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Study of Floating Solar PV with Battery Storage Co-Located with Pumped Storage Hydropower at East Java, Indonesia: A Techno-Economic and Environmental Assessment

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Abstract **- This paper presents a techno-economic and environmental assessment of a 4.48 MWac floating solar photovoltaic (FPV) plant proposed for the Pacitan reservoir in East Java, Indonesia, co-located with a planned 1,000 MW pumped-storage hydropower plant (PSHP). Four configurations were simulated in PVsyst V8.1.3 using Meteonorm 8.2 climate data (annual GHI of 1,928.4 kWh/m²): a monofacial grid-connected array (Sc. 1); a bifacial grid-connected array (Sc. 2); and the same two arrays each integrated with a BYD battery energy storage system operated in a power-shifting mode (Mono+BESS and Bifa+BESS). The bifacial grid-only configuration records the highest annual yield, generating 9,474,473 kWh at a performance ratio (PR) of 89.73% and a specific yield of 1,757 kWh/kWp — approximately 4.91% above the monofacial baseline of 9,031,908 kWh (PR 84.74%). The storage configurations inject somewhat less into the grid, 8,573,928 kWh (Mono+BESS, PR 80.45%) and 8,382,356 kWh (Bifa+BESS, PR 85.55%), owing to round-trip conversion losses; this modest reduction in delivered energy is offset by the dispatch flexibility they provide and by their capacity to supply the PSHP's auxiliary loads.**

Environmental analysis confirms strongly positive lifetime CO_2 balances under Indonesia's grid emission factor of 734 gCO_2/kWh, with net savings of about 162,000–179,000 tCO_2 over a 30-year horizon and a lifecycle emission intensity of 8–16 gCO_2/kWh — roughly 50–100 times lower than conventional fossil-fuel generation. As a secondary co-benefit, reservoir evaporation mitigation yields annual water savings of 208,845–626,535 m³/year at 25–75% FPV surface coverage, a conserved volume that directly augments the water available to the co-located PSHP.

The financial analysis applies Indonesia's regulated tariff under Perpres 112/2022, with a 9% discount rate and a 30-year horizon. As the tariff band is set by AC capacity rather than panel rating, the plant's 4.48 MWac falls within the >3–5 MW tier, priced at 8.77 US¢/kWh for years 1–10 and 5.26 US¢/kWh thereafter (a levelised value of approximately 7.56 US¢/kWh). Under this tariff the grid-only configurations are feasible but only marginally so: their levelised cost of energy (LCOE) of 7.42–7.46 US¢/kWh lies just below the tariff, yielding an internal rate of return (IRR) of 9.2–9.3% and a slightly positive net present value (NPV) of approximately +$0.09–0.12 million. The storage configurations perform considerably better. Article 10 (Pasal 10) of the same regulation permits a storage-equipped plant to receive a battery-facility premium of up to 60% above the benchmark price — equivalent to 160% of the HPT applied to all exported energy — which raises NPV to approximately +$2.23 million (Mono+BESS) and +$1.68 million (Bifa+BESS), increases IRR to 12.5–13.8%, and reduces payback to under seven years. The storage cases reach break-even while drawing on less than one-third of the permitted 60% allowance, indicating that their viability is robust even where the negotiated price falls below the regulatory ceiling. Collectively, these findings offer developers, utilities, and policymakers a quantitative basis for selecting an FPV configuration at tropical reservoir sites with comparable solar resources.

Keywords: Floating PV; Bifacial PV; Pumped Storage Hydropower (PSHP); BESS Auxiliary Power; GHG Emission Reduction; Reservoir Evaporation Mitigation; PVsyst; Indonesia; Techno-Economic Assessment.

I. INTRODUCTION

The global transition toward renewable energy, and solar photovoltaic (PV) technology in particular, has accelerated markedly over the past decade, driven by the imperative to decarbonise energy systems, improve energy security, and meet rising electricity demand. Indonesia — the world's fourth most populous nation and a major emerging economy — exemplifies this dual challenge of rapid demand growth and ambitious decarbonisation. Under its National Energy Policy (Kebijakan Energi Nasional, KEN), the country targets a 23% renewable energy share by 2025 and net-zero emissions by 2060 [20], a trajectory reaffirmed in the National Electricity General Plan (RUKN) 2025–2034, which raises the renewable share toward 29.4% by 2034 [11]. Within this framework, utility-scale solar PV has emerged as a technically mature and

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economically attractive pathway to expand low-carbon generation capacity.

Solar PV (Pembangkit Listrik Tenaga Surya, PLTS) is among the most actively promoted renewable technologies in Indonesia, with an estimated national potential of approximately 207,898 MW against an installed capacity of only about 495 MW to date [21] — a gap that underscores both the scale of the opportunity and the urgency of accelerated deployment. Conventional ground-mounted PLTS, however, requires extensive land, which can compete with agriculture, urban development, and conservation objectives [22]. Floating PV (PLTS Apung, FPV) has emerged as a compelling response to this constraint, offering two principal advantages: more efficient use of land and improved electrical performance. By deploying on water bodies such as reservoirs, lakes, and dams, FPV avoids the need for large land areas while benefiting from the natural cooling effect of the underlying water, which lowers module operating temperature and can raise conversion efficiency [9]. FPV further suppresses reservoir evaporation and inhibits algal growth, supporting more sustainable water-resource management [10].

A particularly synergistic application of FPV arises in co-location with pumped-storage hydropower. The RUPTL 2025–2034 [12] includes a planned 1,000 MW Pumped Storage Hydropower Plant (PSHP) in East Java, scheduled to begin construction in 2028 and to commission by 2033. The PSHP draws surplus power from the Java-Bali 500 kV transmission system during off-peak early-morning hours (~00:00–06:00 WIB) to pump water from a lower to an upper reservoir (charging cycle), and later releases that water during peak evening hours (generation cycle) to dispatch electricity to the GITET 500 kV substation in central java. Both cycles require continuous auxiliary power for station-service equipment. Siting FPV on the PSHP reservoir therefore creates a natural pairing: daytime solar energy can be stored and time-shifted, via a Battery Energy Storage System (BESS), to cover the off-peak pumping-cycle auxiliary loads when solar generation is unavailable, displacing grid-drawn station-service power and reducing plant operating costs while simultaneously mitigating reservoir evaporation.

Two technological developments are central to maximising the value of such an FPV installation. First, bifacial PV modules have emerged as a superior alternative to conventional monofacial panels: they harvest irradiance on both front and rear surfaces, with rear-side gains arising from ground- (or water-) reflected and diffuse irradiance. The bifaciality factor — typically 60–80% — sets the proportion of rear-side output relative to the front-side standard-test-condition (STC) rating [1], and field studies in tropical and subtropical settings report bifacial yield gains of 5–15% over equivalent monofacial systems, depending on albedo, mounting height, row pitch, and local irradiance [2]. Second, the integration of BESS with grid-connected PV addresses solar intermittency by enabling temporal energy shifting — storing surplus daytime generation for dispatch during peak demand or low-solar periods — thereby enhancing grid stability and the capacity value of PV [3]. The BYD Battery Box Premium LVS 4.0, operated in a power-shifting mode, represents a commercially mature, bankable BESS solution increasingly deployed in utility-scale projects across Southeast Asia [16].

Despite a substantial body of PV performance-modelling literature, comparative studies that simultaneously evaluate monofacial grid-connected, bifacial grid-connected, and storage-integrated (FPV+BESS, in both monofacial and bifacial variants) configurations under identical site conditions and a standardised simulation methodology remain scarce — particularly for tropical Indonesian sites, and more specifically for FPV co-located with pumped-storage hydropower, where the BESS serves a dedicated auxiliary-supply role rather than conventional grid arbitrage. The present study addresses this gap through an integrated assessment that couples bankable energy-yield simulation with a full techno-economic and environmental evaluation. Its principal contribution is to combine, within a single consistent framework: PVsyst V8.1.3 [4] energy modelling of the four configurations; a detailed engineering, procurement, and construction (EPC) cost breakdown and Total Project Cost build-up; a five-metric financial analysis (LCOE, NPV, IRR, PI, BCR); a lifecycle GHG emission balance; and a reservoir-evaporation mitigation quantification — and, for the storage configurations, applying the Article 10 battery-facility price component of Perpres 112/2022 (up to 60% of HPT, i.e. price up to 160% HPT) on an AC-capacity tariff band.

The study is applied to the PLTS Pacitan 6 MW project in East Java with the conditions 262 m above mean sea level, mean ambient temperature ≈ 26.64°C, global horizontal irradiation GHI = 1,928.4 kWh/m²/year), which offers a favourable solar resource and a representative tropical-reservoir setting for detailed techno-economic optimisation. Accordingly, the specific objectives are: (1) to simulate and characterise the energy-production performance of the four FPV configurations at the site; (2) to quantitatively compare key performance indicators — annual energy yield, specific production, Performance Ratio (PR), system losses, and CO_2 emission balance — across all scenarios; (3) to analyse the energy-gain mechanism of bifacial technology through rear-side irradiance modelling; (4) to evaluate the impact of BESS integration on net grid-energy delivery, system performance, and PSHP auxiliary-power economics; and (5) to develop the EPC cost framework and techno-economic assessment

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supporting evidence-based technology selection for similar tropical PV projects.

The remainder of this paper is organised as follows. Section 2 reviews the relevant literature on bifacial PV, BESS integration, FPV-PSHP co-location, PVsyst modelling, and techno-economic analysis of solar PV in Indonesia. Section 3 details the materials and methods, encompassing the site and meteorological data, the three system configurations and simulation methodology, the EPC cost and financing framework, and the governing mathematical formulations. Section 4 presents and discusses the results — energy yield and losses, EPC and financial metrics, GHG reduction, and evaporation mitigation. Section 5 consolidates the findings in a multi-criteria assessment, and Section 6 concludes with the principal outcomes and directions for future work.

II. LITERATURE REVIEW

2.1 Bifacial Photovoltaic Technology

Bifacial PV modules generate electricity from incident radiation on both module surfaces. The additional rear-side energy contribution is primarily governed by the bifaciality factor (η_bifacial), the ground albedo coefficient, the ground coverage ratio (GCR), and the module mounting height above ground. Analytical and experimental studies have demonstrated that bifacial systems operating over high-albedo surfaces such as white gravel (albedo 0.50–0.60) or concrete (albedo 0.30–0.40) can achieve rear-side irradiance gains of 10–25% relative to front-side plane-of-array (POA) irradiance [1].

Lopez-Garcia *et al.* [1] demonstrated through outdoor measurements in Spain that bifacial modules with a bifaciality factor of 0.70 yielded 11–14% additional energy compared to monofacial reference modules under similar installation geometry. In tropical environments, Yusufoglu et al. [2] showed that lower solar elevation angles during morning and evening periods and high diffuse fraction ratios (DIF/GHI > 0.45) can significantly enhance relative bifacial gain due to increased rear-side diffuse irradiance capture. The 2D Unlimited Sheds Model implemented in PVsyst provides a physics-based framework for computing rear-side irradiance accounting for sky view factors, inter-row mutual shading, and ground reflection geometry [4].

2.2 Battery Energy Storage Systems in Grid-Connected PV

The integration of BESS with solar PV has been extensively studied from technical, economic, and grid-stability perspectives. Power-shifting strategies — wherein the BESS is charged during surplus PV generation and discharged during peak demand windows — are among the most commonly deployed operational modes in utility-scale projects. The efficacy of power shifting depends on the battery's usable energy capacity, round-trip efficiency, depth of discharge (DoD) limits, and the temporal alignment between solar generation profiles and grid demand patterns.

