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

IN RE: REVIEW OF THE PUERTO RICO ELECTRIC POWER AUTHORITY'S 10-YEAR INFRASTRUCTURE PLAN – DECEMBER 2020	**CASE NO.:** NEPR-MI-2021-0002 **SUBJECT:** Resolution and Order for Request for Approval to Submit to COR3 and FEMA the SOW to Convert San Juan Units 7 & 9 to Operate with Natural Gas as Primary Fuel.

RESOLUTION AND ORDER

I. Relevant Background

On January 14, 2026, Genera PR LLC ("Genera") filed before the Energy Bureau of the Puerto Rico Public Service Regulatory Board ("Energy Bureau") a request seeking approval of the proposed scope of work related to the conversion of San Juan thermal generation units #7 and #9[1] to operate with natural gas as the primary fuel, while maintaining Fuel Oil No. 6 (also known as Bunker C, "FO6") as a backup fuel ("San Juan Units 7 and 9 Proposed Fuel Swap").[2] The requested approval is intended to authorize the submission of such Scope of Work to the Federal Emergency Management Agency ("FEMA") under the Public Assistance Program Alternative Procedures authorized pursuant to Section 428 of the Robert T. Stafford Disaster Relief and Emergency Assistance Act ("Section 428"). As part of the January 14 Motion, Genera included, as Attachment A, the *San Juan Plant Units 7 & 9 Project ISOW* ("SOW") and, as Attachment B, the *Estimated Average Monthly Savings*.

Subsequently, by communication dated January 27, 2026, representatives of Genera requested that an informal technical meeting be held with representatives of the Energy Bureau, including its staff, consultants, and/or Commissioners, for the purpose of discussing certain technical and operational aspects associated with the Proposed Fuel Swaps. After a preliminary review, the Energy Bureau delegated to members of its staff and consultants the initial evaluation of the matters to be discussed during the requested technical meeting. The meeting was scheduled for February 3, 2026, as proposed by Genera.[3]

To prepare for the meeting, on January 29, 2026, the Energy Bureau's staff issued a communication requesting that Genera provide certain information and submit clarifying responses regarding the Palo Seco Units 3 and 4 Proposed Fuel Swap ("Palo Seco ROI-1"). Given the proximity of the proposed meeting date, it was anticipated that the requested information might not be fully available before the meeting. Accordingly, and to advance the clarification process and promoting administrative efficiency, the Energy Bureau determined that the meeting should proceed as scheduled so the parties could discuss the available information and identify any outstanding issues requiring further clarification.

The meeting was held on February 3, 2026, and was attended by several representatives of the Energy Bureau ("February 3 Meeting"). Given that the approach proposed for both

[1] Individually, "San Juan Unit 7" and "San Juan Unit 9," and collectively, "San Juan Units 7 and 9".

[2] *See Motion Requesting Leave to Submit for Approval to COR3 and FEMA the SOW to Convert San Juan Units 7 & 9 to Operate with Natural Gas as Primary Fuel* filed by Genera on January 14, 2026 ("January 14 Motion"). On January 9, 2026, Genera filed before the Energy Bureau a similar request seeking approval for the conversion of Palo Seco thermal generation units #3 y #4 to operate with natural gas as the primary fuel, while maintaining FO6 as a backup fuel ("Palo Seco Units 3 and 4 Proposed Fuel Swap"). Together the San Juan Unit 7 and 9 Proposed Fuel Swap and the Palo Seco Units 3 and 4 Proposed Fuel Swap are referred to as the "Proposed Fuel Swaps").

[3] It was clarified that any statements, positions, or comments made by personnel attending or participating in such informal technical meetings on behalf of the Energy Bureau, including Commissioners, if any participate, shall not be construed as final decisions of the Energy Bureau. It was further emphasized that final decisions may only be adopted by the Commissioners acting in accordance with the applicable legal and statutory provisions governing the Energy Bureau's decision-making authority.

conversions (Palo Seco Units 3 and 4 and San Juan Units 7 and 9) was substantially similar, both requests were discussed during the same meeting. During the meeting, Genera provided additional explanations regarding certain aspects of the proposed projects and informed the Energy Bureau that certain circumstances had changed after the filing of the Proposed Fuel Swaps. Genera indicated that modifications to its previously submitted proposals would be necessary for the projects to be evaluated under current conditions, noting that some of these matters remain under internal evaluation. Also, during the meeting, Genera provided to the Energy Bureau copy of the *No. 6 Fuel Oil Purchase Contract Aguirre, Costa Sur, San Juan and Palo Seco Steam Plants*, Contract Number 110832 ("FO6 Purchase Contract");[4] draft responses to certain requests for information related to the Palo Seco Units 3 and 4 Proposed Fuel Swap; and photographs of certain equipment identified as stored at the Palo Seco and San Juan facilities that could be utilized in connection with the Proposed Fuel Swaps.

On February 12, 2026, Genera submitted to the Energy Bureau an updated request for the San Juan Units 7 and 9 fuel swap ("Updated San Juan Units 7 and 9 Proposed Fuel Swap"). The Updated San Juan Units 7 and 9 Proposed Fuel Swap included, as Attachment A, a *Revised SOW of San Juan Gasification Project* ("Updated SOW") and, as Attachment B, a *FEMA Funds Reapportionment* ("Funds Reapportionment").[5]

On February 26, 2026, Genera submitted technical data to the Energy Bureau regarding the Updated San Juan Units 7 and 9 Proposed Fuel Swap.[6] Through the February 26 Motion, Genera provides as Exhibit 2 the responses to Palo Seco ROI-1, adapting them to the Updated Fuel Swap for San Juan Units 7 and 9 ("San Juan ROI-1 Responses").[7] Specifically, the February 26 Motion included as Exhibit, the following documents:

Exhibit 1 - Request for Information Re: Genera's January 9, 2026 Motion (Case No. NEPR-MI-2021-0002) Palo Seco Units 3 and 4 Fuel Swap Request

Exhibit 2 - Technical Data Submission (Responses to Requests for Information, Re:).

Attachment A of Exhibit 2 – PREPA San Juan Title V Permit, PFE-TV-4911-65-1196-0016 ("Title V Operating Permit")

Attachment B of Exhibit 2 – Cost Savings Excel File

On March 9, 2026, the Energy Bureau requested that Genera provide certain additional clarifications and pertinent documentation to complete the evaluation of the San Juan Units 7 and 9 Proposed Fuel Swap ("San Juan ROI-2"). On the same date, Genera submitted a letter containing their responses to the San Juan ROI-2 ("San Juan ROI-2 Responses").

II. Scope of San Juan Units 7 and 9 Fuel Swap

A. Generation Units Conversion for Dual-Fuel Use

Natural gas (NG) is a naturally occurring hydrocarbon gas mixture composed primarily of methane, with varying amounts of other hydrocarbons and trace impurities. NG is one of the primary fuels used for combustion in power generation facilities, where it is combusted in gas turbines or boilers to produce electricity. Liquefied natural gas (LNG) is NG that has been cryogenically cooled to approximately -162°C (-260°F), causing it to condense into a liquid state, significantly reducing its volume for efficient storage and transportation. Upon

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[4] According to Genera, the FO6 Purchase Contract is the agreement that currently governs the procurement of FO6 for all generating units of the Puerto Rico Electric Power Authority ("PREPA").

[5] Following several procedural filings, by Resolution and Order dated March 6, 2026, the Energy Bureau approved the Palo Seco Units 3 and 4 Proposed Fuel Swap.

[6] *See Motion to Submit Technical Data for Request for Approval to Submit to COR3 and FEMA the SOW to Convert San Juan Units 7 & 9 to Operate with Natural Gas as Primary Fuel* filed by Genera on February 26, 2026 ("February 26 Motion").

[7] For purposes of this Resolution and Order, the term "San Juan ROI-1" is used to refer specifically to the questions that were originally submitted as part of the Palo Seco ROI-1.

regasification, LNG returns to its gaseous state and can be used in power generation facilities in the same manner as NG.

Conversions to natural gas typically involve modifying combustion units that operate on FO6 to use natural gas as the primary fuel, while preserving dual-fuel capability. This allows operation with either natural gas or FO6. Gas conversions involve technical modifications and the installation of additional infrastructure to ensure operational flexibility and fuel supply safety. The conversion adapts the internal combustion engines to primarily run on natural gas, with the option to use FO6 as a backup when necessary. This requires modifications or installations of dual-fuel injection systems, specific combustion controls, and monitoring equipment to efficiently switch between fuels.

In addition to engine modifications, gas handling and regasification infrastructure must also be installed, presumably within the existing premises. This includes distribution piping systems, control and safety valves, leak detection equipment, and measurement devices to ensure safe operation and compliance with applicable regulations. A key element is the regasification system, which will store LNG and convert it to a gaseous state for injection into the generation units. The regasification infrastructure includes cryogenic storage/buffer tanks, ambient vaporizers or other systems, pressure and temperature control equipment, and gas distribution piping. The LNG supply will be delivered by cryogenic trucks transporting LNG (LNG ISO trucks), which will be unloaded into cryogenic buffer tanks for subsequent vaporization and distribution to the generation units.

B. San Juan Units 7 and 9 Proposed Fuel Swap

The Energy Bureau is specifically considering Genera's request to approve switching the primary fuel used to generate electricity to two (2) units, San Juan 7 and San Juan 9, at the San Juan Power Plant in San Juan, Puerto Rico from FO6 to natural gas while allowing FO6 to remain as the backup fuel.[8] The San Juan Units 7 and 9 are conventional steam plants using heavy fuel oil (HFO), with a nameplate capacity of 100 MW[9] each that began commercial operation between 1965 and 1968.[10] According to Genera, the San Juan Unit 7 operated with annual capacity factor of about 19.3% for the fiscal year 2023-2024; 16.0% for the fiscal year 2024-2025; and 0% for the fiscal year 2025-2026 (until January 2026).[11] Also, the San Juan Unit 9 allegedly operated with annual capacity factor of about 64.2% for the fiscal year 2023-

[8] *See* Updated SOW, p. 3.

