NEPR

Received:

Oct 21, 2026

5:04 PM

COMMONWEALTH OF PUERTO RICO
PUBLIC SERVICE REGULATORY BOARD
PUERTO RICO ENERGY BUREAU

IN RE: WHEELING IMPLEMENTATION	CASE NO.: NEPR-MI-2023-0001 SUBJECT: Comments on LUMA's Interim Wheeling Implementation Proposal

COMMENTS OF PHOEBUS FUND PUERTO RICO LLC ON LUMA'S INTERIM WHEELING IMPLEMENTATION PROPOSAL

TO THE HONORABLE PUERTO RICO ENERGY BUREAU:

SUMMARY OF REQUESTED DETERMINATIONS

Phoebus requests prompt approval of interim wheeling, with targeted changes to LUMA's October 14, 2026 proposal. PREB can authorize implementation work now and separately rule on departures from the approved framework. These requests preserve interconnection, metering, payment and nonparticipant protections without guaranteeing supplier returns. [1; 2; 3; 4, §6.30; 12, ch.3, pp.141–142.]

1. Preserve portfolio supply. Regulation 9374 contemplates supply from one or more independent producers, and the accepted WSA combines multiple RES resources for settlement. Permit separately approved and metered resources to settle as one RES portfolio. If phased testing is needed, begin with two resources and objective criteria for expansion. [2, §1.09(B)(24), (28); 3, Attachment B-4, p.44, note (b); 13.]

2. Preserve PRASA's aggregate qualification. Apply the November 27, 2024 ruling to PRASA's eligibility and consolidated settlement. Separately rule that each legal customer counts once under any interim customer limit, supported by auditable meter records. The prior ruling did not address the proposed ten-customer limit. [6, pp.2–5.]

3. Base enrollment on operating capacity. Treat three RES and ten customers per RES as initial planning assumptions, consistent with LUMA's executive summary. Require published queue criteria, processing of every application, workload evidence, written reasons for deferrals and scheduled capacity reviews. [1, Executive Summary, p.2; §§3.3, 9.2, 10; 2, §§2.02, 8.02.]

4. Allow conditional WSA signing before commissioning. Separate contract execution from service readiness. Specify a time-limited reservation tied to milestones, lender protections and startup terms. Identify and approve each change to the accepted WSA. [2, §4.01; 3, §§4.1–4.2, 15.1, 21; 7, Ex. B, §4.2.]

SUMMARY OF REQUESTED DETERMINATIONS (CONTINUED)

5. Identify the authority for every charge. Apply approved tariffs and contract formulas, including the $500 application fee. For each separately proposed charge, identify the governing instrument, payer, calculation, trigger and effective date. The approved $3,073,641 annual program budget does not establish a per-RES charge. Reconcile base-rate, budget and direct recovery. Appendix B distinguishes authorized, conditional and unresolved charges. [2, §6.05; 3, Attachment B; 11, pp.18, 20; 12, ch.3, p.142; 17; 18.]

6. Decide whether net metering and wheeling can operate together. Interpret the governing terms and test residual-load service while preserving net-metering rights and preventing duplicate credits. Concurrent service requires approval. Publish neutral pilot criteria and procedural status. Windmar's June 2026 motion confirms a submission; it does not establish approval or discriminatory treatment. [2, §1.09(B)(28); 18, sheets 64–65, 82; 20, p.1.]

7. Issue separate directives with deadlines and responsible parties. Require clean and redlined contract changes, fee and workload disclosures, an expedited technical conference and public progress reports. Preserve Regulation 9374's application deadlines. Application approval does not authorize energization. Appendix D proposes an order and deadlines for PREB's approval; those deadlines are not existing legal requirements. [2, §§8.02–8.03; 19, p.2.]

Record and process. These comments distinguish accepted rules, prior Phoebus positions, disputed interpretations and proposed changes. Appendix A presents twelve illustrative commercial scenarios. Appendix C identifies project declarations, hourly portfolio analysis and a customer/meter schedule for a supplemental record directed by PREB. The illustrations are not sworn project facts, current customer commitments or lender decisions.

Organization. The main submission explains each request. Appendix A presents commercial scenarios; Appendix B reviews charges; Appendix C provides economic, billing and evidence requirements; Appendix D proposes an order; and Appendix E links the authorities. Bracketed numbers refer to Appendix E, with specific pages or provisions cited in the text.

COMMENTS AND REQUESTS FOR DETERMINATION

1. Phoebus Fund Puerto Rico, LLC (Phoebus) requests clear rulings on the restrictions and unresolved commercial terms in LUMA's interim wheeling proposal. Phoebus's Solargation development needs predictable access and settlement rules to secure customers, diversify approved resources and obtain financing. Phoebus seeks a practical opportunity to compete under the costs and operating obligations PREB has approved. [1, §§3–6; 2; 3.]

I. APPLY THE APPROVED FRAMEWORK AND RULE ON PROPOSED CHANGES

2. The governing rules and PREB's prior decisions support these requests. Regulation 9374 defines an RES by reference to generation produced or acquired from one or more independent power producers. The accepted WSA aggregates multiple RES resources. PREB also approved PRASA's aggregate qualification and consolidated settlement. The implementation filing should not narrow these decisions without express approval. LUMA acknowledges that differences between interim systems and the accepted agreement require an amended WSA or addendum. Phoebus requests a comparison of each departure and a ruling on each disputed term. [2, §1.09(B)(24), (28); 3, Attachment B-4, p.44; 6, pp.2–5; 13; 1, §1.2, pp.7–8.]
3. Act 57-2014 requires reasonable, nondiscriminatory conditions, feasible wheeling and protection of nonsubscribing customers. Act 17-2019 establishes a policy of open and impartial access. These provisions support review of unsupported restrictions while preserving PREB's authority to impose justified technical conditions and set customer eligibility by order. Phoebus requests findings on each restriction's necessity, alternatives, duration and cost. It does not ask PREB to declare every interim restriction unlawful. [4, §§6.20–6.21, 6.30; 5, §§1.3–1.4, 1.7; 2, §§2.02, 7.02.]
4. These requests maintain Phoebus's prior positions on long-term contract certainty, risks beyond supplier control, duplicate cost recovery and timely implementation. PREB rejected a blanket imbalance waiver and denied buyer-of-last-resort protection without prejudice. Phoebus now seeks diversification managed by suppliers and transparent settlements. It does not present the earlier requests as existing rights. [7, Ex. B, §4.2; 8, §§2, 4–6; 9, §§1–4; 10, §§1–2; 11, pp.14–17.]

II. PRESERVE PORTFOLIO SUPPLY AND PRASA AGGREGATION

A. Apply the WSA provisions for portfolio settlement

5. The proposed limit of one resource and one interconnection point excludes portfolios. Yet WSA Attachment B-4, note (b), sums hourly metered generation from multiple RES resources, and note (a) sums loss-adjusted customer loads. Section 1.65 protects the availability of designated resource portions; it sets no one-resource maximum. PREB should require LUMA to accept a schedule identifying each approved facility, meter, availability allocation and interconnection. RES settlement should aggregate only physically eligible output. [1, §§3.2–3.3, pp.13–15; 3, §1.65 and Attachment B-4, p.44.]
6. Portfolio settlement can reduce the cost of simultaneous shortfalls and surplus sales and limit exposure to a single-site outage. Appendix A, Scenario 4, illustrates a $375 difference in one hour under the approved 95% non-peak surplus credit. It does not forecast annual gains or establish financing viability. Correlated storms, shared substations, transmission limits and insufficient storage duration can reduce these benefits. Appendix C therefore calls for an hourly comparison of separate and consolidated settlements that includes physical constraints and adverse cases. [3, Attachment B §§5.1.1–5.1.3 and B-4.]
7. PREPA's supply portfolio provides a relevant comparison. LUMA schedules and dispatches that portfolio as operator and agent; it does not own the generation. LUMA's proposal also integrates RES schedules into system forecasting and unit commitment. This comparison supports reviewing portfolio risk management without assuming identical regulatory obligations or unrestricted resource substitution. Each resource must remain individually visible and subject to its physical limits. [1, §4.1, Step 2, p.18; 5, §1.9.]
8. If manual settlement requires initial testing, PREB should authorize a two-resource demonstration with approved meters, interconnections, hourly schedules and a trial reconciliation. Before restricting additional resources, LUMA should identify the added workload and any failed control. Creating an RES for each site would multiply agreements and collateral and immediately encounter the three-supplier limit. PREB should select the least restrictive workable configuration supported by the record. [1, §§3.3, 9.2; 2, §2.02; 3, Attachment B-4.]

