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Off-shore Solar Energy Generation System in the Energy Community of Providencia (Colombia) - Case Study

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Abstract This study evaluates the technical, reliability, environmental–operational, and financial feasibility of an offshore floating photovoltaic system for an energy community on Providencia Island, Colombia. The stochastic framework integrates Monte Carlo simulation, Latin Hypercube Sampling, satellite-derived hourly irradiance and temperature data, cycle-based battery degradation, marine operating losses, local-grid-supported dispatch, diesel-equivalent accounting, and financial-support sensitivity.

Two pathways are compared: fully isolated photovoltaic–battery operation and a realistic local-grid-supported configuration in which the existing island infrastructure acts as a diesel-equivalent backup, with no electricity exports assumed. The lowest-cost off-grid solution meeting a mean Loss of Load Probability (LOLP) threshold of 5% is 420 kWp + 400 kWh. However, it leaves approximately 2.67% of the annual demand unserved on average, presents a 95th-percentile LOLP of 10.87%, incurs high energy costs, and shows a negligible probability of achieving a positive Net Present Value (NPV).

The recommended transitional configuration is 240 kWp + 100 kWh. It reduces battery capacity by 75% relative to the off-grid reference while achieving a mean LOLP of 1.51%, a renewable fraction of 61.11%, and a diesel-equivalent grid dependency of 38.89%. NASA POWER irradiance data agree closely with ERA5 reanalysis, with a mean difference of only 0.85% across 35 064 hourly records from 2020 to 2023. Under the no-export assumption, a positive mean NPV is reached only with CAPEX co-financing of approximately 40%, resulting in a probability of positive NPV of approximately 55.6%.

Offshore photovoltaic generation is therefore technically relevant as a diesel-reduction strategy for Providencia. However, it should be implemented as a policy-supported transitional pathway rather than as an immediately autonomous and financially self-sufficient system.

Keywords Floating photovoltaic systems; Monte Carlo simulation; photovoltaic-battery sizing optimization; diesel-equivalent local-grid support; cycle-based battery degradation; no-export microgrids; energy communities; techno-economic feasibility; non-interconnected zones.

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1. Introduction

Access to electricity is a fundamental condition for social welfare, productive development, and environmental sustainability, particularly in isolated island territories where conventional grid interconnection is technically or economically limited. In Colombia, Non-Interconnected Zones rely heavily on local generation systems, frequently based on diesel or other fossil fuels, which increases electricity costs, exposes communities to fuel supply volatility, and generates environmental impacts [1, 3]. These challenges are especially relevant in

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island communities, where energy security is closely linked to tourism, public services, water supply, health infrastructure, and local economic activity.

Providencia Island, located in the Archipelago of San Andres, Providencia, and Santa Catalina, represents a critical case of energy vulnerability in the Colombian Caribbean. Due to its insular condition and lack of connection to the National Interconnected System, electricity supply has traditionally depended on local thermal generation. This dependence increases operational costs and carbon emissions while creating risks associated with fuel transportation, storage, and price fluctuations. At the same time, Providencia is part of the Seaflower Biosphere Reserve, a highly sensitive marine and coastal ecosystem recognized for its ecological value [13]. In this context, off-shore floating photovoltaic systems emerge as a promising alternative for island territories with land-use constraints, high solar availability, and proximity to coastal demand centers. Floating photovoltaic systems may reduce land occupation, allow modular deployment, and support decentralized energy schemes when integrated with battery storage and local distribution infrastructure [16, 17, 18, 19, 20].

However, their implementation in isolated communities presents additional challenges related to marine environmental exposure, corrosion, anchoring, submarine cabling, maintenance logistics, storage sizing, and reliability under variable solar-resource conditions. These factors make deterministic feasibility evaluations insufficient when used alone, since they do not fully capture the combined effect of uncertainty in resource availability, demand behavior, investment costs, operational costs, financial parameters, local-grid availability, and battery replacement timing. The proposed off-shore photovoltaic system is intended to support a specific energy community in Providencia Island. The objective of the project is not to introduce a new diesel generation plant as an additional project asset, nor to redesign the complete island power system. Instead, the study evaluates how an off-shore photovoltaic–battery system can supply local demand, reduce dependence on the existing diesel-backed electricity infrastructure, and improve the technical and financial interpretation of renewable deployment in an isolated island context. For this reason, the existing electricity infrastructure of Providencia is represented through a diesel-equivalent local-grid-supported scenario. Under this approach, the local grid is not modeled as an infinite connection to the Colombian National Interconnected System, nor as a conventional electricity market capable of absorbing and remunerating distributed exports.

The local grid is represented as a limited and stochastic backup source. Energy imported from this grid is converted into equivalent diesel consumption, variable fuel cost, and CO_2 emissions. In the base operating case, no sale of electricity to the local grid is assumed; surplus photovoltaic energy that cannot be used directly or stored is curtailed. The analysis therefore distinguishes between two complementary design pathways. The first pathway evaluates a fully isolated photovoltaic–battery configuration, which is useful as a technical reference for autonomous operation. The second pathway evaluates a local-grid-supported photovoltaic–battery configuration, in which the existing island electricity infrastructure is represented as a diesel-equivalent backup system. This distinction is relevant for Providencia because full autonomy requires a larger battery system, whereas the existing local grid can provide transitional support without being treated as a market for surplus electricity sales. The proposed stochastic computational framework combines Monte Carlo simulation, Latin Hypercube Sampling, satellite-derived hourly irradiance and temperature data, photovoltaic–battery dispatch, cycle-based battery degradation, marine operating losses, diesel-equivalent grid accounting, financial support sensitivity, and scenario ranking. This allows the study to move from a single deterministic result to a probability-based assessment of technical, reliability, environmental-operational, and financial performance.

1.1. Research Objective

This study evaluates the technical, environmental-operational, reliability, and financial feasibility of an off-shore photovoltaic generation system for the energy community of Providencia Island. The stochastic framework is introduced to determine whether the deterministic feasibility conclusions remain robust when hourly operation, satellite-derived solar-resource variability, marine operating conditions, battery degradation, local-grid support, and financial support mechanisms are explicitly considered. Accordingly, the guiding research question is: to what extent can an off-shore photovoltaic system for Providencia Island provide reliable and financially viable electricity supply under uncertainty, considering both fully isolated photovoltaic–battery operation and a no-export diesel-equivalent local-grid-supported transition pathway?

1.2. Main Contributions

The main contributions of this study are sixfold:

1. A stochastic simulation framework is developed to evaluate an off-shore floating photovoltaic system for Providencia Island under joint technical, meteorological, operational, reliability, local-grid, and financial uncertainty.
2. Satellite-derived hourly irradiance and temperature data are incorporated into the photovoltaic generation model for the project coordinates, replacing the simplified normalized daily generation profile and improving the representation of solar variability under real operating conditions [26].
3. A marine operating layer is included to represent additional effects of salt-related soiling, marine photovoltaic degradation, cable and connector losses, power electronics derating, marine access constraints, and major anti-corrosion maintenance on system performance and cost.
4. A cycle-based lithium-ion battery degradation model is implemented, in which battery replacement timing emerges from the simulated operating profile through equivalent full cycles, average depth of discharge, calendar aging, temperature stress, and state-of-health evolution.
5. The existing electricity infrastructure of Providencia is represented through a diesel-equivalent local-grid-supported scenario. This allows grid imports to be converted into equivalent diesel consumption, variable fuel cost, and CO_2 emissions, without introducing a new diesel generator as a project asset.
6. A financial support sensitivity is introduced to evaluate tax incentives and CAPEX co-financing under a conservative no-export operating condition, consistent with the limitations of the local island grid. Export-compensation cases are retained only as non-base sensitivities and are not used to define the recommended configuration.

1.3. Paper Organization

The remainder of this paper is organized as follows. Section 1.4 presents the Providencia case study, deterministic baseline, and community demand characterization. Section 2 describes the stochastic simulation framework, including satellite-derived photovoltaic generation, marine operating losses, cycle-based battery degradation, off-grid and local-grid-supported dispatch, diesel-equivalent accounting, reliability indicators, techno-economic indicators, no-export local-grid operation, financial support scenarios, and non-base export sensitivities. Section 3 presents the off-grid results, diesel-equivalent local-grid-supported scenarios, diesel-equivalent validation, financial support sensitivity, and recommended realistic configuration. Section 4 discusses the technical, reliability, environmental-operational, financial, and policy implications of the results. Finally, Section 5 summarizes the main conclusions, limitations, and future research directions.

1.4. Case Study and Deterministic Baseline

Providencia Island is located in the Colombian Caribbean and belongs to the Archipelago of San Andres, Providencia, and Santa Catalina. Due to its geographical isolation, the island is not connected to the Colombian National Interconnected System [1, 2, 3]. As a result, electricity supply has historically relied on local thermal generation, mainly based on diesel fuel. This condition increases generation costs, exposes the community to fuel transportation and price risks, and creates environmental pressure on a highly sensitive island ecosystem. The proposed off-shore photovoltaic system is intended to support an energy community located in Providencia Island. The deterministic baseline study considered residential, institutional, commercial, public lighting, police, health, educational, recreational, and future water-treatment loads. The demand profile was constructed from the classification of community users and the estimated power consumption of each load group. The peak demand was estimated at 40.73 kVA, occurring between 11:00 and 12:00. This hourly demand curve constitutes the basis for the stochastic energy-balance simulation developed in this work. The original deterministic assessment evaluated the technical, environmental, and financial feasibility of an off-shore solar generation system composed of floating photovoltaic modules, battery storage, power conversion equipment, transformers, a submarine cable, and a local distribution network [5, 6, 4, 11]. The deterministic financial indicators suggested a promising result under fixed baseline assumptions. However, these deterministic indicators were obtained under fixed input values and did not explicitly quantify the joint effect of uncertainty or the hourly reliability of the isolated photovoltaic–battery system. Therefore, in this paper, the deterministic case is retained as the conceptual and technical baseline of the study, while the stochastic stage is introduced as a robustness and transition-pathway assessment. The stochastic framework evaluates whether the proposed system remains technically and financially adequate when uncertainty in meteorological, demand, cost, operational, marine, battery-degradation, local-grid, and financial variables is considered.

