Financing Battery Energy Storage Systems in Indonesia

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Abstract

Indonesia's Rencana Usaha Penyediaan Tenaga Listrik (RUPTL) 2025-2034, or Electricity Supply Business Plan, represents a concrete pathway towards achieving the country's objectives to expand its power sector and integrate low-emissions generation. Within this framework, battery energy storage systems (BESS) are identified as critical elements of Indonesia's future power grid. By strengthening system reliability and stability, facilitating the integration of variable renewable energy, and extending access to low-emissions electricity in isolated regions, BESS can offer essential services which will only become more valuable as Indonesia's demand for electricity grows. However, deployment of the technology remains in its early stages in the country today, and meeting the RUPTL's objectives will require both public and private actors to significantly scale-up investment.

Against this backdrop, Indonesia needs business models and financing structures that are adapted to its conditions. Constraints on spending by the country's state-owned utility, PLN, mean that the private sector has the potential to play a significant role in the development of Indonesia's BESS fleet. This report examines how private capital can be mobilised to accelerate BESS deployment across all regions of the country. Current risks associated with BESS development – especially from the perspective of project sponsors and financiers – are identified and addressed through adaptive business models. The analysis also identifies the level of investment needed to complete the RUPTL's BESS pipeline and examines how this spending can be financed. Finally, the report takes a deep dive into the RUPTL by examining the bankability level of archetypal projects and quantifying how these projects can be remunerated.

By identifying the risks and opportunities associated with BESS development in Indonesia, this report aims to support policy makers, regulators, project investors and financiers in creating bankable conditions for the achievement of the RUPTL's battery storage ambitions.

Acknowledgements, contributors and credits

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Executive summary

Indonesia's power sector is facing major evolutions in both supply and demand

Demand for electricity in Indonesia is set to rise sharply over the next ten years, underpinning rapid deployment of new generation capacity and battery energy storage. In the International Energy Agency (IEA's) Stated Energy Policies Scenario (STEPS), electricity demand rises from nearly 500 terawatt-hours (TWh) in 2025 to nearly 800 TWh by 2035, driven especially by residential space cooling as both urban and rural regions see continued economic growth and households see income levels rise. The Electricity Supply Business Plan (Rencana Usaha Penyediaan Tenaga Listrik [RUPTL]) 2025-2034 published by state-owned utility PT Perusahaan Listrik Negara (PLN) addresses demand growth by aiming to install 69 gigawatts (GW) of power capacity, including 6 GW of standalone storage and 3.6 GW of hybrid (solar PV-plus-BESS) capacity. Low-emissions technologies account for less than 10% of PLN's installed capacity in 2025, but they constitute three-fifths of planned capacity additions in the RUPTL, representing a significant step in PLN's shift away from fossil power. This report considers only the RUPTL 2025-2034 as its scope and does not include additional renewable energy development objectives.

By helping to integrate variable renewable energy, battery energy storage systems (BESS) will be a key enabler of reliable low-emissions electricity supply. BESS can perform a wide range of services that support grid stability and reliability, improve the integration of electricity generated by wind and solar photovoltaic (PV) systems, and enhance access to low-emissions electricity in isolated regions. The BESS projects in the RUPTL satisfy four broad needs: standalone assets provide load smoothing and ancillary services, while hybrid systems combine storage with solar PV generation to facilitate renewables integration and improve access to low-emissions electricity in remote areas.

The primary barrier to BESS deployment in Indonesia lies in a limited pipeline of bankable projects, rather than financing constraints. Domestic and international capital markets have demonstrated interest in supporting Indonesia's clean energy ambitions, while concessional lenders such as multilateral climate funds and development finance institutions (DFIs) have established BESS-specific facilities. However, uncertainty over long-term visibility of cash flows stemming from a lack of BESS-specific regulation, especially for standalone assets, leads current projects to face bankability challenges.

Current planning indicates a larger role for the private sector, with over 25% of future BESS capacity allocated to independent power producers

PLN is largely tasked with developing standalone battery storage assets that will support the national grid, while hybrid (solar PV-plus-BESS) installations are generally allocated to independent power producers (IPPs). Of the roughly 6 GW of standalone battery storage outlined in the RUPTL's Accelerated Renewable Energy Development (ARED) scenario, nearly 90% is planned for the regions of Sumatra and Java, Madura and Bali. These regions are the largest in Indonesia according to population, electricity consumption and grid infrastructure development. As a result, these standalone BESS installations will primarily serve as network assets and are closely aligned with PLN's mandate to provide reliable electricity to its customers. Hybrid installations in the regions of Sulawesi and Nusa Tenggara, however, come with additional complexity – in both development and operation – which can benefit from the technical expertise of IPPs.

Constraints on PLN's balance sheet mean that private capital is essential to meet BESS deployment targets. As Indonesia's state-owned utility, PLN is mandated to provide reliable power to its customers at tariffs that are regulated by the state's Ministry of Energy and Mineral Resources (MEMR). Despite maintaining investment-grade credit ratings, the utility's balance sheet relies on government subsidies and equity injections to cover costs and make necessary investments. The participation of IPPs in building out the RUPTL's BESS pipeline is instrumental to meeting investment needs in a financially sustainable manner, especially amid competing priorities for transmission, distribution, and generation infrastructure. Moreover, our analysis suggests that replacing PLN-run diesel generation with hybrid (solar PV-plus-BESS) installations could create further headroom and strengthen energy security for PLN by displacing the cost of imported fuel and reducing exposure to fuel price volatility.

Completing the RUPTL's battery energy storage system pipeline will require total investment of USD 5 billion

IEA analysis shows that investment needs in BESS projects across all regions average nearly USD 560 million annually from 2026 to 2034. This annual spending lies below the country's total investment in solar PV in 2025, but is well above historical investment in BESS, implying a rapid acceleration in spending. Capital expenditure, which is determined by capital costs, grid connection costs and technology degradation rates, varies according to the degree of grid development in each region. In the first half of the RUPTL, one-third of spending is concentrated on the island of Kalimantan to support the development of nearly 0.6 GW of standalone systems for Indonesia's new capital city, Nusantara. By contrast, the second half of the RUPTL sees the region of Java, Maduraand Bali account for the largest share (three-fifths) of spending as PLN builds nearly 3.5 GW of storage to address rapid growth in electricity demand in its most populous region.

Despite being responsible for over 70% of total capacity additions, PLN accounts for only 60% of overall BESS spending needs from 2026 to 2034. Cumulative investment for PLN is estimated to reach nearly USD 3 illion by 2034, mainly towards development in the regions of Sumatra and Java, Madura and Bali. Private sector investment accounts for the remaining USD 2 billion. Projects led by IPPs tend to be in more remote and isolated areas, driving up BESS technology and grid connection costs and leading those projects to face more bankability hurdles than those in Sumatra and Java, Madura and Bali.

Commercial debt accounts for the largest share of financing for the RUPTL's BESS pipeline, though international public financiers are key to bridging gaps in bankability for first-of-a-kind projects. Based on the financing structures considered in this analysis, commercial financiers provide an estimated USD 2.5 billion to deploying Indonesia's BESS projects, representing half of total investment needs. Public finance, which generally comes in the form of equity injections from the government of Indonesia, the country's state-backed development bank PT Sarana Multi Infrastruktur (PT SMI), or sovereign wealth funds Indonesia Investment Authority (INA) and Danantara, provides an estimated USD 2.3 billion. International public finance (IPF) from multilateral climate funds, export credit agencies (ECAs), multilateral development banks (MDBs), DFIs or bilateral lending reaches an estimated USD 275 million. Despite accounting for a relatively small share of total investment, the concessional and other favourable terms associated with some of IPF make it an essential tool for crowding in additional private investment.

Concessional funding is critical to establishing first-of-a-kind projects in the RUPTL, and must be phased out gradually. Grants and below-market-rate loans are particularly effective when used to mitigate precise obstacles such as hedging costs to mitigate currency risk or revenue uncertainty in the first few years of operation. Meanwhile, capacity building and technical assistance programmes can support the design of BESS-specific regulation. Our analysis suggests that an estimated USD 460 million in grants and concessional loans from international and domestic public financiers – representing nearly 10% of total investment – is needed. For Indonesia's first standalone BESS projects, replacing commercial debt with concessional terms could lower necessary availability payments by around 6%, improving bankability and reducing PLN's financial burden. Concessional funding should be accompanied by clear exit strategies to ensure capital recycling. Moreover, the use of concessional funding – while important – should not replace the development of regulation that provides long-term frameworks for projects to succeed.

Remaining uncertainties around BESS implementation result in bankability challenges

Regulatory foundations for BESS remuneration have been established, but additional details are needed to boost investor confidence. Uncertainties around regulation and permitting are cited by the IEA's Cost of Capital Observatory as the main drivers of the weighted average cost of capital in Indonesia, which lies between 9% and 11% for BESS projects. Initial regulatory frameworks for hybrid installations have been implemented through MEMR Regulations 5/2025 and 19/2025 and Presidential Regulation 112/2022. Together, these lay the foundation for IPPs developing hybrid assets to recover costs of both the generation and storage components through the signing of power purchase agreements (PPAs) with PLN. A lack of parallel regulations concerning standalone BESS installations is currently the largest barrier to bankability for these types of projects.

Business models for BESS remain highly dependent on asset configuration and operational use cases, which in turn directly affect revenue certainty and bankability. Within the scope of BESS projects connected to PLN's electricity network, two main models are considered: full tolling schemes for standalone BESS, and PPAs for hybrid projects. While these structures provide revenue visibility, uncertainties remain regarding their practical implementation. Limited clarity around intended BESS use cases, remuneration for specific services and battery degradation can delay investment decisions, ultimately constraining the pace of BESS deployment.

Financing over 7 GW of BESS will require multiple sources of capital, each playing a distinct and complementary role across the capital stack. Multilateral development banks, DFIs, ECAs and other providers of concessional capital can absorb the project-specific risks that commercial lenders are not yet willing to assume during construction and early market formation. As Indonesia's BESS market matures, commercial financing is critical to replicating successful projects and reducing the state's fiscal burden. The scale at which lenders operate is also an important consideration: local banks, with limited experience financing BESS, are likely to be more cautious on technology and performance risk, while international lenders are more sensitive to currency and regulatory risk. A syndicated structure that combines both domestic and international lenders is therefore well suited to addressing the full range of risks for Indonesia's first wave of BESS projects.

Six guiding pillars for to accelerate BESS deployment

Address regulatory risk by clarifying remuneration structures and technical and operational expectations. Investor and lender confidence in Indonesia's emerging pipeline of BESS projects depends heavily on visibility over how assets are expected to be used and remunerated. The classification of BESS as network or generation assets, permitting and licensing requirements, and careful integration of BESS into the national grid code enable developers to design systems that are well suited to PLN's needs. Meanwhile, financiers require visibility over project cash flows before being able to provide capital to new projects – this can be addressed through standardised tolling agreements, PPAs and ancillary service procurement agreements. Our analysis finds that, for standalone BESS, steady capacity payments of an estimated USD 111 per kilowatt (kW) to USD 297/kW per year would be sufficient to deliver the returns that commercial investors seek. Meanwhile, the addition of battery storage to solar PV projects, which ultimately improves solar PV utilisation and facilitates their integration into PLN's network, raises PPA prices by a range of USD 8 per megawatt-hour (MWh) to USD 18/MWh across the RUPTL's main regions.

Prioritise the long-term system benefits offered by the first standalone assets over their short-term profitability. Early standalone BESS projects face bankability challenges, which result from regulatory uncertainty and relatively high financing costs. While Indonesia's first standalone projects may not be profitable in their first years of operation, they will provide long-term grid flexibility that will be essential to maintaining a reliable grid as the country addresses rapidly rising demand for electricity and ambitious targets for the development of renewable generation.

Prioritise financing for the development and construction phases of hybrid projects. While hybrid BESS benefits from well-established regulatory frameworks, the technology remains in its early stages in Indonesia. As a result, hybrid BESS projects struggle to secure financing in phases before the start of commercial operation. Targeted public support, such as guarantees or subordinated debt from international public financiers, can help to unlock commercial lending in subsequent project stages.

Establish pilot projects that clearly demonstrate the range of services BESS can offer. Early pilot projects in the regions with the highest needs for storage can accelerate learning, build investor confidence and demonstrate the full value of BESS services. While standalone projects in Java, Madura and Bali can be used to show BESS' role as network assets, hybrid projects in Sulawesi can demonstrate how BESS can be used to improve utilisation of renewable generation assets.

Tailor concessional funding and technical assistance programmes to address specific challenges. Concessional support is essential to de-risking early BESS projects, particularly first-of-a-kind projects in the easternmost islands of Indonesia where isolation and small system sizes pose challenges to bankability. Targeted instruments, such as first-loss guarantees, long-tenor loans and grants, can address financing barriers for de-dieselisation projects, while technical assistance and capacity building are well suited to projects in regions with more mature grids. However, well-defined exit strategies ensure that future projects do not develop a dependency on concessional capital.

Engage a broad range of stakeholders early and often to demonstrate a long-lasting commitment to BESS development. Visible alignment among key stakeholders in Indonesia is necessary to address political risk, which is perceived in particular by international developers and financiers. Close co-ordination between MEMR and PLN will ensure that regulations are well suited to BESS' needs, while regular engagement with developers and capital providers brings technical expertise. Cross-cutting institutions such as Danantara are positioned to facilitate engagement across many corners of the public and private sectors. Meanwhile, regional co-ordination – especially with other member states of the Association of Southeast Asian Nations (ASEAN) – can strengthen the resilience of supply chains and battery recycling facilities.

Setting the scene: BESS and Indonesia's energy transition

Introduction to battery energy storage systems

Battery energy storage systems (BESS) are highly versatile technologies that can provide a variety of services that range from supporting grid stability and reliability, facilitating the integration of variable renewable energy (VRE), and accelerating access to electricity through the development of off-grid systems.

Over the past decade, significant capital cost declines for BESS technologies – which are largely based on lithium-ion batteries – have enabled their uptake primarily in advanced economies and the People's Republic of China (hereafter, "China"). However, emerging market and developing economies (EMDE) – including countries in the Association of Southeast Asian Nations (ASEAN) region – are expected to account for a growing share of global BESS investments as they pursue ambitions for the deployment of low-emissions power against the backdrop of rapidly rising demand for electricity. This shift is already well underway, with total investment in utility-scale BESS in EMDE (excluding China) nearly tripling from 2024 to 2025.

Battery energy storage systems are critical components in developing secure and reliable electricity systems

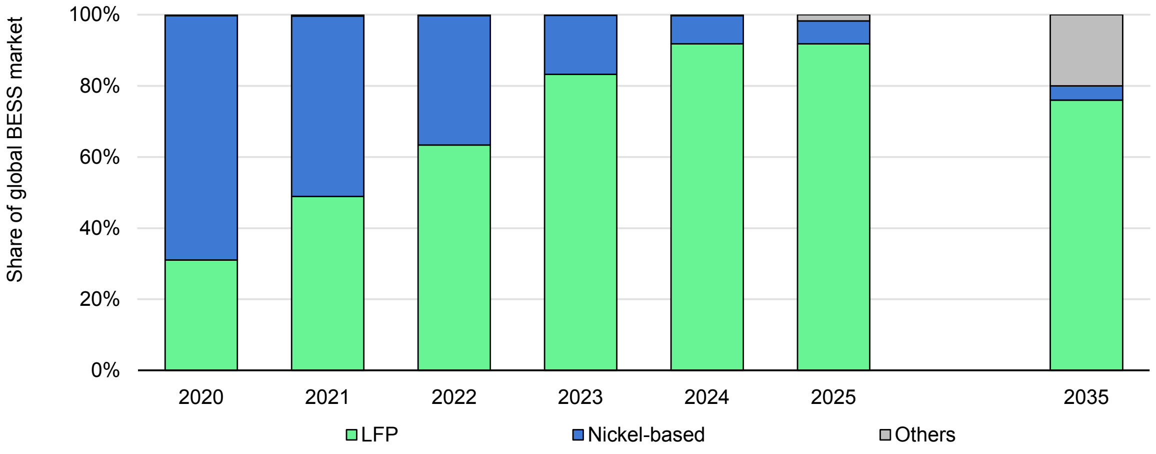
While lithium-ion batteries have traditionally been used to power small electronic devices and, more recently, to electrify transportation, utility-scale BESS are rapidly becoming an essential component of power systems around the world. By absorbing or injecting active power rapidly, BESS can help maintain reliable and flexible power systems. The main purpose of the grid is to transport electricity from generators to consumers – but to do so successfully, the two must always be in equilibrium. Power systems that rely on conventional, fossil-based electricity generation, such as coal and natural gas power plants, have historically maintained equilibrium by ramping electricity generation up or down to match demand.

However, power systems today are evolving as new, low-emissions sources of electricity generation such as solar photovoltaic (PV) and wind account for a growing share of electricity supply. These VREs have a limited ability to modulate generation to match demand, creating the need for new sources of energy storage and grid flexibility. While these services have historically been provided by pumped hydropower using reservoirs and natural gas peaker plants, BESS have emerged as additional sources of storage and are essential to maintaining a secure supply of electricity. As a result of significant technology improvements and manufacturing capacity expansion, the global average cost of turnkey 2-hour storage duration BESS declined by 46% from 2020 to 2025, and costs are expected to continue declining. The falling cost of BESS, combined with similar trends for solar PV, has led to both standalone storage systems and hybrid (solar PV or wind generation paired with storage) systems to become cost-competitive with conventional thermal generation in many countries around the world.

Today, nearly all utility-scale BESS installations use lithium-ion chemistries, which benefit from energy densities that are four to five times higher than those of modern lead acid chemistries. Lithium-ion batteries consist of two electrodes, the positive cathode and negative anode, between which lithium ions move to store or release energy as the battery charges or discharges. A porous separator prevents direct contact between the cathode and anode, while an electrolyte enables ions to move between them.

Two chemistries of lithium-ion chemistries dominate the BESS market today: lithium iron phosphate (LFP) and lithium nickel manganese cobalt oxide (NMC). While the high energy density of NMC chemistries makes them well suited for space-constrained applications, LFP batteries dominate utility-scale energy storage installations due to their lower costs, longer cycle lives and improved thermal stability. Despite the two chemistries accounting for roughly equal shares of global demand in 2020, LFP batteries nearly tripled their share of the market by 2025, now accounting for over 90% of the BESS market globally.

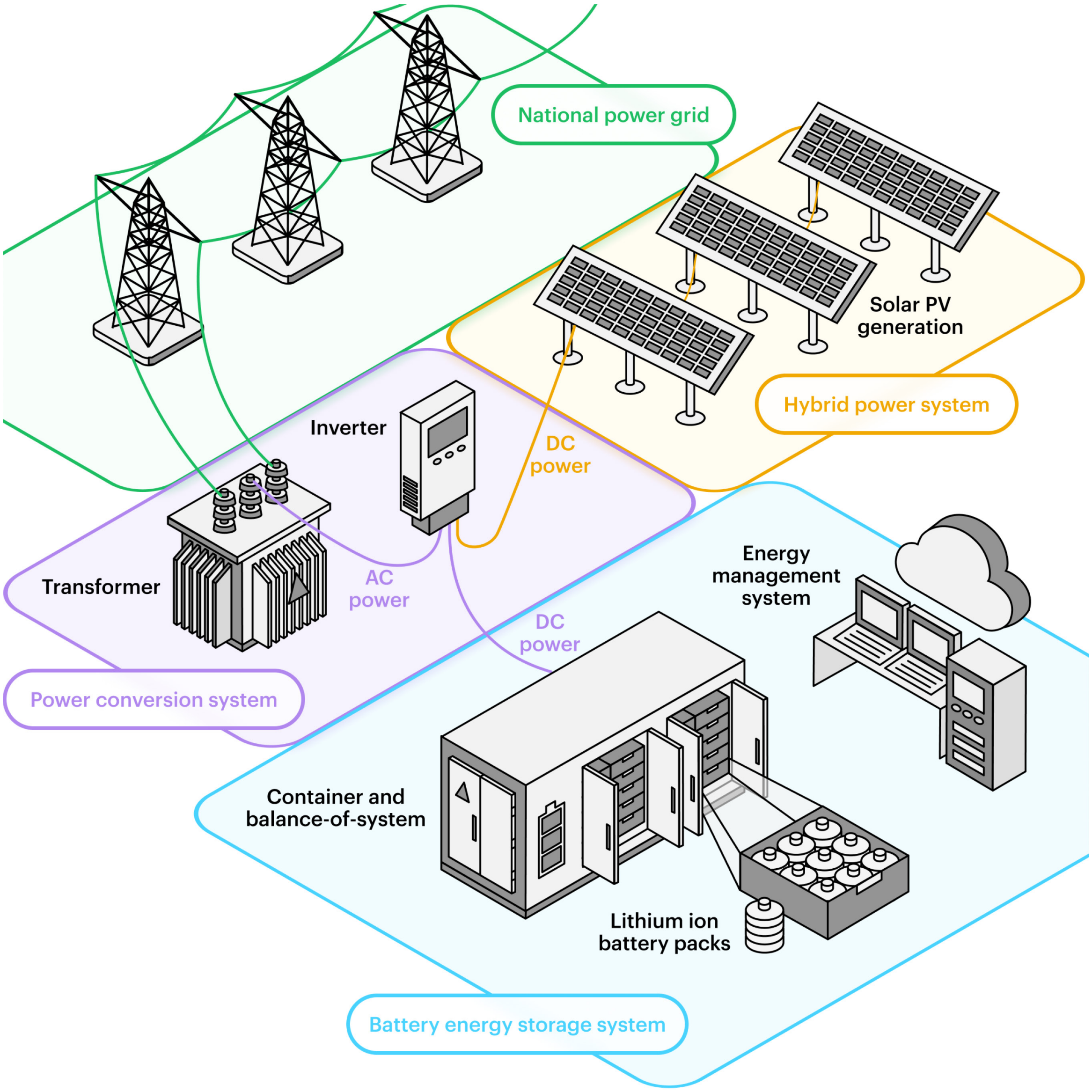
Advanced battery storage shares of global market by chemistry, 2020-2025 and 2030



Notes: LFP = lithium iron phosphate. Nickel-based includes lithium nickel cobalt manganese oxide (NMC) and lithium nickel cobalt aluminium oxide (NCA). Others includes chemistries such as sodium-ion and vanadium redox flow. A small share of lithium iron manganese phosphate (LFMP) is included within the LFP category in 2035. The above figure does not include lead-acid chemistries.

A complete utility-scale BESS installation includes much more than the battery cells themselves. Battery cells are assembled into racks, which are stacked within containers to optimise energy density. Battery racks are located inside a system container alongside balance-of-system components, which include thermal management and safety systems. Outside the container, components include the power conversion system (PCS), which uses inverters to convert direct current (DC) into alternating current (AC); transformers and switchgear, which connect the PCS at the appropriate grid voltage level; and an energy management system, which controls battery dispatch and interfaces with the system operator. Finally, systems include infrastructure that connects the batteries to the grid or sources of power generation (in the case of hybrid installations).

Battery energy storage system and associated generation and grid components



Notes: Standalone BESS configurations do not include a solar PV generation component. AC = alternating current. DC = direct current.

By charging and discharging electricity quickly and precisely, BESS provide a wide range of services to enhance power-system reliability and flexibility, making them the multi-tool of electricity networks. A primary function of BESS is energy arbitrage, in which batteries charge while electricity prices are low and discharge when they are high. Other services such as renewables shifting and firming, congestion relief, and the provision of peak capacity help to mitigate curtailment of renewable generation and improve the overall efficiency of power systems.

Another range of BESS functions can be described as ancillary services, in which assets ensure grid stability and a high quality of power supply. Fast response times make batteries particularly suited to rapid frequency response and voltage support. In networks with rising shares of solar PV and wind generation, ancillary services are especially useful for smoothing VRE output over brief (seconds to minutes) time periods to maintain grid stability.

Finally, BESS can serve as highly strategic assets, deferring big-ticket investment in network expansion. In areas where transmission and distribution lines are highly utilised and local electricity pricing mechanisms are in place, BESS can help to relieve bottlenecks during periods of high electricity production or consumption by being located at points with large price differentials. When paired with solar PV or wind generation, BESS can support the development of distributed energy systems and microgrids in isolated areas, accelerating access to decarbonised electricity.

Summary of battery energy storage system services

Type	BESS service
System reliability and flexibility	Wholesale energy arbitrage; renewables smoothing, shifting, and firming; peak capacity reserves
Ancillary services	Black-start capabilities; frequency regulation; voltage support; synthetic inertia services; spinning and non-spinning reserves; ramping reserves
Grid support and optimisation	Congestion relief; transmission and distribution grid investment deferral; mini-grids

Notes: See Annex for complete definitions of BESS services. For more information regarding BESS services, see IEA (2024), Batteries and Secure Energy Transitions.

Global deployment of BESS is expanding rapidly

Over the last ten years, global installed capacity of utility-scale BESS increased by an average of 65% annually from 1.6 gigawatts (GW) in 2015 to over 220 GW by the end of 2025. Most of today's BESS capacity additions exist in China and advanced economies. China alone accounted for 60% of cumulative additions over the last decade, while advanced economies, driven by the United States, the

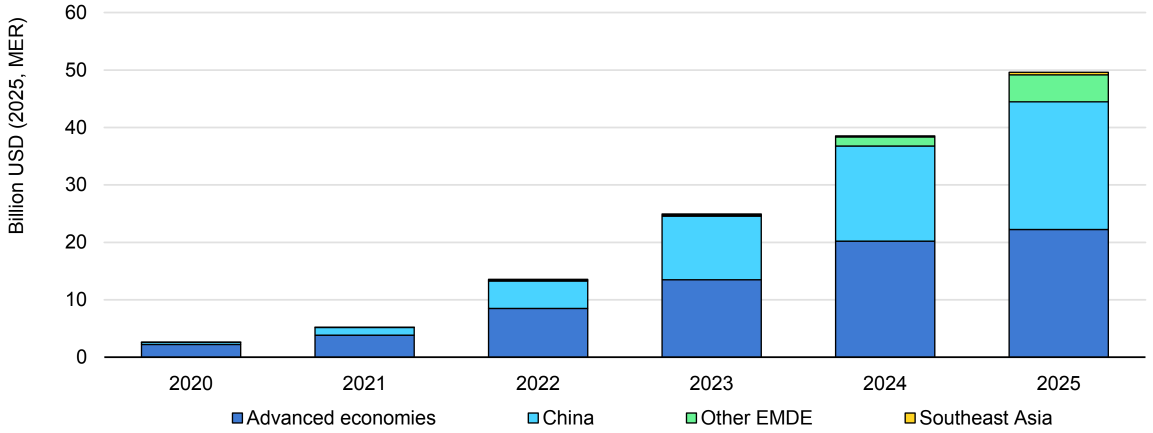
European Union and Australia and New Zealand, account for 35%. Even though only 5% of global BESS installed capacity is currently located in EMDE excluding China, additions are rapidly scaling up to meet the dual challenge of rising VRE penetration and increased demand for electricity. For instance, installed BESS capacity in India more than doubled from 2024 to 2025, while Saudi Arabia saw significant standalone utility-scale storage installations – totalling nearly 3 GW – come online in the same year.

Utility-scale BESS installations exceeded 2 GW across the ASEAN region by the end of 2025. Installed capacity in the region grew by 25% that year, mainly driven by installations in Malaysia and the Philippines. In Malaysia, for instance, the 100 megawatt (MW)/400 megawatt-hour (MWh) Lahad Datu BESS in Sabah – one of the largest in Southeast Asia – is helping to enhance grid stability, reduce reliance on diesel and support renewable integration. However, battery storage remains in its early stages in Indonesia: by the end of 2025, approximately 30 MW of capacity were operational in the country. A 5 MW pilot project developed by PT Perusahaan Listrik Negara (PLN) in collaboration with Indonesia Battery Corporation, PT Indonesia Power and PT Pembangkitan Jawa Bali became the country's first operational BESS asset in 2022.

At the same time that global BESS capacity additions have risen significantly, the capital cost of utility-scale systems has declined significantly. The global average capital cost for two-hour-duration storage systems declined by around 46% from 2020 to 2025. These cost declines are largely driven by a significant expansion in battery manufacturing capacity, particularly in China, where economies of scale, price competition among domestic producers and manufacturing and technological innovations have pushed costs down. The growing share of LFP chemistries – which are less reliant on expensive materials such as cobalt and nickel – has also placed downward pressure on capital costs. A similar trend for solar PV technologies, whose costs went down threefold from 2015 to 2025, is today strengthening the competitiveness of hybrid installations that can turn intermittent renewable energy into firmer sources of power.

Despite capital cost declines, the significant increase in capacity additions has led global utility-scale BESS investment (including utility-scale and behind-the-meter applications) to rise from roughly USD 1.3 billion in 2015 to USD 78 billion in 2025, and is expected to surpass USD 100 billion in 2026. The largest single share (30%) of investment occurred in China at USD 24 billion, while advanced economies together spent USD 46 billion in 2025, equivalent to 60% of the global total. In 2025, Southeast Asia invested USD 0.6 billion in BESS.

Historical investment in utility-scale BESS by region, 2020-2025



Notes: MER = market exchange rate. EMDE = emerging market and developing economies.
Sources: IEA analysis based on Bloomberg (2025), Lithium-ion Battery Price Survey and Benchmark Mineral Intelligence (2026) dataset.

As power systems around the world seek to secure their supplies of electricity and increase their shares of low-emissions generation, BESS capacity installations are expected to rise rapidly. Under the International Energy Agency (IEA) Stated Energy Policies Scenario (STEPS), global installed BESS capacity exceeds 1 300 GW by 2035. China and advanced economies continue to account for a significant share of utility-scale BESS capacity, representing 62% and 24%, respectively, of cumulative global additions over the next decade. The share of BESS capacities in EMDE excluding China also rises rapidly from 5% in 2025 to 13% in 2035, driven primarily by India and the Middle East. Capacity in Southeast Asia alone increases by an average of over 20% annually over the next decade.

Overview of Indonesia's power sector

Today, electricity generation in Indonesia is dominated by coal-fired power plants. However, growing electricity demand, combined with objectives to reduce reliance on fossil fuels, signals major shifts for the Ministry of Energy and Mineral Resources (MEMR) and PLN, the country's primary decision makers on energy strategy.

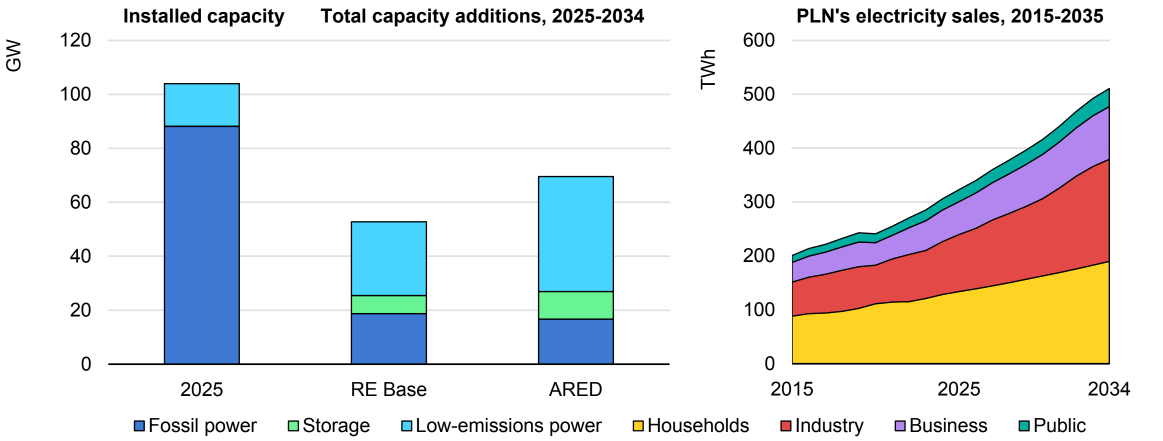
PLN's 2025-2034 electricity supply plan sets ambitious goals for renewables and battery energy storage

Power generation in Indonesia today is dominated by fossil fuels, especially coal-fired thermal power plants. In 2025, coal accounted for 50% of Indonesia's total installed capacity. Low-emissions power – including solar PV, wind, geothermal and hydropower – together accounted for 16 GW of installed capacity in 2025, an 85% increase relative to ten years previous. With hydropower and geothermal together accounting for 70% of Indonesia's low-emissions power capacity in 2025, VRE generation today constitutes a relatively small portion of the country's grid mix.

Total sales of electricity by PLN grew by 61% from 2015 to 2025 to 323 terawatt-hours (TWh), with 41% of generation in 2025 flowing towards households. However, by 2034 PLN expects that total electricity sales will exceed 500 TWh, once again growing by 60% relative to 2025 levels. A near-doubling in electricity sales to industrial consumers accounts for 44% of the total growth from 2025 to 2034. Meanwhile, increasing access to electrified space cooling leads nearly 200 TWh of generation to flow towards households by 2034. Indonesia's rapid growth in electricity demand is similar in scale to that of the Southeast Asian region as a whole. In fact, in the STEPS, Southeast Asia is among the world's fastest-growing regions in terms of electricity demand; rising by over 50% from 2025 to 2035.

The Rencana Usaha Penyediaan Tenaga Listrik (RUPTL), or Electricity Supply Business Plan, is Indonesia's primary electricity-sector planning document. Prepared in collaboration with MEMR and PLN, the document establishes the country's expected electricity demand, generation and transmission capacity additions, and total investment needs for the subsequent decade. While informed by the Rencana Umum Ketenagalistrikan Nasional (RUKN), or National Electricity Plan, which defines the country's long-term strategy for its power sector, the RUPTL more directly translates Indonesian energy policy into detailed project pipelines. The government of Indonesia has announced additional plans for renewable energy development outside of the framework of the RUPTL; most notably a plan to develop 100 GW of solar PV supported by nearly 150 gigawatt-hours (GWh) of BESS by 2030. However, this report considers solely the RUPTL 2025-2034 in its analysis of BESS and solar PV-plus-BESS additions.

