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Rethinking Indonesia's electricity economics to reach the 100GW solar target

Aligning the RUPTL with evolving generation costs and regional diversification can unlock a lower-cost electricity system

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Contents

Figures and tables

Key findings

Coal is no longer Indonesia's cheapest source of electricity, with its generation cost rising by 46% to IDR930/kWh in 2025, and estimated to reach IDR1,060/kWh in 2026. Its levelized cost of electricity (LCOE) exceeds that of solar photovoltaic (PV) and onshore wind. At the lowest end of their respective cost ranges, solar is approximately 44% cheaper than coal, while onshore wind is around 32% cheaper.

Changing generation economics have significant financial implications for Indonesia's national electricity utility, PT Perusahaan Listrik Negara (PLN), and the government. Rising fossil fuel costs, exchange rate volatility, and regulated retail tariffs are widening the gap between electricity supply costs and consumer prices, increasing government subsidies and compensation. Least-cost planning could reduce long-term costs and fiscal pressures.

Electricity costs vary across eastern and western Indonesia, creating different least-cost opportunities. While large interconnected systems in western regions benefit from economies of scale, eastern regions remain heavily dependent on diesel generation. Solar PV paired with battery energy storage systems (BESS) could deliver electricity at a lower cost than diesel.

Future Electricity Supply Business Plan (RUPTL) revisions should adopt a dynamic least-cost planning approach reflecting current and projected generation costs, fuel price risks, financing conditions, and regional electricity economics. Embedding Indonesia's 100GW solar program into the electricity planning framework could reduce electricity costs and strengthen energy security.

Executive summary

Indonesia's Electricity Supply Business Plan (RUPTL) 2025–2034 targets 69.5 gigawatts (GW) of new generation capacity, including 42.6GW of renewable energy and 10.3GW of energy storage, supported by substantial investment in transmission infrastructure. In June 2025, the Government of Indonesia (GOI) announced an ambitious 100GW solar program[1], which President Prabowo Subianto officially launched on 25 August 2026[2], signaling a greater role for renewable energy in the country's electricity supply. This program is expected to be incorporated into future revisions of RUPTL.[3] Together, these plans will require unprecedented investment over the next decade, making cost-effective electricity planning more critical than ever. Developing new generation, transmission, and storage projects at the lowest long-term cost will be essential to maintaining affordability, ensuring the financial sustainability of Indonesia's national electricity utility, PT Perusahaan Listrik Negara (PLN), and minimizing future subsidy requirements.

For decades, electricity planning in Indonesia has assumed that coal-fired generation is the cheapest electricity source. This premise underpins the use of PLN's Basic Cost of Providing Electricity (*Biaya Pokok Penyediaan* [BPP]) as the benchmark for electricity planning and renewable energy procurement. However, the economics of electricity have changed significantly. Rising fossil fuel costs, exchange-rate volatility, and aging thermal power plants have increased the cost of conventional generation, while renewable energy technologies have become steadily cheaper.

In 2025, coal-fired generation cost IDR930 per kilowatt-hour (kWh), compared with IDR313/kWh for hydropower and IDR906/kWh for wind. The Institute for Energy Economics and Financial Analysis (IEEFA) estimates that coal-fired generation costs could rise to approximately IDR1,060/kWh in 2026. As a result, some of the economic assumptions underlying Indonesia's electricity planning no longer fully reflect current market realities. The distortion becomes even clearer when considering the impact of the Domestic Price Obligation (DPO) policy, which masks the true cost of coal generation. Without this policy, the actual cost is estimated to be around IDR1,455/kWh in 2025, highlighting the extent to which regulated pricing influences the apparent cost competitiveness of coal.

The historical cost advantage of fossil fuel generation in Indonesia has narrowed substantially and, in many cases, disappeared. Across the Association of Southeast Asian Nations (ASEAN), utility-scale solar and wind are increasingly cost-competitive with coal-fired generation, while solar photovoltaic (PV) combined with battery energy storage systems (BESS) can already deliver electricity at a lower cost than diesel generation in many remote power systems. Global projections indicate that the costs of solar PV, wind, and BESS are expected to continue declining, further strengthening the long-term competitiveness of renewable energy.

[1] Sekretariat Kabinet Republik Indonesia. Pacu Program Energi Surya Nasional 100 Gigawatt, Presiden Prabowo Targetkan 17 Gigawatt PLTS Terbangun Tahun Ini. 21 April 2026.
[2] Jakarta Globe. Prabowo Launches 100 GW Solar Power Program. 25 August 2026.
[3] Listrik Indonesia. KESDM Tegaskan Target PLTS 100 GW Sudah Masuk Revisi RUPTL. 04 August 2026.

Using the levelized cost of electricity (LCOE) to compare generation technologies shows that coal is no longer the cheapest option in Indonesia’s power mix. Coal’s LCOE, ranging from USD10.0–15.1 cents per kilowatt-hour (¢/kWh), is higher than that of utility-scale solar PV (USD5.6–8.4¢/kWh) and onshore wind (USD6.8–10.3¢/kWh). Gas is the most expensive fossil fuel option, with an LCOE ranging from USD14.0–21.0¢/kWh. At the lower end of the estimates, utility-scale solar is approximately 44% cheaper than coal, while onshore wind is around 32% cheaper. Even at the upper end, solar remains about 16% cheaper than coal at its lowest estimated cost, while onshore wind is broadly comparable to coal at the lower end of coal’s range. Overall, the comparison points to a significant shift in the economics of new power generation, with renewable technologies increasingly offering lower-cost alternatives to coal and gas.

There are also significant regional differences in electricity generation costs, meaning the lowest-cost technology varies across Indonesia. Future investment decisions should therefore reflect regional resource availability and generation costs rather than applying uniform planning assumptions nationwide. While large interconnected systems in western Indonesia benefit from relatively low generation costs, many systems in eastern Indonesia remain heavily dependent on expensive diesel generation. These regions offer the greatest opportunity to reduce electricity costs by replacing diesel with renewable energy and battery storage. Diesel generation costs between IDR5,500/kWh and nearly IDR9,000/kWh in these systems, creating potential for significant savings from solar PV and BESS deployment.

Changing electricity economics also has important implications for PLN's financial sustainability. Under Indonesia's regulated tariff framework, higher electricity generation costs increase the government’s subsidies and compensation burden while placing additional pressure on PLN's finances. Renewable energy can provide a more predictable long-term cost structure by reducing exposure to fuel price volatility and exchange rate risks.

Future RUPTL revisions should adopt a more dynamic least-cost planning approach that incorporates updated generation costs, regional differences, and long-term financial sustainability. Integrating the proposed 100GW solar program into this framework could optimize investments in generation, transmission, and energy storage while attracting greater private sector participation. This approach would help ensure that the scale of investment required under the RUPTL is directed toward the most economically efficient technologies and regions.

Indonesia's challenge is no longer whether renewable energy can compete with fossil fuels, but whether its electricity planning framework can keep pace with rapidly evolving generation economics. Aligning future RUPTL revisions with current market realities could help reduce long-term electricity costs, strengthen PLN's financial sustainability, lower future subsidies, and support the country’s energy transition.

Recommendations	
	Update planning assumptions to maintain flexibility and affordability Assumptions should be based on current and projected generation costs rather than historical cost structures. As renewable energy technologies become increasingly cost-competitive and fossil fuel generation costs continue to rise, future planning should place greater emphasis on forward-looking economic assessments that account for lifetime generation costs, fuel price risks, and regional system characteristics.
	Prioritize high-BPP regions and differentiate by area Target high-BPP regions, particularly diesel-dependent systems, where renewable energy offers the greatest economic benefit. In eastern Indonesia, accelerating solar PV combined with BESS could replace costly diesel generation, lowering subsidies and improving energy security. In western Indonesia, diversifying coal-heavy grids with solar, wind, hydro, and geothermal could deliver the lowest long-term generation costs while reducing reliance on coal.
	Integrate the 100GW solar program The 100GW solar program should be embedded within Indonesia's broader electricity system planning framework and not treated as a stand-alone capacity target. Integration through least-cost system planning would ensure that the new solar capacity is developed where it delivers the greatest economic and technical value. A balanced mix of ground-based, floating, and rooftop solar should be prioritized. Early retirement of inefficient coal plants could free grid capacity, reduce subsidies, and create space for renewable additions, directly supporting the 100GW target.
	Expand transmission and energy storage Scaling renewable energy requires more than just adding generation capacity. Timely investment in transmission networks, grid flexibility, balancing capacity, and appropriately sized storage is essential to integrate a growing share of renewables.
	Strengthen private sector participation Delivering Indonesia's renewable targets requires consistent private investment. Strengthening the framework with bankable PPAs, transparent procurement, regulatory certainty, and mechanisms like power wheeling will mobilize capital, lower financing costs, and accelerate deployment.

Indonesia's electricity system is entering a new phase

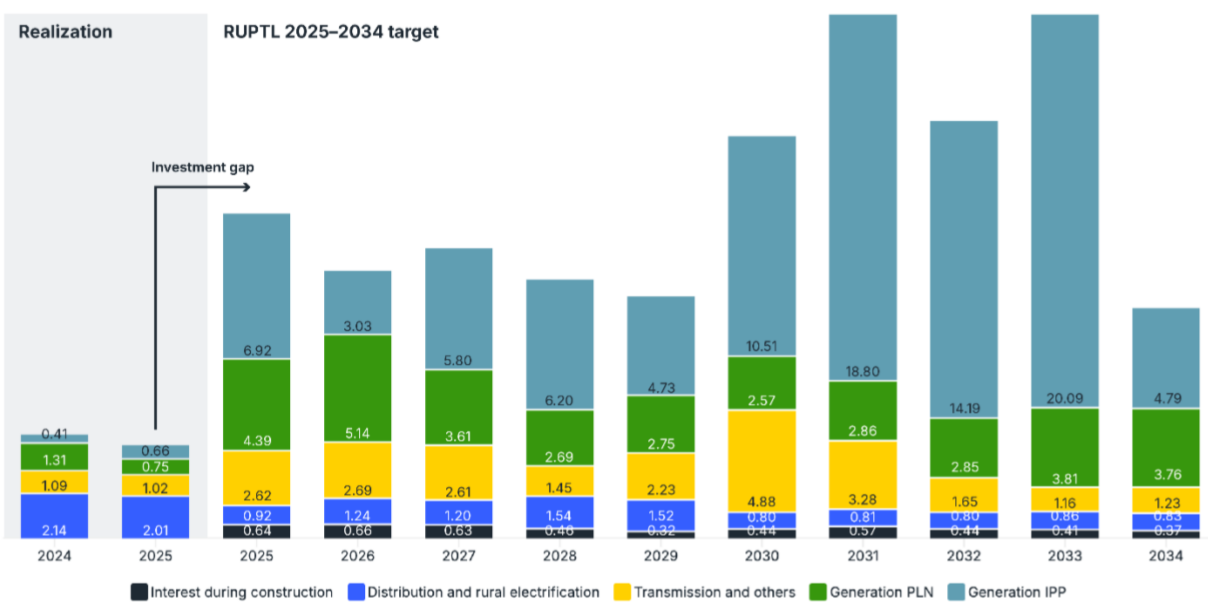
RUPTL sets the direction for the power sector

Indonesia stands at a pivotal moment in shaping its long-term power generation strategy. To achieve its target of 8%[4] economic growth, the country must balance the energy trilemma of affordability, reliability, and sustainability. This challenge is reflected in the Electricity Supply Business Plan (RUPTL) 2025–2034, Indonesia's roadmap for expanding its electricity system over the next decade.

The RUPTL targets 69.5 gigawatts (GW) of new generation capacity, including 42.6GW of renewable energy and 10.3GW of energy storage, along with significant investment in transmission infrastructure.[5] Achieving these targets will require approximately IDR2,780 trillion (USD169 billion [bn]).[6]

Yet investment remains well below the level required, reaching around USD4.9bn in 2024 and USD4.5bn in 2025, revealing a significant difference between current capital flows and the scale required to meet Indonesia's energy transition targets.

Figure 1: Investment realization and RUPTL 2025–2034 target (USD billion)



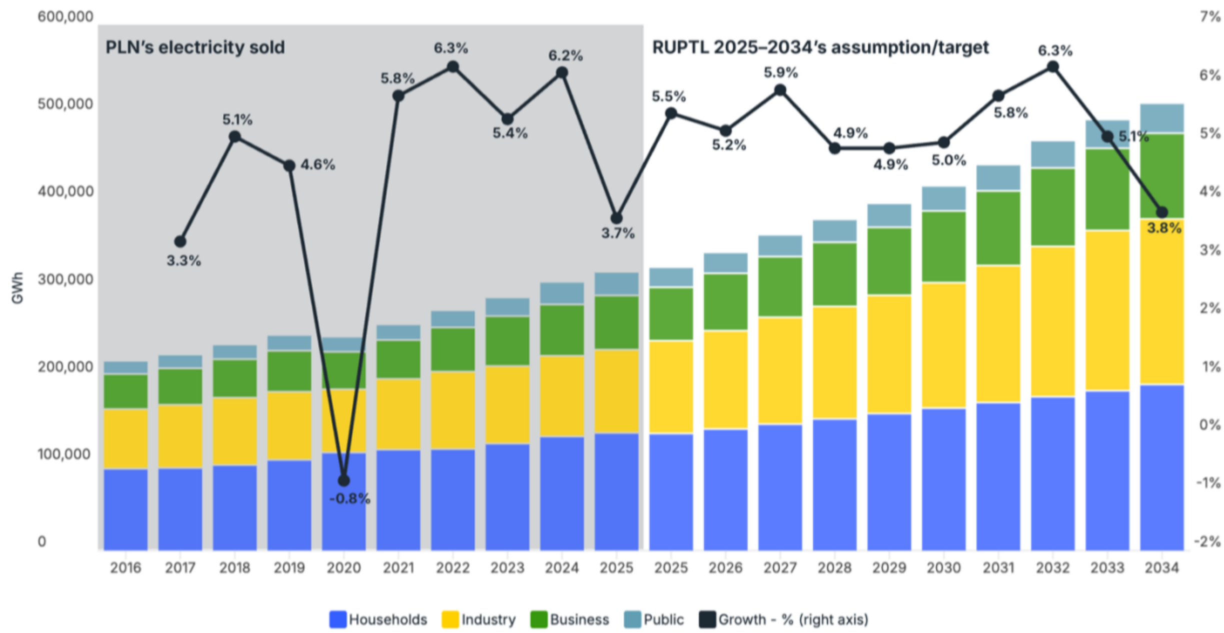
Source: Ministry of Energy and Mineral Resources - Laporan Kinerja 2024 and 2025; RUPTL 2025–2034.

