COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF ENERGY RESOURCES

400 MW REVIEW PUBLIC COMMENTS: JOINT DISTRIBUTION COMPANY COMMENTS

Fitchburg Gas and Electric Light Company d/b/a Unitil ("Unitil"), Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid ("National Grid"), and NSTAR Electric Company d/b/a Eversource Energy ("Eversource") (together, the "Distribution Companies" or "EDCs"), offer these comments to the Department of Energy Resources ("DOER") in response to DOER's request for stakeholder comments on DOER's Straw Proposal for the Solar Massachusetts Renewable Target ("SMART") Program 400 MW review ("Straw Proposal").

In these Comments, which reflect lessons learned in implementing the SMART Program, the Distribution Companies identify potential impacts on their customers if the SMART Program is expanded as outlined in the Straw Proposal and propose the following modifications to the Straw Proposal for DOER's consideration.

I. IMPACT OF SMART PROGRAM 800 MW EXPANSION ON CUSTOMERS

Massachusetts rightly has some of the most well-regarded clean energy policies in the Nation and has developed Nation-leading efforts in distributed generation, energy efficiency and offshore wind. For many of these policies, the state has taken an approach that is aggressive, methodical and cost effective. The state's energy efficiency programs have cost-effectively deployed billions of ratepayer dollars, eliminating load growth and transforming how energy is used in the Commonwealth. Similarly, the development of the offshore wind market has benefitted from a long-term strategy that provides clear signals to market actors about the state's intended deployment trajectory.

In contrast, solar market development in Massachusetts has proceeded rapidly but unevenly over the past decade as the market has throttled up and down based on incentive availability and interconnection capacity constraints. This has perpetuated a unique dynamic in which the Massachusetts solar market continually exceeds expectations but is portrayed by stakeholders as on the brink of failure and in a state of crisis. The use of emergency regulations to extend incentive programs after rapid, unexpected solar market growth has led to significant ratepayer costs. The SREC programs cost EDC ratepayers between $700 million and $1 billion in 2018 alone.[1]

Continuing this trend, the overwhelming response of the solar industry to the SMART Program resulted in the Program reaching capacity almost as soon as it opened, contrary to the multi-year enrollment process envisioned by DOER and stakeholders.

Customers, however, will not share in the benefits of the SMART Program equally. Although all customers will benefit from the reductions in greenhouse gas emissions resulting from the increase in solar energy generation stimulated by the SMART Program, only customers who participate in the SMART Program benefit economically. Despite the variety of direct and indirect benefits from the SMART Program in terms of products received, price suppression effects, and environmental benefits, the Program's direct costs are collected from all customers on their bills. In fact, the very success of the SMART Program and past solar programs has led to diminishing returns, as solar production has helped to push energy, capacity and REC prices

[1] These estimates are based on the 2018 total obligations for SREC and SREC II with upper and lower bound costs of the auction floor and the ACP respectively.

downward in the past several years.[2] Increasing the size of the SMART Program by 50 percent (800 MW) will further increase customers' electric bills and exacerbate affordability concerns. Thus, a review of the rates, adders and other terms of the SMART Program should result in changes that help reduce net costs, and balance demand for Program capacity, by reducing Program base rates and adders, and changing other terms.

In the future, instead of further expanding the SMART Program by extending the declining block model, the Distribution Companies recommend that DOER consider competitive, capacity limited auctions of tariff enrollment with aggressive ceiling prices and no floor, to push the maturing solar industry to make best price offers. This form of competitive bidding system already exists under the Rhode Island Renewable Energy Growth ("RE Growth") Program, and has resulted in solar prices that for each of the five program years to date have often been 10 to 25 percent lower than the ceiling price set in many of the procurement classes. This can be seen in the table below:

Table 1.

