

GOVERNMENT OF PUERTO RICO		NEPR
PUERTO RICO PUBLIC SERVICE REGULATORY BOARD		Received:
PUERTO RICO ENERGY BUREAU		Oct 5, 2026
IN RE:	CASE NO.: NEPR-MI-2019-0009; NEPR-MI-2018-0008	11:33 PM
INTERCONNECTION REGULATIONS	SUBJECT: Comments on Distributed Generation and Microgrid Interconnection Regulation - Case No. NEPR-MI- 2019-0009	

**COMMENTS ON DISTRIBUTED GENERATION AND MICROGRID INTERCONNECTION
REGULATION - CASE NO. NEPR-MI-2019-0009**

**SESA and Solar United Neighbors Proposed Redline — Explanation of Proposed Changes
October 5, 2026**

Filed jointly by the Solar and Energy Storage Association of Puerto Rico (SESA) and Solar United Neighbors (SUN); references to SESA’s proposals in this document are the co-filers’ joint proposals.

To the attention of the Hon. Edison Avilés Deliz, Chairman, Puerto Rico Energy Bureau

Executive Summary

SESA and Solar United Neighbors (SUN) file a complete proposed redline of the Bureau’s draft Distributed Generation and Microgrid Interconnection Regulation in response to the Bureau’s request for comments by October 5 (Sept. 16 R&O § II; Sept. 15 R&O § IV). It is built on the Bureau’s own text: the July 13, 2026 Revised Preliminary Draft with the Bureau’s tracked changes accepted, merged with its September 16 language. Each SESA change is a tracked change authored “SESA.”

The Bureau plans a second draft on October 16, with comments due November 6 and enactment by January 7, 2027 (Sept. 15 R&O § III). Synapse asked for comments by October 5 “so we can incorporate that into a second draft” and for specific redline language (WS3, C. Lane, 05:18:19; A. Star, 04:37:23). It consolidates SESA’s April 15, June 11 and August 14 filings and workshop input, editing the Bureau’s text in place.

What the Redline Does

- **Automatic interconnection ≤ 25 kW (Art. 3.C).** A certified system is deemed interconnected and may operate and export; no countersignature, screen, inspection, meter work or queue position may condition operation or net metering (Act 114-2007 § 9(a)–(b)). The 15-business-day review covers installation conformity, certified equipment and the service transformer; absent a timely written notice, no later restriction or charge applies. Export may be limited in only three ways: temporarily while the EPS Operator upgrades the service transformer or service drop (30 days, from the Reserve Fund); by isolating an installation that is unsafe on its face (backfeed onto the grid during an outage, exposed or overheating equipment, missing code-required grounding or disconnects); or as the Bureau-approved Technical Interconnection Requirements establish for conditions upstream of the service transformer. Synapse: a pre-interconnection check “does not seem like the law allows that” (WS3, 00:20:31).
- **One fee, in the rule (Art. 3.B).** An initial Simplified Interconnection Fee of \$300, or such other amount as the Bureau determines in this proceeding, is the customer’s only charge, for notifications filed once the EPS Operator implements the new process, no later than the 90th day after the effective date (the prior fee applies until then). The initial TIR may adjust it; it is then re-evaluated every three years, and at any other time only in extraordinary circumstances on the EPS Operator’s petition or the Bureau’s own motion, and changed only by Bureau order after at least 30 days of comment. It funds an audited Reserve Fund limited to “Service Upgrades” (service transformer, secondaries, service drop, protective device); upstream work is planned under § 7.11; none is charged to the customer.
- **90-day clock above 25 kW (§§ 4.01.A, 7.01).** Fast Track covers systems above 25 kW up to the Table 1 limits. “Reasonable Efforts” becomes a duty to meet deadlines; absent an executable agreement or a specific written determination within 90 days of filing, the application is automatically approved (Act 114-2007 § 9).

Windmar reported that 35% of its completed commercial evaluations (time to the evaluation letter) exceeded 90 days (Windmar, Aug. 14).

- **A lane for non-exporting and limited-export systems (§ 4.01.D).** Non-exporting systems, and limited-export systems within the export capacity published under § 7.11, are evaluated on Export Capacity: initial results in 15 business days, full evaluation within 45 calendar days.
- **Costs known before decisions; screens (§§ 4.02, 4.04, 7.08.A–B).** Itemized estimate before any election; 15 business days to elect; final cost within 10% of the estimate; least-cost upgrades attributable to the project only (JR 5-2026 § 2). Penetration screen of 30% of peak or 100% of published Daytime Minimum Load, which also covers solar-plus-storage; results state the export that fits without upgrades, and a UL 3141 export limit may be elected instead.
- **The two JR 5-2026 components missing from the Bureau’s text (new §§ 7.10, 7.11).** Excessive Customer Curtailment Compensation (§ 7.10) applies to Simplified, Fast Track and Study systems and credits the value of exports an imposed restriction prevents, when the value of the prevented exports exceeds \$50 in a calendar quarter, the threshold that makes a restriction “excessive”. Proactive planning (§ 7.11): a yearly five-year forecast by feeder, a published hosting capacity analysis, and a three-year Distribution Hosting Capacity Plan funded first from federal funds and then through rates, never by individual customers; the methodology builds on the hosting capacity work in NEPR-MI-2019-0011; a forecast constraint is no ground to deny, delay or restrict a system, apart from an export restriction the Bureau-approved TIR establishes under § 7.10.C.
- **Meter socket adapters (§ 8.03).** Model approval in 20 business days, deemed on silence; monthly list review; licensed electrical engineers and licensed expert electricians registered as Authorized Agents of the EPS Operator to pull meters, with notice, utility seals and photos; no adapter-specific EPS Operator fee; no forced socket relocation (Act 114-2007 § 3).
- **Net metering (Art. 9).** Caps are stated as Export Capacity, including the statutory 25 kW residential cap already in § 9.02.A. Stand-alone storage may interconnect and export only under a Bureau-approved program. Aggregate Net Metering (one customer, several meters) and Shared Net Metering (several customers, one system, same premises) are opened on terms used in other states.
- **Transition and consistency (§§ 1.08, 1.20, 2.05; Art. 11).** Regulations 8915 and 8916 are repealed, preserving existing agreements; the EPS Operator has 90 days to implement the new forms and billing changes; Regulation 7982 and other inconsistent PREPA instruments do not apply to interconnection; utility silence deems a filing complete; only the Bureau imposes sanctions.
- **Direct refunds for missed deadlines (§ 6.01.B).** Besides the Bureau’s \$1,000-per-day fine, a customer whose 30-day net metering or 90-day evaluation deadline is missed may be refunded the bill savings lost, by check or deposit rather than bill credit at the customer’s election.
- **TIR, reporting and corrections (§§ 8.01.G, 12.02).** The TIR gets at least 30 days of comment and may not change the rule’s fees, time frames, thresholds, cost allocation or rights, except the initial fee amount and the one kind of export restriction that Art. 3.C(4)(iv) and § 7.10.C leave to it; reporting becomes quarterly; drafting errors are corrected (Part 5).

What SESA Asks of the Bureau

1. Incorporate the redline into the October 16 second draft.
2. If the Bureau prefers other wording, keep the structure: operation on certification; one fee in the rule, reviewed on a fixed cycle; a bounded review; compensation for imposed restrictions; forward-looking hosting capacity planning; open aggregate and shared net metering.
3. Publish the October 16 draft complete, including daytime minimum load and curtailment language (Sept. 15 R&O § II) and hosting capacity, which WS3 did not reach (05:22:04).
4. Provide a redline of the October 16 draft against the July 13 and September 16 text so parties can respond by November 6.

1. How to Read the Redline

- **Base and markup.** The base is the Bureau’s July 13, 2026 Revised Preliminary Draft with the Bureau’s own tracked changes accepted, merged with its September 16 language (Article 3, the “Meter Socket Adapter” definition and § 8.03). Every SESA change is a tracked change authored “SESA.” The lines at the top of the first page that identify the Bureau’s draft and this filing are labels, not proposed rule text. The redline does not carry the “Preliminary Draft” watermark of the Bureau’s draft; its removal is a formatting change that alters no text.
- **Numbering.** Section numbers are those of the accepted text: new §§ 1.20, 7.10 and 7.11; new paragraphs 4.01.D, 4.04.F, 8.01.G, 8.02.E and 12.02.F–H; §§ 9.03 (A–F) and 9.04 (A–G) replaced. Codes such as [C3.7] identify each change.
- **What SESA did not change.** The Bureau’s structure; most of Articles 2, 5, 6, 10, 12 and 13; the TIR “Attachment X” placeholders; and § 1.13 (Severability), on which SESA relies without proposing a change. New sections are added only for the two JR 5-2026 § 2 subjects the Bureau’s text does not yet address (§§ 7.10, 7.11) and for the repeal of Regulations 8915 and 8916 (§ 1.20).
- **Citations.** WS1 = May 28; WS2 = August 25 and 28; WS3 = September 21, 2026, with speaker and recording time (WS1 and WS2 times are from combined recordings); the recordings are part of the record (WS3, I. Pontes (PREB), 00:04:53). “SESA/SUN Aug. 14” is the Joint Motion of August 14, 2026; “cmt.” is a numbered comment. Other jurisdictions’ rules are cited by instrument.

Figures Proposed in the Redline (SESA + SUN Proposals, Open to Adjustment)

Item	Proposed figure	Record basis
Fee (Art. 3.B(1))	\$300 initial, or such other amount as the Bureau determines in this proceeding; from implementation of the new process (no later than day 90 after the effective date)	July 13 figure; SESA \$250–\$350 (Apr. 15, p. 23); prospective (WS3, 03:26:57)
Fee review (Art. 3.B(5))	Every 3 years; otherwise only in extraordinary circumstances, on the EPS Operator’s petition or the Bureau’s motion; ≥30 days’ comment	SESA Apr. 15, p. 23 (“perhaps every 3 years”); LUMA (WS3, 03:46:36)
Service Upgrade (Art. 3.C(4)(iii))	30 calendar days, from the Reserve Fund	SESA (WS3, 01:24:21); Synapse: “helpful recommendation” (01:28:19)
No/limited-export lane (§ 4.01.D)	Results in 15 business days; decision ≤45 calendar days	SESA (WS2, 00:41:50; WS3, 02:22:54); Windmar Aug. 14, Ask 2
Penetration screen (§ 4.02.B(1))	30% of peak, or 100% of published DML	LUMA (WS3, 04:11:07; WS1, 04:59:45); IREC (WS3, 04:07:48)
Elections; estimates (§§ 4.02–4.04, 7.08.B)	15 business days (was 5); final cost ≤ estimate + 10%	Bureau’s §§ 4.04.A, 4.04.E; OIPC Aug. 14, cmts. 22, 26
Compensation (§ 7.10.D)	Prevented exports worth over \$50 per quarter	Hawaii threshold cited by SESA (Apr. 15, p. 18; WS2, 01:31:36)

Item	Proposed figure	Record basis
Planning (§ 7.11)	Yearly 5-year forecast; Plan every 3 years	SESA Apr. 15, p. 13; SESA/SUN Aug. 14, App. A § III

2. The Statutory Floor

The redline is written to the following texts, quoted as they appear in the record.

Act 114-2007 § 9(a)–(d) (22 L.P.R.A. § 1019), systems of 25 kW or less: they “[s]hall be interconnected automatically”; they “[s]hall begin operating automatically once a professional engineer or an expert electrician ... certifies the compliance thereof with the regulatory technical requirements for interconnection”; it “[s]hall not be necessary to submit an application for interconnection to be deemed interconnected and to activate net metering”; “[t]he fact that the feeder exceeds its capacity shall not constitute an obstacle for interconnection. In such cases, the necessary improvements and/or changes to be made to the feeder shall be defrayed by the requesting company”; and “[n]one of the provisions of this Section prevent the subsequent review of the correction of the certification” (as quoted in Synapse’s Aug. 25 presentation). Net metering must appear on the bill “not later than thirty (30) days after the receipt of notice” of the certification (§ 9(b); Bureau draft § 9.02.B).

Act 114-2007 § 9, systems above 25 kW: the evaluation “shall not exceed ninety (90) days from the filing thereof. In the event of noncompliance with the term provided, the application for interconnection shall be automatically approved ...” (SESA Aug. 25 presentation), “until” the utility substantiates grounds for denial or determines that additional requirements or improvements are necessary (read into the record by LUMA, WS2, G. Bonet, 00:46:48).

Act 114-2007 § 3: “the Meter shall be installed in the existing meter socket ... [the utility] may not establish additional requirements, reject requests, deny endorsements, or request the relocation of an existing meter socket, through regulations, technical order, directors’ orders, or otherwise,” except where the socket fails National Electrical Code safety standards. **§ 4(c):** the utility “shall not impose any charge or modify the monthly electric power usage consumption rate of its net metering customers, or customers who interconnect any distributed generation system, without prior authorization from the Bureau.”

Joint Resolution 5-2026 § 2 (unofficial translation of the Spanish text as quoted by OIPC, Apr. 15): the regulation “shall adopt modern interconnection technologies and concepts, including proactive hosting capacity planning and budgeting, meter socket adapters, daytime minimum load, compensation for economic losses of customers who suffer restrictions on the export of energy (curtailment) associated with the imposition of inverter configurations, and the costs of the transmission and distribution system operator for grid studies, among others.” The costs of required modifications or improvements “shall be determined in accordance with the principles of reasonableness, proportionality and benefit received, preventing such costs from being unfairly shifted to all of the customers of the electric system,” under a methodology the Bureau sets by regulation (as quoted in SESA/SUN Aug. 14, App. A § IV; Synapse, Aug. 25). **§ 1:** “No Supplemental Study fee will be charged for any photovoltaic system whose generation capacity is less than or equal to 25kW” (Synapse, Aug. 25).

The Bureau’s published text (July 13 plus September 16) addresses these components as follows:

JR 5-2026 § 2 component	In the Bureau’s published text	In the redline
Meter socket adapters	§ 8.03 (Sept. 16)	Edited in place (§ 8.03)

JR 5-2026 § 2 component	In the Bureau’s published text	In the redline
Daytime minimum load	§ 4.04.C(2), PV without storage only; language under consideration (Sept. 15 R&O § II)	Definition (§ 1.11.B(11)); §§ 4.02.B(1), 4.04.C(2)
Curtailment compensation	None; under consideration (Sept. 15 R&O § II)	New § 7.10
Grid-study costs	No study fees for Simplified customers (Art. 3.D(1)); Reserve Fund (Art. 3.B)	Art. 3.B, 3.D
Cost principles	≤25 kW only (Art. 3.B(4)); no updated text above 25 kW (Sept. 16 R&O § I; WS3, C. Lane, 03:57:39)	Art. 3.B(4); § 7.08.A
Proactive hosting capacity planning and budgeting	None; not reached at WS3 (C. Lane, 05:22:04)	New § 7.11

3. Section-by-Section Explanation

Each item states what the Bureau’s text provides (“PREB text”), what the redline does (“SESA change”), and the record on which it rests (“Basis”). Figures that are SESA proposals rather than statutory are identified as such and are open to adjustment.

Article 1 — General Provisions

Legal Basis (§ 1.02); Other Instruments (§ 1.08)

PREB text. Section 1.02 cites Acts 82-2010, 17-2019, 57-2014 and 38-2017, but not Act 114-2007 or JR 5-2026, which the draft implements; § 1.08 makes inconsistent regulations and similar documents yield to the Regulation.

SESA change [C1.2, C1.3]. Adds both instruments to § 1.02. For interconnection, net metering enrollment and adapter installation, an inconsistent PREPA or EPS Operator regulation, communiqué, directive or terms of service—naming Regulation 7982 and Technical Communiqués 19-02 and 20-01—“shall not be applied.” **Basis.** Part 2; SESA/SUN Aug. 14, App. B § A.1. LUMA said meter handling is governed by Regulation 7982, which in its view JR 5-2026 did not address (WS3, G. Bonet (LUMA), 04:27:45; 04:32:49); SESA suggested that the rule supersede other instruments “for the purpose of interconnection” (PJ Wilson, 04:29:44); LUMA’s own redline provides that the Regulation “supersedes any provision included in any other prior regulation that is contrary” to it (LUMA Aug. 14, Exh. 2, proposed Repeal article).

Definitions (§ 1.11)

PREB text. “Export Capacity” is stated “in alternating current (AC)” and “Nameplate Rating” states no unit; “Small inverter based system” uses 50 kW nameplate and 25 kW export; the Material Modification exclusions omit adapters and storage added without new export; daytime minimum load and hosting capacity are undefined.

SESA changes [C1.4, C1.5, C9.10]. Both ratings are in kW AC, as SESA/SUN proposed, “consistent with the statute and with revenue metering” (App. A § I.5); “Small inverter based system” keys to 25 kW of Export Capacity; an approved adapter, and storage added without increasing Export Capacity (on notice of its § 9.01.C restriction), are not Material Modifications; “Daytime Minimum Load” (the § 4.04.C(2) windows, as gross load), “Hosting Capacity” and “Simplified Interconnection Fee” are defined; the net metering program definitions follow §§ 9.03–9.04. **Basis.** SESA/SUN App. B § E.1; C. López Maisonave asked for “notice and updated attestation rather than discretionary pre-approval” for changes not increasing Export Capacity (López Maisonave

Aug. 13, § V); LUMA would treat added storage as a Material Modification (LUMA Aug. 14, Exh. 2, cmt. [A20]). SESA described the gross-load method in April (SESA Apr. 15, p. 16).

Repeal and Transition (new § 1.20)

PREB text. None. **SESA change [C1.6].** Repeals Regulations 8915 and 8916 as of the effective date; existing agreements and net metering enrollments continue without re-application, re-study or new fees; pending matters proceed under the new Regulation without loss of Queue Position. The EPS Operator implements the forms, Cyber Portal functions and billing changes of Article 3 and § 9.02 within 90 days; customers’ rights under Art. 3.C(3) and § 9.02.B apply from the effective date. **Basis.** LUMA wrote that “[t]he Draft Interconnection Regulation will repeal current Regulations 8915 and 8916” (LUMA Aug. 14, Exh. 1 n.1); Synapse: “We’re not looking to retroactively place a fee on customers that interconnected previously” (WS3, C. Lane, 03:26:57).

Article 2 — Application Process

Completeness, Modifications and Incomplete Notifications (§§ 2.05.D–E, 2.06.B)

PREB text. The EPS Operator has five Business Days to say whether a filing is complete and ten to decide whether a modification is material, with no consequence for silence; an uncured Simplified notification “will be deemed withdrawn.” **SESA change [C2.2–C2.4].** Silence deems the filing complete and the modification not material; an uncured notification suspends net metering enrollment, not the operation of a certified system. **Basis.** OIPC proposed the § 2.06.B consequence in nearly the same words (OIPC Aug. 14, cmt. 10) and asked for “a clear and enforceable framework of consequences” for EPS Operator non-compliance (general cmt. 2); SESA/SUN App. A § I.1. A certified system operates under Art. 3.C(3) and § 9 (Part 2), so a “withdrawal” has no defined effect on it.

Article 3 — Simplified Process

Eligibility on Export Capacity (Art. 3.A)

PREB text. The September 16 text limits eligibility to “a Nameplate Rating of 25 kW or less” (July 13: 50 kW nameplate and 25 kW export); item (vi) repeats item (iv); item (vii) has a broken cross-reference. **SESA change [C3.1–C3.6].** Eligibility is Export Capacity of 25 kW or less, in kW AC at the Point of Common Coupling; with storage, including storage with an integrated inverter, the system’s Export Capacity at the Point of Common Coupling governs, not PV nameplate or battery kWh; duplicate item (vi) is deleted, and former item (vii), now (vi), provides that an approved adapter cannot cause a failure. **Basis.** SESA/SUN App. A § I.5; IREC: eligibility “would generally be based on the export capacity rather than the nameplate ratings” (WS3, B. Lydic (IREC), 01:49:23). Other views: OIPC would require 25 kW of both nameplate and export, reading Act 114-2007’s “generating capacity” (OIPC Aug. 14, cmt. 3); LUMA proposed nameplate only (LUMA Aug. 14, Exh. 2, cmt. [A28]).

Fee and Reserve Fund (Art. 3.B)

PREB text. September 16 B(1): a nonrefundable fee “in an amount established in the TIR and approved by the Energy Bureau” (July 13: “\$300 dollars, or an amount subsequently determined through the TIR”); B(3): a Reserve Fund for “Distribution System Upgrades, administrative costs, and any supplemental studies”; B(4): no assignment of “the full cost” of an upgrade to one customer “solely because” of its system; B(5): adjustment no more than every 12 months “in the TIR.”

SESA change [C3.7–C3.13]. (a) *Amount and transition:* the initial fee is \$300, or such other amount as the Bureau determines in this proceeding (the figure is bracketed in the redline for the Bureau’s determination), payable by the customer or its installer, for notifications filed once the EPS Operator implements the new process, and no later than the 90th day after the effective date (the prior fee applies until then); the initial TIR may modify

it; it is “the sole and complete financial obligation” for the interconnection. (b) *Scope*: a segregated, audited Reserve Fund under the EPS Operator’s control pays only administration, reviews and “Service Upgrades”—the service transformer serving the Point of Common Coupling, the secondary conductors and service drop to the customer’s Meter, and the fuse or other protective device on them. Primary conductors, regulators, capacitor banks, reclosers, feeder equipment and substations are excluded and are planned under § 7.11. (c) *Statute*: the fee “constitutes the contribution of the requesting company” under § 9(c) and JR 5-2026 § 2; no upgrade cost is assigned to, or conditions, an individual Simplified system. (d) *Review*: after the initial TIR, the amount is re-evaluated every three years, and at any other time only in extraordinary circumstances on the EPS Operator’s petition or the Bureau’s own motion; it changes only by Resolution and Order after at least 30 days of comment, on the EPS Operator’s filing of Service Upgrade costs by feeder, notification counts and the Fund balance; surpluses reduce the fee and shortfalls are recovered prospectively. (e) Reporting is quarterly (B(6); § 12.02), and § 8.01.G exempts the fee amount from the rule that the TIR may not set fees.

Basis—the request. Synapse sought “agreement from the parties on what that fee should look like,” a “reasonable value,” and true-up and refund proposals (WS3, C. Lane, 02:48:57; 02:52:35; 03:28:22). Commissioner Ramos stated that improvement costs “have to be assigned to the cost-causer” (02:56:54) and, as his “particular opinion,” that the fee would mean “substituting the \$300 fee for the supplemental study in one fee” (03:00:49); LUMA was “very supportive” (A. Baretty, 03:21:58).

Basis—amount, transition and review. \$300 is the Bureau’s July 13 figure and within SESA’s range of \$250–\$350, “an increase from the current \$100” (SESA Apr. 15, p. 23). R. García Cooper objected that the September 16 text leaves the amount to the TIR “with no floor, no ceiling, and no formula” (WS3, 03:04:55); C. López Maisonave asked the Bureau to “[s]tate the exact fee” and to adjust it only after notice, comment and a Bureau order (López Maisonave Aug. 13, § II). The transition reflects that the fee is forward-looking (C. Lane, 03:26:57) and the phase-in Synapse suggested in the adapter discussion “to allow the necessary underlying systems to be developed,” after LUMA said a new one-time fee requires billing-system changes (A. Star, 05:01:48; M. Jeppesen (LUMA), 05:00:26). SESA proposed review “perhaps every 3 years” without a new rulemaking (SESA Apr. 15, p. 23; WS2, PJ Wilson, 01:05:26); the extraordinary-circumstances review answers LUMA’s point that upgrades “are not linear” and adjustments “could be significant from time to time” (WS3, A. Baretty, 03:46:36). The amount, transition and cycle are SESA proposals.

Basis—scope and statute. SESA distinguished service-transformer upgrades, which a fund can cover promptly, from poles-and-wires upgrades belonging to proactive planning; Synapse called this a “helpful recommendation” (WS3, PJ Wilson, 01:24:21; C. Lane, 01:28:19). SESA described the universe as “residential or commercial service transformers” and asked for a “guardrail” so that LUMA “actually gets the money they collect” (J. Rúa-Jovet, 03:29:46); a segregated fund also keeps the fees from clawback or withholding by PREPA; LUMA called the service transformer “the most common network upgrade” (A. Baretty, 04:06:15); Commissioner Ramos observed that “[t]here is no money for distribution transformers and secondary cables in the FEMA funds” (WS2, 04:32:23). Section 9(c) says feeder improvements “shall be defrayed by the requesting company,” a phrase the statute does not define (J. H. Román-Morales Aug. 14, § VIII); LUMA’s position is that “no regulation language can overcome the law” (WS3, G. Bonet, 02:59:24). SESA’s proposed reading is that a fee paid in advance by the customer or its installing company, pooled for the upgrades these systems require and set under the JR 5-2026 principles, is the requesting company’s contribution; SESA called the choice between one fee and a customer–company split “academic in nature” (WS3, 01:24:21), so either may pay.

Operation on Certification (Art. 3.C(1)–(3), (5); §§ 6.01, 7.04.B)

PREB text. September 16 C(3): upon certification, “the system may begin operating in accordance with Act No. 114-2007”; C(5) ties countersignature to the screens; § 7.04.B requires prior written authorization for Parallel Operation. **SESA change [C3.14–C3.16, C3.18, C6.1, C7.4].** The certified system “shall be deemed

interconnected and may begin operating, including Parallel Operation and export”; no countersignature, screen, review, inspection, meter work or Queue Position conditions operation or net metering; the notification follows the certification, with no filing deadline whose lapse could affect net metering eligibility; countersignature within 15 Business Days is deemed on silence and records, rather than conditions, the interconnection; § 6.01 conforms and § 7.04.B excepts Simplified systems. **Basis.** Act 114-2007 § 9(a)–(b). Synapse called this “the biggest change” in the September 16 text (WS3, C. Lane, 00:15:09) and said a pre-interconnection check “does not seem like the law allows that” (00:20:31). LUMA said systems would “operate under self-consumption mode until that screening happens,” and Synapse noted that “operating” is not defined (WS2, A. Baretty, 02:27:15; C. Lane, 02:30:11); the redline defines it to include export. OIPC: prior written authorization “cannot apply to the Simplified Process” (OIPC Aug. 14, cmt. 32).

Why the redline says “export.” Section 9 of Act 114-2007 says a system of 25 kW or less is interconnected automatically, operates automatically, and has its net metering activated and reflected on the bill within 30 days; it does not use the word “export.” Net metering has no meaning unless energy flows to the grid for credit, so the redline states the word the statute implies. The redline then states the only three ways export may be limited after the fact (Art. 3.C(4)(iv)): the temporary limitation while the service transformer is upgraded, the isolation of an unsafe installation, and the measures the Bureau-approved Technical Interconnection Requirements establish for conditions upstream of the service transformer. The last is how system-level conditions, including a day on which installed distributed generation exceeds demand, are to be managed: by measures that apply to all systems and are compensated under § 7.10, not by gatekeeping customers one at a time or feeder by feeder, which § 9(a) and (c) do not permit for small systems.

Bounded Post-Interconnection Review (Art. 3.C(4))

PREB text. A post-interconnection review within 15 Business Days “to verify compliance with applicable safety and reliability requirements,” with export restricted or suspended “to the extent authorized by applicable law and regulation and reasonably necessary.” **SESA change [C3.17].** The review covers only (a) conformity with the certification and supporting documentation, including the one-line diagram, (b) Certified equipment and (c) whether the service transformer and secondary can accommodate the Export Capacity, under criteria in the rule and the approved TIR. A field check is at the EPS Operator’s election, as a review cost paid from the Reserve Fund, not by the customer. (i) A timely written notice states the condition, data, criteria and corrective action; otherwise nothing may later be imposed, other than isolating an unsafe installation under (vi). (ii) A condition of the customer’s own installation gets at least 20 Business Days to cure while operating, unless the notice identifies an unsafe installation. (iii) Where the service transformer, secondary conductors or service drop need a Service Upgrade, the notice says so, the upgrade is completed from the Reserve Fund within 30 calendar days, export meanwhile may be limited—not suspended—to what the existing facilities carry, and the limitation ends no later than day 30, with no second limitation for the same condition. (iv) No restriction may rest on the condition or capacity of anything upstream of the service transformer—feeder, circuit, substation—unless the Bureau-approved Technical Interconnection Requirements so establish; feeder capacity is no impediment to the interconnection or operation of a system of 25 kW or less (Act 114-2007 § 9); and these three—the transformer limitation, the isolation of an unsafe installation, and a restriction so established—are the only restrictions permitted under Article 3. (v) Notices are reviewable under § 13.02. (vi) An installation is unsafe only where the EPS Operator observes at the premises, and states in its notice, backfeed onto the grid during an outage, exposed, damaged, overheating or arcing conductors or equipment, or missing code-required grounding or disconnecting means; a conforming system’s operation or export is not an unsafe condition, nor is any condition of the EPS Operator’s own facilities; the EPS Operator acts at the system’s disconnect where possible, gives notice before acting or within one Business Day after, and restores the interconnection within two Business Days after the correction is certified.

Basis. LUMA agreed the review “[c]annot be forever” (WS3, A. Baretty, 01:04:25) and said a system passing its screen “should get NEM under 30 days as the law states” (01:18:35). R. García Cooper asked that “a clear description of what entails a safety condition” be documented (01:30:54); Synapse said the criteria are “needed before people can sign off” (C. Lane, 01:33:36). SESA would not object to the utility “double-checking that paperwork” (00:23:09) and proposed the 30-day transformer remedy (01:24:21); a SESA member company (Sunrun) said that “no export for an undetermined period of time” is “not really an acceptable place” (01:13:05). The 20- and 30-day periods are SESA proposals. The three permitted restrictions separate what is the customer’s to fix (an unsafe installation, which the EPS Operator may isolate at any time), what is the EPS Operator’s to fix on a clock (its own service transformer and service drop), and what is for the Bureau to establish for all systems alike (conditions upstream of the service transformer); the time limits keep a limitation from outlasting the upgrade that justified it.

