

**GOVERNMENT OF PUERTO RICO
PUBLIC SERVICE REGULATORY BOARD
PUERTO RICO ENERGY BUREAU**

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CASE NO.: NEPR-MI-2019-0009
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SUBJECT: Comments on Distributed
Generation and Microgrid Interconnection
Regulation - Case No. NEPR-MI-2019-0009
Post-Workshop Comments of Robert A.
Garcia Cooper on Subjects Discussed During
Virtual Stakeholder Workshop 3, Held
September 21, 2026

**POST-WORKSHOP COMMENTS OF ROBERT A. GARCIA COOPER ON SUBJECTS
DISCUSSED DURING VIRTUAL STAKEHOLDER WORKSHOP 3, HELD
SEPTEMBER 21, 2026**

TO THE HONORABLE PUERTO RICO ENERGY BUREAU:

Attention: Edison Avilés Deliz, Chairman

COMES NOW Robert A. Garcia Cooper, in his individual capacity as state-certified Engineer in Training (EIT, Certificate No. 28591), licensed Expert Electrician (Perito Electricista, License No. 10971), PhD student in electrical engineering at the University of Puerto Rico at Mayaguez, published researcher in energy systems and resilience economics, Senior Member of the Institute of Electrical and Electronics Engineers (IEEE), and former electricity metering technician, Probador Especial de Contadores by its official Spanish title, at PREPA's Electricity Metering Research Center Centro de Estudios de Medición, and Wholesale Metering Districts of San Juan and Bayamón, and respectfully submits these post-workshop comments in connection with the above-captioned proceeding.

I. PURPOSE OF THESE COMMENTS

These comments address subjects arising from the virtual stakeholder workshop held on September 21, 2026 (Workshop 3). The undersigned respectfully submits these observations to

assist the Bureau in developing a final regulation that is technically grounded, legally defensible, and equitable to all participants in the interconnection process.

Where arguments developed in earlier filings remain controlling, the undersigned cross-references those filings rather than reproducing the analysis here. These post-workshop comments address only matters that were raised, clarified, or modified at Workshop 3, or that require supplementation based on the workshop record.

II. LEGISLATIVE AND REGULATORY FRAMEWORK FOR COST ALLOCATION

A. The Legislative Tension Between Act 114-2007 and JR 5-2026

Act 114-2007 established a first-come-first-served interconnection framework in which the triggering, or last-connecting, party bears the cost of required upgrades. Joint Resolution 5-2026, Section B.4, subsequently required that interconnection cost allocation follow proportionality and benefit-received principles, and explicitly prohibited the unjust transfer of such costs to the general ratepayer base ("evitando que tales costos se trasladen de forma injusta a la totalidad de los clientes del sistema electrico"). These two instruments are in direct tension. The undersigned respectfully submits that JR 5-2026 governs the Bureau's regulatory framework in this proceeding, and that declining to apply its proportionality mandate may not constitute a legally defensible regulatory posture. The legal basis for that submission is developed in the paragraphs that follow.

During Workshop 3, LUMA Regulatory Vice President Gustavo Bonet and Senior Manager for Renewable Integration and Generation Assets, Engineer Alfonso Baretty, expressed a framework preference that satisfies Act 114-2007 but does not comply with JR 5-2026. Vice President Bonet characterized JR 5-2026 as "complementary" to Act 114-2007¹, suggesting that the absence of an express statutory amendment limits its regulatory reach. The undersigned respectfully disagrees and places that disagreement in writing for the record, as the point was not fully developed in the workshop transcript. This matter was partially addressed in Section III of the September 18 filing. Workshop 3 exposed additional elements that require supplementation here.

Joint Resolution 5-2026 (R.C. de la C. 193) is a full bicameral expression of legislative will, not a unilateral or advisory instrument. The operative resolution clause states verbatim: "RESUELVESE POR LA ASAMBLEA LEGISLATIVA DE PUERTO RICO," meaning this directive was issued by the full Legislative Assembly of Puerto Rico encompassing both the House of Representatives and the Senate. The "(Conferencia)" designation on the face of the resolution confirms that both chambers completed a formal conference committee process before final passage. The Department of State of Puerto Rico certified the resolution on January 8, 2026, and Section 4 of the resolution

¹ Puerto Rico Energy Bureau. (2026, September 21). NEPR-MI-2019-0009 Virtual Stakeholder Workshop 3 [Video]. YouTube. <https://youtu.be/UA4hiGtMODc?t=4207>

provides that it takes effect immediately upon approval. A resolution that has cleared both chambers of the full Legislative Assembly through conference, received executive certification, and entered into immediate legal force is not a policy preference. It is a directive of the Puerto Rico Legislature. That directive has a defined and as yet unfulfilled purpose, being that Section 2 of JR 5-2026 ordered the Bureau to adopt a new interconnection regulation consistent with its proportionality and benefit-received principles within 180 days of approval, with the final regulation to follow within 365 days. The final regulation has not been issued. Under 2 L.P.R.A. Section 200, a Joint Resolution retains full legal force until its stated purpose is fulfilled, and the undersigned respectfully submits that JR 5-2026 therefore governs this proceeding. The undersigned further respectfully invites the Bureau to consider whether a regulation adopted under JR 5-2026's express directive, but inconsistent with JR 5-2026's proportionality and benefit-received mandate, would constitute the new interconnection regulation that JR 5-2026 ordered, or whether it would instead be inconsistent with the legislative directive commanding its creation. The Puerto Rico Supreme Court has recognized that regulatory and executive actors are not at liberty to evade clear legislative mandates through operational choices, and the undersigned respectfully submits that this principle is relevant to the Bureau's consideration of cost allocation in this proceeding. *CRIM v. Mendez*, 2008 TSPR 118(174 DPR 120, 2008).

The deadlock resulting from this legislative tension was documented in the undersigned's Comments on Revised Preliminary Draft (July 18, 2026), Section II; Second Supplementary Comments (August 27, 2026), Section V; and Third Supplementary Comments (September 11, 2026), Section II. It was also stated orally at Workshop 3 at 00:58:53. The deadlock is structural: the new prosumer cannot bear the full upgrade cost because JR 5-2026 requires proportionality; the general ratepayer base cannot bear it because JR 5-2026 prohibits unfair cost transfer; and the gap between what proportionality permits and what the upgrade actually costs has no funding mechanism in the current legal framework. That gap is a legislative creation, not a prosumer creation. The Bureau is respectfully directed to the prior filings above for the full development of this argument.

B. Selective Application of JR 5-2026

Workshop 3 revealed a pattern that warrants the Bureau's attention. LUMA confirmed through Engineer Alfonso Baretty that it is not currently conducting individual supplemental studies for low-complexity Category 3 systems at or below 25 kW, and is not invoicing for them, which is consistent with JR 5-2026's prohibition on unjust cost transfer ². The undersigned commends this as the correct application of the legislative mandate. The draft rules should be consistent with it.

However, Act 114-2007 was framed throughout Workshop 3 as the primary governing instrument for cost allocation methodology at larger scales, with JR 5-2026's proportionality requirement treated as inapplicable to that broader question. The undersigned respectfully submits that selective

² Puerto Rico Energy Bureau. (2026, September 21). NEPR-MI-2019-0009 Virtual Stakeholder Workshop 3 [Video]. YouTube. <https://youtu.be/P0od4vwKXpE?t=4122>

application of JR 5-2026 at this scale may not be legally sustainable. An instrument that prohibits charging the last-connecting customer for costs attributable to prior adopters cannot simultaneously require that same customer to bear full upgrade costs at larger system scales.

The undersigned also notes that Engineer Alfonso Baretty acknowledged at Workshop 3 that average feeder DER penetration in Puerto Rico is approximately 50 percent ³. At that penetration level, the thermal loading of shared infrastructure is a function of cumulative adoption over time, not of the last-connecting customer alone. Assigning 100 percent of upgrade costs to the last-connecting party is inconsistent with JR 5-2026 and inconsistent with the underlying physics of the loading condition

The undersigned invites the Bureau to consider whether these outcomes are consistent with the Legislature's intent when issuing JR 5-2026.

C. Regulation 6030 as Precedential Authority

The undersigned introduced during Workshop 3, the relevance of PREPA Regulation 6030 (July 6, 1999), Section 3.A.5, which establishes a proportional cost allocation model based on installed load contribution and sets a 50 kVA trigger ⁴. The undersigned notes for the record that moderator Courtney Lane mistakenly attributed this citation to LUMA's Gustavo Bonet when reading from the chat log aloud during the session. The citation originated with the undersigned.

To the undersigned's knowledge, Regulation 6030, Section 3.A.5 has not been formally superseded. No evidence of supersession has been presented in this proceeding. A cost allocation instrument grounded in proportionality and benefit-received principles already exists in Puerto Rico's regulatory record. The undersigned does not propose Regulation 6030 as the direct cost allocation methodology for distributed generation interconnection, as its scope addresses shared load contribution and does not expressly address DER export behavior. It is offered as precedential authority establishing that proportional cost attribution based on contribution is a recognized principle in this jurisdiction, predating the present proceeding.

D. Cost Allocation Methodology for Voltage and Protocol for Thermal Violations

The undersigned's impedance-based attribution methodology, developed in the Third Supplementary Comments (September 11, 2026) and validated by Timbus et al. (IEEE 2007, DOI 10.1109/PESC.2007.4342176), provides a delta-V / delta-I framework for attributing voltage violations to individual DER systems on a shared circuit. That methodology is the only attribution methodology currently on the docket record, and the Bureau is respectfully directed to the September 11 filing for its full technical development.

³ Puerto Rico Energy Bureau. (2026, September 21). NEPR-MI-2019-0009 Virtual Stakeholder Workshop 3 [Video]. YouTube. <https://youtu.be/UA4hiGtMODc?t=5263>

⁴ Puerto Rico Energy Bureau. (2026, September 21). NEPR-MI-2019-0009 Virtual Stakeholder Workshop 3 [Video]. YouTube. <https://youtu.be/UA4hiGtMODc?t=5675>

At Workshop 3, Engineer Alfonso Baretty reframed cost attribution around thermal and current violations, specifically around the question of which customer caused a transformer overload ⁵. The undersigned respectfully submits that this framing is contradicted by two independent sources. First, although Engineer Baretty's comments are aimed at the party that triggers the need for grid upgrades, we must highlight that said need becomes necessary to the extent that the system becomes saturated with DER penetration, meaning that all existing customers contributed to the loading condition, not just the last-connecting party ⁶; and second, JR 5-2026, Section B.4, which requires proportional and benefit-received cost allocation regardless of which customer connected last.

For thermal violations specifically, the undersigned proposes the following supplemental methodology as a complement to the voltage-based impedance approach. The underlying measurement data can be obtained through the impedance-based attribution methodology filed on September 11. The proportional thermal contribution of each prosumer household i is computed as the ratio of that household's DER output current at minimum daytime load to the sum of all DER output currents on the circuit at minimum daytime load:

$$\text{Thermal contribution fraction} = \frac{I_{DER_i}}{\text{SUM}(I_{DER_j})},$$

for $j = 1$ through N households with DER systems on the circuit.

Minimum daytime load is the appropriate measurement basis because it corresponds to the period of maximum net DER export, and therefore to the condition under which thermal stress attributable to DER output is greatest.

The technical protocol supporting this methodology is set forth in the following sub-section.

D.1 AMI-Based Secondary Transformer Thermal Loading Protocol

In plain terms, this protocol uses smart meter data that the utility already collects to detect when the combined solar and battery output of homes connected to a neighborhood transformer exceeds what that transformer can safely carry, and to temporarily pause exports from those homes until the loading condition clears. It does not replace the transformer's physical protection equipment. It is a management layer that prevents unnecessary thermal wear on shared infrastructure before a physical fault occurs. The intervention is uniform, applying equally to all net-exporting homes on the affected circuit, and reverses automatically after one hour if the loading condition has resolved.

The technical formulation follows.

1. Purpose and Scope

⁵ Puerto Rico Energy Bureau. (2026, September 21). NEPR-MI-2019-0009 Virtual Stakeholder Workshop 3 [Video]. YouTube. <https://youtu.be/UA4hiGtMODc?t=3796>

⁶ Puerto Rico Energy Bureau. (2026, September 21). NEPR-MI-2019-0009 Virtual Stakeholder Workshop 3 [Video]. YouTube. <https://youtu.be/UA4hiGtMODc?t=3804>

This protocol establishes a standards-based, field-executable methodology for detecting when a single-phase residential secondary distribution transformer is being loaded beyond its allowable threshold as a consequence of aggregate distributed energy resource reverse power flow, and for applying a uniform, deterministic intervention using the electric power system operator's existing advanced metering infrastructure.