Indonesia's current grid mix and RUPTL capacity additions (left) and PLN's electricity sales by consumer type as assumed by the RUPTL, 2015-2034 (right)



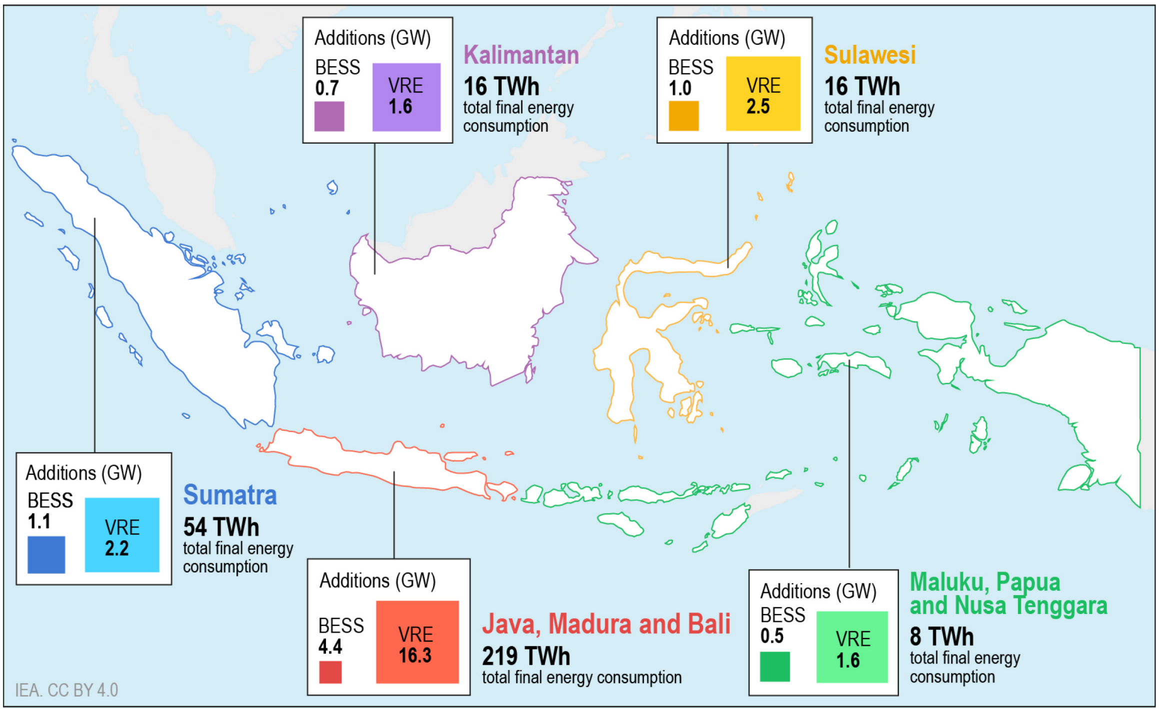
Notes: RE Base = Renewable Indonesia Base scenario, ARED = Accelerated Renewable Energy Development scenario. 2025 installed capacity includes captive coal power.
Fossil power includes coal, natural gas, and oil-fired generation. Storage includes battery storage and pumped hydropower. Low-emissions power includes solar PV, wind, geothermal, hydro, and biomass generation.
Source: PLN (2025), RUPTL 2025-2034.

The document also presents two cases for power system development: the relatively conservative Renewable Indonesia Base (RE Base) scenario, which prioritises affordability and grid reliability, and the Accelerated Renewable Energy Development (ARED) scenario, which favours deployment of renewable energy and targets carbon dioxide (CO_2) emissions reductions of 151 million tonnes compared with business-as-usual conditions. The analysis presented in this report is based on capacity additions outlined in the ARED scenario, which is also aligned with the STEPS.

Indonesia's most recent RUPTL, applying to the period from 2025 to 2034, signals a notable departure from historical trends in the country's power sector. With a strong emphasis on the deployment of low-emissions power, the RUPTL establishes Indonesia's commitment to renewable energy development. In total, PLN plans for the addition of over 42 GW of low-emissions power by 2035, including 13 GW of solar PV, 7 GW of wind and 5 GW of geothermal power. Nearly 70% of power capacity additions are allocated to independent power producers (IPPs), with the remaining additions to be developed by PLN itself. The RUPTL also estimates that capital expenditures totalling IDR 2 800 trillion (Indonesian rupiah) – or USD 165 billion – will be needed to complete all power generation and transmission capacity additions outlined in the document.

For the first time, the RUPTL 2025-2034 also outlines the additions of both standalone and hybrid BESS, thus recognising the role of battery energy storage in enhancing grid stability and facilitating the integration of VRE. The ARED scenario adds over 6 GW of standalone BESS, three-fifths of which is located on the islands of Java, Maduraand Bali. These assets are expected to be used mainly to support grid reliability and flexibility through short-duration load smoothing, frequency regulation, and voltage support. Meanwhile, a total of 3.6 GW of hybrid installations, most of which is located on the island of Sulawesi, will be used to optimise the utilisation of electricity generated by solar PV installations. PLN estimates that, for every 1 GW of solar PV in hybrid installations, between 0.1 and 0.3 GW of BESS will also be added. Finally, a pipeline of projects totalling 0.5 GW on the islands of Maluku, Papua and Nusa Tenggara is expected to support access to electricity in Indonesia's most isolated regions by creating mini-grid systems and replacing small-scale diesel generation.

RUPTL regional groupings capacity additions in the ARED scenario



Notes: BESS capacity includes standalone additions and the storage component of solar PV-plus-BESS additions. VRE capacity includes solar PV, wind, and the generation components of solar PV-plus-BESS and wind-plus-storage additions. Total final energy consumption refers to the year 2025.
Sources: IEA analysis based on PLN (2025), RUPTL 2025-2034 and PLN (2025), 2025 Statistical Report.

Indonesia's regulated, single-buyer electricity market makes PLN the most important player in BESS development

Indonesia's electricity sector is characterised by a highly centralised structure, with PLN operating as a vertically integrated state-owned utility across generation, transmission, distribution and retail. PLN served more than 80 million households in 2025 and accounts for most of the electricity supply, covering close to 70% of Indonesia's power generation. This dominant position reflects a long-standing policy framework in which the state retains control over electricity as a strategic sector.

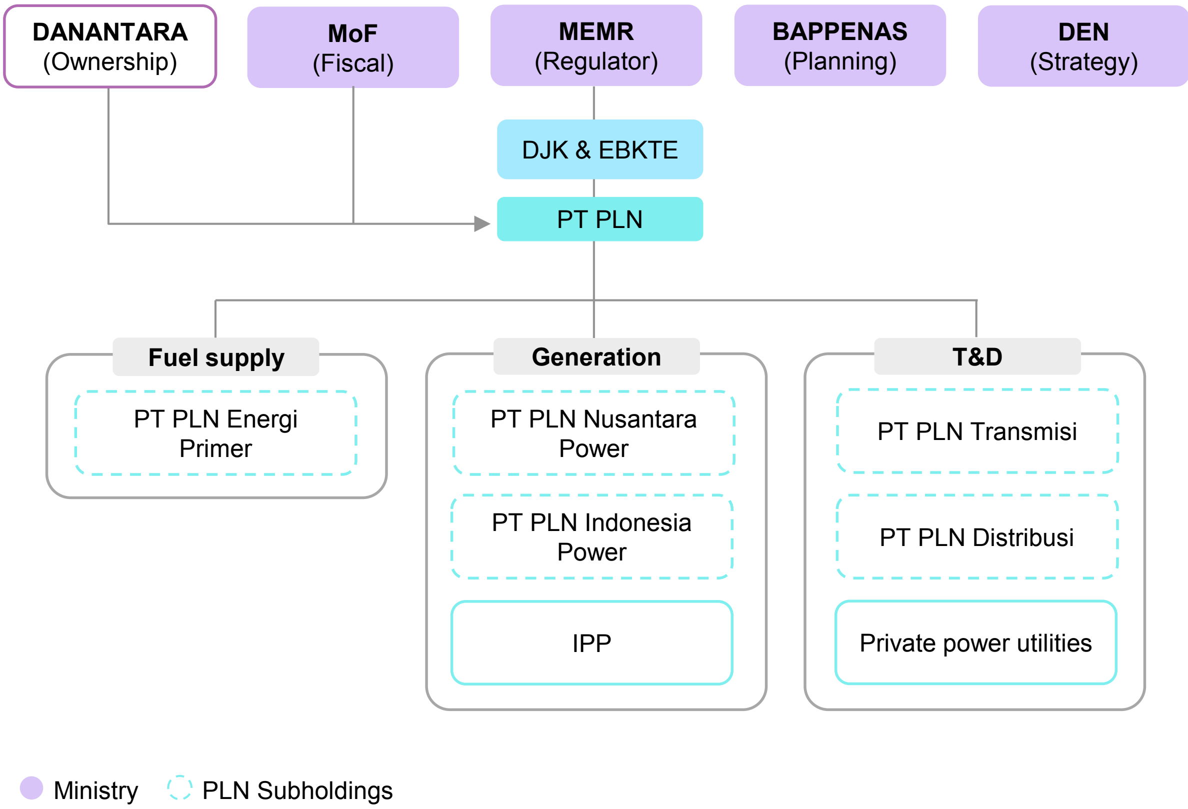
The current market structure is the result of several reform attempts. Early efforts in the 2000s aimed to introduce unbundling and competition were partially reversed following constitutional rulings emphasising the state's obligation to control electricity provision. The Electricity Law 30/2009 ultimately reaffirmed PLN's role as a vertically integrated utility. While IPPs are allowed to participate in generation, their role remains limited to selling electricity to PLN under long-term power purchase agreements (PPAs) and subject to obtaining an electricity supply business licence (Izin Usaha Penyediaan Tenaga Listrik [IUPTL]), which sets the framework for market entry and operation. While PLN is not formally designated as the sole off-taker of electricity, it effectively acts as a dominant single buyer in practice, as most electricity generated by IPPs is sold to the utility. This arrangement centralises system operation and investment decisions, enabling PLN to retain control over dispatch, network development and long-term planning, while limiting the scope for competition beyond generation. The conditions and procedures for obtaining an IUPTL are primarily set out in MEMR Regulation 11/2021 on the implementation of electricity business, within the broader framework established by Electricity Law 30/2009.

The regulatory framework is led by MEMR, whose Directorate General of Electricity (DJK) oversees licensing, tariffs and system planning, while the Directorate General of New and Renewable Energy and Energy Conservation (EBTKE) drives renewable energy deployment. Other government bodies also play an important role in shaping the sector. The Ministry of National Development Planning (BAPPENAS) coordinates long-term infrastructure and development planning across ministries and helps integrate electricity sector priorities into national economic plans. The National Energy Council (DEN), chaired by the President and comprising representatives from government, industry and academia, is responsible for coordinating the implementation of the National Energy Policy (KEN) and aligning energy strategies across government institutions. Tariff-setting remains highly regulated and is closely linked to the Biaya Pokok Penyediaan (BPP), which represents PLN's per-kilowatt-hour cost of electricity supply. End-user tariffs are benchmarked against the BPP but are not fully cost-reflective due to heavy subsidisation: in 2024, PLN received an estimated total of IDR 713.5 trillion (USD 46 billion) in subsidies. Finally, tariff adjustments are infrequent due to political and affordability considerations, limiting flexibility in response to cost fluctuations.

As a result, PLN operates under a strong public service obligation to ensure universal access and affordability. Regulated tariffs are often below cost-recovery levels, requiring the utility to rely on government support. PLN's financial model therefore depends heavily on state subsidies and compensation mechanisms, which are managed by the Ministry of Finance. In practice, this reliance is substantial: in 2022 alone, subsidy and compensation transfers from the government of Indonesia amounted to around IDR 123 trillion (approximately USD 9 billion). However, these transfers do not always fully cover rising operational and investment costs, leading to structural financial pressure. At the same time, PLN faces constraints on its ability to adjust tariffs, optimise spending or expand borrowing, as these decisions are closely supervised by government authorities to maintain fiscal discipline and affordability objectives.

Internally, PLN has been restructured into several sub-holdings, particularly for generation to improve efficiency and facilitate access to financing, notably including PLN Nusantara Power and PLN Indonesia Power, as well as sub-holdings in transmission and distribution (PLN Transmisi and PLN Distribusi, respectively). The recent creation of sovereign wealth fund Daya Anagata Nusantara (Danantara), under Law 1/2025, as a strategic holding entity for state-owned enterprises introduces an additional layer of oversight aimed at improving governance and capital allocation across state-owned enterprises, including PLN. Although its role in the power sector is still evolving, Danantara has the potential to be directly involved in the execution of procurement procedures as well as the funding of selected projects.

Selected government and PLN stakeholders in Indonesia's power sector



Notes: MoF = Ministry of Finance; MEMR = Ministry of Energy and Mineral Resources; BAPPENAS = Ministry of National Development Planning; DEN = Dewan Energi Nasional; DJK = Directorate General of Electricity; EBKTE: Directorate General of New and Renewable Energy and Energy Conservation; IPP = independent power producer, T&D = transmission and distribution.

Within this centralised framework, the operation of grid infrastructure and system flexibility assets remains largely under PLN's control, with limited participation from private actors beyond generation. In most cases, IPPs are responsible for building the power lines that connect their storage assets to PLN's network. Ownership and operation of these lines is then transferred to PLN upon completion. Private developers may develop dedicated transmission lines in specific cases – particularly when developing projects in remote areas.

Overall, Indonesia's power sector remains defined by a state-driven, centralised model, where PLN's vertically integrated structure, combined with regulated tariffs and strong fiscal support, ensures system stability and affordability but limits competitive dynamics. The challenge going forward will be to balance this model with the increasing need for flexibility, private investment and innovation to support the energy transition.

Indonesia's investment landscape

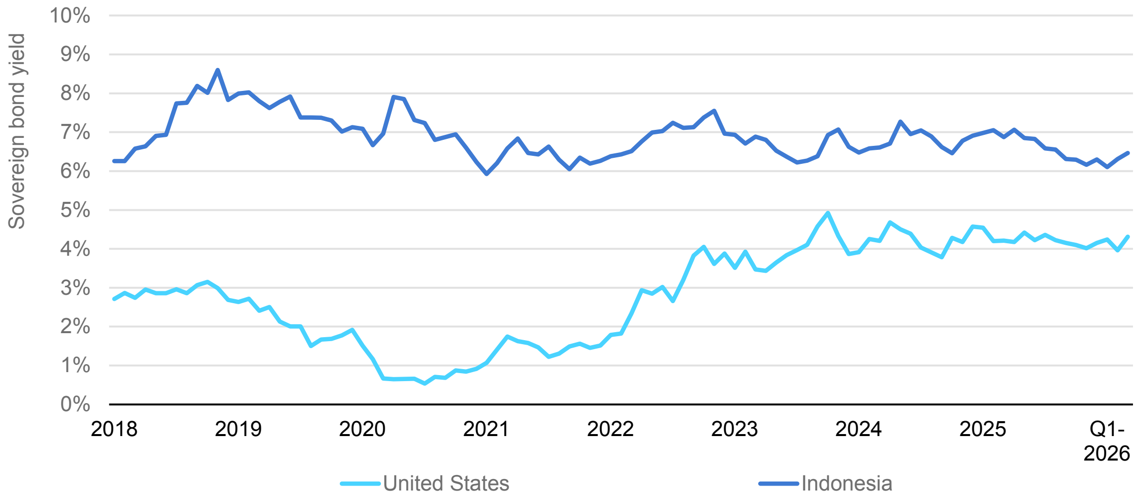
Indonesia's BESS market presents a combination of large investment needs and unique set of financing conditions supported by strong growth momentum and uncertain global rates environment. This section reviews the macro environment for investment and the financial position of PLN as the key investor and stakeholder for Indonesia's BESS sector.

Macro environment for investing

Indonesia is a large, fast-growing Group of Twenty (G20) economy with relatively deep domestic capital markets, but continues to carry the structural risks and institutional constraints for emerging markets. It currently holds investment-grade ratings from all three major agencies at BBB from S&P, BBB from Fitch, and Baa2 from Moody's. However, both Moody's and Fitch changed their outlook to negative in the first quarter of 2026, citing uncertainty around the financing and governance of Danantara, the new sovereign investment holding company that now oversees PLN among other state-owned enterprises.

Market pricing reflects these concerns. Indonesia's ten-year sovereign yield has risen from around 6% in January 2026 to around 7.0% by June 2026, against a US ten-year Treasury yield of around 4.5%. This spread of around 265 basis points is the additional return investors would demand for holding Indonesian sovereign debt rather than US government debt, compensating them mainly for country risk premium that includes fiscal, policy and currency uncertainty. Over the past decade, the spread has narrowed considerably, but this compression was driven mainly by the rise in US yields rather than a repricing of Indonesian risk. Within 2026, the direction has reversed, with the spread re-widening by close to 70 basis points as markets responded to the rating outlook revisions, currency pressure and fiscal concerns.

10-year bond movement in the United States and Indonesia, 2018 to Q1-2026



Sources: IEA analysis based on Investing.com (2026), Indonesia 10-year bond yield; Investing.com (2026), United States 10-year bond yield.

Sovereign yields affect clean energy investment as they anchor the cost of debt and the equity return expectations applied to BESS projects in the country. Higher sovereign yields could be translated into higher required capacity payments and PPA tariffs for BESS projects for domestic and international investors.

Despite these conditions, Indonesia is recognised as an important market for long-term asset allocation and the clean energy transition. It is the largest economy and power system in Southeast Asia, with electricity demand growing by around 5% per year from 2025 to 2035, while the RUPTL 2025-2034 targets renewables as the largest source of capacity additions for the first time. Its growth trajectory and policy ambitions make Indonesia a strong example of how clean energy investment can support an emerging market's overall development. Moreover, lessons can be learned from how stakeholders address challenges related to technical and regulatory uncertainties, currency risk, and fiscal constraints.

PLN balance sheet analysis

PLN is the central counterparty for virtually all grid-scale power investment in Indonesia. It is the sole transmission and distribution operator, the dominant generator and the sole off-taker for IPPs. As a result, the bankability of every standalone and hybrid BESS project in Indonesia depends on PLN's creditworthiness, given that PLN serves as the primary source of project revenues.

PLN is one of the largest utilities in Asia, with total assets of IDR 1 837 trillion (approximately USD 110 billion) at the end of 2025. Total liabilities are IDR 773 trillion (USD 47 billion), the largest component of which is interest-bearing debt in the form of bank loans (IDR 212 trillion/USD 13 billion), bonds and [*sukuk ijarah*, a variety of bond under Islamic finance] (IDR 194 trillion/USD 12 billion) and multilateral facilities. Operational performance has been strong, with reported revenues of IDR 583 trillion (around USD 35 billion), up 6.8% year-on-year and continuing a multi-year growth trend in electricity sales.

At the same time, PLN operates within a regulated tariff framework. Retail tariffs are set by the government and have been held broadly flat since 2017 in support of affordability objectives, with the gap to cost-reflective levels bridged by subsidy and compensation transfers, which reached IDR 200 trillion (USD 12 billion) in the 2025 fiscal year (an electricity subsidy of IDR 87 trillion and compensation income of IDR 113 trillion), equivalent to around a third of total revenues. These transfers are an integral part of PLN's revenue model and reflect the public service obligations the company carries.

The scale of PLN's existing debt and its reliance on government transfers under the regulated tariff framework together define the boundaries of PLN's balance sheet capacity. Preserving the company's quasi-sovereign credit standing, which is one of its most valuable assets as a borrower, requires keeping leverage within the thresholds that rating agencies and lenders apply. Funding even a minority share of the RUPTL's BESS pipeline through new lending would multiply the PLN's debt exposure, which has already risen by 10% year-on-year. Given that PLN's revenues are set within the regulated tariff and transfer framework, any additional PLN debt must ultimately be serviced from the same fiscal envelope that funds the subsidy and compensation transfers.

To address this challenge, PLN has created holding companies to bring substantial financial capacity of their own. PLN Nusantara Power's [financial statements for the 2025 fiscal year] show total assets of IDR 358 trillion (USD 22 billion) against liabilities of just IDR 42.5 trillion (USD 2.5 billion), a conservatively geared position with considerable headroom to absorb project-level investment. However, the sub-holding structure is one of the enabling mechanisms to address the headroom rather than a complete solution. The bankability of the underlying projects still rests on the offtake contracts written by PLN (Persero) and, behind them, on the tariff and transfer framework described above. How those contracts are designed and priced therefore determines the project's financial structuring.

This approach is reflected in the RUPTL 2025-2034, which envisages BESS projects being funded from both the PLN group's own balance sheet and IPPs. Much of the BESS build-out could be financed by private capital, supported by enabling tariff structures for standalone and hybrid projects and priced with reference to PLN's off-taker credit and the macro environment described previously. The risks and challenges that shape this pricing are discussed in the following chapter.

BESS project implementation in Indonesia

Overview of existing business models

Battery energy storage systems (BESS) operate under a range of revenue streams and business models that vary depending on their application, system configuration and off-takers' strategy. These systems can be deployed as standalone assets or integrated with generation sources in hybrid projects, with each framework determining how value is captured.

Business models are shaped by market design, regulatory framework and the relative importance of different services within the power system. In some cases, BESS revenues are driven by single-use applications, while in others they rely on stacked value streams that combine multiple services to improve project viability. The choice of model ultimately reflects local system needs, contractual structures and the maturity of electricity markets, which define both the risks and opportunities for storage deployment.

Indonesia's market structure, with PT Perusahaan Listrik Negara (PLN) acting as the sole off-taker and system operator, constrains the range of business models available for BESS. As a result, standalone projects are likely to be remunerated under a full tolling agreement, while power purchase agreement (PPA) contracts are more common for BESS projects co-located with generation assets. Nevertheless, a broader range of business models has emerged in liberalised electricity markets, reflecting different market designs and opportunities for BESS assets to access multiple value streams.

Full tolling models offer long-term visibility but eliminate upside potential

A tolling agreement for a BESS asset is a fixed-priced capacity offtake agreement. Under this model, the asset owner makes all or a portion of the battery's capacity exclusively available to a third-party off-taker in exchange for a regular, fixed payment. This provides a stable, predictable revenue stream for the BESS owner, while giving the off-taker access to battery capacity without having to build and operate it itself.

The tolling fee compensates the asset owner for making the storage capacity available and covers aspects such as degradation and operation and maintenance services. The owner retains responsibility for construction, performance and availability, and maintains ownership of the asset and its residual value at the end of the contract period. The off-taker, in turn, secures dispatch rights over the contracted capacity without bearing upfront capital expenditure.

From a financing perspective, tolling arrangements provide a high degree of revenue certainty, particularly when contracted with a creditworthy off-taker under long-term agreements. This can support limited-recourse project financing by reducing exposure to market risk and stabilising cash flows. However, the bankability of such arrangements depends on the clarity of contractual terms, including the allocation of operational risks, compensation mechanisms for underperformance or degradation, and the robustness of availability payments. The absence of standardised contract structures or market precedents may increase perceived risk for lenders, particularly where tolling agreements are shorter than the expected economic life of the asset.

Examples of full tolling business models

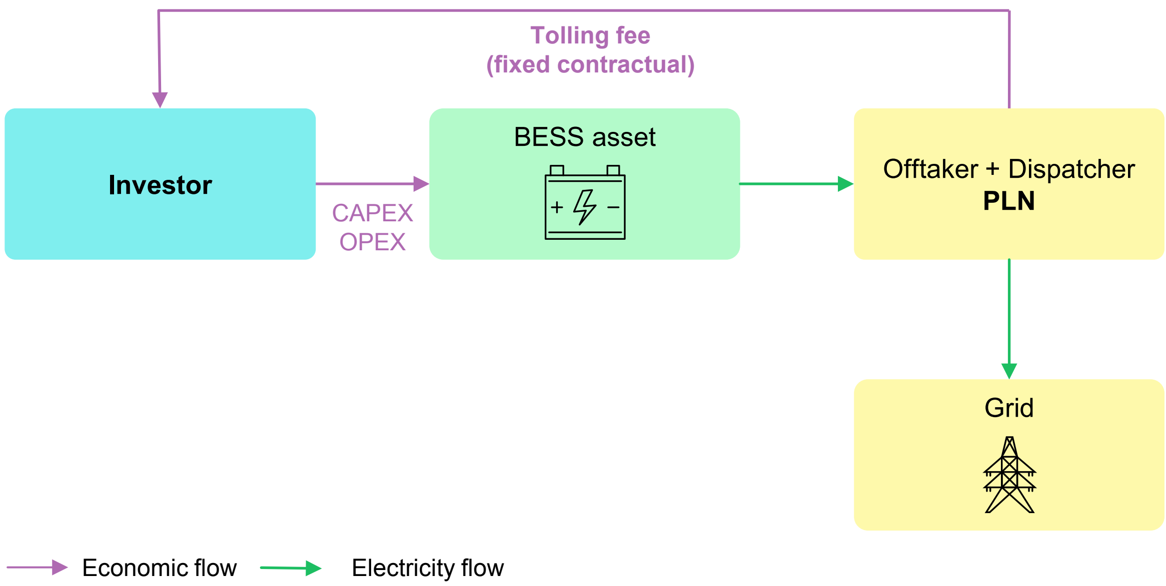
This model is widely used in more mature and liberalised electricity markets, particularly in the United States, in Australia and increasingly in parts of Europe.

For instance, in the United Kingdom, Drax signed a ten-year tolling agreement in January 2026 with West Burton C Limited (owned by Fidra Energy) for 250 megawatts (MW)/500 megawatt-hours (MWh) of new BESS capacity. Under this arrangement, Drax will pay a fixed annual tolling fee from the commercial operation date (expected in 2029) in exchange for full dispatch rights and operational control, while Fidra Energy remains responsible for construction, maintenance and asset availability throughout the contract period. This structure enables the off-taker to procure system flexibility without incurring upfront capital expenditure, while providing the asset owner with contracted revenues.

Similar arrangements are observed in Australia, where the 200 MW/400 MWh Rangebank BESS in Victoria, operational since December 2024, operates under a full tolling agreement with Shell Energy securing 100% of the battery's capacity for 20 years.

From an independent power producer (IPP) perspective, the viability of tolling arrangements in Indonesia remains subject to several uncertainties. While the model can, in principle, provide stable and predictable revenues, its effectiveness depends on the robustness of the contractual framework, including payment security arrangements, risk allocation and the enforceability of contractual provisions. In the absence of established precedents for standalone BESS, developers face challenges in assessing key parameters such as contract duration, revenue adequacy and risk allocation.

Schema of main players in full tolling business model, economic and power flows



Hybrid models support firm electricity generation and improve BESS utilisation

Hybrid models have been gaining increasing attention worldwide in recent years. These solutions can take different forms, as they combine multiple energy sources. Within the scope of this report, the focus is on configurations where a renewable energy project (solar photovoltaic [PV] or wind) is paired with BESS. In this structure, both assets are complementary and mutually beneficial, contributing to grid stability and security of supply. The BESS can supply electricity when renewable generation is not producing due to weather conditions, while it can be charged when renewables are generating but electricity demand is low.

Beyond their technical complementarity, hybrid systems can provide flexibility services, reduce curtailment of renewable generation and optimise the use of existing grid infrastructure. From an investment perspective, these configurations can improve project economics by diversifying revenue streams, including energy arbitrage and, where permitted by market rules and project design, ancillary services. However, their deployment depends on enabling regulatory frameworks and market design, as well as overcoming challenges such as higher upfront costs and integration complexity.

Hybrid systems are often supported by long-term PPAs, which provide stable and predictable revenues. Under these contracts, an off-taker commits to purchasing electricity at an agreed price over a defined period. In hybrid configurations, the presence of BESS can enhance the value of PPAs by improving dispatchability and allowing better alignment between generation profiles and demand.

In some more mature markets, hybrid projects may be structured through separate contractual arrangements for the generation asset and the battery, reflecting differences in asset lifetimes, cost structures and operational roles. This can involve, for example, distinct PPAs or remuneration mechanisms for each component, allowing risks and revenues to be allocated more precisely. However, such approaches remain largely unexplored in Indonesia, where BESS are typically embedded within a single PPA framework.

Examples of hybrid PPA business models

A recent example of hybrid solar and storage PPAs can be found in Malaysia, where data centre developer DayOne signed large-scale bilateral agreements with subsidiaries of Tenaga Nasional Berhad (TNB). The contracts cover around 1.5 gigawatts (GW) of solar PV combined with 2.2 gigawatt-hours (GWh) of battery storage, deployed as hybrid systems pairing BESS with both ground-mounted and floating solar installations. These projects are structured under Malaysia's Corporate Renewable Energy Supply Scheme (CRESS), enabling long-term renewable electricity procurement – alongside renewable energy credits – to support decarbonisation of energy-intensive users such as data centres while improving system flexibility.

This case illustrates how solar PV-plus-BESS projects can be enabled through dedicated procurement frameworks and bankable long-term PPAs, with corporate demand acting as a key anchor. It also highlights the role of storage in enhancing the integration of variable renewables and ensuring reliability of supply. Such models remain less developed in Indonesia, where regulatory and procurement uncertainties continue to constrain similar hybrid configurations.

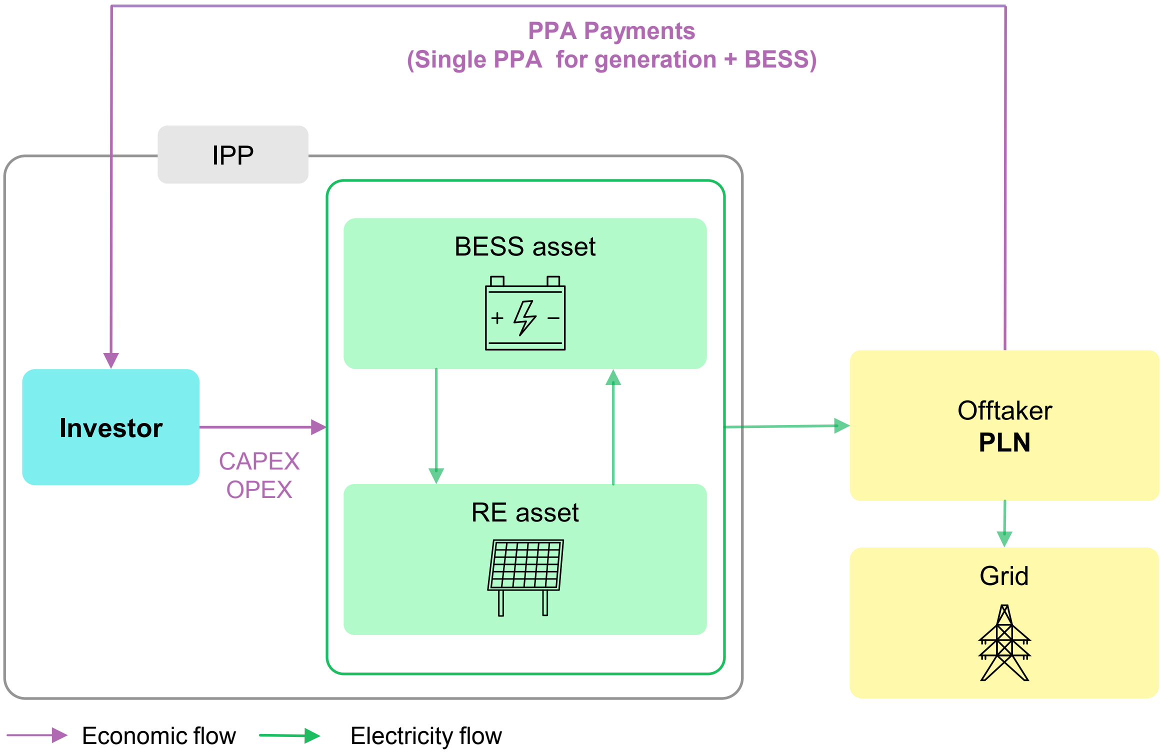
Another example can be found in Chile, where Grenergy has signed a 12-year hybrid PPA linked to the fifth phase (Algarrobal) of its Oasis de Atacama platform, one of the largest solar PV-plus-BESS developments globally. The contract covers the supply of around 350 GWh per year starting in 2028 to an investment-grade off-taker.

The project combines 242 MW of solar PV capacity with approximately 1.4 GWh of battery storage, allowing electricity to be delivered beyond daylight hours. This hybrid structure enables the shifting of solar generation to higher-value periods, effectively providing a form of dispatchable renewable energy and enhancing system flexibility.

More broadly, the Oasis de Atacama platform – which includes multiple phases and several gigawatt-hours of storage (including a 3.5 GWh BESS component in later phases) – has secured over USD 1.2 billion in non-recourse financing, supported by long-term PPAs with creditworthy counterparties. This demonstrates how hybrid PPAs can underpin large-scale BESS deployment by providing predictable revenue streams while capturing the added value of storage.

In Indonesia, hybrid BESS projects are expected to be structured under long-term PPAs, which remain the main contractual framework for IPPs. Under these arrangements, the off-taker, PLN, commits to purchasing electricity at a predetermined tariff rate over a defined period, providing a degree of revenue certainty. The integration of BESS can enhance the value of these PPAs by improving the dispatchability of renewable generation and allowing a better alignment between production profiles and system needs.

Schema of main players in a hybrid PPA business model, economic and power flows



IEA. CC BY 4.0.

Note: PPA = power purchase agreement; IPP = independent power producer; RE asset = renewable energy asset.

BESS business models beyond the Indonesian market framework

The full merchant model comes with high risks and high rewards

The full merchant model exposes BESS assets entirely to market revenues, offering both high risks and potentially high rewards. Under this model, the asset owner does not rely on long-term contracted payments but instead generates income from participation in wholesale electricity markets, ancillary services and other flexibility mechanisms. Revenues therefore depend on market price dynamics, volatility and the availability of services that can be monetised, which can vary significantly over time.

For asset owners, this model provides maximum upside potential, particularly in markets with strong price signals and well-developed flexibility services. However, it also entails significant revenue uncertainty and exposure to market risk, as well as higher transaction costs and increased operational complexity, which can affect bankability and financing conditions. For off-takers, the merchant model offers full optionality and avoids long-term contractual commitments, allowing them to procure flexibility directly from the market as needed. However, this approach may expose buyers to price volatility and uncertainty over the availability of services, particularly during periods of high demand when storage capacity is constrained. This structure is most viable in mature and liberalised electricity systems, where transparent price formation and liquid markets enable storage assets to capture multiple value streams.