Supplemental Review as Planning; Review Rights (Art. 3.D)

PREB text. D(1) allows a Supplemental Review without study fees; D(2) lets it impose “restrictions on the amount of power that can be transferred,” with a five-Business-Day election; D(3) quotes § 9(c) with the bracketed words “[and requires system modifications]”; the September 16 text deleted the July 13 right to Administrative Review of cost allocation. **SESA change [C3.19–C3.23].** A Supplemental Review serves the EPS Operator’s planning, at its expense, and cannot delay, condition or reopen operation or net metering; an identified upgrade is funded from the Reserve Fund or planned under § 7.11, and any export limitation is subject to the limits that apply to a limitation during a service transformer upgrade (Art. 3.C(4)(iii)); D(3) restates § 9(c) without the bracketed words and says how improvements are funded—Service Upgrades from the Reserve Fund, upstream work under § 7.11—none being charged to the customer; new D(4) restores review under § 13.02. **Basis.** JR 5-2026 § 1; the Bureau read JR 5-2026 as requiring PREPA and LUMA to “cease collecting all charges for Supplemental Study and grid improvements” for systems up to 25 kW (Mar. 19 R&O); LUMA is not “doing the individual supplemental studies, nor we are invoicing for them” (WS3, A. Baretty, 01:07:57). R. García Cooper noted that D(3) and B(4) conflict (García Cooper Sept. 18); the bracketed words are not in § 9(c). OIPC asked for review of any cost determination (OIPC Aug. 14, cmt. 15).

Article 4 — Fast Track

Scope and 90-Day Limit (§ 4.01.A)

PREB text. Fast Track is available within “the size limits” of § 4.01 and “is not applicable to projects utilizing the Simplified Process”; no evaluation limit is stated. **SESA change [C4.0].** Fast Track applies above 25 kW of Export Capacity up to the Table 1 limits; smaller systems use Article 3, and larger or ineligible ones Article 5; evaluation, including supplemental review, may not exceed 90 calendar days from filing, after which the application is automatically approved. **Basis.** Act 114-2007 § 9 (Part 2); § 7.01.D below.

Non-Exporting and Limited-Export Systems (new § 4.01.D)

PREB text. Table 1 limits Fast Track to 500 kW below 5 kV and 1 MW from 5 to 15 kV; the penetration screen exempts Non-Exporting systems, but there is no faster path for them. **SESA change [C4.1].** Notwithstanding Table 1, a Non-Exporting system, or a Limited Export system (UL 3141 Power Control System or other § 7.09 means) within the export capacity published for its line section or service transformer under § 7.11, is evaluated on its Export Capacity: initial results within 15 Business Days of completeness, and an executable agreement or § 7.01.D determination within 45 calendar days of filing. A Non-Exporting system goes to Supplemental Review or Study only on a specific written finding about its Inadvertent Export or fault current. **Basis.** SESA asked for a path for systems above 25 kW that export “zero electrons,” adding that “the limited export and zero export is perhaps in the same category” (WS2, PJ Wilson, 00:41:50; 00:42:58), and for “maybe 30 days rather than a 90-day process” (WS3, 02:22:54). Windmar asked that zero-export and PCS-limited elections skip hosting-capacity

screens and get “a short, hard, published clock” for the safety screens (Windmar Aug. 14, Ask 2). OIPC asked for calendar-day deadlines (OIPC Aug. 14, general cmt. 1). The 45-day period is a SESA proposal.

Penetration Screen (§ 4.02.B(1))

PREB text. Aggregated Export Capacity may not exceed 15% of line-section annual peak load. **SESA change [C4.2].** 30% of peak or, where Daytime Minimum Load is published under § 7.11, 100% of it. **Basis.** LUMA said average penetration “is really closer to, say, 50% rather than 15%. So we can certainly agree on a higher number” (WS3, A. Baretty, 04:11:07), and at WS1, “We don’t have major concerns to increasing this to a 30% threshold” (WS1, 04:59:45); it does not support a 100% daytime minimum load limit, though that “could also serve as another criteria” (WS3, 04:12:33). IREC called 15% “a rule of thumb for trying to conservatively estimate what minimum load might be” (B. Lydic, 04:07:48) and noted states using 100% of minimum load in initial review (IREC WS3 deck). SESA’s reading of LUMA’s data—“not official numbers”—showed 81% of the island over 15% and 74% over 30% (04:16:28). OIPC, J. H. Román-Morales and C. López Maisonave asked the Bureau to revisit 15% (OIPC Aug. 14, cmt. 18; Román-Morales Aug. 14, § IV; López Maisonave Aug. 13, § VIII). The figures are SESA proposals, open to the number LUMA said it would provide.

Daytime Minimum Load for Solar-Plus-Storage (§ 4.04.C(2))

PREB text. PV “with no Energy Storage” uses daytime minimum load; “all other generation uses absolute minimum load.” **SESA change [C4.5].** PV paired with storage also uses Daytime Minimum Load, on the PV system’s Export Capacity. **Basis.** SESA/SUN: the draft leaves unclear how “solar-plus-storage systems — nearly all of what is deployed today — are to be handled” (App. A, p. 4); J. H. Román-Morales asked that storage-paired systems be screened on their verifiable Operating Profile (Román-Morales Aug. 14, §§ III.1, VII); LUMA would use Operating Profile and Nameplate Rating (LUMA Aug. 14, Exh. 2, cmt. [A66]).

Estimates Before Elections (§§ 4.02.C(2)–(3), 4.04.D(2)–(3), 7.08.B)

PREB text. A customer told that modifications are needed must elect within five Business Days; a “non-binding good faith cost estimate” follows with the agreement. **SESA change [C4.3, C4.4, C4.6, C4.7, C7.7].** The results notice includes an itemized estimate and schedule; the customer has 15 Business Days to proceed, elect Limited Export or withdraw (with a reminder and five more days in § 4.02.C(2)); an executable agreement follows within 15 Business Days; under § 7.08.B the final charge may not exceed the estimate by more than 10% absent a customer-requested scope change. **Basis.** SESA/SUN: “No blind elections” (App. A § II.4). OIPC asked that the election period “begin only after receipt of” an itemized estimate (OIPC Aug. 14, cmt. 26) and that estimates stay binding “within a defined reasonable variance” (cmt. 22); a Commissioner asked, “Is there going to be a cap ...?” (WS2, 04:18:35). Fifteen Business Days is the Bureau’s own period in §§ 4.04.A and 4.04.E; the 10% variance is a SESA proposal.

Limited Export and Design Changes During Review (§§ 4.04.F, 7.09)

PREB text. A Power Control System must be “NRTL certified” and stop exporting on failure; no provision allows a design change after screen results. **SESA change [C4.8, C7.9, C7.10].** Results state the Export Capacity that fits without upgrades, and the customer may reduce to it within the election period without losing Queue Position (new § 4.04.F); a § 7.09 configuration may be elected at any election point; Power Control Systems are certified to UL 3141; on loss of communications a Limited Export system reverts to its certified limit rather than ceasing export. **Basis.** IREC recommended “allowing for system design changes during review” and results showing “the exact thresholds that were exceeded” (WS3, B. Lydic, 01:42:13; 02:00:15), and identified UL 3141 (01:44:14). A SESA member company (Sunrun) said it has “saved probably millions of dollars of different transformer and other related upgrades through the use of PCS” (02:08:06). SESA/SUN App. A § II.5.

Articles 5 and 6 — Study Process; Interconnection Agreement

Meter Installation (§ 6.02.F)

PREB text. Meters are installed “within twenty (20) working days” if requested. **SESA change [C6.2].** Twenty Business Days, in the existing socket or, where an adapter approved under § 8.03 is installed, into the adapter. **Basis.** Act 114-2007 § 3 (Part 2); SESA/SUN Aug. 14, App. B § A.4. Other Article 5 and 6 edits are corrections (Part 5).

Direct Refunds for Missed Time Frames (§ 6.01.B)

PREB text. The Bureau “may fine the EPS Operator one thousand dollars (\$1,000) per day” for failing to meet the time frames and other requirements of the Regulation. **SESA change [C6.4].** Where a time frame owed to a particular customer is missed—the 30-day net metering period of § 9.02.B or the 90-day evaluation period of § 7.01.D—the Bureau may also order a direct refund to that customer equal to the bill savings lost, including the net metering credits the customer would have received; at the customer’s election the refund, and any retroactive credit under § 9.02.B, is paid by check or electronic deposit within 30 days rather than as a bill credit, and a refund for a period replaces the credit for the same period. **Basis.** OIPC asked for “a clear and enforceable framework of consequences” for EPS Operator non-compliance (OIPC Aug. 14, general cmt. 2). Solar United Neighbors reports customers in Buen Pastor, Cataño and elsewhere who went months without net metering credits and received a \$1,000 credit from LUMA; the refund formalizes that remedy. A payment is money the customer can use without restriction and, unlike an accumulated credit, is not subject to the year-end treatment of unused credits under Act 114-2007, a portion of which is retained for the Department of Education subsidy.

Article 7 — Provisions for All Applications

Deadlines and the 90-Day Clock (§ 7.01)

PREB text. The EPS Operator “shall make Reasonable Efforts to meet all time frames”; the 90-day limit is not implemented. **SESA change [C7.1, C7.2].** It “shall meet all time frames” (A). New D: evaluation under Articles 4 and 5 may not exceed 90 calendar days from filing; absent by then an executable agreement or a written determination denying the interconnection or requiring added requirements or Upgrades, with specific grounds, the application is automatically approved and the agreement issues within five Business Days; days awaiting the customer are excluded; a later determination does not reverse the approval but may be reviewed under § 13.02. New E: Article 3 and § 9.02.B time frames cannot be extended by the EPS Operator. **Basis.** Act 114-2007 § 9. Windmar reported that 12 of 34 completed evaluations—35%—exceeded 90 days (Windmar Aug. 14). SESA/SUN asked for “[o]ne master clock” and “[d]eadlines, not ‘reasonable efforts’” (App. A § II.1–2). LUMA read the statute as approval “until” the utility substantiates grounds (WS2, G. Bonet, 00:46:48); SESA answered that “the 90-day marker can’t be a meaningless thing” (00:49:44). The redline gives the “until” clause effect within the 90 days and, as SESA’s proposed reading, sends a later determination to Bureau review.

Self-Inspection (§ 7.03.D); Operation Without an Agreement (§ 7.04.C)

PREB text. For Simplified systems “the field inspection” checks the installation against “the EPS Operator’s evaluation of the design” and the “application”; the EPS Operator “may disconnect” a system operating without an agreement. **SESA change [C7.3, C7.5].** A self-inspection by the installer, certified in the notification, with optional EPS Operator verification at its expense within the Art. 3.C(4) period; before disconnecting a system lacking a filing, written notice and at least 30 calendar days to cure, unless the installation is unsafe as defined in Art. 3.C(4)(vi). **Basis.** SESA/SUN noted that no “evaluation of the design” or “application” exists in the Simplified Process (App. A, pp. 5–6); C. López Maisonave asked for on-site inspection “only when justified by the system’s characteristics or a specific safety or reliability concern” (López Maisonave Aug. 13, § VI). A

certified system operates first and files after (Art. 3.C(1), (3)), so a missing filing should be curable. The 30-day period is a SESA proposal.

Cost Responsibility (§ 7.08.A)

PREB text. The customer pays for Interconnection Facilities and Distribution Upgrades “as described and itemized.” **SESA change [C7.6].** Cost responsibility follows the JR 5-2026 § 2 principles and is limited to least-cost upgrades necessary for, and attributable to, the interconnection; no charge for a pre-existing condition or for upgrades serving customers generally, which are planned under § 7.11. SESA is not proposing a reimbursement mechanism in this round. **Basis.** LUMA said that where there is “a pre-existing condition, that customer, that GD, is not responsible for that improvement” (WS2, A. Baretty, 04:17:14). J. H. Román-Morales asked that the JR 5-2026 principle govern Distribution Upgrade allocation generally (Román-Morales Aug. 14, § III.5); OIPC asked that costs not fall on a later customer without analyzing earlier projects’ contribution (OIPC Aug. 14, cmt. 24).

Excessive Customer Curtailment Compensation (new § 7.10)

PREB text. None; the Bureau is still considering curtailment compensation (Sept. 15 R&O § II). **SESA change [C7.11].** The section implements JR 5-2026 § 2 (A) and applies to every Net Metering System, whether under the Simplified, Fast Track or Study Process (B), for restrictions imposed by the EPS Operator or through settings it or the Bureau requires—not voluntary Limited Export or Non-Export elections or periods of documented noncompliance. A restriction arising from a condition of the EPS Operator’s facilities—the service transformer, secondary conductors or service drop, or anything upstream—is compensable; one attributable to a condition of the customer’s own installation is not, for the period of the condition (B). A restriction requires prior written notice with data and criteria, must be the least restrictive, is reviewed every six months and is lifted when resolved (C). After interconnection, no restriction may be imposed because of the condition or capacity of facilities upstream of the service transformer—by instruction, remote command or inverter settings—unless the Bureau-approved Technical Interconnection Requirements so establish (C). Compensation is the value, at the customer’s Article 9 credit, of the energy the customer would have exported but for the restriction, estimated from pre-restriction exports or a Bureau-approved production model, for any quarter in which that value exceeds \$50 (D), which is the measure of an “excessive” restriction; it is credited on the bill within 30 days after the quarter without a claim, as a cost of the EPS Operator’s compliance not recovered through fees under the Regulation (E), and reported (F). **Basis.** JR 5-2026 § 2 (Part 2). SESA proposed the Hawaii threshold of “\$50 in lost energy value over a three-month period” (SESA Apr. 15, p. 18; WS2, PJ Wilson, 01:31:36) and set out scope, measure and process (SESA/SUN App. A § V); C. López Maisonave asked that material restrictions be “paired with compensation” (López Maisonave Aug. 13, § IV); LUMA said compensation should be “contingent on measured persistent impacts after the settings have been implemented” (WS1, M. H. Rivera (LUMA), 03:12:00), which § 7.10 reflects by measuring exports foregone under restrictions actually imposed.

Concerns raised, and SESA’s position. Commissioner Torres asked, “Why should other people who aren’t benefiting from net metering have to pay for that curtailment?” (WS2, 01:30:17); LUMA called a curtailment payment “another subsidy” requiring legislative evaluation under Act 22-2016, Art. 2.4 (WS2, G. Bonet, 01:13:04; 01:40:47); the Energy Czar opposed any additional compensation (Energy Czar Aug. 14). SESA’s position is that the compensation is directed by JR 5-2026 § 2, not created by regulation; that it arises only when the EPS Operator imposes a restriction it can avoid by completing upgrades or accepting a customer’s certified limit (SESA/SUN App. A § V.4), so it is a cost of the EPS Operator’s compliance rather than a charge to other interconnection customers; and that it pays the Article 9 credit the customer would otherwise have received, not a new rate. Rate treatment is left to the Bureau. The \$50 threshold, six-month review and 30-day crediting are SESA proposals.

Proactive Hosting Capacity Planning and Budgeting (new § 7.11)

PREB text. None; WS3 did not reach the topic (C. Lane, 05:22:04). **SESA change [C7.12].** (A) *Purpose*: plan and build the distribution system ahead of demand so that forecast generation and storage can interconnect and export without restriction, rather than one interconnection at a time. (B) *Forecast*: within 12 months and annually, a forecast by feeder of the generation and storage expected over at least five years, from historical volumes, the Public Queue and Act 17-2019 goals. (C) *Hosting capacity analysis* supporting it, published for every feeder (and line sections and service transformers where data permit), under a Bureau-approved methodology using gross Daytime Minimum Load and Export Capacity, validated in the field, with queue data updated monthly. (D) *Plan and budget*: within 12 months and every three years, a Distribution Hosting Capacity Plan covering at least five years that identifies where the forecast exceeds hosting capacity and the least-cost measures, scheduled ahead of need, funded from federal funds to the greatest extent possible and otherwise through Bureau-approved rates, never by individual customers. (E) *Effect*: a forecast constraint is not a basis to deny, delay or restrict any system, other than a restriction of export established in the Bureau-approved Technical Interconnection Requirements as § 7.10.C provides; the remedy is timely completion of the planned Upgrades. (F) A Bureau proceeding opens within 60 days.

What SESA means by proactive hosting capacity planning. Commissioner Ramos asked parties for a “really high level discussion on what they think proactive hosting capacity entails” (WS3, 05:22:42). In SESA’s description it has four steps, each in § 7.11: *forecast* where generation and storage will connect; *measure* how much each feeder can host; *plan and budget* the least-cost measures ahead of need; and *build* them, so that constraints are removed rather than rationed—“looking in the future ... five, 10 years ... And kind of reverse engineer” (WS3, PJ Wilson, 04:18:27).

Basis. JR 5-2026 § 2. Synapse observed that “in an ideal world, LUMA would have preemptively used proactive hosting capacity analysis and upgraded the system” (WS3, C. Lane, 01:09:05); IREC said that with proactive planning, “hopefully ... we don’t actually get to this point where you have an upgrade that you need to deal with” (B. Lydic, 02:17:26); ICSE wrote that “[p]roject-specific information supplied during the interconnection process is not a substitute for system-wide planning” (ICSE Sept. 15, Exh. 1). SESA asked that the rule “spell out exactly what that process is and how often it’s repeated and updated” (WS2, PJ Wilson, 00:27:25), with a dedicated docket (SESA/SUN App. A § III). On funding, SESA said that without a price tag “it’s not possible to really go to FEMA as a clear package” (WS1, PJ Wilson, 04:45:13) and that federal funds “should not be ignored” (WS3, 03:13:12); LUMA said it does not “request federal funds for individual customer upgrades” because FEMA funds are system-wide (WS3, G. Bonet, 03:15:03), so the Plan’s system upgrades are where such funds can apply. The cadences are SESA proposals.

Coordination with NEPR-MI-2019-0011. Section 7.11.C and F direct the EPS Operator and the Bureau to build on, and coordinate with, the Bureau’s Distribution Resource Planning proceeding (NEPR-MI-2019-0011), which convened a Hosting Capacity Working Group in 2019–2020 and has required interconnection-capacity maps and progressively more detailed hosting-capacity analyses. That docket is an existing technical foundation for the requirements of § 7.11. SESA recommends that the Bureau, in compliance with JR 5-2026, incorporate proactive hosting capacity planning expressly into this Regulation as the binding vehicle for hosting-capacity analysis, forecasting, publication of system information, treatment of foreseeable constraints and interconnection customer protections, and coordinate those requirements with the work already performed in NEPR-MI-2019-0011.

Article 8 — Technical Requirements

TIR Process (§ 8.01.G)

PREB text. The TIR and its amendments take effect on approval by Resolution and Order; the September 16 text places the Simplified fee amount and adapter fees in the TIR. **SESA change [C8.1].** The TIR and any amendment

are published for at least 30 days of comment, and the Bureau acts no earlier than 30 days after the comment period closes. Except for the Simplified fee amount (Art. 3.B), the TIR may not set or change a fee, time frame, eligibility criterion, screen threshold or cost allocation, or add to, restrict or condition any right or obligation under the rule, other than a restriction of export because of the condition or capacity of a facility upstream of the service transformer, which Art. 3.C(4)(iv) and § 7.10.C leave to the Bureau-approved TIR; no PREPA or EPS Operator communiqué or directive on interconnection has effect without Bureau approval. **Basis.** OIPC asked that the Regulation guarantee notice and “a reasonable opportunity to review and submit comments” before a TIR or amendment is approved (OIPC Aug. 14, cmt. 35); ICSE asked for “timely access” to TIR materials (ICSE Sept. 15, Exh. 1); the Bureau ruled that the TIR “must be approved shortly thereafter” (Aug. 5 R&O). The second 30 days lets parties answer one another, the value Synapse saw in seeing “the comments of other parties ahead of time” (WS2, A. Star, 07:04:52). SESA asked for a TIR amendment procedure with stakeholder input and Bureau approval of directives (SESA Apr. 15, pp. 21, 27). The periods are SESA proposals.

Certified Equipment (§ 8.02)

PREB text. Equipment meeting standards is allowed, but “[t]hese have to be evaluated and approved by the EPS Operator”; the list is updated “annually”; no decision period is stated. **SESA change [C8.2–C8.4].** Inverters, Power Control Systems and storage listed by the California Energy Commission, or certified by an NRTL to UL 1741 (with supplements) and IEEE 1547-2018 and 1547.1-2020, are approved on listing (B); the list is updated at least monthly (C); other equipment is decided in writing within 20 Business Days, reviewable under § 13.02 (new E); PEPP approval (A) is unchanged. Paragraph D refers to the “interconnecting equipment,” the device that connects to the grid. **Basis.** SESA/SUN asked for acceptance of CEC-listed equipment on “a short, defined cadence” and a decision clock (App. A § I.6); C. López Maisonave asked for “a fixed review period” (López Maisonave Aug. 13, § VII); OIPC asked the Bureau to “avoid creating two separate and potentially conflicting equipment approval processes” (OIPC Aug. 14, cmt. 36).

Meter Socket Adapters (§ 8.03)

PREB text. The September 16 section covers customer-owned adapters in single-phase services of 200 A or less; a model list reviewed “at least annually”; a main breaker and socket “contained in the same electrical panel”; 20 Business Days on an installation “application”; meter removal by “EPS Operator personnel or its authorized agents”; fees in the TIR with a one-time fee per site visit; and relocation costs to the customer. **SESA changes [C8.5(a)–(t)],** each an edit to the Bureau’s text:

- *Right to use; model approval* (A(2), B(1)–(5), (8)). No denial, condition or delay because of a compliant, customer-owned adapter, which is not a Material Modification; list updates within 10 Business Days and review “at least monthly”; “the National Electrical Code as adopted in Puerto Rico,” not a supplementary PREPA regulation, governs; NRTL listing to UL 414; one adapter per socket; model decisions within 20 Business Days, deemed approved on silence, with no separate installation approval; verification at the EPS Operator’s expense.
- *Authorized Agents* (C(2)–(4), (6)). A licensed electrical engineer or licensed expert electrician registered with the EPS Operator (within 20 Business Days, with free training and seals) may, as its agent, remove and reinstall the Meter, giving two Business Days’ notice, inspecting the socket, applying a numbered EPS Operator seal and filing photographs; no EPS Operator site visit is a precondition; the EPS Operator may inspect and reseal at any time, and does the work itself within 10 Business Days if the customer asks.
- *Fees; existing socket* (D). No EPS Operator fee for model evaluation, Authorized Agent installation, inspection or resealing; an Authorized Agent’s own charges are not regulated; if the customer asks the EPS Operator to pull the Meter, only the Bureau-approved fee, if any, for pulls requested for other customer electrical work

applies. The Meter goes in the existing socket unless it fails National Electrical Code safety standards (Act 114-2007 § 3).

Basis. SESA asked for “at least monthly” review, a definition of the code “in force” and a fix to the panel clause; Synapse invited “specific redline language,” noting the text was “adapted from another state, so maybe it was poorly written” (WS3, PJ Wilson, 04:34:55–04:36:47; A. Star, 04:37:23). Enphase asked for product decisions “within 60 or 90 days” (04:48:03), and Synapse said approval and installation could be separated (C. Lane, 04:50:01). SESA proposed that “licensed electricians are hereby authorized as agents,” with safeguards (PJ Wilson, 04:50:53); Enphase said that in other states “authorized agents and or qualified electricians are able to do this work,” and ConnectDER that “it’s far more common for the utility to not be involved than to be involved” (04:37:56; 04:39:44); Synapse called the draft “a bit of a learn to walk before you run approach” (A. Star, 04:40:15). LUMA said that Regulation 7982 and Act 83-1941 reserve meter handling to PREPA and its agents and that it “will be violating our T&D OMA” if an independent contractor does it (G. Bonet, 04:27:45; 04:54:19); PREPA said “we need to be there” (WS2, F. Vergés, 06:56:13); Commissioner Ramos observed that others could argue a meter pull does not infringe LUMA’s responsibility as operator (WS3, 05:26:24). The redline therefore makes registered professionals agents of the EPS Operator—the category the Bureau’s C(2)–(3) already uses—keeping its inspection, sealing and registration control (see § 1.08). On fees, SESA said a charge made only because of an adapter “would be a new discriminatory fee” (WS3, 04:25:47); LUMA estimated a truck roll at “somewhere between \$45 and \$75” and undertook to file its meter charges (M. Jeppesen, 05:03:36; 05:04:43); Commissioner Torres suggested that “the client has to pay LUMA a fee” (WS2, 06:58:13), which D(1) applies where the EPS Operator does the work at the customer’s request. The 20-day periods and deemed approval are SESA proposals.

Article 9 — Net Energy Metering

Eligibility Caps as Export Capacity (§§ 9.01.A, 9.02.A)

PREB text. Section 9.01.A lists 1 MW and 5 MW tiers but no residential tier, reads “Not more one” and gives voltages in “kW”; § 9.02.A states the caps as “installed AC capacity.” **SESA change [C9.0, C9.1, C9.3a].** A system qualifies “if it has” an Export Capacity of not more than 25 kW (residential), 1 MW (distribution, up to 13.2 kV) or 5 MW (38 or 115 kV); § 9.02.A uses the same Export Capacity caps. **Basis.** The residential cap is not a new restriction: 25 kW is the residential limit in Act 114-2007, Art. 2(a) (22 L.P.R.A. § 10113) (“no mayor de veinticinco kilovatios (25 kW) para clientes residenciales”) and in the Bureau’s § 9.02.A; OIPC warned that without it § 9.01.A “could therefore be interpreted as excluding residential customers from eligibility” (OIPC Aug. 14, cmt. 37). Á. Zayas asked that §§ 9.01–9.02 use Export Capacity and that voltages “be expressed in kilovolts (kV), not kilowatts (kW)” (Zayas Aug. 14, §§ IV–V); see Art. 3.A above for OIPC’s contrary reading of “generating capacity.”

Energy Storage (§ 9.01.C); Credits from Day 30 (§ 9.02.B)

PREB text. Stand-alone storage “does not qualify as a Net Metering System”; paired storage “shall be programmed with one or both” of two restrictions, changed only with written approval; § 9.02.B keys the 30-day rule to “maximum installed AC power capacity.” **SESA change [C9.1a–C9.4].** Stand-alone storage still does not qualify for net metering but may be interconnected, and may export only under a Bureau-approved virtual power plant, demand response or similar program, which compensates that export. For paired storage the customer elects one operating restriction of the Energy Storage Device unless a Bureau-approved program provides otherwise; a revised attestation is effective on filing. Section 9.02.B uses Export Capacity and cites § 9(b); if meter or billing work is late, credits from day 30 apply retroactively and, at the customer’s election, are paid by check or deposit under § 6.01.B. **Basis.** C. López Maisonave asked the Bureau to “preserve participation in any Energy Bureau-approved time-of-use, demand-response, or virtual-power-plant program” and to require “notice and updated

attestation rather than discretionary pre-approval” (López Maisonave Aug. 13, § V); a SESA member company (Sunrun) noted that “[i]f a battery can’t export to the grid, it can’t really participate in the [CBES] program or future programs” (WS2, K. Wallace, 02:55:07); SESA/SUN asked that credits “accrue from day 30 even where the utility’s meter exchange or billing update is still pending” (App. A § I.4).

Aggregate and Shared Net Metering (§§ 9.03–9.05)

PREB text. Section 9.03 limits Aggregate Net Metering to “governmental Entities and non-profit academic institutions,” with all locations in “the same account” and served “at the same voltage level,” at the generating site or on “the same power line” within two miles; § 9.04 limits Shared Net Metering to horizontal-property condominiums and public housing served from “the same point of delivery”; § 9.05.F–G credit energy “equally,” within 100% or 120% of consumption.

SESA change [C9.5–C9.10]. The two programs are distinguished: *Aggregate* is one customer with several meters, at the same or different premises; *Shared* is several customers sharing one system at the same premises. Under § 9.03, any customer may aggregate service agreements held in its name or by entities under common ownership or control, anywhere in the territory and at any voltage, with Export Capacity capped per generating location rather than across locations, and with customer-designated percentages totaling no more than 100%, changeable once in 12 months. Under § 9.04, customers at the same premises—a building or complex under one owner, horizontal property regime or owners’ association, on one or contiguous parcels—may share a system without a single delivery point; the owner or association is the Interconnection Customer and files a participation agreement with percentages; customers join or leave on 30 days’ notice; the Bureau’s transformer cap and 25 kW per residential participant remain. Under § 9.05, daily maximums are summed across participating agreements (D), and exports are credited in the percentages on file, each agreement being treated as if it had exported at its own Meter, with unassigned shares to the host (F) and a vacant unit’s share to a designated agreement (G).

Basis—the Puerto Rico record. The Bureau’s definitions say both programs were created to comply with “Amended Order CEPR-MI-2014-0001.” That Order and the December 18, 2014 Order direct PREPA to incorporate “la práctica conocida como Medición Neta Agregada o Virtual” and to establish a Shared Renewable Energy Program “principalmente dirigido a aquellos clientes residenciales y comerciales que no puedan instalar sistemas de energía renovable en sus propiedades”; their text sets no customer-class limits (Order, Dec. 18, 2014, items (6)–(7); Amended Order, Mar. 20, 2015, items (8)–(9)). The government-and-university limit appears in PREPA’s May 2016 draft rule filed in that docket (§ VII-B.1), with the same-account, same-voltage, two-mile, delivery-point and equal-split terms (§ VII-B to D) that §§ 9.03–9.05 carry forward nearly verbatim. J. H. Román-Morales, a Commissioner in 2014, described the restrictions as “a practical, administrable starting point” and asked that the programs reach multi-unit buildings outside the horizontal property regime (Román-Morales Aug. 14, §§ III.8, IX); Á. Zayas asked to open Aggregate Net Metering to private entities and to “properties under common ownership or control” (Zayas Aug. 14, § VI). Act 114-2007, Art. 2(b) requires each system to be connected after the customer’s meter; under § 9.03.D each sits at a participating service agreement.