This protocol addresses transformer thermal loading exclusively. Voltage rise attribution and feeder source impedance characterization are addressed in the Third Supplementary Comments (September 11, 2026). Transformer thermal violations are a separate physical phenomenon requiring a separate attribution approach, based on aggregate DER contribution to transformer loading rather than individual service point impedance. This protocol provides that approach.

The application context is single-phase residential secondary circuits where rapid rooftop photovoltaic and battery energy storage system deployment creates conditions of reverse power flow that may exceed transformer nameplate capacity.

2. Physical and Regulatory Basis

2.1 Transformer Nameplate Rating

A single-phase secondary distribution transformer has a manufacturer nameplate kVA rating, designated S_{rated} , representing the rated output deliverable at rated secondary voltage and rated frequency without exceeding specified temperature-rise limits under standard service conditions, as defined in IEEE Std C57.12.00-2021, Section 5.4.1.

2.2 Normal Estimated Life Loading

Under IEEE Std C57.91-2025, Section 9.3.1, continuous loading at nameplate kVA constitutes the normal estimated life loading condition, corresponding to a winding hottest-spot temperature of 110 degrees Celsius. Any loading above S_{rated} consumes transformer insulation life at a rate exceeding the normal estimated life basis.

The default allowable loading threshold for this protocol is therefore:

$$L_{crit} = 1.00 \text{ per unit of nameplate}$$

This value requires no additional engineering justification. It is anchored directly to the transformer manufacturer nameplate rating as defined in IEEE Std C57.12.00-2021 and to the normal estimated life loading condition as defined in IEEE Std C57.91-2025.

2.3 Utility-Elected Alternative Threshold

The electric power system operator may elect an alternative threshold through an engineering analysis conducted under IEEE Std C57.91-2025. If an alternative threshold is adopted, the intervention criterion becomes:

$$L_{TR}(t) > L_{crit,utility}$$

Any value above 1.00 per unit represents loading that IEEE Std C57.91-2025 classifies as above nameplate, with associated insulation life consumption above the normal estimated life basis. The engineering justification for any alternative threshold is the responsibility of the operator.

2.4 Relationship to Current Utility Practice

Conditions consistent with transformer thermal loading driven by DER reverse power flow exist on Puerto Rico's distribution system today, independently of any smart inverter mandate. As documented in the Second Supplementary Comments (August 27, 2026), specific feeders exhibit chronic above-threshold voltage and DER penetration levels that produce daytime reverse power flow on secondary circuits. Feeder 1903-01, substation Juan Domingo, carries 57.48 percent DG penetration against a daytime light demand of 0.089 MVA and 818 kW of existing DG capacity. These field conditions confirm that aggregate DER output on residential secondaries is already capable of exceeding local load absorption capacity and loading secondary transformers in the reverse direction.

This protocol provides a transparent, standards-based, auditable mechanism for detecting and managing that condition using infrastructure already deployed, without requiring new field equipment, third-party inverter communications, or cost allocation determinations as a precondition for implementation.

3. Measurement Requirements

3.1 Meter Fleet

All active single-phase premises connected to a secondary transformer shall be metered with utility-grade single-phase electricity meters meeting ANSI C12.20 Class 0.5 accuracy for active power measurement. The electric power system operator's historical meter procurement requirements independently mandate that all AMI meters measure and display real and reactive power in the first and fourth quadrants, with a rated accuracy of plus or minus 0.5 percent at 0.5 power factor. Both P and Q measurements used in this protocol therefore meet the plus or minus 0.5 percent accuracy standard under the operator's own established procurement criteria.

The Itron OpenWay Riva CENTRON meters deployed in the operator's AMI fleet support bidirectional active and apparent energy registers and full four-quadrant reactive energy measurement, confirming physical capability consistent with those procurement requirements.

3.2 Measurement Interval

For secondary transformers identified as subject to DER saturation conditions, the operator shall configure load profile recording at intervals not exceeding five minutes. This is the minimum programmable interval supported by the deployed meter platform and provides sufficient temporal resolution for the monitoring function described in Section 4.

3.3 Sign Convention

The following sign convention applies throughout this protocol:

$P_i(t) > 0$: premises i is consuming active power from the grid.

$P_i(t) < 0$: premises i is exporting active power to the grid.

$Q_i(t) > 0$: premises i is consuming reactive power.

$Q_i(t) < 0$: premises i is supplying reactive power.

3.4 Topology Mapping

Accurate meter-to-transformer topology mapping is a precondition for implementation. Responsibility for maintaining, verifying, and correcting the mapping ($Meter_i$ to $SecondaryTransformer_k$) rests with the operator as a core AMI infrastructure management obligation.

4. Aggregate Apparent Power Calculation

For each secondary transformer k serving N metered premises:

Step 1. Aggregate active and reactive power:

$$P_{TR,k}(t) = \sum P_i(t) \text{ for all } i \text{ in } k$$

$$Q_{TR,k}(t) = \sum Q_i(t) \text{ for all } i \text{ in } k$$

Step 2. Aggregate apparent power:

$$S_{TR,k}(t) = \sqrt{P_{TR,k}(t)^2 + Q_{TR,k}(t)^2}$$

Step 3. Per-unit loading:

$$L_{TR,k}(t) = \frac{S_{TR,k}(t)}{S_{rated,k}}$$

The complete expression is:

$$L_{TR,k}(t) = \frac{\sum_{i=1}^N [P_i(t) + jQ_i(t)]}{S_{rated,k}}$$

5. Measurement Uncertainty and Conservatism

5.1 Aggregate Measurement Uncertainty

Each meter carries a worst-case measurement uncertainty of plus or minus 0.5 percent on individual P and Q readings. Because the transformer loading calculation involves summation rather than multiplication of individual meter readings, the relative error of the aggregate is bounded by the maximum relative error of any individual term. For any number of premises N, worst-case aggregate uncertainty remains plus or minus 0.5 percent. Error magnitude does not increase with the number of premises served.

5.2 Effective Intervention Threshold

To account for worst-case measurement uncertainty in the protective direction, the effective intervention threshold is:

$$L_{crit, effective} = L_{crit} \times (1 - 0.005)$$

For a nominal L_{crit} of 1.000 (default), the effective trigger is 0.995. For a nominal L_{crit} of 1.050 (utility-elected), the effective trigger is 1.045.

This adjustment ensures that when the protocol triggers intervention, actual transformer loading is at or above the nominal threshold even in the worst case where all meters simultaneously read at the low end of their accuracy range.

5.3 Secondary Conductor Losses

Premise meters measure apparent power at the point of common coupling, downstream of the transformer secondary terminals. Secondary conductor resistance between the transformer and each premise causes real line losses not captured in the premise meter readings. The aggregate S_{TR} calculated from premise meters therefore systematically understates actual transformer loading by the amount of those secondary conductor losses. The protocol is conservative in the protective direction: when calculated loading reaches the effective threshold, actual transformer loading is at or above the nominal threshold. The protocol does not trigger late.

6. Intervention Criterion

Intervention is triggered when both of the following conditions are simultaneously satisfied:

$$P_{TR,k}(t) < 0 \ \wedge \ L_{TR,k}(t) > L_{crit, effective}$$

The first condition confirms that aggregate loading is driven by net reverse power flow from DER generation. The second confirms that loading has exceeded the effective allowable threshold. Both conditions must be true simultaneously.

Net-exporting premises are those for which $P_i(t) < 0$ at the time intervention is triggered. These premises have already served their own household load with their own DER generation, and what flows through their meter toward the grid is surplus complex power. Net-consuming premises, for which $P_i(t)$ is greater than or equal to 0, are not subject to intervention.

7. Intervention Action

When the criterion of Section 6 is satisfied, the operator shall issue a remote service disconnect command to all premises on secondary transformer k for which $P_i(t) < 0$.

The intervention is applied uniformly to all active net exporters. No selective discrimination among exporting customers based on customer identity, DER size, interconnection date, or any factor other than the sign of $P_i(t)$ is permitted. Uniform treatment based solely on the electrical state of the secondary eliminates questions of preferential treatment and simplifies enforcement.

7.1 Consequence for Premises Without Storage

Grid-tied inverters are required by IEEE Std 1547-2018 to cease energizing the area electric power system upon loss of voltage at the point of common coupling. When the meter service disconnect opens, anti-islanding protection in the inverter trips within milliseconds. Premises without battery energy storage will experience a temporary full disconnection of electrical service. This consequence is the same consequence the prosumer would experience if the transformer failed thermally, with the difference that the protocol provides a defined reconnection path whereas a failed transformer does not. The operator should communicate this protocol and its consequences to affected customers as part of the DER interconnection process.

8. Reconnection Protocol

The intervention condition is expected to occur during the midday solar production window, when photovoltaic output peaks and residential load is at its daily trough. The driving condition is a predictable generation profile, not a momentary fluctuation. Reconnection is time-gated to prevent repeated connect-disconnect cycling.

8.1 Reconnection procedure

Step 1. At the moment of disconnect (t_0), the operator logs the thermal loading condition, the number of premises affected, and the transformer identifier.

Step 2. At t_0 plus one hour, the operator issues a remote reconnect command to all previously disconnected premises and records the resulting thermal loading ratio $L_{TR,k}$ at that moment.

Step 3. If $L_{TR,k}$ at t_0 plus one hour is at or below $L_{crit,effective}$, the intervention concludes and the premises remain reconnected.

Step 4. If $L_{TR,k}$ at t_0 plus one hour exceeds $L_{crit,effective}$, the operator may, upon a documented finding that the loading condition persists and no alternative remediation is available, issue a remote disconnect command to all previously reconnected premises and extend the intervention for one additional hour. The maximum total intervention duration is 2 hours from t_0 . No further extensions are permitted unless the affected circuit appears on the operator's Thermal Violation Baseline Report filed with the Bureau pursuant to Section II.D. For all circuits not appearing on that report, the 2-hour ceiling is absolute. A prosumer affected by an extension beyond 2 hours

may raise a concern with the Bureau, which may review the operator's filed baseline data to determine whether the extension was justified for that circuit.

Step 5. At t_0 plus 2 hours, or at the extended intervention ceiling specified in the Thermal Violation Baseline Report for the affected circuit, whichever applies, the operator shall issue a remote reconnect command to all previously intervened premises regardless of the loading condition. Continued loading management after mandatory reconnection shall proceed through the AMI supervisory monitoring function described in Section 10 of this Protocol. Any transformer whose loading condition has not resolved within 2 hours of initial intervention shall be reported to the Bureau within 5 business days as an infrastructure adequacy concern and placed on the operator's priority upgrade tracking list.

The two-hour ceiling reflects the typical duration of solar production peak conditions in Puerto Rico, where solar noon falls between approximately 12:00 and 14:00 AST and minimum daytime load conditions do not typically persist beyond the early afternoon. A fixed ceiling protects prosumers from indefinite disconnection while giving the operator sufficient operational flexibility to manage acute loading during the solar production window.

8.2 AMI Communications Failure

The AMI provider shall configure meter firmware so that any active disconnect command issued under this protocol must be refreshed at intervals not exceeding 15 minutes. If the refresh command is not received within the configured timeout period, the meter shall automatically reconnect the service. This ensures that a communications failure results in prosumer reconnection rather than indefinite disconnection. Physical transformer protection devices remain independent of and unaffected by AMI communications status at all times.

9. Relationship to Physical Protection

This protocol constitutes a supervisory loading-management layer. It does not replace the transformer's physical overcurrent and thermal protection devices, which remain the ultimate protection against fault conditions and operate independently of AMI data availability. The physical protection layer shall remain in service at all times regardless of the AMI supervisory system's status.

The supervisory and physical protection layers operate in a defined hierarchy:

Layer 1. Supervisory monitoring. AMI calculates L_{TR} from aggregated P and Q measurements and issues intervention commands when the criterion of Section 6 is satisfied.

Layer 2. DER intervention. Remote service disconnect of net-exporting premises reduces reverse power flow and transformer loading.

Layer 3. Physical protection. Transformer overcurrent and thermal protection devices operate independently if the supervisory system is unavailable or if loading reaches unsafe levels regardless of the supervisory system's status.