Research by Stroe *et al.* [3] established that lithium iron phosphate (LFP) battery chemistries, as employed in the BYD Battery Box Premium LVS 4.0 utilized in this study, exhibit superior cycle life (>4,000 cycles at 80% DoD), high round-trip efficiency (>93–95%), and enhanced thermal stability compared to NMC alternatives. The State of Wear (SOW) metric, which aggregates calendar aging and cycle degradation, serves as a key indicator of BESS longevity in PVsyst simulations. In the context of PSHP co-location, the BESS serves an additional operational role beyond conventional grid-injection power shifting: it functions as a dedicated station service power supply for PSHP auxiliary loads during the off-peak early-morning pumping cycle, when solar generation is unavailable.

2.3 Floating PV and Pumped Storage Hydropower Integration

The co-location of Floating PV (FPV) systems on Pumped Storage Hydropower Plant (PSHP) reservoirs represents an emerging paradigm in hybrid renewable energy development. Liu et al. [23] evaluated FPV-PSHP integration at a 2 GW FPV / 1 GW PSHP configuration in China, finding that the integrated system reduces daily energy imbalance by 23.06 MW and curtails reservoir evaporation by approximately 19.06 million m^3/year. The temporal complementarity between FPV daytime generation and the PSHP's off-peak (early-morning) pumping and evening generation cycles creates a natural synergy: daytime solar energy can be stored and time-shifted to cover the early-morning pumping-cycle station-service loads, optimizing reservoir water utilization and reducing off-peak auxiliary energy costs.

Sahu *et al.* [9] reviewed FPV technology co-benefits, documenting evaporation reduction of 50–90% per unit covered reservoir area and module efficiency improvements of 5–15% from passive water cooling. Cazzaniga et al. [10] further quantified FPV structural and operational considerations for reservoir deployments, noting that pontoon-based systems eliminate land acquisition requirements while adding water surface rights and mooring engineering costs. Pérez-Díaz et al. [22] reviewed operational trends in PSHP worldwide, establishing that modern reversible pump-turbine units achieve round-trip efficiencies of 75–85% with variable-speed technology improving partial-load performance and frequency regulation capability.

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2.4 PV Performance Modeling with PVsyst

PVsyst is widely recognized as the de facto industry standard for bankable PV yield assessment. The software implements the one-diode equivalent circuit model for PV module electrical simulation, the Perez transposition model [6] for converting horizontal irradiance to plane-of-array irradiance, and comprehensive loss factor accounting including thermal losses, DC wiring resistive losses, module quality losses, mismatch losses, IAM (Incidence Angle Modifier) losses, and inverter conversion losses. The Meteonorm 8.2 database provides synthetic hourly meteorological time series derived from satellite and ground station observations over the 2016–2021 reference period, offering high spatial resolution climate data suitable for Indonesian sites [4].

2.5 Techno-Economic Analysis of Solar PV in Indonesia

Financial viability assessment of utility-scale PV projects employs multiple complementary metrics. Branker et al. [18] reviewed LCOE calculation methodologies, emphasizing sensitivity to capital cost, discount rate, and degradation rate assumptions. For Indonesian utility-scale PV, the governing price ceiling is the Highest Benchmark Price (Harga Patokan Tertinggi, HPT) set out in Lampiran I of Presidential Regulation (Perpres) No. 112/2022 [24], which establishes a two-stage, non-escalating tariff scaled by capacity and a location factor F. For floating/ground-mounted PV of >3–5 MW (the band applicable to the Pacitan project on its 4,480 kWac AC capacity) the HPT is 8.77 US¢/kWh × F for years 1–10 and 5.26 US¢/kWh for years 11 to a maximum of 30, with F = 1.0 for the Java–Madura–Bali system [24]. The HPT functions as the upper bound of a direct-selection negotiation and replaces the former reliance on PLN's regional Biaya Pokok Penyediaan (BPP) ceiling; PLN's Java–Bali generation BPP was USD 0.089/kWh in 2024 [7] and is retained here only as a cost-of-supply reference point. Pasal 5 of Perpres 112/2022 additionally permits a negotiated agreed price (harga kesepakatan) for business-to-business arrangements, which in practice can exceed the HPT where project economics require it. A geospatial bankability study of Indonesian utility-scale PV [8] established a consensus WACC of 9.5% for IPP/SOE projects, which informs the 9.0% WACC applied in the present study as a conservative base case.

III. MATERIALS AND METHODS

This section consolidates the materials, data, system configurations, cost framework, and mathematical formulations underpinning the integrated assessment. It is organised into four coherent parts: the site description and meteorological resource (Section 3.1); the three FPV system configurations, the PVsyst simulation methodology, and the energy-performance formulations (Sections 3.2–3.7); the engineering, procurement, and construction (EPC) cost framework, financing, total project cost, and the integrated financial analysis (Section 3.8); and the governing formulations for greenhouse-gas reduction and evaporation mitigation (Sections 3.9–3.10). Together these define a reproducible workflow from solar resource input through techno-economic and environmental outputs.

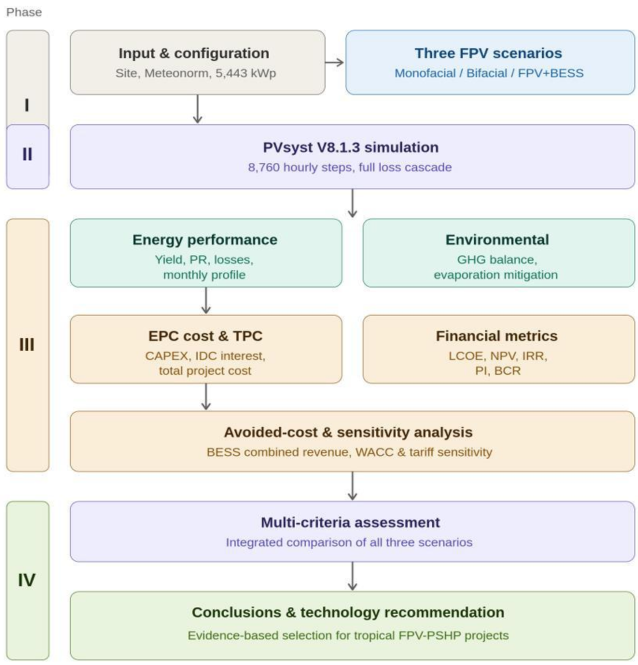

Figure 1: Research methodology framework, organised into four phases: (I) input and configuration of the four FPV scenarios; (II) PVsyst V8.1.3 energy simulation; (III) techno-economic and environmental analysis; and (IV) multi-criteria synthesis and technology recommendation

3.1 Site Description and Meteorological Data

The PLTS Pacitan is situated in Pacitan Regency, East Java Province, Indonesia. The site geographical at an elevation of 262 m above mean sea level (AMSL), within the UTC+7 time zone. The site is co-located in proximity to the planned East Java PSHP development corridor, providing the meteorological and solar resource baseline for the integrated FPV-PSHP assessment. Meteorological input data were sourced from the Meteonorm 8.2 database covering the 2016–2021 reference period.

The host reservoir has a total surface area of approximately 66.3 ha (663,000 m²) at normal water level. The 6 MW FPV array modelled in this study occupies a water-surface footprint of about 4.84 ha (48,403 m²), derived from the 26,573 m² total module area at the constrained shed ground-coverage ratio (GCR) of 54.9%, equivalent to roughly 7.3% of the reservoir surface.

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This coverage lies well within the regulatory ceiling: Permen PUPR No. 7/2023 on the utilisation of part of a reservoir inundation area for floating solar PV permits installation over up to 20% of the inundation surface at normal water level [26], corresponding to a maximum allowable FPV area of about 13.26 ha for this reservoir. The modelled footprint therefore uses only ~37% of the permitted area, leaving an ample compliance margin of approximately 8.4 ha for future expansion. The higher coverage fractions (25–75%) examined in the evaporation-mitigation analysis (Section 4.6) are presented as hypothetical sensitivity cases that bound the co-benefit potential, rather than as the deployed configuration.

Figure 2: Site location of the Pacitan reservoir, East Java, showing the proposed FPV deployment area on the PSHP host reservoir

Table 1: Annual Meteorological Summary — Pacitan Site (Meteonorm 8.2, 2016–2021)

Parameter	Annual Value	Unit
Global Horizontal Irradiation (GHI)	1,928.4	kWh/m²/year
Horizontal Diffuse Irradiation (DiffHor)	874.16	kWh/m²/year
Global Incident in Collector Plane (GlobInc)	1,957–1,958	kWh/m²/year
Average Ambient Temperature (T_Amb)	26.64	°C
Diffuse Fraction (DIF/GHI)	0.453	—
Site Altitude	262 m AMSL	—
Time Zone	UTC+7 (WIB)	—
Site Albedo (monofacial / bifacial model)	0.20 / 0.30	—

The three FPV system configurations and their PVsyst simulation methodology are detailed in the following subsections (3.2–3.6), covering the common design basis, the three technology scenarios, and the simulation setup and validation procedure.

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3.2 PV System Configurations

Four distinct PV system configurations were modeled and simulated within PVsyst V8.1.3 under identical site and meteorological baseline conditions. All four scenarios utilise Longi Solar 400 Wp-class modules and eight SMA Sunny Central 560 HE inverters (4,480 kWac total AC capacity — the rating that governs the applicable HPT capacity band). The primary differentiating factors are the PV module type (monofacial vs. bifacial), bifacial rear-side irradiance modeling geometry, and the inclusion of a BESS operated in a power-shifting mode (Mono+BESS and Bifa+BESS variants).

Table 2: System Configuration Summary — Four Simulation Scenarios

Parameter	Sc. 1 (Mono)	Sc. 2 (Bifacial)	Mono+BESS	Bifa+BESS
PV Module	Longi LR5-54HPB-400M	Longi LR5-54HABB-400M	Longi LR5-54HPB-400M	Longi LR5-54HABB-395M
Module Type	Monofacial	Bifacial (HABB)	Monofacial	Bifacial (HABB)
Number of Modules	13,608	13,482	13,608	12,831
Installed Capacity (STC)	5,443 kWp	5,393 kWp	5,443 kWp	5,004 kWp
Inverter	SMA SC 560 HE	SMA SC 560 HE	SMA SC 560 HE	SMA SC 560 HE
Number of Inverters	8	8	8	8
Total Inverter Power	4,480 kWac	4,480 kWac	4,480 kWac	4,480 kWac
DC:AC Ratio (Pnom)	1.21	1.20	1.21	1.12
Orientation (Tilt/Azimuth)	12° / 0°	12° / 0°	12° / 0°	12° / 0°
Shading Model	No shadings	Unlimited Sheds 2D	No shadings	Unlimited Sheds 2D
BESS	None	None	BYD LVS 4.0 (LFP)	BYD LVS 16.0 (LFP)
BESS Nominal Energy	—	—	20.58 MWh	20.38 MWh
BESS Useable Energy	—	—	15.43 MWh	15.29 MWh
BESS Strategy	—	—	Power shifting	Power shifting
BESS Charging Window	—	—	09:00–16:00 WIB	09:00–16:00 WIB

3.3 Scenario 1: Monofacial Grid-Connected FPV System

The baseline monofacial scenario employs 13,608 units of Longi Solar LR5-54HPB-400M modules (400 Wp each) in 648 strings of 21 modules in series, yielding 5,443 kWp DC installed capacity. Eight SMA Sunny Central 560 HE inverters provide 4,480 kWac total AC capacity. Collector plane orientation is fixed at 12° tilt / 0° azimuth (north-facing per southern hemisphere convention). Module area totals 26,573 m² (cell area 24,341 m²), corresponding to a module conversion efficiency of 20.50% at STC. Array loss parameters: DC wiring loss 1.50%, module quality loss −0.75%, module mismatch loss 2.00% at MPP, string mismatch 0.15%, thermal coefficient Uc = 20.0 W/m²K. IAM profile: 1.000 at 0°, 0.995 at 45°, 0.962 at 60°.