[9] It is clarified that there are inconsistencies regarding the capacity of San Juan Units 7 and 9. In the SOW and the Updated SOW, Genera states that the units are rated at 100 MW (see January 14 Motion, SOW, p. 6, and February 12 Motion, p. 6). However, in the San Juan ROI-1 Responses, Genera indicates that San Juan Units 7 and 9 operate at an available capacity of 80 MW each (see San Juan ROI-1 Responses, pp. 6–7). In addition, several exhibits submitted with the calculations of capacity factors, service hours, and other related parameters state that the available capacity of San Juan Units 7 and 9 is 100 MW (see San Juan ROI-2 Responses, Attachment B). Moreover, in the Updated SOW, Genera indicates that the objective is to bring the units to an available capacity of 100 MW. By contrast, LUMA's Fiscal Year 2026 Resource Adequacy Study reflects that San Juan Unit 7 has a capacity ranging between 70 and 90 MW, while San Juan Unit 9 has a capacity of 90 MW (see Motion to Submit LUMA's Fiscal Year 2026 Resource Adequacy Study and Request for Confidential Treatment filed by LUMA on December 5, 2025, in Case No. NEPR-MI-2022-0002, p. 110). The Energy Bureau is aware of the distinction between the nameplate capacity of the units and the concept of available capacity. However, the information submitted by Genera appears to indicate that its intent is for San Juan Units 7 and 9 to be considered, for purposes of the conversion, as having an available capacity of 100 MW.

[10] *See* Updated SOW, p. 5-6.

[11] *See* San Juan ROI-1 Responses, p. 6. Through its evaluation of this case, the Energy Bureau is not assessing the accuracy of the capacity factors calculated by Genera. It is further clarified that the capacity factor reported by Genera in this case is expressed in energy terms rather than in terms of hours of operation. In this context, the capacity factor represents the ratio between the actual amount of electricity generated by the unit over a given period and the maximum amount of electricity that the unit could have generated if it had operated at its full rated capacity during that same period. In other words, it measures the actual energy output of the unit relative to its maximum potential energy output. This differs from an operational metric based on hours of operation, which simply measures the percentage of time a unit is running, regardless of the level of output at which it operates.

2024; 57.3% for the fiscal year 2024-2025; and 60.9% for the fiscal year 2025-2026 (until January 2026).[12]

Genera also states that the Heat Rates for San Juan Units 7 over the last five years are: 11,357 Btu/KWh for fiscal year 2023-2024; 11,183 Btu/KWh for fiscal year 2024-2025; and 0 for fiscal year 2025-2026 (through January 2026).[13] For San Juan Unit 9, Genera reports the following Heat Rates: 11,024 Btu/KWh for fiscal year 2023-2024; 10,994 for fiscal year 2024-2025; and 10,899 for fiscal year 2025-2026 (through January 2026).[14] Regarding Service Hours, Genera states that San Juan Unit 7 operated 2,684 hours in fiscal year 2023-2024; 1,864 hours in fiscal year 2024-2025; and 0 hours in fiscal year 2025-2026 (through January 2026).[15] For San Juan Unit 9, the reported Service Hours are 7,794 in fiscal year 2023-2024; 6,823 in fiscal year 2024-2025; and 4,417 in fiscal year 2025-2026 (through January 2026).[16]

According to Genera, San Juan Units 7 and 9 operate under a Title V Operating Permit issued by the Department of Natural & Environmental Resources ("DNER") on May 31, 2005.[17]

Genera proposes that the natural gas required for the operation of San Juan Units 7 and 9 will be supplied using the same infrastructure owned by NFEnergia LLC ("NFE") that serves San Juan Units 5 and 6.[18] Genera further indicates that the same entity will act as the gas supplier under a separate contract.[19] According to Genera, this approach would rely on existing gas delivery facilities to support the fuel needs of the additional units, thereby leveraging existing infrastructure and minimizing the need for additional construction or system modifications.[20] Genera also stated that multiple components and parts required for the gas conversion of the San Juan Units 7 and 9 had been purchased by PREPA. After inspecting those parts, Genera informed that they appear to be in good condition and functionally operable and determined that procuring new replacement parts with federal funding is not necessary. Genera presented a revised cost estimate that accounts for these reductions.[21]

In the February 26 Motion, Genera describes its assumptions regarding the fuel costs that would be incurred using FO6 versus natural gas for San Juan Units 7 and 9. Genera calculates that operating San Juan Units 7 and 9 on natural gas would result in approximately $3.23/MMBtu in savings.[22] To calculated the estimated savings, Genera states that FO6 is forecasted to cost $17.17/MMBtu, while LNG in San Juan Units 7 and 9 is forecasted to cost $7.95 + HH (115%)]/MMBtu.[23] Genera further states that the proposed fuel swap will not

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[12] *See Id*.

[13] *See* San Juan ROI-1Responses, p. 6. It is clarified that, based on the evaluation conducted by the Energy Bureau, it should not be understood that the values represented by Genera are being accepted as true, nor should it be understood that the Energy Bureau has passed judgment on them.

[14] *See Id*.

[15] *See* San Juan ROI-1Responses, p. 6.

[16] *See Id*.

[17] *See* Title V Operating Permit included as part of the February 26 Motion.

[18] *See* January 14 Motion, p. 3-4.

[19] *See Gas Sale Agreement* signed by NFE Energia LLC, Puerto Rico Public Private Partnership Authority and PREPA on December 4, 2025 ("NG Purchase Contract"). *See*, also, January 14 Motion, p. 3-4.

[20] *See Id*.

[21] *See* February 12 Motion, Attachment B.

[22] *See* January 14 Motion, p. 6, ¶13.

[23] *See Id*.

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impact rates, as the conversion works will be performed using FEMA funds[24], and that the proposed fuel swap will generate significant environmental benefits.[25]

Initially, Genera asserted that it would be possible to switch between natural gas and FO6, thereby allowing the units to operate using whichever fuel is more cost-effective at any given time.[26] However, Genera later clarified that switching between fuels based on relative prices was not feasible. Genera noted that fuel prices, including FO6 and natural gas, are highly volatile and subject to significant fluctuations driven by market speculation, geopolitical events, supply and demand imbalances, macroeconomic conditions, and movements in relevant commodity indices.[27] It also indicated that, while historical data may provide a reasonable basis for projections, actual future fuel costs—and potential fuel savings—may differ significantly due to factors beyond its control.[28]

Genera asserts that PREPA and Genera have obligated A&E funding for design work during the project formulation phases.[29] Genera also asserts this funding will be used for technical studies, engineering assessments, and preparation of scopes of work and cost estimates, consistent with FEMA's purpose for A&E allocations.[30] Additional, Genera states that conversion costs will be eligible for advances under the working capital advance program once FEMA obligates the scope of work.[31]

Genera states that switching a power generation unit from FO6 to natural gas is expected to significantly extend equipment life.[32] According to Genera, natural gas combustion produces negligible ash, very low particulate emissions, and sulfur content in parts per million, reducing deposit formation and corrosion on boilers, turbines, and exhaust systems.[33] Genera states this cleaner combustion maintains thermal efficiency, reduces wear on engine components, lowers lube oil contamination, and decreases maintenance frequency and overhaul costs, resulting in improved operational stability and longer equipment lifespan compared to FO6 operation.[34]

Genera requests the Energy Bureau's authorization to submit a federal fund request to the Central Office for Reconstruction, Recovery and Resiliency ("COR3") and FEMA under the Section 428 and/or Section 406 Hazard Mitigation Program to enable these units to operate on dual fuels, using natural gas as the primary fuel and FO6 as backup.[35] Genera alleges that, under PREPA FAASt, the conversion work is eligible for FEMA Section 428 funding, and, due to single-point-of-failure considerations, also qualifies for FEMA funding under Section 406 HMP.[36] Genera indicates that its approach is to initially formulate the project under Section 428 and subsequently submit the mitigation narrative for FEMA's consideration under Section

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[24] *See* January 14 Motion, p. 6.

[25] *See* January 14 Motion, pp. 8-9.

[26] *See* January 14 Motion, p. 3.

[27] *See* San Juan ROI-1Responses, p. 7.

[28] *See Id*.

[29] *See* San Juan ROI-1Responses, pp. 9-10.

[30] *See Id*.

[31] *See Id*.

[32] *See* San Juan ROI-1Responses, p. 10.

[33] *See Id*.

[34] *See Id*.

[35] *See* February 12 Motion, p. 3-4, ¶7 and San Juan ROI-1 Responses, pp. 9-10.

[36] *See* San Juan ROI-1Responses, pp. 11-12.

406.[37] According to Genera, this sequencing preserves flexibility and allows the project to transition to Section 406 once final costs and supporting documentation are available, under FEMA policy.[38]

III. Analysis of the San Juan Units 7 and 9 Fuel Swap

A. Alignment with the Integrated Resources Plan

1. *Alignment with the Approved IRP*[39]

The Energy Bureau recognizes the Approved IRP as a fundamental planning instrument for the development, transformation, and operation of Puerto Rico's electric system. The Energy Bureau also notes that significant changes in the system since the approval of the current IRP, including changes affecting the availability of generation resources and modifications to Puerto Rico's public energy policy through the enactment of Act 1-2025,[40] have impacted the evaluation of various initiatives contemplated under the Approved IRP. Notwithstanding these developments, the Energy Bureau acknowledges the importance of evaluating the San Juan Units 7 and 9 Proposed Fuel Swap under the framework of the Approved IRP to assess its consistency with the directives set forth.

