).
[19] OPA thanks AARP Maine for proposing this idea during the DG Stakeholder Group meetings. This recommendation is also included in the Electric Ratepayer Advisory Council Report. *See* Maine Office of the Public Advocate, Electric Ratepayer Advisory Council, Initial Annual Report at 44 (December 1, 2022), available at https://www.maine.gov/meopa/reports-and-testimony/council.
[20] Jocelyn Durkay, NCSL, Energy Efficiency and Renewables in Lower-Income Homes, Feb. 2017, https://www.ncsl.org/research/energy/energy-efficiency-and-renewables-in-lower-income-homes.aspx#:~:text=Did%20you%20know%3F,and%20lack%20of%20home%20ownership.
[21] As discussed above, specific DG projects could be designated to benefit low-income customers.
[22] Synapse Energy Economics & Sustainable Energy Advantage, Workshop #4: Draft Results of Economic Evaluation, at 18-20, 31-32, November 17, 2022.
[23] Synapse Energy Economics & Sustainable Energy Advantage, Final Benefit-Cost Analysis Results and Sensitivity Analyses, at 12-19, December 6, 2022.

contracts. The incremental administrative expense of managing additional contracts will be much lower compared to the complexities of managing the arcane bill credit system created by NEB.

The PPA model also allows Maine to capture the value of RECs generated by DG projects. Project owners would be required to transfer RECs to the utilities under the terms of the PPA. The utility would be required to resell the RECs to increase the monetary benefits of the program to benefit ratepayers.[24]

3. **Replacing NEB programs with competitive procurements and limiting NEB to projects less than 1 MW in size that are either located behind-the-meter or in close proximity to all offtakers strikes an appropriate balance between reducing the costs of NEB while still allowing for rooftop and community solar projects.**

The final report should recommend that the NEB programs for projects larger than 1 MW should be replaced entirely by a competitive procurement model for the reasons discussed above. Procurements would be open to projects of any size under 5 MW, or that meet the definition of distributed generation as otherwise defined.

OPA recommends that NEB continue to be available for projects smaller than 1 MW in size, but only if the project is located behind the customer's meter or in close proximity (within one mile) to all offtakers. For simplicity, NEB should be limited to the kWh credit program, and such projects should continue to be treated as load reducers. These changes will return NEB to what existed prior to the enactment of LD 1711,[25] with a somewhat higher capacity cap for community solar projects located near all offtakers.[26] The Commission should continue to monitor the costs of NEB and recommend changes as needed to control costs.

This compromise between prioritizing competitive procurements for larger developments, while still allowing for rooftop and true community solar, will limit the cost of NEB and encourage DG development in a more cost-effective manner.

4. **Including energy storage can add value to DG projects but there remain significant questions about how storage can be required to perform and how it should be compensated.**

Due to the intermittent nature of renewables like solar and wind, energy storage will be an important part of achieving Maine's climate goals. Maine has adopted aggressive targets of 300 MW of installed energy storage capacity by 2025 and 400 MW by 2030.[27] The analysis performed by Synapse and SEA shows that storage has great potential to increase the value of

[24] Synapse Energy Economics & Sustainable Energy Advantage, Workshop #4: Draft Results of Economic Evaluation, at 23, November 17, 2022.
[25] P.L. 2019 ch. 478.
[26] Prior to LD 1711, NEB was limited to projects with an installed capacity of 660 kW or less. *Public Utilities Commission*, Amendments to Chapter 313 – Net Energy Billing, No. 2019-00197 Notice of Rulemaking, Chapter 313 Redlined (Me. P.U.C. Aug. 21, 2019).
[27] 35-A M.R.S. § 3145.

DG by allowing a facility to deliver energy to the grid during peak times when it is more valuable.[28]

As a general matter, OPA supports including cost-effective energy storage in DG procurements. However, there are significant questions around how energy storage can best be incorporated in a DG program, including:

1. How to incentivize or require that energy storage deliver energy to the grid during times when it is most valuable.
2. The feasibility and cost of adding storage to existing DG projects.
3. Whether energy storage is more valuable when co-located with a DG project or sited independently at strategic locations across the grid.