Table 1. Main characteristics of the Providencia case study.

Parameter	Description
Location	Providencia Island, Colombia
Energy context	Non-Interconnected Zone
Current dependency	Diesel-based local thermal generation
Project type	Off-shore floating photovoltaic system for an energy community
Main objective	Technical, reliability, environmental-operational, and financial feasibility assessment
Demand model	Hourly community load profile
Peak demand	40.73 kVA, approximated as 40.73 kW
Main users	Residential, school, store, health post, police station, public lighting
Environmental context	Seaflower Biosphere Reserve
Local-grid interpretation	Diesel-equivalent backup source, not a surplus-energy market
Simulation extension	Monte Carlo, satellite data, battery degradation, grid support, financial sensitivity

Table 2. Deterministic baseline assumptions retained as reference for the stochastic extension.

Parameter	Reference value or interpretation
Project location	Providencia Island, Colombia
Energy context	Non-Interconnected Zone with local thermal generation
Community peak demand	40.73 kVA, approximated as 40.73 kW
Deterministic annual energy reference	280,352.64 kWh/year
Hourly-profile annual energy	265,106.8 kWh/year before stochastic multipliers
Baseline PV capacity	240.38 kWp
Baseline PV module configuration	476 modules of 505 Wp
Baseline battery capacity	240 kWh
Baseline battery configuration	48 battery units of 5 kWh
Project lifetime	25 years
Financial indicators	LCOE, NPV, IRR, payback period
Reliability indicators in stochastic stage	LOLP, EENS, served demand fraction
Baseline stochastic role	Reference case for robustness and sizing assessment

The deterministic baseline is therefore used as the conceptual and technical reference for the energy community design, while the stochastic model evaluates whether such a design remains reliable and financially robust under uncertainty. The distinction between deterministic feasibility and stochastic robustness is important because the deterministic assessment relies on fixed input assumptions, whereas the stochastic extension explicitly evaluates uncertainty in demand, satellite-derived solar resource, costs, financial parameters, battery degradation, marine operation, and local-grid support.

1.5. Community Demand Characterization and Stochastic Baseline Definition

The community demand was characterized from the deterministic feasibility study, which identified the main user groups of the proposed energy community in Providencia Island. The load assessment included 30 houses, one school, one store, one health post, one police station, public lighting, a park, and a future water-treatment plant. These users represent the residential, institutional, commercial, public-service, and future infrastructure loads considered in the original project. The deterministic study estimated a peak demand of 40.73 kVA between 11:00 and 12:00. For the hourly stochastic simulation, a near-unity power factor was assumed; therefore, apparent power values from the deterministic assessment were approximated as active power values in kW. Under this assumption, the peak demand of 40.73 kVA was treated as approximately 40.73 kW in the photovoltaic–battery dispatch model. The hourly load profile used in the stochastic simulation is shown in Table 3. This profile represents the average hourly power demand and is used as the base demand curve for all Monte Carlo realizations. In each realization, the deterministic hourly profile is multiplied by a stochastic demand multiplier and by the annual demand growth factor.

Table 3. Hourly demand profile used in the stochastic simulation.

Hour	0	1	2	3	4	5	6
Demand [kW]	23.82	23.82	24.02	24.02	24.02	26.84	32.54
Hour	7	8	9	10	11	12	13
Demand [kW]	31.52	31.71	32.06	32.06	40.73	40.13	40.13
Hour	14	15	16	17	18	19	20
Demand [kW]	32.00	24.27	24.35	24.98	28.96	34.96	34.76
Hour	21	22	23				
Demand [kW]	34.01	33.89	26.72				

The daily energy demand associated with the hourly load profile is calculated as:

$$E_d = \sum_{h=0}^{23} P_{d,h} \Delta t, \qquad \Delta t = 1 \text{ h}, \tag{1}$$

where E_d is the daily electrical energy demand, $P_{d,h}$ is the average demand during hour h, and Δt is the hourly simulation time step. The profile presented in Table 3 sums to 726.32 kWh/day, equivalent to 265,106.8 kWh/year before applying stochastic demand multipliers and annual demand growth. The deterministic study reported an annual energy reference of 280,352.64 kWh/year; therefore, this value is retained as the deterministic feasibility reference, while the hourly profile is used for the stochastic reliability assessment. The photovoltaic reference capacity retained from the deterministic design corresponds to a modular configuration of 476 monocrystalline modules of 505 Wp each:

$$P_{pv,base} = 476 \times 505 \text{ Wp} = 240.38 \text{ kWp}. \tag{2}$$

Similarly, the stochastic baseline battery capacity was normalized to 240 kWh, consistent with a modular lithium-ion battery configuration of 48 battery units of 5 kWh each. This value is close to the storage capacity reported in the deterministic design and provides a practical reference for evaluating whether the original storage concept is sufficient under hourly operation. Therefore, the stochastic baseline is defined as 240 kWp of photovoltaic capacity and 240 kWh of battery storage. This baseline is not introduced as a change in the original objective of the study, but as a normalized reference configuration for uncertainty propagation and hourly reliability assessment. The analysis then evaluates two complementary pathways. The first pathway corresponds to fully isolated off-grid operation, where photovoltaic and battery capacities are adjusted to determine the autonomous configuration required to satisfy the selected reliability criterion. The second pathway corresponds to a local-grid-supported configuration, where the existing island electricity system is represented as a diesel-equivalent backup source with limited import capacity and stochastic availability. In the base case, the local grid is not assumed to purchase or remunerate electricity exports. This structure allows the study to distinguish between the technical requirements of full autonomy and the more practical transitional pathway in which the proposed off-shore photovoltaic system reduces, but does not immediately eliminate, dependence on the existing diesel-backed local grid.

1.6. Deterministic Baseline, Off-grid Robustness, and Local-grid-supported Extension

The original deterministic design was developed as a feasibility case study for an off-shore photovoltaic system serving the Providencia energy community. It included photovoltaic generation, lithium-ion battery storage, power conversion equipment, transformers, submarine cabling, and a radial distribution network. Under fixed assumptions, the deterministic assessment reported favorable economic indicators and suggested that the system could represent a feasible renewable alternative for the island. However, deterministic annual feasibility does not ensure hourly reliability under uncertainty, particularly in isolated photovoltaic–battery systems. Energy availability depends on the temporal alignment between solar generation, demand, storage capacity, state-of-charge constraints, and battery degradation. For this reason, the present work complements the deterministic baseline with an hourly stochastic assessment and a reliability-based sizing procedure. The framework evaluates two complementary configurations. First, a fully off-grid photovoltaic–battery configuration is simulated to determine the storage and photovoltaic capacity required for autonomous operation. Second, a local-grid-supported configuration is evaluated to represent a more realistic transitional pathway for Providencia, where the existing island grid acts as a diesel-equivalent backup source. In the local-grid-supported configuration, photovoltaic generation first supplies the load, surplus energy charges the battery, remaining surplus is curtailed in the base no-export case, and residual deficits are supplied by the local grid subject to availability and import-capacity limits.

Table 4. Deterministic baseline and stochastic extensions used in this study.

Component	**Deterministic assessment**	**Stochastic extension**
Purpose	Feasibility evaluation	Robustness, sizing, and transition assessment
Main approach	Fixed input assumptions	Monte Carlo uncertainty propagation
Solar resource	Deterministic reference	Satellite-derived hourly irradiance
Battery model	Fixed design reference	SOH, EFC, DoD, calendar aging, temperature stress
Marine operation	General feasibility consideration	Marine losses and O&M multipliers
Reliability assessment	Not probabilistic in detail	LOLP, EENS, served fraction
Off-grid sizing	Conceptual design basis	PV–battery sizing sweep
Local-grid support	Not explicitly modeled	Diesel-equivalent island-grid representation
Export to local grid	Not considered	No-export base case; export only as non-base sensitivity
Financial support	Baseline financial indicators	Tax incentive and CAPEX-support sensitivity
Scenario selection	Deterministic interpretation	Realism-adjusted multicriteria ranking

2. Stochastic Simulation Framework

The stochastic simulation framework was designed to evaluate the robustness of the proposed off-shore photovoltaic system under meteorological, demand, technical, marine-operational, reliability, local-grid, diesel-equivalent, and financial uncertainty. The framework integrates stochastic input definition, Latin Hypercube Sampling, satellite-derived hourly photovoltaic generation, marine operating-loss modeling, cycle-based battery degradation, off-grid and local-grid-supported dispatch, diesel-equivalent accounting for grid imports, and financial support sensitivity. The simulation procedure follows these steps:

1. Define the deterministic technical and financial reference parameters of the off-shore photovoltaic system.
2. Obtain satellite-derived hourly irradiance and temperature data for the project coordinates.
3. Define stochastic input variables and probability distributions for demand, costs, financial parameters, photovoltaic degradation, battery degradation, marine operating factors, and local-grid support.
4. Generate input samples using Latin Hypercube Sampling.
5. Simulate hourly photovoltaic generation, direct load supply, battery charging and discharging, grid imports, curtailment, and unmet demand.

6. Compute reliability indicators, including Loss of Load Probability, Expected Energy Not Supplied, and served demand fraction.
7. Convert local-grid imports into equivalent diesel consumption, variable fuel cost, and CO_2 emissions.
8. Compute financial indicators, including Levelized Cost of Energy, Net Present Value, Internal Rate of Return, and payback period.
9. Evaluate fully off-grid photovoltaic–battery configurations and local-grid-supported scenarios.
10. Apply financial-support sensitivities under the no-export base case.
11. Rank candidate scenarios using technical, financial, reliability, and realism-adjusted criteria.

