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Subject: Comments on Distributed Generation and Microgrid Interconnection Regulation - Case No. NEPR-MI-2019-0009

GOVERNMENT OF PUERTO RICO

PUERTO RICO PUBLIC SERVICE REGULATORY BOARD

PUERTO RICO ENERGY BUREAU

IN RE: INTERCONNECTION REGULATIONS

CASE NO.: NEPR-MI-2019-0009/ CEPR-MI-2018-0008

SUBJECT: Comments of José Humberto Román-Morales, PE, on the Revised Preliminary Draft of the Distributed Generation and Microgrid Interconnection Regulation, and on Related Screening, Cost-Allocation, and Net Metering Provisions

COMMENTS OF JOSÉ HUMBERTO ROMÁN-MORALES, PE ON THE REVISED PRELIMINARY DRAFT INTERCONNECTION REGULATION

TO THE HONORABLE PUERTO RICO ENERGY BUREAU:

Attention: Edison Avilés Deliz, Chairman

COMES NOW José Humberto Román-Morales, a Professional Engineer licensed in Puerto Rico and former Acting Chairman of this Energy Bureau's predecessor agency, and respectfully submits these comments in response to the Energy Bureau's Resolution and Order inviting comments on the Revised Preliminary Draft of the Distributed Generation and Microgrid Interconnection Regulation ("Revised Preliminary Draft"), on or before August 14, 2026.

These comments are filed from a public interest, statutory, and full-cycle perspective. The interconnection process this docket regulates is not a self-contained engineering exercise. It is the point at which the public policy goals of Act 17-2019 — a resilient, reliable energy system with just and reasonable rates for all classes of customers — and Act 57-2014, which directs the Energy Bureau to ensure safe and adequate service at the lowest reasonable cost, Article 6.25(b), either take practical effect or fail to. A rulemaking of this scope cannot be evaluated in isolation from the Energy Bureau's other pending proceedings, including the 2025 Integrated Resource Plan review in Case No. NEPR-AP-2023-0004 and the still-unresolved Tranche 2 interconnection cost-allocation motion pending within Case No. NEPR-MI-2020-0012 (captioned In Re: The

Implementation of the Puerto Rico Electric Power Authority Integrated Resource Plan and Modified Action Plan), each of which this Regulation directly touches and is touched by in turn. The commenter is separately supplementing the record in Case No. NEPR-AP-2023-0004 with a related package of filings applying an integrated framework addressing firmness, cost, welfare, and grid resilience; these comments should be read together with that filing, and the Energy Bureau is respectfully urged to consider the interconnection, resource-planning, and cost-allocation dockets as one interconnected policy question rather than three isolated proceedings.

I. INTEREST OF THE COMMENTER AND SCOPE OF THESE COMMENTS

The commenter is a Professional Engineer licensed in Puerto Rico. He served as a Commissioner and later as Acting Chairman of this Energy Bureau's predecessor, the Puerto Rico Energy Commission, during which tenure the Commission issued the foundational rate order under Docket No. CEPR-AP-2015-0001. Since leaving the Commission, the commenter has personally designed, installed, and inspected numerous Distributed Generation Systems, including photovoltaic-plus-storage systems, and has provided regulatory and technical oversight for Distributed Generation programs at multiple institutions. This work has exposed the commenter directly to the practical interconnection experience of a wide range of customer types — residential, commercial, and institutional — under the existing regulatory framework this docket proposes to replace.

A properly structured, storage-paired renewable microgrid of the kind the commenter has designed and installed improves firmness for the individual customer it serves — providing dispatchable capacity and islanding capability that a bare, intermittent photovoltaic system does not — while simultaneously providing additional benefits to the broader grid, including reduced feeder-level peak stress and Virtual Power Plant-type dispatch capability available to all ratepayers. The commenter accordingly has a direct, practical interest, grounded in that hands-on design and inspection experience, in ensuring that the interconnection screening, cost-allocation, and net metering framework adopted in this proceeding accurately reflects both dimensions of that value — the private benefit realized by the interconnecting customer and the public benefit realized by the grid and by other ratepayers — rather than treating the interconnection process as a narrow, siloed engineering transaction between the Interconnection Customer and the EPS Operator alone.

These comments address several discrete issues that follow from that dual private-and-public benefit and that the Energy Bureau is well positioned to address in this proceeding.

II. WHY THIS DOCKET, THE 2025 INTEGRATED RESOURCE PLAN, AND THE TRANCHE 2 COST-ALLOCATION DOCKET ARE ONE POLICY QUESTION, NOT THREE

Section I of these comments states that this docket, the 2025 Integrated Resource Plan review in Case No. NEPR-AP-2023-0004, and the Tranche 2 cost-allocation matter pending in Case No. NEPR-MI-2020-0012 should be considered together. That statement is not a general appeal for holistic thinking. It describes three specific, mechanical points of contact between three separately-captioned dockets, each of which independently justifies treating them as connected rather than as three unrelated case numbers on three unrelated tracks.

First, this docket and Case No. NEPR-MI-2020-0012 are answering the identical legal and economic question — who bears the cost of the grid upgrades a new interconnection requires — for two different classes of generator, on two different tracks, without either docket referencing the other. Section VIII of these comments shows that Case No. NEPR-MI-2020-0012 already gives Tranche 2 utility-scale generators a defined structure for recovering interconnection cost from ratepayers — a pre-negotiated cap, a recovery mechanism smoothed into the generator's energy price, and a defined mechanism for costs above the cap. Every part of that structure is still ratepayer money, as Section VIII.D below discusses; what utility-scale generators have that Distributed Generation customers do not is a predictable structure for how that ratepayer-funded cost is distributed, not access to some other funding source. This docket gives Distributed Generation customers no comparable structure for the identical underlying question. If the Energy Bureau resolves that question one way for a 50 MW utility-scale generator in one docket and a different way for a 25 kW residential system in another, without ever stating why the two classes of generator warrant different cost-allocation architectures, the Energy Bureau has decided the same question twice, inconsistently, on two separate records that do not speak to each other. An agency is generally expected to explain, not silently allow, that kind of inconsistency between two contemporaneous proceedings addressing the same underlying issue; treating the dockets as unrelated does not make the inconsistency disappear, it only means no one has yet been asked to justify it.

Second, this docket's screening and cost-allocation rules determine whether the Distributed Generation growth the 2025 Integrated Resource Plan assumes is actually achievable, and the Integrated Resource Plan proceeding is where the factual record on current system-wide DG penetration is being developed — including testimony and amicus filings placing that penetration at roughly three times the Section 4.02.B(1) screening threshold, discussed further in Section V below, and LUMA's own published Hosting Capacity Dashboard reproduced in Exhibit A. In the other direction, if the Integrated Resource Plan's resource mix assumes continued growth in distributed, storage-paired generation to help meet Act 17-2019's renewable and reliability targets, and this docket's interconnection rules make that same growth slower and more expensive than necessary on the feeders identified in Exhibit A — which is to say, on most of the island — then the Integrated Resource Plan's assumptions and this Regulation's rules are working against each other. Nothing requires the Bureau to notice that tension unless the two dockets are read together; nothing about reading them separately makes the tension go away.