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Under Scenario 1, the FPV plant operates purely as a grid-connected generator: daytime FPV generation is exported in full to the 20 kV PLN distribution grid at Pacitan at the regulated Perpres 112/2022 HPT tariff. No BESS is deployed, and the scenario has no interaction with the PSHP pumping or generation cycles — it serves only the local 20 kV system.

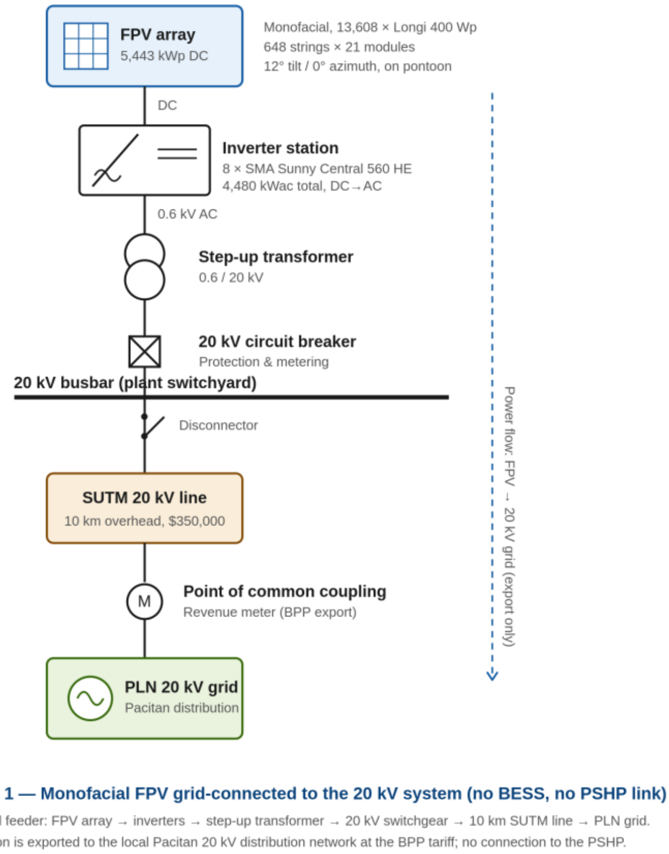

Figure 3: Single line diagram of Scenario 1 — monofacial FPV grid-connected to the 20 kV system. The plant forms a single radial feeder: the 5,443 kWp FPV array feeds eight SMA Sunny Central 560 HE inverters, a 0.6/20 kV step-up transformer, 20 kV switchgear, and a 10 km medium-voltage (SUTM) line to the point of common coupling with the PLN 20 kV distribution grid at Pacitan. No BESS is deployed and there is no connection to the PSHP; all generation is exported to the grid at the Perpres 112/2022 HPT tariff

3.4 Scenario 2: Bifacial Grid-Connected FPV System

The bifacial scenario utilizes 13,482 units of Longi Solar LR5-54HABB-400M bifacial modules, yielding 5,393 kWp. The PVsyst Unlimited Sheds 2D rear-side irradiance model is applied with: shed spacing 5.50 m, sensitive width 3.00 m, shed width 3.04 m, limit profile angle 13.9°, GCR (bifacial) 55.3%, mounting height 1.50 m above pontoon deck. Bifacial model parameters: ground albedo (water surface effective) 0.30, bifaciality factor 70%, rear shading factor 5.0%, rear mismatch loss 10.0%. The rear-side contribution produces 203 kWh/m²/year (10.6% of front-side incident), computed as: $G_{eff} = 1{,}906 + 0.70 \times 202.7$ kWh/m².

The water surface albedo of 0.30 applied for bifacial rear-side modeling is conservative relative to typical land-based bifacial installations (concrete 0.30–0.40, grass 0.20–0.25), reflecting the dynamic reflective properties of reservoir water surfaces which exhibit specular reflection components dependent on solar elevation angle and wave conditions. Surplus FPV generation follows the same 20 kV grid export pathway as Scenario 1.

3.5 Storage-Integrated Configurations: FPV+BESS (Mono+BESS and Bifa+BESS)

Two storage-integrated configurations are modelled. Mono+BESS integrates the monofacial FPV array (5,443 kWp, identical to Sc. 1) with a utility-scale BYD Battery-Box Premium LVS BESS of 20.58 MWh nominal energy (15.43 MWh useable at 95.0%/20.0% SoC limits, fixed operating temperature 20°C). Bifa+BESS pairs the bifacial array (5,004 kWp) with a comparable

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BYD LVS BESS of 20.38 MWh nominal (15.29 MWh useable). Both share the same 4,480 kWac inverter platform as the grid-only cases, so the applicable HPT capacity band (>3–5 MW, set by AC capacity) is identical across all four scenarios.

The planned 1,000 MW PSHP in East Java operates on two distinct cycles, both requiring continuous auxiliary power for station service equipment (lighting, HVAC, control systems, motor-pump auxiliaries, transformer cooling, and protection relay panels):

Pumping Cycle (off-peak, ~00:00–06:00 WIB): The motor-pump sets draw power from the Java-Bali 500 kV off-peak surplus to pump water from the lower to upper reservoir during the early-morning hours. Because solar generation is unavailable at this time, FPV cannot directly supply the pumping-cycle auxiliary loads. Scenarios 1 and 2 do not participate in PSHP station-service supply at all: they operate purely as grid-connected generators exporting daytime FPV output to the 20 kV PLN distribution network, while the PSHP auxiliary loads in those cases remain on the PSHP's own grid supply. Only under the storage configurations (Mono+BESS, Bifa+BESS) does the project serve PSHP auxiliaries: the battery — charged from daytime FPV surplus — discharges in the early morning to cover the pumping-cycle auxiliary loads.

Generation Cycle (peak demand, ~17:00–22:00 WIB): The reversible turbine-generators release stored water to dispatch electricity to the 500 kV Pedan substation. During this evening cycle, solar generation is also unavailable. Under the storage configurations, the BESS has already been fully discharged during the preceding early-morning pumping cycle and therefore does not serve the evening cycle; the turbine-generator auxiliary loads are supplied from the 20 kV grid. This single-discharge strategy prioritises the off-peak pumping cycle, when grid-drawn auxiliary power would otherwise add to off-peak pumping demand.

PSHP Auxiliary Power Load Estimates (indicative, 1,000 MW PSHP East Java):

- Pumping Station Auxiliary Load: ~2.0–3.5 MW (motor-pump lube oil, cooling water, ventilation, control)
- Turbine-Generator Auxiliary Load: ~1.5–2.5 MW (excitation, cooling, hydraulic governor, protection)
- Total Station Service Load: ~3.5–6.0 MW (combined pumping + generation auxiliary demand)
- FPV+BESS Sizing Target: BESS capacity to cover ~6 hours of pumping-cycle auxiliary load (00:00–06:00)

Note: Auxiliary load values are indicative for feasibility analysis. Final sizing requires the PSHP detailed station service load schedule from the EPC design package.

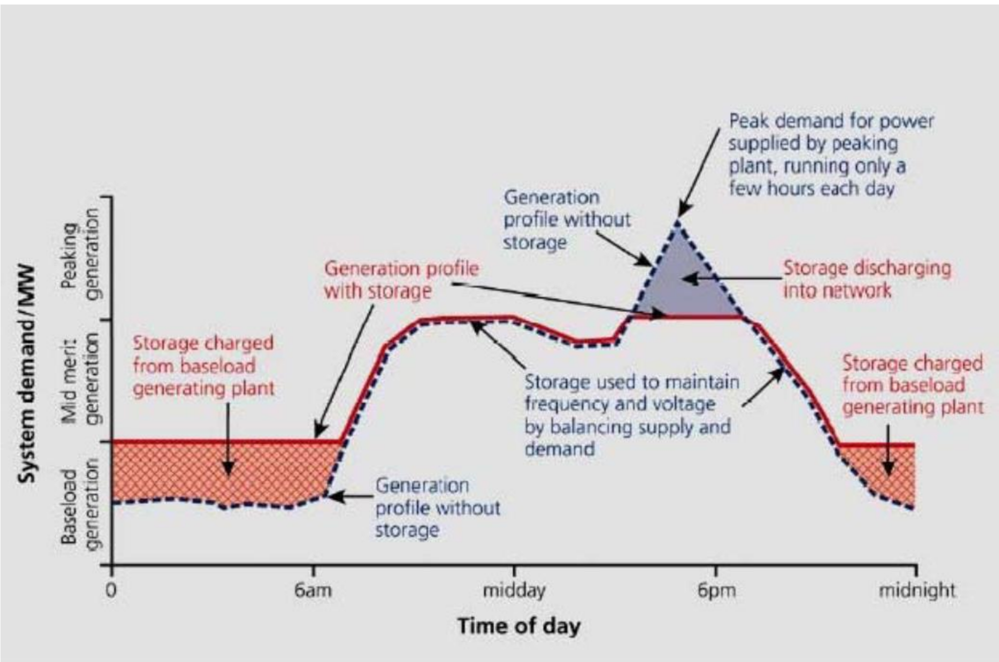

Figure 4: Daily system demand curve illustrating generation profiles with and without energy storage. During off-peak hours the storage is charged from baseload generation, and during the evening peak it discharges into the network, displacing high-cost peaking

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generation while helping to maintain frequency and voltage. This load-shifting principle underlies the role of the BESS in the storage configurations (Mono+BESS and Bifa+BESS), which charge from daytime FPV surplus and discharge during the early-morning pumping window to supply the PSHP auxiliary loads. Source: Hultholm (2014), as reproduced in Antal, B. A. (2014), *Pumped Storage Hydropower: A Technical Review*, Master Report, University of Colorado Denver, Fig. 1.

