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Received:

Nov 21, 2025

9:56 PM

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

IN RE: REVIEW OF THE PUERTO RICO ELECTRIC POWER AUTHORITY INTEGRATED RESOURCE PLAN	**CASE NO.:** NEPR-AP-2023-0004 **SUBJECT**: Motion Submitting Transmission Needs Studies Report, Request for Confidential Treatment, and Memorandum in Support of Confidentiality

MOTION SUBMITTING TRANSMISSION NEEDS STUDIES REPORT, REQUEST FOR CONFIDENTIAL TREATMENT, AND MEMORANDUM IN SUPPORT OF CONFIDENTIALITY

TO THE HONORABLE PUERTO RICO ENERGY BUREAU:

COME NOW LUMA Energy, LLC ("ManagementCo"), and **LUMA Energy ServCo, LLC** ("ServCo"), (jointly referred to as "LUMA"), and respectfully state and request the following:

I. Introduction and Submission of Transmission Needs Studies Report

1. On May 13, 2025, the Energy Bureau issued a Resolution and Order setting October 17, 2025, as the date for LUMA to submit the 2025 Integrated Resource Plan ("2025 IRP"), specifically the primary sections of the *Regulation on Integrated Resource Plan for the Puerto Rico Electric Power Authority*, Regulation No. 9021, dated April 20, 2018 ("Regulation 9021") that require resource plan development, selection of a Preferred Resource Plan, and reporting on existing and planned transmission and distribution system elements ("May 13th Order").

2. Further, the Energy Bureau provided two additional filing deadlines: (a) November 21, 2025, to file the portion of the requirements that commands LUMA to test the Preferred Resource Plan to determine any implications it may have on the transmission and distribution

system; and (b) "shortly thereafter" November 21, 2025 to file the "Supplemental" modeling runs identified in the May 13th Order.

3. On October 17, 2025, LUMA filed a *Motion Submitting 2025 IRP and Request for Confidential Treatment*. Therein, LUMA submitted the 2025 IRP recommending that the Energy Bureau approve Resource Plan Hybrid A as LUMA's Preferred Resource Plan. Resource Plan Hybrid A represents a balanced, cost-effective path to meeting Puerto Rico's energy needs, reflecting current expectations for fuel and technology costs. In compliance with the May 13th Order, LUMA filed the 2025 IRP as *Exhibit 1* and the workpapers and models relied on in developing the 2025 IRP as *Exhibit 2.*

4. On October 17, 2025, LUMA also filed the *Motion Requesting Extension of the Review Period for Determination of Completeness*, requesting to extend the completeness review period until the Supplemental Scenarios are filed on December 12, 2025, or until after December 19, 2025, when the Rate Review Process evidentiary hearings have concluded.

5. On October 24, 2025, the Energy Bureau issued a Resolution and Order granting LUMA until December 19, 2025, to file the five Supplemental Scenarios and indicating that on that same date, the Energy Bureau will formally commence the 2025 IRP completeness review specified in Section 3.02(A) of Regulation 9021.

6. On October 29, 2025, LUMA filed a *Memorandum of Law in Support of Request for Confidential Treatment of Revised 2025 IRP and Submission of Public Version and Confidential Version of Revised 2025 IRP*. LUMA submitted a revised, redacted version of the 2025 IRP, along with the workpapers and models relied on in developing the 2025 IRP, for public

disclosure.[1] Moreover, pursuant to this Energy Bureau's Policy on Confidential Information, LUMA filed the corresponding memorandum of law stating the legal basis for the request to treat certain portions of the revised version of the 2025 IRP and the workpapers and models relied on in developing the 2025 IRP confidentially.

7. In compliance with the May 13th Order, LUMA hereby submits the Transmission Needs Studies Report, thus, in conformity with the portion of the Regulation 9021 requirement that commands LUMA to test the Preferred Resource Plan to determine any implications it may have on the transmission and distribution system, as *Exhibit 1* to this Motion. The Transmission Need Studies Report serves as an addendum to the 2025 IRP. The content of this report provides a description of the second of two methodologies used by LUMA to assess the implications of the 2025 IRP-selected Preferred Resource Plan on the Puerto Rico transmission system.

8. LUMA did not complete a comprehensive analysis of the implications of the Preferred Resource Plan ("PRP") on the distribution system. The inclusion of distributed photovoltaic ("DPV") and electric vehicle ("EV") charging installations in the PRP reflects forecasts of customer choices for these installations that are not under LUMA's control and are driven solely by customer choice. Therefore, the location and quantity of distribution resources are not within LUMA's planned resource deployment and must be addressed reactively in accordance with current laws and regulations.

9. Furthermore, LUMA has not performed an analysis of EV charging but anticipates that, as EV load grows, a significant portion of EV charging loads will need to be enrolled in managed charging programs to potentially reduce the grid upgrades required for non-managed

[1] The revised version differed from the version filed on October 17, 2025, in that it addressed some grammatical errors and formatting issues, and revised the data presented in Tables 66, 67, and 68, specifically the values in the second column labeled "PR100 Cost Scaling Factor." It also revisited some of the confidential designations originally made.

charging. The above information is needed to complete a distribution analysis of the implications of the PRP. Based on the above, LUMA is requesting the Energy Bureau to recognize this omission as part of the waivers granted in the Resolution of Order dated April 15, 2024, where it indicated: "LUMA cannot file information it does not have," and granted LUMA a waiver recognizing LUMA's inability to comply with Regulation 9021 as a result of not possessing the required data.

10. LUMA also presents with this submission the workpapers and models relied on in the development of the Transmission Needs Studies Report, as *Exhibit 2*. In addition, LUMA submits as *Exhibit 3* to this Motion the revised pre-filed direct testimonies of Dr. Ajit Kulkarni, Grid Modernization Manager, and Dr. Daniel Haughton, Planning and Integration Director, in support of the Transmission Needs Studies Report. Dr. Kulkarni and Mr. Haughton previously submitted on October 17, 2025, pre-filed direct testimonies in support of certain sections of the 2025 IRP. The revised version submitted herein incorporates testimony in support of the Transmission Needs Studies Report

11. LUMA respectfully submits that the Transmission Needs Studies Report and the workpapers and models relied on in the development of the Transmission Needs Studies Report contain confidential information that garners protection from public disclosure pursuant to applicable law and regulations, as will be expounded upon below. Thus, LUMA is submitting a redacted version of the Transmission Needs Studies Report for public disclosure. Accordingly, pursuant to this Energy Bureau's Policy on Confidential Information, LUMA hereby submits the corresponding memorandum of law stating the legal basis for the request to treat certain portions of the Transmission Needs Studies Report confidentially.

II. Applicable Laws and Regulations for submitting information confidentially before the Energy Bureau

12. Section 6.15 of Act 57-2014 regulates the management of confidential information filed before this Energy Bureau. It provides, in pertinent part, that: "[i]f any person who is required to submit information to the Energy [Bureau] believes that the information to be submitted has any confidentiality privilege, such person may request the Commission to treat such information as such . . . . " 22 LPRA § 1054n (2025). If the Energy Bureau determines, after appropriate evaluation, that the information should be protected, "it shall grant such protection in a manner that least affects the public interest, transparency, and the rights of the parties involved in the administrative procedure in which the allegedly confidential document is submitted." *Id*., Section 6.15(a).

13. In connection with the duties of electric power service companies, Section 1.10(i) of Act 17-2019[2] further provide that electric power service companies shall submit information requested by customers, except for: (i) confidential information in accordance with the Rules of Evidence of Puerto Rico. 22 LPRA § 1141i (2025).

14. Access to the confidential information shall be provided "only to the lawyers and external consultants involved in the administrative process after the execution of a confidentiality agreement." Section 6.15(b) of Act 57-2014, 22 LPRA § 1054n (2025). Finally, Act 57-2014 provides that this Energy Bureau "shall keep the documents submitted for its consideration out of public reach only in exceptional cases. In these cases, the information shall be duly safeguarded and delivered exclusively to the personnel of the [Energy Bureau] who needs to know such information under nondisclosure agreements. However, the [Energy Bureau] shall direct that a non-confidential copy be furnished for public review". *Id*., Section 6.15(c).

[2] Known as the "Puerto Rico Energy Public Policy Act" (hereinafter, "Act 17-2019").

15. Moreover, the Energy Bureau's Policy on Confidential Information details the procedures that a party should follow to request that a document or portion thereof be afforded confidential treatment. In essence, the Energy Bureau's Policy on Confidential Information requires identification of the confidential information and the filing of a memorandum of law, "no later than ten (10) days after filing of the Confidential Information", explaining the legal basis and support for a request to file information confidentially. *See* Policy on Confidential Information, Section A, as amended by the Resolution of September 16, 2016, CEPR-MI-2016-0009. The memorandum should also include a table identifying the confidential information, a summary of the legal basis for the confidential designation, and a summary of the reasons each claim or designation conforms to the applicable legal basis for confidentiality. *Id*., paragraph 3. The party that seeks confidential treatment of information filed with the Energy Bureau must also file both a "redacted" or "public version" and an "unredacted" or "confidential" version of the document that contains confidential information. *Id*., paragraph 6.

16. The Energy Bureau's Policy on Confidential Information also states the following with regard to access to Validated Confidential Information:

> 2. Critical Energy Infrastructure Information ("CEII")
>
> The information designated by the [Energy Bureau] as Validated Confidential Information on the ground of being CEII may be accessed by the parties' authorized representatives only after they have executed and delivered the Non-Disclosure Agreement.
>
> Those authorized representatives who have signed the Non-Disclosure Agreement may only review the documents validated as CEII at the [Energy Bureau] or the Producing Party's offices. During the review, the authorized representatives may not copy or disseminate the reviewed information and may bring no recording device to the viewing room.

Id., Section D (on Access to Validated Confidential Information).

17. Relatedly, Energy Bureau Regulation No. 8543, *Regulation on Adjudicative, Notice of Noncompliance, Rate Review, and Investigation Proceedings*, includes a provision for filing confidential information in adjudicatory proceedings before this honorable Energy Bureau. To wit, Section 1.15 provides that, "a person has the duty to disclose information to the [Energy Bureau] considered to be privileged pursuant to the Rules of Evidence, said person shall identify the allegedly privileged information, request the [Energy Bureau] the protection of said information, and provide supportive arguments, in writing, for a claim of information of privileged nature. The [Energy Bureau] shall evaluate the petition and, if it understands [that] the material merits protection, proceed accordingly to . . . Article 6.15 of Act No. 57-2015, as amended."

III. Legal Basis and Arguments in Support of Confidentiality

18. Act 40-2024, better known as the *Commonwealth of Puerto Rico Cybersecurity Act*, defines "Critical Infrastructure" as those "services, systems, resources, and essential assets, whether physical or virtual, the incapacity or destruction of which would have a debilitating impact on Puerto Rico's cybersecurity, health, economy, or any combination thereof." 3 LPRA § 10124(p) (2024). Generally, CEII or critical infrastructure information is generally exempted from public disclosure because it involves assets and information, pose public security, economic, health, and safety risks. Federal Regulations on CEII, particularly, 18 C.F.R. § 388.113, state that:

> Critical energy infrastructure information means specific engineering, vulnerability, or detailed design information about proposed or existing critical infrastructure that:
>
> (i) Relates details about the production, generation, transportation, transmission, or distribution of energy;
> (ii) Could be useful to a person in planning an attack on critical infrastructure;
> (iii) Is exempt from mandatory disclosure under the Freedom of Information Act, 5 U.S.C. 552; and
> (iv) Does not simply give the general location of the critical infrastructure.

Id.

19. Additionally, "[c]ritical electric infrastructure means a system or asset of the bulk-power system, whether physical or virtual, the incapacity or destruction of which would negatively affect national security, economic security, public health or safety, or any combination of such matters." ***Id.*** Finally, "[c]ritical infrastructure means existing and proposed systems and assets, whether physical or virtual, the incapacity or destruction of which would negatively affect security, economic security, public health or safety, or any combination of those matters." *Id.*

20. The Critical Infrastructure Information Act of 2002, 6 U.S.C. §§ 671-674 (2020), part of the Homeland Security Act of 2002, protects critical infrastructure information ("CII").[3]

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[3] Regarding protection of voluntary disclosures of critical infrastructure information, 6 U.S.C. § 673, provides in pertinent part, that CII:

(A) shall be exempt from disclosure under the Freedom of Information Act;
(B) shall not be subject to any agency rules or judicial doctrine regarding ex parte communications with a decision making official;
(C) shall not, without the written consent of the person or entity submitting such information, be used directly by such agency, any other Federal, State, or local authority, or any third party, in any civil action arising under Federal or State law if such information is submitted in good faith;
(D) shall not, without the written consent of the person or entity submitting such information, be used or disclosed by any officer or employee of the United States for purposes other than the purposes of this part, except—
  (i) in furtherance of an investigation or the prosecution of a criminal act; or
  (ii) when disclosure of the information would be--
    (I) to either House of Congress, or to the extent of matter within its jurisdiction, any committee or subcommittee thereof, any joint committee thereof or subcommittee of any such joint committee; or
    (II) to the Comptroller General, or any authorized representative of the Comptroller General, in the course of the performance of the duties of the Government Accountability Office;
(E) shall not, be provided to a State or local government or government agency; of information or records;
  (i) be made available pursuant to any State or local law requiring disclosure of information or records;
  (ii) otherwise be disclosed or distributed to any party by said State or local government or government agency without the written consent of the person or entity submitting such information; or
  (iii) be used other than for the purpose of protecting critical Infrastructure or protected systems, or in furtherance of an investigation or the prosecution of a criminal act.
(F) does not constitute a waiver of any applicable privilege or protection provided under law, such as trade secret protection.

CII is defined as "information not customarily in the public domain and related to the security of critical infrastructure or protected systems...." 6 U.S.C. § 671 (3).[4]

21. The portions of the Transmission Needs Studies Report identified in Section IV of the present Motion and the workpapers and models relied on in the development of the Transmission Needs Studies Report, include CEII, because it contains single-line diagrams that qualify as CEII. They contain information on the engineering and design of critical infrastructure, existing and proposed, for the transmission of electricity, provided in sufficient detail to be helpful to a person planning an attack on this or other energy infrastructure facilities interconnected with or served by this facility and its equipment. In addition, the portions of the revised version of the Transmission Needs Studies Report that have been identified in Section IV and the workpapers and models relied on in the development of the Transmission Needs Studies Report qualify as CEII because each of these documents contains the express coordinates for power transmission and distribution facilities (18 C.F.R. § 388.113(iv)), and these specific coordinates could potentially be helpful to a person planning an attack on the energy facilities. The information identified as confidential in this paragraph is not common knowledge, is not made publicly available, and if disclosed to the public, will expose key assets to security vulnerabilities or attacks by people

[4] CII includes the following types of information:

> (A) actual, potential, or threatened interference with, attack on, compromise of, or incapacitation of critical infrastructure or protected systems by either physical or computer-based attack or other similar conduct (including the misuse of or unauthorized access to all types of communications and data transmission systems) that violates Federal, State, or local law, harms interstate commerce of the United States, or threatens public health or safety;
> (B) the ability of any critical infrastructure or protected system to resist such interference, compromise, or incapacitation, including any planned or past assessment, projection, or estimate of the vulnerability of critical infrastructure or a protected system, including security testing, risk evaluation thereto, risk management planning, or risk audit; or
> (C) any planned or past operational problem or solution regarding critical infrastructure or protected systems, including repair, recovery, construction, insurance, or continuity, to the extent it is related to such interference, compromise, or incapacitation.

seeking to cause harm to the systems. Therefore, it is in the public interest to keep the information confidential. Confidential designation is a reasonable and necessary measure to protect critical infrastructure from attacks and to enable LUMA to leverage information without external threats, *see e.g.,* 6 U.S.C §§ 671-674; 18 C.F.R. §388.113 (2020), and the Energy Bureau's Policy on Confidential Information.

22. In several proceedings, this Energy Bureau has considered and granted requests by PREPA to submit CEII under seal of confidentiality.[5] In at least two proceedings on Data Security[6] and Physical Security,[7] this Energy Bureau, motu proprio, has conducted proceedings confidentially, thereby recognizing the need to protect CEII from public disclosure.

23. Additionally, this Energy Bureau has granted requests by LUMA to protect CEII in connection with LUMA's System Operation Principles. *See* Resolution and Order of May 3, 2021, table 2 on page 4, Case No. NEPR-MI-2021-0001 (granting protection to CEII included in LUMA's Responses to Requests for Information). Similarly, in the proceedings on LUMA's proposed Initial Budgets and System Remediation Plan, this Energy Bureau granted confidential designation to several portions of LUMA's Initial Budgets and Responses to Requests for Information. *See* Resolution and Order of April 22, 2021, on Initial Budgets, table 2 on pages 3-4,

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[5] *See e.g., In re Review of LUMA's System Operation Principles,* NEPR-MI-2021-0001 (Resolution and Order of May 3, 2021); *In re Review of the Puerto Rico Power Authority's System Remediation Plan*, NEPR-MI-2020-0019 (order of April 23, 2021); *In re Review of LUMA's Initial Budgets*, NEPR-MI-2021-0004 (order of April 21, 2021); *In re Implementation of Puerto Rico Electric Power Authority Integrated Resource Plan and Modified Action Plan,* NEPR MI 2020-0012 (Resolution of January 7, 2021, granting partial confidential designation of information submitted by PREPA as CEII); *In re Optimization Proceeding of Minigrid Transmission and Distribution Investments*, NEPR MI 2020-0016 (where PREPA filed documents under seal of confidentiality invoking, among others, that a filing included confidential information and CEII); *In re Review of the Puerto Rico Electric Power Authority Integrated Resource Plan*, CEPR-AP-2018-0001 (Resolution and Order of July 3, 2019 granting confidential designated and request made by PREPA that included trade secrets and CEII) *but see* Resolution and Order of February 12, 2021 reversing in part, grant of confidential designation).

[6] *In re Review of the Puerto Rico Electric Power Authority Data Security Plan,* NEPR-MI-2020-0017.

[7] *In re Review of the Puerto Rico Electric Power Authority Physical Security Plan,* NEPR-MI-2020-0018.

and Resolution and Order of April 22, 2021, on Responses to Requests for Information, table 2 on pages 8-10, Case No. NEPR-MI-2021-0004; Resolution and Order of April 23, 2021, on Confidential Designation of Portions of LUMA's System Remediation Plan, table 2 on page 5, and Resolution and Order of May 6, 2021, on Confidential Designation of Portions of LUMA's Responses to Requests for Information on System Remediation Plan, table 2 at pages 7-9, Case No. NEPR-MI-2020-0019.

24. Likewise, Section 4(x) of the *Puerto Rico Open Government Data Act*, Act 122-2019, exempt from public disclosure commercial or financial information whose disclosure will cause competitive harm. 3 LPRA § 9894. The workpapers and models relied on in the development of the Transmission Needs Studies Report, included as *Exhibit 2* to this Motion, contain or reference proprietary PLEXOS© formulas and pivot tables belonging to third parties. These PLEXOS© formulas and pivot tables constitute commercial or financial information within Section 4(x) of Act 122-2019, as they possess independent economic value and provide a business advantage by virtue of not being generally known or readily accessible to competitors or the public.

25. Moreover, reasonable measures have been taken to maintain the confidentiality of this information, consistent with statutory requirements. Disclosure of these PLEXOS© formulas and pivot tables would risk competitive harm to the third party and undermine public policy favoring the protection of commercially valuable confidential information. Therefore, LUMA requests that the Energy Bureau grant confidential treatment to these PLEXOS© formulas and pivot tables, all of which are proprietary to third parties, to ensure compliance with the statutory protections afforded under Puerto Rico law.

IV. Identification of Confidential Information

26. In compliance with the Energy Bureau's Policy on Confidential Information, CEPR-MI-2016-0009, a table summarizing the hallmarks of this request for confidential treatment is hereby included.

Document	**Name**	**Pages in which Confidential Information is Found**	**Summary of Legal Basis for Confidentiality Protection**	**Date Filed**
Exhibit 1	Table 4: 2026 IRP Transmission Needs Addressing N-1 Thermal Violations	Pages 18-19	Critical Energy Infrastructure Information 18 C.F.R. § 388.113; 6 U.S.C. §§ 671-674	November 21, 2025
	Table 5: 2026 IRP Transmission Needs Addressing N-1-1 Thermal Violations	Pages 19-20	Critical Energy Infrastructure Information 18 C.F.R. § 388.113; 6 U.S.C. §§ 671-674	November 21, 2025
	Table 6: 2026 IRP Transmission Needs Addressing N-1 Voltage Violations	Pages 20-27	Critical Energy Infrastructure Information 18 C.F.R. § 388.113; 6 U.S.C. §§ 671-674	November 21, 2025
	Table 7: 2026 IRP Transmission Needs Addressing N-1-1 Voltage Violations	Pages 27-32	Critical Energy Infrastructure Information 18 C.F.R. § 388.113; 6	November 21, 2025

Document	Name	Pages in which Confidential Information is Found	Summary of Legal Basis for Confidentiality Protection	Date Filed
			U.S.C. §§ 671-674	
	Table 8: 2034 IRP Transmission Needs Addressing N-1 Thermal Violations	Pages 34-35	Critical Energy Infrastructure Information 18 C.F.R. § 388.113; 6 U.S.C. §§ 671-674	November 21, 2025
	Table 9: 2034 IRP Transmission Needs Addressing N-1-1 Thermal Violations	Pages 35-36	Critical Energy Infrastructure Information 18 C.F.R. § 388.113; 6 U.S.C. §§ 671-674	November 21, 2025
	Table 10: 2034 IRP Transmission Needs Addressing N-1 Voltage Violations	Pages 36-38	Critical Energy Infrastructure Information 18 C.F.R. § 388.113; 6 U.S.C. §§ 671-674	November 21, 2025
	Table 11: 2034 IRP Transmission Needs Addressing N-1-1 Voltage Violations	Pages 38-44	Critical Energy Infrastructure Information 18 C.F.R. § 388.113; 6 U.S.C. §§ 671-674	November 21, 2025

Document	Name	Pages in which Confidential Information is Found	Summary of Legal Basis for Confidentiality Protection	Date Filed
	Table 13: Solutions Addressing N-1 Thermal Violations in the 2026 IRP Transmission Needs	Pages 47-48	Critical Energy Infrastructure Information 18 C.F.R. § 388.113; 6 U.S.C. §§ 671-674	November 21, 2025
	Table 14: Solutions for Addressing N-1-1 Thermal Violations in the 2026 IRP Transmission Needs	Pages 49-51	Critical Energy Infrastructure Information 18 C.F.R. § 388.113; 6 U.S.C. §§ 671-674	November 21, 2025
	Table 15: Solutions for Addressing N-1 Thermal Violations in the 2034 IRP Transmission Needs	Pages 52-53	Critical Energy Infrastructure Information 18 C.F.R. § 388.113; 6 U.S.C. §§ 671-674	November 21, 2025
	Table 16: Solutions for Addressing N-1-1 Thermal Violations in the 2034 IRP Transmission Needs	Pages 54-56	Critical Energy Infrastructure Information 18 C.F.R. § 388.113; 6 U.S.C. §§ 671-674	November 21, 2025
	Table 23: Cost of Common Solutions for Addressing N-1 Thermal Violations for both 2026	Pages 63-66	Critical Energy Infrastructure Information 18 C.F.R. § 388.113; 6	November 21, 2025

Document	Name	Pages in which Confidential Information is Found	Summary of Legal Basis for Confidentiality Protection	Date Filed
	and 2034 IRP Transmission Needs		U.S.C. §§ 671-674	
	Table 24: Cost of Common Solutions for Addressing N-1-1 Thermal Violations for both 2026 and 2034 IRP Transmission Needs	Pages 66-71	Critical Energy Infrastructure Information 18 C.F.R. § 388.113; 6 U.S.C. §§ 671-674	November 21, 2025
	Table 25: Cost of Common Solutions for Addressing Both N-1 and N-1-1 Thermal Violations for 2026 and 2034 IRP Transmission Needs	Pages 71-77	Critical Energy Infrastructure Information 18 C.F.R. § 388.113; 6 U.S.C. §§ 671-674	November 21, 2025
Exhibit 2	Workpapers	Entire File	Critical Energy Infrastructure Information 18 C.F.R. § 388.113; 6 U.S.C. §§ 671-674	November 21, 2025
	Workpapers	Entire File	Third-Party Proprietary Information	November 21, 2025

WHEREFORE, LUMA respectfully requests that the Energy Bureau **take notice** of the aforementioned; **accept** the Transmission Needs Studies Report, as *Exhibit 1* of this Motion, the workpapers and models relied on in the development of the Transmission Needs Studies Report, as *Exhibit 2* of this Motion, and revised pre-filed direct testimony of Dr. Ajit Kulkarni and Dr. Daniel Haughton, as *Exhibit 3* to this Motion; **approve the request for confidential treatment** of the information submitted in *Exhibits 1 and 2* to this Motion; and **deem** LUMA complied with the May 13th Order based on the information that is currently available.

WE HEREBY CERTIFY that this Motion was filed using the electronic filing system of this Energy Bureau and that electronic copies of this Motion will be notified to the Puerto Rico Electric Power Authority: lionel.santa@prepa.pr.gov and through its attorneys of record Mirelis Valle-Cancel, mvalle@gmlex.net; and Alexis G. Rivera Medina, arivera@gmlex.net; and Genera PR, LLC, through its attorney of record Luis R. Román Negrón, lrn@roman-negrom.com.

RESPECTFULLY SUBMITTED.

In San Juan, Puerto Rico, on November 21, 2025.

DLA PIPER

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Exhibit 1

2025 Integrated Resource Plan (2025 IRP)

Transmission Needs Studies Report

NEPR-AP-2023-004

Executive Summary

The 2025 Integrated Resource Plan (2025 IRP) and this Transmission Needs Study Report provide the analytical framework to evaluate the current condition of Puerto Rico's electric grid and identify the transmission investments required to support a more reliable, resilient, and cleaner system in the years ahead. Together, these filings outline the data-driven pathways necessary to meet Puerto Rico's long-term energy objectives while maintaining a dependable transmission and distribution system for customers.

As widely recognized, Puerto Rico's electric grid continues to face significant challenges resulting from decades of underinvestment by the former operator, Puerto Rico Electric Power Authority (PREPA), including aging infrastructure, vulnerability to severe weather, and limited generation capacity. These conditions underscore the need for the 2025 IRP analysis and the associated transmission planning work presented in this report.

As part of LUMA's ongoing efforts to stabilize the electric grid, the following improvements have been completed to date: installed more than 35,500 storm-resilient poles; cleared over 7,017 miles of hazardous vegetation; deployed more than 10,641 grid automation devices to reduce outage impacts; and replaced over 183,000 streetlights to enhance public safety. These actions have contributed to measurable improvements in service reliability. Importantly, this work has been completed within approved budgets and consistent with LUMA's commitment not to increase rates during its first three years as operator.

In this context, LUMA remains focused on stabilizing and improving the transmission and distribution (T&D) system while advancing the long-term planning required by the Energy Bureau. Since assuming operation of the T&D system, LUMA has carried out work aligned with the System Remediation Plan (SRP) and approved budgets to deliver measurable improvements.

2025 IRP Timeline

On May 13, 2025, the Energy Bureau of Puerto Rico (Energy Bureau) issued a Resolution and Order (May 13th R&O)[1] recognizing the complexity and time-intensive nature of resource modeling, as well as the significant changes introduced by Act No. 1-2025. The May 13th R&O ordered LUMA to file on October 17, 2025, the final 2025 IRP with all portions of Regulation 9021, except the transmission and distribution

[1] See at: https://energia.pr.gov/wp-content/uploads/sites/7/2025/05/20250513-AP20230004-Resolution-and-Order.pdf

implications (Transmission Needs Studies Report (PSS®E analysis))[2] of the selected Preferred Resource Plan (PRP) that was waived until November 21, 2025. The Energy Bureau also ordered LUMA to file the five Supplemental Scenarios shortly after the Transmission Needs Studies Report (PSS®E analysis).

LUMA is hereby submitting the Transmission Needs Studies Report (PSS®E analysis) of the selected PRP in accordance with the May 13th R&O.

2025 IRP Transmission Needs Studies Report

The results of the PSS®E analysis refer to the expenses for the transmission solutions required to support the PRP. These results replace the transmission upgrade results derived from the PLEXOS® analysis in the 2025 IRP Report as they provide greater detail modeling of the transmission grid. The Present Value Revenue Requirement (PVRR) impacts of the transmission upgrades for the PSS®E analysis yielded a range of costs from $599M to $1.67B, whereas the PLEXOS® modeling yielded $312M. The $278M to $1.36B additional cost PSS®E analysis should be added to the total PVRR for the selected PRP in the 2025 IRP. This cost addition results in a revised PVRR for the PRP of $34.6B to $35.8B, compared to the prior value in the 2025 IRP report, based solely on the PLEXOS® modelling of $34.4B.

These costs are for the transmission solutions required to support the PRP. The range in costs resulting from the PSS®E analysis comes from the reconductoring of projects. The low end of the range only includes the costs of new conductors and assumes the rest of the existing infrastructure does not need to be replaced during the reconductoring. The high end of the range assumes most of the infrastructure does need to be replaced (i.e. existing towers cannot support the weight of the conductors; does not meet current standards and requirements, as for example wind loading; and hence need to be replaced) as part of reconductoring. In addition, as discussed in the 2025 IRP report, the PRP is designed to support a trajectory that will enable the attainment of the 100% Renewable Portfolio Standard (RPS) goal by 2050.

The transmission PSS®E Analysis was based solely on steady-state power flow and contingency analysis to identify the thermal overloads and voltage violations that result. The results focus only on the 115kV and 230kV transmission backbone, and do not include the 38kV overloads or voltage violations. PSS®E Analysis for N-1 and N-1-1 contingency show considerable thermal overloads and voltage violations on the 115 and 230kV transmission lines stemming from even single contingency events. These single contingency events include, for example, loss of a transmission line, of a substation circuit breaker, or loss of a busbar.

The magnitude and severity of contingency results before and after the PRP indicate that fixed resource decisions in the ten-year plan do not solve system voltage stability concerns. This is evidenced by the numerous contingencies that result in widespread voltage depression which will lead to major island-wide disturbances without the implementation of mitigation solutions and proposed projects. This certainly results because generators will trip offline for extreme low-voltages such as those identified. The extensive mitigation solutions presented are core and essential investments to provide a basic level of

[2] The PSS®E analysis is required in Regulation 9021 Section 2.03(J)(2)(e) to documents the transmission and distribution implications of the Preferred Resource Plan, including assessing if the plan requires incremental transmission or distribution mitigation or changes.

adequate voltage and reactive power support. The results of the Transmission Needs Study Report presented herein must be interpreted with the primary understanding that Puerto Rico's Transmission & Distribution system requires significant improvements to operate reliably and meet minimum industry standards.

The PSS®E Analysis highlights the estimated transmission costs and upgrades needed to support the PRP, and to achieve a stable and reliable bulk transmission network.[3] Additional studies and a separate and detailed implementation plan will be necessary to fully define and execute the needed improvements. In addition, while the 2025 IRP involves economic assessments, the identification of sources of funding for recommended investments is outside the 2025 IRP's scope. Therefore, discussions on identifying funding for new generation technologies or Transmission and Distribution improvements are not covered within the 2025 IRP Report or the present Transmission Needs Study Report. As indicated, in the 2025 IRP Report, the 2025 IRP is a planning tool intended to guide the Energy Bureau and stakeholders in developing Puerto Rico's electric system that is reevaluated every three years to reflect new technologies and changes affecting the electric system.

[3] Some of the estimated costs in this report are already included in current federally funded projects.

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Tables

1.0 Introduction

Transmission Needs Assessment

This 2025 IRP Transmission Needs Studies Report serves as an addendum to the 2025 IRP filed with the Energy Bureau in Case NEPR-AP-2023-004 on October 17, 2025. The content of this report provides a description of the second of two methodologies used by LUMA to assess the implications of the 2025 IRP-selected Preferred Resource Plan (PRP) on the Puerto Rico transmission system.