Third, and most simply: RC 193's "reasonableness, proportionality, and benefit received" cost standard, discussed in Section VIII.B below, is a single statutory mandate. It does not have one meaning in a docket about residential net metering and a different meaning in a docket about utility-scale procurement. A ratemaking principle that means different things depending on which docket happens to be captioned on the order is not being applied consistently, whatever the technical merits of any individual proceeding.

The commenter raises this not as a request that the Energy Bureau expand the scope of this docket, but as a request that the Energy Bureau read the record it already has — including its own findings in Case No. NEPR-AP-2023-0004 and the cost-allocation architecture already before it in Case No. NEPR-MI-2020-0012 — when it evaluates the specific requests made in this docket below.

III. SUMMARY OF COMMENTS AND REQUESTED ACTION

The commenter respectfully requests that the Energy Bureau:

1. Direct that the minimum-load screening methodology in Section 4.04.C(2), and any corresponding provision of the Technical Interconnection Requirements ("TIR"), evaluate energy-storage-paired Distributed Generation Systems according to their configured, verifiable Operating Profile — including any Export Capacity limitation implemented under Section 7.09 — rather than

applying the more restrictive "absolute minimum load" test uniformly to any system that includes storage, regardless of how that storage is configured to interact with export;

2. Confirm that the operating-profile principle already embedded in Section 7.09.E of the Revised Preliminary Draft applies equally to the minimum-load screen in Section 4.04.C(2);

3. Direct that the agenda for Stakeholder Workshop 2 on August 25, 2026, and the corresponding TIR provisions, take into account the Puerto Rico-specific hosting-capacity research identified in Section IV below, portions of which are already part of the record of this docket;

4. Direct LUMA, in the TIR proceeding, to evaluate whether the 15 percent aggregated Export Capacity screen in Section 4.02.B(1) — a threshold with no Puerto Rico-specific technical derivation — should be differentiated for feeders and configurations employing smart inverter Volt-VAR functions and paired energy storage;

5. Direct LUMA to propose a Distribution Upgrade cost-reimbursement or cost-sharing mechanism, analogous to but more fully specified than the cash-repayment provision already present in Section 7.08.B for Network Upgrades, and generalize the "reasonableness, proportionality and benefit received" principle that Article 3.D(2)(i)(2) presently applies only to the statutory 25-kilowatt exemption so that it governs Distribution Upgrade cost allocation generally under Section 7.08, consistent with the mandate of Joint Resolution 193;

6. Direct the EPS Operator to record, as part of the Public Queue required under Section 12.01, which Distribution Upgrades were funded by which Interconnection Application and what latent capacity each created;

7. Reconcile any cost-allocation determination issued in Case No. NEPR-MI-2020-0012 regarding Tranche 2 interconnection costs with the cost-allocation rules adopted in this proceeding;

8. Direct that the Aggregate Net Metering Program (Section 9.03) and the Shared Net Metering Program (Section 9.04) be extended, or that an analogous program be adopted, to accommodate Third-Party Microgrid Operators serving multiple, separately-named customer accounts, and multi-unit residential structures such as duplexes, triplexes, and quadplexes with individually metered accounts that are not organized under the horizontal property regime;

9. Direct LUMA to report Interconnection Application and completed-interconnection counts broken out by Net Metering Program type (Basic, Aggregate, Shared) in future Section 12.02 reports;

10. Direct LUMA to report, in the Public Queue and future Section 12.02 reports, the number and share of Interconnection Applications and completed interconnections that are photovoltaic-only versus storage-paired, broken out by customer class; and

11. Address the discrete drafting gaps identified in Section X below concerning Minor System Modifications, the Pre-Application Report fee, the timeline for Administrative Review under Section 13.02, and the Section 2.02.G(8) cross-reference error.

IV. THE 15 PERCENT SCREEN IS AN IMPORTED NATIONAL DEFAULT, NOT A PUERTO RICO-DERIVED ENGINEERING LIMIT

Section 4.02.B(1) of the Revised Preliminary Draft provides that, for interconnection to a radial distribution circuit, aggregated Export Capacity on the circuit "shall not exceed fifteen percent (15%) of the line section annual peak load as most recently measured at the substation." This screen, together with the Supplemental Review process in Section 4.04 that follows a Fast Track failure, mirrors the Federal Energy Regulatory Commission's pro forma Small Generator Interconnection Procedures, first adopted in Order No. 2006 (2005) and revised in Order No. 792 (2013).

The 15 percent figure was not derived from Puerto Rico grid conditions. It originated as a national screening default intended to identify, with minimal engineering effort, which interconnection applications were unlikely to cause distribution-system problems and could therefore proceed on an expedited basis — not as a technical finding that higher penetration is unsafe. FERC's own 2013 rulemaking record recognized that the screen was already causing high-penetration jurisdictions to fail Fast Track review at a rate inconsistent with actual system capability, which is precisely why the Supplemental Review process — now reproduced in Section 4.04 of the Revised Preliminary Draft — was added: to give interconnection customers a path other than the full Study Process when a feeder's actual minimum load, voltage, and protection characteristics support a higher safe penetration level than the 15 percent screen alone would suggest.

The commenter raises this background because the Revised Preliminary Draft imports the national default and its national fix without adaptation to Puerto Rico-specific technical evidence that is already available — including evidence developed under this very docket, discussed below.

V. PUERTO RICO-SPECIFIC, PEER-REVIEWED RESEARCH ALREADY IN THIS DOCKET SUPPORTS A STORAGE-DIFFERENTIATED SCREENING THRESHOLD

A thesis titled Increasing Hosting Capacity of Distribution Feeders Through Energy Storage and Smart Inverter Functions (Anny Huaman Rivera, University of Puerto Rico at Mayagüez, 2022) was filed in this docket on April 12, 2024, and was subsequently published in peer-reviewed form as Huaman-Rivera, Irizarry-Rivera & Calloquispe-Huallpa, "Increasing photovoltaic hosting capacity in distribution networks in Puerto Rico: Seasonal and technical characteristics analysis and solutions," Energy Reports, Vol. 14 (2025), pp. 867–885.

The underlying thesis modeled a representative, real Puerto Rico distribution feeder — a radial, 4.16 kV primary circuit serving 708 households across 56 distribution transformers in southern Puerto Rico — in OpenDSS across PV penetration levels from 0 to 150 percent, in four progressive case studies: (1) PV only; (2) PV with residential battery storage; (3) PV with smart-inverter Volt-VAR control; and (4) PV combined with both storage and Volt-VAR control. Table 5.1 of the thesis reports maximum per-unit voltage by hour of day for the PV-only case: the feeder remains within the ANSI C84.1 Range A ceiling of 1.05 p.u. through 60 percent penetration (reaching 1.046 p.u. at solar noon) and first exceeds that ceiling at 70 percent penetration (1.055 p.u.). Figure 5.7 reports the corresponding thermal results: no distribution transformer exceeds its rated capacity until approximately 90 percent penetration, when Transformer 51 is the first to do so. That is the PV-only, no-mitigation baseline — already four to six times the Section 4.02.B(1) screening threshold — before Cases 2 through 4 (storage, Volt-VAR, and the combination) are applied, each of which the thesis found further raises the feeder's safe hosting capacity.