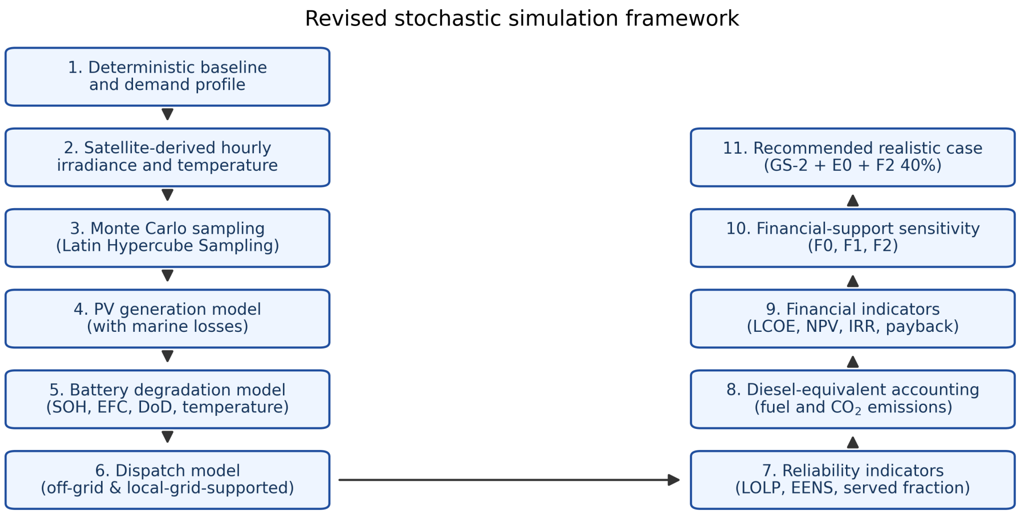

Figure 1. Revised stochastic simulation framework including satellite-derived photovoltaic generation, marine operating losses, cycle-based battery degradation, no-export local-grid-supported dispatch, diesel-equivalent accounting, and financial-support sensitivity.

2.1. Stochastic Input Variables

The Monte Carlo model incorporates uncertainty in meteorological, demand, technical, marine-operational, grid-support, diesel-equivalent, and financial variables. These variables influence photovoltaic output, useful energy delivered to the load, battery replacement timing, grid dependency, equivalent diesel consumption, emissions, investment cost, operating cost, and long-term financial performance. Monte Carlo simulation was used to propagate uncertainty in the system outputs [37], while Latin Hypercube Sampling was used to improve coverage of the input space compared with simple random sampling [38]. Let $\mathbf{x}$ denote the vector of uncertain input variables:

$$\mathbf{x} = [x_{irr}, x_{temp}, x_{dem}, x_{capex}, x_{opex}, x_{tariff}, r, d_{pv}, N_{cyc,80}, d_{cal}, \Delta T_{bat}, \beta_{DoD}, x_{marine}, x_{grid}, x_{diesel}, \pi], \quad (3)$$

where x_{irr} represents the irradiance-related uncertainty applied to the satellite-derived hourly profile, x_{temp} is ambient temperature uncertainty, x_{dem} is the demand multiplier, x_{capex} and x_{opex} are cost multipliers, x_{tariff} is the tariff multiplier, r is the discount rate, d_{pv} is annual photovoltaic degradation, $N_{cyc,80}$ is the battery equivalent cycle life until 80% state of health, d_{cal} is calendar aging, ΔT_{bat} is the battery temperature rise, β_{DoD} is the depth-of-discharge stress exponent, x_{marine} groups marine operating-loss variables, x_{grid} groups local-grid availability and import-capacity variables, x_{diesel} groups diesel-equivalent conversion parameters, and π is the inflation rate.

Table 5. General stochastic input variables used in the Monte Carlo simulation.

Variable	Distribution	Description
Irradiance multiplier	Triangular (0.95, 1.00, 1.05)	Correction factor for hourly satellite irradiance
Ambient temperature [°C]	Normal (28.0, 2.0)	Ambient operating temperature
Demand multiplier	Normal (1.00, 0.08)	Aggregate demand uncertainty
CAPEX multiplier	Triangular (0.90, 1.00, 1.20)	Investment cost uncertainty
OPEX multiplier	Triangular (0.80, 1.00, 1.40)	Operating cost uncertainty
Tariff multiplier	Triangular (0.85, 1.00, 1.15)	Electricity tariff uncertainty
Discount rate	Triangular (0.08, 0.10, 0.13)	Project discount rate
PV degradation	Normal (0.005, 0.0015)	Annual photovoltaic degradation
Battery cycle life to 80% SOH	Triangular (4000, 6000, 8000)	Equivalent full cycles to end of life
Battery calendar aging	Triangular (0.005, 0.010, 0.020)	Annual calendar capacity loss
Battery temperature rise [°C]	Triangular (0.0, 2.0, 5.0)	Battery temperature above ambient
DoD stress exponent	Triangular (0.8, 1.1, 1.5)	Degradation sensitivity to depth of discharge
Inflation	Normal (0.035, 0.010)	Annual inflation rate

Table 6. Additional marine, grid, diesel-equivalent, and policy variables.

Variable	Reference value or distribution	Description
PV salt/soiling loss	Triangular (0.00, 0.015, 0.04)	Salt spray, biofouling, and marine soiling loss
Marine PV degradation adder	Triangular (0.000, 0.0015, 0.004)	Additional annual degradation due to marine exposure
Cable/connector loss adder	Triangular (0.000, 0.005, 0.015)	Additional marine electrical losses
Power electronics derating	Triangular (0.000, 0.005, 0.020)	Derating of inverters and enclosures
Structure corrosion multiplier	Triangular (1.00, 1.10, 1.30)	Floating-structure corrosion O&M multiplier
Mooring inspection multiplier	Triangular (1.00, 1.10, 1.25)	Mooring and anchoring inspection multiplier
Marine access multiplier	Triangular (1.00, 1.15, 1.50)	Access and offshore maintenance multiplier
Major anti-corrosion maintenance year	Triangular (5.0, 7.0, 10.0)	Major marine intervention year
Grid import limit	40 kW	Community/project import limit from local grid
Grid availability	Triangular (0.95, 0.98, 1.00)	Annual availability of the local grid
Base export limit	0 kW	No electricity sales to the local grid in the base case
Diesel specific fuel consumption	Triangular (0.28, 0.307, 0.34) L/kWh	Diesel-equivalent conversion factor
Diesel emission factor	2.68 kg CO_2/L	CO_2 emissions per liter of diesel
CAPEX co-financing	0%, 20%, 40%, or 60%	Financial-support sensitivity
Tax incentive timing	5 or 15 years	Fiscal incentive sensitivity

2.2. Cycle-Based Battery Degradation Model

To represent the operational dependence of lithium-ion battery aging, the battery state of health (SOH) is updated annually as a function of calendar aging, equivalent full cycles, depth-of-discharge stress, and temperature effects. Battery replacement is triggered when the SOH falls below 80%. The annual battery state of health is calculated as:

$$SOH_y = SOH_{y-1} - D_{cal,y} - D_{cyc,y}, \tag{4}$$

where SOH_y is the battery state of health in year y, $D_{cal,y}$ is the calendar aging contribution, and $D_{cyc,y}$ is the cycle aging contribution. The equivalent full cycles in year y are estimated from the discharged energy:

$$EFC_y = \frac{E_{dis,y}}{E_{bat}}, \tag{5}$$

where $E_{dis,y}$ is the annual energy discharged from the battery to the load, and E_{bat} is the nominal battery capacity. Calendar aging is modeled as:

$$D_{cal,y} = d_{cal} f_T, \tag{6}$$

where d_{cal} is the annual calendar capacity fade and f_T is a temperature stress factor. The temperature stress factor is approximated as:

$$f_T = 2^{\frac{T_{bat}-T_{ref}}{10}}, \tag{7}$$

where T_{bat} is the estimated battery operating temperature and T_{ref} is the reference temperature, assumed to be 25°C. Cycle aging is modeled as:

$$D_{cyc,y} = 0.20 \left(\frac{EFC_y}{N_{cyc,80}} \right) f_{DoD} f_T, \tag{8}$$

where $N_{cyc,80}$ is the number of equivalent full cycles required to reach 80% SOH. The depth-of-discharge stress factor is calculated as:

$$f_{DoD} = \left(\frac{DoD_{avg}}{DoD_{ref}} \right)^{\beta_{DoD}}, \tag{9}$$

where DoD_{avg} is the average daily depth-of-discharge swing obtained from the hourly dispatch simulation, DoD_{ref} is the reference depth of discharge, and β_{DoD} is a stochastic exponent representing uncertainty in the sensitivity of battery degradation to discharge depth. Battery replacement is triggered when:

$$SOH_y \leq SOH_{EOL}, \tag{10}$$

with $SOH_{EOL} = 0.80$. After replacement, battery SOH is reset to 1.0 and the corresponding replacement cost is included in the project cash flow and LCOE calculation. This approach allows the replacement schedule to emerge from the simulated operating profile rather than being imposed as a fixed lifetime.

2.3. Satellite-derived Photovoltaic Generation and Marine Loss Model

The photovoltaic generation model uses satellite-derived hourly irradiance and temperature data for the project coordinates in Providencia Island. Hourly solar and meteorological data were obtained from the NASA POWER hourly data service for the coordinates 13.346834°N and 81.394147°W [26]. The use of an 8760-hour irradiance profile allows the model to represent day-to-day and intra-day variability, including cloudy periods and seasonal changes, without imposing an idealized bell-shaped generation profile. For each hour h, the photovoltaic DC output is estimated as:

$$P_{pv,h}^{DC} = P_{pv} \frac{G_h}{G_{STC}} f_{T,h} f_{deg,y} f_{marine,h}, \tag{11}$$

where P_{pv} is the installed photovoltaic capacity in kWp, G_h is the hourly irradiance obtained from the satellite-derived dataset, G_{STC} is the standard irradiance of 1 kW/m^2, $f_{T,h}$ is the temperature correction factor, $f_{deg,y}$ is the photovoltaic degradation factor in year y, and $f_{marine,h}$ is the aggregated marine operating factor. The cell temperature is approximated using a NOCT-based expression [25]:

$$T_{cell,h} = T_{amb,h} + \frac{T_{NOCT} - 20}{0.8} G_h, \tag{12}$$

where $T_{amb,h}$ is the hourly ambient temperature and T_{NOCT} is the nominal operating cell temperature. The temperature correction factor is given by:

$$f_{T,h} = 1 + \gamma(T_{cell,h} - T_{STC}), \tag{13}$$

where γ is the photovoltaic temperature coefficient and T_{STC} is the standard test condition temperature. The annual photovoltaic degradation factor is modeled as:

$$f_{deg,y} = (1 - d_{pv} - d_{marine})^{y-1}, \tag{14}$$

where d_{pv} is the standard annual photovoltaic degradation rate and d_{marine} is an additional degradation term associated with marine exposure. The marine operating factor aggregates additional losses related to salt deposition, soiling, cable and connector losses, and power electronics derating:

$$f_{marine,h} = (1 - L_{salt})(1 - L_{cable})(1 - L_{conn})(1 - L_{der}), \tag{15}$$

where L_{salt} represents salt-related soiling losses, L_{cable} represents additional cable losses, L_{conn} represents connector and junction losses, and L_{der} represents derating of power electronics under marine operating conditions. Finally, the useful AC photovoltaic output is limited by the inverter capacity:

$$P_{pv,h}^{AC} = \min(P_{pv,h}^{DC}\eta_{inv}, P_{inv}^{max}), \tag{16}$$

where η_{inv} is the inverter efficiency and P_{inv}^{max} is the maximum inverter output. This formulation uses hourly satellite-derived solar-resource conditions and includes marine operating losses, improving the representation of resource variability and off-shore operating conditions.