As part of the development of the 2018 Proposed IRP,[41] PREPA evaluated the operational condition and regulatory status of the San Juan Units 7 and 9.[42] That evaluation identified significant operational and environmental compliance challenges, including the poor physical condition of the units and their inability to comply with the Mercury and Air Toxics Standards ("MATS"). In addition, the units are in an area designated as nonattainment regarding the Environmental Protection Agency ("EPA") sulfur dioxide ("SO_2") National Ambient Air Quality Standard ("SO_2 NAAQS"), and their emissions contribute to the ambient sulfur dioxide concentrations associated with that nonattainment designation. PREPA determined that substantial capital investments would be required for the units to remain operational and achieve compliance with applicable environmental regulations. PREPA recognized in the 2018 Proposed IRP that the "San Juan Steam Units" are not in acceptable operational conditions and would require a non-economically viable capital investment to reach MATS compliance and acceptable operational conditions.[43] According to PREPA, the San Juan Steam Units require substantial capital investment to be operational and in compliance with the applicable

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[37] *See Id*.

[38] *See Id*.

[39] *Final Resolution and Order on the Puerto Rico Electric Power Authority's Integrated Resource Plan, In re. Review of the Puerto Rico Electric Power Authority Integrated Resource Plan,* Case No. CEPR-AP-2018-0001, August 24, 2020 ("Approved IRP"). Minor modifications and/or clarifications to the Approved IRP were introduced through a *Resolution and Order on Reconsiderations* issued by the Energy Bureau on December 2, 2020, in case: *In re. Review of the Puerto Rico Electric Power Authority Integrated Resource Plan,* Case No. CEPR-AP-20 18-0001.

[40] Act No. 1 of March 12, 2025 ("Act 1-2025").

[41] PREPA's Motion to Leave File IRP Main Report "ERRATA" version, dated June 19, 2019, which included a corrected version of the Main IRP Report submitted on June 7,2019, and is titled Integrated Resource Plan 2018-2019, Draft for the Review of the Puerto Rico Energy Bureau, Prepared for the Puerto Rico Electric Power Authority, June 7, 2019 (Rev. 2.1), In re. Review of the Puerto Rico Electric Power Authority Integrated Resource Plan, Case No. CEPR-AP-2018-0001 ("2018 Proposed IRP").

[42] In the 2018 Proposed IRP only two (2) out of the four (4) San Juan Steam Units were considered as available generation units. (*See* 2018 Proposed IRP, Exhibit 4-5, p. 4-3, p. 4-19, p. 4-23, and p. 4-26). The San Juan Steam Units 7 and 8 were included in the 2018 Proposed IRP. (*See Id.*) However, since the San Juan Units 7, 8, 9 and 10 are substantially identical, they were modeled as interchangeable for purposes of the 2018 Proposed IRP. (*See Id.*) Nevertheless, only two (2) of the four (4) units were included in the 2018 Proposed IRP and the Approved IRP as available generation resources, and both were expected to be retired by 2025. (*See* Approved IRP, ¶870, p. 270 and 2018 Proposed IRP, Exhibit 4-6, p. 4-4).

[43] *See* 2018 Proposed IRP, Exhibit 4-2, p. 4-1 and Exhibit 4-6, p. 4-4.

environmental regulations.[44] Based on that assessment, PREPA concluded that no capital projects should bring these units into compliance with MATS and that the units should instead be retired by 2025, thereby avoiding potential penalties or enforcement actions related to MATS noncompliance.[45] PREPA primarily considered limited-use and retirement options to address MATS compliance. Based on the simulations conducted as part of the 2018 Proposed IRP, San Juan Units 7 and 9 were projected to retire between approximately 2025, although they were recommended to remain for potential conversion to synchronous condensers.[46] The Energy Bureau ultimately adopted PREPA's recommendation in the Approved IRP, which established the retirement of these units within that timeframe.

Notwithstanding the foregoing, in the Approved IRP the Energy Bureau approved the retirement plans for PREPA steam units under PREPA's caveats indicating a need for replacement capacity, assurance of meeting the overall reliability needs, and in alignment with more specific timing thresholds described in the Modified Action Plan.[47] This means that the retirement dates proposed in the Approved IRP are not definitive, but remain subject to periodic evaluation, considering the needs of the system and the operational condition of the units.

The current circumstances of the system, as recognized by the Energy Bureau in this and other proceedings, have required that the San Juan Units 7 and 9 remain in operation to maintain system stability and avoid the implementation of load shedding, given the generation limitations affecting the system.[48] Under these circumstances, the Energy Bureau **DETERMINES** that maintaining the San Juan Units 7 and 9 in operation beyond the estimated retirement year of 2025 is not inconsistent with the Approved IRP.[49]

Separately, the modeling conducted as part of the 2018 Proposed IRP did not contemplate the specific fuel swap proposed by Genera for the San Juan Units 7 and 9 and, therefore, did not evaluate its economics. Notwithstanding, the 2018 Proposed IRP considered a new LNG terminal as a preferred option for supplying natural gas to the San Juan and Palo Seco plants.[50] The project contemplated an onshore LNG storage and vaporization facility with an estimated capital cost of approximately $472 million, supplied by LNG carriers delivering fuel directly to onshore tanks.[51]The proposal cost included the construction of a natural gas pipeline of 4.2 miles connecting the San Juan facility to the Palo Seco plant, with an estimated cost of $25 million.[52] The pipeline was intended to supply natural gas to a new combined cycle unit of approximately 300 MW at Palo Seco. The 2018 Proposed IRP also established incremental costs for the gas supply infrastructure and the pipeline connecting San Juan to Palo Seco in the event that additional natural gas-fired units were to be installed at the Palo Seco Plant. Nevertheless, the proposal did not contemplate the conversion of the existing San Juan Units 7 and 9 to natural gas. Additionally, the 2018 Proposed IRP analysis assumed that the residual fuel oil units at the San Juan and Palo Seco power plants would eventually be replaced, retired,

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[44] See *Moción para presentar Documento: Reporte Detallado del Estatus Actual de la Flota de Generación de la Autoridad, In Re: Puerto Rico Electric Power Authority's Permanent Rate*, Case No.: NEPR-MI-2020-0001, filed by PREPA on October 23, 2021.

[45] *See* 2018 Proposed IRP, infra, Section 8.2.3, p 8-23.

[46] *See* 2018 Proposed IRP, infra, Section 8.2.3, p 8-23, Section 10.1.3.3, p. 9-5.

[47] *See* Approved IRP, ¶ 630, p. 193.

[48] *See*, for example, *Puerto Rico Electrical System Resources Adequacy Analysis Report*, dated December 5, 2025, filed by LUMA in Case No. NEPR-MI-2022-0002.

[49] As discussed further below, this determination is also consistent with the 2025 Proposed IRP, *infra*, which proposes retirement dates for the San Juan Units 7 and 9 that could extend to as late as 2034.

[50] *See* 2018 Proposed IRP, Section. 10.1.6.1, p. 9-7.

[51] *See* 2018 Proposed IRP, Section 7.1.2.9, p. 6-13.

[52] *See* 2018 Proposed IRP, Section. 10.1.6.1, p. 9-7.

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or limited in operation to achieve compliance with MATS, and that replacement generation would be capable of operating on natural gas and diesel.[53]

The foregoing proposal was rejected in part as part of the Approved IRP, although the continued evaluation of certain initiatives related to the potential installation of a 300 MW combined cycle unit at Palo Seco was allowed to proceed. This determination was influenced by the estimated capital cost of approximately $472 million required to develop the LNG terminal in San Juan, a factor that weighed heavily in the economic evaluation leading to the rejection of that alternative.

Nevertheless, Genera's fuel swap proposal explicitly states that no capital investment from ratepayers will be required for the conversion of the San Juan Units 7 and 9, as those costs are expected to be covered by FEMA.[54] In addition, Genera stated that natural gas will be delivered through the existing regasification infrastructure and connecting additional piping for San Juan 7 & 9 to the existing NFE gas delivery facilities.[55] Therefore, if the proposed fuel cost savings can be implemented as described in Genera's proposal, without requiring capital investments that would impact ratepayers, the proposal would be substantially aligned with the Approved IRP.

Genera estimated annual savings of $3.23/MMBtu for the San Juan Units 7 and 9.[56] Later in this Resolution and Order, the savings proposed by Genera will be evaluated. However, considering the caveats regarding Genera assumptions, as discussed in this Resolution and Order, the Energy Bureau acknowledges that some level of savings may exist, though not to the extent calculated by Genera.

Based on the reasons discussed above, including the fact that the continued operation of the San Juan Units 7 and 9 beyond the previously projected 2025 retirement date is not inconsistent with the Approved IRP, and that the conversion to natural gas proposed by Genera is not expected to require capital investment from ratepayers, the Energy Bureau finds that the proposed fuel swap for the San Juan Units 7 and 9 does not conflict with the Approved IRP. The Energy Bureau determines that the proposed fuel swap **IS NOT INCONSISTENT** with the Approved IRP.

2. *Alignment with the 2025 Proposed IRP*

As required by Act 57-2014, on July 12, 2023, the Energy Bureau initiated a new Integrated Resource Plan (IRP) process to update the previously approved IRP.[57] This update is mandated by law to account for changes in available resources and to reflect updated circumstances and conditions affecting the electric system, thereby ensuring that Puerto Rico's long-term energy planning remains aligned with current realities and future needs. As part of this process, LUMA recently submitted a proposed IRP.[58] The IRP process is ongoing, with further evaluations and stakeholder engagements planned to ensure a sustainable and reliable energy future for the island.

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[53] *See Id*.

[54] *See* January 14 Motion, p. 3, ¶5.