[4] Cabinet Secretariat of The Republic of Indonesia. President Prabowo Subianto Expresses Optimism for 8% Economic Growth. 16 January 2025.
[5] MEMR. Electricity Supply Business Plan (RUPTL 2025-2034). Section V.5.7. 26 May 2025.
[6] MEMR. Electricity Supply Business Plan (RUPTL 2025-2034). Section VI.1. 26 May 2025.

Ensuring that new generation, transmission, and storage projects are developed at the lowest long-term cost will be essential to maintaining affordable electricity, preserving the financial sustainability of the national electricity utility PT Perusahaan Listrik Negara (PLN), and minimizing future government subsidies.

Rapid electricity demand growth further underscores the need for least-cost planning. Electricity sales increased from 216 terawatt-hours (TWh) in 2016 to 317TWh in 2025[7], and are projected to reach approximately 511TWh by 2034 under the current RUPTL.[8] Meeting this demand will require substantial investment from both PLN and independent power producers (IPPs), making investment certainty and project economics increasingly important.

Figure 2: PLN's electricity sold and forecast



Source: PLN's Statistics Report 2025, RUPTL 2025–2034.

At the same time, Indonesia's electricity system remains dominated by fossil fuels, driving greenhouse gas (GHG) emissions to an estimated 812 million tonnes of carbon dioxide equivalent ($MtCO_2e$) in 2024, a 5.13% year-on-year increase.[9] The RUPTL 2025–2034 target of 42.6GW renewable energy capacity is a critical step toward meeting rising electricity demand while reducing emissions.

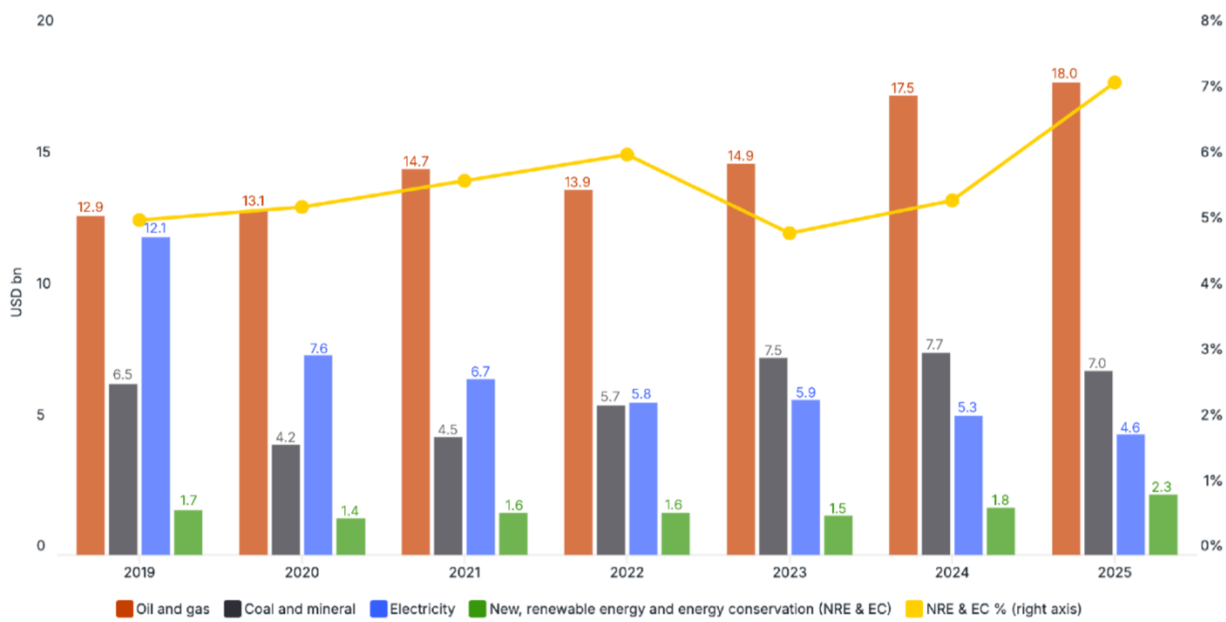
[7] PLN. PLN Statistics 2025. Table 46. 29 July 2026.
[8] MEMR. Electricity Supply Business Plan (RUPTL 2025-2034). Section VIII. 26 May 2025.
[9] WorldOMeter. Indonesia CO2 Emissions.

Indonesia's renewable energy ambitions have continued to evolve. In 2025, the government announced a 100GW solar program[10], comprising utility-scale and distributed solar systems, supported by battery energy storage. Although the program is not included in the current RUPTL, it is expected to be incorporated into future revisions, further increasing the role of renewable energy in the electricity system.

Achieving RUPTL targets requires a stronger economic foundation

The RUPTL establishes an ambitious roadmap for expanding Indonesia's electricity system. However, translating planned capacity into operating power plants requires sustained investment over the long term. While renewable energy investment grew 31% from USD1.8bn in 2024 to USD2.3bn in 2025, project development has remained sluggish. Much of the growth has been concentrated in geothermal projects[11], which typically face long construction and development timelines, indicating that financial and market challenges continue to constrain investment.[12]

Figure 3: Investment realization in the energy and mineral resources sector



Source: MEMR Performance Report.

Investment decisions are driven by economics, with developers, lenders, and utilities evaluating projects based on expected costs, returns, and risks over an asset's lifetime. These assessments determine which technologies are built, where investment flows, and how quickly new capacity is deployed. As Indonesia seeks to mobilize substantial private investment to deliver the RUPTL's goals

[10] Cabinet Secretariat of the Republic of Indonesia. Gov't to Accelerate Energy Transition. 15 September 2025.
[11] MEMR. Laporan Kinerja Kementerian ESDM Tahun 2025. 11 February 2026.
[12] IEEFA. Realizing Indonesia's ambitious renewable energy goals calls for a new approach. 19 June 2025.

and balance the energy trilemma of security, affordability, and sustainability, aligning planning with the lowest-cost investment opportunities is essential. If planning frameworks continue to favor outdated cost assumptions, investment could be directed toward higher-cost fossil fuel projects, slowing renewable energy deployment and undermining Indonesia's energy transition.

Such misallocation could lock in expensive generation for decades, increasing costs for both PLN and the Government of Indonesia (GOI). PLN would face higher operating costs, while the GOI would need to cover the gap between generation costs and regulated tariffs through subsidies and compensation.

A more dynamic planning approach that reflects the true cost of generation technologies — accounting for fuel price volatility, financing conditions, and the declining costs of renewables — could create a transparent and competitive investment environment and attract private capital at scale.

This report assesses the changing economics of Indonesia's electricity system through three key areas:

- Comparing conventional and renewable generation costs, highlighting how changes in fuel prices, financing, and technology costs are shifting relative competitiveness.
- Evaluating regional differences across the archipelago, including variations in electricity costs driven by differences in resource availability, infrastructure, and demand patterns.
- Assessing implications for future RUPTL revisions, emphasizing the need to align planning assumptions with Indonesia's energy transition and least-cost development objectives.

Is coal still Indonesia's lowest-cost source of electricity?

For decades, Indonesia's electricity planning has assumed that coal-fired generation is the cheapest source of electricity, particularly given the country's abundant coal reserves. However, this assumption does not reflect the full cost of coal-fired generation. Policies such as the Domestic Price Obligation (DPO) and Domestic Market Obligation (DMO) keep coal prices below market levels, creating high implicit costs and obscuring the true cost of coal-fired electricity.

These policies have created artificially low tariffs, making it challenging for renewable energy to compete. Renewable energy procurement is benchmarked against PLN's Basic Cost of Providing Electricity (*Biaya Pokok Penyediaan* [BPP]), while coal-fired generation benefits from subsidies embedded in the DPO and DMO framework.

However, the economics of electricity generation have changed significantly in recent years, as the rapid decline in renewable technology costs has altered the competitive landscape. The next section examines whether the assumptions underlying Indonesia's electricity planning remain valid by comparing changes in conventional generation costs with the declining costs of renewable energy.

Understanding Indonesia's electricity cost framework

Indonesia's electricity sector has historically been planned around two fundamental objectives: maintaining affordability while ensuring a secure and reliable electricity supply. Central to this approach is the BPP, one of the most important economic indicators in Indonesia's power sector. The BPP influences electricity tariffs, subsidy requirements, and investment decisions.

Coal has played a dominant role in the power system, accounting for approximately 68% of the total electricity generation.[13] The DPO and DMO policies have helped keep coal-fired generation costs low and electricity affordable. However, they have also shifted part of the actual cost of generation to coal producers and the government through subsidies that are indirectly borne by taxpayers. As a result, BPP understates the true cost of coal-fired generation, creating an uneven benchmark for renewable energy projects competing for investment.[14]

Under Presidential Regulation (PR) No. 112 of 2022, the GOI introduced a new ceiling tariff that varies by technology and geographic location.[15] However, renewable energy tariffs continue to be benchmarked against the regional BPP, which remains heavily subsidized and supported by coal policies. This structure reduces the attractiveness of renewable energy projects for private investors[16], as competitiveness depends not only on the cost of renewable technologies, but also on the prevailing generation costs in the region where projects are developed.

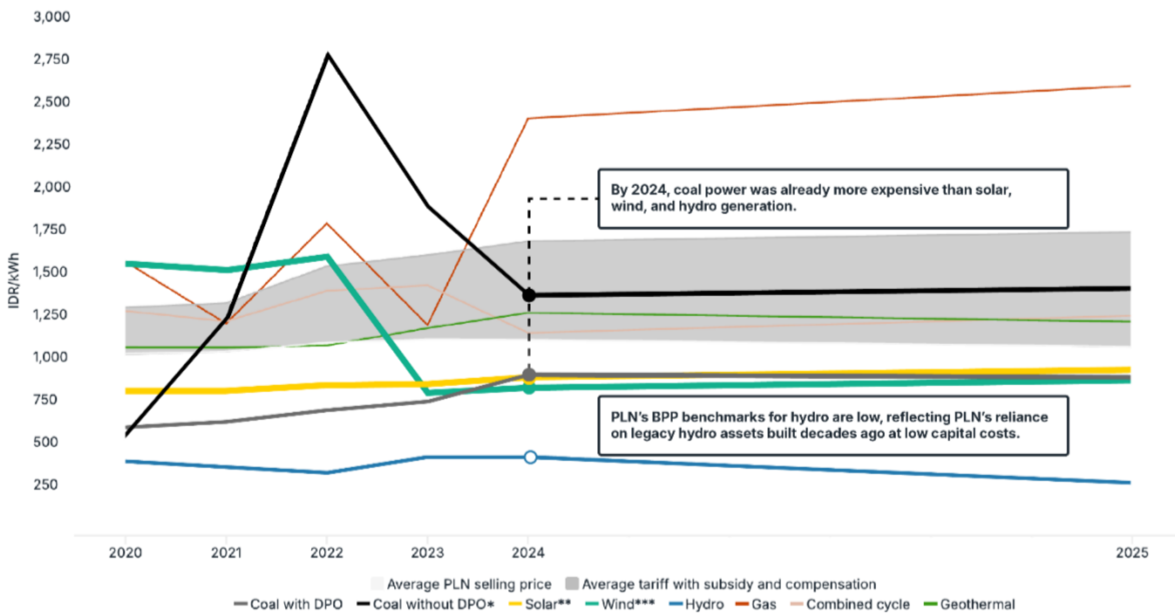
While BPP remains an important indicator of the cost of operating Indonesia's existing electricity system, it should not be the primary benchmark for future investment decisions. Planning new generation projects requires comparing technologies based on their full lifetime costs rather than the historical cost structure embedded in the current electricity system. Indonesia's electricity planning should shift from legacy benchmarks to least-cost analysis that reflects true economic costs and evolving market conditions.

The economics of electricity have fundamentally changed

Over the past several years, the economics of electricity generation have shifted considerably. Despite the DPO and DMO policies, the cost of conventional fossil fuel generation has increased due to rising fuel prices, aging generation assets, higher operation and maintenance costs, and greater exposure to international commodity markets (Figure 4).

[13] IEEFA. Transforming Indonesia's Coal Dependence into Clean Energy Opportunities. November 2025.
[14] IEEFA. Unlocking Indonesia's Renewable Energy Investment Potential. July 2024.
[15] Database Peraturan. Peraturan Presiden (PERPRES) Nomor 112 Tahun 2022 Percepatan Pengembangan Energi Terbarukan untuk Penyediaan Tenaga Listrik. 13 September 2022.
[16] IEEFA. Unlocking Indonesia's Renewable Energy Investment Potential. July 2024.

Figure 4: PLN's average Basic Cost of Providing Electricity (BPP), 2020–2025



Source: PLN 2025 statistics report, IEEFA analysis.
Note: Diesel power plants are excluded from the chart due to their high cost, averaging around IDR8,748 in 2023, IDR5,513.75 in 2024, and IDR5,669.65 per kWh in 2025.
Solar and wind power plants are using the PPA tariff, as most of their capacity is owned by IPPs, while PLN's share remains relatively small.
** Coal without DPO is an IEEFA estimate derived using the Ministry of Energy and Mineral Resources (MEMR) Harga Batubara Acuan (HBA), or Coal Reference Price, as a proxy for the market-based coal price, rather than the regulated domestic coal price under the DPO framework.*
*** Based on PPA's tariff for 25MW Bali solar at USD5.9c/kWh.*
**** Based on PPA's tariff for 70MW Tanah Laut wind at USD5.5c/kWh.*

Figure 4 illustrates PLN's average electricity generation costs between 2020 and 2025. It shows that the historical cost advantage of conventional fossil fuel generation has narrowed substantially, with utility-scale solar, wind, and hydropower increasingly cost-competitive with coal-fired generation.

Coal-fired generation costs have risen substantially over the longer term, increasing from IDR637 per kilowatt-hour (kWh) in 2020 to IDR930/kWh in 2025[17], a 46% increase. Although there was a slight decline from IDR941/kWh in 2024, the longer-term trend has been upward. The Institute for Energy Economics and Financial Analysis (IEEFA) estimates that the average cost of coal-fired generation could rise further to approximately IDR1,060/kWh in 2026. This projection reflects the 2020–2025 trajectory of international coal prices, including the Newcastle coal price, and the Ministry of Energy and Mineral Resources (MEMR) *Harga Batubara Acuan* (HBA), or Coal Reference Price.

