



Powering Indonesia's Growth

A More Electrified, More Renewable
Economy With Solar At Its Core

Prepared by

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The authors also wish to extend their appreciation to the many other stakeholders and contributors who supported the research but could not be individually mentioned in this report.

Forewords



Eka Satria

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Indonesia has an immense renewable resource base, from solar irradiation across the archipelago to the world's largest geothermal potential and substantial hydropower. Yet this potential remains untapped. Meanwhile, Indonesia will need more electricity as our economy grows, industry expands and transport, households and sectors such as data centres become electrified.

This report is important because it shows that the energy transition can support Indonesia's growth. It finds that electricity demand could grow by around 7 percent annually, while a more electrified economy supplied by renewables could strengthen industrial competitiveness, reduce fuel imports and lower power-system costs. Renewables should therefore be viewed not simply as an environmental objective, but as critical industrial infrastructure.

For APLSI, the priority is to build a power system that remains reliable, affordable, secure and progressively cleaner. Solar will play an increasingly important role, alongside storage and stronger grids, while geothermal, hydro, gas and eventually nuclear can support system reliability. The Government's 100 Gwp solar programme provides direction, but ambition must now be translated into bankable projects.

The private sector is ready to invest. What we need is a clear and predictable framework: competitive procurement, reasonable tariffs and risk-adjusted returns, land and grid access, efficient permitting, appropriate risk allocation and long-term regulatory certainty. Renewable electricity exports can also provide an early catalyst, bringing investment, foreign exchange and scale to Indonesia's renewable supply chain.

Our expectation is straightforward: We, the Government, PLN and industry must work together to turn targets into projects and projects into competitive electricity. If we get the framework right, Indonesia's energy transition can become not a burden on growth, but one of its engines.



Fabby Tumiwa

CEO, IESR



Indonesia's next phase of economic growth depends on a power system that is affordable, reliable and clean. IESR has long argued that the energy transition is not a burden on development, but a condition for competitiveness, and support 8 percents economic growth goal.

This report strengthens that case: electrification could lift electricity demand growth to around 7 percent per year, and a least-cost mix built around solar and storage could meet that demand at 5 to 15 percent lower total system cost by 2035, without adding new coal or gas plants.

This should change the policy debate. The central question is no longer whether Indonesia can afford a renewable power system, but whether policy, regulation and investment can move fast enough to build it. The government's 100 GWp solar programme sets the right level of ambition; it now needs an implementation framework that makes large-scale solar, storage and grid expansion bankable and timely. The priorities are practical and urgent: secure suitable land, streamline permitting, accelerate grid connection, improve procurement, and lower financing costs. The modelling shows the destination is within reach; policy must now turn evidence into installed capacity.



Lord Adair Turner

Co-chair, Energy
Transitions Commission



Energy
Transitions
Commission

Across the world the economics of clean power have changed faster than almost anyone predicted: Over the past three years the cost of solar modules and batteries has roughly halved, so every dollar of investment now buys twice as much clean electricity. Across the world's sun belt, solar plus storage is becoming the cheapest source of new power.

Indonesia sits squarely in that sun belt, with significant solar irradiation across its geography. Yet solar generation costs in Indonesia remain high and unpredictable, spanning 5 to 10 cents per kilowatt-hour depending on the project, against around 3 cents in India. Solar deployment is held back not by the resource but by the cost of land, grid connection and finance. This report shows that those costs can fall by 30 to 50 percent by 2035, bringing Indonesian solar within reach of other leading countries.

The transition to a more renewable power system that supplies a more electrified economy is an economic and development opportunity as much as, if not more than, a climate one. Specifically for Indonesia, the two opportunities point the same way: the least-cost development path for the power system is also the lower-carbon one, avoiding emissions and clearing the air in fast-growing cities. The evidence from India, China and other early movers is that costs fall fastest where deployment is quickest. Scale is the mechanism, for cost and emissions alike.

Indonesia has set an ambitious course with its 100 GWp solar programme. The opportunity now is to get Indonesia on the path to delivering on low-cost solar: to remove the barriers on land, grid and financing that keep costs high, and unleash the power of scale. The prize is a cheaper, cleaner, more secure economy.



Dr Fadhil Hasan

Founder and President
Commissioner, INDEF

INDEF

Indonesia's ambition to grow at 8 percent a year is central to the Indonesia Emas 2045 vision. At the core of this 8% growth target, a question of productivity and structural transformation remains: How can Indonesia move into higher-value industries and build more resilient sources of prosperity? Energy policy sits at the centre of that question, and this report explains why.

Our dependence on imported oil is a structural weakness. As INDEF's own analysis has shown, every dollar on the oil price widens the fiscal deficit. So long as fossil fuels dominate our energy structure, global price volatility will keep transmitting risk into the budget, into inflation, and into the cost of doing business.

A more electrified economy, supplied by more renewable power, addresses that weakness at its source and provides a pathway to integrate industrial manufacturing and the power sector as a new growth engine. The report quantifies the gains: lower import bills, reduced subsidy pressure, new investment, and industries better placed to compete as trading partners begin to price the carbon.

The economic case for modernising the power sector is therefore clear. Reliable, affordable, low-carbon electricity is a precondition for the industrial competitiveness Indonesia needs. The task now is to align energy policy with the 8 percent growth vision, and to treat the transition as an engine of long-term growth rather than a cost to be managed.

Endorsements

Representative from Directorate General of Electricity

Ministry of Energy and
Mineral Resource

A reliable, secure, affordable, and sustainable electricity system is essential to Indonesia's growth and energy security, with the accelerated development of renewable energy playing an important role. We welcome analytical contributions that support the 100 GWp solar programme and Indonesia's broader energy transition

Rama Dinara

AESI

Solar is set to become the backbone of Indonesia's power system. This report quantifies what the industry has long argued: with the right interventions on land, grid connection and financing, Indonesian solar can reach globally competitive costs by 2035 and drive a new wave of industrial investment.

Udit Mathur

Assistant Vice
President, Chairmans
Office, ReNew India

The economics of solar and storage have shifted decisively, as we have seen first-hand in the Indian market. This report shows Indonesia can follow the same cost-reduction trajectory, with the right focus on land, grid and finance, and become one of the next leading solar markets in Asia.

Enda Ginting

Country Manager,
Indonesia, Gurin Energy

The report could not have come at a better time. Demand for energy is growing even as access, affordability and sustainability are challenged by macroeconomic and geopolitical factors. In the midst of all of this, Indonesia has a unique opportunity to capture long-term economic growth and competitiveness by harnessing its abundance of natural resources to deploy renewable energy at scale. Written for economists, energy professionals, environmentalists, technocrats and the general public, this report combines rigorous analysis and practical guidance into a valuable read for anyone interested in Indonesia's energy future.

Aditya Mahalana

International Council on
Clean Transportation

Electrified transport can generate the electricity demand needed to underpin Indonesia's 100 GWp solar programme, turning the country's mobility transition into a growth engine for its power system. This report provides the evidence base to align power, industry and transport decarbonisation around a single low-cost pathway, one that delivers both stronger economic outcomes and cleaner air in Indonesia's fast-growing cities.

About



Energy
Transitions
Commission

The Energy Transitions Commission (ETC) is a global coalition of leaders from across the energy landscape committed to achieving net-zero emissions by mid-century, in line with the Paris climate objective of limiting global warming to well below 2°C and ideally to 1.5°C. The ETC is co-chaired by Lord Adair Turner and Jules Kortenhorst. The ETC team is led by Ita Kettleborough (Director), and Mike Hemsley (Deputy Director). The ETC also delivers regional programmes across key economies including Europe, the United States, China, India, Japan, Canada, Indonesia, Sub-Saharan Africa and Australia, working with local partners to develop country-specific transition pathways, engage policymakers, and translate global insights into actionable national strategies.

S Y S T E M I Q

Systemiq is a system-change company founded in 2016 to accelerate the achievement of the Sustainable Development Goals and the Paris Agreement by transforming the markets and business models that underpin society. A certified B Corp, Systemiq partners with businesses, policymakers, investors, and civil society organizations to reimagine and reshape five key systems—energy, nature and food, materials and circularity, urban areas (the built environment), and sustainable finance—in order to drive the transition to a sustainable and inclusive economy. Combining strategic advisory with high-impact, on-the-ground implementation, Systemiq operates globally with offices in Brazil, France, Germany, Indonesia, the Netherlands, the United Kingdom, and Nairobi.



The Institute for Essential Services Reform (IESR) is an independent think tank that accelerates Indonesia's energy transition through evidence-based research, policy advocacy, and cross-sector collaboration. IESR translates technical analysis and modelling, including studies of pathways to net-zero emissions by 2050, into actionable policy recommendations. Through capacity building and stakeholder collaboration, IESR promotes a clean, technically feasible, socially just, and economically resilient energy system.



The Institute for Development of Economics and Finance (INDEF) is an independent and autonomous policy research institute established in Jakarta in August 1995, focusing on economic and financial policy analysis to inform public debate and support better policymaking in Indonesia. Building on this mandate, INDEF initiates the Green Transition Initiative (GTI) as an international platform to embed climate and clean energy into core growth and development strategies, positioning the green transition as a new engine for investment, productivity, and inclusive economic transformation. Our work spans key areas including energy transition, climate policy, carbon markets, green industrialisation, and sustainable finance, supporting evidence-based policymaking and real-world impact across government, industry, and civil society.

List of Abbreviations

Abbreviation	Full term
AC	Air Conditioning
ALMM	Approved List of Models and Manufacturers
APL	<i>Area Penggunaan Lain</i> (Other Use Area)
APLSI	<i>Asosiasi Produsen Listrik Swasta Indonesia</i> (Indonesian Independent Power Producers Association)
ATR/BPN	<i>Kementerian Agraria dan Tata Ruang/Badan Pertanahan Nasional</i> (Ministry of Agrarian Affairs and Spatial Planning/National Land Agency)
BAU	Business-as-Usual
BESS	Battery Energy Storage System
BKPM	<i>Badan Koordinasi Penanaman Modal</i> (Indonesia Investment Coordinating Board)
BoS	Balance-of-System
BPN	Badan Pertanahan Nasional (National Land Agency)
BUMN	Badan Usaha Milik Negara (State-Owned Enterprise)
CAPEX	Capital Expenditure
CBAM	Carbon Border Adjustment Mechanism
CCGT	Combined Cycle Gas Turbine
CFPP	Coal-Fired Power Plant
CO ₂	Carbon dioxide
CREA	Center for Research on Energy and Clean Air
DMO	Domestic Market Obligation
DPO	Domestic Price Obligation
E2W	Electric Two-Wheeler
EAF	Electric Arc Furnace

Abbreviation	Full term
EPC	Engineering, Procurement and Construction
ETC	Energy Transition Commission
EV	Electric Vehicle
FDI	Foreign Direct Investment
FID	Final Investment Decision
G20	Group of Twenty
GDP	Gross Domestic Product
GW	Gigawatt
GWh	Gigawatt-hour
HCV	High Conservation Value
HGBT	<i>Harga Gas Bumi Tertentu</i> (Designated Natural Gas Price)
HPK	<i>Hutan Produksi Konversi</i> (Convertible Production Forest)
ICE	Internal Combustion Engine
IEA	International Energy Agency
IESR	Institute for Essential Services Reform
IKN	<i>Ibu Kota Nusantara</i> (Indonesia's new capital)
IPP	Independent Power Producer
Jamali	Java-Madura-Bali
kt	Kilotonne
kWh	Kilowatt-hour
kWp	Kilowatt-peak
LCOE	Levelised Cost of Electricity
LCR	Local Content Requirement
LPG	Liquefied Petroleum Gas

Abbreviation	Full term
MASEN	Moroccan Agency for Sustainable Energy
MEMR	Ministry of Energy and Mineral Resources
MNRE	Ministry of New and Renewable Energy
MoE	Ministry of Environment
MPNT	Maluku, Papua, and Nusa Tenggara
Mt	Million tonnes
MW	Megawatt
MWp	Megawatt-peak
MWh	Megawatt-hour
NDC	Nationally Determined Contribution
PHS	Pumped Hydro Storage
PLI	Production Linked Incentive
PLN	Perusahaan Listrik Negara (State Electricity Company)
PPA	Power Purchase Agreement
PV	Photovoltaic
RDTR	<i>Rencana Detail Tata Ruang</i> (Detailed Spatial Plan)
REIPPPP	Renewable Energy Independent Power Producer Procurement Programme
REZ	Renewable Energy Zone
RUPTL	Rencana Usaha Penyediaan Tenaga Listrik (Electricity Supply Business Plan)
SOE	State-Owned Enterprise
TWh	Terawatt-hour
VAT	Value-Added Tax
WACC	Weighted Average Cost of Capital
WHO	World Health Organization

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Four Key Insights From This Study

1

Indonesia's electricity demand will grow significantly, driven by economic growth and electrification of end uses.