The subsequent peer-reviewed publication building on this thesis — Huaman-Rivera, Irizarry-Rivera & Calloquispe-Huallpa, "Increasing photovoltaic hosting capacity in distribution networks in Puerto Rico: Seasonal and technical characteristics analysis and solutions," Energy Reports, Vol. 14 (2025), pp. 867–885 — extended this analysis to six actual Puerto Rico distribution feeders of varying voltage and topology, and found that 13.2 kV feeders tolerate materially higher penetration with fewer violations than lower-voltage feeders; that the Volt-VAR function of smart

inverters, implemented per IEEE Std 1547-2018, reduces or eliminates voltage violations without requiring energy storage; and that the combination of battery storage and Volt-VAR increases hosting capacity by 20 to 90 percent depending on feeder characteristics. The published paper's own conclusion is that Puerto Rico's current 15 percent PV penetration cap is conservative, and that higher integration levels are technically feasible with appropriate mitigation strategies.

This finding is corroborated by data already in the amicus record before this Energy Bureau. A Second Supplemental Brief filed by amicus curiae Robert A. García Cooper in Case No. NEPR-AP-2023-0004 on May 7, 2026, states that Puerto Rico's current average distribution-circuit penetration is approximately 49 percent as of August 2025 — more than three times the Section 4.02.B(1) screening threshold — citing the 2025 IRP, Section 6.2, page 63. The commenter attempted to independently verify that citation against the publicly available main IRP report and found that the main report's own table of contents places Section 6.2 ("Energy Resource Technologies Review") at page 191, not page 63; the citation may refer instead to one of the separately paginated technical appendices or workpapers LUMA filed alongside the main report, which the commenter has not been able to locate and match. The commenter accordingly presents the 49 percent figure as it appears in the amicus record, not as independently verified fact; regardless of the precise figure, Exhibit A to these comments supplies independently verifiable, LUMA-published confirmation of the same basic point using LUMA's own public Hosting Capacity Dashboard, discussed further below.

This is not a hypothetical concern. Exhibit A to these comments reproduces LUMA's own published Hosting Capacity Dashboard data: only 15 percent of LUMA's mapped feeder segments island-wide fall within the Section 4.02.B(1) screening band, while 52 percent already exceed 30 percent penetration and 26 percent exceed 70 percent outright. That is a directly verifiable, LUMA-sourced, island-wide data set, not a single academic feeder model or a disputed secondary citation. The regulatory question this docket must answer is not abstract.

VI. THE APPROPRIATE SCREENING THRESHOLD SHOULD BE SET THROUGH THE TIR OR A DEDICATED PUERTO RICO HOSTING CAPACITY STUDY, NOT FIXED IN THIS REGULATION

Section III of the Energy Bureau's July 13, 2026 Resolution and Order explains why the Technical Interconnection Requirements exist as a document separate from this Regulation: the TIR is meant

to hold "requirements such as technical codes, standards, and fees that may warrant more frequent revisions and updates than the interconnection regulation." A numeric hosting-capacity screening threshold is precisely that kind of requirement. It is not a legal standard; it is an engineering parameter that should track the state of Puerto Rico-specific hosting-capacity research, smart-inverter and storage technology, and the grid conditions LUMA's own Hosting Capacity Dashboard (Exhibit A) documents — all of which continue to evolve, as Section VII below describes in the specific context of residential storage adoption since Hurricane Maria.

Section 4.02.B(1) of the Revised Preliminary Draft instead fixes the 15 percent figure directly in the Regulation's own text, subject only to the same amendment process as the rest of the Regulation. That placement is in tension with the Energy Bureau's own stated rationale for creating the TIR category in the first place. The commenter respectfully submits that the Energy Bureau should either (a) relocate the numeric screening threshold from Section 4.02.B(1) into the TIR, where it can be revised as Puerto Rico-specific hosting-capacity evidence develops without requiring a full amendment of this Regulation, or (b) direct that a dedicated Puerto Rico hosting-capacity study — whether conducted in the TIR proceeding, in Case No. NEPR-AP-2023-0004, or in a new docket — determine the appropriate screening threshold and mitigation-based adjustments (including the storage- and Volt-VAR-differentiated treatment discussed in Sections V above and VII below) before the Energy Bureau commits to a single, generally-applicable percentage for the life of this Regulation. Either path is preferable to fixing a nationally-imported figure in the Regulation's text on the current record.

VII. THE REVISED PRELIMINARY DRAFT'S OWN LOGIC ALREADY SUPPORTS OPERATING-PROFILE-BASED SCREENING FOR STORAGE-PAIRED SYSTEMS

Minimum load screens of this kind are generally understood in Distributed Generation interconnection practice to guard against reverse power flow. If Distributed Generation on a line section exceeds what local load can absorb at that line section's weakest moment, the surplus must flow backward toward the substation rather than toward customers. Distribution equipment — voltage regulators, load tap changers, protective relays — is generally designed and tuned assuming power flows in one direction, from the substation outward, and reverse flow can raise voltage beyond acceptable limits, desensitize protective devices calibrated for one-way fault current, and interfere with voltage-regulation equipment not designed for bidirectional flow.

Neither this Regulation nor the FERC proceedings its screens are modeled on state this rationale explicitly, but a test structured as aggregate Export Capacity held below the line section's minimum load is consistent with, and most readily explained by, that underlying concern: it functions as a proxy for ensuring Distributed Generation output has somewhere local to go even at the least favorable moment.

The daytime/absolute distinction in Section 4.04.C(2) reflects sound engineering logic as far as it goes. A photovoltaic-only system cannot physically export power at night; there is no generation to export. Testing such a system against the full 24-hour absolute minimum load — which, because overnight demand is typically the lowest point of the day for most customer classes, is almost always a smaller number than the daytime minimum — would test the system against a scenario it cannot produce. Restricting the test to daylight hours, when photovoltaic generation could plausibly exceed local load, is the only technically meaningful version of the test for that resource. Other generation types, including storage discharging on a schedule the Interconnection Customer controls, genuinely could export during the overnight trough, so testing them against the full 24-hour minimum is, as a category matter, also sound.

The Revised Preliminary Draft already distinguishes screening treatment along these lines. Section 4.04.C(2) applies the favorable daytime minimum load window (10 a.m. to 4 p.m., or 8 a.m. to 6 p.m. for tracking systems) to solar photovoltaic systems with no energy storage, while all other generation — which, as drafted, includes any solar system paired with storage, regardless of how that storage is configured — is evaluated against the absolute minimum load over the full 24-hour period. Section 7.09.E separately provides that where an Interconnection Application proposes to limit export under Section 7.09, the Fast Track screens and subsequent studies “shall study the project according to how it intends to operate,” considering the proposed design, Export Capacity, and Operating Profile identified in the application.

