



For a thriving New England

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Submitted via E-mail: DOER@maine.gov

Department of Energy Resources
22 State House Station
Augusta, Maine 04333

Re: Front-of-the-Meter Distributed Energy Resource Draft Program Proposal

Director Cunningham and Deputy Commissioner Tremblay:

The Conservation Law Foundation (“CLF”) is pleased to provide comments on the Draft Program Proposal circulated by the Department of Energy Resources (“DOER”) for a Front-of-the-Meter (“FTM”) Distributed Energy Resource (“DER”) program (henceforth, the “Draft Proposal”). CLF’s mission is to protect New England’s environment for the benefit of all people. We use the law, science, and the market to create solutions that preserve our natural resources, build healthy communities, and sustain a vibrant economy.

In LD 1679 (2019), Maine codified binding targets for the state’s gross annual greenhouse gas emissions, and the Maine Climate Council has, in its implementing plan, *Maine Won’t Wait*, set out particular sector-specific goals for reaching those statutory requirements. Electrification sits at the heart of this plan. A core challenge, therefore, is how to grow Maine’s use of electricity—particularly from zero-emitting sources—while keeping energy affordable and Maine’s economy competitive. The rapid expansion of renewable energy generation in the state has created benefits in lowering wholesale energy prices by reducing our reliance on costly and volatile fossil fuels. Rates keep going up, though, driven in recent years principally by distribution costs. The Integrated Grid Plans (“IGPs”) filed by Central Maine Power (“CMP”) and Versant earlier this year make clear that, absent material changes in when and where we use power, significant new investments in their distribution systems will be needed to meet increasing demand. These investments will likely raise costs for consumers and businesses, reducing affordability and competitiveness in Maine.

DERs can, and should, play an important role in deferring or delaying need for grid investment. Most distribution feeders have ample capacity in most hours. Upgrades are driven by *peak* draws of power from the transmission grid into a distribution feeder. DERs can reduce these peaks and thus defer or delay the need for other solutions. CLF is, therefore, interested in supporting development of a robust program that can tap this potential solution to rising future distribution costs, as well as providing additional renewable energy to the grid.

These comments are structured as follows:

- Section 2 summarizes our responses to questions asked in the proposal, with reference to more detailed answers in subsequent sections;
- Section 3 discusses why both Parts 1 and 2 of a program should be implemented on Day 0;

- Section 4 outlines a competitive procurement process for DERs;
- Section 5 discusses how locational value for DERs could be implemented;
- Section 6 raises concerns about the Draft Proposal's treatment of storage;
- Section 7 addresses issues regarding procurement of the capacity value of DERs; and
- Section 8 discusses cost allocation and recovery.

§2. Summary of Responses to DOER's Questions

Section 6 of the Draft Program Proposal raises eight questions for public input; Section 5 raises 3 additional questions. We will refer to these as question 1 through 8 and A through C, respectively.

1. **Cost Allocation:** The mark-to-market net value of procured energy should be an adder or offset to the Stranded Cost Rate, recovered broadly from ratepayers who benefit from lower wholesale prices created by more renewable energy on the system. The procured RECs should offset the quantity of RECs that the Standard Offer provider needs to procure, thus lowering the Standard Offer rate.¹ Part 2 (Distribution System Services, or DSS) payments should be included in utility distribution rates, which is where cost savings from deferred or delayed capital expenses will appear. See Section 8 below.
2. **Capacity:** The capacity value of DERs can only be monetized by wholesale market participants, which many DER developers are not. We recommend that DOER develop some mechanism to procure and monetize capacity value, and to conduct the procurement recognizing the differential capacity values of various projects. See Section 7 below.
3. **Cost Recovery:** See #1. CLF is not in favor of adding the complexity of managing these resources into the existing Standard Offer program.
4. **Price Setting:** CLF believes that DERs should be procured through a competitive solicitation process so that the market, not an administrator, sets the price. The price should be capped at a level to ensure that the resulting contracts are cost-effective. The Part 2 DSS value of each resource should be set by the assessed likelihood of future overloads in that location. We understand that that Efficiency Maine Trust ("Efficiency Maine") is developing a similar locational value framework for its storage programs, which could readily be adapted to the DER program. See Section 4 below.
5. **DSS:** We view the detailed DSS approach of the Draft Proposal to be unworkably complex and detailed. The chief locational value of DERs is their ability to inject power into constrained areas of the distribution system when needed. The other technical services, such as frequency regulation, provide second- or third-order value and can largely be realized by appropriate engineering of the DERs, much as voltage ride-through is today. See Section 5 below.
6. **Additional cost allocation options.** CLF is opposed to creating an export charge for DERs, which would be unduly discriminatory compared to similar resources on the transmission grid or behind the meter. See Section 8 below.