LUMA assessed the implications of the PRP on the transmission system using two different but complementary modeling methods, which is consistent practice within the utility industry.

The first method used the resource planning software, PLEXOS®, to perform production-cost-modeling assessment of the current capability and future needs of the transmission system's ability to transfer power between the eight transmission planning areas (TPAs), which represent geographic regions of the island. As discussed more fully in Sections 7.3.5 and 8.2.3 of the 2025 IRP Report, the resource modeling software uses a simplified representation of the Island's transmission capability and power flows and yields a least cost plan that endeavors to co-optimize energy resources and any required transmission upgrades.

However, in order to achieve computational efficiency, PLEXOS® makes several simplifying assumptions that limit that limit its ability to fully capture transmission system performance, including:

- Assuming all transmission buses can operate at rated voltages
- Simplifying the network representation to TPAs and the ties between them

Collectively, these assumptions are common for production-cost modeling, which is computationally intensive, but they do not allow for assessment of system losses, voltages, and reactive power requirements. The production-cost modeling software results in a plan with resources and timing of additions and retirements, as well as a list of major transmission corridors requiring upgrades to enable the resource changes to operate while meeting transmission, and other (e.g., generation, battery, RPS), constraints. While this representation and assessment of the transmission system in the resource modeling software is directional and balances the economics of resource costs and location respective to transmission limitations and costs of upgrades, the technical and physics-based analysis of the transmission network must be evaluated.

After the PLEXOS® simulations were completed, a detailed industry-standard transmission analysis modeling tool, PSS®E, was used to more fully assess the transmission implications of the PRP. This second analysis addresses gaps in the production-cost-modeling software that relies on simplifying assumptions to provide computational efficiency to enable running an hourly model out to 20+ years, with detailed load and generation modeling. Conversely, the PSS®E model represents the detailed physical transmission system complete with losses, real and reactive power flows, and individual node voltages, which all must be in balance to provide an acceptable transmission network solution. In addition, the power flow software assesses the transmission system reliability and identifies any thermal and voltage violations under normal, and individual element contingencies N-1 and N-1-1[4]. Using PSS®E, the PRP was assessed under the high load forecast scenario for two different years, 2026 and 2034, and load conditions of system stress, peak load and maximum solar generation, for each of these years. The analysis served to identify transmission thermal and voltage violations[5] occurring under both N-1 and N-1-1 conditions. The inputs for each of the four snapshots, two for 2026 and two for 2034, were obtained from the PLEXOS® solution (e.g., generation commitment and dispatch, BESS dispatch, load). The combined use of PLEXOS® and PSS®E provided extensive modeling of the power system (load, transmission, generation).

Once the violations were identified, a proposed list of infrastructure projects was defined to mitigate each potential violation. Planning level cost estimates were developed for each solution; note that planning-level cost estimates are based solely on unit costs (e.g. cost/conductor, cost/mile, or similar estimates for comparable projects; and did not include field verification, field surveys, civil structural assessments, environmental reviews, or constructability reviews).

[4] N-1 and N-1-1 are standard industry contingency conditions that are defined in Section 1.1 of this report.

[5] Thermal and voltage violations occur when either current flow or voltage fluctuations exceed acceptable parameters. These terms are more fully defined in in Section 1.1 of this report.

2.0 Transmission and Distribution Implications of Preferred Resource Plan

2.1 Methodology Used to Assess Transmission System

To assess the implications of the 2025 Integrated Resource Plan (2025 IRP) Preferred Resource Plan (PRP), which was filed with the Energy Bureau in this case on October 17, 2025, LUMA completed an IRP Transmission Needs Studies[6] using PSS®E as the primary modeling software. PSS®E is an industry standard transmission planning tool that allows transmission planning engineers to use power flow models to evaluate thermal and voltage violations under normal and contingency conditions. For these studies, two types of power flow models were utilized: the Transmission Planning (TPL) model and a power flow constructed to represent the PRP from the 2025 IRP model. The TPL model includes Day-Peak (DPK) and Night-Peak (NPK) scenarios, while the IRP model comprises Peak-Solar (PS) and Highest Native Load (HNL) scenarios. All these models were developed in PSS®E for the planning years 2026 and 2034.

Once LUMA developed the PSS®E models, the 2025 IRP transmission needs, due to thermal and voltage violations, were identified by performing reliability assessments under N-1 and N-1-1 contingencies according to Transmission Planning Standard: Puerto Rico Transmission Planning Standard, included as Attachment A.3 to Appendix 1 in the 2025 IRP Report. For clarity, the key terms are described below:

- **Thermal Violation**: Occurs when electrical current passing through a transmission line, transformer, or other equipment exceeds its specified thermal rating, in other words, the current (and power flow) exceeds the design capability of the infrastructure. Thermal violations can cause infrastructure outages due to infrastructure failures. Utility system protection devices are designed to interrupt power flow to protect equipment and prevent injury.

- **Voltage Violation**: Occurs when the voltage exceeds the maximum or falls below the minimum permissible limits as specified by the utility's operating standards. Voltage violations can cause damage to both customer-owned and utility-owned electrical equipment. Utility system protection devices are designed to interrupt power flow when voltage variations exceed acceptable levels to prevent potential damage to electrical devices.

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[6] The results presented herein are valid based on the assumptions made by the planners to reflect the system conditions for developing the 2025 IRP models for the years 2026 and 2034. Reliability studies were performed under N-1 and N-1-1 contingencies to identify both thermal and voltage violations, for which mitigation projects were proposed. For any additional assumptions, new models need to be developed to accurately reflect the updated system conditions, and new reliability studies need to be performed.

- **N-0:** This is the normal operation of the system with no major outages (N = normal, 0 = zero elements out of service). The power system is expected to remain stable and operational, supplying all customer loads.
- **N-1 Contingency**: This contingency condition assumes a single major component like a transmission line, generator, or transformer fails (Normal with 1 element out of service). The power system is expected to remain stable and operational, supplying all customer loads.
- **N-1-1 Contingency**: This contingency condition assumes that two major components fail sequentially with adjustments allowed between failures (Normal with 1 element out of service, followed by 1 additional element out of service). N-1-1 contingency is a scenario where a power system must withstand two sequential, single-component failures. This means the system is first subjected to a single outage (N-1), and after operators make adjustments to stabilize the system, a second unrelated outage occurs to another piece of equipment. The power system is expected to remain stable and operational, supplying all customer loads.

Thermal and voltage violations that are identified in normal operations (N-0) are considered transmission needs that require immediate mitigation solution provided the corresponding violations are present in the 2025 IRP models only.

The transmission analysis was conducted for two load conditions in two different years, 2026 and 2034. The year 2026 was chosen as an early year in the 2025 IRP study horizon that needed to enable substantial supply resource additions from the fixed decision projects planned for operation by 2026. The year 2034 was selected since it both met the 10-year transmission planning horizon required by Regulation 9021 and included many of the new utility-scale resource additions identified in the PRP. Given that reliability assessments were conducted in 2026 and 2034, certain identified 2025 IRP transmission needs may be present in both years. In such cases, common IRP transmission solutions are considered to determine the cost of their corresponding solutions. Note that if a project is required in the 2026 case and also in the 2034 case, this confirms that the project scope provides near-term system benefit (as identified in the 2026 case) and continues to provide systemwide benefits to enable future resource additions according to the varied resource scenarios evaluated (as identified in the 2034 cases).

The analysis was based on the high-load conditions for both 2026 and 2034, from Scenario 8 conditions used in the 2025 IRP resource modeling. LUMA chose to use the high-load forecast conditions to analyze the transmission system since the conditions were judged to be representative of the extreme load conditions typically used for T&D planning, and because as an island, Puerto Rico must satisfy 100% of forecasted demand inclusive of potential forecast error. As described in the report, Scenario 8 is a flex run where Portfolio A was subjected to a high load forecast. For the analysis of the PRP implications, LUMA studied the transmission system at two snapshots for both 2026 and 2034 that were judged to represent likely stress conditions for the transmission system. The first snapshot was at the forecasted peak solar output for each respective year. The second snapshot was at the peak load for each year.

The total cost of the 2025 IRP transmission needs includes solution projects to resolve thermal and voltage violations under N-0, N-1 and N-1-1 contingencies.

The data sources used to develop the IRP models in PSS®E, the identified 2025 IRP transmission needs, their individual (N-1 and N-1-1) and common solutions (which can resolve both N-1 and N-1-1 solutions with a single project), and their corresponding costs for 2026 and 2034 are described in the following subsections. Note that resolution of a grid violation identified in both 2026 and 2034 with an infrastructure project that is common to both situations ensures that near-term investments provide long-term reliability, resilience, and resource expansion value.

2.1.1 2026 and 2034 IRP PSS®E Model Development

For the development of the 2025 IRP peak solar (PS) and heavy night load (HNL) models, LUMA assessed the TPL day peak (DPK) and night peak (NPK) PSS®E models for 2026 and 2034. Information on transmission projects, as well as area load data for the 2026 and 2034 IRP models, is provided in the following subsections.

2.1.2 Development of 2026 IRP PSS®E Models

The development of the PSS®E models for 2026 commenced from the 2025 TPL base cases. The 2026 TPL DPK and NPK models are developed based on transmission, generation, and load projects planned to be in service in 2026. Building on these models, the 2026 IRP PS and HNL models were created using generation and load data from the corresponding PLEXOS® simulations.

2.1.3 Development of 2034 IRP PSS®E Models

The development of the PSS®E models for 2034 commenced from the 2029 TPL base cases. The TPL DPK and NPK models are developed based on transmission, generation, and load projects scheduled to be in service in 2034. Building on these models, the 2026 IRP PS and HNL models were created using generation and load data from the corresponding PLEXOS® simulations.

2.2 Distribution System Implications

LUMA did not complete a comprehensive analysis of the implications of the PRP on the distribution system. The forecast of distributed photovoltaic (DPV) and electric vehicle (EV) charging installations in the 2025 IRP represent forecasts of customer choices for these installations that are not under the control of LUMA, and are driven solely by customer choice, and so the location and quantity is not within LUMA's planned resource deployment but must be reactively addressed according to present laws and regulations.

As discussed in Section 5 of Appendix 1 of the 2025 IRP report, LUMA has recently completed a comprehensive Distribution Planning Area Planning review of the entire service territory. Through this effort LUMA identified required modernization investments including distribution circuits, distribution substations, and supporting infrastructure that requires capacity upgrade, reliability investments due to poor asset performance, grid modernization and distribution automation investments, and investments due to customer load, and customer Distributed Energy Resources (DER) interconnections.

LUMA performs continuous analysis of all distribution circuits experiencing rapid DER growth. Each feeder with aggregate installed Photovoltaic (PV) capacity (in MW) exceeding 15% of the circuit's most recent annual peak load is studied. Over 68% of the existing feeders[7], have been assessed with high confidence results indicating that the current distribution system cannot support the DPV currently installed, and will be challenged to accommodate the incremental DPV growth reflected in the 2025 IRP scenarios. Note that Puerto Rico sees one of the highest growth rates of residential DPV in North America, partly spurred by electricity rates, below-industry-standard grid reliability, and desired resilience to extreme weather. Required modifications include:

- Adoption of smart inverter settings for all existing and future DPV deployments where each customer connection “does no harm” to the grid
- Extensive number of upgraded distribution customer transformers
- Extensive number of circuit-level voltage control device upgrades, including modernization from fixed to controllable (e.g. capacitor banks)
- Extensive upgrades of the distribution circuit infrastructure (conductor capacity upgrades, voltage conversions to 13.2kV, and configuration)
- Upgrades to substation transformer capacities, transformer protection and supervisory data acquisition and control (SCADA)

Additional opportunities to explore include:

- Because Puerto Rico customers adopt DPV with high attachment rates (>80%) of batteries, there are opportunities to control-export
- Also, high concentrations of DPV paired with battery storage provide opportunity for utility interactive programs (e.g. Virtual Power Plants – VPP) and cost-reasonable expansion should be explored

LUMA has not performed analysis of EV charging but anticipates that as EV load grows, a significant portion of EV charging loads will need to be enrolled in managed charging programs to potentially reduce the grid-upgrades that would be required from non-managed charging.

Based on the above, LUMA has requested the Energy Bureau recognize this omission of identifying distribution impacts of the PRP as part of the waivers granted in the April 15, 2024, Resolution of Order, where it indicated: “LUMA cannot file information it does not have,” and granted LUMA a waiver recognizing LUMA’s inability to comply with Regulation 9021 as a result of not possessing the required data.

[7] LUMA has completed analysis of 765 of the total 1127 circuits. However, the analysis was focused on the current needs and not the future hosting capacities of the circuits.

3.0 Summary of Results

The transmission PSS®E Analysis was based solely on steady-state power flow and contingency analysis to identify the thermal overloads and voltage violations that result. The results focus only on the 115kV and 230kV transmission backbone, and do not include the 38kV overloads or voltage violations which are also extensive. PSS®E Analysis for N-1 and N-1-1 contingency show considerable thermal overloads and voltage violations result on the 115 and 230kV transmission from even single contingency events such as loss of a transmission line, substation circuit breaker, or loss of a busbar. The PSS®E analysis yields numerous thermal and voltage violations requiring solutions to support the PRP. The types of solution projects recommended in the following sections include:

- **Thermal Solutions:**
  - Installing new transformers
  - Rebuilding existing transmission lines
  - Reconductoring existing transmission lines
  - Replacing Transformers
- **Voltage Solutions**
  - Upgrade existing capacitor banks and include control
  - Add new capacitor banks
  - Add new Static VAR Compensators
  - Add new BESS capacity
  - Add new 230/115 kV transformers
  - Add new transmission lines
  - Change transmission transformer tap ratios

Table 1 and Table 2 summarize the estimated cost range of solutions proposed based on the PSS®E analysis in 2025 dollars (2025$), as used in the remaining tables, in nominal dollars (nominal$) and in PVRR in nominal dollars, assuming an 8% weighted average cost of capital. The lower range cost estimates assume no transmission line structures will need to be rebuilt for the reconducting projects identified in the solutions. The upper range cost estimates assume that many transmission line structures will need to be rebuilt for the reconducting projects identified in the solutions, due to the condition of the existing structures.

Table 1: Summary of Lower Range Cost Estimate for Thermal and Voltage Solutions

Year	Thermal Solutions (2025$)	Voltage Solutions (2025$)	Total Solutions (2025$)	Thermal Solutions (Nominal$)	Voltage Solutions (Nominal$)	Total Solutions (Nominal$)	PVRR Total Solutions (Nominal$)
2026	379,948,703	157,345,610	537,294,313	389,447,421	161,279,250	550,726,671	437,184,587
2034	295,071,652	7,134,080	302,205,732	368,504,060	8,909,488	377,413,548	161,866,202
Total	**675,020,355**	**164,479,690**	**839,500,045**	**757,951,480**	**170,188,739**	**928,140,219**	**599,050,789**

Table 2: Summary of Upper Range Cost Estimate for Thermal and Voltage Solutions

Year	Thermal Solutions (2025$)	Voltage Solutions (2025$)	Total Solutions (2025$)	Thermal Solutions (Nominal$)	Voltage Solutions (Nominal$)	Total Solutions (Nominal$)	PVRR Total Solutions (Nominal$)
2026	1,182,780,000	306,729,081	1,489,509,081	1,212,349,500	314,397,308	1,526,746,808	1,211,980,840
2034	848,750,362	7,134,080	855,884,442	1,059,972,898	8,909,488	1,068,882,386	458,425,334
Total	**2,031,530,362**	**313,863,161**	**2,345,393,523**	**2,272,322,398**	**323,306,796**	**2,595,629,194**	**1,670,406,174**

3.1.1 Discussion of Thermal Results

The transmission analysis identifies numerous N-1 and N-1-1 contingency violations. Note that contingencies that result in a large overload will create cascading failures. This means that another line that overloads to 150 or 200%, for example, will also trip based on protective relay settings, and this will cause other transmission lines that have to carry the rerouted power flows to trip, eventually resulting in area-wide or island-wide disturbances and outages.

The mitigation solutions presented herein are required to prevent these types of significant overloads, to prevent the major cascading failures, and to achieve an industry standard level or reliability. The projects proposed include a mix of those already requested for FEMA funding, projects for which customer funding has been requested in the ongoing Rate Case, and other newly identified recommendations to support the PRP that will need to have future funding sources.

3.1.2 Discussion of Voltage Results

The transmission analysis does not include detailed voltage stability, or transient stability analysis of the PRP and must be performed as future work (e.g., interconnection studies, annual transmission planning studies which consider the following couple of years). The magnitude and severity of contingency results before and after the PRP indicate that fixed resource decisions in the ten-year plan do not solve system voltage stability concerns. This is evidenced by the numerous contingencies that result in widespread voltage depression which will lead to major island-wide disturbances without the implementation of mitigation solutions and proposed projects. This certain observation exists because generators will trip offline for extreme low-voltages like those identified in the study results.

The extensive mitigation solutions presented are core and essential investments to provide a basic level of adequate voltage and reactive power support. The results of the Transmission Needs Study Report presented herein must be interpreted with the primary understanding that Puerto Rico’s Transmission & Distribution system requires significant improvements to operate reliably and meet minimum industry standards.

4.0 2026 IRP Transmission Needs

The following sections summarize the IRP transmission needs identified according to the LUMA TPL standard and criteria for the year 2026, focusing on thermal and voltage violations under N-1 and N-1-1 contingency conditions. The tables present the pre-project loading percentages and the pre-project voltage violation levels for the monitored facilities, highlighting the transmission needs associated with each element. For each identified need, targeted or common mitigation solutions to mitigate thermal overloads and voltage violations are proposed. As discussed, the thermal overloads are extensive, and require significant investment to maintain a stable and reliable grid. Similarly, the voltage violations and required solutions indicate that the PRP fixed resource decisions alone do not provide a stable grid, and that significant investment in static and dynamic voltage and reactive power resources are required to provide a stable grid.

4.1 2026 IRP Thermal Violations: N-1 and N-1-1

Table 3 provides a listing of the definition of each contingency type. The list of all N-1 thermal violations considered for the year 2026 as shown in Table 4. Loading percentage of more than 100% of a transmission facility rating under any N-1 contingency is considered a thermal violation.

Table 3: Contingency Type Definitions

Category		Initial Condition	Event
P0	No Contingency	Normal System	None
P1	Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission circuit 3. Transformer 4. Shunt device 5. Single Pole of a DC line
P2	Single Contingency	Normal System	1. Opening of a line section without a fault 2. Bus section fault 3. Internal breaker fault (non-bus-tie breaker) 4. Internal breaker fault (bus-tie breaker)
P3	Multiple Contingency	Loss of generator unit followed by System adjustments	Loss of one of the following: 1. Generator 2. Transmission circuit 3. Transformer 4. Shunt device 5. Single pole of a DC line
P4	Multiple Contingency (Fault Plus Stuck Breaker)	Normal System	Loss of multiple elements caused by a stuck breaker 10 (non-bus-tie breaker) attempting to clear a fault on one of the following: 1. Generator 2. Transmission circuit 3. Transformer 4. Shunt device

Category		Initial Condition	Event
			5. Bus section 6. Loss of multiple elements caused by a stuck breaker (Bus-tie breaker) attempting to clear a fault on the associated bus
P5	Multiple Contingency (Fault Plus Relay Failure to Operate)	Normal System	Delayed fault clearing due to the failure of a non-redundant relay protecting the faulted element to operate as designed for one of the following: 1. Generator 2. Transmission circuit 3. Transformer 4. Shunt device 5. Bus Section
P6	Multiple Contingency (Two Overlapping Singles)	Loss of one of the following followed by System adjustments 1. Transmission Circuit 2. Transformer 3. Shunt Device 4. Single pole of a DC line	Loss of one of the following: 1. Transmission circuit 2. Transformer 3. Shunt device 4. Single pole of a DC line
P7	Multiple Contingency (Common Structure)	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on a common structure 2. Loss of a bipolar DC line

Table 4: 2026 IRP Transmission Needs Addressing N-1 Thermal Violations

Model	If This Contingency Occurs or If This Element Fails	Then This Element Overloads	kV	Area	Loading Level (%)	Contingency Type
HNL	[redacted]	L38300	115	1	156.6	P2
		L40000	115	1	110.0	P2
HNL		TRANSFORMER: JOBOS 2	115/38	5	155.5	P1
HNL		TRANSFORMER: JOBOS 1	38/115	5	154.8	P2
HNL		L36100	115	2	140.1	P1
PS		L38700	115	2/1	137.3	P2
HNL		L37100	115	6/8	124.7	P7
PS		L36200	115	4/3	117.7	P2
HNL		L38900	115	1	116.2	P2
HNL		L38500	115	1	105.3	P7

Model	If This Contingency Occurs or If This Element Fails	Then This Element Overloads	kV	Area	Loading Level (%)	Contingency Type
PS	[redacted]	L40300	115	6	103.7	P2
HNL		L40500	115	1	102.0	P1
HNL		L37400	115	2	102.0	P7
PS		TRANSFORMER: SANTA ISABEL 1	115/38	6/5	100.7	P7
HNL		L38100	115	1	100.2	P7

The list of all N-1-1 thermal violations considered for the 2026 IRP are shown in Table 5. A loading percentage of more than 100% of a transmission facility rating under any N-1-1 contingencies is considered a thermal violation.

Table 5: 2026 IRP Transmission Needs Addressing N-1-1 Thermal Violations

Model	If These Contingencies Occur or If These Elements Fail	Then This Element Overloads	kV	Area	Loading Level (%)	Contingency Type
HNL	[redacted]	TRANSFORMER: DAGUAO 1	38/115	3	150.4	P6
HNL		L37200	115	8	147.2	P6
HNL		L40500	115	1	141.0	P6
PS		TRANSFORMER: JOBOS 2	115/38	5	140.2	P6
		TRANSFORMER: JOBOS 1	38/115	5	140.1	P6
PS		L38700	115	2/1	132.4	P6
PS		L37500	115	1	131.9	P6
PS		L41200	115	3	127.8	P6
HNL		L36100	115	7/2	124.6	P6
PS		L36800	115	3	123.5	P6
PS		L37500	115	2	123.3	P6
HNL		L37400	115	7	122.7	P6
HNL		L36100	115	2	122.0	P6

Model	If These Contingencies Occur or If These Elements Fail	Then This Element Overloads	kV	Area	Loading Level (%)	Contingency Type
PS	[redacted]	L37500	115	2/1	118.9	P6
HNL		L38100	115	1	115.4	P6
HNL		TRANSFORMER: ANASCO	38/115	8	115.3	P6
HNL		L38400	115	1	115.0	P6
PS		L40300	115	6	113.8	P6
HNL		L37100	115	8	112.0	P6
HNL		L36100	115	7	111.1	P6
HNL		L38900	115	1	109.6	P6
HNL		L38500	115	1	105.3	P6
HNL		L39800	115	8	105.1	P6
PS		L37100	115	6	104.7	P6
HNL		L40000	115	1	104.3	P6
HNL		L50400	230	6/8	103.8	P6
PS		L36100	115	2/1	103.5	P6
PS		L36200	115	4/3	100.3	P6

4.2 2026 IRP Voltage Violations: N-1 and N-1-1

The list of all N-1 voltage violations considered for the 2026 IRP is shown in Table 6. Voltage magnitudes that are higher than 110% (or 1.1) or lower than 90% (or 0.9) under any N-1 contingency are classified as violations.

Table 6: 2026 IRP Transmission Needs Addressing N-1 Voltage Violations

Model	If This Element Fails (Contingency Occurs)	A Voltage Violation Results at This Bus	Bus Name	kV	Area	Voltage Violation (%)
PS	[redacted]	281	QUEB NEGRITO	115	1	0.779
		16	R.BLANCO 115	115	4	0.786

Model	If This Element Fails (Contingency Occurs)	A Voltage Violation Results at This Bus	Bus Name	kV	Area	Voltage Violation (%)
PS	[redacted]	2002	SSHV	115	3	0.719
		2001	PCC	115	3	0.721
		101	DAGUAO 115	115	3	0.721
		3000	INF_HV	115	3	0.721
		3001	INF_GEN	115	3	0.721
PS		231	AÑASCO 115	115	8	0.693
		10001	MORA 115 _02	115	7	0.698
		100	MORA 115	115	7	0.698
		277	MAY TC 115	115	8	0.7
		428	ALTURAS MAY	115	8	0.7
		29	MAYAGUEZ 115	115	8	0.701
		232	MAYA TC 230	230	8	0.705
		352	MORA 230	230	7	0.712
		35201	MORA TAP	230	8	0.712
		116	ACACIAS 115	115	8	0.725
		440	CAMB GP 230	230	7	0.738
		555	MOROVIS	115	2	0.755
		177	CIALES 115	115	7	0.755
		83	COROZAL 115	115	2	0.756
		400	MONTEREY	115	2	0.758
		38	DOS BOCA 115	115	7	0.762
		3801	DOS BOCA _02	115	7	0.762
		93	DORADO 115	115	2	0.765
		335	HATILLO 115	115	7	0.767

Model	If This Element Fails (Contingency Occurs)	A Voltage Violation Results at This Bus	Bus Name	kV	Area	Voltage Violation (%)
	[redacted]	97144	HATILLO	115	7	0.767
		40	CAMBALACH115	115	7	0.775
		196	MANATI 230	230	7	0.776
		169	SGERMANTC115	115	8	0.776
		97094	SOLANER	115	8	0.776
		441	CAMB GP 115	115	7	0.778
		41	VEGA BAJA115	115	2	0.78
		97064	VEGASERENA	115	2	0.78
		343	ABBOTT 115	115	7	0.796
		102	BARCLONET115	115	7	0.796
		149	A.BUENAS 115	115	4	0.798
		442	DUPONT	115	7	0.799
		452	ROCHE	115	7	0.799
		15301	MANATI 11_02	115	7	0.8
		153	MANATI 115	115	7	0.8
		15302	MANATI_XFM	115	7	0.8
		23	GUANICA 115	115	6	0.848
PS		111	H.CREA	115	2	0.753
		378	HATO TEJASTC	115	2	0.753
		63	PALOSECO 115	115	2	0.754
		5001	MONACILLO_02	115	1	0.764
		21	CAGUAS 115	115	4	0.779
		120	S.LLANA 230	230	3	0.781
		45	BAYAMON 115	115	2	0.756

Model	If This Element Fails [redacted]	A Voltage Violation Results at This Bus	Bus Name	kV	Area	Voltage Violation (%)
	[redacted]	271	R BAYAMON115	115	2	0.757
		190	CANA 115	115	2	0.757
		545	GRANA	115	1	0.757
		211	PALMER 115	115	3	0.758
		492	CANDE ARENAS	115	2	0.759
		31001	BO PINAS _02	115	2	0.76
		310	BO PINAS 115	115	2	0.76
		632	ISLA GDE 115	115	1	0.761
		63201	ISLA GDE _02	115	1	0.761
		86	VIADUCTO 115	115	1	0.761
		8602	VIADUCTO 01A	115	1	0.761
		8601	VIADUCTO _02	115	1	0.761
		8603	VIADUCTO 02A	115	1	0.761
		87	HATO REY 115	115	1	0.761
		8701	HATO REY _02	115	1	0.761
		392	M PENA GIS	115	1	0.762
		127	CACHETE13	115	1	0.762
		82	CANOVANAS115	115	3	0.764
		8201	CANOVANAS_02	115	3	0.764
		50	MONACILLO115	115	1	0.764
		18	FAJARDO 115	115	3	0.764
		88	SJSP 115	115	1	0.764
		1040	BUEN PASTOR	115	1	0.768
		280	VILLA BETINA	115	1	0.769

Model	If This Element Fails (Contingency Occurs)	A Voltage Violation Results at This Bus	Bus Name	kV	Area	Voltage Violation (%)
	[redacted]	175	CONQUISTADOR	115	1	0.772
		84	BERWIND 115	115	1	0.773
		480	ENCANTADA	115	1	0.773
		583	ESCORIAL	115	1	0.775
		85	S.LLANA 115	115	3	0.777
		8501	S.LLANA 1_02	115	3	0.777
		1027	SUB SAN JOSE	115	4	0.788
		451	AGUBUENAS230	230	4	0.789
		99	BAYAMON 230	230	2	0.789
		10	CAYEY 115	115	4	0.792
		1206	AMGEN_115	115	4	0.803
		23401	JUNCOS 11_02	115	4	0.803
		234	JUNCOS 115	115	4	0.803
		14	HUMACAO	115	4	0.807
		1401	HUMACAO _02	115	4	0.807
		97047	COMETA_HV	115	4	0.807
		233	YABUCOA 230	230	4	0.808
		5	YABUCOA 115	115	4	0.81
		5002	YABUCOA 1_02	115	4	0.81
		275	COMERIO 115	115	4	0.81
		185	SUN OIL	115	4	0.817
		106	AGUIRRE 230	230	5	0.817
		353	BARRANQT 115	115	4	0.817
		1025	J MARTIN SEC	115	5	0.818

Model	If This Element Fails (Contingency Occurs)	A Voltage Violation Results at This Bus	Bus Name	kV	Area	Voltage Violation (%)
	[redacted]	97134	YABUCOA	115	5	0.818
		321	AES 230	230	5	0.822
		184	MAUNABO115	115	5	0.822
		334	MAUNABO TAP	115	5	0.822
		8	JOBOS 115	115	5	0.828
		6202	SW-39045	115	6	0.83
		107	AGUIRRE 115	115	5	0.839
		97014	CIRO	115	5	0.839
		213	TORONEGRO115	115	6	0.842
		59999	CIRO SECT	115	5	0.843
		296	SANTA ISABEL 115	115	6	0.862
		313	JDIAZ TC	115	6	0.865
		59300	I-1-P	115	5	0.865
		1800	PATTERN	115	6	0.866
		7000	POI	115	5	0.866
		266	JAYUYA	115	7	0.871
		7200	SIT1HV	115	5	0.872
		6200	TAP 36400-1	115	6	0.873
		3	PONCE 115	115	6	0.873
		30001	PONCE 115_02	115	6	0.873
		363	PONCE TC 230	230	6	0.877
		96	COSTA SUR230	230	6	0.879
		103	CANAS 115	115	6	0.882
		319	ECOELECT 230	230	6	0.895

Model	If This Element Fails (Contingency Occurs)	A Voltage Violation Results at This Bus	Bus Name	kV	Area	Voltage Violation (%)
	[redacted]	6204	DEMACO PPG	115	6	0.896
		489	UNIONCARBIDE	115	6	0.897
		2	COSTA SUR115	115	6	0.897
HNL		335	HATILLO 115	115	7	0.818
		97144	HATILLO	115	7	0.818
HNL		97021	YAROTEK_HV	115	7	0.654
HNL		29	MAYAGUEZ 115	115	8	0.738
		428	ALTURAS MAY	115	8	0.738
		277	MAY TC 115	115	8	0.738
		10001	MORA 115 _02	115	7	0.747
		100	MORA 115	115	7	0.747
		232	MAYA TC 230	230	8	0.749
		352	MORA 230	230	7	0.767
		35201	MORA TAP	230	8	0.767
		440	CAMB GP 230	230	7	0.815
		196	MANATI 230	230	7	0.868
		38	DOS BOCA 115	115	7	0.873
		3801	DOS BOCA _02	115	7	0.873
		40	CAMBALACH115	115	7	0.874
		441	CAMB GP 115	115	7	0.877
		177	CIALES 115	115	7	0.883
		555	MOROVIS	115	2	0.887
		83	COROZAL 115	115	2	0.893
		343	ABBOTT 115	115	7	0.894

Model	If This Element Fails (Contingency Occurs)	A Voltage Violation Results at This Bus	Bus Name	kV	Area	Voltage Violation (%)
	[redacted]	102	BARCLONET115	115	7	0.894
		400	MONTEREY	115	2	0.899

The list of all N-1-1 voltage violations considered for the 2026 IRP is shown in Table 7. Voltage magnitudes that are higher than 110% or lower than 90% under any N-1-1 contingencies are classified as violations.