The flaw is not that the absolute-minimum-load test is wrong for generation that can export during the overnight trough; it is that Section 4.04.C(2) applies that stricter test to every system that includes storage, without asking whether that particular system is configured, and can be verified, to export only during the same daylight window a PV-only system would use. The Revised Preliminary Draft already contains the tools to make that distinction. Section 7.09 allows an Interconnection Customer to install a certified Power Control System that verifiably limits export

to a defined operating window, and Section 7.09.E already provides that Fast Track screens and subsequent studies shall study a project according to how it intends to operate. The commenter is not asking the Energy Bureau to relax the Minimum Load Screen's underlying safety purpose. The commenter is asking that the Energy Bureau apply the verification framework the Revised Preliminary Draft already built for this exact purpose consistently — extending it to Section 4.04.C(2) — rather than defaulting every storage-paired system to the stricter test regardless of how its export is actually configured.

This is not a marginal case, and the commenter's knowledge of it comes from two different vantage points at two different times. Before Hurricane Maria, the commenter was not yet in private practice but served as a Commissioner of this Energy Bureau's predecessor. During a rate proceeding's public hearings in that period, Distributed Generation professionals testified that approximately 95 percent of the systems they were selling at the time were photovoltaic-only, without storage, installed primarily to reduce the monthly utility bill. After Maria, the Commission received numerous customer complaints from photovoltaic-only system owners who expected their systems to keep working during the outage and were surprised to learn a standard grid-tied, PV-only system provides no backup power during a grid outage — it must cease exporting when the grid goes down, by design. Since then, in private practice, most of the residential systems the commenter has been personally involved with have been storage-paired, with the remaining design question being how much storage: whether to size for critical loads only or for full household backup, and, even with battery storage installed, whether a supplemental thermal generator is still needed for outages that exceed battery capacity. There have been extended outages since Maria, though none of comparable scale, and the design pattern has held. Commercial customers have generally followed a different path, often remaining PV-only for bill reduction while installing separate thermal backup after Maria rather than integrating storage, because storage materially increases system cost at commercial scale.

What has changed more recently is that storage-paired systems are increasingly configured not only for backup but to export to the grid — the precise configuration Section 7.09 and the minimum-load screen in Section 4.04.C(2) must accommodate, and precisely the configuration the current screen treats least favorably. LUMA's own interconnection application already asks whether batteries will be used for export, confirming that the EPS Operator already treats this as a

standard, expected configuration question rather than an edge case requiring special justification. The Regulation's screening logic has not caught up to a distinction LUMA's own intake process already recognizes.

The commenter's description of this shift is based on direct professional experience, not published data, because no published data currently exists to check it against. Section 2.02.E(6) of the Revised Preliminary Draft already requires an Interconnection Customer to disclose, at the Pre-Application Report stage, whether the Distributed Generation System or Microgrid is paired with Energy Storage — meaning the EPS Operator already collects this exact data point on every application. Neither the Public Queue required under Section 12.01 nor the Biannual Interconnection Report required under Section 12.02 currently requires that data to be aggregated or reported, alone or broken out by customer class (residential, commercial, governmental, industrial, agricultural, educational, or hospital-medical — the categories Section 9.01.A already uses for other purposes). The commenter respectfully requests that the Energy Bureau direct LUMA to report, in the Public Queue and in future Section 12.02 reports, the number and share of Interconnection Applications and completed interconnections that are photovoltaic-only versus storage-paired, broken out by customer class. That data would let the Energy Bureau, and every other participant in this proceeding, verify empirically whether the shift described in this Section reflects current island-wide reality rather than only the commenter's own experience, and would directly inform the hosting-capacity determination requested in Section VI above, since a feeder's realistic hosting capacity depends materially on what share of its connected Distributed Generation is storage-paired.

VIII. COST ALLOCATION FOR DISTRIBUTION UPGRADES IS UNADDRESSED AND SHOULDN'T BE EVALUATED AS A SELF-CONTAINED TECHNICAL QUESTION

A. What the Revised Preliminary Draft Currently Provides

Section 7.08.A of the Revised Preliminary Draft assigns the Interconnection Customer full responsibility for the cost of Interconnection Facilities and Distribution Upgrades, “as described and itemized pursuant to the Interconnection Agreement and its attachments.” Section 7.08.B addresses Network Upgrades — defined in Section 1.11(47) as additions to the Transmission System — separately, providing that their actual cost “shall be borne initially by the

Interconnection Customer; provided, however, that the Interconnection Customer may have a cash repayment pursuant to the Interconnection Agreement." Section 2.08.B confirms that Queue Position — the sequential order in which Interconnection Applications are received — "will be used to determine the cost responsibility for the Upgrades required to accommodate the interconnection."

Distribution Upgrades — defined in Section 1.11(13) as additions to the Distribution System, and the category that will apply to virtually every residential, small commercial, and community-scale interconnection processed under Article 3 or Article 4 — carry no reimbursement or cost-sharing mechanism of any kind, unlike Network Upgrades. Even for Network Upgrades, the cash-repayment right is not guaranteed by the Regulation itself: Section 7.08.B states that the Interconnection Customer "may have a cash repayment pursuant to the Interconnection Agreement" — meaning repayment exists only if, and to the extent, the individual Interconnection Agreement happens to include such a provision. The Revised Preliminary Draft does not require that an Interconnection Agreement include one, does not state what triggers it when one exists, who funds it, over what period it runs, or whether interest accrues. If no repayment provision is negotiated into a given Interconnection Agreement, the Regulation does not say who bears that cost, or whether it simply remains with the Interconnection Customer permanently. FERC Order No. 2003-B, by contrast, does not leave this to negotiation: it requires a Transmission Provider to reimburse an Interconnection Customer for its upfront Network Upgrade payments through credits against the Interconnection Customer's transmission bills, refunded with interest within five years of the Generating Facility's commercial operation date.

This contingency is not merely a drafting gap; it is itself an economic cost. Any technoeconomic analysis of a proposed Distributed Generation System or Microgrid — the financing terms available to it, the return an investor or lender will require, the price at which an Interconnection Customer can responsibly offer service to an underlying customer — depends on knowing, before capital is committed, what portion of interconnection cost will ultimately be borne by the Interconnection Customer and what portion, if any, will be reimbursed or shared. A cost-allocation rule that leaves this open until an Interconnection Agreement is individually negotiated, on terms the Regulation does not specify, does not merely create a risk that a project turns out more expensive than expected; it prevents the project from being reliably underwritten in the first place.

The commenter respectfully submits that the Energy Bureau should treat this uncertainty, and not only the ultimate cost outcome, as a cost the current draft imposes on interconnection generally.

B. Article 3.D(2)(i)(2) Already States the Governing Principle — It Should Be Generalized, Not Confined to the 25-Kilowatt Exemption

Article 3.D(2)(i) of the Revised Preliminary Draft, addressing Interconnection Applications eligible for the Simplified Process, quotes the governing statutory framework directly. Subsection (1), citing Act 114-2007, provides that a feeder exceeding its capacity "shall not constitute an obstacle" for the interconnection of photovoltaic or renewable energy systems of 25 kilowatts or less, and that necessary feeder improvements "shall be defrayed by the requesting company." Subsection (2), citing Joint Resolution 193, then states the standard that governs how those costs are to be allocated: costs "will be determined in accordance with the principles of reasonableness, proportionality and benefit received, preventing such costs from being unfairly transferred to all the customers of the electricity system."