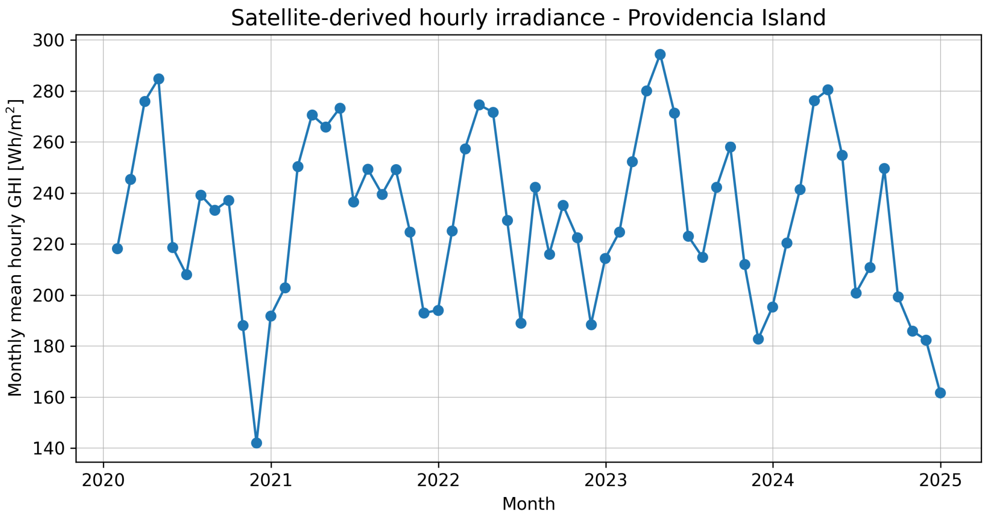

Figure 2. Satellite-derived hourly solar resource used for the project coordinates in Providencia Island. The monthly mean hourly GHI profile is derived from NASA POWER hourly data and replaces the idealized bell-shaped photovoltaic generation profile.

To provide an additional consistency check on the satellite-derived irradiance data, hourly global horizontal irradiance from NASA POWER was cross-validated against the independent ERA5 reanalysis product accessed via Open-Meteo [39, 40] for the same project coordinates (13.346834°N, 81.394147°W) over the period 2020–2023 (35,064 common hourly records).

The mean irradiance was 232.23 W/m^2 for NASA POWER and 234.21 W/m^2 for ERA5, corresponding to a relative difference of -0.85%, with NASA POWER slightly lower. The hourly mean absolute error was 78.01 W/m^2, the root-mean-square error was 124.08 W/m^2, and the Pearson correlation during daytime hours was 0.839. The low long-term bias supports the use of NASA POWER as a reasonable solar-resource proxy in the absence of on-site pyranometer measurements, while the hourly-scale scatter reinforces the need to propagate irradiance uncertainty through the stochastic multiplier used in Table 5.

2.4. Off-grid and Local-grid-supported Dispatch Model

The dispatch model evaluates the hourly balance between photovoltaic generation, demand, battery charging and discharging, local-grid imports, curtailment, and unmet demand. Two operating modes are considered: fully off-grid operation and local-grid-supported operation.

2.4.1. Off-grid photovoltaic–battery dispatch At each hour h, direct photovoltaic supply is calculated as:

$$P_{direct,h} = \min(P_{pv,h}^{AC}, P_{d,h}), \tag{17}$$

where $P_{d,h}$ is the demand at hour h. The surplus photovoltaic energy available for charging is:

$$P_{surplus,h} = P_{pv,h}^{AC} - P_{direct,h}, \tag{18}$$

and the remaining deficit after direct photovoltaic supply is:

$$P_{deficit,h} = P_{d,h} - P_{direct,h}. \tag{19}$$

The battery state of charge is constrained by minimum and maximum values:

$$SOC_{min} = E_{bat}(1 - DOD), \tag{20}$$

$$SOC_{max} = E_{bat}, \tag{21}$$

where E_{bat} is the installed battery capacity and DOD is the maximum depth of discharge. When surplus photovoltaic energy is available, the battery is charged according to:

$$SOC_{h+1} = SOC_h + \min(P_{surplus,h}\eta_{ch}, SOC_{max} - SOC_h). \tag{22}$$

When a demand deficit remains, the battery discharges according to:

$$P_{dis,h} = \min(P_{deficit,h}, (SOC_h - SOC_{min})\eta_{dis}). \tag{23}$$

The updated state of charge during discharge is:

$$SOC_{h+1} = SOC_h - \frac{P_{dis,h}}{\eta_{dis}}. \tag{24}$$

The unmet demand in fully off-grid operation is:

$$P_{unmet,h}^{off} = P_{deficit,h} - P_{dis,h}. \tag{25}$$

This dispatch rule prioritizes direct photovoltaic supply, uses surplus generation to charge the battery, and discharges the battery only when photovoltaic generation is insufficient to meet demand.

2.4.2. Diesel-equivalent local-grid-supported dispatch In the local-grid-supported configuration, the dispatch sequence remains based on self-consumption. Photovoltaic generation first supplies the demand directly. Surplus photovoltaic generation is used to charge the battery. In the base local-grid-supported case, electricity export is not allowed; therefore, after direct photovoltaic supply and battery charging, any remaining photovoltaic surplus is curtailed. Residual deficits after photovoltaic supply and battery discharge are supplied by the local grid when it is available and subject to the project import limit:

$$P_{grid,h} = \min(P_{deficit,h} - P_{dis,h}, P_{grid,h}^{max}), \tag{26}$$

where $P_{grid,h}$ is the power imported from the local grid and $P_{grid,h}^{max}$ is the available import capacity at hour h. The remaining unmet demand is:

$$P_{unmet,h}^{grid} = P_{deficit,h} - P_{dis,h} - P_{grid,h}. \tag{27}$$

The local grid is not modeled as the Colombian National Interconnected System. It represents the existing diesel-backed island electricity infrastructure available to the community under limited import capacity and stochastic availability. The 40 kW import limit represents the community/project interconnection limit, not the total installed capacity of the Providencia island power plant.

2.5. *Diesel-equivalent Representation of the Existing Local Grid*

The existing local grid is represented as a diesel-equivalent backup source. This representation allows the model to estimate the equivalent fuel use and emissions associated with grid imports without introducing a new diesel generator as a project asset or performing unit-commitment dispatch of each island generator. The annual diesel-equivalent energy imported from the local grid is:

$$E_{grid,y} = \sum_{h=1}^{8760} P_{grid,h}. \tag{28}$$

The equivalent annual diesel consumption is calculated as:

$$Fuel_y = E_{grid,y} \times SFC, \tag{29}$$

where $Fuel_y$ is the annual equivalent diesel consumption in liters, $E_{grid,y}$ is the annual energy imported from the local grid in kWh, and SFC is the specific fuel consumption in L/kWh. The specific fuel consumption is modeled as:

$$SFC \sim Triangular(0.28, 0.307, 0.34)\ \mathrm{L/kWh}. \tag{30}$$

The most likely value of 0.307 L/kWh is consistent with reported fuel-consumption information for the Providencia power system, where 0.0812 gal/kWh is equivalent to approximately 0.307 L/kWh [31]. This value is also consistent with the specific-fuel-consumption approach commonly used in hybrid microgrid modeling [30]. Annual diesel-equivalent CO_2 emissions are calculated as:

$$CO_{2,y} = Fuel_y \times EF_{CO2}, \tag{31}$$

where $EF_{CO2} = 2.68$ kg CO_2/L is the diesel emission factor. This value is consistent with international diesel emission factors expressed on a volume basis [32]. The diesel-equivalent indicators are not used to modify the private NPV calculation directly, in order to avoid double counting with the electricity tariff paid for grid imports. Instead, they are reported as system-level environmental-operational indicators that quantify the remaining diesel-equivalent dependency and the avoided diesel use relative to a diesel-only local-grid baseline.

The diesel-equivalent indicators reported in the results section are calculated using this same formulation. Therefore, local-grid imports are interpreted as diesel-equivalent energy supplied by the existing island power system, and not as electricity purchased from an infinite national grid. This distinction is essential because the local grid is used only as backup and is not assumed to purchase surplus photovoltaic electricity from the community.

2.6. *Reliability Indicators*

Two reliability indicators are used to quantify the adequacy of the photovoltaic–battery system: Loss of Load Probability and Expected Energy Not Supplied [28]. The Loss of Load Probability is defined as the fraction of simulated hours in which the system presents unmet demand:

$$LOLP = \frac{\sum_{h=1}^{H} I(P_{unmet,h} > 0)}{H}, \tag{32}$$

where H is the total number of simulated hours and $I(\cdot)$ is an indicator function equal to one when unmet demand occurs. The Expected Energy Not Supplied is calculated as:

$$EENS = \sum_{h=1}^{H} P_{unmet,h}. \tag{33}$$

A served demand fraction is also calculated to measure the percentage of annual demand supplied by the system:

$$SF = \frac{E_{served}}{E_{demand}}. \tag{34}$$

These indicators are essential because a configuration with favorable annual energy production or financial indicators may still fail to provide reliable hourly supply in an isolated microgrid.