Table 7: 2026 IRP Transmission Needs Addressing N-1-1 Voltage Violations

Model	Model If These Contingencies Occur or If These Elements Fail	A Voltage Violation Occurs at This Bus #	Bus Name	kV	Area	Voltage Violation (p.u.)
HNL	[redacted]	59300	I-1-P	115	5	0.51
HNL		97021	YAROTEK_HV	115	7	0.558
PS		2002	SSHV	115	3	0.577
		101	DAGUAO 115	115	3	0.578
		2001	PCC	115	3	0.57 8
		3000	INF_HV	115	3	0.578
		3001	INF_GEN	115	3	0.578
		18	FAJARDO 115	115	3	0.586
		211	PALMER 115	115	3	0.591
PS		277	MAY TC 115	115	8	0.619
		232	MAYA TC 230	230	8	0.619
		428	ALTURAS MAY	115	8	0.619
		29	MAYAGUEZ 115	115	8	0.621
PS		63	PALOSECO 115	115	2	0.699
		86	VIADUCTO 115	115	1	0.7
		632	ISLA GDE 115	115	1	0.7
		63201	ISLA GDE _02	115	1	0.7

Model	Model If These Contingencies Occur or If These Elements Fail	A Voltage Violation Occurs at This Bus #	Bus Name	kV	Area	Voltage Violation (p.u.)
	[redacted]	8602	VIADUCTO 01A	115	1	0.7
		8601	VIADUCTO _02	115	1	0.7
		8603	VIADUCTO 02A	115	1	0.7
		88	SJSP 115	115	1	0.702
		111	H.CREA	115	2	0.702
		87	HATO REY 115	115	1	0.702
		8701	HATO REY _02	115	1	0.702
		392	M PENA GIS	115	1	0.702
		271	R BAYAMON115	115	2	0.703
		127	CACHETE13	115	1	0.703
		45	BAYAMON 115	115	2	0.703
		545	GRANA	115	1	0.704
		378	HATO TEJASTC	115	2	0.704
		5001	MONACILLO_02	115	1	0.708
		50	MONACILLO115	115	1	0.708
		190	CANA 115	115	2	0.708
PS		83	COROZAL 115	115	2	0.71
PS		492	CANDE ARENAS	115	2	0.71
		82	CANOVANAS115	115	3	0.713
		8201	CANOVANAS_02	115	3	0.713
		31001	BO PINAS _02	115	2	0.713
		310	BO PINAS 115	115	2	0.713
HNL		280	VILLA BETINA	115	1	0.713

Model	Model If These Contingencies Occur or If These Elements Fail	A Voltage Violation Occurs at This Bus #	Bus Name	kV	Area	Voltage Violation (p.u.)
PS	[redacted]	1040	BUEN PASTOR	115	1	0.713
HNL		84	BERWIND 115	115	1	0.714
		175	CONQUISTADOR	115	1	0.714
		480	ENCANTADA	115	1	0.714
		583	ESCORIAL	115	1	0.715
		85	S.LLANA 115	115	3	0.717
PS		400	MONTEREY	115	2	0.717
HNL		8501	S.LLANA 1_02	115	3	0.717
PS		93	DORADO 115	115	2	0.719
HNL		281	QUEB NEGRITO	115	1	0.719
PS		41	VEGA BAJA115	115	2	0.721
PS		97064	VEGASERENA	115	2	0.721
HNL		120	S.LLANA 230	230	3	0.723
HNL		16	R.BLANCO 115	115	4	0.726
PS		555	MOROVIS	115	2	0.729
PS		21	CAGUAS 115	115	4	0.729
HNL		1206	AMGEN_115	115	4	0.73
HNL		234	JUNCOS 115	115	4	0.73
HNL		23401	JUNCOS 11_02	115	4	0.73
HNL		451	AGUBUENAS230	230	4	0.732
HNL		14	HUMACAO	115	4	0.734
HNL		1401	HUMACAO _02	115	4	0.734
HNL		97047	COMETA_HV	115	4	0.735

Model	Model If These Contingencies Occur or If These Elements Fail	A Voltage Violation Occurs at This Bus #	Bus Name	kV	Area	Voltage Violation (p.u.)
PS	[redacted]	38	DOS BOCA 115	115	7	0.736
	[redacted]	3801	DOS BOCA _02	115	7	0.736
PS	[redacted]	196	MANATI 230	230	7	0.737
HNL	[redacted]	5	YABUCOA 115	115	4	0.737
HNL	[redacted]	5002	YABUCOA 1_02	115	4	0.737
HNL	[redacted]	99	BAYAMON 230	230	2	0.738
PS	[redacted]	177	CIALES 115	115	7	0.738
PS	[redacted]	440	CAMB GP 230	230	7	0.738
PS	[redacted]	1027	SUB SAN JOSE	115	4	0.739
HNL	[redacted]	185	SUN OIL	115	4	0.739
HNL	[redacted]	1025	J MARTIN SEC	115	4	0.739
HNL	[redacted]	97134	YABUCOA	115	4	0.739
PS	[redacted]	169	SGERMANTC1 15	115	8	0.74
	[redacted]	97094	SOLANER	115	8	0.74
HNL	[redacted]	8	JOBOS 115	115	5	0.741
	[redacted]	184	MAUNABO115	115	5	0.741
	[redacted]	334	MAUNABO TAP	115	5	0.741
	[redacted]	233	YABUCOA 230	230	4	0.741
PS	[redacted]	23	GUANICA 115	115	6	0.742
PS	[redacted]	442	DUPONT	115	7	0.744
PS	[redacted]	35201	MORA TAP	230	8	0.744
PS	[redacted]	153	MANATI 115	115	7	0.745

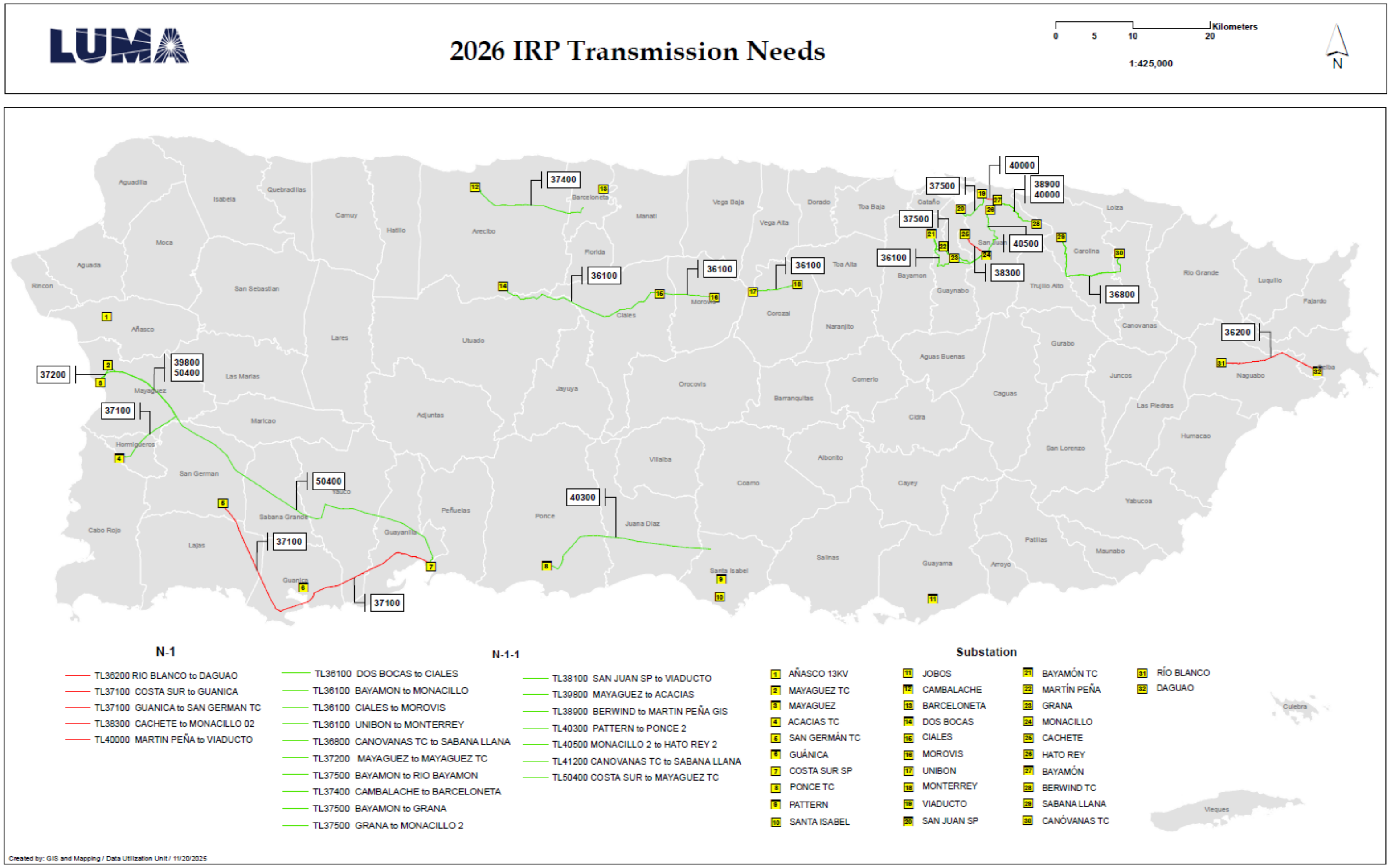
Model	Model If These Contingencies Occur or If These Elements Fail	A Voltage Violation Occurs at This Bus #	Bus Name	kV	Area	Voltage Violation (p.u.)
PS	[redacted]	15301	MANATI 11_02	115	7	0.745
		15302	MANATI_XFM	115	7	0.745
PS		10	CAYEY 115	115	4	0.746
		149	A.BUENAS 115	115	4	0.748
PS		452	ROCHE	115	7	0.748
PS		335	HATILLO 115	115	7	0.752
		97144	HATILLO	115	7	0.752
		213	TORONEGRO1 15	115	6	0.756
HNL		59999	CIRO SECT	115	5	0.757
		106	AGUIRRE 230	230	5	0.757
PS		6202	SW-39045	115	6	0.758
		353	BARRANQT 115	115	4	0.76
HNL		321	AES 230	230	5	0.763
PS		275	COMERIO 115	115	4	0.763
PS		40	CAMBALACH11 5	115	7	0.764
PS		441	CAMB GP 115	115	7	0.764
HNL		107	AGUIRRE 115	115	5	0.766
		97014	CIRO	115	5	0.766
PS		343	ABBOTT 115	115	7	0.776
		102	BARCLONET11 5	115	7	0.776
PS		313	JDIAZ TC	115	6	0.788
PS		1800	PATTERN	115	6	0.829

Model	Model If These Contingencies Occur or If These Elements Fail	A Voltage Violation Occurs at This Bus #	Bus Name	kV	Area	Voltage Violation (p.u.)
PS	[redacted]	7000	POI	115	5	0.829
HNL		266	JAYUYA	115	7	0.834
PS		7200	SIT1HV	115	5	0.835
HNL		6200	TAP 36400-1	115	6	0.836
HNL		3	PONCE 115	115	6	0.837
HNL		30001	PONCE 115_02	115	6	0.837
HNL		103	CANAS 115	115	6	0.85
HNL		363	PONCE TC 230	230	6	0.851
PS		96	COSTA SUR230	230	6	0.858
PS		6204	DEMACO PPG	115	6	0.873
PS		489	UNIONCARBIDE	115	6	0.874
PS		2	COSTA SUR115	115	6	0.874
PS		319	ECOELECT 230	230	6	0.876

4.2.1 Transmission Needs Map 2026

LUMA is including the PSS®E analysis results for N-1 and N-1-1 contingencies in Figure 1: 2026 IRP Transmission Needs Maps.

Figure 1: 2026 IRP Transmission Needs



5.0 2034 IRP Transmission Needs

The following sections provide a summary of the IRP transmission needs identified for the year 2034, specifically addressing thermal and voltage violations under N-1 and N-1-1 contingencies. The tables included in these sections present both the pre-project overloading percentage and the pre-project voltage violation level of the monitored facilities, highlighting the transmission needs for each corresponding element. For each of the transmission needs identified, individual and/or common solutions to mitigate both thermal overloads and voltage violations are proposed.

5.1 2034 Thermal Violations: N-1 and N-1-1

The list of all N-1 thermal violations considered for the 2034 IRP is shown in Table 8. Thermal loading percentage of more than 100% of a transmission facility rating under any N-1 or N-1-1 contingency is considered a thermal violation.

Table 8: 2034 IRP Transmission Needs Addressing N-1 Thermal Violations

Model	If This Contingency Occurs or If This Element Fails	Then This Element Overloads	kV	Area	Loading Level [%]	Contingency Type
HNL	[redacted]	L38300	115	1	304.6	P4_6
			115	1	292.1	P4_6
HNL		L38700	115	2/1	246.2	P2
		L38900	115	1	219.3	P2
HNL		L40500	115	1	205.1	P4
HNL		L38900	115	3/1	203.5	P2
HNL		L40000	115	1	194.8	P4_6
HNL		L38900	115	1	188.8	P2
HNL		L38400	115	1	185.4	P4
HNL		L38500	115	1	178.6	P7
HNL		L38100	115	1	169.4	P7
HNL		L40400	115	1	155.5	P7
PS		L51100	230	6	148.1	P1-1
HNL		L38900	115	1	122.0	P2
HNL		L41200	115	3	109.9	P4

Model	If This Contingency Occurs or If This Element Fails	Then This Element Overloads	kV	Area	Loading Level [%]	Contingency Type
HNL	[redacted]	TRANSFORMER: SJSP 1	38/115	1	108.8	P2
HNL		L37400	115	2	105.8	P4_6
HNL		TRANSFORMER:	115/38	3	105.7	P1
HNL		L38800	115	1	104.9	P1
HNL		L37900	115	1	104.5	P2
HNL		L37100	115	6/8	100.2	P4

The list of all N-1-1 thermal violations considered for the 2034 IRP is shown in Table 9 Thermal loading percentage of more than 100% of a transmission facility rating under any N-1 or N-1-1 contingency is considered a thermal violation.

Table 9: 2034 IRP Transmission Needs Addressing N-1-1 Thermal Violations

Model	If These Contingencies Occur or If These Elements Fail	Then This Element Overloads	kV	Area	Loading Level [%]	Contingency Type
PS	[redacted]	L38300	115	1	208.3	P6
PS		L38300	115	1	200.8	P6
HNL		TRANSFORMER: PALMER 1	38/115	3	152.8	P6
HNL		TRANSFORMER: PALMER 1	38/115	3	152.8	P6
PS		L40500	115	1	149.5	P6
HNL		L37400	115	2	145.1	P6
PS		L38700	115	2/1	139.9	P6
HNL		L36100	115	2	123.9	P6
HNL		L37200	115	8	121.6	P6
HNL		L37500	115	1	119.4	P6
HNL		L37100	115	8	116.0	P6
HNL		L37400	115	2	110.8	P6
HNL		L36100	115	2	108.9	P6
HNL		L37900	115	1	107.8	P6

Model	If These Contingencies Occur or If These Elements Fail	Then This Element Overloads	kV	Area	Loading Level [%]	Contingency Type
PS	[redacted]	L38900	115	1	107.2	P6
HNL		L36800	115	3	105.5	P6
PS		L40000	115	1	105.1	P6
PS		L38100	115	1	103.5	P6
PS		L38400	115	1	103.5	P6
HNL		L37500	115	2/1	102.3	P6
HNL		L37400	115	2	101.4	P6
HNL		L37500	115	2	100.5	P6
PS		L38900	115	3/1	100.2	P6
PS		L51100	230	6	Insufficient operating system reserves	P3

5.2 2034 Voltage Violations: N-1 and N-1-1

The list of all N-1 voltage violations considered for the 2034 IRP is shown in Table 10. Voltage magnitudes that are higher than 110% (1.1) or lower than 90% (0.9) under any N-1 contingency are classified as violations.

Table 10: 2034 IRP Transmission Needs Addressing N-1 Voltage Violations

Model	If This Contingency Occurs or If This Element Fails	A Voltage Violation Occurs at This Bus #	Bus Name	kV	Area	Voltage Violation
PS	[redacted]	35	SSEBASTIA115	115	8	0.889
PS		7780	P LIMA BESS1	115	3	0.693
		101	DAGUAO 115	115	3	0.693
		50040	P LIMA BESS2	115	3	0.693
		50340	AZ-1-E	115	3	0.693
		500080	DAGUAO GE PE	115	3	0.693
		3000	PPOA P LIMA	115	3	0.693
HNL		82	CANOVANAS115	115	3	0.802

Model	If This Contingency Occurs or If This Element Fails	A Voltage Violation Occurs at This Bus #	Bus Name	kV	Area	Voltage Violation
	[redacted]	8201	CANOVANAS_02	115	3	0.802
		211	PALMER 115	115	3	0.812
		18	FAJARDO 115	115	3	0.835
HNL	[redacted]	93	DORADO 115	115	2	0.899
HNL	[redacted]	440	CAMB GP 230	230	7	0.898
		500010	G BESS CAMBA	230	7	0.898
HNL	[redacted]	231	AÑASCO 115	115	8	0.837
		428	ALTURAS MAY	115	8	0.841
		29	MAYAGUEZ 115	115	8	0.841
		277	MAY TC 115	115	8	0.841
HNL	[redacted]	50210	TR2 194-01	115	7	0.763
		41	VEGA BAJA115	115	7	0.763
		97064	VEGASERENA	115	7	0.763
		335	HATILLO 115	115	7	0.797
		40500	XZERTA	115	7	0.797
		97144	HATILLO	115	7	0.797
HNL	[redacted]	32	AGUADILLA115	115	8	0.697
		10001	MORA 115 _02	115	7	0.705
		100	MORA 115	115	7	0.705
		50800	TR 4 252-01	115	8	0.705
		97020	ORIANA	115	8	0.705
		97030	ASAP BESS OR	115	8	0.705
		352	MORA 230	230	7	0.705
		35201	MORA TAP	230	8	0.705
HNL	[redacted]	232	MAYA TC 230	230	8	0.854

Model	If This Contingency Occurs or If This Element Fails	A Voltage Violation Occurs at This Bus #	Bus Name	kV	Area	Voltage Violation
HNL	[redacted]	50350	HOSTO RD GEN	230	8	0.854
HNL		16	R.BLANCO 115	115	4	0.895

The list of all N-1-1 voltage violations considered for the 2034 IRP is shown in Table 11. Voltage magnitudes that are higher than 110% (1.1) or lower than 90% (0.9) under any N-1-1 contingencies are classified as violations.

Table 11: 2034 IRP Transmission Needs Addressing N-1-1 Voltage Violations

Model	If These Contingencies Occur or If These Elements Fail	A Voltage Violation Occurs at This Bus #	Bus Name	kV	Area	Voltage Violation
HNL	[redacted]	7780	P LIMA BESS1	115	3	0.508
		101	DAGUAO 115	115	3	0.508
		50040	P LIMA BESS2	115	3	0.508
		50340	AZ-1-E	115	3	0.508
		500080	DAGUAO GE PE	115	3	0.508
		3000	PPOA P LIMA	115	3	0.508
		18	FAJARDO 115	115	3	0.514
HNL		100	MORA 115	115	7	0.612
		50800	TR 4 252-01	115	8	0.612
		97020	ORIANA	115	8	0.612
		97030	ASAP BESS OR	115	8	0.612
		352	MORA 230	230	7	0.612
		35201	MORA TAP	230	8	0.612
		277	MAY TC 115	115	8	0.613
		428	ALTURAS MAY	115	8	0.613
		232	MAYA TC 230	230	8	0.614
		50350	HOSTO RD GEN	230	8	0.614
		29	MAYAGUEZ 115	115	8	0.615

Model	If These Contingencies Occur or If These Elements Fail	A Voltage Violation Occurs at This Bus #	Bus Name	kV	Area	Voltage Violation
PS	[redacted]	632	ISLA GDE 115	115	1	0.704
		63201	ISLA GDE _02	115	1	0.704
		86	VIADUCTO 115	115	1	0.704
		392	M PENA GIS	115	1	0.704
		88	SJSP 115	115	1	0.704
		50250	ENERGIZA ST	115	1	0.704
		50251	ENERGIZA GT	115	1	0.704
		87	HATO REY 115	115	1	0.705
		8701	HATO REY _02	115	1	0.705
		451	AGUBUENAS230	230	4	0.705
		63	PALOSECO 115	115	2	0.706
		500040	G BESS PALO	115	2	0.706
		82	CANOVANAS115	115	3	0.706
		8201	CANOVANAS_02	115	3	0.706
		127	CACHETE13	115	1	0.706
		120	S.LLANA 230	230	3	0.707
		545	GRANA	115	1	0.708
		271	R BAYAMON115	115	2	0.708
		4502	BAYAMON TC 2	115	2	0.708
		45	BAYAMON 115	115	2	0.708
		111	H.CREA	115	2	0.709
		99	BAYAMON 230	230	2	0.709
		50	MONACILLO115	115	1	0.709
		175	CONQUISTADOR	115	1	0.710

Model	If These Contingencies Occur or If These Elements Fail	A Voltage Violation Occurs at This Bus #	Bus Name	kV	Area	Voltage Violation
	[redacted]	480	ENCANTADA	115	1	0.710
		378	HATO TEJASTC	115	2	0.710
		85	S.LLANA 115	115	3	0.711
		583	ESCORIAL	115	1	0.711
		84	BERWIND 115	115	1	0.711
		280	VILLA BETINA	115	1	0.711
		190	CANA 115	115	2	0.714
		492	CANDE ARENAS	115	2	0.714
		281	QUEB NEGRITO	115	1	0.715
		31001	BO PINAS _02	115	2	0.718
		310	BO PINAS 115	115	2	0.718
		16	R.BLANCO 115	115	4	0.718
		93	DORADO 115	115	2	0.720
		233	YABUCOA 230	230	4	0.722
		321	AES 230	230	5	0.723
		106	AGUIRRE 230	230	5	0.724
		97010	ASAP BESS FO	115	4	0.725
		14	HUMACAO	115	4	0.725
		1401	HUMACAO _02	115	4	0.725
		970410	FONROCHE	115	4	0.725
		5002	YABUCOA 1_02	115	4	0.726
		5	YABUCOA 115	115	4	0.726
		50300	AX-1-E	115	4	0.726
		500060	G BESS YABUC	115	4	0.726

Model	If These Contingencies Occur or If These Elements Fail	A Voltage Violation Occurs at This Bus #	Bus Name	kV	Area	Voltage Violation
	[redacted]	500100	YABUCOA PEAK	115	4	0.726
		50320	AT-1-P	115	5	0.726
		1206	AMGEN_115	115	4	0.729
		23401	JUNCOS 11_02	115	4	0.729
		234	JUNCOS 115	115	4	0.729
		50140	AQ-1-P	115	4	0.729
		185	SUN OIL	115	4	0.729
		1025	J MARTIN SEC	115	4	0.730
		97134	YABUCOA	115	4	0.730
		50720	AK-1-P	115	4	0.730
		184	MAUNABO115	115	5	0.731
		196	MANATI 230	230	7	0.739
		50020	A-2-E	115	5	0.740
		8	JOBOS 115	115	5	0.740
		50730	AE-2-E	115	5	0.740
		50660	AE-1-P	115	5	0.740
		50000	A-1-P	115	5	0.740
		107	AGUIRRE 115	115	5	0.745
		97014	CIRO	115	5	0.745
		500020	G BESS AGUI	115	5	0.745
		149	A.BUENAS 115	115	4	0.751
		50070	CIRO-ONEX B	115	5	0.751
		50090	CIRO-ONE X	115	5	0.751
		50100	C-2-E	115	5	0.751

Model	If These Contingencies Occur or If These Elements Fail	A Voltage Violation Occurs at This Bus #	Bus Name	kV	Area	Voltage Violation
	[redacted]	50150	AD-2-E	115	5	0.751
		59999	CIRO SECT	115	5	0.751
		50640	AD-1-P	115	5	0.751
		40510	CIRO-ONE	115	5	0.751
		50080	C-1-P	115	5	0.751
		275	COMERIO 115	115	4	0.754
		440	CAMB GP 230	230	7	0.757
		500010	G BESS CAMBA	230	7	0.757
		353	BARRANQT 115	115	4	0.758
		50210	TR2 194-01	115	7	0.759
		41	VEGA BAJA115	115	7	0.759
		97064	VEGASERENA	115	7	0.759
HNL		343	ABBOTT 115	115	7	0.764
		102	BARCLONET115	115	7	0.764
		50460	W-3-P	115	7	0.764
		50480	W-2-E	115	7	0.764
		442	DUPONT	115	7	0.766
		452	ROCHE	115	7	0.767
		153	MANATI 115	115	7	0.767
		15302	MANATI_XFM	115	7	0.767
		15301	MANATI 11_02	115	7	0.767
PS		6202	SW-39045	115	6	0.767
		213	TORONEGRO115	115	6	0.777
		50750	TR2 367-01	115	8	0.784

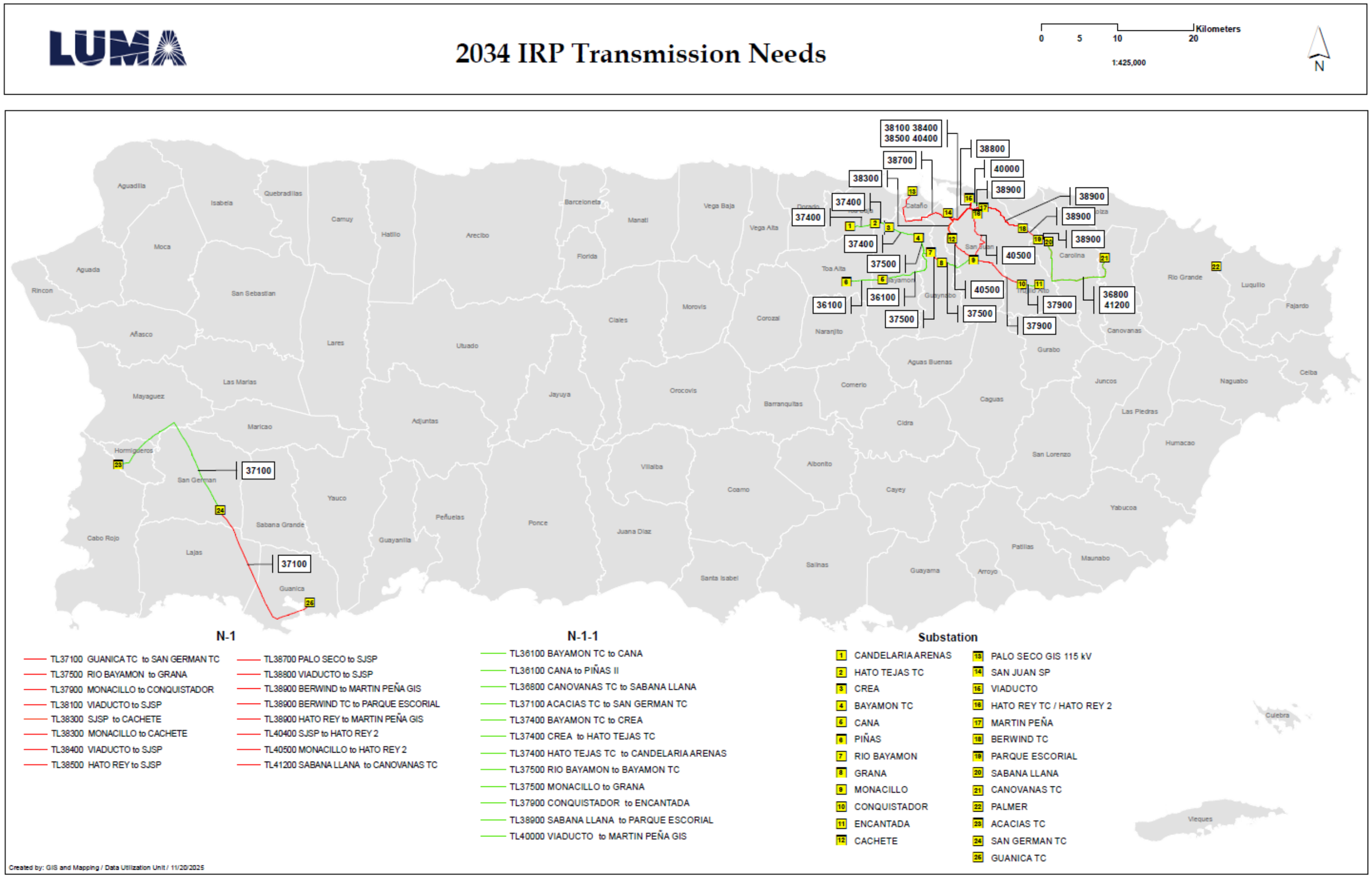
Model	If These Contingencies Occur or If These Elements Fail	A Voltage Violation Occurs at This Bus #	Bus Name	kV	Area	Voltage Violation
	[redacted]	296	SANTA ISABEL 115	115	5	0.784
		59300	I-1-P	115	5	0.789
		1800	PATTERN	115	5	0.791
		7000	POI	115	5	0.791
		50420	AA-2-E	115	6	0.791
		7200	PATTERN PPOA	115	6	0.791
		335	HATILLO 115	115	7	0.796
		97144	HATILLO	115	7	0.796
		40500	XZERTA	115	7	0.796
		313	JDIAZ TC	115	6	0.798
		40	CAMBALACH115	115	7	0.800
HNL		1040	BUEN PASTOR	115	1	0.800
PS		441	CAMB GP 115	115	7	0.805
		266	JAYUYA	115	7	0.809
		3	PONCE 115	115	6	0.809
		6200	TAP 36400-1	115	6	0.809
HNL		21	CAGUAS 115	115	4	0.813
PS		363	PONCE TC 230	230	6	0.814
		103	CANAS 115	115	6	0.816
		96	COSTA SUR230	230	6	0.823
		50120	ASAP BESS EC	230	6	0.823
HNL		1027	SUB SAN JOSE	115	4	0.825
PS		6204	DEMACO PPG	115	6	0.833
		50200	L-3-E	115	6	0.833

Model	If These Contingencies Occur or If These Elements Fail	A Voltage Violation Occurs at This Bus #	Bus Name	kV	Area	Voltage Violation
	[redacted]	2	COSTA SUR115	115	6	0.833
		489	UNIONCARBIDE	115	6	0.833
		500030	G BESS COSTA	115	6	0.833
		500070	CS GEN PEAKE	115	6	0.833
		319	ECOELECT 230	230	6	0.844
PS		583	ESCORIAL	115	1	1.109

5.2.1 Transmission Needs Map 2034

LUMA is including the PSS®E analysis results for N-1 and N-1-1 contingencies in Figure 2: 2034 IRP Transmission Needs Maps.

Figure 2: Figure 2: 2034 IRP Transmission Needs Maps



6.0 Solutions for 2026 and 2034 IRP Transmission Needs Addressing Thermal Violations

Transmission solutions are proposed to eliminate the 2025 IRP thermal overloads identified in Sections 1.3 and 1.4. Transmission solutions are comprised of the following types: new transmission line, new transformer, replacing transformer, reconductor transmission line, and rebuild transmission line. A summary of the proposed transmission solutions, including mitigation measures for thermal overloads, is presented in Table 12.

Table 12: Summary of the proposed N-1 and N-1-1 thermal solutions for both 2026 and 2034

Year	Single Outage (N-1)		Double Outages (N-1-1)	
	Project Type	Quantity	Project Type	Quantity
2026	New Transformer	2	New Transformer	3
	Rebuild	3	Rebuild	4
	Reconductor	9	Reconductor	20
	Replace Transformer	1	Replace Transformer	1
2034	Rebuild	4	Rebuild	4
	Rebuild & Add New Transformer	1	Rebuild & Add New Transformer	1
	Reconductor	11	Reconductor	15
	Replace Transformer	2	Replace Transformer	1

The following two subsections outline the solutions proposed to address the transmission overloads of the years 2026 and 2034.