Several factors have contributed to the rising cost of coal-fired generation. Aging coal plants require higher maintenance spending, operate less efficiently, and consume more coal to produce the same

[17] PLN. PLN Statistics 2025. Table 38. 29 July 2026.

output. Increasing fuel prices and operating expenses have further eroded coal's cost advantage, underscoring its declining competitiveness in Indonesia's electricity mix.[18] The estimated cost of coal generation without the DPO was IDR1,455/kWh in 2025 — 56% higher than the IDR930/kWh cost with the DPO applied. This difference illustrates how regulated domestic coal prices materially influence the apparent cost competitiveness of coal-fired generation. These factors challenge the long-held assumption that coal will remain the country's cheapest source of electricity and reinforce the need to reassess future generation planning using current and underlying economic costs rather than regulated historical benchmarks alone.

Gas-fired generation has experienced even greater cost volatility, rising from IDR1,612/kWh in 2020[19] to IDR2,646/kWh in 2025, a 64% increase. Generation costs reached IDR2,455/kWh in 2024 before increasing further to IDR2,646/kWh in 2025, according to IEEFA analysis. The escalating costs and unpredictability of gas generation also challenge its traditional role as a stable transition fuel and highlight the value of technologies with less exposure to international fuel prices and exchange rate fluctuations.

Diesel remains the most expensive source of electricity by far, with generation costs ranging from IDR5,500/kWh to nearly IDR9,000/kWh, particularly in remote electricity systems where transportation costs add to fuel expenses.

While the majority of Indonesia's coal and natural gas is produced domestically, both commodities are priced in United States (US) dollars. As a result, fossil fuel generation remains exposed to volatility in international commodity prices and exchange rates, as fuel procurement costs are linked to global market conditions. The DMO and DPO policies help shield PLN from these market fluctuations, but do not reflect the underlying economic value of coal. Instead, they establish regulated domestic coal prices that differ from prevailing market prices, meaning the BPP reflects a policy-supported cost rather than the full economic cost of coal-fired generation. The 2025 difference in coal generation costs with and without the DPO illustrates the scale of this policy effect.

In contrast, renewable energy has demonstrated far greater cost stability within PLN's portfolio. Hydropower remains the cheapest source of electricity, averaging IDR468/kWh in 2024 and falling further to IDR313/kWh in 2025, nearly 66% cheaper than coal-fired generation with the DPO. Geothermal generation was IDR1,259/kWh in 2025, above the average retail tariff of IDR1,113/kWh. However, its compound annual growth rate (CAGR) has been considerably lower than that of fossil fuel generation, which is highly exposed to price volatility.

For solar and wind, PLN's direct ownership remains limited, with only 36.34 megawatts (MW) of solar and 0.17MW of wind capacity in 2025. As a result, their economics are better assessed through power purchase agreements (PPAs) signed with IPPs.

[18] IEEFA. Transforming Indonesia's coal dependence into clean energy growth. 19 November 2025.
[19] PLN. PLN Statistics 2024. Table 38. 30 June 2025.

For solar, the highest PPA tariff for a utility-scale solar project to date was USD5.9 cents per kilowatt-hour (¢/kWh) for the 25MW Bali solar project. At the 2024 exchange rate of IDR16,475 per USD, this equates to IDR935/kWh, already below the average coal generation cost of IDR941/kWh in the same year. Wind generation has followed a similar trajectory, with costs declining significantly. Indonesia’s first wind project, the 75MW Sidrap Wind project, signed a PPA in 2015 at USD11¢/kWh. Costs have fallen sharply since, with PLN recently signing a PPA for the 70MW Tanah Laut Wind project at USD5.5¢/kWh (IDR872/kWh).

These numbers demonstrate how utility-scale solar and wind projects have become increasingly cost-competitive. Global projections indicate that the costs of solar photovoltaic (PV), wind, and battery energy storage systems (BESS) are expected to continue falling as technology improvements, manufacturing scale, and learning effects drive further efficiency gains.[20] These trends are expected to further improve the economics of renewable energy, particularly solar PV paired with BESS for applications requiring firm and dispatchable electricity.[21, 22] The continued decline in renewable energy and storage costs strengthens the case for considering these technologies in future electricity planning. While benchmarking renewables against subsidized BPP remains challenging, the underlying economics increasingly favor clean energy deployment.

Levelized cost of electricity as a guide to investment decisions

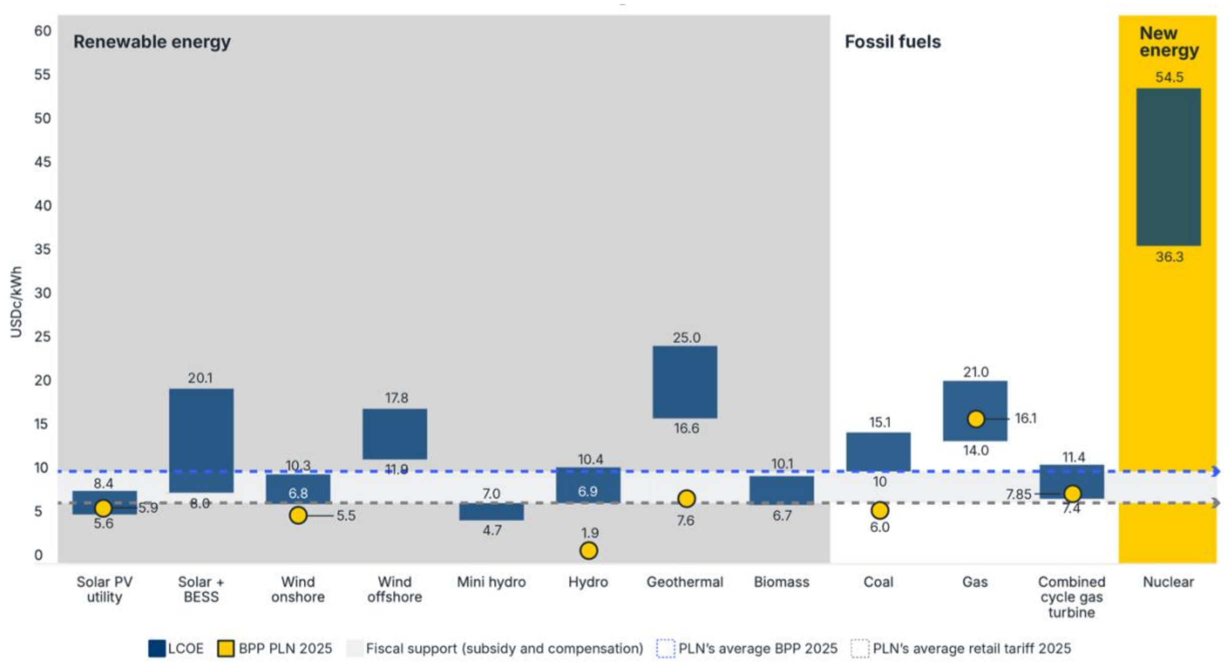
Technological improvements, economies of scale, and declining equipment expenses have significantly reduced the cost of renewable energy worldwide, as shown by the levelized cost of electricity (LCOE). The LCOE represents the average lifetime cost of producing electricity from a generating asset. It incorporates capital expenditure, operation and maintenance costs, financing expenses, fuel costs (where applicable), and expected electricity generation over a project's lifetime.

By standardizing costs across different technologies, LCOE provides a useful basis for comparing renewable and conventional power generation. It is therefore a critical tool for policymakers, investors, and utilities when assessing project feasibility, competitiveness, and long-term energy planning.

Figure 5 compares the LCOE for renewable energy technologies with PLN's average generation costs, demonstrating that renewable energy is increasingly cost-competitive with conventional fossil fuels. In many cases, utility-scale solar and wind projects are now cheaper than coal-fired electricity, while solar PV combined with BESS can deliver electricity at a lower cost than diesel generation in many remote electricity systems, where costs range from USD31–50¢/kWh.[23]

[20] IRENA. Renewable power generation costs in 2025. 2 July 2026.
[21] IEA. Electricity 2026. 6 February 2026.
[22] IEA. World Energy Outlook 2025. 12 November 2026.
[23] Exchange-rates.org. Exchange rates IDR17,849/USD in June 2026. July 2026

Figure 5: IEEFA's LCOE comparison with BPP



Source: IEEFA analysis.
Note: The funding assumptions applied in this analysis are based on 100% equity financing. Additional information is provided in Appendix II.

Coal is no longer the cheapest option in Indonesia's power mix. Its LCOE, ranging from USD10.0–15.1¢/kWh, is higher than utility-scale solar PV (USD5.6–8.4¢/kWh) and onshore wind (USD6.8–10.3¢/kWh). This indicates that coal's historical cost advantage has diminished, despite subsidies and capped fuel prices. Gas is the most expensive fossil fuel option, with an LCOE ranging between USD14.0–21.0¢/kWh, making it more expensive than nearly all renewable technologies, due to its exposure to fuel price and exchange rate fluctuations.

These ranges point to a significant shift in the economics of new power generation. At the lower end of their respective cost ranges, utility-scale solar is approximately 44% cheaper than coal, while onshore wind is around 32% cheaper. The comparison is also notable across the full range of estimates. The upper end of solar's LCOE (USD8.4¢/kWh), remains below the lowest estimate for coal (USD10.0¢/kWh). Wind overlaps with coal only at the margins, with its upper-end estimate of USD10.3¢/kWh broadly comparable to coal at the bottom of its range.

Gas faces an even larger cost disadvantage. Its lowest estimated LCOE of USD14.0¢/kWh is already close to the upper end of the coal range and substantially above the cost range for both solar and most onshore wind projects. This suggests that, on a levelized-cost basis, new fossil fuel generation carries a cost premium relative to renewable alternatives. While LCOE does not capture all system-level considerations, it provides a useful measure of the underlying cost of generating electricity over the lifetime of an asset. On this measure, the economics of new generation in Indonesia increasingly favor renewable technologies over coal- and gas-fired power.

Solar PV paired with BESS (solar + BESS) remains relatively costly at around USD20¢/kWh under a pessimistic scenario (assuming higher capital and operating expenditure). However, it is strategically valuable as it can provide reliable power. In remote and island systems, solar + BESS already delivers electricity at a lower cost than diesel, while reducing exposure to fuel logistics. Moreover, project economics are improving rapidly as battery costs decline and storage technology advances. Notably, the appropriate BESS capacity can be tailored to local demand patterns and grid conditions, potentially reducing overall system costs and improving the competitiveness of hybrid solar + BESS solutions.

Mini-hydro has the lowest LCOE among renewable technologies, ranging from USD4.7–7.0¢/kWh under the pessimistic scenario. However, PLN's BPP benchmarks for hydro are even lower, reflecting the utility's reliance on legacy hydro assets built decades ago at low capital costs.

Nuclear, by contrast, remains the most expensive option in Indonesia. With an LCOE of approximately USD36.3–54.5¢/kWh, it is substantially more expensive than both renewable and fossil fuel generation, making it economically uncompetitive under current financing and market conditions.

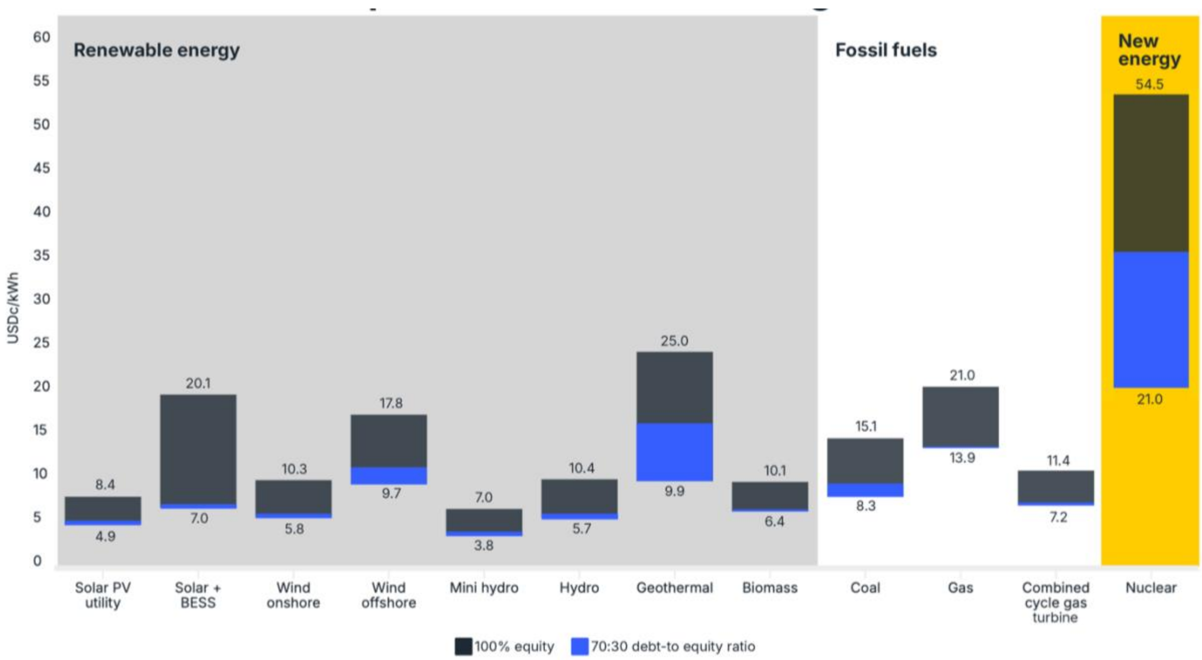
Furthermore, scenario analysis demonstrates that the LCOE is not a fixed metric. It is highly sensitive to financing structures, technology performance, and policy support, resulting in significant variation across scenarios.

Scenario 1: Financing structures and their effect on LCOEs

Project financing structures have a significant impact on LCOEs. Projects financed with debt have a lower cost of capital because lenders typically require lower returns than equity investors. Additionally, interest payments are tax-deductible, creating a tax shield that further reduces the cost of borrowing. Together, these factors lower the weighted average cost of capital (WACC), which in turn reduces the discount rate used in LCOE calculations. As a result, debt-financed projects generally have a lower LCOE than those funded entirely with equity (Figure 6).