B. Preserve PRASA aggregation and decide how customers are counted

9. The November 27, 2024 Interpretative Resolution allows PRASA to meet the 250-kVA threshold through aggregate demand and consolidate charges and credits using identifiable meters, auditable data and voltage-specific losses. The ruling is specific to PRASA's circumstances. PREB should preserve that treatment and separately rule that each legal customer counts once under an interim customer limit, while measuring meter workload separately. The resolution did not decide this counting issue or establish automatic eligibility for all multisite entities. [6, pp.2–5; 1, §§3.2–3.3.]

10. PREB should require phased PRASA meter enrollment that supports consolidated service without limiting the customer to ten meters. For other entities, it should establish a petition process covering legal identity, tariff qualification, consolidated credit responsibility and auditable meter data. The PRASA order's references to more than 2,000 locations and over 640 million kWh describe PRASA's historical submission, not Phoebus's current contracted load. [6, pp.2–5; Appendix C, Exhibit C-5.]

III. BASE PARTICIPATION LIMITS ON MEASURED OPERATING CAPACITY

11. LUMA describes three RES and ten customers per RES as planning values, but the proposed limits could indefinitely delay a fourth supplier. Its staffing model also estimates the additional staff needed for another supplier. PREB should require LUMA to reconcile that estimate with the proposed cap and report work hours by supplier, resource, meter, schedule change and invoice. Supplier count alone does not reliably measure workload across portfolios of different sizes. [1, Executive Summary, p.2; §§3.3, 9.2–10.]

12. Phoebus requests neutral readiness criteria, a published queue, preservation of receipt and completeness dates, and written reasons for deferrals. Quarterly capacity reviews should assess processing times, staffing, settlement errors, meter counts, unresolved exceptions and demand from qualified applicants. Evaluate replacements and additions against these measured constraints. Scenario 3 shows how replacing one large customer with three smaller customers can preserve sales while exceeding the customer limit. The approved annual imbalance method does not guarantee recovery of lost contract margin. [2, §§2.02, 8.02–8.03; 3, Attachment B-4; 1, §10.]

13. Regulation 9374's application deadlines and deemed outcomes must remain in effect during implementation. LUMA's proposed month-two enrollment opening and six-month advance operational-data requirement should not restart those periods. The status register should separately track receipt, completeness, determination, contracting, testing and activation. Approved applications must still meet interconnection, commissioning, metering and other lawful service requirements. [2, §§4.01, 8.02–8.03; 1, §§4.1, 4.3, 7.]

14. The April 2026 Rate Order required a proposal within six months; it did not establish an October 2026 service-start deadline. Its direction to use existing resources supports requiring LUMA to explain the critical path for its additional nine-month schedule, identify work that can proceed concurrently and publish milestone reports. Each supplier restriction should have a review date and an evidence-based test for continuation, without waiting for replacement software. [12, ch.3, pp.141–142; 1, §§7, 10.]

IV. ALLOW FINANCING CONTRACTS BEFORE SERVICE BEGINS

15. LUMA accepts projects in the interconnection queue but proposes signing a WSA only after commissioning. Regulation 9374 requires an executed WSA before power delivery; WSA §4.1 separately sets the conditions for service. PREB should require conditional signing after application approval and satisfaction of applicable contracting requirements, with a time-limited resource reservation tied to documented milestones. Construction, interconnection and operation would remain subject to their separate requirements. [1, §4.1, Step 1a, p.17; 2, §§2.03, 4.01; 3, §4.1.]

16. The accepted WSA addresses a five-year service term, renewal notices, collateral assignment and amendments. Phoebus requests an addendum covering financing conditions, milestone extensions for documented events beyond supplier control, lender notice and cure rights, renewal continuity, and migration to permanent systems without duplicate qualification costs. Preserve existing collateral-assignment terms. Additional lender rights and a longer term require PREB approval. [3, §§4.1(a), 4.2(e), 15.1, 21; 7, Ex. B, §4.2.]

17. Early signing creates a timing conflict. Attachment B-4 measures startup annual-imbalance thresholds from contract execution, while the service term begins at service commencement. Signing eighteen months before operation can exhaust the first-year allowance before any delivery. Phoebus requests an express amendment starting these

thresholds at service commencement and specifying fiscal-year proration. PREB's April 2024 reasoning recognized that under-subscription can hinder renewable entry while guarding against oversizing. That reasoning supports review of this conflict but did not change the start date. [3, §4.2(e), Attachment B-4, pp.46–48; 14, pp.3–4; Appendix A, Scenario 5.]

V. TEST WHEELING FOR DEMAND REMAINING AFTER NET METERING

18. Regulation 9374's wheeling definition excludes distributed generation subject to net metering. LUMA interprets this exclusion to disqualify the entire customer site. Phoebus requests a narrower interpretation allowing independently supplied residual demand under an approved settlement protocol. The definition and WSA §1.67 require interpretation. Neither the current net-metering rider nor WCR clearly resolves concurrent service on its own. PREB should issue an express ruling. [2, §1.09(B)(28); 3, §1.67; 1, §4.1, Step 1b, pp.17–18; 18, sheets 64–65, 82.]

19. Exhibit C-2 proposes a test using dual-register interval data, a protected net-metering credit ledger, utility imports remaining after existing credits, a separate wheeling allocation, voltage-specific losses and retained utility charges. It includes an allocation method and reconciliation controls. Net-metered exports must not count as RES deliveries, and no kWh may receive both a net-metering credit and a second avoided FCA/PPCA benefit. PREB should approve any required tariff or agreement changes before concurrent commercial billing. [18, sheets 64–65, 82; 3, Attachment B §§5, 7.]

20. Windmar's June 1, 2026 public confidentiality motion reports submission of a proposed wheeling/net-metering pilot. It does not establish approval, service commencement or preferential treatment. Phoebus requests publication of the pilot's procedural status and neutral eligibility, data-protection and evaluation criteria for any demonstration. Commercially sensitive information may remain protected while criteria and reasons for decisions remain public. [20, p.1, paragraphs 1–2; 4, §§6.15, 6.21.]

VII. RESOLVE REMAINING OPERATING TERMS THROUGH PREB REVIEW

21. PREB should establish a clear path for distribution-connected resources, determine whether the one-MW intraday scheduling provision is being misapplied as an eligibility minimum, and permit customer agreements that pass a documented review of approved

consumer protections. Storage resources should identify committed and available capability, state of charge, duration and network limits. Additional capacity or grid-service revenue requires a valid separate contract and must not impair wheeling obligations. [4, §6.30; 2, §§7.01–7.03; 3, §§1.65, 9.1(b), 9.2(b); 1, §1.2 and §§3.2–4.1; Appendix A, Scenario 8.]