Basis—practice elsewhere. Each term is in force elsewhere (table below). Some states limit aggregation to listed classes (Md. Code, Pub. Util. § 7-306.3(b); N.Y. Pub. Serv. Law § 66-j(3)(e)); distance or circuit limits like the Bureau’s appear in 52 Pa. Code § 75.14(e) (two miles) and Or. Admin. R. 860-039-0065(1)(c) (same primary feeder). PG&E’s Schedule NEM2V closed to new applications after February 14, 2024; its successor also uses an owner-set allocation (CPUC, Virtual Net Metering page).

Redline	Term	Where it is done
§ 9.03.A	Any customer class; own or commonly owned accounts	Cal. Pub. Util. Code § 2827(b)(4)(A), (h)(4)(A); Minn. Stat. § 216B.164, subd. 4a; 23 CAR § 457-205(b)–(c) (Ark.) (accounts “under common ownership”; sworn affidavit)
§ 9.03.B	Anywhere in the territory	NY PSC, Order on Value Stack Eligibility Expansion, Cases 15-E-0751/15-E-0082 (Sept. 12, 2018), pp. 19–20 (interzonal crediting “causes no additional cost shifts between customers”); 220 CMR 18.05(1)(a)–(b) (Mass.); 23 CAR § 457-205(b)
§ 9.03.C	Different rate schedules (no same-voltage rule found)	Cal. Pub. Util. Code § 2827(h)(4)(C); 4 CCR 723-3-3664(h)(IV) (Colo.); Or. Admin. R. 860-039-0065(2)
§§ 9.03.D, 9.04.F	Cap per facility, not per aggregation	Md. Code, Pub. Util. § 7-306(g)(8), (i) (5 MW per aggregated facility; combined capacity may exceed 5 MW); Minn. Stat. § 216B.164, subd. 2a(c) (MW AC at the point of interconnection)
§§ 9.03.E, 9.04.D–E	Customer-set shares ≤100%; limited changes	Md. Code, Pub. Util. § 7-306.3(c); COMAR 20.50.10.08B(2); 220 CMR 18.05(1) (“as designated in writing”); D.C. Code § 34-1518.01(c), (l); yearly changes: Minn. Stat. § 216B.164, subd. 4a(b); Joint Utilities, NY Remote Crediting Program Details, Case 19-E-0735, slide 6; twice yearly, within 30 days: 4 CCR 723-3-3664(i)(IV)
§ 9.04.A–C	Same premises; several delivery points; owner as customer	CPUC D.20-08-007 (accounts “behind multiple service delivery points and on multiple contiguous parcels” of one multitenant or multi-meter facility); PG&E Schedule NEM2V (“Property”; “Qualified Customer”); 4 CCR 723-3-3664(i), (a); Minn. Stat. § 216B.164, subd. 2a(e)
§§ 9.04.E, 9.05.G	New tenant keeps share; vacant unit to designated account	PG&E Schedule NEM2V, Special Condition 3.h (“Change in Tenancy”; Default Account); 4 CCR 723-3-3664(i)(III) (common-area meter)
§ 9.05.D, F	Limits summed; credit as if exported at own meter; unassigned to host	COMAR 20.50.10.08B(1)–(2); Cal. Pub. Util. Code § 2827(h)(4)(A); 220 CMR 18.04(8); D.C. Code § 34-1518.01(h)

Articles 11 to 13 — Penalties, Reporting, Review

Sanctions by the Bureau (Art. 11)

PREB text. Violators “shall be penalized by the EPS Operator and/or Energy Bureau.” **SESA change [C11.1–C11.3].** Sanctions are imposed by the Bureau, on referral by the EPS Operator where applicable. **Basis.** LUMA wrote that “[a]s a private operator, the EPS Operator lacks authority to impose administrative sanctions under Act 83-1941 or Act 57-2014; only the Energy Bureau, as the regulatory agency, has this authority” (LUMA Aug. 14, Exh. 2, cmt. [A95]).

Quarterly Interconnection Report (§ 12.02)

PREB text. A “Biannual Interconnection Report,” made “as part of its Interconnection Progress Reports” in Docket No. NEPR-MI-2019-0016. **SESA change [C12.0, C12.1].** A “Quarterly Interconnection Report” filed in that docket within 30 days after each quarter, adding (F) compliance with the 30-day net metering and 90-day evaluation time frames, (G) Reserve Fund and § 7.10 data, and (H) adapter decisions, installations and Authorized Agents. **Basis.** SESA noted that the net metering compliance reports required since 2020 are quarterly and asked that they focus on the 30-day and 90-day requirements (SESA Apr. 15, pp. 25–26); § 7.10 credits run by quarter; SESA/SUN proposed adapter reporting (App. B § A.4).

4. Answers to Synapse’s September 21 Requests

Request at Workshop 3	Where the redline answers it
Criteria language for the 15-day review (C. Lane, 01:32:23; 01:33:36)	Art. 3.C(4): three bounded review items; criteria in the rule and TIR; notice with data; the three permitted restrictions
Fee amount (C. Lane, 02:48:57; 02:52:35)	Art. 3.B(1): \$300 initial amount, bracketed for the Bureau’s determination, from implementation of the new process (no later than day 90 after the effective date)
True-up and refunds (C. Lane, 03:28:22)	Art. 3.B(5): review every 3 years, otherwise only in extraordinary circumstances; surpluses reduce the fee; shortfalls recovered prospectively
Specificity of “upgrades” and “modifications” (C. Lane, 03:18:48; G. Bonet, 03:19:25)	Art. 3.B(3): “Service Upgrades” defined, upstream facilities excluded; Art. 3.D(3); § 7.08.A
Cost allocation above 25 kW (C. Lane, 03:57:39; 04:02:19)	§ 7.08.A–B: JR 5-2026 principles, least-cost attributable upgrades, estimate before election
High-level description of proactive hosting capacity (Commissioner Ramos, 05:22:42)	§ 7.11; Part 3 (Article 7) above
TIR pointers (G. Bonet, 01:32:41; C. Lane, 01:33:36)	§ 8.01.G; Art. 3.C(4)
Adapter text points; approval apart from installation (A. Star, 04:37:23; C. Lane, 04:50:01)	§ 8.03.B(1), B(2)(i), B(4), B(5)

5. Conforming and Technical Corrections

Location	Correction	Change
Art. 1	Deletes a misplaced duplicate of § 1.19 before § 1.01	C1.1
§ 1.11.B: Cyber Portal; Interconnection Agreement	Adds the Simplified Process and published data; corrects “Technical Information Requirements” (as Á. Zayas noted)	C1.4(a), (d)
§ 1.11.B: Fast Track; Force Majeure; TIR	“Article 3” corrected to “Article 4”; “Even0t” corrected; opening quotation mark added	C1.4(c), (h); G1

Location	Correction	Change
§ 2.02.G(8)	Cross-reference corrected to § 4.04.C(2) (as J. H. Román-Morales noted)	C2.1
Art. 3.A(2)(vi), D(1), D(2)	Three “Error! Reference source not found.” fields fixed	G2–G4
Art. 3.C(1)–(2); Art. 3.D	“(Attachment *)” and “applicable fee” corrected; “Interconnecting Customer” conformed	C3.14–C3.15; G7
§§ 5.03.D, 5.04.D, 5.05.F	“EPS Operator” → “Interconnection Customer” for the upfront study payment; “TRI” → “TIR”; “Sixty” → “sixty”	C5.1–C5.3
§ 6.02.G	“the Microgrid” → “the Distributed Generation System or Microgrid”	C6.3
§ 9.01.A	“Not more one” and “if it is:” corrected; “13.2kW,” “38kW,” “115kW” corrected to kV	C9.0, C9.1
Art. 11.B	“Microgrids with the EG” → “Distributed Generation Systems and Microgrids with the EPS”	C11.2
§ 13.01.A	Period runs from notice “issued and notified by the EPS Operator,” as in § 13.02	C13.1

6. Closing

SESA and SUN remain available to work with the Bureau, Synapse and all stakeholders on this language before the October 16 draft and at Workshop 4.

RESPECTFULLY SUBMITTED.

In San Juan, Puerto Rico, this 5th day of October, 2026.

s/Javier Rúa-Jovet

Javier Rúa-Jovet
PR Supreme Court ID No. 12602
[javrua@sesapr.org](mailto:javrúa@sesapr.org)
(787) 396-6511

CERTIFICATE OF SERVICE: I hereby certify that a copy of this Joint Motion was filed with the Energy Bureau through its electronic filing system at <https://radicacion.energia.pr.gov/> and by electronic mail.

Distributed Generation and Microgrid Interconnection Regulation

(July 13 + Sep 16 2026) Energy Bureau DRAFT

SESA and Solar United Neighbors Proposed Redline of the July 13, 2026 Revised Preliminary Draft (as modified by the September 16, 2026 Draft Language)

Filed October 5, 2026

Filed jointly by the Solar and Energy Storage Association of Puerto Rico (SESA) and Solar United Neighbors (SUN). The tracked changes authored “SESA” are the co-filers’ joint proposals.

TABLE OF CONTENTS

	<u>Page</u>
<u>ARTICLE 1. GENERAL PROVISIONS.....</u>	<u>1</u>
<u>SECTION 1.01. Title</u>	<u>1</u>
<u>SECTION 1.02. Legal Basis.....</u>	<u>1</u>
<u>SECTION 1.03. Purpose.....</u>	<u>1</u>
<u>SECTION 1.04. Executive Summary.....</u>	<u>1</u>
<u>SECTION 1.05. Cost-Benefit Analysis.....</u>	<u>2</u>
<u>SECTION 1.06. Applicability</u>	<u>2</u>
<u>SECTION 1.07. Interpretation</u>	<u>2</u>
<u>SECTION 1.08. Provisions of Other Regulations</u>	<u>2</u>
<u>SECTION 1.09. Unforeseen Proceedings</u>	<u>3</u>
<u>SECTION 1.10. Dates and Time Periods.....</u>	<u>3</u>
<u>SECTION 1.11. Definitions</u>	<u>3</u>
<u>SECTION 1.12. Controlling Version</u>	<u>15</u>
<u>SECTION 1.13. Severability</u>	<u>15</u>
<u>SECTION 1.14. Cyber Portal and Forms.....</u>	<u>15</u>
<u>SECTION 1.15. Mode of Submission</u>	<u>16</u>
<u>SECTION 1.16. Effect of Submission.....</u>	<u>16</u>
<u>SECTION 1.17. Confidential Information</u>	<u>16</u>
<u>SECTION 1.18. Validity.....</u>	<u>17</u>
<u>SECTION 1.19. Compliance with Other Applicable Legal Requirements</u>	<u>17</u>
<u>SECTION 1.20. Repeal and Transition</u>	<u>17</u>
<u>ARTICLE 2. INTERCONNECTION APPLICATION PROCESS</u>	<u>17</u>
<u>SECTION 2.01. Process Overview.....</u>	<u>17</u>
<u>SECTION 2.02. Pre-Application Report and Interconnection Application Filing Mechanisms.....</u>	<u>18</u>
<u>SECTION 2.03. Electronic Signatures.....</u>	<u>21</u>
<u>SECTION 2.04. Communications.....</u>	<u>21</u>
<u>SECTION 2.05. Submittal of the Interconnection Application or the Simplified Interconnection Notification.....</u>	<u>22</u>
<u>SECTION 2.06. Modification of the Interconnection Application</u>	<u>23</u>

SECTION 2.07.	Site Control	24
SECTION 2.08.	Queue Position	25
ARTICLE 3.	DISTRIBUTED GENERATION SYSTEM SIMPLIFIED PROCESS	25
ARTICLE 4.	DISTRIBUTION SYSTEM FAST TRACK PROCESS	33
SECTION 4.01.	Applicability and eligibility requirements	33
SECTION 4.02.	Initial Review	35
SECTION 4.03.	Customer Options Meeting	38
SECTION 4.04.	Supplemental Review	39
ARTICLE 5.	STUDY PROCESS	43
SECTION 5.01.	Purpose	43
SECTION 5.02.	Scoping Meeting	43
SECTION 5.03.	Feasibility Study	44
SECTION 5.04.	System Impact Study	46
SECTION 5.05.	Facilities Study	48
ARTICLE 6.	INTERCONNECTION AGREEMENT	50
SECTION 6.01.	Simplified Process	50
SECTION 6.02.	Fast Track and Study Process	50
SECTION 6.03.	Energy Bureau’s Approval for Microgrids Above 5 MW	51
ARTICLE 7.	PROVISIONS THAT APPLY TO ALL INTERCONNECTION APPLICATIONS	51
SECTION 7.01.	Time Frames and Extensions	51
SECTION 7.02.	Non-Warranty	52
SECTION 7.03.	Commissioning, Inspection, Testing, Authorization	53
SECTION 7.04.	Authorization Required Prior to Parallel Operation	54
SECTION 7.05.	Confidentiality	55
SECTION 7.06.	Insurance	55
SECTION 7.07.	Comparability	55
SECTION 7.08.	Design, Procurement, Installation and Construction of Interconnection Facilities and Upgrades	55
SECTION 7.09.	Export Capacity of a Distributed Generation System or Microgrid	58
SECTION 7.10.	Excessive Customer Curtailment Compensation	60
SECTION 7.11.	Proactive Hosting Capacity Planning and Budgeting	62
ARTICLE 8.	TECHNICAL REQUIREMENTS	63

SECTION 8.01.	General Technical Requirements	63
SECTION 8.02.	Approval of Use of Certified Equipment	64
SECTION 8.03.	Meter Socket Adapters.....	65
ARTICLE 9.	NET ENERGY METERING.....	70
SECTION 9.01.	Participation in Net Metering Programs.....	70
SECTION 9.02.	Basic Net Metering Program	71
SECTION 9.03.	Aggregate Net Metering Program	72
SECTION 9.04.	Shared Net Metering Program.....	73
SECTION 9.05.	Energy Compensation for Customers that Participate in the Net Metering Programs	74
ARTICLE 10.	DISPUTE RESOLUTION	76
ARTICLE 11.	PENALTIES	77
ARTICLE 12.	PUBLIC REPORTING AND RECORD RETENTION	78
SECTION 12.01.	Public Queue.....	78
SECTION 12.02.	Quarterly Interconnection Report.....	79
SECTION 12.03.	Record Retention.....	80
ARTICLE 13.	RECONSIDERATION AND JUDICIAL REVIEW	80
SECTION 13.01.	Reconsideration.....	80
SECTION 13.02.	Administrative Review	81
SECTION 13.03.	Judicial Review	81
ARTICLE 1.	GENERAL PROVISIONS.....	1
Section 1.01.	Title — 1	
Section 1.02.	Legal Basis	1
Section 1.03.	Purpose and Executive Summary.....	1
Section 1.04.	Applicability	1
Section 1.05.	Interpretation.....	1
Section 1.06.	Provisions of Other Regulations.....	1
Section 1.07.	Unforeseen Proceedings	2
Section 1.08.	Dates and Time Periods	2
Section 1.09.	Definitions.....	2
Section 1.10.	Controlling Version	13
Section 1.11.	Severability.....	13

~~Section 1.12. Cyber Portal and Forms~~	~~13~~
~~Section 1.13. Mode of Submission.....~~	~~14~~
~~Section 1.14. Effect of Submission~~	~~14~~
~~Section 1.15. Confidential Information.....~~	~~14~~
~~Section 1.16. Validity~~	~~15~~
~~Section 1.17. Compliance with Other Applicable Legal Requirements.....~~	~~15~~
~~ARTICLE 2. INTERCONNECTION APPLICATION PROCESS~~	~~15~~
~~Section 2.01. Process Overview~~	~~15~~
~~Section 2.02. Pre-Application Report and Interconnection Application Filing Mechanisms.....~~	~~16~~
~~Section 2.03. Electronic Signatures~~	~~19~~
~~Section 2.04. Communications~~	~~19~~
~~Section 2.05. Submittal of the Interconnection Application or the Simplified Interconnection Notification.....~~	~~20~~
~~Section 2.06. Modification of the Interconnection Application.....~~	~~21~~
~~Section 2.07. Site Control~~	~~22~~
~~Section 2.08. Queue Position~~	~~22~~
~~ARTICLE 3. DISTRIBUTED GENERATION SYSTEM SIMPLIFIED PROCESS~~	~~23~~
~~ARTICLE 4. DISTRIBUTION SYSTEM FAST TRACK PROCESS~~	~~25~~
~~Section 4.01. Applicability and eligibility requirements~~	~~25~~
~~Section 4.02. Initial Review.....~~	~~26~~
~~Section 4.03. Customer Options Meeting~~	~~29~~
~~Section 4.04. Supplemental Review~~	~~30~~
~~ARTICLE 5. STUDY PROCESS.....~~	~~33~~
~~Section 5.01. Purpose~~	~~33~~
~~Section 5.02. Scoping Meeting.....~~	~~33~~
~~Section 5.03. Feasibility Study.....~~	~~34~~
~~Section 5.04. System Impact Study~~	~~36~~
~~Section 5.05. Facilities Study~~	~~38~~
~~ARTICLE 6. INTERCONNECTION AGREEMENT~~	~~40~~
~~Section 6.01. Simplified Process~~	~~40~~
~~Section 6.02. Fast Track and Study Process.....~~	~~40~~
~~Section 6.03. Energy Bureau's Approval for Microgrids Above 5 MW.....~~	~~41~~

~~ARTICLE 7. PROVISIONS THAT APPLY TO ALL INTERCONNECTION APPLICATIONS~~	~~41~~
~~Section 7.01. Time Frames and Extensions~~	~~41~~
~~Section 7.02. Non-Warranty~~	~~42~~
~~Section 7.03. Commissioning, Inspection, Testing, Authorization~~	~~42~~
~~Section 7.04. Authorization Required Prior to Parallel Operation~~	~~43~~
~~Section 7.05. Confidentiality~~	~~44~~
~~Section 7.06. Insurance~~	~~44~~
~~Section 7.07. Comparability~~	~~44~~
~~Section 7.08. Design, Procurement, Installation and Construction of Interconnection Facilities and Upgrades~~	~~44~~
~~Section 7.09. Export Capacity of a Distributed Generation System or Microgrid~~	~~46~~
~~ARTICLE 8. TECHNICAL REQUIREMENTS~~	~~49~~
~~Section 8.01. General Technical Requirements~~	~~49~~
~~Section 8.02. Approval of Use of Certified Equipment~~	~~50~~
~~ARTICLE 9. NET ENERGY METERING~~	~~51~~
~~Section 9.01. Participation in Net Metering Programs~~	~~51~~
~~Section 9.02. Basic Net Metering Program~~	~~52~~
~~Section 9.03. Aggregate Net Metering Program~~	~~52~~
~~Section 9.04. Shared Net Metering Program~~	~~53~~
~~Section 9.05. Energy Compensation for Customers that Participate in the Net Metering Programs~~	~~54~~
~~ARTICLE 10. DISPUTE RESOLUTION~~	~~55~~
~~ARTICLE 11. PENALTIES~~	~~56~~
~~ARTICLE 12. PUBLIC REPORTING AND RECORD RETENTION~~	~~57~~
~~Section 12.01. Public Queue~~	~~57~~
~~Section 12.02. Annual Interconnection Report~~	~~58~~
~~Section 12.03. Record Retention~~	~~59~~
~~ARTICLE 13. RECONSIDERATION AND JUDICIAL REVIEW~~	~~59~~
~~Section 13.01. Reconsideration~~	~~59~~
~~Section 13.02. Administrative Review~~	~~59~~
~~Section 13.03. Judicial Review~~	~~59~~

ARTICLE 1. GENERAL PROVISIONS

~~Compliance with this Regulation shall relieve no Party affected by this Regulation from complying with other applicable legal and regulatory requirements enforced by any other Government Entity.~~

SECTION 1.01. Title

This Regulation shall be known as the *Distributed Generation System and Microgrid Interconnection Regulation* (“Regulation”).

SECTION 1.02. Legal Basis

The Energy Bureau of the Public Service Regulatory Board (“Energy Bureau”) adopted this Regulation pursuant to Act 82-2010, as amended, known as the *Public Policy on Energy Diversification by Means of Sustainable and Alternative Renewable Energy in Puerto Rico Act*; Act 17-2019, as amended, known as the *Puerto Rico Energy Public Policy Act*; [Act 114-2007, as amended, known as the Puerto Rico Net Metering Act](#); [Joint Resolution 5-2026](#); Act 57-2014, as amended, known as the *Puerto Rico Energy Transformation and RELIEF Act*; and Act 38-2017, known as the *Uniform Administrative Procedures Act of the Government of Puerto Rico* (“LPAU” for its Spanish acronym). This Regulation shall be interpreted and implemented in a manner consistent with the authority granted to the Energy Bureau under the foregoing Acts.

SECTION 1.03. Purpose

The purpose of this Regulation is to establish the regulatory framework governing the interconnection of Generating Facilities and Microgrids to the Electric Power System in Puerto Rico.

This Regulation is intended to promote a safe, reliable, efficient, transparent, and nondiscriminatory interconnection process, while supporting the reliability and operational integrity of the Electric Power System and implementing the public policy established by the laws of Puerto Rico.

SECTION 1.04. Executive Summary

This Regulation establishes the requirements, procedures, technical standards, and responsibilities governing the interconnection of facilities subject to this Regulation to the Electric Power System.

It establishes the respective roles and responsibilities of the Interconnection Customer, the Electric Power System Operator, and other participants in the interconnection process, as well as the applicable technical requirements, procedures, and operational standards.

This Regulation is intended to provide a uniform and transparent framework for the interconnection process while supporting the safe and reliable operation of the Electric Power System.

SECTION 1.05. Cost-Benefit Analysis

The Bureau has evaluated the costs and benefits associated with the adoption of this Regulation and has determined that its benefits outweigh any associated costs.

This Regulation establishes a comprehensive regulatory framework governing the interconnection of Generating Facilities and Microgrids to the Electric Power System. The Bureau finds that the adoption of uniform technical and administrative requirements will promote regulatory certainty, improve administrative efficiency, facilitate the orderly processing of interconnection requests, and support the safe and reliable operation of the Electric Power System.

The Bureau further finds that this Regulation does not impose requirements beyond those reasonably necessary to accomplish its regulatory objectives and to implement the public policy established by the laws of Puerto Rico.

SECTION 1.06. Applicability

This Regulation applies to any Distributed Generation System, including Community Solar, or Microgrid seeking to interconnect to the Electric Power System, except those that only operate independently of the Electric Power System (*i.e.*, not in Parallel Operation). Customers may participate in Net Metering Programs pursuant to of this Regulation and Act 114-2007, known as the Puerto Rico Net Metering Act, as amended.

SECTION 1.07. Interpretation

This Regulation shall be interpreted so it promotes the highest public benefit, consumer protection, and system reliability, and in such a way that proceedings are carried out rapidly, justly, and economically.

SECTION 1.08. Provisions of Other Regulations

This Regulation constitutes the regulatory framework governing the interconnection of Distributed Generation Systems and Microgrids subject to the jurisdiction of the Energy Bureau. Any regulation, tariff, manual, technical requirement, guideline, operating procedure, administrative policy, or other normative document applicable to such interconnections shall be interpreted and implemented in a manner consistent with this Regulation. To the extent any such document is inconsistent with this Regulation, the provisions of this Regulation shall govern.

Without limiting the foregoing, this Regulation governs the interconnection of Distributed Generation Systems and Microgrids, the enrollment of Net Metering Systems, and the installation of Meter Socket Adapters. Any provision of a regulation, technical communiqué, directive, or terms and conditions of service of PREPA or the EPS Operator, including Regulation 7982 and Technical Communiqués 19-02 and 20-01, that is inconsistent with this Regulation as applied to those matters shall not be applied to them.

SECTION 1.09. Unforeseen Proceedings

When a specific proceeding has not been planned for in this Regulation, the Energy Bureau may attend to it in any way that is consistent with Act 114-2007, Act 57-2014, Act 17-2019, and any other applicable laws.

SECTION 1.10. Dates and Time Periods

In computing any time period established in this Regulation, or by Order of the Energy Bureau, the day of the act, event, or noncompliance that triggers the period shall not be counted, and the established period shall begin to elapse on the following calendar day. Whenever a due date falls on a Saturday, Sunday, or legal holiday, said due date shall be extended until the next Business Day. All days if not specifically indicated shall be calculated as calendar days except for periods equal or less than seven (7) which shall be calculated as business days.

SECTION 1.11. Definitions

- A. These definitions are to be used for this Regulation and are not intended to modify the definitions used in any other Energy Bureau Regulation or Order.
- B. For this Regulation, the following terms will have the meaning established below, unless the context of the content of any provision clearly indicates something else:
 - (1) “Aggregate Net Metering Program” – means the extension of the Basic Net Metering Program, created to comply with Amended Order CEPR-MI-2014-0001 of the Puerto Rico Energy Bureau. This program allows a participant to credit the excess energy produced by a Distributed Generation System based on Renewable Energy Sources ~~between~~among service agreements ~~under~~of the same ~~name, located in the same locality as the Distributed Generation System or in different localities~~customer or of entities under common ownership or control with it, located anywhere in the EPS Operator’s service territory, provided that it complies with the conditions set out in Article 9, Section 9.03 of this Regulation.
 - (2) “Basic Net Metering Program” – means the service provided to customers with a Distributed Generation System or Microgrid that use Renewable Energy Sources, interconnected with the EPS, as provided

by Act 114-2007. This service allows for the flow of energy to and from the customer's premises through the billing meter. This system supplies part or all of the electricity consumption in the locality where the system is located. At the end of the billing period, the EPS Operator will charge the customer's net consumption or credit the excess energy exported to the EPS Operator's electric system on their next bill.

- (3) "Billing Period" – means the interval of time between one billing statement date and the next billing statement date. The billing period is the time for which energy use and credits for energy exports are calculated.
- (4) "Business Day" – means Monday through Friday, excluding Federal and local holidays.
- (5) "Cease to Energize" – means the cessation of active power delivery under steady-state and transient conditions and limitation of reactive power exchange. This does not necessarily imply, nor exclude disconnection, isolation, or a Trip. Limited reactive power exchange may continue as specified (*e.g.*, through filter banks).
- (6) "Certified" – means a piece of equipment has been tested in accordance with the applicable requirements of IEEE Std 1547™-2018 and IEEE Std 1547.1™-2020 by any nationally recognized testing laboratory (NRTL) recognized by the United States Occupational Safety and Health Administration to test and certify equipment pursuant to the applicable standard and the equipment has been labeled and is publicly listed by such NRTL at the time of the interconnection application. Equipment installed prior to March 28, 2023 will also be considered certified if it has been tested in accordance with IEEE Std 1547™-2003 and 1547.1™-2005.
- (7) "Community Solar" – means a Distributed Generation System that generates electricity by means of a solar photovoltaic device, and subscribers to the facility receive a bill credit for the electricity generated in proportion to the subscriber's share of the facility's kilowatt-hour output.
- (8) "Confidential Information" - means any confidential and/or proprietary information provided by one Party to the other Party clearly marked or otherwise designated "Confidential." For purposes of this Regulation all design, operating specifications, and Metering data provided by the Interconnection Customer shall be deemed confidential information regardless of whether it is clearly marked or otherwise designated as such. Confidential Information does not include information previously available in the public domain, required to be publicly submitted or

divulged by Governmental Authorities (after notice to the other Party and after exhausting any opportunity to oppose such publication or release), or necessary to be divulged in an action to enforce this Regulation. Each Party receiving Confidential Information shall hold such information in confidence and shall not disclose it to any third party nor to the public without the prior written authorization from the Party providing that information, except to fulfill obligations under this Regulation, or to fulfill legal or regulatory requirements.

- (9) “Credit for Energy Export” – means a credit per kilowatt hour (kWh) for the excess of exported energy during a billing period, in accordance with the rate or compensation mechanism authorized by the Energy Bureau in Act No. 114 of August 16, 2007, as amended. This credit applies for the next billing period.
- (10) “Cyber Portal” or “DG Portal” – means ~~an~~the internet site maintained by the EPS Operator where Parties can electronically submit all documents required by this Regulation, monitor the Simplified Process, Fast Track Process and Study Process, ~~and~~ approve the interconnection, and access the information this Regulation requires the EPS Operator to publish. This site also provides the ability to electronically sign agreements required in this Regulation.
- (11) “Daytime Minimum Load” – means the minimum electrical load on a line section during the hours of 10 a.m. to 4 p.m. (8 a.m. to 6 p.m. for systems using tracking), calculated as gross load by adding the estimated output of Distributed Generation Systems already interconnected to the line section to the measured net load, using the methodology published under Section 7.11.
- ~~(11)~~(12) “Distributed Generation System” – means the device(s) for the production and/or storage of electrical energy, including generators, inverters, protection and control systems, interconnection equipment, and other associated devices, capable of operating in parallel with the Electric Power System. For the purpose of this Regulation, Community Solar is considered a Distributed Generation System. This shall not include the EPS Operator’s Interconnection Facilities.
- ~~(12)~~(13) “Distribution System” – means the physical equipment used to distribute electric power at voltages below 38,000 volts, including but not limited to poles, primary lines, secondary lines, service drops, transformers and Meters.
- ~~(13)~~(14) “Distribution Upgrades” – means the additions, modifications, and upgrades to the Distribution System at or beyond the Point of Common Coupling to facilitate interconnection of the Distributed

Generation System(s) or the Microgrid and render the distribution service necessary to effectuate the connection to the Distribution System. For Microgrids with multiple Generating Facilities connected to the Distribution System, Distribution Upgrades may occur behind the Microgrid Point of Common Coupling. Distribution Upgrades do not include Interconnection Facilities.

~~(14)~~(15) “Electric Power System” or “EPS” – means the Puerto Rico electric power Transmission and Distribution System, excluding equipment owned by Interconnection Customers.