Figure 6 illustrates the sensitivity of LCOE to financing conditions, particularly the share of debt and equity financing. Under the base case, which assumes that projects are financed with 100% equity, LCOEs are significantly higher than under scenarios with a 30% equity share. This reflects the higher returns required by equity investors, who bear greater financial risk. By contrast, debt providers typically receive lower returns because they have priority claims in case of default.

Figure 6: LCOE comparison based on financing structures



Source: IEEFA analysis.
Note: Details about cost of equity and interest rate assumptions are provided in Appendix II.

A greater equity share translates into higher LCOEs, particularly for fossil fuel plants, which already face volatile fuel costs and aging infrastructure. While renewables are also sensitive to financing conditions because of their high upfront expenditure, they remain comparatively resilient because there are no ongoing fuel costs. Even under tighter financial conditions, solar PV and wind remain among the least-cost options for long-term electricity planning, offering greater cost certainty than fossil fuels in a high-risk environment.

Reducing the equity share lowers the LCOE for renewables such as solar PV, wind, and mini-hydro. Solar PV falls to USD4.9¢/kWh, while onshore wind declines to USD5.8¢/kWh, further improving their cost advantage over fossil fuels. The impact is particularly pronounced for capital-intensive technologies such as nuclear.

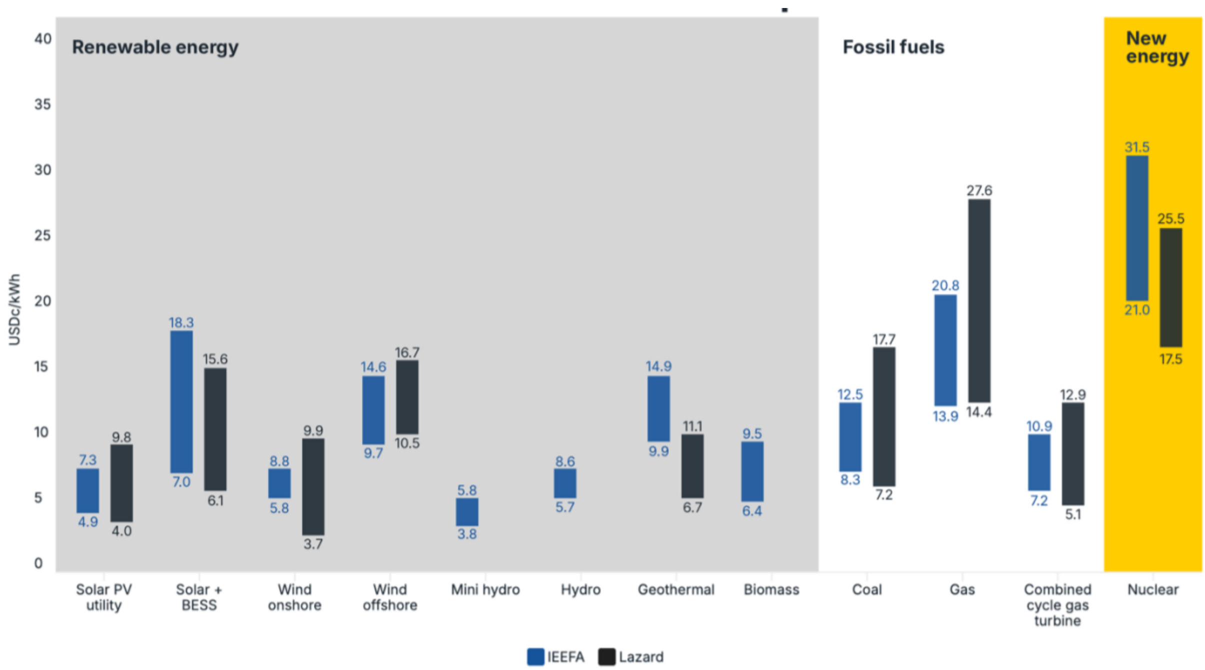
For renewable energy technologies, debt financing can significantly improve competitiveness by reducing costs. Capital-intensive projects with longer construction periods, such as geothermal and nuclear, show the largest differences. The LCOE for nuclear falls from USD54.5 per megawatt-hour (MWh) under equity financing to USD21.0/MWh under debt-equity financing. Fossil fuel projects also benefit, though their LCOEs remain higher than those of many renewable technologies.

While debt financing can lower the LCOE, fossil fuel projects increasingly face challenges in accessing loans. Banks and institutional investors are tightening lending policies due to climate commitments, environmental, social, and governance (ESG) standards, and stranded asset risks. As a result, coal and gas projects often face higher financing costs or exclusion from credit portfolios.

This difficulty in securing debt means fossil fuel projects are more likely to rely on equity financing, which raises their WACC and LCOE. In contrast, renewable projects benefit from broader access to concessional loans, green bonds, and blended finance, further improving their cost competitiveness. This sensitivity is particularly crucial in Indonesia's current context. Geopolitical uncertainty and higher government spending to offset rising oil and gas prices have weakened Indonesia's fiscal position. Consequently, major credit rating agencies, including Moody's and Fitch, revised the country's sovereign outlook to negative in early 2026, increasing financing costs and making access to capital more challenging across the economy, including for power sector investments.

A comparison between IEEFA's Indonesia-specific analysis and Lazard's US benchmarks shows similar trends. Renewables are either cheaper than or equal to fossil fuels across markets. While Lazard's dataset does not cover all the technologies available in Indonesia, the overlap reinforces the conclusion that renewables are increasingly cost-effective.

Figure 7: IEEFA and Lazard LCOE comparison

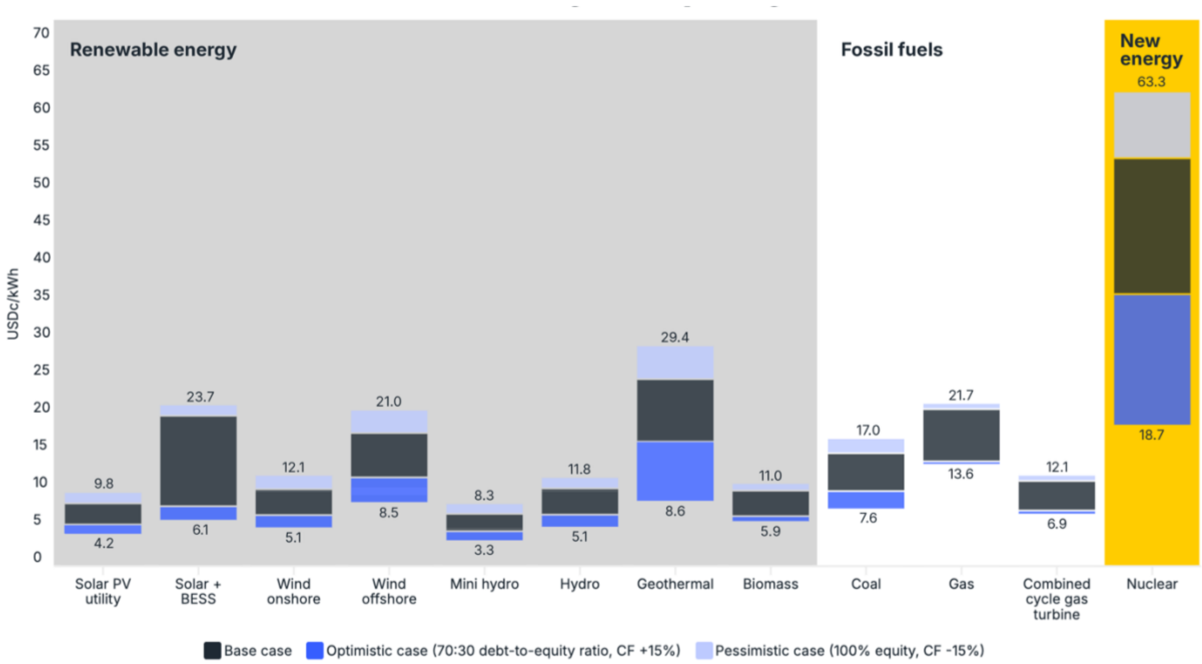


Source: IEEFA analysis.
Note: Lazard's analysis reflects US LCOE benchmarks and does not cover all technologies available in Indonesia. IEEFA's analysis applies a 70:30 debt-to-equity financing assumption.

Scenario 2: Capacity factor sensitivity

IEEFA's analysis demonstrates that renewable energy offers not only a cost advantage but also greater resilience to variations in capacity factor assumptions. Even under the lowest capacity factor scenarios, utility-scale solar PV and onshore wind remain more cost-competitive than fossil fuel technologies under the highest capacity factor assumptions. The LCOEs for solar PV and onshore wind range from USD4.2–12.1¢/kWh, while coal-fired, gas-fired, and combined-cycle gas turbine (CCGT) generation have LCOEs ranging from USD7.6–21.7¢/kWh.

Figure 8: LCOE sensitivity to capacity factor



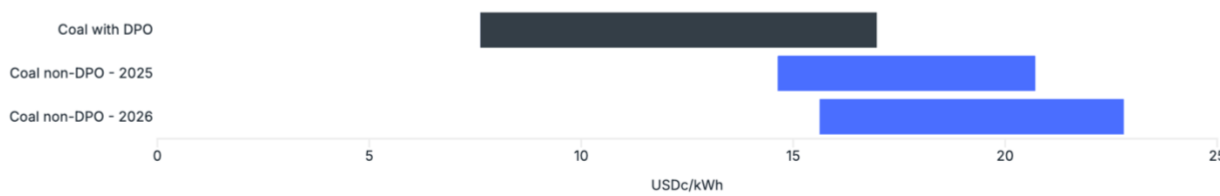
Source: IEEFA analysis.

Figure 8 shows that renewables are structurally more cost-effective and resilient under Indonesia's financing conditions, while fossil fuels and nuclear are disadvantaged by higher costs and greater risk exposure. Fossil fuel-based electricity generation remains vulnerable to market risks, resulting in high implicit costs. As renewable energy technologies become increasingly cost-competitive and remain insulated from fuel price volatility, Indonesia's electricity planning assumptions should be periodically reassessed to ensure that future investment decisions reflect the least-cost pathway for supplying electricity.

Leveraging least-cost planning and competitive procurement would allow Indonesia to diversify away from coal and gas while reducing long-term generation costs, easing pressure on government subsidies and compensation, and strengthening PLN's financial sustainability.

These findings suggest that the historical cost advantage of fossil fuel generation has narrowed substantially and, in some cases, disappeared. The LCOE of coal-fired power plants (CFPPs) is now higher than that of utility-scale solar PV, onshore wind, and hydropower. This comparison accounts for the DPO, which caps coal prices for CFPPs at USD70 per tonne. Without this policy, every USD1 increase in coal prices would raise the LCOE by USD0.06¢/kWh (Figure 9).

Figure 9: LCOE comparison for coal (with and without DPO)



Source: IEEFA analysis.

Implications for PLN's financial sustainability

In 2025, Indonesia operated approximately 80.2GW of on-grid generation capacity, 81% of which was from fossil fuels. This heavy reliance on volatile fuel markets has significant implications for PLN's financial sustainability. Rising fossil fuel costs increase the cost of electricity supply, while retail tariffs remain largely controlled by the government. As generation costs rise, the gap between PLN's supply cost and the regulated tariff widens, escalating the financial burden on both PLN and the state budget.

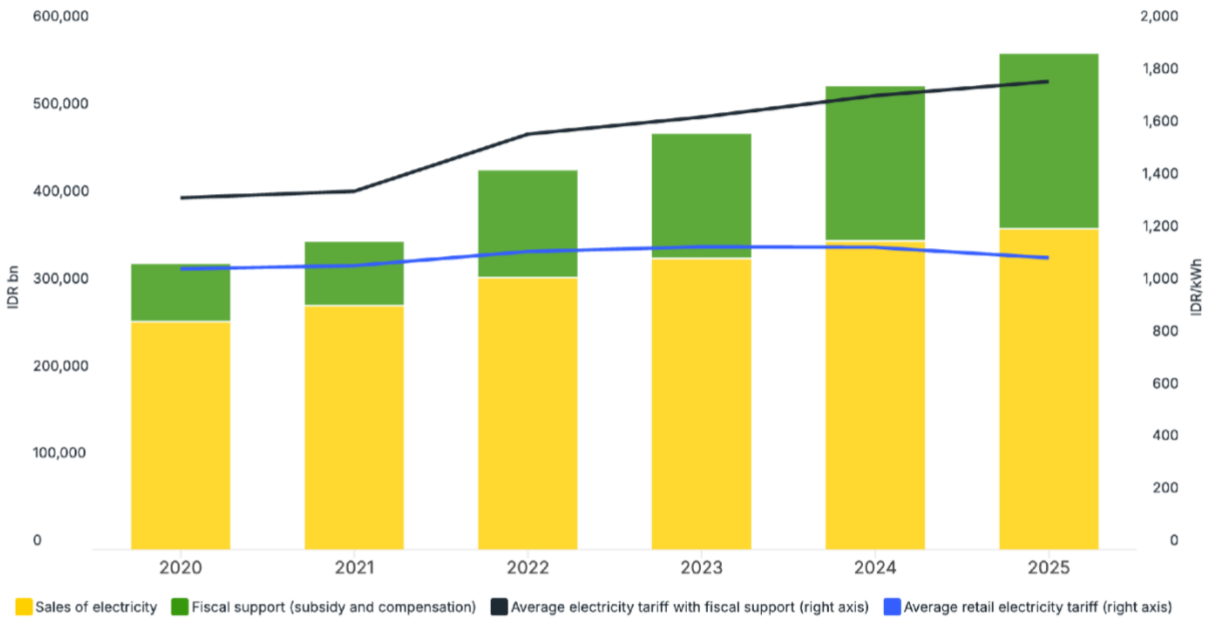
Indonesia's electricity tariff framework is based on a cost-plus margin approach, under which retail electricity tariffs are determined by PLN's allowable costs plus a regulated business margin. Under the RUPTL 2025–2034, PLN's Public Service Obligation (PSO) business is modeled using a 7% margin to estimate future subsidies and compensation. This margin is a regulatory assumption used for planning purposes rather than a guaranteed commercial return. If actual costs exceed the assumptions underpinning BPP and tariff calculations, PLN's realized financial performance may fall below the modeled outcome, increasing financial pressure on the utility and the state.