Rhode Island Renewable Energy Growth Program 2015 - 2018 Summary

	Medium-Scale Solar			Commercial-Scale Solar			Large-Scale Solar		
Program Year	Ceiling Price	Awarded Average Price	% Below Ceiling Price	Ceiling Price	Awarded Average Price	% Below Ceiling Price	Ceiling Price	Awarded Average Price	% Below Ceiling Price
2015	24.40	24.40	0.00%	20.95	18.81	-10.23%	16.70	16.34	-2.18%
2016	22.55	22.55	0.00%	19.30	17.77	-7.94%	15.10	12.58	-16.68%
2017	22.75	22.75	0.00%	18.75	17.19	-8.32%	15.05	14.10	-6.30%
2018	24.95	23.08	-7.48%	19.65	17.51	-10.89%	16.45	12.32	-25.11%

(Note that the 2015-17 Medium Scale Solar program was offered at a fixed Standard Incentive and was not competitive.)

[2] In Eversource's Western Massachusetts territory, the total capacity of installed PV and the current interconnection queue exceed the all-time peak load for the territory, suggesting limited further grid benefits from additional capacity.

All Rhode Island customers have benefited from the lower solar prices produced by this competitive procurement process. Moving in such a direction will enhance the ability of the SMART Program as it matures to be the "stable and self-sustaining" solar program called for by its enabling legislation. Alternatively, the assessment structure of the energy efficiency programs, which require technologies to meet strict benefit-cost tests, could serves as a model going forward, ensuring that the interest of ratepayers is not lost in efforts to maintain solar market activity.

II. APPLICATION PROCESS

The introduction of the SMART Program resulted in a spike in the number of interconnection applications, many of which were in the very early stages of development, which has resulted in a slowing down of the distributed generation interconnection process. A key driver has been the requirement for applicants proposing projects larger than 25 kW to have a signed Interconnection Service Agreement ("ISA") to apply to the SMART Program, coupled with the immediate availability of all the capacity of the declining block model.

DOER should introduce the option for applicants to use a deposit guarantee mechanism instead of an executed ISA. This change would dramatically cut down on speculative interconnection applications, reduce costs and wasted effort, and subdue the "race to the finish" environment seen in Massachusetts over the past nine months since the SMART Program first launched. This would instead provide a pathway for some projects to secure financial backing before going through a full interconnection impact study.

Additionally, the Distribution Companies recommend a "controlled" enrollment process to better manage application intake and approval by opening up 50 percent of the Program expansion for enrollment when approved, and after a pause of six months, opening up the other 50 percent of the Program expansion. Applicants who do not get into the first round of open capacity would need to reapply for subsequent block allocations.

Finally, the Distribution Companies recommend that DOER establish a better policy for managing cancellations in the SMART Program. Currently, the capacity for all canceled projects is added to an EDC's block in which applications are currently being qualified, which has produced some "super blocks" under the existing Program. With the expansion still 9 to 12 months away realistically, the Distribution Companies suggest adding any canceled capacity from the initial 1600 MW, and any canceled capacity from the expansion, first to additional blocks that step down in value under the current tariffs, and then to the end of the expansion once it is in place, by creating additional declining blocks all of the same size to further reduce Program cost and expand the opportunity for applicants that were foreclosed from participating in the initial Program, such as large behind-the-meter projects and public sector projects.

III. METERING

The Distribution Companies strongly disagree with the suggested metering options in the Straw Proposal.[3] Not only are these suggestions outside the scope of issues called to be examined by the review in the SMART regulations, they go beyond the statutory authority of DOER in general, and pose changes in long-standing policy by the Department of Public Utilities as to who should own meters, how they should be operated and maintained, and how information from them should be reported and used.

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[3] Metering is outside the scope of the 400 MW review, which is intended to address Base Compensation Rates and Compensation Rate Adders (both as defined in the regulations) and overall cost impact to ratepayers. 225 CMR 20.07(5).

A. Evidence from the SMART Program Does Not Indicate a Change in Metering Requirements Is Warranted

The Distribution Companies' experience belies the Straw Proposal assertions that current metering requirements have not interfaced well with solar plus energy storage system ("ESS") business models and that the majority of solar industry stakeholders advocate eliminating EDC ownership of production meters and requiring EDCs to accept inverter readings.