22. The April 1, 2024 Resolution states that this proceeding is non-adjudicative and that submitting comments does not confer party status. Phoebus requests PREB-directed disclosures and a focused technical conference, without asserting automatic discovery, cross-examination or intervention rights. Confidential exhibits should be supported by a confidentiality request. Public filings should include redacted methods, aggregate results and reasons sufficient for meaningful comment. [19, p.2; 4, §6.15; 3, §16.]

23. Appendix C identifies the information LUMA and Phoebus should submit. Appendix D proposes separate directives that allow undisputed implementation to proceed while PREB decides contested issues. Phoebus requests adoption of these directives and written reasons for any alternative safeguards. The proposed deadlines are case-management requests and do not replace existing regulatory deadlines.

RESPECTFULLY SUBMITTED.
PHOEBUS FUND PUERTO RICO, LLC
By: _____
Name: _____
Title: _____
Date: _____

APPENDIX A
COMMERCIAL SCENARIOS AND FORESEEABLE CONSEQUENCES

These twelve scenarios illustrate the commercial effects of the requested decisions. Prices, loads, project values, financing conditions and outcomes are assumptions, not executed Phoebus contracts or actual lender decisions. The citations identify the governing rules; the calculations show possible consequences. Appendix C addresses the project evidence needed to support these examples.

Scenario 1 A net-metering customer needs supply for its remaining demand

Assume an eligible commercial customer with net-metered rooftop solar still imports 8,000,000 kWh annually. Phoebus could supply eligible residual imports from an offsite resource. If an approved combined-service calculation showed total-bill savings of $0.02 per eligible kWh, annual savings would be $160,000. The proposed site exclusion would prevent this benefit even though the offsite generation is separate from the rooftop system. This example assumes all 8,000,000 kWh qualify after the required accounting. It is not a savings forecast and does not assume monthly net-metered consumption automatically qualifies as hourly wheeling load. [1, §4.1, Step 1b; 2, §1.09(B)(28); 18, English sheets 64–65 and 82.]

LUMA's principal billing concern is that export and offsite supply credits could overlap if simply added together. Phoebus requests an approved calculation showing interval imports and exports, wheeling allocations, net-metering treatment and remaining tariff charges. No unit of energy may receive duplicate credits. PREB should distinguish arrangements that fail this test from customers whose residual demand can be settled separately. This would address the accounting issue while retaining demand that can support renewable generation. [2, §§2.02(D)–(E) and 9.01–9.02; 3, Attachment B-4; 14, pp.3–4.]

LUMA should provide at least one worked example with imports in some hours and exports in others, and another with separate service points. Each should reconcile the utility bill, RES invoice and net-metering credits to the same measured energy flows. PREB could then approve compliant arrangements, require tariff amendments or reject arrangements with demonstrated defects. A site-wide exclusion should explain why none of these narrower options meets the governing requirements. [1, §§4.1 and 6.1; 2, §§2.02 and 7.02; 18, English sheets 64–65 and 82.]

Scenario 2 A qualified fourth supplier cannot obtain a service date

Assume three suppliers have entered the interim process and Phoebus is the next qualified applicant ready to operate. A cap without an expansion date could prevent Phoebus from offering customers or lenders a credible service date. A procurement window or financing commitment could expire while the application waits in the queue. This is a risk of uncertain access, not an allegation of improper treatment of another supplier. Phoebus requests published readiness criteria, a scheduled expansion review and reasons for each deferral. Entry should depend on demonstrated operating capacity rather than the availability of one of three places. [1, §§3.3 and 10; 2, §2.02(B)–(C); 4, §6.21.]

Administrative simplicity matters, but supplier count alone does not measure work. One supplier with complex accounts may require more work than another using standard data and simple accounts. LUMA should identify the tasks that limit expansion and compare their actual costs with practical controls: standard templates, scheduled testing, automated checks in existing tools and phased meter additions. Its estimate of additional staffing is a starting point. PREB's 2026 direction to use available systems supports expansion while larger technology projects proceed. [1, §§5, 9.2 and 10; 12, ch.3, pp.139–142.]

Scenario 3 Replacing one departing customer requires three new customers

Assume Phoebus serves ten customers and loses one that buys 30,000 MWh of non-peak energy annually. Three eligible replacements each need 10,000 MWh. They restore the same demand but increase the customer count from ten to twelve: nine existing customers plus three replacements. The ten-customer cap could block full replacement despite no increase in contracted volume. This illustrates the under-subscription risk PREB considered when supporting the launch of wheeling. Phoebus requests prompt replacement review and permission to exceed the planning count when measured workload and approved technical conditions permit. [1, §3.3; 11, pp.13–14 and 16–17; 14, pp.3–4.]

The annual settlement formula illustrates the financial effect. In a hypothetical WSA Year 3, assume 100,000 MWh of non-peak generation, loss-adjusted customer load falling from 100,000 to 70,000 MWh, a 105% threshold, a realized non-peak overproduction rate of \$120/MWh and a reference rate of \$100/MWh. Excess production is 100,000 − (70,000 × 1.05) = 26,500 MWh. Positive AEIC is 26,500 × (\$120 − \$100) = \$530,000. Restoring loss-adjusted load to 100,000 MWh in the same annual calculation would eliminate excess above the threshold and the AEIC under these assumptions. [3, Attachment B-4, pp.46–48.]

The \$530,000 adjusts previously earned overproduction compensation; it is not total business loss and should not simply be added to lost gross customer revenue. The analysis must also model hourly sales, replacement-supply costs and contract terms. A customer cap can prevent the load matching encouraged by the approved settlement design. Phoebus asks PREB to address this conflict rather than assume annual compensation fully resolves the loss of a customer. [3, Attachment B-4; 11, pp.13–14; 14, pp.3–4.]

Scenario 4 One site is unavailable while another has deliverable supply

Assume two approved resources each serve 50 MWh of loss-adjusted customer demand in a non-peak hour. Resource A has an equipment outage and produces nothing. Resource B can deliver 100 MWh, including 50 MWh above its assigned demand. At a positive hourly marginal cost of \$150/MWh, separate settlements produce a \$7,500 shortfall charge for A and a \$7,125 surplus credit for B, leaving a \$375 net cost. In one approved RES portfolio, total supply and loss-adjusted load both equal 100 MWh, with zero net hourly imbalance. This assumes B's output is available, uncommitted, properly scheduled and physically deliverable. It cannot cross an unavailable network connection. [3, §1.65 and Attachment B §§5.1.1–5.1.3 and B-4; 16, pp.3–4.]

Portfolio settlement can combine available, compliant resources under the approved formula. It cannot overcome an island-wide outage, an empty battery or an interconnection limit. Phoebus requests individual resource schedules, meters, availability limits and outage reports within one consolidated RES account. These controls give LUMA the location and availability data it needs without requiring each site to operate as a separate business. [2, §§2.02–2.03; 3, §§9.2 and 10 and Attachment B-4, notes (a)–(b).]

This one-hour example does not measure annual financing benefits. The full comparison should retain site-specific network limits and outages affecting multiple sites, then calculate cash flow, collateral and debt coverage over a full operating year and adverse cases. [Appendix C, Exhibits C-3 and C-4.]

Scenario 5 Construction financing depends on a WSA signed after construction

Assume a $100 million project uses $60 million of debt and $40 million of equity, and the proposed lender requires an executed WSA before funding. If LUMA signs only at commissioning, financing depends on a contract unavailable until construction is complete. A lender could require a different structure, more sponsor capital or bridge financing. This example does not claim that a Phoebus lender has imposed those conditions. PREB can resolve the sequencing problem by allowing an enforceable WSA before construction, with service conditional on the approvals and completed facilities required by §4.1. [1, §4.1, Step 1a; 3, §§4.1 and 15.1; 7, Ex. B, §4.2 comments.]