Indonesia's economic growth is expected to drive a significant increase of electricity demand by up to 7% per year over the next decade. High Electrification, especially in transport and manufacturing, could add 160 terawatt-hours (TWh) to electricity demand versus Business-as-Usual (BAU) by 2035. This would catapult Indonesia's electricity demand per capita from around 1,500 to around 2,800 kilowatt-hours (kWh) per capita, creating demand for large-scale renewable energy deployment.

2

Solar is the standout renewable opportunity to meet this demand, but its deployment remains constrained by a low-volume equilibrium driven by weak revenues and high costs.

- Solar is the standout renewable opportunity for Indonesia: it holds the largest domestic renewable resource potential, is fastest to build and on a steep global cost decline. The government's 100 gigawatt (GW) solar programme makes solar a national priority, signalling a step change in ambition compared with Indonesia's current Electricity Supply Business Plan (RUPTL).
- Most of Indonesia's utility-scale solar market is currently stuck in a low-volume equilibrium, in which economics are weak because scale is absent and scale is absent because economics are weak.
 - Revenues for solar are (mostly) set by the State Electricity Company (PLN) and are constrained by an unlevel playing field, as existing coal-fired generation benefits from price-capped coal, resulting in coal-fired power generation costs of around 3.5–5 US cents per kWh.
 - Indonesia's solar generation costs are currently well above leading-market levels and vary widely at 5–10 US cents per kWh compared with 3 US cents per kWh in India, constraining commercial scale-up.
 - Total solar generation costs could fall by 30–50% to around 4–7 US cents per kWh by 2035 through targeted interventions to reduce component, land and transmission costs. Scaling deployment and improved procurement processes could further reduce financing costs, with benefits across all cost components.
 - Battery storage completes the solar story. As battery costs fall, solar plus storage is becoming a cost-competitive alternative to new coal and gas in sunny markets globally. Although Indonesia's current solar-plus-storage cost of around 15 US cents per kWh remains well above leading-market levels, compared with around 4.5 US cents per kWh for near round-the-clock solar plus battery in India, costs could decline alongside reductions in standalone solar costs.
 - The first utility-scale solar projects show that solar can be economically viable in Indonesia, but under specific conditions, for example where land has already been secured or projects have been designated as national strategic projects. A next wave of catalytic projects and targeted interventions could unlock the scale required to bring down the costs of solar further.

3

Moving towards a more electrified economy and a more renewable power system could contribute around 8–10% of the additional gross domestic product (GDP) needed for Indonesia to reach its 8% growth ambition, while improving energy security, affordability and competitiveness.

- **The Least-Cost, High Electrification scenario delivers around US\$160 billion of additional GDP in 2025–2035 compared with BAU**, driven by two direct GDP components. Around US\$35 billion will be generated from additional investment across the energy system, electrification, clean manufacturing and new growth sectors enabled by low-carbon power, such as data centres. Around US\$125 billion will be generated in the form of additional net exports from reduced oil imports and regional electricity exports.
- **Increased electrification and a more renewable energy mix strengthen Indonesia's energy resilience and reduce import dependence**, reducing oil demand by 22% annually by 2035 and generating cumulative oil-import savings of US\$60–75 billion between 2025–2035. Savings are concentrated in transport, where electrification of two-wheelers, cars, vans, buses and trucks is increasingly cost-effective.
- **Increased electrification and a more renewable energy mix could reduce spending on energy subsidies by US\$20 billion over the next decade**, strengthening government budget resilience to imported fuel price shocks and freeing fiscal space for other uses.
- **A more renewable energy supply mix improves power system affordability** while meeting higher demand. By 2035, total power system costs could fall by around 5–15% compared with the RUPTL supply mix, reaching around 8.5 US cents per kWh from around 10 US cents per kWh, with no new coal or gas plants required to meet 160 TWh of additional demand.
- **A more renewable supply mix could also strengthen Indonesia's competitiveness in green industries.** Global markets increasingly reward low-carbon supply, including through mechanisms such as the Carbon Border Adjustment Mechanism (CBAM). Countries with cleaner power systems will therefore be better positioned for exports and more attractive as a base for international manufacturers seeking to establish low-carbon supply chains.

4

Capturing these gains requires four coordinated interventions to bring down the costs of solar generation: fast-tracking catalytic (grid-scale) projects, removing barriers to rooftop solar, providing policy support to bring down solar cost components and designing a phased local content strategy.

- **Catalytic grid-scale solar projects with premium buyers** can anchor early demand at scale, overcome current revenue hurdles and create bankable precedents that reduce financing costs and support supplier capacity expansion. Potential demand sources include electricity exports to neighbouring markets and data centres together with the first phase of the 100 GWp solar programme.
- **Rooftop solar deployment can be unblocked** by updating regulations around quota and permits, allowing capacity to scale more quickly and increasing demand for domestic modules.
- **Targeted policy support for land acquisition and grid connection** could reduce two of the solar generation cost components responsible for much of the gap with leading solar markets. These interventions could also benefit other renewable energy sources, including geothermal and hydropower.
- **A phased local content strategy** can balance domestic manufacturing ambitions with cost competitiveness, building the supply base without locking in higher costs that hold back deployment.

Box A | The 100 GWp solar programme

Delivering the 100 GWp programme by 2030 is ambitious, but such pace is not unprecedented

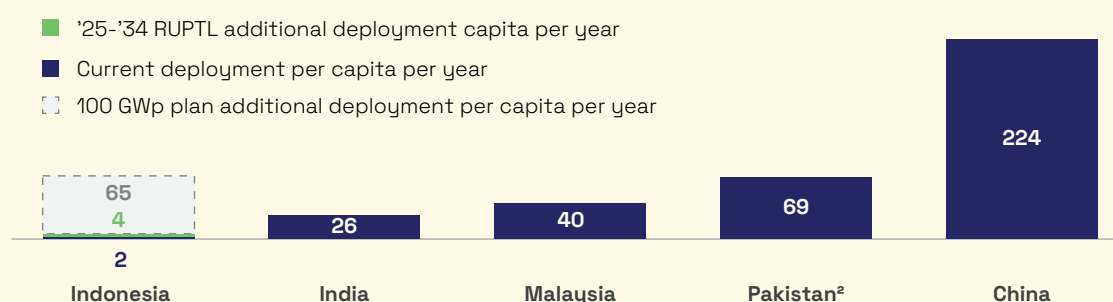
In August 2025, the government set a target to install 100 GWp of solar power by 2030, combining off-grid, rooftop and utility-scale. This would represent a major step up in deployment. The current RUPTL envisages just 17 GW of on-grid, utility-scale solar by 2035, while achieving 100 GWp would almost double Indonesia's entire installed capacity in five years.

The target seems daunting but is not unprecedented in the region [Figure 1]. Indonesia would need to increase annual solar deployment from around 2 megawatts (MW) per million people to around 65 MW per million people, close to Pakistan's deployment pace over the last two years. The scale is also not unprecedented: India installed 38 GW of solar in 2025 alone, while China installed 315 GW.¹ Pakistan, with a population comparable to Indonesia's, added roughly 27 GW of distributed solar in around two years without a national programme².

Figure 1 | Regional peers show what is achievable regarding the deployment pace of solar capacity.

Regional peers show what is achievable regarding the deployment pace of solar Capacity

Solar capacity installation per capita per year, MW per million people, 2024/2025¹



Notes: 1. Most recent available year used: 2024 for Pakistan, 2025 for all others. No reliable annual installation figure is available for Pakistan. The 17 GW figure represents solar panel imports in 2024. 2. Assumes the 100 GWp is realised over five years.

Sources: Indonesia: MEMR/IESR (2026), reported in pv magazine. Pakistan: Ember (2024), Chinese Solar Export Data; WRI (2025), The Perfect Storm Fueling Pakistan's Solar Boom. India: MNRE (2026), reported in pv magazine. China: NEA (2026), reported in pv magazine. Population: UN (2024), UN World Population Prospects 2024. Malaysia: IEA and PVPS (2026), Malaysia's Solar Capacity Surpasses 5.7 GW.

1 pv magazine (2026), *India Deploys 37.9 GW of Solar in 2025*.
2 Ember (2026), *The Solarization of Pakistan's Energy Economy*.

Indonesia faces one important challenge that these markets do not: very cheap existing coal power. Coal supplied to Indonesian power stations is subject to a price cap well below the market price. This keeps coal-fired electricity artificially cheap, making it harder for solar to compete. Even so, the cost gap is closing fast. In India, new utility-scale solar farms can already generate electricity at a lower cost than running Indonesia's existing coal plants on price-capped coal.

This is made possible by one of the fastest cost declines in industrial history. Since 2010, solar module costs have fallen by around 97% and the installed cost of utility-scale batteries by around 93%³ Solar is now the cheapest source of new electricity in most of the world, while cheaper batteries make it increasingly practical to store solar power for use after dark.

That combination is particularly important for a sunbelt country like Indonesia. Solar produces most of its power in the middle of the day, but demand peaks in the evening, when families come home, switch on lights and run air conditioning. Batteries bridge that gap. They can store cheap daytime solar for use at night, keeping air conditioners and appliances running long after the sun has set. This makes solar plus storage an important opportunity for Indonesia. The Energy Transitions Commission (ETC) finds that in countries with strong solar resources, the combined decline in solar and battery costs is making power systems with high shares of solar and wind as affordable as, or cheaper than, today's fossil-fuelled systems. These countries mainly need to balance electricity supply between day and night, rather than across seasons, as is often required in colder and cloudier countries⁴.

Increased electrification and storage can absorb new electrons

At this scale, solar deployment gains further momentum when demand grows to absorb it. As Indonesia's economy grows and electrifies, its need for electricity can climb steeply, creating demand for new solar generation. In a High Electrification scenario, in which transport and industry electrify faster, households increasingly use air conditioning (AC) and electric cooking and new electricity-intensive sectors, such as power exports and data centres, grow, Indonesia could need around 160 TWh more electricity in 2035 than it would under BAU.