This relationship is reflected in the growing gap between electricity generation costs and regulated retail tariffs. In 2025, the average retail electricity tariff charged to consumers was approximately IDR1,112.69/kWh.[24] Meanwhile, IEEFA estimates that PLN's actual average electricity generation cost (BPP) plus business margin was IDR1,785.64/kWh. The difference was covered through government subsidies and compensation, allowing consumers to continue paying affordable electricity prices despite rising generation costs.

Over the same period, government fiscal support increased significantly from IDR65.9 trillion in 2020 to IDR200 trillion in 2025. This was more than twice the state expenditure on Nusantara, Indonesia's new capital city (approximately IDR89 trillion), through the end of 2024. As pressure on the state budget grows, reducing electricity generation costs would benefit not only consumers but also PLN's financial performance and the government's fiscal position.

[24] PLN. PLN Statistics Unaudited 2025. February 2026.

Figure 10: PLN's sales of electricity, fiscal support, and average electricity tariff



Source: PLN's audited financial reports; PLN's statistic reports; IEEFA analysis.

PLN also faces increasing financial risks from its dependence on fossil fuel generation. Although Indonesia's DMO and DPO policies help moderate domestic coal prices, they do not eliminate the underlying financial exposure. Instead, some of these costs are transferred to the government through subsidies and compensation, increasing the fiscal burden of maintaining affordable electricity.

PLN is also exposed to exchange-rate risks because fossil fuel purchases are denominated in US dollars. The Indonesian rupiah has depreciated by approximately 32%, from IDR13,542/USD in 2018 to around IDR17,849/USD in June 2026.[25] Meanwhile, electricity tariffs have remained fixed since 2022.[26] This depreciation increases fuel procurement costs, placing further pressure on the state utility and government to maintain regulated electricity tariffs. Therefore, rising electricity generation costs have implications beyond individual power projects, making it increasingly important to identify where lower-cost renewable energy can most effectively reduce these expenses.

The next section examines regional differences in electricity generation costs and determines where renewable energy can deliver the greatest economic benefit.

[25] Exchange-rates.org. Exchange rates. July 2026
[26] CNBC Indonesia. PLN Tegaskan Tarif Listrik Juni 2026 Tidak Naik!. 2 June 2026.

Renewable energy is a financial hedge

Unlike fossil fuel generation, renewable energy does not require continuous fuel purchases. This reduces exposure to global commodity price fluctuations and exchange-rate volatility, improving cost predictability over the asset's lifetime. In Indonesia, where fossil fuel imports and many energy transactions are denominated in US dollars, increasing renewable energy deployment can also reduce foreign exchange exposure and future subsidy requirements.

Renewable projects can also deliver higher and more stable profit margins than fossil fuel projects. CFPPs, in particular, face declining profitability over time as maintenance costs rise and external risks, such as supply constraints, disrupt operations. By contrast, renewable projects benefit from fixed upfront investment and minimal variable costs, allowing margins to remain resilient even as market conditions change.

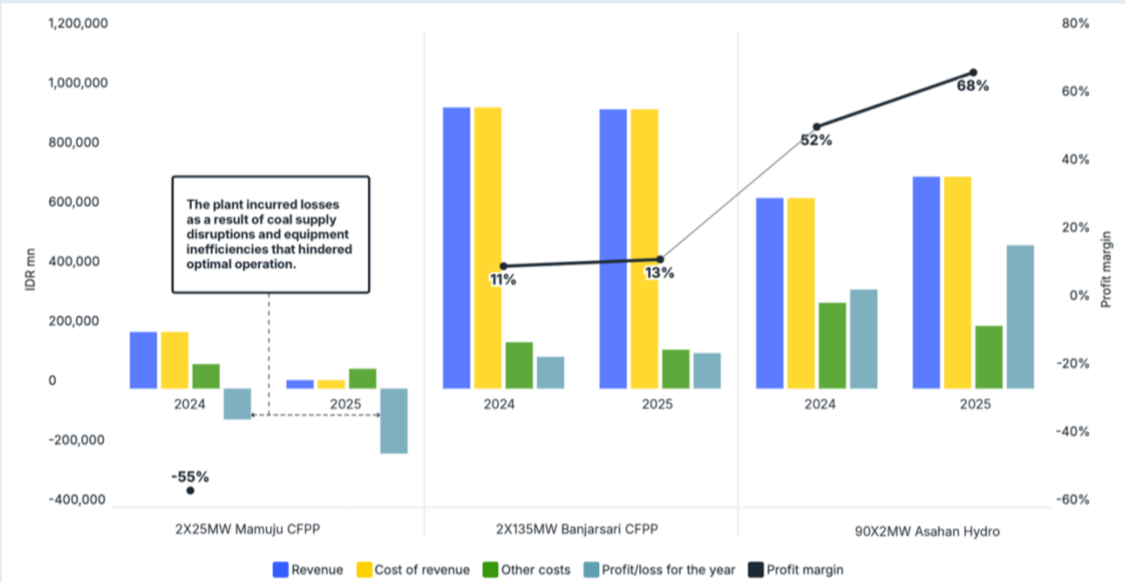
This trend is evident in PT PLN Nusantara Power (a PLN generation subholding company) projects. Financial results show clear differences between selected coal and hydropower projects. Revenue from the 2x25MW Mamuju CFPP dropped from IDR190bn in 2024 to just IDR28bn in 2025, while costs remained high.[27] Losses widened to IDR218bn, with margins turning sharply negative, reflecting significant inefficiencies and supply disruptions.

The 2x135MW Banjarsari CFPP performed relatively better, with revenue remaining stable at around IDR939bn and profits rising modestly from IDR107bn in 2024 to IDR119bn in 2025.[28] However, margins of 11–13% indicate limited profitability, leaving the plant vulnerable to rising fuel and maintenance costs.

In contrast, the 90x2MW Asahan hydropower project delivered strong results. Operational since 2011, the project generated revenues of IDR641bn in 2024 and IDR712bn in 2025, while costs remained low. Profits surged from IDR333bn in 2024 to IDR482bn in 2025[29], with margins rising to 68%. This performance highlights the efficiency and stability of hydropower, demonstrating the potential financial advantages of renewable energy over coal-fired generation.

[27] PLN Nusantara Power. Consolidated Financial Statements 2025. 23 April 2026.
[28] PLN Nusantara Power. Consolidated Financial Statements 2025. 23 April 2026.
[29] PLN Nusantara Power. Consolidated Financial Statements 2025. 23 April 2026.

Figure 11: Financial performance comparison between selected PLN CFPPs and hydropower projects



Source: PLN Nusantara Power's audited financial reports; IEEFA analysis.
Note: Solar and wind projects were not included as examples due to the limited availability of information on operational projects.

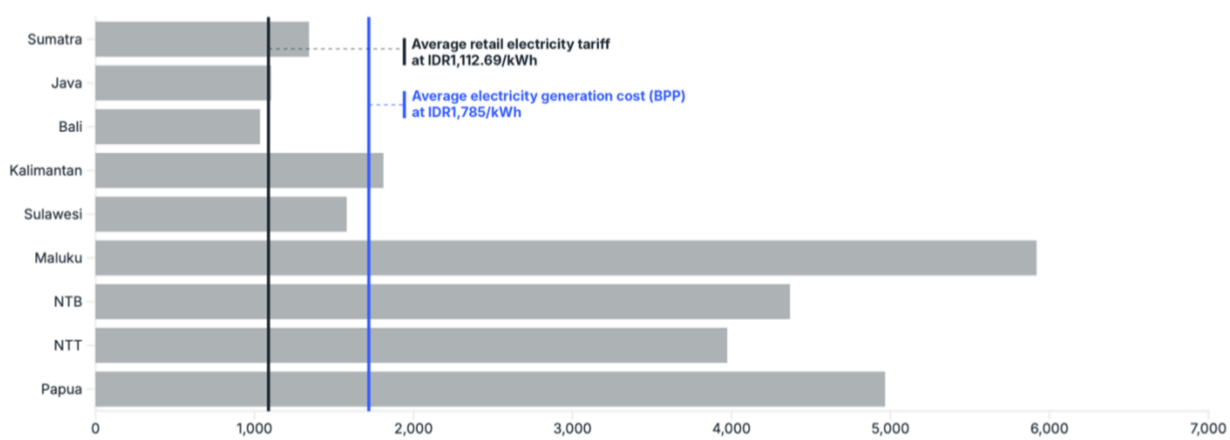
Where can Indonesia achieve the greatest savings?

Electricity costs vary significantly across regions

As an archipelago with more than 17,000 islands, Indonesia faces unique challenges in providing electricity across the country. Unlike nations with contiguous landmasses, Indonesia cannot rely on a single interconnected transmission network. Transmission lines cannot easily span vast stretches of ocean, while submarine cables remain costly and technically complex to deploy and maintain. As a result, Indonesia's electricity system comprises multiple interconnected and isolated grids, each with distinct demand profiles, generation mixes, and electricity costs. The economics of electricity vary significantly, with differences in fuel dependence, renewable resource availability, and grid configuration shaping the least-cost investment pathway for each region.

These regional differences are reflected in PLN's electricity generation costs (BPP). As shown in Figure 12, generation costs are considerably lower in the large interconnected systems of Java and Sumatra, while Maluku, Papua, West Nusa Tenggara (NTB), and East Nusa Tenggara (NTT) record some of the highest costs in Indonesia. These differences reflect the varying characteristics of regional power systems, rather than differences in electricity tariffs alone.

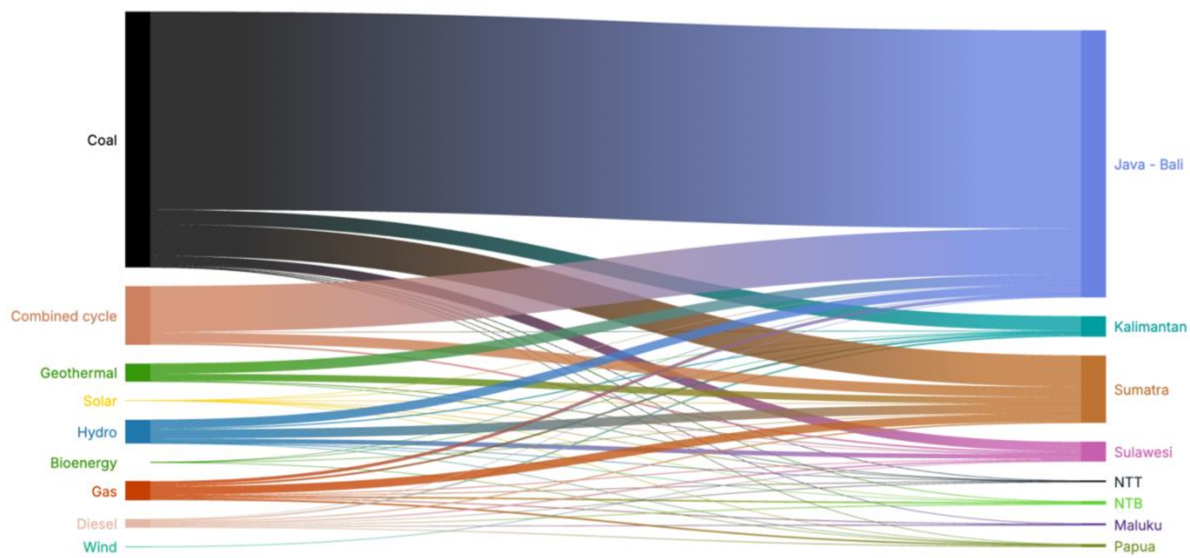
Figure 12: Generation cost by region (IDR/kWh)



Source: PLN 2025 statistics report; IEEFA analysis.

Understanding these cost differences requires examining how electricity is generated across the country. Electricity generation remains highly concentrated in western Indonesia. Of the 354TWh of electricity produced nationally, approximately 70% comes from Java, followed by 17.5% from Sumatra (Figure 13). In comparison, eastern Indonesia accounts for a relatively small share of national generation, reflecting its lower population density and smaller electricity systems.

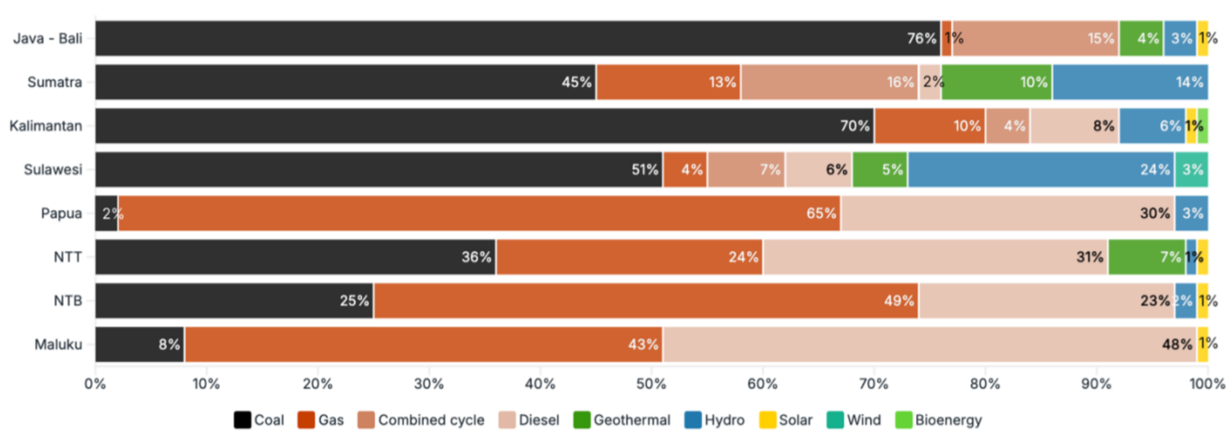
Figure 13: Electricity generation by region (GWh)



Source: MEMR. Statistik Ketenagalistrikan 2024. September 2025; PLN 2025 statistics report; IEEFA analysis.

Regional differences in generation costs are closely linked to the underlying energy mix. As shown in Figure 14, Java, Sumatra, Kalimantan, and Sulawesi rely predominantly on coal-fired power. In contrast, many electricity systems in eastern Indonesia remain heavily dependent on diesel generation because their smaller, isolated grids cannot benefit from the economies of scale available to larger interconnected systems.