~~(15)~~(16) “Electric Power System Operator” or “EPS Operator” – means the entity that controls or operates the Electric Power System.

~~(16)~~(17) “Energy Bureau” – means the Puerto Rico Energy Bureau, established by virtue of the Reorganization Plan of the Puerto Rico Public Service Regulatory Board, and Act No. 211-2018, known as the *Reorganization Plan Execution Act of the Public Service Regulatory Board*, formerly the Puerto Rico Energy Commission created under Act 57-2014, which is a specialized independent entity in charge of regulating, overseeing, and enforcing the public policy on energy of the Government of Puerto Rico.

~~(17)~~(18) “Energy Storage” – means any commercially available, customer-sited system, including batteries and batteries paired with on-site generation, that is capable of retaining, storing, and delivering electrical energy by chemical, thermal, mechanical, or other means. For the purposes of this Regulation, an Energy Storage system can be considered part of a Distributed Generation System in whole that operates in parallel with the distribution system.

~~(18)~~(19) “Enter Service” – means begin operation of the Distributed Generation System or Microgrid with an energized EPS.

~~(19)~~(20) “Export Capacity” – means the maximum amount of ~~power~~real power, expressed in kilowatts of alternating current (kW AC), that can be transferred from the Distributed Generation System or Microgrid to the Electric Power System ~~in alternating current (AC)~~at the Point of Common Coupling. Export ~~capacity~~Capacity is the Nameplate Rating unless such capacity is limited by an acceptable means as identified in Section 7.09.

~~(20)~~(21) “Fast Track Process” – means the procedures in ~~Article 3~~Article 4 for evaluating an Interconnection Application that meets the eligibility requirements of Section 4.01 and includes the initial review screens, customer options meeting, and optional supplemental review.

~~(21)~~(22) “Force Majeure Event” – means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party’s control. A Force Majeure ~~Event~~Event does not include an act of negligence or intentional wrongdoing.

~~(22)~~(23) “Good Utility Practice” – means the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the time period, or the practices, methods and act which, in exercising reasonable judgment, given the facts known when the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

~~(23)~~(24) “Governmental Authority” or “Government Entity” - means the government of Puerto Rico, any political subdivision thereof, and any agency, authority, instrumentality, regulatory body, board, bureau, court, or other entity exercising executive, legislative, judicial, taxing, regulatory or administrative powers or functions of or pertaining to government.

~~(24)~~(25) “Host Load” - means the electrical power consumed at the interconnection site.

~~(26)~~ “Hosting Capacity” – means the amount of Export Capacity that can be interconnected to a feeder, line section, or service transformer without adversely affecting power quality, reliability, or safety and without requiring Upgrades, as determined and published under Section 7.11.

~~(25)~~(27) “Inadvertent Export” - means the unscheduled export of power exceeding a contractually specified magnitude and for a limited duration.

~~(26)~~(28) “Intentional Island” – means a planned electrical Island capable of being energized by one or more Generating Facilities. These (1) have Distributed Generation System(s) and load, (2) have the ability to disconnect from and to operate in Parallel with the EPS, (3) include one or more customers, and (4) are intentionally planned.

~~(27)~~(29) “Interconnection Agreement” – means the standard form agreement between an Interconnection Customer and the EPS Operator, ~~as well as governing the interconnection and~~ the ongoing

operation of the Distributed Generation System or Microgrid after it is interconnected. For the Simplified Process, the Interconnection Agreement is incorporated into the Simplified ~~Process~~ Interconnection Notification ~~form~~ and Agreement, provided as Attachment X to the Technical ~~Information~~ Interconnection Requirements.

~~(28)~~(30) “Interconnection Application” – means the Interconnection Customer’s request to interconnect a new Distributed Generation System or Microgrid, or to increase the Nameplate Rating of, or make a Material Modification to the operating characteristics of, an existing Distributed Generation System or Microgrid that is interconnected with the Electric Power System.

~~(29)~~(31) “Interconnection Customer” – means any entity or individual, including PREPA, the EPS Operator, their affiliates and subsidiaries, that proposes to interconnect to the Electric Power System.

~~(30)~~(32) “Interconnection Facilities” – means the EPS Operator’s Interconnection Facilities and the Interconnection Customer’s Interconnection Facilities (collectively, “Interconnection Facilities”) which include all facilities and equipment between the Distributed Generation System or Microgrid, and the Electric Power System, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Distributed Generation System and/or Microgrid to the Electric Power System. For Microgrids with multiple Distributed Generation Systems, Interconnection Facilities may occur behind the Microgrid Point of Common Coupling. Interconnection Facilities are facilities used solely by the Interconnection Customer’s Distributed Generation System and shall not include Distribution Upgrades or Network Upgrades.

~~(31)~~(33) “Interconnection Ombudsperson” – means a person appointed by the Energy Bureau to facilitate resolution of disputes regarding the interconnection process and to track and monitor the interconnection process, amongst other duties, as defined by the Energy Bureau.

~~(32)~~(34) “Interconnection Transformer” – means the transformer through which a Distributed Generation System interconnects with the EPS. This may also be the electrical transformer that supplies energy to the Host Load.

~~(33)~~(35) “Island” – means a condition in which a portion of an EPS is energized solely by one or more Generating Facilities while that portion of the EPS is electrically separated from the rest of the EPS on all phases to which the Distributed Generation System is connected. When an Island exists, the Distributed Generation System energizing

the Island may be said to be “Islanding” or “Islanded.” Islands may be Intentional or Unintentional.

~~(34)~~[\(36\)](#) “Limited Export” - means the exporting capability of a Distributed Generation System or Microgrid whose Export Capacity is limited below the Nameplate Rating by any configuration or operating mode described in Section 7.09.

~~(35)~~[\(37\)](#) “Material Modification” – means a modification to machine data or equipment configuration or to the interconnection site after receiving notification by the Electric Power System Operator of a complete Interconnection Application with a material impact on the cost, timing, or design of any Interconnection Facilities or Upgrades, or a material impact on the cost, timing or design of any Interconnection Application with a later queue priority date. A Material Modification shall include, but may not be limited to, a modification from the approved Interconnection Application that: (1) increases the Nameplate Rating, Export Capacity, Operating Profile, or output characteristics of the proposed interconnection; (2) changes or replaces generating equipment, such as generator(s), inverter(s), transformers, relaying, controls, etc., and substitutes equipment that is not a like-kind substitution in certification, size, ratings, impedances, efficiencies or capabilities of the equipment; (3) changes transformer connection(s) or grounding; and/or (4) changes to certified inverters with different specifications or different inverter control specifications or set-up.

A Material Modification shall not include a modification from the approved Interconnection Application that: (1) changes in ownership; (2) changes the address, so long as the proposed interconnection remains on the same parcel(s); (3) changes or replaces generating equipment such as generator(s), inverter(s), solar panel(s), Energy Storage device(s), transformers, relaying, controls, etc. and substitutes equipment that is a like-kind substitution in certification, size, ratings, impedances, efficiencies or capabilities of the equipment; ~~and/or~~ (4) changes the DC/AC ratio but does not increase the maximum AC output capability of the proposed interconnection; [\(5\) incorporates a Meter Socket Adapter approved under Section 8.03; and/or \(6\) adds Energy Storage to an existing Distributed Generation System without increasing its Export Capacity, upon notice to the EPS Operator through the Cyber Portal identifying the equipment and its operating restriction under Section 9.01.C.](#)

~~(36)~~[\(38\)](#) “Meter” or “Metering” – means the equipment or instruments which function is to measure and register the bi-directional flow of

electric energy (*i.e.*, energy delivered and received) by a Distributed Generation System or Microgrid interconnected to the EPS.

~~(37)~~(39) “Meter Socket Adapter” or “MSA”– means a device installed in the existing primary meter socket behind the utility meter at an Interconnection Customer’s premises for the purpose of interconnecting a Distributed Generation System, Energy Storage, standby generation, transfer equipment, electric vehicle supply equipment, or other load and energy-management applications. A Meter Socket Adapter is equipment owned by the Interconnection Customer and is not part of the Electric Power System.

~~(38)~~(40) “Microgrid” – means a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity that can connect and disconnect from the Electric Power System to enable it to operate in either Parallel (grid-connected) or Islanded (off-the-grid) mode. This shall include the Interconnection Customer’s Interconnection Facilities. In some cases, the EPS Operator’s Interconnection Facilities may also be included in the Microgrid.

~~(39)~~(41) “Microgrid Operator” – means the registered operator of a Microgrid, which shall be the primary party responsible for overseeing the operation of the microgrid equipment (including, but not limited to, Distributed Energy Resources and Distribution Infrastructure), providing maintenance, delivering contracted services, billing for such services, and serving as the primary point of contact. The Microgrid Operator may or may not be the owner of the Microgrid.

~~(40)~~(42) “Minor System Modifications” – means modifications to the Electric Power System or other minor system changes that the Electric Power System Operator estimates will entail less than ten (10) hours of work and five thousand dollars (\$5,000) in materials. The Electric Power System Operator may also deem other more substantial work, including the upgrade of transformers, as Minor System Modifications at its discretion.

~~(41)~~(43) “Nameplate Rating” – means the sum total of maximum rated power output of a Distributed Generation System, Community Solar, or Microgrid’s constituent generating units or Energy Storage system, expressed in kilowatts of alternating current (kW AC) as identified on the manufacturer’s nameplate, regardless of whether it is limited by export controls pursuant to Section 7.09 and Section 7.09.A.

~~(42)~~(44) The Nameplate Rating may be distinct from the Export Capacity where a facility uses export controls pursuant to Section 7.09 and Section 7.09.A.

~~(43)~~(45) “Nationally Recognized Testing Laboratory” or “NRTL” – means an accredited laboratory that performs certification tests required by Institute of Electrical and Electronics Engineers and American National Standards Institute (ANSI) standards.

~~(44)~~(46) “Net Consumption” – means the resulting amount from subtracting the Interconnection Customer’s consumed energy from the energy exported to the EPS and credits for energy export, if any. Applied when the energy the Customer consumes is greater than the energy exported and any applicable exported energy credits.

$$C_{net} = kWh_{con} - kWh_{exp} - CR_{exp}$$

Where:

C_{net} = net consumption

kWh_{con} = kWh kilowatt-hours consumed

kWh_{exp} = kWh kilowatt-hours exported

CR_{exp} = credit for energy export (from previous billing period)

~~(45)~~(47) “Net exports” – means the resulting amount when the sum of the energy exported by the Interconnection Customer’s to the EPS and credits for energy export, if any, are subtracted from the energy consumed by the Customer. Applied when the energy consumed by the Customer is less than the sum of the energy exported and any applicable credits for energy exports.

$$E_{net} = kWh_{exp} + CR_{exp} - kWh_{con}$$

Where:

E_{net} = net export

kWh_{con} = kWh kilowatt-hours consumed

kWh_{exp} = kWh kilowatt-hours exported

CR_{exp} = credit for energy export (from previous billing period)

~~(46)~~(48) “Net Metering Program”- means the Basic Net Metering Program established in Act 114-2007; the Aggregate Net Metering

Program established by the Energy Bureau’s Amended Order CEPR-MI-2014-0001; and the Shared Net Metering Program established by the Energy Bureau’s Amended Order CEPR-MI-2014-0001. The rules for these programs are described in Article 9 of this Regulation.

~~(47)~~(49) “Net Metering System” – means a Distributed Generation System or Microgrid based on one or more Renewable Energy Sources that participates in the Basic Net Metering Program, the Aggregate Net Metering Program, or the Shared Net Metering Program.

~~(48)~~(50) “Network Upgrades” – means additions, modifications, and upgrades to the Transmission System to accommodate the interconnection. Network Upgrades are at or beyond the Point of Common Coupling. Network Upgrades do not include Distribution Upgrades.

~~(49)~~(51) “Non-Export” or “Non-Exporting” - means the Distributed Generation System or Microgrid is sized and designed using any of the methods identified for non-export in Section 7.09 and Section 7.09.A, such that the output is used for Host Load only and no electrical energy (except for any Inadvertent Export) is transferred from the Distributed Generation System or Microgrid to the Electric Power System.

~~(50)~~(52) “Operating Profile” - means how the Distributed Generation System or Microgrid is designed to be operated, as designated in the Interconnection Application, including the amount of export, the times of year, hours of the day and other relevant conditions.

~~(51)~~(53) “Operator” – means any natural or legal person responsible for the interconnection, operation, and/or maintenance of a Distributed Generation System or Microgrid.

~~(52)~~(54) “Parallel Operation” – means the simultaneous operation of the Distributed Generation System or Microgrid such that power can be transferred across the Point of Common Coupling from or to the Electric Power System. This is also referred to as operating in “grid connected” mode, operating in parallel, or paralleling.

~~(53)~~(55) “Party” or “Parties” – means the Electric Power System Operator and the Interconnection Customer, individually or collectively, as applicable.

~~(54)~~(56) “Point of Common Coupling” or “PCC” – means the point of connection between the Distributed Generation System or Microgrid and the Electric Power System.

~~(55)~~(57) “Power Control System” – means systems or devices which electronically limit or control the steady state AC currents, or DC currents, to a programmable limit or level.

~~(56)~~(58) “Puerto Rico Electric Power Authority” or “PREPA” – means the Puerto Rico Electric Power Authority, a corporate entity created by virtue of Act No. 83 of May 2, 1941, as amended, known as the *Puerto Rico Electric Power Authority Act* (“Act 83-1941”), and any of its affiliates or subsidiaries.

~~(57)~~(59) “Pre-Application Report” – means the report issued by the EPS Operator under Section 2.02 of this Regulation.

~~(58)~~(60) “Queue Position” – means the sequential order of a valid Interconnection Application, relative to all other pending valid Interconnection Applications, that is established based upon the date and time of receipt of the valid Interconnection Application by the EPS Operator.

~~(59)~~(61) “Reasonable Efforts” – means regarding an action required to be attempted or taken by a Party under this Regulation, efforts timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

~~(60)~~(62) “Renewable Energy” – means “sustainable renewable energy,” “alternative renewable energy,” and “distributed renewable energy,” jointly, as such terms are defined in Act No. 82-2010, as amended, known as the *Public Policy on Energy Diversification by Means of Sustainable and Alternative Renewable Energy in Puerto Rico Act*.”

~~(61)~~(63) “Return to Service” – means the reentry into service following recovery from a Trip.

~~(62)~~(64) “Shared Net Metering Program” – means the extension of the Basic Net Metering Program, created to comply with the Energy Bureau’s Amended Order CEPR-MI-2014-0001. This permits the use of renewable energy produced by a single Distributed Generation System based on Renewable Energy Sources among multiple participants whose service agreements are located ~~in~~at the same ~~locality~~premises as the Distributed Generation System, provided that it complies with the conditions set forth in Article 9, Section 9.04 of this Regulation.

~~(63)~~(65) “Simplified Interconnection Notification” – means the form submitted to the EPS Operator by Interconnection Customers with Distributed Generation Systems qualifying for the Distributed Generation System Simplified Process found in Article 3.

(66) “Simplified Interconnection Fee” – means the single, all-inclusive fee established in Article 3.B.

~~(64)~~(67) “Simplified Process” – means the expedited procedure for evaluating an Simplified Interconnection Notification available to small inverter-based systems that interconnect to the Distribution System. The eligibility requirements are found in Article 3 and the Simplified Interconnection Notification and Agreement is found in Attachment X of the Technical Interconnection Requirements.

~~(65)~~(68) “Small inverter based system” – means an inverter-based Distributed Generation System with ~~a Nameplate Rating of 50 kW or less, and~~ an Export Capacity of 25 kW or less.

~~(66)~~(69) “Subscriber” – means a customer of the EPS Operator that: (i) holds a subscription to a community solar energy generating system; and (ii) has identified one or more individual meters or accounts to which the subscription shall be attributed.

~~(67)~~(70) “Study Process” – means the procedure for evaluating an Interconnection Application that includes the scoping meeting, the system impact study, and the facilities study established under Article 5 of this Regulation.

~~(68)~~(71) “Technical Interconnection Requirements” or “TIR” – means the technical document prepared by the EPS Operator pursuant to this Regulation, establishing the engineering, operational, protection, communications, interoperability, metering, commissioning, testing, safety, and other technical requirements applicable to interconnections governed by this Regulation. The TIR shall be subject to the review and approval of the Energy Bureau through Resolution and Order issued under the applicable docket and shall not amend, modify, supersede, or conflict with this Regulation..

~~(69)~~(72) “Transmission System” – means the facilities used to provide subtransmission (38kV) and transmission (115kV) service.

~~(70)~~(73) “Trip” – means inhibition of immediate Return to Service, which may involve disconnection. Trip executes or is subsequent to Cessation of Energization.

~~(71)~~(74) “Unintentional Island” – means an unplanned Island event.

~~(72)~~(75) “Upgrades” – means the required additions and modifications to the Electric Power System. For an application to interconnect, Upgrades must be at or on the Electric Power System side of the Point Common Coupling. Upgrades may be Network Upgrades or

Distribution Upgrades. Upgrades do not include Interconnection Facilities.

~~(73)~~(76) “Voltage Flicker” - means a voltage fluctuation or instability in the EPS that can cause changes in lighting, damage equipment, or that may adversely affect the quality of customer’s electric service.

SECTION 1.12. Controlling Version

Should any discrepancy between the Spanish version and the English version of this Regulation arise, the English version shall prevail.

SECTION 1.13. Severability

If any article, provision, word, sentence, paragraph, subsection, or section of this Regulation is disputed before a court and declared unconstitutional or null and void, such ruling shall not affect, damage, or invalidate the remaining provisions of this Regulation, rather the effect shall be limited to the article, provision, word, sentence, paragraph, subsection, or section declared unconstitutional or null and void. The nullity or invalidity of any article, word, sentence, paragraph, subsection, or section, in any specific case, shall not affect or jeopardize in any way its application or validity in any other case, unless it has been specifically and expressly invalidated for all cases.

SECTION 1.14. Cyber Portal and Forms

The Energy Bureau, with the recommendation of the EPS Operator, shall establish the forms (printed or electronic) it deems necessary to conduct the proceedings pursuant to this Regulation and shall timely inform the public via its website and/or the EPS Operator’s website, as applicable.

The EPS Operator shall commence the operations of the Cyber Portal required under this Regulation on or before one-hundred eighty (180) calendar days from the effective date of this Regulation. Until the commencement of operations of the Cyber Portal, the filing, processing and notification of any document required under this Regulation will be executed by the Parties using the EPS Operator’s existing online portal at the time of adoption of this Regulation, to the extent practical.

Consistent with the foregoing, the EPS Operator shall submit to the Energy Bureau for evaluation and approval, the Cyber Portal before its commencement of operations. The fact that the Energy Bureau has not approved or adopted one or more forms, including the Cyber Portal, is reviewing them, or the Internet website is out of service, shall relieve no party of its obligation to comply with the provisions stated, provide the information required by this Regulation, or otherwise comply with any Energy Bureau Order.

Accordingly, these forms will be proposed by the EPS Operator to the Energy Bureau and will be adopted as reviewed and approved by the Energy Bureau and may be revised from time to time as proposed by the EPS Operator, subject to the review and approval of

the Energy Bureau. The EPS Operator will provide public notice of any revised or new form at least forty-five (45) days prior to requiring the use of the form.

SECTION 1.15. Mode of Submission

The forms, documents, and appearances required by this Regulation or any Order of the Energy Bureau must be submitted to the EPS Operator as applicable in electronic format according to the instructions which, from time to time, the EPS Operator publishes on its website.

If the electronic filing system is temporarily not operating or functioning, the forms, documents, and appearances required by this Regulation or by any Order of the Energy Bureau shall be submitted to the EPS Operator in accordance with any instructions the Energy Bureau shall provide through an Order from time to time.

SECTION 1.16. Effect of Submission

In filing any document with the EPS Operator, the party undersigning such document shall be deemed to have certified that the content of the document is true and that, according to the signer's best knowledge, information, and belief, formed after reasonable inquiry, the document is based on reliable and trustworthy facts, arguments, judicial sources, and information.

SECTION 1.17. Confidential Information

If in compliance with the provisions of this Regulation or any of the Energy Bureau's Orders, a Party has the duty to disclose information to the Energy Bureau considered to be confidential, a commercial or industrial secret under Act 80-2011, known as the *Puerto Rico Trade Secrets Act*, or privileged, pursuant to applicable evidentiary privileges, said Party shall identify the alleged privileged information and request in writing for the Energy Bureau to treat such information as confidential, pursuant to Article 6.15 of Act 57-2014. In identifying privileged information and requesting confidential treatment by the Energy Bureau, the requesting party shall follow the rules and procedures established by the Energy Bureau in Resolution CEPR-MI-2016-0009¹, as such resolution may be amended from time to time, for the filing, handling, and treatment of confidential information. Except with information protected under the attorney-client privilege, the claim of confidential treatment shall, under no circumstances, be grounds for denying such information from being filed with the Energy Bureau.

¹ See, In re: Policy on Management of Confidential Information in Procedures Before the Commission, Case No.: CEPR-MI-2016-0009, August 31, 2016.

SECTION 1.18. Validity

Pursuant to Section 2.8 of LPAU, this Regulation shall enter into effect thirty (30) days after its submission to the Puerto Rico Department of State and the Legislative Library of the Office of Legislative Services.

SECTION 1.19. Compliance with Other Applicable Legal Requirements

Compliance with this Regulation shall relieve no Party affected by this Regulation from complying with other applicable legal and regulatory requirements enforced by any other Government Entity.

SECTION 1.20. Repeal and Transition

Regulations 8915 and 8916 are repealed as of the effective date of this Regulation. Interconnection agreements executed under those regulations, and the net metering enrollment of systems interconnected under them, remain in effect and are not subject to re-application, re-study, or new fees under this Regulation. Interconnection Applications and notifications pending on the effective date shall be processed under this Regulation without loss of Queue Position, and any deadline in this Regulation shall run from the effective date for those pending matters.

The EPS Operator shall implement the forms, Cyber Portal functions, and billing changes required by Article 3 and Section 9.02 no later than ninety (90) days after the effective date of this Regulation. During that period, Simplified Interconnection Notifications shall be received through the means in use on the day before the effective date, and the Simplified Interconnection Fee shall apply as provided in Article 3.B(1). The rights of Interconnection Customers under Article 3.C(3) and Section 9.02.B apply from the effective date and are not conditioned on that implementation.

ARTICLE 2. INTERCONNECTION APPLICATION PROCESS

SECTION 2.01. Process Overview

There are three paths for interconnection of Distributed Generation Systems and Community Solar in Puerto Rico.

- A. Simplified Process: This is for small inverter-based systems that meet the eligibility criteria in Article 3 and the combined Simplified Interconnection Notification and Agreement contained in Attachment X of the TIR.
- B. Fast Track Process: This is available to an Interconnection Customer proposing to interconnect a certified system with the Distribution System, if the proposed interconnection does not exceed the size limits and other eligibility requirements identified in Section 4.01.B. The Fast Track Process includes the optional supplemental review.

- C. Study Process: This is for all applications to interconnect that do not meet the eligibility requirements for either the Simplified or Fast Track Process. Such applications shall be evaluated under the Study Process in Article 5. The Study Process may include a feasibility study, a system impact study, a Transmission System impact study, and a facilities study.

For Microgrids with a Nameplate Capacity above five (5) MW, Interconnection Customers must apply to interconnect to the Transmission System and must be approved by the Energy Bureau in a process that includes citizen participation in Section 6.03.

SECTION 2.02. Pre-Application Report and Interconnection Application Filing Mechanisms

Interconnection Customers may request a Pre-Application Report to acquire information about system conditions at their proposed Point of Interconnection without submitting a full Interconnection Application. Interconnection Customers shall submit all Pre-Application Report requests and Interconnection Applications through the Cyber Portal. Pre-Application Report requests are generally not applicable to Small Inverter-based Systems.

- A. Besides the information described in Section 2.04, which may be provided in response to an informal request, an Interconnection Customer may submit a formal written request form along with a non-refundable fee of three hundred dollars (\$300.00) for a Pre-Application Report on a proposed project at a specific site.
- B. The EPS Operator shall provide the Pre-Application Report described in Section 2.02.G to the Interconnection Customer within ten (10) Business Days of receipt of the completed request form.
- C. The Pre-Application Report produced by the EPS Operator is non-binding, confers no rights, and the Interconnection Customer must still apply to interconnect to the Electric Power System.
- D. The written Pre-Application Report request form shall include the information in Section 2.02.E to clearly and sufficiently identify the location of the proposed Point of Common Coupling .
- E. The Pre-Application Report request shall include the following information:
 - (1) Project contact information, including name, address, phone number, and email address;
 - (2) Project location (street address(es) with nearby cross streets and town, or place registered with the Property Registry Office);

- (3) Meter number, pole number, or other equivalent information identifying proposed Point of Common Coupling(s), if available;
 - (4) For Microgrids, Microgrid type (*e.g.*, Personal, Cooperative, Third-Party);
 - (5) Distributed Generation type(s) (*e.g.*, solar, wind, combined heat and power, etc.);
 - (6) Whether the Distributed Generation System or Microgrid is paired with Energy Storage;
 - (7) Nameplate Rating and Export Capacity (*i.e.*, alternating current kW);
 - (8) Single or three phase generator configuration; and
 - (9) Whether new service is requested. If there is existing service, include the customer account number(s), site minimum, and maximum current or proposed electric loads in kW (if available) and specify if the load is expected to change.
- F. Using the information provided in the Pre-Application Report request form, the EPS Operator will use best efforts to identify the substation/area bus, bank, or circuit likely to serve the proposed Point of Common Coupling. If any information required to be provided to the Interconnection Customer is considered Confidential Information, then an NDA will need to be signed with the Interconnection Customer or that information will not be provided. This selection by the EPS Operator does not necessarily indicate, after application of the screens and/or study, this would be the circuit the project ultimately connects to. The Interconnection Customer must request additional Pre-Application Reports if information about multiple Points of Common Coupling is requested. If any information required to be provided to the Interconnection Customer is considered Confidential Information, then the Interconnection Customer will be required to sign a Non-Disclosure Agreement in order to receive the required information.
- G. Within ten (10) Business Days of receipt of a completed Pre-Application Report Request, the Utility shall provide a Pre-Application Report to the Applicant. Subject to Section 2.02.H, the Pre-application Report shall include the following information, if available:
- (1) Total capacity (in megawatts (MW)) of substation/area bus, bank or circuit based on normal or operating ratings likely to serve the proposed Point of Common Coupling.
 - (2) Existing aggregate Nameplate Rating and Export Capacity (in MW) interconnected to a substation/area bus, bank or circuit (*i.e.*, amount of

generation online) likely to serve the proposed Point of Common Coupling.

- (3) Aggregate queued Nameplate Rating and Export Capacity (in MW) for a substation/area bus, bank or circuit (*i.e.*, amount of generation in the queue) likely to serve the proposed Point of Common Coupling.
- (4) Available Nameplate Rating and Export Capacity (in MW) of substation/area bus or bank and circuit likely to serve the proposed Point of Common Coupling (*i.e.*, total capacity less the sum of existing aggregate Export Capacity and aggregate queued Export Capacity).
- (5) Substation nominal distribution voltage and/or transmission nominal voltage if applicable.
- (6) Nominal circuit voltage at the proposed Point of Common Coupling.
- (7) Approximate circuit distance between the proposed Point of Common Coupling and the substation.
- (8) Relevant line section(s) actual or estimated peak load and minimum load data, including ~~daytime minimum load as described in Section 4.04.C(1) below~~Daytime Minimum Load as described in Section 4.04.C(2) and published under Section 7.11, and absolute minimum load, when available.
- (9) Number, type and rating of protective devices, and number, type and rating (standard, bi-directional) of voltage regulating devices between the proposed Point of Common Coupling and the substation/area. Identify whether the substation has a load tap changer.
- (10) Number of phases available at the proposed Point of Common Coupling. If only a single phase is available, specify the distance from the three-phase circuit.
- (11) Limiting conductor ratings from the proposed Point of Common Coupling to the distribution substation.
- (12) Whether the Point of Common Coupling is located on a spot network, grid network, or radial supply.
- (13) Based on the proposed Point of Common Coupling, existing or known constraints such as, but not limited to, electrical dependencies at that location, short circuit interrupting capacity issues, power quality or stability issues on the circuit, capacity constraints, or secondary networks.

- H. The Pre-Application Report need only include existing data. A Pre-Application Report request does not bind the EPS Operator to conduct a study or other analysis of the proposed generator in the event that data is not readily available. If the EPS Operator cannot complete all or some of a Pre-Application Report due to lack of available data, the EPS Operator shall provide the Interconnection Customer with a Pre-Application Report that includes the data that is available and shall list what additional data is not provided, if any. The provision of information on “available capacity” pursuant to Section 2.02.G(4) does not imply that an interconnection up to this level may be completed without impacts since there are many variables studied as part of the interconnection review process, and data provided in the Pre-Application Report may become outdated at the time of the submission of the complete Interconnection Application. Notwithstanding the provisions of this section, the EPS Operator shall, in good faith, include data in the Pre-Application Report that represents the best available information at the time of reporting.
- I. Once the Pre-Application Report is conducted for a particular substation, area bus, bank, or circuit, the EPS Operator will publish all relevant generation information, grid data, and reports in a publicly accessible location on its website within 30 days. Confidential customer information, and any other information deemed confidential by the EPS Operator or customer, shall be redacted.

SECTION 2.03. Electronic Signatures

All required applications, agreements and forms must be signed using electronic signatures. Electronic signatures must have a digital audit trail or an image of the signature with timestamp.

SECTION 2.04. Communications

- A. The EPS Operator shall designate an Interconnection Coordinator(s), and this person or persons shall serve as a single point of contact from which information on the status of an application process can be obtained, other than the information provided by the Cyber Portal.
- B. The name, telephone number, and e-mail address of such contact employee or office shall be made available on the EPS Operator’s website.
- C. The EPS Operator may have several Interconnection Coordinators assigned, based on the geographical size of its electrical service territory and/or the amount of Interconnection Applications.
- D. The Interconnection Coordinator(s) shall be available to answer questions, connect Interconnection Customers with persons who can address and resolve questions, and otherwise help facilitate communication with the EPS Operator about the status of the Interconnection Application.