RC 193's operative mandate — eliminating Supplemental Study and grid-improvement charges previously imposed under Regulation 8915 — was directed specifically at systems of 25 kilowatts or less, and appears to have originated in residential complaints about the $300 supplemental study charge those smaller systems faced. But the cost-allocation principle RC 193 supplies, as quoted in Article 3.D(2)(i)(2) itself, is not drafted as a rule limited to that same population. The 25-kilowatt threshold appears only in the preceding subsection (1), sourced to Act 114-2007; subsection (2)'s own text — reasonableness, proportionality, and benefit received, preventing costs from being unfairly transferred to all customers of the electricity system — contains no comparable capacity qualifier. A legislative response to a specific residential complaint does not, by its own terms, need to be read as limited to the population that prompted it, particularly where the principle the Legislature articulated is general ratemaking language rather than a size-specific rule.

This is not merely a policy suggestion the commenter is asking the Energy Bureau to adopt; it is the Legislature's own statutory standard, already quoted in the Revised Preliminary Draft. The difficulty is that the Revised Preliminary Draft applies it only within the narrow context of the 25-kilowatt statutory exemption in Article 3. Section 7.08, which governs Distribution Upgrade cost allocation for every Interconnection Application above that threshold — the entire Fast Track and Study Process population — contains no comparable reference to reasonableness, proportionality,

or benefit received. The same RC 193 standard that Article 3.D(2)(i)(2) applies to a 25-kilowatt residential system has no textual home in the provision that governs cost allocation for a 100-kilowatt commercial system, a community-scale project, or a Third-Party Microgrid.

The commenter respectfully submits that RC 193's directive was not intended to apply only below an arbitrary capacity threshold. A cost-allocation principle grounded in reasonableness, proportionality, and benefit received is, by its nature, a general ratemaking standard, not a size-specific carve-out. The Energy Bureau should direct that Section 7.08 be amended to state expressly that Distribution Upgrade cost allocation for all Interconnection Applications — not only those eligible for the Simplified Process — is governed by the same principle, and that the TIR or a subsequent Resolution and Order define the methodology by which "reasonableness, proportionality, and benefit received" will be measured, including the reimbursement mechanism requested in Section III above and discussed further in Section VIII.A above.

C. A Comparison to Puerto Rico's Own Utility-Scale Practice Illustrates the Gap

In connection with the Tranche 2 renewable energy procurement, the Tranche 2 RFP fixed a pre-established Network Upgrade Charge of $85,000 per MW of net capacity, known to each Proponent before its price submission and built directly into the Proponent's bid price — recovered as part of the Proponent's revenue stream over the life of its Power Purchase and Operating Agreement — a revenue stream itself funded through LUMA's revenue requirement, which is collected from ratepayers, the same source that funds every other cost discussed in this section. Costs for PREPA's Interconnection Facilities are similarly capped at the Facility Study estimate, and LUMA has asked the Energy Bureau, in Case No. NEPR-MI-2020-0012, to confirm that any cost in excess of that cap, as well as the entirety of LUMA's own Interconnection Works, is recovered from ratepayers generally through the Power Purchase Cost Adjustment mechanism, rather than borne by the Proponent.

Every element of that architecture is still ratepayer money. A capped charge, a recovery mechanism embedded in an energy price, and a Power Purchase Cost Adjustment do not create funding from some source other than ratepayers; they distribute a ratepayer-funded cost according to a defined structure, as Section VIII.D below discusses at greater length. What that structure provides is predictability: a cap known before construction begins, recovery smoothed into an ongoing rate rather than billed as a lump sum, and a defined, itemized path for any amount above

the cap. A residential or small commercial Interconnection Customer under this Regulation receives none of that structure — not a different funding source, but no defined structure at all: no pre-established cap, no mechanism to smooth recovery into an ongoing rate, and no defined path for reimbursement if the actual cost exceeds the estimate. The customer is not being asked to fund something a utility-scale generator does not; the customer is being asked to fund the identical kind of ratepayer-sourced cost directly and immediately, without the structure that makes utility-scale cost recovery predictable. The Energy Bureau has, in substance, already built a complete cost-allocation architecture for utility-scale generation. This Regulation does not extend an equivalent architecture, or even the general statutory standard the Legislature already provided in RC 193, to the distributed generation customers it otherwise governs.

D. Whoever Fronts the Capital, the Ratepayer Class Ultimately Bears the Cost — the Real Question Is How It Is Allocated, Not Whether Ratepayers Are Involved

Section 7.08 frames the cost-allocation question as a choice between the EPS Operator and the Interconnection Customer. That framing is incomplete. Three parties could, in principle, front the initial capital for a Distribution Upgrade: the EPS Operator, the Interconnection Customer directly, or, where the Interconnection Customer obtains its system through a third-party developer, that developer. The cost does not disappear once someone fronts it; it is either reimbursed by someone or it is not, and identifying who ultimately carries it requires following the money past the initial outlay. If the EPS Operator fronts the cost, it is recovered from ratepayers generally through rates, like any other capital expenditure. If the Interconnection Customer fronts the cost directly, that customer bears it unless reimbursed — and, as Section VIII.A above shows, no reimbursement mechanism currently exists for Distribution Upgrades. If a third-party developer fronts the cost as part of delivering a system to the Interconnection Customer, ordinary business practice means the developer will incorporate that cost into the price it charges, whether as a higher upfront system price or a higher per-kilowatt-hour rate under an Energy Service Agreement — meaning the Interconnection Customer still ultimately pays, only indirectly. In every scenario, the cost lands, in some form, on a ratepayer: the individual Interconnection Customer, the general ratepayer body, or both in some proportion. Section 7.08 does not need to decide whether ratepayers bear this cost; in Puerto Rico's utility structure they inevitably do. It needs to decide which ratepayers, in what proportion, and by what principle.

This three-way framing does not displace the statutory language already discussed in Section VIII.B above; it maps onto it. Act 114-2007, as quoted in Article 3.D(2)(i)(1), assigns the initial cost of feeder improvements for the 25-kilowatt-and-under population to "the requesting company" — a phrase the statute does not itself define. That phrase is capable of designating any of the three parties identified above: the EPS Operator; the Interconnection Customer, if organized as a company; or the third-party developer or installer many residential Distributed Generation customers in Puerto Rico work with directly, and whom customers and the industry commonly refer to simply as "the company." The commenter does not take a position on which reading is correct, and notes the ambiguity here only because the answer does not change the analysis. Whichever of the three parties "the requesting company" designates, the cost that party initially fronts is, as explained above, ultimately recovered from the general ratepayer body — directly, through the EPS Operator's revenue requirement, or indirectly, through the price a business passes on to the customers it serves. The conclusion that follows from the three-way framing above holds regardless of which party the statute assigns for the 25-kilowatt population, or which party an Interconnection Agreement assigns for every Interconnection Application above that threshold under Section 7.08.