10. Reporting Requirements

Prior to the effective date of this protocol, the undersigned invites the Bureau to consider requiring the operator to file a Thermal Violation Baseline Report identifying all secondary circuits where historical AMI data demonstrates that thermal loading conditions attributable to distributed generation export have persisted beyond 2 hours from the initiation of a supervisory intervention. The report shall include, for each identified circuit, the historical loading data supporting the determination, the circuit identifier, and the operator's proposed extended intervention ceiling grounded in that data. Circuits not identified in the Baseline Report are subject to the 2-hour absolute ceiling.

The undersigned further invites the Bureau to consider requiring the operator to update this report annually and to maintain intervention event logs including the transformer identifier, trigger conditions at t_0 , loading ratio at t_0 plus one hour, action taken, duration, premises affected, and resolution status, submitted to the Bureau on a quarterly basis or upon request.

11. Standards References

- a. IEEE Std C57.12.00-2021: Definition of transformer nameplate kVA rating (Section 5.4.1); basis for S_{rated} .
- b. IEEE Std C57.91-2025: Loading above nameplate classified as life-sacrificing (Sections 9.3.1, 9.4); basis for $L_{crit} = 1.00$.
- c. IEEE Std 1547-2018: Anti-islanding requirements governing inverter response to service disconnect.
- d. ANSI C12.20: Class 0.5 accuracy standard; basis for active power measurement accuracy requirement.
- e. Historical PREPA Procurement Requirements for polyphase meters requiring bidirectional P and Q measurement at plus or minus 0.5 percent accuracy at 0.5 power factor; basis for complex power measurement accuracy.

12. Request for Bureau-Directed Data Production

The undersigned respectfully invites the Bureau to consider requesting from the electric power system operator a representative sample of secondary transformer AMI loading data for feeders with DG penetration above 40 percent, including bidirectional real and reactive power measurements at the individual premise level, transformer nameplate ratings in kVA, and secondary circuit topology mappings identifying which metered premises are served by each transformer. The deployed Itron OpenWay Riva CENTRON meter fleet has the hardware

capability to measure and record these values ⁷. Whether the operator's AMI back-end infrastructure is currently configured to collect, store, and produce this data at the transformer level is a question the Bureau's request would resolve.

The operator's response, including any representation that such data is not currently available, would itself be informative to the Bureau regarding the state of the AMI data infrastructure and its readiness to support the monitoring functions described in this protocol. Independent application of the criteria in Sections 4 through 8 against real field conditions from Puerto Rico's distribution system would assist the Bureau in evaluating the protocol's operational feasibility before incorporation into the TIR or the draft regulation. The undersigned is available to assist the Bureau in interpreting any data so produced, upon the Bureau's invitation.

E. Cost Allocation for Systems 25 kW and Under

The Bureau's preliminary draft established a reserve fund mechanism for this category. The undersigned commended this approach in the September 18 filing, and it is now reflected in the Bureau's preliminary position. These comments do not repeat that argument.

In Maine, Chapter 324 (Docket No. 2023-00103) establishes four levels of interconnection review ⁸. The rulemaking originated in L.D. 1100, which directed the Maine Public Utilities Commission to adopt cost allocation methods ensuring that on-site solar generators "do not bear prohibitive costs" for interconnection. Faced with a legislative mandate to protect prosumers from prohibitive cost exposure, the Commission determined that full cost waivers were not required and that pooled cost-sharing fees struck the appropriate balance between prosumer protection and ratepayer equity. The IREC, retained by the Commission as its independent expert, confirmed that the cost-causer pays approach implemented through tiered fees reflects nationally recognized best practices.

The Commission also held that single-phase service transformer costs should not be charged to the individual interconnecting customer, because such transformers benefit multiple customers and are appropriately recovered through rate base. This treatment is consistent with the principle that shared infrastructure costs should be allocated to the benefiting class, not assigned entirely to the last-connecting party.

Level 1 applies to inverter-based systems at or below 25 kW and carries a flat cost-sharing fee of \$150. The operative language of Chapter 324, Section 3(B)(1) reads as follows:

"The cost-sharing fee shall be \$150. The T&D Utility shall use the cost-sharing fee to pay for all costs associated with Distribution Upgrades, including travel and labor, for Level 1 Interconnection Customers only. In addition to the cost-sharing fee, a Level 1 Interconnection Customer is responsible for all costs associated with Distribution Upgrades in excess of \$5,000,

⁷ LUMA Smart Meter Initiative. <https://lumapr.com/smart-meters/?lang=en>

⁸ Item No. 40 Adopting Rule Approved Effective 11/20/2023 <https://mpuc-cms.maine.gov/CQM.Public.WebUI/Common/CaseMaster.aspx?CaseNumber=2023-00103>

as may be adjusted for Contingent Upgrades pursuant to Section 14(F). The Commission may adjust the cost-sharing fee and the \$5,000 cap in an outside proceeding."

The Maine, Chapter 324 (Docket No. 2023-00103) Level 1 provisions are a directly comparable reference point for systems at or below 25 kW.

In Massachusetts, the Department of Public Utilities has an active proceeding (D.P.U. 26-57, filed April 21, 2026) on a proposed Common System Modification Fee applicable to all Simplified Process distributed generation applicants ⁹. As proposed by the Distribution Companies and unanimously endorsed by the Department's Interconnection Implementation Review Group, the CSM Fee is \$225 per applicant for National Grid and NSTAR Electric, with a maximum cost-sharing benefit of \$10,000 per interconnecting customer. The fee is designed to be self-sustaining, with pooled collections covering system modification costs up to the benefit threshold, and any under-collection recovered through base distribution rates. The operative policy rationale stated in the filing is that the proposed cost-sharing approach "is intended to reduce the financial burden on individual Simplified Process Interconnecting Customers when EPS modifications are necessary." Separately, Massachusetts application and study fees for distributed generation interconnection are \$4.50 per kW, with a minimum of \$300 and a maximum of \$7,500, sourced from utility interconnection tariff materials; the Bureau is respectfully requested to independently verify these figures before relying on them ¹⁰.

F. Cost Allocation for Systems Above 25 kW

No draft regulation language exists for systems above 25 kW, as confirmed by the Bureau at Workshop 3. The workshop presented two comparative reference points: the New York model, in which the first mover bears 100 percent of upgrade costs and subsequent connecting parties reimburse proportionally by AC watt ratio up to \$100,000 in total upgrade costs; and the California cluster study model, in which costs are shared by nameplate kVA.

Nameplate kVA is a flawed allocation basis. A system with battery storage or a high daytime minimum load may share a nameplate kVA rating with a system that exports substantially more active power to the grid, yet the two impose categorically different loading conditions on shared infrastructure. The correct basis is actual measured export contribution. The undersigned's impedance-based attribution methodology addresses this directly, and the Bureau is respectfully directed to the September 11 filing.

⁹ D.P.U. 26-57 - Notice of Filing and Request for Comments - Joint Petition of NSTAR Electric Company d/b/a Eversource Energy; Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid; and Fitchburg Gas and Electric Light Company d/b/a Unitil for approval by the Department of Public Utilities of proposed revisions to the Model Standards for Interconnection of Distributed Generation Tariff that incorporate a Common System Modification Fee, pursuant to Department Inquiry, D.P.U. 25-48.

<https://www.nationalgridus.com/media/pdfs/our-company/dpu/2026/d.p.u.-26-57-notice-of-filing-and-request-for-comments.pdf>

¹⁰ Distributed Energy Resources Interconnection Seminar Standard / Expedited Process

<https://www.mass.gov/doc/dg-workshop-05072025/download>

In Maine, however, Chapter 324 (Docket No. 2023-00103) Level 2 applies to systems between 25 kW and 250 kW serving on-site load and carries a fee of \$25 per kW, with individual project cost responsibility capped at \$10,000¹¹. Level 3 applies to non-exporting projects up to 10 MW. Level 4 covers all other projects not qualifying for Levels 1 through 3 and not subject to FERC jurisdiction. The Level 2 through Level 4 structure is noted because it illustrates the tiered, comprehensive approach Maine adopted across all capacity categories, which the Bureau may find instructive when designing the regulation's treatment of larger systems in the section that follows. The undersigned respectfully submits that the Maine experience demonstrates that a legislative mandate to prevent prohibitive cost exposure for prosumers is workable through pooled, tiered fees and infrastructure cost socialization, without requiring case-by-case cost waiver determinations.

III. HOSTING CAPACITY AND INFRASTRUCTURE

A. Current Penetration at Scale

DER penetration in Puerto Rico is not a future scenario being modeled for planning purposes. It is the current operating reality and technical condition that frames every substantive issue in this proceeding.

SESA presented saturation LUMA hosting capacity data at Workshop 3 showing that 81 percent of feeders exceed 15 percent DER penetration, 74 percent exceed 30 percent, and 50 to 70 percent of circuits exceed 100 percent of daytime minimum load¹², meaning that thresholds are already exceeded for most of the island. Whereas any attribution methodology question becomes operationally universal, not marginal.

Brian Lydic from IREC commented at Workshop 3 that South Australia and Hawaii are the most globally comparable jurisdictions to Puerto Rico by DER penetration levels, with South Australia operating for sustained periods on rooftop solar alone¹³. Both jurisdictions use static and/or dynamic export limiting models and may be valid operational comparisons for grid architecture and export management. Section V of these comments addresses why they are not valid economic comparisons for market saturation projections or cost allocation design.

¹¹ Item No. 40 Adopting Rule Approved Effective 11/20/2023 <https://mpuc-cms.maine.gov/CQM.Public.WebUI/Common/CaseMaster.aspx?CaseNumber=2023-00103>

¹² Puerto Rico Energy Bureau. (2026, September 21). NEPR-MI-2019-0009 Virtual Stakeholder Workshop 3 [Video]. YouTube. <https://youtu.be/UA4hiGtMODc?t=5544>

¹³ Puerto Rico Energy Bureau. (2026, September 21). NEPR-MI-2019-0009 Virtual Stakeholder Workshop 3 [Video]. YouTube. <https://youtu.be/P0od4vwKXpE?t=9132>

B. Voltage Screening and TIR Specificity

The undersigned raised at Workshop 3 that the TIR should explicitly specify each of the parameters and tests applied in the export study, including per-unit voltage screening consistent with ANSI C84.1 Class B, which sets an upper limit of 1.06 per unit ¹⁴. LUMA confirmed through Bonet that the TIR is the appropriate vehicle for this specification ¹⁵, in response to Moderator Courtney Lane's request for LUMA to include comments on the draft language proposed by the undersigned.

The undersigned also wishes to note that the 1.06 per unit limit should be an absolute ceiling, not a screening trigger. Feeders already operating at 1.04 to 1.05 per unit should require evaluation before reaching that ceiling, not after, and the TIR language should reflect that pre-limit evaluation requirement.

C. Section 8.01 and TIR Modification Authority

Section 8.01 of the draft regulation requires Energy Bureau Resolution and Order approval for TIR modifications. LUMA's proposed automatic-entry mechanism for TIR updates directly contradicts this requirement. The undersigned respectfully requests that the Bureau require that every screening criterion applied in the TIR, including penetration analysis and voltage impact analysis, be explicitly described with defined scope, triggering conditions, and technical parameters, and must be modifiable only through the Bureau's Resolution and Order process.

D. Zero-Export Fast Track and Bridge-to-Wire

SESA proposed at Workshop 3 a 30-day review period for zero-export systems ¹⁶. The undersigned agrees with this proposal, consistent with the September 18 Comments, and adds that a zero-export fast track requires a standard operating procedure in the regulation or TIR specifying: (a) application intake criteria and completeness definition; (b) technical verification of the export limiting configuration; (c) defined timeline milestones with a deemed-approved consequence if the utility does not act within 30 days; and (d) compliance monitoring obligations. A timeline without a deemed-approved consequence is not an enforceable timeline.

IV. POWER CONTROL SYSTEMS

Throughout the discussion surrounding the IREC presentation during Workshop 3, a bridge-to-wire approach was presented in which large systems begin operation at a PCS-limited reduced

¹⁴ Puerto Rico Energy Bureau. (2026, September 21). NEPR-MI-2019-0009 Virtual Stakeholder Workshop 3 [Video]. YouTube. <https://youtu.be/P0od4vwKXpE?t=5467>

¹⁵ Puerto Rico Energy Bureau. (2026, September 21). NEPR-MI-2019-0009 Virtual Stakeholder Workshop 3 [Video]. YouTube. <https://youtu.be/P0od4vwKXpE?t=5562>

¹⁶ Puerto Rico Energy Bureau. (2026, September 21). NEPR-MI-2019-0009 Virtual Stakeholder Workshop 3 [Video]. YouTube. <https://youtu.be/P0od4vwKXpE?t=8614>

export capacity immediately and increase to full capacity once the required grid upgrade is complete¹⁷. The undersigned agrees that this approach merits inclusion in the draft rules as an alternative to deferring interconnection entirely pending upgrade completion.