2.7. *Techno-Economic Indicators*

The financial evaluation considers capital expenditure, annual operating expenditure, energy delivered to the load, grid imports, regulated tariff, inflation, photovoltaic degradation, battery replacement, and discount rate [33, 15]. The Levelized Cost of Energy is calculated as:

$$LCOE = \frac{CAPEX + \sum_{t=1}^{T} \frac{OPEX_t + C_{rep,t}}{(1+r)^t}}{\sum_{t=1}^{T} \frac{E_t}{(1+r)^t}}, \tag{35}$$

where $CAPEX$ is the initial investment, $OPEX_t$ is the operating expenditure in year t, $C_{rep,t}$ is the replacement cost in year t, E_t is the delivered energy in year t, r is the discount rate, and T is the project lifetime. The Net Present Value is calculated as:

$$NPV = -CAPEX^{net} + \sum_{t=1}^{T} \frac{R_t - OPEX_t - C_{rep,t} - C_{grid,t}}{(1+r)^t}, \tag{36}$$

where $CAPEX^{net}$ is the net capital expenditure after co-financing support, R_t is the revenue or avoided-cost value of useful energy delivered to the community, and $C_{grid,t}$ is the cost of electricity imported from the local grid. The useful-energy value is estimated as:

$$R_t = E_{served,t}\tau_t, \tag{37}$$

where τ_t is the electricity tariff in year t. The grid-import cost is estimated as:

$$C_{grid,t} = E_{grid,t}\tau_t. \tag{38}$$

In the base case, electricity export to the local grid is not allowed. Therefore, no export revenue is included in the recommended scenario. Surplus photovoltaic energy that cannot be used directly or stored in the battery is curtailed. The Internal Rate of Return is the discount rate that satisfies:

$$0 = -CAPEX^{net} + \sum_{t=1}^{T} \frac{R_t - OPEX_t - C_{rep,t} - C_{grid,t}}{(1+IRR)^t}. \tag{39}$$

The stochastic financial assessment is implemented as an unlevered project cash-flow model. Debt and equity participation are therefore not explicitly amortized in the Monte Carlo cash-flow calculation, avoiding double counting of financing costs. Financing mechanisms such as concessional debt, public incentives, FENOGE participation, or public co-financing are represented as sensitivity scenarios rather than explicit debt schedules.

2.8. *Local-grid Operating Cases and Financial-support Scenarios*

Three local-grid operating cases are defined to evaluate the effect of possible surplus treatment. The E0 case is adopted as the base operating condition because the local grid in Providencia is not treated as a conventional electricity market capable of absorbing and remunerating distributed exports. Therefore, the proposed energy community is not assumed to sell surplus electricity to the local grid.

Table 7. Local-grid operating cases considered in the analysis.

Case	Export limit	Export credit	Interpretation
E0	0 kW	0%	Base case; no electricity sales to the local grid
E1	20 kW	30% of tariff	Non-base sensitivity only
E2	40 kW	50% of tariff	Optimistic sensitivity only; not recommended

The E1 and E2 cases are retained only as exploratory sensitivities. They are not used to define the recommended configuration because they require export compensation conditions that are not assumed to be available in the local island grid. Financial-support scenarios are evaluated as a post-processing layer over the technical and financial Monte Carlo results. These scenarios do not modify the hourly dispatch, LOLP, EENS, renewable fraction, or diesel-equivalent dependency. They modify only the financial indicators by changing the effective investment burden or tax benefit.

Table 8. Financial-support scenarios evaluated in the analysis.

Case	Definition	Interpretation
F0	No support	Base financial case
F1a	Tax incentive distributed over 15 years	Conservative fiscal benefit
F1b	Tax incentive distributed over 5 years	Accelerated fiscal benefit
F2 20%	CAPEX co-financing of 20%	Moderate public or fund-based support
F2 40%	CAPEX co-financing of 40%	Policy-sensitive break-even support level
F2 60%	CAPEX co-financing of 60%	High-support sensitivity

These financial-support mechanisms are consistent with Colombian renewable-energy incentives and public support instruments for Non-Interconnected Zones, including tax incentives, FAZNI, and FENOGE-type support mechanisms [34, 35, 36].

The CAPEX co-financing cases are not interpreted as guaranteed subsidies. They are policy-sensitive support levels used to estimate the threshold required for financial robustness. In particular, the 40% CAPEX co-financing case is evaluated because the conservative no-export local-grid-supported case requires support close to this level to reach a positive mean NPV.

2.9. Off-grid Sizing and Local-grid-supported Scenario Definition

The off-grid photovoltaic–battery sizing analysis was implemented as an exhaustive discrete grid search over predefined photovoltaic and battery capacities. This approach was selected because the design space was finite and the objective was to compare technically feasible configurations under the same stochastic simulation framework. The evaluated photovoltaic capacities were:

$$P_{pv} \in \{180, 240, 320, 420, 540\} \text{ kWp}, \tag{40}$$

and the evaluated battery capacities were:

$$E_{bat} \in \{240, 400, 600, 900, 1300\} \text{ kWh}. \tag{41}$$

For each pair (P_{pv}, E_{bat}), an inner Monte Carlo simulation was performed. The objective was to minimize the expected cost of energy subject to a reliability criterion:

$$\min_{P_{pv}, E_{bat}} \mathbb{E}[LCOE(P_{pv}, E_{bat})], \tag{42}$$

subject to:

$$\mathbb{E}[LOLP(P_{pv}, E_{bat})] < 0.05. \tag{43}$$

The capital cost was scaled by component shares to preserve comparability across system sizes:

$$CAPEX(P_{pv}, E_{bat}) = CAPEX_0 \left[\alpha_{fix} + \alpha_{pv} \frac{P_{pv}}{P_{pv,0}} + \alpha_{bat} \frac{E_{bat}}{E_{bat,0}} \right], \tag{44}$$

where $CAPEX_0$ is the reference capital cost, $P_{pv,0}$ and $E_{bat,0}$ are the reference photovoltaic and battery capacities, and α_{fix}, α_{pv}, and α_{bat} are the fixed, photovoltaic-scalable, and battery-scalable CAPEX shares, respectively. Operating expenditure was scaled proportionally to the CAPEX ratio:

$$OPEX(P_{pv}, E_{bat}) = OPEX_0 \frac{CAPEX(P_{pv}, E_{bat})}{CAPEX_0}. \tag{45}$$

The CAPEX scaling coefficients used in Equation (44) were defined as parametric assumptions for comparative prefeasibility analysis: $\alpha_{fix} = 0.57$, $\alpha_{pv} = 0.18$, and $\alpha_{bat} = 0.25$. These coefficients were applied to the base CAPEX of COP 2,295.17 million corresponding to the reference 240 kWp + 240 kWh system. They represent assumed shares for fixed infrastructure and project-level costs, PV-capacity-dependent costs, and battery-capacity-dependent costs, respectively. These shares are internal modelling assumptions and should not be interpreted as independently validated market benchmarks or detailed vendor quotations. They are reported explicitly to ensure transparency and reproducibility, while general investment-cost uncertainty is represented through the CAPEX multiplier in the Monte Carlo simulation.

Table 9. Parametric CAPEX shares used for the scaling model.

Component group	**Coefficient**	**Assumed share [%]**
Fixed infrastructure, submarine cable, and project-level costs	α_{fix}	57
PV modules, floating structure, and inverters	α_{pv}	18
Battery storage system	α_{bat}	25
Total		100

The scaling coefficients were derived from the component shares of the deterministic prefeasibility budget. The coefficient α_{fix} represents common infrastructure, engineering, installation, transformers, submarine cabling, protection equipment, and balance-of-system costs that do not scale directly with photovoltaic or battery capacity. The coefficient α_{pv} represents photovoltaic-module-related costs, while α_{bat} represents battery-storage-related costs. These coefficients satisfy $\alpha_{fix} + \alpha_{pv} + \alpha_{bat} = 1$ and are used only for comparative prefeasibility sizing. Therefore, the formulation should not be interpreted as an EPC-level cost estimate, but as a consistent parametric method to compare candidate configurations under uncertainty.

This parametric cost-scaling formulation is used as a prefeasibility approximation. It allows consistent comparison across system sizes but does not replace supplier quotations, EPC-level estimates, or detailed marine installation studies. In addition to the fully off-grid sizing sweep, five local-grid-supported scenarios were evaluated. These scenarios were designed to assess whether the existing diesel-backed island grid can reduce the battery capacity required for reliable operation without assuming electricity sales to the local grid.

Table 10. Local-grid-supported scenarios evaluated in the analysis.

Scenario	**PV capacity**	**Battery capacity**	**Local-grid support**
GS-1	240 kWp	0 kWh	Yes
GS-2	240 kWp	100 kWh	Yes
GS-3	420 kWp	0 kWh	Yes
GS-4	420 kWp	100 kWh	Yes
GS-5	420 kWp	200 kWh	Yes

The GS scenarios are not designed as a new diesel-hybrid plant. Instead, they represent photovoltaic–battery operation supported by the existing local diesel-backed grid. The local grid supplies residual deficits within the project import limit and availability constraints, while surplus photovoltaic generation is curtailed in the E0 base case.

3. Results

This section presents the numerical results obtained from the deterministic baseline assessment, the fully off-grid photovoltaic–battery simulation, the diesel-equivalent local-grid-supported scenarios, the diesel-equivalent validation, and the financial-support sensitivity. The results are organized to distinguish between autonomous operation and the more realistic no-export local-grid-supported pathway.

3.1. Deterministic Baseline Results

The deterministic assessment provided the initial technical and financial feasibility basis for the off-shore photovoltaic system in Providencia Island. Under fixed assumptions, the system showed favorable indicators, including a positive Net Present Value, an Internal Rate of Return of approximately 10.97%, and a payback period close to ten years. The peak community demand was estimated at 40.73 kVA between 11:00 and 12:00, and the annual energy reference was about 280,352.64 kWh/year. The deterministic result serves as a baseline design and reference economic scenario. However, it does not quantify the probability of adverse outcomes under joint uncertainty or evaluate hourly demand under storage limitations. Therefore, it is retained as the conceptual baseline, while stochastic simulation is applied to assess the robustness of the feasibility conclusion.

Table 11. Summary of deterministic baseline indicators.