Figure 14: Electricity generation share by technology



Source: MEMR. Statistik Ketenagalistrikan 2024. September 2025. IEEFA analysis.

Figures 12–14 indicate that Indonesia's electricity systems operate under varying conditions. Large interconnected systems in western Indonesia benefit from lower-cost generation technologies and economies of scale, while smaller systems in eastern Indonesia continue to depend on high-cost diesel and gas generation. These structural differences explain the significant variation in electricity costs across the country.

High-cost regions present the greatest opportunity for renewable energy

The heavy reliance on diesel and gas-fired power in eastern Indonesia presents a significant opportunity to reduce electricity generation costs. Diesel-fired generation is among the most expensive sources of electricity because it relies on imported fuel, extensive transportation logistics, and relatively small production units. Although gas is sourced domestically, its costs are highly exposed to global price volatility and exchange rate fluctuations. Together, these factors increase operating costs and leave electricity systems vulnerable to changes in fuel prices and exchange rates.

Electricity production costs in Maluku, NTB, NTT, and Papua are substantially higher than in Java and Sumatra. In several eastern systems, generation costs are four to five times higher than PLN's average selling price of electricity. These higher costs are ultimately absorbed by the utility and the government through subsidies and compensation, underscoring the financial burden of maintaining diesel-dependent electricity systems.

Eastern Indonesia has some of the country's strongest renewable energy resources. For example, NTT has among the highest and most consistent solar irradiation levels in the archipelago, yet solar deployment remains limited. Recent analysis indicates that utility-scale solar PV paired with BESS can already generate electricity at a lower cost than diesel-fired generation in many isolated systems. Crucially, solar + BESS enables firm, dispatchable supply in these systems, allowing it to replace diesel generation rather than simply displacing fuel consumption during daylight hours. Since these systems are small and isolated, this substitution can be achieved without the large-scale transmission and grid-integration investments required to assimilate renewable energy into the interconnected grids of Java and Sumatra.

Replacing diesel with renewable energy, therefore, offers multiple benefits: lower generation costs, reduced fuel imports, greater energy security, and limited exposure to volatile fuel markets. The introduction of the Ministry of Energy and Mineral Resources (MEMR) Decree No. 264/2026, which establishes a hybrid tariff framework for renewable energy projects paired with storage, further strengthens this opportunity. By providing a clear pricing mechanism for hybrid systems, the decree addresses uncertainty in PLN's procurement process and creates a pathway to scale solar + BESS in high-cost regions.

The decree also highlights important challenges. Tariff design must balance consumer affordability and investor bankability, ensuring that hybrid projects can attract financing while remaining cost-competitive. Implementation will also require PLN to modify its planning and procurement practices, which have historically favored fossil fuels.

In contrast, the western regions of Indonesia — Java, Sumatra, Kalimantan, and Sulawesi — rely predominantly on CFPPs. These larger, interconnected grids benefit from economies of scale but remain heavily dependent on coal, resulting in high emissions and continued exposure to coal price policies. However, the western regions present a different opportunity: combining solar, wind, hydro, and geothermal resources can create a diversified generation mix that lowers average generation costs over time. Geothermal and hydro could provide baseload supply, while solar and wind could complement them with variable generation, creating a balanced portfolio that reduces reliance on coal and improves cost stability.

Replacing diesel in the east and coal in the west with renewables could deliver several benefits, including lower generation costs in high-cost regions, a reduction in emissions, and improved long-term financial sustainability in the largest grids. Rather than applying a uniform approach to renewable energy deployment, Indonesia could maximize the economic value of future investment by prioritizing diesel-dependent systems in the east and diversifying coal-heavy systems in the west.

Indonesia does not face a single electricity transition. It faces multiple regional transitions, each with different economics. Future investment should therefore prioritize regions where renewable energy delivers the greatest reduction in system costs.

Aligning the RUPTL with the changing economics of electricity generation

Electricity planning should reflect current economics

Future revisions of the RUPTL should be based on the fundamentally changed economics of electricity and current market conditions rather than historical assumptions embedded in the existing system.

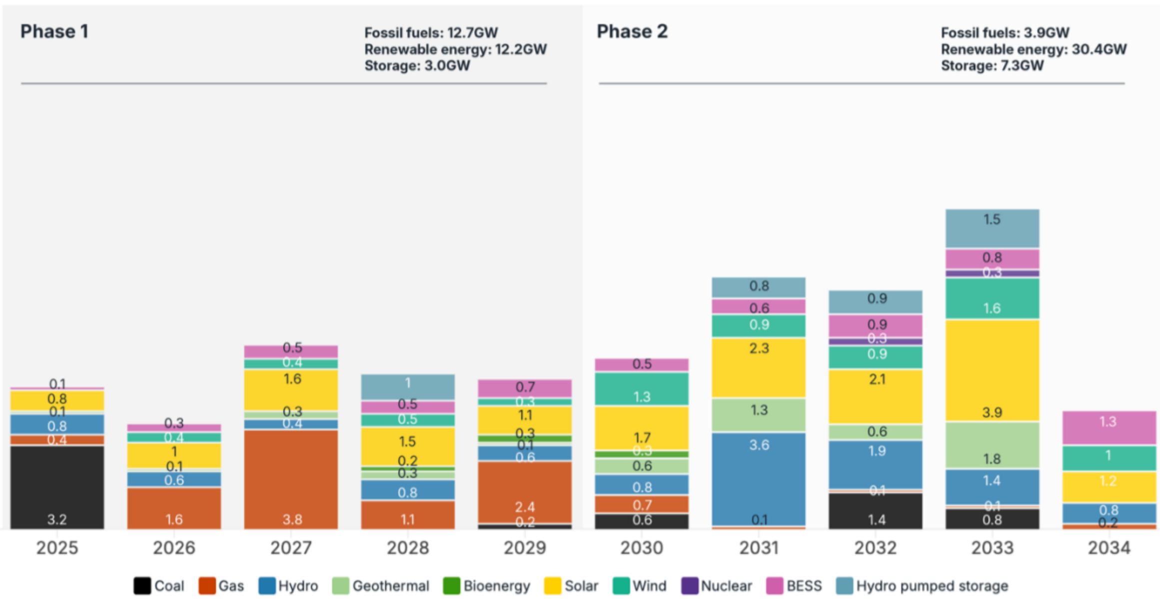
The RUPTL 2025–2034 represents a significant step forward in Indonesia's electricity transition. Compared with previous planning periods, it substantially increases renewable energy deployment, targeting 42.6GW of renewable energy and 10.3GW of storage by 2034.[30] Combined with significant investment in transmission infrastructure, the RUPTL could provide a strong foundation for expanding renewable energy while supporting Indonesia's growing electricity demand.

However, the transition is cautiously phased. During the first implementation period (2025–2029), the RUPTL allocates 12.7GW (45%) of planned capacity additions to fossil fuel generation, compared with 12.2GW (44%) for renewable energy and 3GW (11%) for energy storage.[31] A more pronounced

[30] MEMR. Electricity Supply Business Plan (RUPTL 2025-2034). 26 May 2025.
[31] MEMR. Electricity Supply Business Plan (RUPTL 2025-2034). 26 May 2025.

shift towards renewable energy occurs only in the second half of the planning period (2030–2034), when renewables become the dominant source of new generation capacity.[32] The plan's first five years continue to allocate significant capacity to fossil fuels, particularly natural gas.

Figure 15: Additional capacity plan under RUPTL 2025–2034



Source; RUPTL 2025–2034.

While gas-fired generation could support system flexibility, its long-term economics have become increasingly uncertain (Figure 4). Although Indonesia has abundant gas reserves, gas-fired electricity requires substantial investment across the value chain, including exploration, processing, transportation, and power generation infrastructure. The country's geography adds further complexity, making gas supply particularly expensive and logistically challenging due to short-distance LNG transportation. Gas-fired electricity generation also remains exposed to fuel price volatility, exchange rate fluctuations, and supply constraints arising from pipeline limitations, LNG logistics, and competing demand. These risks can significantly increase production costs and reduce cost certainty over the lifetime of gas-fired power plants.

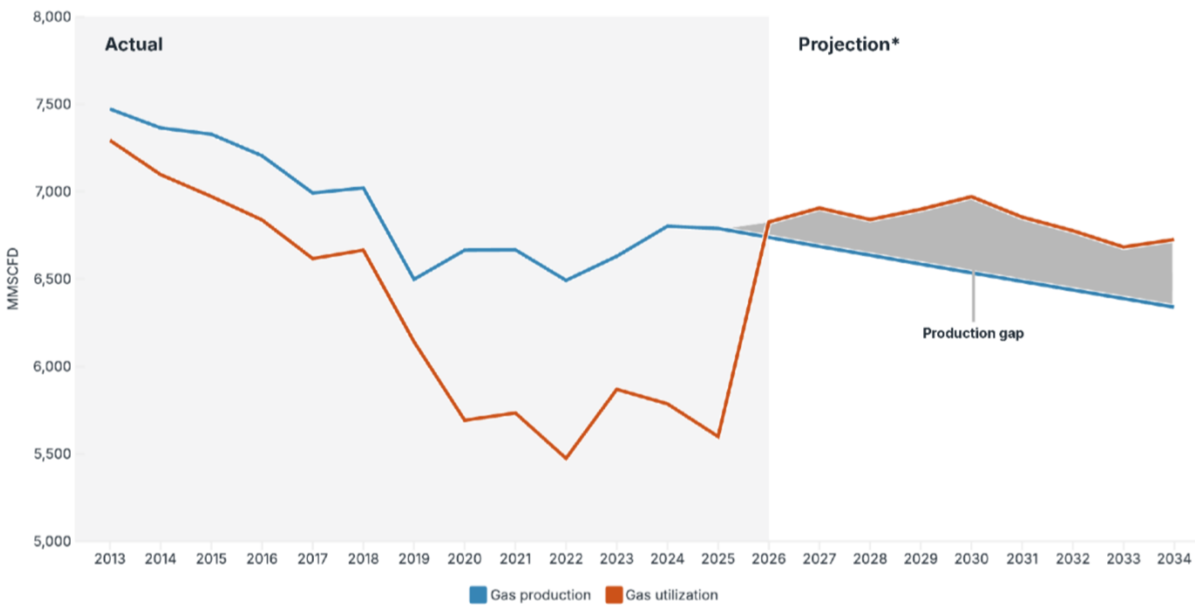
Indonesia's domestic gas reserves have declined since 2019, while new reserve additions have not kept pace with production. As domestic supply tightens, expanding gas-fired generation could increase reliance on LNG imports (Figure 15), exposing the electricity sector to international commodity price volatility and exchange-rate risks.

[32] IEEFA. The risks of fossil fuel dependence in Indonesia's Electricity Supply Business Plan (RUPTL) 2025–2034. 23 June 2025.

The development of the Masela project, operated by Japan-based INPEX Corporation through INPEX Masela Ltd., is expected to yield 9.5 million tonnes of LNG annually, along with 150 million standard cubic feet of gas per day (MMSCFD) and 35,000 barrels of condensate. However, the project is unlikely to eliminate the gas supply gap, and the economics would remain challenging. LNG from Masela is expected to be costly and would be better prioritized for hard-to-abate industries such as fertilizer production, where alternatives are limited.[33] This would allow the limited domestic gas resources to be directed towards sectors that depend most critically on them, while accelerating the power sector's transition to renewables.

In effect, the first phase targets of RUPTL 2025–2034 risk locking in exposure to expensive and volatile fossil fuel costs for the next 25–30 years.

Figure 16: Gas production and utilization in Indonesia



Source: MEMR, RUPTL 2025–2034; IEEFA analysis.
Note: Production is projected using an average annual decline rate of 0.76%, while utilization is estimated based on a 2% decline in demand combined with the additional demand outlined in the RUPTL 2025–2034.

This phased approach also reflects the need for coordinated electricity system planning. Scaling up renewable energy requires more than adding generation capacity. It also needs timely investment in transmission networks, grid flexibility, balancing capacity, and energy storage to integrate a growing share of variable renewable energy. These investments should be developed in parallel to prevent transmission constraints from becoming a bottleneck to renewable energy deployment. As highlighted in a recent IEEFA report, accelerating renewable energy utilization depends as much on

[33] The Jakarta Post. Ground Broken on Long-delayed Masela Project. 19 July 2026.

strengthening and financing the electricity network as on building new generation capacity.[34] Integrating generation, transmission, and storage planning will enable Indonesia to accelerate renewable energy deployment while maintaining reliability and minimizing long-term system costs.

The evolving role of natural gas illustrates a broader principle: long-term electricity planning should reflect changing market conditions rather than fixed assumptions about technologies. As generation economics evolve, future planning should incorporate the latest evidence on technology costs, fuel markets, system reliability, and regional electricity economics to ensure that investment decisions follow the least-cost pathway.

Renewable energy technologies, particularly grid-forming inverters and BESS, are challenging the traditional assumptions about how load balancing, frequency regulation, and voltage control are delivered. Power systems no longer require 100% fossil fuel-based dispatchable capacity to maintain power quality. Large grids comparable in scale to the Java-Bali grid (with around 200TWh of annual electricity demand) are routinely served by high shares of renewable energy:

- California, with an electricity demand of 278TWh[35], operated with 100% renewable energy for more than 20% of 2025 and reached 100% renewable energy supply at some point on more than 76% of days during the year.[36]
- Spain, with an electricity demand of 270TWh[37], averaged 33% of solar and wind during 2025.[38] During the Middle East conflict, Spain also recorded some of the lowest electricity prices in Europe due to the insulating effect of renewable energy.[39]

However, power system constraints are not uniform across Indonesia. The factors that support a phased transition in large interconnected systems apply less strongly in the isolated, diesel-dependent systems of eastern Indonesia. In these systems, the generating units being replaced are small, and solar PV combined with BESS can provide firm, equivalent power without the extensive transmission expansion required for large-scale integration in Java or Sumatra.