However, the undersigned invites the Bureau to consider whether the draft regulation should explicitly address the distinction between static PCS settings, which are fixed at commissioning and do not change during operation, and scheduled PCS settings, which vary as a function of time, voltage, or other measured parameters. The undersigned respectfully submits that the TIR should address this distinction to avoid ambiguity in commissioning verification.

A. Static vs. Scheduled PCS: Distinct Technologies, Distinct Evidentiary Bases

The ten-year track record cited by Brian Lydic at Workshop 3 [006794.96-006803.18] applies to static export limiting only, not to scheduled PCS. These are distinct technologies with distinct operational records, and the draft rules must be explicit about which track record applies to which technology.

Static PCS is a fixed export ceiling programmed at installation, unchanged unless a qualified technician reprograms the device. Hawaii adopted static PCS in 2015; California in 2016. This is the baseline technology with a demonstrated field record.

Scheduled PCS involves time-varying export limits programmed into the device under UL 3141, up to 24 hourly values per day, or up to 576 values with weekday and weekend differentiation. No sub-hourly granularity is available and no built-in ramp rate exists. California is the only jurisdiction that has implemented scheduled PCS, as a "limited generation profile" downloadable from a hosting capacity tool, and it has been operational for only 2 to 4 years in that one jurisdiction.

B. Volt-Watt and Scheduled PCS Interaction

Sunrun's Kyle Wallace discussed at Workshop 3 that scheduled PCS is preferable to autonomous Volt-Watt response for utility planning purposes because it is deterministic¹⁸. The undersigned respectfully submits that determinism does not resolve sequencing incompatibility if Volt-VAR is sufficient and Volt-Watt therefore should not activate. A scheduled curtailment that fires anyway is not operating within the mandatory sequence established in LUMA's own filing.

To clarify the control sequence for the record, the Volt-VAR function operates by adjusting the inverter's reactive power output to counteract voltage rise on the feeder. If Volt-VAR brings voltage within acceptable limits, the process stops there. Volt-Watt then reduces active power output, which means the customer generates less and earns less, only when Volt-VAR alone is insufficient to hold voltage within the allowable range (ANSI C84.1 Class B: upper limit of 1.06

¹⁷ Puerto Rico Energy Bureau. (2026, September 21). NEPR-MI-2019-0009 Virtual Stakeholder Workshop 3 [Video]. YouTube. <https://youtu.be/P0od4vwKXpE?t=7772>

¹⁸ Puerto Rico Energy Bureau. (2026, September 21). NEPR-MI-2019-0009 Virtual Stakeholder Workshop 3 [Video]. YouTube. <https://youtu.be/P0od4vwKXpE?t=9635>

per unit). This sequence is mandatory under LUMA's June 11 filing, Section 4.0, and the Energy Czar's August 14 Comments.

A scheduled PCS operates on a pre-programmed time-varying export ceiling derived from historical data. It does not respond to real-time voltage. It cannot determine whether Volt-VAR has been utilized, whether it has been exhausted, or whether curtailment is physically warranted at any given moment. If a PCS schedule imposes curtailment at a time when Volt-VAR is sufficient to maintain voltage compliance, the schedule reduces prosumer output without any physical basis for doing so. That is curtailment driven by a calendar, not by grid conditions.

LUMA's June 11 filing, Section 4.0, and the Energy Czar's August 14 Comments both confirm the mandatory sequence described above. The undersigned clarifies for the record that the Volt-VAR compensation framework proposed in the August 7 Comments is not a Volt-Watt compensation methodology; said Comments did not propose Volt-Watt compensation.

If the regulation is going to address power control systems in any form, the undersigned respectfully suggests that the following questions be answered on the record before adoption: what is the intended interaction between any scheduled or static PCS mechanism with the Volt-VAR / Volt-Watt autonomous response sequence? Which mechanism governs under what conditions, and in what order of precedence? The undersigned proposes that the regulation should not be silent on this.

V. MARKET SATURATION AND DEMOGRAPHIC CONSTRAINTS

The analysis in this section is submitted to the docket record by the undersigned for the first time in these post-workshop comments.

A. Introduction

The regulatory discussion in this docket has proceeded, in significant part, from an assumption of continued and substantial growth in residential distributed generation installations. That assumption underlies concerns raised regarding net metering sustainability, feeder hosting capacity, and the urgency of certain cost allocation proposals. The undersigned respectfully submits that this assumption is not supported by the data, and that the Bureau's decisions in this proceeding would benefit from a grounded assessment of where the rooftop PV market in Puerto Rico actually stands. These statements are not advocacy for the status quo. They are aimed at grounding projections in facts rather than assumptions.

B. Methodology

The conclusions in this section result from a structured analytical effort employing the following methods:

- time-series analysis of monthly PV adoption, outage costs and import data;
- market-saturation normalization using the remaining addressable market;
- Bass Diffusion Model estimation using the full 85-period monthly installation series to derive the innovation coefficient (p), imitation coefficient (q), and implied market potential, compared to the empirically defined $M(0)$, with results presented for the first time in these comments;
- Pearson correlation and linear regression analysis;
- lead-lag correlation testing across multiple time offsets to identify the relationship between reliability burden and subsequent adoption activity; the thirteen-month lag finding reported in Mechanism A of Section V.E below is presented for the first time in these comments and builds on the outage cost framework established in prior peer-reviewed work of the undersigned;
- competing causal-hypothesis evaluation;
- saturation assessment of the rooftop PV market; and
- contextual interpretation using major grid reliability and disaster events.

C. Addressable Market Definition and Current Penetration

The defined addressable residential market, designated $M(0)$, is constructed from U.S. Census Bureau American Community Survey data for Puerto Rico, updated to the 2024 survey cycle ¹⁹. Households earning above \$50,000 annually, adjusted by a factor of 0.81 to reflect the proportion occupying single-unit housing structures, which are the primary eligible configuration for standard rooftop PV interconnection, yield a defined addressable market of 275,931 residential units.

As of June 2026, the total installed residential DG base in Puerto Rico is approximately 206,007 systems, representing a penetration rate of approximately 74.7 percent of the defined addressable market and leaving an estimated remaining pool of 69,924 potential customers within this defined segment. As of June 2026, there are 125,202 Commercial Class customers as reported in the Master Metrics Summary document of August 2026 within the NEPR-MI-2019-0007 docket.

D. Market Capacity Scenarios

¹⁹ S2503 Financial Characteristics. 2024: ACS 1-Year Estimates Subject Tables
<https://data.census.gov/table/ACSST1Y2024.S2503?q=Housing&g=040XX00US72>

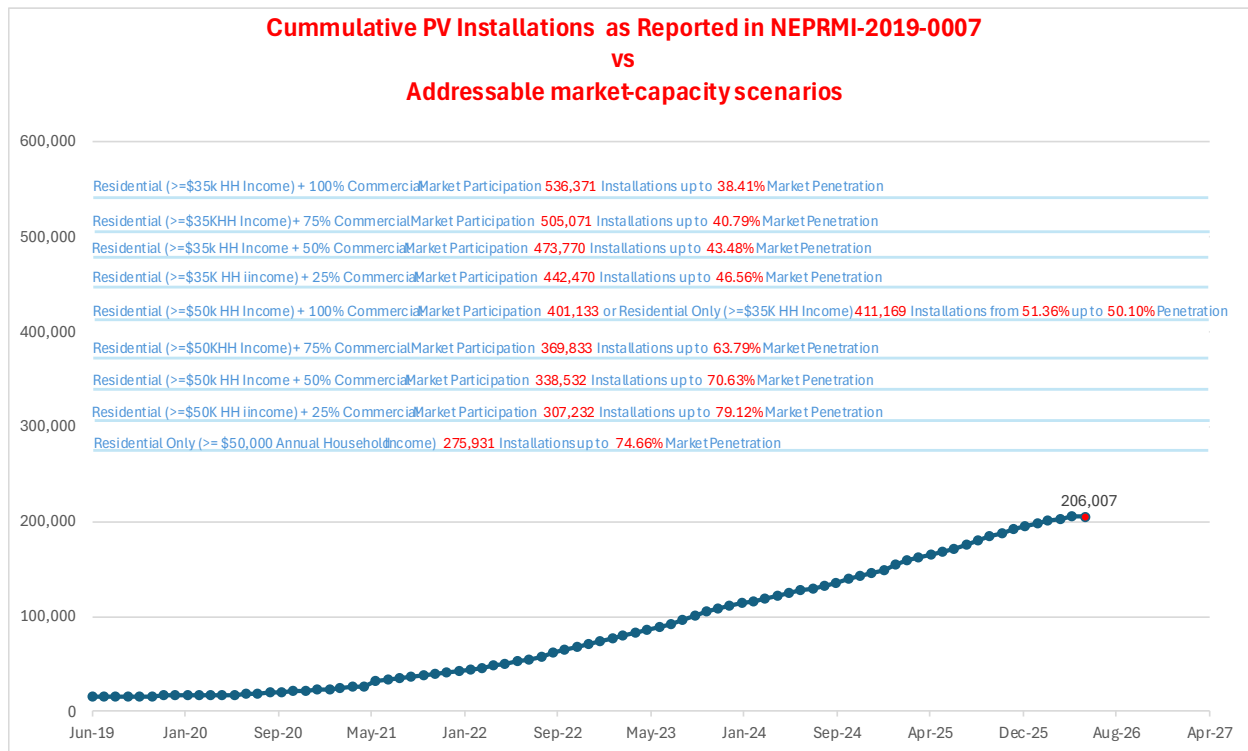


Fig. 1. Cumulative PV installations over time, from NEPR-MI-2019-0007 docket record

The following scenarios present total theoretical market capacity under varying assumptions about income threshold and commercial DG participation, as a complement to the residential saturation analysis. All scenarios incorporate the 74.7 percent residential penetration already achieved against the primary M(0) of 275,931. The baseline figure already accounts for the fact that 81 percent of Puerto Rican households occupy single-unit structures with exclusive roof rights. It does not account for whether each remaining roof is structurally appropriate for a PV installation, or whether the occupant has the legal right to authorize one, as renters typically do not.

Primary income threshold (\$50,000 adjusted): 0 percent commercial: 275,931. At 25 percent: 307,232. At 50 percent: 338,532. At 75 percent: 369,833. At 100 percent: 401,133.

Expansive income threshold (\$35,000): 0 percent commercial: 411,169. At 25 percent: 442,470. At 50 percent: 473,770. At 75 percent: 505,071. At 100 percent: 536,371.

E. Monthly Adoption Trend

E.1 Cumulative Penetration

The 74.7 percent penetration figure above reflects the primary market definition, applying the \$50,000 income threshold and single-unit occupancy filter. Under the most expansive market definition tested, which lowers the income threshold to \$35,000 and includes full commercial participation, current penetration stands at approximately 38 percent of the theoretical ceiling.

Under all tested definitions, the adoption curve has advanced well past the growth acceleration phase and is in a decelerating trajectory, as the normalized deployment rate analysis in Section V.E.3 below demonstrates.

E.2 Raw Deployment

Monthly net additions to the residential DG base reached a series peak of 4,995 installations in a single month and have since declined to 1,067 installations in June 2026, a reduction of approximately 79 percent from peak.

E.3 Normalized Deployment Rate

The preceding observation is susceptible to the objection that declining raw PV installation counts are a mathematical consequence of a shrinking remaining customer pool rather than evidence of genuine saturation. The analysis addresses this directly by computing the monthly deployment rate as a fraction of the remaining addressable market at each period.

Under the primary market definition, the normalized monthly PV adoption rate rose to a peak of approximately 4.6 percent of the remaining addressable market per period and has since declined to approximately 1.5 percent as of June 2026, a reduction of approximately 67 percent from peak. Under the most expansive market definition tested, the normalized PV rate rose to approximately 1.3 percent at peak and has since declined to approximately 0.3 percent. This pattern holds consistently across all tested market scenarios.

The decline in PV deployment is not simply a mathematical consequence of having fewer customers left to serve. The conversion rate of the remaining market is itself declining. This is the distinguishing signature of saturation, where not only is the remaining pool smaller, but the rate at which that pool is being activated is falling. This finding is robust to any reasonable variation in market definition assumptions.

Similar analysis applied to BESS deployment yields a consistent result, with the normalized BESS deployment rate also in decline from its series peak, pointing toward the same structural conclusion where the remaining active market for distributed energy resources is in late-stage deceleration across both resource types.