[55] *See* February 12 Motion, p. 4.

[56] *See* January 14 Motion, p. 6, ¶13.

[57] *See In Re: Review of the Puerto Rico Electric Power Authority Integrated Resource Plan*, Case No.: NEPR-AP-2023-0004.

[58] *See Memorandum of Law in Support of Request of Confidential Treatment of Revised 2025 IRP and Submission of Public Version and Confidential Version of Revised 2025 IRP*, filed by LUMA Energy, LLC and LUMA Energy ServCo, LLC on October 29, 2025 ("2025 Proposed IRP").

While the development of the updated IRP was ongoing, Act 1-2025 was enacted, amending Act 17-2019[59] and the Act 82-2010,[60] eliminating the interim renewable energy targets of 40% by 2025 and 60% by 2040, while retaining the statutory objective of achieving 100% renewable energy generation by 2050. These legislative amendments modified the energy transition framework to better align with current conditions of the electric system and to ensure continued system reliability. The amendments allow, during a transitional period, the integration of other generation resources into the system that are not necessarily based on renewable energy sources, provided that such integration supports the achievement of the 100% renewable energy goal by 2050 and that such resources are procured at competitive prices capable of competing with renewable energy alternatives. This significant change in public policy not only affects the planning framework reflected in the Approved IRP but also requires modifications to earlier versions of the proposed IRP under development.

In addition, consistent with Act 1-2025, on March 19, 2025, the Energy Bureau issued a Resolution and Order,[61] in which it determined that: (i) given the pattern of forced outages affecting PREPA's existing aging thermal generation fleet, the available generation capacity is limited and may hinder necessary maintenance and repairs to the system; (ii) there is a need to explore the costs and timeframe associated with the availability of new, modern generation resources that would allow Puerto Rico to meet the objectives of the updated public energy policy while serving the best interests of electricity customers; and (iii) such procurement effort should explore between 2,500 and 3,000 MW of new capacity.

Although the directive to procure new generation capacity, as stated in the March 19 Resolution, may not fully align with the Approved IRP, it falls within the Energy Bureau's delegated authority to implement Puerto Rico's energy policy and to issue determinations in furtherance thereof. The March 19 Resolution illustrates how, given the current conditions of the electric system and the enactment of Act 1-2025, the Energy Bureau has in certain instances had to adopt measures that may depart, to a limited extent, from the assumptions reflected in the Approved IRP and, in some cases, from those contemplated in the 2025 Proposed IRP, while acting within the scope of the authority delegated to it by law.

As is well established, conversion projects must be evaluated for consistency with an Integrated Resource Plan that has been duly approved under applicable legal provisions. In other words, such projects are not required to conform to an Integrated Resource Plan that is still under review and has not yet been approved. However, the particular circumstances of this case warrant that the Energy Bureau consider, to some extent, the consistency of the proposed conversion of the San Juan Units 7 and 9 with certain relevant aspects of the Integrated Resource Plan under evaluation.[62] This is appropriate because the current conditions of the electric system, particularly the limited availability of adequate generation resources required to maintain system reliability, as well as the enactment of Act 1-2025, have required the Energy Bureau to make determinations that may depart, to a limited extent, from certain elements of the Approved IRP.

One of the essential components of an Integrated Resource Plan is the evaluation of the generation resources available to the system and the way those resources are proposed to be utilized or retired over the planning horizon. Under Act 57-2014, the IRP is developed using a planning horizon of twenty (20) years, while establishing a five-year action plan to guide near-term implementation.[63] As part of this process, the IRP must identify the generation resources available to the system, as well as those proposed to be developed or retired, and evaluate

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[59] Puerto Rico's Public Energy Policy Act ("Act 17-2019").

[60] *Public Policy on Energy Diversification by Means of Sustainable and Alternative Renewable Energy in Puerto Rico Act*, as amended ("Act 82-2010").

[61] See *Resolution and Order* issued in the case *In Re: Electric System Priority Stabilization Plan*, Case No. NEPR-MI-2024-0005 ("March 19 Resolution").

[62] An analogous situation arose during the evaluation of the proposed fuel swap for Palo Seco Units 3 and 4.

[63] *See* Articles 1.3(ll) and 6.29 of Act 57-2014 and Sections 1.03 and 1.08(B)(1) of the Regulation on Integrated Resource Plan for the Puerto Rico Electric Power Authority Regulation 9021 dated April 24, 2018 ("Regulation 9021").

them based on a range of technical, economic, and regulatory parameters associated with such resources.

The 2025 Proposed IRP identifies San Juan Unit 7 as a generation resource, with a nameplate capacity of 100 MW, an available capacity of 100 MW, a heat rate of 11,880 Btu/kWh, and a forced outage rate of 45%.[64] Regarding San Juan Unit 9, the nameplate capacity is 100 MW, the available capacity is 100 MW, the heat rate is 11,550 Btu/kWh, and the forced outage rate is 10%.[65] The 2025 IRP also identifies FO6 as the primary fuel used by the San Juan Units 7 and 9. [66]

As part of the modeling assumptions in the 2025 Proposed IRP, the potential retirement of certain FO6 units was evaluated within a defined time window.[67] Specifically, regarding the San Juan Units 7 and 9, the modeling assumed these units could retire within a window between 2030 and 2034.[68] The earliest retirement year of 2030 was selected as the first year in which new firm capacity could reasonably be developed and placed into operation to replace the units' capacity. The end of the window, 2034, allowed the resource modeling framework to determine a preferred retirement date within a five-year period based on the cost and reliability criteria applied to generation additions and retirements.[69] The modeling results in the 2025 Proposed IRP propose specific retirement dates for San Juan Unit 7 and San Juan Unit 9, with San Juan Unit 7 projected to retire in 2030[70] and San Juan Unit 9 projected to retire in 2031.[71]

The retirement recommendations included in the 2025 Proposed IRP are subject to certain conditions related to the addition of new resources and the ability of the electric system to maintain adequate reliability levels.[72] Specifically, regarding San Juan Unit 7, the 2025 Proposed IRP indicates that its planned retirement, identified for 2030 in the modeling results, would be contingent upon future resource adequacy analyses confirming that the system has sufficient capacity to maintain acceptable reliability levels. Such evaluations would consider reliability indicators, including Loss of Load Expectation (LOLE), Expected Unserved Energy (EUE), or similar metrics, to ensure that adequate generation resources are available before the unit's retirement.[73]The discussion in this section of the 2025 Proposed IRP refers specifically to San Juan Unit 7 because it is the unit proposed for retirement within the five-year action plan. San Juan Unit 9 is projected to retire in 2031, which falls outside the five-year action plan; however, if its retirement were to be considered in the future, a similar resource adequacy evaluation would be expected to apply.

As reflected in the preceding discussion, the 2025 Proposed IRP contemplates that San Juan Unit 7 and San Juan Unit 9 could remain in operation until approximately 2034, representing an additional operational period of roughly nine years. Although the utilization of these units

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[64] *See* 2025 Proposed IRP, p. 164.

[65] *See Id.*

[66] *See* 2025 Proposed IRP, p. 82.

[67] *See* 2025 Proposed IRP, p. 225. It appears that the reference to San Juan Unit 8 in the 2025 Proposed IRP is the result of an error and should instead refer to San Juan Unit 9. This is because, in several instances, Genera has stated that San Juan Unit 8 is currently out of operation and is not expected to return to service. For purposes of the evaluation in this Resolution and Order, this deviation is not material, since, as with the Approved IRP, the 2025 Proposed IRP includes only two of the four units known as the San Juan Steam Units as generating resources. (*See* 2025 Proposed IRP, p. 161).

[68] *Id.*

[69] *Id.*

[70] *See* 2025 Proposed IRP, p. 275.

[71] *See Id*.

[72] *See* 2025 Proposed IRP, p. 293.

[73] *See Id*.

NEGOCIADO DE ENERGÍA DE PUERTO RICO NEPR JUNTA REGLAMENTADORA DE SERVICIO PÚBLICO is projected to decline after 2029, the planning framework of the IRP nevertheless recognizes these units may continue operating for a period of time rather than being immediately retired. From a retirement perspective, the proposal to operate the units using natural gas is not inconsistent with the planning assumptions of the 2025 Proposed IRP. This is particularly so because, as discussed further below, the units are expected to remain in operation for most of the term of the NG Purchase Contract, which commenced in December 2025 and extends through December 2032.

The Energy Bureau recognizes that the 2025 Proposed IRP does not evaluate the economic aspects associated with the conversion to natural gas proposed for San Juan Units 7 and 9. However, the circumstances presented by Genera differ from those considered in the planning assumptions of the 2025 Proposed IRP. As represented in the record, the conversion works themselves are expected to be funded through FEMA under the Section 428 and/or Section 406 programs and without capital investment from ratepayers. In addition, the supply of natural gas is expected to rely on existing infrastructure, further limiting the need for new capital expenditures. Under these circumstances, the principal economic element remaining for evaluation from an IRP perspective relates to fuel costs. To the extent that, as discussed above regarding the Approved IRP, any fuel cost savings materialize as a result of the proposed conversions, the Energy Bureau considers that the proposal may be consistent with the framework contemplated in the 2025 Proposed IRP.

While the 2025 Proposed IRP did not specifically model the conversion of San Juan Units 7 and 9 to natural gas, it contemplates measures aimed at addressing environmental compliance and system needs, including the use of ultra-low sulfur diesel ("ULSD") and the conversion of certain units to natural gas to support compliance with applicable environmental standards, including the EPA's SO_2 NAAQS.[74] Accordingly, although the specific proposal at issue was not expressly modeled in the 2025 Proposed IRP, it may nonetheless be considered as part of the IRP process, consistent with the determinations adopted by the Energy Bureau in this Resolution and Order.