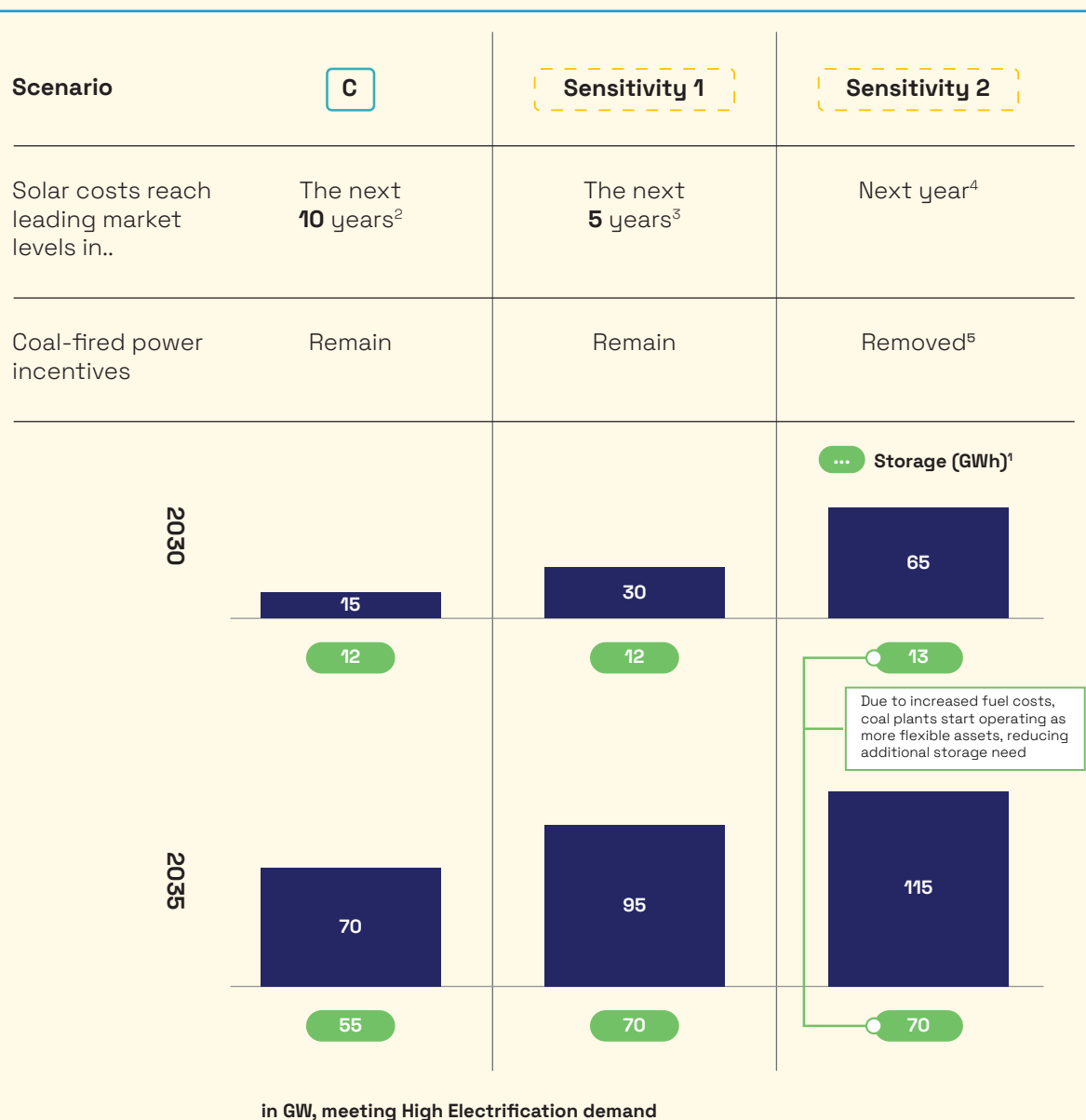
Scaling solar can meet that additional demand. Expanding Indonesia's power system at the lowest cost would add around 70 GW of utility-scale solar by 2035, and up to 114 GW if solar costs fall faster and the coal price cap is removed [Figure 2]. Adding the rooftop and captive solar installed on homes and factories would bring the total to the 100 GWp ambition by 2030. The scale is well calibrated. A system designed to keep costs down would build close to this much solar anyway.

3 Irena (2025), *Renewable Power Generation Costs in 2024*.

4 ETC (2025), *Power Systems Transformation*.

What that solar needs to be dependable is storage. Batteries are needed to store cheap daytime power and release it after dark. Modelling shows Indonesia will need around 55–70 gigawatt-hours (GWh) of storage by 2035 to keep pace with this solar deployment. These volumes are achievable, but they will not appear on their own: storage has to be deployed deliberately, in step with solar.

Figure 2 | Solar and storage capacity under different scenarios.



Notes: 1. PHS and BESS. For BESS, assuming a four-hour storage duration. 2. Scenario C assumes a solar LCOE of 4.5–9 US cents per kWh in 2030 and 4–7 US cents per kWh in 2035. 3. Sensitivity 1 assumes a solar LCOE of 4–7 US cents per kWh in 2030 and 3.5–5 US cents per kWh in 2035. 4. Sensitivity 2 assumes a solar LCOE of 3.7 US cents per kWh in 2027 (India's current level, adjusted for Indonesia's lower capacity factor). 5. Sensitivity 2 assumes a coal LCOE increase of 30% to 4.5 US cents per kWh for existing assets and 9 US cents per kWh for new assets.

Source: IESR analysis.

The 100 GWp programme can strengthen resilience and unlock green growth

Cost is not the only reason countries are racing to build solar. The cost declines have been visible for a decade, yet the countries moving fastest are those where solar and storage not only lower the electricity bill but also strengthen energy security, increase access to electricity, improve air quality and cut emissions. Indonesia stands to gain these benefits. The value of the 100 GWp solar programme is not the panels themselves but the resilience and green growth that solar can deliver.

In addition to reducing emissions, cheap, abundant and home-grown solar power can strengthen Indonesia in six ways:

- **Powering a new economy.** Low-cost clean power can drive the development of high-value industries in Indonesia, from data centres and downstream processing to green metals, and extend reliable electricity to communities that currently lack access.
- **Lowering power costs.** A more renewable supply mix could cut total power-system costs by around 5–15% by 2035, with no new coal or gas plants needed to meet rising demand.
- **Reaching every island.** Solar and batteries can be built close to the communities and industries where power is needed, easing the strain on transmission and reducing reliance on a single, centralised system in a vast and fragmented country.
- **Strengthening energy security.** Solar power is generated at home, so every diesel generator or oil-burning engine it replaces cuts Indonesia's need for imported fuel. Scaling renewables and electrification could save the country tens of billions of dollars in oil imports over the coming decade, keeping more of that spending within Indonesia's economy.
- **Improving competitiveness.** Global markets increasingly favour lower-carbon products, driven by measures such as CBAM and growing demand for less carbon intensive products. Increased availability of cleaner power makes Indonesia a more attractive base for manufacturers looking to build resilient, lower-carbon supply chains.
- **Improving air quality and overall health.** A more electrified, more renewable system reduces air pollution both where electricity is consumed, for instance when an electric motorbike replaces a petrol motorbike, and where it is generated, when renewables replace coal. Cleaner air means better health across Indonesia's cities.

The scale is achievable. Now is the time to accelerate delivery

The scale of the 100 GWp target is achievable, but reaching it by 2030 is a stretch considering where Indonesia stands today. Rather than continuing to debate the timeline, however, what matters is turning the ambition into projects on the ground. Three things will decide how fast that happens.

First, build where it is easiest to win. The fastest way to build momentum is to start where the economics already work. Premium buyers, such as data centres and international manufacturers that want clean power, are willing to pay for it now and can anchor the next wave of large-scale projects. Concentrating solar in renewable energy zones, where industrial demand meets strong solar exposure, available land and grid access, lets developers build quickly and turns these first deals into a pipeline.⁵ Solar and batteries can also replace expensive diesel generators in remote areas today, cutting fuel costs immediately.⁶ Alongside this, targeted action to bring down Indonesia's two biggest solar cost premiums, land and grid connection, would lower costs across every project that follows.

Second, build demand in step with supply. In the near term, the quickest way to absorb a large increase in solar supply is to grow demand alongside it. Policies that accelerate the electrification of transport and industry, together with new demand from data centres and rural electrification, can keep consumption rising in step with generation, securing a ready market for new solar.

Third, scale storage alongside solar. Deploying batteries in step with generation keeps the system stable and makes sure cheap solar is available when demand peaks in the evening. Peer countries have paired renewables with batteries deliberately. In China, provincial co-location mandates from 2017 onwards required new solar and wind projects to include storage. This helped cut curtailment from over 17% in 2016 to below 5%, while installed battery capacity grew to more than 74 GW by 2024.⁷ India offered funding of up to 30–40% of capital expenditure (CAPEX) for battery storage projects, alongside tenders for hybrid projects combining storage and renewables that now account for around half of all renewable auctions.⁸

None of this rests on government alone. Developers, investors, industry and the state each have work to do. Their contributions reinforce each other. Rising demand pulls in solar and storage, while cheaper solar makes electrification more attractive, which in turn increases demand. Levelling the playing field between solar and Indonesia's price-capped coal would accelerate solar deployment further, though that is a longer-term shift rather than a near-term intervention.

What is not in doubt is the destination. The prize of the 100 GWp solar programme is not the panels themselves, but the cheaper power, stronger energy security and the new industries unlocked. The sooner Indonesia scales solar; the sooner it captures these benefits.

5 Systemiq (2026), *Advancing Indonesia's Industrial Energy Transition: The role of Renewable Energy Zones*.

6 IESR (2026), *Solar Archipelago: Indonesia's 100 GWp Leap to Energy Sovereignty*.

7 Ember (2025), *From Scale to System: Navigating the Next Phase of China's Battery Storage*.

8 IEEFA/JMK Research (2025), *The Standalone Energy Storage Market in India*.

Introduction

Indonesia is targeting a step change in economic growth from around 5% per year today to 8% by 2029, in line with the Indonesia Emas 2045 vision. Achieving this would require a major expansion in electricity supply, as rising incomes, industrial downstreaming and new electricity-intensive sectors will significantly increase electricity demand over the next decade, with further growth expected in the decades that follow as the economy grows and electrifies.

Indonesia's current power system is heavily reliant on fossil fuels, with coal, gas and diesel accounting for around 85% of electricity generation in 2025. Renewables currently make up just 15% of generation, with the bulk of that share coming from a small number of legacy hydropower and geothermal plants. Solar and wind, which have driven most of the global renewable build-out in recent years, together account for less than 1% of Indonesia's electricity generation today.⁹

Indonesia's current power system is heavily reliant on fossil fuels, with coal, gas and diesel accounting for around 85% of electricity generation in 2025.

There is a growing opportunity to change this. Indonesia has significant renewable energy resources, with the potential to support decades of economic growth through domestically generated electricity that does not depend on imported fuels. The country has strong solar irradiation across the archipelago, the world's largest geothermal potential and significant hydropower capacity. Solar in particular stands out. The Institute for Essential Services Reform (IESR) analysis suggests it could meet up to 88% of expanded electricity demand by 2060.¹⁰ The potential for a renewables-led power system is there.

At this point, however, affordability remains a genuine barrier in Indonesia. Under regulated Domestic Market Obligation (DMO) pricing, coal-fired power generation costs around 3.5–5 US cents per kilowatt-hours (kWh), compared with 5–10 US cents per kWh for solar. While some early solar projects have been developed in locations where conditions were especially favourable, they have proved difficult to replicate at scale. The result is a low-volume equilibrium: solar project economics are weak because scale is absent, and scale is absent because economics are weak.

9 MEMR (2026), *Handbook of Energy & Economic Statistics of Indonesia 2025*.

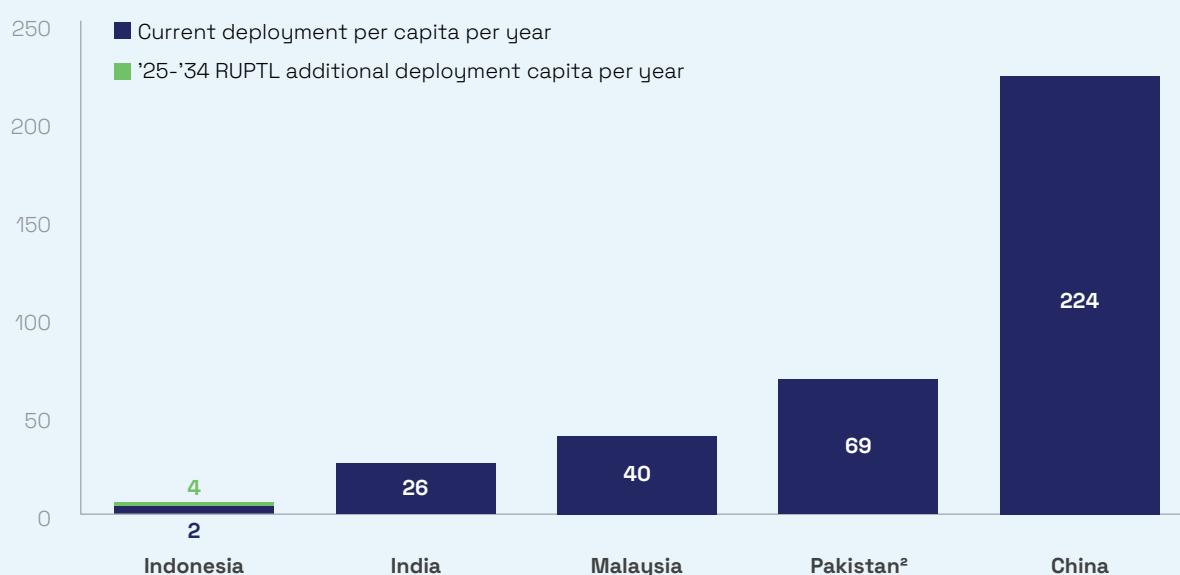
10 IESR (2021), *Deep Decarbonization of Indonesia's Energy System*.