Indicator	**Deterministic baseline value**
Peak demand	40.73 kVA
Annual energy reference	280,352.64 kWh/year
Levelized Cost of Energy	0.222 USD/kWh
Net Present Value	Positive
Internal Rate of Return	10.97%
Payback period	10 years and 1 month
Main interpretation	Feasible under fixed assumptions

Although the deterministic indicators suggest feasibility, the stochastic results presented below show that feasibility is sensitive to uncertainty, hourly storage-constrained operation, marine losses, battery degradation, and the availability of financial support.

3.2. Fully Off-grid Photovoltaic–Battery Results

The fully off-grid configuration represents an autonomous photovoltaic–battery system for the community, without support from the local grid. This case is useful as a technical reference for energy autonomy. However, it requires significant battery capacity to satisfy hourly reliability under uncertainty. The off-grid sizing analysis identified a 420 kWp photovoltaic system with 400 kWh of battery storage as the lowest-cost autonomous configuration satisfying the mean LOLP criterion. This configuration achieved a mean LOLP of approximately 4.87%, an Expected Energy Not Supplied of approximately 7.60 MWh/year, and a served demand fraction close to 97.33%. Despite this technical improvement, the financial indicators remained weak, with a high cost of energy and a negligible probability of positive NPV.

Table 12. Fully off-grid photovoltaic–battery reference case.

Indicator	**Off-grid result**
Configuration	420 kWp PV + 400 kWh battery
CAPEX	2.9864 G COP
Mean cost of energy	2612.85 COP/kWh
Mean LOLP	4.87%
LOLP p95	10.87%
Mean EENS	7.60 MWh/year
Served demand fraction	97.33%
Probability of positive NPV	0.0%
Mean IRR	-13.59%
Battery EFC, year 1	313.58 equivalent cycles/year
Average daily DoD	88.14%
Battery replacements over project life	4.11
Median first replacement	Year 6

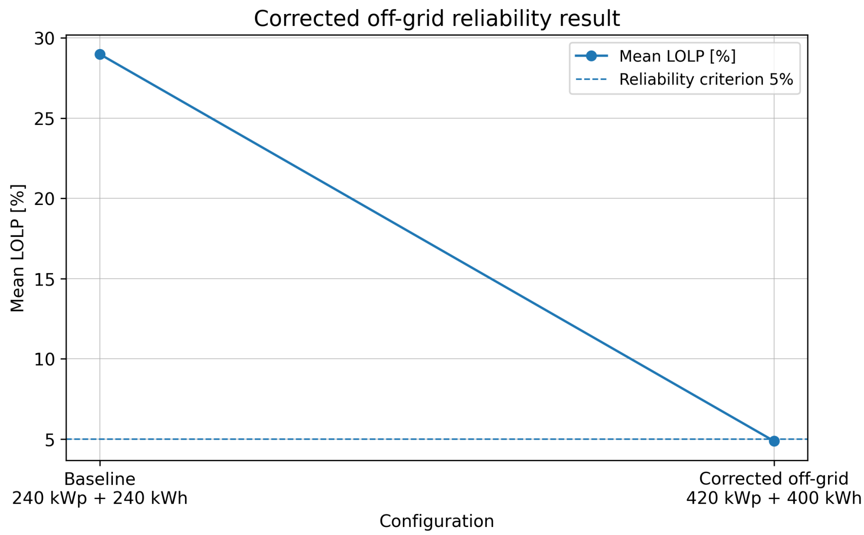

Figure 3. Corrected off-grid reliability result. The baseline 240 kWp + 240 kWh configuration does not satisfy the reliability criterion, while the corrected 420 kWp + 400 kWh off-grid reference reaches a mean LOLP close to 5%.

The autonomous off-grid alternative is technically feasible but financially non-robust under the simulated assumptions. It requires a large battery system, experiences frequent battery replacement, and does not reach investment-grade financial performance without additional support. This result justifies the evaluation of a local-grid-supported pathway that uses the existing island electricity infrastructure as a diesel-equivalent backup source.

3.3. Diesel-equivalent Local-grid-supported Scenarios

The local-grid-supported analysis evaluates photovoltaic–battery configurations that can import energy from the existing local grid when photovoltaic generation and battery discharge are insufficient to meet demand. In the base case, no electricity exports to the local grid are allowed. Therefore, the local grid is used only as a backup source, and surplus photovoltaic energy that cannot be consumed directly or stored is curtailed. The local-grid-supported scenarios significantly reduce the battery capacity required for reliable operation. In particular, GS-2, composed of 240 kWp of photovoltaic capacity and 100 kWh of battery storage, maintains a mean LOLP close to 1.51%, a renewable fraction near 61.1%, and a diesel-equivalent grid-dependency fraction close to 38.9%.

Table 13. Base no-export local-grid-supported scenarios.

Scenario	PV [kWp]	BESS [kWh]	Cost [COP/kWh]	NPV [G COP]	P(NPV>0) [%]	LOLP [%]	Renewable [%]	Grid dep. [%]
GS-1	240	0	1911.85	-0.4399	6.5	2.36	48.98	51.02
GS-2	240	100	2024.77	-0.7495	1.7	1.51	61.11	38.89
GS-3	420	0	2041.56	-0.7998	0.6	2.38	50.46	49.54
GS-4	420	100	2153.86	-1.1086	0.2	1.42	62.56	37.44
GS-5	420	200	2264.41	-1.4161	0.0	0.81	74.62	25.38

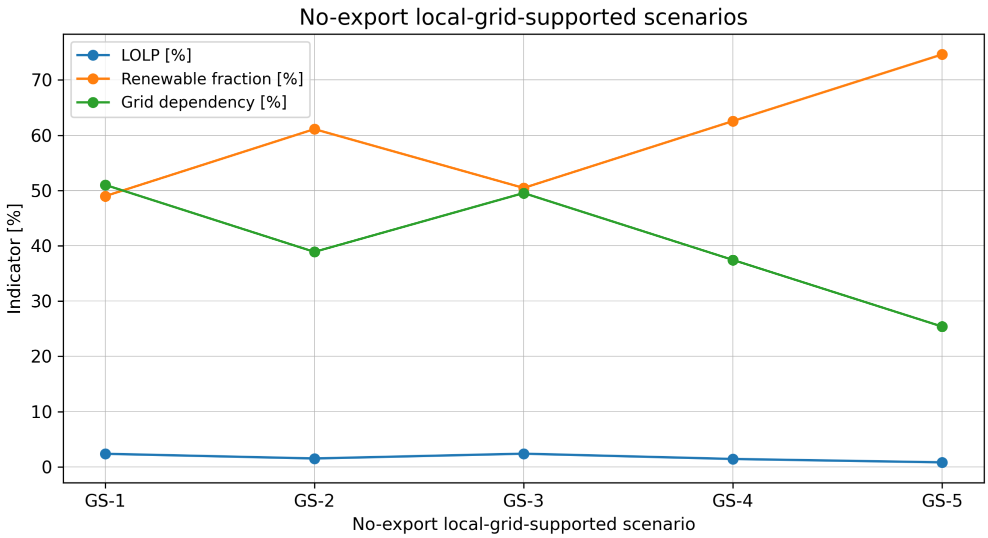

Figure 4. Technical performance of the no-export local-grid-supported scenarios. The GS-2 configuration provides a balanced trade-off between reliability, renewable fraction, battery size, and diesel-equivalent grid dependency.

Although GS-1 presents a lower cost and less negative pre-support NPV, it is not selected as the recommended transition pathway because it does not include battery storage, its renewable fraction remains below 50%, and its diesel-equivalent grid dependency exceeds 50%. Therefore, GS-2 is preferred as the realistic no-export transition case because it balances reliability, storage reduction, renewable penetration, and reduced dependence on the existing diesel-backed local grid.

These results show that local-grid support improves reliability and reduces storage requirements compared with the fully off-grid case. However, without financial support, none of the no-export local-grid-supported scenarios reaches robust financial performance. The GS-2 scenario offers the best balance between reliability, renewable fraction, battery size, and investment requirement under realistic no-export operation.

3.4. Diesel-equivalent Validation and Avoided Emissions

The diesel-equivalent model converts local-grid imports into equivalent diesel consumption and CO_2 emissions. This provides a system-level interpretation of the remaining dependency on the existing diesel-backed local grid. For the GS-2 no-export case, the annual energy imported from the local grid is approximately 102.4 MWh/year. Using the Providencia-calibrated specific fuel consumption value of 0.307 L/kWh, the equivalent diesel consumption is approximately:

$$102{,}423 \text{ kWh/year} \times 0.307 \text{ L/kWh} \approx 31{,}444 \text{ L/year}. \tag{46}$$

Using an emission factor of 2.68 kg CO_2/L, the corresponding emissions are:

$$31{,}444 \text{ L/year} \times 2.68 \text{ kgCO}_2/\text{L}/1000 \approx 84.3 \text{ tCO}_2/\text{year}. \tag{47}$$

These values provide a diesel-equivalent interpretation of the remaining local-grid dependency. The proposed photovoltaic–battery system does not eliminate diesel-equivalent consumption, but it reduces it substantially relative to a local-grid-only baseline.

Table 14. Diesel-equivalent indicators for the GS-2 local-grid-supported case.

Indicator	Approximate value
Local-grid imports	102.4 MWh/year
Specific fuel consumption used for validation	0.307 L/kWh
Diesel-equivalent consumption	31,444 L/year
CO_2 emissions	84.3 tCO_2/year
Avoided diesel relative to local-grid-only baseline	Approximately 61%

Table 15. Diesel-only baseline scenario for comparison.

Indicator	D0 (diesel-only)	GS-2 (recommended)
Diesel-equivalent energy supplied [MWh/year]	265.8 (full demand)	102.4 (grid import)
Diesel consumption [L/year]	81,601	31,444
Approx. variable fuel cost [COP/year]	344,710,342	132,830,201
CO_2 emissions [tCO_2/year]	218.69	84.27

The diesel-only baseline (D0) represents full community demand supplied exclusively by the existing diesel-equivalent local grid, without any photovoltaic or battery contribution. Compared to this baseline, the recommended GS-2 configuration reduces diesel-equivalent consumption by approximately 61.5% (50,157 L/year avoided), CO_2 emissions by approximately 134.4 tCO_2/year, and approximate diesel variable cost by about 211.9 million COP/year. The D0 baseline reflects only the variable fuel-cost component of already existing diesel infrastructure and does not include a levelized capital cost, since no new diesel asset is proposed; this comparison therefore isolates the operational fuel-cost and emissions benefit attributable to the proposed photovoltaic–battery system.