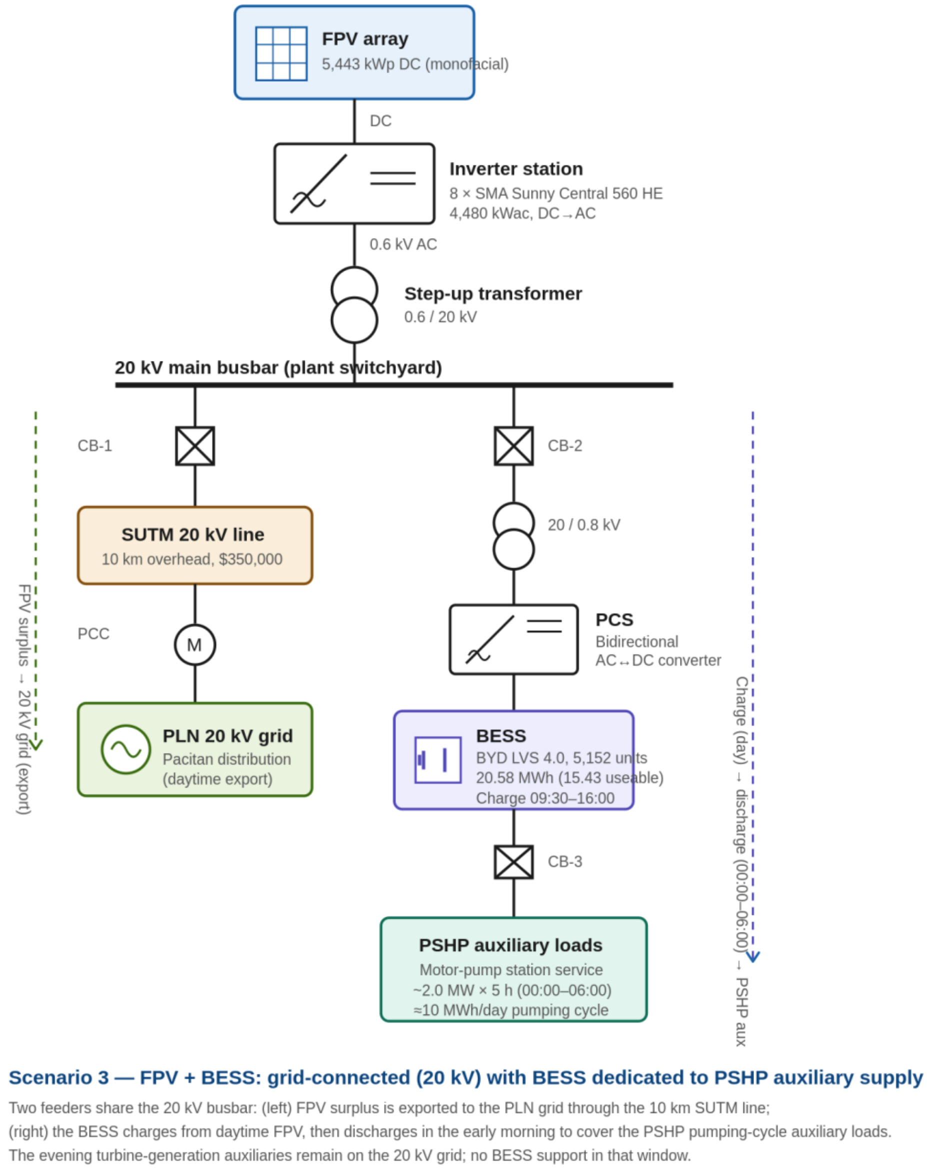

Figure 5: Single line diagram of the storage-integrated FPV+BESS configuration (representative of both Mono+BESS and Bifa+BESS) — grid-connected to the 20 kV system with the BESS dedicated to PSHP auxiliary supply. The FPV array, inverters, and 0.6/20 kV step-up transformer feed a common 20 kV busbar that splits into two feeders: the left feeder (CB-1) exports daytime FPV surplus to the PLN 20 kV grid through the 10 km SUTM line and point of common coupling, while the right feeder (CB-2) connects, via a 20/0.8 kV transformer and a bidirectional power-conversion system (PCS), the BYD LVS BESS (≈20.4–20.6 MWh nominal, ≈15.3–15.4 MWh useable). The BESS charges from daytime FPV (09:00–16:00 WIB) and discharges at ~2.0 MW over the early-morning pumping window (00:00–06:00 WIB, ≈10 MWh/day) to supply the PSHP motor-pump station-service auxiliary loads; the evening turbine-generation auxiliaries remain on the 20 kV grid

3.6 Simulation Setup and Validation

All four simulations were executed at hourly time-step resolution (8,760 steps/annual cycle) in PVsyst V8.1.3. The Perez algorithm [6] is employed for diffuse irradiance transposition. Circumsolar irradiance is treated separately from isotropic diffuse. Horizon profile: free horizon (no topographic shading). Simulation dates: Sc. 1 and Sc. 2 — 21/06/26; Mono+BESS and

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Bifa+BESS — 29/06/26 (V8.1.3). Meteorological data: Meteonorm 8.2, Bakalan station, 100% satellite-derived synthetic hourly time series, 2016–2021 reference climatological period.

The engineering, procurement, and construction (EPC) cost framework is developed in the following subsections (3.8–3.12), beginning with the PSHP auxiliary-power integration rationale and proceeding through the EPC cost structure, the detailed scenario breakdown, interest during construction (IDC), and the resulting Total Project Cost (TPC).

3.7 Energy Performance Formulations

The annual energy performance of each configuration is quantified through a sequence of physically based relations that translate the incident solar resource into delivered alternating-current (AC) energy. The formulation follows the simulation logic implemented in PVsyst V8.1.3, in which the plane-of-array (POA) irradiance is first established from the global horizontal irradiation through the Perez transposition model, and is subsequently converted to electrical output via the system's nameplate capacity and an aggregate performance ratio that embeds the full loss cascade. For the bifacial configuration, an additional rear-side irradiance term is superposed on the front-side resource, as defined in Eqs. (2)–(3). The governing expressions are given below.

$$E_{AC} = \frac{H_{POA} \times P_{STC} \times PR}{G_{STC}} \quad \ldots\ldots (1)$$

In Eq. (1), E_{AC} is the net annual AC energy delivered at the inverter output (kWh/year); H_{POA} is the annual in-plane (POA) irradiation incident on the collector surface (kWh/m²/year); P_{STC} is the installed DC capacity at standard test conditions (5,443 kWp for Scenarios 1 and 3, and 5,393 kWp for Scenario 2); G_{STC} is the reference irradiance at standard test conditions (1,000 W/m²); and PR is the dimensionless performance ratio. The performance ratio aggregates the complete chain of system losses — including thermal derating, module quality and mismatch, DC and AC ohmic losses, inverter conversion efficiency, soiling, and, for the storage configurations, battery round-trip losses — and therefore serves as the principal figure of merit for comparing configurations on an equal-resource basis. The simulated performance ratios of 84.74%, 89.73%, 80.45%, and 85.55% for Sc. 1, Sc. 2, Mono+BESS, and Bifa+BESS respectively reflect the favourable thermal environment of the water-cooled floating array, the rear-side energy gain of the bifacial modules, and the storage-conversion penalty incurred by the battery.

$$G_{eff,bif} = G_{front} + \eta_{bf} \times G_{rear} \quad \ldots\ldots (2)$$

$$G_{rear} = \rho \times G_{GHI} \times VF_{sky} \times (1 - f_{shade,rear}) \times (1 - f_{mm,rear}) \quad \ldots\ldots (3)$$

Equations (2) and (3) describe the additional rear-side contribution that distinguishes the bifacial configuration (Scenario 2). In Eq. (2), $G_{eff,bif}$ is the effective bifacial irradiance, G_{front} is the front-side POA irradiance, η_bf is the module bifaciality factor (0.70 for the modules adopted here), and G_{rear} is the rear-side irradiance reaching the back of the array. Equation (3) resolves G_{rear} from the reflected component of the global horizontal irradiation: ρ is the ground (water-surface) albedo, G_{GHI} is the global horizontal irradiation, VF_{sky} is the sky view factor governing the fraction of reflected light intercepted by the rear plane, and the terms $(1 - f_{shade,rear})$ and $(1 - f_{mm,rear})$ account for rear-side shading and rear mismatch losses, respectively. For the present site, an effective water-surface albedo of 0.30, a rear shading factor of 5.0%, and a rear mismatch loss of 10.0% were applied, yielding a rear-side contribution of 203 kWh/m²/year — equivalent to 10.6% of the front-side incident irradiance. This rear-side gain is the physical origin of the 4.91% higher annual yield of the bifacial configuration relative to the monofacial baseline, and it is captured implicitly within the elevated performance ratio used in Eq. (1).

3.8 EPC Cost Framework, Financing, and Financial Analysis

This subsection consolidates the EPC cost framework, the financing treatment through interest during construction (IDC), the resulting total project cost (TPC), and the governing economic formulations. EPC unit-cost benchmarks (USD/Wp) are taken from FS PLTS reference data and scaled to installed capacity. The bifacial configurations (Sc. 2 and Bifa+BESS) carry a 15% PV-module premium; the two storage configurations (Mono+BESS and Bifa+BESS) add a BYD BESS (≈20.4–20.6 MWh nominal) priced on an energy basis. Each cost category (A–F in Table 3) is obtained by multiplying its reference unit cost (USD/Wp) from the FS PLTS benchmark by the installed capacity, then summed to the total EPC CAPEX; the BESS component is priced on an energy basis (USD/Wh).

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Table 3: Consolidated EPC cost breakdown, financing (IDC), and total project cost — four scenarios

Item	Sc. 1 Mono	Sc. 2 Bifacial	Mono+BESS	Bifa+BESS
A. Main components (PV)	\$3.456M	\$3.753M	\$3.456M	\$3.753M
B. Battery storage (BESS)	—	—	\$0.933M	\$0.924M
C. Balance of system	\$0.327M	\$0.327M	\$0.327M	\$0.327M
D. Cabling & accessories	\$0.737M	\$0.737M	\$0.737M	\$0.737M
E. Civil & M&E works	\$0.245M	\$0.245M	\$0.245M	\$0.245M
F. Eng., inst. & comm.	\$0.686M	\$0.686M	\$0.811M	\$0.811M
TOTAL EPC CAPEX	\$5.451M	\$5.747M	\$6.509M	\$6.797M
Loan amount D (70%)	\$3.816M	\$4.023M	\$4.556M	\$4.758M
IDC interest	\$0.038M	\$0.040M	\$0.046M	\$0.048M
TPC = EPC + IDC	\$5.489M	\$5.787M	\$6.555M	\$6.845M
TPC per Wp (USD/Wp)	1.008	1.073	1.204	1.368

Financing and total project cost

IDC is the interest accrued on the debt portion (70% of EPC) over the 12-month construction period at a 2.0% p.a. concessional (soft-loan) rate — representative of KfW/JICA climate-finance facilities for renewable-energy projects in Indonesia — computed on an S-curve disbursement (drawdown factor 0.50, i.e. ~50% average outstanding balance) and capitalised into the TPC:

$$D = EPC_{CAPEX} \times Debt_{Ratio} \,(Debt_{Ratio} = 70\%) \;\ldots\ldots\; (4)$$

$$IDC = D \times r_{loan} \times T_c \times f_d \,(r_{loan} = 2.0\%, T_c = 1\,yr, f_d = 0.50) \;\ldots\ldots\; (5)$$

$$TPC = EPC_{CAPEX} + IDC \text{ (Development cost and financing fees = 0)} \;\ldots\ldots\; (6)$$

IDC adds only 0.7% to EPC (0.7% of TPC) in every scenario under the concessional rate, giving a TPC of \$5.489M–\$6.845M (Table 3). This all-in financed figure is the investment base for all financial metrics.