Startup allowances also need to match the service date. Signing the WSA 18 months before service would place commencement six months into WSA Year 2 under Attachment B-4's execution-based terms. The 125% first-year allowance would have expired, leaving six months of the 115% second-year allowance, subject to fiscal-year proration. Starting these allowances at service commencement would preserve the initial flexibility to acquire customers that PREB intended. Phoebus requests an express amendment so investors need not rely on a favorable interpretation. [3, Attachment B-4, pp.46–48; 11, pp.14 and 16–17.]

Renewal uncertainty also affects financing. When a customer contract or financing term exceeds the WSA's initial five years, continued wheeling service becomes important to repayment. Phoebus requests published renewal criteria, an advance review schedule and clear treatment of timely pending renewals. PREB would retain authority over lawful rate changes and defaults. Defined terms would allow investors to assess renewal risk without assuming either automatic continuation or inevitable termination. [3, §§4.1(a), 4.2(e) and 21; 7, Ex. B, §4.2 comments.]

Scenario 6 Meter limits prevent an aggregated public customer from participating

Assume PRASA enrolls twenty separately metered pumping sites, each with 100 kVA of qualifying demand and 2,000 kVA combined under PREB's approved aggregation method. Requiring each meter to meet 250 kVA would exclude all twenty. Treating the ten-customer allowance as a ten-meter limit could split or restrict the account solely by meter count. These figures are illustrative, not PRASA's actual equipment or demand. Phoebus asks PREB to

preserve the PRASA ruling while requiring an identified meter list and individual readings for accurate settlement. [6, pp.2–5; 1, §§3.3 and 4.1, Step 1b.]

Aggregation must preserve the correct losses and data quality for each meter. Apply the relevant transmission or primary-distribution loss factor before consolidating load. Address defective readings through the approved meter-specific estimation or correction process. Phoebus requests separate definitions for legal customer, service account and meter. This would measure operating workload without changing PRASA's approved basis for eligibility. Comparable treatment for other multisite customers requires a separate PREB decision. [6, pp.4–5; 3, Attachment B §7.0 and Attachment B-4, note (a); 2, §7.02.]

The requested customer-count ruling is additional relief. The PRASA resolution established aggregation eligibility and settlement treatment; it did not decide the later ten-customer proposal. PRASA's historical system size does not establish Phoebus's current customer commitment. [6, pp.2–5.]

Scenario 7 A complete application waits behind implementation work

Assume Phoebus submits every item required by the approved application form on Day 0. If LUMA does not respond within 30 calendar days, Regulation 9374 §8.02(A) provides for deemed completeness, provided the required information is present. Section 8.02(D) then requires a determination within 30 days after completeness and provides for deemed approval if LUMA does not complete its evaluation and respond. LUMA's proposal acknowledges these outcomes. Phoebus requests confirmation that a portal, testing queue or staffing limit does not restart these periods. Separate service requirements must still be met before delivery. [2, §8.02(A)–(D); 1, §4.3, Table 4-1; 3, §4.1.]

An uncertain service date can increase financing costs once capital is committed. A hypothetical $10 million loan at 8% simple annual interest would incur $600,000 over a nine-month delay, before fees or compounding: $10,000,000 × 8% × 9/12. This does not estimate the avoidable part of LUMA's nine-month schedule or assume financing is drawn throughout that period. It shows why the schedule should distinguish work that must precede service from work that can proceed concurrently. Phoebus requests a documented critical path, readiness dates for each supplier and periodic reports on the causes and duration of delays. [1, §7; 12, ch.3, pp.141–142; 11, p.18.]

Scenario 8 Storage capability must be allocated between services

Assume a battery can discharge 100 MW in a specified hour and has committed 60 MW to wheeling customers. A separate service could use the remaining 40 MW only if stored energy, interconnection capacity and operating availability are sufficient and the same capability has not been committed twice. MW alone is insufficient if duration, state of charge or charging restrictions prevent delivery. Phoebus requests review of separately designated capability without disqualifying the entire asset merely because another agreement exists. [3, §§1.65 and 8.1(a); 1, §3.2, Table 3-1.]

The review should specify dispatch priority, energy and capacity reserved for each obligation, charging sources and tariff treatment, losses, outage treatment and compliance meter data. Approval of the interim wheeling plan would not create capacity revenue or a right to free grid charging. PREB has recognized that dispatchable resources and storage can support resource adequacy. That reasoning supports evaluation of a specific proposal but does not approve payment for a second service. [14, p.5; 11, p.14; 3, §§1.65, 8.1(a) and 9.1(b).]

Scenario 9 An undefined surcharge changes customer pricing and debt coverage

Assume annual sales of 100,000,000 kWh, $2 million of cash available for debt service after other operating costs and taxes, and $1.5 million of annual debt service. Coverage is $2 million ÷ $1.5 million = 1.33 times. A $0.01/kWh charge would cost $1 million annually. If fixed customer prices prevented pass-through, available cash would fall to $1 million and coverage to 0.67 times. If passed through, the charge would reduce customer savings by $1 million. This is a sensitivity analysis. LUMA's proposal does not state that this surcharge is approved or will be imposed. [1, §6; 3, Attachment B §5.2; 14, p.5.]

Even a small charge per kWh can materially affect financing. This example also reflects PREB's reasoning that a charge imposed on an RES may ultimately reach the customer. Phoebus requests a ruling on any currently proposed assessment before binding enrollment and financing commitments, with clear effective dates and a defined process for future changes. Lawful future rate review would remain available; Phoebus does not seek a permanent cost freeze. [11, p.13; 14, pp.5–6; 4, §6.25; 3, §21.3.]

Participation affects fixed-cost allocation. A hypothetical $3 million cost pool equals $30/MWh across 100,000 MWh and $10/MWh across 300,000 MWh. These are illustrative allocations, not approved rates, and exclude additional variable costs from wider participation. LUMA should quantify this tradeoff before using low participation to justify high charges and administrative costs to justify low participation. The same analysis should reconcile LUMA's testimony on common foundation costs with its current staffing estimates. [12, ch.3, pp.139–142; 1, §§6.2 and 9.2–10.]

Scenario 10 Gross invoices and delayed credits increase working-capital needs

Assume one monthly WSA cycle produces $600,000 in charges and $500,000 in credits for the same RES. Contractual netting leaves $100,000 payable. Collecting the full $600,000 while delaying credits requires $500,000 in additional temporary cash without changing the net liability. This comparison covers only amounts eligible for WSA netting. Revenue under separate storage or capacity agreements is not automatically eligible. Phoebus requests consistent application of §§8.1(a) and 13 in interim spreadsheets and invoices. [3, §§8.1(a) and 13; 1, §6, Table 6-1.]

The billing basis also affects collateral. At a 25% assurance level, an estimated monthly bill of $100,000 requires $25,000 of collateral; a $600,000 bill requires $150,000. The $125,000 difference shows why PREB should clarify how expected settlement credits enter the bill estimate. Section 9.1(c) may still justify additional assurance, and credits may not be

immediately available. Publish the approved basis, credit class, estimation method and release rule before enrollment. Customer payment delays remain the RES's responsibility under §8.1(b), making avoidable cash requirements especially relevant to financing. [3, §§8.1(b), 9.1(c), 13 and Attachment A.]

Scenario 11 Excess generation has no guaranteed price to replace lost contracts

Assume annual excess generation of 10,000 MWh above the applicable threshold, a realized non-peak overproduction rate of $80/MWh and an annual reference rate of $100/MWh. The difference is negative. Attachment B-4 does not provide a $200,000 payment to raise compensation to the reference rate. The reference rate applies within the annual adjustment and is not an unconditional revenue floor. Phoebus asks PREB to assess customer access, portfolio flexibility and overproduction treatment together. A supplier unable to replace lost demand cannot assume the grid will purchase all excess energy at a price sufficient to cover debt service. [3, Attachment B-4, pp.47–50; 11, pp.16–17.]