As previously noted, it is not necessary at this stage to determine whether the proposed conversion to natural gas complies with the 2025 Proposed IRP. However, the analysis conducted suggests that, with adjustments, the proposal may be consistent with the planning framework contemplated in the 2025 Proposed IRP.

B. Alignment with the Energy Public Policy

Article 1.11 of Act 17-2019 provides that PREPA's Legacy Generation Assets sold as part of a PREPA Transaction may be converted to dual-fuel capability, with at least two fossil fuels, one of which may be natural gas. Nevertheless, Act 17-2019 does not prohibit existing units within PREPA's Generation Legacy Assets (not sold as part of a PREPA Transaction) from being converted to dual-fuel capability. Therefore, if a proposed conversion aligns with the Approved IRP and applicable energy public policy principles, the Energy Bureau may authorize the conversion of a PREPA Legacy Generation Asset to dual-fuel use, with natural gas as one of the fuels.

A careful review of Genera's filings also shows that the proposed fuel swap substantially aligns with the energy public policy, as it meets the objectives of providing affordable and reasonable electric power service, allowing fossil fuel units to operate with multiple fuel types, including natural gas, ensuring that fuel and power purchases are made at reasonable prices based on market and local conditions.[75]

C. Relevant Permits

According to Genera, San Juan Units 7 and 9 operate under the Title V Operating Permit issued by the DNER on May 31, 2005, which authorizes the operation of the two units using FO6. San

[74] *See* 2025 Proposed IRP, p. 79.

[75] *See,* in general, Article 1.5 of Act 17-2019.

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Juan Units 7 and 9 currently may not operate using natural gas. The conditions in the permit for the operation of San Juan Units 7 and 9 would need to be modified to allow the use of natural gas.[76] Additionally, Genera represents that the Prevention of Significant Deterioration ("PSD") permit will be required for the proposed fuel swap, however, it has not yet submitted to corresponding application to the EPA.[77] Genera has submitted no further information about other local or federal permits necessary for implementing the proposed fuel swap at San Juan, nor has it provided a detailed schedule for obtaining such permits.

Genera has conveyed that the project is effectively ready for implementation as early as December 2026. [78] However, it has not provided a reasonable timeline for securing several key permits that are typically required for projects of this nature. Based on experience with similar permitting processes, obtaining these authorizations can be complex and time-consuming, raising questions as to whether the project is as imminently executable as Genera has suggested.

Nevertheless, the Energy Bureau **CLARIFIES** that it is solely Genera's responsibility to obtain all required permits for the project's execution, and the Energy Bureau has not assessed the status or adequacy of these permits. All permits obtained in connection with the proposed fuel swap must be secured to benefit PREPA. Further, Genera **SHALL** only operate the San Juan Units 7 and 9 using natural gas and **SHALL** only commit under the NG Purchase Contract to procure additional quantities under the Take-or-Pay provision of such contract, once it has fully complied with all applicable legal requirements and obtained all necessary permits.

D. Project Cost

In the Updated San Juan Units 7 and 9 Proposed Fuel Swap, Genera submitted certain information regarding the scope of work and costs associated with the requested conversions for the San Juan Units 7 and 9. Genera indicated that the conversion of the San Juan Units 7 and 9 from FO6 to natural gas would not require PREPA to incur any capital expenditures, as such costs may be funded through FEMA.[79] In the Updated Proposed Fuel Swap Genera indicated that "*in the alignment with Puerto Rico's Public Energy Policy, Genera has identified the San Juan Units 7 & 9 conversion project as a key initiative that can significantly reduce fuel costs without requiring capital investment from customers*".[80] Genera also asserted the project will be eligible for FEMA Section 428 funding. In the Updated San Juan Units 7 and 9 Proposed Fuel Swap, Genera indicated that it "*intends to submit to COR3 and FEMA a request for funds under the 428 program to undertake the works to convert the units to burn natural gas*…".[81]

Genera asserts that, based on its analysis and inventory, the originally proposed project scope and cost for converting San Juan Units 7 and 9 to dual fuel may be significantly reduced.[82] Initially, Genera estimated that the project cost would be $33,250,000.[83] Notwithstanding, in the Updated Proposed Fuel Swap Genera states a reduction in the cost approximately about

[76] It is noted that the Title V Operating Permit establishes an aggregate consumption limitation for FO6 applicable to the four San Juan steam generating units (San Juan Units 7, 8, 9, and 10). Because this limitation applies on an aggregate basis and given that the units are substantially identical in their operational characteristics, the aggregate limit would reasonably be expected to constrain the individual operating hours of each unit to approximately 6,442 hours per year. However, Genera represents that, since San Juan Units 8 and 10 are currently not in operation, it seeks to operate San Juan Units 7 and 9 for up to 8,760 hours per year each, which would not exceed the maximum aggregate fuel consumption established in the Title V Operating Permit (*See* San Juan ROI-2 Responses, p. 2).

[77] *See* February 26 Motion, p. 5.

[78] *See* San Juan ROI-1 Responses, p. 9.

[79] *See* January 14 Motion, pp. 7-8, ¶19.

[80] *See* February 12 Motion, pp. 3-4.

[81] *See* February 12 Motion, p. 4.

[82] *See* February 12 Motion, pp. 4-5, ¶12.

[83] *See* SOW, p. 8.

$8,250,000, resulting in a revised estimated total project cost of $25,000,000.[84] Through the Updated SOW, Genera indicates that it identified various components and parts previously purchased by PREPA for the regasification of San Juan Units 7 and 9 and in a preliminary inspection suggests that these items are in good condition and functionally operable, supporting the cost reduction.[85] Genera algo states that, while the fuel-conversion scope remains unchanged, the cost estimate for FEMA project formulation will be adjusted accordingly.[86]

Genera states that, in line with prudent administration of federal funds, it has identified $113,000,000 from FEMA PWs 10710, 108115, 10819, and 009510 that could be used for the fuel conversion of Cambalache, Palo Seco units 3 & 4 and San Juan Units 7 and 9. If the Energy Bureau approves the project, Genera will submit the scope of work and project formulation to FEMA to expedite the fuel swap for San Juan Units 7 and 9.

Regardless of whether certain equipment and components are already available at PREPA's facilities for the execution of the project, the total cost of the project is approximately $32,250,000, since even if $8,250,000 is attributed to existing equipment and parts, such costs were incurred at some point.

Previous conversion requests submitted by Genera contemplated cost structures under which the costs associated with such conversions could ultimately be borne by ratepayers. With respect to the Proposed Fuel Swaps, this is the first instance in which Genera has represented that the conversion costs will not be passed through to, or otherwise borne by, ratepayers. This distinction is particularly relevant in light of Genera's acknowledgment that projected fuel savings are inherently uncertain and may vary depending on future fuel price fluctuations.

Based on the representations made by Genera, the Energy Bureau notes that the proposed conversion of the San Juan Units 7 and 9 to natural gas would not require capital expenditures to be borne by PREPA's customers, as the costs associated with the project are expected to be funded through federal programs. While the Energy Bureau is not conducting, as part of this proceeding, a specific cost-benefit analysis regarding the use of such federal funds for the proposed conversions, the record suggests that the project may provide certain potential benefits. These include the possibility of fuel cost savings, although potentially not to the magnitude asserted by Genera, as well as environmental and operational benefits. The conversion to natural gas could facilitate improved compliance with applicable environmental requirements, including those related to MATS, support compliance with the SO_2 NAAQS, and result in lower pollutant emissions compared to the continued use of FO6. Additionally, the use of a cleaner fuel may contribute to improved maintenance conditions and operational reliability of the units. Considering these factors, and under the particular circumstances of the system, the Energy Bureau finds that the balance of these considerations reasonably supports the costs that may be incurred to convert the units to operate with natural gas.

E. Proposed Fuel Cost Savings

In the January 14 Motion, Genera states that switching the primary fuel from FO6 to natural gas will benefit PREPA's customers through savings in fuel costs.[87] Genera also alleges that the proposed conversion will also have additional savings in operation and maintenance ("O&M") costs.[88]

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[84] *See* February 12 Motion, pp. 4-5, ¶12.

[85] *See* February 12 Motion, p. 4, ¶10.

[86] *See* February 12 Motion, pp. 4-5, ¶12.

[87] *See* January 14 Motion, p. 3.

[88] *See* San Juan ROI-1Responses, p. 3, ¶9.

Genera provides a numerical comparison, stating that FO6 is forecasted to cost \$17.17/MMBtu,[89] while LNG is forecasted to cost \$[7.95 + HH (115%)]/MMBtu, and concludes this represents savings of approximately \$3.23/MMBtu.[90] Genera further alleges that, based on the historical operation of the San Juan Units y and 9 over the past thirty months, the proposed fuel conversion will result in savings for ratepayers.[91] Specifically, Genera estimates that when the units operates in the future using natural gas, it could yield an a cumulative savings of \$63,957,134.37 over an 30-month period,[92] equivalent to an approximate monthly amount of \$2,131,904.48. In support of this allegation, Genera includes as Attachment B an Excel table illustrating the historical fuel consumption of the San Juan Units 7 and 9. Genera also estimates that if both units operate with natural gas, the estimated combined savings would be approximately \$25,582,853.75 annually.[93]

The Energy Bureau finds that Genera's methodology for estimating the projected savings does not reasonably reflect the savings that may be expected from the proposed natural gas operations. Genera relies on historical average cost data from approximately the last thirty (30) months to estimate annual savings, a methodology that is not reliable and does not accurately reflect future operating conditions. Rather, evaluating savings associated with the operation of the San Juan Units 7 and 9 on natural gas must be based using the pricing structure established in the NG Purchase Contract and the FO6 Purchase Contract. This methodology is not reliable because the averaging approach relies on historical data that is not representative of current or expected market conditions. The calculation incorporates older periods in which natural gas prices were significantly lower and do not reflect the upward trend observed in recent years, thereby artificially lowering the resulting average natural gas price. Conversely, regarding FO6, the methodology incorporates earlier periods when prices were relatively higher, which increases the resulting average fuel oil price. The calculated averages do not provide an appropriate basis for estimating the potential fuel cost savings.[94] The methodology does not account for the fuel price levels reasonably expected in the coming years based on prevailing market trends, expected fuel volumes, and the existing contractual arrangements for the procurement of both fuels.