The argument that residential solar plus ESS cannot bear the burden of additional utility metering to accommodate the unique wiring configurations chosen by installers is not consistent with the information provided by solar financing companies as part of their SMART Program applications. Ratepayer funded solar plus ESS incentives are generous enough to support systems with limited access to sunlight. Despite the expected poor production of these systems, residents are still able to sign power purchase agreements ("PPA") well below current utility rates. Specific examples of systems with DC-coupled ESS include:

- A 9.1kW PV system with a 9.3kWh ESS. The customer signed a 20-year $0.173 PPA. This system is highly shaded with 15 of its 26 panels on a north-facing roof.
- 9.3kW PV system with a 9.3kWh ESS. The customer signed a $0.158 PPA, well below current utility rates. The system has two arrays, one facing NE and another smaller array facing SW. Due to poor orientation and shading, the combined capacity factor of the system is below 9.5 percent.[4]
- A 9.28kW system with 9.3kWh battery. The system contract was for a 20 year $0.133 per kWh PPA. The system has two north facing arrays and a calculated capacity factor of 9.6 percent.

[4] For reference, the average capacity factor for a system in Massachusetts is typically around 13.64 percent.

- A 10.54 kW system with a 9.3 kWh battery. The system contract was for 20 years at a PPA rate of $0.153 per kWh. The total system capacity factor was 10.7 percent with one 12 panel array oriented NE under several large trees.

These systems have been built without advanced metering to account for losses associated with backup panel wiring despite the EDC's longstanding offer to provide these metering solutions.[5] While solar companies have painted a dire picture to regulators about their inability to bear the costs of utility metering, the EDCs' experience indicates that SMART incentives are generous enough to support very poorly performing PV systems with battery storage even when less than all the solar production is metered for incentive purposes. A total of 268 small solar plus ESS projects have been approved by the SPA, and 167 are now operating, all with single generation meter installations.

Furthermore, information received from SolarEdge Corp., the predominant manufacturer of the StorEdge inverters that use two AC outputs the powering of a back-up panel and the main panel separately, indicates that they may discontinue that inverter design and may move to a single output with the use of a transfer switch for any backup loads, whether partial or whole house. Such a product would obviate the need for the two-meter solution or other work arounds that have been offered by the EDCs, and would only require a single generation meter, were that to become the standard product installers use to provide back-up loads. If such a solution were to enter the market and eliminate the need for a two meter solution, that also would eliminate the need for costs associated with billing system changes, saving all customers money.

[5] Eversource has worked in good faith with solar financing companies to develop metering solutions for the specific solar + ESS wiring configurations favored by individual companies. Solar financing companies walked away from these discussions and indicated that they would not accept any solution that included utility metering, as they preferred to self-report generation for incentive purposes.

B. Self-Reported Generation and Billing Data Is Incompatible with the SMART Program Structure

DOER proposes to require the EDCs to accept inverter readings as long as the inverters contain revenue grade meters.[6] Using inverter data for solar plus ESS for billing purposes under the SMART Program would be highly problematic for data collection and verification. The use of reads from customer-owned inverter-sited metering for EDC billing and incentive payment purposes would be a substantial shift in the long-standing precedent around utility meter ownership and location, which allows for Department of Public Utilities regulation of meters used for utility revenue purposes, and safe verification and maintenance of meters. While in a different context, the reasoning behind the SMART decision was highly similar to the reasoning established in an examination of competitive and non-utility owned metering, which rejected third party meter ownership and reporting, and reconfirmed the public interest of utility ownership and responsibility for revenue metering nearly 20 years ago.[7] Utility ownership of meters used for billing is also preferred, as found in the SMART Order[8] most recently, because the DPU can regulate the maintenance, accuracy standards, and dispute resolution involving such meters.

Pushing some meters in the SMART Program outside of this paradigm would lead to a lack of oversight, and a lack of clear jurisdiction for dispute resolution. Moreover, it would lead to substantial complexity for a subgroup of customers that is not necessary or advisable and bears little benefit for the customer in question. Likely, it will only be a cost savings for third-party owners of solar plus ESS that will not benefit the customer but rather, would simply flow as increased profits to the owner or the owner's shareholders.

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[6] DOER Straw Proposal PowerPoint, Slide 21.

[7] "Report to the General Court Pursuant to Section 312 of the Electric Restructuring Act, Chapter 164 of the Acts of 1997 on Metering, Billing and Information Services," Massachusetts Department of Telecommunications and Energy, Dec. 29, 2000

[8] Joint Petition of EDCs for Approval of Model SMART Provision, D.P.U. 17-140-A Order at 79 (2018).