¹ Note that we do not propose transferring the RECs to the Standard Offer provider; rather, the REC obligation of the provider is reduced by the *pro rata* quantity of RECs procured under this program.

7. **Primary requirements for implementation.** Under CLF's vision of a revised program, the principal parameters needed (discussed in Section 4 and 5 below) are:
 - a. **Procurement price cap** for the value of energy + RECs. We recommend this be set with reference to current market pricing for long-term contracts, with a modest premium for the reduced losses and transmission charges created by DERs.
 - b. **Ratio of peak/off-peak energy prices.** The value of energy injections varies over time, and the program will generate the most value if it procures resources able to inject power at peak hours. Setting by rule a ratio of peak to off-peak energy prices will then allow head-to-head comparisons of the competing projects.
 - c. **Rules for delineating distribution need areas.** We propose a simplified model of evaluating DSS value, clustering distribution feeders into four "buckets" based on the nature and likelihood of future overloads. The precise rules for putting each circuit into the appropriate bucket, based on utility data, need to be established.
 - d. **Locational premiums.** With the four buckets established, a premium or discount for project location needs to be established with reference to an estimate of the expected avoided costs. Maine Efficiency is designing a similar program for storage, and we recommend adopting consistent values and buckets.
 - e. **Qualification requirements for projects.** Clear rules need to be set as to how far along in the development process a project must be to offer the project. This need exists independent of the procurement mechanism.
 - f. **Tie-breaking and edge-condition rules.** Under the Draft Proposal, a rule is needed as to which projects will be selected if more than the desired quantity is offered. The need for a tie-breaking rule is less likely under competitive procurement, but they may still be needed, particularly under the case where multiple projects bid at the price cap.
8. **Additional factors for consideration.** This program should not move forward without implementation of both Parts 1 and 2 together. As pure energy + REC resources, DERs are typically more costly than grid-scale resources, which benefit from economies of scale. Therefore, the chief reason to foster DERs is for their locational value. Poorly sited DERs procured in early auctions cannot be relocated to valuable grid locations. We should, therefore, find a simplified path for valuing Part 2 services promptly. See Section 3 below.
 - A. **Capacity Value:** Because DERs can vary widely in their capacity values,² we believe the program must recognize and capture that value in choosing among DER projects. See Question 2. See Sections 4 and 7 below.
 - B. **Price Setting:** CLF proposes a competitive single-price auction with a price cap to procure energy and RECs. The submitted bid from each DER would be adjusted based on its locational value and capacity value, to put each bid on a like-to-like basis. See Sections 4 and 5 below.
 - C. **Cost Recovery:** We favor broad cost recovery through distribution rates and stranded cost rates. See Question 1.

² That is, the ratio of the accredited capacity to the nameplate capacity of the DER.

§3. Parts 1 and 2 Must Be Implemented Concurrently

Part 1 values of the Draft Proposal, namely energy and RECs, have no location-specific value. Rational developers will, therefore, site DERs where they are cheapest and easiest to build, which are likely to be in locations away from load centers, where the need for distribution-level generation is highest. Therefore, contracting with DERs solely on the basis of their energy costs creates an adverse selection against the locations the program ought to prioritize.