The Maldives, as an island nation reliant on expensive diesel generation, provides an example of similar challenges. In 2012, when the Government of the Maldives began its partnership with the Climate Investment Funds (CIF) Scaling Up Renewable Energy Program in Low Income Countries (SREP), the Asian Development Bank (ADB), and the World Bank, renewables contributed just 1% of the national energy mix. Grid systems distributed across the country’s islands and atolls relied on costly diesel generators operating on fuel shipped from the capital, Malé. Since the SREP program

[34] IEEFA. Unlocking Indonesia's transmission grid investment. 12 May 2026.
[35] California Energy Commission. 2024 Total System Electricity Generation. Accessed July 2026.
[36] California Energy Commission. Tracking Progress Toward 100% Clean Energy. Accessed July 2026.
[37] Red Electrica. The Spanish Electricity System in 2025': Electricity demand, generation, and installed power capacity increase. 11 March 2026.
[38] The Renewable Energy Institute. Spain's Renewable Energy Sector Hits New Milestones. 6 January 2026.
[39] Ember. Renewables shield Spanish consumers from elevated gas prices. 16 June 2026.

was launched, the share of renewable energy in the national energy mix has increased fivefold, with solar installations reaching 70% of inhabited islands.[40]

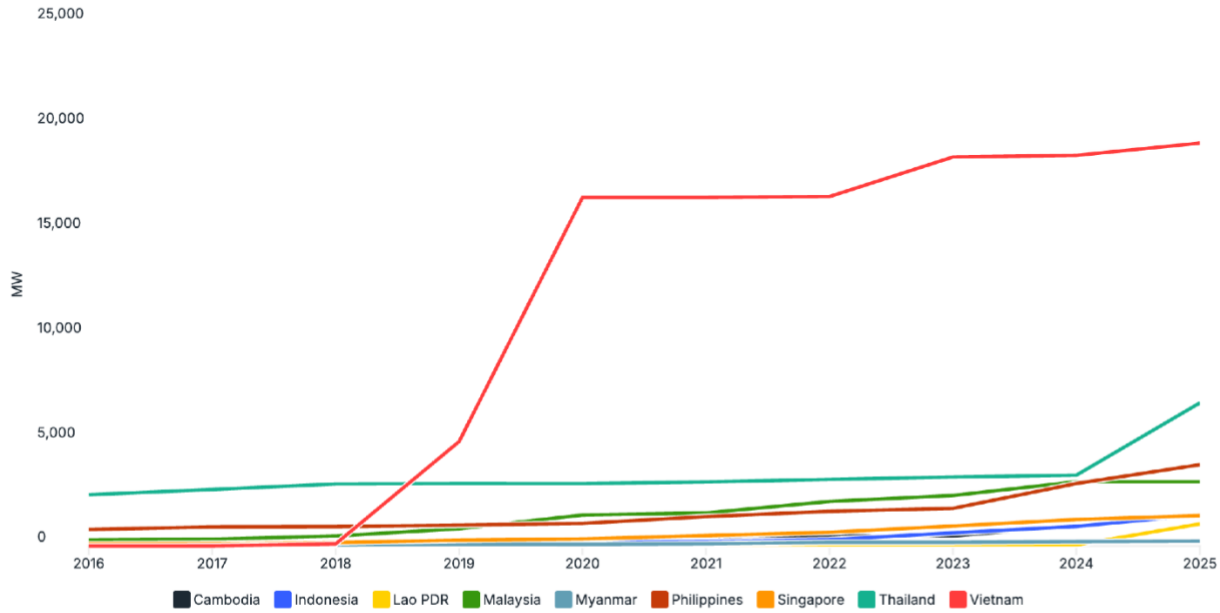
Beyond solar and BESS, some supporting investment will still be needed, including adequate storage and, in some systems, local network upgrades. However, the grid-integration challenges that warrant caution in major systems are largely absent in the regions where potential cost savings are the most significant. Thus, there is limited economic or technical rationale for deferring renewable deployment in these areas to the second phase of the planning period.

Regional experience also shows that renewable energy can be procured at highly competitive prices when supported by effective procurement frameworks and an enabling investment environment. Vietnam has achieved some of the lowest tariffs in the region, with recent utility-scale projects securing PPAs at USD2.7–3.4¢/kWh for hydropower, USD3.9–5.3¢/kWh for solar PV, and USD7.0–7.6¢/kWh for onshore wind.[41] The Philippines, despite higher electricity prices due to the absence of subsidies, has also achieved competitive outcomes. Hydropower projects have been contracted at USD2.7¢/kWh, while geothermal tariffs range from USD3–11¢/kWh.[42] High retail tariffs have further accelerated solar adoption, supported by government loans of up to PHP500,000 for rooftop solar at a 5% interest rate, below prevailing market rates.

Indonesia's new 100GW solar target presents an opportunity to translate this ambition into electricity planning. Experience across the region shows that gigawatt-scale additions are achievable with appropriate policies and investment support. Vietnam has already deployed 19GW of solar and 6.2GW of wind, while Thailand has reached 6.8GW of solar and 1.5GW of wind capacity. The Philippines operates 3.9GW of solar and 518MW of wind. Beyond Southeast Asia, the scale is even more significant. China has built 1,202GW of solar and 640GW of wind capacity, while India has achieved 56GW of solar and 55GW of wind.[43] These examples demonstrate that rapid renewable deployment is achievable at scale. Indonesia should similarly translate its 100GW solar target into clear and actionable deployment plans.

[40] Climate Investment Funds (CIF). Empowering Policy Collaborations for Maldives' Energy Transition. 6 February 2026.
[41] Compiled from various sources: (1) Hydropower – Lowest rate: UNFCCC CDM. Dong Nai 2 project financial analysis. November 2012; Highest rate: UNFCCC CDM. Hoi Xuan project financial analysis. July 2011; (2) Solar PV: Vietnam's Solar Feed-in Tariffs in 2025: Incentivizing Energy Storage; (3) Wind: Vietnam 2025 ceiling power tariff.
[42] Compiled from various sources: (1) Hydropower – Low rate: Philippine Energy Regulatory Commission (ERC). Magat project; High rate: San Roque; (2) Geothermal: Makban. (In the Philippines, electricity rate might differ based on the time. Therefore, the same power plant may have different electricity rates).
[43] IRENA. Renewable Energy Statistics 2026. July 2026.

Figure 17: Solar power capacity in selected ASEAN countries (2016–2025)



Source: IRENA; IEEFA analysis.

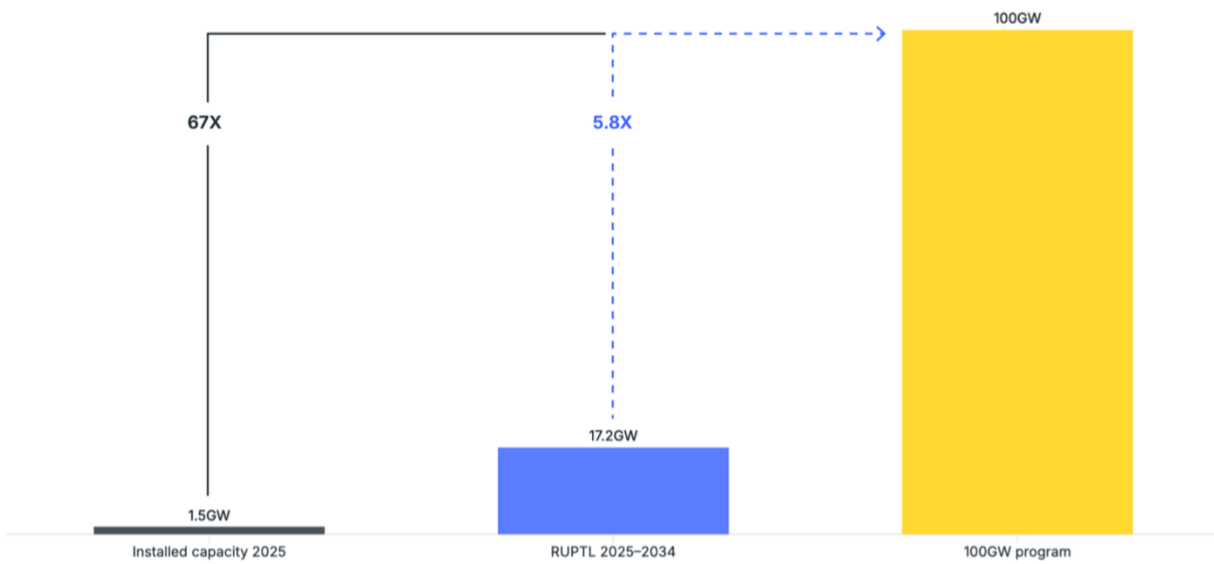
These findings suggest that future revisions of the RUPTL should focus not only on meeting renewable energy capacity targets, but also on ensuring that generation planning reflects current electricity economics. Least-cost planning should be dynamic: as technology costs, fuel prices, financing conditions, and electricity demand evolve, so should the assumptions that underpin Indonesia's electricity planning. This is particularly relevant in diesel-dependent regions, where the case for accelerating renewable energy deployment is most compelling and barriers to deployment are relatively low.

Unlocking the full potential of Indonesia's 100GW solar program

Indonesia's 100GW solar program is one of Southeast Asia's most ambitious renewable energy targets. It could help reduce electricity costs, strengthen energy security, and accelerate the transition away from fossil fuels. The RUPTL 2025–2034 currently targets 42.6GW of renewable energy capacity, including 17.2GW of solar, and 10.3GW of storage by 2034. However, this falls short of the presidential mandate. Incorporating the 100GW target into the RUPTL would more than double planned renewable capacity additions and require a 67-fold increase from the 1.5GW of solar capacity installed in 2025.[44]

[44] MEMR. Capaian Positif Tahun 2025, Negara Hadir Penuhi Kebutuhan Energi Masyarakat. 9 January 2026.

Figure 18: Solar capacity gap



Source: MEMR; RUPTL 2025–2034.

High-cost, diesel-dependent regions in eastern Indonesia already demonstrate the economic case for solar + BESS, with generation costs four to five times higher than PLN's average selling price. However, scaling solar development nationally will require a diversified strategy that leverages ground-based, floating, and rooftop technologies.

Ground-based solar power plants

Ground-based solar is expected to deliver the bulk of Indonesia's 100GW solar program because of its scalability and relative ease of deployment. Utility-scale projects typically range from 50MW to 500MW, meaning the national target would require hundreds of installations across the archipelago. The RUPTL 2025–2034 currently allocates 17.2GW of solar capacity by 2034, with a significant share expected to come from ground-based projects. To align with the presidential mandate, Indonesia would need to more than double this allocation, establishing ground-based solar as the backbone of future capacity expansion.

The success of ground-based solar projects will depend on a robust procurement framework that can attract private investment at scale. This requires transparent tendering processes, predictable tariff structures, bankable PPAs, and long-term contracts that provide certainty to developers and financiers. The introduction of a hybrid tariff framework for solar + BESS under MEMR Decree No. 264/2026 is an important step, providing greater clarity for projects that combine solar with storage. However, further regulatory certainty is needed to unlock financing and accelerate deployment.

Land availability is another critical constraint. Deploying tens of gigawatts of ground-based solar could require hundreds of thousands of hectares of land, creating competition with agriculture, forestry, and other land uses. The government should establish clear guidelines on land acquisition, permitting, and community engagement to minimize conflict and delays. Prioritizing underutilized land, industrial zones, degraded areas, and brownfield sites could help reduce social resistance and accelerate deployment. Additionally, integrating land-use planning into the RUPTL framework could also help ensure that solar expansion is geographically balanced and aligned with regional electricity demand.

Floating solar power plants

Floating solar power plants could play a strategic role in Indonesia's energy transition by addressing land constraints in densely populated regions. Unlike ground-based projects, floating solar uses reservoirs, lakes, and other water bodies, reducing competition for land and the risk of disputes. Floating PV could also deliver higher energy yields, with annual output up to 12% higher than ground-mounted panels, due to higher irradiance (albedo effect) and lower, more stable operating temperatures for PV cells and conductors installed over water.[45]

Indonesia has a floating solar potential of 91.6GW, including 74.6GW across 36 lake sites, 1.8GW across 12 micro-hydro sites, and 14.7GW across 259 dam sites. An additional 450MW of hydropower could also be integrated into the national energy mix.[46] This substantial potential positions floating solar as an important component of Indonesia's future generation mix. Integrating it into the RUPTL could accelerate progress toward the goals of the presidential mandate while diversifying Indonesia's solar portfolio.

Rooftop solar

Rooftop solar offers one of the most direct ways for consumers to participate in Indonesia's energy transition. However, adoption remains limited due to structural barriers, including restricted net metering, quota limitations, high upfront costs, and subsidized electricity tariffs.[47] Expanding rooftop solar quotas and introducing stronger incentives, such as tax credits, concessional loans, and meaningful net metering, could accelerate adoption among households and businesses by lowering upfront costs and improving payback periods. Enabling consumers to generate their own electricity could also shift the energy transition from being utility-driven to community-driven, fostering broader participation in clean energy.

Rooftop solar could also deliver significant economic benefits. For PLN, widespread adoption could reduce the subsidy burden by offsetting electricity demand in high-cost regions where generation costs exceed regulated retail tariffs. This could generate fiscal savings while improving energy security. Importantly, rooftop solar requires no capital expenditure from PLN, as households and businesses finance and install the systems themselves.

[45] EA-Energy Analyses. Technology Data for the Indonesian Power Sector 2024. March 2024.
[46] MEMR. Tarif Kian Kompetitif, Pemerintah Utilisasi Potensi PLTS Terapung 91,6 GW. 17 January 2024.
[47] IEEFA. Indonesia's Blackouts Expose the Need for Rooftop Solar. 29 June 2026.

The scale of the rooftop solar opportunity is substantial. As of 2025, PLN served approximately 87 million households, each consuming an average of 1.5MWh of electricity annually, and around 5.6 million businesses, each with an average annual consumption of 11MWh If 10 million households and 1 million businesses installed systems averaging 3–5kW each, rooftop solar could contribute 30–40GW of capacity nationwide. This could represent nearly the entire renewable energy capacity planned in the first phase of the RUPTL 2025–2034, which allocates 12.2GW of renewables by 2029 and 30.4GW by 2034.

The current RUPTL allocates 3,037 MW of new rooftop solar over the next nine years. While this provides an important starting point, it also highlights the vast untapped potential of distributed solar generation in Indonesia. Embedding rooftop solar into the RUPTL would accelerate progress toward the 100GW solar target, while diversifying Indonesia’s solar portfolio beyond utility-scale projects.