The Energy Bureau deems that a reasonable calculation of the expected savings associated with the operation of San Juan Units 7 and 9 on natural gas should be based substantially on the following parameters: (i) the dependable capacity of the units and an operating profile consistent with the expected dispatch levels of the units over the coming years; (ii) natural gas pricing calculated in accordance with the pricing structure established in the NG Purchase Contract; (iii) forward-looking natural gas price projections based on the Henry Hub indices

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[89] In none of the filings submitted by Genera has it explained or provided information that would allow an evaluation of the FO6 cost at \$17.17/MMBtu that it represents as the forecasted fuel price. In fact, an examination of the fuel cost data submitted by Genera for the thirty-month period spanning July 2023 through December 2025 shows that in none of the months for which information was provided did the reported cost reach \$17.17/MMBtu. Additionally, FO6 costs for the thirty-month period are approximately \$14.00/MMBtu, and for calendar year 2025 are approximately \$12.48/MMBtu. Likewise, the independent evaluations conducted by the Energy Bureau, based on data from the U.S. Energy Information Administration, do not indicate adjusted FO6 costs at such an elevated level. Accordingly, neither figure approaches the \$17.17/MMBtu value asserted by Genera. It should also be noted that the higher the assumed FO6 cost, the greater the alleged savings that could result from the proposed measures; accordingly, this figure is viewed with a degree of skepticism.

[90] *See* January 14 Motion, p. 6, ¶13.

[91] *See* January 14 Motion, p. 8, ¶20.

[92] *See Id*.

[93] *See* January 14 Motion, p. 8, ¶20.

[94] Genera assumes an average fuel savings of \$3.23 per MMBtu based on a 30-month average, which reflects variability in both natural gas and FO6 prices. Notably, that 30-month period captures conditions in which FO6 prices were relatively higher and natural gas prices comparatively lower than more recent levels, thereby inflating the implied savings differential. However, when a more recent 12-month period within 2025 is considered, the resulting average savings is significantly lower, approximately \$0.94/MMBtu. In other words, the estimated savings would be roughly less than one-third of what Genera estimates. This is without considering that projections from the U.S. Energy Information Administration indicate a forward trend of decreasing FO6 prices and increasing natural gas prices. Under such projected conditions, there may be scenarios in which the cost of generation using natural gas exceeds that of FO6.

published in the Short-Term Energy Outlook (STEO) of the U.S. Energy Information Administration; and (iv) an FO6 price benchmark based on the pricing structure established in the applicable FO6 purchase contract, or on equivalent proxy indices published by the U.S. Energy Information Administration.

The Energy Bureau will not undertake a further review of the projected fuel price assumptions at this time. Given the particular circumstances surrounding fuel price dynamics and the nature of the projections, the Energy Bureau will rely on Genera's representations and will not require additional information regarding the projected savings associated with the proposed conversion. Nevertheless, Genera must submit, on an annual basis, detailed calculations of the savings allegedly realized as a result of the conversion of San Juan Units 7 and 9 to natural gas, as described below.

On February 1 of the calendar year following the commencement of commercial operation of the San Juan Units 7 and 9 using natural gas, and on February 1 of each year thereafter, Genera shall file with the Energy Bureau an annual report detailing the savings realized as a result of operating the San Juan Units 7 and 9 using natural gas. The annual report shall include, for each unit: (i) the number of hours the unit operated during the reporting year; (ii) the resulting capacity factor for that unit; (iii) the unit's total natural gas consumption and the corresponding cost of natural gas incurred; (iv) an estimate of the cost that would have been incurred to operate the unit on FO6 during the same period, based on the FO6 purchase contract in effect at the time; (v) a calculation of the savings attributable to operating the unit on natural gas as compared to FO6; (vi) the amount by which the minimum take-or-pay obligations under the NG Purchase Contract increased as a result of the inclusion of the San Juan Units 7 and 9 as additional generation units under that agreement; (vii) the amount incurred by PREPA during the applicable calendar year (January 1 through December 31) as a result of natural gas volumes not taken but paid for under the take-or-pay provisions of the NG Purchase Contract; and (viii) a separate section identifying and supporting the maintenance costs attributable to each unit during the reporting year, as well as any capital expenditures incurred in connection with the operation of such units.

F. Fuel Price Trends

The Energy Bureau reviewed historical fuel price data for FO6 and natural gas using publicly available price indices published by the U.S. Energy Information Administration ("EIA").[95] The Energy Bureau's review was not intended to constitute a detailed or comprehensive economic analysis, but rather a high-level assessment of historical cost behavior, including an examination of relative volatility patterns. That review suggests that, while natural gas may exhibit greater short-term statistical volatility in percentage terms, FO6 historically displays larger cyclical price movements and periods of sustained price increases, particularly during oil-market disruptions.[96]

Although the data reviewed suggests a potential reduction in FO6 prices during the 2026–2027 period, the Energy Bureau does not interpret this as indicative of a persistent long-term trend. The historical record instead shows that residual fuel oil prices have been subject to significant cyclical variability and may experience substantial and prolonged increases. The Energy Bureau cannot make a definitive determination regarding future relative fuel price movements based solely on this limited review and instead relies on the representations made by Genera, which was retained by PREPA (among others) to procure fuel and assess fuel market conditions on its behalf and is expected to possess the relevant expertise in such matters.[97]

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[95] *See No. 6 Residual Fuel Wholesale Price*, Short-Term Energy Outlook Data Browser, U.S. Energy Information Administration ("No. 6 Fuel Wholesale Price"); and *Natural Gas Henry Hub Spot Rice*, Short-Term Energy Outlook Data Browser, US. Energy Information Administration ("NG Henry Hub Price").

[96] *See*, for example, the significant global oil-market disruptions associated with the 2008 oil price shock, the 2020 pandemic-related market collapse and subsequent recovery, and the 2022 energy market disruptions following Russia's invasion of Ukraine.

[97] Nothing herein shall be construed as limiting the Energy Bureau's authority to intervene if the evidence demonstrates that Genera's determinations are not supported by adequate analysis or may result in outcomes contrary to the public interest, in which event the Energy Bureau retains full authority under applicable law to take such actions as it deems necessary.

The Energy Bureau notes that, while it generally relies on the representations provided by Genera regarding the procurement of natural gas, the savings projected by Genera for the years 2026–2027 may ultimately be materially lower than currently estimated or may not materialize at all.[98] This conclusion is reached without considering recent geopolitical developments, including the evolving conflict involving Iran, which historically has been associated with sustained increases in global oil prices.

The Energy Bureau also notes that the fuel price forecast included in the 2025 Proposed IRP reflects a methodology that generally projects a more pronounced long-term increase in FO6 prices relative to natural gas. While the Energy Bureau does not adopt or validate those projections in this Resolution and Order, the projected trend is consistent with the broader historical patterns observed in the data reviewed.

The Energy Bureau reiterates that, at this stage, it does not undertake an independent assessment of those fuel price projections. Rather, the Energy Bureau relies on Genera's representations together with the high-level review described above and proceeds with the expectation that more substantial savings associated with the fuel transition may materialize in subsequent years.

G. Environmental Benefits

1. SO_2 NAAQS Compliance

Genera states that the San Juan power plant is in an SO_2 NAAQS Non-Attainment Area.[99] According to Genera, as a result of this designation, the Government of Puerto Rico must implement measures through its State Implementation Plan (SIP) to reduce SO_2 emissions and achieve compliance with the SO_2 NAAQS.[100] Genera further contends that converting San Juan Units 7 and 9 from FO6 to natural gas would significantly reduce SO_2 emissions and other pollutants associated with FO6 combustion. Genera represents that, based on preliminary emissions calculations it conducted, operating the units on natural gas would reduce emissions for most pollutants, except for carbon monoxide (CO) and greenhouse gases (GHG); however, such calculations were not submitted as part of its filing.[101] Genera also asserts these reductions, particularly those related to SO_2, could help address the plant's location within a SO_2 Non-Attainment Area, potentially improving environmental conditions and public health in nearby communities and helping the area move closer to attainment status under EPA standards.[102] Genera further alleges that achieving such status could allow for eliminating possible restrictions on the award of federal funds to certain government agencies.[103]

Consistent with this approach, the DNER, as part of the SO_2 State Implementation Plan (SIP) process, proposed to the EPA that compliance with the SO_2 NAAQS would be achieved, among

[98] Preliminary high-level calculations performed by the Energy Bureau, based on the data reflected in No. 6 Fuel Wholesale Price and NG Henry Hub Price, as well as certain assumptions regarding the projected use of San Juan Units 7 and 9, consistent with their historical utilization levels and the historical FO6 cost assumptions used by Genera PR, were prepared as part of the Energy Bureau's review. These calculations indicate that, contrary to Genera's assertions, for the years 2026 and 2027 operating these units using FO6 would result in a reduction in fuel costs of nearly the same magnitude as the savings that Genera claims would be achieved by operating the units using natural gas. These preliminary calculations, however, do not consider the potential upward pressure on fuel prices that could arise from current geopolitical developments, including the ongoing conflict involving Iran. As widely reported, such events may lead to increases in the prices of oil and natural gas in international energy markets, which could affect the relative cost comparison between FO6 and natural gas in the coming years.