Fully merchant BESS projects are most commonly observed in markets such as the Electric Reliability Council of Texas (ERCOT) in the United States, the National Electricity Market (NEM) in Australia, and the United Kingdom, where storage operators rely on energy arbitrage and ancillary service revenues without long-term contracted capacity payments.

Partial tolling balances stable remuneration with bounded entry into the market

The partial tolling agreement offers a hybrid structure that balances stable remuneration with limited exposure to market dynamics. Under this model, a portion of the battery's capacity is contracted under fixed payments, ensuring predictable revenues for the asset owner, while the remaining capacity is either merchant or subject to alternative contractual arrangements. This allows asset owners to secure a baseline level of income while retaining some upside from market participation, such as energy arbitrage or ancillary services.

For off-takers, partial tolling provides greater flexibility compared with full tolling arrangements. It reduces long-term financial commitments and contracted volumes, while still securing access to dedicated storage capacity when needed. At the same time, it allows off-takers to optimise procurement strategies by relying on market-based flexibility for part of their needs, rather than locking in the full capacity under fixed payments.

This structure is particularly relevant in markets where revenue streams are sufficiently mature to support a combination of contracted and merchant exposure, enabling both parties to balance risk mitigation with value maximisation. Partial tolling structures are increasingly observed in mature and liberalised markets such as Australia, the United Kingdom and the United States. In these markets, several BESS projects combine contracted revenues with merchant participation in wholesale and ancillary service markets, allowing asset owners to secure stable revenues while retaining exposure to upside from price volatility and system service revenues.

End-of-life considerations for BESS: Recycling and ownership structures

BESS are expected to have an operational lifetime of around 10-15 years, depending on battery chemistry, cycling intensity, environmental conditions and operational strategy. In practice, end of life does not necessarily mean that the battery can no longer operate, but rather that its performance has degraded below the level required for the intended application, often measured through reduced usable capacity, lower round-trip efficiency or increasing maintenance needs. At that stage, several pathways may be considered: continued operation at lower performance, refurbishment or repowering through replacement of modules, second-life use in less demanding stationary applications, or final decommissioning and recycling. Across major markets, the growing volume of end-of-life batteries has made recycling an increasingly important element of battery policy, not only for environmental reasons but also for resource security and the recovery of critical materials such as lithium, nickel and cobalt.

Internationally, leading jurisdictions are moving towards more comprehensive frameworks for battery end-of-life management. In the European Union, Regulation (EU) 2023/1542 establishes a life-cycle-based framework covering sustainability, collection, reuse and recycling of batteries, including industrial batteries used in storage applications. The regulation introduces binding targets for material recovery, including 50% lithium recovery by 2027 and 80% by 2031, as well as minimum recycled-content requirements in new batteries and a digital battery passport for industrial batteries above 2 kilowatt-hours (kWh) from February 2027. China has also introduced a range of policies promoting battery traceability and producer responsibility, while several provinces have launched pilot frameworks for the tracking and recycling of retired energy storage batteries. These approaches reflect a broader shift towards circular economy frameworks and highlight the importance of clearly assigning end-of-life responsibilities.

The allocation of end-of-life responsibilities depends strongly on ownership structures under different contracting models, notably PPA and full tolling frameworks. Under PPA-based structures, where storage is typically combined with generation, the asset usually remains part of the project company (typically a special purpose vehicle), implying that the IPP retains responsibility for maintenance, repowering and end-of-life management unless otherwise specified. In contrast, under full tolling models, the asset owner contracts out operational rights while retaining ownership, requiring clear contractual allocation of degradation risk, residual value and decommissioning obligations. Across both models, the definition of ownership at contract expiry is critical, particularly given the shorter effective lifetime and performance uncertainty of battery assets.

In Indonesia, recent regulatory developments have significantly altered this allocation of ownership. Historically, renewable PPAs followed a build-own-operate-transfer (BOOT) model, under which assets were transferred to PLN at the end of the contract, implicitly shifting long-term ownership and associated life-cycle risks to the utility. With the introduction of MEMR Regulation 5/2025, where PPAs for BESS in hybrid projects are regulated for the first time, greater flexibility has been introduced through longer contract durations (up to 30 years) and the possibility of adopting build-own-operate (BOO) or other contractual structures, allowing IPPs to retain ownership of assets beyond the contract term. This shift improves bankability and aligns more closely with the technical characteristics of storage, but also transfers greater responsibility for long-term asset management to project developers, as BESS replacement obligation falls on the IPP.

At the same time, Indonesia's regulatory framework for battery recycling remains limited, relying mainly on general hazardous waste provisions with limited guidance specific to lithium-ion batteries or utility-scale storage. As BESS deployment scales up, aligning ownership structures with clear recycling obligations and life-cycle management rules will be critical to ensure both environmental sustainability and project bankability. In addition, compliance with internationally recognised safety and testing standards, such as IEC 62933-5-2 (safety standards for grid-connected electrochemical technologies), UL 9540/9540A (thermal runaway and fire prevention standards) and NFPA 855 (safe installation standards), can further support project bankability by facilitating permitting processes, improving insurability, and reducing perceived technology and operational risks among lenders and investors.

Remaining uncertainties for business models in Indonesia

Despite growing interest in BESS in Indonesia, significant uncertainties remain around the business models that could underpin investment and support project bankability. These uncertainties are particularly relevant in a market where PLN remains the dominant off-taker and system operator, limiting the range of commercial structures available to private investors. Globally, BESS projects can rely on a variety of remuneration mechanisms, including capacity payments, ancillary service revenues, energy arbitrage and hybrid models that combine multiple value streams. In Indonesia, however, such monetisation pathways remain limited and insufficiently defined, particularly for standalone projects.

A key uncertainty relates to the intended use cases of BESS and how PLN may choose to dispatch these assets in practice. Project economics depend heavily on whether batteries are used for renewable integration, peak shaving, reserve provision, network support or island system reliability, as each use case implies different cycling patterns, performance requirements and degradation profiles. At present, there is limited clarity on how these services would be prioritised, valued or remunerated, and whether revenue stacking would be permitted. This reduces revenue visibility and complicates project financial modelling.

From an IPP perspective, the lack of standardised and bankable contractual arrangements represents an additional barrier. While hybrid BESS may be structured through a PPA linked to a renewable generation asset, and standalone systems may potentially rely on a full tolling model, both approaches remain at an early stage of development. Key issues such as risk allocation, availability requirements, indexation, compensation for battery degradation, replacement obligations and the treatment of underutilisation are not yet clearly established. As a result, developers and lenders face difficulties in assessing long-term cash flow stability and allocating risks.

These challenges are particularly acute for standalone BESS, which remains the least defined segment despite growing market interest. While PLN's planning documents increasingly recognise the role of storage in supporting system flexibility and renewable integration, a clearer commercial and regulatory framework will be needed to translate this strategic interest into investable opportunities. Establishing fit-for-purpose business models, with transparent remuneration principles and clearer contractual precedents, will be essential to unlock private participation and accelerate BESS deployment in Indonesia.

Key regulations for BESS remuneration

The role of BESS in Indonesia's power sector has gained increasing attention in recent years, reflecting the growing need for system flexibility, renewable energy integration and grid reliability. As deployment progresses, the development of a clear regulatory framework is essential to provide certainty for project developers, investors and lenders, and to support the emergence of viable business models. While Indonesia does not yet have a dedicated framework for standalone storage projects, several regulations have established important foundations for the deployment of BESS, primarily as a component of hybrid renewable energy projects. Presidential Regulation 112/2022 represented the first explicit recognition of energy storage as a complement to renewable generation assets. Subsequent regulations, including MEMR Regulation 5/2025 governing PPAs and MEMR Regulation 19/2025, have further clarified the contractual, procurement and remuneration arrangements applicable to projects incorporating storage. Together, these regulations form the main regulatory basis for BESS deployment in Indonesia today. As the market continues to develop, further clarification of the roles, remuneration mechanisms and operational requirements associated with storage may help facilitate broader deployment and support the emergence of additional business models, including standalone applications.

Presidential Regulation 112/2022

First issued by MEMR's Directorate General of Electricity (DJK) in 2022, Presidential Regulation 112/2022 (hereafter, "PR 112") aims to accelerate the deployment of renewable energy for electricity generation in Indonesia, in line with national energy transition and emissions-reduction objectives. The regulation prohibits the development of new coal-fired power plants and establishes a new framework for the procurement and remuneration of renewable energies.

Under PR 112, renewable energy tariffs are no longer benchmarked against PLN's system-wide Biaya Pokok Penyediaan (BPP), which is largely driven by low-cost and subsidised coal generation. Instead, the regulation introduces a ceiling tariff mechanism, differentiated by renewable technology and project location. This shift improves price signals for renewable energy, supports the participation of IPPs, and results in a more technology-appropriate remuneration framework as tariffs are no longer anchored to fossil fuel generation costs.

BESS are regulated under PR 112 as hybrid or enabling components integrated with renewable generation. Battery-related charges are capped at a share of the applicable base tariff, indicating that storage is recognised primarily as a cost component supporting variable renewable energy (VRE) integration. Standalone BESS are not explicitly regulated or remunerated under the current tariff framework, limiting their deployment to use cases linked to renewable generation.

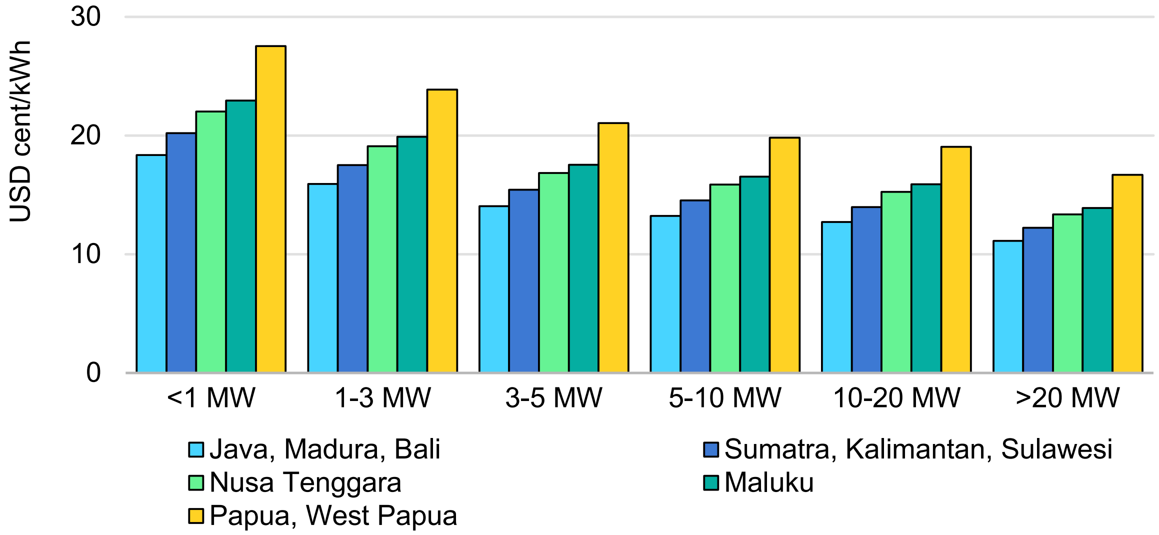
Electricity purchase price

PR 112 introduces a ceiling tariff mechanism (*harga patokan tertinggi*) as the reference price for all renewable energy electricity purchases by PLN, expressed in USD cents per kWh. Prices are differentiated by technology, installed capacity, and project location, the latter through a location factor ranging from 1.00 (Java, Madura, Bali) to 1.50 (Papua), which is particularly relevant for hybrid projects targeting remote or off-grid areas.

Ceiling prices follow a two-period structure, with higher tariffs applicable during the first ten years of operation to support capital recovery, stepping down for the remainder of the contract term. For solar PV and wind, the ceiling price applies with no escalation during the PPA term. For hybrid projects equipped with battery storage, the BESS component is subject to a separate ceiling of 60% of the applicable electricity purchase price, automatically serving as the minister's price approval; prices exceeding this threshold require explicit ministerial consent.

Where project-specific cost structures cannot be accommodated within the ceiling price framework, an agreed price (*harga kesepakatan*) may be negotiated between the IPP and PLN, subject to ministerial approval.

Ceiling tariff prices for privately developed hybrid solar PV-plus-BESS projects, 2025



Notes: kWh = kilowatt-hour. MW = Megawatt. Ceiling tariffs for small islands are not shown in the figure. Only ceiling tariffs for the first ten years are shown in the figure.
Source: IEA analysis based on Presidential Regulation 112/2022 (2026)

Where grid connection infrastructure is required to link the power plant to PLN's network, the associated costs are negotiated separately between the parties and capped at 30% of the electricity purchase price, automatically serving as the minister's approval. Costs exceeding this threshold require explicit ministerial consent.

Procurement procedure

Article 14 provides for two procurement methods for electricity purchases: direct appointment (*penunjukan langsung*) and direct selection (*pemilihan langsung*). The choice of procurement method depends on the technology used and, for certain generation sources, specific project characteristics, including ownership arrangements.

In the case of solar PV projects coupled with BESS, electricity procurement shall be conducted through direct selection. In the case of only one bidder after two rounds, the purchase shall be executed through direct appointment.

Procurement procedure under PR 112/2022

Characteristic	Direct appointment	Direct selection
Principles	Administrative, technical and financial document evaluation is required.	Selection on basis of the lowest price offer subject to the ceiling price.
Timeline	90 calendar days from submission to signature.	180 calendar days from submission to signature.

Source: Republic of Indonesia (2022), Peraturan presiden Republik Indonesia nomor 112 tahun 2022 tentang percepatan pengembangan energi terbarukan untuk penyediaan tenaga listrik.

All procurement processes begin with a pre-qualification stage, where business entities are screened. PLN maintains and publishes a list of selected providers, updated every three months, that constitutes a prerequisite for participation in subsequent tenders.

Following the procurement process, the winning business entity enters into a PPA with PLN, at which point it is formally designated as a power plant developer. The PPA terms are governed by guidelines established by the minister.

Regulation 5/2025

Issued on March 2025, MEMR Regulation 5/2025 establishes specific guidelines for PPAs between IPPs and PLN as the sole off-taker for renewable energy sources, replacing MEMR Regulation 10/2017, which covered both renewable and conventional technologies under a single framework. Under this new regulation, energy storage is, for the first time, brought within the scope of PPA frameworks. The regulation implements the PPA structure outlined by PR 112/2022 and represents a significant step towards improving the bankability of renewable energy projects in Indonesia.

The regulation fixed the maximum PPA duration to 30 years from commercial operation date (COD), improving project bankability by strengthening the debt service coverage ratio (DSCR). The longer contract tenure increases revenue certainty over the project lifetime and enables longer debt repayment periods, reducing annual debt service obligations and improving access to financing for capital-intensive hybrid projects. The ownership scheme shifts from BOOT – under which assets transferred to PLN at expiry – to a BOO structure, allowing IPPs to retain ownership of project assets, including storage components, which has implications for residual asset value and refinancing. For agreements extending beyond 30 years, the applicable tariff reverts to the highest reference price determined after the first 10 years rather than the originally contracted tariff, discouraging over-reliance on long-tenor extensions. New minimum PPA provisions are introduced covering electrical installation certification, use of domestic products, environmental attributes, refinancing mechanisms and language requirements.

The regulation replaces the previous BPP-linked tariff with a take-or-pay structure based on contracted energy and availability factor, under which PLN is obliged to purchase electricity up to the contracted level at the PPA tariff. Excess generation may be sold to PLN at up to 80% of the PPA tariff subject to demand – relevant for hybrid projects where battery dispatch may push output above contracted levels. A deemed dispatch mechanism requires PLN to compensate IPPs for curtailed energy, providing protection against grid curtailment risk. The application of availability penalties to intermittent technologies nonetheless remains ambiguous, warranting close attention in PPA negotiations for hybrid configurations.

The regulation reduces the cap on performance security from up to 20% to 10% of project cost and strengthens lender protections through clarified step-in rights before COD, reducing construction-phase risk for hybrid projects. Tariff adjustments are permitted for changes in taxes, levies and environmental obligations, providing partial cost pass-through protection for IPPs.

Regulation 19/2025

Issued in December of 2025 by MEMR's Directorate General of New Renewable Energy and Energy Conservation (EBTKE), Regulation 19/2025 represents one of the first official recognitions of BESS within the framework of Indonesia's power infrastructure. Regulation 19 aims to facilitate the development of hybrid power plants, with a particular focus on projects replacing diesel generation in remote or isolated areas of Indonesia. Hybrid power plants are defined as those pairing renewable energy generation with other renewable energy, non-renewable energy, and/or BESS.

In addition to accepting BESS as a component of hybrid power plants, Regulation 19 establishes a procurement scheme and tariff-setting framework for such installations. The electricity generated by IPP-developed hybrid power plants is purchased by PLN through the signing of a PPA, and the electricity purchase price negotiated between PLN and the IPP must fall within a range determined by MEMR. These floor and ceiling prices have yet to be defined quantitatively but are expected to be announced in a ministerial decree. According to Regulation 19, PLN is entitled to state compensation in the case that purchase of electricity from a hybrid power plant results in an increase in system BPP.

While Regulation 19, in addition to its upcoming ministerial decree defining the permissible range of PPA prices, represents an important improvement in the legal framework for BESS in Indonesia, some uncertainties persist for prospective hybrid power plant developers. For instance, the definition of technical parameters, such as the sizing of BESS assets relative to associated renewable energy assets, are not explicitly addressed. However, the foremost uncertainty lies in how BESS are treated within the single hybrid PPA signed between IPPs and PLN. Specific guidance on which services BESS assets are permitted to provide and whether they can stack multiple revenues is necessary for developers to accurately anticipate project cash flows. Moreover, additional details determining whether IPPs or PLN are responsible for BESS dispatch, and whether BESS assets co-located with renewable generation are permitted to charge from PLN's grid, would further clarify developers' position as operators of the hybrid power plant.

Comparison of key BESS-related regulations

Characteristic	Regulation 112/2022	Regulation 19/2025
Date issued	September 2022	December 2025
Technologies targeted	Geothermal, hydroelectric, solar PV, wind, biomass, biogas, ocean energy and biofuel. BESS are considered as enabling technologies with PV and wind projects.	Hybrid power plants (combining renewable power with other renewables, non-renewable power, and/or BESS).
Objective	Development of renewable sources of energy generation.	Accelerate de-dieselisation efforts in remote and isolated areas while scaling up renewable energy deployment.
Procurement procedure	Direct selection for hydropower, solar PV, wind, biogas, biomass, biofuels and tidal power. Pre-qualified participants respond to tenders and tariffs are determined by the lowest bids (which cannot exceed a ceiling tariff). Direct appointment for hydropower utilising dams or reservoirs constructed by the government, geothermal, and expansion project. No competitive process, and PLN directly negotiates PPA price with relevant IPPs.	Direct selection, in which pre-qualified participants respond to tenders. Tariffs are determined by the lowest bids falling between floor and ceiling tariffs, with the possibility of price negotiation between PLN and selected IPPs.
Electricity purchase price	Must not exceed a ceiling price determined by MEMR.	Must fall between a price floor and ceiling determined by MEMR.

Characteristic	Regulation 112/2022	Regulation 19/2025
Other tariff components	Network tariffs cannot exceed 30% of the negotiated electricity purchase price. Battery storage charges cannot exceed 60% of the negotiated electricity purchase price. Over this price, approval from the minister is mandatory.	Network tariffs cannot exceed 5% of the negotiated electricity purchase price.
Locational differentiation	Java, Maduraand Bali: 1.0 Sumatra, Kalimantan, and Sulawesi: 1.1 Nusa Tenggara: 1.2 North Maluku and Maluku: 1.25 West Papua and Papua: 1.5	Locational factors are applied but have yet to be defined quantitatively.
Contract type and parties	PPA between IPP and PT PLN.	Single PPA signed between IPP developer and PLN.
Contract price stability	Ceiling tariff benchmark is reviewed annually by MEMR.	Price remains unchanged over the duration of the contract, but price floor and ceiling are revised at least every two years.
Status	Effective from September 2022.	Awaiting ministerial decree to quantitatively define price floor and ceiling.

Source: PricewaterhouseCoopers (2026), Legal Alert 54/2026, Umbra Law (2026), Client alert: New MEMR regulation on hybrid power plants for small islands or isolated areas, Republic of Indonesia (2022), Peraturan presiden Republik Indonesia nomor 112 tahun 2022 tentang percepatan pengembangan energi terbarukan untuk penyediaan tenaga listrik, Ministry of Energy and Mineral Resources (2025), Peraturan nomor 19 tahun 2025 tentang pembangkit listrik tenaga hibrida

Remaining regulatory uncertainties for BESS deployment in Indonesia

Despite recent regulatory progress – including PR 112/2022 and MEMR regulations 5/2025 and 19/2025 – several uncertainties continue to affect the development and bankability of BESS in Indonesia, potentially slowing progress towards the deployment targets outlined in PLN's Rencana Usaha Penyediaan Tenaga Listrik (RUPTL), or Electricity Supply Business Plan.

Standalone BESS remain undefined within the current regulatory framework. While storage is recognised in the context of hybrid or integrated systems, there is no clear legal classification or dedicated licensing regime for standalone assets providing grid services. While Indonesia's Badan Pusat Statistik (BPS, or Central Agency of Statistics) explicitly includes battery storage in its industrial business classification for electrical storage facilities, additional specifications on how

MEMR regulations apply to standalone BESS are not yet available. This creates ambiguity around procurement eligibility, applicable remuneration mechanisms and licensing requirements, ultimately limiting the emergence of independent storage business models and constraining investment to projects coupled with generation.

In addition, the co-existence of MEMR 5/2025 and MEMR 19/2025 introduces uncertainty regarding the classification and treatment of projects. The boundary between grid-connected renewable energy projects under MEMR 5/2025 and hybrid systems in isolated or small networks under MEMR 19/2025 remains unclear, particularly for projects with partial grid connectivity or evolving system configurations. This lack of clarity complicates the selection of the applicable procurement framework, tariff structure and contractual arrangements, increasing development risk for project developers.

Further uncertainty arises from the pending publication of pricing benchmarks and ceiling tariffs under MEMR 19/2025. The absence of these reference values limits visibility on project revenues and constrains the ability of developers to structure competitive bids and secure financing. In this context, ensuring that ceiling tariffs appropriately reflect not only the generation asset but also the installed capacity and system value of the BESS component would be essential to enable cost-reflective remuneration and support project viability.

While MEMR 5/2025 strengthened the contractual framework for project financing, debt tenors available from commercial lenders may remain shorter than PPA durations. This could limit the extent to which longer-term contracts improve project bankability, particularly for capital-intensive BESS projects.

More broadly, procurement processes would benefit from greater transparency and clarity in their design and implementation. Strengthening visibility on evaluation criteria, tender timelines and contractual allocation of risks would help reduce perceived regulatory risk, enhance investor confidence and facilitate broader participation from IPPs.

Finally, uncertainties remain regarding the role of IPPs and the extent of private sector participation in storage deployment, as well as evolving technical and system integration requirements. Clarification in these areas – including ownership structures, dispatch rules and grid integration standards – will be critical to ensure consistency across projects and support the scaling of BESS in Indonesia.

BESS remuneration in Indonesia

The remuneration of BESS services is the single most important determinant of project bankability. However, the dual role of BESS as consumers and producers of electricity, together with their ability to provide a variety of services, also makes them more complex to remunerate than traditional generation assets. Identifying transparent tariff schemes that satisfy both PLN's and IPPs' needs is essential to improving cash flow predictability for investors and financiers.

Challenges for BESS assets and PLN

Like renewable energy technologies, BESS projects are associated with high upfront capital costs and comparatively low operational costs. Capital costs typically account for over 90% of the levelised cost of electricity (LCOE) of solar PV-plus-BESS hybrid projects and around 60% of utility-scale standalone projects' levelised cost of storage (LCOS). As a result, the level and frequency at which assets are remunerated determine how capital costs are recovered throughout the project's lifetime.

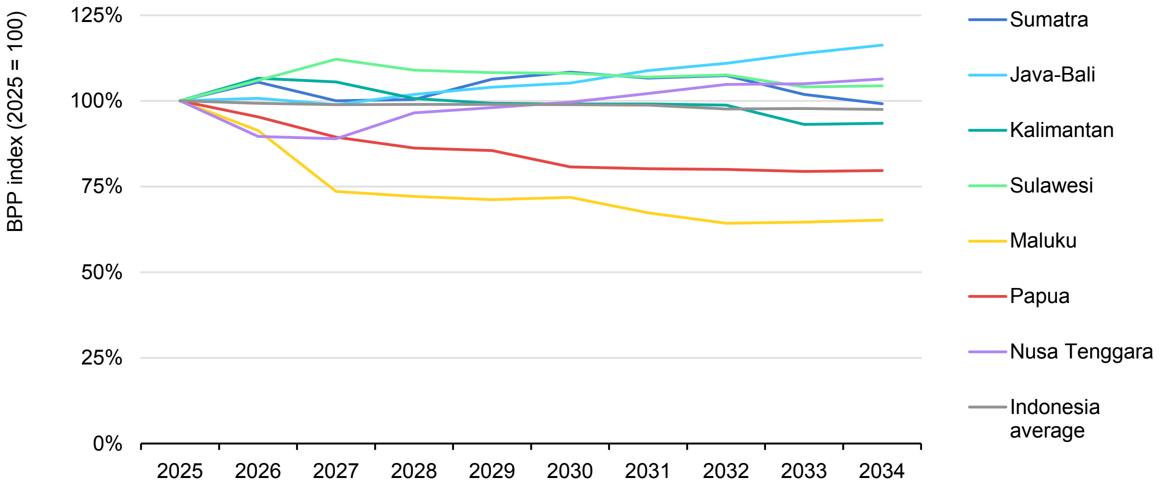
The ability for BESS to provide a wide range of system services – including renewables smoothing, capacity reserves, and frequency and voltage support – means that higher economic values for both standalone and hybrid assets come from the provision of multiple services, a practice known as revenue stacking. However, successful revenue stacking is dependent upon the availability of remuneration frameworks that explicitly value these services and allow assets to participate across them. Revenue stacking also introduces additional technical complexity; as a result, clear definitions of system needs provide essential operational parameters within which BESS developers can design their assets.

Unlike traditional generation assets such as natural gas power plants and solar PV installations, BESS are both producers and consumers of electricity. While hybrid assets have the possibility of charging exclusively from the generation asset with which they are paired, standalone installations must charge from the grid. As a result, the rate at which BESS should be charged for consuming grid electricity must be clearly defined, either as a fixed rate or as a percentage of the rate at which BESS sell electricity to PLN. Moreover, BESS can benefit from provisions that prevent the double-charging of taxes and network tariffs on BESS assets as they both consume and produce electricity.

Challenges faced by PLN in compensating IPP assets

Much of PLN's planning and investment decisions are tied to the BPP, which measures the utility's average cost of electricity supply in each of its distinct systems. The BPP considers factors such as historic fuel costs, operating expenses and capital recovery for existing generation assets; as a result, PLN has an incentive to prioritise investments that minimise increases in average system costs, which can make it more challenging to justify higher upfront investments with longer-term system benefits. In fact, the RUPTL 2025-2034 endeavours to meet rising demand for electricity without raising the country-wide BPP, mainly by recognising the value of upfront investments in VRE, which benefit from low operational costs and zero fuel purchases over the long term. Indonesia's overall BPP was estimated at IDR 1 970/kWh in 2025, and decreases to IDR 1 622/kWh by 2034 in the RUPTL's Accelerated Renewable Energy Development (ARED) scenario (USD 0.11/kWh and 0.09/kWh, respectively).

Changes to system-level BPP in the RUPTL's ARED scenario, 2025-2034



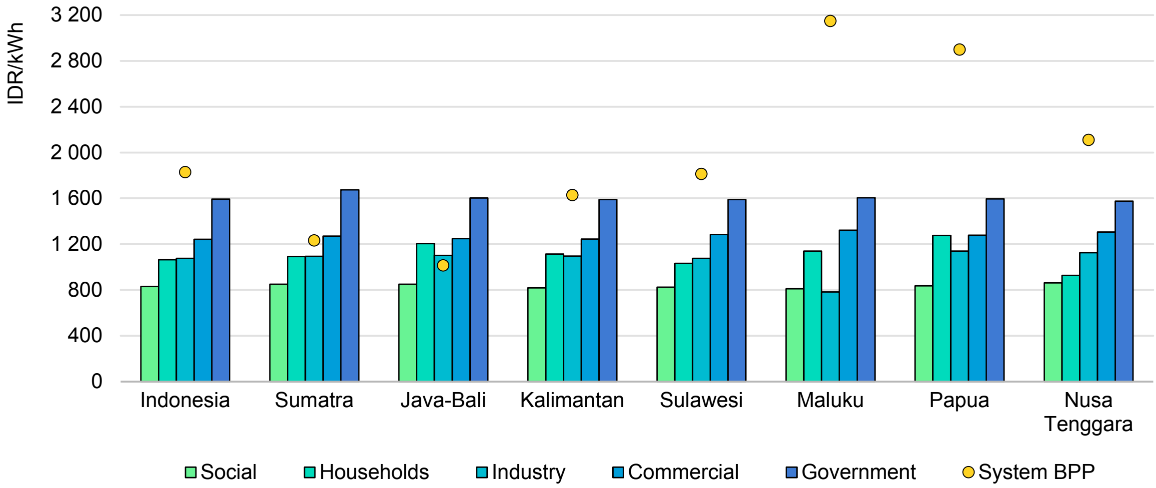
Note: ARED = Accelerated Renewable Energy Development; BPP = Biaya Pokok Penyediaan (system cost of electricity supply).
Source: IEA analysis based on PLN (2025), RUPTL 2025-2034.

BESS assets, however, do not conveniently fit into PLN's current methodology for calculating BPP because they do not independently generate electricity and provide additional services that are not quantified under current Indonesian regulatory frameworks. The only existing legal classification of BESS today is as a capital component of hybrid power plants. Therefore, the addition of electricity storage tends to increase the contribution to BPP of VRE generation without also reflecting cost savings associated with improved system flexibility, reliability and reduced requirements for additional generation capacity to meet planning reserve margins. The resulting BPP estimation then risks being too high, leading PLN to base investment decisions on information that does not truly reflect long-term system costs.

Under current methodology, system BPP incorporates fuel costs by dividing historical fuel expenditures by total generation over an equivalent period of time. While having the advantage of using data that are readily available to PLN, this approach can result in an estimation of system costs that emphasises historic costs over forward-looking trends. Consequently, long-term investment decisions are not based on estimates that accurately anticipate future costs, leading fossil fuel-based generation – notably coal-fired power plants – to appear unrealistically cost-competitive.

Although the average system cost of electricity supply, represented by BPP, is used to distinguish between investment decisions, it bears limited relation to the retail tariff at which PLN sells electricity to consumers. Obligations to maintain affordability, enforced through Electricity Law 30/2009, mean that PLN is frequently required to sell electricity to final consumers at a price below the corresponding system BPP, with the difference between retail tariffs and BPP being compensated for by significant government subsidisation and, to a lesser extent, cross-subsidisation by commercial and industrial tariffs. The Indonesian government provided an estimated IDR 176 trillion (nearly USD 10 billion) in support to PLN and electricity consumers to maintain affordability, equivalent to 0.7% of the country's total gross domestic product (GDP) in that year.

Retail electricity tariff by consumer type and overall system cost (BPP) by region, 2025



Note: BPP = Biaya Pokok Penyediaan (system cost of electricity supply).
Sources: IEA analysis based on PLN (2025), RUPTL 2025-2034. and PLN (2025), 2025 Statistical Report.

Because consumer electricity tariffs are not fully cost-reflective, PLN has a limited ability to pass on the costs of capital-intensive projects to consumers. Moreover, the political sensitivity of electricity affordability in Indonesia incentivises PLN to minimise costs rather than seeking out the possibility of increases in consumer tariffs to accommodate the need for power sector expansion. Consideration of these challenges is essential to addressing the remuneration of BESS: while payments must be sufficiently flexible to allow assets to perform a range of services, they must also minimise upfront financial burden on PLN.

Types of BESS compensation

The remuneration of BESS assets, as well as their abilities to combine multiple revenue streams by providing a variety of services, is the single biggest determinant of project bankability. While regulations 112/2022, 05/2025, and 19/2025 establish frameworks for the PPA contracts to be negotiated between IPPs and PLN, uncertainties around how these contracts would relate to BESS services persist. The following section outlines in detail the three types of remuneration that BESS assets receive, their compatibilities with current policies in Indonesia and how these can be further integrated into MEMR's regulatory frameworks.

Capacity-based remuneration

The simplest of the three types of remuneration, capacity-based payments, compensate BESS assets for their ability to provide system services when called upon. Assets are typically remunerated on a per-megawatt and per-hour basis for their installed capacity, regardless of whether they are dispatched. Under capacity-based remuneration schemes, BESS usually provide services related to grid stability and reliability, such as black-start capabilities and peak capacity reserves. The full tolling business model employs capacity payments as the primary source of remuneration, prioritising stable and predictable revenues that strengthen project bankability. Such mechanisms are therefore well suited for BESS projects that primarily aim to support the electricity network, such as those designated by the RUPTL for the system of Java, Madura and Bali.

Capacity-based payments are also currently the most compatible type of remuneration under Indonesia's current regulatory framework, but only for hybrid projects. In order for BESS projects to be remunerated under a capacity-based mechanism, they must be treated as a component of the capital expenditures of renewable energy projects. However, current regulation does not explicitly define standalone BESS as a distinct asset class, making such projects incompatible with existing regulatory structures.

Availability-based remuneration

Similarly to its capacity-based counterpart, availability-based remuneration operates on a per-megawatt and per-hour basis. However, where capacity-based payments are linked to the installed power of BESS assets, availability-based payments typically include additional requirements around asset performance such as response time and accuracy. This is because availability-based payments are generally used to remunerate the provision of ancillary services such as frequency regulation and voltage support. The regularity of availability-based payment also makes this mechanism compatible with the full tolling business model. As BESS asset operators gain sufficient experience to be able to meet operational standards reliably, the addition of availability-based payments through, for instance, the creation of ancillary service procurement agreements (ASPAs) can enable operators to "stack" multiple revenue streams.