- E. Upon request, EPS information provided to the Interconnection Customer should include materials useful to an understanding of an interconnection at a particular point on the EPS, including system studies, interconnection studies, workpapers, and supporting documentation (*i.e.*, relevant power flow, short circuit and stability databases), to the extent such provision does not violate confidentiality provisions of prior agreements or critical infrastructure requirements.
- F. Upon request of either party, the EPS Operator and the Interconnection Customer shall each identify one (1) point of contact with technical expertise for their respective organizations.
- G. Upon the request of either party, status calls could be established every other week.

SECTION 2.05. Submittal of the Interconnection Application or the Simplified Interconnection Notification

- A. The Interconnection Customer shall submit its Interconnection Application (Attachment X of the TIR) or Simplified Interconnection Notification and Agreement (Attachment X of the TIR) to the EPS Operator, together with the applicable processing fee or deposit specified in the Interconnection Application or Simplified Interconnection Notification. Additional fees or deposits shall not be required, except as otherwise specified in this Regulation or by an Energy Bureau Order.
- B. The Interconnection Application shall be date- and time-stamped upon receipt by the EPS Operator. The original date- and time-stamp applied to the Interconnection Application at the time of its original complete submission shall be accepted as the qualifying date- and time-stamp for the purposes of any timetable in this Regulation.
- C. The Interconnection Customer shall be notified of receipt by the EPS Operator within one (1) Business Day of receiving the Interconnection Application; this may be an automatic e-mail that includes the date and time stamped on the Interconnection Application.
- D. For Interconnection Customers using the Simplified Interconnection Notification and Agreement, the EPS Operator shall notify the Interconnection Customer within five (5) Business Days of receiving the Simplified Interconnection Notification whether the Simplified Interconnection Notification is complete. If the EPS Operator does not so notify the Interconnection Customer within five (5) Business Days, the Simplified Interconnection Notification shall be deemed complete. If the Interconnection Notification is incomplete, the EPS Operator shall provide, along with the notice that the Interconnection Notification is incomplete, a written list detailing all information that must be provided to complete the Interconnection

Notification. The Interconnection Customer will have five (5) Business Days after receipt of the notice to submit the listed information. The EPS Operator shall review the additional material and notify the Interconnection Customer that the Interconnection Notification is complete within five (5) Business Days. If the Interconnection Customer does not provide the listed information within the deadline, ~~the Interconnection Notification will be deemed withdrawn, unless by mutual agreement of the Interconnection Customers and the EPS Operator this deadline is extended~~enrollment in the Net Metering Program under Section 9.02 shall be suspended until the information is provided; the operation of a system certified under Article 3.C(3) shall not be affected.

- E. For Interconnection Customers using the Interconnection Application, the EPS Operator shall notify the Interconnection Customer within five (5) Business Days of receiving the Interconnection Application whether the Interconnection Application is complete. If the EPS Operator does not so notify the Interconnection Customer within five (5) Business Days, the Interconnection Application shall be deemed complete. If the Interconnection Application is incomplete, the EPS Operator shall provide, along with the notice that the Interconnection Application is incomplete, a written list detailing all information that must be provided to complete the Interconnection Application. The Interconnection Customer will have ten (10) Business Days after receipt of the notice to submit the listed information. The EPS Operator shall have an additional five (5) Business Days to review the additional material and notify the Interconnection Customer that the Interconnection Application is complete. If the Interconnection Customer does not provide the listed information within the deadline, the Interconnection Application will be deemed withdrawn, unless by mutual agreement of the Interconnection Customers and the EPS Operator this deadline is extended.
- F. An Interconnection Application will be deemed complete, not approved, upon the correct submission of all of the listed information or documentation to the EPS Operator.

SECTION 2.06. Modification of the Interconnection Application

- A. At any time, including after receiving Simplified Process, Fast Track, supplemental review, feasibility, system impact, and/or facilities study results, the Interconnection Customer or the EPS Operator may identify modifications to the planned interconnection that may improve the costs and benefits (including reliability) of the interconnection, and/or the ability of the EPS Operator to accommodate the interconnection. The Interconnection Customer shall submit to the EPS Operator, in writing, all proposed modifications to any information provided in the Interconnection Application.
- B. Within ten (10) Business Days of receipt of a proposed modification, the EPS Operator shall evaluate whether a proposed modification constitutes a Material

Modification and notify the Interconnection Customer in writing. If the EPS Operator does not so notify the Interconnection Customer within that period, the modification shall be deemed not to be a Material Modification.

- C. If the proposed modification is determined to be a Material Modification, then the EPS Operator shall notify the Interconnection Customer in writing that the Interconnection Customer may: (1) withdraw the proposed modification; or (2) proceed with a new Interconnection Application for such modification. The Interconnection Customer shall notify the EPS Operator of its determination in writing within ten (10) Business Days after being provided the Material Modification determination results. If the Interconnection Customer does not provide its determination, the Interconnection Customer's Application shall be deemed withdrawn.
- D. If the proposed modification is determined not to be a Material Modification, then the EPS Operator shall notify the Interconnection Customer in writing that the modification has been accepted and that the Interconnection Customer shall retain its eligibility for interconnection, including its place in the interconnection queue.
- E. Any dispute as to the EPS Operator's determination that a modification constitutes a Material Modification shall proceed in accordance with Article 10 of this Regulation.
- F. Any modifications to an Interconnection Application not agreed to in writing by the EPS Operator and the Interconnection Customer may be deemed a withdrawal of the Interconnection Application and may require submission of a new Interconnection Application. The EPS Operator shall notify the Interconnection Customer within five (5) Business Days of deeming the Interconnection Application as withdrawn.

SECTION 2.07. Site Control

The Interconnection Application must include evidence of site control. Site control may be demonstrated through the following:

- A. Ownership of, a leasehold interest in, or a right to develop a site or sites for the purpose of constructing the Distributed Generation System or Microgrid. Documents that show ownership of, a leasehold interest in, or a right to develop a site, listing deed, lease, purchase agreement, option, concession, or license are acceptable. In the case of a Fast Track application, the applicant may submit a sworn statement from the property owner when the applicant resides there under a lease agreement;
- B. An option to purchase or acquire a leasehold site(s) for such purpose; or

- C. An exclusivity or other business relationship between the Interconnection Customer and the entity having the right to sell, lease, or grant the Interconnection Customer the right to possess or occupy a site(s) for such purpose.

SECTION 2.08. Queue Position

- A. The EPS Operator shall assign the Interconnection Application a Queue Position based upon the date- and time-stamp of when it is deemed complete under Section 2.05.
- B. The Queue Position of each Interconnection Application will be used to determine the cost responsibility for the Upgrades required to accommodate the interconnection. The EPS Operator shall maintain a single sequential queue.
- C. Subject to the provisions of Section 2.02, Section 2.05, and Section 2.06, Interconnection Customers shall retain the Queue Position assigned to their initial Interconnection Application throughout the review process, including when moving through the processes covered by Article 3, Article 4, and Article 5.
- D. If a Distributed Generation System has a prior Queue Position and is now seeking to join or convert to a Microgrid then the prior Queue Position will be abandoned in favor of the Queue Position of the Microgrid. Queue position shall not be transferred to a different proponent, project, or application.

ARTICLE 3. DISTRIBUTED GENERATION SYSTEM SIMPLIFIED PROCESS

- A. Eligibility
 - (1) The Simplified Process is available to Interconnection Customers for inverter-based Distributed Generation Systems with ~~a Nameplate Rating~~ an Export Capacity of 25 kW or less, ~~and who submit the Simplified Interconnection Notification and Agreement~~ measured in kilowatts of real power (kW AC) at the Point of Common Coupling, that submit the Simplified Interconnection Notification and Agreement. For a Distributed Generation System paired with Energy Storage, including an Energy Storage Device with an integrated inverter, eligibility is determined by the system's Export Capacity at the Point of Common Coupling, not by the Nameplate Rating of the generating source or the energy capacity (kWh) of the Energy Storage.
 - (2) A proposed Distributed Generation ~~system~~ System is eligible for the Simplified Process only if the following requirements are satisfied, as certified under Article 3.C(3):
 - (i) Have a single Point of Common Coupling;

- (ii) Have a Point of Common Coupling on a radial distribution circuit, or a spot network serving one customer;
- (iii) Have no more than one service drop;
- (iv) The system is inverter-based and uses Certified ~~Equipment~~equipment meeting the applicable standards identified in Section 8.02 of this Regulation and the TIR;
- (v) The Point of Common Coupling is located on the Distribution System at secondary voltage, including 120/240 V single-phase, 120/208 V three-phase, 277/480 V three-phase, or another secondary voltage expressly permitted by the TIR;
- ~~(vi) Be certified in accordance with Article 8 of this Regulation; and~~
- ~~(vii)~~(vi) Meet the technical requirements in ~~Error! Reference source not found.~~Article 8 as well as the codes, standards, and certification requirements of Attachment X of the TIR. The use of a Meter Socket Adapter approved under Section 8.03 shall not cause an interconnection to fail any requirement of this Section.

B. Fees

- (1) The Simplified Interconnection Notification and Agreement shall be accompanied by the ~~submission of a nonrefundable fee in an amount established in the TIR and approved by the Energy Bureau~~Simplified Interconnection Fee, paid by the Interconnection Customer or by the company installing the system on the Interconnection Customer's behalf. The initial amount of the Simplified Interconnection Fee is [three hundred dollars (\$300), or such other amount as the Energy Bureau determines in this rulemaking proceeding, to be modified, if at all, after conclusion of the Technical Interconnection Requirements process], which applies to systems whose Simplified Interconnection Notification and Agreement is submitted on or after the date on which the EPS Operator implements the Simplified Process under this Article, including the forms, Cyber Portal functions, and billing changes it requires, which shall be no later than the ninetieth (90th) day after the effective date of this Regulation (Section 1.20); the fee in effect on the day before the effective date applies until then. The initial amount may be modified in the initial Technical Interconnection Requirements approved by the Energy Bureau under Section 8.01 after this Regulation is published, and thereafter only as provided in paragraph (5). The Simplified Interconnection Fee is the sole and complete financial obligation of the Interconnection Customer for the

interconnection of the system, including administration, any review or study, any Distribution Upgrades, and the installation or configuration of the Meter. No other fee, deposit, or charge shall be assessed for a system under the Simplified Process.

- (2) The Simplified Interconnection Fee is intended to:
- (i) Provide a predictable, equitable mechanism for funding the Distribution System—Upgrades reasonably necessary to accommodate the cumulative interconnection of multiple Distributed Generation Systems of 25 kW or less on the same service transformer, secondary, circuit, or feeder, or Distribution System segment; and administrative costs and the EPS Operator’s administrative costs of the Simplified Process; and
 - (ii) Avoid assigning ~~the full cost of Distribution System modifications to any~~any Distribution Upgrade cost to an individual Interconnection Customer under the Simplified Process.
- (3) The EPS Operator shall deposit all revenues collected from the Simplified Interconnection Fee into a segregated account under its control (the “Reserve Fund”) and shall ~~allocate the fee exclusively towards Distribution System Upgrades, administrative costs, and any supplemental studies triggered by the interconnection of Distributed Generation Systems 25 kW or less~~use the Reserve Fund exclusively for (i) Service Upgrades, meaning Distribution Upgrades limited to the service transformer that serves the Interconnection Customer’s Point of Common Coupling, the secondary conductors and service drop between that service transformer and the Interconnection Customer’s Meter, and the fuse or other protective device installed on that service transformer or on those secondary conductors, and excluding any facility on the primary distribution system or otherwise upstream of that service transformer, such as primary conductors, voltage regulators, capacitor banks, reclosers, feeder equipment, and substations; (ii) the administrative costs of the Simplified Process; and (iii) any post-interconnection review or Supplemental Review of systems under this Article. Upgrades to primary feeders, substations, and other facilities upstream of the service transformer shall be planned and funded under Section 7.11 and shall not be charged to the Reserve Fund. The Reserve Fund is subject to audit by the Energy Bureau.
- (4) ~~The EPS Operator shall not assign the full cost of a Distribution System Upgrade to an individual Interconnection Customer solely because that~~

~~customer's Distributed Generation System, either alone or in combination with other Distributed Generation Systems of 25 kW or less, causes or contributes to the need for the upgrade. Any allocation of such costs shall be consistent with applicable statutory requirements and the principles of reasonableness, proportionality, and benefit received.~~In accordance with Section 9(c) of Act 114-2007, as amended, and Section 2 of Joint Resolution 5-2026, the Simplified Interconnection Fee constitutes the contribution of the requesting company to the improvements or changes to the feeder associated with the interconnection of Distributed Generation Systems of 25 kW or less, determined in accordance with the principles of reasonableness, proportionality, and benefit received. The EPS Operator shall not assign the cost of any Distribution Upgrade, in whole or in part, to an individual Interconnection Customer under the Simplified Process, whether the need for the upgrade arises from that customer's system alone or in combination with other systems, and shall not condition the interconnection, operation, export, or Net Metering enrollment of such a system on the payment of any such cost.

- (5) ~~The Fee shall be reviewed by the EPS Operator and may be adjusted no more frequently than every twelve (12) months in the TIR as approved by the Energy Bureau, based on~~After the initial Technical Interconnection Requirements are approved, the amount of the Simplified Interconnection Fee shall be re-evaluated every three (3) years. The Energy Bureau may re-evaluate it at any other time, on its own motion or on a petition by the EPS Operator, only in extraordinary circumstances. The amount may be changed only by Resolution and Order of the Energy Bureau after notice and a period of not less than thirty (30) days for stakeholder comment, on the basis of the EPS Operator's filing of:

~~the actual aggregate cost of the Distribution System Upgrades attributable to Distributed Generation Systems 25 kW or less incurred by the EPS Operator during the preceding period; number and cost of any supplemental studies; and administrative costs.~~

- (i) ~~the number of Customer interconnection applications for Distributed Generation Systems 25 kW or less received during the preceding period; and~~actual aggregate cost of the Service Upgrades paid from the Reserve Fund during the preceding period, itemized by circuit or feeder and type of Upgrade;
- (ii) ~~the balance, if any, remaining in the Reserve Fund.~~number of Simplified Interconnection Notifications received during the preceding period and the administrative and review costs incurred; and

(iii) the balance remaining in the Reserve Fund. Any surplus in the Reserve Fund in excess of the projected requirements for the following period shall be applied to reduce the fee; any shortfall shall be recovered only prospectively through an adjusted fee.

(6) The EPS Operator shall report on the ~~fees collected and usage of such fees~~Simplified Interconnection Fees collected and the use of the Reserve Fund as part of the ~~Biannual~~Quarterly Interconnection Report in accordance with Section 12.02, including the total fees collected; the Service Upgrade costs paid from the Reserve Fund, by circuit or feeder; the number of interconnections completed under the Simplified Process; and the Reserve Fund's ending balance.

~~(7) The EPS Operator shall report on the total Simplified Interconnection Fees collected; Distribution System Upgrade costs paid from the Reserve Fund, by circuit or feeder; the number of interconnections completed for Distributed Generation Systems 25 kW or less; and the Fund's ending balance.~~

C. Interconnection Process

(1) The Interconnection Customer submits a Simplified Interconnection Notification and Agreement to the EPS Operator ~~(Attachment *)~~through the Cyber Portal (Attachment X of the TIR) after the certification described in paragraph (3).

(2) Receipt of the Simplified Interconnection Notification and Agreement and the ~~applicable fee~~Simplified Interconnection Fee will start the process of enrollment in Basic Net Metering described in Section 9.02.

(3) Upon certification by ~~a professional engineer or expert electrician meeting~~a licensed electrical engineer or licensed expert electrician meeting the requirements of Act No. 114-2007, as amended, that the Distributed Generation System complies with the applicable requirements of Article 3.A, the system ~~may begin operating~~shall be deemed interconnected and may begin operating, including Parallel Operation and export, in accordance with Section 9 of Act No. 114-2007. No countersignature, screening result, review, inspection, meter installation or configuration, or Queue Position shall be a precondition to the operation of the system or to its enrollment in the Net Metering Program under Section 9.02.

(4) To ensure the ~~reliably~~reliability and safety of the EPS, the EPS Operator may conduct a post-interconnection review within fifteen (15) Business Days after receipt of the Simplified Interconnection Notification and Agreement ~~to verify compliance with applicable safety~~

~~and reliability requirements. If the EPS Operator identifies a specific safety or reliability concern, it shall notify the Interconnection Customer in writing of the basis for that determination and any corrective action required. Any restriction or suspension of export shall be limited to the extent authorized by applicable law and regulation and reasonably necessary to address the identified concern. The~~ review shall be limited to verifying, from the information submitted and, at the EPS Operator's election and as a review cost payable from the Reserve Fund under Article 3.B(3) and not charged to the Interconnection Customer, in the field, that (a) the installation conforms to the certification and the supporting documentation submitted, including the one-line diagram, (b) the equipment is Certified, and (c) the service transformer and secondary serving the Point of Common Coupling can accommodate the system's Export Capacity, applying only the objective criteria stated in this paragraph and in the TIR as approved by the Energy Bureau. The following shall apply to any such review:

- (i) If the EPS Operator identifies a specific safety or reliability condition, it shall notify the Interconnection Customer in writing within the fifteen (15) Business Day period, stating the condition, the data and criteria relied upon, and the corrective action required. If no such notice is issued within that period, no corrective action, restriction, or charge may thereafter be imposed under this Section. This does not prevent the EPS Operator from isolating an unsafe installation as provided in subparagraph (vi).
- (ii) A condition of the installation on the Interconnection Customer's side of the Meter shall be corrected by the Interconnection Customer within a cure period of not less than twenty (20) Business Days stated in the written notice under subparagraph (i); the system may continue to operate during the cure period unless that notice identifies an unsafe installation as provided in subparagraph (vi).
- (iii) Where the service transformer that serves the Point of Common Coupling, or the secondary conductors or service drop between that service transformer and the Interconnection Customer's Meter, require a Service Upgrade under Article 3.B(3) to accommodate the system's Export Capacity, the EPS Operator shall state so in its written notice under subparagraph (i) and shall complete the Service Upgrade from the Reserve Fund within thirty (30) calendar days after that notice. During that period the EPS Operator may limit, but not suspend, export to the level that the existing

service transformer and secondary can accommodate, using the smart inverter or export-control settings stated in that notice. The limitation shall be lifted upon completion of the Service Upgrade, and in no event later than the end of that thirty (30) calendar-day period, and no further limitation may be imposed for the same condition.

- (iv) No restriction or suspension of export shall be imposed because of the condition or capacity of any facility upstream of the service transformer, including the feeder, the circuit, or the substation, unless so established in the Technical Interconnection Requirements as approved by the Energy Bureau. In accordance with Section 9 of Act 114-2007, the capacity of the feeder shall not be an impediment to the interconnection or operation of a system of 25 kW or less. No restriction or suspension of export may be imposed under this Article other than: (a) under subparagraph (iii), a temporary limitation while the service transformer, secondary conductors or service drop are upgraded; (b) under subparagraph (vi), the isolation of an unsafe installation; or (c) a restriction established in the Technical Interconnection Requirements as approved by the Energy Bureau.
- (v) The Interconnection Customer may request review of any notice under this paragraph before the Energy Bureau under Section 13.02.
- (vi) Nothing in this paragraph prevents the EPS Operator from isolating or disconnecting a Distributed Generation System whose installation, on the Interconnection Customer's side of the Meter, is unsafe. An installation is unsafe only where the EPS Operator observes at the premises, and identifies in the written notice required by this subparagraph, a condition that (1) feeds energy onto the Electric Power System's conductors during an outage of the Electric Power System, instead of isolating from them, (2) involves exposed, damaged, overheating or arcing conductors or equipment, or (3) lacks the grounding or disconnecting means required by the National Electrical Code as adopted in Puerto Rico. The operation or export of a system that conforms to its certification is not an unsafe condition, and a condition of the service transformer, secondary conductors or service drop addressed in subparagraph (iii), or of any facility upstream of the service transformer, is not an unsafe installation. The EPS Operator shall act at the system's disconnecting means where possible; shall give the Interconnection Customer written

notice of the condition observed and the corrective action required before acting or, where the condition does not permit prior notice, within one (1) Business Day after acting; and shall restore the interconnection within two (2) Business Days after the Interconnection Customer certifies the correction. The action may be reviewed under Section 13.02.

- (5) ~~If the interconnection passes the screens described in Article 3.A(2) and the EPS Operator does not identify a specific safety or reliability concern, the EPS Operator shall countersign the Simplified Interconnection Notification and Agreement and provide the executed interconnection agreement to the Interconnection Customer when it provides the results of the screens.~~ Within fifteen (15) Business Days after receipt of a complete Simplified Interconnection Notification and Agreement, the EPS Operator shall countersign it and provide the executed agreement to the Interconnection Customer through the Cyber Portal, together with the results of its review under paragraph (4). If the EPS Operator does not do so within that period, the Simplified Interconnection Notification and Agreement shall be deemed countersigned. The countersigned agreement records the interconnection and is not a precondition to operation, export, or Net Metering.

D. Supplemental ~~Studies~~Review

- (1) The EPS Operator may conduct a Supplemental Review as described in ~~Error! Reference source not found.. Should the EPS Operator conduct a Supplemental Review, no Supplemental Study Fees (including deposits) will be charged to Interconnecting Customers utilizing the Simplified Process.~~ Section 4.04.C of a system interconnected under this Article, for its own planning purposes and at its own expense. A Supplemental Review shall not delay, condition, suspend, or reopen the interconnection, operation, export, or Net Metering enrollment of the system, and no Supplemental Study Fee, deposit, or Distribution Upgrade cost shall be charged to an Interconnection Customer under the Simplified Process, in accordance with Joint Resolution 5-2026.
- (2) Notwithstanding any other ~~provisions of Error! Reference source not found., if after completion of the Supplemental Review, the EPS Operator determines that the interconnection requires system modifications, including but not limited to restrictions on the amount of power that can be transferred from the Distributed Generation System to the Electric Power System, then the EPS Operator will notify the Interconnecting Customer of the Supplemental Study results. Within five (5) Business Days, the Interconnection Customer must~~

~~inform the EPS Operator if the Interconnection Customer elects to continue. If the Interconnection Customer makes such an election, the EPS Operator shall provide an Interconnection Agreement, and construction schedule for such upgrades, to the Interconnection Customer within fifteen (15) Business Days after the EPS Operator receives such an election~~provision of Section 4.04, if a Supplemental Review identifies a Distribution Upgrade needed to accommodate systems under this Article, the Upgrade shall be funded from the Reserve Fund under Article 3.B(3) or planned under Section 7.11, as applicable. Any export limitation the EPS Operator proposes as a result of a Supplemental Review is subject to the limits that apply under Article 3.C(4)(iii) to a limitation during a service transformer upgrade.

- (3) The fact that the feeder exceeds its capacity ~~[and requires system modifications]~~ shall not constitute an obstacle for the interconnection of photovoltaic or renewable energy systems with a generation capacity that does not exceed 25 kilowatts (Section 9(c) of Act 114-2007, as amended). In such cases, the necessary improvements ~~and/or~~ changes ~~to be made to the feeder shall be defrayed by the requesting company. (Act 114-2007, as amended)~~ shall be funded as follows, and in no case charged to the Interconnection Customer: (i) a Service Upgrade to the service transformer that serves the Point of Common Coupling, or to the secondary conductors or service drop between that service transformer and the Interconnection Customer's Meter, is paid from the Reserve Fund under Article 3.B; and (ii) an improvement to the primary feeder, a substation, or any other facility upstream of that service transformer is planned, budgeted, and funded by the EPS Operator under Section 7.11.
- (4) If the Interconnection Customer disagrees with a determination of the EPS Operator under this Article, the Interconnection Customer may request an Administrative Review by the Energy Bureau as provided in Section 13.02.

ARTICLE 4. DISTRIBUTION SYSTEM FAST TRACK PROCESS

SECTION 4.01. Applicability and eligibility requirements

- A. The Fast Track Process ~~is available to an Interconnection Customer proposing to interconnect with the Distribution System if the proposed interconnection does not exceed the size limits and other requirements identified in this Section 4.01. However, eligibility~~applies to a Distributed Generation System or Microgrid with an Export Capacity greater than 25 kW that does not exceed the size limits in Section 4.01.B (Table 1). A system with an Export Capacity of 25 kW or less is processed under the Simplified Process in Article 3 and not under this Article; a system that exceeds the Table 1 limits or is not otherwise eligible

is processed under the Study Process in Article 5. Eligibility is distinct from the Fast Track Process itself, and eligibility does not imply or indicate that an Interconnection Application will pass the Fast Track screens in Section 4.02 or the supplemental review screens in Section 4.04. ~~The Fast Track Process is not applicable to projects utilizing the Simplified Process~~In accordance with Section 9 of Act 114-2007 and Section 7.01.D, the EPS Operator's evaluation of an Interconnection Application under this Article, including any supplemental review, shall not exceed ninety (90) calendar days from filing, after which the Application is automatically approved.

B. Fast Track Eligibility

An Interconnection Application is eligible for Fast Track if the proposed interconnection includes:

- (1) A single Point of Common Coupling;
- (2) A Point of Common Coupling on a radial distribution circuit, or a spot network serving one customer;
- (3) No more than one service drop;
- (4) Only certified Distributed Generation Systems certified in accordance with Section 8.02 of this Regulation; and
- (5) Has an Export Capacity that does not exceed the limits defined in Table 1 below.

Table 1: Export Capacity for Fast Track Eligibility

Line Voltage	Nameplate Rating Regardless of Location
< 5 kV	≤ 500 kW
≥ 5 kV and < 15 kV	≤ 1 MW

- C. In addition to the requirements of Section 4.01, the proposed interconnection must meet the technical requirements in the TIR document, which will include the applicable codes, standards, and certification requirements. Alternatively, if the proposed interconnection varies from those requirements, the EPS Operator may review the design and/or test the proposed interconnection to ensure it is safe to operate.

D. Non-Exporting systems and systems within published export capacity. Notwithstanding the size limits in Section 4.01.B, an Interconnection

Application for (i) a Non-Exporting Distributed Generation System, or (ii) a Limited Export Distributed Generation System, using a Power Control System certified to UL 3141 or another means in Section 7.09, whose Export Capacity does not exceed the export capacity the EPS Operator has published for the applicable line section or service transformer under Section 7.11, shall be evaluated under this Article using its Export Capacity. For such an Application, the EPS Operator shall provide the initial review results under Section 4.02 within fifteen (15) Business Days after the Application is deemed complete and shall complete its evaluation, by providing an executable Interconnection Agreement or a written determination under Section 7.01.D, within forty-five (45) calendar days after the Application is filed. A Non-Exporting system shall not be referred to a Supplemental Review or to the Study Process absent a written finding, stated with specificity, that the system's Inadvertent Export or fault current contribution presents a safety or reliability concern.

SECTION 4.02. Initial Review.

A. Screening Timeline

The EPS Operator shall perform an initial review of the Interconnection Application using the Fast Track screens set forth below and shall notify the Interconnection Customer of the initial review results, and include with the notification copies of the analysis and data underlying the EPS Operator's determinations under the screening requirements.

- (1) For Interconnection Customers using the Interconnection Application, the EPS Operator shall provide these results within fifteen (15) Business Days after notifying the Interconnection Customer it has received a complete Interconnection Application.

B. Fast Track Screens:

- (1) For interconnection to a distribution circuit, the aggregated Export Capacity, including the proposed Distributed Generation System or Microgrid, on the circuit shall not exceed ~~fifteen~~thirty percent (~~15~~30%) of the line section annual peak load as most recently measured at the substation or, where the EPS Operator has published Daytime Minimum Load data for the line section under Section 7.11, one hundred percent (100%) of the Daytime Minimum Load of the line section. A line section is that portion of the Distribution System connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line. This screen does not apply to a Non-Exporting Distributed Generation System or Non-Exporting Microgrid, or existing facilities proposing to add no new Export Capacity.
- (2) For interconnection to the load side of spot network protectors, the proposed interconnection must utilize an inverter-based equipment

package and, the Nameplate Rating of the Distributed Generation System or Microgrid, together with the aggregated other inverter-based generation, shall not exceed the smaller of five percent (5%) of a spot network's maximum load or 50 kW.²

- (3) The Nameplate Rating of the proposed Distributed Generation System or Microgrid, in aggregate with the Nameplate Rating of other generation on the distribution circuit, shall not contribute over ten percent (10%) to the distribution circuit's maximum fault current at the point on the high voltage (primary) level nearest the proposed Point of Common Coupling. The EPS Operator may allow Generating Facilities or Microgrids with a Nameplate Rating of 50 kW or less to skip this screen.
- (4) The Nameplate Rating of the proposed Distributed Generation System or Microgrid, in aggregate with the Nameplate Rating of other generation on the distribution circuit, shall not cause any distribution protective devices and equipment (including, but not limited to, substation breakers, fuse cutouts, and line reclosers), or Interconnection Customer equipment on the system to exceed ninety (90%) of the short circuit interrupting capability; nor shall the interconnection be proposed for a circuit that already exceeds ninety percent (90%) of the short circuit interrupting capability. The EPS Operator may allow Generating Facilities or Microgrids with a Nameplate Rating of 50 kW or less to skip this screen.
- (5) Using the applicable criteria in the TIR, determine the type of interconnection to a primary distribution line. This screen includes a review of the type of electrical service provided to the Interconnection Customer, including line configuration and the transformer connection to limit the potential for creating over-voltages on the EPS due to a loss of ground during the operating time of any anti-islanding function.