One further point completes this picture. Even where an individual Interconnection Customer is the one who initially bears a Distribution Upgrade cost, a properly structured allocation does not leave that cost there permanently. It carries an expectation of reimbursement running back to that individual ratepayer — and that reimbursement, when it occurs, is not drawn from some separate pool; it is funded by the general ratepayer body, through the EPS Operator's revenue requirement, the same mechanism that funds the EPS Operator's own capital expenditures. Reimbursing the individual Interconnection Customer and spreading the cost across the general ratepayer base are not two different funding mechanisms. They are the same mechanism, described from two different points in time: the individual fronts the cost first, and the general ratepayer body funds the reimbursement after, through rates. A cost-allocation rule that omits the reimbursement step, as Section 7.08 currently does for Distribution Upgrades, does not avoid ratepayer funding; it simply stops the mechanism halfway through, leaving the individual Interconnection Customer permanently holding a cost the broader ratepayer-funded system was always going to bear.

This is not a distinction without a difference from how cost responsibility is typically allocated for an investor-owned utility. There, if a utility acts imprudently, a public utility commission can disallow cost recovery and require the utility's shareholders — not its ratepayers — to bear the resulting cost, because an investor-owned utility has an equity capital base distinct from its customers that can absorb the consequences of imprudence. PREPA is a public corporation, and LUMA operates the T&D system under an operation and maintenance agreement, not as a rate-based, investor-owned utility with shareholder equity at risk in that same sense. There is no comparable pool of investor capital this Energy Bureau can direct to absorb Distribution Upgrade costs instead of ratepayers. That structural fact makes the allocation question Section 7.08 leaves open more, not less, consequential: absent an investor class to bear the cost of an arbitrary allocation rule, whatever rule this Regulation adopts falls entirely on some combination of the individual Interconnection Customer and the general ratepayer body, with no third option.

Puerto Rico's energy public policy does not treat that allocation question as open-ended. Act 17-2019 and Act 82-2010 affirmatively promote distributed and renewable generation, and Act 57-2014 directs this Energy Bureau toward rates that are just and reasonable at the lowest reasonable cost. A default rule that concentrates the full, uncapped cost of shared infrastructure on whichever individual Interconnection Customer's Queue Position happens to trigger it — the practical effect of Section 7.08 as drafted — is in tension with a public policy that is supposed to make Distributed Generation more accessible, not less. At the same time, the commenter does not suggest the answer is to shift these costs onto the general ratepayer body without limit; broader cost-spreading carries its own welfare cost if pursued without bound, since rates should not rise to a level that increases the energy burden on Puerto Rico's ratepayers or discourages economic development. The Energy Bureau should give equal weight to the narrower but equally real welfare cost of forcing an individual Interconnection Customer to bear so much upfront, uncertain interconnection cost that the customer's own defensive energy expenditures — spending on generators, fuel, and other self-supplied reliability measures taken because the grid alone cannot be relied upon — increase rather than decrease as a result of adopting Distributed Generation. A cost-allocation rule that makes storage-paired Distributed Generation prohibitively expensive to interconnect defeats the welfare gain that firm, resilient Distributed Generation is otherwise positioned to deliver, a point the commenter develops further in a forthcoming filing in Case No. NEPR-AP-2023-0004.

The choice before the Energy Bureau in this proceeding is broader than how tightly to calibrate a single screening percentage or how precisely to itemize a single cost category. Sections IV through VIII of these comments describe the same underlying pattern from several angles: a screening threshold imported from national practice without Puerto Rico-specific validation; a threshold fixed in the Regulation's own text rather than left to evolve through the TIR as the Energy Bureau's own stated rationale for the TIR would suggest; a screening logic that has not caught up to how residential Distributed Generation Systems have actually been built in Puerto Rico since Hurricane Maria; and a cost-allocation rule that assigns the full expense of shared infrastructure to whichever customer happens to apply first, applying RC 193's cost-fairness standard in one narrow corner of the text but not throughout. Each of these, addressed individually, looks like a drafting refinement. Addressed together, they describe a Regulation still built around the assumption that Distributed Generation is an exception to be accommodated within a centralized system, rather than a resource that — properly configured with storage and smart inverter functions, as Sections V and VII and Exhibit A demonstrate — can itself supply the firmness, hosting capacity, and reliability contribution the Electric Power System needs. The Energy Bureau's own stated objectives in Sections 1.03 and 1.07 of the Revised Preliminary Draft are best served by a Regulation that treats storage-paired Distributed Generation as part of the solution to Puerto Rico's grid constraints, not merely as a category of interconnection application to be screened as conservatively as possible.

IX. THE NET METERING PROGRAMS STRUCTURALLY EXCLUDE THIRD-PARTY MICROGRID OPERATORS AND COMMON RESIDENTIAL STRUCTURES OUTSIDE THE HORIZONTAL PROPERTY REGIME

Article 9 establishes three Net Metering Programs: Basic (Section 9.02), Aggregate (Section 9.03), and Shared (Section 9.04). Two of the three contain eligibility restrictions that exclude arrangements Act 17-2019 and Act 57-2014 otherwise direct the Energy Bureau to treat without undue discrimination.

Section 9.03.A limits the Aggregate Net Metering Program to “governmental Entities and non-profit academic institutions,” and Section 9.03.C requires that “all locations with service agreements that take advantage of this program must be included in the same account.” That single-account requirement is a structural bar: a Third-Party Microgrid Operator recognized under Regulation 9028, serving multiple, separately-named residential or commercial customers under

individual Energy Service Agreements, cannot satisfy a same-account requirement by definition, because each served customer holds its own account with the EPS Operator, not the Microgrid Operator's account.

This restriction has a concrete practical effect beyond the categorical exclusion itself. A customer with limited physical space — a small urban lot, a shaded roof, an apartment building with little usable common area — may be unable to host a Distributed Generation System sized to meet its own consumption, even though a properly structured third-party arrangement could install additional capacity at a different location with more available space and serve the space-constrained customer's account from there. The single-account requirement forecloses exactly that arrangement: it does not merely restrict who may operate a shared system, it restricts whether a customer whose only obstacle is a lack of physical space can participate in Distributed Generation at all.

Section 9.03.C's requirement that participating locations be "included in the same account" also raises a definitional question the Revised Preliminary Draft does not resolve. "Account" is not among the terms defined in Section 1.11, and the phrase is capable of two materially different readings: it could mean the same account number — a single, literal billing account covering every participating location — or it could mean the same account holder — the same customer, under whatever separate account numbers that customer holds at each of its locations. The distinction matters more than it might first appear. Utility billing accounts are typically assigned per meter or per service address; a government agency such as the Department of Education, for example, would ordinarily hold a separate account number for each individual school building it operates, even though every one of those accounts belongs to the same account holder. If Section 9.03.C requires a single, identical account number across all participating locations, the Aggregate Net Metering Program may be effectively unusable by the very governmental and nonprofit entities Section 9.03.A makes eligible for it, since few such entities are likely to hold one consolidated account spanning multiple physical addresses. If the provision instead requires only a common account holder across separately numbered accounts, the program can function as its own eligibility criteria suggest it was intended to. The commenter respectfully requests that the Energy Bureau clarify, in the TIR or in Section 9.03.C itself, which of these two readings governs.