[99] *See* February 12 Motion, p. 5.

[100] *See Id*.

[101] *See* February 12 Motion, p. 6.

[102] *See Id*.

[103] *See Id*.

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other measures, through the reduction of SO_2 emissions resulting from the retirement of certain generating units, including San Juan Units 7 and 9. However, given the current need to maintain adequate generation resources to ensure system reliability, the retirement of these units has not been feasible. Puerto Rico has not yet achieved the reductions contemplated in the proposed SO_2 NAAQS SIP Plan.

In addition, the ongoing development of the 2025 Proposed IRP will require the identification of alternative mechanisms to address compliance with the applicable SO_2 NAAQS requirements. In this context, the Energy Bureau considers that the proposed conversion of San Juan Units 7 and 9 to natural gas may constitute a reasonable mechanism to reduce SO_2 emissions while maintaining needed generation capacity, particularly given that, as represented in the record, the conversion would not require capital investment from ratepayers.

The Energy Bureau also notes that failure to attain the SO_2 NAAQS and to secure approval of an adequate SO_2 SIP Plan may trigger federal consequences under the Clean Air Act, including the imposition of stricter emissions offset requirements for new or modified sources and, after certain statutory periods, potential sanctions affecting the availability of federal highway funds. Such consequences may also constrain economic development in nonattainment areas by limiting the ability to authorize new sources of emissions. These considerations weigh in favor of the Energy Bureau approving the proposed conversion to natural gas, as it represents a mechanism that may contribute to advancing progress toward SO_2 NAAQS compliance while addressing the current operational needs of the electric system.

2. MATS

As part of the IRP process that led to the approval of the Approved IRP, PREPA represented to the Energy Bureau that San Juan Units 7 and 9 were not in compliance with the MATS and had therefore been designated as limited-use units. However, in the 2025 Proposed IRP, these units are identified as being in compliance with the applicable MATS requirements.[104] The Energy Bureau has not conducted an independent verification of that representation. Nonetheless, the Energy Bureau notes that the proposed conversion of San Juan Units 7 and 9 to natural gas may place the units under a different emissions source category, under which the applicable MATS requirements may be less stringent or may not apply, depending on their classification under EPA regulations. Even if compliance with MATS were uncertain under the current operating configuration, the proposed conversion may improve the regulatory conditions applicable to these units. These considerations further weigh in favor of the Energy Bureau approving the proposed conversion.

H. Proposed Implementation Schedule

In the San Juan ROI-1 Responses, Genera indicates that the San Juan Unit 7 is expected to operate on natural gas by September 2026. Genera also states that full (100%) operation is expected by December 2026.[105]

The schedule proposed to commence operations using natural gas appears to be highly aggressive, as it presumes that all necessary permits and authorizations from state and federal agencies, including the EPA, will be obtained within a period of approximately four months. However, the Energy Bureau does not intervene in the permitting process, and any approval it may grant is necessarily subject to Genera's ability to obtain all required permits and regulatory authorizations.

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[104] *See* 2025 Proposed IRP, p. 82. It is clarified that there appears to be an error in the 2025 Proposed IRP in the MATS compliance table for San Juan Unit 9. While the table reflects that the unit is *Compliant*, it also indicates that the unit was not considered a future generating resource in the 2025 Proposed IRP. However, supporting materials included as part of the 2025 Proposed IRP and reviewed by the Energy Bureau indicate that this latter statement should have been removed, and that only the *Compliant* designation should have remained.

[105] *See* San Juan ROI-1Responses, p. 9.

Nevertheless, for this project to succeed, it must be executed within a relatively short timeframe so that any potential benefits associated with the conversion to natural gas can be realized and maximized. This consideration becomes even more relevant when considering that the generation mix reflected in the 2025 Proposed IRP indicates that, beginning around 2029 and thereafter, the expected utilization of San Juan Units 7 and 9 would be minimal.[106] Accordingly, while the Energy Bureau is not imposing specific implementation deadlines, it does not appear to be in the public interest for these projects to be executed over a period exceeding one year, as such delay would likely diminish or eliminate the potential benefits to consumers. However, responsibility for the timely execution of the project remains with Genera, including the design of the necessary modifications, the processing and obtaining of all required permits, the construction and implementation of the project, and placing the facilities into service.

I. Natural Gas Supply/Take-or-Pay Provisions

Genera proposes to procure the natural gas required to supply San Juan Units 7 and 9 through the NG Purchase Contract. The NG Purchase Contract establishes that the Annual Take-or-Pay for additional generation units shall be calculated based on the added unit's Net Dependable Capacity and the operating profile in the applicable "Required Permits".[107] The calculations derived from the parameters in the NG Purchase Contract demonstrate that the Annual Take-or-Pay quantity implied by the contractual methodology may result in an operational requirement that is not consistent with the expected dispatch profile of San Juan Units 7 and 9.[108] Therefore, it is necessary to evaluate the relevant contractual provisions, as well as the circumstances and parameters presented by Genera, to ensure that any procurement under the referenced contract safeguards the public interest.

Although Genera did not respond to the specific question regarding the applicable Take-or-Pay obligations for the conversion of San Juan Units 7 and 9 under the NG Purchase Contract, it provided estimated quantities of natural gas to be used by the units.[109] These quantities likewise require evaluation by the Energy Bureau in this proceeding, as they may imply an operational profile for the units that differs from, and potentially reflects lower utilization than, the levels represented by Genera.

For purposes of this analysis, the Energy Bureau's calculations rely on the maximum heat input included in the Title V Operating Permit for each unit (1,007.3 MMBtu/hr) and the proposed FO6 consumption of 117.7 million gallons/yr. Applying these parameters to the available capacity of 100 MW for each unit, the resulting estimated annual natural gas consumption for each of San Juan Units 7 and San Juan Unit 9 is approximately 8.82 TBtu, resulting in a combined consumption of natural gas of approximately 17.64 TBtu for both units.[110]

This level of gas consumption, estimated based on the parameters established in the NG Purchase Contract, would require San Juan Units 7 and 9 to operate essentially at their available capacity for virtually the entire year to avoid paying for gas that is not consumed. Such an operating requirement is inconsistent with the likely operational role of the unit and could effectively obligate the T&D Operator to dispatch the units for a substantially greater

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[106] *See* 2025 Proposed IRP, p. 275.

[107] Section 4.3.3 of the NG Purchase Contract provides that:

> *...For purposes of determining the increase to the Annual TOP Quantity, the maximum annual Gas consumption of the applicable Generation Unit shall be calculated on the basis of such Generation Unit's net dependable capacity and the operating profile set forth in the applicable Required Permits.*

[108] *See* in general, February 26 Motion, Attachment B; San Juan ROI-2 Responses, Attachment A; San Juan ROI-2 Responses Attachment B; San Juan ROI-2 Responses Attachment C, and San Juan ROI-2 Responses Attachment D.

[109] As discussed below, Genera's filings contain inconsistent data.

[110] *See* San Juan ROI-2 Responses, p. 2. The proposed consumption of 117.7 million gallons/yr of FO6 for each for each unit, when considered in light of the units' maximum heat maximum heat input specified in the Title V Operating Permit implies that the units would be operating at up to 8,760 hours per year.

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number of hours than would otherwise be economically or operationally justified. It would be reasonable for the parties to revisit the Annual Take-or-Pay quantity under the NG Purchase Contract and consider using a different set of assumptions that more accurately reflects the expected operational profile of the units, thereby establishing a Take-or-Pay level that does not effectively require the unit to operate nearly year-round to avoid incurring payment obligations for unused fuel. The quantity resulting from the permit profile should not be used, by itself, to establish the Annual Take-or-Pay obligation, because it is based on a maximum theoretical operating scenario rather than on the unit's realistic expected dispatch. Specifically, the estimate of approximately 17.64 TBtu reflects unit operation at the maximum permitted heat input for the full year and therefore represents a theoretical upper bound on fuel consumption, not a reasonable projection of expected annual usage. Moreover, the units' historical heat rates of approximately 11,550 Btu/kWh (San Juan Unit 9) and 11,880 Btu/kWh (San Juan Unit 7) suggests that its actual operating characteristics do not fully align with the assumptions implicit in the permitting profile.[111] Accordingly, the Annual Take-or-Pay quantity should be based on a more reasonable and representative operational assumption, rather than solely on the maximum profile reflected in the permit.

The implications of the Annual Take-or-Pay quantity calculated pursuant to the contractual methodology become even more significant when considering the expected timing of the commercial operation of San Juan 7 and 9 using natural gas, the remaining term of the NG Purchase Contract, and the system's long-term planning assumptions. The NG Purchase Contract commenced in December 2025 and has a term of seven years. However, the San Juan Unit 7 are expected to begin operations using natural gas on September 2026, and San Juan Unit 9 are expected to begin operations using natural gas on December 2026.[112] Consequently, the Take-or-Pay obligation would effectively apply for approximately six year and three months of the contract term for San Juan Unit 7, and for six year contract term in the case of San Juan Unit 9.

The contractual methodology results in an estimated annual gas consumption of approximately <u>17.64 TBtu</u>, a level that would require the San Juan Units 7and 9 to operate essentially at its available capacity (100 MW) for nearly the entire year to avoid payment obligations for unused fuel. This concern is further exacerbated when considering the projected evolution of the system's generation mix. The 2025 Proposed IRP contemplates the retirement of San Juan Unit 7 around 2030 and San Juan Unit 9 around 2031, with a potential latest retirement date of approximately 2034. The 2025 Proposed IRP anticipates that the operational role of these units will decline substantially well before their expected retirement, with minimal utilization expected beginning around 2029 as significant new resources are added to the system. These additions include, among others, new battery energy storage systems, peaking resources, and the Energiza combined cycle natural gas plant expected to enter service around 2029. As a result, a substantial portion of the contract term for the gas supply would coincide with a period during which the 2025-Proposed IRP anticipates limited operation of San Juan Units 7 and 9. Under these circumstances, establishing a Take-or-Pay quantity derived solely from the maximum parameters in the permits and operating profile could result in the system incurring payment obligations for gas volumes unlikely to be consumed.