There is a direct analogy to the early markets of the New England Power Pool (“NEPOOL”). NEPOOL published a single price for the entire New England bulk power system. It managed congestion by making constrained-off payments to resources to operate at lower operating points, refunding the lost profit. Not only was this an expensive way to operate the grid, it encouraged developers to locate where land and natural gas were cheapest, regardless of the grid’s ability to deliver that power to load.³ This perverse incentive led to substantial reforms in both interconnection practices and energy pricing in the ISO New England control area to better align incentives for economically optimal resource siting. We should not fall into the same poor market design by procuring DERs without reflecting appropriate premiums for when and where they can deliver power to the grid.

The Draft Proposal concedes this point. Section 3.2 warns “a single system-wide rate may risk incentivizing resources that do not defer substantial costs, ultimately leading to higher costs for ratepayers....”⁴ Nonetheless, the Draft Proposal then goes on to suggest that Part 2 payments for locational services may need to be deferred until highly detailed cost avoidance studies are completed. We disagree.

Siting is irreversible, which is what makes concurrency urgent rather than merely preferable. Yet our reading of Section 5.2 of the Draft Proposal is that Part 2 values will be subject to a complex tariff, detailed engineering analyses of each possible location for DERs, and complex control and monitoring systems. Implicit in this complexity is delay. As we discuss in Section 5 below, we believe that there is a simple solution that accords with an “80/20” rule: yielding most of the benefits at a fraction of the complexity. Such an approach can and should be finalized concurrently with the Part 1 procurement approach.

The concurrency is also important because DERs, considered solely as a source of zero-emitting energy and RECs, are unlikely to be as cost-effective as grid-scale resources. Solar installations benefit from economies of scale. Investment bank Lazard’s most recent report on the levelized cost of energy by technology type reports costs of utility-scale solar ranging between \$40 to \$98/MWh, while community and C&I solar costs range between \$88 and \$197/MWh—a factor of

³ See, e.g. *Champion International Corporation and Bucksport Energy, L.L.C. v. ISO-New England, Inc., New England Power Pool (NEPOOL)*, and *Central Maine Power Company*, FERC Docket EL98-69-000.

⁴ Draft Proposal at 8.

two higher.⁵ Unless the locational value of DERs is explicitly valued in the procurement process, it is unlikely that the program will meet its statutory requirements under 35-A M.R.S. §3209-I.

§4. DER Selection and Part 1 Compensation Should Be Set By Competitive Auction

The Draft Proposal discusses four possible mechanisms for setting prices:

1. Economic analysis of avoided costs
2. Informational solicitation of developers, verified by third-party data
3. Competitive solicitation
4. Modification of Standard Offer prices

CLF strongly recommends a hybrid approach: use an annual competitive solicitation with a price cap, set with reference to the long-term value of energy and RECs. Using a competitive solicitation as the workhorse design element assures that ratepayers are not over-paying for resources; the price paid will be no higher than needed to attract the quantity of DERs desired. The price cap acts as a fail-safe to ensure that a competitive price for DERs is also competitive relative to other options, such as procurement of transmission-level assets and upgrading distribution systems.

The other three methods (avoided costs, information solicitation, and modified Standard Offer) all suffer from the same potential defect: a procurement mechanism cannot fix both the price and quantity. The administrative price will almost certainly be too high or too low. If it's too low, then the target quantity of DERs won't be procured and their potential value to the grid is unrealized. If it's too high, consumers are overpaying, and excess resources enter early-stage development chasing uneconomic rents. Furthermore, when overly high prices attract more resources than the procurement target, a rule will be needed to choose among the surplus of DER offers that are willing to accept this too-high price. A competitive auction, by contrast, uses bid prices as the tiebreaker, assuring the most cost-efficient, highest value resources are selected.