Recommendations for reinforcing Indonesia's electricity planning framework

IEEFA recommends the following actions to reduce electricity generation costs, strengthen energy security, and support a sustainable transition:

1. Update planning assumptions to maintain flexibility and affordability

Indonesia's electricity planning framework should evolve with changing market conditions. While BPP has historically provided a useful benchmark for electricity costs, it reflects the cost of the existing system rather than identifying the cheapest options for future investment. As renewable energy technologies become increasingly cost-competitive and conventional generation expenses continue to rise, future planning should place greater emphasis on forward-looking economic assessments that account for lifetime generation costs, fuel price risks, and regional system characteristics. This approach could help avoid locking in fossil fuel assets and ensure investment follows the least-cost pathway.

Future planning should also remain responsive to changing electricity demand. Indonesia's experience with the 35GW power capacity addition program highlights the importance of maintaining flexibility in long-term planning.[48] This experience demonstrates that electricity demand, project development, and investment conditions do not always progress as expected. Regularly reviewing demand forecasts and generation plans could help minimize the risk of overcapacity while ensuring a reliable and affordable electricity system.

Maintaining cost-effective electricity should remain a critical policy objective. Under the current regulatory framework, when PLN's electricity generation costs exceed regulated retail tariffs, the difference is covered by government subsidies and compensation. The RUPTL projects an average BPP of approximately IDR1,798/kWh during 2025–2034, based on assumptions that include an

[48] IEEFA. Pathways to Financial Sustainability for PLN through Renewable Energy Development. 13 May 2024.

exchange rate of around IDR16,000–16,100 per US dollar and continued government support. Currently, subsidies and compensation account for 34% of PLN's revenue[49], and this share has been steadily increasing. Identifying lower-cost energy supply options, particularly alternatives to coal and gas, is essential to maintaining fiscal discipline and keeping electricity affordable. As generation costs evolve, applying least-cost planning to future investment decisions could help reduce long-term subsidies while strengthening PLN's financial resilience.

2. Prioritize high-BPP regions and differentiate by area

Regional differences should play a greater role in electricity planning. Generation costs vary significantly across Indonesia, particularly between the large interconnected systems in the west and the isolated, diesel-dependent systems in the east. Rather than applying a uniform approach to renewable energy deployment, future RUPTL revisions should prioritize investments where renewable energy can deliver the largest reductions in system costs. Replacing diesel generation with solar PV and BESS presents a clear opportunity to lower electricity costs while improving energy security in the country's eastern region.

In coal-heavy western grids, diversifying the energy mix with solar, wind, hydro, and geothermal can reduce long-term generation costs and reliance on coal. Future RUPTL revisions should reflect regional resources and electricity systems to ensure investment is directed toward the most economical options.

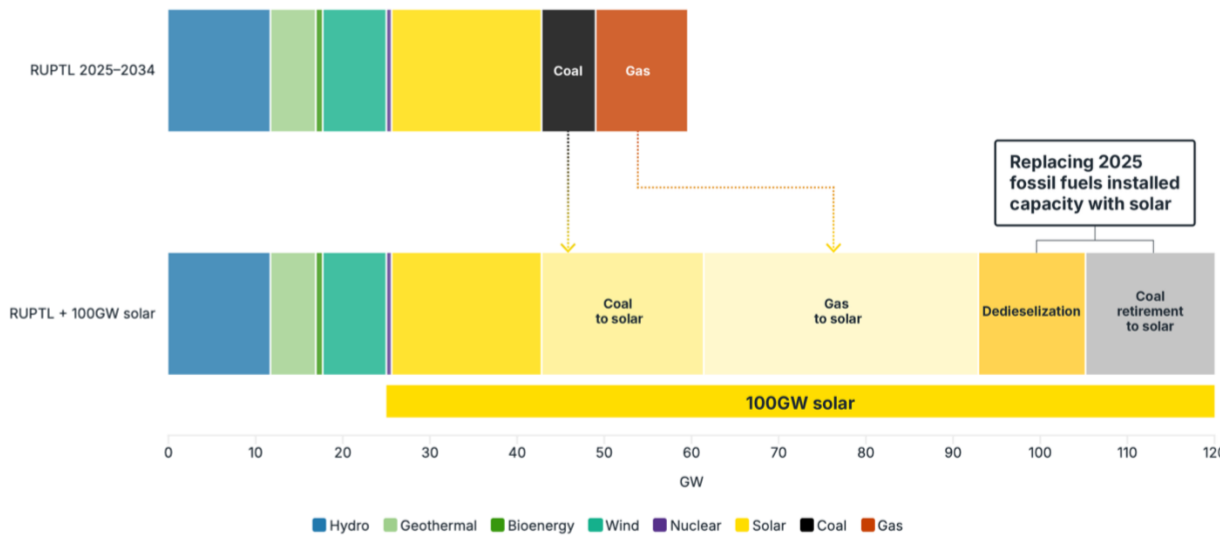
3. Integrate the 100GW solar program into RUPTL

The 100GW solar program should be embedded in Indonesia's electricity planning framework rather than treated as a stand-alone ambition. Integrating the target into least-cost system planning would ensure that new solar capacity is deployed where it delivers the greatest economic and technical advantages. RUPTL revisions should incorporate a balanced portfolio of ground-based solar, floating solar (up to 91.6GW potential across lakes and dams), and rooftop solar (30–40GW potential from households and businesses).

Indonesia should also adopt an early retirement strategy for inefficient fossil fuel power plants, particularly aging coal facilities. Retiring these plants ahead of schedule would free up grid capacity, reduce subsidies, and create space for renewable additions, directly supporting the achievement of the 100GW solar target.

[49] PLN. Consolidated Financial Statement 2025. 19 May 2026.

Figure 19: Substituting RUPTL 2025–2034 and 2025 installed fossil capacity with 100GW solar



Source: MEMR; RUPTL 2025 – 2034.
Note: Replacing coal and gas capacity requires approximately three times as much solar to produce the same amount of electricity, while diesel replacement requires about twice as much solar.

4. Expand transmission and energy storage

Scaling renewable energy requires more than just adding generation capacity. Timely investment in transmission networks, grid flexibility, balancing capacity, and appropriately sized storage is essential to integrate a growing share of renewables. Transmission upgrades would reduce curtailment and bottlenecks, while BESS could provide dispatchable power, frequency regulation, and voltage control. Coordinating generation, transmission, and storage planning could help maintain system reliability, minimize long-term costs, and avoid overcapacity risks.

5. Strengthen private sector participation

Achieving renewable energy capacity targets will require substantial private investment. As Indonesia scales up deployment through the RUPTL and the proposed 100GW solar program, it will need to attract private sector participation on a consistent, predictable, and reliable basis. Strengthening the investment framework through bankable PPAs, transparent procurement, regulatory certainty, and appropriate market mechanisms — including power wheeling — could help mobilize private capital while reducing financing costs and accelerating project delivery. A stronger partnership between PLN and private investors will be essential to delivering Indonesia's long-term electricity transition.

Conclusion

For decades, Indonesia's electricity planning has assumed that coal is the cheapest source of electricity. This premise no longer holds. Domestically sourced natural gas has been viewed as a complement to coal but has proven to be far more expensive. Rising fuel prices, exchange-rate depreciation, and higher operating costs have increased the cost of fossil fuel generation, while declining technology costs have made renewable energy increasingly competitive. In the diesel-dependent systems of eastern Indonesia, the case is already clear: solar PV paired with BESS can deliver firm electricity at a lower cost than the diesel generation it would replace.

Continuing to plan electricity system development based on historical assumptions is likely to prove uneconomical. Every new fossil fuel plant commissioned on the basis that it is the cheapest option locks in decades of exposure to volatile fuel prices and exchange-rate risks. When these costs exceed regulated tariffs, the difference is absorbed by PLN and, ultimately, the state budget through subsidies and compensation. Planning assumptions that no longer reflect market conditions therefore do more than misallocate individual projects. They commit the electricity system to higher long-term costs and increase the fiscal burden of maintaining affordable electricity. The longer these assumptions persist, the more embedded this financial burden becomes.

The opportunity, however, is equally significant. Aligning electricity planning with current economics would allow Indonesia to expand renewable energy while reducing system costs. Least-cost renewable deployment can lower generation costs, improve energy security, reduce dependence on imported fuel, and insulate the electricity system from commodity price and exchange-rate volatility. These benefits are most significant where costs are highest: in high-BPP, diesel-dependent regions where renewable resources are strong and barriers to deployment are relatively low.

Indonesia does not face a single electricity transition but multiple regional ones. Realizing this opportunity will require the planning framework to evolve. Future RUPTL revisions should reflect current and projected generation costs rather than historical cost structures, prioritize investment in high-cost regions where renewable energy could deliver the highest savings, and integrate the 100GW solar program through least-cost system planning rather than simply adding capacity targets. Expanding transmission and energy storage, while strengthening private sector participation through bankable PPAs and transparent procurement, will also be essential to mobilize investment at the required scale.

Ultimately, the objective should not simply be to deploy more renewable energy, but to build a financially sustainable electricity system. The assumptions that underpinned Indonesia's electricity planning in the past reflected the conditions of the time. As generation economics evolve, ensuring that planning decisions keep pace will be critical to delivering an energy transition that is sustainable, affordable, and resilient.

Appendix I: Understanding LCOE

General Formula:

$$LCOE = \frac{NPV\ of\ Total\ Costs\ Over\ Lifetime}{NPV\ of\ Electrical\ Energy\ Produced\ Over\ Lifetime}$$

Source: Corporate Finance Institute[50]

The outcome of the LCOE calculation is shaped by several critical variables. These include:

Category	Component	Description	Impact on LCOE
Cost Over Lifetime	Initial Investment Costs	These costs include all expenditures to construct the energy asset.	Higher upfront costs increase LCOE, while lower capital costs improve competitiveness.
	Cost of Capital	These costs can include interest paid on loans, costs from selling shares, and issuing bonds. Cost of capital is the cost incurred to obtain project funding.	Higher financing costs increase LCOE; lower costs improve project viability.
	Operation and Maintenance (O&M) Costs	O&M costs are used to maintain equipment. The amount depends on the size, technology, and location of the power plant. Typically, O&M costs for renewable energy-based power plants are lower than those for fossil fuels due to fluctuating fuel prices. The higher the O&M costs, the higher the LCOE.	Higher O&M costs raise LCOE. Renewables typically have lower O&M costs than fossil fuels.
	Fuel Cost	This cost is only calculated for units that require fuel, such as coal-fired power plants, gas or diesel power plants.	Volatile fuel prices can significantly increase LCOE, while renewables avoid this cost.
Energy Produced	Capacity Factor	The capacity factor is obtained by comparing the energy produced by an energy asset over a specified period of time to the energy produced by the unit when fully operational during that period.	Higher capacity factors lower LCOE by maximizing utilization of the asset.
Net Present Value (NPV)	Analysis Period	The analysis period can be the expected lifespan of an energy asset which usually ranging from 20 to 30 years.	Longer lifespans spread costs over more years, reducing LCOE.
	Discount Rate	The discount rate is the interest rate used to calculate the present value of future cash flows.	A higher discount rate raises LCOE, reducing attractiveness of long-term projects.

[50] Corporate Finance Institute. Levelized Cost of Energy (LCOE). 15 January 2020.

Appendix II: Assumptions for LCOE

Technology	Initial Investment Cost (USD Million / MW)	Cost of Equity	Cost of Debt	Operating Costs (including major maintenance) (USD/MW)	Fuel Cost (USD/ MWh)	Variable O&M (USD/MWh)	Capacity Factor*	Construction Period. (Months)	Analysis Period (Years)
Utility Solar PV	0.77 – 1.15	10.0%	7.4%	12,574.5	-	-	20.5%	12	21.0
Solar PV + BESS	1.10 – 2.00	10.0%	7.4%	68,750.0	-	-	20.5%	12	21.0
Wind - Onshore	1.28 – 1.92	10.0%	7.4%	28,000.0	-	-	28.0%	18	31.5
Wind - Offshore	2.75 – 4.12	10.0%	7.4%	51,454.7	-	-	36.0%	36	33.0
Mini Hydro	1.60 – 2.40	10.6%	7.8%	37,485.2	-	-	55.0%	24	32.0
Hydropower	1.99 – 3.00	10.6%	7.8%	23,891.3	-	12.8	55.0%	36	33.0
Geothermal	4.00 – 6.00	14.0%	10.6%	131,000.0	-	-	85.3%	120	40.0
Biomass Power Plant	1.45 – 2.18	10.0%	7.4%	111,558.3	-	29.2	85.0%	30	32.5
Coal-Fired Power Plant	1.7 – 2.56	13.3%	11.3%	64,940.4	29.4	0.6	70.0%	96	38.0
Gas-Fired Power Plant	0.98 – 1.48	13.3%	11.3%	24,064.2	117.0	0.1	70.0%	18	31.5
Combined Gas Cycle	1.00 – 1.61	13.3%	11.3%	16,475.4	46.6	4.9	80.0%	25	27.1
Nuclear	5.80 – 8.70	14.5%	13.0%	-	5.5	27.5	85.0%	180	75.0

**Based on MEMR's Technology Data for Indonesia Power Sector 2024*.

Cost of debt (interest rate) assumptions by technology

1. Solar, wind, and biomass: Based on the average SOFR (July 2023 – July 2026) + 175 bps margin.
2. Hydro: Benchmark derived from PT Arkora Hydro loan interest rate.
3. Geothermal: Calculated using Cost of Debt = US Risk-Free Rate + Indonesia Country Premium + Liquidity Premium + Project Premium + 175 bps margin.
4. Coal and gas: Based on BI Rate + Lending Facility Rate.
5. Nuclear: Given Indonesia's limited experience with nuclear power and the high level of uncertainty, the cost of debt for nuclear projects is expected to face elevated financing costs and is considered a high-risk option.

Cost of equity assumptions by technology:

1. Hydro and mini hydro used Arkora hydro cost of equity (Source: Alpha spread)
2. Geothermal used PT Pertamina Geo Energy cost of equity (Indonesia risk free rate + (beta x risk market premium))
3. Coal, gas and CCGT used PT Cikarang Listrindo cost of equity (Indonesia risk free rate + (beta x risk market premium))
4. Fossil fuel cost of equity added by the difference between fossil fuel cost of equity and nuclear cost of equity in US and Europe which is 1.2% (Source: Energy Policy Journal)

About IEEFA

The Institute for Energy Economics and Financial Analysis (IEEFA) examines issues related to energy markets, trends and policies. The Institute's mission is to accelerate the transition to a diverse, sustainable and profitable energy economy. www.ieefa.org

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