Accordingly, it is important that the Annual Take-or-Pay quantity be established at a reasonable level that reflects the realistic operational expectations of the units over the remaining years of their useful life. Genera and/or the 3PPO must therefore ensure that the quantity ultimately negotiated adequately safeguards the public interest when establishing the Take-or-Pay obligation applicable to San Juan Units 7 and 9. Failure to do so could expose ratepayers to unnecessary fuel payment obligations and raise questions regarding the prudence of committing to gas volumes that may ultimately become stranded as the system transitions toward the resource mix contemplated in the 2025 Proposed IRP.

The Energy Bureau understands that the San Juan Units 7 and 9 conversion project and the related gas supply arrangements do not necessarily require that the supply of natural gas for

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[111] *See* 2025 Proposed IRP, p. 164.
[112] *See* San Juan RO1-1 Responses, p. 9.

San Juan Units 7 and 9 be provided on an exclusive basis by NFE.[113] The Energy Bureau does not interpret the NG Purchase Contract as granting exclusivity, and it recognizes that another supplier could provide such natural gas. However, given the current circumstances, in which there is no alternative infrastructure capable of supplying natural gas directly from another source, such as a regasification facility that could deliver natural gas to the San Juan Power Plant, the only viable option available is supply through NFE under the existing contractual framework.[114] Under these circumstances, and in light of past experiences already known to the parties, it is also important that any additional Take-or-Pay quantities that may be incorporated into the contract as a result of converting San Juan Units 7 and 9 to operate on natural gas, and supplying such gas through NFE, be determined in a manner that serves the best interests of the public.

Originally, Genera represented that the natural gas consumption for San Juan Units 7 and 9 would be approximately 6.1 TBtu.[115]However, it did not clarify whether this amount corresponded to the Take-or-Pay obligation under the NG Purchase Contract or to total expected consumption. In a subsequent filing, Genera indicated that the total consumption for both units would range between approximately 6.1 TBtu and 7.9 TBtu.[116] Genera further represented that the total estimated natural gas consumption in San Juan would be approximately 75 TBtu annually, after accounting for the consumption attributed to San Juan Units 5 and 6 (27.2 TBtu), the San Juan TM2500 units (17.0 TBtu), the Palo Seco TM2500 units (6.1 TBtu), and Palo Seco Units 3 and 4 (20.4 TBtu).[117] Based on these figures, the aggregate consumption would total approximately 76.8 TBtu assuming 6.1 TBtu for San Juan Units 7 and 9, and approximately 78.6 TBtu assuming 7.9 TBtu, amounts that approach the upper bound of the contractual tolerance limit of approximately 78.8 TBtu under the NG Purchase Contract.

As follows from the foregoing, even under the limited natural gas consumption levels that Genera attributes to the conversion of San Juan Units 7 and 9 -which will be discussed further below in this Resolution and Order- the total quantities of natural gas under the NG Purchase Contract would be exceeded. The foregoing amounts do not include the portion attributable to the three Palo Seco TMPs (MegaGens),[118]whose conversion has been approved, nor do they account for the potential use of natural gas at Cambalache Units 2 and 3,[119] whose conversion was conditionally approved by the Energy Bureau. In both cases, the natural gas supply for these units would be sourced under the NG Purchase Contract. This situation raises significant concerns, as the NG Purchase Contract provides that any quantities consumed over the contracted volumes are not subject to the established pricing terms and must instead be negotiated by mutual agreement of the parties, and that the provision of such additional quantities remains at the discretion of the gas supplier, NFE. This creates an additional risk that the gas supplier, given the operational dependence of converted units on natural gas as their primary permitted fuel, could impose constraints or exert undue pressure, including the imposition of higher prices than those contemplated under the NG Purchase Contract. This is a circumstance that must be considered when establishing Take-or-Pay quantities, not only for the San Juan Units 7 and 9 conversion, but also for any other authorized conversions for which natural gas would be supplied under the NG Purchase Contract.

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[113] *See*, 4.1(c) of the NG Purchase Agreement.

[114] It should be noted that once San Juan Units 7 and 9 are incorporated as additional Generation Units under the NG Purchase Contract, they will generally remain subject to the terms of that agreement for the remainder of its contractual term, except under limited and narrowly defined circumstances.

[115] *See* San Juan ROI-1 Responses, p. 10.

[116] *See* San Juan ROI-2 Responses, pp. 3-4.

[117] *See* San Juan ROI-1 Responses, p. 10; San Juan ROI-2 Response, p.4. See also Palo Seco ROI-2 Response, p. 4, where Genera represented that the corrected total natural gas consumption attributable to Palo Seco Units 3 and 4 was 20.4 TBtu.

[118] *See* Resolution and Order dated January 23, 2026, issued in case *In Re: Review of Genera PR, LLC Request to Operate Palo Seco MP and Mayaguez CT with Natural Gas as Primary Fuel*, Case No.: NEPR-MI-2024-0004.

[119] *See* Resolution and Order dated July 4, 2025, issued in case *In Re: Review of Genera PR, LLC Request to Operate Palo Seco MP and Mayaguez CT with Natural Gas as Primary Fuel*, Case No.: NEPR-MI-2024-0004.

As the Energy Bureau previously recognized, it is important that Take-or-Pay provisions be established in a manner that reflects the expected dispatch levels of San Juan Units 7 and 9 over the term of the NG Purchase Contract. This is necessary to avoid circumstances in which fuel must be paid for even if it is consumed. However, the quantities of natural gas proposed for consumption by Genera, particularly at the lower bound of approximately 6.1 TBtu per year for both units (or approximately 3.05 TBtu per unit), may have additional operational implications. When such fuel quantities are evaluated with the available capacity of each unit, as well as the applicable maximum heat input , the resulting implied operating hours would be significantly lower than the levels historically represented by Genera. By way of illustration, the estimated consumption levels would correspond to approximately 3,028 operating hours per year for each unit .[120] Such reduced utilization levels may adversely affect system reliability to the extent that the units would be operated substantially less than in prior periods. This outcome is also in tension with representations that the units would be available at or near 100 MW for up to 8,760 hours per year. While continuous operation at 8,760 hours per year is not consistent with the current dispatch profile of these units, the substantially lower utilization implied by the proposed fuel quantities likewise raises concerns regarding the availability of reliable generation resources. This issue must also be considered in evaluating and establishing the appropriate natural gas quantities under the NG Purchase Contract, including the Take-or-Pay quantities.

IV. Conclusion

Considering the foregoing, and guided by the public interest, the Energy Bureau **DETERMINES** that the balance of interests favors the approval of Genera's proposal and that the proposal complies with the applicable regulatory framework. The Energy Bureau **APPROVES** the proposed fuel swap for San Juan Units 7 and 9. This **APPROVAL** shall be limited to the project described in Genera's filings regarding the San Juan Units 7 and 9. Any modifications to the project shall require obtaining the corresponding authorization from the Energy Bureau before implementation.

The Energy Bureau **CLARIFIES** that this approval of the fuel swap for the San Juan Units 7 and 9 does not constitute, nor shall it be deemed, construed, or interpreted as a determination regarding the request for a fuel swap at any other site or any initiatives under Genera's Fuel Optimization Plan ("FOP").[121] The evaluation of the fuel swap for the San Juan Units 7 and 9 as a potential fuel saving measure shall be conducted under the applicable criteria and procedures governing such matters, should the proposal be formally submitted.

The Energy Bureau **WARNS** Genera that:

(i) noncompliance with this Resolution and Order, regulations and/or applicable laws may carry the imposition of fines and administrative sanctions of up to one hundred twenty-five thousand dollars ($125,000) per day;

(ii) for any recurrence of non-compliance or violation, the established penalty shall increase to a fine of not less than fifteen thousand dollars ($15,000) nor greater than two hundred fifty thousand dollars ($250,000) at the discretion of t/e Energy Bureau

[120] According to Genera, the Service Hours for San Juan Unit 9 were 7,794 hours in FY23-24, 6,823 hours in FY24-25, and 4,417 hours during the first six months of FY25-26. *See* San Juan ROI-1 Response, p. 6.

[121] *See In Re: Genera PR, LLC Fuel Optimization Plan*, Case No.: NEPR-MI-2023-0004.

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Be it notified and published.

Edison Avilés Deliz
Chairman

Lillian Mateo Santos
Associate Commissioner

Sylvia B. Ugarte Araujo
Associate Commissioner

Antonio Torres Miranda
Associate Commissioner

CERTIFICATION

I certify that the majority of the members of the Puerto Rico Energy Bureau has so agreed on March 20, 2026. Associate Commissioner Ferdinand A. Ramos Soegaard dissented without a written opinion. I also certify that on March 20, 2026 I have proceeded with the filing of the Resolution and Order issued by the Puerto Rico Energy Bureau and a copy was notified by electronic mail to regulatory@genera-pr.com, legal@genera-pr.com, jfr@sbgblaw.com, jdiaz@ecija.com, sromero@ecija.com; alexis.rivera@prepa.pr.gov; nzayas@gmlex.net; mvalle@gmlex.net; rcruzfranqui@gmlex.net; alejandro.figueroara@lumapr.com; Yahaira.delarosa@us.dlapiper.com; Emmanuel.porrogonzalez@us.dlapiper.com.

I sign this in San Juan, Puerto Rico, today March 20, 2026.

Sonia Seda Gaztambide
Clerk

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