Our hybrid proposal does include a cap. This cap is an important consumer protection to ensure that prices stay in the range of reasonableness. CLF believes that, since it is energy and RECs being procured at this stage in the auction, the appropriate benchmark is forward strip prices of energy and RECs. We note that the Standard Offer price is not a good proxy for the value of energy, as that price includes a broad range of additional risk management services.

The greatest strength of our proposed auction is that competition among suppliers drives prices down toward their marginal costs. To ensure that there is in fact real competition among suppliers, the DOER should develop metrics to assess the competitiveness of the supply offers and, if the offers are not sufficiently competitive, adjust downward the desired procurement quantity to assure sufficient competition. For example, the rule might require that the volume of qualified offers exceeds 120 percent of the target procurement quantity, and that there is no bidder whose project or projects represent such a large share that some or all of that volume must be selected in

⁵ Lazard, "Levelized Cost of Energy+", July 2026 <https://www.lazard.com/news-announcements/lazard-releases-2026-levelized-cost-of-energyplus-report-pr/>

order to meet that target. Under this example rule, if only 90 MW of resources are bid, then the maximum procurement would be $90/120\% = 75$ MW. If any one bidder controlled more than 15 MW of that bid supply, the target procurement would have to be further reduced to ensure that no bidder is pivotal.

When comparing bids from DERs, we must quantify the value of different characteristics of the various DER technologies. There are three important characteristics to include in the bid evaluation:

1. Expected delivery time of energy
2. Capacity value
3. Locational value

The *timing of the energy* is a risk that should be internalized by the bidder. Recognizing that energy injections have different values at different times of day and different seasons, the DER procurement plan should have a fixed ratio, or set of ratios, of the value of power at different times. For example, referencing a recent time-of-use docket in Massachusetts, there could be six time periods defined: three seasons (Summer, Winter, Shoulder) and two time blocks (Peak and Off-peak, where “peak” is defined as 4pm-8pm on non-holiday weekdays). Recent ISO New England data yield the following approximate ratios for average bulk power prices in those blocks (where prices are shown as a percentage of the time-weighted all-hours average price):

	Weekday 4-8 PM	Weekend/holiday + weekday off-peak
Summer	141%	74%
Winter	207%	167%
Shoulder	94%	70%

The actual payment under this contract for energy deliveries would be based on the clearing price of the auction and the applicable ratio. For example, if the auction clears at \$50/MWh, deliveries in the winter peak period would be paid $\$50 \times 207\% = \$103.50/\text{MWh}$, while deliveries in the summer peak would be paid $\$50 \times 141\% = \$70.50/\text{MWh}$, and so on for other periods. Structuring energy payments on a fixed ratio basis then puts the responsibility on the developer to estimate its own delivery pattern and to bid accordingly. If, for an extreme example, a DER knew it could only deliver power in off-peak summer periods, and it needed a \$60/MWh price to make the project pencil out, then it would need to bid $\$60/74\% = \$81/\text{MWh}$. If by adding storage the developer could shift half its generation into summer peak hours while rising the break-even energy price to \$75/MWh, then it could bid $\$75/(50\% \times 141\% + 50\% \times 74\%) = \$70/\text{MWh}$, \$11/MWh lower than without storage. Thus the

more expensive project, by shaping its energy injections, could be more competitive in the auction.⁶

The *capacity value* of DERs depends on the future of ISO New England's capacity market construct. Assuming today's design as a general reference, though, it is relatively straightforward to assign any resource a capacity accreditation value based on its technology type (e.g., tracking solar, fixed solar, solar + storage, standalone storage). Recent auction clearing prices can then be used to value the capacity of each DER project bid. This imputed value should then be deducted from the as-submitted energy bid of the DER, making DERs with higher capacity values more competitive than those with lower capacity values. Cleared resources are paid their deemed capacity value in addition to the energy prices established by the auction (though, on this, see Section 7).

Finally, the *locational value* of a DER must also be taken as an offset to the as-submitted bid. Section 5 below lays out a proposal for arriving at a locational value.