Section 9.04.A limits the Shared Net Metering Program "exclusively" to customers "under the horizontal property regime, such as residential, commercial or mixed-use condominiums," and to public housing managed by the Department of Housing. A duplex, triplex, or quadplex with separately metered accounts, but not formally organized as a condominium regime under Puerto Rico's Horizontal Property Act, does not qualify under either program, even though it presents the identical technical and consumption profile — multiple individually metered residential units served from a single point of delivery — that the Shared Net Metering Program was designed to accommodate.

Section 1.03 of the Revised Preliminary Draft states that the Regulation is "intended to promote a safe, reliable, efficient, transparent, and nondiscriminatory interconnection process." The commenter respectfully submits that categorically excluding an entire class of interconnection customer — the Third-Party Microgrid Operator that Regulation 9028 itself creates and recognizes, and the multi-unit residential structure that falls outside the horizontal property regime only as a matter of legal organization rather than technical configuration — from the net metering programs otherwise available to functionally identical arrangements is difficult to reconcile with that nondiscrimination standard. There is no stated technical or ratemaking rationale in the Revised Preliminary Draft for either restriction; each appears to be an inherited limitation from the 2014 Energy Bureau orders that first created these programs, carried forward without reexamination in a Regulation whose own stated purpose is to align interconnection rules with current public policy under RC 193 and Act 17-2019.

The commenter also notes a related drafting inconsistency: Section 9.03.F retains language making the Aggregate Net Metering Agreement effective "thirty (30) days after the first rate revisions established in Law 57," while the parallel provision in Section 9.04 (numbered paragraph H in the underlying draft) appears to have been struck from the current text. The Energy Bureau may wish to confirm whether that deletion was intentional and, if so, apply the same treatment to Section 9.03.F, since both provisions tie program effectiveness to an undefined, apparently stale reference to a prior rate proceeding.

The commenter offers one further observation on this point with direct personal knowledge. The commenter served as a Commissioner of this Energy Bureau's predecessor in 2014, when Amended Order CEPR-MI-2014-0001 first created the Aggregate and Shared Net Metering

Programs and set the eligibility restrictions Sections 9.03 and 9.04 carry forward unchanged. Those restrictions were adopted as a practical, administrable starting point for programs that did not yet exist in any form — not as a considered, permanent judgment that government entities, nonprofit academic institutions, and horizontal-property-regime condominiums were the only arrangements that should ever qualify. The intent at the time was to begin the programs simply and expand them as experience warranted. Eleven years of subsequent experience, including the structural exclusion of Third-Party Microgrid Operators that did not exist as a regulatory category in 2014 but do today under Regulation 9028, have demonstrated that the initial, narrowest starting point does not reflect the range of arrangements the programs should serve. The commenter respectfully submits that carrying a 2014 starting point forward unchanged, without the reexamination the Regulation's own alignment with RC 193 and Act 17-2019 is meant to provide, risks mistaking administrative convenience at the program's inception for a permanent policy boundary.

The commenter was unable to locate, in the Biannual Interconnection Reports LUMA files in Case No. NEPR-MI-2019-0016, a breakdown of Interconnection Applications specifically by Net Metering Program type — Basic, Aggregate, or Shared. Without that data, neither the Energy Bureau nor any commenter can determine how much demand for the Aggregate or Shared programs exists, or how much has gone unserved because of the current eligibility restrictions. The commenter respectfully requests that the Energy Bureau direct LUMA to report Interconnection Application and completed-interconnection counts broken out by Net Metering Program type in future Section 12.02 reports, so that this question can be answered with data rather than inference.

The commenter respectfully requests that the Energy Bureau direct that Sections 9.03 and 9.04 be revised to extend eligibility to Third-Party Microgrid Operators serving multiple customer accounts and to multi-unit residential structures with individually metered accounts that are not organized under the horizontal property regime, or that an analogous net metering program be created to accommodate these arrangements, consistent with the nondiscrimination principle Section 1.03 already articulates.

X. FOUR ADDITIONAL DRAFTING GAPS WARRANT ATTENTION

A. Minor System Modifications

Section 1.11(39) defines "Minor System Modifications" as work the EPS Operator estimates will require less than ten hours of labor and $5,000 in materials, but further provides that the EPS Operator "may also deem other more substantial work, including the upgrade of transformers, as Minor System Modifications at its discretion." This discretion is unbounded: the Regulation sets a numeric floor for what qualifies as minor but no ceiling on how far the EPS Operator may extend that classification. Because Minor System Modifications receive a faster, less costly review path than upgrades exceeding that classification, this open-ended discretion creates real unpredictability for an Interconnection Customer's cost and timeline expectations, particularly for residential customers for whom $5,000 already represents a substantial share of total project cost. The commenter requests that the Energy Bureau either establish an outer bound on the EPS Operator's discretion to classify larger work as "minor," or require that any such classification be disclosed and justified in writing at the time it is made.

B. The Pre-Application Report Fee Applies Per Point of Common Coupling

Section 2.02.A sets a non-refundable $300 fee for a Pre-Application Report "on a proposed project at a specific site," and Section 2.02.F requires an Interconnection Customer to submit "additional Pre-Application Reports if information about multiple Points of Common Coupling is requested." Read together, a developer or Third-Party Microgrid Operator comparing several candidate interconnection points during early site selection — a routine and prudent practice — incurs a separate $300 non-refundable fee for each, notwithstanding that Section 2.02.C makes clear the resulting report is "non-binding" and "confers no rights." The Revised Preliminary Draft states no rationale for the $300 figure and imposes no cap on the number of Pre-Application Reports a single prospective project may require. The commenter requests that the Energy Bureau ask LUMA to justify the fee amount in the TIR proceeding and consider whether a reduced fee, or no fee, should apply to reports for the second and subsequent Points of Common Coupling evaluated for the same underlying project.

C. Administrative Review Has a Filing Deadline But No Resolution Deadline

Section 13.02 gives an Interconnection Customer twenty days to file a request for Administrative Review of an EPS Operator decision, including a cost-allocation determination under Article

3.D(2)(ii). The Revised Preliminary Draft does not state any corresponding deadline by which the Energy Bureau must resolve that review. A customer disputing a cost allocation therefore faces a firm deadline to act and no defined timeline for an answer, during which the underlying interconnection application remains unresolved. The commenter requests that the Energy Bureau establish a target resolution timeline for Administrative Review requests under Section 13.02, consistent with the time-frame discipline the Revised Preliminary Draft otherwise imposes on the EPS Operator throughout Articles 2 through 7.