6.1 Solutions to 2026 IRP Transmission Needs Addressing Thermal Violations: N-1 and N-1-1

Table 13 summarizes the proposed solutions for addressing the N-1 thermal violations identified in the 2026 IRP transmission needs presented in Table 4. Note that the column "Solution Description" below identifies conductor gauge and material that are directional only. These specific conductors are described for three primary reasons: (1) they are a common gauge used at LUMA, but may utilize advanced conductors and materials, (2) they are used for estimating the cost of a mitigation project based on publicly available cost information, and (3) they represent conductors with the minimum MVA rating capacity required to fully mitigate the observed thermal overload.

Table 13: Solutions Addressing N-1 Thermal Violations in the 2026 IRP Transmission Needs

Model	If This Contingency Occurs or If This Element Fails	Then This Element Overloads	kV	Area	Loading Level (%)	Contingency Type	Solution Description	New Capacity /Ratings (MVA)	Post-project Loading (%)
HNL	[redacted]	L38300	115	1	156.6	P2	Rebuild to 556.5 ACSS	289	77.0
HNL		Transformer : JOBOS 2	115/38	5	155.5	P1	Add New 115/38 kV TRANSFORMER at JOBOS	60 80/100/112	75.6
HNL		Transformer : JOBOS 1	38/115	5	154.8	P2	Add New 115/38 kV TRANSFORMER at JOBOS	60 80/100/112	75.0
HNL		L36100	115	2	140.1	P1	Reconductor to 556.5 ACSS	289	52.6
PS		L38700	115	2/1	137.3	P2	Reconductor to 556.5 ACSS	289	90.4
HNL		L37100	115	6/8	124.7	P7	Reconductor to 556.5 MCM ACSS	289	63.0
PS		L36200	115	4/3	117.7	P2	Reconductor to 556.5 MCM ACSS	289	59.2
HNL		L38900	115	1	116.2	P2	Reconductor to 556.5 ACSS	289	79.0
HNL		L40000	115	1	110.0	P2	UG Conductor	289	72.5
HNL		L38500	115	1	105.3	P7	Reconductor to 556.5 ACSS	289	85.3
PS		L40300	115	6	103.7	P2	Reconductor to 556.5 ACSS	289	51.8

Model	If This Contingency Occurs or If This Element Fails	Then This Element Overloads	kV	Area	Loading Level (%)	Contingency Type	Solution Description	New Capacity /Ratings (MVA)	Post-project Loading (%)
HNL	[redacted]	L40500	115	1	102.0	P1	UG Conductor	448	39.2
HNL		L37400	115	2	102.0	P7	Reconductor to 556.5 ACSS	289	72.8
PS		Transformer : SANTA ISABEL 1	115/38	6/5	100.7	P7	Replace 115/38 kV TRANSFORMER at SANTA ISABEL	60 80/100/112	48.7
HNL		L38100	115	1	100.2	P7	Reconductor to 556.5 ACSS	289	70.6

Table 14 summarizes the proposed solutions for addressing the N-1-1 thermal violations identified in the 2026 IRP transmission needs presented in Table 5. Note that the column “Solution Description” below identifies conductor gauge and material that are directional only. These specific conductors are described for three primary reasons: (1) they are a common gauge used at LUMA, but may utilize advanced conductors and materials, (2) they are used for estimating the cost of a mitigation project based on publicly available cost information, and (3) they represent conductors with the minimum MVA rating capacity required to fully mitigate the observed thermal overload.

Table 14: Solutions for Addressing N-1-1 Thermal Violations in the 2026 IRP Transmission Needs

Model	If These Contingencies Occur or If These Elements Fail	Then This Element Overloads	kV	Area	Loading Level (%)	Contingency Type	Solution Description	New Capacity /Ratings (MVA)	Post-project Loading (%)
HNL	[redacted]	TRANSFORMER: DAGUAO 1	38/115	3	150.4	P6	Replace 115/38 kV TRANSFORMER at DAGUAO	60 80/100/112	70.9
HNL		L37200	115	8	147.2	P6	Reconductor to 556.5 MCM ACSS	289	74.1
HNL		L40500	115	1	141.0	P6	UG Conductor	448	58.9
PS		TRANSFORMER: JOBOS 2	115/38	5	140.2	P6	Add New 115/38 kV TRANSFORMER at JOBOS	60 80/100/112	66.2
PS		TRANSFORMER: JOBOS 1	38/115	5	140.1	P6	Add New 115/38 kV TRANSFORMER at JOBOS	60 80/100/112	65.4
PS		L38700	115	2/1	132.4	P6	Reconductor to 556.5 ACSS	289	84.9
PS		L37500	115	1	131.9	P6	Reconductor to 556.5 ACSS	289	65
PS		L41200	115	3	127.8	P6	Reconductor to 556.5 ACSS	289	63.8
HNL		L36100	115	7/2	124.6	P6	Reconductor to 556.5 ACSS	289	39.7

Model	If These Contingencies Occur or If These Elements Fail	Then This Element Overloads	kV	Area	Loading Level (%)	Contingency Type	Solution Description	New Capacity /Ratings (MVA)	Post-project Loading (%)
PS	[redacted]	L36800	115	3	123.5	P6	Reconductor to 556.5 ACSS	289	61.7
PS		L37500	115	2	123.3	P6	Reconductor to 556.5 ACSS	289	60
HNL		L37400	115	7	122.7	P6	Reconductor to 556.5 ACSS	289	62.0
HNL		L36100	115	2	122.0	P6	Rebuild to 1192.5 ACSR	231.1	64.5
PS		L37500	115	2/1	118.9	P6	Reconductor to 556.5 ACSS	289	60
HNL		L38100	115	1	115.4	P6	Reconductor to 556.5 ACSS	289	81.5
HNL		TRANSFORMER: ANASCO	38/115	8	115.3	P6	Replace Transformer 115/38 kV ANASCO	60 80/100/112	63.7
HNL		L38400	115	1	115.0	P6	Reconductor to 556.5 ACSS	289	81.2
PS		L40300	115	6	113.8	P6	Reconductor to 556.5 ACSS	289	56.4
HNL		L37100	115	8	112.0	P6	Reconductor to 556.5 MCM ACSS	289	55.9
HNL		L36100	115	7	111.1	P6	Rebuild to 556.5 ACSR	145.4	72.0
HNL		L38900	115	1	109.6	P6	Reconductor to 556.5 ACSS	289	73.0
HNL		L38500	115	1	105.3	P6	Reconductor to 556.5 ACSS	289	85.3
HNL		L39800	115	8	105.1	P6	Reconductor to 556.5 MCM ACSS	289	46.4

Model	If These Contingencies Occur or If These Elements Fail	Then This Element Overloads	kV	Area	Loading Level (%)	Contingency Type	Solution Description	New Capacity /Ratings (MVA)	Post-project Loading (%)
PS	[redacted]	L37100	115	6	104.7	P6	Reconductor to 556.5 ACSS	289	52.8
HNL	[redacted]	L40000	115	1	104.3	P6	UG Conductor	289	57.9
HNL	[redacted]	L50400	230	6/8	103.8	P6	Reconductor to 1192.5 ACSS Bunting	896	48.0
PS	[redacted]	L36100	115	2/1	103.5	P6	Reconductor to 556.5 ACSS	289	43.5
PS	[redacted]	L36200	115	4/3	100.3	P6	Reconductor to 556.5 MCM ACSS	289	50.4

6.2 Solutions to 2034 IRP Transmission Needs Addressing Thermal Violations: N-1 and N-1-1

Table 15 summarizes the proposed solutions for addressing the N-1 thermal violations identified in the 2034 IRP transmission needs presented in Table 8.

Table 15: Solutions for Addressing N-1 Thermal Violations in the 2034 IRP Transmission Needs

Model	If This Contingency Occurs or If This Element Fails	Then This Element Overloads	kV	Area	Loading Level (%)	Contingency Type	Solution Description	Post-project Loading (%)
HNL	[redacted]	L38300	115	1	304.6	P4_6	Rebuild to 1192.5 ACSS Bunting	98.9
HNL	[redacted]	L38300	115	1	292.1	P4_6	Rebuild to 1192.5 ACSS Bunting	94.8
HNL	[redacted]	L38700	115	2/1	246.2	P2	Rebuild to 2 X 1192.5 ACSS Bunting	53.2
HNL	[redacted]	L38900	115	1	219.3	P2	Reconductor to 1192.5 ACSS Bunting	96.0
HNL	[redacted]	L40500	115	1	205.1	P4	UG Conductor & Add a New 115/38 XFRM at San Juan	37.5
HNL	[redacted]	L38900	115	3/1	203.5	P2	Reconductor to 1192.5 ACSS Bunting	93.6
HNL	[redacted]	L40000	115	1	194.8	P4_6	UG Conductor	84.0
HNL	[redacted]	L38900	115	1	188.8	P2	Reconductor to 1192.5 ACSS Bunting	95.3
HNL	[redacted]	L38400	115	1	185.4	P4	Reconductor to 1192.5 ACSS Bunting	87.8
HNL	[redacted]	L38500	115	1	178.6	P7	Reconductor to 1192.5 ACSS Bunting	95.5
HNL	[redacted]	L38100	115	1	169.4	P7	Reconductor to 1192.5 ACSS Bunting	80.6
HNL	[redacted]	L40400	115	1	155.5	P7	Reconductor to 1192.5 ACSS Bunting	90.5
HNL	[redacted]	L38900	115	1	122.0	P2	Reconductor to 1192.5 ACSS Bunting	68.2
HNL	[redacted]	L41200	115	3	109.9	P4	Reconductor to 556.5 ACSS	55.3

Model	If This Contingency Occurs or If This Element Fails	Then This Element Overloads	kV	Area	Loading Level (%)	Contingency Type	Solution Description	Post-project Loading (%)
HNL	[redacted]	TRANSFORMER: SJSP 1	38/115	1	108.8	P2	Replace 115/38 kV TRANSFORMER at San Juan	72.6
HNL		L37400	115	2	105.8	P4_6	Reconductor to 1192.5 ACSS Bunting	49.1
HNL		TRANSFORMER:	115/38	3	105.7	P1	Replace 115/38 kV TRANSFORMER at Fajardo	42.3
HNL		L38800	115	1	104.9	P1	Reconductor to 556.5 ACSS	56.0
HNL		L37900	115	1	104.5	P2	Reconductor to 556.5 ACSS	55.0
HNL		L37100	115	6/8	100.2	P4	Reconductor to 556.5 ACSS	50.6

Table 16 summarizes the proposed solutions for addressing the N-1-1 thermal violations identified in the 2034 IRP transmission needs presented in Table 11.

Table 16 Solutions for Addressing N-1-1 Thermal Violations in the 2034 IRP Transmission Needs

Model	If These Contingencies Occur or If These Elements Fail	Then This Element Overloads	kV	Area	Loading Level (%)	Contingency Type	Solution Description	New Capacity/ Ratings (MVA)	Post-project Loading (%)
PS	[redacted]	L38300	115	1	208.3	P6	Rebuild to 1192.5 ACSS Bunting	448	67.6
PS	[redacted]	L38300	115	1	200.8	P6	Rebuild to 1192.5 ACSS Bunting	448	65.1
HNL	[redacted]	TRANSFORMER: PALMER 1	38/115	3	152.8	P6	Replace 115/38 kV TRANSFORMER at Palmer	60 80/100/112	27.9
HNL	[redacted]	TRANSFORMER: PALMER 1	38/115	3	152.8	P6	Add a new 9.66-mile 115 kV 1192.5 ACSR line from 18 Fajardo to 211 Palmer Ckt 2 (Parallel)	231	27.9
PS	[redacted]	L40500	115	1	149.5	P6	UG Conductor & Add a New 115/38 kV XFRM at San Juan	578 & 60 80/100/112	29.3
HNL	[redacted]	L37400	115	2	145.1	P6	Reconductor to 1192.5 ACSS Bunting	448	67.6
PS	[redacted]	L38700	115	2/1	139.9	P6	Rebuild to 2 X 1192.5 ACSS Bunting	896	29.8

Model	If These Contingencies Occur or If These Elements Fail	Then This Element Overloads	kV	Area	Loading Level (%)	Contingency Type	Solution Description	New Capacity/ Ratings (MVA)	Post-project Loading (%)
HNL	[redacted]	L36100	115	2	123.9	P6	Reconductor to 1192.5 ACSS Bunting	448	59.9
HNL		L37200	115	8	121.6	P6	Reconductor to 556.5 MCM ACSS	289	61.2
HNL		L37500	115	1	119.4	P6	556.5 ACSS	289	58.0
HNL		L37100	115	8	116.0	P6	Reconductor to 556.5 MCM ACSS	289	58.0
HNL		L37400	115	2	110.8	P6	Reconductor to 1192.5 ACSS Bunting	448	56.55
HNL		L36100	115	2	108.9	P6	Reconductor to 1192.5 ACSS Bunting	448	54.5
HNL		L37900	115	1	107.8	P6	Reconductor to 556.5 ACSS	289	46.6
PS		L38900	115	1	107.2	P6	Reconductor to 1192.5 ACSS Bunting	448	47.0
HNL		L36800	115	3	105.5	P6	Reconductor to 556.5 ACSS	289	80.7
PS		L40000	115	1	105.1	P6	UG Conductor	448	39.0
PS		L38100	115	1	103.5	P6	Reconductor to 1192.5 ACSS Bunting	448	48.9

Model	If These Contingencies Occur or If These Elements Fail	Then This Element Overloads	kV	Area	Loading Level (%)	Contingency Type	Solution Description	New Capacity/ Ratings (MVA)	Post-project Loading (%)
PS	[redacted]	L38400	115	1	103.5	P6	Reconductor to 1192.5 ACSS Bunting	448	48.88
HNL	[redacted]	L37500	115	2/1	102.3	P6	Reconductor to 556.5 ACSS	289	51.2
HNL	[redacted]	L37400	115	2	101.4	P6	Reconductor to 556.5 ACSS	289	80.0
HNL	[redacted]	L37500	115	2	100.5	P6	556.5 ACSS	289	50.0
PS	[redacted]	L38900	115	3/1	100.2	P6	Reconductor to 1192.5 ACSS Bunting	448	58.0

7.0 Common Solutions to 2026 and 2034 IRP Transmission Needs Addressing Voltage Violations

Voltage solutions are proposed to resolve the 2025 IRP voltage violations identified in Sections 1.3 and 1.4. Voltage solutions comprise the following types: new capacitor bank, new SVC, new transformer, new BESS, new transmission line, and transformer tap changes. Instead of proposing individual solutions for each bus voltage violation, which could be more expensive, we proposed common solutions addressing all N-1 and N-1-1 voltage violations for each of the study years. A summary of these proposed solutions including mitigation measures for voltage violations is presented in Table 17.

Table 17: Summary of the proposed N-1 and N-1-1 voltage solutions for both 2026 and 2034

Year	Project Type	Single Outage (N-1)		Double Outages (N-1-1)	
		Quantity	MVAR	Quantity	MVAR
2026	Activate existing cap banks	1	31.7	2	56.9
	Place existing cap banks on voltage control	1	11.2	1	46.6
	New cap banks	10	570	5	218
	New SVC	6	345	1	25
	New BESS	1	30 MW		
	New 230/115 kV transformers			1	
	New 115 kV lines	2			
	Change 230/115 kV transformer tap ratios	1			
2034	Activate existing cap banks	1	31.7	2	56.9
	Place existing cap banks on voltage control	1	11.2	1	46.6
	New cap banks	10	570	5	166
	New SVC	6	345	2	85
	New BESS	1	30 MW		
	New 230/115 kV transformers			1	
	New 115 kV lines	2			
	Change 230/115 kV transformer tap ratios	1			

7.1 Common Solutions to 2026 IRP Voltage Violations: N-1 and N-1-1

Table 17 summarizes the proposed devices for addressing the N-1 voltage violations identified in the 2026 IRP transmission needs presented in Table 6 and Table 7. After implementing all proposed devices, all voltage violations are resolved, with post-project voltages ranging between 0.95 and 1.05 p.u. Table 18 provides the detailed list of mitigation measures at each station to address the 2026 IRP transmission needs N-1 Voltage Violations identified in Table 6.

Table 19 summarizes the proposed solutions for addressing the N-1-1 voltage violations identified in the 2026 IRP transmission needs presented in Table 7 which are in addition to those presented in Table 18. After implementing all proposed devices, all voltage violations are resolved, with post-project voltages ranging between 0.95 and 1.05 p.u.

Table 18: Mitigation Measures Required to Address N-1 Voltage Violations in the 2026 IRP Transmission Needs

Model	Bus #	Bus Name	kV	Area	Proposed Device	Required MVAr[8]
PS, HNL	101	DAGUAO	115	3	Line	N/A
PS, HNL	101	DAGUAO	115	3	Line	N/A
PS, HNL	353	BARRANQT	115	4	SVC	45.0
PS, HNL	14	HUMACAO	115	4	Cap	45.0
PS, HNL	632	ISLA GDE 115	115	1	Cap	30.0
PS, HNL	378	HATO TEJASTC	115	2	Cap	55.0
PS, HNL	313	JDIAZ TC	115	6	Cap	35.0
HNL	313	JDIAZ TC	115	6	BESS	30.0
PS, HNL	177	CIALES 115	115	7	SVC	60.0
PS, HNL	38	DOS BOCA 115	115	7	SVC	80.0
PS, HNL	266	JAYUYA	115	7	Cap	40.0
PS, HNL	343	ABBOTT 115	115	7	Cap	70.0
PS, HNL	40	CAMBALACH115	115	7	Cap	80.0
PS, HNL	35	SSEBASTIA115	115	8	SVC	20.0

[8] For a new line, transformer, or adjusting transformer tap there's no "Required MVAR", thus N/A or not applicable is shown in the table for these mitigation measures.

Model	Bus #	Bus Name	kV	Area	Proposed Device	Required MVAr[8]
PS, HNL	116	ACACIAS 115	115	8	Cap	100.0
PS, HNL	100	MORA 115	115	7	Cap	40.0
PS, HNL	352	MORA 230	230	7	SVC	100.0
PS, HNL	274	HATILLO NO	38	7	Cap	11.2
PS, HNL	41	VEGA BAJA115	115	2	Cap	75.0
PS, HNL	335	HATILLO 115	115	7	SVC	40.0
PS, HNL	440	CAMB GP 230	230	7	Change Transformer Tap	N/A
PS, HNL	8201	CANOVANAS_02	115	3	Cap	31.7

Table 19: Additional Mitigation Measures Required to Address N-1-1 Voltage Violations in the 2026 IRP Transmission Needs

Model	Bus #	Bus Name	kV	Area	Proposed Device	Required MVAr[9]
PS, HNL	296	SANTA ISABEL 115	115	6	New TRANSFORMER	N/A
PS, HNL	23	GUANICA 115	115	6	Cap	72.0
PS, HNL	169	SGERMANTC115	115	8	Cap	72.0
PS, HNL	29	MAYAGUEZ 115	115	8	Cap	44.0
PS, HNL	32	AGUADILLA115	115	8	Cap	26.9
PS, HNL	10	CAYEY 115	115	4	Cap	30.0
PS, HNL	211	PALMER 115	115	3	Cap	20.0
PS, HNL	84	BERWIND 115	115	1	Cap	46.6
PS, HNL	32	AGUADILLA115	115	8	SVC	25.0
PS, HNL	231	AÑASCO 115	115	8	Cap	10.0

[9] Ibid.

7.2 Common Solutions to 2034 IRP Voltage Violations: N-1 and N-1-1

Table 20 summarizes the proposed devices for addressing the N-1 voltage violations identified in the 2034 IRP transmission needs assessment which are shown in Table 10. After implementing all proposed devices, all voltage violations are resolved, with post-project voltages ranging between 0.95 and 1.05 p.u.

Table 20: Summary Mitigation Measures Required to Address N-1 Voltage Violations in the 2034 IRP Transmission Needs

Model	Bus #	Bus Name	kV	Area	Proposed Device	Required MVAr[10]
PS, HNL	101	DAGUAO	115	3	Line	N/A
PS, HNL	101	DAGUAO	115	3	Line	N/A
PS, HNL	353	BARRANQT	115	4	SVC	45.0
PS, HNL	14	HUMACAO	115	4	Cap	45.0
PS, HNL	632	ISLA GDE 115	115	1	Cap	30.0
PS, HNL	378	HATO TEJASTC	115	2	Cap	55.0
PS, HNL	313	JDIAZ TC	115	6	Cap	35.0
HNL	313	JDIAZ TC	115	6	BESS	30.0 MW
PS, HNL	177	CIALES 115	115	7	SVC	60.0
PS, HNL	38	DOS BOCA 115	115	7	SVC	80.0
PS, HNL	266	JAYUYA	115	7	Cap	40.0
PS, HNL	343	ABBOTT 115	115	7	Cap	70.0
PS, HNL	40	CAMBALACH115	115	7	Cap	80.0
PS, HNL	35	SSEBASTIA115	115	8	SVC	20.0
PS, HNL	116	ACACIAS 115	115	8	Cap	100.0
PS, HNL	100	MORA 115	115	7	Cap	40.0
PS, HNL	352	MORA 230	230	7	SVC	100.0
PS, HNL	274	HATILLO NO	38	7	Cap	11.2

[10] Ibid.

Model	Bus #	Bus Name	kV	Area	Proposed Device	Required MVAr[10]
PS, HNL	41	VEGA BAJA115	115	2	Cap	75.0
PS, HNL	335	HATILLO 115	115	7	SVC	40.0
PS, HNL	440	CAMB GP 230	230	7	Change TRANSFORMER Tap	N/A
PS, HNL	8201	CANOVANAS_02	115	3	Cap	31.7

Table 21 summarizes the additional proposed solutions for addressing the N-1-1 voltage violations identified in the 2034 IRP transmission needs as identified in Table 11. The proposed devices are in addition to those presented in Table 20. After implementing all proposed devices, all voltage violations are resolved, with post-project voltages ranging between 0.95 and 1.05 p.u.

Table 21: Additional Mitigation Measures Required to Address N-1-1 Voltage Violations in the 2034 IRP Transmission Needs

Model	Bus #	Bus Name	kV	Area	Proposed Device	Required MVAr[11]
PS, HNL	296	S. ISABEL 115	115	6	New Transformer	N/A
PS, HNL	23	GUANICA 115	115	6	Cap	72.0
PS, HNL	169	SGERMANTC115	115	8	Cap	72.0
PS, HNL	29	MAYAGUEZ 115	115	8	Cap	44.0
PS, HNL	32	AGUADILLA115	115	8	Cap	26.9
PS, HNL	10	CAYEY 115	115	4	Cap	30.0
PS, HNL	211	PALMER 115	115	3	Cap	20.0
PS, HNL	84	BERWIND 115	115	1	Cap	46.6
PS, HNL	32	AGUADILLA115	115	8	SVC	25.0
PS, HNL	231	AÑASCO 115	115	8	Cap	10.0
PS, HNL	211	PALMER 115	115	3	Cap	20.0
PS, HNL	23	GUANICA 115	115	6	SVC	60.0

[11] Ibid.

8.0 Cost of Common Solutions for 2026 and 2034 IRP Transmission Needs Addressing Thermal Overloads

This section provides the cost estimates associated with implementing thermal solutions for the 2025 IRP transmission needs for the years 2026 and 2034. The tables included here contain the costs for addressing various types of N-1 and N-1-1 thermal overloads. These tables offer an overview of the investment needed to ensure the reliability and efficiency of the transmission network, highlighting the economic considerations crucial for effective resource planning. The costs encompass the 2025 IRP common transmission needs obtained from both 2026 and 2034, providing a holistic view of the short and long-term financial implications.

A summary of the cost of the common thermal solutions for both 2026 and 2034 is presented in Table 22 below.

Table 22: Cost of the common thermal solutions for both 2026 and 2034

Project Type	Quantity	Lower Range Cost Estimate (2025$)	Upper Range Cost Estimate (2025$)
New Transformer	2	10,000,000	10,000,000
Rebuild	11	190,821,224	344,432,362
Rebuild & Add New Transformer	1	28,494,840	62,900,000
Reconductor	41	385,704,291	1,554,198,000
Replace Transformer	5	60,000,000	60,000,000
Grand Total	**60**	675,020,355	2,031,530,362

The cost for each proposed common thermal solution is presented in the following two subsections.

8.1 Cost of Common Solutions to 2026 and 2034 IRP Transmission Needs Addressing Thermal Violations

The cost of common solutions for the N-1 thermal violations for the 2026 and 2034 IRP is shown in Table 23. Note that the range of costs provided range from reconductoring only with no change in structures, to full rebuild where most of the structures require replacement. These are planning level estimates and will change significantly depending on detailed engineering design and constructability reviews.

Table 23: Cost of Common Solutions for Addressing N-1 Thermal Violations for both 2026 and 2034 IRP Transmission Needs

Year	Model	If This Contingency Occurs or If This Element Fails	Then This Element Overloads	kV	Area	Loading Level (%)	Type	Solution Description	New Capacity/ Ratings (MVA)	Post-project Loading (%)	Cost Estimate (2025$)
2034	HNL	[redacted]	L38300 San Juan SP – Cachete	115	1	304.6	P4_6	Rebuild to 1192.5 ACSS Bunting	448	98.9	8,879,802
2034	HNL		L38300 Cachete – Monacillos	115	1	292.1	P4_6	Rebuild to 1192.5 ACSS Bunting	448	94.8	8,879,802-18,000,000
2034	HNL		L38700 Palo Seco-San Juan SP	115	2/1	246.2	P2	Rebuild to 2 X 1192.5 ACSS Bunting	896	53.2	25,098,295 - 44,400,000
2034	HNL		L38900 Berwind – Martin Pena GIS	115	1	219.3	P2	Reconductor to 1192.5 ACSS Bunting	448	96.0	7,336,075 - 26,160,000
2034	HNL		L40500 Monacillos – Hato Rey	115	1	205.1	P4	UG Circuit & Add a New 115/38 XFRM at San Juan	578 80/100/112	37.5	28,494,840 – 62,900,000
2034	HNL		L38900 Sabana Llana – Escorial	115	3/1	203.5	P2	Reconductor to 1192.5 ACSS Bunting	448	93.6	1,786,187 - 6,000,000
2034	HNL		L40000 Viaducto-Martin Pena	115	1	194.8	P4_6	UG Conductor	448	84.0	N/A
2034	HNL		L38900 Berwind – Escorial	115	1	188.8	P2	Reconductor to 1192.5 ACSS Bunting	448	95.3	3,000,794 - 10,080,000
2034	HNL		L38400 Viaducto-San Juan SP 1	115	1	185.4	P4	Reconductor to 1192.5 ACSS Bunting	448	87.8	5,889,051 - 21,000,000

Year	Model	If This Contingency Occurs or If This Element Fails	Then This Element Overloads	kV	Area	Loading Level (%)	Type	Solution Description	New Capacity/ Ratings (MVA)	Post-project Loading (%)	Cost Estimate (2025$)
2034	HNL	[redacted]	L38500 Hato Rey – San Juan SP 1	115	1	178.6	P7	Reconductor to 1192.5 ACSS Bunting	448	95.5	5,636,663 – 20,100,000
2034	HNL	[redacted]	L38100 Viaducto-San Juan SP 2	115	1	169.4	P7	Reconductor to 1192.5 ACSS Bunting	448	80.6	5,889,051 - 21,000,000
2026	HNL	[redacted]	L38300 Cachete – Monacillos	115	1	156.6	P2	Rebuild to 556.5 ACSS	289	77	6,836,835 - 18,000,000
2034	HNL	[redacted]	L40400 Hato Rey – San Juan SP 2	115	1	155.5	P7	UG Circuit	448	90.5	5,754,444 - 34,200,000
2026	HNL	[redacted]	TRANSFORMER: JOBOS 2	115/38	5	155.5	P1	Add New 115/38 kV TRANSFORMER at JOBOS	60 80/100/112	75.6	10,000,000
2026	HNL	[redacted]	TRANSFORMER: JOBOS 1	38/115	5	154.8	P2	Add New 115/38 kV TRANSFORMER at JOBOS	60 80/100/112	75.0	N/A
2026	HNL	[redacted]	L36100 Bayamon - Cana	115	2	140.1	P1	Reconductor to 556.5 ACSS	289	52.6	8,255,886 – 39,540,000
2026	HNL	[redacted]	L37100 Guanica – San German	115	6/8	124.7	P7	Reconductor to 556.5 MCM ACSS	289	63.0	18,949,534-79,800,000
2034	HNL	[redacted]	L38900 Hato Rey – Martin Pena	115	1	122.0	P2	Reconductor to 1192.5 ACSS Bunting	448	68.2	2,254,665 - 8,040,000
2026	PS	[redacted]	L36200 Rio Blanco- Daguao	115	4/3	117.7	P2	Reconductor to 556.5 MCM ACSS	289	59.2	11,882,640 - 50,040,000
2026	HNL	[redacted]	L40000 Martin Pena GIS - Viaducto	115	1	110.0	P2	UG Circuit	289	72.5	4,584,976 - 17,800,000

Year	Model	If This Contingency Occurs or If This Element Fails	Then This Element Overloads	kV	Area	Loading Level (%)	Type	Solution Description	New Capacity/ Ratings (MVA)	Post-project Loading (%)	Cost Estimate (2025$)
2034	HNL	[redacted]	L41200 Sabana Llana- Canovanas	115	3	109.9	P4	Reconductor to 556.5 ACSS	289	55.3	10,842,553 - 45,660,000
2034	HNL		TRANSFORMER: SJSP 1	38/115	1	108.8	P2	Replace 115/38 kV TRANSFORMER at San Juan	90 120/150/168	72.6	10,000,000
2034	HNL		L37400 Bayamon- Hogar Crea	115	2	105.8	P4_6	Reconductor to 1192.5 ACSS Bunting	448	49.1	5,047,758 - 18,000,000
2034	HNL		TRANSFORMER:	115/38	3	105.7	P1	Replace 115/38 kV TRANSFORMER at Fajardo	60 80/100/112	42.3	10,000,000
2034	HNL		L38800 Viaducto – Hato Rey	115	1	104.9	P1	Reconductor to 556.5 ACSS	289	56.0	4,986,720 - 21,000,000
2034	HNL		L37900 Monacillo - Conquistador	115	1	104.5	P2	Reconductor to 556.5 ACSS	289	55.0	8,548,662 - 36,000,000
2026	PS		L40300 Pattern - Ponce	115	6	103.7	P2	Reconductor to 556.5 ACSS	289	51.8	21,799,088 - 91,800,000
2026	HNL		L40500 Monacillos – Hato Rey	115	1	102.0	P1	UG circuit	448	39.2	52,900,000
2026	PS		TRANSFORMER: SANTA ISABEL 1	115/38	6/5	100.7	P7	Replace 115/38 kV TRANSFORMER at SANTA ISABEL	60 80/100/112	48.7	10,000,000
2034	HNL		L37100 Guanica – San German	115	6/8	100.2	P4	Reconductor to 556.5 ACSS	289	50.6	16,662,107 - 79,800,000

Year	Model	If This Contingency Occurs or If This Element Fails	Then This Element Overloads	kV	Area	Loading Level (%)	Type	Solution Description	New Capacity/ Ratings (MVA)	Post-project Loading (%)	Cost Estimate (2025$)
2026	HNL	[redacted]	L38100 San Juan SP- Viaducto	115	1	100.2	P7	Reconductor to 556.5 ACSS	289	70.6	4,986,720 - 21,000,000
Total Range of Costs		[redacted]									**325,183,148 - 710,520,520**

The cost of common solutions for the N-1-1 thermal violations for the 2026 and 2034 IRP is shown in Table 24. Note that the range of costs provided range from reconductoring only with no change in structures, to full rebuild where most of the structures require replacement. These are planning level estimates and will change significantly depending on detailed engineering design and constructability reviews.