Economic analysis formulations

Using TPC as the investment base, the LCOE, NPV, IRR, PI, and BCR are evaluated over n = 30 years at WACC = 9.0%, with energy degradation d = 1.0%/year and annual OPEX of 1.5% of EPC:

$$LCOE = \frac{TPC + \sum_{t=1}^{n} \frac{C_{OPEX,t}}{(1+WACC)^t}}{\sum_{t=1}^{n} \frac{E_{AC,t}}{(1+WACC)^t}} \;\ldots\ldots\; (7)$$

$$E_{AC,t} = E_{AC,0} \times (1 - d)^t \;\ldots\ldots\; (8)$$

$$NPV = \sum_{t=1}^{n} \frac{(R_t - C_t)}{(1+WACC)^t} - TPC, R_t = E_{AC,t} \times HPT(t) \;\ldots\ldots\; (9)$$

$$0 = \sum_{t=1}^{n} \frac{(R_t - C_t)}{(1+IRR)^t} - TPC \;\ldots\ldots\; (10)$$

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$$PI = \frac{NPV + TPC}{TPC} \; ; \; BCR = \frac{\sum_{t=1}^{n} \frac{R_t}{(1 + WACC)^t}}{TPC + \sum_{t=1}^{n} \frac{C_{OPEX,t}}{(1 + WACC)^t}} \quad \ldots\ldots (11)$$

where HPT(t) is the Perpres 112/2022 Highest Benchmark Price applicable in year t. The capacity band is set by the plant AC capacity (4,480 kWac, total inverter rating), placing the project in the >3–5 MW band — 0.0877 USD/kWh for years 1–10 and 0.0526 USD/kWh for years 11–30 (location factor F = 1.0 for Java–Madura–Bali) [24], equivalent to an energy-weighted levelised tariff of ≈0.0756 USD/kWh; PLN's Java–Bali generation BPP of 0.089 USD/kWh [7] is reported alongside as a cost-of-supply reference. For the storage-integrated configurations (Mono+BESS, Bifa+BESS), Article 10 (Pasal 10) of Perpres 112/2022 adds a battery-facility price component of up to 60% of the HPT, so the applicable price reaches up to 160% of the HPT (0.1403/0.0842 USD/kWh for years 1–10/11–30), applied here to the full grid-injected energy. A project is competitive when LCOE (Eq. 7) falls below the applicable purchase tariff and feasible when NPV > 0 (Eq. 9), IRR exceeds the 9% WACC (Eq. 10), and PI and BCR exceed unity (Eq. 11); Eq. (8) applies the 1.0%/year degradation. Because the HPT is two-staged, the year-by-year revenue R_t uses the stage-appropriate price rather than a single flat tariff. Using TPC as the base ensures IDC interest is fully reflected in every metric.

3.9 GHG Emission Reduction Formulations

The environmental benefit of the FPV plant is quantified as the net greenhouse-gas (GHG) emissions avoided over the project lifetime, expressed in carbon-dioxide-equivalent terms. The avoided emissions arise because every kilowatt-hour of solar energy injected into the grid displaces an equivalent unit that would otherwise be generated by the fossil-dominated Indonesian power system. Equations (16)–(18) formalise this balance, first computing the gross annual displacement, then netting out the embodied (lifecycle) emissions of the PV system itself, and finally expressing the latter as an emission intensity for comparison against conventional generation.

$$\Delta CO_{2t} = E_{AC,t} \times EF_{grid} \left(EF_{grid} = 734 \, gCO_2/kWh \right) \quad \ldots\ldots (16)$$

$$Net\ CO_{2\,30yr} = \sum_{t=1}^{30} \Delta CO_{2t} - C_{lifecycle} \quad \ldots\ldots (17)$$

$$EI_{PV} = \frac{C_{lifecycle}}{E_{AC,lifetime}} \; [gCO_2eq/kWh] \quad \ldots\ldots (18)$$

In Eq. (16), ΔCO_{2t} is the annual gross emission displacement (gCO_2/year), $E_{AC,t}$ is the AC energy delivered in year t — degraded at 1.0%/year per Eq. (8) — and EF_{grid} is the Indonesian grid emission factor, taken as 734 gCO_2/kWh to reflect the coal-dominated Java–Bali system. Equation (17) yields the net lifetime balance: the summed annual displacements over the 30-year horizon are reduced by $C_{lifecycle}$, the cradle-to-grave embodied emissions of the PV (and, for the storage variants, the battery) hardware, so that the reported saving is a conservative, fully net figure rather than a gross avoidance. Equation (18) normalises the embodied burden by the lifetime energy yield to give the PV emission intensity EI_{PV} (gCO_2eq/kWh); this intensity is the basis for the comparison against coal, diesel, and combined-cycle gas references, and confirms that the embodied emissions are recovered within a small fraction of the operating life.

3.10 Evaporation Reduction Formulations

A secondary environmental co-benefit of the floating configuration is the suppression of open-water evaporation, since the portion of the reservoir shaded by the FPV modules is shielded from direct solar radiation and wind. Equations (19)–(21) translate the local climatic evaporation potential into the annual water volume conserved and the corresponding percentage reduction. The formulation proceeds from the pan-evaporation measurement, through a pan coefficient that converts it to free-lake evaporation, to the volumetric saving scaled by the FPV-covered area.

$$E_{lake} = K_p \times E_{pan} \left(K_p = 0.75, E_{pan} = 1{,}680 \, mm/yr \right) \quad \ldots\ldots (19)$$

$$\Delta V_{evap} = E_{lake} \times A_{FPV} \times 10^{-3} \times (1 - f_{trans}) \; [m^3/yr] \quad \ldots\ldots (20)$$

$$f_{evap,red} = \frac{A_{FPV}}{A_{reservoir}} \times (1 - f_{trans}) \times 100\% \quad \ldots\ldots (21)$$

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In Eq. (19), E_{lake} is the free-water-surface evaporation rate (mm/year), obtained from the measured pan evaporation E_{pan} (1,680 mm/year for the Pacitan site) scaled by the pan coefficient K_p = 0.75, which corrects for the difference between an evaporation pan and an open reservoir. Equation (20) converts this rate into the annual volume of water conserved, ΔV_{evap} (m³/year): the lake evaporation is multiplied by the FPV-covered area A_{FPV}, with the factor 10^{-3} reconciling millimetres and metres, and the term $(1 - f_{trans})$ discounting the residual evaporation that still occurs through gaps between modules and partial vapour transmission. Equation (21) expresses the result as a dimensionless reduction fraction $f_{evap,red}$, the ratio of covered to total reservoir area weighted by the same transmission factor; evaluated across 25–75% surface coverage, it yields the annual savings of 208,845–626,535 m³/year reported in the results. Because the PSHP reservoir is a managed hydraulic asset, this conserved volume directly augments the water available for energy storage, coupling the evaporation benefit to the plant's generation capacity.

IV. RESULTS AND DISCUSSION

4.1 Energy Yield, Loss Cascade, and Environmental Performance

Table 4 consolidates the annual energy performance of the four configurations, from incident irradiance through the full PVsyst loss cascade to net grid injection, on an identical resource basis (GHI = 1,928.4 kWh/m²/yr) that isolates the technology effect. The bifacial configuration (Sc. 2) is the strongest performer, delivering 9,474,473 kWh/yr and a specific yield of 1,757 kWh/kWp/yr — a +4.91% gain over the monofacial baseline (Sc. 1: 9,031,908 kWh/yr, 1,659 kWh/kWp/yr) despite a 50 kWp smaller array — driven by a +10.6% rear-side irradiance gain (203 kWh/m²/yr) captured through the Unlimited Sheds 2D model. For the storage configurations, the power-shifting strategy time-shifts daytime surplus through the battery before grid injection: of the inverter output, 3,832,307 kWh/yr (Mono+BESS) and 3,669,301 kWh/yr (Bifa+BESS) is routed through the BESS and dispatched to the grid, while the remainder — 4,741,621 kWh/yr (Mono+BESS) and 4,713,055 kWh/yr (Bifa+BESS) — is injected directly into the 20 kV grid without passing through the battery (Table 4, "Direct Grid Injection" row). Net grid injection is 8,573,928 kWh/yr for Mono+BESS at PR = 80.45% and 8,382,356 kWh/yr for Bifa+BESS at PR = 85.55%. The Performance Ratio (84.74%, 89.73%, 80.45%, 85.55% for Sc. 1, Sc. 2, Mono+BESS, Bifa+BESS) reflects these dynamics; the grid-only bifacial case has the highest conventional PR, while its bifacial PR (83.37%) is reported on the more conservative basis that normalises against the total effective collector irradiance including the rear contribution (Section 4.1.2). The slightly lower PR of the monofacial storage case stems from the additional battery conversion stages rather than any array deficiency.

Table 4: Annual Energy Performance Indicators — All Four Scenarios

Performance Indicator	Sc. 1 (Mono)	Sc. 2 (Bifacial)	Mono+BESS	Bifa+BESS
Installed PV Capacity (kWp)	5,443	5,393	5,443	5,004
Global Horiz. Irradiation (kWh/m²)	1,928.4	1,928.4	1,928.4	1,928.4
Global Incident Coll. Plane (kWh/m²)	1,958.0	1,958.0	1,957.9	1,957.9
Array Energy E_Array (kWh/yr)	9,184,785	9,634,495	9,191,652	8,982,393
Inverter Output (kWh/yr)	9,031,908	9,474,473	9,038,644	8,989,945
Grid Injection E_Grid (kWh/yr)	9,031,908	9,474,473	8,573,928	8,382,356
BESS Dispatched Energy (kWh/yr)	0	0	3,832,307	3,669,301
Direct Grid Injection (excl. BESS) (kWh/yr)	9,031,908	9,474,473	4,741,621	4,713,055
BESS Storage Strategy	—	—	Power shifting	Power shifting
BESS Nominal Energy (MWh)	—	—	20.58	20.38
Specific Production (kWh/kWp/yr)	1,659	1,757	1,575	1,675
Performance Ratio PR (%)	84.74	89.73	80.45	85.55

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Performance Indicator	Sc. 1 (Mono)	Sc. 2 (Bifacial)	Mono+BESS	Bifa+BESS
Bifacial PR (%)	—	83.37	—	79.49
Bifacial Rear Irradiance Gain	—	+10.6% (203 kWh/m²/yr)	—	+10.6% (203 kWh/m²/yr)
CO_2 Saved Balance (tCO_2/30yr)	165,913.6	174,369.2	166,042.3	162,110.4

4.1.1 System Loss Cascade Analysis

The energy loss cascade from incident irradiance to delivered grid energy was extracted from the PVsyst loss diagram for each scenario (Table 5). Temperature-related losses dominate across all configurations, at −9.4% to −9.5% of nominal array energy, consistent with the tropical climate of Pacitan: an average ambient temperature of 26.64°C combined with a thermal loss coefficient Uc = 20.0 W/m²K drives operating cell temperatures well above STC during peak irradiance. With a temperature power coefficient of −0.35%/°C for the Longi LR5-54HPB/HABB series and modelled peak cell temperatures near 50°C, thermal derating of roughly 8.75% at peak is expected.

The bifacial scenario shows slightly higher IAM losses (−2.2% vs. −1.9%) due to inter-row shed geometry imposing additional incidence-angle effects, plus a −0.4% mutual-shading loss reflecting the constrained shed configuration (GCR 54.9%, limit profile angle 13.9°). For the FPV+BESS scenarios (Mono+BESS, Bifa+BESS), cumulative battery-related losses amount to about 5.1% of available inverter output, consistent with the round-trip efficiency chain (charger 96.5% × storage 94% × discharge inverter 96.5% ≈ 87.7% total cycle efficiency).