D. Section 2.02.G(8) Cites the Wrong Subsection for the Daytime Minimum Load Definition

Section 2.02.G(8), listing the contents of a Pre-Application Report, directs the EPS Operator to disclose "relevant line section(s) actual or estimated peak load and minimum load data, including daytime minimum load as described in Section 4.04.C(1) below and absolute minimum load, when available." The daytime minimum load concept, however, is defined in Section 4.04.C(2) ("Type of generation"), not Section 4.04.C(1) (the general "Minimum Load Screen"). This is a small drafting error, but one worth correcting given how much turns on the daytime/absolute distinction, discussed in Section VII above. The commenter requests that the Energy Bureau correct the cross-reference in Section 2.02.G(8) to cite Section 4.04.C(2).

XI. REQUEST FOR RELIEF

For the foregoing reasons, the commenter respectfully requests that the Energy Bureau grant the relief requested in Sections II, III, VI, VIII, IX, and X above, and consider the Puerto Rico-specific evidence discussed in Section V in connection with Stakeholder Workshop 2, the Revised Draft TIR, and the final interconnection regulation to be adopted in this proceeding.

XII. DECLARATION

In compliance with Section 7.01(B)(4) of Regulation No. 8543, the commenter declares as follows:

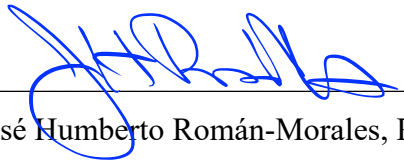
A) No party or lawyer in this proceeding assisted in drafting these comments.

B) No party or lawyer in this proceeding contributed funds or any other type of resource for the preparation or submission of these comments.

C) No person other than the commenter contributed funds or any other type of resource for the preparation or submission of these comments.

Respectfully submitted.

In San Juan, Puerto Rico, on August 14, 2026.



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CERTIFICATE OF SERVICE

I hereby certify that on August 14, 2026, a copy of these Comments was filed with the Office of the Clerk of the Puerto Rico Energy Bureau by electronic mail to comentarios@jrsp.pr.gov, addressed to the attention of Edison Avilés Deliz, Chairman.

José Humberto Román

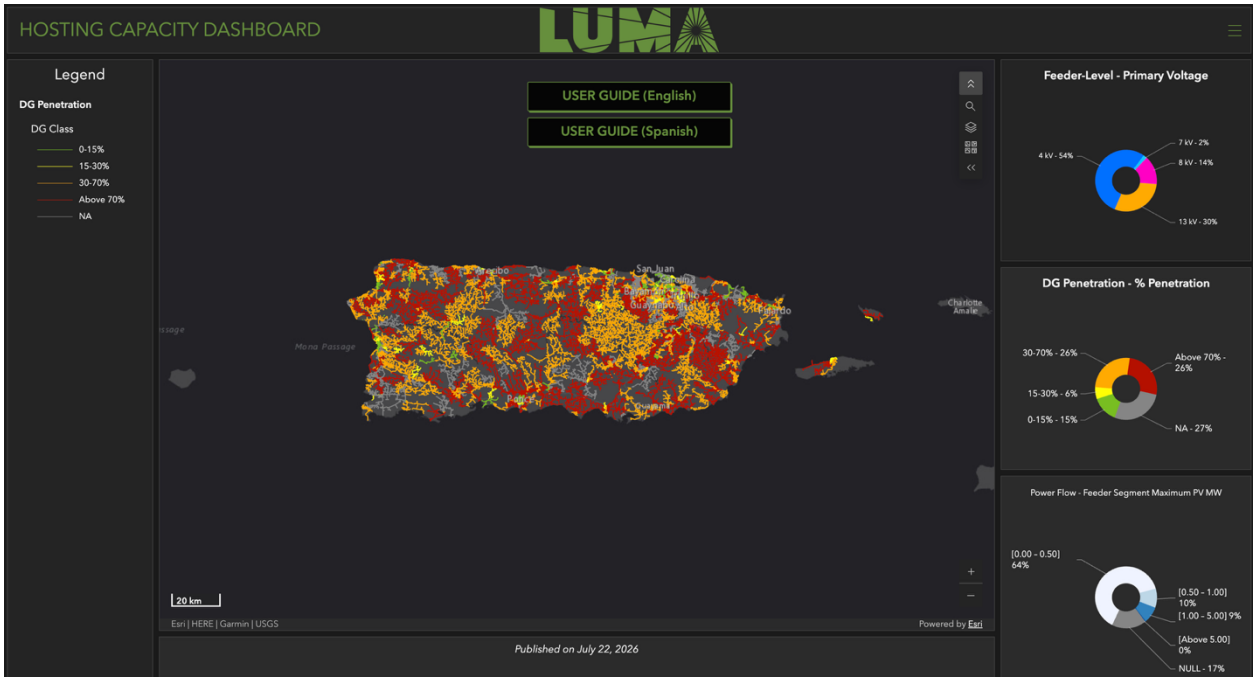
EXHIBIT A
LUMA's Own Hosting Capacity Dashboard Confirms the 15 Percent Screen Is Exceeded Across Most of Puerto Rico

LUMA maintains a public "Hosting Capacity Dashboard" (published July 22, 2026, accessible via LUMA's website, Esri-powered) that displays DG Class penetration for every mapped feeder segment on the island, classified into the same bands this Regulation uses for screening purposes. The dashboard's own summary statistics, as published, are as follows:

DG Penetration Band	Share of Mapped Feeder Segments
0–15% (within §4.02.B(1) screen)	15%
15–30%	6%
30–70%	26%
Above 70%	26%
Not available / not measured	27%

On this data, only 15 percent of LUMA's own mapped feeder segments fall within the Section 4.02.B(1) 15 percent screening band. Fifty-two percent — more than half of all mapped segments — already exceed 30 percent penetration, double to more than quadruple the screening threshold, and 26 percent exceed 70 percent penetration outright. Visually, the dashboard's island-wide map is dominated by orange (30–70%) and red (above 70%) feeder segments across nearly every populated region of Puerto Rico, from Arecibo through metropolitan San Juan to Ponce and Guayama; green segments within the nominal 0–15% screening band are sparse and scattered. The Energy Bureau's own regulated utility has, in effect, already mapped and published the answer to the question these comments raise in Sections IV and V: the 15 percent screen does not describe a safety boundary the grid operates within, and has not for some time.

A second layer of the same dashboard, "Incremental Hosting Capacity," maps the additional PV capacity, in MW, that each feeder segment could still accommodate. That layer shows sparse, isolated pockets of remaining headroom — concentrated in a minority of segments, mostly outside the dense metropolitan corridors — rather than capacity distributed evenly across the system. Read

together with the penetration data above, the two layers describe a grid where most feeders are already well past the screening threshold and the remaining unused capacity is geographically concentrated and limited. A case-by-case screening and study process calibrated to a threshold most of the system has already passed is not well matched to that reality. This is the concrete, island-wide version of the argument in Section VI above: the Energy Bureau does not need a new study to know that Puerto Rico's actual hosting capacity, and the mitigations available to expand it, are more relevant to this Regulation than the 15 percent figure inherited from national practice — LUMA's own published dashboard says so.

Source: LUMA Hosting Capacity Dashboard, published July 22, 2026, accessed by the commenter August 11, 2026. Percentages are as displayed in the dashboard's summary panel and are subject to the dashboard's own stated update cadence.