F. Four Behavioral Mechanisms

The adoption trajectory reflects four simultaneous and mutually reinforcing mechanisms, each supported by independent statistical evidence.

Mechanism A: Reliability and outage burden. Using outage-related cost metrics as a proxy for cumulative reliability burden, lead-lag correlation testing identifies a statistically meaningful relationship between outage burden and subsequent normalized adoption activity, with a peak Pearson correlation coefficient of $r = 0.389$ ($R^2 = 15.1\%$) at a thirteen-month lag. This thirteen-month lag finding is presented for the first time in these post-workshop comments. It builds on the framework for measuring the economic burden of outage events established in prior peer-reviewed work of the undersigned: Garcia Cooper et al., "True Cost of Electric Service: What Reliability Metrics Alone Fail to Communicate," *The Electricity Journal*, Vol. 37 (2024), Article 107386, DOI: 10.1016/j.tej.2024.107386. The thirteen-month interval is consistent with a behavioral model in which customers first observe a significant reliability event, then observe neighbors whose installed systems mitigated the burden of that event, and over the following months develop the conviction and organize the financial commitment required to complete an installation.

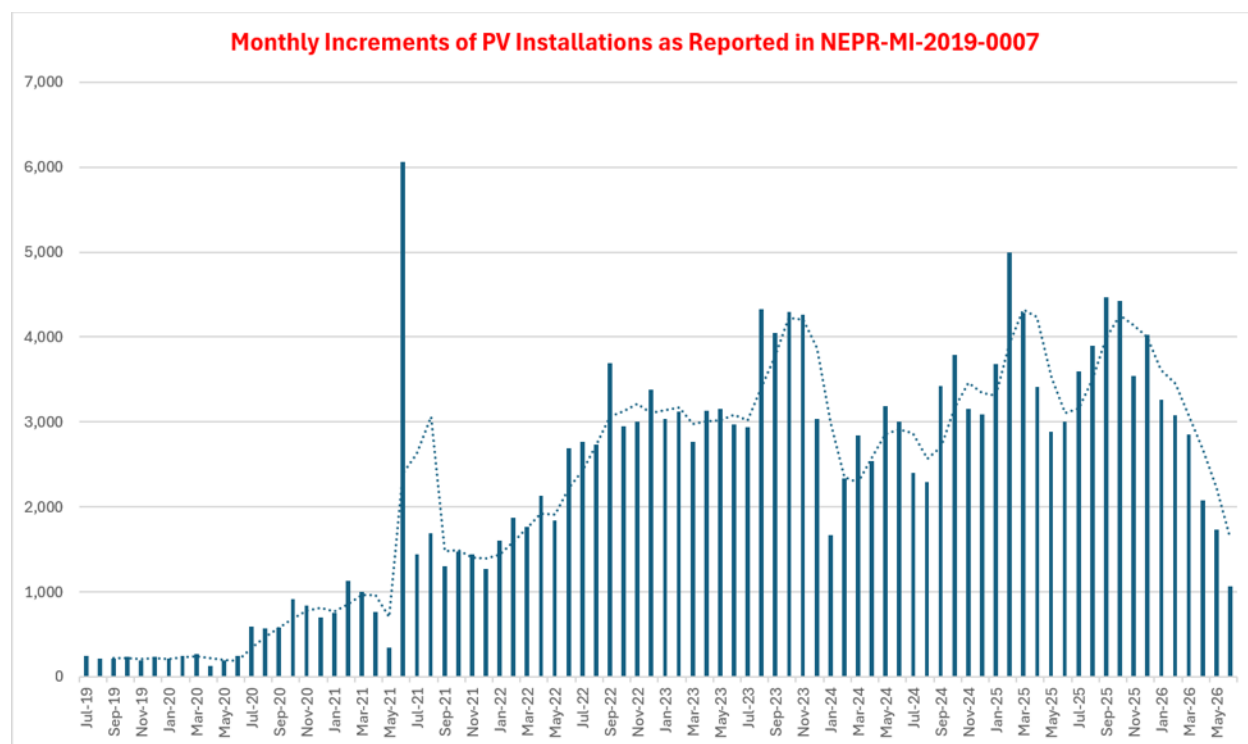


Fig. 2. Monthly delta (new installations per month), from NEPR-MI-2019-0007 docket record

Independent corroboration of the reliability motivation thesis is found in NREL's Puerto Rico Grid Study (PR-100), which acknowledged, in connection with research then in preparation by the undersigned at the University of Puerto Rico at Mayaguez, that a non-trivial number of Puerto Rico households have purchased rooftop PV and storage systems with no intention to interconnect. PR-100 observed directly: "customers continue to purchase systems even without any net metering compensation for these systems."²⁰ These households are investing in energy independence without seeking grid interaction or export compensation of any kind. Their motivation is not economic arbitrage through net metering. It is protection from a grid perceived as insufficiently reliable. This national laboratory finding provides independent confirmation, from a source entirely outside utility reporting and outside this docket, that reliability motivation is a sufficient and operative driver of DG investment decisions in Puerto Rico.

Mechanism B: Supply chain procurement response. Monthly PV equipment import data from the Puerto Rico Institute of Statistics, sourced from U.S. Customs and Border Patrol records as compiled by PRISA, shows a robust positive correlation with the deployment series ²¹. The strongest relationship appears at a two-month lead from installations to imports (Pearson correlation of $r = 0.674$, $R^2 = 45.4\%$), consistent with a procurement replenishment mechanism in which installers observe completed installation volumes and place procurement orders that arrive as imports approximately two months later. Imports follow deployment demand; they do not lead it. The import series thereby provides independent corroboration, from a source entirely outside utility reporting, that the deceleration in monthly installation counts is apparent and seems to be propagating through the supply chain with the expected two-month delay.

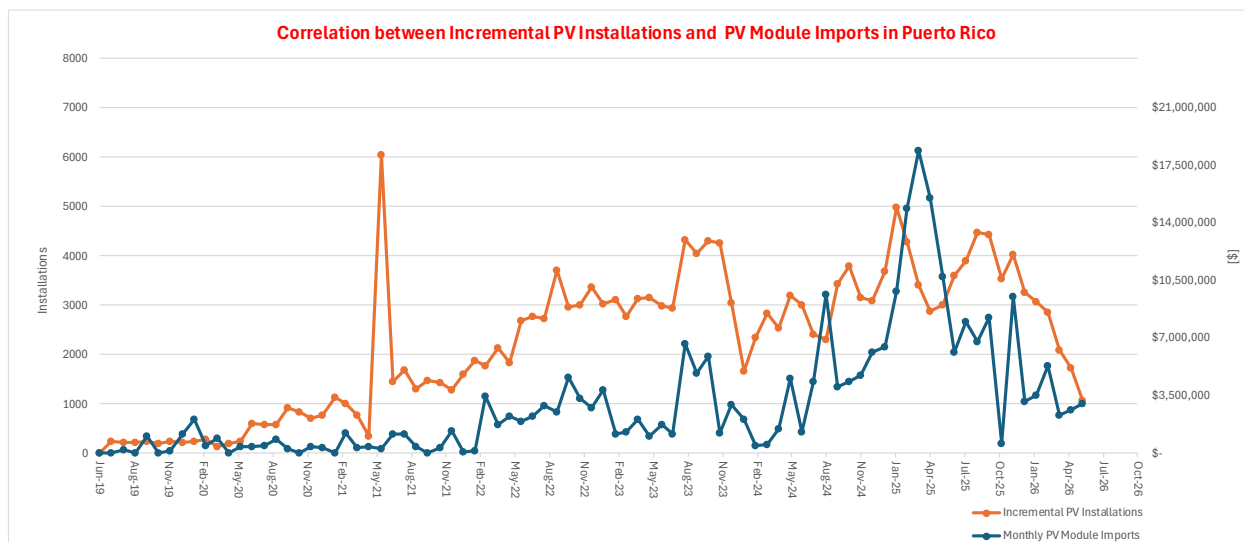


Fig. 3. Monthly delta (new installations per month), from NEPR-MI-2019-0007 docket record

²⁰ Puerto Rico Grid Resilience and Transitions to 100% Renewable Energy Study (PR100): Final Report

<https://www.osti.gov/servlets/purl/2335361>

²¹ Comercio externo desde julio 2009 <https://datos.estadisticas.pr/dataset/comercio-externo/resource/b8367825-a3de-41cf-8794-e42c10987b6f>

Mechanism C: Market saturation. As documented in Section V.E above, the conversion rate of the remaining market is itself declining. This structural constraint operates independently of both reliability burden and supply availability.

Mechanism D: Social diffusion structure. To examine the internal dynamics of the adoption trajectory, the undersigned estimated a Bass Diffusion Model over the full 85-period monthly installation series. The model yields an innovation coefficient (p) of 0.0000 and an imitation coefficient (q) of 0.0507, with $R^2 = 81\%$ and $F = 352.88$. The imitation coefficient is statistically significant ($t = 18.79$, $p = 1.24 \times 10^{-31}$). The innovation coefficient at zero indicates that autonomous adoption independent of peer influence is negligible. In other words, no meaningful share of Puerto Rico residential PV investment originated from independent consumer discovery absent prior outage experience or social observation. The market developed almost entirely through peer influence and social diffusion. A household responding to cumulative outage experience does not act in isolation. It acts after observing that neighbors with installed systems did not share the outage burden, after concluding through that observation that the investment is reliable and worthwhile, and after organizing the financial resources required. The Bass imitation coefficient quantifies the strength of that social diffusion mechanism. These results are consistent with the thirteen-month lag finding in Mechanism A and with the PR-100 observation that households invest in PV and storage even without net metering compensation. The driver is reliability motivation transmitted through a peer observation channel, not economic calculation of export returns.

The regulatory implication is that arguments treating adoption as a simple function of reliability conditions are incomplete. Projections that extrapolate historical growth rates forward should account for all four of the constraints identified in this section, not merely demand-side factors.

G. Income Profile and Comparative Jurisdiction Economic Distance

Brian Lydic confirmed at Workshop 3 that South Australia and Hawaii are the most globally comparable jurisdictions to Puerto Rico by DER penetration level ²². As noted in Section III.A, these are valid operational comparisons for grid architecture and export management. They are not valid economic comparisons.

Puerto Rico median wage is below \$11 per hour. Hawaii median wage is over \$22 per hour. New Zealand median wage is approximately \$27 per hour. Australia is comparable to New Zealand. Puerto Rico's median wage is less than half that of any comparison jurisdiction cited in this proceeding. The income differential data cited in this paragraph derive from Bureau of Labor Statistics data for Puerto Rico and Hawaii and from cost-of-living comparison data for New Zealand sourced from LivingCost.org (LivingCost.org, "New Zealand vs United States - Cost of

²² Puerto Rico Energy Bureau. (2026, September 21). NEPR-MI-2019-0009 Virtual Stakeholder Workshop 3 [Video]. YouTube. <https://youtu.be/P0od4vwKXpE?t=9132>

Living Comparison," 2023, available at livingcost.org/cost/new-zealand/united-states), as compiled and analyzed in the peer-reviewed work of the undersigned referenced in Section V.F, Mechanism A above. Willingness to pay (WTP) for energy technology to avoid power outages correlates with income, as established in that same peer-reviewed work, and market saturation follows willingness to pay.

This same income comparability problem was identified in the IRP docket (NEPR-AP-2023-0004) in connection with the 2018-2019 IRP's use of New Zealand and Hawaii Value of Lost Load data. The jurisdictions cited as DER penetration comparables in this proceeding carry the same income incompatibility for willingness-to-pay and market saturation analysis. Technical frameworks developed for South Australia and Hawaii are valid comparisons for grid management at scale. They are not transferable to Puerto Rico without explicit adjustment for the economic distance between those markets and this one.

In Workshop 3 testimony, SESA's representative stated that he hoped 500,000 Puerto Rico households would have solar within ten years, and separately projected that the installed base would reach 400,000 systems within a few years ²³. The market scenario analysis in Section V.D above allows the Bureau to evaluate these projections against the demographic record. The projection of 500,000 thus depends on both an expansive income assumption and a level of commercial participation with no established precedent in comparable markets. These figures do not yet account for how many of those remaining households may lack the physical or economic conditions for a DER investment.