Curtailment creates additional risk by changing metered energy and the applicable marginal-cost classification. The accepted WSA assigns zero marginal cost to Level 2 curtailment and a negative value tied to the specified curtailed resource for Level 3. Phoebus requests event notices and settlement explanations identifying the rule and duration, together with the reporting PREB ordered for future review. This request seeks accurate application and supporting evidence; it does not renew the blanket imbalance waiver PREB rejected. [3, §10.4 and Attachment B §5.1.2; 11, pp.15 and 19.]

Scenario 12 An extended grid outage changes the applicable charges

In a hypothetical 75-day T&D outage under WSA §10.2, treatment changes on day 60. For days 60 through 75 (16 days), PREPA-supplied energy is excluded from monthly and annual imbalance calculations. The RES pays FCA and PPCA on customer consumption. Phoebus requests reconciliation by date to prevent both treatments applying to the same energy. Identify applicable major-outage or emergency provisions. Outage costs are not automatically waived; consistent event classification and auditable billing remain necessary. [3, §§10.1–10.3; 1, §6, n.35.]

APPENDIX B
FEE AUTHORITY AND RECOVERY AUDIT

This matrix distinguishes expressly authorized charges, conditional contractual obligations and amounts not verified in the cited instruments. A budget is not a rate, and an unresolved rate reference does not permanently bar future charges. LUMA should identify any superseding authority and its effective date before relying on it. The charge register below completes the review of payer, trigger and cost recovery for each proposed collection. [2, §9.01; 3, Attachment B; 11; 12; 17–18.]

The implementation proposal is a compliance filing. Listing charges in Table 6-1 does not establish additional tariff approval. Each invoice should identify the effective tariff, agreement and order, with enough quantity and date detail to reproduce the calculation. [1, §6 and Table 6-1; 2, §9.01.]

Charge / obligation	**Authority and conditions**	**Requested ruling or control**
Application fee	The $500 nonrefundable fee is expressly approved. Regulation 9374 §6.05 limits it to necessary application-processing costs. The January 22, 2024 Order approved this amount after reviewing its cost basis. [2, §6.05; 11, p.20; 1, Table 6-1.]	Apply the approved fee. Identify authority for any additional resource, customer, renewal or resubmission fee.
Implementation budget	Approved PBCS4 funding is $3,073,641 in each of FY2027 and FY2028. The proposal requests no additional funding. This program budget does not establish a charge for each RES. [12, ch.3, pp.141–142; 1, §8.]	Confirm use of approved funding and disclose allocations and actual costs. Do not assess the budget amount against suppliers.
Separate implementation / operating fee	No separately billable amount was verified. WSA Attachment B §5.2 has an incomplete rate reference. The January 2024 Order deferred recovery; the later budget order sets no per-RES, per-customer or per-MWh rate. [3, Attachment B §5.2; 11, p.18; 12, ch.3, p.142; 18.]	Identify the effective tariff and approval before separate collection, or obtain further approval. Reconcile with budget and base-rate recovery.
Ordinary customer tariff / WCR	Otherwise applicable customer charges remain, except FCA and PPCA under WCR. The revised tariff was approved July 22, 2026. Existing base demand charges remain; WCR does not exempt customers from all utility costs. [17, p.2; 18, English sheet 82; 1, §6.1.]	Publish sample bills by customer class, with each current rate and rider. Prevent duplication with RES charges.
Additional ancillary, standing-capacity or POLR levy	The 2024 orders rejected these charges. No superseding approval was identified. PREB accepted the objection that charges could be passed through and found the claimed additional net costs speculative. Future review remains possible. [11, p.13; 14, pp.5–6; 15, pp.9 and 22.]	Maintain the rejection unless a later applicable order authorizes the charge. Distinguish ordinary tariff demand charges and specified outage costs.

Charge / obligation	Authority and conditions	Requested ruling or control
Hourly imbalance (HEIC)	The approved formula charges shortfalls at hourly marginal cost and credits surplus at 95% in non-peak hours and 100% in peak hours. Curtailment can produce zero or negative marginal costs. This is not a fixed access fee. [3, Attachment B §§5.1.1–5.1.3 and B-4; 16, pp.3–4.]	Provide reproducible hourly inputs, current peak definitions, curtailment classifications and net settlements. Preserve approved RES portfolio aggregation.
Annual imbalance (AEIC) and RECs	The approved B-4 methodology sets non-peak annual thresholds at 125%, 115%, then 105%. Only positive AEIC is charged; no negative AEIC payment is due. The April 2024 ruling requires RECs equal to annual excess on a calendar-year basis. [3, Attachment B-4, pp.46–50; 14, p.4; 16, p.4.]	Publish the annual reference rate and a reconciliation example. Amend startup thresholds to begin at service commencement. Clarify REC accounting and prevent double attribution.
Loss adjustment	The WSA specifies factors of 1.03 for transmission, 1.0831 for primary and 1.1016 for secondary service, subject to approved updates. These adjust customer load; they are not separate flat fees. [3, Attachment B §7.0; 1, Table 6-1.]	Apply the correct service-level factor once and identify approved updates. Retain meter-level calculations for aggregated accounts.
Credit / collateral	Collateral is an approved obligation, not an earned fee. Attachment A requires 5%, 25%, 50% or 100% of the estimated monthly RES bill by credit class, including qualifying third-party assurance. Section 9.1(c) separately governs additional or replacement assurance. [11, p.15; 3, §9.1(c) and Attachment A.]	Disclose bill estimates, netting and grounds for additional assurance. Apply the contractual release rule after credit improvement and prevent duplicate security.
Late payment	Contractual authority exists, but the rate and incorporated tariff were not verified. Section 8.1(b) requires payment of undisputed invoices within 30 calendar days. Attachment B §5.3 has an incomplete tariff reference; the reviewed FY2027 Volume 2 does not supply the rate. [3, §8.1(b) and Attachment B §5.3; 18.]	Identify the approved rate, accrual method, payer and effective date before collection. Preserve dispute, netting and payment terms.
Metering, studies and interconnection	Cost responsibility is recognized, but this proposal approves no uniform project-specific price. WSA §9.3(b) leaves meter cost allocation to applicable requirements or PREB. WCR allows customers to pay for interval metering or petition for an estimated load shape. [3, §§4.1, 9.1(g), 9.3(b); 18, sheet 82; 1, §4.1, Step 1a.]	Identify study/interconnection authority, scope and estimated cost. Itemize meter cost allocation and preserve petitions for an alternative.
Data testing and scheduling charges	Authority is conditional; no rate schedule was verified. WSA §12.2 provides for applicable setup/verification charges when RES changes require retesting. Section 12.3 bars charges for operator-caused retesting. Section 9.2(c)(iv) references scheduling-failure charges without setting an amount. [3, §§9.2(c)(iv), 12.2–12.3.]	Identify the approved schedule and trigger. Do not impose unspecified onboarding, file-transfer, scheduling penalties or testing fees for operator migration.

Charge / obligation	Authority and conditions	Requested ruling or control
Insurance	Insurance is an approved contract compliance cost, not a LUMA program fee. PREB accepted Phoebus's IPP comparison and required coverage matching the latest approved PPOAs, rather than LUMA's grid-operator coverage. [11, p.15; 3, §22.]	Apply the accepted WSA coverage and identify authority for increases. Preserve PREB's distinction between supplier and operator roles.
Extended outage energy costs	WSA §10.2 distinguishes outages below 60 consecutive days from those at or above that threshold. Starting on day 60, affected energy is excluded from monthly/annual imbalance calculations and the RES pays FCA and PPCA on customer consumption. Section 10.3 separately addresses major-outage relief. [3, §§10.2–10.3; 1, §6, n.35.]	Show event dates and classification, prevent both treatments from applying to the same period, and preserve agreed relief. These terms do not authorize a general POLR charge.