One possibility for structuring a PPA to include storage would be to provide two-tiered pricing in contracts awarded in DG procurements. One price for energy delivered during off-peak hours, and a higher price for energy delivered during peak hours. This would incentivize the owner of the project to manage the energy storage system to deliver energy to the grid during peak hours when it is most valuable.

Given the complexity that energy storage presents, the legislature should consider delegating to GEO and the Commission the task of developing a plan to include energy storage in procurements in the most cost-effective manner.

Conclusion

OPA thanks GEO for convening the DG Stakeholder Group and the other stakeholders for participating in this important process. The information generated and valuable insights from stakeholders in this group will provide a foundation for legislation to create a more cost-effective and sustainable DG program.

William S. Harwood, Public Advocate

Brian T. Marshall, Senior Counsel

[28] Synapse Energy Economics & Sustainable Energy Advantage, Final Benefit-Cost Analysis Results and Sensitivity Analyses, at 25-27, December 6, 2022.

SOLAR ENERGY ASSOCIATION OF MAINE

December 12, 2022

To: Distributed Generation Stakeholder Group

From: Steve Weems, Executive Director

Subject: Additional Comments on the Proposed Framework for the Distributed Generation successor Program

Thank you for the opportunity to comment further on the Proposed Framework for the Distributed Generation Successor Program published November 23, 2022. Please add the comments below to those submitted on December 5, which are included in this communication after the comments submitted today.

DG Successor Program

It was disturbing to listen to the commentary among the DG stakeholders last Tuesday (December 6) about potentially eliminating the Moderate Hedge component of the Proposed Framework, and/or eliminating the provision that named Offtakers would be the participants in the Moderate Hedge component. Whatever the economic analysis machinations may be, it is clear having a Moderate Hedge component would have a *de minimis* impact on all ratepayers as a class (both absolutely and compared to the all Wholesale PPA option), and could disqualify Maine from some federal funding to support low and moderate-income (LMI) people.

The Solar Energy Association of Maine (SEAM) urges that the Moderate Hedge (fixed price) component of the successor program be retained, with the provision that it is for named Offtakers. Any additional administrative costs associated with this approach can be managed to be minimal, and the idea that customers cannot understand it is a "red herring." Admittedly there is some confusion around the community solar farm (CSF) concept as marketed to Maine electricity customers, but this primarily is due to less-than-full-disclosure marketing, high pressure sales tactics, and failure to provide understandable program descriptive materials. In general people (individuals and C&I customers) like this concept and want to participate in it. It seems to us that virtually all the ratepayer cost shift would be eliminated by setting the (low) fixed price envisioned in the Proposed Framework, so the "throw the baby out with the bathwater" approach of eliminating named Offtakers is unnecessary and an insult to individuals and C&I customers who want to do the right thing and participate directly in a program, with the added benefit of some economy of scale.

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A possible variant of this approach would be to limit the participation in the Moderate Hedge component of the program to C&I customers only, who as a class are fewer in number and more easily educated in the program elements. This would be far better than eliminating the Moderate Hedge component altogether. SEAM is reluctant to even suggest this outcome, which would leave the residential sector able to participate directly in the climate solution only in the smaller net energy billing (NEB) program (under 1 or 2 MW, wherever the cutoff is set), and because it would appear to eliminate the possibility of targeting LMI customers in the successor program. Yet it would be better than no possibility of retail participation.

There is unquestionable interest on the part of both residential and C&I customers in participating as Offtakers in the successor DG program being considered by the DG stakeholder group. Given that the costs of this approach will be minimized by the wholesale PPA bidding process and the setting of a (low to median) fixed price for the Modified Hedge component, we believe this interest should be honored and accommodated by having a Moderate Hedge component in the framework for the successor DG program, with the provision this aspect of the successor program would be available to named Offtakers.

Renewable Energy Certificates

SEAM also recommends you include an explicit explanation about the disposition of renewable energy certificates (RECs), and the rationale behind this treatment), in any and all aspects of the successor program. While this is included in the benefit/cost analysis, and may be an issue beyond the scope of the DG Stakeholder Group's charge, it nonetheless is an important and opaque aspect of the current situation. Specifically, it seems important to know what the impact of the DG successor program will be on Maine's ability to meet its RPS standards, and how this will be measured. It would be upsetting to many if there is any kind of double-counting or greenwashing occurring, as a consequence of taking advantage of the value of RECs.