The timing claim is the more significant constraint. Current monthly installations are 1,067 systems, at the lowest point in the recorded series. The remaining gap between the current installed base of 206,007 and a target of 500,000 is approximately 294,000 systems. At current installation rates, closing that gap would require approximately 23 years. Reaching 500,000 within ten years would require a sustained average monthly installation rate of approximately 2,450 systems, more than twice the current rate. Reaching 400,000 within a few years, on a two-and-a-half-year reading, would require approximately 6,500 systems per month, more than five times the current rate and approximately 30 percent above the series peak of 4,995. The Bass Diffusion Model results in Section V.E, Mechanism D confirm that the structural driver of adoption, the imitation coefficient ($q = 0.0507$), produces a decelerating trajectory as the remaining market shrinks, not an accelerating one.

The undersigned respectfully invites the Bureau to consider these projections alongside the demographic and behavioral evidence assembled in this section before relying on growth assumptions in structuring the cost allocation or interconnection queue management frameworks that will emerge from this proceeding.

²³ Puerto Rico Energy Bureau. (2026, September 21). NEPR-MI-2019-0009 Virtual Stakeholder Workshop 3 [Video]. YouTube. <https://youtu.be/P0od4vwKXpE?t=8761>

H. Regulatory Implications

Regarding net metering: The concern that net metering compensation represents an unsustainable and growing cross-subsidy burden assumes continued acceleration of adoption. A market whose normalized adoption rate has declined approximately 67 percent from its peak, with monthly additions at a recorded series low, does not support that assumption. The question before the Bureau is how to manage an existing installed base, not how to contain an accelerating wave. The undersigned notes that Commissioner Torres Miranda referenced at Workshop 2 a study conducted by Key Logic indicating that non-net-metering participants may be subsidizing the net metering program to the extent of approximately \$37 million annually ²⁴. The undersigned respectfully invites the Bureau to consider whether that study incorporated the market saturation dynamics documented in this section, and whether its forward projections would be affected by the saturation trajectory presented here.

Regarding feeder hosting capacity: Arguments that feeders face imminent crisis from continued DG installations rest on growth assumptions the data does not support. The adoption wave that created feeder concentration challenges has, in significant measure, already broken. This observation does not minimize the real threat posed by existing feeders with serious violations that may jeopardize health and safety. It is aimed at clarifying that projections of continuous unprecedented growth are not warranted by the data.

Regarding cost allocation: If the remaining interconnection applicant pool is predominantly drawn from income brackets facing meaningful financing barriers, requiring those applicants to bear full upgrade costs as the last-connecting party forecloses the population most likely to complete the residential transition, while providing no workable mechanism to allocate infrastructure costs that the earlier adoption wave made necessary. That gap is a legislative creation, not a prosumer creation.

Regarding adoption modeling: Projections that extrapolate historical growth rates forward must account for the finite size of the remaining financeable customer population. The import data, sourced entirely outside utility reporting, independently confirms through its own deceleration that the market trend is real and is not a reporting artifact.

Regarding meter socket adapters and microgrid integration devices: The undersigned does not oppose meter socket adapters with integrated microgrid integration devices as a cost-reduction mechanism for residential battery storage installations. If such hardware lowers the installation cost for households and reduces the cost basis for installers, that is a reasonable efficiency for the Bureau to consider, particularly given the reliability motivation documented in the behavioral analysis in Section V.F above. The consideration the undersigned invites the Bureau to hold

²⁴ Puerto Rico Energy Bureau. (2026, August 25). NEPR-MI-2019-0009 Virtual Stakeholder Workshop 2 [Video]. YouTube. <https://youtu.be/Axpq2QQPcOk?t=5875>

alongside that support is that the BESS market is subject to the same saturation trajectory documented for PV in Section V.E above.

The battery attach rate cited during Workshop 3, by Enphase's Senior Manager in Field Applications Engineering, Marko Rosenfeldt, is a statement about the proportion of new PV installations that include storage ²⁵. It is not a statement about the volume of new installations to come. An 80 percent attach rate applied to a decelerating installation base is not an 80 percent attach rate applied to a growing one. Monthly BESS additions and monthly PV additions exhibit a Pearson correlation of $r = 0.845$ ($R^2 = 71.4\%$), meaning that as PV deployment slows, BESS deployment slows with it at a structurally coupled rate. With those two trajectories moving in lockstep, the addressable market for MSA deployment should be projected using the same saturation framework applied to the PV market in this section, not extrapolated from historical attach rates applied to historically elevated installation volumes.

The undersigned further notes that PREB has approved the Customer Battery Energy Sharing (CBES) program, which is advancing from pilot to program status through fiscal years 2026 to 2028 ²⁶. In practical terms, CBES creates a BESS-specific economic incentive that operates analogously to a time-of-use rate: enrolled BESS customers dispatch stored energy during peak demand events and receive compensation from approved aggregators, then recharge at the standard utility rate during off-peak periods. The net economic benefit to participating households reflects the spread between those two rates. This design correctly limits program participation to customers whose battery storage assets give them the actual capability to respond to peak-period price signals.

The undersigned invites the Bureau to recognize the CBES architecture as an appropriate example for any future demand-time differentiated pricing in this market. A broad time-of-use rate applied across all customer classes would impose peak-period pricing on low-income households without BESS or net metering capability, who are typically returning home from work during peak demand hours and lack any practical means to shift their load. The cost burden would fall with greatest force on precisely those households that derive no benefit from the DER investment wave documented in this section. That outcome would be inconsistent with the proportionality and benefit-received principles of Joint Resolution 5-2026 and with the prohibition on unjust cost transfer in Section B.4 of that resolution. CBES, by limiting participation to BESS-equipped NEM customers, avoids that harm while achieving its demand-management objective.

The undersigned also invites the Bureau to note that the scale of CBES as a grid resource is bounded by the same saturation dynamics documented for BESS deployment in Section V.E above. Projections of CBES program growth should account for the fact that the population of eligible participants, households with both BESS and NEM enrollment, is subject to the same

²⁵ Puerto Rico Energy Bureau. (2026, September 21). NEPR-MI-2019-0009 Virtual Stakeholder Workshop 3 [Video]. YouTube. <https://youtu.be/UA4hiGtMODc?t=8686>

²⁶ Customer Battery Energy Sharing. <https://lumapr.com/battery-demand-response/?lang=en>

decelerating trajectory as the broader BESS and PV markets. The program is a well-designed grid management tool, but its addressable scale is not unlimited.

The undersigned does not, however, does not regard the current CBES economics as sustainable as a long-term program design. According to LUMA's FY2026 Q4 Consolidated Transition Period Plan and Demand Response Administrative Costs Annual Report filed in Case No. NEPR-MI-2022-0001 on August 14, 2026, participant incentive payments for the fiscal year totaled \$11,829,280 against 9,903,124 kWh of energy delivered, resulting in an effective payment rate of approximately \$1.19 per kilowatt-hour to participating households. The report describes CBES as having a 'performance-based compensation structure' and an 'approved program compensation model' but does not, to the undersigned's knowledge, disclose the analytical basis on which that rate was derived. The undersigned invites the Bureau to require that the compensation model be supported by a levelized cost of storage analysis and a properly constructed avoided-cost study that accounts for the full range of grid benefits applicable to Puerto Rico, including avoided peak capacity costs and the economic cost of outages that demand response prevents or shortens, before the program's economics are incorporated into the Three-Year Plan cycle. The Bureau's attention is respectfully directed to Case No. NEPR-AP-2023-0004, where the methodological tools for Puerto Rico-specific outage cost quantification have been placed in the record and remain available for application to CBES program evaluation.

VI. METER SOCKET ADAPTERS - SECTION 8.03.B.8: ACCURACY AND COMMUNICATIONS VERIFICATION

A. Installation Authority

Workshop 3 produced substantive discussion on the question of who may install meter socket adapters. Proposals were placed on the record that Regulation 7982 be amended to allow licensed electricians to perform MSA installation. Other participants urged that the regulation be examined more closely before any amendment was considered. The undersigned agrees that a close reading is warranted. Joint Resolution 5-2026 directed the Bureau to incorporate MSAs into the interconnection regulatory framework. It did not direct, and should not be read to require, amendment of Regulation 7982, as LUMA's Vice President of Regulatory Affairs Gustavo Bonet correctly pointed out ²⁷. The regulatory obligation governing who may interact with metering equipment exists independently of this proceeding and is not altered by the adoption of an MSA framework unless the Bureau expressly provides otherwise.

²⁷ Puerto Rico Energy Bureau. (2026, September 21). NEPR-MI-2019-0009 Virtual Stakeholder Workshop 3 [Video]. YouTube. <https://youtu.be/UA4hiGtMODc?t=6210>

For the record, Regulation 7982 (2011), Section IX, Article A strictly prohibits any person not employed by the utility from operating, manipulating, or intervening in metering equipment, conductors, transformers, seals, rings of meters, or any other artifact forming part of the utility's installation. Meters and all associated components remain the utility's property under Act 83. Installation must therefore be performed by utility employees. Any extension of that authority to utility-authorized contractors would require an express regulatory provision and cannot be inferred from silence or from the adoption of a new interconnection framework. This obligation applies to behind-meter configurations in which the MSA is placed between the utility meter socket and the utility revenue meter, and to installation within the meter socket or meter panel. It does not apply to load-side configurations on a separate non-utility meter socket or panel, where the utility revenue meter is not in the electrical circuit path of the MSA. Where an MSA product supports multiple configurations, those designating behind-meter installation for utility-authorized personnel exclusively are consistent with, and not an alternative to, the utility's regulatory obligation under Regulation 7982. As noted by the undersigned in the Fourth Supplementary Comments of September 18, 2026 and confirmed on the record at Workshop 3, Enphase Energy's own quick installation guide for the IQ Meter Collar designates the behind-meter installation step for utility personnel exclusively, stating in bold that the IQ Meter Collar can be installed behind the utility meter only by personnel authorized by the utility. Nevertheless, the manufacturer's designation does not create that obligation. The regulation does.

The undersigned's post-Workshop 2 continuance comments and initial filings in this proceeding set out in full the technical and professional basis for the position that utility employees must perform MSA installation, including the revenue integrity and energy theft considerations that inform this requirement. The undersigned's position has not changed, nor does the undersigned repeat those arguments here, and respectfully directs the Bureau and all parties to those filings.

B. Product Acceptance Testing

Utilities do not accept manufacturer tolerances on revenue metering equipment. The undersigned has direct professional experience applying product acceptance testing protocols to metering equipment and has personally rejected meter lots that did not meet acceptance testing requirements. ANSI/ASQ Z1.4 sample testing is required for meter socket adapters prior to field deployment, covering both revenue meter accuracy (ANSI C12.20 Class 0.5 for type testing or ANSI C12.1 in-service accuracy limits as applicable) and AMI signal compatibility with LUMA's infrastructure. The undersigned's Fourth Supplementary Comments of September 18, 2026 proposed a proportionate alternative to ANSI/ASQ Z1.4 for MSA model-level type approval, recognizing that an MSA functions as a passive mechanical pass-through rather than a revenue measurement device in its own right, and further proposed a non-invasive clamp-on CT on-site testing protocol with 0.10 percent reference accuracy traceable to NIST, covering both installation configurations. The Bureau may consider that alternative at its discretion.

That protocol was proposed for field conditions because it is unknown to the undersigned whether LUMA currently possesses laboratory infrastructure capable of evaluating meter accuracy through MSA performance under phantom load conditions and replicating the Itron CENTRON OpenWay Riva AMI signal environment in a bench setting. If LUMA does have such laboratory infrastructure, a pre-installation bench protocol would satisfy the same requirement and may be preferable. The undersigned takes no position on which approach is used. What the undersigned respectfully suggests is that the regulation require that one of the two is performed before MSAs are authorized for field deployment. AMI signal compatibility verification is not addressed by UL 414 or CFR 47 Part 15B under either testing modality. The draft regulation requires neither. The undersigned respectfully submits that this gap should be addressed before the regulation is finalized.

VII. PROACTIVE HOSTING CAPACITY PLANNING - CONCEPT PAPER IN RESPONSE TO COMMISSIONER RAMOS'S INVITATION

A. Definition

A hosting capacity map is not proactive simply because it exists. Puerto Rico's existing map represents a static, point-in-time calculation of feeder capacity. Developers who access it today receive a snapshot that may not reflect the DERs already interconnected since the last study, or the thermal and voltage conditions that prevail under different load and generation combinations. When interconnection studies later identify violations that the map did not predict, developers and the Bureau learn about the problem only after an application is pending and a queue position is at stake.