Table 24: Cost of Common Solutions for Addressing N-1-1 Thermal Violations for both 2026 and 2034 IRP Transmission Needs

Year	Model	If These Contingencies Occur or If These Elements Fail	Then This Element Overloads	kV	Area	Loading Level (%)	Type	Solution Description	New Capacity/ Ratings (MVA)	Post-project Loading (%)	Cost Estimate (2025$)
2034	PS	[redacted]	L38300 San Juan SP-Cachete	115	1	208.3	P6	Rebuild to 1192.5 ACSS Bunting	448	67.6	8,879,802-18,000,000
2034	PS		L38300 Cachete -Monacillos	115	1	200.8	P6	Rebuild to 1192.5 ACSS Bunting	448	65.1	8,879,802-18,000,000
2034	HNL		TRANSFORMER: PALMER 1	38/ 115	3	152.8	P6	Replace 115/38 kV TRANSFORMER at Palmer & Add a New 9.66-mile 115 kV 1192.5 ACSR line from 18 Fajardo to 211 Palmer Ckt 2 (Parallel)	60 80/100/112 & 231	27.9	10,000,000 & 25,763,877

Year	Model	If These Contingencies Occur or If These Elements Fail	Then This Element Overloads	kV	Area	Loading Level (%)	Type	Solution Description	New Capacity/ Ratings (MVA)	Post-project Loading (%)	Cost Estimate (2025$)
2026	HNL	[redacted]	TRANSFORMER: DAGUAO 1	38/ 115	3	150.4	P6	Replace 115/38 kV TRANSFORMER at DAGUAO	60 80/100/112	70.9	10,000,000
2034	PS	[redacted]	L40500 Monacillos -Hato Rey	115	1	149.5	P6	Rebuild to Double Bundle 1192.5 ACSS Bunting & Add a New 115/38 kV XFRM at San Juan	578 & 60 80/100/112	29.3	52,900,000
2026	HNL	[redacted]	L37200 Mayaguez-Mayaguez TC	115	8	147.2	P6	Reconductor to 556.5 MCM ACSS	289	74.1	2,322,387-9,780,000
2034	HNL	[redacted]	L37400 Bayamon – Hogar Crea	115	2	145.1	P6	Reconductor to 1192.5 ACSS Bunting	448	67.6	5,047,758 - 18,000,000
2026	HNL	[redacted]	L40500 Monacillos – Hato Rey	115	1	141.0	P6	UG Conductor	448	58.9	52,900,000
2026	PS	[redacted]	TRANSFORMER: JOBOS 2	115/ 38	5	140.2	P6	Add New 115/38 kV TRANSFORMER at JOBOS	60 80/100/112	66.2	10,000,000
2026	PS	[redacted]	TRANSFORMER: JOBOS 1	38/ 115	5	140.1	P6	Add New 115/38 kV TRANSFORMER at JOBOS	60 80/100/112	65.4	-
2034	PS	[redacted]	L38700 Palo Seco – San Juan SP	115	2/1	139.9	P6	Rebuild to 2 X 1192.5 ACSS Bunting	896	29.8	25,098,295-44,280,000
2026	PS	[redacted]	L37500 Grana - Monacillos	115	1	131.9	P6	Reconductor to 556.5 ACSS	289	65	6,696,452-28,200,000

Year	Model	If These Contingencies Occur or If These Elements Fail	Then This Element Overloads	kV	Area	Loading Level (%)	Type	Solution Description	New Capacity/ Ratings (MVA)	Post-project Loading (%)	Cost Estimate (2025$)
2026	PS	[redacted]	L41200 Canovanas-Sabana Llana 2	115	3	127.8	P6	Reconductor to 556.5 ACSS	289	63.8	10,842,553-45,600,000
2026	HNL		L36100 Ciales - Morovis	115	7/2	124.6	P6	Reconductor to 556.5 ACSS	289	39.7	5,984,063-25,440,000
2034	HNL		L36100 Bayamon-Cana	115	2	123.9	P6	Reconductor to 1192.5 ACSS Bunting	448	59.9	11,088,242-39,540,000
2026	PS		L36800 Canovanas-Sabana Llana 1	115	3	123.5	P6	Reconductor to 556.5 ACSS	289	61.7	13,692,107-57,600,000
2026	PS		L37500 R Bayamon-Bayamon TC	115	2	123.3	P6	Reconductor to 556.5 ACSS	289	60	1,424,777-6,000,000
2026	HNL		L37400 Cambalache-Barceloneta	115	7	122.7	P6	Reconductor to 556.5 ACSS	289	62.0	12,264,814-58,740,000
2026	HNL		L36100 Corozal - Monterey	115	2	122.0	P6	Rebuild to 1192.5 ACSR	231.1	64.5	8,938,745-22,200,000
2034	HNL		L37500 Monacilloas-Grana	115	1	119.4	P6	556.5 ACSS	289	58.0	6,696,452 - 28,200,000
2026	PS		L37500 R Bayamon-Bayamon TC	115	2/1	118.9	P6	Reconductor to 556.5 ACSS	289	60	1,424,777-6,000,000
2034	HNL		L37100 Acacias-San German	115	8	116.0	P6	Reconductor to 556.5 MCM ACSS	289	58.0	19,946,878 - 84,000,000
2026	HNL		L38100 San Juan SP- Viaducto	115	1	115.4	P6	Reconductor to 556.5 ACSS	289	81.5	4,986,720-21,000,000

Year	Model	If These Contingencies Occur or If These Elements Fail	Then This Element Overloads	kV	Area	Loading Level (%)	Type	Solution Description	New Capacity/ Ratings (MVA)	Post-project Loading (%)	Cost Estimate (2025$)
2026	HNL	[redacted]	TRANSFORMER: AÑASCO	38/ 115	8	115.3	P6	Replace Transformer 115/38 kV ANASCO	60 80/100/112	63.7	10,000,000
2026	PS	[redacted]	L40300 Pattern-Ponce	115	6	113.8	P6	Reconductor to 556.5 ACSS	289	56.4	21,799,088-91,800,000
2026	HNL	[redacted]	L36100 Dos Bocas-Ciales	115	7	111.1	P6	Rebuild to 556.5 ACSR	145.4	72.0	32,647,082-86,340,000
2034	HNL	[redacted]	L37400 Hogar Crea-Hato Tejas	115	2	110.8	P6	Reconductor to 1192.5 ACSS Bunting	448	56.55	4,559,808 - 16,260,000
2026	HNL	[redacted]	L38900 Berwind-Martin Pena GIS	115	1	109.6	P6	Reconductor to 556.5 ACSS	289	73.0	6,212,028-26,160,000
2034	HNL	[redacted]	L36100 Cana-Bo. Pina	115	2	108.9	P6	Reconductor to 1192.5 ACSS Bunting	448	54.5	5,047,758-18,000,000
2034	HNL	[redacted]	L37900 Conquistador-Encantada	115	1	107.8	P6	Reconductor to 556.5 ACSS	289	46.6	4,986,720-21,000,000
2034	PS	[redacted]	L38900 Berwind- Martin Pena GIS	115	1	107.2	P6	Reconductor to 1192.5 ACSS Bunting	448	47.0	7,336,075-26,160,000
2034	HNL	[redacted]	L36800 Canovanas-Sabana Llana	115	3	105.5	P6	Reconductor to 556.5 ACSS	289	80.7	13,692,107-57,660,000
2026	HNL	[redacted]	L38500 Hato Rey-San Juan SP	115	1	105.3	P6	Reconductor to 556.5 ACSS	289	85.3	4,773,003-20,400,000
2034	PS	[redacted]	L40000 Viaducto-Martin Pena GIS	115	1	105.1	P6	UG Conductor	448	39.0	5,268,683-10,680,000

Year	Model	If These Contingencies Occur or If These Elements Fail	Then This Element Overloads	kV	Area	Loading Level (%)	Type	Solution Description	New Capacity/ Ratings (MVA)	Post-project Loading (%)	Cost Estimate (2025$)
2026	HNL	[redacted]	L39800 Mayaguez-Acacias	115	8	105.1	P6	Reconductor to 556.5 MCM ACSS	289	46.4	21,371,655-90,000,000
2026	PS		L37100 Costa Sur-Guanica	115	6	104.7	P6	Reconductor to 556.5 ACSS	289	52.8	15,245,114-64,200,000
2026	HNL		L40000 Martin Pena GIS- Viaducto	115	1	104.3	P6	UG Conductor	289	57.9	4,584,976-10,800,000
2026	HNL		L50400 Costa Sur-Mayaguez TC	230	6/8	103.8	P6	Reconductor to 1192.5 ACSS Bunting	896	48.0	66,982,013-225,000,000
2026	PS		L36100 Bayamon-Monacillos	115	2/1	103.5	P6	Reconductor to 556.5 ACSS	289	43.5	10,543,350-44,580,000
2034	PS		L38400 Viaducto-San Juan SP 1	115	1	103.5	P6	Reconductor to 1192.5 ACSS Bunting	448	48.88	5,889,051-21,000,000
2034	PS		L38100 Viaducto-San Juan SP 2	115	1	103.5	P6	Reconductor to 1192.5 ACSS Bunting	448	48.9	5,889,051-21,000,000
2034	HNL		L37500 Bayamon-Grana	115	2/1	102.3	P6	Reconductor to 556.5 ACSS	289	51.2	1,424,777-6,000,000
2034	HNL		L37400 Hato Tejas – Cande Arenas	115	2	101.4	P6	Reconductor to 556.5 ACSS	289	80.0	3,106,014-13,080,000
2034	HNL		L37500 R Bayamon-Bayamon TC	115	2	100.5	P6	556.5 ACSS	289	50.0	1,424,777-6,000,000
2026	PS		L36200 Rio Blanco-Daguao	115	4/3	100.3	P6	Reconductor to 556.5 MCM ACSS	289	50.4	11,882,640-50,040,000

Year	Model	If These Contingencies Occur or If These Elements Fail	Then This Element Overloads	kV	Area	Loading Level (%)	Type	Solution Description	New Capacity/ Ratings (MVA)	Post-project Loading (%)	Cost Estimate (2025$)
2034	PS	[redacted]	L38900 Sabana Llana - Escorial	115	3/1	100.2	P6	Reconductor to 1192.5 ACSS Bunting	448	58.0	1,809,407-6,078,000
Total Range of Costs											**582,253,678 - 1,462,818,000**

8.2 Cost of Common Solutions for Addressing Both N-1 and N-1-1 Thermal Violations in the 2026 and 2034 IRP Transmission Needs

The cost of common solutions for both N-1 and N-1-1 thermal violations for the 2026 and 2034 IRP is shown in Table 25.

Table 25: Cost of Common Solutions for Addressing Both N-1 and N-1-1 Thermal Violations for 2026 and 2034 IRP Transmission Needs

Year	Model	If This Contingency Occurs or If This Element Fails	Then This Element Overloads	kV	Area	Loading Level (%)	Type	Solution Description	New Capacity/ Ratings (MVA)	Post-project Loading (%)	Cost Estimate (2025$)
2034	HNL	[redacted]	L38300 San Juan SP – Cachete	115	1	304.6	P4_6	Rebuild to 1192.5 ACSS Bunting	448	98.9	8,879,802
2034	HNL		L38300 Cachete – Monacillos	115	1	292.1	P4_6	Rebuild to 1192.5 ACSS Bunting	448	94.8	8,879,802-18,000,000
2034	HNL		L38700 Palo Seco-San Juan SP	115	2/1	246.2	P2	Rebuild to 2 X 1192.5 ACSS Bunting	896	53.2	25,098,295 - 44,400,000

[12] It is an N-1 contingency issue.

Year	Model	If This Contingency Occurs or If This Element Fails	Then This Element Overloads	kV	Area	Loading Level (%)	Type	Solution Description	New Capacity/ Ratings (MVA)	Post-project Loading (%)	Cost Estimate (2025$)
2034	HNL	[redacted]	L38900 Berwind – Martin Pena GIS	115	1	219.3	P2	Reconductor to 1192.5 ACSS Bunting	448	96.0	7,336,075 - 26,160,000
2034	HNL	[redacted]	L40500 Monacillos – Hato Rey	115	1	205.1	P4	UG Conductor & Add a New 115/38 XFRM at San Juan	578 80/100/112	37.5	28,494,840 – 62,900,000
2034	HNL	[redacted]	L38900 Sabana Llana – Escorial	115	3/1	203.5	P2	Reconductor to 1192.5 ACSS Bunting	448	93.6	1,786,187 - 6,000,000
2034	HNL	[redacted]	L40000	115	1	194.8	P4_6	UG Conductor	448	84.0	5,268,683
2034	HNL	[redacted]	3,000,794 - 10,080,000	115	1	188.8	P2	Reconductor to 1192.5 ACSS Bunting	448	95.3	3,000,794 - 10,080,000
2034	HNL	[redacted]	L38400 Viaducto-San Juan SP 1	115	1	185.4	P4	Reconductor to 1192.5 ACSS Bunting	448	87.8	5,889,051 - 21,000,000
2034	HNL	[redacted]	L38500 Hato Rey – San Juan SP 1	115	1	178.6	P7	Reconductor to 1192.5 ACSS Bunting	448	95.5	5,636,663 – 20,100,000
2034	HNL	[redacted]	L38100 Viaducto-San Juan SP 2	115	1	169.4	P7	Reconductor to 1192.5 ACSS Bunting	448	80.6	5,889,051 - 21,000,000
2026	HNL	[redacted]	L38300 Cachete – Monacillos	115	1	156.6	P2	Rebuild to 556.5 ACSS	289	77	6,836,835 - 18,000,000
2034	HNL	[redacted]	L40400 Hato Rey – San Juan SP 2	115	1	155.5	P7	UG Circuit	448	90.5	5,754,444 - 34,200,000

Year	Model	If This Contingency Occurs or If This Element Fails	Then This Element Overloads	kV	Area	Loading Level (%)	Type	Solution Description	New Capacity/ Ratings (MVA)	Post-project Loading (%)	Cost Estimate (2025$)
2026	HNL	[redacted]	Transformer: JOBOS 2	115/38	5	155.5	P1	Add New 115/38 kV Transformer at JOBOS	60 80/100/112	75.6	10,000,000
2026	HNL		Transformer: JOBOS 1	38/115	5	154.8	P2	Add New 115/38 kV Transformer at JOBOS	60 80/100/112	75.0	N/A
2034	HNL		Transformer: PALMER 1	38/115	3	152.8	P6	Replace 115/38 kV Transformer at Palmer & Add a New 9.66-mile 115 kV 1192.5 ACSR line from Fajardo to Palmer	60 80/100/112 & 231	27.9	10,000,000 & 25,763,877
2026	HNL		Transformer: DAGUAO 1	38/115	3	150.4	P6	Replace 115/38 kV Transformer at DAGUAO	60 80/100/112	70.9	10,000,000
2026	HNL		L37200 Mayaguez-Mayaguez TC	115	8	147.2	P6	Reconductor to 556.5 MCM ACSS	289	74.1	2,322,387-9,780,000
2034	HNL		L37400 Bayamon – Hogar Crea	115	2	145.1	P6	Reconductor to 1192.5 ACSS Bunting	448	67.6	5,047,758 - 18,000,000
2026	HNL		L40500 Monacillos – Hato Rey	115	1	141.0	P6	UG Conductor	448	58.9	52,900,000
2026	PS		L37500 Grana - Monacillos	115	1	131.9	P6	Reconductor to 556.5 ACSS	289	65	6,696,452-28,200,000
2026	PS		L41200 Canovanas-Sabana Llana 2	115	3	127.8	P6	Reconductor to 556.5 ACSS	289	63.8	10,842,553-45,600,000

Year	Model	If This Contingency Occurs or If This Element Fails	Then This Element Overloads	kV	Area	Loading Level (%)	Type	Solution Description	New Capacity/ Ratings (MVA)	Post-project Loading (%)	Cost Estimate (2025$)
2026	HNL	[redacted]	L37100 Guanica – San German	115	6	125.7	P2	Reconductor to 556.5 ACSS	289	63.4	16,662,107 - 79,800,000
2026	HNL		L37100 Guanica – San German	115	6/8	124.7	P7	Reconductor to 556.5 MCM ACSS	289	63.0	18,949,534- 79,800,000
2026	HNL		L36100 Ciales - Morovis	115	7/2	124.6	P6	Reconductor to 556.5 ACSS	289	39.7	5,984,063- 25,440,000
2034	HNL		L36100 Bayamon- Cana	115	2	123.9	P6	Reconductor to 1192.5 ACSS Bunting	448	59.9	11,088,242- 39,540,000
2026	PS		L36800 Canovanas- Sabana Llana 1	115	3	123.5	P6	Reconductor to 556.5 ACSS	289	61.7	13,692,107- 57,600,000
2026	PS		L37500 R Bayamon- Bayamon TC	115	2	123.3	P6	Reconductor to 556.5 ACSS	289	60	1,424,777- 6,000,000
2026	HNL		L37400 Cambalache- Barceloneta	115	7	122.7	P6	Reconductor to 556.5 ACSS	289	62.0	12,264,814- 58,740,000
2026	HNL		L36100 Corozal - Monterey	115	2	122.0	P6	Rebuild to 1192.5 ACSR	231.1	64.5	8,938,745- 22,200,000
2034	HNL		L38900 Hato Rey – Martin Pena	115	1	122.0	P2	Reconductor to 1192.5 ACSS Bunting	448	68.2	2,254,665 - 8,040,000
2034	HNL		L37500 Grana - Monacillos	115	1	119.4	P6	556.5 ACSS	289	58.0	6,696,452- 28,200,000
2026	PS		L37500 R Bayamon- Bayamon TC	115	2/1	118.9	P6	Reconductor to 556.5 ACSS	289	60	1,424,777- 6,000,000

Year	Model	If This Contingency Occurs or If This Element Fails	Then This Element Overloads	kV	Area	Loading Level (%)	Type	Solution Description	New Capacity/ Ratings (MVA)	Post-project Loading (%)	Cost Estimate (2025$)
2026	PS	[redacted]	L36200 Rio Blanco-Daguao	115	4/3	117.7	P2	Reconductor to 556.5 MCM ACSS	289	59.2	11,882,640 - 50,040,000
2034	HNL		L37100 Acacias-San German	115	8	116.0	P6	Reconductor to 556.5 MCM ACSS	289	58.0	19,946,878 - 84,000,000
2026	HNL		L38100 San Juan SP-Viaducto	115	1	115.4	P6	Reconductor to 556.5 ACSS	289	81.5	4,986,720 - 21,000,000
2026	HNL		TRANSFORMER: AÑASCO	38/115	8	115.3	P6	Replace Transformer 115/38 kV ANASCO	60 80/100/112	63.7	10,000,000
2026	PS		L40300 Pattern-Ponce	115	6	113.8	P6	Reconductor to 556.5 ACSS	289	56.4	21,799,088-91,800,000
2026	HNL		L36100 Dos Bocas-Ciales	115	7	111.1	P6	Rebuild to 556.5 ACSR	145.4	72.0	32,647,082-86,340,000
2034	HNL		L37400 Hogar Crea-Hato Tejas	115	2	110.8	P6	Reconductor to 1192.5 ACSS Bunting	448	56.55	4,559,808 - 16,260,000
2026	HNL		L40000 Martin Pena GIS - Viaducto	115	1	110.0	P2	UG Conductor	289	72.5	4,584,976 - 17,800,000
2034	HNL		L41200 Sabana Llana-Canovanas	115	3	109.9	P4	Reconductor to 556.5 ACSS	289	55.3	10,842,553 - 45,660,000
2026	HNL		L38900	115	1	109.6	P6	Reconductor to 556.5 ACSS	289	73.0	6,212,028-26,160,000
2034	HNL		L36100	115	2	108.9	P6	Reconductor to 1192.5 ACSS Bunting	448	54.5	5,047,758-18,000,000

Year	Model	If This Contingency Occurs or If This Element Fails	Then This Element Overloads	kV	Area	Loading Level (%)	Type	Solution Description	New Capacity/ Ratings (MVA)	Post-project Loading (%)	Cost Estimate (2025$)
2034	HNL	[redacted]	TRANSFORMER: SJSP 1	38/115	1	108.8	P2	Replace 115/38 kV TRANSFORMER at San Juan	90 120/150/168	72.6	10,000,000
2034	HNL	[redacted]	L37900 Conquistador-Encantada	115	1	107.8	P6	Reconductor to 556.5 ACSS	289	46.6	4,986,720-21,000,000
2034	HNL	[redacted]	TRANSFORMER: FAJARDO 1	115/38	3	105.7	P1	Replace 115/38 kV TRANSFORMER at Fajardo	60 80/100/112	42.3	10,000,000
2034	HNL	[redacted]	L36800 Canovanas-Sabana Llana	115	3	105.5	P6	Reconductor to 556.5 ACSS	289	80.7	13,692,107-57,660,000
2034	PS	[redacted]	L40000 Viaducto-Martin Pena GIS	115	1	105.1	P6	UG Conductor	448	39.0	5,268,683-10,680,000
2026	HNL	[redacted]	L39800 Mayaguez-Acacias	115	8	105.1	P6	Reconductor to 556.5 MCM ACSS	289	46.4	21,371,655-90,000,000
2034	HNL	[redacted]	L38800 Viaducto – Hato Rey	115	1	104.9	P1	Reconductor to 556.5 ACSS	289	56.0	4,986,720 - 21,000,000
2034	HNL	[redacted]	L37900 Monacillo - Conquistador	115	1	104.5	P2	Reconductor to 556.5 ACSS	289	55.0	8,548,662 - 36,000,000
2026	HNL	[redacted]	L50400 Costa Sur-Mayaguez TC	230	6/8	103.8	P6	Reconductor to 1192.5 ACSS Bunting	896	48.0	66,982,013-225,000,000
2026	PS	[redacted]	L36100 Bayamon-Monacillos	115	2/1	103.5	P6	Reconductor to 556.5 ACSS	289	43.5	10,543,350-44,580,000

Year	Model	If This Contingency Occurs or If This Element Fails	Then This Element Overloads	kV	Area	Loading Level (%)	Type	Solution Description	New Capacity/ Ratings (MVA)	Post-project Loading (%)	Cost Estimate (2025$)
2034	HNL	[redacted]	L37500 Bayamon-Grana	115	2/1	102.3	P6	Reconductor to 556.5 ACSS	289	51.2	1,424,777-6,000,000
2034	HNL		L37400 Hato Tejas – Cande Arenas	115	2	101.4	P6	Reconductor to 556.5 ACSS	289	80.0	3,106,014-13,080,000
2026	PS		TRANSFORMER: SANTA ISABEL 1	115/38	6/5	100.7	P7	Replace 115/38 kV TRANSFORMER at SANTA ISABEL	60 80/100/112	48.7	10,000,000
2034	HNL		L37500 Bayamon-Grana	115	2	100.5	P6	556.5 ACSS	289	50.0	1,424,777-6,000,000
2034	HNL		L37100 Guanica – San German	115	6/8	100.2	P4	Reconductor to 556.5 ACSS	289	50.6	16,662,107 - 79,800,000
2034	PS		L38900 Sabana Llana - Escorial	115	3/1	100.2	P6	Reconductor to 1192.5 ACSS Bunting	448	58.0	1,809,407-6,078,000
Total Range of Costs											**675,020,355 - 2,031,530,362**

9.0 Cost of Common Solutions for 2026 and 2034 IRP Transmission Needs Addressing Voltage Violations

This section provides the cost estimates associated with implementing voltage solutions for the 2025 IRP transmission needs for the years 2026 and 2034. The tables included here contain the costs for addressing voltage violations identified in these two years. A summary of the cost of the common voltage solutions for both 2026 and 2034 is presented in Table 26 below.

Table 26: Cost of the common voltage solutions for both 2026 and 2034

Project Type	Quantity	MVAR/MW	Lower Range Cost Estimate (2025$)	Upper Range Cost Estimate (2025$)
Activate existing cap banks	3	88.6		
Place existing cap banks on voltage control	2	57.8		
New cap banks	16	808	9,593,384	9,593,384
New SVC	8	430	49,099,550	49,099,550
New BESS	1	30 MW	35,550,000	35,550,000
New 230/115 kV transformers	1		23,699,849	23,699,849
New 115 kV lines	2		46,536,907	195,920,378
Change 230/115 kV transformer tap ratios	1			
Grand Total	**34**	**1,384 MVAR 30 MW**	**164,479,690**	**313,863,161**

The cost for each proposed common voltage solution is presented in the following two subsections.

9.1 Cost of Common Solutions to 2026 IRP Voltage Violations: N-1 and N-1-1

The cost of the proposed common solutions addressing N-1 and N-1-1 voltage violations in the 2026 IRP transmission needs is presented in Table 27 and Table 28, respectively.

Table 27: Cost of Proposed Devices for Common Solutions Addressing N-1 Voltage Violations for 2026 Transmission Needs

Model	Bus #	Bus Name	kV	Area	Proposed Device	Required MVAr	Cost Estimate (2025$)
PS, HNL	101	DAGUAO	115	3	Line	N/A	21,360,486 - 89,927,646
PS, HNL	101	DAGUAO	115	3	Line	N/A	25,176,421 - 105,992,732

Model	Bus #	Bus Name	kV	Area	Proposed Device	Required MVAr	Cost Estimate (2025$)
PS, HNL	353	BARRANQT	115	4	SVC	45.0	5,138,325
PS, HNL	14	HUMACAO	115	4	Cap	45.0	534,285
PS, HNL	632	ISLA GDE 115	115	1	Cap	30.0	356,190
PS, HNL	378	HATO TEJAS TC	115	2	Cap	55.0	653,015
PS, HNL	313	JDIAZ TC	115	6	Cap	35.0	415,555
HNL	313	JDIAZ TC	115	6	BESS	30.0	35,550,000
PS, HNL	177	CIALES 115	115	7	SVC	60.0	6,851,000
PS, HNL	38	DOS BOCA 115	115	7	SVC	80.0	9,134,800
PS, HNL	266	JAYUYA	115	7	Cap	40.0	474,920
PS, HNL	343	ABBOTT 115	115	7	Cap	70.0	831,110
PS, HNL	40	CAMBALACH 115	115	7	Cap	80.0	949,840
PS, HNL	35	SSEBASTIA 115	115	8	SVC	20.0	2,283,700
PS, HNL	116	ACACIAS 115	115	8	Cap	100.0	1,141,850
PS, HNL	100	MORA 115	115	7	Cap	40.0	474,920
PS, HNL	352	MORA 230	230	7	SVC	100.0	11,418,500
PS, HNL	274	HATILLO NO	38	7	Cap	11.2	-
PS, HNL	41	VEGA BAJA 115	115	2	Cap	75.0	890,475
PS, HNL	335	HATILLO 115	115	7	SVC	40.0	4,567,400
PS, HNL	440	CAMB GP 230	230	7	Change TRANSFORMER Tap	N/A	-
PS, HNL	8201	CANOVANAS_02	115	3	Cap	31.7	-
Total							**128,202,792 - 277,586,265**

Table 28: Cost of Proposed Common Solutions Addressing N-1-1 Voltage Violations for 2026 Transmission Needs

Model	Bus #	Bus Name	kV	Area	Proposed Device	Required MVAr	Cost Estimate (2025$)
PS, HNL	296	SANTA ISABEL 115	115	6	New Transformer	N/A	23,699,849
PS, HNL	23	GUANICA 115	115	6	Cap	72.0	854,856
PS, HNL	169	SAN GERMAN TC 115	115	8	Cap	72.0	854,856
PS, HNL	29	MAYAGUEZ 115	115	8	Cap	44.0	522,412
PS, HNL	32	AGUADILLA 115	115	8	Cap	26.9	-
PS, HNL	10	CAYEY 115	115	4	Cap	30.0	-
PS, HNL	211	PALMER 115	115	3	Cap	20.0	237,460
PS, HNL	84	BERWIND 115	115	1	Cap	46.6	-
PS, HNL	32	AGUADILLA 115	115	8	SVC	25.0	2,854,625
PS, HNL	231	AÑASCO 115	115	8	Cap	10.0	118,760
Total							**29,142,818**

9.2 Cost of Common Solutions to 2034 IRP Voltage Violations: N-1 and N-1-1

The cost of the proposed common solutions addressing N-1 and N-1-1 voltage violations in the 2034 IRP transmission needs is presented in Table 29 and Table 30, respectively.

Table 29: Cost of Proposed Common Solutions Addressing N-1 Voltage Violations for 2034 Transmission Needs

Model	Bus #	Bus Name	kV	Area	Proposed Device	Required MVAr	Cost Estimate (2025$)
PS, HNL	101	DAGUAO	115	3	Line	N/A	21,360,486 - 89,927,646
PS, HNL	101	DAGUAO	115	3	Line	N/A	25,176,421 - 105,992,732
PS, HNL	353	BARRANQT	115	4	SVC	45.0	5,138,325
PS, HNL	14	HUMACAO	115	4	Cap	45.0	534,285
PS, HNL	632	ISLA GDE 115	115	1	Cap	30.0	356,190
PS, HNL	378	HATO TEJAS TC	115	2	Cap	55.0	653,015

Model	Bus #	Bus Name	kV	Area	Proposed Device	Required MVAr	Cost Estimate (2025$)
PS, HNL	313	JDIAZ TC	115	6	Cap	35.0	415,555
HNL	313	JDIAZ TC	115	6	BESS	30.0	35,550,000
PS, HNL	177	CIALES 115	115	7	SVC	60.0	6,851,100
PS, HNL	38	DOS BOCA 115	115	7	SVC	80.0	9,134,800
PS, HNL	266	JAYUYA	115	7	Cap	40.0	474,920
PS, HNL	343	ABBOTT 115	115	7	Cap	70.0	831,110
PS, HNL	40	CAMBALACH 115	115	7	Cap	80.0	949,840
PS, HNL	35	SAN SEBASTIAN 115	115	8	SVC	20.0	2,283,700
PS, HNL	116	ACACIAS 115	115	8	Cap	100.0	1,187,300
PS, HNL	100	MORA 115	115	7	Cap	40.0	474,920
PS, HNL	352	MORA 230	230	7	SVC	100.0	11,418,500
PS, HNL	274	HATILLO	38	7	Cap	11.2	-
PS, HNL	41	VEGA BAJA 115	115	2	Cap	75.0	890,475
PS, HNL	335	HATILLO 115	115	7	SVC	40.0	4,567,400
PS, HNL	440	CAMBALACHE GP	230	7	Change Transforme r Tap	N/A	-
PS, HNL	8201	CANOVANAS	115	3	Cap	31.7	-
Total Range of Costs							**128,248,342 - 277,631,813**

Table 30: Cost of Proposed Common Solutions Addressing N-1-1 Voltage Violations for 2034 Transmission Needs

Model	Bus #	Bus Name	kV	Area	Proposed Device	Required MVAr	Cost Estimate (2025$)
PS, HNL	296	SANTA ISABEL 115	115	6	New TRANSFORMER	N/A	23,699,849
PS, HNL	23	GUANICA 115	115	6	Cap	72.0	854,856
PS, HNL	169	SAN GERMAN TC 115	115	8	Cap	72.0	854,856
PS, HNL	29	MAYAGUEZ 115	115	8	Cap	44.0	522,412
PS, HNL	32	AGUADILLA 115	115	8	Cap	26.9	-

Model	Bus #	Bus Name	kV	Area	Proposed Device	Required MVAr	Cost Estimate (2025$)
PS, HNL	10	CAYEY 115	115	4	Cap	30.0	-
PS, HNL	211	PALMER 115	115	3	Cap	20.0	237,460
PS, HNL	84	BERWIND 115	115	1	Cap	46.6	-
PS, HNL	32	AGUADILLA 115	115	8	SVC	25.0	2,854,625
PS, HNL	231	AÑASCO 115	115	8	Cap	10.0	118,730
PS, HNL	211	PALMER 115	115	3	Cap	20.0	237,460
PS, HNL	23	GUANICA 115	115	6	SVC	60.0	6,851,100
Total							**36,231,348**

<u>Exhibit 2- CONFIDENTIAL</u>

(to be submitted via email)

Exhibit 3

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

IN RE: REVIEW OF THE PUERTO RICO ELECTRIC POWER AUTHORITY INTEGRATED RESOURCE PLAN	**CASE NO.:** NEPR-AP-2023-0004

Direct Testimony of

Daniel Haughton

Planning and Renewables Integration Director, LUMA Energy ServCo LLC

October 15, 2025 (Revised on November 20, 2025, to include Transmission and Distribution Implications of the Preferred Resource Plan)

Summary of Prepared Direct Testimony of
DANIEL HAUGHTON
ON BEHALF OF
LUMA ENERGY LLC AND LUMA ENERGY SERVCO, LLC

Dr. Daniel Haughton ("Dr. Haughton") is Planning and Renewables Integration Director at LUMA Energy ServCo, LLC. In his prepared Direct Testimony, Dr. Haughton supports the Transmission and Distribution Plan (Appendix 1) portion of the Integrated Resource Plan, along with the Transmission and Distribution Implications of the Preferred Resource Plan.