Table 5: System Energy Loss Components by Scenario

Loss Component	Sc. 1	Sc. 2 (Bifacial)	Mono+BESS	Bifa+BESS
IAM Factor Loss	−1.9%	−2.2%	−1.9%	−2.2%
Near Shading (Mutual)	None	−0.4%	None	−0.4%
PV Loss – Irradiance Level	−0.4%	−0.2%	−0.4%	−0.2%
PV Loss – Temperature	−9.5%	−9.5%	−9.4%	−9.4%
Module Quality Gain	+0.8%	+0.8%	+0.7%	+0.8%
Mismatch (Modules / Strings)	−2.2% / −0.15%	−2.1% / −0.15%	−2.1% / −0.15%	−2.2% / −0.15%
Ohmic Wiring Loss	−1.1%	−1.1%	−1.1%	−1.1%
Inverter Loss (Operation)	−1.6%	−1.6%	−1.6%	−1.6%
Battery Charger Loss	—	—	−1.3%	−1.3%
Battery Global Loss	—	—	−2.8%	−2.8%
Battery Inverter Loss	—	—	−1.0%	−1.0%
Bifacial Rear Irradiance Gain	—	+10.6% (rear)	—	+10.6% (rear)
Rear Mismatch Loss	—	−0.7%	—	−0.7%

4.1.2 Bifacial Energy Gain Analysis

The bifacial configuration delivers a 4.91% absolute energy advantage over the monofacial baseline despite a 50 kWp smaller array (Sc. 2: 5,393 kWp vs Sc. 1: 5,443 kWp); normalising for this capacity difference, the specific-production gain is larger still — 1,757 vs 1,659 kWh/kWp/year, a 5.91% uplift. The mechanism is traced explicitly through the PVsyst rear-

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irradiance chain. Of the 855 kWh/m²/year of global irradiance incident on the water surface beneath the array, a ground albedo of 0.30 sets the reflected resource; the rear view factor removes −55.1% (the fraction of the sky/ground hemisphere not seen by the rear face at the 12° tilt and 54.9% ground-coverage ratio), while sky-diffuse adds +2.6% and beam-effective +0.0%, leaving a net rear-side irradiance of 203 kWh/m²/year — equal to 10.6% of front-side incident. After the module bifaciality factor of 0.70 and rear shading/mismatch losses, the effective rear gain converts to the observed +5.91% normalised premium, confirming that the floating geometry (uniform low-albedo water, no row-to-row obstruction beyond the modelled sheds) captures rear-side energy efficiently. The premium is resource-limited rather than module-limited: a higher-albedo deployment surface would raise it further, whereas the bifaciality factor and tilt are already near-optimal for this site.

The two Performance-Ratio definitions reported for the bifacial case must not be conflated. The conventional PR (89.73%) normalises delivered energy by front-side plane-of-array irradiance only, so the rear gain inflates it above the monofacial PR (84.74%); the bifacial PR_Bifi (83.37%) instead normalises by the total effective collector irradiance including the rear contribution, and is therefore the more conservative and physically complete figure. The 6.36-percentage-point gap between the two is precisely the rear-side energy expressed in PR terms. For bankability this distinction is material: a yield assessment quoting the 89.73% conventional PR alongside the higher bifacial energy double-counts the rear gain if the reader assumes a front-only basis, so the present study reports PR_Bifi as the lender-grade figure and flags the convention explicitly to avoid an optimistic bias in the P50 energy estimate.

4.1.3 FPV+BESS System Performance (Mono+BESS and Bifa+BESS)

The two storage configurations make explicit the trade-off between temporal dispatch flexibility and net grid-energy efficiency. Taking Mono+BESS as the worked case, of the 9,038,644 kWh available at the inverter output the battery cycles 3,832,307 kWh/yr — about 42.4% of throughput — and exports the remainder directly during the 09:00–16:00 charging window, time-shifting the stored fraction to higher-value dispatch windows. The round-trip conversion penalty of the battery path is the source of the lower net injection: Mono+BESS delivers 8,573,928 kWh/yr to the grid (5.1% below the 9,031,908 kWh/yr of the equivalent grid-only monofacial case), and Bifa+BESS delivers 8,382,356 kWh/yr (Bifa+BESS cycles 3,669,301 kWh/yr). This ≈5% energy give-up is the quantifiable cost of dispatchability, and is the reason the storage Performance Ratios (80.45% and 85.55%) fall below their grid-only counterparts rather than any array-side deficiency. Battery aging analysis returns a Cycles State of Wear of ≈96.3–96.4% and a Static State of Wear of 90.0% at end of the 30-year simulation; the static SOW being the binding term identifies calendar aging — governed by operating temperature and mean state of charge — as the dominant degradation pathway at this tropical site. Because the model fixes cell temperature at 20°C, real-world thermal stress is likely understated, so the 90.0% static-SOW figure should be read as an optimistic bound; an active-cooling or partial-SoC operating strategy would be the primary lever to protect end-of-life capacity. Even on this conservative reading the BYD LVS retains capacity consistent with utility-scale warranty terms.

Beyond the energy give-up, the power-shifting strategy converts an intermittent daytime export into a controllable injection profile: stored energy can be released into windows aligned with the evening demand peak, the PSHP early-morning pumping cycle, or grid-stability events, rather than being constrained to the solar window. Two distinct value streams follow. First, dispatchability commands a regulated premium — the Article 10 battery-facility price component (up to 160% HPT) quantified in Section 4.2.2 — which more than offsets the ≈5% round-trip energy loss. Second, the same stored energy can serve the co-located PSHP auxiliary loads during the off-peak pumping window, displacing grid-drawn station service. The storage configurations therefore trade a small, well-quantified energy penalty for a disproportionately larger gain in both revenue (Section 4.2) and system-integration value, which is the central economic finding of this study for PSHP-co-located FPV.

4.1.4 Lifecycle CO_2 Emission Balance

Environmental performance was evaluated through a 30-year lifecycle CO_2 emission balance using Indonesia's grid emission factor of 734 gCO_2/kWh (IEA emission-factor database). System-generated emissions (construction and manufacturing) total 6,650.01 tCO_2 for all four scenarios (PV-only basis; storage variants add battery-related embodied emissions in the lifecycle intensity of Tables 11–12), comprising module lifecycle emissions (1,713 $kgCO_2$/kWp × 3,000 kWp = 5,138,160 $kgCO_2$), support structure (4.90 $kgCO_2$/kg × 75,000 kg = 367,184 $kgCO_2$), and inverters (485 $kgCO_2$/unit × 2,360 units = 1,144,664 $kgCO_2$). The detailed balance is shown in Table 6.

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Table 6: CO_2 Emission Balance — 30-Year Lifetime Analysis

CO_2 Parameter	Sc. 1 (Mono)	Sc. 2 (Bifacial)	Mono+BESS	Bifa+BESS
Generated Emissions (tCO_2)	6,650.01	6,650.01	6,650.01	6,650.01
Replaced Emissions (tCO_2)	198,882.6	208,627.9	199,030.9	194,499.4
Net Saved CO_2 Balance (tCO_2)	165,913.6	174,369.2	166,042.3	162,110.4
Grid Emission Factor (gCO_2/kWh)	734	734	734	734
System Lifetime (years)	30	30	30	30
Annual Degradation Rate (%)	1.0	1.0	1.0	1.0

All four scenarios show strongly positive CO_2 balances over the 30-year lifetime, with net savings from 162,110.4 tCO_2 (Bifa+BESS) to 174,369.2 tCO_2 (Sc. 2 bifacial). The grid-only bifacial scenario provides the highest environmental benefit, displacing about 8,455.6 tCO_2 more than the monofacial baseline over the project life; the two storage variants save marginally less because their grid-injected energy is slightly lower after round-trip losses. The break-even point — where cumulative replaced emissions exceed generated lifecycle emissions — occurs at approximately year 4–7 across scenarios, after which the systems deliver net environmental benefit for the remaining operational life. These results are consistent with the GHG intensity discussion in Section 4.5.

4.2 Techno-Economic and Financial Analysis

Table 7 summarises the investment build-up, financing assumptions, and LCOE sensitivity for the four configurations on a Total Project Cost (TPC) basis, with development cost and loan financing fees excluded (TPC = EPC + IDC interest only). EPC CAPEX rises from $5.451M (monofacial) to $6.797M (Bifa+BESS), giving CAPEX intensities of 1.001–1.358 USD/Wp; financing the debt at a 2.0% concessional (soft-loan) rate keeps the capitalised IDC interest to just +0.7% of EPC (TPC = $5.489M–$6.845M, 1.008–1.368 USD/Wp). The 9.0% base-case WACC follows the Indonesian IPP/SOE consensus (risk-free ≈6.5–7.0%, equity risk premium ≈5–6%, D/E = 70/30).

Table 7: Investment Cost, Financing, Assumptions & LCOE Sensitivity to WACC (TPC basis, development cost excluded), with a Reference / Benchmark column citing the cost source or regulatory basis for each row

Cost / Parameter	Sc. 1 (Mono)	Sc. 2 (Bifacial)	Mono+BESS	Bifa+BESS	Reference / Benchmark
(A) EPC CAPEX	$5.451M	$5.747M	$6.509M	$6.797M	FS PLTS USD/Wp benchmark
EPC per Wp (USD/Wp)	1.001	1.066	1.196	1.358	FPV+BESS typ. 0.9–1.4 USD/Wp
(B) IDC — Interest on Debt	$38,157	$40,229	$45,563	$47,579	IDC @ 2.0% concessional, Tc=1 yr
Loan (70% of EPC)	$3.816M	$4.023M	$4.556M	$4.758M	Debt ratio 70% (IPP norm)
TOTAL PROJECT COST — TPC	$5.489M	$5.787M	$6.555M	$6.845M	TPC = EPC + IDC (investment base)
TPC per Wp (USD/Wp)	1.008	1.073	1.204	1.368	All-in financed unit cost

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Cost / Parameter	Sc. 1 (Mono)	Sc. 2 (Bifacial)	Mono+BESS	Bifa+BESS	Reference / Benchmark
Annual OPEX (1.5% × EPC)	$81,765	$86,205	$97,635	$101,954	O&M 1.5% of EPC/yr (industry norm)
WACC / Lifetime	9.0% / 30 yr	9.0% / 30 yr	9.0% / 30 yr	9.0% / 30 yr	IPP/SOE consensus WACC 9% [8]
Applicable price scheme	HPT energi	HPT energi	160% HPT (Psl 10)	160% HPT (Psl 10)	Perpres 112/2022; Pasal 10 storage
Price Yr1–10 / Yr11–30 (US¢)	8.77 / 5.26	8.77 / 5.26	14.03 / 8.42	14.03 / 8.42	HPT >3–5 MW (AC band), Lampiran I [24]
LCOE @ WACC 5% (US¢/kWh)	5.41	5.43	6.80	7.26	Sensitivity (low discount)
LCOE @ WACC 7%	6.38	6.41	8.03	8.57	Sensitivity
LCOE @ WACC 9% (Base)	7.42	7.46	9.34	9.97	vs levelised HPT ≈7.56¢; BPP 8.90¢ [7]
LCOE @ WACC 11%	8.51	8.56	10.71	11.44	Sensitivity (high discount)

WACC = 9.0% and Tariff Framework:

WACC = 9.0% is applied as the base-case discount rate (Indonesian IPP/SOE consensus, ScienceDirect 2023). Components: Risk-free rate (SBN 10-yr) ≈ 6.5–7.0% | Equity Risk Premium ≈ 5–6% | Cost of equity ≈ 10–11% | After-tax cost of debt ≈ 6–7% | D/E = 70/30 | Weighted WACC ≈ 9.0%.