California's Integration Capacity Analysis (ICA) portal may be an example for hosting capacity data transparency²⁸. It publishes capacity data updated monthly, and developers retrieve those figures, perform their own calculations, and make sizing and siting decisions from raw output. That framework is more transparent than Puerto Rico's current approach, but it remains reactive in one important sense: the developer bears the analytical burden. The grid operator has the data; the developer has to figure out what it means for their specific project.

Proactive hosting capacity planning means the grid operator computes the result, not just the data. The developer provides a few project-specific inputs, and the system returns a pre-screening determination. The analysis runs in the background using data the grid operator already maintains.

²⁸ California Public Utilities Commission, Data Portals Workshop for the High DER Grid Planning Proceeding, Proceeding No. R.21-06-017, July 26, 2022. <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/infrastructure/distribution-planning/july26dataportalsslides.pdf>

This section defines what that framework requires, what its minimum performance standards are, and what infrastructure must exist to support it.

B. Minimum Performance Indicators

Update frequency. The hosting capacity dataset shall be updated at a minimum monthly, consistent with the California ICA update standard under CPUC Proceeding R.21-06-017²⁹. Each update shall be accompanied by a change log identifying which line sections changed, the direction of change, and the triggering factor. This audit trail allows the Bureau and interested parties to verify data integrity and identify anomalies over time.

Granularity. Hosting capacity shall be calculated and reported at the line-section level for primary feeder circuits and at the secondary circuit level for low-voltage segments downstream of each distribution transformer. Secondary circuits shall be individually identified, labeled, and linked to their parent feeder within the network model. A hosting capacity assessment that models only the primary feeder does not capture the thermal and voltage constraints that govern actual DER interconnection limits, given that the predominant share of total circuit impedance resides on the secondary side of the distribution transformer. Thermal violations are a secondary circuit phenomenon and will not appear in a primary-only model regardless of aggregate feeder load. Voltage violations originating on individual secondary circuits may propagate upstream and affect adjacent secondaries served by the same transformer, and are likewise not resolvable from primary feeder data alone. Line-section granularity at the primary level allows a developer to identify the specific segment of a feeder where capacity is available or constrained. Secondary circuit granularity resolves the constraint that actually binds first as DER penetration deepens. Feeder-level aggregates mask variation within a feeder and contribute to the accuracy failures that 100 percent of California stakeholders familiar with the ICA portal identified as problematic.³⁰

Constraint coverage. Each line-section entry shall report conditions across three constraint categories: thermal loading, voltage deviation, and system impedance and fault current. These three categories are technically interrelated and, as described below, derive from measurement protocols already before the Bureau in this docket. Operational flexibility, the utility's ability to perform switching and contingency response, is a grid operations obligation that LUMA shall address through its own planning and is not a constraint properly imposed on individual interconnection applicants.

Thermal loading. The hosting capacity data shall flag any line section where DER addition would bring projected cable ampacity loading to 90 percent (advisory), 95 percent (warning), or above 95 percent (constraint), consistent with the thermal violation protocol in Section II.D of these

²⁹ Id. p.45.

³⁰ California Public Utilities Commission, Data Portals Workshop for the High DER Grid Planning Proceeding, Proceeding No. R.21-06-017, July 26, 2022. p.66. <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/infrastructure/distribution-planning/july26dataportalsslides.pdf>

comments. Transformer and secondary conductor thermal limits shall be reported on the same advisory, warning, and constraint scale as primary line sections. A project that approaches but does not cross the constraint threshold shall receive an advisory classification with a recommended maximum sizing cap rather than a blanket denial.

Voltage deviation. The hosting capacity data shall flag any line section where the addition of modeled DER capacity at the proposed scale would produce voltage deviations approaching 1.04 per unit (warning) or exceeding 1.06 per unit (critical), consistent with ANSI C84.1-2020 Range A and Range B boundary conditions. At 1.04 per unit, the feeder is approaching the Range A ceiling and the margin is shrinking. At 1.06 per unit, the condition exceeds the Range B ceiling of 127 volts and no additional DER interconnection should be approved without demonstrated mitigation. The voltage entry shall state the simulated condition under all existing interconnected DERs combined with the proposed addition. This requirement is consistent with the Volt-VAR compensation protocol filed by Intervenor in PREB Case No. NEPR-MI-2019-0009 on August 7, 2026, under which Volt-VAR correction is the first mitigation measure and Volt-Watt curtailment is applied only where Volt-VAR correction is insufficient.

System impedance and fault current. System impedance at the point of common coupling, measured using the protocol filed by undersigned on September 11, 2026, yields two directly derived values relevant to hosting capacity: the Short Circuit Ratio at the PCC, and the estimated fault current contribution of any proposed DER addition. The SCR below 10 at the point of interconnection indicates a weak grid condition in which DER additions produce disproportionate voltage fluctuations; projects on such circuits require explicit Volt-VAR analysis prior to interconnection approval. The fault current estimate supports a binary protection coordination flag: if the aggregate DER fault current contribution on the circuit, including the proposed addition, exceeds the protection coordination threshold at the most remote point of the feeder, the hosting capacity entry flags the project as requiring a formal protection study before approval. Because both the SCR and the fault current value derive from the same impedance measurement, these two analyses are unified under a single data category and a single measurement protocol. Reporting a numeric protection capacity value separate from the impedance calculation is unnecessary and, as California's implementation demonstrated, difficult to automate reliably without circuit-specific protection engineering. The binary flag approach provides the required information without requiring individual circuit protection modeling for every monthly update cycle.

BESS ramp rate threshold. Where BESS interconnection is included in the proposed project, the hosting capacity entry shall note whether cumulative BESS capacity on that circuit, including the proposed addition, reaches 20 percent of measured peak load. The Southern California Edison EASE project demonstrated that BESS capacity at 20 percent of peak load reduces feeder ramp rate from approximately 2,438 kW per hour to 661 kW per hour, a 73 percent reduction that

materially changes the thermal stress profile of the circuit ³¹. When a circuit crosses this threshold, BESS transitions from a load-adding resource to a net thermal management asset. Projects that would push cumulative BESS above this threshold shall be reviewed for their ramp management contribution, not only for their nameplate load impact.

Planning horizon. A five-year forward projection, equivalent to California's Grid Needs Assessment under R.21-06-017 ³², shall accompany the monthly dataset and shall be updated annually. Distribution infrastructure projects require three to five years from capital programming through completion. A planning horizon shorter than five years leaves insufficient time to deploy infrastructure before DER penetration triggers violations, eliminating the capacity deferral benefit that proactive planning is intended to provide. Where the five-year projection indicates that a circuit will reach constraint thresholds before planned infrastructure is deployed, that circuit shall be identified as a priority for demand-side or DER-based mitigation alternatives.

C. Developer Pre-Screening Portal

Publishing a hosting capacity dataset satisfies a transparency obligation but does not tell a developer whether their specific project is viable at a specific address before they invest in a formal application. The Bureau should require LUMA to build and maintain a developer-facing pre-screening portal that automates the calculations a developer currently has to perform manually or cannot perform at all without access to LUMA's internal data.

The portal accepts four inputs from the developer: the address of the proposed installation, the proposed PV system size in kW-DC, the proposed storage size in kWh, and the customer's average daily consumption disaggregated by month. Monthly disaggregation is the default. A developer who can only provide an annual figure may do so, with the understanding that the pre-screening result will carry less seasonal precision.

The backend calculation proceeds as follows. The system maps the address to the feeder and line section using LUMA's geographic information system and identifies the transformer serving that address, with its rated capacity and impedance, from LUMA's distribution asset registry. It retrieves the current hosting capacity data for that line section. It applies the monthly irradiance and AC generation profiles for a 1 kW-DC reference system, derived from a pre-loaded dataset covering all 902 Puerto Rico sub-municipalities extracted from the National Laboratory of the Rockies' PVWatts Calculator ³³, and scales those values to the proposed PV system size. It then applies LUMA's residential sector load curve to the AMI-reported consumption data for existing

³¹ Castaneda and Ioan, EASE Final Project Report, CEC-500-2024-064, June 2024. P.35.

<https://www.energy.ca.gov/sites/default/files/2024-06/CEC-500-2024-064.pdf>

³² California Public Utilities Commission, Data Portals Workshop for the High DER Grid Planning Proceeding, Proceeding No. R.21-06-017, July 26, 2022. p.46. <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/infrastructure/distribution-planning/july26dataportalsslides.pdf>.

³³ National Laboratory of the Rockies (NLR). PVWatts Calculator. <https://pvwatts.nlr.gov/>

customers on that feeder to estimate the daytime minimum load during the applicable daytime window (10 a.m. to 4 p.m. for fixed-panel systems; 8 a.m. to 6 p.m. for tracking systems), consistent with the supplemental review screen defined in Section 4.04.C(2) of the Interconnection Regulation, and compares projected PV generation against that daytime minimum load to assess the potential for reverse power flow. Where the developer provides a storage size, the system evaluates whether the proposed storage capacity is sufficient to absorb daytime PV generation that would otherwise exceed local consumption, and assesses whether cumulative BESS on that feeder, including the proposed addition, approaches or exceeds the 20 percent of peak load ramp rate threshold. Using the transformer impedance from the asset registry plus a 5 percent scaling factor to account for conductor distance between the transformer and the estimated point of common coupling, the system produces a first-order system impedance estimate and derives an approximate SCR and protection coordination flag for the proposed installation point. Existing DER conditions on the feeder are incorporated into all capacity and impedance calculations and are not disclosed to the developer.

The portal returns a monthly comparison of projected PV production and estimated storage dispatch against the developer-provided consumption profile, a three-category hosting capacity flag for thermal, voltage, and system impedance conditions, indicating whether the proposed system falls within available capacity, approaches a threshold, or exceeds available capacity for that line section, and, where any upgrade or construction costs would be required, the percentage of those costs that would be allocated to the developer under the cost-sharing framework applicable at the time of formal application.

The pre-screening result is not an interconnection approval and does not constitute a reservation of hosting capacity. A developer who receives a favorable pre-screening result must still submit a formal interconnection application and complete the required study process. Where the pre-screening indicates a threshold concern or a likely cost allocation, the developer can adjust system size or storage configuration, evaluate the cost implications, or decide not to proceed before committing resources to a formal application.

D. The Measurement Infrastructure Gap and the AMI Solution

A hosting capacity calculation is only as accurate as the data that feeds the network model. A static model calibrated through a periodic engineering study drifts from actual conditions as DERs are added, loads shift, and equipment ages. The Southern California Edison EASE project demonstrated the operational consequence of measurement latency³⁴. In the field deployment, the Distribution Management System publishing data to the DERMS sent updated circuit measurements every 20 minutes. When a thermal or voltage violation occurred, the DERMS dispatched DERs to respond but then had to wait up to 20 minutes for updated measurements to

³⁴ Castaneda and Ioan, EASE Final Project Report, CEC-500-2024-064, June 2024. P.38.
<https://www.energy.ca.gov/sites/default/files/2024-06/CEC-500-2024-064.pdf>.

confirm whether the dispatch resolved the violation. With a 5-minute DER response lag, the circuit could remain in a violation condition for up to 25 minutes per event.

Puerto Rico's AMI deployment may resolve this at lower cost than the dedicated SCADA measurement network the EASE project required. AMI meters report load and voltage measurements at 15-minute intervals from every customer node and may be programmed to register at smaller intervals, which is more granular, more current, and spatially more comprehensive than point sensors on circuit switches. Voltage deviation is measured at the customer endpoint under AMI rather than at the substation, which is the most common current measurement point and the least informative location for identifying end-of-feeder voltage problems. The undersigned would suggest as a regulatory requirement that LUMA integrates AMI measurement data into its distribution network model as a primary data source, updated at a minimum monthly for the published hosting capacity dataset and available in near-real-time for operational constraint management.

E. Static Versus Dynamic Hosting Capacity and the Digital Twin Requirement

A static hosting capacity model assigns a fixed value to a line section based on a study conducted at a specific moment. That value does not change when DERs are added, loads shift, or equipment is modified between studies. Puerto Rico's current map is static in this sense.

A dynamic model updates hosting capacity values in response to actual changing conditions. Monthly updates anchored to AMI measurement data constitute quasi-dynamic operation: values are not real-time but are current enough to be commercially reliable for interconnection screening and materially more accurate than an annual re-study. Full dynamic operation, as the EASE DERMS demonstrated, updates in near-real-time and dispatches DERs to manage constraints as they develop. Quasi-dynamic operation with monthly AMI-fed updates is the appropriate regulatory standard at this stage; full dynamic DERMS operation is a longer-term objective the Bureau can address in a subsequent proceeding.