Required charge register and reconciliation of cost recovery

Field	Required disclosure
Authority and status	Exact docket, order date and page; effective tariff sheet or agreement clause; approved, proposed or conditional status; any later amendment.
Payer and trigger	RES, RWC or project owner; application, meter installation, delivered kWh, imbalance, retesting, delinquency or other event; whether recurring or one-time.
Amount and timing	Dollar amount or complete formula; unit, quantity source, rate period, effective date, invoice timing, credits, taxes and any escalation.
Cost recovery reconciliation	Cost pool; allocation basis; budget/base-rate recovery; application-fee or directly assigned receipts; unrecovered balance; confirmation that no cost is collected twice.
Disputes and correction	Notice address and contractual deadline; itemized explanation; undisputed balance and due date; correction/true-up method; expedited referral for unresolved authority.

LUMA should complete this register before collecting a newly proposed or previously unquantified charge. Existing approved obligations remain payable. WSA §8.1(b) requires payment of undisputed invoices within 30 calendar days and timely notice of disputes; §13 governs netting. A clarification request does not authorize withholding all payments. [3, §§8.1(b), 13.]

APPENDIX C
ECONOMIC ANALYSIS, BILLING TEST AND SUPPORTING EVIDENCE

Exhibit C-1. Cost comparison for nonparticipating customers

Purpose and scope. Compare wheeling and no-wheeling cases using the same customer load, weather, fuel assumptions, network conditions and period. Report customer savings, RES cash flow and changes in the remaining utility revenue requirement separately. Use hourly dispatch and settlement data, distinguishing cash costs from accounting allocations and approved fixed spending. This framework addresses PREB's April 2026 concern without assuming a favorable system outcome. [12, ch.3, p.141; 4, §6.30.]

Define Δ as the wheeling case minus the no-wheeling case. Net change borne by other customers = Δ gross utility generation/purchased-power cost + Δ administration + Δ network/other attributable cost + Δ net utility-to-RES settlement payments − Δ utility customer and directly assigned revenue. A positive result increases the revenue requirement; a negative result reduces it. Exclude RES settlement payments from gross generation cost and count them once on their own line. Revenue includes retained customer charges, foregone fuel/purchased-power collections, application fees and direct reimbursements. Do not count any recovery twice. This is a proposed analytical formula, not an approved tariff formula.

Illustrative item ($000)	**No wheeling**	**Wheeling A**	**Wheeling B**
Affected energy (MWh)	1,000	1,000	1,000
Avoided gross generation cost	—	180	130
Incremental administration	0	20	20
Incremental network/other cost	0	0	0
Net utility payment to RES	0	5	5
Retained non-fuel utility revenue	50	50	50
FCA/PPCA customer revenue	150	0	0
Additional direct reimbursement	0	0	0
Change borne by other customers	—	−5	+45
Customer payment to RES	0	120	120
Customer total energy payment	200	170	170
Participating-customer saving	—	30	30

Assumptions and results. The values are hypothetical and demonstrate the accounting only. Common fixed/demand charges and unaffected utility costs cancel out; actual analysis must capture any changes in them. Case A: −180 + 20 + 0 + 5 − (−150) = −5 ($000). Case B: −130 + 20 + 0 + 5 − (−150) = +45. Both produce $30,000 of customer savings. Neither calculates RES profit, which also depends on generation, financing and other supplier costs. Direct reimbursements may change the allocation only under lawful authority and must also appear in supplier cash flow.

Operating evidence. LUMA should provide affected hourly generation/purchased-power marginal costs, curtailment, losses and settlement payments. Identify avoidable, fixed and incremental costs and revenue retained under each customer tariff. Reconcile program costs with the approved FY2027/FY2028 budget and actual spending. Phoebus's resource and load analysis should test observed weather and correlated outages without adding speculative capacity or ancillary benefits to energy savings already counted. Report central, low-benefit and adverse cases, sensitivity to allocation assumptions, and data limitations. [3, Attachment B; 12, ch.3, pp.141–142; 14, pp.3–6; 16, pp.3–4.]

Requested ruling. PREB should determine whether the arrangement meets §6.30's protections for nonparticipants, identify remaining exposure and select a supported remedy. Savings for PRASA or another customer do not resolve that question. An unfavorable result also does not automatically justify a supplier cap if a targeted operating or cost-allocation measure addresses the cause. [4, §§6.21, 6.30; 12, ch.3, p.141.]

Exhibit C-2. Proposed test of residual-load service and customer protections

Status. This protocol requires PREB interpretation and approval; it does not establish a current right to concurrent service. Preserve the net-metering tariff's import/export credit rules, carryforwards and year-end treatment. The simplified kWh ledger assumes eligible credits can offset the illustrated imports. Actual implementation must retain the tariff's valuation rules and all account limits. [18, sheets 64–65; 2, §1.09(B)(28).]

Sequence. (1) Read interval import and export registers separately. (2) Apply existing net-metering rules and opening credits first, without transferring title to those exports to an RES. (3) Identify imports remaining after all applicable net-metering credits. (4) Allocate only those residual imports to the proposed wheeling service. (5) Apply WCR-retained charges and approved RES settlement and loss rules once. (6) Reconcile meter corrections and credit use through an audit trail and customer statement. Participation waives no tariff rights. PREB must resolve conflicts before commercial billing.

Monthly kWh ledger	Month 1	Month 2	Month 3
Utility imports	100,000	20,000	60,000
Net-metered exports	20,000	30,000	5,000
Opening eligible credit bank	10,000	0	10,000
Export/credit offset applied	30,000	20,000	15,000
Residual imports for test	70,000	0	45,000
Closing credit bank	0	10,000	0
Maximum proposed wheeling allocation	70,000	0	45,000

Hourly allocation test. Let I_h equal measured imports for each hour and R equal monthly residual imports after lawful credits. The proposed reconciliation assigns $r_h = I_h \times R / \Sigma I_h$ (zero if imports are zero). Month 1 therefore allocates 70% of each hour's imports to the residual ledger. This accounting allocation does not mean exports physically served imports at other times. Use forecast residual quantities for advance schedules and actual quantities for transparent settlement adjustments. PREB must determine whether the allocation preserves tariff rights and hourly settlement integrity. LUMA should compare it with a separate-service-point alternative before accepting or rejecting it.

Loss and imbalance test. In a Month 1 hour with 100 kWh of imports, proposed residual load is 70 kWh. Applying the accepted primary-voltage factor of 1.0831 produces a loss-adjusted RES obligation of 75.817 kWh. Supply of 75.817 kWh by an eligible RES resource produces zero modeled imbalance for this allocation. Apply the approved hourly formula to any shortfall or surplus. Net-metered exports must not count as RES generation. Month 2 has no residual customer allocation; any actual excess RES output remains subject to the WSA and receives no second customer credit. [3, Attachment B §§5.1, 7 and B-4.]

Illustrative Month 1 bill. Assume $2,000 in fixed/demand charges, residual utility energy components of $0.20/kWh, including $0.15 for FCA/PPCA, and an RES energy price of $0.12/kWh. After the same net-metering credits, the baseline bill is $2,000 + 70,000 × $0.20 = $16,000. The proposed concurrent bill retains $2,000 + 70,000 × $0.05 = $5,500 at the utility and adds $8,400 to the RES, totaling $13,900. The $2,100 difference illustrates customer savings only. These are hypothetical rates, not FY2027 class tariffs. Actual fixed, demand, rider, tax and credit components require validation. [18, sheets 64–65, 82, for the relevant tariff structure.]