There is a path to break through this equilibrium, and regional peers are already showing what it looks like [Figure 1]. India has delivered solar power at around 3 US cents per kWh and solar plus battery at 4.5 US cents per kWh, on an almost round-the-clock basis.¹¹ The country also managed to install 38 gigawatt (GW) of solar in 2025 alone.¹² Pakistan, with a comparable population and lower income per capita, installed 27 GW of distributed solar in just two years, without a national programme.¹³

Figure 1 | Regional peers show what is achievable in the pace of solar deployment.

Regional peers show what is achievable regarding the deployment pace of solar capacity

Annual solar capacity installation per capita, 2024/2025¹
In MW per million people



Notes: 1. Most recent available year used: 2024 for Pakistan, 2025 for all others. No reliable annual installation figure is available for Pakistan. The 17 GW figure represents solar panel imports in 2024. 2. Assumes the 100 GWp is realised over five years.

Sources: Indonesia: MEMR/IESR (2026), reported in pv magazine. Pakistan: Ember (2024), Chinese Solar Export Data; WRI (2025), The Perfect Storm Fueling Pakistan's Solar Boom. India: MNRE (2026), reported in pv magazine. China: NEA (2026), reported in pv magazine. Population: UN (2024), UN World Population Prospects 2024. Malaysia: IEA and PVPS (2026), Malaysia's Solar Capacity Surpasses 5.7 GW.

¹¹ Solar plus BESS provides 75–85% of annual availability.

¹² pv magazine (2026), *India Deploys 37.9 GW of Solar in 2025*.

¹³ Ember (2026), *The Solarization of Pakistan's Energy Economy*.

The window for change is opening. Globally, solar photovoltaic (PV) module costs have fallen by around 20% per year over the past decade and battery costs by around 16% per year, faster than earlier projections anticipated.¹⁴ Solar is now the cheapest source of new electricity across most sunny climates, with global benchmark levelised cost of electricity (LCOEs) at around 4 US cents per kWh.¹⁵ Combining solar with batteries is also increasingly affordable, at 5–8 US cents per kWh across sunny climates.¹⁶ Electrification amplifies this advantage. Electrified technologies are structurally more efficient than their fossil-fuel equivalents, and the enabling technologies, e.g., batteries, electric motors and heat pumps, keep getting cheaper as they scale.

The moment for action

Three factors make this a decisive moment for action.

First, energy resilience has become an immediate fiscal priority. The 2026 Iran conflict pushed oil above US\$100 per barrel, compared with a state budget assumption of US\$70, exposing Indonesia's structural vulnerability as a net oil importer. Each dollar increase in the oil price adds approximately Rp6.8 trillion to government spending, with energy subsidies already consuming over 5% of the state budget.¹⁷ Reducing oil dependence through electrification, particularly in transport, where oil consumption is concentrated, and the use of renewable power to replace diesel generation directly addresses this fiscal exposure.

Second, government ambition is accelerating. The 100 GWp solar programme announced in 2025 represents a step change from the 17 GW of utility-scale solar targeted under the previous Electricity Supply Business Plan (RUPTL). Meeting this timeline will require solar generation costs to fall so that solar can compete with existing coal-fired generation. This will require changes to market structure and regulation, including the rooftop solar quota system, alongside a concerted effort to grow electricity demand in step with supply.

Third, several time-bound opportunities are available now. Renewable electricity exports to neighbouring markets and demand from international data centre operators are immediate sources of demand, with buyers willing to pay a premium for clean power. These sources of demand help overcome existing revenue barriers for the State Electricity Company (PLN) and can anchor catalytic large-scale renewable projects. If Indonesia does not act quickly, these opportunities will move to competing markets.

14 BNEF (2025), *Lithium-Ion Battery Price Survey*.

15 BNEF (2026), *Battery Storage Costs Hit Record Lows as Costs of Other Clean Power Technologies Increased*; BloombergNEF.

16 Irena (2026), *24/7 Renewables: The Economics of Firm Solar and Wind; Modelled Firm LCOE for Solar and Battery Setups with 95% Availability*.

17 IDN Financials (2026), *Oil Hits USD 100, Indonesia to Keep Fuel Subsidies through 2026*.

What this report does

This report examines whether higher electrification combined with a more renewable electricity supply could strengthen Indonesia's economic growth prospects. It is structured as follows:

Chapter 1

Examines how electricity demand could evolve under Business-as-Usual (BAU) and a High Electrification scenario. Demand grows by around 5% per year under BAU and 7% under High Electrification, driven by accelerated electrification of transport, industry and residential demand.

Chapter 2

Shows that Indonesia is lagging on renewables deployment despite a large resource base and identifies the structural barriers preventing scale.

Chapter 3

Diagnoses why Indonesia's solar costs sit above leading-market levels and sets out how this cost gap can be reduced. With targeted action, Indonesia's solar LCOE could fall by 30–50% by 2035, approaching leading-market levels.

Chapter 4

Assesses how supply can evolve to meet demand by comparing the current RUPTL with a Least-Cost supply mix featuring greater renewable deployment. A more renewables-led supply mix could deliver around 5–15% lower total system costs by 2035 than the current RUPTL pathway, while meeting the expanded electricity demand.

Chapter 5

Quantifies the economic implications of electrifying the economy and scaling renewables, such as reduced fossil fuel imports and subsidies, increased investment, new growth sectors enabled by clean power and improved export competitiveness.

Chapter 6

Sets out the policy interventions required to deliver a more electrified economy powered by more renewables, focusing on the interventions needed to bring solar costs down and scale deployment as well as sector measures that can accelerate electrification.

Taken together, these chapters make the case that a shift to a more electrified economy supplied by a more renewable power system is not just a climate objective but also an economic one. The evidence in this report suggests that if the right actions are taken now, Indonesia can build the power system needed to sustain faster growth at lower cost, while improving competitiveness and resilience.



Image source: gggi.org/wp-content/uploads/2021/08/energy-fun-fact-1.jpg



Chapter 1

Indonesia's electricity demand will grow materially over the next decade

Indonesia is entering a decisive decade for economic growth, with ambitious targets supported by plans to strengthen industrial competitiveness. Historically, faster growth of gross domestic product (GDP) in emerging economies has been accompanied by rising electricity demand.¹⁸ If Indonesia's ambitions are realised, alongside rising household incomes and the emergence of new digital and manufacturing sectors, electricity demand can be expected to increase significantly over the next decade.

This chapter examines the scale and drivers of Indonesia's electricity demand growth. Section 1.1 sets out Indonesia's economic growth ambitions and explains how rising incomes and industrial expansion translate into higher electricity demand. Section 1.2 presents the key demand drivers and introduces BAU and High Electrification as the two demand scenarios used in the report. Sections 1.3 and 1.4 set out the demand outlook under each scenario in detail. Section 1.5 examines how demand growth is distributed across Indonesia and between captive and on-grid supply. Section 1.6 concludes by examining what these trajectories imply for the scale of power system expansion required.

1.1 Indonesia's growth ambitions

Indonesia has set an ambitious economic growth target as part of its long-term development strategy. The government targets an annual GDP growth of **8% by 2029**, in line with the Indonesia Emas 2045 vision [Figure 2]. Achieving this target would represent a step-change from the country's annual GDP growth of around 5% over the past decade.

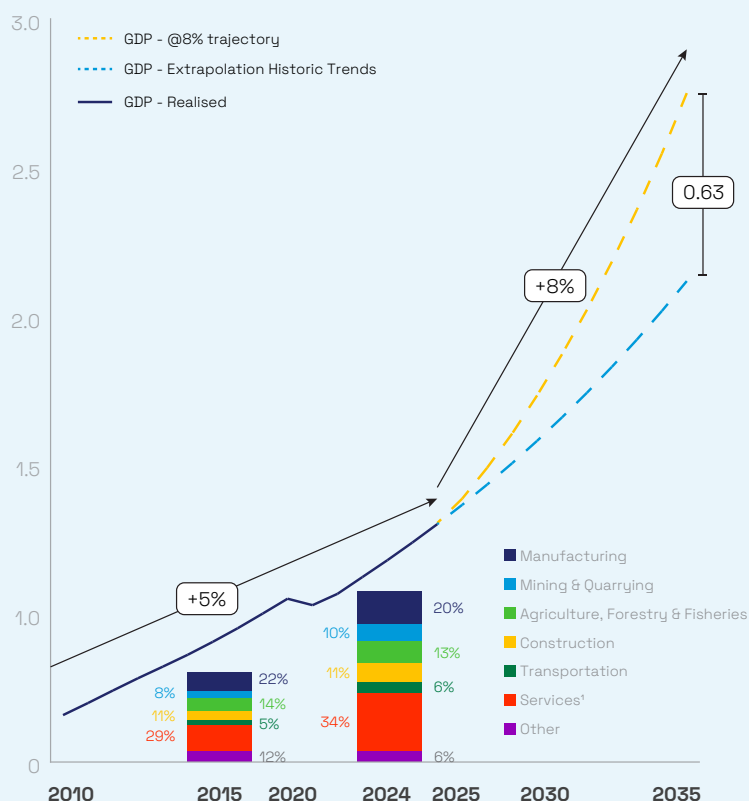


18 IEA (2026), *Electricity 2026: Analysis and Forecast to 2030*.

Figure 2 | Indonesia has set an ambitious target to accelerate economic growth.

Indonesia's ~8% annual economic growth ambition by 2028-2029 is a step change from historical growth rate

Historic and forecast GDP, Trillion USD (constant 2015)



Relevant Policies

National Vision: Indonesia Emas 2045 (RPJPN 2025-2045)



Industrialisation as the central driver for long-term economic transformation, with manufacturing's GDP share rising from 22% to 28% by 2045.

Strengthening the foundation (RPJMN 2025-2029)



Focuses on downstreaming, priority industries, industrial zones and export-oriented manufacturing to strengthen industry as the primary growth engine.

Industrial transformation as the pathway to 8% growth



Indonesia positions manufacturing-led growth as essential for lifting productivity and enabling Indonesia to achieve 8% sustainable growth.

Notes: 1. Services includes wholesale, trading, repair of vehicles, accommodation and food service, IT, Telco, financial and insurance, real estate and business activities.

Source: BPS, Quarterly Growth Domestic Product 2020-2024 and 2021-2025.

As Figure 2 shows, services account for the largest share of Indonesia's GDP today at 34%. Manufacturing contributes around 20% of the GDP, down from close to 30% in the early 2000s and below levels seen in several fast-growing Asian economies during their industrialisation phases.^{19,20} This decline is driven by several structural factors. Commodity-led growth from nickel, palm oil and coal crowded out manufacturing investment, while the country's manufacturing competitiveness continued to decline relative to regional peers such as Vietnam, China and Thailand. This was exacerbated by an early shift toward the service sectors.