As with capacity-based payments, availability-based remuneration in Indonesia is currently possible only for BESS that are paired with renewable energy assets under hybrid projects. Regulation 19/2025 lays the groundwork for performance standards for the BESS component of hybrid assets, which include flexibility capabilities to respond to demand-side fluctuations, frequency and voltage control stability, and the inclusion of an energy management system that optimises operational cost while preserving frequency and voltage quality. While these standards are an important first step to enabling availability-based remuneration, regulatory clarity could be further improved through the quantification of performance requirements. Moreover, existing MEMR regulation has yet to explicitly define ancillary services as they relate to BESS assets. Clear identification of which services fall under this category, with quantified links to performance standards, will be important enablers of PLN's first ancillary service procurements.

Energy-based remuneration

Energy-based payments compensate BESS assets on a per-kilowatt-hour basis for electricity that is consumed or injected onto the grid. The most common service remunerated through energy-based payments is energy arbitrage, in which BESS assets are charged when electricity prices are low and discharged when electricity prices are high, therefore benefiting from electricity price spreads. While such remuneration does not come with the predictability of capacity- and availability-based payments, energy arbitrage allows BESS assets to access significant upside potential, especially within systems with growing shares of solar PV generation.

As a merchant mechanism, energy-based remuneration often utilises transparent spot pricing in liberalised electricity markets to drive charging/discharging decisions. As a result, Indonesia's vertically integrated and single-buyer system using fixed tariffs is not currently able to accommodate energy arbitrage services. However, such mechanisms could become a possibility should PLN ever choose to adopt time-of-use electricity pricing. Such a mechanism, which would align electricity prices with daily demand trends, would enable BESS operators to be remunerated on a per-kilowatt-hour basis based on when they choose to charge or discharge their assets.

BESS services and expected remuneration approach

Service type	BESS service	Expected remuneration approach	Current readiness level in Indonesia
System reliability and flexibility	Black-start capabilities	Capacity	
	Renewables smoothing	Capacity	
	Peak capacity	Capacity	
	Renewables shifting	Availability	
	Renewables firming	Availability	
	Electricity price arbitrage	Energy	
Ancillary services	Contingency reserve	Capacity	
	Ramping reserve	Capacity	
	Frequency regulation	Availability	
	Voltage support	Availability	
	Synthetic inertia services	Availability	
Grid support and optimisation	Transmission and distribution investment deferral	N/A	
	Congestion relief	Energy	

= insufficient regulatory and/or market frameworks; = additional definitions necessary in regulation and/or grid codes;
= achievable under existing frameworks.
Notes: Readiness levels are indicative and will vary depending on project type and location.
BESS assets are rarely remunerated specifically as a result of transmission and distribution investment deferral; the benefit of this service comes in the form of savings to the network operator itself.

Blended remuneration schemes in emerging economies

While energy arbitrage by BESS assets is today most commonly found in systems with a well-established fleet of battery installations – as is the case in Australia, Germany and parts of the United States – some countries have succeeded in integrating energy-based payments for storage assets using frameworks that do not rely on electricity spot markets. The ability to combine the predictability of capacity- or availability-based payments with the upside potential of energy-based remuneration – consistent with the partial tolling business model – enables BESS operators to harness the full potential of their assets by providing a wide range of system services.

In South Africa, state-owned utility Eskom is vertically integrated and accounted for nearly 90% of the country's electricity generation in 2025. The Renewable Energy Independent Power Producers Procurement Programme enables BESS assets developed by IPPs to sell power to Eskom through long-term PPA contracts. In project procurement stages, Eskom also offers five-year contracts for operations and maintenance (O&M) services. Together, these contracts provide steady remuneration to IPP developers. Meanwhile, assets that charge during periods of low-cost generation (especially during midday) and discharge during peak demand periods support Eskom in avoiding the costs of more expensive peaker plant generation, thereby generating energy-based value for the utility without the presence of an entirely liberalised wholesale electricity market.

In the Philippines, BESS assets receive a significant portion of their remuneration through ASPAs, in which operators are compensated at a rate of PHP 2.08 (Philippine pesos) per kilowatt (kW) per hour (USD 0.034/kW/hr) in exchange for providing the National Grid Corporation of the Philippines (NGCP) with frequency reserves and PHP 1.50/kW/hr (USD 0.02/kW/hr) for contingency reserves. Since these services are performance-linked, payments act as availability-based remuneration. The Philippines has also developed a wholesale electricity spot market (WESM) system that allows electricity producers to engage in market-based competition. The rate at which electricity injected by BESS assets is compensated on the WESM is determined by the sum of ancillary service payments and variable costs, enabling developers to recover O&M expenses through energy payments.

Case study on Viet Nam's PPA framework for standalone BESS assets

Like Indonesia, Viet Nam's power sector operates under a single-buyer system in which Viet Nam Electricity (EVN), the country's state-owned utility, sells electricity at government-regulated retail tariff levels. With an objective of increasing the share of renewables in primary energy supply to 15-20% by 2030 and around

65-70% by 2045, Viet Nam faces many of the same challenges related to power sector expansion and increased need for system flexibility as Indonesia. These similarities make Viet Nam's Circular 62, the country's first comprehensive framework for BESS PPAs, particularly instructive in Indonesia.

Circular 62 applies to standalone BESS projects with capacities exceeding 10 MW. Prices negotiated between IPPs and EVN must be greater than VND 0 (Vietnamese dong) per kilowatt-hour and cannot exceed an annually determined maximum price P_C, which is defined as follows:

$$P_C = P_{CD} + FOMC + P_{BD}$$

where P_{CD} is the asset's fixed investment cost annualised over its economic life, $FOMC$ is the fixed O&M cost, and P_{BD} is the variable cost of charging the BESS asset. Annualised investment cost (P_{CD}) takes into consideration the asset's upfront investment, economic life, and a weighted average cost of capital that assumes a capital structure of 70% debt and 30% equity. The variable cost of charging (P_{BD}), meanwhile, provides pricing visibility to operators by being benchmarked against Viet Nam's off-peak manufacturing retail tariff.

By combining fixed and variable cost components, the maximum PPA price outlined by Circular 62 successfully combines availability- and energy-based payments, in which the former enables developers to recover costs at a maximum internal rate of return (IRR) of 12% and the latter compensates the actual discharge of the asset. In addition to establishing this price range for PPAs, Circular 62 defines technical parameters relating to BESS asset design, including discharge duration, total number of expected charge/discharge cycles over the project's lifetime, annual capacity loss rate, rates of self-consumption and transmission and distribution losses, and availability requirements.

Circular 62 aims to improve revenue projections and, by extension, project bankability by clearly defining remuneration structures for utility-scale standalone BESS. While the framework does not explicitly address how assets may be compensated for the provision of ancillary services, it does demonstrate that bankable payment mechanisms that combine availability-based with energy-based remuneration can exist under single-buyer systems. Moreover, the provision of transparent formulas that place a cap on IRR enables IPPs to recover upfront costs while maintaining affordability standards for EVN.

Investment needs and financing structures for BESS in Indonesia

Investment needs and sources of finance

Understanding the level of investment needed to achieve the objectives of the Rencana Usaha Penyediaan Tenaga Listrik (RUPTL), or Electricity Supply Business Plan; who is responsible for those investments; and how they can be financed is necessary to identifying potential risks. Capital structures can then take these risks into consideration to arrive at financing models that are best suited to enhancing project bankability.

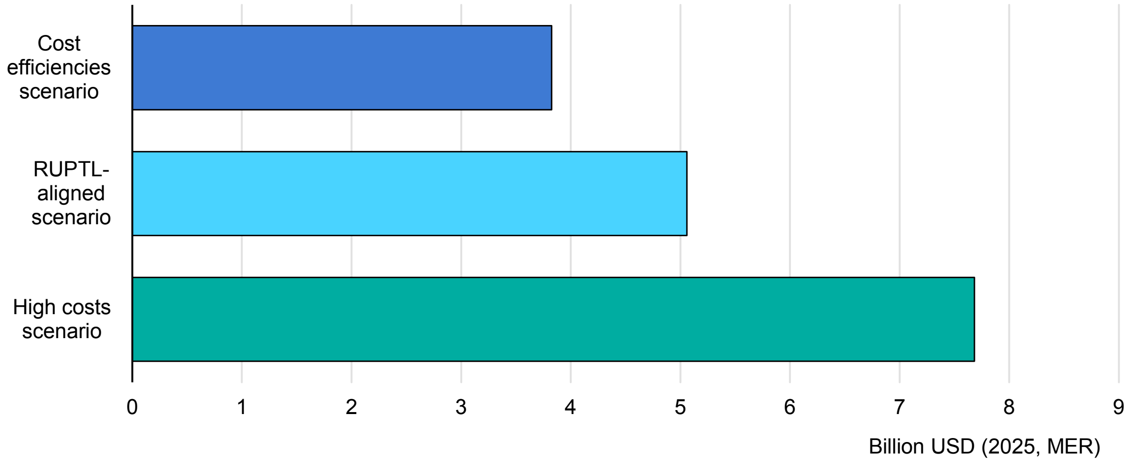
Investment needs for the RUPTL's ARED scenario

The RUPTL's objective of adding around 6 gigawatts (GW) of standalone battery energy storage system (BESS) capacity and 3.6 GW of hybrid generation capacity has the potential to bring substantial benefits to Indonesia's evolving electricity grid. By supporting grid stability and reliability, BESS can help to prevent system failures while also protecting essential infrastructure from potentially damaging frequency or voltage fluctuations. Moreover, the provision of peak capacity and ramping reserve services can provide PT Perusahaan Listrik Negara (PLN) an alternative to calling upon expensive diesel generators during periods of high demand, while also absorbing more power from solar photovoltaic (PV) and wind generation. In the United Kingdom, BESS installations helped consumers save an estimated USD 27 million from January to April 2026 by reducing curtailment of wind power and discharging at a lower price than fossil fuelled peaker plants. Nearly 40% of these savings occurred in the months of March and April, when the cost of fuel inputs for gas-fired generation increased significantly.

Finally, hybrid solar PV and BESS installations have already become cost-competitive with small-scale diesel generation in remote regions (see next chapter). In Indonesia, where connecting hundreds of small islands to the national grid would be expensive and time-consuming, hybrid installations have the potential to more quickly improve access to decarbonised, reliable sources of electricity.

A total of USD 5 billion is needed to achieve the battery storage additions detailed in the RUPTL's Accelerated Renewable Energy Development (ARED) scenario from 2025 to 2034, roughly equivalent to the country's spending on fossil fuel power in 2025 alone. This level of investment takes into consideration the capital expenditures for standalone systems and the BESS component of hybrid systems, grid connection expenses and additional spending on battery capacity augmentations.

Total investment needs by cost scenario, 2025-2034 cumulative



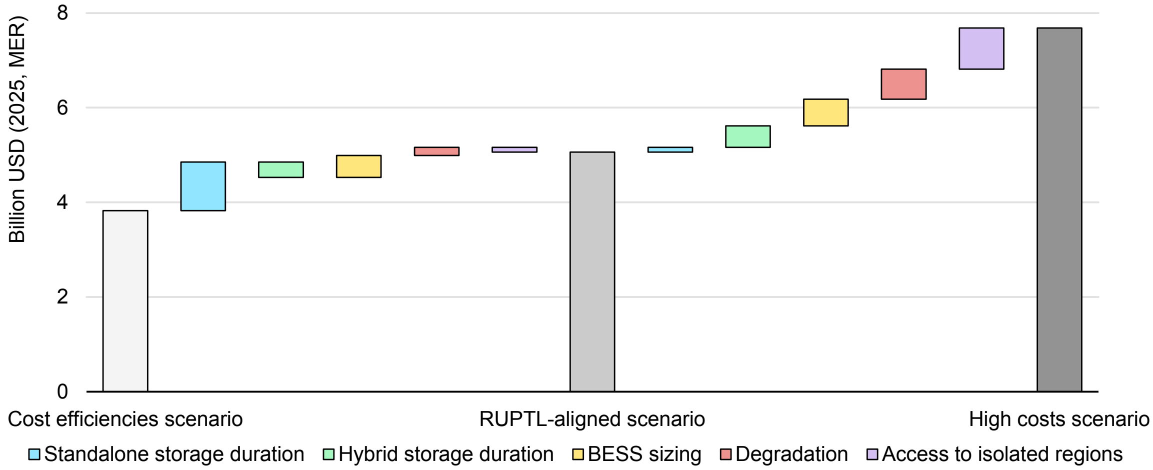
Note: MER = market exchange rate.
Source: See Annex for the full methodology and sources used for investment needs modelling.

Even though battery costs are rapidly declining, the use cases and associated technical specifications of BESS installations that PLN will choose to prioritise can have significant impacts on capital costs. In order to capture a realistic range of investment needs based on varying decisions, three cost scenarios are modelled. Each of these scenarios differs based on relative costs in different PLN subsystems with varying degrees of isolation, annual battery degradation rates, capacity of BESS relative to solar PV in hybrid installations, and battery storage duration:

- **Cost efficiencies scenario**: PLN prioritises the lowest-cost technologies, opting for shorter storage durations (mainly one to two hours) and smaller shares (10%) of BESS capacity relative to solar PV installations. Annual degradation rates are kept low (1%) as a result of strict limitations on battery cycling, and installation costs are minimally variable across regions due to a prioritisation of easily accessible locations.
- **RUPTL-aligned scenario**: PLN adheres to the technical parameters that are implied in the RUPTL, prioritising systems with four-hour storage durations and sizing BESS to 20% of solar PV additions in hybrid projects. Annual degradation rates are 2% and the variation in capital and installation costs across subsystems is proportional to that of system-level Biaya Pokok Penyediaan (BPP) in 2025.

- **High costs scenario**: The decision to expand into a wider variety of use cases compels PLN to invest in technologies ranging from one- to eight-hour storage durations, and the storage component of hybrid projects is equivalent to 30% of the solar PV component's generation capacity. More frequent battery cycling brings annual degradation rates to 3%, and the expansion into more remote areas results in a higher degree of cost differentiation across subsystems.

Breakdown of differences in total investment across cost scenarios, 2025-2034



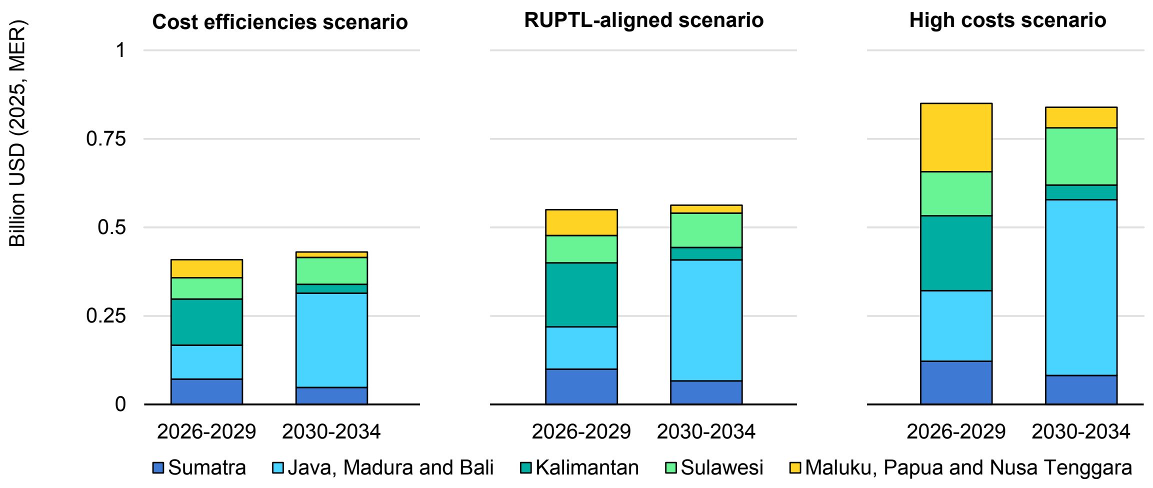
Note: MER = market exchange rate.
Source: See Annex for the full methodology and sources used for investment needs modelling.

Total spending in the cost efficiencies scenario reaches USD 3.8 billion – three-quarters of the RUPTL-aligned scenario's USD 5 billion. Over 55% of this difference can be accounted for by the use of technologies with shorter storage durations. Where the RUPTL-aligned scenario mainly opts for systems that can charge or discharge at maximum power for up to four hours, the cost efficiencies scenario favours one- and two-hour batteries. In general, the per-kilowatt capital costs of power storage batteries increase by a factor of 1.7 for every doubling in storage duration, implying cost reductions when shorter-duration batteries are used. However, these savings come at the expense of a more limited range of services. While most of the services expected to be delivered by standalone BESS assets can be performed using one- and two-hour duration storage, longer-duration BESS in hybrid projects will become increasingly important for renewables shifting as variable renewable energy penetration in the grid mix rises.

In the high costs scenario, total investment for the RUPTL's ARED pipeline reaches USD 7.7 billion. Greater levels of deployment of standalone and hybrid BESS projects in isolated regions account for one-third of the increase relative to the RUPTL-aligned scenario. Meanwhile, the shift in annual degradation rate from

2% to 3% increases total investment by 20% as a result of greater capacity augmentation needs. Increasing the BESS-to-solar PV ratio in hybrid installations from 20% to 30% accounts for a 25% increase in total investment. While the high costs scenario results in an additional USD 2.6 billion of investment, it also offers a higher degree of flexibility through the availability of many BESS services. Moreover, the installation of projects in isolated regions contributes more substantially to PLN's objective to improve electricity access without undertaking expensive grid expansions.

Average annual investment needs by subsystem and scenario, 2026-2034

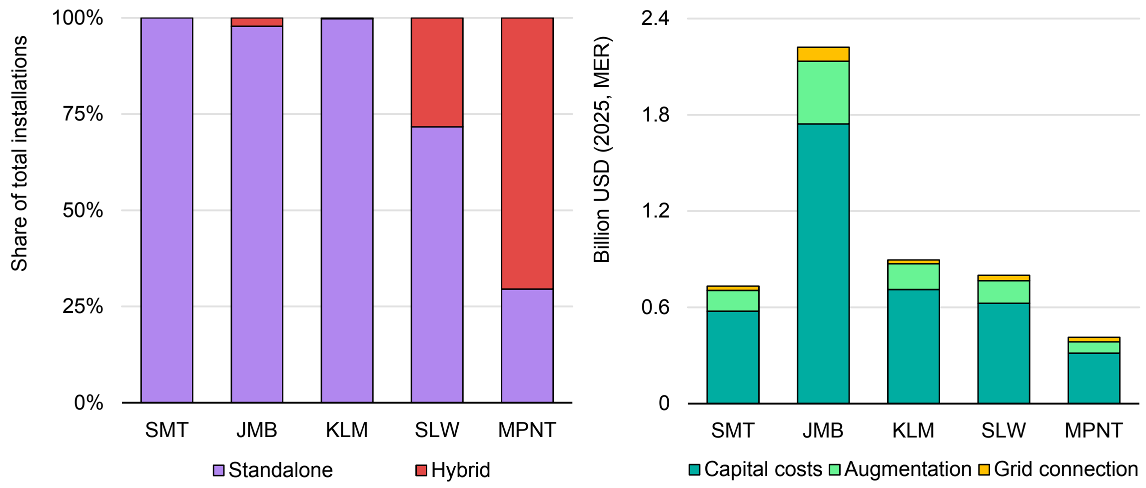


Note: MER = market exchange rate.
Source: See Annex for the full methodology and sources used for investment needs modelling.

While spending on utility-scale BESS prior to 2025 was minimal, annual investment reaches USD 550 million from 2026 to 2029 and USD 560 million from 2030 to 2034 according to the RUPTL-aligned scenario. Driven by the construction of Indonesia's new capital city of Nusantara, the island of Kalimantan accounts for one-third of investment in the first half of the RUPTL period, reaching close to USD 180 million annually. Similar trends apply in the first half of the cost efficiencies scenario, though the region of Java, Madura and Bali takes on a slightly larger share of total investment (24%) as fewer projects are undertaken in remote regions. In the high costs scenario, spending in the region of Maluku, Papua and Nusa Tenggara reaches an average of USD 190 million annually as projects in isolated regions – especially hybrid installations that aim to replace ageing diesel generators – are prioritised.

By contrast, investment during the second half of the RUPTL period – from 2030 to 2034 – is dominated by the region of Java, Madura and Bali, which accounts for around 60% of investment across all three cost scenarios. This is a result of rapidly rising electricity demand in the country's most populous islands, which drives a need for additional sources of system flexibility. This rising demand in electricity is addressed in part by additions of renewable energy generation in the region Sulawesi, which is at times paired with BESS to create hybrid systems. In the high costs scenario, which assumes a BESS-to-generation sizing ratio of 30%, spending in Sulawesi exceeds USD 160 billion annually from 2030 to 2034.

Share of investment by technology (left) and total investment by cost component (right) by region, 2025-2034



Note: MER = market exchange rate; SMT = Sumatra; JMB = Java, Madura and Bali; KLM = Kalimantan; SLW = Sulawesi; MPNT = Maluku, Papua and Nusa Tenggara.
Source: See Annex for the full methodology and sources used for investment needs modelling.

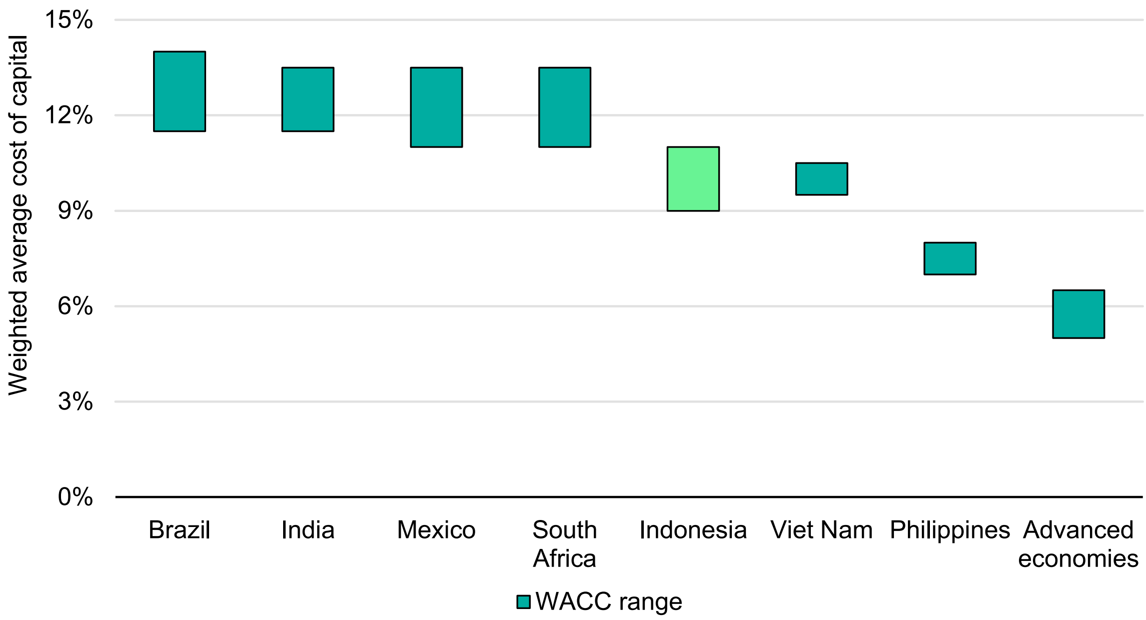
In the RUPTL-aligned scenario, system capital costs – which include expenses for physical battery equipment and associated infrastructure, engineering, procurement and construction (EPC) costs, and additional development margins – account for over three-quarters of total investment. Augmentation, in which battery capacity is replaced to keep assets' nameplate capacities consistent as equipment naturally degrades with time, is another important source of capital expenditure for developers. A total of nearly USD 90 billion, or 18% of spending, across all five regions is invested in additional BESS capacity to account for annual degradation rates of 2%. While investment needed for the connection of BESS projects to PLN's grid infrastructure is relatively small, its share of total costs varies by region. For example, cumulative BESS additions in Kalimantan are 40% higher than in Maluku, Papua and Nusa Tenggara; however, the higher degree of isolation for projects on Indonesia's easternmost islands results in grid connection spending that is USD 4 million higher than in Kalimantan.

The cost of capital for BESS remains high in Indonesia

An elevated cost of capital is a barrier to scaling BESS in Indonesia. The cost of capital reflects the minimum rate of return required to justify an investment and is particularly important for capital-intensive technologies such as BESS and renewable power technologies, where financing costs make up a large share of lifetime project costs.

The weighted average cost of capital (WACC) – the weighted average of financing costs from both debt and equity – for utility-scale BESS in Indonesia was in the range of 9-11% in 2024. This is almost double levels seen in advanced economies (5-6.5%). While this is competitive relative to other emerging market and developing economies (EMDE), the premium materially impacts project costs and bankability. Notably within the Association of Southeast Asian Nations (ASEAN), the Philippines (7-8%) sees a lower cost of capital than Indonesia, reflecting established regulatory framework and remuneration mechanisms, greater market experience in deploying BESS, and a lower cost of debt from domestic lenders. Despite showing a country premium, the 2024 cost of capital for BESS in Indonesia does not come with a substantial technology premium, as evidenced by its alignment with other technologies such as solar PV (8.5-11%), natural gas generation (9-10%), hydropower (9-11%) and offshore wind (10.5-11.5% in 2023).

Weighted average cost of capital for utility-scale BESS in selected countries and advanced economies, 2024



Note: Median WACC (nominal, post-tax, local currency) gathered from survey respondents. Responses capture a mix of actual WACC from financed projects, and WACC expectations from respondents.
Source: IEA (2025), Cost of capital observatory dashboard.

Cost of capital reflects real and perceived risks faced by investors at the country, sector and project levels. Market participants surveyed through the IEA Cost of Capital Observatory cite political, regulatory and permitting risks as the key risks contributing to elevated cost of capital in Indonesia.

Policy and regulatory shifts can add to perceived risks for investors. The absence of an established business model and remuneration for standalone BESS means that prospective investors do not have visibility over long-term revenues, preventing projects from being considered for financing. Procurement and permitting processes are viewed by developers as complex and slow-moving, and the involvement of multiple government bodies adds to the risk of project delays. A lack of transparency in procurement and permitting also reinforces risk perceptions. Moreover, projects may incur currency risk if the currency of BESS revenues – most likely to be in Indonesian rupiah – differ from the currency through which the project receives financing. In these cases, a depreciation in local currency would hamper the project's ability to repay debt obligations.

Finally, a mismatch between the loan tenor and asset life can make debt servicing more challenging. Most domestic commercial lending to the private sector is between three and five years, with longer tenors for loans to state-owned enterprises (SOEs). This is significantly shorter than the expected average lifetime of BESS assets, which generally lies between 10 and 15 years. As a result, annual debt servicing requirements may be particularly high and even risk refinancing, in which front-loaded debt service creates a cash flow shortfall during the BESS asset's first operating years, compelling developers to seek new financing under potentially less favourable terms.

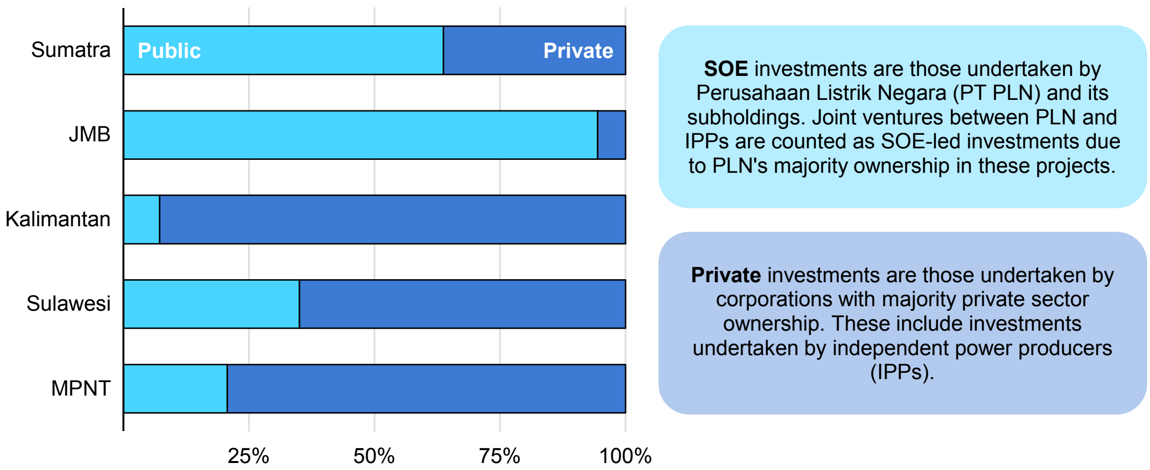
Sources of finance and concessional funding

While total investment needs indicate the magnitude of capital needed to achieve the RUPTL ARED scenario's BESS objectives, understanding where that capital comes from – and how it is financed – can give more precise indications of how the necessary capital can be mobilised. The following section breaks down investment needs according to the RUPTL-aligned scenario by sponsor, instrument and financier.

The RUPTL 2025-2034 directly allocates capacity additions for standalone BESS and hybrid projects to PLN (and its sub-holdings or subsidiaries) and independent power producers (IPPs). Capacities allocated to PLN's sub-holdings can be undertaken solely by that entity or in collaboration with IPPs in a joint venture, in which case the PLN sub-holding retains a majority (51% or greater) ownership share of the project. For the purposes of this analysis, investments associated with the capacities allocated to PLN's sub-holdings are therefore considered to be SOE-led.

In the RUPTL-aligned scenario, PLN and its sub-holdings account for USD 3 billion, or 60%, of total investment. PLN is the main sponsor in the regions of Sumatra and Java, Madura and Bali, where standalone BESS projects are closely aligned with the utility's mandate to maintain the reliability of electricity supply. The state-owned utility also invests close to USD 115 million in the region of Maluku, Papua and Nusa Tenggara, where projects that emphasise improved access to electricity – rather than system reliability – require public participation to achieve bankability.

Sponsor breakdown of total BESS investment in the RUPTL-aligned cost scenario by region

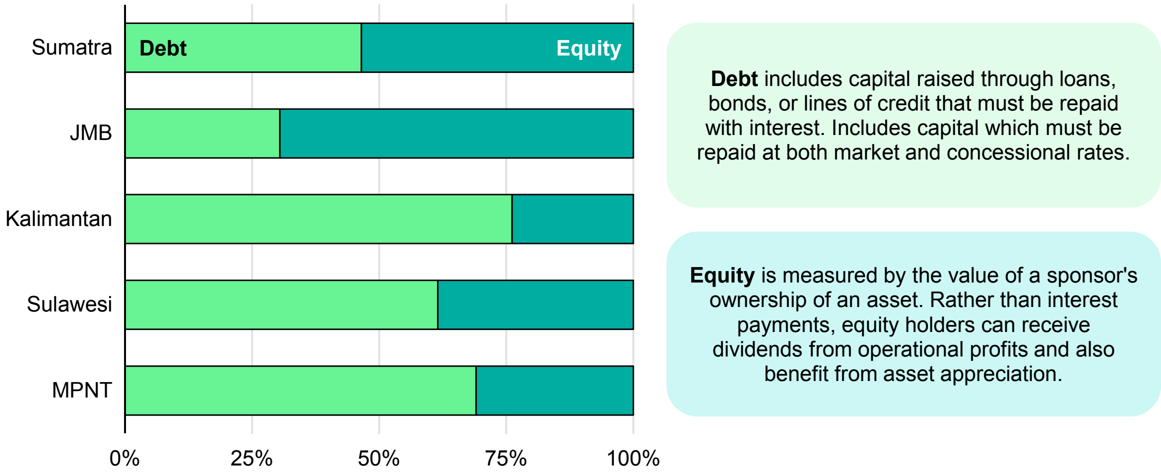


Note: JMB = Java, Madura and Bali; MPNT = Maluku, Papua and Nusa Tenggara; SOE = state-owned enterprise.
Source: Sponsorship shares are directly calculated according to RUPTL 2025-2034 capacity additions. See Annex for the full methodology and sources used for the sources of finance modelling.

Through the participation of IPPs, the private sector contributes an additional USD 2 billion – mainly in the regions of Kalimantan; Sulawesi; and Maluku, Papua and Nusa Tenggara. Taken together, these regions account for over 80% of the country's additions of solar PV-plus-BESS hybrid additions. The higher degree of complexity of hybrid projects – which PLN has limited experience in developing – justifies the involvement of IPPs, which can often bring high degrees of technical experience. Moreover, current regulation more readily enables IPPs to monetise the BESS component of hybrid assets through bundled PPA agreements, while PLN is constrained to recovering the costs of new generation assets through regulated electricity tariffs that broadly fall beneath required levels.

Overall, PLN generally favours projects that directly support its mandates and strategic initiatives, and that are located in relatively low-risk geographies with existing transmission and distribution grid infrastructure. This preference is driven by constraints on the utility's balance sheet: with a high level of legacy debt and limited ability to generate revenue beyond the sale of electricity at regulated tariff levels, PLN is compelled to prioritise BESS projects that serve primarily as network – rather than generation – assets.

Instrument breakdown of total BESS investment in the RUPTL-aligned cost scenario by region



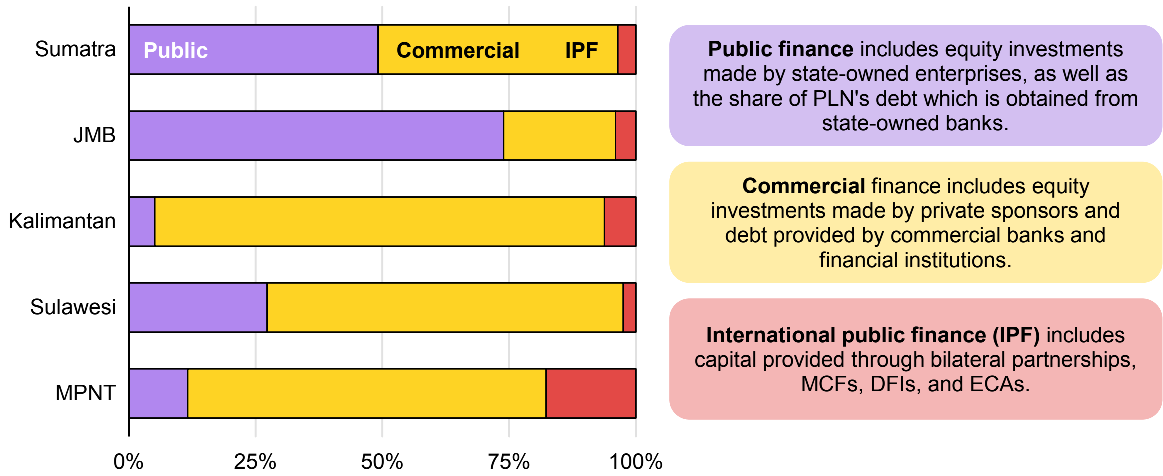
Note: JMB = Java, Madura and Bali; MPNT = Maluku, Papua and Nusa Tenggara.
Source: S&P Capital IQ (2026), PT Perusahaan Listrik Negara corporate finance dataset, accessed July 2026; Green Street Infrastructure (2026), Infrastructure project finance dataset, accessed July 2026. See Annex for the full methodology and sources used for the sources of finance modelling.