Acceptance controls. Reconcile opening credits and eligible exports with credits used, the closing balance and authorized year-end treatment. Require no duplicate net-metering/wheeling credits, reconciliation between meters and ledgers, validated loss factors, reproducible hourly settlements and customer consent to disclosed test terms. Begin with parallel test bills that

preserve tariff rights. Live concurrent billing requires PREB approval of necessary changes. Publish neutral pilot criteria and procedural status while protecting information supported by a confidentiality request. [18; 20, p.1; 4, §§6.15, 6.21.]

Exhibit C-3. Development and financing declaration

Phoebus requests permission to submit a declaration from an authorized development or finance officer within Appendix D's schedule. Identify the officer's role, personal knowledge, supporting records and limitations. Attach or accurately summarize the agreement provisions and dated financing communications supporting each statement. Distinguish preliminary interest from binding commitments.

Project record. Identify each resource's location, technology, ownership/control, certification, interconnection application and study milestones, permits, metering plan, expected commissioning date and remaining conditions. Document development spending and remaining commitments, the proposed WSA/RSA signing sequence, customer contract status, proposed lender security, funding conditions, and cure/assignment requirements. Confidential terms may be filed with a supported confidentiality request and meaningful public summary. [2, §§2.03, 4.01; 3, §§4.1, 15.1, 16; 4, §6.15.]

Financing comparison. Identify the LUMA clause creating the obstacle, the corresponding lender or contract condition, the requested less restrictive change and its modeled cash-flow effect. Separate incurred costs, unavoidable future costs and costs affected by delay. Support any claimed increase in capital cost with actual alternatives or a clearly labeled sensitivity analysis. General financing practice does not establish a binding lender refusal. Scenario 5's financing condition and Scenario 7's carrying-cost calculation remain illustrative until supported by this evidence.

Exhibit C-4. Hourly portfolio operating and financing analysis

Analysis component	Evidence and output required
Inputs and sources	Timestamped hourly site output, customer imports, export/credit ledger where applicable, tariff class/voltage, losses, network availability, weather source, storage state of charge and dispatch constraints; identify measured versus modeled inputs.
Consistent comparison	Hold sites, load, prices, dispatch feasibility and time period constant. Compare stand-alone RES settlements with consolidated RES settlement under the accepted formulas. Do not treat energy behind a failed interconnection as deliverable.
Adverse cases	Common storm/substation outages; staggered construction delays; loss of a major customer; low marginal-cost/curtailment periods; restricted storage duration; delayed or corrected credits. State probabilities only if supported.
Financial outputs	Monthly/annual HEIC and AEIC, excess-energy reference-price exposure, RECs, net invoicing, estimated collateral, working-capital peak, CFADS, debt service and DSCR. Separate billing-cycle cash timing from economic cost.
Audit and reproducibility	Provide formulas, units, time zone, versioned input files, constrained dispatch assumptions and reconciliation totals. Identify every requested regulatory change used in the model; run the accepted terms as the base case.

Debt-service coverage ratio equals cash flow available for debt service divided by debt service. In Scenario 9, hypothetical coverage of $2 million / $1.5 million = 1.33× falls to $1 million / $1.5 million = 0.67× after a $1 million charge that cannot be passed through. This sensitivity does not establish that LUMA has authorized the charge or that Phoebus has these financing terms. Project-specific claims require supported inputs. The model must apply the approved settlement and credit rules, rather than rely on general diversification claims. [3, §§8–9, Attachment A and B-4.]

Exhibit C-5. Customer, service-point and meter schedule

Field group	Required customer and meter information
Identity and commitment	Legal customer/counterparty; affiliate relationships; RSA date and term; binding, conditional, proposed or nonbinding status; consent and any conditions precedent. Separate prospects from contracted demand.
Qualification and count	Each service account and meter; aggregate and individual kVA; applicable tariff; PRASA-specific authority or requested alternative treatment; proposed legal-customer count and actual meter workload.
Load and billing	Historical/forecast hourly imports and exports; monthly consumption; voltage and loss factor; current net-metering agreement and credit bank; forecast residual load; retained utility charges.
Readiness and phasing	Meter type and interval-data availability; required replacement/testing; data consent; proposed enrollment tranche; dependencies, estimated completion and responsible party.
Evidence and controls	Source bills, load files and agreements; reconciliation to aggregate totals; confidentiality request/redactions; customer-replacement process and prohibited double counting.

This schedule allows PREB to distinguish one legal customer with multiple meters from several independent customers, and eligibility from processing workload. Apply the PRASA ruling to PRASA's circumstances and identify any requested extension to other entities. [6, pp.2–5; 2, §§7.01–7.03; 18, sheet 82.]

APPENDIX D
PROPOSED ORDER WITH SEPARATE DIRECTIVES

Phoebus requests the following directives. Unless stated otherwise, proposed deadlines are calendar days from issuance of the order. They supplement existing deadlines without suspending or restarting them. Each directive is independently severable, allowing implementation to proceed while PREB resolves individual issues.

1. Begin implementation under the approved framework. LUMA shall proceed with undisputed interim infrastructure, secure data exchange, staffing, application processing and settlement testing within approved funding. Acceptance of this compliance filing shall not itself amend Regulation 9374, the accepted WSA, an effective tariff or the PRASA Interpretative Resolution. Each departure requires an express Bureau ruling. [2; 3; 6; 12, ch.3, pp.141–142; 13.]
2. Contract changes and conditional signing — LUMA, within 20 days. Submit clean and redlined versions of the interim WSA/addendum and related forms. Explain each change by clause, including its authority, purpose, alternatives and expiration or review date. Address conditional signing before commissioning, objective service requirements, time-limited milestone reservations, lender notice and cure proposals, startup-threshold timing, renewal continuity and migration treatment. Distinguish requested amendments from accepted terms. [1, §1.2; 2, §4.01; 3, §§4, 15.1, 21, Attachment B-4.]
3. Portfolio eligibility and procedures — Bureau and LUMA. The Bureau should confirm that approved, separately metered and physically eligible resources may be aggregated for one RES under Attachment B-4. Within 30 days, LUMA shall submit operating and validation procedures, including a two-resource initial test if needed, individual resource constraints and objective expansion criteria. Any claimed inability to support aggregation must identify the failed control, workload and proposed remedy for Bureau decision. It shall not establish an indefinite one-resource cap. [2, §1.09(B)(24), (28); 3, Attachment B-4, p.44.]
4. Customer aggregation and counting — Bureau and LUMA. Preserve PRASA's approved aggregate qualification and consolidated settlement. The Bureau should rule that each legal customer counts once under an interim customer limit. Within 30 days, LUMA shall submit PRASA meter-enrollment procedures and petition criteria for other multisite entities. Individual meter data, losses and technical limits remain applicable. [6, pp.2–5.]
5. Queue, workload and expansion — LUMA, within 20 days. Publish neutral application and readiness criteria, the status fields in Part III, and the distinction between planning assumptions and admission restrictions. Report work hours by supplier, resource and meter, staffing capacity, error rates, backlog and projected service dates. Review capacity every 90 days and recommend changes to the Bureau. Give written reasons and review dates for deferrals. Evaluate customer replacements without treating the planning count as an automatic bar. Preserve Regulation 9374's processing and appeal periods and all energization requirements. [1, §§9.2–10; 2, §§8.02–8.03.]
6. Charge register — LUMA, within 20 days and before collecting any newly proposed or previously unquantified charge. Provide the Appendix B information and reconcile each cost with budget, base-rate, application-fee and direct recovery. Identify effective authority or seek the required approval. Continue authorized charges under their existing terms. Acceptance of this filing shall not itself authorize unsupported new charges. [2, §§6.05, 9.01; 3, Attachment B; 11, pp.18, 20; 12, ch.3, p.142.]