¹⁹ World Bank (2024), *World Development Indicators*.

²⁰ Manufacturing accounted for around 29–30% of GDP in South Korea during the 1980s–1990s, around 30–32% in China during the 2000s and around 28–30% in Taiwan during its peak industrial expansion.

Indonesia's current strategy for increasing economic growth seeks to reverse this trend by expanding higher-value manufacturing and downstream processing, particularly in resource-based sectors such as nickel, aluminium and other critical minerals. A stronger industrial base would increase manufacturing exports and therefore the sector's contribution to GDP, while supporting higher-value economic activity.

Regardless of the exact growth rate ultimately achieved, the target signals a clear policy direction: Indonesia aims to expand its industrial base, increase productivity, and strengthen its position in the global manufacturing and commodity value chains.

Indonesia's current strategy for increasing economic growth seeks to reverse this trend by expanding higher-value manufacturing and downstream processing, particularly in resource-based sectors such as nickel, aluminium and other critical minerals.

1.2

Drivers of electricity demand and future scenarios

Rising incomes and industrial expansion will significantly increase Indonesia's energy demand, particularly for electricity, over the next decade.

As economies develop, energy and electricity use per capita typically rise alongside incomes, reflecting higher household consumption, expanding services and growing industrial activity. During China's rapid industrialisation from 2000 to 2015, for example, electricity use rose from around 1,000 kWh to 4,000 kWh per person, equivalent to around 10% of annual growth and broadly in line with annual GDP growth of almost 10% over the same period. Since then, electricity consumption has risen further to more than 7,500 kWh per person.²¹ Vietnam experienced even faster growth over the same period, from around 300 kWh to 1,600 kWh per person, and now stands at around 2,700 kWh per person.²² This was equivalent to annual growth of around 12%, outpacing average GDP growth of around 6.5% per year.²³ By comparison, Indonesia's electricity use remains low today at around 1,500 kWh per person,²⁴ leaving considerable room for further rise as incomes and industrial activity expand.

In Indonesia, rising incomes are expected to drive energy demand across the residential, commercial and transport sectors. Higher appliance ownership and increased use of AC will raise electricity consumption [Figure 3]. Commercial electricity demand is also expected to grow with the expansion of digital infrastructure, with data centres emerging as a fast-growing contributor. At the same time, growing passenger and freight traffic will drive energy demand in the transport sector.

In Indonesia, rising incomes are expected to drive energy demand across the residential, commercial and transport sectors.

²¹ Ember (2026), *Global Electricity Review 2026*.

²² World Bank (2026), *Electric Power Consumption*.

²³ World Bank (2026), *GDP Growth*.

²⁴ Systemiq's analysis based on data from Databoks (2025) and the MEMR (2025).

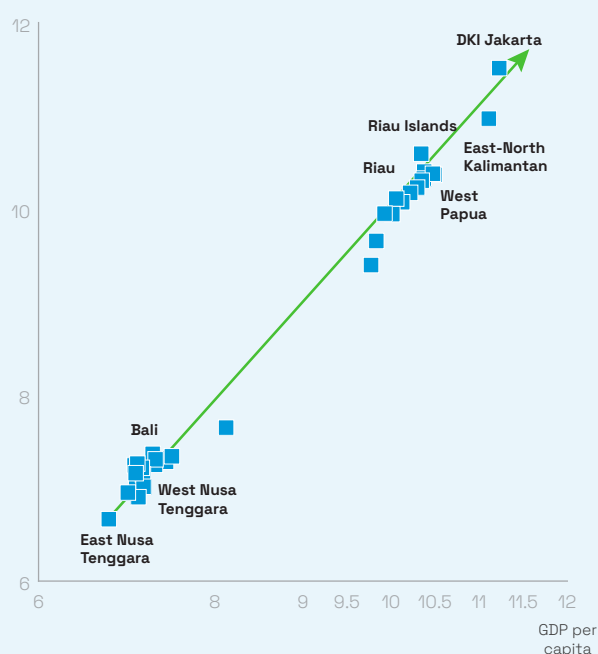
Figure 3 | As GDP per capita and incomes rise, residential electricity demand will increase, driven largely by cooling demand.

Higher-income regions already see higher residential electricity consumption

Mean Electricity Consumption vs. GDP per capita for regions in Indonesia

Log scales, 2014-2022

Mean electricity consumption per household

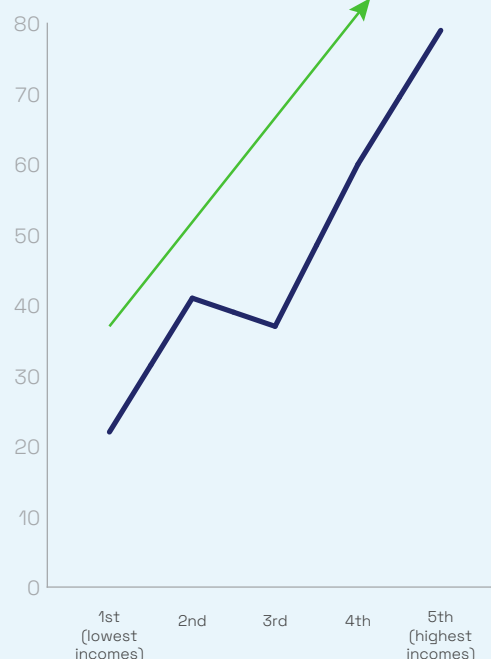


AC uptake will increase as incomes increase

Est. AC penetration by income quintile in East Asia and Pacific

% Penetration vs income quintile

% Penetration



Sources: IEA (2025), Staying Cool Without Overheating the Energy System; Basconcillo et al. (2023), GMM Approach to Residential Electricity Consumption in Indonesia.

Industrial expansion will also increase energy and electricity demand in two ways. First, expanding industrial activity across sectors such as manufacturing, mining and metals processing will raise overall energy use. Second, Indonesia's downstreaming strategy shifts economic activity from the extraction and export of raw materials towards more energy-intensive processing and materials production within the country.

Key areas of industrial growth include aluminium and nickel processing, iron and steel production and battery manufacturing, alongside the expansion of data centres. These activities are energy intensive and are expected to contribute significantly to rising industrial electricity [Figure 4]. Government projections point to particularly rapid expansion in aluminium production, which is projected to grow by around 30% per year over the next decade. Nickel output, meanwhile, is projected to increase from 2.4 million tonnes (Mt) to 2.8 Mt per year, maintaining Indonesia's position as the world's largest nickel producer.

Figure 4 | Industrial growth is expected to play a central role in delivering economic growth.

Industrial Growth is Expected to Play a Central Role in Delivering Economic Growth

Projected production output of selected manufacturing sectors

2025-2035 CAGR

Current GDP Contribution⁷

in Mt	2025	2035	in %	in %
Iron & Steel ¹	13	19	+4%	1.1%
Nickel ²	2.4	2.8	+2%	
Aluminium ³	0.2	3.1	+30%	
Copper ⁴	0.8	0.8	0%	
Minerals ⁵	81	75	-1%	0.5%
Chemicals	10	14	+3%	1.8%
Pulp & Paper	23	25	+1%	0.6%
Textiles	7	11	+5%	1.0%
Food & Beverage ⁶	116	130	+1%	7.1%

Notes: 1) Based on Mol growth projections. 2) Based on existing capacity, derived from CREA (2024). 3) Aluminium growth is based on pipeline projects at Kalimantan Aluminium Industry (2027 COD), Hua Chin Indonesia (2025 COD), INALUM extension (2028 COD) and Bintan Electrolytic (2028 COD). 4) Minerals comprises cement, glass and ceramics. Growth is based on PIH and Housing & Settlement Statistics. 5) Food & Beverage includes sugar and palm oil production, the largest subsectors within F&B. 6) Based on BPS (2025 preliminary data). Total manufacturing contribution in 2025 was 19.1%. Among sectors not included here, the only sectors contributing more than 1% were manufacture of coal products and oil and gas refineries (1.9%), manufacture of fabricated metal products (1.6%) and manufacture of transport equipment (1.3%).

Sources: Petromindo; GAIKINDO; AISI; EMBER; PIH; BPS; IESR and Systemiq analysis.

Taken together, these trends point to **significantly higher electricity demand over the next decade**. The scale of that increase will depend not only on how fast the economy grows but also on how quickly households as well as the transport and industrial sectors adopt electrified technologies, and how strongly new electricity-intensive sectors grow. To capture this uncertainty, two scenarios for the evolution of electricity demand have been developed for this report [Figure 5].

Figure 5 | Electricity demand grows differently under BAU and High Electrification.**Assumptions for two electricity demand scenarios**

	BAU Scenario	High Electrification Scenario
Parameter	Continuation of historic trends, demand is aligned with projected population and economic growth	Higher electricity demand through electrification and growth of renewables-anchored sectors
 Sectoral drivers of electricity demand growth	- Demand for households and commercial in line with RUPTL's forecasts (annual population growth of 0.6%; annual GDP growth of 5% between '25-'35) Continued trajectory of residential AC adoption, to 24% of households to own an AC by 2035 (up from 12% in 2025) Continued trajectory of EV adoption (0.8 million EVs and 2 million E2Ws by 2035) - Pipeline of new aluminium smelters is projected to add ~3 Mt production capacity by 2035. - Pipeline of new nickel smelters planned, adding 350 kt production capacity by 2035. - Pipeline of data centers, based on existing pipeline and government target of 2000 MW by 2029	Same basis growth trajectory as in business-as-usual, with the addition of: - Assumes increased residential electricity demand (through increased AC adoption, 38% of households to own an AC by 2035, and 8% electrification of cooking by 2035) - Accelerated electrification of cars and motorcycles (EVs making up 26% of car stock by 2035, E2Ws 37% of 2W fleet) and of heavy duty trucks used in the mining sector (37% electric by 2035) Demand unlocked by renewables-anchored growth sectors: - Additional demand from increased data centers build-out - Additional regional power export to neighbouring markets, growing to 5 GW in the next decade - A gradual and partial substitution of captive demand by on-grid demand, growing to ~10% of captive demand connecting to the grid by 2035
 Electrification of industry	No change - assumed consistent with today's industrial electrification rates	Increased electrification of industry: - Increased share of EAF steel production - Shift from oil, gas and coal boilers to heat pumps and e-boilers in food and textile industries - Shift from coal, oil and gas boilers to biomass and e-boilers in pulp & paper

For (sub)sector specific assumptions, please see the accompanying Technical Appendix

The **BAU scenario** reflects continued growth in electricity demand driven by population and income growth, rising household cooling demand, ongoing uptake of electric vehicles and the current pipeline of power-intensive industrial sectors such as metal smelting and data centres, while keeping industrial electrification rates stable.

The **High Electrification scenario** uses the same underlying macroeconomic growth trajectory as BAU but tests what increased electricity demand could look like **if electrified technologies scale faster across households, transport and industry. It also assumes stronger growth in demand that depends on access to renewable power, i.e. green data centres and electricity exports.**

The High Electrification scenario is not just theoretical. **It reflects a global shift already underway**, driven by three reinforcing factors:

- **Electrified technologies are structurally more energy efficient.** Electric vehicles (EVs) convert over 77% of grid electricity into motion at the wheels, compared with only 12–30% in conventional petrol vehicles.²⁵ Heat pumps are three to five times as energy efficient as fossil-fuel boilers.²⁶ Analysis by the International Energy Agency (IEA) and Ministry of Energy and Mineral Resources (MEMR) finds that household energy bills in Indonesia would take up a smaller share of disposable income by 2030 under a more electrified scenario than under the stated policies scenario. This is mainly driven by efficiency gains from technologies such as more efficient appliances as well as electric two-wheelers (E2Ws) and cars.²⁷
- **The cost of electrified technologies is falling rapidly and durably.** Technologies such as batteries, electric motors, power electronics and heat pumps follow steep learning curves: costs fall predictably as production scales. Since the early 1990s, battery pack costs have fallen nearly 99%, electric motor costs by a similar magnitude and power electronics costs by 99.5%.²⁸ By contrast, mature fossil-fuel technologies have less room for structural cost declines, while their operating costs remain tied to fuel prices.
- **Electrification reduces exposure to fuel import bills and price volatility**, lowering risk for households and manufacturers alike, as described in Chapter 5. The 2026 Iran conflict made this concrete. Oil prices rose above US\$100 per barrel, exposing Indonesian manufacturers using oil-based heat to a near-50% spike in fuel costs.²⁹

Electrification therefore offers a pathway to lower costs for households, greater competitiveness for manufacturers and improved energy resilience, if electricity demand can be satisfied by domestic sources. This could strengthen Indonesia's prospects of reaching its ambitious economic growth targets. China shows how quickly electrification can scale. Electricity in the country accounted for around 15% of final energy demand in 2010, roughly the same share as in Indonesia today. That share has since risen to over 30%, driven by EVs, industrial electrification and heat pumps.^{30,31} Across transport and most of industry, electrified technologies are already, or will soon become, the lower-cost option. The question is how fast Indonesia captures this shift.