What the pre-screening portal and the monthly dataset together require is, in practical terms, a distribution system digital twin: an integrated data environment where feeder topology, transformer and conductor specifications from the asset registry, AMI-reported consumption data at the customer level, the existing DER interconnection registry, and the monthly hosting capacity calculations reside in a unified model that the portal can query in real time and that is refreshed on the required monthly schedule. None of these data components are new to the utility. AMI is being deployed, the asset registry exists, the DER registry is required by this regulation, and the GIS mapping system is operational. The gap is integration, not data collection. No human operator can process AMI data from thousands of customer nodes, update a distribution network model, recalculate hosting capacity across all line sections, and produce the monthly dataset through manual engineering studies. The hosting capacity system shall be maintained by automated software capable of ingesting AMI measurement data, updating the network model, and producing

the required monthly dataset without requiring individual circuit re-engineering for each update cycle.

F. Proposed Regulatory Requirement

The undersigned respectfully proposes that the Bureau require LUMA to submit, within 90 days of the effective date of this regulation, a Proactive Hosting Capacity Plan that: (a) defines the update schedule, data sources, and automation tools LUMA will use to maintain the dataset; (b) commits to the minimum performance indicators enumerated above; (c) describes how AMI measurement data will be integrated into the distribution network model; (d) establishes the developer pre-screening portal with the four-input interface and output specifications described above; (e) describes the data integration architecture supporting both the monthly dataset and the portal; (f) provides a change log protocol ensuring each monthly update is auditable by the Bureau and interested parties; and (g) establishes a secondary circuit identification and mapping schedule, completing mapping as a first priority for all feeders where any line section has been flagged at the warning or constraint tier under the thermal, voltage, or system impedance performance indicators defined in Section VII.B of these comments, and completing mapping for all remaining feeders within 18 months of the effective date of this regulation. The EPS Operator may request a single extension of up to 6 months upon a showing of good cause, which shall include a detailed justification of the technical or operational circumstances preventing timely completion and a revised milestone schedule. The extension shall not take effect unless approved by the Bureau. The monthly hosting capacity dataset shall reflect secondary circuit constraints for all feeders for which mapping has been completed. A feeder for which secondary circuit mapping has not yet been completed shall be flagged as incomplete in the published dataset.

VIII. SUMMARY OF OBSERVATIONS AND CONTRIBUTIONS FOR THE ENERGY BUREAU'S CONSIDERATION

The undersigned respectfully summarizes for the Bureau's reference the substantive observations and technical contributions offered in these post-workshop comments.

First, on the governing legal framework, the undersigned respectfully submits that Joint Resolution 5-2026 constitutes a directive of the full Puerto Rico Legislative Assembly, enacted through formal conference committee, certified by the Department of State, and effective immediately. Its proportionality and benefit-received mandate governs cost allocation in this proceeding. A regulation adopted under JR 5-2026's express directive but inconsistent with that mandate would not constitute the interconnection regulation the Legislature ordered. The structural deadlock that results from the tension between Act 114-2007's last-connecting-party framework

and JR 5-2026's prohibition on unjust cost transfer is a legislative creation. The Bureau is respectfully directed to the prior filings identified in Section II.A for the full development of this argument.

Second, on proportional cost attribution for voltage violations, the undersigned has placed on the docket record an impedance-based attribution methodology employing a delta-V / delta-I framework that allocates voltage violation contributions to individual DER systems on a shared circuit in proportion to their measured contribution. That methodology is the only attribution methodology currently in the docket record and was validated by Timbus et al. in IEEE peer-reviewed literature. The Bureau is respectfully directed to the Third Supplementary Comments filed September 11, 2026 for the full technical development.

Third, on thermal loading attribution, the undersigned proposes a proportional thermal contribution methodology in which each prosumer's share of transformer thermal stress is computed as the ratio of that household's DER output current at minimum daytime load to the aggregate of all DER output currents on the circuit at minimum daytime load. Minimum daytime load is the correct measurement basis because it corresponds to the period of maximum net DER export and maximum thermal stress attributable to DER output.

Fourth, on the AMI-Based Secondary Transformer Thermal Loading Protocol set forth in Section II.D.1, the undersigned has provided a complete, standards-based, field-executable methodology for detecting and managing secondary transformer thermal violations driven by aggregate DER reverse power flow using the operator's existing AMI infrastructure. The protocol requires no new field equipment, no third-party inverter communications, and no cost allocation determination as a precondition for implementation. It establishes intervention criteria, a uniform disconnection and reconnection sequence with a two-hour absolute ceiling, an AMI communications failure safeguard requiring automatic reconnection on timeout, and a Thermal Violation Baseline Report obligation. All intervention thresholds derive directly from IEEE Std C57.12.00-2021 and IEEE Std C57.91-2025 without independent engineering justification. The undersigned respectfully invites the Bureau to consider incorporating this protocol, or an equivalent standards-based methodology, into the Technical Interconnection Requirements.

Fifth, on comparative cost allocation frameworks for systems at or below 25 kW, the undersigned has introduced two directly comparable regulatory benchmarks. Maine Chapter 324 establishes a flat \$150 cost-sharing fee for Level 1 inverter-based systems, with individual cost exposure capped at \$5,000, and socializes single-phase transformer costs through rate base rather than charging the last-connecting customer. Massachusetts Docket D.P.U. 26-57 proposes a \$225 Common System Modification Fee with a \$10,000 maximum cost-sharing benefit, designed to be self-sustaining through pooled collections. Both instruments demonstrate that a legislative mandate to prevent prohibitive cost exposure for prosumers can be operationalized through tiered fees and infrastructure cost socialization without case-by-case cost waiver determinations.

Sixth, on cost allocation for systems above 25 kW, the undersigned respectfully submits that nameplate kVA is a technically deficient allocation basis because it does not distinguish between systems that export substantially different active power loads on shared infrastructure despite identical nameplate ratings. Actual measured export contribution, derivable from the impedance-based methodology already in the record, is the appropriate basis.

Seventh, on DER penetration as an existing operating condition, the undersigned notes for the record that SESA's data presented at Workshop 3 demonstrates that 81 percent of feeders exceed 15 percent DER penetration, 74 percent exceed 30 percent, and 50 to 70 percent of circuits exceed 100 percent of daytime minimum load. At this penetration level, attribution methodology questions are operationally universal, applying to most of the island's circuits today, not marginal cases. The undersigned also notes Engineer Baretty's confirmation that average feeder DER penetration in Puerto Rico is approximately 50 percent, which is inconsistent with assigning 100 percent of upgrade costs to the last-connecting party as the primary driver of the loading condition.

Eighth, on voltage screening, the undersigned respectfully submits that the TIR should specify, explicitly and with defined parameters, that voltage screening shall be conducted consistent with ANSI C84.1 Class B, which sets an absolute ceiling of 1.06 per unit. The 1.06 per unit ceiling is the outer limit of permissible operation, not the screening trigger. Feeders already operating at 1.04 to 1.05 per unit are approaching the Range A ceiling and require evaluation before reaching the ceiling, not after. The TIR should reflect that pre-limit evaluation requirement and should make every screening parameter modifiable only through a Bureau Resolution and Order process, consistent with Section 8.01 of the draft regulation.

Ninth, on power control systems, the undersigned places on the record a technical distinction that the draft rules do not currently address. Static PCS, a fixed export ceiling programmed at installation, has a demonstrated ten-year operational record in Hawaii and California. Scheduled PCS, with time-varying export limits under UL 3141, has been implemented in California alone and has been operational for two to four years in one jurisdiction. These are distinct technologies with distinct evidentiary bases, and the regulation should be explicit about which record applies to which technology. Furthermore, a scheduled PCS curtailment that fires regardless of whether Volt-VAR correction has been applied is calendar-driven curtailment, not grid-condition-driven curtailment. The regulation should not be silent on the order-of-precedence between PCS and the mandatory Volt-VAR / Volt-Watt response sequence.

Tenth, on market saturation and demographic constraints, the undersigned presents for the first time in these post-workshop comments a structured quantitative analysis of the residential rooftop PV market in Puerto Rico. Current penetration is approximately 74.7 percent of the defined addressable market under the primary income threshold. The normalized monthly PV adoption rate has declined approximately 67 percent from its series peak and is at a recorded series low. A Bass Diffusion Model estimated over the full 85-period series yields an innovation coefficient of

zero, meaning that autonomous adoption independent of peer influence is negligible, and an imitation coefficient of 0.0507 with R2 of 81 percent, meaning that the market developed almost entirely through peer observation of reliability outcomes. A thirteen-month lag relationship between outage burden and subsequent normalized adoption activity is identified for the first time in these comments. Import data from PRISA sourced from U.S. Customs records independently corroborates the deceleration finding with a two-month lead from installations to imports. These findings have material implications for net metering cross-subsidy projections, feeder hosting capacity planning, and cost allocation design, all of which have proceeded in this docket from growth assumptions the data does not support.

Eleventh, on comparative economic distance, the undersigned respectfully submits that South Australia and Hawaii are valid technical comparisons for grid architecture and export management at high DER penetration. They are not valid economic comparisons for willingness to pay, market saturation, or cost allocation design. Puerto Rico median wage is below \$11 per hour. Hawaii median wage exceeds \$22 per hour. Australia is comparable to New Zealand at approximately \$27 per hour. Technical frameworks developed for jurisdictions with median wages more than twice Puerto Rico's are not transferable to this market without explicit adjustment for economic distance.

Twelfth, on the CBES program, the undersigned notes that participant incentive payments in FY2026 totaled \$11,829,280 against 9,903,124 kWh of delivered energy, yielding an effective payment rate of approximately \$1.19 per kilowatt-hour. The analytical basis for that rate is not disclosed in the filing record. The undersigned respectfully invites the Bureau to require a levelized cost of storage analysis and an avoided-cost study that accounts for the full range of grid benefits applicable to Puerto Rico before the program's economics are incorporated into the Three-Year Plan cycle. The Bureau is respectfully directed to Case No. NEPR-AP-2023-0004 for methodological tools applicable to that analysis.

Thirteenth, the Bureau may wish to consider that the installation authority question for meter socket adapters is settled by existing regulation, that Regulation 7982 (2011), Section IX, Article A prohibits non-utility personnel from interacting with metering equipment and is not altered by this proceeding or by Joint Resolution 5-2026, and that the product acceptance testing framework proposed in Section VI of these comments, which incorporates the proportionate alternative to ANSI/ASQ Z1.4 set out in the Fourth Supplementary Comments of September 18, 2026, provides the per-model deployment authorization structure the TIR currently lacks, covering both revenue meter accuracy verification through the installed MSA under actual service load and AMI signal compatibility with LUMA's infrastructure, with the choice of field or bench testing methodology left to the EPS Operator's discretion.

Fourteenth, on proactive hosting capacity planning, the undersigned has provided, in response to Commissioner Ramos's invitation, a concept paper defining proactive hosting capacity as a framework in which the grid operator computes the pre-screening result, not merely publishes the

data. The concept paper establishes minimum performance indicators covering update frequency, line-section granularity, three-category constraint coverage, and a five-year planning horizon; specifies a developer-facing pre-screening portal accepting four project-specific inputs and returning a hosting capacity determination without requiring a formal application; identifies AMI as the appropriate measurement backbone, capable of providing 15-minute interval data from every customer node at lower cost than the dedicated SCADA measurement network that the EASE demonstration required; and describes the distribution system digital twin integration architecture that must underlie both the monthly dataset and the portal. The undersigned respectfully proposes that the Bureau require LUMA to submit a Proactive Hosting Capacity Plan within 90 days of the effective date of this regulation, satisfying the specifications set forth in Section VII.F.

IX. DECLARATION

In compliance with applicable Energy Bureau procedural requirements, the undersigned declares as follows:

- A) No party or attorney in this proceeding assisted in drafting these comments.
- B) No party or attorney 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 undersigned contributed funds or any other type of resource for the preparation or submission of these comments.

Respectfully submitted,

In San Juan, Puerto Rico, on September 30, 2026.



Robert A. Garcia Cooper

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CERTIFICATE OF SERVICE

I hereby certify that on September 30, 2026, a copy of these Comments was filed with the Puerto Rico Energy Bureau under the title Comments on Distributed Generation and Microgrid Interconnection Regulation - Case No. NEPR-MI-2019-0009 - Post-Workshop 3 Comments of Robert A. Garcia Cooper, held on September 21, 2026, addressed to the attention of Edison Avilés Deliz, Chairman, and submitted electronically through the Energy Bureau's electronic filing tool at <https://radicacion.energia.pr.gov/>.

Robert A. Garcia Cooper