The previous paradigm under which projects reported production data to the Production Tracking System ("PTS") is not workable under a utility tariff. Under the SREC programs, more than 85,000 PV systems report their production monthly to the PTS. SREC systems frequently miss reporting deadlines, requiring PTS staff to provide case-by-case exceptions to ensure customers receive their production incentives. This dynamic would be unworkable under a utility tariff, particularly, as system production is used to calculate the monthly SMART factor requiring production meter read dates to align with billing meter read dates to properly bill (and credit) customers.

Given that SMART production meters serve as billing meters, allowing customers to self-report inverter data (or to own billing meters) would raise a number of critical questions. For instance, 220 CMR 25.02 dictates that utilities must read residential billing meters at least every other month. It is unclear if and how the EDCs would comply with these requirements if billing meters are not under an EDC's control, are not readily accessible to EDC meter readers in an outside location (inverters are typically located inside a residence) and do not comply with EDC safety standards for their personnel. Similarly, it is unclear what motivation customers will have to self-report data after the end of their incentive eligibility period but during the period of time when the EDCs are required to continue to charge the SMART Factor using a project's gross production as a critical input.

At most, 300 of the 85,000 systems in the PTS receive onsite inspections annually. In order to protect the EDCs' customers from a potential increase in fraud, this extremely low rate of system verifications could not be maintained and would require all EDCs to expend significant time and expense verifying these systems. Under a self-reporting paradigm, unlike for SREC systems, residents would need regular on-site verification inspections by the EDCs, adding costs and inconvenience to the SMART Program. The costs associated with these ongoing inspections would substantially increase the overall Program cost and, ultimately, these costs would be borne by the EDCs' customers, if not the SMART customers directly.

C. Incorporating DC-Metering Will Add Unnecessary Complexity and Cost to the SMART Program and Will Favor a Limited Number of Developers

With respect to the metering of DC-coupled stand alone solar plus ESS facilities, the Distribution Companies oppose this change for more fundamental reasons. At present, there are no standards from the American National Standards Institute for DC metering by utilities, and as such there is a lack of testing procedures, location and form standards, and products available to utilities for DC metering. As such, utilities are generally unable to own and operate DC meters within their retail, distribution businesses. In addition, the Distribution Companies have proposed an incentive solution, in comments they submitted in D.P.U. 19-55, to compensate for battery cycling losses incurred by DC-coupled solar plus ESS facilities that would allow for DC metering that is not owned by the utilities to be used to calculate those losses annually. This solution is broadly applicable across all DC-coupled solar plus ESS systems and requires no additional investment in either customer metering or EDC systems.

DC measurement devices have been used to operate DC transmission lines but they have not been used as revenue meters.[9] Expansion of this concept within the wholesale markets space by sophisticated entities willing to bear the costs of meter testing and maintenance, and meter reading and communications, among other responsibilities, may be possible, and may make the participation of DC-coupled assets more fully as separate assets in the ISO-NE markets possible in the medium term. Even this progress forward would be highly challenging due to the loss

[9] In a single exception, Hydro Quebec installed a revenue meter on the DC transmission lines in an existing station in Canada; however, ISO-NE uses the pre-existing AC revenue meters located on this line in Massachusetts.

estimations, data analysis and novelty of the undertaking, and the likelihood of multiple assets or product owners, temporal differences in generation versus output at the AC meter, and unaccounted for losses from exceeding the AC capacity of the joint facility to export (aka, "generation clipping").

In short, the Distribution Companies do not think it is advisable or possible for DC metering to occur with utility ownership of the meters at this time; rather, the Distribution Companies see a path over the longer term where this may be possible and desirable. In the interim, collaborative efforts by developers, utilities and ISO-NE may make possible the separation of DC generation for market purposes, though this too is challenging and may not be possible, with or without regulatory direction to make it so.