7. Settlement controls and disputes — LUMA, within 30 days. Publish sample invoices, marginal-cost inputs and methods, loss and annual-imbalance reconciliations, REC treatment, collateral estimates, and netting and correction procedures. Establish expedited referral of unresolved charge-authority disputes to the Bureau. RES shall pay undisputed amounts and provide notices within the accepted agreement's deadlines. Preserve applicable outage relief and prohibit duplicate charges for periods subject to alternative treatment. [3, §§8.1, 10, 13, Attachments A–B; 16, pp.3–4.]
8. Net-metering compatibility — LUMA, within 30 days; Bureau ruling after comments. Assess Exhibit C-2 and a separate-service-point alternative against existing net-metering rights, hourly settlement and WCR. Identify required tariff or contract changes and the approval process. Publish neutral pilot criteria and procedural status while protecting confidential customer information. Filing a pilot petition does not establish approval. Concurrent commercial billing requires an express compatibility ruling and any necessary amendments. [2, §1.09(B)(28); 18, sheets 64–65, 82; 20.]
9. Supplemental economic and project evidence — LUMA and Phoebus, within 30 days. LUMA shall provide available data and methods for Exhibit C-1, including reconciliation to the approved budget and hourly avoided-cost and settlement inputs. Phoebus may submit the declarations, records and analyses in Exhibits C-3 through C-5. Identify assumptions and missing data, and support any request for confidentiality. Illustrative figures shall not be accepted as project facts without evidence. [4, §§6.15, 6.30; 12, ch.3, p.141; 19, p.2.]
10. Technical conference and comments — Bureau-directed process. Hold a focused conference within 45 days on portfolio controls, nonparticipant costs, fee authority, net-metering compatibility and the critical path to service. Allow supplemental written comments within 15 days after the conference or publication of relevant nonconfidential materials, whichever occurs later. This process creates no automatic adjudicative-party or discovery rights. [19, p.2.]
11. Schedule and public reporting — LUMA, within 20 days and monthly thereafter. File a critical-path schedule showing each task's owner, dependencies, opportunities for concurrent work and reasons for delay. Report progress and exceptions monthly. At each 90-day capacity review, recommend whether to remove, change or retain each disputed restriction, supported by current evidence. Evaluate expansion without waiting for a permanent platform. [12, ch.3, pp.141–142; 1, §§7, 10.]
12. Remaining operating terms. The 30-day procedures shall identify a compliant path for distribution-connected resources, distinguish the WSA's intraday scheduling threshold from eligibility, and specify the conformity review for RSAs and separately committed storage services. These procedures shall not authorize additional-service compensation without applicable authority or waive interconnection, availability or consumer-protection requirements. [4, §6.30; 2, §§7.01–7.03; 3, §§1.65, 9.1–9.2; 1, §1.2.]

APPENDIX E
AUTHORITIES AND RECORD REFERENCES

Citations use each instrument's printed pages, sections or tariff sheets, not combined PDF page numbers. References [7]–[10] contain prior Phoebus positions. Reference [20] is a party motion, not a Bureau order. The accepted WSA in [3] is identified by the order in [13].

[1] LUMA, Motion in Compliance with Final Rate Order Directive Regarding Wheeling Proposal, October 14, 2026, NEPR-MI-2023-0001, Exhibit 1, Retail Wheeling Interim Solution Proposal. October 14 implementation filing

[2] Regulation No. 9374, Regulation on Electric Energy Wheeling, April 20, 2022, particularly §§1.09, 2.02, 4.01, 7.01–7.03 and 8.02. Official regulation

[3] LUMA, Motion in Compliance with Order of December 9, 2024, December 23, 2024, NEPR-MI-2023-0001, revised WSA §§1.65, 3.2, 4.1, 9.2 and Attachment B-4; accepted by PREB February 27, 2025. Revised agreement

[4] Act 57-2014, Puerto Rico Energy Transformation and RELIEF Act, as amended, §§6.20, 6.21 and 6.30. Official English compilation revised May 8, 2025. Official statute

[5] Act 17-2019, Puerto Rico Energy Public Policy Act, as amended, §§1.3, 1.4, 1.7 and 1.9. Official English compilation revised May 8, 2025. Official statute

[6] PREB, Interpretative Resolution, November 27, 2024, NEPR-IR-2024-0002, PRASA, pp.2–5. PRASA aggregation and settlement ruling

[7] Phoebus, Response and Comments to April 21, 2023 Draft of Wheeling Service Agreement, filed June 22, 2023, NEPR-MI-2023-0001, Exhibit B, §4.2 comments. Prior Phoebus submission

[8] Phoebus, Final Position Paper, Wheeling Services Agreement Stakeholder Collaboration Period, September 26, 2023, NEPR-MI-2023-0001, §§2, 4–6. Prior Phoebus submission

[9] Phoebus, Response to LUMA's December 28 Motion, docketed January 8, 2024 under Phoebus Final Comments and Response to Attachment of November 15, 2023 Resolution and Order, NEPR-MI-2023-0001, §§1–4. Prior Phoebus submission

[10] Phoebus, Response on LUMA's Motion for Partial Reconsideration and Request for Further Process, March 1, 2024, NEPR-MI-2023-0001, §§1–2. Prior Phoebus submission

[11] PREB, Final Resolution and Order Approving Wheeling Services Agreement, Wheeling Services Agreement Application Form, and Non-refundable Fee, January 22, 2024, NEPR-MI-2023-0001, Part III. Controlling implementation order

[12] PREB, Final Resolution and Order on Electricity Rates, April 15, 2026, NEPR-AP-2023-0003, Chapter Three, pp.141–142. Interim implementation directive

[13] PREB, Resolution and Order accepting Exhibit 1 including the revised WSA submitted December 23, 2024, February 27, 2025, NEPR-MI-2023-0001, p.1. Order accepting the revised WSA

[14] PREB, Resolution and Order denying LUMA's partial reconsideration, April 24, 2024, NEPR-MI-2023-0001, pp.3–6 (supplier viability, excess-energy compensation, RECs and demand-related charges). Reconsideration ruling

[15] PREB, Final Resolution and Order Establishing Wheeling Tariffs and Further Process, March 24, 2022, NEPR-AP-2018-0004, pp.9, 19–20 and 22. Wheeling tariff findings

[16] PREB, Resolution and Order on energy-imbalance calculations and marginal-cost disclosure, December 9, 2024, NEPR-MI-2023-0001, pp.3–4. Settlement methodology and disclosure

[17] PREB, Resolution and Order approving the amended English and Spanish Tariff Book, July 22, 2026, NEPR-MI-2026-0005, pp.1–2. Current tariff approval

[18] LUMA, June 30, 2026 Motion to Submit Revised Tariff Book, Exhibit I, Attachment B (clean English and Spanish versions), FY2027 Volume 2; English Wheeling Customer Rider, original sheet 82; Net Metering Rider, sheets 64–65. Approved by reference [17]. Approved FY2027 tariff book

[19] PREB, Resolution, April 1, 2024, NEPR-MI-2023-0001, p.2 (non-adjudicative proceeding and Bureau-directed information requests). Procedural ruling

[20] Windmar P.V. Energy, Inc., Motion Requesting Confidential Treatment of Petition, June 1, 2026, NEPR-MI-2023-0001, p.1, paragraphs 1–2 (submission of proposed wheeling/net-metering pilot). Public confidentiality motion