Note that the auction proceeds with the *net bid* of each DER, that is, the as-submitted bid (in which the bidder has implicitly accounted for the timing of energy deliveries) net of the capacity and locational values of the DER.

§5. Part 2: A Simplified Locational Value Available on Day 1

The Draft Proposal discusses a wide range of potential Distribution System Services a DER might provide. The difficulty, as the proposal itself acknowledges, is that measuring and valuing each of these services is complex and highly resource-specific. CLF believes that an "80/20" approach to locational value will have measurable benefits and allow for the prompt creation of a DER procurement that provides reasonably accurate locational price signals for developers.

CLF proposes that the program focus solely on the DSS value of energy injections. Various grid stability services, such as voltage management and reactive power, are likely of second- or third-order value than the ability to manage network utilization and substation constraints, which in turn will defer, mitigate, or eliminate the need for costly distribution system upgrades. We note that, in ISO New England's markets in 2025, 87.3% of payments to generators was for energy, 10.6% for capacity, and ancillary services payments only amounted to approximately 2.1% of the total.⁷ By analogy, the ancillary service-like DSSs associated with grid stability are likely to be of small monetary value. Some of these benefits may be best achieved by setting interconnection standards for DERs that will include appropriate inverters to provide key grid stability services automatically.

We propose simplifying the approach of valuing locational energy value of DERs by proposing broader zonal "buckets" rather than location-specific values. The Draft Proposal (Section 5.2)

⁶ These numbers are merely intended to be illustrative of the thought process a developer might use. The actual values are arbitrary and not indicative of expected auction clearing prices.

⁷ ISO-NE Internal Market Monitor's 2025 Annual Markets Report, published May 29, 2026. <https://www.iso-ne.com/static-assets/documents/100035/2025-annual-markets-report.pdf>

states that the compensation will need to be set “specific to the service, time, and location of the need.” It also requires the utilities, in their IGPs, to develop “an inventory of distribution system needs suitable for DER solutions....” These suggestions raise two concerns.

First, relying on the utilities’ assessment of where DER solutions are suitable to address distribution needs creates a clear conflict of interest. Investor-owned utilities have a financial disincentive to find and implement non-wires alternatives (“NWA”) to distribution needs. Versant’s own record illustrates the point: across roughly one hundred targeted grid needs it identifies in its most recent IGP, peak-shifting battery dispatch was evaluated as an alternative in 62 scorecards spanning four violation types and was selected in none; every distribution solution selected in Tables 5-8 and 5-9 is a wires or device upgrade. CLF does not suggest impropriety. It observes that a utility earning a return on rate base should not be asked to certify when expanding its own rate base is unnecessary, and that a mechanical rule removes the need to ask.⁸

Second, the highly granular approach suggested in the Draft Proposal might be appropriate for a Request for Proposal but not for an annual market-based procurement. If each location is unique, then it is highly unlikely that competition can be brought to bear in each location. Instead, aggregating similarly-situated distribution circuits can create meaningful price formation for meeting those future needs.

Specifically, we propose that each distribution substation and circuit be categorized into one of four buckets based on the projected urgency and severity of forecast overloading, and the driver of the overloading. For example:

- Bucket 1: Load-driven; medium severity (110%-150% overloading) to high severity (>150% overloading) in the near-term (2-5 years) or high severity in the longer term (6-10 years)
- Bucket 2: Load-driven; all forecast violations not included in Bucket 1
- Bucket 3: All substations and circuits not included in Buckets 1, 2, or 4
- Bucket 4: All DER-driven violations.

Our approach to “bucketing” is akin to the approach CMP itself uses in its IGP. As that report states: “Given that detailed solution comparative analysis, engineering, and cost estimate develop for all 715 needs identified through the IGP process was not feasible or practical, CMP took the approach of categorizing the needs into similar groups for evaluation.” Our proposed buckets are super-sets of CMPs ten distribution-level categories.⁹

⁸Source: Versant IGP Tables 5-7 through 5-9. Peak-shifting BESS dispatch appears as an explored alternative across four violation types totaling 62 scorecards; demand response across six types totaling 76. Neither appears among the selected solutions in either operating region.