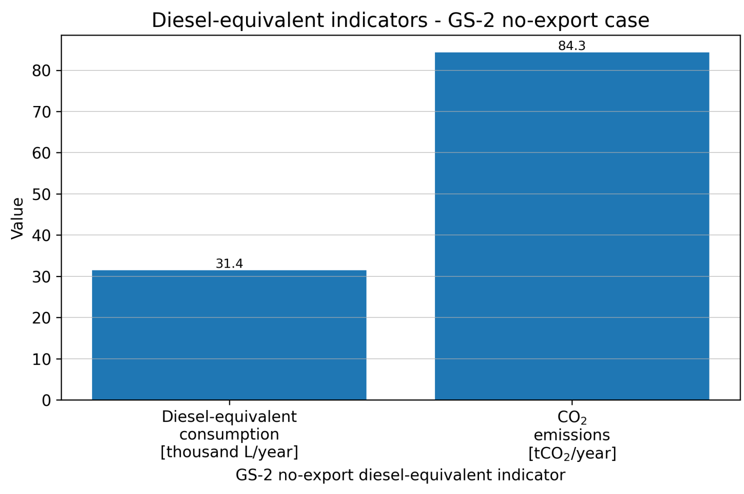

Figure 5. Diesel-equivalent indicators for the GS-2 no-export local-grid-supported case. Local-grid imports are converted into equivalent diesel consumption and CO_2 emissions to represent the existing diesel-backed island electricity infrastructure.

The proposed photovoltaic–battery system does not eliminate diesel-equivalent dependency, but it reduces it substantially relative to a case in which the full community demand is supplied by the existing local grid. This interpretation is consistent with a transitional pathway for island energy communities: photovoltaic generation and battery storage reduce diesel-equivalent imports while the local grid remains available as backup.

3.5. Financial-support Sensitivity under the No-export Base Case

Financial support was evaluated as a post-processing layer over the technical Monte Carlo results. The support mechanisms do not modify the dispatch, reliability, renewable fraction, or diesel-equivalent grid dependency. They modify the investment burden and therefore affect NPV, probability of positive NPV, IRR, and payback. For the GS-2 no-export case, the pre-support mean NPV is negative. The break-even CAPEX support required to bring the mean NPV close to zero is approximately 36.8–36.9%. Therefore, a 40% CAPEX co-financing case is evaluated as the lowest round support level that makes the conservative no-export scenario financially viable.

Table 16. Break-even support requirement for selected no-export scenarios.

Case	Scenario	PV [kWp]	BESS [kWh]	Required CAPEX support
E0	GS-2	240	100	36.8–36.9%
E0	GS-5	420	200	Approximately 54.4%

Under 40% CAPEX co-financing, the GS-2 no-export case reaches a positive mean NPV of approximately 0.060 G COP and a probability of positive NPV close to 56%. Although this probability is lower than in export-compensated sensitivities, it is more realistic for Providencia because it does not require the local grid to purchase or remunerate surplus electricity.

Table 17. Recommended no-export scenario under CAPEX co-financing.

Indicator	GS-2 + E0 + F2 40%
PV capacity	240 kWp
Battery capacity	100 kWh
Local-grid role	Diesel-equivalent backup source
Export to local grid	Not allowed
CAPEX co-financing	40%
Mean NPV after support	0.0606 G COP
Probability of positive NPV	55.6%
Mean LOLP	1.51%
Renewable fraction	61.11%
Diesel-equivalent grid dependency	38.89%
Main interpretation	Realistic recommended pathway

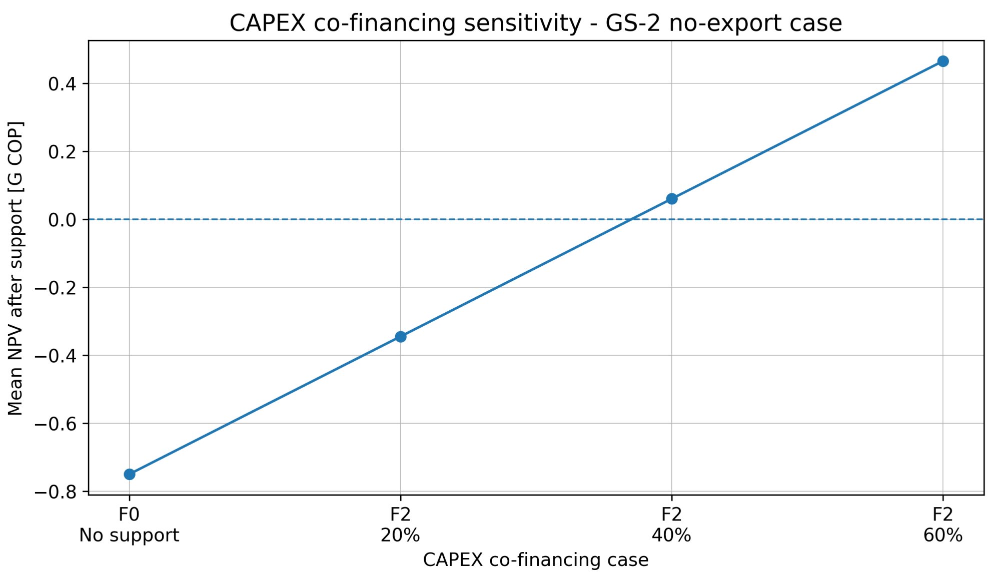

Figure 6. CAPEX co-financing sensitivity for the GS-2 no-export local-grid-supported scenario. The 40% CAPEX co-financing case is interpreted as the policy-sensitive support level required to reach a positive mean NPV under realistic no-export operation.

3.6. Non-base Export Sensitivities

Although the recommended scenario is based on no electricity sales to the local grid, export-compensated cases were evaluated as exploratory sensitivities. These cases illustrate how the financial results would improve if limited surplus recognition were available. However, they are not adopted as the recommended pathway because Providencia's local grid is not assumed to operate as a conventional market for distributed energy exports.

Table 18. Interpretation of no-export and export-compensated cases.

Case	Export assumption	Financial effect	Use in this study
E0	No export, no credit	Conservative and realistic	Recommended base case
E1	Limited export, partial credit	Improves NPV	Non-base sensitivity
E2	Higher export, higher credit	Strongly improves NPV	Optimistic sensitivity only

Export-compensated cases improve financial performance, but they require assumptions that are not used in the final recommendation. The final scenario selection therefore prioritizes technical reliability, reduced battery size, no-export operation, diesel-equivalent accounting, and CAPEX co-financing.

3.7. Scenario Selection

The scenario selection uses a practical interpretation rather than selecting the most optimistic financial case. Scenarios are evaluated according to reliability, renewable fraction, diesel-equivalent dependency, battery size, financial performance, and realism of the operating assumptions. The no-export case receives the highest realism weight because it does not require electricity sales to the local grid.

Table 19. Final scenario interpretation.

Category	Case	Scenario	Support	PV	BESS	Interpretation
Recommended realistic	E0	GS-2	F2 40%	240 kWp	100 kWh	No export; realistic pathway
Non-base moderate sensitivity	E1	GS-2	F2 40%	240 kWp	100 kWh	Requires partial export credit
Optimistic sensitivity	E2	GS-5	F2 40%	420 kWp	200 kWh	Not used as base case

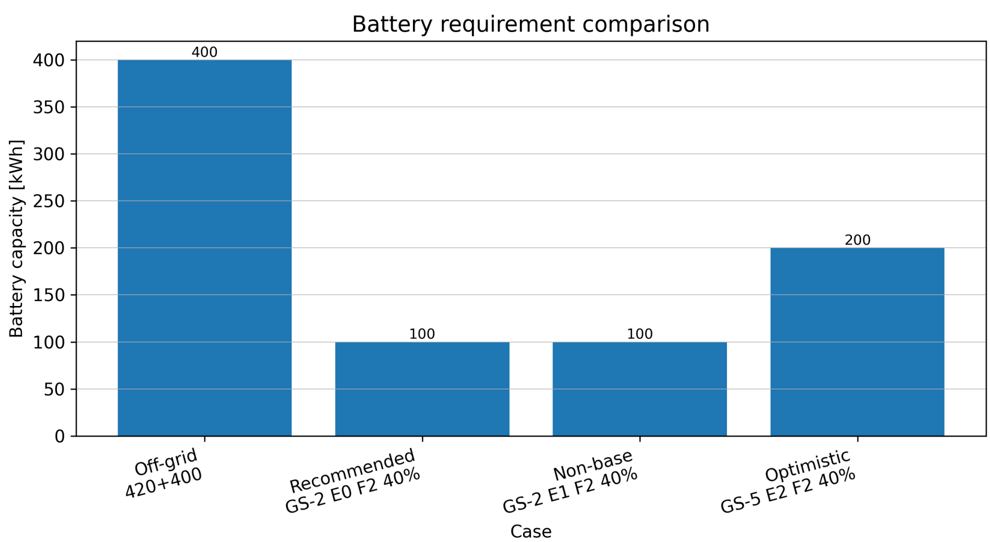

Figure 7. Battery-capacity comparison among the corrected off-grid reference, the recommended no-export local-grid-supported case, and non-base export-compensated sensitivities. The recommended realistic pathway is GS-2 + E0 + F2 40%, which does not rely on electricity sales to the local grid.

The recommended realistic case is GS-2 + E0 + F2 40%, because it does not require electricity exports to the local grid and therefore better represents the operating constraints of Providencia. Although its financial robustness is lower than export-compensated sensitivities, it reaches a positive mean NPV under 40% CAPEX co-financing while maintaining adequate reliability and reducing the battery requirement by 75% relative to the fully off-grid reference.