Table of Contents

I. INTRODUCTION

A. Witness Identification

Q.1 Please state your name, business address, title, and employer.

A. My name is Daniel Haughton. My business address is LUMA Energy, PO Box 363508, San Juan, Puerto Rico 00936-3508. I am the Director for Transmission and Distribution Planning for LUMA Energy LLC and LUMA Energy ServCo, LLC (together "LUMA" or "LUMA Energy").

Q.2 On whose behalf are you testifying before the Puerto Rico Energy Bureau ("Energy Bureau" or "PREB")?

A. My testimony is on behalf of LUMA as part of the Commonwealth of Puerto Rico Energy Bureau's Case No. NEPR-AP-2023-0004, *In re: Review of the Puerto Rico Electric Power Authority [("PREPA")] Integrated Resource Plan ("IRP")*.

B. Qualifications and Professional Background

Q.3 What is your educational background?

A. I earned a Bachelor's Degree in Electrical Engineering with a concentration in Electric Power Systems from the University of South Florida in 2006 and a Master's Degree in Electrical Engineering with a concentration in Electric Power Systems from Arizona State University in 2009. Additionally, I earned a Doctor of Philosophy in Electrical Engineering with a concentration in Electric Power Systems from Arizona State University in 2012, with research focused on modeling and simulation, as well as state estimation of Transmission and Distribution systems with high penetration of distributed renewable energy systems.

Q.4 What is your professional experience?

A. I have professional, technical, and industry experience in the electric utility industry in various technical, engineering, and leadership roles across transmission, distribution, and large industrial facilities. I spent 11 years at Arizona Public Service ("APS"), an investor-owned utility in Phoenix, Arizona. There, I served as Director of Technical Engineering Support (2022), Director of Customer to Grid Solutions (2021), Manager of Distribution Planning and Engineering (2018), and Manager of Distributed Energy Resource Engineering (2016). Prior to these roles, I held various technical positions at APS encompassing Transmission Planning and Transmission Operations support, including obtaining a Reliability Coordinator ("RC") certification from the North American Electric Reliability Corporation ("NERC") for three years.

Prior to APS, I worked at Intel Corporation in both Rio Rancho, New Mexico and Chandler, Arizona, as a facilities engineer. I also worked at California Independent System Operator ("CAISO") in Folsom, California, and at Tampa Electric in the Electric Distribution Engineering business. In addition, I have been an adjunct faculty member at Arizona State University, teaching graduate and undergraduate level Electrical Engineering courses since 2014.

Q.5 Have you previously testified in adjudicated proceedings before the Energy Bureau?

A. No.

II. SUMMARY OF DIRECT TESTIMONY

Q.6 What is the purpose of your Direct Testimony?

A. The purpose of my testimony is to sponsor: (1) the Transmission and Distribution ("T&D") Plan, Appendix 1 ("Appendix 1"); and (2) a portion of the T&D implications of the 2025 IRP Preferred Resource Plan.

Q.7 Are you sponsoring any statements, schedules, or exhibits in conjunction with your testimony?

A. No.

Q.8 Are there any documents you relied on for your testimony that have not already been produced in this proceeding?

A. Yes, I have relied on the following documents:

1. Puerto Rico Grid Resilience and Transitions to 100% Renewable Energy Study ("PR100 Study"), March 2024;
2. Resolution and Order on the System Stabilization Plan, March 28, 2025, filed in Docket No. NEPR-MI-2024-0005;
3. LUMA's System Remediation Plan, May 8, 2021, filed in Docket No. NEPR-MI-2020-0019; and
4. Expert Report of Synapse Energy Associates, November 23, 2016, filed in Docket No. CEPR-AP-2015-0001.

Q.9 Are any of the materials you are sponsoring confidential?

A. Yes. The map of the Puerto Rico Transmission system may contain Critical Energy Infrastructure Information ("CEII"). A public version of this map is provided.

In Section 8 of the report, there are also data and results on critical contingencies and critical elements that must be kept confidential to protect the integrity of the fragile Transmission and Distribution networks.

III. TRANSMISSION AND DISTRIBUTION PLANNING

Q.10 Are there any legal requirements for LUMA to submit its IRP?

A. Yes. LUMA is required to develop its IRP in accordance with the requirements set forth in the *Regulation on Integrated Resource Plan for the Puerto Rico Electric Power Authority*, Regulation No. 9021 of the Energy Bureau, dated April 20, 2018 ("Regulation 9021").

Q.11 What is your understanding of what Regulation 9021 mandates, as it pertains to your testimony??

A. As it pertains to T&D System Planning, Regulation 9021 mandates that LUMA describe the existing and planned electric transmission, distribution systems, and advanced grid technologies, and analyze the T&D system's stability, reliability, and compliance with applicable standards.

Q.12 What analyses must the IRP include regarding the T&D system?

A. Table 1 below sets forth a detailed breakdown of the requirements.

Table 1: Regulation 9021 – Transmission and Distribution Planning

Code	Subsection	Description
Regulation 9021	2.03(J)(1)(a)	**Existing Transmission Facilities Descriptions** - The IRP shall include a brief narrative description of the existing electric transmission system and identify any transmission constraints and critical contingencies. The information shall include at a minimum:
Regulation 9021	2.03(J)(1)(a)(i)	A summary of the characteristics of all existing transmission and sub-transmission facilities of thirty-eight kilovolts (38 kV) or higher;
Regulation 9021	2.03(J)(1)(a)(ii)	A discussion of whether the transmission system constrains the transfer of electricity from existing projects, potential new projects, or projects under development or consideration, including a description of its ability to interconnect intermittent renewable generation projects and microgrids, as applicable, and with as much specificity as practical;
Regulation 9021	2.03(J)(1)(a)(iii)	A schematic map of the transmission and sub-transmission network showing transfer limits, which shall be treated as Critical Energy Infrastructure Information and handled in accordance with the procedures set forth in CEPR-MI-2016-0009 as currently amended and may be amended from time to time; and
Regulation 9021	2.03(J)(1)(a)(iv)	A map showing the actual, physical routing of the transmission and sub-transmission, geographic landmarks, major metropolitan areas, and the location of substations and generating plants, and interconnections with distribution substations. The IRP shall include two copies of this map on a 1:250,000 scale. Such map shall be treated as Critical Energy Infrastructure Information and handled in accordance with the procedures set forth in CEPR-MI-2016-0009 as currently amended and may be amended from time to time.

Code	Subsection	Description
Regulation 9021	2.03(J)(1)(b)	**Existing Distribution Facilities Description** - The IRP shall include a brief narrative description of the distribution system, including description of its ability to accommodate incremental penetration of distributed generation, including intermittent distributed generation, and its ability to receive new loads overtime, such as, for example, increasing penetrations of electric vehicles. In addition, the IRP shall provide PREPA's current distribution system design criteria. Information of PREPA's current distribution system shall include:
Regulation 9021	2.03(J)(1)(b)(i)	Load flow or other system analysis by voltage class of the electric utility's distribution system performance that identifies and considers each of the following:
Regulation 9021	2.03(J)(1)(b)(i)(A)	Any thermal overloading of distribution circuits and equipment.
Regulation 9021	2.03(J)(1)(b)(i)(B)	Any voltage variations on distribution circuits that do not comply with the current version of the American National Standard Institute ("ANSI") Standard C 84.1, Electric Power Systems and Equipment Voltage Ratings or Standard as later amended.
Regulation 9021	2.03(J)(1)(b)(i)(C)	[The utility] shall identify any portion of this analysis that it deems Confidential Energy Infrastructure Information. The Commission will handle it in accordance with the procedures set forth in CEPR-MI-2016-0009 as currently amended and may be amended from time to time.
Regulation 9021	2.03(J)(1)(b)(ii)	Adequacy of the electric utility distribution system to withstand natural disasters and overload conditions.
Regulation 9021	2.03(J)(1)(c)	**Existing Advanced Grid Technologies Description** - The IRP shall identify the areas within the service territory where advanced meters and other advanced grid technologies have been installed, along with any plans to expand the integration of any such technologies into its system. The IRP shall include a brief description of the installed advanced grid technologies.
Regulation 9021	2.03(J)(1)(d)	**Planned Transmission Facilities Description** - The IRP shall provide a detailed narrative description of any planned electric transmission and sub-transmission, and a description of the plans for development of facilities during the next ten years of the Planning Period. The description shall include, at a minimum, all information regarding:
Regulation 9021	2.03(J)(1)(d)(i)	New lines, including any requirements of new rights-of-way;
Regulation 9021	2.03(J)(1)(d)(ii)	Lines in which changes in capacity, either in terms of current, voltage or both, are scheduled to take place; and
Regulation 9021	2.03(J)(1)(d)(iii)	Other changes in transmission lines or rights-of-way, which would be considered as substantial additions.
Regulation 9021	2.03(J)(1)(d)(iv)	A listing of all proposed substations including size and location;
Regulation 9021	2.03(J)(1)(d)(v)	The transmission forecast shall include maps of the planned transmission system as follows: A. A map showing the planned transmission lines, substation, and generating plants as they will tie into the existing system to provide as complete a picture of the system as is possible.
Regulation 9021	2.03(J)(1)(d)(vi)	[The utility] shall submit a justification of its transmission development plans, including: A. Description and transcription diagrams of the base case load flow studies, one for the current year and one as projected five and ten years into the future, and provide base case load flow studies in a standard industry format (such as PSS/E or PSLF) along with transcription diagrams for the base cases. Such information shall be treated as Critical Energy Infrastructure Information and handled in accordance with the procedures set forth in CEPR-MI-2016-0009 as currently amended and may be amended from time to time.
Regulation 9021	2.03(J)(1)(d)(vii)	A tabulation of and transcription diagrams for a representative number of contingency cases studied along with brief statements concerning the results.
Regulation 9021	2.03(J)(1)(d)(viii)	Adequacy of [the utility's] transmission system to withstand natural disasters and overload conditions.
Regulation 9021	2.03(J)(1)(d)(ix)	A high-level analysis of [the utility's] transmission system's ability to permit power interchange with microgrids and other independent power producers. [The utility] should provide examples of interconnection studies from recent renewable integration projects.
Regulation 9021	2.03(J)(1)(d)(x)	A diagram showing [the utility's] import and export transfer capabilities and identifying the limiting element(s) during each season of the next ten years. In addition, [the utility] will

Code	Subsection	Description
		provide a listing of transmission loading relief (TLR) procedures called during the last two seasons for which actual data are available. For each TLR event, the listing shall include the maximum level, and the duration at the maximum level, and the magnitude (in MW) of the power curtailments.;
Regulation 9021	2.03(J)(1)(d)(xi)	A description of any studies regarding transmission system improvement, including, but not limited to, any studies of the potential for reducing line losses, thermal loading, and low voltage, and for improving access to alternative energy resources.
Regulation 9021	2.03(J)(1)(d)(xii)	A one-line diagram of the transmission network. Such information shall be treated as Critical Energy Infrastructure Information and handled in accordance with the procedures set forth in CEPR-MI-2016-0009 as currently amended and may be amended from time to time.
Regulation 9021	2.03(J)(1)(e)	**Planned Distribution Facilities Description** - The IRP shall provide a detailed narrative description of any planned changes in approach, standard practice, or broadly applicable substation, circuit, or feeder design for [the utility's] distribution system for the next ten years. This description shall address any changes in distribution facilities that impact the ability to accommodate incremental penetration of distributed generation, including intermittent distributed generation, and the ability to receive new loads over time. [The utility] shall submit a substantiation of distribution development plans, including, if available:
Regulation 9021	2.03(J)(1)(e)(i)	Load flow or other system analysis by voltage class of the electric utility's distribution system performance that identifies and considers each of the following: A. Any thermal overloading of distribution circuits and equipment. B. Any voltage variations on distribution circuits that do not comply with the current version of the American National Standard Institute ("ANSI") Standard C 84.1, Electric Power Systems and Equipment Voltage Ratings or Standard as later amended.
Regulation 9021	2.03(J)(1)(e)(ii)	Adequacy of the electric utility distribution system to withstand natural disasters and overload conditions.
Regulation 9021	2.03(J)(1)(e)(iii)	Analysis and consideration of any studies regarding distribution system improvement, including, but not limited to, any studies of the potential for reducing line losses, thermal loading and low voltage or any other problems, and for improving access to alternative resources.
Regulation 9021	2.03(J)(2)(a)	**Transmission and Distribution System Analysis** - The IRP shall identify [the utility's] transmission standards and shall confirm that the [the utility's] transmission standards are in compliance with the standards of the North American Electric Reliability Corporation. If any of [the utility's] transmission standards are inconsistent with standards from the North American Electric Reliability Corporation, then [the utility] shall identify each such inconsistent standard and provide the explanation and rationale for the inconsistency.
Regulation 9021	2.03(J)(2)(b)	The IRP shall include a System Stability Analysis, which shall be treated as Critical Energy Infrastructure Information and handled in accordance with the procedures set forth in CEPR-MI- 2016-0009 as currently amended and may be amended from time to time. The analysis shall provide operational criteria, define Ancillary Services requirements, and demonstrate least-cost mitigation solutions to maintain system stability;
Regulation 9021	2.03(J)(2)(c)	The IRP shall identify thermal and voltage reliability issues in [the utility's] transmission system and distribution systems. Such information shall be treated as Critical Energy Infrastructure Information and handled in accordance with the procedures set forth in CEPR-MI-2016-0009 as currently amended and may be amended from time to time;
Regulation 9021	2.03(J)(2)(d)	The IRP shall identify transmission, distribution, and substation potential improvements to increase reliability and meet minimum transmission standards;
Regulation 9021	2.03(J)(2)(e)	The IRP shall document the transmission and distribution implications of the Preferred Resource Plan, including assessing if the plan requires incremental transmission or distribution mitigation or changes.

Q.13 Please briefly explain the difference between LUMA's transmission and distribution systems.

A. The transmission system is the critical backbone of higher voltage towers, lines, and substations that connect major generation resources to denser urban load centers. The distribution system, by contrast, is an expansive network of over 340 distribution substation transformers and over 1,100 distribution circuits that directly serve customer loads, feed new load requests, and integrate distributed generation that connects to customer rooftops.

Q.14 Please summarize LUMA's methodology for planning the transmission and distribution systems.

A. The strategic objectives driving LUMA include: system stabilization, updating end-of-life assets, reliability improvement, generation and renewable integration, and resilience hardening. Investment priorities are defined after completing thorough assessments that include: asset and field condition verification; operational experiences; transmission planning analysis and studies; studies in support of customer load requests; and studies in support of generation and renewable projects.

LUMA's methodology for planning the transmission system includes first stabilizing the system by restoring critical out-of-service facilities to service, then addressing critical performance deficiencies through reconfiguration and redesign, and finally optimizing the grid's performance by rebuilding and hardening critical assets. These factors must all account for integrating both new customer loads and renewable energy, as well as new generation projects which are growing rapidly across the system. The system must be planned to achieve essential reliability performance based on NERC Transmission Planning criteria (TPL-001-5) and related reliability standards; for example, loss of a single transmission line, substation breaker, transformer or busbar (known as N minus 1 or "N-1") should not result in consequential load loss.

The distribution system planning methodology, in order of emphasis for distribution circuits, includes: (i) focus on restoration of critical out-of-configuration circuits, circuit breakers at substations, and substation transformers; (ii) focus on worst-performing reliability circuits and distribution automation device deployments to improve customer experience and reliability; and (iii) rebuilding and hardening of circuit backbones and selected branches to address reliability deficiencies.

Substations that supply distribution circuits are also a major focus including rebuilding of existing substations that are in poor physical condition and those with a history of operational deficiencies; and mitigating flood risk with barriers, elevation or relocation of substation assets as practicable. Also, in individual substations, LUMA focuses on reinforcing and upgrading existing system infrastructure to improve reliability, including replacing aging transformers, oil circuit breakers, distribution circuit breakers, other high-voltage equipment, and other systems as necessary to improve asset performance, system reliability, and safety.

IV. THE EXISTING TRANSMISSION AND DISTRIBUTION SYSTEM

Q.15 Please describe the state of the T&D system when LUMA assumed operational responsibility.

A. The T&D System was operated and maintained exclusively by PREPA prior to LUMA's commencement of operations on June 1, 2021. By all accounts, LUMA inherited a T&D System that was significantly deteriorated, in bankruptcy, and being operated in a manner inconsistent with Prudent Utility Practices; i.e., operational indicators, such as reliability metrics, price, wait times, and billing accuracy, indicated that PREPA was not performing at the same level as its comparable utilities. The T&D System was fragile, having suffered decades of neglect.

The Puerto Rico Legislature included findings on the dire state of the T&D System when it enacted both Act 120-2018, which allowed the process to select a private operator for the T&D System and laid the groundwork for the transformation of Puerto Rico's electric power system, and Act 17-2019. For example, in enacting Act 120-2018, the legislature stated that "[p]ractically no infrastructure maintenance was performed during the past decade." The Puerto Rico legislature also stated that Puerto Rico's electric power generation and distribution systems were deficient and obsolete.

The 2017 Rate Order[1] and the 2020 Fiscal Plan also acknowledged PREPA's chronic underinvestment in the system. Specifically, the 2017 Rate Order notes that PREPA's infrastructure spending was not based on actual system needs.[2] The 2020 Fiscal Plan stated that, "in recent years, capital investments in the T&D System were limited to the most urgent projects to avoid imminent system failure rather than to proactively improve the grid for the future."[3]

Though these conditions were known, and therefore, not entirely unanticipated, the severity of the deterioration and consequent challenges that LUMA still faces cannot be overstated. A 2016 Study commissioned by the Energy Bureau in

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[1] Resolution and Order dated January 10, 2017, as amended in reconsideration in Case No. CEPRAP-2015-0001 ("2017 Rate Order").
[2] *See* 2017 Rate Order, at p. 3.
[3] *See* 2020 Fiscal Plan for the Puerto Rico Electric Power Authority as Certified by the FOMB on June 29, 2020 ("2020 Fiscal Plan"), at p. 14, available at https://docs.pr.gov/files/AAFAF/Financial_Documents/Fiscal%20Plans/CERTIFIED%20FISCAL%20PLANS/2020-PREPA-Fiscal-Plan-as-Certified-by-FOMB-on-June-29-2020.pdf.

PREPA's last rate case, which was conducted by Synapse Energy Economics, Inc. ("Synapse T&D Study") found that the T&D System was "falling apart quite literally"[4] due, in part, to capital constraints and an inability to replace and construct lines. Lack of funds forced PREPA to play "a catch-up game on maintenance – following outages, instead of improving the fundamental system."[5]

During the Front-End Transition Period ("FET"),[6] LUMA conducted a system-wide gap assessment and identified over 1,000 gaps.[7] Over 600 initiatives were identified to address those "gaps" (i.e., the difference between the state of the T&D System, work practices, procedures, and processes at the time of the FET compared to Prudent Utility Practice, applicable codes and standards, and the T&D OMA).[8] The gap assessment spanned the entire T&D System, including physical infrastructure, operational procedures and protocols, supporting infrastructure and information systems, and administrative practices (including employee training and certifications).

These legislative findings, the findings of the Energy Bureau, LUMA's FET evaluation and independent studies, reflect a consistent theme: the decades-long

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[4] Synapse Report at 18, *see also* at 12, 26, *available at* https://energia.pr.gov/wp-content/uploads/sites/7/2016/11/Expert-Report-Revenue-Requirements-Fisher-and-Horowitz-Revised-20161123.pdf.

[5] *Id.* at 33.

[6] The FET was the period of time from and including the Effective Date (that is, June 22, 2020) and until Commencement Date (this period, the "Front-End Transition Period") as defined by the Puerto Rico Transmission and Distribution System Operations and Maintenance Agreement and the Supplemental Agreement ("T&D OMA") executed among PREPA, the Puerto Rico Public Private Partnership Authority, and LUMA dated June 22, 2020. During the FET, LUMA was required to provide "Front-End Transition Services" to ensure an orderly transition of the responsibility for the management, operation, maintenance, repairs, restoration and replacement of the T&D System, without disruption of customer service and business continuity. The Front-End Transition Services was included in the T&D OMA to complete the transition and handover to LUMA of the operation, management and other rights and responsibilities with respect to the T&D System.

[7] *See* System Remediation Plan at p. 1, *available at* https://energia.pr.gov/wp-content/uploads/sites/7/2021/05/Motion-in-Compliance-with-Order-Submitting-Revised-Redacted-Version-of-SRP-and-Redacted-Attachments-to-Responses-to-RIs-NEPR-MI-2020-0019.pdf.

[8] *Id.*

degradation of Puerto Rico's energy system is predominantly driven by a well-documented historical lack of investment in the grid, resulting from both poor planning and insufficient funding.

Q.16 What has LUMA done since assuming operational responsibility to improve the T&D system?

A. In compliance with Section 4.1(d)(ii) of the T&D OMA, LUMA developed a System Remediation Plan ("SRP"). At the highest level, the SRP provides a roadmap for the transition from a state in which utility assets and activities are not in compliance with Contract Standards and Prudent Utility Practices, to one where the minimum conditions are met to achieve the vision of providing safe and reliable electric service to customers. The SRP was approved by the Energy Bureau in Case No. NEPR-MI-2020-2019.[9]

Since the approval of the SRP, LUMA has implemented multiple programs that focus on improving the T&D System, which have resulted in tremendous progress across all facets of Puerto Rico's electric grid. Examples include:

- **Strengthened the energy system against storms and hurricanes**: by replacing more than 32,400 utility poles with new stronger poles able to withstand winds of 160+ mph;
- **Reduced the size and the impact of outages:** by installing over 10,500 grid automation devices, which have served to avoid over 460 million service interruption minutes for our customers;

[9] Case No.: NEPR-MI-2020-0019, Determination on LUMA's Proposed System Remediation Plan, Resolution & Order of June 23, 2021.

- **Addressed the largest cause of outages:** by clearing vegetation from over 6,491 miles of powerlines and electric infrastructure;
- **Improved community safety and energy efficiency:** by replacing over 84,000 streetlights as part of LUMA's Community Streetlight Initiative;
- **Enabled the adoption of Distributed Solar Photovoltaics ("DPV"):** by connecting over 175,000 customers to rooftop solar, representing 1,282 MW of clean, renewable energy for Puerto Rico, along with a recorded 153,000 Battery Energy Storage Systems representing 850 MW and 2,600 MWh of energy storage capacity, and;
- **Improved reliability during generation shortfalls:** by launching the Customer Battery Energy Sharing ("CBES") initiative to aggregate customer home batteries to provide system support during known generation shortfall events. By October 2025, CBES had over 80,000 participants reliably providing up to 65 MW of response over 4-hour events during the summer of 2025.

A. Existing Transmission System

Q.17 Please describe the existing transmission system.

A. Puerto Rico's electric transmission system includes approximately 424 miles of 230kV, 711 miles of 115kV and 1,563 miles of 38kV transmission lines and 299 substation sites spread across eight transmission planning zones spanning the Island.

Q.18 Please summarize the transmission constraints and critical contingencies on the existing system.

A. The detailed technical analysis used to evaluate the performance of the transmission network identified 26 critical contingencies that lead to significant thermal overloads for loss of a single element, and another 17 critical contingencies that lead to significant voltage violations across areas of the Puerto Rico grid. These thermal and voltage issues are so significant that they lead to area-wide disturbances, or have been shown historically to cause cascading failures that can impact large regions of the island. Examples include for a single 115/38kV transformer tripping, multiple elements overload by as much as 190% of rated capacity, potentially triggering cascading failures of other lines and transformers.

Q.19 Has LUMA conducted a system analysis to assess the adequacy of the existing transmission system to withstand natural disasters and overload conditions?

A. Yes. LUMA has conducted physical assessments of field assets to determine those at risk which likely would not withstand high winds in natural disasters. Note that a detailed engineering 'Pole Loading Analysis' would be required to calculate a structure's probability to withstand specified wind speeds; however, visual inspections only identified the at-risk assets that would be highly likely to fail in high winds. LUMA has also conducted an assessment involving extensive load flow simulations, including 982 N-1 and 77,006 N-1-1 contingencies. These simulations evaluated the transmission system's performance under various operational scenarios and identified potential vulnerabilities. The contingencies consider a broad listing of equipment type including transmission line segments, substation transformers, generators, buses, breakers and other equipment. The guidance in LUMA's Transmission Planning Criteria document are derived directly from the North American Reliability Corporation ("NERC") Transmission Planning (TPL 001-05) active standard for transmission planning entities.

B. Existing Distribution System

Q.20 Please describe the existing distribution facilities.

A. Puerto Rico's electric distribution system includes 342 distribution substations that supply loads to 1,127 distribution circuits (also referred to as feeders). The source of the substation is fed from either 115 or 38kV transmission, and the load side of substations and feeders are energized at one of five primary voltage levels: 13.2 kV, 8.32 kV, 7.2 kV, 4.8 kV or 4.16 kV. LUMA manages six operational regions across Puerto Rico: Arecibo, Bayamón, Caguas, Mayaguez, Ponce and San Juan. Section 5.1 of Appendix 1 provides a description of the existing distribution system.

Q.21 Please summarize the existing distribution system's ability to accommodate incremental penetration of distributed generation and its ability to receive new loads over time.

A. LUMA has worked to incorporate and mitigate the impact of distributed energy resources ("DERs") on Puerto Rico's system through both corrective action and forward-looking strategies. On one hand, LUMA continues to identify required upgrades, such as service transformers, voltage regulators and thermal capacity improvements. On the other hand, a proactive approach is being implemented through the adoption of Smart Inverter Settings, aligned with IEEE-2018. These settings were developed through robust stakeholder engagement and were informed by operational data and system simulations, and are designed to improve grid stability and reliability.

However, LUMA is quickly approaching the physical and technical limit of the distribution system to accommodate incremental distributed generation. Without significant intervention, the distribution grid will collapse under the current pace of interconnections. This means that LUMA will be unable to manage system voltage, control thermal loads, and ensure the safety and reliability of the distribution circuit infrastructure.

Q.22 Has LUMA conducted a system analysis to assess the adequacy of the existing distribution system to withstand natural disasters and overload conditions?

A. Yes. The analysis reveals that portions of the network are well equipped to withstand natural disasters (e.g., those with underground or covered conductors and rebuilt infrastructure). However, it also reveals that a large portion of the network is very exposed to natural disasters. The analysis also reveals that a significant number of circuits and circuit sections are experiencing thermal overloads and need to be rebuilt to accommodate existing and planned future growth.

C. <u>Advanced Grid Technologies</u>

Q.23 Please describe the current state of advanced grid technologies employed on the existing T&D system.

A. LUMA is in the process of advancing its grid modernization efforts by deploying automated switchgear, fault sensors, and advanced monitoring technologies across its distribution and transmission systems to enhance reliability and resilience. The program includes the installation of three-phase and single-phase smart reclosers with microprocessor-based controllers, enabling remote monitoring and control via Supervisory Control and Data Acquisition ("SCADA"), as well as the deployment of communicating Fault Circuit Indicators ("FCIs") to improve fault location accuracy and speed up service restoration. The initiative also involves upgrading outdated protection devices and implementing feeder automation schemes that allow for automatic isolation and restoration of feeder segments, thereby minimizing outages. Additionally, LUMA is integrating advanced sensor technologies such as Phasor Measurement Units ("PMUs") to provide high-speed, synchronized data for real-time system monitoring, event analysis, and support for renewable energy integration. These technologies are being deployed in substations, on feeders, and as part of microgrid projects in Vieques and Culebra, where they will enhance situational awareness, power quality monitoring, and operational flexibility. Collectively, these efforts are designed to create a more reliable, efficient, and future-ready electric grid for Puerto Rico.

Q.24 Does LUMA have plans to expand the integration of advanced grid technologies?

A. Yes. As of September 2025, LUMA has already installed a total of 308 three-phase reclosers and 674 single-phase reclosers under its distribution automation initiative, impacting 156 distribution feeders. LUMA has plans to deploy over 13 thousand single-phase reclosers and over 3 thousand three-phase reclosers by FY2035. Additionally, LUMA has already installed thousands of FCIs and plans to continue expanding this deployment through 2029, with optimal device placement determined by reliability studies.

Q.25 Are there any other conclusions you would like to draw from the existing T&D System?

A. Yes. Puerto Rico is at a critical juncture where the policy, laws and regulations impacting the integration of distributed renewable energy systems must be updated to reflect the pace and volume of existing conditions, and to allow for the hardening of the grid to accommodate these installations before future installations are deployed. LUMA stands ready to support accelerated deployment of customer owned resources, but the balanced approach must include: (a.) enabling customer technologies and leveraging their capabilities like smart inverter settings, (b.) protecting the grid from physical damage so safety and reliability are available to all customers, and (c.) ensuring costs are equitably assigned to protect the affordability of both technology adopters and non-participants alike.

V. <u>PLANNED TRANSMISSION AND DISTRIBUTION FACILITIES</u>

Q.26 Please describe the electric transmission and sub-transmission facilities planned to be installed during the IRP planning period.

A. The electric transmission and sub-transmission facilities in LUMA infrastructure plans during the IRP planning period can be divided into two categories: (1) those that were developed prior to commencement of the IRP; and (2) those that arise from the selection of the Preferred Resource Plan.

With respect to the first category, Appendix 1 outlines LUMA's comprehensive five-year strategy to enhance Puerto Rico's transmission and sub-transmission infrastructure, driven by: (a.) System Stabilization efforts to restore out-of-service transmission and substation infrastructure, and (b.) findings from the 2025 Transmission Planning Assessment. The assessment identified a range of projects to address reliability, resilience, and the integration of renewable energy, including the construction of new transmission lines, reconductoring to increase the capacity of existing lines, restoring additional facilities to service, rebuilding and reconfiguring substations, and adding and restoring out-of-service transformers.

Extensive load flow simulations and contingency analyses (N-1 and N-1-1) were conducted to pinpoint system vulnerabilities and thermal or voltage violations under various operational scenarios, including natural disasters and peak loading conditions. Key planned transmission line rebuild projects are listed in Section 4.3.4 which are anticipated to utilize FEMA funding. Additionally, \$89.6-\$129M have been requested in an ongoing Rate Case Filing for the next three fiscal years to address the thermal overloads and voltage violations needing immediate mitigation. No new substations were proposed as a result of the 2025 Transmission Planning assessment.

With respect to the second category of planned transmission projects to support the Preferred Resource Plan, these will be identified concurrent with LUMA's PSS®E analysis, which will be filed with the Energy Bureau on November 21, 2025.

Q.27 Please describe the planned changes in approach, practice, and design of the distribution system over the IRP planning period.

A. As with LUMA's proposed changes to the transmission system, the changes to the distribution system fall into two categories: (1) those planned before release of the IRP; and (2) those needed as a result of the Preferred Resource Plan selected in the IRP. With respect to the first category, the planned changes span substation and feeder rebuilds, automation, reliability upgrades, and targeted infrastructure improvements, as detailed below:

Substation Rebuilds and Upgrades: The Substation Rebuild program focuses on the rebuilding of existing substations that are in poor physical condition, the rebuilding of substations with a history of operational deficiencies, the mitigation of flood risk where applicable, and the relocation of substations with a high risk of flooding when flood mitigation alone is not an option.

Substation Reliability: This program will reinforce and upgrade existing system infrastructure to improve reliability, including replacing aging transformers, oil circuit breakers, distribution circuit breakers, other high-voltage equipment, alternating current/direct current (AC/DC) systems, standby generators, relays, remote terminal units, and auxiliary systems. It will also include protection and control upgrades and procurement of emergency spares.