Thank you for allowing SEAM to present these additional comments, and hopefully for considering them. Our comments submitted previously still apply, and are reproduced below to get all of them in one document.

December 5, 2022

In the interest of efficiency, I am providing these comments, on behalf of the Solar Energy Association of Maine, in brief form, with limited supporting commentary. Please accept

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these as interim comments, our own work-in-progress, subject to change, to adhere to your meeting schedule.

First, kudos to the Governor's Energy Office (GEO), and Ethan Tremblay specifically, for establishing and running a professional process, marked by high quality work. Reserving the right to modify or add comments during the comment period, our specific recommendations about the proposed framework leading up to the December 6 meeting are:

1. Define "successor program" as distributed generation (DG) projects in the 2-5 MW range, labelled herein as "medium-scale projects." Leave projects of less than 2 MW (labelled herein as "small-scale projects") in the existing net energy billing (NEB) program. A potential variant of this recommendation would be to distinguish between kWh NEB projects and C&I tariff projects, modifying the "small-scale project" definition to mean kWh NEB projects of less than 2 MW and C&I tariff projects of less than 1 MW.

2. Change the split between the "Wholesale PPA" and "Moderate Hedge" components to 50% each. This assumes participants in the Moderate Hedge program would be named Offtakers. SEAM thinks the DG Stakeholder Group may be underestimating the desirability of, and market demand for, projects built for or by identified Offtakers. We think such groups are the bedrock of the DG program. Whatever final split between Wholesale PPA and Modified Hedge is decided upon, it is essential that the Modified Hedge program be defined as a program with identified Offtakers.

3. Change the fixed price of the Moderate Hedge component to be the weighted average price of the selected (accepted) Wholesale PPA component bids (50% percentile), not the 20% percentile of such bids. This seems like a provision of basic fairness.

4. There should be no definitional restriction on the type of Offtaker who can participate in the Moderate Hedge program. Restricting this to one class of customer over another will be too stifling of innovation and good projects.

5. Clarify what is meant by the statement that solicitations for the Wholesale PPA component of the program will be "inclusive of renewable energy attributes." SEAM thinks it is important to state clearly whether or not these attributes would include a project's renewable energy certificates (RECs). If this is so, presumably it means the Standard Buyer of Wholesale PPA projects (utilities, we assume) would get the RECs. In this case, it seems

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logical they should be required to retain them to qualify these projects as meeting RPS standards. If this is required, it would seem the same requirement should apply to the Moderate Hedge projects - i.e., that the RECs would be retired by the project owner(s). This is a confusing aspect of the straw proposal, at least to us. SEAM suggests this issue should be addressed explicitly. We reserve judgement about this issue, until we understand it better.

6. Keep small projects (under 1 MW or under 2 MW, depending on where this line is ultimately drawn) out of the proposal and within the established NEB program.

Additional comment

Please clarify how the amount of Maine's "in-state electricity sales coming from solar" (shown as a mere 2.7%) is measured. It seems to us that this same measurement should apply to how compliance with the State's RPS standards is determined. SEAM has never been clear about this, perhaps more a comment on our lack of understanding about the subject than anything else.

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VERSANT POWER

December 15, 2022

Recommendations of the LD 936 Distributed Generation Stakeholder Group
Versant Power Comments

Versant Power appreciates the significant time and effort by the Governor's Energy Office, Office of the Public Advocate, Commission and various stakeholders that went into formulating these recommendations. We are generally supportive of the high-level program designs contained in the recommendations, believe they represent a significant step in the right direction and could help achieve important state policy goals at far lower cost than the current DG programs.

As the Legislature deliberates these recommendations, Versant Power believes that four important policy goals should be prioritized in any future DG program: 1) the use of competitive wholesale procurements designed to maximize beneficial outcomes while minimizing electric customer impacts; 2) ensuring benefits of a future DG program flow significantly to Low-to-Moderate Income (LMI) Mainers, who have not accessed current programs in comparable rates to higher income populations; 3) a program that is carefully designed to maximize the amount of federal funding Maine projects are eligible to receive, savings that should lower costs to all customers; and 4) minimizing program designs that would result in additional administrative costs or burdens.