3.8. *Synthesis of Results*

The results show three main findings. First, the fully off-grid photovoltaic–battery system is technically feasible but financially non-robust under the simulated assumptions. Full autonomy requires 420 kWp of photovoltaic capacity and 400 kWh of battery storage, resulting in high cost and frequent battery replacements. Second, the local-grid-supported diesel-equivalent pathway substantially reduces the storage requirement. The GS-2 configuration, with 240 kWp of photovoltaic capacity and 100 kWh of battery storage, maintains adequate reliability with a mean LOLP close to 1.51%, while reaching a renewable fraction of approximately 61.1%. Third, financial viability under realistic no-export operation is conditional on investment support. Under 40% CAPEX co-financing, the GS-2 + E0 case reaches a positive mean NPV and becomes the recommended practical pathway. Export-compensated cases improve financial performance, but they are retained only as sensitivities because they are not assumed to reflect the operating nature of the local grid in Providencia.

4. Discussion

The stochastic results refine the deterministic feasibility assessment of the proposed off-shore photovoltaic system for Providencia Island. While the deterministic baseline suggested favorable technical and financial indicators under fixed assumptions, the stochastic simulation shows that this conclusion is conditional when uncertainty, hourly operation, marine losses, battery degradation, and local-grid constraints are considered.

4.1. *Technical Implications of Fully Off-grid Operation*

The fully off-grid case shows that photovoltaic–battery autonomy is technically possible but storage-intensive. Under the simulated assumptions, the autonomous system requires 420 kWp of photovoltaic capacity and 400 kWh of battery storage to reach a mean LOLP close to 5%. This result indicates that the system is not mainly constrained by the annual solar resource, but by the ability to shift daytime photovoltaic generation to evening, nighttime, and early morning demand. The battery degradation model reinforces this finding. Battery replacement timing is affected by equivalent full cycles, average depth of discharge, calendar aging, and temperature stress. As a result, autonomy based only on photovoltaic generation and battery storage increases long-term replacement needs and weakens financial performance.

4.2. *Role of the Existing Diesel-backed Local Grid*

The existing island grid provides a more realistic transitional pathway for Providencia. The local grid is not treated as a national-grid connection or as a market for surplus electricity exports. Instead, it is represented as a diesel-equivalent backup source that supplies residual deficits after photovoltaic generation and battery discharge. This representation is consistent with the scope of the project. The proposed system is an off-shore photovoltaic–battery system for an energy community, not a new island-wide diesel-hybrid power plant. Therefore, the local grid is modeled as existing infrastructure that can support reliability while the photovoltaic–battery system reduces diesel-equivalent dependency.

4.3. *Battery Sizing and Reliability Trade-off*

The comparison between the fully off-grid case and the local-grid-supported case shows the importance of transitional support. The fully off-grid reference requires 400 kWh of battery storage, whereas the recommended local-grid-supported GS-2 configuration requires only 100 kWh. This represents a 75% reduction in battery capacity while maintaining a mean LOLP close to 1.5%. This reduction is important for technical, economic, and environmental reasons. Smaller battery capacity reduces investment cost, replacement cost, installation complexity, and end-of-life management requirements. However, the trade-off is that the system remains partially dependent on the diesel-equivalent local grid.

4.4. Diesel-equivalent Emissions and Transition Value

The diesel-equivalent accounting shows that the proposed system does not eliminate diesel dependency, but it reduces it substantially. For the GS-2 configuration, approximately 61% of the diesel-equivalent energy that would otherwise be supplied by the local grid is avoided. The remaining grid imports are converted into equivalent diesel consumption and CO_2 emissions, providing a transparent environmental-operational interpretation. This result supports a transition-oriented interpretation. Rather than claiming immediate full decarbonization or full autonomy, the proposed pathway reduces diesel-equivalent consumption while preserving reliability through the existing local grid. This is particularly relevant for isolated island systems, where abrupt replacement of firm generation with storage-only renewable systems may be financially and operationally difficult.

4.5. Financial Viability and Policy-sensitive Support

The financial results show that technical feasibility does not automatically imply financial robustness. The fully off-grid case is financially non-robust. The local-grid-supported GS-2 case improves cost and reliability, but under no-export operation it still requires CAPEX co-financing close to 40% to reach a positive mean NPV. This finding is relevant for Colombian Non-Interconnected Zones. Investment support, concessional financing, tax incentives, and public co-financing mechanisms can play a decisive role in enabling renewable energy communities. However, such mechanisms must be presented as policy-sensitive scenarios rather than guaranteed subsidies. The 40% co-financing case is interpreted as a break-even support level for the conservative no-export configuration.

4.6. Implications for Colombian Non-Interconnected Zones

The results have implications for renewable energy planning in Colombian ZNI and island territories. First, reliability metrics such as LOLP and EENS should be included in feasibility studies because annual energy balance alone does not guarantee hourly adequacy. Second, local-grid conditions must be represented realistically. In Providencia, the local grid should not be treated as an unlimited grid connection or as a conventional market for distributed surplus sales. Third, financial viability depends strongly on investment cost, support mechanisms, and realistic operating constraints. The recommended pathway is therefore based on self-consumption, reduced battery sizing, limited diesel-equivalent grid backup, and investment support. This approach provides a more realistic foundation for community-scale off-shore photovoltaic deployment in Providencia.

4.7. Limitations

This study has some limitations.

- The photovoltaic model uses satellite-derived hourly irradiance and temperature data rather than on-site pyranometer measurements. Future field measurements would improve site-specific calibration.
- The existing island grid is represented as an aggregate diesel-equivalent backup source. The model does not perform unit-commitment dispatch of each diesel generator, minimum loading constraints, generator start-stop cycles, or detailed fuel curves.
- The 40 kW import limit represents the community/project interconnection limit, not the total installed capacity of the Providencia island power plant.
- The marine operating model includes salt-related losses, additional degradation, cable and connector losses, derating, O&M multipliers, and anti-corrosion maintenance, but it does not replace detailed marine engineering, anchoring design, hydrodynamic simulation, bathymetry, or cyclone-resilience assessment.
- Although the study evaluates the technical and financial behavior of the proposed off-shore photovoltaic system, a detailed site-constraint analysis remains outside the scope of this work. Future engineering stages

should quantify the available water surface, bathymetry, anchoring feasibility, exclusion zones, exposure to waves and extreme weather, distance to the interconnection point, cable routing, and environmental restrictions associated with the Seaflower Biosphere Reserve. These constraints may affect the final layout, anchoring system, installation cost, permitting process, and long-term maintainability.

- The CAPEX model is parametric and based on component scaling. Detailed EPC quotations, supplier proposals, and marine installation studies would be required for investment-grade decisions.
- Export compensation and CAPEX co-financing are modeled as policy-sensitive scenarios rather than guaranteed mechanisms. The recommended scenario does not rely on electricity sales to the local grid.
- Environmental feasibility is limited to marine operating conditions and diesel-equivalent emissions. A full ecological impact assessment would be required before any physical intervention in the Seaflower Biosphere Reserve.

5. Conclusions

This study evaluated the technical, reliability, environmental-operational, and financial feasibility of an off-shore floating photovoltaic generation system for the energy community of Providencia Island, Colombia. The proposed framework integrates Monte Carlo simulation, satellite-derived hourly irradiance, cycle-based battery degradation, marine operating losses, local-grid-supported dispatch, diesel-equivalent accounting, and financial support sensitivity. The fully off-grid photovoltaic–battery system is technically feasible but financially non-robust under the simulated assumptions. Autonomous operation requires 420 kWp of photovoltaic capacity and 400 kWh of battery storage to reach a mean LOLP close to 5%. However, this configuration presents a high cost of energy, frequent battery replacements, and a negligible probability of positive NPV. When the existing local island grid is represented as a diesel-equivalent backup source, the required battery capacity can be reduced from 400 kWh to 100 kWh. The GS-2 configuration, composed of 240 kWp of photovoltaic capacity and 100 kWh of battery storage, maintains a mean LOLP close to 1.5%, a renewable fraction near 61%, and a diesel-equivalent grid-dependency fraction close to 39%. This result indicates that the existing local grid can provide transitional reliability support while the photovoltaic–battery system reduces diesel-equivalent consumption. Under the realistic no-export assumption, the GS-2 configuration requires approximately 40% CAPEX co-financing to reach a positive mean NPV. Therefore, the recommended practical pathway is GS-2 + E0 + F2 40%: a 240 kWp photovoltaic system with 100 kWh of battery storage, supported by the existing diesel-equivalent local grid, without electricity sales to the local grid, and with policy-sensitive investment support. Export-compensated cases improve financial performance, but they are retained only as non-base sensitivities because the local grid in Providencia is not assumed to operate as a conventional market for distributed energy exports. The final recommendation is therefore based on self-consumption, storage optimization, limited diesel-equivalent grid backup, and CAPEX co-financing rather than surplus electricity sales. The results show that off-shore photovoltaic generation in Providencia is technically feasible and environmentally relevant as a diesel-reduction strategy. However, implementation should proceed as a carefully supported transition pathway rather than as a fully autonomous storage-only system. Future work should include on-site solar measurements, detailed marine engineering, environmental assessment for the Seaflower Biosphere Reserve, investment-grade EPC cost estimates, and operational validation with local-grid data.

Data Availability Statement

The data used in this study were obtained from the deterministic feasibility assessment of the Providencia off-shore photovoltaic system, publicly available regulatory and technical references, satellite-derived irradiance and temperature datasets, and stochastic simulation outputs generated by the authors. The Monte Carlo results, off-grid sizing results, local-grid-supported scenario outputs, diesel-equivalent indicators, and financial support sensitivity results can be made available by the corresponding author upon reasonable request.

Code Availability Statement

The computational framework was developed in Python and includes the Monte Carlo simulation, satellite-derived photovoltaic generation model, marine operating-loss model, hourly photovoltaic–battery dispatch, local-grid-supported dispatch, diesel-equivalent accounting, battery degradation model, financial evaluation, reliability calculation, scenario ranking, and financial support sensitivity. The code can be made available by the corresponding author upon reasonable request.

Ethical and Environmental Statement

This study is based on simulation, modeling, and techno-economic analysis. No field intervention, biological sampling, human subject research, or physical installation was conducted as part of this work. Any future implementation would require detailed environmental assessment, institutional authorization, marine engineering validation, and compliance with applicable regulations for marine and coastal ecosystems, including those associated with the Seaflower Biosphere Reserve.

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