Electricity in the country accounted for around 15% of final energy demand in 2010, roughly the same share as in Indonesia today.

Together, the two scenarios illustrate both how electricity demand could evolve and what faster electrification could mean for Indonesia's economy.

25 US Department of Energy, www.fueleconomy.gov

26 IEA (2022), *The Future of Heat Pumps*.

27 IEA (2022), *An Energy Sector Roadmap to Net Zero Emissions in Indonesia*.

28 McCormick and D'Amico (2025), *The Electric Slide*.

29 According to MEMR (2024a), oil made up around 5% of industrial energy demand in 2023.

30 Ember (2025), *China Energy Transition Review*.

31 Enerdata (2025), *World Energy & Climate Statistics – Yearbook 2025*.

1.3

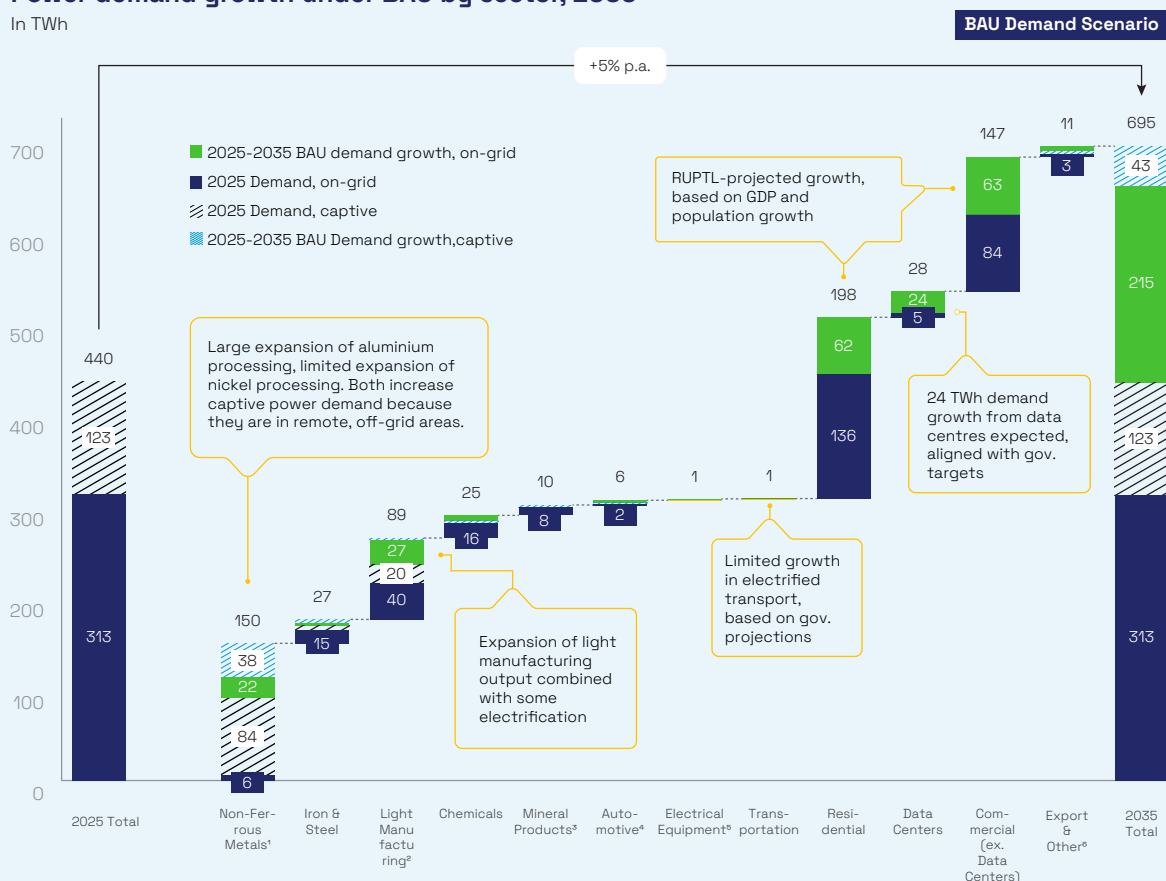
Electricity demand growth under BAU

Under BAU, total electricity demand is projected to grow by 5% per year between 2025 and 2035, from 440 terawatt-hours (TWh) in 2025 to 695 TWh by 2035 [Figure 6]. This trajectory reflects a continuation of historic economic growth of around 5% per year and the implementation of currently announced industrial projects, without a major acceleration in electrification or growth in electricity-intensive new sectors. Residential and commercial demand, non-ferrous metals and data centres account for the largest shares of demand growth over the next decade.

Figure 6 | Electricity demand grows to 695 TWh by 2035 under BAU.

Power demand growth under BAU by sector, 2035

In TWh



Notes: For sectoral breakdown of demand assumptions, see accompanying technical appendix. 1. Nickel, Aluminium, Copper, and other NF metals. 2. Food & Beverage, Textiles, Rubber, Pharma, Pulp & Paper 3. Cement, glass and ceramics 4. Manufacturing of cars and other transport vehicles. 5. Production of electrical products, including batteries and solar modules. 6. Includes other industries

Demand growth in the BAU scenario is driven primarily by four structural trends:³²

- **Residential and commercial electricity consumption rises** as incomes grow. AC ownership is projected to continue its steady rise, increasing from around 12% of households in 2025 to roughly 24% by 2035. **The residential sector adds 62 TWh while commercial adds 63 TWh of demand between 2025 and 2035.**
- **Expansion of metals processing industries**, particularly aluminium and nickel smelting, adds substantial new electricity demand. The current pipeline of industrial projects is projected to add roughly 3 Mt of aluminium production capacity and around 350 kilotonnes (kt) of nickel processing capacity by 2035, making non-ferrous metals the single largest contributor to demand growth **at 60 TWh above 2025 levels.** However, most of this demand growth is expected to occur outside the main grid, supplied by dedicated captive power plants. This is because metal processing facilities, particularly for nickel and aluminium, are often close to mines in remote locations with limited or no grid access. As a result, roughly **15% of total electricity demand growth** in the BAU pathway is projected to come from off-grid captive demand.
- **Data centres emerge as a fast-growing source of electricity demand.** Indonesia's relatively low electricity prices make it an attractive location for digital infrastructure. Under the BAU scenario, **the 2.7 GW data centre pipeline is projected to add around 24 TWh of electricity demand by 2035.** The government is actively supporting data centre development through tax exemptions and by allowing 100% foreign ownership in Special Economic Zones.³³
- **Continued expansion of light manufacturing and services** contributes additional demand growth of **29 TWh from 2025**, of which 27 TWh is on-grid. This includes growth in sectors such as food processing, textiles and other manufacturing and service activities that expand alongside Indonesia's broader economic development.

1.4

Electricity demand growth under High Electrification

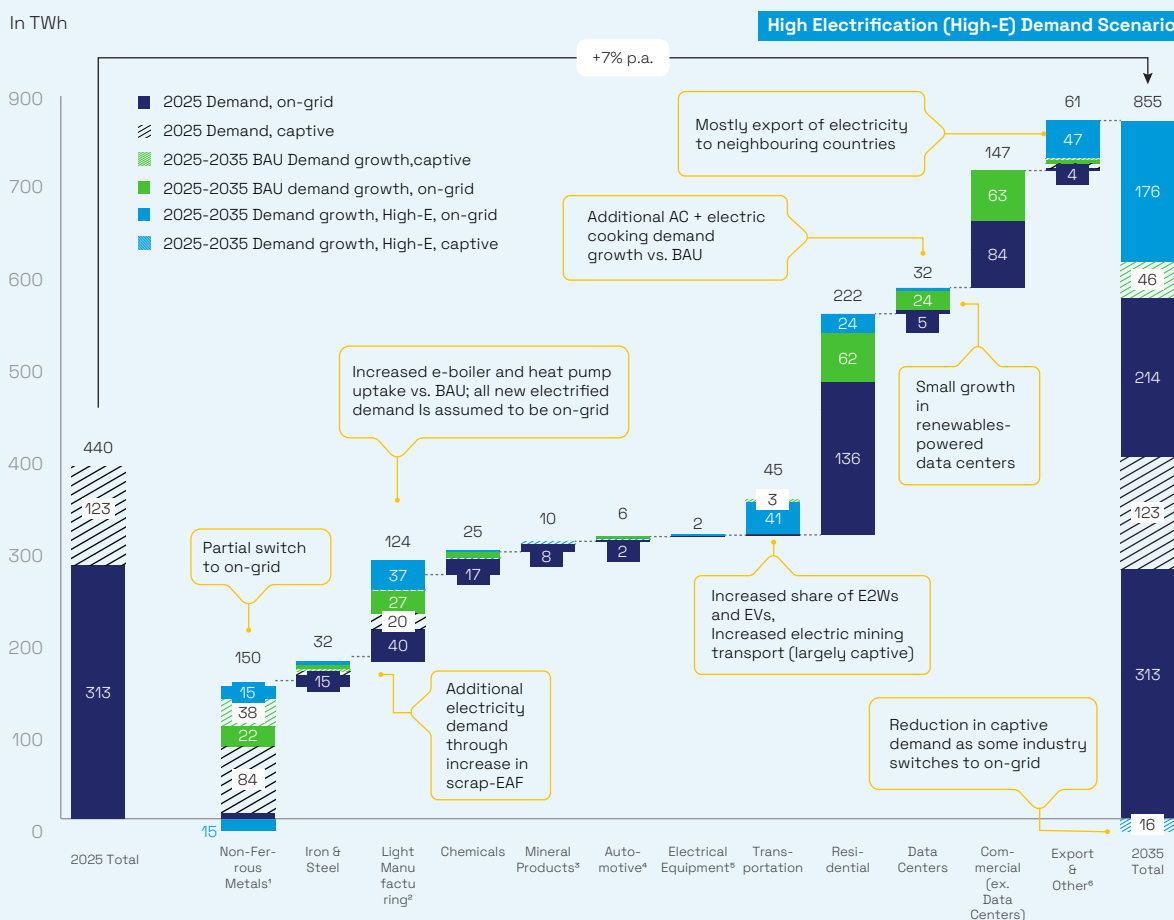
Under High Electrification scenario, electricity demand is projected to grow by around 7% per year between 2025 and 2035. This results in 855 TWh of demand by 2035, around 20% higher than under BAU [Figure 7]. This will increase Indonesia's electricity consumption per capita from around 1,300 to around 2,800 kWh. Around 655 TWh of total demand is expected to be on-grid by 2035.

Two broader trends drive this additional demand:

1. Increased electrification across the industrial, transport and residential sectors.
2. New demand from growth sectors that depend on access to renewable power.

³² See Technical Appendix for the assumptions used in the sectoral demand modelling.

³³ Research and Markets (2026), *Indonesia Data Centre – Market Share Analysis, Industry Trends & Statistics, Growth Forecasts (2026–2031)*.