Tariff Note: The base-case purchase tariff is the Perpres 112/2022 Highest Benchmark Price (HPT). The capacity band follows the plant AC capacity (4,480 kWac, total inverter rating), i.e. the >3–5 MW band: 0.0877 USD/kWh × F for years 1–10 and 0.0526 USD/kWh for years 11–30, with F = 1.0 for the Java–Madura–Bali system [24]; energy-weighted levelised ≈0.0756 USD/kWh. For the storage configurations, Article 10 (Pasal 10) of Perpres 112/2022 adds a battery-facility price of up to 60% of the HPT (price up to 160% HPT, applied to the full grid-injected energy, subject to Ministerial price approval). PLN's Java–Bali generation BPP (USD 0.089/kWh, 2024 [7]) is shown only as a cost-of-supply reference. On this basis the two grid-only scenarios are feasible (LCOE below the levelised HPT, IRR above the 9% WACC), and the two storage scenarios are strongly feasible once the Article 10 component is applied; sensitivity to the facility-price utilisation is shown in Table 9.

At the 9% base case, the four configurations yield a system LCOE of 7.42, 7.46, 9.34, and 9.97 US¢/kWh on total injected energy (Table 7, lower block) for Sc. 1, Sc. 2, Mono+BESS, and Bifa+BESS respectively. The decisive comparison is against the applicable purchase price. For the two grid-only cases the regulated >3–5 MW HPT has an energy-weighted levelised value of ≈7.56 US¢/kWh, which sits just above their LCOE (7.42 and 7.46 US¢/kWh), so both are feasible on the regulated tariff under concessional financing. For the two storage cases, the Article 10 battery-facility component lifts the applicable price to up to 160% of the HPT (levelised ≈12.09 US¢/kWh), comfortably above their LCOE, so both clear feasibility with margin. The grid-only LCOE values also remain below PLN's 2024 BPP cost-of-supply reference (8.90 US¢/kWh), confirming the underlying generation cost is competitive.

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4.2.1 Financial Metrics — NPV, IRR, PI, and BCR

Table 8 reports the five-metric results at WACC = 9% (TPC basis) under concessional (2.0%) construction financing, on the applicable Perpres 112/2022 price for each configuration: the grid-only scenarios (Sc. 1, Sc. 2) on the two-stage >3–5 MW HPT (8.77 / 5.26 US¢/kWh), and the storage scenarios (Mono+BESS, Bifa+BESS) on that HPT plus the Article 10 battery-facility component at the 60% ceiling (price 160% HPT, applied to the full grid-injected energy). On this basis all four configurations are feasible: Sc. 1 and Sc. 2 reach IRR of 9.3% and 9.2% with marginally positive NPV (≈+$0.12M and +$0.09M), while Mono+BESS and Bifa+BESS reach IRR of 13.8% and 12.5% with NPV of ≈+$2.23M and +$1.68M and payback of 5.9 and 6.4 years. The storage cases clear feasibility even though the Article 10 component need not be taken at the full ceiling — break-even is reached using only 23.5% (Mono+BESS) and 31.9% (Bifa+BESS) of the 60% facility-price allowance (Table 9).

Table 8: Financial Analysis Results — NPV, IRR, PI, BCR, Payback Period for all four configurations (WACC=9%, TPC basis, n=30 yr). Grid-only scenarios (Sc. 1, Sc. 2) priced on the regulated >3–5 MW HPT (AC-capacity band); storage scenarios (Mono+BESS, Bifa+BESS) priced on the HPT plus the Article 10 battery-facility component at the 60% ceiling (price 160% HPT, applied to full grid-injected energy). A Reference / Benchmark column states the regulatory criterion or data source against which each row is assessed (NPV>0, IRR>WACC 9%, PI/BCR>1; levelised HPT ≈7.56¢/kWh; PLN BPP 8.90¢/kWh [7])

Financial Metric	Sc. 1 (Mono)	Sc. 2 (Bifacial)	Mono+BESS	Bifa+BESS	Reference / Benchmark
TOTAL PROJECT COST (TPC)	$5.489M	$5.787M	$6.555M	$6.845M	Investment base (EPC + IDC)
Applicable price scheme	HPT energi	HPT energi	160% HPT (Psl 10)	160% HPT (Psl 10)	Perpres 112/2022; Pasal 10
Price Yr-1 (US¢/kWh)	8.77	8.77	14.03	14.03	HPT >3–5 MW (AC band) [24]
Year-1 Energy (kWh/yr)	9,031,908	9,474,473	8,573,928	8,382,356	PVsyst V8.1.3 E_Grid
Year-1 Revenue (USD/yr)	$792,098	$830,911	$1,203,094	$1,176,212	Energy × applicable price
Year-1 OPEX (USD/yr)	$81,765	$86,205	$97,635	$101,954	1.5% × EPC/yr
Year-1 Net Cash Flow (USD/yr)	$710,333	$744,706	$1,105,459	$1,074,258	Revenue − OPEX
LCOE (US¢/kWh)	7.42	7.46	9.34	9.97	< levelised HPT ≈7.56¢; < BPP 8.90¢ [7]
NPV @ WACC=9% (USD)	+$0.12M	+$0.09M	+$2.23M	+$1.68M	Feasible if NPV > 0
IRR (%)	9.3%	9.2%	13.8%	12.5%	Feasible if IRR > WACC = 9.0%
Payback Period (years)	7.7	7.8	5.9	6.4	Shorter is better (no threshold)
Profitability Index (PI)	1.02	1.02	1.34	1.25	Feasible if PI > 1.0
Benefit-Cost Ratio (BCR)	1.02	1.01	1.30	1.21	Feasible if BCR > 1.0
Feasibility (5 criteria)	Met ✓	Met ✓	Met ✓	Met ✓	Perpres 112/2022; Permen ESDM 5/2025

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Under concessional financing all four configurations are bankable. The grid-only monofacial and bifacial cases reach IRR = 9.3% and 9.2%, NPV ≈ +$0.12M and +$0.09M, PI ≈ 1.02, BCR ≈ 1.01–1.02, and payback ≈ 7.7–7.8 years, the bifacial case marginally behind on absolute NPV despite its higher yield because of its larger TPC. The storage-integrated cases are the strongest performers once the Article 10 battery-facility price (up to 60% of HPT) is applied: Mono+BESS reaches NPV ≈ +$2.23M, IRR 13.8%, PI 1.34, BCR 1.30, payback 5.9 years, and Bifa+BESS NPV ≈ +$1.68M, IRR 12.5%, PI 1.25, BCR 1.21, payback 6.4 years. Mono+BESS leads on the storage side because of its lower TPC and larger injected energy; the bifacial module premium in Bifa+BESS is not fully repaid at this price level. Every configuration clears all five feasibility criteria.

Table 9: Sensitivity of the storage configurations to the Article 10 battery-facility component — NPV and IRR of Mono+BESS and Bifa+BESS as a function of the fraction of the 60% HPT facility-price ceiling actually applied (WACC = 9%, TPC basis, n = 30 yr). The grid-only scenarios (Sc. 1, Sc. 2) are priced on the HPT energy tariff alone and shown for reference

Article 10 facility-price applied	Price Yr-1 (US¢/kWh)	Mono+BESS NPV / IRR	Bifa+BESS NPV / IRR
0% (HPT energy only)	8.77	−$1.44M / 5.7%	−$1.91M / 4.8%
30% of HPT	11.40	+$0.40M / 9.9%	−$0.12M / 8.8%
Break-even (23.5% / 31.9%)	10.83 / 11.57	≈$0 / 9.0%	≈$0 / 9.0%
60% of HPT — full ceiling (160% HPT)	14.03	+$2.23M / 13.8%	+$1.68M / 12.5%

Table 9 shows that the storage configurations clear the 9% WACC threshold well before the Article 10 facility-price ceiling is fully used: Mono+BESS reaches NPV = 0 (IRR = 9.0%) at only 23.5% of the 60% allowance, and Bifa+BESS at 31.9%. At the full 60% ceiling both are comfortably bankable (IRR 12.5–13.8%). Mono+BESS leads Bifa+BESS at every utilisation level because its lower TPC and larger injected energy outweigh the bifacial yield gain at this price. Because break-even is reached using less than a third of the allowance, the storage cases remain feasible even if the negotiated battery-facility price falls well below the regulatory ceiling — a substantial margin of safety against the Ministerial price-approval outcome.

4.2.2 Battery-Facility Price Component under Article 10 (Pasal 10) of Perpres 112/2022

The feasibility of the two storage configurations rests on Article 10 (Pasal 10) of Perpres 112/2022, under which a PLTS Fotovoltaik equipped with a battery or other energy-storage facility is entitled to a storage-facility price of up to 60% of the electricity purchase price, subject to Ministerial price approval (and mandatory approval where the facility price exceeds 60%). The applicable price for a PV+BESS plant therefore rises from the energy HPT alone to up to 160% of the HPT. On the AC-capacity >3–5 MW band (8.77 / 5.26 US¢/kWh), the full ceiling gives 14.03 / 8.42 US¢/kWh (energy-weighted levelised ≈12.09 US¢/kWh). In this study the storage configurations Mono+BESS and Bifa+BESS are evaluated with this 160% HPT price applied to their full grid-injected energy — a right unavailable to the grid-only configurations (Sc. 1, Sc. 2).

Applying the full 60% ceiling, Mono+BESS reaches NPV ≈ +$2.23M (IRR 13.8%, PI 1.34, BCR 1.30, payback 5.9 yr) and Bifa+BESS NPV ≈ +$1.68M (IRR 12.5%, PI 1.25, BCR 1.21, payback 6.4 yr) — both stronger than the grid-only cases. The storage cases do not require the full ceiling: break-even (NPV = 0, IRR = 9%) is reached at only 23.5% of the allowance for Mono+BESS and 31.9% for Bifa+BESS (Table 9), so feasibility holds with a wide margin even if the negotiated facility price settles below the cap. The 60% figure is a ceiling on the facility price relative to the HPT, established as a Ministerial price approval rather than automatically; the procedural basis and the special transaction provisions for storage-equipped plants are codified in Permen ESDM No. 5/2025 on PJBL. Beyond this regulated price, the BESS also provides dispatchability and PSHP early-morning auxiliary-supply capability that the grid-only configurations cannot offer.

4.3 GHG Emission Reduction Analysis

4.3.1 Lifecycle CO_2 Balance

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Table 10: 30-Year Lifetime CO_2 Emission Balance — All Four Scenarios

CO_2 Parameter	Sc. 1 (Mono)	Sc. 2 (Bifacial)	Mono+BESS	Bifa+BESS
Lifetime Energy Generated (GWh)	235.1	246.6	223.1	218.1
Grid CO_2 Displaced (tCO_2, EF=734)	172,564	181,019	163,813	160,153
Lifecycle C_lifecycle (tCO_2eq)	1,992	1,980	3,536 (incl. BESS)	3,524 (incl. BESS)
Net CO_2 Savings Balance (tCO_2)	170,571	179,040	160,277	156,629
Lifecycle Emission Intensity EI_PV (gCO_2/kWh)	8.5	8.0	15.8	16.2
CO_2 Break-even Year	Year 4	Year 4	Year 7	Year 7

Table 11: Lifecycle GHG Emission Intensity: FPV vs. Fossil Fuel Reference Plants

Technology	Lifecycle EI (gCO_2eq/kWh)	CO_2 per 30-yr (tCO_2)*	EI Ratio vs. Coal	Category
Coal Steam Turbine	820	192,782	1.00× (baseline)	Fossil Fuel
Diesel Reciprocating Engine	650	152,815	0.79× vs. Coal	Fossil Fuel
Natural Gas CCGT	490	115,199	0.60× vs. Coal	Fossil Fuel
Indonesian Grid EF	734	—	0.90× vs. Coal	Grid Average
Sc. 1 Monofacial PV	8.5	1,992	97× lower	Solar PV ✓
Sc. 2 Bifacial PV	8.0	1,980	102× lower	Solar PV ✓
Mono+BESS	15.8	3,536	52× lower	Solar PV ✓
Bifa+BESS	16.2	3,524	51× lower	Solar PV ✓

* Fossil fuel CO_2 estimated for equivalent lifetime energy of 235100 GWh (Scenario 1 basis). PV CO_2 = lifecycle manufacturing emissions only (C_lifecycle).