This screen does not apply to Generating Facilities or Microgrids with a Nameplate Rating of 50 kW or less.
- (6) If the proposed interconnection is on single-phase shared secondary, the aggregate Export Capacity on the shared secondary, including the proposed Distributed Generation System or Microgrid, shall not exceed sixty five percent (65%) of the transformer nameplate rating.

² A spot network is a type of distribution system found within modern commercial buildings to provide high reliability of service to a single customer. See STANDARD HANDBOOK FOR ELECTRICAL ENGINEERS, 11th Edition, Donald Fink, McGraw Hill Book Company.

- (7) If the proposed interconnection is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition shall not create an imbalance between the two sides of the 240 volt service of over 20% of the nameplate power rating of the service transformer.
- (8) The Nameplate Rating of the Distributed Generation System or Microgrid, in aggregate with other generation interconnected to the transmission side of a substation transformer feeding the circuit where the Microgrid proposes to interconnect shall not exceed 10 MW in an area where there are known, or posted, transient stability limitations to generating units located in the general electrical vicinity (*e.g.*, three (3) or four (4) transmission busses from the Point of Common Coupling).

C. Notifications and Execution of Applicable Agreements

If the proposed interconnection passes the screens, or if the proposed interconnection fails the screens, but the EPS Operator determines that the proposed interconnection may nevertheless be interconnected consistent with safety, reliability, and power quality standards, the Interconnection Application shall proceed as follows:

- (1) If the proposed interconnection requires no construction of facilities on the Electric Power System, the EPS Operator shall provide the Interconnection Customer with an executed Interconnection Agreement within fifteen (15) Business Days after the determination.
- (2) If the proposed interconnection requires only Minor System Modifications, the EPS Operator shall notify the Interconnection Customer of such requirement when it provides initial review results and copies of the analysis and data underlying the determinations under the screens. ~~Within five (5) Business Days, the Interconnection Customer must inform the EPS Operator if the Interconnection Customer elects to continue the Application. If the Interconnection Customer makes such an election, together with an itemized cost estimate and construction schedule for such modifications prepared in accordance with Section 7.08. Within fifteen (15) Business Days, the Interconnection Customer must inform the EPS Operator whether it elects to continue the Application, to elect a Limited Export configuration under Section 7.09 in lieu of the modifications, or to withdraw; if no election is made within that period, the EPS Operator shall so notify the Interconnection Customer, who shall have five (5) additional Business Days to elect before the Application is deemed withdrawn. If the Interconnection Customer elects to continue,~~ the EPS Operator shall provide an executable Interconnection Agreement;

~~along with a non-binding good faith cost estimate and construction schedule for such upgrades, to the Interconnection Customer within thirty (30) Business Days after the EPS Operator receives such an~~
within fifteen (15) Business Days after receiving the election.

- (3) If the proposed interconnection requires more than Minor System Modifications, the EPS Operator shall notify the Interconnection Customer of such requirement when it provides the initial review results and copies of the analysis and data underlying the screen determinations. ~~Within five (5), together with an itemized cost estimate and construction schedule for such Upgrades prepared in accordance with Section 7.08. Within fifteen (15) Business Days, the Interconnection Customer must inform the EPS Operator if the Interconnection Customer~~whether it elects to proceed with the proposed interconnection, to elect a Limited Export configuration under Section 7.09 in lieu of the Upgrades, or to withdraw. If the Interconnection Customer ~~makes such an election~~elects to proceed, the EPS Operator ~~may elect to~~shall either (i) provide an executable Interconnection Agreement,~~along with a non-binding good faith cost estimate and construction schedule for such upgrades, within forty (40).~~within fifteen (15) Business Days after the EPS Operator receives such an election or (ii) notify the Interconnection Customer that an interconnection facilities study must be performed pursuant to Section 5.05, and provide a facilities study agreement within ten (10) Business Days after the EPS Operator receives such an election.
- (4) If the proposed interconnection fails the screens, and the EPS Operator cannot determine from the initial review that the proposed interconnection may nevertheless be interconnected consistent with safety, reliability, and power quality standards unless the Interconnection Customer considers minor modifications or further study, the EPS Operator shall provide the Interconnection Customer with the opportunity to attend the customer options meeting in Section 4.03 of this Regulation.

SECTION 4.03. Customer Options Meeting

- A. If the EPS Operator determines the Interconnection Application cannot be approved without (1) a supplemental study or other additional studies or actions or (2) incurring significant cost to address safety, reliability, or power quality problems, the EPS Operator shall notify the Interconnection Customer of that determination and provide a detailed explanation supporting its conclusion.

- B. If requested by the Interconnection Customer, within ten (10) Business Days of the EPS Operator's determination, the EPS Operator shall convene a customer options meeting with the Interconnection Customer and the EPS Operator.
- C. At the customer options meeting, the Parties shall review the screen analysis and related results, possible Distributed Generation System or Microgrid modifications, and determine what further steps are needed to permit the safe and reliable interconnection.
- D. At the time of notification of the EPS Operator's determination, or at the customer options meeting, the EPS Operator shall:
 - (1) Offer to perform a supplemental review in accordance with Section 4.04 and provide a non-binding good faith estimate of the costs of such review; or
 - (2) Obtain the Interconnection Customer's agreement to continue evaluating the Interconnection Application under the Study Process in Article 5.

SECTION 4.04. Supplemental Review

- A. To accept the offer of a supplemental review, the Interconnection Customer shall agree in writing and submit a deposit for the estimated costs of the supplemental review in the amount of the EPS Operator's good faith estimate of the costs of such review, both within fifteen (15) Business Days of the offer. If only the written agreement, but not the deposit, has been received by the EPS Operator within that timeframe, the Interconnection Application shall continue to be evaluated under the Article 5 Study Process unless it is withdrawn by the Interconnection Customer. If the deposit is not received within 90 Business Days from the date of submission of the written agreement, the application is deemed withdrawn.
- B. Interconnection Customers submitting an Interconnection Application shall be responsible for the EPS Operator's actual costs for conducting the supplemental review. The Interconnection Customer must pay any review costs that exceed the deposit within twenty (20) Business Days of receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced costs, the EPS Operator will return such excess within twenty (20) Business Days of the invoice without interest. Interconnection Customers eligible for the Simplified Process shall not be responsible for any of the EPS Operator's costs for conducting the supplemental review.
- C. Within thirty (30) Business Days following receipt of the deposit for a supplemental review, the EPS Operator shall (1) perform a supplemental review using the screens set forth below; (2) notify in writing the Interconnection Customer of the results; and (3) include with the notification

copies of the analysis and data underlying the determinations under the screens.

- (1) *Minimum Load Screen:* Where 12 months of line section minimum load data (including Host Load but not station service load served by the proposed Distributed Generation System or Microgrid) are available, can be calculated, can be estimated from existing data, or determined from a power flow model, the aggregate Export Capacity of the Generating Facilities on the line section is less than 100% of the minimum load for all line sections bounded by automatic sectionalizing devices upstream of the proposed interconnection. If minimum load data is not available, or cannot be calculated, estimated or determined, the EPS Operator shall include the reason(s) that it is unable to calculate, estimate or determine minimum load in its supplemental review results notification under Section 4.04.D This screen does not apply to a Non-Exporting Distributed Generation System or Non-Exporting Microgrid, or existing facilities proposing to add no new Export Capacity.
- (2) *Type of generation:* The type of generation used by the proposed interconnection will be considered when calculating, estimating, or determining circuit or line section minimum load relevant for applying screening requirements of Section 4.04.C(1). Solar photovoltaic (PV) generation systems, including PV systems paired with ~~no~~ Energy Storage, use ~~daytime minimum load~~ Daytime Minimum Load (i.e., 10 a.m. to 4 p.m. for fixed panel systems and 8 a.m. to 6 p.m. for PV systems utilizing tracking systems), while evaluated on the Export Capacity of the PV system; all other generation uses absolute minimum load. The EPS Operator shall apply this screen using the Operating Profile and system design designated in the Interconnection Application. For example, the EPS Operator shall evaluate the maximum Export Capacity only during the hours of the day designated by the customer as operational, and shall consider any export controls that comply with Section 7.09.
 - (i) Only the net injection of power into the EPS will be considered as part of the aggregate Export Capacity.
 - (ii) For the purposes of this screen, the EPS Operator will not consider as part of the aggregate Export Capacity any existing Export Capacity already reflected in the minimum load data.
 - (iii) Although export will not be considered, load reducers that are applying to interconnect, that do not export, will be considered to effectively reduce circuit or circuit section load by the amount of load the generator is displacing.

- (3) *Voltage and Power Quality Screen:* In aggregate with existing generation on the line section: (1) the voltage regulation on the line section can be maintained in compliance with requirements under all system conditions; (2) the voltage fluctuation, including Rapid Voltage Change is within acceptable limits as defined by Institute of Electrical and Electronics Engineers (IEEE) Standard 1453 or Standard 1547-2018, or utility practice similar to IEEE Standard 1453 or Standard 1547-2018;³
 - (4) *Safety and Reliability Screen:* The location of the proposed interconnection and the aggregate generation on the line section do not create impacts to safety or reliability that cannot be adequately addressed without application of the Study Process. The EPS Operator shall consider the following and other factors in determining potential impacts to safety and reliability in applying this screen.
 - (i) Whether the line section has significant minimum loading levels dominated by a small number of customers (*e.g.*, several large commercial customers).
 - (ii) Whether the loading along the line section is uniform or even.
 - (iii) Whether the proposed interconnection is located in close proximity to the substation (*i.e.*, less than 2.5 electrical circuit miles), and whether the line section from the substation to the Point of Common Coupling is a Mainline rated for normal and emergency ampacity.
 - (iv) Whether the proposed interconnection reduces operational flexibility, such that transfer of the line section(s) of the Distributed Generation System or Microgrid to a neighboring distribution circuit/substation may trigger overloads or voltage issues.
 - (v) Whether the proposed interconnection employs equipment or systems certified by recognized standards organization to address technical issues such as, but not limited to, Islanding, reverse power flow, or voltage quality.
- D. If the proposed interconnection passes the supplemental screens in Section 4.04.C above, or if the proposed interconnection fails the screens, but the EPS Operator determines that it may nevertheless be interconnected consistent

³ Voltage fluctuation and harmonics limits are both addressed by IEEE 1547-2018. However, until full adoption of IEEE 1547-2018 is complete, IEEE 1453 and IEEE 519 may be used for the respective requirements. Equipment tested to comply with the updated harmonics requirements of IEEE 1547-2018 will not be available until approximately 18 months or more after publication of the revision of IEEE 1547.1.

with safety, reliability, and power quality standards, the interconnection shall proceed as follows:

- (1) If the proposed interconnection passes the supplemental screens in Sections Section 4.04.C and does not require construction of facilities on the Electric Power System, the EPS Operator shall provide the Interconnection Customer an executed Interconnection Agreement at the time it provides the supplemental review results in accordance with the timeline in Section 4.04.C. If using the Simplified Process, the EPS Operator shall countersign the Simplified Interconnection Notification and Agreement and provide the fully executed interconnection agreement to the Interconnection Customer at the same time it provides the supplemental review results.
- (2) If the proposed interconnection requires only Minor System Modifications, the EPS Operator shall notify the Interconnection Customer of such requirement when it provides supplemental review results. ~~Within five (5) Business Days, the Interconnection Customer must inform the EPS Operator if the Interconnection Customer elects to continue. If the Interconnection Customer makes such an election~~The notice shall include an itemized cost estimate and construction schedule for such modifications prepared in accordance with Section 7.08. Within fifteen (15) Business Days, the Interconnection Customer must inform the EPS Operator whether it elects to continue, to elect a Limited Export configuration under Section 7.09 in lieu of the modifications, or to withdraw. If the Interconnection Customer elects to continue, the EPS Operator shall provide an executable Interconnection Agreement,~~along with a non-binding good faith cost estimate and construction schedule for such upgrades, to the Interconnection Customer~~ within fifteen (15) Business Days after the EPS Operator receives such an election.
- (3) If the proposed interconnection requires more than Minor System Modifications, the EPS Operator shall notify the Interconnection Customer of such requirement when it provides the supplemental review results. ~~Within five (5)~~The notice shall include an itemized cost estimate and construction schedule for such Upgrades prepared in accordance with Section 7.08. Within fifteen (15) Business Days, the Interconnection Customer must inform the EPS Operator ~~if the Interconnection Customer~~whether it elects to proceed with the proposed interconnection, to elect a Limited Export configuration under Section 7.09 in lieu of the Upgrades, or to withdraw. If the Interconnection Customer ~~makes such an election~~elects to proceed, the EPS Operator ~~may elect to~~shall either (i) provide an executable Interconnection Agreement,~~along with a non-binding good faith cost estimate and construction schedule for such upgrades, within twenty~~

~~(20)~~ within fifteen (15) Business Days after the EPS Operator receives such an election or (ii) notify the Interconnection Customer that an interconnection facilities study must be performed pursuant to Section 5.05, and provide a facilities study agreement within ten (10) Business Days after the EPS Operator receives such an election.

- E. If the proposed interconnection fails the screens, and the EPS Operator does not or cannot determine that it may nevertheless be interconnected consistent with safety, reliability, and power quality standards unless the Interconnection Customer will consider minor modifications or further study, the EPS Operator shall provide the customer the option of commencing the Study Process in Article 5. If the Interconnection Customer wishes to proceed it shall notify the EPS Operator within fifteen (15) Business Days to retain its queue position.

F. Where the results of the initial review or supplemental review identify a constraint, the notice of results shall state the Export Capacity, if any, that could be accommodated without the identified modifications or Upgrades. The Interconnection Customer may, within the election period, reduce the Export Capacity of the proposed interconnection by a means identified in Section 7.09 to that level, in which case the Interconnection Application shall proceed without the modifications or Upgrades and without loss of Queue Position, and the reduction shall not be a Material Modification.

ARTICLE 5. STUDY PROCESS

SECTION 5.01. Purpose

The Study Process shall be used by an Interconnection Customer proposing to interconnect with the EPS if the Interconnection Application (1) is not eligible for Fast Track Process, or (2) did not pass the Fast Track Process. The Study Process is not applicable to projects utilizing the Simplified Process.

SECTION 5.02. Scoping Meeting.

- A. The purpose of the scoping meeting is to discuss the Interconnection Application and review existing studies relevant to the Interconnection Application. The Parties shall further discuss whether the EPS Operator should perform feasibility study, or proceed directly to a system impact study or studies, a facilities study, or an Interconnection Agreement. If the EPS Operator and Interconnection Customer determine there is no potential for adverse system impacts, the Interconnection Customer shall proceed directly to a facilities study or an executable Interconnection Agreement, as agreed to by the Parties
- B. A scoping meeting shall be held within fifteen (15) Business Days after the Interconnection Application is deemed complete and, if applicable, the Fast Track Process has been completed. The EPS Operator and the Interconnection

Customer will bring the relevant personnel to the meeting, including system engineers and others that may be required to accomplish the purpose of the meeting.

- C. The scoping meeting may be waived by agreement of the Parties.

SECTION 5.03. Feasibility Study.

- A. A feasibility study shall be conducted only upon the request of the Interconnection Customer. The EPS Operator shall not require a feasibility study.
- B. If the EPS Operator determines a feasibility study is necessary, the EPS Operator shall perform a feasibility study, the EPS Operator shall provide the Interconnection Customer, as soon as possible, but not later than five (5) Business Days after the scoping meeting, a feasibility study agreement. In the form proposed by the EPS Operator and approved by the Energy Bureau.
- C. If the scoping meeting is omitted but the Parties agree that the EPS Operator should conduct a feasibility study, the EPS Operator shall provide the Interconnection Customer a feasibility study agreement within ten (10) Business Days after the Interconnection Application is deemed complete and, if applicable, the Fast Track Process has been completed. If the Interconnection Customer decides not to proceed with the feasibility study the Interconnection Application will be considered withdrawn.
- D. The scope of and cost responsibilities for the feasibility study are described in the attached feasibility study agreement (Attachment X of the TIR). The feasibility study agreement shall specify that the Interconnection Customer is responsible for the actual cost of the feasibility study and require the Interconnection Customer to include with the signed agreement certain technical data identified in (Attachment X of the TIR) to the Feasibility Study Agreement (Attachment X of the TIR). The ~~EPS Operator~~Interconnection Customer will be required to make an upfront ~~full~~ payment of the estimated cost of the study. A true up cost will be done at the end of the study.
- E. If an Interconnection Customer requests that the feasibility study evaluate multiple potential Points of Common Coupling, any additional evaluations shall be paid for by the Interconnection Customer.
- F. To remain in consideration for interconnection, an Interconnection Customer must return the executed feasibility study agreement and pay the required study deposit within five (5) Business Days.

- G. The feasibility study shall consider a base case,⁴ as well as all Distributed Generation Systems and Microgrids (and any identified Network Upgrades) that, on the date the study commenced: (i) are directly interconnected to the EPS; (ii) have a pending higher or lower queued Interconnection Application depending on the geographical location of the project; and (iii) have no Queue Position but have executed an Interconnection Agreement. The feasibility study will consist of a power flow and short circuit analysis. The feasibility study shall consider the proposed interconnection's Export Capacity, design, and operating characteristics and study the project according to how it is proposed to be operated if the proposed interconnection complies with Section 7.09, uses devices tested to national standards, or is approved by the EPS Operator.
- H. A feasibility study report shall be completed and transmitted to the Interconnection Customer within forty (40) Business Days after the feasibility study agreement is signed by the Parties. The feasibility study report shall identify any potential adverse system impacts that would result from the interconnection as proposed, including but not limited to:
- (1) Initial identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;
 - (2) Initial identification of any thermal overload or voltage limit violations resulting from the interconnection;
 - (3) Initial review of grounding requirements per IEEE C62.92.6 for inverter-based systems, and electric system protection; and
 - (4) Description and non-binding good faith estimated cost and construction schedule of facilities required to interconnect and to address the identified short circuit and power flow issues, including identification of potential increased expenses due to location, Distribution System assets, or other relevant factors. Good faith cost estimates provided in each instance should be itemized and break down costs by equipment, labor and other cost categories. They should also provide the components for direct, indirect, and other identified cost categories .
- I. The EPS Operator may not require a system impact study when the feasibility study concludes there is no adverse system impact, or when the study identifies an adverse system impact, but the EPS Operator is able to identify a remedy without the need for a system impact study.

⁴ Base case means the power flow, short circuit, and stability data reflecting the current system conditions.

SECTION 5.04. System Impact Study.

- A. A system impact study shall identify and detail the incremental EPS impacts that would result if the proposed Distributed Generation System or Microgrid interconnected without project modifications or EPS modifications, and study potential impacts, including but not limited to those identified in the scoping meeting. A system impact study shall evaluate the impact of the proposed interconnection on the reliability of the EPS. This may include evaluation of impacts to portions of the EPS within the boundaries of a Microgrid. A system impact study shall consider all Generating Facilities and Microgrids (and any identified Network Upgrades) that, on the date the study commenced: (i) are directly interconnected to the EPS; (ii) have a pending higher queued Interconnection Application; and (iii) have no Queue Position but have executed an Interconnection Agreement. The system impact study shall consider the proposed interconnection's Export Capacity, design, and operating characteristics and study the project according to how it is proposed to be operated if the proposed interconnection complies with Section 7.09, uses devices tested to national standards, or is approved by the EPS Operator.
- B. The EPS Operator shall provide the Interconnection Customer a system impact study agreement (Attachment X of the TIR) according to the following timeline:
 - (1) In tandem with the results of the Interconnection Customer's feasibility study.
 - (2) If the feasibility study is omitted, as soon as possible, but not later than five (5) Business Days after the scoping meeting.
 - (3) If the scoping meeting and feasibility study are omitted, within ten (10) Business Days after the Interconnection Application is deemed complete and, if applicable, the Fast Track Process has been completed.
- C. The system impact study agreement (Attachment X of the TIR) shall include an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study. The scope of and cost responsibilities for a system impact study are described in the attached system impact study agreement. A deposit of the good faith estimated costs for each system impact study shall be provided by the Interconnection Customer when it returns the study agreements.
- D. To remain in consideration for interconnection, an Interconnection Customer who has requested a system impact study must return the executed system impact study agreement and pay the required study deposit detailed in (Attachment X of the ~~TIR~~TIR) within five (5) Business Days.
- E. A system impact study shall be completed and the results transmitted to the Interconnection Customer within forty-five (45) Business Days after the

system impact study agreement is signed by the Parties. The system impact study report shall provide:

- (1) The underlying assumptions of the study.
 - (2) A summary of the analyses.
 - (3) The results of the analyses, including detailed information on any impacts identified, the drivers and reasons for those impacts, including load, voltage, thermal and other limitations as well as the boundaries of the impacts to the extent possible.
 - (4) Identification of any equipment short circuit capability limits exceeded as a result of the interconnection and information regarding technical thresholds that drive modifications.
 - (5) Identification of any thermal overload or voltage limit violations resulting from the interconnection and information regarding technical thresholds that drive modifications.
 - (6) Identification of any instability or inadequately damped response to system disturbances resulting from the interconnection, and information regarding technical thresholds that drive modifications.
 - (7) Identification of any protection elements being de-sensitized and reduction in performance grounding as a result of the interconnection and information regarding technical thresholds that drive modifications.
 - (8) A non-binding construction schedule and good faith estimate of cost and time to construct any required distribution upgrades. Good faith cost estimates should be itemized and break down costs by equipment, labor and other cost categories. They should also provide the components for direct, indirect, and other identified cost categories.
- F. Where the system impact study shows potential for Transmission System adverse system impacts, within five (5) Business Days following the identification of such impacts, the EPS Operator shall send the Interconnection Customer a Transmission System impact study agreement, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study.
- G. To remain in consideration for interconnection, an Interconnection Customer must return the executed Transmission System impact study agreement within fifteen (15) Business Days.

- H. A Transmission System impact study, if required, shall be completed within thirty (30) Business Days and the results transmitted to the Interconnection Customer after the Transmission System impact study agreement is signed by the Parties.

SECTION 5.05. Facilities Study

- A. The EPS Operator shall provide the Interconnection Customer a facilities study agreement according to the following timeline:
 - (1) In tandem with the results of the system impact study or, if required, Transmission System impact study.
 - (2) If no system impact studies are required and feasibility study is performed, in tandem with the results of the feasibility study.
 - (3) If no studies are performed, as soon as possible, but not later than five (5) Business Days after the scoping meeting.
 - (4) If the scoping meeting is omitted by agreement and no studies are performed, within ten (10) Business Days after the Interconnection Application is deemed complete and, if applicable, the Fast Track Process has been completed.
- B. The facilities study agreement shall come with an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the facilities study. The scope of and cost responsibilities for the facilities study are described in the attached facilities study agreement. A deposit of the good faith estimated costs for the facilities study shall be provided by the Interconnection Customer when it returns the study agreement.
- C. To remain under consideration for interconnection, the Interconnection Customer must return the executed facilities study agreement and pay the required study deposit within ten (10) Business Days.
- D. The facilities study shall specify and estimate the cost of the equipment, permitting, engineering, procurement and construction work (including overheads) needed to implement the conclusions of the system impact study(s).
- E. Design for any required Interconnection Facilities and/or Upgrades shall be performed under the facilities study agreement. The EPS Operator may contract with consultants to perform activities required under the facilities study agreement. The Interconnection Customer and the EPS Operator may agree to allow the Interconnection Customer to separately arrange for the design of some of the Interconnection Facilities. In such cases, facilities design will be reviewed and/or modified before acceptance by the EPS Operator,

under the provisions of the facilities study agreement. If the Parties agree to separately arrange for design and construction, and provided security and confidentiality requirements can be met, the EPS Operator shall provide sufficient information to the Interconnection Customer in accordance with confidentiality and critical infrastructure requirements to permit the Interconnection Customer to obtain an independent design and cost estimate for any necessary facilities.

- F. The facilities study must be completed and provided to Interconnection Customer within ~~Sixty~~sixty (60) Business Days of receiving the executed facilities study agreement. The facilities study shall estimate the cost of the equipment, engineering, procurement and construction work, including overheads, needed to implement the conclusions of the interconnection feasibility study and the interconnection system impact study. Good faith cost estimates shall be itemized and break down costs by equipment, labor and other cost categories. They should also provide the components for direct, indirect, and other identified cost categories. The facilities study shall consider the proposed interconnection's Export Capacity, design and operating characteristics and study the project according to how it is proposed to be operated if the proposed interconnection complies with Section 7.09, uses devices tested to national standards, or is approved by the EPS Operator. The facilities study shall identify:
- (1) The electrical switching configuration of the equipment, including transformer, switchgear, meters and other station equipment.
 - (2) The nature and estimated cost of the EPS Operator's interconnection facilities and upgrades necessary to accomplish the interconnection.
 - (3) A good faith estimate for the time required to complete the construction and installation of the facilities.
- G. Once the facilities study is completed, a draft facilities study report shall be prepared and transmitted to the Interconnection Customer. Upon request, the EPS Operator shall provide Interconnection Customer supporting documentation, workpapers, and databases or data developed to prepare the facilities study, subject to confidentiality arrangements consistent with these Regulations and the facilities study agreement.
- H. Within three (3) Business Days of providing a draft Facilities Study Report to the Interconnection Customer, the EPS Operator and Interconnection Customer shall set up a mutually agreeable meeting date to discuss the results of the facilities study.
- I. Interconnection Customer may, within eight (8) Business Days after receipt of the draft report, provide written comments to the EPS Operator, which the EPS Operator shall include in the final report.

- J. The EPS Operator shall issue the final facilities study report and provide it to the Interconnection Customer within nine (9) Business Days of receiving Interconnection Customer's comments or within five (5) Business Days upon receiving Interconnection Customer's statement it will not provide comments.

ARTICLE 6. INTERCONNECTION AGREEMENT

SECTION 6.01. Simplified Process

For the Simplified Process, the Interconnection Customer ~~will sign~~ assigns the interconnection agreement form ~~at the time it submits its Interconnection Notification, and the EPS Operator will return a counter-signed interconnection agreement with the screen results incorporated in the Simplified Interconnection Notification and Agreement at the time it submits the notification, and the EPS Operator returns the countersigned agreement within the period, and with the effect, stated in Article 3.C(5).~~

SECTION 6.02. Fast Track and Study Process

- A. Except for microgrids above 5 MW as provided in Section 6.03, the EPS Operator shall provide the Interconnection Customer an executable Interconnection Agreement according to the following timeline:
 - (1) Within five (5) Business Days after completing the final facilities study report.
 - (2) If no facilities study is required, within five (5) Business Days after completing the system impact study or, if required, Transmission System impact study.
 - (3) If no facilities or system impact study is required, within five (5) Business Days after completing the feasibility study.
 - (4) If no feasibility, facilities, or system impact study is required, within fifteen (15) Business Days after the scoping meeting.
 - (5) If no feasibility, facilities, or system impact study is required, and the scoping meeting is omitted by agreement, within ten (10) Business Days after the Interconnection Application is deemed complete and, if applicable, the Fast Track Process has been completed.
- B. After receiving an Interconnection Agreement from the EPS Operator, the Interconnection Customer shall have thirty (30) Business Days to sign and return the Interconnection Agreement.
- C. The Interconnection Agreement must be signed by the Interconnection Customer and include a signed certification from a professional engineer that the interconnection meets the specifications established through regulations

by the Energy Bureau and that the same was completed according to the laws, regulations, and rules applicable to interconnections.

- D. If the Interconnection Customer does not sign the Interconnection Agreement or request an extension pursuant to these Regulations, within thirty (30) Business Days, the Interconnection Application shall be deemed withdrawn.
- E. The EPS Operator shall provide the Interconnection Customer an executed Interconnection Agreement within five (5) Business Days after receiving a signed Interconnection Agreement from the Interconnection Customer.
- F. The EPS Operator shall install (if necessary) and configure any ~~meters~~Meter required for operation of the Distributed Generation System within twenty (20) ~~working days~~Business Days after the Interconnection Customer signs the executed Interconnection Agreement, ~~provided that the Interconnection Application included such a request,~~and shall install the Meter in the existing meter socket, except where a Meter Socket Adapter approved under Section 8.03 is installed in that socket, in which case the Meter shall be installed into the Meter Socket Adapter.
- G. After the Interconnection Agreement is signed by the Parties, the interconnection of the Distributed Generation System or Microgrid shall proceed under the provisions of the Interconnection Agreement, except to the extent these Regulations remain applicable, including, but not limited to, Section 7.03, Section 7.04, Section 7.08, and Article 8.

SECTION 6.03. Energy Bureau's Approval for Microgrids Above 5 MW

For Microgrids with an Export Capacity above 5 MW, after the Facilities Study has been completed according to Section 5.05, the Interconnection Customer or the EPS Operator shall submit the completed System Impact Study and Facility Study to the Energy Bureau for approval. If approved by the Energy Bureau, the EPS Operator shall issue the corresponding Interconnection Agreement in accordance with Section 6.02 as applicable.