Distribution Line Rebuilds: The Distribution Line Rebuild program focuses on rebuilding distribution feeders with poor reliability performance and those that serve critical power facilities, targeting the worst-performing feeders first. This program will result in significant system improvements in the short term and incremental improvements for the remaining program duration.

Distribution Pole and Conductor Repair: This program focuses on minimizing the safety hazards caused by distribution poles, equipment, and conductors that must be repaired or replaced. Major repairs and replacement will be based upon the results of assessments of the distribution system and an analysis by engineers to schedule the repair or replacement based on the structure criticality. Following this process, safety hazards and priority poles will be replaced, along with damaged equipment, conductors, and hardware.

Distribution Automation: This program involves deploying automated switchgear and fault sensors on distribution feeders to improve grid reliability. It will take place as part of LUMA's efforts to enhance system performance through remote operations, fault detection, and faster service restoration, utilizing advanced communication tools and system analysis.

Distribution Grid Reliability: This program focuses on reducing outages, improving response times, and ensuring the delivery of safe and reliable electricity to customers. Assessing the worst performing feeders, targeting localized reliability concerns, and performing reliability system upgrades, such as integrating FCIs and fuse coordination are the three main drivers of this program.

Distribution Streetlighting: This program deals with upgrading and replacing distribution streetlights that are a physical and safety hazards scheduled for repair or replacement based on their criticality. Along with increasing the number of distribution streetlights in service, this process will include light-emitting diode ("LED") replacements and geographic information system ("GIS") data entry of all streetlights.

The second category of planned distribution changes will be identified concurrent with LUMA's PSSE analysis, which will be filed with the Energy Bureau on November 21, 2025.

VI. TRANSMISSION AND DISTRIBUTION SYSTEM ANALYSIS

Q.28 Please describe the transmission system standards LUMA adheres to.

A. LUMA's transmission system standards are covered in two documents – (i.) Transmission Planning Criteria and (ii.) LUMA Transmission Design Criteria and Manual. The Transmission Planning Criteria document is derived from the NERC reliability standards and incorporates best practices from other Regional Reliability Organizations. The Transmission Design Criteria document provides the physical and structural requirements for designs to meet or exceed current American Society of Civil Engineers ("ASCE") and Institute of Electrical and Electronics Engineers ("IEEE") codes and standards, which include wind loading and other parameters such as ground and structure clearances. These two together ensure that transmission network performance meets essential reliability and applicable codes and standards.

Q.29 Is the transmission system that LUMA inherited in compliance with those standards?

A. No. As discussed previously, transmission planning criteria is not met, as 26 critical contingencies produce thermal violations and 17 critical contingencies produce widespread voltage violations. Also, present transmission design criteria was not the standard in place at the time most transmission facilities were constructed, so poles, structures and associated infrastructure do not meet current codes and standards today. For example, Act 17 - 2019 requires wind loading of 155 mph, but very few transmission structures are designed or built to this existing requirement.

Q.30 Did LUMA conduct a system stability analysis of the T&D system?

A. Yes. The discussion and results of the System Stability Analysis are located in Section 7.0 of Appendix 1.

Q.31 What thermal and voltage reliability issues were identified in the T&D systems?

A. For the "as operated" transmission system, 26 critical contingencies cause major overloads on neighboring transmission facilities, with overloads greater than 190% of a line rating in some cases. These cause cascading overloads of other facilities that can result in regional or island-wide instability and outages. Additionally, another 17 critical contingencies cause major voltage disturbances that can impact regions or island-wide instability and outages. Due to the sensitive nature of these facilities, LUMA requests to treat these critical contingencies as CEII. Transmission analysis concludes that the Puerto Rico grid is not in compliance with NERC Transmission Planning standards for system performance.

Distribution substation analysis discussed in Section 5.3.1 identified 25 distribution substations at a loading of 90% of the transformer maximum thermal loading or higher. When including already requested new business customers, an additional 22 transformers would exceed 90% or more of the transformer maximum thermal loading or higher. This means that significant transformer capacity increases or new distribution substations will be required over the 3-year and 10-year investment planning horizons.

Distribution circuit analysis discussed in Section 5.3.1 identified approximately 304 of 1,127 circuits with notable voltage violations due especially to night-time and evening peaks in hot summer months, and 164 circuits with thermal overloads.

DER and the bi-directional flows during daytime, and during lightly loaded shoulder months also contribute to 285 voltage issues, and 638 thermal issues including service transformer overloads and primary circuit conductors in neighborhoods across the island. Note, the timeframe of study for DER and PV injection impacts (light load, often in February – April) and mid-day load and generation levels means that these violations are mostly unique from the evening peak thermal and voltage violations that occur when PV is not producing, and demand is high, especially in the summer months (June – October).

Q.32 What potential transmission, distribution, and substation improvements are planned to increase reliability and meet minimum transmission standards?

A. As discussed above, LUMA's investment strategy is driven by strategic pillars of system stabilization and asset replacements to improve public and worker safety and equipment and community support, reliability and resilience improvements to address the worst reliability impacts first and harden the grid against resilience threats, while supporting regulatory and community objectives of driving deep decarbonization and supporting distributed energy integration. The activities in the System Stabilization plan include, but are not limited to, restoring out of service transmission lines, restoring out of service substation transformers, deploying grid automation devices and enabling technologies like information technology and telecommunications investments and enabling technologies like substation relays and remote terminal units. These will have the near-term impact of improving reliability, but facilities like transmission lines will not be upgraded to withstand higher wind speeds (as only necessary structure installations to return the lines to service are being implemented).

LUMA also has requested funding in an active Rate Case (NEPR-AP-2023-0003) to begin addressing high priority capacity constrained transmission and distribution circuit thermal and voltage violations, as well as emergent safety and reliability risks due to DERs.

VII. TRANSMISSION & DISTRIBUTION IMPLICATIONS OF THE PREFERRED RESOURCE PLAN

Q.33 What is your understanding of the requirements for the portion T&D System Planning section of the 2025 IRP that you are sponsoring?

A. With respect to the T&D System section of the 2025 IRP Report, LUMA followed the requirements set forth in Section 2.03(J)(2)(e) of Regulation 9021. This section requires the 2025 IRP to document the T&D implications of the PRP, including assessing if the PRP requires incremental T&D mitigation or changes.

Q.34 Did LUMA receive any clarifications regarding the Energy Bureau's expectation for LUMA's 2025 IRP fulfilling the T&D requirements in Regulation 9021?

A. Yes. On April 15, 2024, the Energy Bureau issued a Resolution and Order in this case, granting a portion of LUMA's request for a waiver of certain specific requirements in Regulation 9021 and denying LUMA request for waivers to other requirements. In addition, in this R&O, the Energy Bureau clarified that: LUMA cannot provide information it does not have.

Q.35 What portion of the T&D system analysis of the implications of the PRP does your testimony address?

A. As noted above, my testimony addresses the existing state of the T&D system, which was used as inputs into the analysis of the PRP's impacts to the transmission system (addressed by LUMA witness Ajit Kulkarni). My testimony also addresses the analysis of the PRP implications on the distribution system.

Q.36 What analysis did LUMA perform to assess the implications of the PRP on the distribution system?

A. LUMA did not complete a comprehensive analysis of the implications of the PRP on the distribution system. The inclusion of distributed photovoltaic (DPV) and electric vehicle (EV) charging installations in the PRP represent forecasts of customer choices for these installations that are not under the control of LUMA and are driven solely by customer choice. Therefore, the location and quantity of the distributed resources is not within LUMA's planned resource deployment but must be reactively addressed according to present laws and regulations.

LUMA has developed recommended smart-inverter settings whose adoption is imperative to improve near-term distribution circuit voltage performance under normal conditions, and also support transmission grid stability by having inverters respond to grid frequency and grid voltage disturbances; however, these recommended smart-inverter settings require PREB action to implement. LUMA re-iterates again, as stated in response to question 22 that the system is already quickly approaching the physical and technical limit of the distribution system to accommodate incremental distributed generation (evidenced by the prevalence of DG related high voltages, distribution transformer and circuit thermal overloads being identified, and volume of repairs and upgrades that are being newly driven by DPV). These items will need to be considered in any implementation plan to execute the improvements needed for a reliable grid that meets minimum industry requirements.

Given the impossibility of performing a detailed distribution system analysis of the PRP without knowing where on the system the resources may be placed, and the waivers and clarifications granted by the Energy Bureau in its R&O of April 15, 2024, which recognized and waived LUMA's ability to comply with Regulation 9021 when it did not possess the required data, LUMA has requested the Energy Bureau to waive the requirement of completing the distribution analysis of the PRP

Q.37 Does this conclude your direct testimony?

A. Yes.

ATTESTATION

Affiant, Daniel Haughton, being first duly sworn, states the following:

The prepared Direct Testimony that I am sponsoring constitutes my Direct Testimony in the above-styled case before the Puerto Rico Energy Bureau. I would provide the answers set forth in the Direct Testimony if asked the questions included in the Direct Testimony. I further state that the facts and statements provided herein are my Direct Testimony and, to the best of my knowledge, are true and correct.

Daniel Haughton, Ph.D. SMIEEE

Affidavit No. 148

Acknowledged and subscribed before me by Daniel Haughton, in his capacity as Planning and Renewables Integration Director of LUMA Energy ServCo, LLC, of legal age, married, and resident of San Juan, Puerto Rico, who is personally known to me.

In San Juan, Puerto Rico, this 20th day of November 2025.

JUAN PABLO TORRES DEL RÍO ABOGADO - NOTARIO

Notary Public

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

IN RE: REVIEW OF THE PUERTO RICO ELECTRIC POWER AUTHORITY INTEGRATED RESOURCE PLAN	**CASE NO.:** NEPR-AP-2023-0004

Direct Testimony of

Dr. Ajit Kulkarni

Senior Technical Expert and Grid Modernization Manager, LUMA Energy ServCo LLC

October 15, 2025 (Revised on November 21, 2025 to include Transmission and Distribution Implications of the Preferred Resource Plan)

Summary of Prepared Direct Testimony of
AJIT KULKARNI
ON BEHALF OF
LUMA ENERGY LLC AND LUMA ENERGY SERVCO, LLC

Dr. Ajit Kulkarni ("Dr. Kulkarni") is the Senior Technical Expert and Grid Modernization Manager at LUMA Energy ServCo, LLC. The purpose of Dr. Kulkarni's prepared direct testimony in this proceeding is to sponsor the Assumptions and Forecasts, Resource Plan Development, Caveats and Limitations, and Action Plan sections of LUMA's Integrated Resource Plan, along with the Transmission and Distribution Implications of the Preferred Resource Plan.

Table of Contents

I. INTRODUCTION

A. Witness Identification

Q.1 Please state your name, business address, title, and employer.

A. My name is Ajit Kulkarni. My business address is LUMA Energy, PO Box 363508, San Juan, Puerto Rico 00936-3508. I am the Grid Modernization Manager for LUMA Energy LLC and LUMA Energy ServCo, LLC (together "LUMA" or "LUMA Energy").

Q.2 On whose behalf are you testifying before the Puerto Rico Energy Bureau ("Energy Bureau" or "PREB")?

A. My testimony is on behalf of LUMA as part of the Energy Bureau's Case No. NEPR-AP-2023-0004, *In re: Review of the Puerto Rico Electric Power Authority Integrated Resource Plan*.

B. Qualifications and Professional Background

Q.3 What is your educational background?

A. I received a Bachelor of Science Degree in Electrical and Computer Engineering from Arizona State University in 1988 and a Master of Science Degree in Electrical and Computer Engineering from University of Illinois, Urbana-Champaign in 1990. In addition, I received a Doctor of Philosophy Degree in Electrical and Computer Engineering from University of Illinois, Urbana-Champaign in 1996.

Q.4 What is your professional experience?

A. I have over 25 years of technical and managerial experience in the electricity sector with a strong emphasis on IRPs, system master plans/studies, renewable integration studies, congestion/curtailment studies, security-constrained economic dispatch

(“SCED”), security-constrained unit commitment (“SCUC”), optimal power flow (“OPF”), generator and load interconnection and grid codes. Technologies have included onshore and offshore wind, solar, storage, hydrogen, Electric Vehicle (“EV”) charging infrastructure, transmission projects, industrial facilities, data centers, distributed energy resources (“DER”), smart grid, and demand response (“DR”)/ dual-layer capacitor (“DLC”)/ demand side management (“DSM”). In addition, I lead the Resource Planning and Grid Resilience Areas within the Transmission and Regulatory Compliance team.

Q.5 Have you previously testified in adjudicated proceedings before the Energy Bureau?

A. No.

II. SUMMARY OF DIRECT TESTIMONY

Q.6 What is the purpose of your Direct Testimony?

A. The purpose of my testimony in this proceeding is to summarize and sponsor the Assumptions and Forecasts (Section 7), Resource Plan Development (Section 8), Caveats and Limitations (Section 9), and Action Plan (Section 10) sections of LUMA’s 2025 IRP. I am also sponsoring a portion of the Transmission & Distribution Planning Section of the 2025 IRP.

Q.7 Are you sponsoring any statements, schedules, or exhibits in conjunction with your testimony?

A. No.

Q.8 Are there any documents you relied on for your testimony that have not already been produced in this proceeding?

A. No.

Q.9 Are any of the materials you are sponsoring confidential?

A. Yes. Some of the information contained in the sections of the 2025 IRP Report and workpapers that I am sponsoring contains commercially sensitive or trade secret information and Critical Energy/Electric Infrastructure Information (CEII) information.

III. ASSUMPTIONS AND FORECASTS

Q.10 Are there any legal requirements for LUMA to submit its 2025 IRP?

A. Yes. LUMA is required to develop its IRP in accordance with the requirements set forth in the Regulation on Integrated Resource Plan for the Puerto Rico Electric Power Authority, Regulation No. 9021 of the Energy Bureau, dated April 20, 2018 ("Regulation 9021"). With respect to the Assumptions and Forecasts section of the 2025 IRP, LUMA followed the requirements set forth in Section 2.03(G) of Regulation 9021, which requires the IRP to describe the modeling assumptions and inputs incorporated into LUMA's forecasting model, and the requirements in the May 13, 2025 Resolution and Order in this proceeding ("May 13th Order"), which specified certain assumptions.

Q.11 Are there other assumptions and forecasts that go into the modeling?

A. Yes, there are many. Load forecasts and assumptions regarding existing and new resources are also incorporated into the modeling. The forecasts and assumptions are discussed in other sections of the 2025 IRP Report and by different witnesses, as shown in Table 1 below.

Table 1: Summary of 2025 IRP Sections Discussing Assumptions and Forecasts and Their Respective Witnesses

Topic	IRP Section	Sponsoring LUMA Witness
Base Load Forecast	Section 3	Joseline Estrada Rivera
High and Low Load and Load Modifier Forecasts	Section 3	Michael Mount
Existing Resources	Section 4	Raphael Gignac
New Resource Options	Section 6	Michael Mount
Fuel & Other General Assumptions and Forecasts	Section 7	Ajit Kulkarni

Q.12 Please describe the fuel price forecasts that LUMA used in the 2025 IRP.

A. The fuel price forecast was developed by LUMA's Technical Consultant, Black & Veatch ("LUMA Technical Consultant"). That forecast includes existing fuels, coal, heavy fuel oil, diesel and Liquefied Natural Gas ("LNG") as well as forecasts of new fuels options that were included in the modeling, like biodiesel and renewable diesel. For the existing fuels, the LUMA Technical Consultant reviewed historic prices for fuel delivered to Puerto Rico, mainland fuel pricing, and transportation costs. LUMA also held conversations with New Fortress Energy, the company currently delivering LNG to the Island, to better understand their current LNG fuel delivery capabilities, near term plans and how they would address delivery to new locations across the island that are remote to their point of delivery in San Juan. The LUMA Technical Consultant researched the current production locations and pricing and spoke with potential suppliers of the two liquid biofuels considered in the 2025 IRP, biodiesel and renewable diesel. Based on this analysis, the LUMA Technical Consultant developed a base, or most likely forecast, for each of the fuels assessed by LUMA in the 2025 IRP. A high-cost version of the LNG fuel was also developed.

Q.13 Please describe how LUMA estimated annual emission pricing for the 2025 IRP.

A. Neither Puerto Rico's nor the U.S.'s federal regulatory agencies have established regulations for greenhouse gas ("GHG") emissions or the pricing and markets of associated credits or offsets. The absence of emission regulations that tax emissions or cap and trade type regulations that support a structured market-based pricing mechanism means that emissions from PREPA operations and the broader range of GHG emitters are not currently being monetized in a structured and generally accepted manner. Consequently, LUMA has not developed nor included any pricing related to emissions in its 2025 IRP analysis.

Q.14 Please describe how LUMA addressed the Renewable Portfolio Standard ("RPS") requirement to achieve a 100% renewable electric supply by 2050, particularly in light of the recent enactment of 2025 Act 1.

A. Before Act 1, it is my understanding that regulations required the Island to meet interim targets on the way to the 100% renewable target by 2050. 2025 Act 1 eliminated those interim targets but maintained the 2050 RPS goal. LUMA believes that it is impractical to assume that Puerto Rico can achieve a 100% renewable electric supply by 2050 without starting a transition to renewable resources well before 2050. The time required to solicit, contract, design, study, permit, build and interconnect renewable resources will take years.

To allow sufficient time to build and begin operation of the necessary renewable resources by 2050, LUMA and the Energy Bureau's Consultant discussed and agreed upon a 15-year ramp of RPS, starting in 2035 and rising with constant annual increases to 100% by 2050 ("Base Case RPS"). Two alternative RPS ramp rate assumptions were also selected for modeling and included in the supplemental scenarios: (1) starting in 2025 and rising with constant annual increases to 100% by 2050 ("Alternate

RPS 1”); and (2) starting in 2044 and rising with constant annual increases to 100% by 2050 (“Alternate RPS 2”). The three RPS alternatives were included in the May 13th Order and are shown in 2.

Table 2: Three RPS Alternatives

Year	Base Case RPS Constraint	Alternate RPS 1 Constraint	Alternate RPS 2 Constraint
2025	-	4.0%	-
2026	-	8.0%	-
2027	-	12.0%	-
2028	-	16.0%	-
2029	-	20.0%	-
2030	-	24.0%	-
2031	-	28.0%	-
2032	-	32.0%	-
2033	-	36.0%	-
2034	-	40.0%	-
2035	6.7%	44.0%	-
2036	13.3%	48.0%	-
2037	20.0%	52.0%	-
2038	26.7%	56.0%	-
2039	33.3%	60.0%	-
2040	40.0%	64.0%	-
2041	46.7%	68.0%	-
2042	53.3%	72.0%	-
2043	60.0%	76.0%	-
2044	66.7%	80.0%	16.7%
2045	73.3%	84.0%	33.3%
2046	80.0%	88.0%	50.0%
2047	86.7%	92.0%	66.7%
2048	93.3%	96.0%	83.3%
2049	100.0%	100.0%	100.0%
2050	100.0%	100.0%	100.0%

Q.15 Please describe what LUMA assumed for the weighted average cost of capital in the 2025 IRP for the PVRR calculations.

A. LUMA’s base case value for PREPA’s weighted average cost of capital (“WACC”) in the 2025 IRP is 8%. However, since PREPA is in a financial situation that makes it difficult to forecast a long-term cost of capital with any confidence, LUMA chose to assess what it believes to be a plausible range of potential WACC for the 2025 IRP. LUMA tested the results of the PVRR using WACC values of 4%, 5%, 6%, 7% and 8%. The results using the different WACC values had no impact on the relative ranking of the PVRR values for the different Resource Plans or for the selection of the Preferred Resource Portfolio ("PRP").

Q.16 Please describe what LUMA assumed for the annual debt limitation available to PREPA in the 2025 IRP.

A. LUMA did not include an annual debt limitation as a constraint to the analysis of resources. There was insufficient data available on the resolution of the existing PREPA debt and PREPA's future ability to issue new debt for LUMA to develop a justifiable assumption for a debt limitation.

Q.17 Please describe the assumptions and forecasts that LUMA judged would have a significant impact on the results of 2025 IRP.

A. Four factors that LUMA judged to have the likelihood of having a significant impact on the 2025 IRP results include:

1. Load Forecast;
2. Forecast of costs of new resources;
3. Forecast of current fuels in use and the forecast of biodiesel fuel; and
4. Assumption of the renewable energy contribution milestones that will be required prior to 2050.

Q.18 Did LUMA develop a range of possible scenarios based on the factors identified

above?

A. Yes. Using information gathered from stakeholder meetings and consultations with the Energy Bureau's consultant, LUMA assessed a range of scenarios for those four factors as well as other factors. The May 13th Order delineated a list of 12 primary scenarios that represent the most important combination of future characteristics to assess in the 2025 IRP and five supplemental scenarios that provide useful but lower priority analysis. The Energy Bureau ordered testimony and analysis of the 12 scenarios to be produced on October 17th and information regarding the five supplemental scenarios to be produced after the PSS®E filing on November 21, 2025.

LUMA included in the scenario characteristics load forecasts for a high case, base case (or most likely) and low case based on macroeconomic indicator data for the 4th percentile, 50th percentile and 96th percentile respectively. To address the impact of the cost variations on new resources and fuels costs, eight of the 12 primary scenarios include variations of capital and fuel costs. To address the renewable energy contributions that will be required, LUMA used the Base Case RPS Constraint, discussed above, for all 12 of the primary scenarios. The two additional RPS milestone assumptions are included in the supplemental scenarios, as described above. The single RPS assumption included in the 12 primary scenarios is viewed as a baseline or reference assumption that falls in the middle of the three RPS alternatives.

Q.19 Were there other assumptions or forecasts that LUMA judged could impact the results of the 2025 IRP?

A. LUMA considers the following five assumptions and forecasts to have a significant impact to the ability to implement the PRP.

1. Ability for the Energy Bureau to negotiate a contract that will extend the operation of the AES coal plant through 2032;
2. Ability for the Energy Bureau to negotiate a contract with EcoEléctrica that will extend the operation of that plant beyond the current 2032 end date;
3. Forecast of reliability and efficiency of the existing generation resources and their ability to continue operating;
4. Developers' ability to obtain the necessary land, permits, and financing, and to design, construct and operate the planned new resources and supply them with fuel as needed; and
5. LUMA's ability to obtain the necessary approvals and funding to construct and operate transmission and distribution facilities; network upgrades, and the generator specific grid upgrades required to enable the interconnection of new resources.

Q.20 Did LUMA include a range of scenarios for these five additional issues?

A. Due to a limitation of time allowed to model alternative scenarios for the 2025 IRP after the approval of the 2025 Act 1, LUMA did not include any variations of these issues in the 17 Scenarios (12 primary scenarios plus the five supplemental scenarios) included in the 2025 IRP.

IV. <u>RESOURCE PLAN DEVELOPMENT</u>

Q.21 What is your understanding of the requirements for the Resource Plan Development section of the 2025 IRP?

A. With respect to the Resource Plan Development section of the 2025 IRP, LUMA followed the requirements set forth in Section 2.03(H) of Regulation 9021. This section requires the 2025 IRP to identify in detail the mechanisms used by LUMA in developing its Resource Plans and an analysis of its Resource Plan development.

Q.22 What methodology did LUMA use to develop the resource plan alternatives?

A. LUMA describes the process used to develop candidate resource plans in Section 8 of the 2025 IRP. In summary, LUMA completed the 2025 IRP using the following major steps:

1. Worked with the stakeholders who participated in the Solutions for the Energy Transformation of Puerto Rico ("SETPR") meetings to establish the scenario characteristics and performance indicators that should form the basis of the 2025 IRP. The scenario characteristics defined during the SETPR meetings contributed to the development of the 12 primary scenarios. The performance indicators that resulted from the SETPR meetings were then used to define the scorecard used by LUMA to compare and assess candidate resource plans.
2. Developed the needed assumptions and forecasts to perform the resource modeling of candidate technologies. This step included LUMA deciding to divide Puerto Rico into eight distinct Transmission Planning Areas ("TPAs") for the 2025 IRP modeling. Each of the eight TPAs were comprised of geographically contiguous groups of municipalities. Modeling the island as eight TPAs enabled LUMA to incorporate unique characteristics of each TPA relative to its customer load and generation capabilities, wind and solar resource potential, existing transmission transfer capability, and current LNG fuel import capabilities.
3. Refined the scenario development considerations such that seven of the 12 primary scenarios were used to define seven core Resource Plans for which an optimized

Resource Plan was developed for each under the conditions of one of seven core scenarios. The remaining five scenarios were defined and used to assess the flexibility of the core Resource Plans to perform under a range of future load and cost conditions. LUMA terms this analysis a Flexibility Analysis and the resulting Resource Plans are called Flex Resource Plans. LUMA considered assessing candidate Resource Plans under a range of future conditions to be a critical element to developing a recommendation for a PRP.

4. Identified a short list of Resource Plans based on the results of the modeling of the 12 primary scenarios.
5. Performed additional sensitivity modeling on two shortlisted scenarios.
6. Incorporated the knowledge gained from the prior resource plan modeling and analysis to define and model a new Hybrid Resource Plan.
7. Based on the assessment of candidate Resource Plans as measured by their respective performance indicators in the scorecard, with the PVRR being the primary performance indicator, LUMA selected the Resource Plan Hybrid A as the PRP.

Q.23 Please describe the capacity expansion methodology LUMA used to develop the Resource Plans.

A. LUMA used the PLEXOS®, energy modeling software created by Energy Exemplar, as a tool to develop its candidate Resource Plans. At a high level, PLEXOS® simulates operation of the Island's electric system under different forecasted conditions, defined by the characteristics of the scenarios, that LUMA inputs into the model. For example, the model takes characteristics of existing resources (e.g., dispatchability, fuel type, size, rate at which it can increase output, forced outage rate and planned outage rate (i.e., the maintenance rate) and characteristics of potential new resources and determines an optimized mix of resources to meet forecasted energy and capacity needs at the lowest cost, considering required constraints (e.g., RPS compliance). The detailed PLEXOS® results allow for the calculation of the present value revenue requirements ("PVRR") for each plan that identify the total costs of that plan over the planning period which then allows for a cost comparison.

PLEXOS® contains multiple modular components that divide the modeling steps into modules. The results of each module are used as inputs to the next module. A brief description of the four modules of the PLEXOS® model is provided below:

1. Long Term Simulation module ("LT"): Performs a capacity expansion simulation over the long- term horizon. It evaluates the system and its needs over the entire horizon and attempts to minimize all types of costs (capital, fixed, variable and fuel) while meeting system load, reliability requirements and constraints, ultimately providing a plan of resource additions and retirements.
2. Projected Assessment of System Adequacy module ("PASA"): Develops schedules for planned outages while simultaneously minimizing the impact on system reliability. It calculates, simplified, high-level estimates of reliability statistics such as Loss of Load Expectation ("LOLE").
3. Middle Term Simulation module ("MT"): The MT horizon is usually set for one year. It performs an initial pass before the most granular module, the ST, to provide a starting point for the solution of battery optimization (e.g., charging and discharging schedules), coordination of annual limits, such as annual energy limits

on generators.

4. Short Term Simulation module ("ST"): The ST is the most granular of the PLEXOS® modules and is commonly known as a production cost model. For the LUMA 2025 IRP, a chronological hourly simulation was used to solve the unit commitment and dispatch problem, simulating actual system commitment and dispatch by LUMA operations.

Q.24 Did you find the PLEXOS® capacity expansion model results acceptable, and did you rely upon the results to determine the PRP?

A. Early in the 2025 IRP development process (i.e., in early 2024), LUMA found the resource plans produced by the PLEXOS® LT module, using the standard modeling process, did not produce resource plans with acceptable reliability. That is, LUMA found the results of the LT module consistently produced resource plans with unacceptably high expected unserved energy ("EUE") (i.e., EUE that exceed the target values for the corresponding years). LUMA worked with its Technical Consultant and Energy Exemplar to investigate the root cause and solution to the unacceptable EUE results being obtained.

LUMA found the LT module uses a derate method as a simplified approach to estimate the long-term impacts to unit availability due to planned and forced outages. For example, a 100 MW generator with a 10% forced outage rate and a planned outage rate that equates to 5% of the hours in a year, will be treated in the LT module as a perfect 85 MW generator with no planned or forced outage hours (i.e., 100 MW minus a 15% derate attributable to the combined effects of planned and forced outages). This simplified approach proved problematic for LUMA given the reality of the characteristics of the existing generating resources (i.e., many units experiencing unusually high forced outage rates).

The planned and forced outages calculated in the ST module are based on a more complex and realistic analysis performed in the PASA module. The PASA module schedules a specific time to perform planned maintenance, considering the planned maintenance needs of other units. The PASA module then uses a stochastic simulation to schedule a repeatable pattern of forced outage events. These schedules of planned and forced outages are then fed into the ST module that performs the hourly unit commitment and economic dispatch. Due to the different methods of addressing planned and forced outages, the generation addition and retirement plan provided by the LT module proved insufficient to deliver acceptable EUE results in the ST module in the typical single pass through the PLEXOS® modules.

The LT module's simplified method of deducting the planned and forced outage rates from the unit capacity to model the planned and forced outages, did not adequately account for the actual hourly impact of outages which can remove 100% of the capacity of a unit during an outage, not just the fraction of the capacity equal to the annual forced outage rate. In addition, the very high forced outage rates of the existing PREPA fleet of thermal generators were thought by LUMA's Technical Consultant and Energy Exemplar to be exacerbating the problem. The Puerto Rico thermal fleet of generators is projected in the 2025 IRP to average 25% forced outage rate (weighted by capacity), which is over three times higher than the NERC 7.8% national average in 2023 (from NERC State of Reliability report, June 2024).

In addition, LUMA and its Technical Consultant found the actual outage events, for both planned and forced outages, would shift in time from one modeling run to the next. This underlying shift in timing of outages made it difficult to isolate whether changes in results were due to difference in the scenario characteristics or due to a shifting outage schedule. LUMA and its Technical Consultant determined that it needed to develop a modeling approach that would result in acceptable EUE results and eliminate the variations in results that were due to differences in shifting outage schedules.

Q.25 How did LUMA address the model issues to define Resource Plans with acceptable EUE results?

A. To address these issues, a unique iterative feedback methodology was collaboratively developed and agreed to by LUMA, Energy Exemplar, and LUMA's Technical Consultant. The method involves an iterative feedback process that takes resulting post-2029, annual EUE values from a complete modeling run (i.e., through the full LT, PASA, MT, ST modules) and feeds them into subsequent modeling runs as fixed load adders at the specific hour and TPA location of the EUE events. These fixed load adders artificially increased the load, for purposes of expansion planning only, where the initial iteration did not provide sufficient capacity to avoid the EUE event. The feedback process serves to incent the capacity expansion planning module (i.e., the LT module), to build sufficient capacity to reduce EUE in the specific hours and locations of EUE events, in subsequent iterations.

To reduce the potential impact of the variation in outages between runs, the iterative method starts with an initial PLEXOS® run, LT through ST, used to determine the hourly outage schedule for individual generators, reflecting planned and forced outages. As the purpose of this foundational run is strictly to develop the outage schedule, for both planned and forced outages, for use in all subsequent simulations, only the schedule of outages is used from this run. The resulting outage schedule is used as an input in all subsequent runs, with corresponding adjustments to the outage modeling in all of the modules and all runs. By including the specific outage schedule in subsequent runs, the problems associated with the LT module's derate approximation for outages was resolved. Further, by holding the outages constant, there should be no variations in results, for example across scenarios, due to changes in generator outages.

Q.26 You noted that PLEXOS® develops Resource Plans under different forecasted conditions. Please explain what you mean by that.

A. LUMA calls the different forecasted conditions it uses to evaluate resource plans scenarios. Each scenario varies one or more key assumptions to identify different Resource Plans defined to be the least cost mix of resources for the defined conditions. For this filing, LUMA modeled 12 primary scenarios that vary load, cost, and other assumptions described in detail below. Following the results of those 12 scenario analyses, LUMA also performed separate modeling runs to assess the performance of two short-listed Resource Plans emanating from the 12 primary scenarios.

Q.27 What did the key assumptions for the scenarios include?