⁹ Specifically, Bucket 1 maps into CMP Categories 2, 3, 5, 7, and 9; Bucket 2 maps into CMP Categories 1, 4, 6, and 8; and Bucket 4 maps to CMP Category 10. CMP Categories 11 through 16 are transmission-level needs that seem too far removed from DERs to include.

CLF recommends that MPUC direct each utility to publish, annually and in machine-readable form, for every distribution circuit in its territory: (i) the number of forecast thermal and voltage violations by snapshot, distinguishing peak-load from minimum-load snapshots; (ii) the first forecast year in which each violation occurs; (iii) forecast peak loading as a percentage of equipment rating in the terminal forecast year; and (iv) forecast front-of-the-meter and behind-the-meter DER capacity on the circuit.

Each of these is already produced in the current IGP cycle. Versant's Appendix B reports load, EV load, heating load, energy efficiency, and separate FTM and BTM DER capacity for each of approximately 185 circuits across all six required snapshots. CMP's Exhibit 4.4 reports violation counts by snapshot, and its published hosting capacity maps report remaining load and generation headroom by circuit.¹⁰

Bucket assignment should then follow from a rule adopted by the Commission and applied to those reported values — without utility recommendation, utility ranking, or utility judgment as to whether a distributed resource is a suitable solution.

Having now assigned each part of the distribution grid into a bucket, we need to establish a reasonable proxy for the locational value of DERs installed in each bucket. By construction, Bucket 3 has zero locational value, as there was no projected need for distribution system upgrades in those locations. The values for Buckets 1 and 2 should be set at an estimate for the future deferred, mitigated, or avoided cost of distribution system capital (appropriate time-discounted). We leave open for discussion a reasonable methodology for such an estimate of avoided costs for aggregated circuits.

Bucket 4 carries no adder in the auction, but it has a penalty value for injection during declared feeder overload periods, sized so that avoiding such injections will either finance co-located storage or account for economic losses from curtailment.

These locational values (along with the capacity value discussed above) figure into the auction mechanics as follows:

1. The auctioneer adjusts the as-submitted price of all qualified bids down by (a) the deemed capacity value and (b) the locational value of that resource's grid location, adjusted by a technology-specific factor.¹¹

¹⁰Sources: Versant IGP Appendix B, "Detailed Feeder Level Forecasts," six worksheets corresponding to the six required snapshots, each reporting per-circuit base load, EV load, heating load, energy efficiency, and separate BTM DER and FTM DER capacity; CMP Integrated Grid Plan Exhibit 4.4 and published hosting capacity maps.

¹¹ For example, a solar project in Maine, unpaired with storage, has a predictable time pattern of generation. If this pattern only overlaps with the period of forecast distribution needs for 1 in 8 hours, then the adjustment for solar resources should only be 12.5% of the whole locational value. By contrast, a solar+storage project might be forecast to be available in all high-demand hours and so would benefit by reducing its as-submitted bid by the whole locational value.

2. The bids are stacked in ranked order based on their adjusted prices
3. The auction clears at the (adjusted) price set by the marginal bidder selected to meet the quantity target, unless:
 - a. The price cap is hit, in which case only resources with adjusted prices at or below the price cap clear the auction and the price is set at the cap.

All DERs in Buckets 1, 2, and 4 carry a performance obligation for their DSS. Specifically—given that we have simplified the definition of DSS to mean the timing of energy injections—DERs in Buckets 1 and 2 are scored based on their delivery of energy equal to their cleared nameplate capacity during high-need periods. Until and unless we develop more complex control and communication systems between the utilities and DER resources, the “high-need periods” will likely need to be a pre-defined set of hours, e.g. 4-8 PM on non-holiday weekdays in the winter and summer. A score of 100% is earned when the DER delivers its full rated power in all high-need hours. Shortfalls reduce the score. The adder is paid to each resource in accordance with its score.