Figure 7 | Electricity demand grows to 855 TWh by 2035 under High Electrification.**Power demand in High Electrification scenario by sector, 2035**

Notes: For sectoral breakdown of demand assumptions, see accompanying technical appendix.1. Nickel, Aluminium, Copper, and other NF metals. 2. Food & Beverage, Textiles, Rubber, Pharma, Pulp & Paper 3. Cement, glass and ceramics 4. Manufacturing of cars and other transport vehicles. 5. Production of electrical products, including batteries and solar modules. 6. Includes other industries

First, **increased electrification across the industrial, transport and residential sectors** raises electricity consumption above the BAU pathway in several areas:³⁴

- In **industry and manufacturing**, electric technologies gradually replace fossil-fuel heat in several processes, **increasing electricity demand by 43 TWh compared with BAU** (37 TWh in light manufacturing and 6 TWh in iron and steel). This starts in sectors where electrification is already cheaper, or close to becoming cheaper, than fossil-fuel alternatives, as outlined in Box B. In textile fibre production, for example, the share of electric boilers and heat pumps expands to around 42% of supply, while the share of coal-fired boilers declines from around 75% today to roughly 30% by 2035. In iron and steel production, the share of scrap-based electric arc furnace (EAF) production increases from roughly 30% to around 38%, partially replacing blast furnace–basic oxygen furnace, under the assumptions used (see Technical Appendix).

³⁴ See Technical Appendix for the assumptions used in the sectoral demand modelling.

- In **non-ferrous metals, 15 TWh** of electricity demand shifts to the grid from captive supply, as the grid expands and more industrial facilities are connected.
- In **transport, electric mobility expands significantly, increasing electricity demand by 45 TWh compared with BAU.** The total passenger vehicle fleet grows in both demand scenarios. Car ownership rises from around 70 cars per 1,000 people to 110 cars per 1,000 people by 2035,³⁵ while motorcycle ownership remains broadly stable at around 500 motorcycles per 1,000 people. The difference is how much of this fleet becomes electric. Under High Electrification, electric cars make up around 26% of the car fleet and E2Ws around 30% of the two-wheeler fleet by 2035, compared with around 0.5% and 0.6%, respectively, under BAU.³⁶ On top of that, heavy-duty trucks used in the mining sector also electrify, with 37% of the total fleet assumed to be electric by 2035. This adds 4 TWh of demand, of which 1 TWh is on-grid.
- **Residential electricity demand is 24 TWh higher under High Electrification than under BAU** by 2035. Of this additional demand, **16 TWh comes from higher cooling demand** and **8 TWh from the electrification of cooking.** AC ownership rises from 12% of households in 2025 to around 38% by 2035 under High Electrification, compared with roughly 24% under BAU. For electric cooking, the share of households with a grid connection capable of supporting it remains small, rising from around 3% in 2025 to around 4.5% in 2035. However, those households are assumed to switch almost entirely to electric cooking by 2035.

Second, **new electricity demand potentially emerges from growth sectors that depend on access to renewable power.**

- **Regional electricity trade expands** as neighbouring countries seek low-carbon electricity imports, largely to supply data centres, leading to around **47 TWh of electricity exports by 2035.**
- **Data centre demand grows further** as access to renewable power attracts additional investment from international hyperscale technology companies seeking low-carbon electricity and renewable power arrangements [see Box C], although significant data centre demand also appears under BAU due to Indonesia's relatively low electricity prices. As a result, electricity demand from data centres reaches **around 32 TWh by 2035**, compared with roughly **28 TWh under BAU.**³⁷

Together, faster electrification and new demand from sectors that depend on renewable power push electricity demand substantially above the BAU pathway.

³⁵ This only covers private passenger cars.

³⁶ The adoption of E2Ws under High Electrification represents a significant increase: in 2025, just 0.2% of the two-wheeler fleet is electric.

³⁷ Future data centre demand is uncertain and changing rapidly. This analysis assumes around 3 GW of data centre capacity by 2035 under High Electrification, although one stakeholder suggested it could reach around 20 GW.

BOX B | First movers in industrial electrification

Industrial electrification is likely to begin with low- to medium-temperature heat processes, where commercially available technologies such as electric boilers and heat pumps can already replace fossil-fuel boilers [Figure 8]. These opportunities are strongest in light manufacturing sectors such as textiles, food processing, paper and selected chemicals, where a large share of heat demand is below 200°C and electrification is already technically mature. Higher-temperature processes in cement, steel and chemicals are expected to move later, as they remain harder to electrify and depend more on emerging technologies.

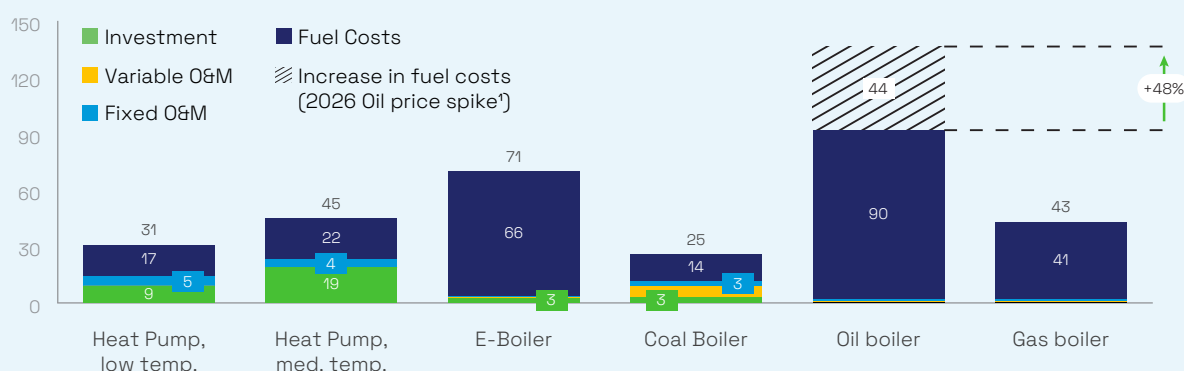
In Indonesia, the first movers are likely to be the firms that currently use oil boilers, since oil-based heat is much more expensive than electric alternatives. Oil also leaves firms exposed to imported fuel price shocks, with costs rising sharply during geopolitical disruptions, as seen during the Iran conflict in early 2026. Figure 8 shows how the 2026 price spike caused near 50% increase in the cost of oil-based heat.

By contrast, coal boilers can still be cheaper than electrified options, weakening the purely economic case for electrification. However, in consumer-facing export sectors, pressure from international buyers can still make electrification strategically attractive even where coal remains low-cost, particularly as major brands phase out coal from their supply chains. This mechanism is explored in depth in Chapter 5.

Figure 8 | Near-term electrification opportunities exist across industry and transport, particularly where electric technologies already offer lower operating costs.

Levelized Cost of Industrial Heat for Various Technologies

2024, \$(2022)/MWh,th



Notes: 1. While most fuel costs remained stable between 2024–2026, oil prices spiked following the conflict in Iran in early 2026. This range represents the LCOH at a diesel price of 20,000 IDR/L (versus the previously assumed price of 13,400 IDR/L).
Source: Global Petrol Prices; PLN Statistics (2024); Direktorat Jenderal Mineral Dan Batubara (2026) Harga Acuan; Expert interviews; Levelized Cost of Heat adapted from Danish Energy Agency & MEMR (2024) Techno-Economic Analysis of Decarbonization Technology options for energy end-use sectors in Indonesia.

BOX C | AWS opens the route for renewables

Data centre demand is already helping to advance Indonesia's renewable power procurement framework. Amazon Web Services (AWS) launched its Asia Pacific (Jakarta) Region in December 2021, committing to invest US\$5 billion over 15 years in data centre construction, operations and the local supply chain. The investment is estimated to contribute US\$10.9 billion to GDP and support 24,700 direct and indirect jobs annually over the period.³⁸ The AWS commitment is part of a broader expansion by hyperscale technology companies in Indonesia, including Microsoft, Google, Oracle and Alibaba. This is projected to grow Indonesia's hyperscale data centre market from US\$3.5 billion in 2025 to US\$8 billion by 2031.³⁹

To match data centre demand with clean power, AWS signed a power purchase agreement (PPA) with PLN in November 2022, contracting 210 megawatts (MW) of capacity across four utility-scale solar PV projects in Java and Bali. The deal was Indonesia's first corporate PPA for off-site facilities, opening a procurement route that had previously been constrained by PLN's monopoly on retail electricity sales and historically limited access to the PLN grid for private suppliers.

Construction has begun across all four sites, with the East Bali Solar PV Plant starting commercial operations in September 2025. The remaining three sites in Karangates, Saguling and West Bali are currently under construction, with commercial operation targeted for 2026.^{40,41,42,43,44}

PLN has signalled its intention to extend the model to other corporate offtakers, while the regulatory environment has continued to evolve, with MEMR Regulation 5/2025 setting clearer principles for renewable PPAs.

The AWS case shows that corporate demand for clean power can be a lever for both renewable deployment and changes to the procurement framework. Capturing the next wave of data centre and artificial intelligence investment will depend on whether this model can be scaled, with multi-hundred-megawatt corporate green PPAs becoming more common, alongside the transmission, permitting and storage infrastructure needed to deliver renewable power at competitive prices and at the scale data centres require.

38 AWS (2021), *AWS Launches AWS Asia Pacific (Jakarta) Region in Indonesia*.

39 Mordor Intelligence (2025), *Indonesia Hyperscale Data Center Market Size, Share & 2030 Growth Trends Report*.

40 Medco Energi (2025), *Medcosolar Bali Timur*.

41 PLN Nusantara Power (2026), *Accelerating the Clean Energy Transition, PLN Nusantara Power Strengthens the Development of the Karangates Floating Solar Power Plant*.

42 PT Indo ACWA Tenaga Saguling (2025), *Saguling Floating Solar PV Commencement Ceremony*.

43 Medco Energi (2025), *Annual Report*.

44 No sources confirm the commercial operation date for the sites are still under construction.

1.5

Demand growth will differ by region

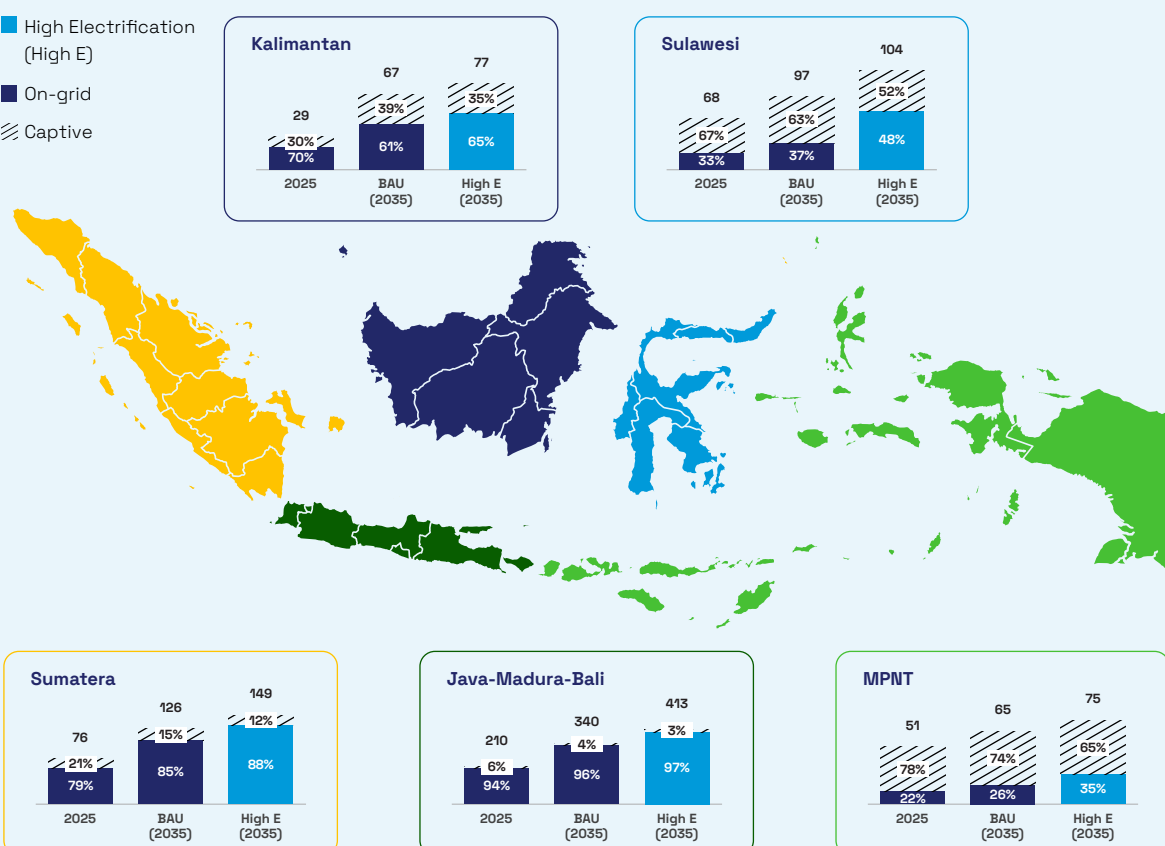
Electricity demand growth will not be evenly distributed across Indonesia. Differences in population density, industrial activity and the location of resource deposits mean that some regions will see substantially faster growth than others. The balance between on-grid and captive power will also vary significantly across the archipelago [Figure 9].