The instruments used to finance BESS investments are closely tied to the type of sponsor that is making those investments. As an SOE and provider of essential grid services, PLN must remain in solid fiscal health and avoid becoming overly dependent on debt. PLN thereby tends to rely more heavily on equity financing for the assets it owns directly, particularly in regions where project risks are relatively low. From 2025 to 2034, 75% of the USD 2.6 billion in total equity flows are invested in the regions of Sumatra and Java, Madura and Bali.

By contrast, debt finances at least 60% of investments in the regions of Kalimantan; Sulawesi; and Maluku, Papua and Nusa Tenggara, totalling USD 2.5 billion across all regions. IPPs, which are the main sponsors of investments in these regions, generally use project finance models to structure their projects financially, which allow them to raise debt relative to project cash flows. Domestic debt providers, as well as international financiers, also favour hybrid projects over standalone assets due to the long-term revenue visibility offered by bundled PPAs. Projects in the region of Kalimantan receive the greatest absolute level of debt investments, totalling USD 680 million.

The relative shares of equity and debt used to finance the RUPTL's BESS pipeline can provide insights into project bankability and potential risks. Equity financing generally comes with higher financing costs but is also better suited to absorbing risks associated with first-of-a-kind projects – when, for instance, cash flow certainty is limited for standalone projects. Regions such as Sumatra and Java, Bali and Madura therefore risk delays in deployment should PLN's balance sheet grow more constrained. Debt, on the other hand, is associated with lower financing costs but requires more concrete revenue streams. Providing cash flow certainty through stable regulatory frameworks is therefore essential to scaling up deployments in the regions of Kalimantan; Sulawesi; and Maluku, Papua and Nusa Tenggara.

Financier breakdown of total BESS investment in the RUPTL-aligned cost scenario by region



Note: JMB = Java, Madura and Bali; MPNT = Maluku, Papua and Nusa Tenggara; MCFs = multilateral climate funds; DFIs = development finance institutions; ECAs = export credit agencies.
Source: See Annex for the full methodology and sources used for the sources of finance modelling.

Half – or USD 2.5 billion – of the investment needed for the RUPTL's BESS additions is financed by commercial providers, which include both domestic and international commercial banks. This is particularly true in regions where development is led by IPPs, which predominantly finance their projects through debt acquired from commercial banks. Domestic commercial banks such as Bank Mandiri, Bank Rakyat Indonesia, Bank Central Asia, and Bank Negara Indonesia are most likely to finance hybrid installations that benefit from long-term PPAs, and are generally less sensitive to political risks than their international counterparts. While PLN's regulated income makes the utility investment-grade for many commercial debt providers, lenders typically prefer to engage with projects that are financed on-balance sheet, which minimises the risk of loan repayment delays due to insufficient BESS revenues.

The government of Indonesia, by contrast, finances the equity portion of PLN-led investments, which totals USD 2.1 billion from 2025 to 2034. Meanwhile, public debt providers include PT Sarana Multi Infrastruktur (PT SMI) – the country's state-backed infrastructure development institution – as well as Indonesia's two sovereign wealth funds, Indonesia Investment Authority and Daya Anagata Nusantara (Danantara).

The third and final portion of investment is financed by international public financiers, which provide around USD 275 million in funding. The region of Maluku, Papua and Nusa Tenggara accounts for 31% of this total, with an additional 20% supporting investment in Kalimantan. International public financiers use a wide range of instruments, including loans, grants, guarantees, results-based financing and blended finance structures, to support BESS projects – often at concessional financing rates. These instruments are particularly crucial for supporting first-of-a-kind projects, especially in geographies with limited access to existing grid infrastructure, by reducing the cost of capital and shouldering first-loss risks to strengthen private investor confidence.

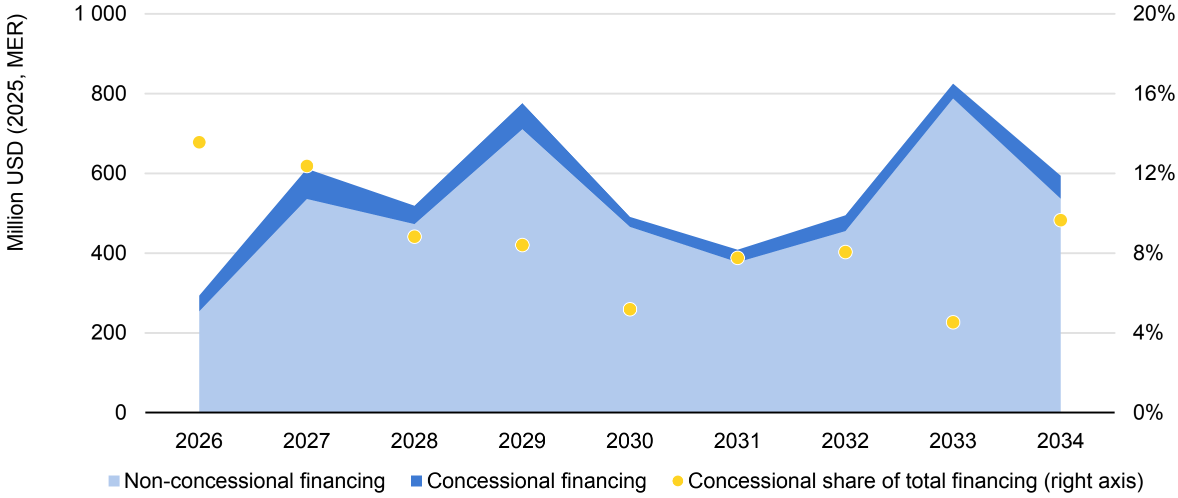
The Indonesia Just Energy Transition Partnership

An important potential source of both concessional and commercial finance is the Indonesia Just Energy Transition Partnership (JETP). Established in 2022, the JETP aims to mobilise USD 20 billion in financing from both public and private sources to support Indonesia in reaching its decarbonisation and renewable energy development targets by 2030. The Comprehensive Investment and Policy Plan (CIPP) created within the framework of the JETP is a non-binding pathway for Indonesia to achieve peak power sector emissions of 250 million tonnes and a renewables share of 44%, both by 2030.

Under the CIPP, battery energy storage is considered a critical contributor of system flexibility and reliability, which itself becomes increasingly important as the share of renewables in Indonesia's grid rises. Moreover, the health benefits of replacing incumbent diesel power with solar PV-plus-BESS installations, especially on small or isolated island systems, fit squarely within JETP priorities. As a result, BESS projects – especially first-of-a-kind installations in Indonesia's easternmost region of Maluku, Papua and Nusa Tenggara, are strong candidates for JETP funding.

Concessional finance broadly constitutes capital support that is offered with favourable terms relative to market conditions. Multilateral climate funds (MCFs), development finance institutions (DFIs), export credit agencies (ECAs) and bilateral lending are common sources of concessional capital, though domestic public financiers may also offer support on concessional terms. Financial instruments include grants, guarantees, and loans offered at relatively low interest rates and/or long tenors, while additional support through capacity building, policy development and technical assistance can facilitate the transfer of valuable skills and knowledge. By assuming subordinate positions in project capital structures, concessional financiers play an important role in de-risking early-stage projects and boosting project bankability enough to encourage private sector participation.

Annual investment and concessional financing share in the RUPTL-aligned scenario, 2026-2034



IEA. CC BY 4.0.

Source: See Annex for the full methodology and sources used to estimate concessional financing needs.

The RUPTL-aligned scenario estimates that USD 460 million, or 9% of total investment required to install its BESS pipeline, is needed to support the RUPTL's first BESS projects, in addition to projects located in isolated regions. Concessional financing needs are highest in the first half of the RUPTL period, averaging USD 53 million annually from 2025 to 2029. However, this declines to an average of USD 39 million from 2030 to 2034 as regulation, financing structures and revenue streams are proven and project sizes are scaled up. Due to limited access to grid infrastructure, the region of Maluku, Papua and Nusa Tenggara receives 20% of total concessional capital. However, the high volume of standalone projects in Java, Madura and Bali – which currently face bankability challenges due to a lack of regulatory frameworks to define remuneration – ultimately drives this region to receive nearly half of total concessional financing over the RUPTL period.

Financing structures for BESS

While business models shape how a BESS project generates revenue, financing structures determine the project's capital stack, the return requirement necessary for project viability, and how risk is allocated among stakeholders. The type of financing structure is largely determined by the level of certainty around revenue streams and, to a lesser extent, who is sponsoring investments.

Summary of financing models

	Corporate finance (on-balance-sheet)	Project finance (off-balance-sheet)
Ownership	Utility-owned (PLN)	Project company (special purpose vehicle) owned by IPP sponsors and/or PLN
Main instruments used	State capital injection, corporate loans and bonds (often sovereign guaranteed)	Sponsor equity, project debt (non-recourse or limited recourse)
Credit basis	PLN corporate credit and/or sovereign support	PPA bankability and off-taker (PLN) credit risk
Repaid through	PLN's consolidated revenues (tariffs and government compensation)	Project revenues under the PPA (capacity or tolling payments)
Ideally suited to	Network assets, grid-connected BESS providing system services	Hybrid assets with a contracted revenue stream (e.g. tolling or capacity payments)
Key advantages	Speed, lower cost of capital via sovereign backing	Mobilises private capital, no direct burden on PLN balance sheet, transfers construction and performance risk to sponsors
Risks	Crowds PLN's constrained balance sheet and competes with other CAPEX	Higher transaction costs and longer lead times; potential foreign exchange mismatch

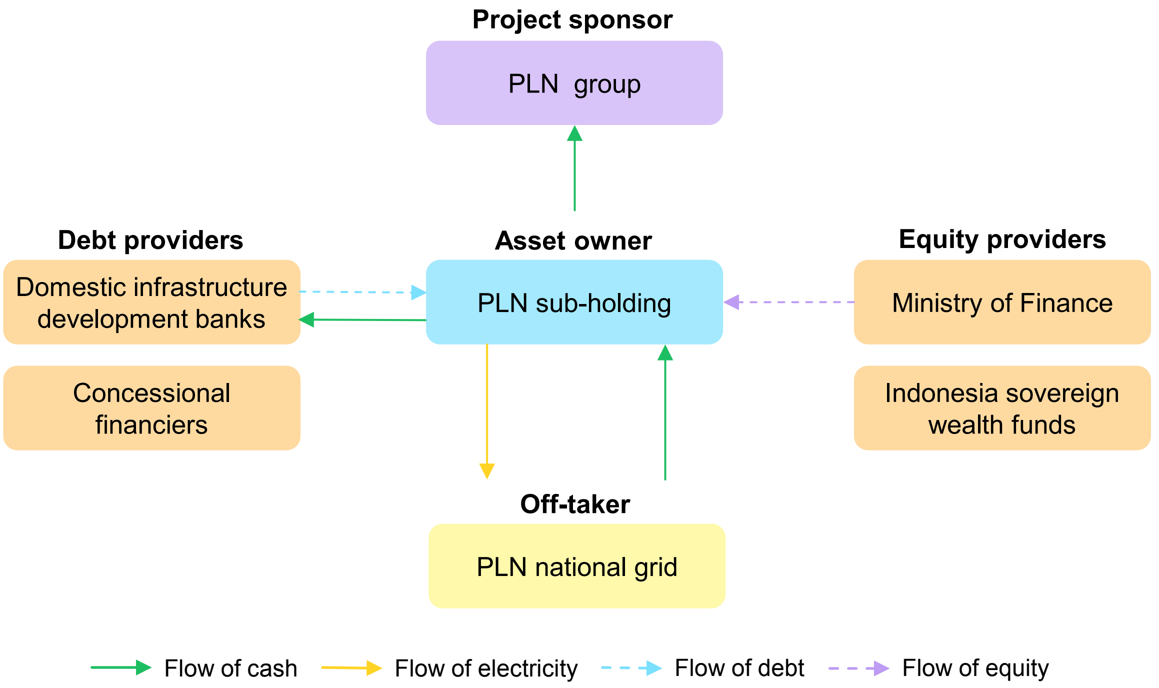
Notes: Non-recourse financing means lenders are repaid solely from project cash flows, with no claim on sponsors' balance sheets beyond their equity commitment. Limited-recourse structures add narrowly defined sponsor obligations, typically during construction. Off-balance sheet does not imply purely private ownership. PLN, its subsidiaries or other SOEs can participate in the project company as minority or majority shareholders.

Financing for PLN-led projects

Projects developed by PLN and its sub-holdings will typically rely on corporate financing structures, which raise capital at the company level and use PLN's entire balance sheet, rather than project cash flows. A combination of sovereign-backed and corporate loans from institutions including the Ministry of Finance, PT SMI and commercial banks provide debt, while equity is made available through government injections or PLN's retained earnings. Corporate financing structures provide PLN with the flexibility to allocate capital internally, allowing the utility to prioritise projects that most directly support objectives related to improving system reliability and grid stability.

Relatively lower transaction complexity, in addition to the security that comes with having debt be secured by a combination of PLN's total revenues, regulated tariffs, and the government of Indonesia's support through subsidies and cash injections, mean that corporate financing structures are generally associated with lower financing costs. However, PLN's capacity to take on additional debt is constrained by its already highly leveraged balance sheet, restrictions on borrowing limits due to its status as an SOE and single borrower limits. As a result, both standalone and hybrid BESS projects that are supported by corporate finance must compete with other essential investments such as transmission and distribution grid expansions and generation additions.

Corporate financing structure: PLN- led



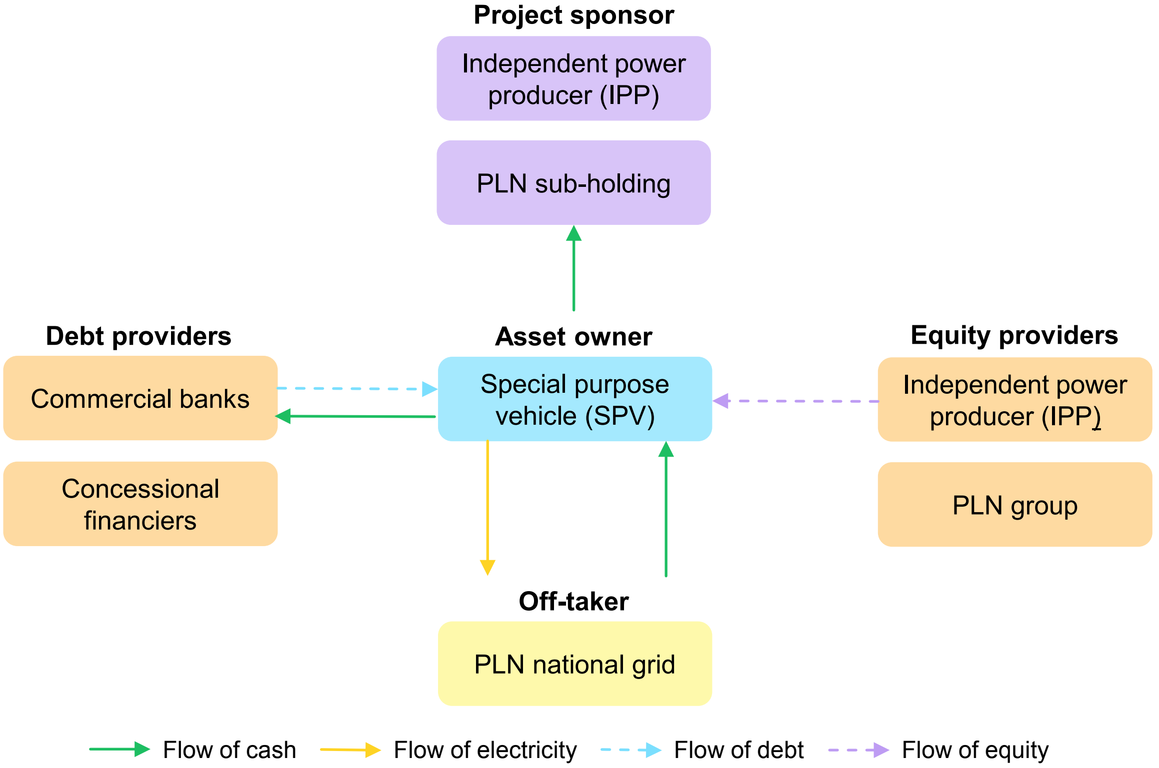
BESS projects that are closely aligned with PLN's mandates – especially standalone installations in regions with well-developed grids – are best suited to corporate financing structures. However, lenders under corporate financing structures make capital available at a broad, balance-sheet level, and are therefore more concerned with PLN's overall cash flow rather than that of specific BESS assets. As a result, this financing structure does not provide incentives to measure BESS performance, and therefore is not well suited to the development of frameworks for availability-based payments and the provision of ancillary services whose remuneration is linked to asset performance. Standalone BESS assets that serve as extensions of transmission grid infrastructure by providing frequency regulation, voltage support and congestion management services – therefore having minimal operational complexity – are most likely to succeed under corporate financing structures.

Financing for IPP-led projects

In contrast to PLN's corporate financing approach, BESS installations developed by IPPs are most likely to follow a project financing model. Under this approach, IPPs begin by creating a special purpose vehicle (SPV) that is responsible for development and ownership of the asset. The SPV may be formed by a single private developer but can also be established by a consortium of sponsors that includes other private developers, institutional investors and, in some cases, PLN or its sub-holdings. The SPV then raises capital – typically a mix of non-recourse debt and sponsor equity – that is repaid directly through the BESS asset's contracted revenues. Therefore, lenders will carefully consider the details of an asset's design, including services provided and technical characteristics (such as storage duration, degradation rate and round-trip efficiency), as well as the availability of regulatory frameworks that guarantee the ability for assets to generate steady cash flows.

Under project financing models, lenders' perceptions of risk – and resulting cost of capital – are closely tied to the predictability of the asset's revenue streams. The SPV is ring-fenced from its parent company (or companies), so lenders have a limited access to sponsors' balance sheets to recoup their investments. As a result, project financing structures are just as well suited to experienced developers managing a variety of assets as they are to new market entrants. Under Indonesia's direct selection procurement procedure, which uses competitive tendering to allocate projects to IPPs, the use of project financing structures can therefore put downward pressure on the tariff that PLN offers private developers by enabling the participation of a broader range of developers, including those who are willing to assume the risks of bidding low prices in order to win projects – with the prospects that BESS projects will become profitable over the long term.

Project financing structure: IPP-led or joint ventures



Because lenders expect long-term, predictable revenue streams, project finance is well suited to hybrid BESS projects with clearly defined tariffs and standalone BESS installations that receive availability-based payments in exchange for the provision of specific grid and ancillary services such as capacity reserves, load smoothing and frequency regulation. Under power purchase agreements (PPA) contracts or ancillary services procurement agreements, these projects receive steady cash flows that can accommodate high leverage ratios and thereby reduce the amount of equity that project sponsors must contribute. Taken together, these characteristics facilitate rapid deployment in regions where PLN prefers not to employ its own balance sheet – especially across the eastern islands of Maluku, Papua and Nusa Tenggara.

In the case of joint ventures between IPPs and PLN, which are explicitly permitted under the RUPTL 2025-2034, project financing models can still accommodate shared ownership while maintaining the benefits of SPV ring-fencing. While PLN or its sub-holding will account for a minimum of 51% of shareholding in the SPV, the IPP (or consortium thereof) can retain ownership of the asset throughout its development, construction and operation phases. PLN's involvement can facilitate permitting, land access and grid connection, while the IPP contributes expertise in the development and operation of the asset. This hybrid structure therefore allows PLN to gain experience in installing BESS assets that it can then apply to its own projects.

Types of independent power producers

While this report refers to IPPs as a broad group, in reality they comprise a variety of different types of private developers. IPPs will have varying levels of experience in developing BESS, as well as distinct tolerances for risk and expectations for internal rate of return. One way to distinguish between different IPPs is by considering where they generally do business:

Local developers such as Xurya Daya Indonesia, PT Sumber Energi Surya Nusantara and MedcoEnergi operate primarily in Indonesia. As a result, they are likely to rely more on local banks, face tighter borrowing limits and may have limited access to international capital. However, their familiarity with Indonesia translates to a robust knowledge of local regulations and permitting procedures, while lending from domestic banks reduces currency risk.

Regional developers including Sembcorp Industries (Singapore), ACEN Renewables (Philippines), and Vena Energy (Singapore) operate in Southeast Asian countries. These developers generally have access to regional commercial banks such as DBS (Singapore) and Maybank (Malaysia), which may offer capital at lower rates than local institutions. Technical assistance programmes or collaborations with PLN through joint ventures can support regional developers in addressing challenges related to regulatory unfamiliarity, especially for their first Indonesian projects.

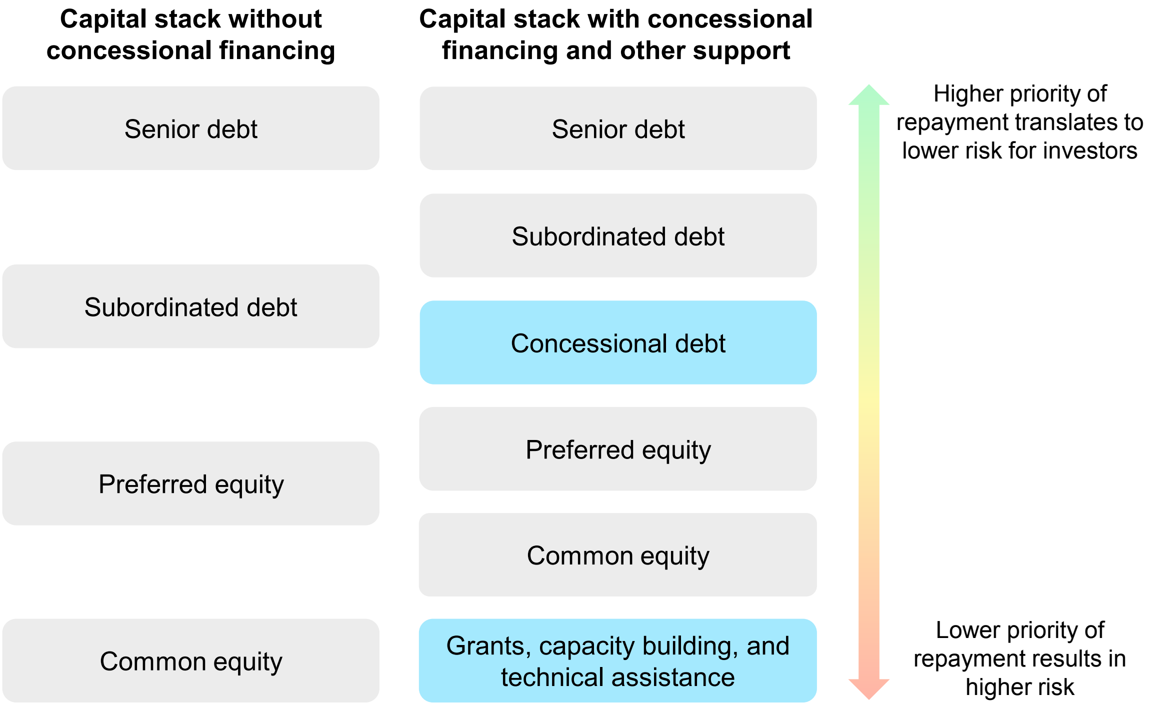
International developers such as ib vogt (Germany), EDF (France) and (Saudi Arabia) have global portfolios and operate with larger balance sheets than their local and regional counterparts. Their scale facilitates access to international lenders, and often leads them to favour a portfolio – rather than project-by-project – approach to development. However, international developers require high degrees of regulatory certainty before entering new markets.

The role of concessional and blended finance

According to the RUPTL-aligned costs scenario, an annual average of USD 300 million in financing on PLN's balance sheet, as well as an annual average of USD 210 million in private sector financing, will be required to deploy the RUPTL's full BESS pipeline. Given the historically low levels of investment in BESS so far, these figures represent significant increases in spending over a short period of time. While constraints on PLN's balance sheet may limit PLN's ability to raise more debt without negatively impacting its credit rating, private sector investors currently lack the long-term visibility on revenue streams that is needed to secure sufficient financing. However, concessional funding can play an important role in boosting the bankability of the RUPTL's first BESS projects and bridge investment gaps.

Concessional finance refers to funding in the form of loans, grants, guarantees or equity that is provided on more favourable terms than those of commercially available sources of finance. Typically offered through bilateral support, multilateral development banks, bilateral DFIs and ECAs – concessional finance can lower the cost of capital by providing funding at below-market interest rates. Longer loan tenors are also particularly beneficial to BESS projects, which typically have lifetimes that exceed the tenors of commercial loans. Blended finance structures, in which concessional instruments are combined with commercial debt or equity, can catalyse further private sector investments by assuming specific risks, such as delays in project development or technology underperformance.

Structures that integrate concessional support move traditional instruments into less risky portions of the capital stack



In PLN-sponsored projects, structured according to corporate financing principles, concessional finance generally appears in the form of sovereign-backed loans or equity injections channelled through the government of Indonesia. Equity injections from the state to PLN – either directly or through state-backed development banks such as PT SMI – can be funded by low-interest, long-tenor loans provided by MDBs such as the World Bank or the Asian Development Bank (ADB). As a result, PLN's needs for commercial borrowing are reduced and its balance sheet benefits from a lower leverage ratio. Since corporate finance does not distinguish between the costs and revenues from each of PLN's assets, sovereign-backed loans or equity injections may require clear earmarking or disbursement conditions that are linked to performance in order to ensure that BESS projects receive the concessional funding as intended.

By contrast, BESS assets developed by IPPs with project finance structures typically receive concessional financing directly at the SPV level. Loans provided at below-market interest rates bring down the cost of capital, and can also take subordinated positions to ensure that commercial lenders are repaid first. Meanwhile, guarantees can mitigate concerns about regulatory uncertainty, which is particularly important for first-of-a-kind projects that often serve to demonstrate how regulations are implemented in practice. In joint ventures between IPPs and PLN, concessional finance is also provided directly at the SPV level to support both parties. The ring-fenced nature of project financing structures often makes them favourable to MDBs relative to corporate financing, as it allows them to target precise projects and more accurately measure additionality.

The use of concessional financing instruments for targeted projects can demonstrate the bankability of BESS assets and their revenue structures, thus allowing similar projects to subsequently be scaled up and more rapidly deployed. Therefore, concessional funding is most effective when used precisely to support first-of-a-kind projects, assets in higher-risk regions or projects aiming to benefit from yet-untested revenue streams. For instance, the first utility-scale standalone installation on the island of Java and the first solar PV-plus-BESS project on the island of Sulawesi are likely to benefit from relatively higher shares of concessional funding than similar projects in subsequent years. These instruments must be used in combination with exit strategies that clearly define the stage at which concessional financing is no longer provided. The achievement of certain projects or market conditions can trigger the exit of below-market rate loans, thus enabling that capital to be recycled towards other projects.

Concessional finance for BESS projects in South Africa and Cambodia

Established in 2008, the Climate Investment Funds (CIF) is one of the world's largest multilateral climate funds (MCF). CIF channels concessional financing and technical assistance through six multilateral development banks (MDBs) to address high financing costs, accelerating the deployment of low-emissions technologies and facilitating the ability of private actors to support energy projects in emerging markets. CIF's Clean Technology Fund (CTF) supports BESS investment, notably through its Renewable Energy Integration (REI) programme and its Dedicated Private Sector Program (DPSP), under which the Global Energy Storage Program (GESP), launched by CIF in 2019, is among the world's first investment programmes dedicated to piloting storage solutions for renewable power including BESS.

South Africa's battery energy storage programme, implemented by state-owned utility Eskom and supported by the CTF, is among the largest grid-scale BESS installations on the African continent. Targeting a total of 360 MW/1440 MWh of BESS deployment, the programme benefits from multiple CTF contributions, including a USD 215 million concessional loan under the stewardship of the World Bank and USD 58 million in funding administered by the African Development Bank (AfDB). The CTF also supported the development of South Africa's BESS-specific grid codes and expansion of Eskom's operational capacity.

Meanwhile, multilateral development banks also play an essential role in providing concessional financing products and technical assistance to BESS projects in EMDE. For instance, ADB has approved financing for a 250 MW/500 MWh BESS project in Cambodia, which is designed to address growing electricity demand by storing and releasing renewable energy and strengthening Cambodia's interconnectivity with neighbouring networks. The project is backed by a USD 40 million concessional loan and USD 5 million grant from ADB, and mobilizes an additional USD 18.4 million in cofinancing provided by the Green Climate Fund and the United Kingdom, managed by ADB through its ASEAN Catalytic Green Finance Facility. In some cases, ADB can also provide local currency financing to address the foreign exchange risk that emerges from the use of USD-denominated loans.

Remaining uncertainties for financial models

While both PLN and IPPs are well accustomed to the corporate- and project-finance structures outlined above, some uncertainties – which elevate risks perceived by project sponsors and lenders – persist. The first BESS projects deployed in Indonesia will likely demonstrate whether these risks are real or simply perceived, but policy actions are also within reach to alleviate these risks explicitly.

The first uncertainty lies in the presence of foreign exchange risk, which occurs when the currency in which a project generates revenue differs from that of its financing. In the case that the revenue-generating – or local – currency depreciates, investors will face challenges in repaying lenders. In Indonesia, BESS revenues will be denominated in Indonesian rupiah. By contrast, the likely use of imported equipment and involvement of international lenders means that a significant portion of capital expenditure and debt is likely to be denominated in foreign currencies. In PLN-led projects, the state-owned utility depreciation in the value of rupiah relative to foreign currencies results in foreign-currency debt repayments becoming more expensive. In IPP-led projects and joint ventures, which are likely to rely on a higher share of debt to finance BESS investments, foreign exchange risk also has the potential to increase the cost of capital. Lenders may require higher interest rates, shorter loan tenors or third-party guarantees to mitigate currency volatility.

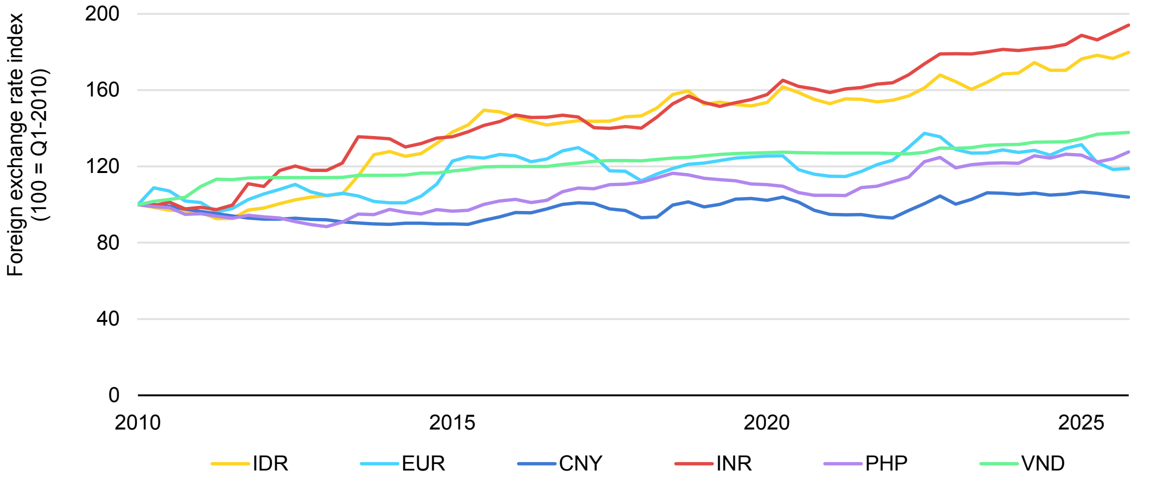
Mitigation of foreign exchange risk in EMDE

Institutional investors evaluate investment risks in EMDE by analysing project-specific risks, sovereign risks, political and regulatory risks, and foreign exchange (FX) risks. Among these, FX risk is consistently cited as one of the single largest barriers for institutional investors to enter EMDE infrastructure markets. While currency risk cannot be completely removed as long as the currencies of a project's financing and revenues do not align, strategies exist to mitigate and distribute it among stakeholders.

One solution is local currency financing, which MDBs and domestic financing institutions have previously provided in Southeast Asia. However, local currency financing is generally not feasible for global commercial investors, whose funding base is raised in hard currency. Another approach is a sovereign – or FX – guarantee provided by the host government or a DFI. In such structures, commercial investors can recover losses from FX mismatches by calling on the guarantee when depreciation exceeds an agreed threshold.

A further option is currency hedging, but the availability of such products varies significantly by market. They tend to be available only for short tenors (6 to 24 months) and at high cost, well short of the ten-plus-year year life of an energy infrastructure asset. Development-backed facilities such as TCX can provide local currency hedging in EMDE, but their hedging capacity remains limited relative to financing needs in the region. In practice, the most sustainable mitigation entails mobilising domestic institutional capital for local currency financing by deepening domestic capital markets and building institutional investor capacity over time.

Foreign exchange movement of selected currencies against the US dollar, 2010-2025



Note: IDR = Indonesian rupiah; EUR = euro; CNY = Chinese Yuan renminbi; INR = Indian rupee; PHP = Philippine peso; VND = Vietnamese dong.
Source: International Monetary Fund (2026) International Financial Statistics Exchange Rates dataset.