DERs in Bucket 4 have a performance obligation to *avoid* injections during high-export hours, either by curtailment or storage. There is a tension here between what level of delivery capacity the DER paid for as part of its interconnection, however. A Bucket 4 penalty would be appropriate under a “connect and manage” approach to interconnection, but if a resource has paid for upgrades to assure full delivery, then it should perhaps be exempt from Bucket 4 penalties. The developer would, in effect, have bought out its Bucket 4 penalties by paying for the distribution upgrades needed. CLF believes that distribution interconnection standards should be revisited to allow more flexibility, lower costs, and shorter interconnection queues, akin to the “connect and manage” approach used in the Electricity Reliability Council of Texas (“ERCOT”) and similar concepts under development by PJM Interconnection, the Southwest Power Pool (“SPP”), and the Midcontinent Independent System Operator (“MISO”). We recognize that such a shift is beyond the scope of this proposal. Under such a system, however, the Bucket 4 penalties would have a stronger economic impact.

Simplifying the DSS definition also partially resolves a conflict in scoring performance noted in the Draft Proposal, at least for resources in Buckets 1 through 3. Under CLF’s proposal for these resources, fulfilling one’s DSS obligation is always met by injecting power onto the grid. Therefore, good DSS performance is fully aligned with the energy delivery obligation of Part 1.

Nonetheless, it remains possible that a utility will request a generator to limit or cease output to manage unusual system conditions. The principles that should govern in this circumstance should parallel those that apply to generators in ISO New England’s wholesale market. Specifically, if a generator is backed down to provide an ancillary service, it is both paid for that service and made whole for the lost opportunity value of selling energy. On the other hand, if a generator’s output is undeliverable due to system congestion, then they receive no compensation. If a generator has paid for system upgrades to enable full delivery, it has a reasonable expectation that these curtailments will be minimal and driven by exceptional system conditions not anticipated in the system interconnection modeling.

We note that it is likely that the program, as CLF proposes it, will procure few or no DERs in Buckets 3 or 4. Given the Lazard data referenced above, DERs are unlikely to be an economic source of energy + RECs, relative to the cost of grid-scale alternatives. Therefore, absent locational value created by DERs delaying, mitigating, or eliminating future distribution system capital costs, it is likely that DERs in Buckets 3 and 4 will not meet the §3209-I net-benefit test. The program will, therefore, provide much-needed incentives for DERs to locate where their injections will create the most value for ratepayers.

§6. Energy Storage: The Draft Proposal Offers Nothing

By statute, this program is intended to be technology agnostic. The Draft Proposal, however, effectively forecloses standalone batteries and offers little to no value for co-located batteries. A battery generates no RECs and is net-negative on energy after round-trip losses. Under Part 1 in the Draft Proposal, storage earns nothing on its own account; its only Part 1 value is derivative, arising from shifting host-solar output into a higher-priced window, but these windows are not defined nor their relative values set. Standalone storage is assigned to a program component (the Part 2 DSS value) with no start date, no volume, and no committed rate, which is not financeable. The proposal is therefore not technology-agnostic as it repeatedly claims. The near-term component (Part 1) buys precisely the two products solar makes and storage does not, and the deferred component (Part 2) contains everything storage is uniquely good at.

The design changes proposed above supply the missing revenue streams without needing a separate storage carve-out:

1. Paying a market-based premium for energy deliveries during daily peak periods creates financeable value for storage, whether stand-alone or co-located, by properly valuing the time-shifting capacity of batteries.
2. The four-bucket design for locational value, and the attendant performance metrics, augments the missing revenue stream. Because the Bucket 1 and 2 premium is contingent on injection during defined high-need periods, a solar project will in most cases require a battery to sustain its performance score; and because Bucket 4 compliance consists of withholding injection during declared overload periods, storage is likely the cheapest route to compliance there as well, relative to curtailment.

The more nuanced proposal we suggest in this filing is a strong step towards creating a truly technology agnostic market structure.