IV. BEHIND-THE-METER INCENTIVE PAYMENT

A. Value of Energy

The Distribution Companies share the view that the proposed change in the Straw Proposal in the calculation of the Value of Energy for behind-the-meter ("BTM") applicants should only apply to Alternative On-Bill Credit ("AOBC") facilities. The regulations should clearly state that these changes only apply to those facilities that obtain AOBC status and are not net metered facilities, and that they cannot become net metered facilities after the fact. The structure of the BTM deduction in Value of Energy was meant to enable the combination of the SMART Program with the Net Metering Provision, even at the Market Net Metering Rate for net exports (60 percent of the full retail rate), to encourage systems to size to historic load when located behind the meter. It is understandable to extend a different calculation of the Value of Energy to BTM systems that opt for the new AOBC status available under the changes proposed in the Straw Proposal, assuming that usage will not continue to be netted each month, i.e., all imports will be billed and all exports will be credited at the AOBC rate. Otherwise, it is the experience of the Distribution Companies with net metering facilities located with commercial loads that very few are sized to create substantial net exports, and many do not net export at all. As such, this is how the Distribution Companies would intend to implement this desired change through the SMART Provision.

B. Supporting BTM Projects in SMART

The Distribution Companies agree that the participation of BTM projects in the SMART Program expansion should be enhanced, while the influx of new large stand-alone projects is limited. To do this, the Distribution Companies suggest that DOER should establish a set-aside for large (greater than 25 kW) BTM systems within all of the expansion capacity blocks. When the SMART Program opened, all capacity for large projects (over 25kW AC) in most EDC territories was consumed within just a few short months. In the National Grid queue, of the 414 large systems in the queue or completed (representing 600.05MW), 339 projects are standalone (584.62MW), and 75 projects (15.43MW) are BTM. The Department has emphasized their consideration to increase BTM projects in this proposed expansion. The Distribution Companies suggest the most direct way to encourage BTM projects and help program diversity is to allocate 30 percent of each block's capacity for large BTM applications. Once this 30 percent is filled, BTM systems would also be able to apply for the remaining percentage of any available large project capacity.

V. CONSUMER PROTECTION

Nearly all energy sales in the Commonwealth are subject to consumer protection laws and regulations. The Department of Public Utilities regulates the sale of gas and electricity. The

Division of Standards oversees devices used for the sale of gasoline, fuel oil and propane.[10] Even the purchase of cord wood is subject to consumer protection laws in the Commonwealth.[11] To date, similar oversight has not been applied to the sale of power to Massachusetts residents via solar financing companies.

Unfortunately, this lack of oversight has led to negative consequences for Massachusetts consumers. A review of documents submitted as part of the SMART program shows what appears to be targeted efforts to misrepresent to low income consumers the financial benefits of signing 25-year solar financing agreements. A review of nearly 100 low income solar contracts under the SMART program showed that 45 percent of customers signed lease agreements that were above the customer's current electricity price. Some of these customers had not paid their Eversource bill for months or even years, for example, meaning they were already struggling financially before signing expensive solar financing contracts.

Massachusetts ratepayers provide the solar industry with some of the most generous incentives in the nation, and financing companies that sign agreements with low-income customers receive additional compensation under the SMART Program. Despite this, some solar companies have chosen to aggressively market harmful financing products to low-income customers.

Given this context, the EDCs applaud the DOER's efforts to enhance consumer protections under the SMART program. The Distribution Companies hope that the changes outlined in the 400MW review are quickly implemented, as the issues noted above have not abated.

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[10] Through its oversight and inspection activities, the Division of Standards frequently finds that devices used for the sale of energy in the Commonwealth are inaccurate and require recalibration.
https://www.mass.gov/files/documents/2018/09/04/2018%20Annual%20Report.pdf

[11] https://malegislature.gov/Laws/GeneralLaws/PartI/TitleXV/Chapter94/Section298

A. Comments on Proposed Protections for Consumers in Straw Proposal

Moving from a low-income definition of a utility low income rate to the Environmental Justice income-only criterion is a clear means to expand eligibility and make "low-income" project enrollment easier. But very likely, it will also create the ability for developers to simply sign up the most well-off in those Environmental Justice census tracks, due to the credit score and direct withdrawal provisions that many community solar companies insist customers maintain and likely will continue to require. Those better off customers may not be low, or even moderate income.