An additional uncertainty, this time relating to the implementation of concessional financing, lies in the design of transparent exit strategies. Concessional capital is most effective when it mitigates precise risks for early-stage or first-of-a-kind projects, such as uncertainty in remuneration structures or technology performance. Exit strategies thus define how concessional mechanisms are gradually phased out as markets mature, PLN and IPPs gain experience in developing BESS projects, and commercial lenders grow more confident that successful projects can be replicated. Effective exit strategies also facilitate the recycling of capital – especially by international public financiers and Indonesia's state-backed financial institutions – towards new nascent projects rather than becoming entrenched in long-term commitments. Time-bound concessionality provisions, step-down interest rates or sunset clauses can be used to structure exit strategies. Performance-based triggers, which signal the withdrawal of concessional finance once predefined targets or milestones have been achieved, are also effective. Well-structured exit strategies help to strengthen investor confidence by improving visibility for long-term financing structures, while also facilitating the development of more active commercial markets as these financiers take over when concessional support is no longer needed.

The execution of joint ventures between PLN and IPPs brings forth additional uncertainties in financial structuring. In the RUPTL's ARED scenario, over 10% of hybrid projects and over 50% of standalone BESS projects are allocated to PLN's sub-holdings, which may choose to form partnerships with IPPs. Collaboration between the state-owned utility and private sector developers means striking a balance between the corporate finance and project finance structures, respectively, that each is most familiar with. For instance, PLN usually shoulders construction, operational and technology risks across the asset it develops, while IPPs operating under project finance use contractual agreements with EPC contractors, operators or the SPV itself to distribute these risks. As a result, joint venture agreements must carefully consider which entity bears distinct risks across the lifetime of the project. Another important ambiguity in joint venture structures comes from the potential for PLN to experience conflicts of interest due to its dual positions as a shareholder in the BESS asset's SPV and sole off-taker of its services. In the case that performance standards – which facilitate the provision of availability-based payments and ancillary services – are established, joint venture agreements must transparently outline how PLN is expected to enforce penalties against an asset that it partially owns.

Saguling floating solar PV plant

The Saguling floating solar PV power plant illustrates the advantages that PLN can enjoy by partnering with IPPs, especially for first-of-a-kind projects. Located on the Saguling reservoir in West Java, the 92 megawatt-peak power plant began construction in October of 2025 and – upon completion in November of 2026 – is expected to generate around 130 gigawatt-hours of electricity annually. PLN's subsidiary Indonesia Power, which primarily builds and operates generation assets, paired with Saudi Arabian developer Acwa to develop the plant in 2022. Under their joint venture agreement, Indonesia Power maintains a 51% majority stake in the SPV, called IAT Saguling, with Acwa possessing the remaining 49%. The plant is to be developed under a build-own-operate scheme by Acwa, which has signed a 25-year PPA with PLN as the sole off-taker.

In May 2025, IAT Saguling secured USD 60 billion in financing from the French and German DFIs Proparco and DEG, respectively, as well as the UK bank Standard Chartered for the development, construction and operation of the project. These funds were raised in the context of , which aims to mobilise USD 20 billion in public and private financing to support the country's energy sector ambitions.

Acwa plays a key role in the development of renewable energy projects throughout the Middle East, Africa and Asia. With a portfolio of 52 GW in operational renewable energy projects at the end of 2025, the developer has acquired vast experience in developing wind and solar PV assets, especially in regions that historically rely on high shares of fossil power. The expertise offered by Acwa's involvement boosts bankability while allowing PLN to expand upon its technical capacity to develop similar projects in the future.

Finally, the alignment of capital structures between PLN and IPPs in the context of joint ventures requires careful consideration. While PLN typically borrows based on sovereign-linked sources and may be constrained by balance sheet limits, IPPs broadly rely on highly leveraged, non-recourse debt. As a result, joint venture agreements must determine the levels of debt and equity that are best suited to the SPV's objectives. Moreover, any special rights – such as step-in powers, veto rights or preferential dividend treatment – that accompany PLN's equity stake in the SPV must be explicitly defined. Such transparency enables lenders to more precisely understand the SPV's capital structure, therefore accelerating the achievement of financial close on projects.

Implications for achieving RUPTL 2025-2034 objectives

BESS as a maturing asset class and Indonesia's pipeline

Battery energy storage has matured over the past decade from a niche technology into an established infrastructure asset class. Institutional investors increasingly underwrite standalone and hybrid battery energy storage systems (BESS) in developed markets on the basis of contracted and merchant revenue models, supported by the expansion of variable renewable energy (VRE) and sustained decline in battery costs. Indonesia's latest Rencana Usaha Penyediaan Tenaga Listrik (RUPTL), or Electricity Supply Business Plan, reflects this shift, positioning BESS as a strategic pillar of the power system plan.

A maturing global asset class

Institutional investors' interest in BESS has grown rapidly as returns in mainstream renewables have become increasingly compressed. Competition in utility-scale renewables has increased for both solar photovoltaic (PV) and wind, narrowing the premium available to institutional investors. Against this backdrop, BESS have emerged as an attractive infrastructure investment opportunity, offering elevated return potential, lower competition for assets, and a premium for the complexity of structuring and operating the BESS asset. Moreover, the pairing of BESS with renewable generation – especially solar PV – can enhance project economics by increasing the utilisation rate of the generation asset.

In advanced economies, BESS have moved past the proof-of-concept stage. BESS are considered an investable, bankable asset class across the construction, operational and refinancing stages. Specialised fund managers in Europe successfully executed dedicated BESS strategies over the past decade in listed and unlisted markets. Capacity additions in the United States also accelerated sharply from 2020 to 2025 as a result of falling costs and tax credit support.

In emerging market and developing economies, BESS remain at a nascent stage due to uncertainty around revenue models. Nonetheless, global investors are increasingly looking towards Southeast Asian markets, including Indonesia, for the next phase of growth. Such investors are carefully approaching BESS opportunities by scrutinising the availability and bankability of revenue streams, the credit quality of the off-taker, the regulatory framework governing grid services, and the ability to manage currency and policy risks within an acceptable return profile. Where these conditions can be established, BESS offer a potentially attractive route to clean energy investment in high-growth emerging markets.

Indonesia's BESS pipeline under the RUPTL

The Accelerated Renewable Energy Development (ARED) scenario in the RUPTL 2025-2034 marks a step change in Indonesia's ambition for battery storage. Total planned BESS capacity reaches nearly 8 gigawatts (GW) across standalone and hybrid projects. The pipeline comprises two distinct project archetypes, each with a different function in the power system and different economics.

Two BESS archetypes in the RUPTL 2025-2034

Characteristic	Standalone BESS	Hybrid BESS (solar PV + storage)
Primary system function	Grid stability and VRE integration	VRE integration and diesel displacement
Expected revenue model	Capacity- or availability-based payment	Generation-based PPA
Key economic value	Flexibility, frequency regulation, smoothing	VRE utilisation and fuel cost savings
Applicable regions	Java, Madura and Bali, Sumatra, Kalimantan	Sulawesi, Maluku, Papua and Nusa Tenggara

Notes: Standalone = grid-connected BESS not co-located with generation. Hybrid = BESS co-located with a utility-scale renewable energy project and contracted jointly with it. VRE = variable renewable energy; PPA = power purchase agreement.
Source: Analysis based on RUPTL and industry interviews.

On the large, interconnected grids of Java, Madura and Bali, Sumatra and Kalimantan, standalone BESS dominate with 4.2 GW, 1.1 GW and 0.7 GW storage capacity planned respectively. In these systems, BESS underpin grid stability and renewables integration through frequency regulation, smoothing and ancillary services. The expected revenue model is a capacity- or availability-based payment, a mechanism that has yet to be established in Indonesia for standalone BESS.

The other two island groups, Sulawesi and Maluku, Papua and Nusa Tenggara, are expected to deploy predominantly hybrid projects. In Sulawesi alone, rising electricity demand is driving a pipeline of 1.5 GW of storage capacity paired with utility-scale renewables, with a further 1.5 GW across Maluku, Papua and Nusa Tenggara to support de-dieselisation. In these systems, BESS are combined with renewable generation to displace expensive diesel-fired generation and reduce fuel imports. The revenue model is anchored by long-term PPAs, which current regulations permit for hybrid renewable energy and storage projects.

This distinction is important from an investment perspective. The bankability of standalone BESS projects depends on the development of BESS revenue mechanisms, such as availability payments or ancillary service markets, which have yet to be established in Indonesia. By contrast, hybrid projects can rely on contracted revenues through conventional power purchase agreement (PPA) structures, making them more readily bankable under existing market arrangements. As a result, the near-term investment case for BESS in Indonesia is likely to be driven by hybrid projects in Sulawesi and Maluku, Papua and Nusa Tenggara, while the large-scale deployment of standalone BESS on Java, Madura and Bali, Sumatra and Kalimantan will depend on further evolution of market design and storage remuneration frameworks.

Ownership and financing of BESS in Indonesia

Standalone and hybrid BESS are treated differently under the current regulatory framework in Indonesia with direct implications for the ownership and financing of each BESS archetype. Each therefore draws on a different pool of investors with distinct return requirements, risk appetites and constraints. Understanding this investor landscape is critical for structuring transactions and for designing the regulatory and market frameworks needed to mobilise capital at the scale of RUPTL ambitions.

Ownership: Equity investors

Across both archetypes, PT Perusahaan Listrik Negara (PLN), the state-owned utility, and its subsidiaries are expected to be the primary equity investors, reflecting their central role in delivering the RUPTL pipeline. The two archetypes differ in the breadth of equity participation beyond PLN, and therefore in how fast private capital can accelerate deployment.

For standalone BESS, private sector participation remains largely to be defined. Standalone projects are likely to be classified as grid infrastructure, which in Indonesia remains under PLN’s ownership. This means the pace of standalone deployment is potentially tied to PLN's balance sheet, which faces competing priorities. Private firms could act as engineering, procurement and construction contractors or greenfield developers, building projects for a fee or a development premium, subject to establishing an enabling regulatory framework for such transactions. Other state-owned enterprises (SOEs) and domestic sovereign wealth funds could co-invest in standalone BESS projects or platforms at the holding company level, keeping ownership within sovereign entities, though this too would require regulatory clarity.

For hybrid BESS, the range of potential equity investors is broader. Hybrid projects are considered as generation assets, allowing an independent power producer (IPP) to own and operate the project and sell power to PLN under a long-term PPA. The most likely owners other than PLN are renewable energy IPPs that are already active in Indonesia, bringing project development experience and familiarity with PLN as an off-taker. Strategic investors, including regional utilities and equipment manufacturers, could take stakes to establish a foothold in a growing storage market. Other SOEs and sovereign wealth funds could participate as co-investors alongside private developers, combining sovereign capital with private sector delivery.

The composition of this investor base can evolve as the market and regulatory framework mature. In the near term, hybrid opportunities could attract private developers and IPP platforms prepared to take first-mover risks, including untested procurement processes and limited operating history. As early projects establish operational track records, infrastructure funds and other long-term owners could enter by acquiring stakes in operational assets if permitted, allowing early movers to recycle capital into new development. Over the longer term, institutional investors such as pension funds and insurance companies could consider investment, subject to an established record of contracted revenues, comfort with PLN's credit standing, and the ability to manage currency risk at an acceptable cost.

Financing: Local and international lenders

For standalone BESS, the absence of a dedicated tariff framework means that project-level financing is unlikely to be viable. Without contracted, bankable revenue streams, lenders would not be able to underwrite project debt unless it carried sovereign or equivalent guarantees. Debt is therefore more likely to be raised at the holding company level, for example through a loan to a PLN subsidiary secured against a portfolio of BESS assets. At this level, the most accessible sources of debt are multilateral development bank (MDB) and development finance institution (DFI) loans to the PLN group and export credit agency (ECA) facilities linked to equipment supply, both of which may require sovereign or PLN guarantees.

For hybrid BESS, financing can be structured at the project or portfolio level, drawing on a broader range of lenders. Debt is most expensive during development and construction phases when projects are most exposed to delays and regulatory uncertainty, and improves once a project reaches COD with a long-term PPA in place. Before COD, direct lending is likely to come from MDBs and DFIs, local banks where PLN or sovereign backing is available, and ECA facilities tied to equipment delivery and construction milestones.

Across both archetypes, the lender base could broaden over time subject to early projects establishing track records and the development of a dedicated revenue framework. For hybrid BESS, as early projects reach commercial operation date (COD) and establish payment track records, commercial banks could refinance construction debt on improved terms, with contracted PPA revenues providing sufficient security. Successful refinancings could open the door to portfolio-level debt and institutional lenders, reducing reliance on concessional capital. For standalone BESS, a broader lender base would depend on the development of a dedicated revenue framework, without which lending is likely to remain confined to the PLN group at the holding company level. Broadening the lender base is critical because PLN's borrowing capacity is limited, and the RUPTL pipeline is unlikely to be financed by the PLN group and concessional lenders alone.

Investor and financing framework for Indonesian BESS

	Standalone BESS	Hybrid BESS
Equity	**Primary** • PLN and subsidiaries **Secondary** • Other SOEs and SWFs as potential co-investors at holding company level	**Primary** • PLN and subsidiaries **Secondary** • Renewable energy IPPs • Strategic investors • Other SOEs and SWFs
Debt	***Holding company financing*** • MDB/DFI loans to PLN group • Transition or green bond issuance at PLN or subsidiary level • ECA loans linked to equipment supply (subject to sovereign/PLN guarantee) • Local bank balance sheet lending (subject to sovereign backing) • International bank balance sheet lending (subject to MDB/DFI credit enhancement or sovereign guarantee)	***Project financing (before COD)*** • MDB/DFI direct lending • Local bank direct lending (subject to PLN/sovereign backing) • International bank direct lending (subject to MDB/DFI credit enhancement) • ECA facilities (subject to equipment delivery and construction milestones) ***Project financing (after COD)*** • International commercial banks • Local banks • ECA facilities

	Standalone BESS	Hybrid BESS
Credit enhancement	Not applicable at project level. Sovereign guarantee is the primary de-risking mechanism for holding company lenders	***Before COD*** • MDB/DFI first-loss tranches, subordinated debt, partial credit guarantees, political risk insurance. Without these, international commercial lending is unlikely and local bank participation is often limited. ***After COD*** • No longer required. Contracted PPA revenues provide sufficient security.

Note: SWFs = sovereign wealth funds.

Bankability assessment

This section presents an illustrative bankability assessment of the two BESS archetypes identified in the RUPTL, modelling the revenue levels each would require to meet commercial return thresholds across Indonesia's five main island systems. The analysis quantifies how required tariffs vary by region and over time, tests their sensitivity to capital costs and financing terms, and illustrates where concessional capital would be most effective in mobilising private investment.

Modelling framework

The bankability assessment tests whether the two BESS archetypes identified in the RUPTL, standalone and hybrid BESS, can be financed on terms suitable to both commercial investors and PLN. The analysis models illustrative project cash flows over a ten-year asset life and solves for the minimum revenue level at which each archetype meets target returns and financial thresholds listed under financial assumptions below. It is intended to illustrate the approximate revenue levels required for each archetype and their sensitivity to key variables rather than to replicate project-level due diligence. A full methodology is provided in the Annex.

Standalone and hybrid BESS projects are modelled separately as they provide different services and benefit from different revenue streams. Standalone BESS are modelled as a 100 megawatt (MW), four-hour system and is assumed to earn 100% of its revenue from an availability-based payment, expressed in US dollars per kilowatt per year. Hybrid BESS are modelled as a one-hour battery co-located with a 100 MW solar PV plant and is assumed to earn its revenue through a long-tern PPA, expressed in US dollars per megawatt-hour. The hybrid model captures only the incremental PPA uplift needed to cover the BESS component, treating the solar PV as financed and viable in on its own. The hybrid result should therefore be read as the additional PPA tariff attributable to the battery, not the all-in tariff for the combined project.

Financial assumptions

Parameters	Value	Source
Cost of debt (commercial rate)	7.50%	1, 2
Cost of debt (blended concessional rate)	4.50%	2, 3
Cost of equity	13.5%	1, 2, 3
Gearing (debt share)	65% (standalone); 70% (hybrid)	1, 2, 3
Minimum DSCR	1.5x	1, 2, 3
Debt tenor	10 years	2, 3
Revenue and OPEX escalation	3% per year	2, 3, 5
Corporate tax rate	22%	1
CAPEX (per MW)	4-hour standalone: USD 0.6-1.6 million 1-hr hybrid: USD 0.2-0.6 million Grid connection: USD 20 000-57 000	4, 5
OPEX (annually)	2.5% (BESS); 1.0% (grid connection)	4, 5

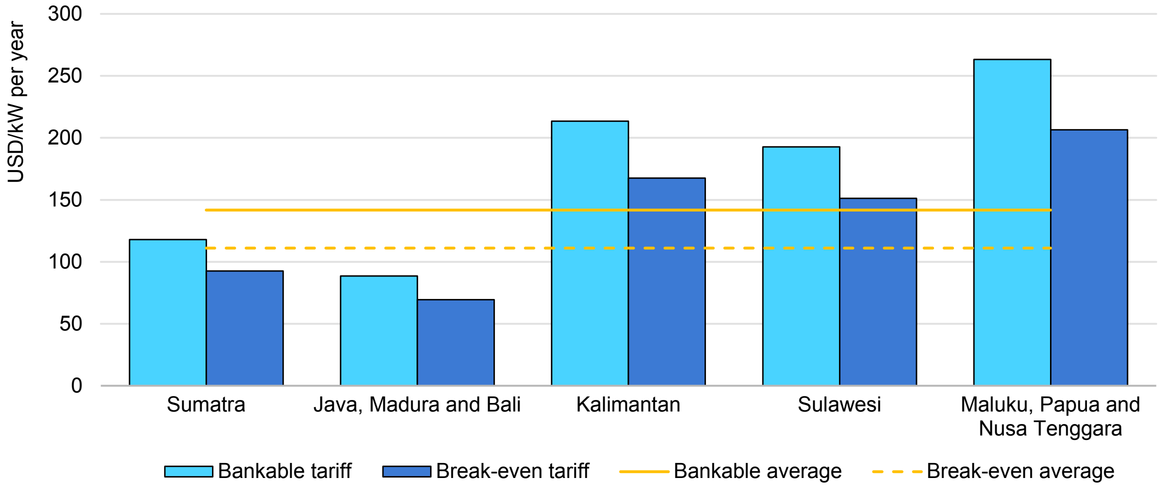
Notes: DSCR = debt service coverage ratio. CAPEX ranges reflect regional variation, with Java, Madura and Bali at the low end and Maluku, Papua and Nusa Tenggara at the high end. Hybrid BESS figures cover the storage and grid connection components only, excluding solar PV. Values shown are for 2025; the model applies declining cost trajectories over 2025-2034, with solar PV falling by approximately 5.5% per year, BESS by approximately 3.5-4% per year, and grid connection costs remaining broadly flat. OPEX is expressed as a percentage of the CAPEX of the respective component.
Sources: 1 = interview with PLN; 2 = interview with PT Sarana Multi Infrastruktur and other commercial lenders; 3 = interview with MDBs and DFIs; 4 = BNEF Energy Storage System Cost Survey (2025) and PLN RUPTL 2025-2034; 5 = interview with global BESS utility companies.

For each archetype, the model builds a full project cash flow, covering revenue, operating costs, debt service, depreciation and tax. It then solves for the lowest revenue level that provides the target equity return over the asset life, while maintaining bankability. The model also calculates a break-even tariff, which is the level of remuneration at which the project covers operating costs and debt service but earns a 0% equity return.

Standalone BESS: Required availability payment

In the absence of an established tariff structure for standalone BESS, this analysis offers a directional guide for regulators and policymakers seeking to quantify and design an availability-based payment for the RUPTL pipeline. For each island system, the financial model solves for the availability payment required to deliver a 13.5% equity internal rate of return, assuming commercial debt priced at 7.5% and a 65:35 debt-to-equity structure.

Average availability payment for standalone BESS with commercial financing, weighted by annual capacity additions, 2025-2034



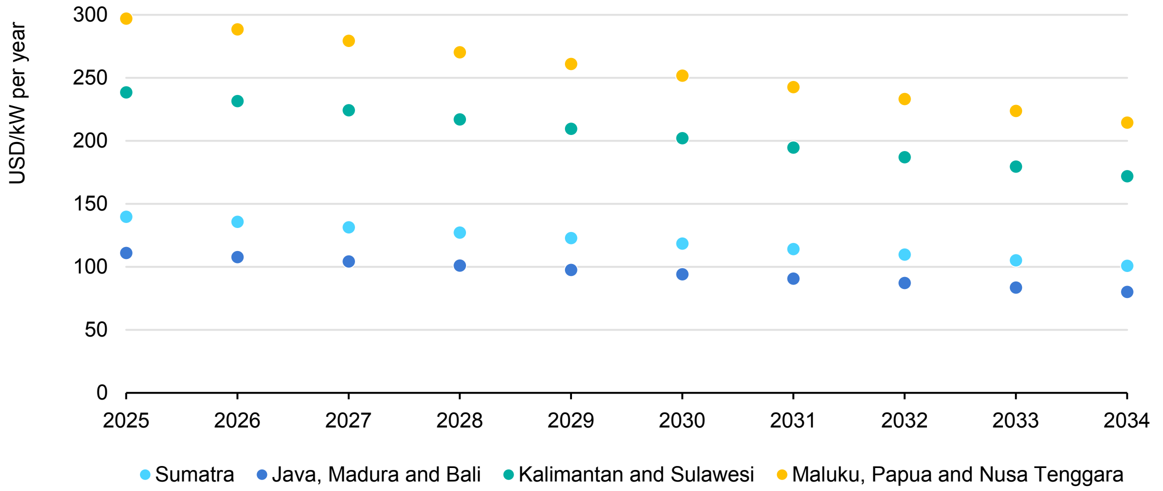
Notes: kW = kilowatt.
Source: IEA internal modelling based on industry consultations. See Annex for the full methodology and sources used in the financial modelling.

The required payment varies widely across the five systems. For projects commissioned in the first year of RUPTL deployment, the target tariff ranges from approximately USD 111 per kilowatt (kW) per year in Java, Madura and Bali, the lowest-cost system, to almost USD 300/kW/year in Maluku, Papua and Nusa Tenggara. Since financing terms are held constant across regions, this near-threefold spread reflects differences in CAPEX alone, driven by the regional cost multipliers applied in the model to capture logistics, delivery and construction cost differences across five island systems.

The analysis also determines each region’s break-even tariff, the level at which a project covers its operating costs and debt service but provides no return on equity. The gap between the two, around 30% across all systems, defines a project's commercial viability. A tariff close to breakeven would offer little equity return and would need to be financed largely by SOEs rather than commercial investors. A tariff below the breakeven point would erode equity investors’ capital return and, once fully exhausted, expose lenders to payment defaults. In practice, lenders would model this default in advance, and would not be able to finance the standalone project at such levels.

The weighted average tariff level lies at around USD 140/kW/year, with each region weighted according to its capacity additions. This indicates the single payment level that would cover the RUPTL pipeline as a whole. Because Java, Madura and Bali and Sumatra account for the majority of the standalone BESS pipeline, the average sits close to their tariffs, well below what the regions of Kalimantan, Sulawesi, and Maluku, Papua and Nusa Tenggara would require. This highlights that a flat nationwide tariff for standalone BESS could potentially fail to attract commercial lenders and investors in the islands with higher BESS CAPEX.

Required availability payment for standalone BESS by region, RUPTL 2025-2034

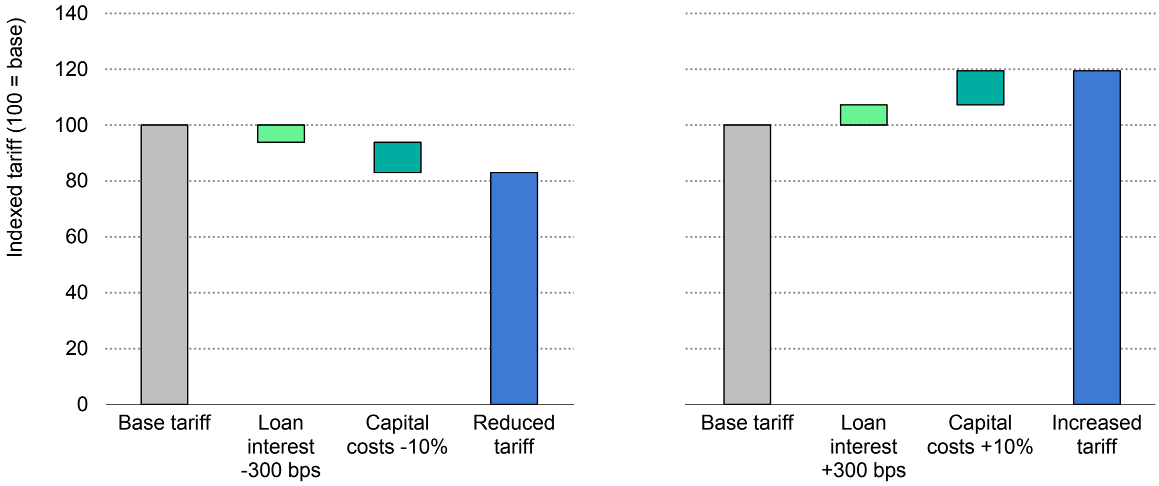


Note: Values show the required payment at the capital costs projected for each year over the RUPTL 2025-2034 planning horizon; commissioning under the plan is expected to phase in over the period.
Source: IEA internal modelling based on industry consultations. See Annex for the full methodology and sources used in the financial modelling

The required availability payment, which is determined upon project commissioning and remains constant throughout the contract's duration, declines steadily across the deployment period in every system, falling by roughly a quarter over the ten-year planning horizon as battery capital costs decline along the cost curve used in the RUPTL-aligned investment scenario. This means a project commissioned later in the decade can achieve the same equity return at a materially lower tariff than an identical project built today.

This trajectory shapes when and where concessional capital would be most needed. The financing challenge is concentrated in the first wave of projects, when CAPEX and the required tariff are highest, especially in Kalimantan, Sulawesi, Maluku, Papua and Nusa Tenggara. Deploying concessional capital strategically could demonstrate the project viability and establish the commercial precedents to crowd in private capital over time. As costs fall and the required tariff converges towards an affordable level for PLN and the government of Indonesia, the concessional capital can be retired over time without undermining the bankability of subsequent projects.

Tariff sensitivity to capital cost and cost of debt for standalone BESS



Notes: bps = basis points. The base tariff is indexed to 100 and reflects fully commercial financing at a 7.5% cost of debt. In the left panel, the 300 basis point reduction corresponds to a blended cost of debt falling from 7.5% to 4.5% through concessional loans. In the right panel, the 300 basis point increase corresponds to the cost of debt rising to 10.5% under an adverse macroeconomic environment. Capital cost changes of ±10% are applied to total CAPEX.

Source: Internal IEA modelling based on industry consultations. See Annex for the full methodology and sources used in the financial modelling

This sensitivity analysis attributes the change in the required tariff to its two principal cost drivers, the cost of debt and CAPEX, applied sequentially from the base tariff and indexed to 100. The left panel presents favourable movements and the right panel adverse movements, showing the contribution of each driver and their combined effect.

On the left, a 300 basis point decline in the cost of debt reflects a scenario where concessional lenders provide the majority of project debt, lowering the blended rate from 7.5% to 4.5%, close to the limit of what concessional capital can achieve. This reduces the required tariff by 6%. A further 10% decrease in CAPEX in line with battery costs declining faster than the base trajectory reduces the tariff by an additional 12%, roughly double the effect despite being the smaller relative change compared to cost of debt. In practice, this suggests that concessional finance has a modest effect on the tariff level with bankability driven primarily by the CAPEX trajectory. The role of concessional capital is catalytic to lower the entry cost of the market's initial projects and to scale back as the CAPEX declines.

On the right, a 300 basis point increase in the cost of debt reflects an adverse macroeconomic environment with the blended rate rising from 7.5% to 10.5%. This is a plausible downside scenario as seen during the Covid-19 pandemic and other periods of emerging market stress. The higher cost of debt raises the required tariff by 7%, and a further 10% increase in CAPEX, reflecting supply chain pressures or cost overruns, raises it by an additional 12%, bringing the combined effect to almost 20%. In practice, this is the scenario investors will stress-test before making investment decisions. A tariff that is bankable only under favourable macroeconomic and market conditions may not attract institutional capital at scale, and the resilience of the revenue mechanisms will be scrutinised closely for the first projects due to limited precedents.

Standalone BESS CAPEX is expected to fall by more than 25% over the next ten-year RUPTL period, which will improve bankability assuming all else being equal. The cost of debt does not offer a comparable improvement. It moves in both directions with macroeconomic conditions and its reduction is often bounded, anchored by long-term sovereign bond yields and the limited availability of concessional capital. This reiterates that the improvement in the standalone BESS investment case is likely to derive from declining technology costs rather than financing terms.

The sensitivity analysis also reinforces the role of concessional capital at the inception stage, supporting early projects and establishing precedents in select island systems rather than serving as a permanent feature of project financing. Without this early support, the initial projects may struggle to reach financial close, keeping risk premiums elevated for subsequent projects. While falling technology costs will improve the economics regardless, the pace at which projects are deployed with private capital depends on establishing these early precedents.

Hybrid BESS: Required PPA uplift

The second archetype under the RUPTL is a hybrid project pairing solar PV generation with battery energy storage. In this configuration, BESS are used to shift a portion of daytime generation into the evening peak. The financial model assumes that the solar PV plant is already fully bankable, and its capital expenditures and operating costs are excluded from the bankability analysis. The model examines how much the additional revenue would be required for the BESS component and its associated grid-connection costs to reach a 13.5% equity return, assuming 70% debt at a 7.5% interest rate, and a minimum debt service coverage ratio target of 1.5x.

The representative configuration used in the model is a 100 MW solar PV plant paired with a 30 MW, one-hour battery used for peak shifting rather than bulk storage function. For each region, the model solves for the annual capacity-based revenue the battery requires and divides it by the solar plant's annual generation to express the result as a tariff uplift to the PPA in USD per megawatt-hour. This uplift should be interpreted as the premium required to convert variable solar output into a firmer, more dispatchable product, not as the all-in tariff for the combined project.

The required uplift at the start of the RUPTL period ranges from approximately USD 8/MWh in Java, Madura and Bali to approximately USD 18/MWh in Maluku, Papua and Nusa Tenggara. This regional dispersion is driven by two competing effects: higher BESS and grid-connection costs in Kalimantan, Sulawesi and Maluku, Papua and Nusa Tenggara raise the revenue the BESS must recover, while the higher solar capacity factors in Sulawesi and Maluku, Papua and Nusa Tenggara spread that cost across greater generation. The required uplift in Maluku, Papua and Nusa Tenggara is over twice that in Java, Madura and Bali, suggesting that government support and concessional finance could be directed towards projects in these higher CAPEX regions.

Required PPA uplift for hybrid PV-plus-BESS by region

Region	BESS CAPEX (million USD)	Target annual tariff (million USD)	Solar capacity factor (%)	Annual PV generation (GWh)	Incremental PPA increase (USD/MWh) in RUPTL 2025	Incremental PPA uplift (USD/MWh) in RUPTL 2034
Sumatra	8.72	1.49	16%	140.2	10.7	7.8
JMB	6.93	1.19	17%	148.9	8.0	5.8
Kalimantan	14.66	2.52	17%	148.9	16.9	12.3
Sulawesi	14.76	2.53	19%	166.4	15.2	11.0
MPNT	18.58	3.19	20%	175.2	18.2	13.2

Notes: GWh = gigawatt-hour; JMB = Java, Madura and Bali; MPNT = Maluku, Papua and Nusa Tenggara. BESS CAPEX is the total CAPEX of the 30 MW battery and its grid connection; the solar PV component is excluded. Target annual tariff is the revenue the 30 MW BESS must earn each year to meet the financing assumptions used in the model. Annual PV generation is calculated from the 100 MW solar plant's regional solar capacity factor. The incremental PPA uplift is the target annual tariff divided by annual PV generation, shown at capital costs prevailing at the start and end of the RUPTL period. Regional CAPEX differences reflect variations in logistics, delivery and construction costs across island systems.

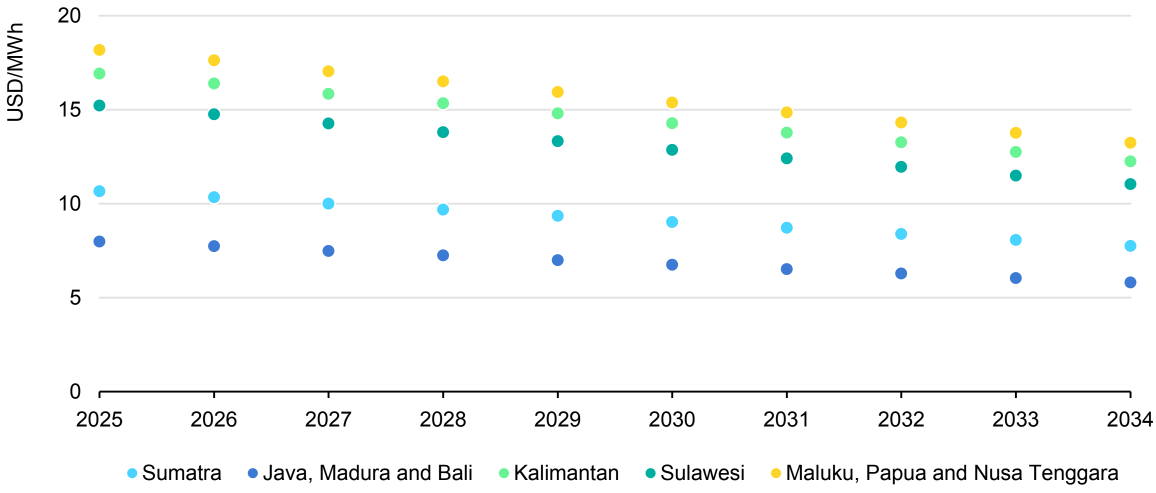
Source: IEA internal modelling based on industry consultations. See Annex for the full methodology and sources used in the financial modelling

The required tariff uplift declines by roughly a quarter in every region over the next ten-year RUPTL period as BESS CAPEX falls along the cost curve used in the RUPTL-aligned investment scenario. By the end of the period, it ranges from approximately USD 6/MWh in Java, Madura and Bali to approximately USD 13/MWh in Maluku, Papua and Nusa Tenggara. Projects commissioned later therefore require a lower uplift than earlier ones.