ARTICLE 7. PROVISIONS THAT APPLY TO ALL INTERCONNECTION APPLICATIONS

SECTION 7.01. Time Frames and Extensions

- A. The EPS Operator shall ~~make Reasonable Efforts to~~ meet all time frames provided in ~~these Regulations~~this Regulation. If the EPS Operator ~~cannot~~fails ~~to~~ meet a deadline provided herein, it shall notify the Interconnection Customer and the Energy Bureau in writing, explain the reason for the failure ~~to meet the deadline, and provide an estimated time by which it will complete the applicable interconnection procedure in the process, and provide the date by which it will complete the applicable step, without prejudice to the consequences provided in this Regulation for the missed deadline.~~

- B. The Energy Bureau may fine the EPS Operator one thousand dollars (\$1,000) per day if it fails to comply with the time frames and other requirements of this Regulation. The Energy Bureau also maintains the authority to impose other applicable fines or administrative penalties to enforce its orders and regulations. Where the EPS Operator fails to meet a time frame of this Regulation that applies to a particular Interconnection Customer, including the thirty (30) day period of Section 9.02.B and the ninety (90) day period of Section 7.01.D, the Energy Bureau may also order the EPS Operator to refund directly to each affected Interconnection Customer an amount equal to the bill savings the customer would have realized had the time frame been met, including the Net Metering credits the customer would have received. At the customer's election, any such refund, and any retroactive credit owed under Section 9.02.B, shall be paid by check or electronic deposit rather than as a credit on the customer's bill, within thirty (30) days after the election or the Energy Bureau's order. A refund under this paragraph for a period replaces any credit under Section 9.02.B for the same period.
- C. For all applicable time frames described in this Regulation, the Interconnection Customer may request in writing one extension equivalent to half of the time originally allotted (*e.g.*, ten (10) Business Days for a twenty (20) Business Day original time frame). No further extensions shall be granted absent a Force Majeure Event or other similarly extraordinary circumstances.
- D. In accordance with Section 9 of Act 114-2007, as amended, the EPS Operator's evaluation of an Interconnection Application under Article 4 or Article 5 shall not exceed ninety (90) calendar days from the date the Interconnection Application is filed. If, within that period, the EPS Operator has neither provided an executable Interconnection Agreement nor issued a written determination denying the interconnection, or requiring additional technical requirements or Upgrades, that states with specificity the grounds relied upon, the Interconnection Application shall be automatically approved and the EPS Operator shall provide the executed Interconnection Agreement within five (5) Business Days. Days during which the EPS Operator is awaiting information, a deposit, an election, or an executed study agreement from the Interconnection Customer are excluded from the ninety (90) days. A determination issued after the ninety (90) days does not reverse an automatic approval but may be reviewed under Section 13.02.
- E. The time frames in Article 3 and Section 9.02.B for systems under the Simplified Process are not subject to extension by the EPS Operator.

SECTION 7.02. Non-Warranty

Neither by inspection, if any, or non-rejection, nor in any other way, does the EPS Operator give any warranty, expressed or implied, as to the adequacy, safety, or other characteristics of any structures, equipment, wires, appliances or devices owned, installed,

or maintained by the Interconnection Customer or leased by the Interconnection Customer from third parties, including without limitation the Generation System and any structures, equipment, wires, appliances, or devices pertinent thereto.

SECTION 7.03. Commissioning, Inspection, Testing, Authorization

- A. The Interconnection Customer shall test and inspect its Distributed Generation System Microgrid, and Interconnection Facilities before interconnection in accordance with the commissioning tests required by IEEE 1547 or other applicable standard. Commissioning tests of the Interconnection Customer's installed equipment shall be performed pursuant to applicable codes and standards and the EPS Operator's Technical Interconnection Requirements approved by the Energy Bureau.
- B. The Interconnection Customer shall notify the EPS Operator of such activities at least ten (10) Business Days (or as agreed to by the Parties) before such testing and inspection. The Interconnection Customer shall send the notification electronically if the Cyber Portal is available. If the Cyber Portal is not available, the Interconnection Customer shall use a notification form provided by the EPS Operator, if such a form is posted on the EPS Operator's website. Testing and inspection shall occur on a Business Day. The EPS Operator may, at its own expense, send qualified personnel to the interconnection site to inspect the interconnection and observe the testing. The Interconnection Customer shall provide the EPS Operator a written test report within five (5) Business Days when such testing and inspection is completed.
- C. The EPS Operator shall provide the Interconnection Customer written acknowledgment it has received the Interconnection Customer's written test report within three (3) Business Days of its receipt. If no written acknowledgement is received by the Interconnection Customer within three (3) Business Days it shall be deemed accepted by the EPS Operator. Such written acknowledgment shall not be deemed to be or construed as any representation, assurance, guarantee, or warranty by the EPS Operator of the safety, durability, suitability, or reliability of the interconnection.
- D. For interconnections using the Simplified Process, the ~~field~~ inspection and testing process shall ~~conform with, and not exceed, the following, instead~~ consist of a self-inspection performed by the Interconnection Customer's installer and certified by the licensed electrical engineer or licensed expert electrician in the Simplified Interconnection Notification and Agreement, in lieu of the requirements of Section 7.03 A, B, and C. The presence or participation of the EPS Operator is not required and shall not be a precondition to interconnection, Parallel Operation, or Net Metering; the EPS Operator may verify the installation in the field, at its own expense as provided in Article 3.C(4), within the period stated in Article 3.C(4). The self-inspection shall conform with, and not exceed, the following:

- (1) ~~The field inspection shall include verification that the installation matches the EPS Operator's evaluation of the design~~Verification that the installation matches the design and supporting documentation described in the Simplified Interconnection Notification and Agreement, including:
- (2) Inverter model matches ~~application~~the notification;
- (3) Certified inverter(s) is utilized;
- (4) Correct labeling/signage;
- (5) ~~Installation matches application one-line (i.e.,~~Installation matches the notification design and supporting documentation (i.e., connections, location of protection, disconnect switch, Metering, etc.);
- (6) Electrical inspection sticker;
- (7) Operational and protection settings;
- (8) Field testing; and
- (9) On-off testing shall be completed.

SECTION 7.04. Authorization Required Prior to Parallel Operation

- A. The EPS Operator shall use Reasonable Efforts to list applicable Parallel Operation requirements in an attachment to the Interconnection Agreement. Additionally, the EPS Operator shall notify the Interconnection Customer of any changes to these requirements as soon as they are known. The EPS Operator shall make Reasonable Efforts to cooperate with the Interconnection Customer in meeting requirements for the Interconnection Customer to commence Parallel Operations by the in-service date.
- B. ~~The~~Except for a system under the Simplified Process, which may operate upon the certification described in Article 3.C(3), the Interconnection Customer shall not operate its Distributed Generation System or Microgrid in Parallel with the EPS without prior written authorization of the EPS Operator. The EPS Operator will provide such authorization within three (3) Business Days from when the EPS Operator receives notification that the Interconnection Customer has complied with all applicable Parallel Operation requirements. Such authorization shall not be unreasonably withheld, conditioned, or delayed.
- C. If the EPS Operator identifies a Distributed Generation System ~~Operating~~operating in Parallel without an Interconnection Agreement,~~the EPS Operator may disconnect the Distributed Generation System or, for the Simplified Process, without having submitted a Simplified Interconnection~~

Notification and Agreement, the EPS Operator shall notify the Interconnection Customer in writing and allow not less than thirty (30) calendar days to submit the required notification or application before disconnecting the system, except an unsafe installation as provided in Article 3.C(4)(vi).

SECTION 7.05. Confidentiality

- A. Each Party shall employ at least the same standard of care to protect Confidential Information obtained from the other Party as it employs to protect its own Confidential Information.
- B. Each Party may have equitable relief, by injunction or otherwise, to enforce its rights under this provision to prevent the release of Confidential Information without bond or proof of damages and may seek other remedies available at law or in equity for breach of this provision.

SECTION 7.06. Insurance

- A. The EPS Operator may only require an Interconnection Customer to purchase General Public Liability Insurance covering damages to the EPS Operator or PREPA, and then only in the following amounts:
- B. Up to one million dollars (\$1,000,000) per occurrence and up to one million dollars (\$1,000,000) in the aggregate if the Distributed Generation System or Microgrid's Export Capacity is greater than 300 kW;
- C. No insurance is required if the Distributed Generation System or Microgrid's Export Capacity is less than or equal to 300 kW.

SECTION 7.07. Comparability

The EPS Operator shall receive, process and analyze all Interconnection Applications as set forth in this Regulation. The EPS Operator shall use the same Reasonable Efforts in processing and analyzing Interconnection Applications from all Interconnection Customers, whether the proposed interconnection is owned or operated by the EPS Operator, PREPA, their subsidiaries or affiliates, or others.

SECTION 7.08. Design, Procurement, Installation and Construction of Interconnection Facilities and Upgrades

- A. The Interconnection Customer shall pay for the cost of the Interconnection Facilities and Distribution Upgrades as described and itemized pursuant to the Interconnection Agreement and its attachments. The cost responsibility of an Interconnection Customer for Upgrades shall be determined in accordance with the principles of reasonableness, proportionality, and benefit received established in Section 2 of Joint Resolution 5-2026, and shall be limited to the least-cost Upgrades necessary for, and attributable to, the interconnection. An

Interconnection Customer shall not be assigned the cost of correcting a pre-existing condition of the Electric Power System, or of Upgrades that serve customers generally, which shall be planned and funded under Section 7.11.

- B. If Network Upgrades are required, the actual cost of the Network Upgrades, including overheads, shall be borne initially by the Interconnection Customer; provided, however, that the Interconnection Customer may have a cash repayment pursuant to the Interconnection Agreement. As stated in the Interconnection Agreement, the EPS Operator shall provide ~~a best~~an itemized cost estimate ~~cost~~, including overheads, for the purchase and construction of the Interconnection Facilities, Distribution Upgrades, and Network Upgrades; ~~and provide a detailed itemization of such costs~~ (i.e. the estimates shall break out the materials, labor and other costs for major components of the Upgrades). The estimate shall be provided before the Interconnection Customer is required to make any election under Article 4 or Article 5, and the final amount charged shall not exceed the estimate by more than ten percent (10%) except for a documented change in the scope of the work requested by the Interconnection Customer.
- C. The Interconnection Customer and the EPS Operator shall agree on milestones for which each Party is responsible and list them in an attachment to the Interconnection Agreement. To the greatest extent possible, the Parties will identify all design, procurement, installation and construction requirements associated with a project, and clear associated timelines, at the beginning of the design, procurement, installation and construction phase, or as early within the process as possible. All timelines shall comport with industry best practices. In addition, whenever possible to capture additional efficiency, the EPS Operator will rely on template designs applicable to certain types of interconnections. These templates shall be publicly available on the EPS Operator's web site and/or provided directly to any interested entity upon request.
- D. Party's obligations under this provision may be extended by agreement. If a Party anticipates that it will be unable to meet a milestone for any reason other than a Force Majeure Event, it shall immediately notify the other Party of the reason(s) for not meeting the milestone and (1) propose the earliest reasonable alternate date by which it can attain this and future milestones, and (2) request appropriate amendments to the Interconnection Agreement and its attachments. The Party affected by the failure to meet a milestone shall not unreasonably withhold agreement to such an amendment unless (1) it will suffer significant uncompensated economic or operational harm from the delay, (2) attainment of the same milestone has previously been delayed, or (3) it has reason to believe that the delay in meeting the milestone is intentional or unwarranted notwithstanding the circumstances explained by the Party proposing the amendment. If the Party affected by the failure to meet a milestone disputes the proposed extension, the affected Party may pursue dispute resolution pursuant to Article 10 of this Regulation.

- E. At least twenty (20) Business Days before the commencement of the design, procurement, installation, or construction of a discrete portion of the EPS Operator's Interconnection Facilities and Upgrades, the Interconnection Customer shall provide the EPS Operator, at the Interconnection Customer's option, a guarantee, a surety bond, letter of credit or other form of security reasonably acceptable to the EPS Operator and is consistent with the Puerto Rico Uniform Commercial Code. Such security for payment shall be in an amount sufficient to cover the costs for constructing, designing, procuring, and installing the portion of the EPS Operator's Interconnection Facilities and Upgrades and shall be reduced on a dollar-for-dollar basis for payments made to the EPS Operator under the Interconnection Agreement during its term. In addition:
- (1) The guarantee must be made by an entity that meets the creditworthiness requirements of the EPS Operator and contain terms and conditions that guarantee payment of any amount that may be due from the Interconnection Customer, up to an agreed-to maximum amount.
 - (2) The letter of credit or surety bond must be issued by a financial institution or insurer reasonably acceptable to the EPS Operator and must specify a reasonable expiration date.
- F. The EPS Operator shall bill the Interconnection Customer for the design, engineering, construction, and procurement costs of Interconnection Facilities and Upgrades described in the Interconnection Agreement monthly, or as otherwise agreed by the Parties in the Interconnection Agreement. The Interconnection Customer shall pay each bill within twenty (20) Business Days of receipt, or as otherwise agreed to by the Parties in the Interconnection Agreement.
- G. Within three (3) months of completing the construction and installation of the EPS Operator's Interconnection Facilities and/or Upgrades described in the Interconnection Agreement and its attachments, the EPS Operator shall provide the Interconnection Customer with a final accounting report of any difference between (1) the Interconnection Customer's cost responsibility for the actual cost of such facilities or Upgrades, and (2) the Interconnection Customer's previous aggregate payments to the EPS Operator for such facilities or Upgrades. If the Interconnection Customer's cost responsibility exceeds its previous aggregate payments, the EPS Operator shall invoice the Interconnection Customer for the amount due and the Interconnection Customer shall pay to the EPS Operator within twenty (20) Business Days. If the Interconnection Customer's previous aggregate payments exceed its cost responsibility under the Interconnection Agreement, the EPS Operator shall refund to the Interconnection Customer an amount equal to the difference within twenty (20) Business Days of the final accounting report.

SECTION 7.09. Export Capacity of a Distributed Generation System or Microgrid

- A. The technical specifications in this Section 7.09 are intended to identify acceptable Export Control methods to facilitate the interconnection and Parallel Operation of Limited-Export and Non-Export Generating Facilities and Microgrids with the EPS.

If a Distributed Generation System or Microgrid uses any configuration or operating mode in this Section 7.09, to limit the export of electrical power across the Point of Common Coupling, then the Export Capacity shall be only the amount capable of being exported (not including any Inadvertent Export). To prevent impacts on system safety and reliability, any Inadvertent Export must comply with the limits identified in this section. The Export Capacity specified in the Interconnection Application will be included as a limitation in the Interconnection Agreement. An Interconnection Customer seeking to interconnect using the operating modes under this Section 7.09 shall submit proposed control and/or protection settings in their Interconnection Application for review by the EPS Operator to verify compliance with the requirements of this Section. [An Interconnection Customer may elect a configuration or operating mode under this Section in its Interconnection Application or at any election point during review, and the EPS Operator shall evaluate the interconnection as so configured.](#)

- B. The export controls identified in this subsection are for Non-Exporting systems only.

- (1) Reverse Power Protection: To limit export of power across the Point of Common Coupling, a reverse power protective function is implemented using a utility grade protective relay. The default setting for this protective function shall be 0.1% (export) of the Interconnection Transformer's nominal base Nameplate Rating, with a maximum 2.0 second time delay to limit Inadvertent Export.
- (2) Minimum Power Protection: To limit export of power across the Point of Common Coupling, a minimum import protective function is implemented utilizing a utility grade protective relay. The default setting for this protective function shall be 5% (import) of the generating unit's total Nameplate Rating, with a maximum 2.0 second time delay to limit Inadvertent Export.
- (3) Relative Distributed Generation System Rating: This option requires the Distributed Generation System or Microgrid's Nameplate Rating to be so small compared to the minimum Host Load that using additional protective functions does not have to ensure that power will not be exported to the EPS. This option requires the Distributed Generation System or Microgrid's Nameplate Rating be no greater than 50% of the

verifiable minimum Host Load over the past 12 months.

For Generating Facilities or Microgrids with a Nameplate Rating above 250 kW, the EPS Operator may require additional assurances, equipment or agreements based upon evaluation of the stability and reliability of the minimum Host Load data.

C. The export controls identified in in this subsections are for Limited Export systems only.

- (1) Directional Power Protection: To limit export of power across the Point of Common Coupling, a directional power protective function is implemented using a utility grade protective relay. The default setting for this protective function shall be the Export Capacity value, with a maximum 2.0 second time delay to limit Inadvertent Export.
- (2) Configured Power Rating: A reduced output active or apparent power rating utilizing the power rating configuration setting may be used to ensure the Distributed Generation System or Microgrid does not generate power beyond a certain value lower than the Nameplate Rating. The reduced power rating shall be indicated with a Nameplate Rating replacement, or by a supplemental adhesive Nameplate Rating tag to indicate the reduced Nameplate Rating. At the discretion of the EPS Operator, the applicant may additionally be required to provide a letter from the manufacturer confirming the reduced Nameplate Rating.

D. The export controls identified in this subsection are for either Non-Export or Limited Export systems.

- (1) Power Control Systems: This option is not available for interconnections to Networked Secondary Systems. A Distributed Generation System or Microgrid may utilize a ~~NRTL-certified~~ Power Control System⁵ certified by a NRTL to UL 3141 (or the NRTL certification requirement decision that preceded it) and inverter system with a maximum open loop response time of no more than 30 seconds. Upon loss of communications, a Limited Export system using a Power Control System shall revert to its certified export limit and shall not be required to cease export. Failure of the control or inverter system resulting from abnormal conditions must result in the Distributed Generation System or Microgrid entering an operational mode where no energy is exported across the Point of Common Coupling to the EPS.

⁵ NRTL testing to the UL Power Control System Certification Requirements Decision shall be accepted until similar test procedures for Power Control Systems are included in a standard.

If a Distributed Generation System or Microgrid with a Nameplate Rating greater than 1 MW uses an NRTL certified Power Control System, the EPS Operator and the Interconnection Customer must mutually agree on an acceptable open loop response time.

- (2) Limited Export Using Mutually Agreed-Upon Means: Generating Facilities or Microgrids may be designed with other control systems and/or protective functions to limit export and Inadvertent Export by agreement between the EPS Operator and the Interconnection Customers. The limits may be based on technical limitations of the Interconnection Customer's equipment or EPS equipment. To ensure Inadvertent Export remains within mutually agreed-upon limits, the Interconnection Customer may use an uncertified Power Control System, an internal transfer relay, energy management system, or other customer facility hardware or software if approved by the EPS Operator.

E. If the Interconnection Application proposes to limit export pursuant to this Section 7.09, the Fast Track screens, and feasibility, system impact, and transmission studies shall study the project according to how it intends to operate. When performing these studies, the EPS Operator:

- (1) Shall consider the proposed design, operating characteristics, Export Capacity, and Operating Profile found in the Interconnection Application.
- (2) Shall use the Export Capacity unless assessing fault current contribution, when the use of the Nameplate Rating may be appropriate. The EPS Operator may use Export Capacity when assessing fault current contribution if the Interconnection Customer demonstrates that fault currents are controlled by some means. The Fast Track screens identify when it is appropriate to use Export Capacity or Nameplate Rating.

SECTION 7.10. Excessive Customer Curtailment Compensation

- A. Purpose. This Section implements Section 2 of Joint Resolution 5-2026, which requires this Regulation to adopt compensation for the economic losses of customers who suffer restrictions on the export of energy associated with the imposition of inverter configurations.
- B. Scope. This Section applies to every Net Metering System, whether interconnected under the Simplified Process, the Fast Track Process, or the Study Process. An Interconnection Customer is entitled to compensation under this Section for any restriction on the export of energy from a Net Metering System that (1) is imposed by the EPS Operator, or results from inverter or

Power Control System settings required by the EPS Operator or the Energy Bureau, whether at interconnection or thereafter, and (2) is not a Limited Export or Non-Export configuration voluntarily elected by the Interconnection Customer under Section 7.09 or Article 4. A restriction arising from a condition of the EPS Operator's facilities, whether the service transformer, secondary conductors or service drop serving the Point of Common Coupling or any facility upstream of the service transformer, is compensable. A restriction attributable to a condition of the installation on the Interconnection Customer's side of the Meter, or to the Interconnection Customer's noncompliance with this Regulation, documented in a written notice, is not compensable for the period of the condition or noncompliance.

- C. Conditions of any restriction. Before imposing a compensable restriction, the EPS Operator shall issue a written notice to the Interconnection Customer stating the condition addressed, the data and criteria relied upon, the restriction imposed, its expected duration, and the Upgrade or other action that will remove it. The restriction shall be the least restrictive measure reasonably necessary, shall be reviewed by the EPS Operator at least every six (6) months, and shall be lifted when the condition is resolved. The notice may be reviewed under Section 13.02. No restriction of export shall be imposed, on any system or group of systems, because of the condition or capacity of any facility upstream of the service transformer, whether by instruction, by remote command, or by inverter or Power Control System settings, unless so established in the Technical Interconnection Requirements as approved by the Energy Bureau.
- D. Measure of compensation. Compensation shall equal the value, at the credit for energy export applicable to the customer under Article 9, of the energy the customer would have exported but for the restriction, estimated from the system's metered exports before the restriction or, where no such record exists, from a production model using the system's Export Capacity and the applicable solar resource, in a methodology published in the TIR as approved by the Energy Bureau. Compensation is payable for any calendar quarter in which the estimated value of the energy the customer would have exported but for the restriction exceeds fifty dollars (\$50).
- E. Administration. The EPS Operator shall apply the compensation as a credit on the customer's bill within thirty (30) days after the end of each calendar quarter, without requiring a claim by the customer, and shall identify the credit on the bill. Compensation paid under this Section is a cost of the EPS Operator's compliance with this Regulation and shall not be assessed to Interconnection Customers through fees under this Regulation.
- F. Reporting. The EPS Operator shall report the number of restrictions imposed, their duration, the feeders affected, and the compensation credited, in the Quarterly Interconnection Report under Section 12.02.

SECTION 7.11. Proactive Hosting Capacity Planning and Budgeting

- A. Purpose. This Section implements Section 2 of Joint Resolution 5-2026, which requires this Regulation to adopt proactive hosting capacity planning and budgeting. Its purpose is that the EPS Operator plan, budget, and build the Distribution System ahead of demand so that the Distributed Generation Systems and Energy Storage forecast to interconnect can do so, and export, without restriction, rather than addressing capacity one interconnection at a time.
- B. Forecast. Within twelve (12) months after the effective date of this Regulation, and annually thereafter, the EPS Operator shall prepare and publish on the Cyber Portal a forecast, by feeder, of the Distributed Generation and Energy Storage expected to interconnect during at least the following five (5) years, based on historical interconnection volumes, the Public Queue, and the public policy objectives of Act 17-2019.
- C. Hosting capacity analysis. Together with the forecast, the EPS Operator shall publish a hosting capacity analysis of every distribution feeder and, where data permit, of each line section and service transformer, prepared under a methodology filed with and approved by the Energy Bureau that (1) states its assumptions, data sources, and data vintage; (2) calculates Daytime Minimum Load as gross load; (3) uses Export Capacity, including the effect of export controls under Section 7.09; and (4) is validated against field measurements. The publication shall include, for each feeder and, where available, line section and service transformer, the Daytime Minimum Load, the Nameplate Rating and Export Capacity of interconnected and queued Distributed Generation Systems, and the available Hosting Capacity, and the interconnected and queued capacity shall be updated monthly. The Energy Bureau may direct the EPS Operator to apply guidance of the Interstate Renewable Energy Council or another recognized source in developing the methodology. The methodology and the analysis shall build on the hosting capacity work developed in Case No. NEPR-MI-2019-0011 (Distribution Resource Planning), including its Hosting Capacity Working Group and the interconnection-capacity maps and hosting-capacity analyses required in that proceeding, and shall be coordinated with it.
- D. Plan and budget. Within twelve (12) months after the effective date of this Regulation, and every three (3) years thereafter, the EPS Operator shall file with the Energy Bureau a Distribution Hosting Capacity Plan covering at least the following five (5) years that (1) identifies each feeder, line section, and service transformer where the forecast under paragraph B exceeds the available Hosting Capacity under paragraph C; (2) identifies the least-cost Upgrades and measures, including smart inverter settings, voltage regulation, and Energy Storage, that will accommodate the forecast without restriction, with their estimated cost and a completion schedule that precedes the forecast need; and (3) identifies the funding for those Upgrades, prioritizing federal

funds to the greatest extent possible and recovering the remainder through rates approved by the Energy Bureau, and proposes the corresponding budgets for consideration in the EPS Operator’s federal funding requests, rate cases, integrated resource plans, and capital plans. The Upgrades identified in the Plan shall not be assigned to individual Interconnection Customers.

E. Effect. The identification of a constraint in the forecast, the analysis, or the Plan shall not be a basis for denying, delaying, or restricting the interconnection, operation, or export of any Distributed Generation System, other than a restriction of export established in the Technical Interconnection Requirements as approved by the Energy Bureau, as provided in Section 7.10.C; the EPS Operator’s remedy for a forecast constraint is the timely completion of the Upgrades and measures identified in the Plan. The Pre-Application Report under Section 2.02 and the screens under Articles 3 and 4 shall use the most recent data published under this Section.

F. Proceeding. The Energy Bureau shall open a proceeding within sixty (60) days after the effective date of this Regulation to approve the methodology under paragraph C, review the Plans filed under paragraph D and the funding proposed in them, and oversee compliance with this Section, and may consolidate with it any existing docket concerning hosting capacity or distribution planning, including Case No. NEPR-MI-2019-0011.

ARTICLE 8. TECHNICAL REQUIREMENTS

SECTION 8.01. General Technical Requirements

The EPS Operator shall develop and maintain Technical Interconnection Requirements consistent with the requirements of this Regulation, which shall be submitted to the Energy Bureau for the Energy Bureau’s review and approval and shall not become effective unless approved by Resolution and Order of the Energy Bureau.

In addition, the Technical Interconnection Requirements may be amended by the EPS Operator from time to time provided that any such amendment shall not become effective unless and until approved by the Energy Bureau through a Resolution and Order..

- A. The technical requirements apply to Distributed Generation Systems and Microgrids when designed to operate in Parallel and shall be met at the Point of Common Coupling.
- B. The technical requirements are established in accordance with standards from IEEE, UL and ANSI, as applicable for the interconnection of Distributed Generation Systems and Microgrids to the EPS. Compliance with these requirements is intended to prevent the Distributed Generation System or Microgrid from causing adverse effects to the EPS such that it may have to be disconnected due to unsafe operating conditions.

- C. This regulation incorporates IEEE Std 1547-2018. Where conflicts exist between IEEE Std 1547-2018 and this regulation, this Regulation and the Technical Interconnection Requirements approved by the Energy Bureau shall govern.
- D. A Distributed Generation System interconnecting to the Distribution System must interconnect through an Interconnection Transformer. A direct interconnection to the Distribution System without a transformer is not permitted.
- E. For Microgrids, the technical requirements may be satisfied by the individual Distributed Generation Systems within the Microgrid, by other Microgrid equipment, or by coordination between Generating Facilities and other Microgrid equipment.
- F. For further information regarding these interconnection requirements, see the TIR approved by the Energy Bureau.
- G. The Technical Interconnection Requirements, and any amendment to them, shall be published for stakeholder comment for not less than thirty (30) days, and the Energy Bureau shall not act on them earlier than thirty (30) days after the close of the comment period. Except for the amount of the Simplified Interconnection Fee, which may be modified only as provided in Article 3.B, the Technical Interconnection Requirements shall not establish or modify any fee, time frame, eligibility criterion, screen threshold, or cost allocation established in this Regulation, and shall not add to, restrict, or condition any right or obligation established in this Regulation, other than a restriction of export because of the condition or capacity of a facility upstream of the service transformer, as provided in Article 3.C(4)(iv) and Section 7.10.C. No technical communiqué, directive, or procedure of PREPA or the EPS Operator concerning interconnection shall have effect unless approved by the Energy Bureau under this Section.

SECTION 8.02. Approval of Use of Certified Equipment

- A. All equipment that forms part of a Distributed Generation System based on renewable energy sources must be approved by the Public Energy Policy Program (“PEPP”), of the Department of Economic Development and Commerce (“DEDC”) including, but not limited to, photovoltaic modules, wind turbines, synchronous generators, induction generators, inverters and control systems. PEPP must certify that the inverters and control systems that interconnect the renewable energy sources with the electrical network comply with the applicable standards.
- B. The EPS Operator allows the use of equipment with inverter technology, generators, relays and other devices that comply with applicable standards and codes. ~~These have to be evaluated and approved~~Inverters, Power Control Systems, and Energy Storage

listed by the California Energy Commission, or certified by a Nationally Recognized Testing Laboratory to UL 1741 (with its applicable supplements) and IEEE Std 1547-2018 and IEEE Std 1547.1-2020, are approved for use upon such listing or certification without further evaluation by the EPS Operator.

- C. The EPS Operator has a list of approved inverters and control systems periodically updated, which is made available on the DG Portal website. The EPS Operator shall ~~keep update~~ this list ~~updated annually~~ at least monthly to reflect equipment approved under the preceding paragraph. The first review and update shall occur no later than 30 Business Days after the approval of this ~~Rule~~ Regulation. The EPS Operator shall issue a notice to customers that all inverters and control equipment must be approved by the EPS Operator in order to connect to the grid.
- D. ~~If the equipment has not been evaluated~~ If the interconnecting equipment has not been evaluated and approved by the EPS Operator, it may request that the manufacturer, distributor or owner send to the EPS Operator, in digital file in PDF format, documents certifying that the inverter complies with the following:
- (1) Are certified by a Nationally Recognized Testing Laboratory. This ensures that they meet the acceptance criteria of the tests required in the IEEE 1547 or UL 1741 standard and its Supplements, as applicable, for equipment that operates continuously in parallel with the systems of the electricity companies.
 - (2) Comply with the permitted harmonic content distortion limits, according to the IEEE 1547-2018 standard and other applicable ones.
 - (3) Comply with the Voltage Flicker limits, depending on the IEEE 1547-2018 standard and other applicable.
 - (4) Comply with these regulations. Should any conflict arise with other standards, these regulations will prevail.
 - (5) Have the ability to Operate in Parallel with the EPS.
 - (6) Have the ability to adjust in the field of frequency, voltage and operating times.

E. The EPS Operator shall approve or deny such equipment in writing, stating the basis for any denial, within twenty (20) Business Days after receiving complete documentation; a denial may be reviewed under Section 13.02.

~~E.F.~~ For further information regarding these interconnection requirement, see the TIR.

SECTION 8.03. Meter Socket Adapters

A. Purpose and applicability

- (1) In accordance with Section 2 of Joint Resolution 5-2026, this Section sets forth requirements for customer-owned Meter Socket Adapters

installed in single-phase services rated two hundred (200) amperes or less, and to other service or meter-socket configurations where the Meter Socket Adapter is NRTL listed for that configuration.