4.4 Reservoir Evaporation Mitigation

Annual open-water evaporation for the Pacitan reservoir is estimated from Equation (14): $E_{lake} = 0.75 \times 1{,}680$ mm/yr = 1,260 mm/yr. Three FPV surface coverage scenarios are evaluated for the reservoir surface area of 66.3 ha (663,000 m²).

Table 12: Annual Reservoir Evaporation Savings — Three FPV Coverage Scenarios

Parameter	No FPV (Base)	FPV 25% Cover	FPV 50% Cover	FPV 75% Cover
FPV Covered Area A_FPV (m²)	—	165,750	331,500	497,250
E_lake (mm/yr)	1,260	1,260	1,260	1,260
Annual Evaporation (m³/yr)	835,380	626,535	417,690	208,845
ΔV_evap Saved (m³/yr)	—	208,845	417,690	626,535

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Parameter	No FPV (Base)	FPV 25% Cover	FPV 50% Cover	FPV 75% Cover
f_evap,red (%)	—	25.0%	50.0%	75.0%
Water Saving (ML/yr)	—	208.8 ML	417.7 ML	626.5 ML
PSHP Extra Energy* (MWh/yr)	—	135.8	271.6	407.3
Revenue Value at lev. HPT (USD/yr)	—	$9,668	$19,336	$29,004

* PSHP extra energy from conserved water: $\Delta V \times H \times g \times \eta / 3.6\times10^9$, where H = 300 m head, g = 9.81 m/s², η = 0.80 round-trip efficiency.

V. CONSOLIDATED MULTI-CRITERIA ASSESSMENT

Table 13: Comprehensive Multi-Criteria Assessment — All Four FPV Configurations. Grid-only scenarios (Sc. 1, Sc. 2) priced on the regulated >3–5 MW HPT (AC-capacity band); storage scenarios (Mono+BESS, Bifa+BESS) on the HPT plus the Article 10 battery-facility component at the 60% ceiling (price 160% HPT, applied to full grid-injected energy). On this basis all four configurations satisfy the five feasibility criteria. The reservoir evaporation savings row reports the annual water conserved at the array footprint (≈50% lake-surface coverage, per Table 12), scaled by installed area; this conserved volume directly augments the water available to the co-located PSHP

Criterion	Sc. 1 Mono	Sc. 2 Bifacial	Mono+BESS	Bifa+BESS
Total EPC CAPEX	$5.451M	$5.747M	$6.509M	$6.797M
CAPEX/Wp (USD/Wp)	1.001	1.066	1.196	1.358
BESS Function	—	—	Power shifting / PSHP aux.	Power shifting / PSHP aux.
Price scheme	HPT energi	HPT energi	160% HPT (Psl 10)	160% HPT (Psl 10)
Year-1 Revenue (USD)	$792,098	$830,911	$1,203,094	$1,176,212
Annual Energy Yield (MWh)	9,032	9,474	8,574	8,382
Performance Ratio PR	84.74%	89.73%	80.45%	85.55%
Grid Dispatchability	Low	Low	High (BESS)	High (BESS)
LCOE (US¢/kWh)	7.42	7.46	9.34	9.97
NPV @ WACC=9%	+$0.12M	+$0.09M	+$2.23M	+$1.68M
IRR (%)	9.3%	9.2%	13.8%	12.5%
Payback Period	7.7 yr	7.8 yr	5.9 yr	6.4 yr
PI / BCR	1.02 / 1.02	1.02 / 1.01	1.34 / 1.30	1.25 / 1.21
Net CO_2 Saved (tCO_2/30yr)	170,571	179,040	160,277	156,629
Reservoir Evaporation Savings (m^3/yr)	417,690	413,853	417,690	384,002
Feasibility (5 criteria)	Met ✓	Met ✓	Met ✓	Met ✓

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VI. CONCLUSIONS

This study delivers a comprehensive performance and techno-economic assessment of four FPV configurations at PLTS Pacitan 6 MW integrated with the planned East Java PSHP, combining: (i) PVsyst V8.1.3 energy simulation (Meteonorm 8.2, 2016–2021) with full key-performance-indicator and loss cascade analysis across 8,760 hourly steps, using Longi LR5-54HPB/HABB-400M modules and SMA Sunny Central 560 HE inverters; (ii) 20-component EPC cost breakdown from FS PLTS reference data (revised scope, excluding the Project Management category and selected Civil/M&E items); (iii) IDC interest (2.0% concessional soft-loan rate) adding to Total Project Cost (TPC), with development cost and loan financing fees excluded from the investment basis; (iv) five-metric financial analysis (LCOE, NPV, IRR, PI, BCR) at WACC = 9%; (v) GHG lifecycle emission comparison against coal, diesel, NGCC, and Indonesian grid; (vi) Penman evaporation mitigation quantification; and (vii) Article 10 (Pasal 10) battery-facility pricing analysis (up to 160% HPT on the full grid-injected energy) establishing the economic viability of the storage configurations.

Energy Yield: PVsyst V8.1.3 simulation (Meteonorm 8.2, GHI = 1,928.4 kWh/m²/year) using Longi LR5-54HPB/HABB-400M modules and SMA Sunny Central 560 HE inverters establishes the bifacial configuration (Scenario 2) as the top energy performer, with annual grid energy of 9,474,473 kWh/year, a Performance Ratio of 89.73%, and specific production of 1,757 kWh/kWp/year — a 4.91% gain over the monofacial baseline (Scenario 1: 9,031,908 kWh/year, PR = 84.74%, 1,659 kWh/kWp/year), driven by a +10.6% rear-side irradiance contribution (203 kWh/m²/year). The two storage configurations inject 8,573,928 kWh/year (Mono+BESS, PR = 80.45%) and 8,382,356 kWh/year (Bifa+BESS, PR = 85.55%) into the grid, gaining temporal dispatch flexibility through their power-shifting strategy and PSHP auxiliary-supply capability. Temperature-related losses (−9.4% to −9.5% of array energy) are the dominant degradation mechanism at this tropical site.

EPC Cost: EPC CAPEX ranges from \$5.451M (1.001 USD/Wp monofacial) to \$6.509M (FPV+BESS), net of the excluded Project Management category and three Civil/M&E items (Fire Suppression, Transformer Fence, Cleaning Water Supply; −\$544,300 per scenario). With development cost and loan financing fees excluded and the debt financed at a 2.0% concessional rate, Total Project Cost (TPC = EPC + IDC interest only) reaches \$5.489M–\$6.555M (1.008–1.204 USD/Wp). The Floater, Anchoring & Mooring System represents 11.8% of EPC cost — the primary additional cost component of FPV relative to ground-mounted PV at equivalent module capacity.

Financial Viability: On the regulated Perpres 112/2022 HPT for the AC-capacity >3–5 MW band (8.77 US¢/kWh years 1–10, 5.26 US¢/kWh years 11–30, F = 1.0; energy-weighted levelised ≈7.56 US¢/kWh) — the band set by the 4,480 kWac inverter rating rather than the DC module capacity — with the debt financed at a 2.0% concessional rate and development cost and loan financing fees excluded, all four configurations are feasible. The grid-only monofacial and bifacial cases reach IRR = 9.3% and 9.2%, NPV ≈ +\$0.12M and +\$0.09M, PI ≈ 1.02, BCR ≈ 1.01–1.02, payback ≈ 7.7–7.8 years, with LCOE of 7.42 and 7.46 US¢/kWh just below the levelised HPT. The two storage configurations are evaluated with the Article 10 battery-facility price component (up to 60% of HPT, i.e. price up to 160% HPT applied to the full grid-injected energy): at the full ceiling Mono+BESS reaches NPV ≈ +\$2.23M (IRR 13.8%, payback 5.9 yr) and Bifa+BESS NPV ≈ +\$1.68M (IRR 12.5%, payback 6.4 yr). Break-even for the storage cases is reached using only 23.5% (Mono+BESS) and 31.9% (Bifa+BESS) of the 60% allowance, so feasibility holds with a wide margin even below the full ceiling. Article 10 prices are established as a Ministerial price approval; the procedural basis is codified in Permen ESDM 5/2025.

GHG Reduction: PV lifecycle emission intensities of 8.5–15.6 gCO_2eq/kWh are 102–52× lower than coal generation (820 gCO_2eq/kWh), with net lifetime CO_2 savings of 165,914–174,369 tCO_2 over 30 years under Indonesia's grid emission factor of 734 gCO_2/kWh, and CO_2 break-even reached at approximately year 13–15.

BESS as PSHP Auxiliary Supply: The storage configurations derive their feasibility from the Article 10 battery-facility price component (up to 60% of HPT, i.e. price up to 160% HPT applied to the full grid-injected energy). On this basis Mono+BESS and Bifa+BESS achieve positive NPV (≈+\$2.23M and +\$1.68M) and double-digit IRR (13.8% and 12.5%) — stronger than the grid-only cases. Beyond this regulated price, the BESS is functionally justified as a PSHP station-service asset, supplying motor-pump auxiliaries during the off-peak early-morning pumping cycle and providing grid dispatchability that the grid-only configurations cannot offer.

Evaporation Mitigation: FPV at 50% reservoir coverage saves 417,690 m³/year of evaporation, equivalent to 271.6 MWh/year additional PSHP generation capacity and USD 19,336/year at the levelised HPT tariff.

The bifacial FPV configuration is recommended as the primary grid-only technology for the Pacitan site on technical and energy-yield grounds; on the AC-capacity >3–5 MW HPT it — like the monofacial case — is feasible (LCOE just below

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the levelised HPT), with payback ≈7.7–7.8 years. For PSHP co-location, the storage configurations (Mono+BESS, Bifa+BESS) are recommended, where the BESS serves a dual function: (i) time-shifting stored daytime FPV energy for dispatch to the grid during higher-value windows, and (ii) exporting surplus FPV generation directly to the 20 kV grid. With the Article 10 battery-facility price (up to 60% of HPT), both storage cases are strongly bankable (IRR 12.5–13.8%, payback 5.9–6.4 years), and Mono+BESS leads on economics owing to its lower TPC. Because break-even is reached using only 23.5–31.9% of the 60% facility-price allowance, the storage cases remain feasible with substantial margin even if the negotiated facility price settles below the regulatory ceiling — all within contract structuring codified in Permen ESDM 5/2025. Across the portfolio, every configuration is feasible on its applicable regulated price, with the dispatchable storage-integrated options central to PSHP co-location offering the strongest returns.

Future Research: Future work should address: (i) outdoor validation of PVsyst bifacial simulation against measured production data from the commissioned Pacitan plant; (ii) optimization of BESS capacity sizing relative to actual PSHP station service load schedules (motor-pump and turbine-generator auxiliary); (iii) sensitivity analysis of bifacial rear-side gain to varying reservoir water surface albedo across seasonal and meteorological conditions; (iv) degradation modeling under tropical humidity and temperature field conditions; (v) grid stability assessment of FPV integration into the Java-Bali 500 kV system with high renewable penetration; and (vi) lifecycle water balance combining FPV evaporation savings and PSHP hydraulic efficiency improvements.

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