The economics of hybrid projects ultimately rest on the diesel generation they replace. BESS costs follow a structural declining trajectory, driven by manufacturing scale and continued technology improvement, while diesel generation costs depend largely on fuel prices, which are volatile and difficult to project for the same period. To the extent that diesel costs remain at recent levels or rise, the economics of hybrid projects improve each year as the uplift required to finance hybrid projects falls while the cost of the diesel generation it avoids does not fall with it.

Therefore, commissioning timing for hybrid project is itself an economic variable as BESS costs are expected to decline sharply over the next ten years. Projects commissioned too early bear higher CAPEX, while delayed deployment prolongs reliance on diesel generation and defers the market precedents on which subsequent investment depends. In practice, this implies pacing hybrid BESS deployment with the growth of solar capacity in each system, so that batteries arrive as the need for firming emerges rather than ahead of it.

Required PPA tariff uplift resulting from the addition of BESS to solar PV, RUPTL 2025-2034



Notes: Values show the required tariff uplift at the capital costs projected for each year over the RUPTL 2025-2034 planning horizon; commissioning under the plan is expected to phase in over the period. The uplift reflects the incremental tariff required to finance the BESS component and associated grid connection costs, with the solar plant assumed independently bankable. Financing terms are held constant across regions and over time.

Source: IEA internal modelling based on industry consultations. See Annex for the full methodology and sources used in the financial modelling

To examine what drives the tariff uplift, the financial model tests its sensitivity to BESS CAPEX and the cost of debt in the highest-cost region of Maluku, Papua and Nusa Tenggara and the lowest-cost region of Java, Madura and Bali. Each cell reports the required tariff uplift at a given combination of CAPEX and interest rate with the two regions shown side by side to illustrate the uplift range of the potential pipeline.

Tariff uplift for hybrid BESS under varying CAPEX and interest rates for Maluku, Papua and Nusa Tenggara (top row of each cell) and Java, Madura and Bali (bottom row of each cell) (USD/MWh)

		Annual interest rate				
		10.5%	9%	7.5% (base)	6%	4.5%
CAPEX	+10%	MPNT: 21.7 JMB: 9.5	21.0 9.2	20.3 8.9	19.6 8.6	18.9 8.3
	+5%	20.6 9.1	19.9 8.7	19.2 8.4	18.6 8.2	17.9 7.9
	Base	19.5 8.6	18.8 8.3	18.2 8.0	17.6 7.7	16.9 7.4
	-5%	18.4 8.1	17.8 7.8	17.1 7.5	16.5 7.3	16.0 7.0
	-20%	17.3 7.6	16.7 7.3	16.1 7.1	15.5 6.8	15.0 6.6

Notes: MPNT = Maluku, Papua and Nusa Tenggara. JMB = Java, Madura and Bali.
Each value is the required PPA uplift in USD per MWh, calculated as the annual revenue the BESS component must earn to meet financial targets, divided by the solar plant's annual generation. CAPEX variations apply to the 30 MW battery and its grid connection. The central cell (USD 8.0/MWh) matches the base case in the uplift analysis. Values reflect capital costs at the start of the RUPTL period and would decline over time as battery costs fall.
Source: IEA internal modelling based on industry consultations. See Annex for the full methodology and sources used in the financial modelling

The required tariff uplift is more sensitive to CAPEX than to financing costs. In Maluku, Papua and Nusa Tenggara, the uplift ranges from USD 16.1/MWh to USD 20.3/MWh across the ±10% CAPEX range at the base interest rate (7.5% per year), and from USD 16.9/MWh to USD 19.5/MWh across ±300 basis points in the interest rate at the base CAPEX. The same pattern holds in Java, Madura and Bali, where the uplift sits at less than half the level of Maluku, Papua and Nusa Tenggara, reflecting its lower capital cost. The least favourable outcome modelled for Java, Madura and Bali (USD 9.5/MWh) remains well below the most favourable outcome for Maluku, Papua and Nusa Tenggara (USD 15.0/ MWh), underscoring the case for directing concessional capital support towards the higher-cost systems to achieve regional balance.

Compared with recent utility-scale solar PPAs in Indonesia, the storage uplift is modest in the lower CAPEX islands but more consequential in the higher CAPEX ones. The all-in tariff for hybrid projects is typically lower than the cost of the diesel-fired generation it would displace [based on historical utility-scale solar and diesel-based electricity costs in Indonesia](). The role of concessional finance is therefore narrower than in the case of standalone projects. It is not a precondition for viability, but a way to widen the margin against the displaced supply cost and bring forward the earliest projects in the higher CAPEX islands, where risk premiums are highest.

Implications for scaling the RUPTL pipeline

The modelling results suggest markedly different pathways to scale for the two BESS configurations identified in the RUPTL.

Hybrid solar PV-plus-BESS presents the more immediate opportunity. Because these projects earn contracted revenue under conventional PPA structures, they are bankable under existing regulatory arrangements and clear commercial return thresholds in the systems where they displace diesel generation. The binding constraint is therefore not viability but the availability of construction-stage finance and the risk mitigation instruments such as first-loss tranches, partial credit guarantees and political risk cover, which can facilitate the entry of commercial lenders into the pre-completion phase at scale.

Standalone BESS faces a more fundamental constraint. In the absence of a dedicated remuneration mechanism, there is currently no contracted revenue against which project-level debt can be raised, and deployment depends instead on PLN's balance sheet, MDB and DFI lending, and sovereign-backed borrowing. Establishing an availability-payment framework, even at a modest initial scale, would convert standalone BESS from a balance-sheet obligation for PLN into a financeable asset class for private capital.

Indonesia's BESS financing ecosystem remains at an early stage of development, with limited transaction precedents available to lenders and investors. Initial projects are therefore important not only for the capacity they add but also for establishing contractual, financing and risk-allocation structures that can be replicated across subsequent deployments. The strategic priority is to sequence that support deliberately, concentrating it where the financing gap is widest and the demonstration value is highest, so that public capital catalyses the market rather than substitutes for it.

Key recommendations

Strategies for overcoming investment barriers and mitigating risks

Achieving the objectives of the Rencana Usaha Penyediaan Tenaga Listrik (RUPTL), or Electricity Supply Business Plan, for standalone and hybrid battery energy storage systems (BESS) deployment requires careful consideration of project business models, financing structures and collaboration among key stakeholders. The following chapter provides guidance on how decision makers in Indonesia can address the challenges identified in previous sections of the report.

Strengthen regulatory certainty by explicitly integrating BESS into remuneration frameworks and grid codes

Regulatory uncertainties are regularly cited by key stakeholders as substantial barriers to investor confidence for both standalone and hybrid BESS projects. Without clear definitions of the expectations that the Ministry of Energy and Mineral Resources (MEMR) and PT Perusahaan Listrik Negara (PLN) have for battery performance, developers will struggle to design projects that are adapted to the needs of Indonesia's power sector, while a lack of visibility over cash flows prevents lenders from being able to trust that their loans will be repaid. First, legally classifying standalone BESS as a network asset and the BESS component of hybrid projects as generation assets will send a strong signal to developers on how different assets are expected to be used. Moreover, clarifying whether standalone assets are required to obtain a license to generate electricity for public use (Izin Usaha Penyediaan Tenaga Listrik [IUPTL]), as well as the explicit allowance for BESS components within hybrid systems to benefit from the same IUPTL as their co-located generation assets, will clarify initial uncertainties around project permitting.

An additional area of clarification concerns Indonesia's Kerjasama Pemerintah dengan Badan Usaha (KPBU), or public-private partnership framework, established under Presidential Regulation 38/2015. The regulation provides a procurement and financing pathway for critical infrastructure that is already familiar to Indonesian regulators, developers and financiers. The explicit identification of standalone BESS assets as being eligible for procurement through the KPBU framework, complemented by MEMR regulation detailing remuneration and contractual structures for these assets, can facilitate the operationalisation of PR 38/112 for storage projects which provide essential services to Indonesia's grid.

Next, PLN and MEMR can work together to explicitly define their expectations for the distinct services that BESS assets can provide. These definitions can be integrated into Indonesia's grid code to ensure that all BESS assets will be held to identical performance standards, regardless of whether they are developed by independent power producers (IPPs) or PLN itself. For grid stability and flexibility, decision makers can explicitly define the timescales used to distinguish between renewables smoothing, load shifting and renewables firming; as well as the response times expected for the provision of black-start capabilities or peak capacity injections. Ancillary services, which are typically contingent upon BESS performance rather than sole capacity, can also benefit from clear definitions of system needs: for example, BESS asset operators must be regularly updated on network conditions in order to understand when they might be called upon by PLN to provide frequency regulation services. In some cases, grid codes that were originally designed for thermal generation assets must also be adapted to reflect the unique abilities of BESS. For instance, existing grid codes include both ramp rate limitations, which are intended to protect the network from sudden spikes in injection, and primary frequency response obligations, which establish expectations for assets to step in when network frequency reaches unhealthy levels. These specifications are in direct conflict with one another, and BESS operators would benefit from a clear hierarchy in how they apply to storage assets.

Finally, specific remuneration frameworks for each of the services that PLN expects to receive from BESS assets must be defined. Grid flexibility and stability services, which will generally be procured through standalone systems, can be integrated directly into tolling agreements that are based on asset capacity. However, current requests for proposals (RFPs) tend to stipulate the provision of ancillary services without clarifying how they will be remunerated. The separate provision of ancillary services procurement agreements (ASPAs), in which the type and quality of ancillary services is clearly defined, would grant BESS developers and operators the option to engage in revenue stacking. Moreover, the contractual separation of essential flexibility services (through tolling agreements) and ancillary services (through ASPAs) also enables operators to gain experience in handling their BESS assets by focusing solely on the former throughout the first years of the project, while then having the option to introduce the provision of ancillary services – which come with additional operational complexity – once they have acquired sufficient expertise.

Under current power market frameworks, the ability for BESS operators to engage in market-based energy arbitrage is limited. However, over the longer term, MEMR may consider implementing more granular time-of-use electricity pricing, which would then lead to opportunities for energy arbitrage. As the country integrates more variable renewable energy into its power sector, time-of-use pricing will also strengthen the business case for hybrid projects that can extract more value from solar photovoltaic (PV) and wind generation, which come at near-zero variable costs.

For the development of standalone systems, prioritise long-term system needs

Standalone BESS projects in Indonesia currently face more bankability challenges than hybrid configurations due to the absence of regulation specifically recognising standalone storage systems as network assets. The RUPTL allocates over 80% of standalone capacity additions to PLN and its sub-holdings for development, which translates to an estimated USD 3.4 billion in investment needs to 2034. However, competing priorities to develop other generation and network projects, in addition to balance sheet constraints and borrowing limitations, mean that PLN is unlikely to be capable of financing each of these projects itself.

An assessment of RUPTL projects indicates that the tariff required to achieve bankability for standalone projects is more sensitive to capital costs than to financing costs; given that BESS capital costs are expected to decline by around 30% from 2025 to 2034, this is a positive result. However, additional steps can be taken to minimise capital costs, such as the procurement of BESS equipment in bulk orders to take advantage of economies of scale. Moreover, PLN can benefit from declining costs by addressing battery degradation through capacity augmentation partway through the project's lifetime, rather than oversizing project capacity at commercial operation date (COD). Finally, the careful consideration of the storage durations used for standalone assets can significantly reduce overall capital expenditures. While the RUPTL plans to prioritise four-hour storage duration assets for its standalone projects, it also intends to use these assets mainly for load smoothing and ancillary services, which can generally be performed over much shorter charge/discharge cycles. In 2025, a doubling in storage duration led to a 1.7-fold increase in per-megawatt capital costs. As a result, shifting to a combination of two-hour and one-hour standalone storage duration assets for its standalone projects has the potential to save PLN an estimated USD 1 billion, while broadly maintaining the utility's ability to benefit from improved grid stability and flexibility.

The status of standalone BESS as nascent technologies within Indonesia's power sector means that early projects may require several years of operation before becoming profitable. However, this possibility should not deter PLN from prioritising these projects as strategically important investments. While early projects will face tighter economics, they will also create value by improving PLN's operational experience and informing regulatory adjustments, ultimately reducing risks and improving bankability for subsequent investments. For PLN, moving forward on standalone BESS projects today, rather than waiting for capital costs to decline, will offer benefits to grid flexibility and power quality that will only become more important as demand for electricity in Indonesia grows rapidly.

Crowd in commercial financing for hybrid projects by de-risking the early stages of BESS project development

In contrast to standalone BESS configurations, hybrid systems are already clearly recognised by Presidential Regulation 112/2022 and MEMR Regulation 19/2025. As a result, project developers and financiers have relatively clear visibility over how MEMR and PLN envision remuneration structures for these projects. The standardisation of power purchase agreement (PPA) contracts, however, would give project developers and lenders greater foresight into detailed project cash flows, which would allow them to more confidently agree upon investment plans, financing products and equitable risk-allocation structures. Transparent PPA contracts should be developed in collaboration among MEMR, PLN and key renewables developers and used across all RFPs. This level of consistency will also help developers to accurately understand MEMR's and PLN's expectations around asset performance.

The main obstacle that hybrid projects now face in Indonesia relate to their abilities to access financing during their development and construction phases. Among many existing facilities, including the Indonesia–Sustainable Least-Cost Electrification (ISLE) programme provided to PLN by the World Bank Group to support the deployment of renewable and BESS projects, loans become available only upon the achievement of agreed results, which usually occurs at or after COD. However, PLN's equity alone may not be sufficient to support projects through development and construction.

This "valley of death" challenge is even more present among IPPs, which rely on commercial lending to finance their projects. The cost of debt from commercial banks is likely to be at least 7.5%, placing additional pressure on project cash flows to meet debt servicing requirements. However, public support from domestic or international financiers can play a key role in supporting hybrid projects through their early stages. Interventions such as guarantees that specifically address pre-COD risks or the provision by international public financiers of subordinated debt through the development and construction phases can go a long way towards improving project bankability. Rather than replacing commercial financing, these mechanisms serve to enable it by supporting the very phases of BESS projects that commercial lenders see as the most risky. Moreover, when applied to the first hybrid projects in each region, they can rapidly improve bankability for the remainder of the RUPTL's hybrid project pipeline by demonstrating that the risks perceived by commercial financiers in the development and construction phases are often unrealistically high.

Prioritise developing the RUPTL's first BESS projects in the regions where they can most easily achieve bankability

Identifying the regions where BESS projects are most likely to achieve bankability is critical to accelerating early deployment and thus improving investor confidence. Location – especially a project's degree of isolation from national grid infrastructure – has an important role in determining project costs and services delivered. Before venturing into full-scale projects, PLN and MEMR can develop strategic pilot projects that enable them to develop experience with operating BESS assets and strengthen local operations and maintenance capacity, all while creating a replicable model for larger deployments.

The RUPTL's first standalone projects are most likely to succeed in the region of Java, Madura and Bali, where grid infrastructure is most developed and electricity demand is highest. Taken together, this region is best suited to allowing standalone systems to prove their value by providing essential grid services such as load smoothing, peak capacity reserves and frequency regulation. Careful intra-regional planning can also allow standalone BESS assets to be optimally placed so that they can also provide congestion relief services when transmission and distribution networks are overwhelmed.

For hybrid project configurations, early opportunities are likely to be most successful in the region of Sulawesi, which generally receive the highest levels of solar irradiation in Indonesia. As a result, strong generation profiles lead to more robust project economics. The costs of project development in this region is also closely aligned with Indonesia-wide averages, meaning that they are not expected to result in significant burdens on system Biaya Pokok Penyediaan (BPP), or average cost of electricity supply. Growing electricity demand makes Sulawesi a strong candidate to demonstrate the ability of hybrid assets to turn intermittent solar PV generation into reliable power while meeting expectations for the internal rate of return and supplying at a lower cost than diesel generators.

Taken together, the careful consideration of suitable locations for pilot projects – Java, Madura and Bali for standalone systems and Sulawesi for hybrid assets – can play a substantial role in lowering the cost of capital for future projects. Such initiatives allow MEMR and PLN to gain the experience necessary to tackle more complex projects in the isolated region of Maluku, Papua and Nusa Tenggara.

Leverage concessional financing to support de-dieselisation initiatives in Maluku, Papua and Nusa Tenggara

Concessional financing will play an essential role in de-risking Indonesia's first BESS projects, especially in eastern regions where system needs are high but projects struggle to reach commercial bankability. In particular, early projects in Maluku, Papua and Nusa Tenggara face higher costs due to a greater degree of isolation and limited system size. Moreover, hybrid projects that are intended to contribute to PLN's de-dieselisation initiatives face tight project economics when they are replacing operational diesel generation assets. As a result, concessional instruments are necessary to absorb risks that are currently too high for commercial financiers to take on.

Targeted support through the provision of low-interest loans, longer loan tenors, grants or first-loss guarantees can significantly improve financing costs for BESS projects: while concessional interest rates help to reduce the burden of debt service payments in a project's early years, long-tenor loans help to align repayment periods with the operational lifetimes of BESS assets. In regions with relatively higher degrees of grid infrastructure development, such as Java, Madura and Bali, lower financing costs mean that projects may not require concessional loans to achieve bankability. However, support in the form of technical assistance, capacity building and policy design can help MEMR and PLN more quickly acquire the experience needed to deploy BESS projects at scale.

The impact of concessional finance is maximised when it is deployed to address precise risks or phases of the project lifetime that create obstacles to project bankability. For instance, loans offered on concessional terms can be used to cover the costs of feasibility studies, system needs assessments, or logistics and construction in isolated regions. The mitigation of currency risk through the provision of loans in Indonesian rupiah can also go a long way towards reassuring lenders that BESS assets will be capable of generating sufficient revenues to service loans. When used to mitigate specific risks, concessional support facilitates the successful development of projects that can then be replicated using traditional financial products.

Although concessional support is most important for early-stage projects, it is expected that some level of below-market-rate financing will be necessary throughout the 2025-2034 timeline. This results from the fact that new project types and locations are gradually phased in, which means that PLN and developers will regularly face challenges that they have not previously encountered. However, all concessional support must be paired with transparent exit strategies to avoid long-term dependence and facilitate the recycling of capital into new projects. The utilisation of exit triggers, such as the deployment of a defined level of BESS capacity, the successful operation of an asset over a defined number of years, or the stabilisation of revenues under BESS-specific regulatory frameworks, is a structured approach to preventing the risk of dependence. This being said, it is also important to gradually step-down concessional funding, rather than removing it too suddenly, once these triggers are activated.

Establish a working group comprising key stakeholders to support implementation of BESS in Indonesia

Concrete alignment among Indonesia's key institutions, such as MEMR, PLN, the Ministry of Finance, Danantara and varied financial institutions, is frequently cited as a much-needed initiative for accelerating BESS deployment. Developers and financiers, especially international ones, seek demonstrations of collaboration among governments, utilities and industries in order to mitigate concerns around political or regulatory risks. Because PLN must deliver electricity at affordable rates within strict financial constraints, close co-ordination with MEMR is essential to ensuring that BESS-related regulations accurately reflect system needs and costs. The joint preparation of a BESS deployment roadmap, for instance, which directly translates RUPTL ambitions into policy adjustments, would go a long way towards demonstrating alignment between MEMR and PLN.

Co-ordination with developers and financiers, who frequently bring a high degree of technical experience in developing storage technologies, is also essential. Such collaboration can take the form of a regular consultations or structured dialogues through the creation of a BESS development task force, which includes representatives from all relevant stakeholders. Indonesia's sovereign wealth funds, especially Danantara, can also play a valuable role in bringing together key stakeholders and translating MEMR's policy objectives into tangible frameworks that are consistent with PLN's financial and operational constraints.

Finally, Indonesia's BESS deployment ambitions are not isolated from those of neighbouring countries. Strengthening co-ordination between Indonesia and other Southeast Asian countries can be mutually beneficial to addressing obstacles that exist on a regional scale: for example, the creation of regional supply chains and manufacturing hubs can ultimately lower capital costs for BESS technologies across all Southeast Asian countries and enhance resiliency. Similarly, Southeast Asian countries can work together to jointly develop battery recycling facilities that address risks related to battery waste treatment. Given its significant expected growth in electricity demand and robust momentum to move forward on BESS development objectives, Indonesia is well-positioned to become a leader in Southeast Asia's emerging BESS market while ensuring that early projects receive the support necessary to succeed.

Summary of priority actions

The recommendations listed above can be translated into distinct actions to be undertaken by government, PLN, project developers and financiers. Short-term actions emphasise the formal integration of standalone BESS into Indonesia's grid code and regulatory frameworks, in addition to the development of pilot projects that resolve early uncertainties around system design, operation and remuneration. Over the medium term, actions primarily focus on unlocking additional revenue streams, especially through the provision of ancillary service procurement agreements. Finally, long-term actions address challenges that are more likely to arise after Indonesia's first BESS projects are operating, such as end-of-life treatment and recycling. Throughout all actions, co-ordination among stakeholders through formal working groups, as well as collaboration with other member states of the Association of Southeast Asian Nations (ASEAN) to establish regional supply chains, is critical to ensuring that Indonesia's battery energy storage fleet is developed in a sustainable and cost-effective manner.

Precise actions for government, PLN, developers and financiers

Timeline	Action	Challenge(s) addressed
Short term (1-2 years)	***System integration of BESS*** • Standardise the technical characteristics expected for BESS assets connected to PLN's national grid • Clearly define the services that BESS are expected to provide • Ensure that the national grid code considers BESS functionality, especially regarding ramp rates and frequency response obligations • Develop pilot projects: standalone in Java, Madura and Bali and hybrid in Sulawesi	Operational risk and lack of BESS design standards
	Remuneration and contractual structures • Create standardised tolling agreements for standalone projects and PPA frameworks for hybrid projects, clearly specifying which services are requested and their remuneration mechanism • Define how ownership of BESS assets is determined at the end of contractual periods	Insufficient visibility over revenue streams for network services; uncertainty over end-of-life responsibilities

Timeline	Action	Challenge(s) addressed
Short term (1-2 years) (continued)	***Regulation*** • Legally recognise standalone BESS as a network asset • Clarify whether standalone BESS assets require an IUPTL to operate • Clarify whether IUPTLs obtained for hybrid projects cover both the generation and storage assets	Lack of regulatory specificity for standalone BESS
	Access to financing • Explore opportunities to give/receive concessional support through both financial products and technical assistance • Create financial products that prioritise support during the development and construction phases • Prioritise offering rupiah-denominated loans where possible	High cost of capital; lack of access to pre-COD financing; and currency risk
	Economy-wide and regional co-ordination • Form a working group comprising representatives from government, PLN, developers and financiers, and establish regular consultations	Knowledge sharing and stakeholder engagement
Medium term (3-5 years)	***System integration of BESS*** • Clearly define technical characteristics and performance standards expected for ancillary services	Lack of clarity around expectations for ancillary services
	Remuneration and contractual structures • Create standardised ancillary service procurement agreements	Insufficient visibility over ancillary services remuneration
	Regulation • Establish a methodology for integrating the services provided by BESS into system BPP • Explicitly permit BESS assets to engage in revenue stacking	Capturing the value of BESS in overall system costs; ability to receive multiple revenue streams

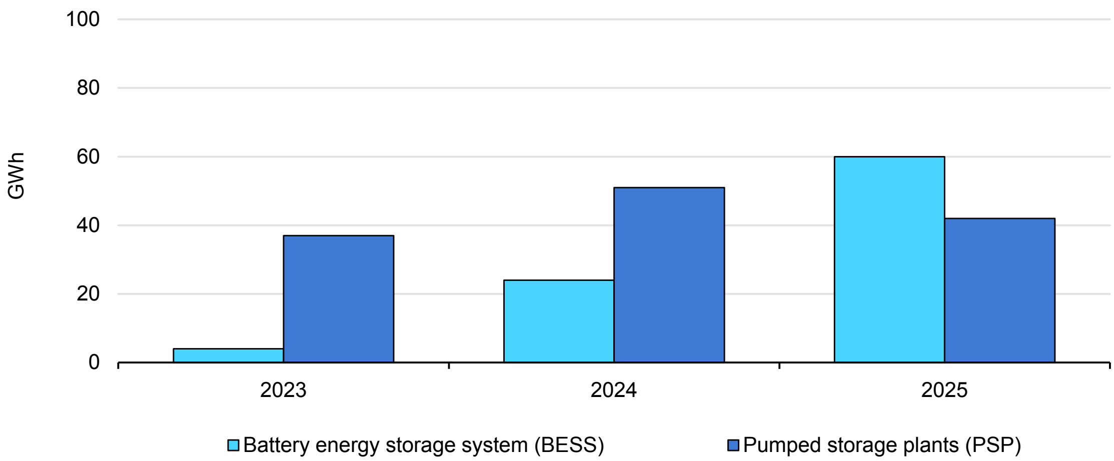
Timeline	Action	Challenge(s) addressed
Medium term (3-5 years) (continued)	***Access to financing*** • Define appropriate exit triggers for concessional financing	Recycling of concessional capital
	Economy-wide and regional co-ordination • Publish a joint roadmap that establishes Indonesia's long-term vision for the role of BESS in its energy and industrial strategies • Establish regular knowledge sharing with other ASEAN members states	Demonstrated commitment by MEMR and PLN to a long-term BESS strategy
Long term (5+ years)	***Regulation*** • Introduce granular time-of-use electricity pricing to open up opportunities for energy price arbitrage • Establish recycling standards for lithium-ion batteries used in stationary storage	Facilitate energy-based payments; decommissioning risk
	Economy-wide and regional co-ordination • Co-ordinate with other ASEAN member states to create a regional supply chain and recycling system for BESS technologies	Development of domestic or regional supply chains

Annex

India case study

India's BESS market has moved from pilot projects to large-scale procurement, supported by national planning, competitive tendering, viability gap funding and state-level policies. The Central Electricity Authority's revised Resource Adequacy Planning projects a requirement of 80 gigawatts (GW)/321 gigawatt-hours (GWh) of BESS and 94 GW/567 GWh of pumped storage by 2035. Moreover, 102 GWh of energy storage system (ESS) capacity was tendered in 2025, a year-on-year jump of 1.4 times in terms of cumulative capacity. BESS tendered capacity increased even faster, rising from 4 GWh in 2023 to 60 GWh in 2025. By March 2026, cumulative ESS tenders reached 247 GWh, including 111 GWh of BESS. The market also broadened in 2025, with around 50 new players entering the BESS developer space. Alongside established power producers such as JSW Energy, Greenko and Torrent Power, newer entrants included infrastructure investors such as IndiGrid; engineering, procurement and construction (EPC) companies such as Pace Digitek and Bondada Engineering; and emerging renewable energy developers such as Oriana Power and Kintech Synergy.

Cumulative tendered capacity for battery energy storage in India, 2023-2025



Source: India Energy Storage Alliance (2026), Annual Report 2025.

India's storage procurement has diversified across tenders for standalone BESS, solar PV-plus-BESS, and firm and dispatchable renewable energy. According to the Institute for Energy Economics and Financial Analysis (IEEFA), standalone BESS accounts for around 60% of the tendered standalone ESS capacity, with a majority of projects addressing daily peak management and short-term grid flexibility with two-hour storage duration technologies. This growth coincided with declining battery prices and supportive policy measures such as the introduction and expansion of the viability gap funding for standalone BESS projects.

National agencies such as Solar Energy Corporation of India Ltd.[1], National Thermal Power Corporation, National Hydroelectric Power Corporation Limited and Satluj Jal Vidyut Nigam[2] have administered large procurements, while state utilities and distribution companies are increasingly active. State-level targets are also emerging: Andhra Pradesh has targeted 25 GWh of BESS by 2029; Bihar 4.5 GWh of BESS by 2030 and Maharashtra's 2026 policy targets an estimated equivalent storage capacity of 100 GWh per day by 2035/36.

India's regulatory framework treats energy storage as part of the power system, with classification linked to use case. Storage assets can be developed, owned, leased or operated by generators, transmission licensees, distribution licensees or independent storage service providers. This allows BESS to function as generation-linked storage, a network asset, a distribution-level resource or a standalone storage service. Supply-side incentives focus on domestic manufacturing and value addition. For example, India's production-linked incentive programme for advanced chemistry cells supports 50 GWh of advanced chemistry cell manufacturing. Battery testing, safety and waste-management frameworks are developing through Central Electricity Authority safety regulations, Ministry of New and Renewable Energy battery-testing guidance, and battery waste-management amendments.

Standalone BESS business models remain dominated by build-own-operate (BOO), EPC and build-own-operate-transfer (BOOT). The India Energy Storage Alliance's first-quarter 2026 energy storage market tracker records 67 GWh of cumulative standalone BESS tenders from March 2022 to March 2026, of which 44.3 GWh used BOO, 14.4 GWh EPC and 2.1 GWh BOOT.

[1] Solar Energy Corporation of India provides a payment security mechanism to de-risk developer cash flows by ensuring timely payments through a structured security fund and intermediary contracting with distribution companies.
[2] Satluj Jal Vidyut Nigam is a central public sector undertaking under the Ministry of Power that develops hydropower, renewable energy and storage projects.

Standalone BESS system in New Delhi, India

The 20 megawatt (MW)/40 megawatt-hour (MWh) project in Delhi by BSES Rajdhani Power Limited (BRPL) and the Global Energy Alliance for People and Planet (GEAPP) represents one of India's first commercial utility-scale standalone, grid-connected BESS deployments. The project is implemented through a dedicated special purpose vehicle (SPV) under a 12-year BOOT structure. The SPV finances, builds, owns and operates the BESS asset, supported by GEAPP's concessional debt (70% CAPEX at 1% interest) and private equity. BRPL provides land, grid connectivity and charging energy; schedules dispatch; and pays the SPV a fixed annual capacity tariff, with ownership transferring to BRPL at the end of the contract period. The project discovered a final tariff of INR 58 (Indian rupee) lakh/MW/year (approximately USD 62 000/MW/year), reflecting the risks and costs associated with an early-stage BESS market.

The project provides key lessons for emerging markets on enabling early-stage BESS deployment. The SPV-based model helps ring-fence project risks, mobilise private capital and enable utilities to access storage services without upfront ownership or operational risks. The project also highlights the importance of early regulatory engagement, technical assistance and blended finance in establishing bankable BESS markets. Estimates suggest projected benefits around 1.5 times tariff cost[1] over the lifetime of the asset. Energy arbitrage is estimated to account for the largest share (~75%), followed by ancillary services and deferral of capital expenditures.

[1] Projected benefit stack versus tariff (INR lakh/MW/year). The benefits were estimated based on the monetisable value streams and energy modelling on BRPL's 2023 fiscal year data.

Standalone BESS tariffs have fallen sharply as tender volumes have risen. Between 2022 and 2025, average standalone BESS tariffs declined by roughly 80%, falling from INR 10.8 lakh/MW/month (USD 11 500/MW/month) to INR 2.2 lakh/MW/month (USD 2 342/MW/month) for two-hour projects. The IEEFA estimates benchmark tariffs of INR 2.3 lakh/MW/month (USD 2 449/MW/month) for two-hour, two-cycle, twelve-year systems and INR 4.3 lakh/MW/month (USD 4 578/MW/month) for four-hour, one-cycle, twelve-year systems.

Public finance has been central to standalone BESS procurement. The Viability Gap Funding (VGF) scheme was introduced to address the early-stage bankability challenges of standalone BESS projects, where high upfront costs, limited operating history and evolving revenue models constrain private financing, especially prior to the commercial operation date (COD). Concessional support could help bridge the financing gaps and enable greater IPP participation, especially in emerging markets such as Indonesia. VGF 1 (2023) supported 13.2 GWh with around 30% of CAPEX support and an estimated INR 3 760 crore (approximately USD 4 billion) support envelope. VGF 2 was launched in 2025 to support 30 GWh, funded through INR 5 400 crore (approximately USD 5.8 billion)VGF-supported BESS projects have also begun to include localisation requirements: the second VGF tranche requires 20% domestic value addition for BESS using the VGF. Of the 2025 standalone BESS allocations, VGF support was present in most large tenders. Commercial financing, however, remains conservative. The IEEFA indicates lender return expectations of around 15-20% internal rate of return for BESS projects, reflecting limited operating history, battery degradation risk, uncertain augmentation costs, input-price volatility and off-taker risk. The structure of the BRPL-GEAPP project, described above, shows how concessional debt can lower tariff discovery: 70% of CAPEX was financed at 1% interest, enabling commercial equity participation.

India's next phase is focused on converting a large tender pipeline into operational assets while preserving tariff sustainability and ensuring long-term system value. As of April 2026, operational BESS capacity stands at approximately 5.9 GWh, indicating that the sector is still at an early execution stage despite a rapidly expanding pipeline. Going forward, the focus will be on strengthening project bankability and ensuring sustainable tariffs through improved bid design, cost-reflective benchmarking and robust payment security mechanisms. Greater clarity on technical and contractual frameworks, including performance standards and augmentation requirements, will further enhance investor confidence. In parallel, sharper definition of use cases across peak management, congestion relief and ancillary services will help optimise system value and improve dispatch outcomes, enabling India's BESS ecosystem to scale in a structured and financially sustainable manner.

Methodology

Investment needs and sources of finance

Overview

Identifying investment needs is an essential step to successfully deploying a pipeline of BESS projects, as doing so enables decision makers to more accurately weigh the costs and benefits of development, identify opportunities for cost savings, and prioritise investments that will have the highest impact per dollar. While PLN's RUPTL 2025-2034 estimates that total investment for the development of Indonesia's full power sector will be IDR 2 780 trillion (USD 155 billion), the document does not provide investment totals for individual technologies. As a result, this report models investment needs for the RUPTL's BESS pipeline under the Accelerated Renewable Energy Development scenario.

The report then goes on to connect modelled investment needs with the IEA's existing sources of finance model, which provides further breakdowns on investment sponsorship, instrument and financing.

Data sources

The IEA exclusively uses reputable and peer-reviewed data sources in its modelling of investment needs and sources of finance. Capacity additions of BESS are drawn directly from data tables in Chapter V of PLN's RUPTL 2025-2034. Technical specifications on system design, including battery storage duration, storage-to-generation sizing ratios, battery lifetimes and degradation rates are also acquired through the RUPTL, when available, or through direct communication between the IEA and PLN. Additional technical specifications are gathered from Benchmark Mineral Intelligence datasets.