- (2) The EPS Operator shall not deny, condition, or delay any step of the interconnection process, the installation or configuration of a Meter, or enrollment in a Net Metering Program on the ground that the interconnection incorporates a Meter Socket Adapter that meets this Section. A Meter Socket Adapter is owned by the Interconnection Customer, is not a Material Modification, and shall not cause an interconnection to fail any screen or trigger a Supplemental Review.

B. General Requirements

- (1) No later than thirty (30) Business Days after the effective date of this Regulation, the EPS Operator shall publish and maintain on the DG Portal: (a) the minimum product and technical requirements for Meter Socket Adapters, which shall not exceed the criteria in Section 8.03.B.2; (b) the installation procedures required by Section 8.03.C; (c) the list of Meter Socket Adapter models approved for use in Puerto Rico; and (d) a dedicated electronic mail address and submission instructions for ~~Meter Socket Installation requests~~model evaluation requests and installation notices. The EPS Operator shall ~~review and~~ update the list of approved Meter Socket Adapter models within ten (10) Business Days after each approval and shall review it at least ~~annually~~monthly.
- (2) The EPS Operator shall ~~facilitate the installation of a Meter Socket Adapter~~approve a Meter Socket Adapter model, and shall facilitate its installation, if the device:
- (i) is qualified to be connected to the supply side of the service disconnect pursuant to the applicable provisions of the National ~~Electric Code in force~~Electrical Code as adopted in Puerto Rico; a supplementary regulation of PREPA or the EPS Operator shall not be applied to prohibit or condition a Meter Socket Adapter that meets this Section;
 - (ii) is ~~approved or listed by a nationally recognized testing laboratory~~listed by a Nationally Recognized Testing Laboratory to UL 414 and to the standards applicable to the other functions the device performs, and is rated appropriately for the meter socket into which it is intended to be installed;
 - (iii) is certified to meet all applicable standards, as determined by a nationally recognized testing laboratory approved by the Energy Bureau; and,

- (iv) does not prevent access to the sealed meter socket compartment or the pull section of the service section of the electric meter or switchboard, as applicable;
- (3) Any existing Customer generation or Energy Storage sources on the property that are interconnected with the EPS Operator service must be identified on the application for the installation of a Meter Socket Adapter and submitted drawings;
- (4) ~~Subject to exceptions approved by the EPS Operator, the main breaker and meter socket are contained in the same electrical panel.~~ Only one (1) Meter Socket Adapter may be installed in a meter socket; Meter Socket Adapters shall not be stacked.
- (5) The EPS Operator shall approve or deny ~~an application for the installation of~~ a Meter Socket Adapter model in writing no later than twenty (20) Business Days after ~~an Interconnection Customer submits such application~~ receiving a complete evaluation request from a manufacturer, an Interconnection Customer, or a registered installer. If the EPS Operator neither approves nor denies the model within that period, the model shall be deemed approved and shall be added to the published list within five (5) Business Days. No separate application or approval is required for the installation of an approved model; the Interconnection Customer shall identify the model in the Simplified Interconnection Notification or Interconnection Application and, where the installation is performed under Section 8.03.C(2), the Authorized Agent shall give the notice required there.
- (6) The EPS Operator shall not reject Meter Socket Adapters for reasons other than justified safety concerns or demonstrated non-compliance with established national industry standards. The EPS Operator shall assess Meter Socket Adapters on an objective, consistent, and non-discriminatory basis, based solely on the criteria established in this Section and applicable national industry standards.
- (7) Any device rejection shall be in writing and shall state with specificity the factual and technical basis for the denial, including any testing evidence relied upon to demonstrate non-compliance with applicable safety criteria or standardized interoperability requirements. A denial may be appealed to the Energy Bureau under Section 13.02.
- (8) The EPS Operator shall not require testing beyond Nationally Recognized Testing Laboratory listing, except a verification that the Meter Socket Adapter does not impair Meter accuracy or Meter communications. Such verification shall be performed at the EPS Operator's expense within the period stated in paragraph (5). The EPS

Operator shall accept equivalent verification results obtained by a manufacturer or another electric utility for the same model, unless the EPS Operator identifies in writing a material difference between the metering and communications equipment used to obtain those verification results and its own.

C. Installation Requirements

- (1) The EPS Operator shall facilitate the installation of Meter Socket Adapters that meet the ~~aforementioned safety criteria and standards~~criteria in Section 8.03.B.2.
- (2) ~~Only EPS Operator personnel or its authorized agents shall perform installation, removal, or related services on the Meter Socket Adapter.~~The installation, removal, or servicing of a Meter Socket Adapter, including the removal and reinstallation of the Meter for that purpose, shall be performed by the EPS Operator or by an Authorized Agent. For purposes of this Section, an Authorized Agent is a licensed electrical engineer or expert electrician licensed in Puerto Rico who is registered with the EPS Operator under paragraph (6), and such a person is hereby authorized, as an agent of the EPS Operator, to remove and reinstall the Meter for the installation, removal, or servicing of an approved Meter Socket Adapter. An Authorized Agent shall (i) give notice through the Cyber Portal not less than two (2) Business Days before removing the Meter, identifying the service address, the Meter serial number, and the approved model; (ii) before reinstalling the Meter, inspect the meter socket and not proceed where a condition would prevent the Meter from being reinstalled safely; (iii) apply a numbered tamper-evident seal furnished by the EPS Operator; and (iv) submit a completion notice with the seal number and photographs of the meter socket before and after the installation within one (1) Business Day. No site visit by the EPS Operator shall be required as a condition of the installation or of the operation of the system; the EPS Operator may inspect and reseal the installation at any time.
- (3) Only EPS Operator personnel or the EPS Operator's authorized agents are permitted to remove or reinstall an EPS Operator meter. ~~No~~Except as provided in paragraph (2), no Interconnection Customer, their agents, or any non-EPS Operator third-party may access, or otherwise breach the seal surrounding the electric meter. If installation of the Meter Socket Adapter requires removal of the EPS Operator meter, removal and reinstallation of the meter must be performed by the EPS Operator or ~~its authorized agents~~an Authorized Agent.
- (4) Any maintenance of a Meter Socket Adapter which requires its removal ~~must involve an on-site, EPS Operator personnel or the EPS Operator's~~

~~authorized agents who will first remove the EPS Operator's meter to allow a third party to perform maintenance on the Meter Socket Adapter~~ shall be performed by, or with the Meter removed by, the EPS Operator or an Authorized Agent in accordance with paragraph (2).

- (5) Interconnection Customers will supply and retain the ownership of Meter Socket Adapters and associated equipment, exclusive of any EPS Operator-owned metering hardware.
- (6) The EPS Operator shall register a licensed electrical engineer or licensed expert electrician who requests registration as an Authorized Agent within twenty (20) Business Days after a complete request, shall make training on its installation procedures available at no charge in Spanish and English, and shall furnish tamper-evident seals at no charge. The EPS Operator may suspend or revoke a registration for cause by written notice stating the basis, subject to review under Section 13.02. Where the Interconnection Customer requests that the EPS Operator itself remove and reinstall the Meter, the EPS Operator shall do so within ten (10) Business Days after the request.

D. Fees

- (1) ~~All fees imposed under this Section, including any fee for an additional site visit, shall be based on the reasonable cost of providing the applicable service and shall be established in the TIR as approved by the Energy Bureau.~~ The EPS Operator shall not charge any fee for the evaluation or approval of a Meter Socket Adapter model, for the installation of an approved Meter Socket Adapter by an Authorized Agent, or for the inspection or resealing of a Meter Socket Adapter; the charges of an Authorized Agent for its own services are not regulated by this Section. Where the Interconnection Customer requests that the EPS Operator remove and reinstall the Meter under Section 8.03.C(6), the EPS Operator may charge only the fee, if any, approved by the Energy Bureau for the removal and reinstallation of a Meter requested for other customer electrical work; no fee shall apply solely because a Meter Socket Adapter is involved.
- ~~(2) The Interconnection Customer, or authorized agent on the customer's behalf, shall pay the EPS Operator a one-time fee for the cost of providing support, including reasonable administration, time, and materials, for removal of the utility meter to enable installation, removal, or related service of a Meter Socket Adapter. Any additional support or services required or requested will be charged an additional one-time fee for each site visit.~~

~~(3)~~(2) ~~If the installation of an approved Meter Socket Adapter requires~~Consistent with Section 3 of Act 114-2007, as amended, the EPS Operator shall install the Meter in the existing meter socket and shall not require the relocation of the meter enclosure or the replacement of the meter housing ~~solely~~ to accommodate ~~the~~a Meter Socket Adapter, except where the location of the existing meter socket fails to meet the safety standards of the National Electrical Code. Where relocation or replacement is so required, the EPS Operator shall, upon request of the customer, provide an estimate of the associated costs. ~~Such costs, which~~ shall be the responsibility of the Interconnection Customer to the extent they are reasonably attributable to the installation of the Meter Socket Adapter and are not otherwise required to be borne by the EPS Operator under applicable law, regulation, or tariff.

ARTICLE 9. NET ENERGY METERING

SECTION 9.01. Participation in Net Metering Programs

- A. A Distributed Generation System fueled by Renewable Energy Sources may participate in net metering if it ~~is~~has:

(1) An Export Capacity of not more than twenty-five (25) kW for residential customers;

~~(1)~~(2) ~~Not more~~An Export Capacity of not more than one (1) MW for commercial, governmental, industrial or agricultural customers, or educational institutions or medical-hospital facilities connected to distribution voltages (up to 13.2~~kW~~ kV); and

~~(2)~~(3) ~~Not~~An Export Capacity of not more than five (5) MW for commercial, governmental, industrial, or agricultural customers, or educational institutions or medical-hospital facilities connected to subtransmission or transmission voltages (38~~kW~~ kV or 115~~kW~~ kV).

- B. An Interconnection Customer that meets these requirements may participate in net metering if the Simplified Interconnection Notification or Interconnection Application includes a request to participate in one of the following Net Metering Programs: the Basic Net Metering Program, the Aggregate Net Metering Program and the Shared Net Metering Program.

C. Energy Storage Paired with Net Metering Systems

- (1) While an Energy Storage device may be paired with a Net Metering System, an Energy Storage device standing alone does not qualify as a Net Metering System. An Energy Storage device standing alone may be interconnected under this Regulation and shall not export energy to the

Electric Power System, except that it may export under the terms of a virtual power plant, demand response, or similar program approved by the Energy Bureau, and shall be compensated for such export as provided in that program.

- (2) When an Energy Storage Device is paired with a Net Metering System, the ~~Distributed Generation System or shall be programmed with one or both of the following operating restrictions~~Interconnection Customer shall elect one of the following operating restrictions of the Energy Storage Device, unless the Energy Storage Device participates in a program approved by the Energy Bureau that provides otherwise:
 - (i) Restricted from exporting electricity to the Electric Power System, beyond Inadvertent Export, and/or
 - (ii) Restricted to being charged solely from the customer's Net Metering System and not from the Electric Power System.
- (3) An election to operate an Energy Storage Device with an operating restriction shall be identified in the Application, including a description of the operating restriction.
- (4) A signed attestation of the operating restriction shall be provided by the Operator of the Energy Storage Device.
- (5) The customer may ~~propose to~~ modify the operating restriction by submitting a revised attestation to the EPS Operator. ~~The EPS Operator must approve the proposed revision in writing; approval shall not be unreasonably withheld or delayed~~ through the Cyber Portal, which shall be effective upon submission.

SECTION 9.02. Basic Net Metering Program

- A. In the Basic Net Metering Program, a Distributed Generation System connected to the Distribution System shall have a maximum ~~installed AC capacity~~Export Capacity (kW AC) of twenty-five (25) kW for residential customers and one (1) MW for commercial, governmental, industrial, agricultural, educational institutions and hospital medical facilities. ~~Generating Facilities~~Distributed Generation Systems connected to the subtransmission or transmission systems shall have a maximum ~~installed AC capacity of 5~~Export Capacity (kW AC) of five (5) MW for commercial customers, governmental, industrial, agricultural, educational institutions and hospital medical facilities.
- B. Net metering for a Distributed Generation System whose ~~maximum installed AC power capacity~~Export Capacity does not exceed twenty-five (25) kW shall be reflected in the customer's monthly bill not later than thirty (30) days after the receipt of notice of ~~their~~the certification of the distributed generator

~~installed by a professional engineer or expert electrician~~by a licensed electrical engineer or licensed expert electrician, in accordance with Section 9(b) of Act 114-2007. Where the EPS Operator has not installed or configured the Meter or updated its billing system within that period, credits for energy exported from the thirtieth (30th) day after the notice shall be applied retroactively to the customer's bill, based on metered exports or, where the Meter was not yet installed, on the system's estimated exports. At the customer's election, the retroactive credits shall instead be paid by check or electronic deposit as provided in Section 6.01.B.

SECTION 9.03. Aggregate Net Metering Program

- A. ~~The Aggregate Net Metering Program applies only to governmental Entities and non-profit academic institutions~~Eligibility. Any customer may aggregate two (2) or more service agreements held in its name or by an entity under common ownership or control with it, as the customer shall certify through the Cyber Portal.
- B. ~~For customers with service on distribution voltages, the maximum installed AC capacity of the Distributed Generation System must be 1 MW. For customers with service on transmission or subtransmission voltages, the maximum installed AC capacity of the Distributed Generation System must be 5 MW~~Locations. Participating service agreements may be anywhere in the EPS Operator's service territory, on or off the premises of the Net Metering System.
- C. ~~All locations with service agreements that take advantage of this program must be included in the same account~~Voltage levels. Participating service agreements may differ in voltage level and rate schedule.
- D. ~~The locations may be interconnected to primary distribution, secondary distribution,~~Export Capacity. The Export Capacity at each generating location, meaning each participating service agreement where a Net Metering System is installed, shall not exceed one (1) MW at distribution voltage or five (5) MW at subtransmission, or transmission systems. However, all participating locations must receive service at the same voltage levelvoltage, nor any lower limit under Section 9.01.A. These limits apply per generating location, not to the combined Export Capacity of different locations.
- E. ~~The service agreements to which the energy is to be accredited must be (1) within the same location where the Distributed Generation System is installed or (2) in other locations interconnected to the same power line at a distance not greater than two miles from the Distributed Generation System~~Allocation. Through the Cyber Portal, the customer shall designate the percentage of each Net Metering System's exported energy credited to each participating service agreement, totaling not more than one hundred percent (100%). The customer may change the percentages or service agreements once in any twelve (12)

months and whenever a service agreement is added or closed; changes take effect with the first billing period beginning at least thirty (30) days after filing.

- F. ~~The Agreement to interconnect the Distributed Generation System and participate in this program will be effective thirty (30) days after the first rate revisions established in Law 57, as amended~~Application and crediting. The Simplified Interconnection Notification or Interconnection Application shall identify each generating location, the other participating service agreements, and the percentages. Energy is credited under Section 9.05.F.

SECTION 9.04. Shared Net Metering Program

- A. ~~The Shared Net Metering Program applies exclusively to residential and commercial customers with primary and secondary voltage distribution services under the horizontal property regime, such as residential, commercial or mixed-use condominiums. This Program also applies to public housing managed by the Department of Housing~~Eligibility. Customers with service agreements at the same premises may share one Net Metering System. Premises means a building or complex (such as a condominium, apartment complex, mixed-use building, commercial center, or public housing) under one owner, horizontal property regime, or owners' association, on one parcel or on contiguous parcels, including parcels separated only by a street, easement, or right-of-way.
- B. ~~The location of the service agreements to which the energy is to be accredited must be within the same location where the Distributed Generation System is installed~~Points of delivery. Participating service agreements need not share a point of delivery or Interconnection Transformer with the Net Metering System.
- C. ~~All service agreements must be serviced from the same point of delivery to which the Distributed Generation System is interconnected. The point of delivery can be the interconnection transformer in secondary distribution systems or the private substation in primary distribution systems~~Interconnection Customer. The owner of the premises, the board or council of owners, the owners' association, or a person authorized by any of them shall be the Interconnection Customer and sign the Interconnection Agreement.
- D. ~~For residential cases, the maximum capacity of the Generation Facility is 25 kW per participating customer or the capacity of the Interconnection Transformer, whatever smaller, up to a maximum of 1 MW~~Participation agreement. The Interconnection Customer shall file through the Cyber Portal a participation agreement with the participating customers assigning each participating service agreement, including any common-area service agreement, a

percentage of the Net Metering System's exported energy, totaling not more than one hundred percent (100%).

- E. ~~For commercial or mixed use cases, the maximum capacity of the Distributed Generation System is the same as the capacity of the Interconnection Transformer, up to a maximum of 1 MW~~Changes. Customers may join or leave on thirty (30) days' notice to the Interconnection Customer, which shall update the filing; Section 9.03.E governs other changes and effective dates. A new customer of record keeps its service agreement's percentage unless the agreement is amended.
- F. ~~As required by these regulations, the owner of the Distributed Generation System must sign an Interconnection Agreement with the EPS Operator and Participate in the Net Metering Program. The owner of the Distributed Generation System can be the Board of Owners, the Owners Association, the owner of the building or any natural or legal entity with similar functions~~Export Capacity. The Export Capacity of the Net Metering System shall not exceed the least of: (1) one (1) MW at distribution voltage or five (5) MW at subtransmission or transmission voltage; (2) the capacity of the Interconnection Transformer, unless upgraded under this Regulation; and (3) for residential premises, twenty-five (25) kW per participating service agreement.
- G. ~~Each participating customer that is not the owner of the Distributed Generation System must sign an Agreement for Participation in the Shared Net Metering Program (see Attachment X of the TIR)~~Responsibilities. The Interconnection Customer shall keep the filing current and notify each participating customer of any change in its percentage. Energy is credited under Section 9.05.F and G.

SECTION 9.05. Energy Compensation for Customers that Participate in the Net Metering Programs

Energy exported by the customer shall be compensated as described below; except in those cases in which any federal law or regulation expressly and specifically orders otherwise:

- A. Energy compensation will be effective at the beginning of the billing period after the installation or configuration of the meter, and no later than 30 days after the installation or configuration of the meter.
- B. For each billing period, the EPS Operator will measure the energy that the customer consumes from and the energy that the customer exports to the EPS.
- C. If during a billing period, the EPS Operator supplies the customer more energy than the customer exports, the customer will be charged for their Net Consumption.

- D. If during a billing period, the customer exports more energy than supplied by the EPS Operator, the customer will be charged the minimum invoice amount corresponding to the rate at which the service is being received. The minimum invoice is the amount that the EPS Operator charges a customer who does not consume electricity during a billing period. The EPS Operator shall register an excess in exported energy during any billing period up to a daily maximum of 300 kWh for residential customers and 10 MWh for commercial customers connected to the Distribution System. For customers connected to the Transmission System, any excess in exported energy during a billing period will be registered up to a daily maximum of 50 MWh. The excess in exported energy will be carried over to the invoice for the next billing period. For the Aggregate and Shared Net Metering Programs, these daily maximums apply to each participating service agreement, so that a Net Metering System's maximum is the sum of those of its participating service agreements.
- E. Any excess in exported energy, that the customer accumulates during the year and that has not been used by the close of the June billing period of each year, will be compensated as described below:
- (1) The EPS Operator shall use the greater of (a) ten cents per kilowatt-hour or (b) the price per kilowatt-hour that results from converting the average of the total price charged to customers throughout the year and subtracting the average of the fuel and power purchase adjustments.
 - (2) The customer will receive a credit on their monthly bill equal to 75% of the surplus energy and the remaining 25% of the surplus energy will be credited to the power bill of the Department of Education.
- F. ~~For customers who participate in the Aggregate Net Metering Program, besides paragraphs A to E of this Section, the following applies:~~ the Aggregate and Shared Net Metering Programs, the EPS Operator shall, for each billing period, credit the energy exported to the EPS at the generating location, as registered by its Meter, to the participating service agreements in the percentages on file. Paragraphs A to E, including the carryover under paragraph D and the annual compensation under paragraph E, apply to each participating service agreement as if the energy credited to it had been exported at its own Meter. Unassigned percentages are credited to the service agreement at the generating location. The EPS Operator may bill the participating service agreements on the same billing cycle.
- ~~(1) — Service agreements at the same location: The maximum amount of energy to be credited to all participating service agreements at the location where the Distributed Generation System is installed may be up to 100% of the consumption of all the service agreements. This energy will be credited first to the service agreement associated with~~

~~the Distributed Generation System and the excess will be credited equally to the rest of the service agreements on the same account.~~

~~(2) Service agreements at different locations: The maximum amount of energy to be credited to all participating service agreements may be up to 120% of the consumption of the service agreements at the location where the Distributed Generation System is installed. This energy will be credited first to the service agreement associated with the Distributed Generation System and the excess will be credited equally to the rest of the service agreements, up to 100% of the consumption of the service agreements within the location where the Distributed Generation System is installed and the remaining 20% of the energy production will be credited equally to the service agreements in the other locations on the same account.~~

- G. For ~~customers participating in~~ the Shared Net Metering Program, ~~besides the provisions of paragraphs A to E of this Section, 100% of the energy produced by the Distributed Generation System will be credited equally among all participants of this program~~the percentage of a closed or vacant service agreement is credited to the service agreement the Interconnection Customer designates.

ARTICLE 10. DISPUTE RESOLUTION

- A. The Parties agree to attempt to resolve all disputes arising out of the interconnection process and associated studies and Interconnection Agreements according to this Article.
- B. If a dispute occurs, the disputing Party shall provide the other Party a written Notice of Dispute containing the relevant known facts pertaining to the dispute, the specific dispute and the relief sought, and express notice by the disputing Party it is invoking the procedures under this Article. The notice shall be sent to the non-disputing Party's email address and physical address in the Interconnection Agreement or Interconnection Application, if there is no Interconnection Agreement. A copy of the notice shall also be sent to the Interconnection Ombudsperson at the Energy Bureau.

The non-disputing Party shall acknowledge the notice within three (3) Business Days of its receipt and identify a representative with the authority to decide for the non-disputing Party regarding the dispute.

- C. If the dispute is principally related to one or both Parties' compliance with timelines specified in these Regulations or associated agreements, the Parties shall seek assistance from the Interconnection Ombudsperson if the Parties cannot mutually resolve the dispute within eight (8) Business Days.

- D. If the dispute is not principally about one or both Parties' compliance with a timeline, then the non-disputing Party shall provide the disputing Party with all relevant regulatory and/or technical details and analysis regarding any interconnection requirements under dispute within ten (10) Business Days of the date of the notice of dispute. The confidentiality provisions of Section 7.05 apply here. Within twenty (20) Business Days of the date of the notice of dispute, the Parties' authorized representatives will have to meet and confer to try to resolve the dispute. Parties shall operate in good faith and use best efforts to resolve the dispute.
- E. If a resolution is not reached in thirty (30) Business Days from the date of the notice, either:
 - (1) A Party may request to continue negotiations for an additional twenty (20) Business Days;
 - (2) The Parties may by agreement make a written request for mediation to the Interconnection Ombudsperson; or
 - (3) Both Parties by agreement may request mediation from an outside third-party mediator with costs to be shared equally between the Parties.
- F. If the results of the mediation are not accepted by one or more Parties and there is still disagreement, the dispute shall proceed to the Energy Bureau's process for reconsideration in accordance with Article 13.
- G. At any time, either Party may request reconsideration by the Energy Bureau in accordance with Article 13.

ARTICLE 11. PENALTIES

- A. Anyone who infringes this Regulation or who alters all or part the EPS or an electric installation in a manner such that the operation of a Distributed Generation System or Microgrid cannot be accurately monitored including, but not limited to, its bi-directional energy flow shall be ~~penalized by the EPS Operator and/or Energy Bureau with the corresponding administrative~~subject to the corresponding administrative sanctions imposed by the Energy Bureau, upon referral by the EPS Operator where applicable, in accordance with the sanctions and penalties established in Act 83-1941 and Act 57-2014 and the regulations adopted pursuant to the same.
- B. The EPS Operator is authorized to investigate matters regarding the interconnection of Distributed Generation Systems and Microgrids with the ~~EG~~EPS, including the veracity of the information stated in the certifications, inspection reports and any other documents filed with the EPS Operator under

this Regulation and can take the appropriate actions (administrative and judicial) authorized by laws.

- C. If the EPS Operator and/or Energy Bureau, as applicable, determines that a Distributed Generation System or Microgrid was interconnected in violation of applicable legal provisions, or detects any irregularity, deficiency, omission or fraud in the certifications filed, the ~~EPS Operator and/or Energy Bureau, as applicable,~~Energy Bureau may impose the administrative sanctions established in Act 83-1941 and Act 57-2014, to the professional responsible of such violation and to refer the professional to the pertinent professional association, to the Public Energy Policy Program of the Department of Economic Development and Commerce for the corresponding disciplinary action.

ARTICLE 12. PUBLIC REPORTING AND RECORD RETENTION

SECTION 12.01. Public Queue

The EPS Operator shall maintain a public interconnection queue pursuant to Section 2.08 on its website in a tabular format, *i.e.*, a sortable spreadsheet, which it shall update on at least a monthly basis. The date of the most recent update shall be clearly indicated. The public queue should include, at a minimum, the following information about each Interconnection Application, where available:

- A. Queue Position, *i.e.*, queue number
- B. Nameplate Rating
- C. Export Capacity
- D. Primary fuel type (*e.g.*, solar, wind, bio-gas, etc.)
- E. Secondary fuel type (if applicable)
- F. Exporting or Non-Exporting
- G. City
- H. Zip code
- I. Substation
- J. Feeder
- K. Status (active, withdrawn, interconnected, etc.)
- L. Date application deemed complete

- M. Date of notification of Fast Track screen results, if applicable
- N. Fast Track Screen results, if applicable (pass or fail, and if fail, identify the screens failed)
- O. Date of notification of supplemental review results, if applicable
- P. Supplemental review results, if applicable (pass or fail, and if fail, identify the screens failed)
- Q. Date of notification of feasibility study results, if applicable.
- R. Date of notification of system impact study results, if applicable
- S. Date of notification of Transmission System impact study results, if applicable
- T. Date of notification of Facilities Study results and/or construction estimates, if applicable
- U. If upgrades were needed, the estimated and final cost of the upgrades

SECTION 12.02. ~~Biannual~~Quarterly Interconnection Report

After the approval of this Regulation, the EPS Operator shall include the following information ~~as part of its~~in a Quarterly Interconnection ~~Progress Reports as~~Report filed in Docket No. NEPR-MI-2019-0016 within thirty (30) days after the end of each calendar quarter:

- A. The number, Nameplate Rating, and Export Capacity of, completed Interconnection Applications for Generating Facilities and Microgrids received, approved, studied, installed, withdrawn, and denied under the Simplified Process, the Fast Track Process, and the Study Process.
- B. The fuel type, number, Nameplate Rating, and Export Capacity of Generation Facilities and Microgrids approved for interconnection.
- C. The fuel type, number, Nameplate Rating, and Export Capacity of all Generation Facilities and Microgrids currently interconnected to the EPS.
- D. A narrative description of the data provided, including any trends identified by the EPS Operator.
- E. Fees collected under the Simplified Process, the Fast Track Process, and the Study Process.
- F. Compliance with the time frames of this Regulation, including the number and percentage of systems under the Simplified Process for which net metering was reflected on the bill within thirty (30) days of the certification notice, and the

number and percentage of Interconnection Applications evaluated within ninety (90) days, with the average and maximum days for each.

G. The Simplified Interconnection Fee and Reserve Fund information required by Article 3.B(6), and the export restriction and compensation information required by Section 7.10.F.

H. The number of Meter Socket Adapter models submitted for evaluation, approved, and denied, with the reasons for each denial and the average days to decision; the number of Meter Socket Adapter installations completed, identified by whether performed by the EPS Operator or an Authorized Agent; and the number of registered Authorized Agents.

~~F.I.~~ The underlying data in tabular format, *i.e.*, a searchable spreadsheet.

SECTION 12.03. Record Retention

- A. The EPS Operator shall maintain the records and reports specified in this Article for at least five years.
- B. The EPS Operator shall retain copies of studies it performs to determine the feasibility of, Distribution system impacts of, Transmission System impacts of, or facilities required by a proposed interconnection.

ARTICLE 13. RECONSIDERATION AND JUDICIAL REVIEW

SECTION 13.01. Reconsideration

- A. Any person who is not satisfied with a decision made by the EPS Operator under this Regulation may first follow the process identified in Article 10, or may file, within the term of twenty (20) days from the date copy of the notice of such decision is ~~filed by the Energy Bureau's Clerk~~issued and notified by the EPS Operator, a request for reconsideration before the Energy Bureau wherein the petitioner sets forth in detail the grounds that support the request and the decisions that, in the opinion of the petitioner, the Energy Bureau should reconsider.
- B. Any person who is not satisfied with a decision made by the Energy Bureau under this Regulation may file, within the term of twenty (20) days from the date copy of the notice of such decision is filed by the Energy Bureau's Clerk, a request for reconsideration before the Energy Bureau wherein the petitioner sets forth in detail the grounds that support the request and the decisions that, in the opinion of the petitioner, the Energy Bureau should reconsider.

SECTION 13.02. Administrative Review

Any person who is not satisfied with a decision made by the EPS Operator under this Regulation may file, within the term of twenty (20) days from the date copy of the notice of such decision is issued and notified by the EPS Operator, a request for review before the Energy Bureau, pursuant to the provisions of Act 57-2014 and Regulation 8543.

SECTION 13.03. Judicial Review

Any person dissatisfied with a final decision of the Energy Bureau under this Regulation may, within thirty (30) days from the date copy of notice of a final decision addressing a request for reconsideration is filed by the Energy Bureau's Clerk, or within thirty (30) days from the date a copy of the notice of an Energy Bureau final decision is filed by the Energy Bureau's Clerk, if a request for reconsideration has not been filed, appear before the Puerto Rico Court of Appeals by way of writ of judicial review.