§7. Capacity Should Be Procured, With Its Mechanics Addressed

Absent aggregation by a qualified market participant, distribution-connected resources cannot access ISO-NE capacity revenue on their own, and Maine has no substantial virtual power plant market. That value will go unrealized unless this program aggregates and bids it. Having said this, CLF acknowledges that including capacity in the market adds significant complexity.

First, ISO New England is undertaking a major rework of its capacity markets. Consequently, no one can say with certainty how DERs will fit into the new design. At a minimum there are questions of double-counting (DERs as load-reducer vs. active generator), resource accreditation, performance metrics, penalties, and financial assurance requirements.

Second, this capacity must be consolidated and bid into the market by a qualified market participant, who then owns the performance risk, penalties, and financial assurance of these resources. There would need to be some means of that consolidator of reaching back to individual non-performing DERs to make itself whole for unexcused non-performance.

Despite these challenges, CLF believes it is important to find solutions rather than discard the capacity value altogether or expect (unrealistically) that DER developers will be able to find some other path to realize the capacity value of their assets. Excluding capacity is a simpler path but strips tangible value from precisely the resource class—storage—that the program most needs to encourage.

§8. Cost Allocation and Recovery

The energy and REC value of the Block, in the eyes of a load-serving entity (“LSE”), is complex. Generators are (almost surely) intermittent, and the LSE may not have dispatch control of the storage in the portfolio. The Block, therefore, likely *adds complexity* to an LSE’s portfolio rather than serving as a hedge to its load-serving obligations.

Given this characteristic, CLF believes that handing the Block (and its payment obligations to DER suppliers) to Standard Offer providers will add cost to the Standard Offer and may even deter qualified parties from participating in the Standard Offer program.

Moreover, energy and RECs from DER resources are adding value to all ratepayers, not just those on Standard Offer. More supply of energy and RECs lowers wholesale prices for all customers.

We therefore suggest that the net cost (or profit) of the Block be assigned to the Stranded Cost Rate, which is allocated to all customers, where the net cost is the difference between the Part 1 energy price paid to a DER supplier and the day-ahead locational energy price for the Maine zone. Energy from the Block participates in the market as any other DER energy. RECs from the Block are owned by the utility and act as an offset to the quantity of RECs that would otherwise need to be procured by the Standard Offer supplier and competitive retailers, *pro rata* to their load served.

Regarding the Part 2 costs, paid to DERs based on their measured performance in helping manage overloads on distribution circuits, we believe these should be included in the respective utility’s distribution rates. The intent of incentivizing DERs to locate in congested areas (or to avoid creating more congestion in export-constrained areas) is to defer, mitigate, or eliminate future distribution upgrade costs. Using the same line item to collect these charges then creates an appropriate offset between the costs and benefits of the Part 2 payments.

CLF does not support charging DERs an export fee for two reasons:

First, there is a strong risk of double-allocation. Maine utilities already collect the cost of DER-driven system upgrades to the interconnecting generator through the application and study process. A developer that has funded the upgrade eliminating a constraint should not then be charged an export fee for using the equipment it has bought and paid for. Using the flexible-interconnection regime CLF recommends, the operating signal is the Bucket 4 penalty, which would itself become another over-allocated charge if there were also an export charge.

Second, an export charge is unduly discriminatory and therefore unlawful. The same physical resource would be assessed grid usage charges in three different ways depending on its particular metering arrangement and voltage class. Behind-the-meter, it pays no export charge and reduces its host's distribution charge. Attached at transmission voltage, it pays no grid usage charges which, per ISO New England's tariff, are assigned to loads. If an export fee were attached to this program, the DERs would bear a charge that neither of its closest cousins is charged, for grid usage that is not cognizably different from them.

For these reasons, CLF encourages the DOER to drop the export charge from consideration as a cost allocation tool.



We hope that these comments are helpful to the DOER as it refines its forthcoming filing at the Public Utilities Commission.

Respectfully,



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