The Distribution Companies think customer eligibility and enrollment in their respective low income discount rates should be used to qualify customers for the low income community solar offer. This will ensure the most vulnerable households in the Commonwealth are benefiting from the low income community solar opportunities first. The Distribution Companies' respective low income discount rates also are used to qualify customers for their respective low income energy efficiency programs, so there would be congruency between the two offers and, therefore, reduced customer confusion and increased administrative efficiencies. Currently, the Distribution Companies collectively have over 270,000 verified electric low income discount rate customers statewide, all of whom potentially could benefit from community solar.

In the future, once ample numbers of income eligible customers have enrolled in available community solar offerings, DOER could introduce the Environmental Justice criteria, and should consider requiring, at a minimum, a self-certification under penalties of perjury by any customer not on a utility low-income rate that their recent two years of income fell below 80 percent of median income in their area to ensure that the best-off in these Environmental Justice communities are not falsely counted toward low-income criteria and are not allowed, without some threat of penalty, to take advantage of offers meant for their low-income neighbors.

B. Additional Proposed Protections for Customers

Based on their experience with some installers taking advantage of the EDCs' customers, the EDCs suggest the following additions to the consumer protection changes outlined in the Straw Proposal:

- Many installers have implemented electronic signatures for the customer disclosure. Electronic signatures may not provide consumers with an opportunity to carefully review the contents of the disclosure document. DOER may wish to consider mandating hard copy signatures for customer disclosure documents, which can be lengthy, to ensure consumers have adequate opportunity to review these important documents.
- The customer disclosure should include information on the customer's current utility rate for comparison purposes. The rate should be from the customer's latest bill and should reflect the low-income discount rate if applicable.
- If the customer is signing a solar lease with a fixed payment, the customer disclosure should list the fixed lease price and not the estimated $/kWh price.
- Many residential third-party ownership contracts that include ESS incorporate language stating that homeowners cannot rely on the ESS to provide power during outages. Given the generous incentives provided to support ESS under the SMART Program, this is concerning.
- The EDCs recommend that DOER incorporate a provision in the disclosure form that states clearly whether the ESS will or will not provide a reliable source of power during an outage.

- The three strikes rule should include any violation of Program rules with violation counted at the individual customer level (e.g., if 10 customers receive identical contracts with improper language, the installer would receive 10 strikes).
- Clear efforts to deceive customers about projected system performance should be deemed a violation of Program rules as should major system quality issues such as roof leaks and code violations.
- The low-income savings guarantee should be firm and not theoretical with customers having rights to petition the DOER if, for whatever reason, savings do not materialize. Savings guarantees should include consideration of ongoing system costs as well.
- The DOER or its designee should audit all low-income contracts to ensure Program standards are met.
- A mechanism for performing routine audits of non-low-income contracts should be developed with any violations triggering more frequent audits.

Given the consumer protection concerns identified during the initial phases of the SMART Program, legislators, the Baker administration, and the Attorney General's Office, should evaluate whether licensing requirements for companies selling solar-generated electricity could benefit Massachusetts consumers. This approach would be consistent with the state's current oversight of nearly all other energy transactions in the Commonwealth.[12]

Any new consumer protection efforts should be clearly established by regulators and or the Office of the Attorney General, so that solar developers and their agents are not intimidated from

[12] The DPU requires licensing for competitive energy suppliers and brokers based on consumer protection grounds. The products sold to residents by solar financing companies are in many ways analogous to the products sold by competitive energy suppliers, although the products sold by solar financing companies present significantly greater risk to consumers given the use of multi-decade contracts.

trying to serve these customers for fear of being barred from the Program altogether. Such an outcome could lead low-income customers to be unserved instead of underserved. In addition, the regulations should try to accommodate various business practices and potentially restructured rate classes (such as demand rates or time of use rates) that could interact with and negate savings in the future.