Capital cost data for lithium-ion BESS are gathered from Bloomberg New Energy Finance (BNEF)'s Energy Storage System Cost Survey (2025). Capital expenditure includes the cost for battery packs and racks, balance-of-system components, developer margins, and overhead. Additional data on grid connection costs are also sourced from the BNEF's cost survey. The estimation of investment needs in this report does not include the cost of land acquisition, operations and maintenance (O&M), decommissioning, or recycling of BESS components.

The sources of finance analysis utilises the financial characteristics of BESS projects led by PLN and independent power producers (IPPs). The main sources of data used for this analysis include:

- S&P Capital IQ – corporate balance sheets and ownership. Primarily used to calculate debt and equity shares for PLN-led projects and joint ventures.
- Green Street Infrastructure – transactions, ownership and financing of BESS assets at the project level. Primarily used to estimate debt and equity shares for IPP-led projects.
- World Bank projects database – project-by-project descriptions of BESS projects financed by the World Bank Group and quantitative financing figures. Primarily used to estimate the share of concessional financing in total BESS project investments.
- Asian Development Bank (ADB) project database – project-by-project descriptions of BESS projects financed by ADB and quantitative financing figures. Primarily used to estimate the share of concessional financing in total BESS project investments.
- Climate Investment Funds, Global Energy Storage Platform (GESP) project list – individual descriptions of GESP-funded projects including descriptions and

concessional funding and co-financing amounts. Primarily used to estimate the share of concessional financing in total BESS project investments.

- The Indonesia technology catalogue – specifications around technical parameters and costs for a wide range of power technologies in Indonesia.

Today, BESS remain a nascent technology in Indonesia and data representing projects in the country are limited. As a result, the models detailed below prioritise Indonesian BESS (standalone and hybrid) projects where available and otherwise use data from similar markets to reinforce data quality. These markets primarily include other Southeast Asian countries, including Cambodia, the Lao People's Democratic Republic (PDR), Malaysia, Myanmar, the Philippines, Thailand and Viet Nam. Data on projects in other middle-income countries, including Brazil, India and South Africa, are also considered.

Investment methodology

The investment model created for this report quantifies annual capital expenditure requirements for both standalone BESS systems and the storage components of hybrid solar PV-plus-BESS projects based on the RUPTL's Accelerated Renewable Energy Development (ARED) scenario. Investment needs are broken down across the RUPTL's five major systems: Sumatra; Java, Madura and Bali (JMB); Kalimantan; Sulawesi; and Maluku, Papua and Nusa Tenggara (MPNT).

First, annual capacity additions for each of these regions are identified based on data tables provided in Chapter V of the RUPTL 2025-2034. Additions are reported in megawatts across most regions, except for Sulawesi and Maluku, Papua and Nusa Tenggara, where they are reported in megawatt-hours. To ensure consistency, additions in these regions are converted to megawatts using an assumed storage duration of four hours – consistent with assumptions communicated by PLN.

Investment needs are highly dependent on the cost of BESS technologies, which are themselves determined by the technical characteristics of the systems installed. Because BESS remain nascent in Indonesia and some technical details remain to be defined by PLN and MEMR, the investment model uses three scenarios to represent the range of costs and resulting investment needed to achieve the RUPTL pipeline. These scenarios are designed as follows:

- **Cost efficiencies scenario**: PLN prioritises the lowest-cost technologies, opting for shorter storage durations (mainly one to two hours) and smaller shares (10%) of BESS capacity relative to solar PV installations. Annual degradation rates are kept low (1%) as a result of strict limitations on battery cycling, and installation costs are minimally variable across regions due to a prioritisation of easily accessible locations.

- **RUPTL-aligned scenario**: PLN adheres to the technical parameters that are implied in the RUPTL, prioritising systems with four-hour storage durations and sizing BESS to 20% of solar PV additions in hybrid projects. Annual degradation rates are 2% and the variation in capital and installation costs across subsystems is proportional to that of system-level BPP (average cost of electricity supply) in 2025.
- **High costs scenario**: The decision to expand into a wider variety of use cases compels PLN to invest in technologies ranging from one- to eight-hour storage durations, and the storage component of hybrid projects is equivalent to 30% of the solar PV component's generation capacity. More frequent battery cycling brings annual degradation rates to 3%, and the expansion into more remote areas results in a higher degree of cost differentiation across subsystems.

Technical parameters defining investment needs scenarios

Scenario	Standalone storage duration	Hybrid storage duration	Annual degradation rate	BESS:Solar PV sizing ratio	Locational multipliers
Cost efficiencies	1 hr: 20% 2 hr: 50% 4 hr: 30% 8 hr: 0%	2 hours	1%	1:5	Limited deviation from country average
RUPTL-aligned	1 hr: 15% 2 hr: 15% 4 hr: 70% 8 hr: 0%	1 hour	2%	1:3	Weights determined by regional BPP relative to country average
High costs	1 hr: 20% 2 hr: 20% 4 hr: 40% 8 hr: 20%	2 hours	3%	1:2	Greater variability across regions

Capital costs are derived from BNEF's Energy Storage System Cost Survey (2025), consistent with all other BESS investment modelling conducted by the IEA. These values include a broad range of system components, including battery packs and racks, balance-of-system equipment, energy management systems, power conversion components, and developer margins and overhead. Global average costs for two- and four-hour systems are provided by BNEF and used to extrapolate costs for one- and eight- hour systems. Given the limited capacity of BESS manufacturing facilities in Southeast Asia, batteries are assumed to be imported primarily from China. Regional variation in system costs, which arises due to different transportation, installation and labour costs, are reflected in each scenario by regional multipliers detailed above.

Grid connection and EPC costs are estimated separately. Global averages for markets outside of China are also extracted from BNEF datasets and scaled to Indonesia based on the ratio of Indonesia's BESS capital costs relative to non-China capital costs. Costs are calculated for two- and four-hour storage durations and linearly extrapolated for one- and eight- hour systems. The same locational multipliers used to differentiate capital costs across regions are applied to grid connection and EPC costs. For hybrid installations, grid connection and EPC costs are proportional to the share of storage capacity in total solar PV-plus-BESS capacity.

Next, an oversizing factor is used to calculate capacity augmentation needs based on annual battery degradation rates defined across each scenario. The oversizing factor is determined according to the following formula:

$$F_O = \frac{1}{(1 - R_D)^T}$$

Where F_O is the oversizing factor, R_D is the annual rate of degradation, and T is the asset lifetime (ten years). Technology degradation is assumed to be addressed by oversizing BESS projects at the beginning of their lifetimes, rather than adding BESS capacity partway through the asset's lifetime. While the latter strategy is expected to result in lower total investment needs due to the continued decline in battery capital costs, the former approach offers a higher degree of price certainty and contractual simplicity. The oversizing factor is applied only to capital costs, and not grid connection and EPC costs, under the assumption that grid infrastructure does not require augmentation.

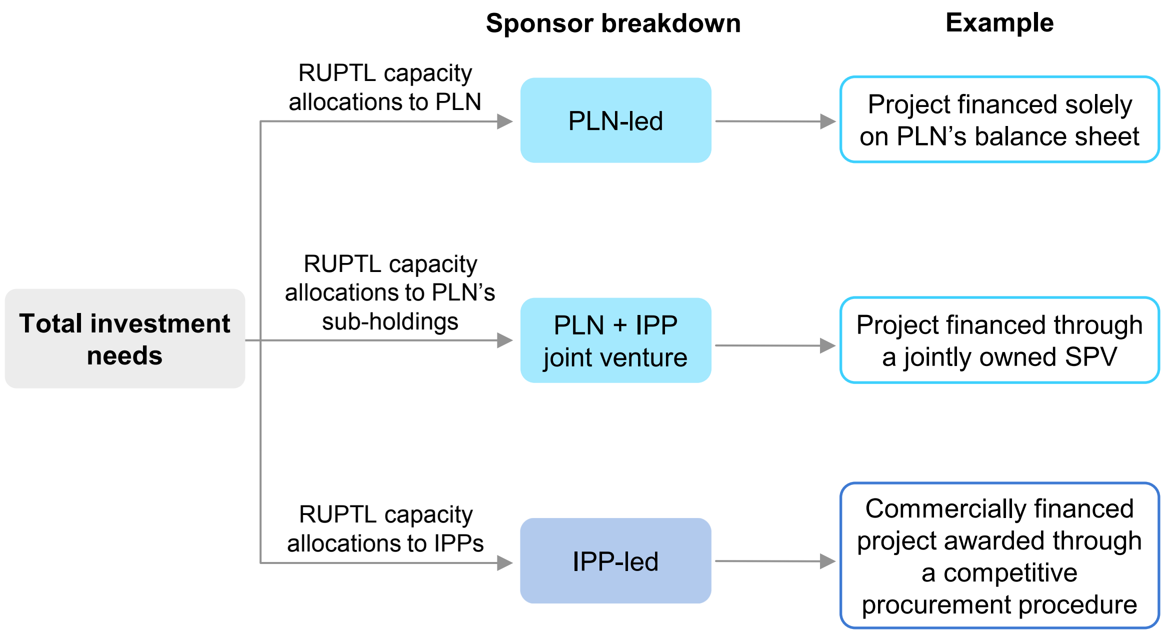
Annual investment is calculated for each region by multiplying annual capacity additions by their corresponding capital cost values. Standalone and hybrid investments are calculated independently and then combined to determine total annual BESS investment by region.

Sources of finance methodology

The IEA's sources of finance model allocates investment requirements across sponsor, instrument and financier types; and was adapted for this report to reflect specific conditions for BESS and Indonesia. These calculations rely on capacity allocations in the RUPTL and debt-equity ratios derived from PLN's balance sheet and existing project finance data.

First, sponsorship is determined according to standalone and hybrid BESS capacity allocations listed in Chapter V of the RUPTL. The document assigns projects to PLN, PLN's sub-holdings (SH-PLN) and IPPs. For hybrid projects, it is assumed that the generation and storage components of each project are developed by the same sponsor(s). As with the investment methodology listed above, megawatt-hour values are converted to megawatts in Sulawesi and MPNT based on an assumed four-hour storage duration. For each region and year, sponsorship shares are calculated by dividing the capacity allocated to PLN and SH-PLN by total additions, with the remainder assigned to IPPs. While capacities allocated to SH-PLN are permitted to pursue joint ventures with IPPs, the RUPTL specifies that PLN is to maintain a majority stake in such arrangements, which is why these additions are considered to be sponsored by PLN. Resulting sponsorship shares are then applied to total investment to determine the portions financed by PLN and IPPs.

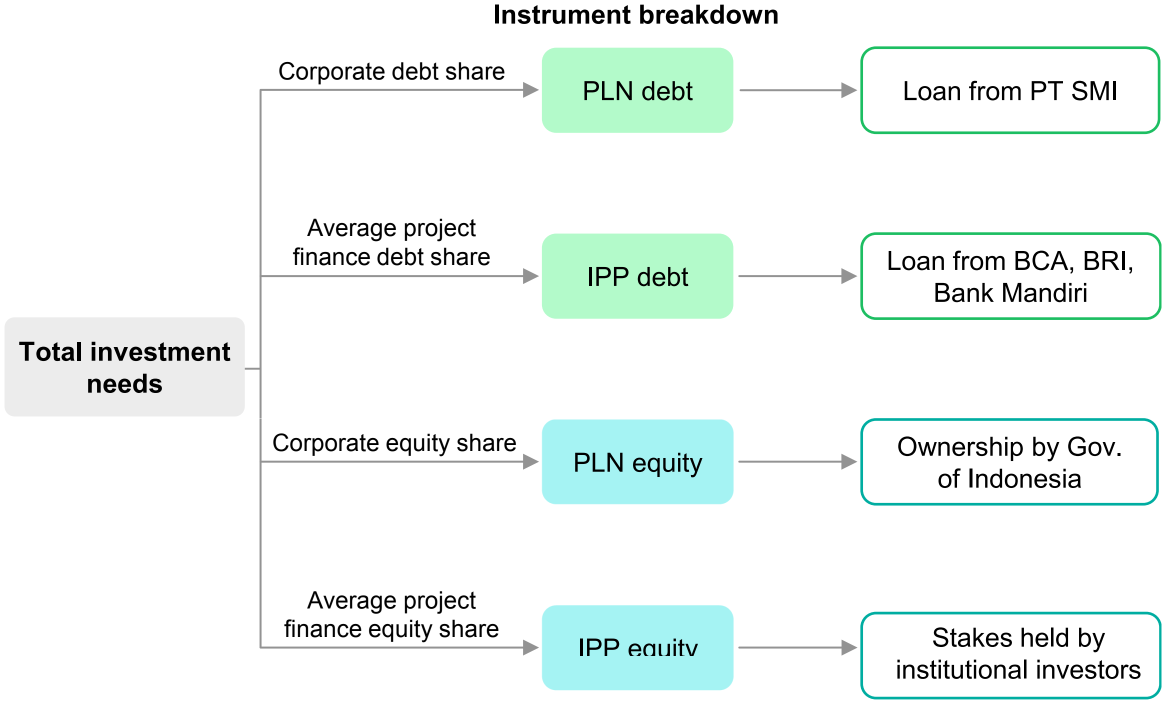
Sponsor breakdown



Note: The RUPTL stipulates that PLN is to retain a majority stake in projects sponsored by joint ventures between PLN and IPPs. Such projects are therefore identified as PLN-sponsored in IEA analysis.

Next, instrument (debt and equity) shares are determined using available project finance data, accessed through Green Street Infrastructure datasets, and PLN's 2024 balance sheet (the most recently published version at the time of analysis), accessed through S&P Capital IQ. Projects sponsored by PLN and its sub-holdings are assumed to be financed on-balance sheet: shares of debt and equity from PLN's balance sheet are therefore applied to PLN's portion of investment. For IPPs, BESS projects are assumed to be financed off-balance sheet. Weighted average debt and equity ratios are therefore calculated based on the financing structures of over 20 solar PV, wind, hybrid and BESS projects across Asia (excluding China, Korea and Japan). Resulting debt and equity shares are then applied to IPPs' portion of investment.

Instrument breakdown



Note: BCA = Bank Central Asia; BRI = Bank Rakyat Indonesia.

Finally, investments are broken down by financier types, which represent the ultimate providers of capital. International public finance (IPF) from multilateral climate funds, export credit agencies, and development finance institutions (among others) are expected to provide a key role in de-risking early projects. As a result, IPF shares are highest in the early years of deployment and decline over time as project bankability improves. The degree of IPF involvement is also likely to vary across regions: for instance, Sumatra and Java, Madura and Bali are expected to require relatively little support due to their mature power systems, while Maluku, Papua and Nusa Tenggara will require more concessional support due to higher project complexity. Shares of IPF are determined based on benchmarks obtained from projects supported by providers of concessional finance, including the World Bank, the ADB and Climate Investment Funds (CIF). The below shares are applied to each region's and year's investments to the level of financing sourced from international providers.

Assumed international public finance shares by year and region

Region	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Sumatra	0%	5%	5%	2%	2%	0%	0%	0%	0%	0%
JMB	10%	5%	2%	2%	2%	0%	0%	0%	0%	0%
Kalimantan	0%	10%	10%	5%	5%	5%	2%	0%	0%	0%
Sulawesi	10%	10%	5%	5%	2%	2%	0%	0%	0%	0%
MPNT	50%	40%	30%	20%	10%	5%	2%	2%	2%	2%

Notes: JMB = Java, Madura and Bali. MPNT = Maluku, Papua and Nusa Tenggara. IPF is to be provided in the first year that capacity additions appear for each region.

Public financing is defined as the equity portion of PLN's investment, consistent with the assumption that PLN's equity is treated as public capital due to its status as a state-owned enterprise. Commercial financing is defined as the sum of PLN's debt portion and all IPP investment, excluding IPF. For each year and region, financing portions are therefore calculated according to the following formulas:

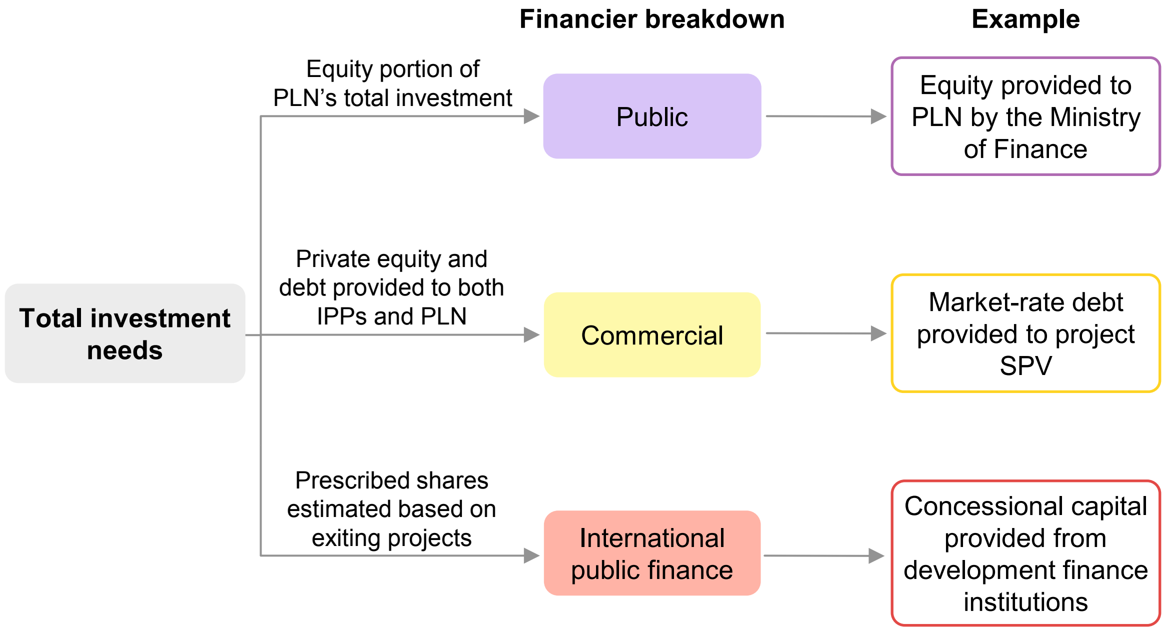
$$F_{IPF} = I \times IPF$$

$$F_{PUB} = I \times \frac{Cap_{PLN}}{Cap_{Total}} \times \frac{Equity_{PLN}}{Total_{PLN}}$$

$$F_{COM} = I \times \left[\frac{Cap_{PLN}}{Cap_{Total}} \times \frac{Debt_{PLN}}{Total_{PLN}} + \frac{Cap_{IPP}}{Cap_{Total}}\right] - F_{IPF}$$

Where F_{IPF} is international public finance, I is total investment for the corresponding year and region, IPF is the share of IPF for the corresponding year and region, F_{PUB} is public finance, Cap_{PLN} is capacity allocated to PLN and its sub-holdings, Cap_{Total} is total capacity additions, $Equity_{PLN}$ is PLN's total equity in 2024, $Total_{PLN}$is PLN's total assets in 2024, F_{COM} is commercial finance, $Debt_{PLN}$ is PLN's total debt in 2024, and Cap_{IPP} is capacity allocated to IPPs.

Financier breakdown



The sources of finance analysis also allows this report to identify the level of concessional finance that is expected to be provided to achieve the RUPTL's BESS pipeline. In this analysis, IPF is always considered to be provided on concessional terms. Moreover, debt offered to PLN by domestic public banks – such as PT SMI – is also considered to be concessional. This is because, when lending to an Indonesian state-owned enterprise, Indonesian public banks are not expected to perceive political and regulatory risks to the same extent as international lenders. The share of financing provided to PLN by domestic public banks is determined through direct consultation between the IEA and PLN's finance divisions, and is applied to PLN's total debt investment as calculated above.

Financial modelling and cash flow analysis

The bankability assessment estimates the minimum revenue level at which each of the two BESS archetypes identified in the RUPTL 2025-2034 – standalone BESS and hybrid solar PV-plus-BESS – meets the return and credit thresholds that commercial investors and lenders would apply to an Indonesian power project. The analysis is designed as a directional guide for policy makers, PLN and prospective investors. It quantifies the approximate revenue requirement for a representative project in each of the five island systems, traces how that requirement evolves over the RUPTL deployment period as capital costs decline and tests its sensitivity to the principal cost and financing drivers. It is not intended to replicate project-level due diligence, and the results should not be read as tariff recommendations for any specific transaction. All monetary values are expressed in nominal US dollars.

Both archetypes are assessed with the same discrete annual cash flow model, built over a ten-year horizon: an investment year (Year 0), in which the full capital cost is incurred, followed by ten years of operations (Years 1-10), corresponding to the assumed economic life of the battery system. The model constructs a complete levered project cash flow for a trial revenue level, comprising the following elements.

Revenue. Annual revenue in Year 1 equals the trial tariff multiplied by contracted capacity, and escalates at 3% per year thereafter, so that revenue in year t equals the Year-1 level multiplied by $(1.03)^{(t-1)}$. Revenue is assumed to be earned on the full contracted capacity in every operating year.

Operating costs. Fixed O&M costs are modelled as a percentage of the capital cost of each asset component per year (2.5% for the battery system and 1.0% for the grid connection), escalating at the same 3% rate as revenue. No variable O&M or charging cost is modelled, consistent with an availability-based revenue structure in which charging energy is supplied by the off-taker (standalone) or by the co-located solar plant (hybrid).

Depreciation and tax. The full capital cost is depreciated on a straight-line basis over the ten-year asset life. Corporate income tax is applied at 22% to earnings after depreciation and interest.

Debt. Debt is sized as a fixed share of total capital cost (65% for standalone and 70% for hybrid projects) and repaid as a level annuity over a ten-year tenor, matching the asset life, at the applicable interest rate (7.5% in the commercial base case). Interest and principal in each year are computed from the annuity schedule.

Equity cash flow and credit metrics. Cash flow available for debt service (CFADS) is equal to EBITDA (earnings before interest, taxes, depreciation, and amortisation) less levered tax; the debt service coverage ratio (DSCR) is CFADS divided by scheduled debt service in each year and is reported against a 1.5x covenant benchmark. Equity cash flow is CFADS less debt service, with the equity investment (35% or 30% of capital cost) incurred in Year 0.

The model reports the unlevered project internal rate of return, the levered equity internal rate of return and the minimum DSCR over the debt tenor at any trial tariff, benchmarked against target values of 7.5%, 13.5% and 1.5x respectively.

Capital expenditures (CAPEX). CAPEX inputs vary across island systems in the standalone case, and vary alongside the solar capacity factor in the hybrid case.

Costs for the battery system, expressed in US dollar per megawatt for the relevant duration (four-hour standalone; one-hour hybrid), and for the grid connection are drawn from the IEA investment model underlying the RUPTL-aligned investment scenario, which reflects regional differences in logistics, installation and balance-of-system costs.

For the analysis of tariffs by commissioning year, capital costs follow the cost curve of the RUPTL-aligned investment scenario, under which battery capital costs decline by approximately 28% between 2025 and 2034 in each system, with grid connection costs declining more modestly. Solar PV capital costs, used for reference in the hybrid configuration, follow the IEA Global Energy and Climate Model 2025 Stated Policies Scenario trajectory. The bankable and break-even tariffs are re-solved for each island system and each commissioning year using the applicable year's capital cost, with all financial parameters held constant. The pipeline-weighted average tariff reported in Chapter 4 weights each island system's bankable tariff by its standalone BESS capacity in the RUPTL pipeline (Sumatra 1 075 MW; Java, Madura and Bali 4 213 MW; Kalimantan 725 MW; Sulawesi 516 MW; Maluku, Papua and Nusa Tenggara 80 MW).

Limitations

The analysis is illustrative by design, and several simplifications should be borne in mind when interpreting the results.

Single revenue stream. Each archetype is assumed to earn one contracted revenue stream, an availability payment for standalone projects and a PPA uplift for hybrid projects. No merchant, ancillary service, arbitrage or capacity market revenue stacking is modelled, reflecting the absence of such markets in Indonesia today.

Financing structure. Debt is repaid as a level annuity over a tenor equal to the asset life, rather than sculpted to cash flows, and the DSCR covenant is reported as a check rather than imposed as a binding constraint. At the bankable tariff the minimum DSCR falls marginally below 1.5x in early operating years; enforcing the covenant strictly would require slightly lower gearing and raise the required tariff by an estimated 2-3%. Financing terms are held constant across regions and years, whereas in practice pricing would reflect system-specific and counterparty risk.

Construction and timing. The full capital cost is incurred in a single investment year, with no construction period phasing, interest during construction or drawdown schedule. Working capital, debt service reserve accounts and upfront financing fees are excluded. These exclusions modestly understate the effective capital requirement and therefore the required tariff.

Asset life and residual value. The ten-year asset life is conservative relative to warranted battery lifetimes of 15 years or more, and no residual or terminal value is credited at the end of the horizon. Revenue is assumed to be earned on full contracted capacity throughout; battery degradation and any augmentation capital required to maintain contracted capacity are treated as implicitly covered within the fixed O&M allowance rather than modelled explicitly.

Currency. The model is denominated in US dollars, implicitly assuming USD-denominated or USD-indexed revenues, consistent with prevailing IPP contracting practice in Indonesia. No currency mismatch between revenues, costs and debt service is modelled, and no hedging cost is included. Projects with rupiah-denominated revenues would face materially different financing conditions.

Hybrid configuration. The hybrid results isolate the battery component and assume the solar plant is independently bankable; they therefore exclude any interaction between the two components in financing, and exclude curtailment, charging losses and round-trip efficiency effects on the solar plant's saleable output. The one-hour, 30% sizing reflects a peak-shifting function; longer-duration configurations would carry higher capital costs and require a larger uplift.

Data basis. Capital cost inputs derive from the IEA investment model and industry consultations rather than observed Indonesian transaction data, of which there are very little for BESS. As transaction precedents accumulate, both the level and the regional dispersion of costs should be recalibrated.

Within these limitations, the framework provides a consistent, transparent basis for comparing revenue requirements across archetypes, island systems and commissioning years, and for assessing where and when concessional support is most likely to be decisive.

Definitions

Active power: The real electrical power delivered to or absorbed from the grid. In BESS, active power determines the charging and discharging rate of the battery.

Ancillary services procurement agreement (ASPA): A contractual agreement between a system operator and a BESS asset owner through which ancillary services are procured and often remunerated through availability payments.

Anode: The negative electrode, typically made of graphite, in a lithium-ion battery.

Black start: The capability by a BESS (or other electricity generator) to restart parts of a grid after a blackout without the support of an external power supply.

Cathode: The positive electrode in a lithium-ion battery. Technologies used for stationary storage most commonly use lithium iron phosphate (LFP) cathodes. The composition of battery cathodes determines properties such as energy density, cost sensitivities and overall battery performance.

Congestion relief: The reduction of strain on transmission or distribution by strategically charging or discharging of BESS assets, thus relieving bottlenecks in power flows, improving system reliability and reducing curtailment of excess electricity.

Commercial operation date (COD): The date upon which a project becomes fully operational, begins delivering contracted services and generates revenue.

Contingency reserve: The provision of backup power to be injected on the system in the case of unexpected outages or generator failures. Contingency reserves can generally be injected instantly by BESS assets.

Currency risk: Also called foreign exchange risk, currency risk occurs when project revenues are denominated in a local currency (such as Indonesian rupiah) while debt obligations are denominated in a foreign currency (such as United States dollars). If the local currency weakens against the foreign currency, project revenues may become insufficient to fulfil debt obligations.

Energy arbitrage: A BESS service that addresses electricity price differentials by charging the asset when prices are low and discharging when prices are high. Energy arbitrage is remunerated through energy-based payments and therefore becomes most valuable in systems with wholesale power markets or granular time-of-use electricity pricing.

Frequency regulation services: The stabilisation of grid frequency through nearly instantaneous injections or absorptions of power.

Hybrid BESS: Under Indonesian regulation, hybrid BESS refers to storage systems co-located with one or more sources of renewable (including solar PV, wind, hydropower or biomass), diesel, or hydrogen generation and integrated under a single project structure.

Independent power producer (IPP): A private sector developer that finances, builds and occasionally operates BESS projects.

Institutional investors: Investors that generally invest large pools of capital and seek stable, long-term returns, such as pension funds, sovereign wealth funds, insurers and asset managers.

Levelised cost of energy (LCOS): An indicator of the expected average production cost for each unit of electricity generated by a technology over its economic lifetime. The LCOE combines into a single metric all the cost elements directly associated with a given power technology, including construction, financing, fuel, maintenance and costs associated with a carbon price. It does not include network integration or other indirect costs.

Levelised cost of storage (LCOS): Measures the lifetime cost of delivering one unit of stored electricity, taking into consideration capital expenditures, operation and maintenance (O&M) costs, efficiency losses and degradation.

Load following: The steady adjustment of power output to match changes in electricity demand or generation.

Load shifting: A BESS service in which assets are charged during periods of low demand and discharged during periods of high demand, thereby reducing curtailment and improving utilisation rates of intermittent renewable generation. Load shifting generally refers to the storage and release of electricity over durations of several minutes to several hours.

Load smoothing: A BESS service similar to load shifting (see above), but over more rapid timescales of seconds and minutes.

Non-recourse debt: Financing that is secured by a project's (or special purpose vehicle's) assets and cash flows rather than the ultimate project sponsor's balance sheet.

Peak capacity reserves: The provision of additional power during a system's periods of highest demand, thereby reducing the need for load shedding and thermal peaker plants.

Power purchase agreement (PPA): A long-term contract (often 10 to 20 years) that defines the tariffs at which an off-taker purchases determined quantities of electricity or services from a BESS asset owner.

Preferential dividend treatment: A contractual agreement wherein specified shareholders are prioritised for the receipt of dividends. Such arrangements are used to attract investors with lower risk tolerances.

Ramping reserve: The charging or discharging of BESS assets during rapid changes in generation or demand (respectively).

Reactive power: Electrical power exchanged with the grid to support voltage control and system stability. Reactive power does not involve a net transfer of energy and can be provided by a BESS through its power conversion system.

Retail electricity market: Markets selling electricity directly to end users, often by large- scale aggregators that acquire electricity on wholesale markets. Retail prices are driven by prices on wholesale markets and distribution costs.

Ring-fencing: The isolation of a project's assets, liabilities and cash flows from its ultimate parent company, generally through the creation of a special purpose vehicle.

Standalone BESS: Storage assets that are not paired with generation assets and are therefore generally treated as network components.

Stated Energy Policies Scenario (STEPS): The IEA scenario that reflects today's policy settings together with announced policy intentions and targets, provided they are supported by detailed implementation plans. It illustrates the direction of the energy system based on current policy frameworks and serves as a benchmark for assessing future energy trends.

Step-down interest rates: Concessional loans in which interest rates gradually decline over time as project revenues stabilise and risks fall.

Step-in powers: Privilege that allows lenders or public financiers to temporarily take control of a project if they consider it to be under financial stress.

Sunset clauses: Included in concessional financing structures, sunset clauses define an end date for support mechanisms, thereby mitigating long-term dependence.

Time-bound concessionality provisions: Limit the provision of concessional support to specified phases of a project's life, such as development or construction.

Voltage support: The stabilisation of network voltage through the rapid absorption or injection of reactive power, thereby maintaining power quality.

Wholesale electricity markets: Markets that enable bulk trading of electricity among generators, system operators and retailers. Wholesale prices are reflective of supply-demand conditions and system constraints.

Abbreviations and acronyms

AC	Alternating current
ADB	Asian Development Bank
ARED	Accelerated Renewable Energy Development
ASEAN	Association of Southeast Asian Nations
ASPA	Ancillary service procurement agreement
BAPPENAS	Ministry of National Development Planning
BESS	Battery energy storage system
BOO	Build-own-operate
BOOT	Build-own-operate-transfer
BPP	biaya pokok penyediaan (PLN's system cost of electricity supply)
BRPL	BSES Rajdhani Power Limited
CAPEX	Capital expenditure
CFADS	cash flow available for debt service
CIPP	Comprehensive Investment and Policy Plan
COD	Commercial Operation Date
DC	Direct current
DEN	Dewan Energi Nasional
DFI	Development finance institution
DJK	Directorate General of Electricity
DSCR	Debt service coverage ratio
EBITDA	Earnings before interest, taxes, depreciation and amortisation
EBTKE	Directorate General of New and Renewable Energy and Energy Conservation
ECA	Export credit agency
EMDE	Emerging market and developing economies
EPC	Engineering, procurement and construction
EVN	Viet Nam Electricity
FX	Foreign exchange
GEAPP	Global Energy Alliance for People and Planet
GESP	Global Energy Storage Platform
IDR	Indonesian rupiah
IEA	International Energy Agency
INA	Indonesia Investment Authority
INR	Indian rupee
IPF	International Public Finance
IPP	Independent power producer
IRR	Internal rate of return
IUPTL	Electricity Supply Business License
JETP	Indonesia Just Energy Transition Partnership
JMB	Java, Madura and Bali
KPBU	Kerjasama Pemerintah dengan Badan Usaha
LCOE	Levelised cost of electricity
LCOS	Levelised cost of storage

LFP	Lithium iron phosphate
MCFs	Multilateral climate funds
MDB	Multilateral development bank
MEMR	Ministry of Energy and Mineral Resources
MER	Market exchange rate
MoF	Ministry of Finance
MPNT	Maluku, Papua and Nusa Tenggara
NMC	Lithium nickel manganese cobalt oxide
O&M	Operation and maintenance
OPEX	Operational expenditure
PCS	Power conversion system
PHP	Philippine pesos
PLN	PT Perusahaan Listrik Negara
PPA	Power purchase agreement
PT SMI	PT Sarana Multi Infrastruktur
PV	Photovoltaic
RE Base	Renewable Indonesia Base
RFP	Request for proposals
RUPTL	Rencana Usaha Penyediaan Tenaga Listrik: PLN's Electricity Supply Business Plan
SOE	State-owned enterprise
SPV	Special purpose vehicle
STEPS	Stated Energy Policies Scenario
US	United States
USD	United States dollar
VGF	Viability Gap Funding
VND	Vietnamese dong
VRE	Variable renewable energy
WACC	Weighted average cost of capital
WESM	Wholesale electricity spot market

Units

bps	basis points
GW	gigawatt
GWh	gigawatt-hour
kW	kilowatt
kWh	kilowatt-hour
MW	megawatt
MWh	megawatt-hour
TWh	terawatt-hour

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