1. <u>Competitive Procurements Should Better Accomplish Policy Goals at Lower Cost to Electric Customers:</u>

Versant Power strongly supports utilizing competitive procurements as the best way to select future DG projects that can meet state policy goals at the lowest cost to customers. Previous Commission procurements, including the most recent §3210-G "RPS Procurement," clearly demonstrate the possibility of achieving clean energy goals while reducing stranded costs. Several of the projects selected during that process will receive fixed prices that currently represent cost savings to utility customers and future DG programs should be designed to similarly capture the benefits of competitive procurements.

Versant Power does however caution policymakers about any program design in which competitive procurements of DG resources include a price cap or ceiling price *that is known to bidders beforehand* as this may lead to bidders pricing projects at or just below the ceiling, artificially raising prices and stranded costs for utility customers. We support measures to protect customers from the impacts of higher-than-necessary bids including by providing the Commission with the discretion to reject bids that are not in the public interest.

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Maine Public District — PO Box 1209, Presque Isle, ME 04769-1209

2. The Next DG Program Should Significantly Benefit LMI Mainers:

Versant Power is strongly supportive of designing the next DG program(s) to be more equitable than the current NEB program. One method to do so is to maximize participation by LMI Mainers. This population has not yet been able to access the individual economic benefits associated with DG in the same way that many higher-income Mainers have to date.

Versant Power also supports designing successor program(s) so that future projects can access the maximum possible tax benefits based on the LMI and siting provisions of the IRA, which should ultimately serve to lower overall project costs and associated rate shifts to non-customers.

3. The Next DG Program Should Minimize Ratepayer Cost by Maximizing Eligibility for Federal Funding

Designing a program that maximizes access to federal tax benefits, primarily those contained within the Inflation Reduction Act, will be one critical factor in achieving a successor DG program that limits unnecessary ratepayer impact while achieving our state policy goals. We believe it is in the best interest of Maine customers to ensure the next generation DG program is able to secure as many available federal dollars as possible. Additionally, we believe our program design should be finalized at a time when full guidance is available from the US Department of Energy and US Department of Treasury regarding implementation of the relevant energy-related provisions of the IRA.

Versant Power is also supportive of successor program designs that take appropriate siting considerations into account when awarding contracts, in order to maximize federal funding eligibility, minimize the costs of new DG projects and associated customer impacts, and align the program with additional state policy goals.

There appears to be broad consensus among stakeholders that siting – both for land-use purposes and grid management/benefit purposes – ought to be an important factor in the Commission's evaluation of bids or applications. There is additional policy value in siting projects on brownfields or rooftops where feasible, rather than on productive farmland or forest. Furthermore, we are well aware that there is value to siting projects at locations on the electrical grid that minimize the total cost.

While, based on the proposed rates of solar penetration as a percentage of load in Versant Power's service territories, there is no guarantee that proposed projects would avoid ISO-NE transmission cluster studies, the Company is committed to working with project developers and customers to ensure that Maine meets the State's climate goals as efficiently and cost-effectively as possible. Versant Power understands that access to dynamic hosting capacity data should make grid-related siting considerations clearer and more transparent for developers and regulators alike. As such, in early 2023, Versant[1] expects to have hosting capacity data available for their full service territories that should assist in project planning and evaluation.

[1] CMP currently makes available hosting capacity Heat Maps. Versant Power plans to have similar capabilities available to the public in Q1, 2023.

4. Successor Program(s) Should be Designed to Minimize Administrative Cost & Burden to Customers:

In recent years Maine has made significant and frequent changes to its DG policies, many of which have required costly changes to utility capabilities and practices to implement. Versant Power is happy to provide information and feedback to policymakers as they deliberate a future DG program about any implementation costs and challenges various options may require as well as ways to potentially mitigate such issues.

We reiterate and emphasize that the current high-level recommendation to primarily use wholesale PPA procurements for a successor program should lessen administrative costs and burdens when compared to the current NEB program. However, care should be taken to ensure future and more detailed policy decisions do not inadvertently raise costs for customers.

Versant Power thanks the GEO, OPA, Commission, and other stakeholders who participated in this valuable and important conversation to provide the Legislature with thoughtful recommendations. We look forward to our continued collaboration to improve these processes.