A. The key assumptions included:

1. **Load –**High, Base and Low versions of load forecasts were incorporated in the modeling. A single version of the forecasts for a number of load modifiers was also incorporated. The detailed discussion of the load and load modifier assumptions

are described in the testimony of LUMA witnesses Joseline Rivera and Michael Mount.

2. **Solar and Storage Capital Expenditures ("CapEx") –**The modeling included utility-scale solar photovoltaic ("UPV") and utility-scale battery energy storage system ("UBESS") capital expenditures under base assumptions and under a lower-cost forecast. Preliminary modeling results indicated that UPV was not being built with the base level cost forecasts so both LUMA and the Energy Bureau's Consultant determined there would be no benefit to including a higher UPV-cost variable in the 2025 IRP modeling. The detailed discussion of the UPV and UBESS cost assumptions are described in the testimony of LUMA witness Michael Mount.

3. **Gas Plant CapEx and Biodiesel Conversion Costs –**The modeling also included gas plant and biodiesel conversion costs under both a base cost and a high-cost assumption. LUMA chose to add this range of biodiesel costs in the modeling after preliminary analyses showed the availability and benefit of the resource in the model varies based on its expected cost. The detailed discussion of the gas plant and biodiesel conversion costs assumptions are described in the testimony of LUMA witness Michael Mount.

4. **Level of Distributed BESS ("DBESS") Control –** LUMA also considered variations on customer programs for controlled DBESS. LUMA's existing Customer Battery Energy Sharing ("CBES") program, intended for use during system emergencies, has shown that LUMA customers are interested in programs that provide incentives in exchange for using customer-owned batteries to benefit

the system. Based on this recent experience, LUMA and the Energy Bureau's Consultant developed two estimates for new DBESS Control programs that would enable dispatch of customer batteries for normal operations, not just during emergency conditions. The first estimate is a base level forecast which was used in all but one scenario, and the second is a high controlled DBESS forecast which will be included in the supplemental scenarios to be filed later in this process. The detailed discussion of the controlled DBESS program assumptions are described in the testimony of LUMA witness Michael Mount.

5. **Natural Gas Fuel Cost** - Fuel costs represent a significant portion of a utility's overall costs, and natural gas represents a significant component of the fuel powering existing and potential new resources. As such, LUMA, with the assistance of its Technical Consultant, developed base and high natural gas fuel cost assumptions for two existing LNG import locations in Puerto Rico as well as the costs of trucking LNG from one of the two import locations.

6. **Biodiesel Availability –** The results of preliminary modeling filed with the Energy Bureau on November 25, 2024 in LUMA's Motion to Submit First Interim 2025 IRP Filing, indicated that biodiesel may be a viable renewable fuel option for Puerto Rico's future energy supply. As such, LUMA and the Energy Bureau's Consultant determined that biodiesel should be included as a potential fuel choice, and one Scenario was defined to test the exclusion of biodiesel as a fuel option.

7. **Fixed Decisions –** There are a number of decisions that have been made by the Energy Bureau and through legislation to add and retire generation capacity and to add BESS capacity to Puerto Rico in the near future. LUMA considered these

decisions as "Fixed Decisions" and used them as common assumptions across each of the 12 primary scenarios and 4 of the 5 supplemental scenarios. The Fixed Decisions included 4,355 MW of generation additions listed in Table 3 below, and 1,401 MW of retirements lists in Table 4.

Table 3: Fixed Decision Additions

Energy Resource Technology	Total Additions 2025 to 2044 (MW)
Fixed Decision Generation	
PREPA HydroCo	38
Natural Gas Emergency Generators[1]	800
Energiza	478
New Genera Units	244
Solar	200
Tranche 1 Solar	739
Tranche 2 Solar	66
Fixed Decision Batteries	
ASAP Phase 1 BESS	190
ASAP Phase 2 BESS	425
New Genera Units	430
Regulation 4x25 BESS	100
Tranche 1 BESS	535
Tranche 2 BESS	60
Tranche 4 BESS	50
Total Fixed Decision Additions	**4,355**

Table 4: Fixed Decision Retirements

Energy Resource Technology	Total Retirements 2025 to 2044 (MW)
Fixed Decision Retirements	
Coal Units	454
Diesel Peaking Units	147
Natural Gas Emergency Generators	800

[1] The 800 MW of Emergency Generators are forecasted to be installed in 2025 and 2026 and then removed from the system by 2029 following the commercial operation of the Energiza combined cycle unit. The removal of the Emergency Generators is treated as a retirement in the modeling software.

Energy Resource Technology	Total Retirements 2025 to 2044 (MW)
Total Fixed Decision Additions	**1,401**

8. **RPS –As noted above, LUMA modeled three alternatives for RPS compliance consisting of:**

    i. Base Case RPS - Starting with an RPS of 0% at the beginning of 2035 and ramping to 100% by 2050. This was considered the base case assumption and was included in all 12 primary scenarios.

    ii. Alternative RPS 1 - Starting with an RPS of 0% at the beginning of 2025 and ramping to 100% by 2050. This was considered the Alternative RPS 1 - assumption and will be included in a later filing in Supplemental Scenario 16.

    iii. Alternative RPS 2 - Starting with an RPS of 0% at the beginning of 2044 and ramping to 100% by 2050. This was considered Alternative RPS 2 assumption and will be included in a later filing in Supplemental Scenario 17.

Table 5 below identifies the criteria associated with each of the 12 primary scenarios.

Table 5: Twelve Primary Scenarios

Scenario	Scenario Description	Load	PV & UBESS CapEx	Natural Gas Plant CapEx + Bio Conversion Costs[2]	Level of DBESS Control	LNG Fuel Cost	Include Biodiesel	Fixed Decisions	Resulting Resource Plan
1	Base assumptions for all variables	Base	Base	Base	Base	Base	Yes	Base	Core Resource Plan A
2	High load conditions with base assumptions for other variables	High	Base	Base	Base	Base	Yes	Base	Core Resource Plan B
3	Base load with high natural gas plant capital costs	Base	Base	High	Base	Base	Yes	Base	Core Resource Plan C
4	Base load with low renewable energy capital costs and high fossil capital costs	Base	Low	High	Base	Base	Yes	Base	Core Resource Plan D
5	Base load with high natural gas fuel costs	Base	Base	Base	Base	High	Yes	Base	Core Resource Plan E
6	Base load with high natural gas fuel costs and high natural gas plant capital costs	Base	Base	High	Base	High	Yes	Base	Core Resource Plan F
7	Flex Run for Resource Plan B run under Scenario 1 conditions	Base	Base	Base	Base	Base	Yes	Base	Flex Resource Plan 1.B
8	Flex Run Resource Plan A run under Scenario 2 conditions	High	Base	Base	Base	Base	Yes	Base	Flex Resource Plan 2.A
9	Flex Run for Resource Plan A run under Low Load conditions	Low	Base	Base	Base	Base	Yes	Base	Flex Resource Plan Low.A
10	Flex Run of Resource Plan A run under Stress conditions	High	Base	High	Base	Base	Yes	Base	Resource Plan Stress.A
11	Flex Run of Resource Plan B run under Stress conditions	High	Base	High	Base	Base	Yes	Base	Resource Plan Stress.B
12	Base assumptions for all variables but biodiesel is unavailable	Base	Base	Base	Base	Base	No	Base	Core Resource Plan H

Q.28 What mechanisms and criteria did LUMA apply in selecting its Preferred Resource Plan from the set of alternatives?

A. As a first step, LUMA used PLEXOS® to develop the following 12 Resource Plans

[2] The costs of Biodiesel conversion was not included in the characteristic of the 12 scenarios in the May 13, 2025, Energy Bureau order. LUMA chose to add the cost of biodiesel conversion to this characteristic since LUMA judged it be consistent with the expressed intent of the Energy Bureau's Consultant's suggestion for this characteristic.

based on the characteristics described by the 12 primary scenarios:

1. Core Resource Plan A based on the optimized results for Scenario 1
2. Core Resource Plan B based on the optimized results for Scenario 2
3. Core Resource Plans C based on the optimized results for Scenario 3
4. Core Resource Plan D based on the optimized results for Scenario 4
5. Core Resource Plan E based on the optimized results for Scenario 5
6. Core Resource Plan F based on the optimized results for Scenario 6
7. Flex Resource Plan 1.B based on a Flexibility Run of Resource Plan B under Scenario 1, base load and most likely conditions (referred to as Scenario 7)
8. Flex Resource Plan 2.A based on a Flexibility Run of Resource Plan A under Scenario 2, high load conditions (referred to as Scenario 8)
9. Flex Resource Plan Low.A based on a Flexibility Run of Resource Plan A under low load conditions (referred to as Scenario 9)
10. Flex Resource Plan Stress.A based on a Flexibility Run of Resource Plan A under Stress conditions of both high load and high cost (referred to as Scenario 10)
11. Flex Resource Plan Stress.B based on a Flexibility Run of Resource Plan B run under Stress conditions of both high load and high cost (referred to as Scenario 11)
12. Core Resource Plan H based on the optimized results for Scenario 12

Once the core Resource Plans were developed, with acceptable EUE, RPS and other reliability targets, the flexibility analysis focused on ascertaining how Resource Plans A, B, and H performed under varying conditions (e.g., different load forecasts, different cost assumptions). Specifically, Resource Plans A and B were assessed under different scenarios, including those that varied load and cost assumptions. Resource

Plans A and H were then further assessed using additional sensitivity analysis that changed the ASAP Phase 2 battery additions from fixed to optional additions. The results of Resource Plans C, D, E and F were developed based upon scenarios that used different capital and fuel costs assumptions than Scenario 1 but were all still modeled under base load conditions. Resource Plans C, D, E and F proved to have higher PVRR costs than Resource Plan A under the same base load conditions, as such, they were not tested under different load and cost assumptions utilized in the Flexibility Analysis since they would have been expected to continue to be higher cost alternatives that Resource Plan A for each Scenarios tested in the Flexibility Analysis. Once the Resource Plans were created to satisfy the RPS, EUE and other reliability targets, the Resource Plans were assessed by comparing their resulting 20-year PVRRs as well as the other performance indicators in the Scorecard.

Q.29 Which key differences distinguish the Preferred Resource Plan from other resource plan alternatives?

A. The Preferred Resource Plan ("PRP"), also referred to as Resource Plan Hybrid A (or Hybrid A), is based on modifications to Resource Plan A. Hybrid A relies on natural gas fueled thermal generation in the early years of the study. Once the annual RPS requirements start in 2035, biodiesel is added in increasing amounts over time by converting existing generation to utilize a blend of biodiesel and diesel and adding new generation which is also fueled by a blend of biodiesel and diesel. The percentage of biodiesel in the fuel blend increases over time as the RPS increases toward the ultimate target of 100% by 2050. Beyond the solar generation included in the Fixed Decisions, no new solar or wind generation is added in the PRP. Resource Plan B is similar to

Hybrid A but includes more generation as it is derived from a high load scenario. Resource Plan H was developed under the assumption that biodiesel is not an option, which results in onshore wind (i.e., land-based wind), offshore wind and solar being added, in part to satisfy the RPS. Resource Plan H also includes LNG fueled thermal generation additions through the late 2030's even though there would be no plan for its regular use after 2050 when Puerto Rico target is attained of 100% RPS.

The results of modeling the 12 primary scenarios showed Resource Plan A and H to be the two lowest cost scenarios under base load conditions and be very close in cost, as measured by their PVRR. As a reminder, Resource Plan A incorporated all the base or most likely assumptions; Resource Plan H used all the same assumptions accept that biodiesel was not included as a fuel option. LUMA used a multi-pronged approach to further analyze and compare these two Resource Plans. In the 12 primary scenarios, the accelerated storage addition program ("ASAP") Phase 2 BESS projects had been included as a Fixed Decision. More recent information made available to LUMA indicated that ASAP Phase 2 BESS could be considered as optional, rather than fixed, as the projects are not as advanced as previously anticipated. As such, LUMA chose to perform a sensitivity run for Resource Plans A and H by changing the ASAP Phase 2 BESS projects to optional additions instead of fixed additions. In results of both A and H, the ASAP Phase 2 battery projects were changed from fixed decisions with a planned installation of 2026, to installations dates and capacity based on need. In addition, LUMA chose to incorporate in this additional modeling a small correction to the battery efficiencies which had been identified based on review of the modeling results. The combined changes delayed the installations of the ASAP Phase

2 batteries which resulted in a lower PVRR for both Resource Plans A and H. However, the resulting PVRR savings for the Resource Plan A with the ASAP Phase 2 batteries as optional additions and the battery efficiency correction was greater for Resource Plan A than for H with the same changes, increasing the PVRR gap between the two Resource Plans, in favor of Resource Plan A so that Resource Plan A provided the lower cost alternative and the least cost option of all Resource Plans.

Building upon the results of the prior modeling, LUMA chose to create a new Resource Plan Hybrid A, with the assumption that the ASAP, Phase 2 Battery additions as optional decisions and corrected the corrected battery efficiency and LUMA selected Resource Plan Hybrid A as the PRP. Since the PRP relies on transition of generators from natural gas to biodiesel, it offers the flexibility of being able to adjust the timing and pace of transition to renewable fuels as desired. The PRP adds the largest capacity new energy resources to either San Juan or Costa Sur where there is existing fuel delivery infrastructure and existing transmission interconnections to the legacy generators (i.e., brownfield sites) which LUMA believes provides an efficient use of existing assets and infrastructure.

V. CAVEATS AND LIMITATIONS

Q.30 What is your understanding of the requirements for the Caveats and Limitations section of the 2025 IRP?

A. With respect to the Caveats and Limitations section of the 2025 IRP, LUMA followed the requirements set forth in Section 2.03(I) of Regulation 9021. This section requires the 2025 IRP to include a list of key caveats and limitations of LUMA's analysis for its PRP.

Did LUMA provide a list of key caveats and limitations associated with its 2025 IRP analysis?

A. Yes. As described in Section 9 of the report, LUMA has identified a few caveats and limitations in its modeling analyses.

The first caveat relates to the physical placement of LNG-fueled resources. For modeling purposes, LUMA made assumptions regarding the LNG infrastructure in Puerto Rico, which had implications for the location of potential new combined cycle and simple cycle generation.

The existing generation fleet includes natural gas-fired generation at San Juan and Costa Sur, which is served by LNG import infrastructure. Additional gas-fired generation is located at Palo Seco. Fuel delivery for Palo Seco is handled by trucking LNG from San Juan and storing it onsite at Palo Seco until it is needed. For potential new generation resources, LUMA considered various fuel delivery options. For new generation located near existing generation at San Juan and Costa Sur (i.e., in the same TPAs), the existing LNG infrastructure was assumed to be capable of supplying the requisite fuel quantities as is or with limited investment. However, if new combined cycle generation was located elsewhere, the fuel would likely require expanding the existing gas delivery infrastructure (i.e., new pipelines to existing or new ports) or trucking the fuel to an onsite storage facility (like Palo Seco). Given the expected quantity of fuel needed for a combined cycle facility (which are both larger and typically operated at higher capacity factors), and given the uncertainty surrounding the ability to gain regulatory approvals for the costs and construction of new gas pipeline, port and storage facilities, LUMA limited the location of new combined cycle power plants to the San Juan and Costa Sur TPAs that possess existing LNG import facilities.

Peaking, or simple cycle, plants generally operate at lower capacity factors and require lower quantities of fuel, per year, than combined cycle plants. Therefore, delivering fuel to simple cycle plants by truck is expected to require fewer truck deliveries per year than a combined cycle generator. Hence, in this 2025 IRP, simple cycle plants are allowed to be built in any location (TPA). For those that are not in San Juan or Costa Sur, an additional cost is included in the model to reflect the cost of fuel delivery from San Juan to the generator.

The second caveat relates to the amount of hydroelectric generation facilities included in the model. In June 2021, an independent consultant completed a report assessing PREPA's generation facilities entitled, "Feasibility Study for Improvements to Hydro Electric System." Based on that report, PREPA HydroCo developed a plan to refurbish some of its hydroelectric facilities, which was approved by the Energy Bureau in Docket NEPR-MI-2021-0002.

The existing hydro generation capacity assumed in the resource modeling model was 4 MW. The refurbishment plan identified the potential for 90 to 120 MW of hydroelectric capacity. To date, the refurbishments have not been completed, and LUMA believes the timing and size of potential refurbishments is uncertain. LUMA conservatively assumed that 38 MW of additional hydro generation would result from the refurbishments, for a total of 42 MW of hydro generation available from 2026 onwards. Given this limit in the model, and the fact that the refurbishments are not yet complete, the actual amount of hydro generation may be more or less than that included in the model.

In August of 2025, as LUMA was reviewing results of the 12 primary scenarios, an error in the round-trip efficiencies of all the BESS, utility scale BESS and DBESS, was discovered. The distributed scale BESS had been set to 100% and the utility scale BESS to 90% round trip efficiency. The intention had been to use an 85% round trip efficiency assumption for all BESS, consistent with NREL's 2024 Annual Technology Baseline assessment. As there was insufficient time to redo all the analysis with this correction, LUMA performed some tests to measure the impact of this error. The efficiencies were changed to 85% for Scenario 1 Core Resource Plan A (most likely conditions) and for Scenario 12 Resource Plan H (no biodiesel) and simulated again. The difference between the PVRR of the two Resource Plans, A and H, with the battery efficiency correction compared to the difference for both resource plans without the correction was only $1.9M, or 0.005% of the PVRR. As a result, the correction was judged to be immaterial to the PVRR results and the relative ranking of the resource plan performance. Where the correction is included, it is specified as included in the report, for example, in the PRP.

A third caveat relates to the ASAP Phase 2 BESS projects. As noted previously, the modeling for the 12 primary scenarios originally included the ASAP Phase 2 BESS projects as Fixed Decisions with commercial operation dates ("CODs") by the end of 2026. Given that those projects are not as far along as has been previously anticipated, LUMA chose to perform some sensitivities where all of the ASAP Phase 2 BESS projects were included as options available for PLEXOS® to select, instead of fixed decisions. Specifically, LUMA allowed the model to change the CODs or reject the projects entirely, on an individual project-by-project basis. Resource Plan A and Resource Plan H were simulated with this change. The results showed that all of the ASAP Phase 2 BESS projects were ultimately selected by PLEXOS®, but individual projects were typically delayed by five or more years from the original COD. It was found that including the ASAP Phase 2 BESS projects as optional reduces the PVRR for both Resource Plan A and H in comparison to including those projects as fixed. The report specifies which results have ASAP Phase 2 BESS as optional (i.e., for the PRP).

Lastly, LUMA's caveats and limitations include correction of a small error related to Controlled DBESS. As noted in the discussion of the Assumptions and Forecasts section above, LUMA recently became aware of a small error in the capacity of Controlled DBESS affecting the early years, 2025 to 2027. As the incorrect inputs are in the first three years of the study period, during which time PLEXOS® does not have the flexibility to make changes (e.g., add new generation or transmission, retire generation), the numbers are small relative to the size of the system. The twelve Primary Scenarios were checked to ensure they all had the same issue, and steps were taken to ensure the issue persists (i.e., consistency). This ensures that comparisons between the twelve Scenarios are made correctly. In other words, the relative differences between Scenarios should not be impacted by this issue. As noted above, LUMA corrected this issue in its PRP, Resource Plan Hybrid A.

VI. ACTION PLAN

Q.31 What is your understanding of the requirements for the Action Plan section of the 2025 IRP?

A. Section 2.03(K) of Regulation 9021 addresses the Action Plan for the 2025 IRP.

This section requires the 2025 IRP to include an Action Plan specifying implementation actions that need to be performed during the first five years of the Planning Period as a result of the PRP.

Q.32 Please provide a brief overview of LUMA's proposed Action Plan.

A. The Action Plan covers the years 2025 through 2030 and includes recommendations divided into broad categories: (1) energy resource additions and retirements; (2) transmission expansion; and (3) detailed recommendations with respect to distributed generation, Fixed Decisions, customer programs, and new gas generation. Details regarding all of the recommendations are available in Section 10 of the 2025 IRP Report.

VII. TRANSMISSION & DISTRIBUTION IMPLICATIONS OF THE PREFERRED RESOURCE PLAN

Q.33 What is your understanding of the requirements for the portion of the Transmission & Distribution (T&D) System Planning section of the 2025 IRP that you are sponsoring?

A. With respect to the T&D System section of the 2025 IRP Report, LUMA followed the requirements set forth in Section 2.03(J)(2)(e) of Regulation 9021. This section requires the 2025 IRP to document the T&D implications of the PRP, including assessing if the PRP requires incremental T&D mitigation or changes.

Q.34 Are there any other legal requirements for LUMA in submitting its documentation of the implications to the T&D system of the PRP?

A. While there are numerous requirements outlined in Regulation 9021 associated with the description and analysis of the T&D system, requirements associated with the

Assumptions and Forecasts section of the 2025 IRP Report are particularly pertinent to the subject of this testimony. LUMA followed the requirements set forth in Section 2.03(G) of Regulation 9021, which requires the 2025 IRP to describe the modeling assumptions and inputs incorporated into LUMA's forecasting model, and the requirements in the May 13, 2025 Resolution and Order in this proceeding ("May 13th Order"), which specified certain assumptions.

Q.35 What assumptions and forecasts go into T&D system modeling of the PRP?

A. The primary assumptions and forecasts include load forecasts, resource and cost assumptions related to the resource modeling results that contributed to the selection of the PRP, and planned modifications to the T&D system unrelated to the PRP. Most of these forecasts and assumptions are discussed in other sections of the 2025 IRP Report, as shown in Table 1 below.

Table 1: Summary of 2025 IRP Report Sections Discussing Assumptions and Forecasts and Their Respective Witnesses

Topic	2025 IRP Section	Sponsoring LUMA Witness
Base Load Forecast	Section 3	Joseline Estrada Rivera
High and Low Load and Load Modifier Forecasts	Section 3	Michael Mount
Existing Resources	Section 4	Raphael Gignac
New Resource Options	Section 6	Michael Mount
Fuel & Other General Assumptions and Forecasts	Section 7	Ajit Kulkarni
Resource Plan Development	Section 8	Ajit Kulkarni
Transmission & Distribution System	Appendix 1	Daniel Haughton

Q.36 Please provide an overview of the analysis performed by LUMA related to the PRP implications to the T&D System.

A. In this testimony, I focus on LUMA's analysis of PRP implications on the impacts to the transmission system. LUMA witness Daniel Haughton addresses LUMA's analysis of PRP implications on to the distribution system. The purpose of my analysis was to define system upgrades that may be needed to the transmission system to enable the planned additions and retirements identified in the PRP.

Q.37 Please describe the modeling methods LUMA uses to assess the implication of the PRP on the transmission system.

A. LUMA assessed the implications of the PRP on the transmission system using two different modeling methods: (1) a high-level assessment of the current capability and future needs of the transmission system's ability to transfer power between the eight transmission planning areas (TPAs) using the PLEXOS® resource model; and (2) a more detailed assessment applying the results of the high-level assessment in PSS®E modeling software.

Q.38 Please describe the high-level assessment LUMA performed.

A. As discussed more fully in Sections 7.3.5 and 8.2.3 of the 2025 IRP report, LUMA chose to perform the resource modeling of Puerto Rico, using PLEXOS®, as a zonal model with eight different geographic regions of the island, which LUMA refers to as TPAs. For the resource modeling, each TPA includes the portion of the island's load residing within the TPA, and the generation located within the geographic boundaries of the TPA. The eight TPAs are connected, by thirteen different bidirectional links, each of which has characteristics such as capacity and losses, which can differ in one direction as opposed to the other (e.g., different characteristics northbound compared to southbound). LUMA completed preliminary transmission analyses prior to beginning the resource modeling to develop a high-level estimate of the bi-directional transfer capacity of each of the links, based on the underlying grid. LUMA also developed high-level estimates of costs to upgrade each of the thirteen different links connecting the eight TPAs, based on the addition of 230 kV capacity using the existing right of ways between the TPAs. The cost and capacity estimates included a high-level consideration of the existing routes/right of ways (ROWs) and existing 230kV facilities connecting the TPAs, and are high-level planning estimates designed to represent average configurations and associated costs for only building additional 230 kV line capacity. LUMA did not perform detailed project level studies (i.e., no survey crews were sent in the field to obtain information), but did consider some possible routes, terrain and the impact to existing facilities (e.g., consideration of the routes, terrain and towers between Ponce ES and Ponce OE).

To develop resource plans, the resource modeling software monitors the movement of power from energy resources to loads on an hourly basis, including the power transfer between TPAs, and across transmission links, to serve loads. The load within a TPA can be served by generation within the TPA or by power transfers across the transmission links from neighboring TPAs. When transmission links become congested and impact the ability to serve load, the resource model can then choose the most economic choice between the following options:

1. Change the generation commitment and dispatch to subject to transmission constraints and serve the load;
2. Build generation within the TPA, or in another TPA that is connected by a link with available capacity to the load;

3. Upgrade the transmission links to increase their transfer capacity; or
4. A combination of the options above.

These constraints and options are evaluated at an hourly level, across the 20-plus year study horizon. Using this simplified representation of the island's transmission capability and power flow, PLEXOS® yields a least cost plan that endeavors to co-optimize energy resources and required transmission upgrades. The output results in a detailed list of resource additions and retirements, hourly loads, system (generation and transmission) unit specific hourly commitment and dispatch, as well as a list of which transmission links required upgrades to enable the resource plan. While this representation and assessment of the transmission system in the resource modeling software is essential in balancing the economics of resource costs and location versus transmission limitations and costs of upgrades, it was necessarily simplified, from a transmission perspective. This initial analysis of the transmission limitations and needs, using the resource modeling software, provided a simplified assessment of the static transfer capacity between TPAs.

On a transmission network such as Puerto Rico's, power does not flow along a single path, such as the path represented by the transmission links used in the resource modeling software. Physics dictate that power flow under real world conditions involves multiple paths that may travel through many transmission infrastructure elements that may be geographically and electrically remote from the transmission conductors physically between two TPAs (e.g., parallel flow, loop flow, line impedances, equipment settings). After the PRP was developed, LUMA employed a second methodology to perform a more detailed assessment of transmission impacts.

Q.39 Please provide an overview of the more detailed assessment LUMA performed.

A. LUMA applied the outputs from the high-level assessment to the PSS®E modeling software to perform a steady state assessment of the transmission system for multiple years and multiple load points within each of the years (e.g., snapshots).

Q.40 What does PSS®E modeling software do?

A. PSS®E allows the modeling of the transmission system, which in this study used power flows to check for thermal and voltage violations under base and contingency conditions.

Q.41 Please explain how LUMA conducted the PSS®E modeling analysis.

A. To test the transmission system impacts, LUMA used the high-load conditions assumed in Scenario 8 of its resource analysis. LUMA chose to use the high-load forecast conditions since the high-load conditions were judged to be representative of the extreme load conditions used for T&D system planning. For the analysis of the PRP implications, LUMA also studied the transmission system in two separate years: 2026 and 2034, under two load conditions as these represent likely stress conditions for the transmission system. The first load condition chosen for analysis was the forecasted date and hour of the peak annual solar output for each respective year. This is a distinct condition when, for example, non-solar generation would be backed down to accommodate the solar, and batteries would tend to be charging, which would result in a different set of flows on the grid. The second load condition chosen for analysis was the highest load point for each respective year, which might result in different stress conditions on the transmission grid.

The year 2026 was chosen as an early year in the 2025 IRP study horizon that still needed to enable substantial supply resource additions from the fixed decision projects planned for operation by 2026. The year 2034 was selected since it met both the 10-year transmission planning horizon required by the Regulation 9021 and included most of the new utility scale resource additions identified in the PRP. The analysis utilized the detailed hourly customer loads, generation dispatch, and battery charging and discharging at the four snapshot hours selected (two for 2026 and two for 2034), from the PLEXOS® solution. PSS®E does not perform a chronological simulation, model generation in detail, etc. as PLEXOS® does. The combined use of PLEXOS® and PSS®E provided extensive modeling of the power system (load, transmission, generation).

The PSS®E analysis performed a load flow analysis, driven by physics that was used to identify thermal and voltage violations for individual transmission infrastructure elements under N-1 and N-1-1,[3] for which mitigation projects were then identified that resolved the violations. Finally, associated cost estimates for the mitigation projects were developed.

LUMA intended for the more detailed transmission analysis resulting from the second method, using PSS®E, to replace the transmission portion of the results from PLEXOS®.

Q.42 Why did LUMA choose to use two different methods to analyze the transmission system?

A. The difference in the time required to complete each of the two methods was the

[3] "N-1" refers to a hypothetical loss of a single transmission line, generating resource, substation breaker, transformer or busbar and the testing of whether the loss of that element results in consequential load loss. "N-1-1" refers to the loss of a single element followed by the loss of a second element after the system has attempted to stabilize and operators have made adjustments.

principal reason LUMA chose to employ two different methods. The first method, using the resource modeling software PLEXOS®, enabled the modeling of the transmission impacts of each candidate resource plan simultaneously with modeling the energy resources. This approach evaluates a variety of options in significant detail (hourly for 20+ years with technical characteristics and constraints of load and generation), which takes days of computer time for a single run. This first method provided a high-level, co-optimized analysis of the energy resources and the transmission system upgrades, across the 17 scenarios. The first method is useful to incent the resource model software to include the constraints and impacts to the transmission system as part of its definition of energy resource plans. The second method was used to define a refined transmission analysis solely for the PRP, for certain snapshots in time, and provided a more detailed determination of the transmission impact and costs of the PRP.

Q.43 What were the results of the first method employing the resource modeling software?

A. For the PRP, under the high-load forecast conditions, the resource modeling software identified the need for transfer capacity upgrades in 2030 and 2033 on the five 230 kV transmission links listed below:

Table 6: Transmission Upgrades from Resource Modeling Software

Transmission Link	2030 Addition	2033 Addition
Carolina to San Juan	X	
Mayagüez to Ponce OE	X	
Ponce ES to Caguas	X	
Ponce OE to Arecibo	X	

Transmission Link	2030 Addition	2033 Addition
Bayamón to Arecibo		X

The combined cost of these upgrades was estimated at \$312M contribution to the total PVRR of the PRP.

Q.44 What were the results of the second method employing the transmission modeling software?

A. For the PRP, under the high-load forecast conditions, the transmission modeling software identified the need for solutions to address the voltage and thermal violations on the transmission system under N-1 and N-1-1 contingency scenarios that were estimated to cost, in terms of a PVRR between \$599M on the low end to \$1.67B on the high end. The lower range costs assume no transmission line structures will need to be rebuilt for the reconducting projects identified in the solutions. The upper range cost estimates assume that the transmission line structures will need to be replaced as part of reconductoring, to their existing condition. These numbers replace the transmission cost numbers from the first method. Hence the PVRR of the PRP increases from the \$34.4B to a range of \$34.6B to \$35.8B based on the combined PLEXOS® analysis together with the PSS®E analysis for the transmission implications of the PRP.

Q.45 Does this conclude your direct testimony?

A. Yes

ATTESTATION

Affiant, Ajit Kulkarni, being first duly sworn, states the following:

The prepared Pre-Filed Direct Testimony and the portions of the 2025 IRP filing I am sponsoring constitute my direct testimony in the above-styled case before the Puerto Rico Energy Bureau. I would give the answers set forth in the Direct Testimony if asked the questions that are included in the Pre-Filed Direct Testimony. I further state that the facts and statements provided herein are my direct testimony and, to the best of my knowledge, are true and correct.

Ajit Y. Kulkarni

Ajit Kulkarni

State of Florida
County of Leon

Affidavit No. ___

Acknowledged and subscribed before me by Ajit Kulkarni, in his capacity as Grid Modernization Manager of LUMA Energy ServCo, LLC, of legal age, married, and resident of Davis, California, who is personally known to me. located in Davis, California this 21st day of November, 2025 having appeared by means of online notarization and provided a drivers license as identification.

Notary Public
MELISSA K. GARNER

NOTARY PUBLIC STATE OF FLORIDA
MELISSA K. GARNER
Notary Public - State of Florida
Commission # HH 356421
My Comm. Expires Mar 28, 2027

Completed Via Remote Online Notarization Using
2-way Audio / Video Technology