C. Alternative Community Shared Solar Models

Currently, the Distribution Companies collectively have over 270,000 verified electric low income discount rate customers statewide, all of whom potentially could benefit from community solar. The Distribution Companies could play a role in offering services to community solar developers that would lend an additional level of regulatory oversight, customer assurance, and standardization to the benefit received by participating customers. National Grid's affiliate in New York recently proposed two offerings to solar developers (consolidated billing for community solar participants to provide customers with a single bill with a net credit, and customer acquisition) to enable equitable access to community solar for all customers, with a focus on low-income customers. This program should lower the cost to serve community solar customers in general and allow savings to flow back to all customers from developers that choose to participate.[13] National Grid intends to propose a similar program for its service territory in Massachusetts. Eversource is considering proposing a similar program and will be providing a brief description of the framework for that program in a separate memorandum. Unitil is reviewing these proposals, as well. In addition, if DOER supports a change to allow a net savings benefit only to be transferred to the customer in lieu of the full AOBC credit, DOER should consider a

[13] Case 19-M-0463 – In the Matter of Consolidated Billing for Distributed Energy Resources, Verified Petition of Niagara Mohawk Power Corporation d/b/a National Grid for Authority to Implement Community Distributed Generation Platform

minimum credit amount that is a fixed value, rather than a percent of the bill, to simplify presentation, implementation and risk for all parties.

VI. SMART PROGRAM QUEUE MANAGEMENT

With regards to the Preferred Interconnection Adder, the Distribution Companies anticipate being able to use maps showing interconnection activity and hosting capacity to be published on line that will enable this adder. In its simplest form the adder or subtractor would apply to feeders and/or substations at the extreme ends of the hosting capacity metrics to encourage systems where there is ample capacity and discourage them where the interconnection queue is currently or nearly congested. That said, the DOER should carefully consider any incentive adders or subtractors as they may serve to rapidly drive development in certain areas, and time-lags in changing adders or updating hosting capacity maps could have unintended consequences. The EDCs would seek to have more detailed discussions with DOER to provide input as any incentive adders or subtractors are developed.

The replacement system rule that DOER proposes will be an improvement as well to ensure that customers to not intentionally uninstall fully subsidized systems and then replace them with newly subsidized ones to maximize their financial returns. The one clarification the EDCs would suggest is that the ratio of the old system to the new system should apply to the BTM net incentive rate, rather than the total compensation rate or the output (kWh) of the system.

Likewise, the change to the Community Shared Solar adder claim – requiring a facility to comply with the terms of the adder at operation – is an excellent start to cleaning up a queue that likely has many speculative Community Shared Solar projects in line. However, DOER should better define if “operation” means Authority to Interconnect by the Distribution Company or approval of the final claim for a Statement of Qualification by an applicant, to avoid confusion when implemented. This change will also improve visibility into the future cost and benefits of the Program.

VII. ENERGY STORAGE REQUIREMENT FOR 500KW AND LARGER SYSTEMS.

The EDCs support the addition of requirements that systems greater than 500 kW include ESS to alleviate grid integration issues; however, the addition of ESS in and of itself does not reduce a system's interconnection cost or its impacts on the grid. The need for operational parameters to achieve these potential benefits of ESS needs further discussion.

VIII. GENERAL COMMENTS

In other components of the Straw Proposal, the Distribution Companies are broadly supportive of the changes proposed: increased Land Use restrictions, subtractors, and refinement with Solar Zoning and Agricultural regulations will better protect open and agricultural space in the Commonwealth; the three changes for public-sector projects are understandably warranted given the processes and standards that public entities are generally held to in the state; the exemption of utility demand response program customers from the Storage Guideline operational requirements of 52 cycles per year; and the pollinator adder.

Finally, it would greatly enhance the refinement of the public review and understanding of the regulation changes that DOER eventually does put forward, if DOER would clearly identify which aspects of the regulatory changes will apply: 1) to all systems with immediate effect; 2) to all applicants that do not have a Final SOQ; 3) to applicants that do not have any provisional claim in the initial or expanded Program (i.e., that could apply to presently unclaimed capacity); and 4) to only that capacity that may be offered in the anticipated regulatory revisions from DOER. The EDCs also suggest that DOER focus on one or two of these options for most of the changes proposed in the Straw Proposal.

IX. CONCLUSION

The Distribution Companies appreciate the opportunity to submit comments in response to the DOER's request for public comments on the Straw Proposal and look forward to continued engagement on the Straw Proposal.

Respectfully Submitted,

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