Figure 9 | Jamali and Sumatera are projected to see the highest electricity demand growth.

Electricity Demand Per Region, 2025-2035

In TWh

■ High Electrification
(High E)
■ On-grid
▨ Captive



Note: excludes power export to neighbouring markets.

Overall, electricity demand grows across all regions, but Java-Madura-Bali (Jamali) and Sumatera dominate. As the most densely populated regions, together they account for around 70% of Indonesia's total electricity demand through 2035 under High Electrification. Across both scenarios, Jamali accounts for approximately 50% of total electricity demand between 2025 and 2035. Sumatera, the second-largest demand region, grows from around 75 TWh in 2025 to around 125 TWh under BAU and 150 TWh under High Electrification by 2035, continuing to account for almost 20% of national demand. Sulawesi, Maluku-Papua-Nusa Tenggara (MPNT) and Kalimantan grow rapidly from smaller bases, driven more by metals processing than population growth.

- **Residential and transport demand broadly scale with population.** Growth in these sectors is therefore concentrated in major demand centres, particularly Jamali and Sumatera, driven primarily by population and commercial expansion.
- **Industrial demand is structurally more uneven.** Captive power dominates electricity supply in the resource-driven outer islands. By 2035, captive demand accounts for around 52–63% of total demand in Sulawesi and 66–74% in MPNT, compared with only 3–4% in Jamali. Key growth sectors such as mining, smelting and metals processing are located close to resource deposits rather than demand centres, while many of the largest projects are concentrated in remote regions with limited grid connectivity.
 - o Nickel processing demand is split across Sulawesi and MPNT and is almost entirely captive. In both scenarios, nickel processing alone accounts for around 100 TWh of captive demand across the two regions by 2035, of which roughly 55 TWh in Sulawesi and 45 TWh in MPNT.
 - o Aluminium processing is concentrated in Sumatera, at around 15 TWh, and Kalimantan, at around 30 TWh. Around half of this demand is supplied by captive power plants.

These regional patterns also influence how Indonesia's electricity demand is supplied. **Captive generation supplies around 30% of total electricity demand today, but this share is projected to decline over the next decade, especially under High Electrification.**

By 2035, it falls to around 25% under BAU and around 20% under High Electrification. The decline is sharper under High Electrification because much of the additional electricity demand is expected to be supplied through the grid. This includes demand from transport electrification, light manufacturing and residential cooling. Meanwhile, captive-heavy industrial demand in the outer islands grows from a smaller base. The modelling also assumes that, by 2035, around 10% of demand that would otherwise be met by captive generation shifts to the grid under High Electrification.

Captive generation supplies around 30% of total electricity demand today, but this share is projected to decline over the next decade, especially under High Electrification.

Catering to this shift will require accelerated grid expansion, particularly to connect industrial clusters in the outer islands that currently rely on dedicated captive supply. Indonesia's archipelagic geography makes this challenging: fragmented grids and limited interconnection between islands constrain the efficient balancing of supply and demand, particularly between resource-rich outer islands with significant generation potential and high-demand centres such as Java. Without targeted grid expansion and interconnection, a growing share of new demand could continue to be met outside the main grid, limiting the system's ability to integrate lower-cost renewable generation.

1.6

Meeting rising electricity demand will require a rapid expansion of Indonesia's power system

Both the BAU and High Electrification scenarios imply a substantial expansion of Indonesia's power system over the next decade. Electricity demand is projected to grow from **440 TWh today to around 695–855 TWh by 2035**, equivalent to **annual growth of around 5–7%**, depending on the demand pathway. **On-grid demand alone increases to around 525 TWh under BAU and 655 TWh under High Electrification by 2035.**

The next decade of electricity demand growth is only the start. The Energy Transitions Commission (ETC) projects global electricity demand to roughly triple by 2050, driven by greater electrification across transport, heating and industry, as well as growing demand from e-fuel⁴⁵ production. Indonesia is likely to see the same trajectory.⁴⁶ Building the supply needed to meet demand through 2035 will therefore also lay the foundation for a much larger power system beyond 2035.

If electricity supply does not expand in line with demand, economic growth could be constrained. Across global supply chains, energy-intensive sectors such as metals processing, manufacturing and data centres increasingly require electricity that is reliable, competitively priced and clean (see Chapter 5). Delays in power system expansion and renewable deployment could therefore slow investment, weaken Indonesia's industrial competitiveness and limit its ability to capture emerging growth opportunities.

A cleaner power system could also strengthen Indonesia's position in clean technology supply chains, including batteries and EVs.

A cleaner power system could also strengthen Indonesia's position in clean technology supply chains, including batteries and EVs.

The scale and timing of new electricity supply will therefore play a decisive role in whether Indonesia can achieve its growth ambitions. Expanding supply quickly while maintaining reliability and competitive costs will be essential to support industrial expansion, attract investment and meet rising household demand.

The chapters that follow assess what it would take to expand Indonesia's power system at the scale required under these different demand pathways. They examine Indonesia's current power system and expansion plans, the availability of renewable resources and whether a higher share of renewables could deliver additional economic benefits while meeting rising electricity demand.

⁴⁵ E-fuel includes hydrogen and e-SAF.

⁴⁶ ETC (2025), *Power Systems Transformation: Delivering Competitive, Resilient Electricity in High-Renewable Systems*.





Chapter 2

Indonesia's power supply: large renewables potential, limited deployment

Chapter 1 demonstrated that Indonesia will undergo rapid electricity demand growth over the coming decade. Meeting that demand will require a major expansion of the power system. Indonesia has the renewable resource base to support this expansion many times over, with solar standing out for its scale, build speed and rapid global cost decline. Yet Indonesia's renewables deployment has consistently lagged regional peers, and the current RUPTL does not close the gap. The barrier is not the availability of resources, but whether projects can be developed commercially at scale. High costs and limited revenues continue to weaken project economics, while market replication has stalled despite the success of first-mover projects. The recently announced 100 GWp solar programme marks a step change in ambition, but delivery will depend on parallel action to bring costs down and scale demand to absorb the additional generation.

This chapter sets out the current supply-side picture in five steps. Section 2.1 outlines the 2025–2034 RUPTL and the country's track record of delivering planned power system expansion. Section 2.2 describes Indonesia's renewable resource base and current deployment. Section 2.3 compares current electricity generation costs across different sources, while Section 2.4 examines why first-mover solar projects have yet to trigger broader replication. Section 2.5 closes with the 100 GWp solar programme.

2.1

The 2025–2034 RUPTL plans for significant renewables expansion, but delivery has repeatedly fallen short

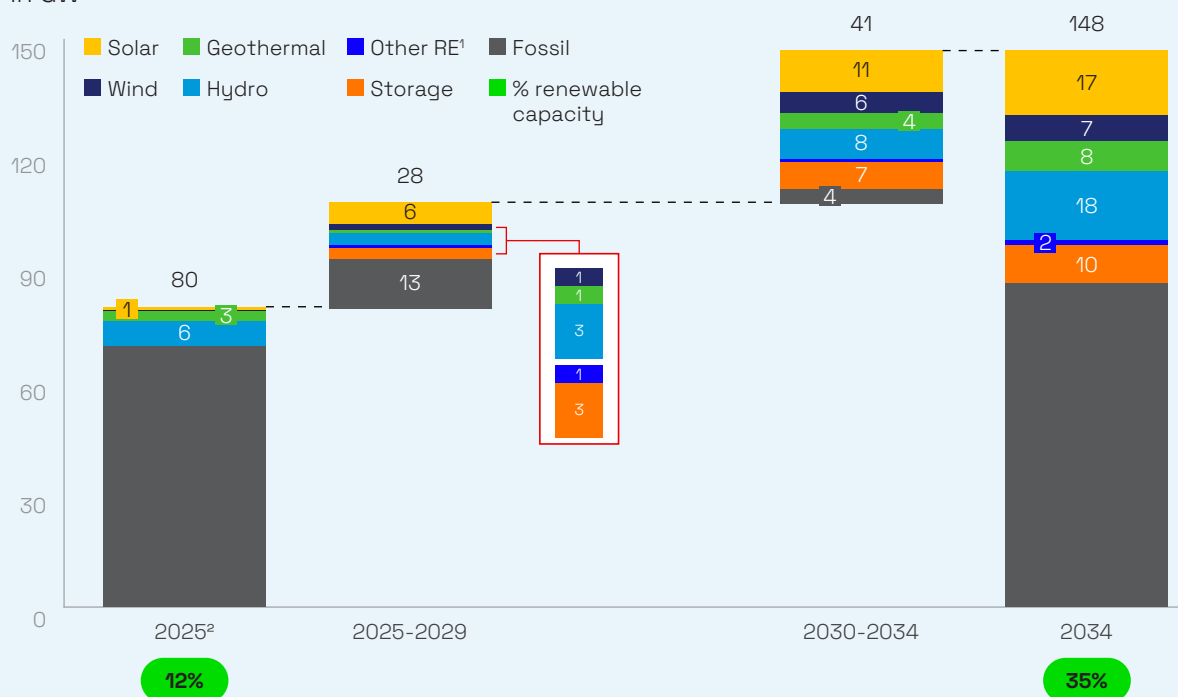
Indonesia's power sector expansion is guided by the RUPTL, the national electricity supply plan prepared by PLN and approved by the MEMR. The RUPTL provides the government's official roadmap for power system expansion, setting out planned additions of generation capacity, transmission infrastructure and supporting investments. It is updated periodically, with previous versions published in 2019 and 2021, and typically uses a ten-year planning horizon. The current RUPTL was finalised before the government's August 2025 announcement of the 100 GWp solar programme (see Section 2.5) and is expected to be revised to reflect the new ambition. Figure 10 should therefore be read as the current plan, which is likely to change.

The RUPTL provides the government's official roadmap for power system expansion, setting out planned additions of generation capacity, transmission infrastructure and supporting investments.

The current RUPTL covers the period of 2025–2034 and outlines a major expansion of Indonesia's electricity system over the coming decade [Figure 10]. In total, the plan schedules the addition of approximately 60 GW of new on-grid generation capacity, an increase of around

Figure 10 | 2025–2034 RUPTL targets 30% renewable capacity by 2035.**On-grid capacity and planned additions under 2025–2034 RUPTL**

in GW



Notes: 1. Includes bio-energy and nuclear. 2. Includes only on-grid PLN supply.

Source: MEMR (2025), Handbook of Energy & Economic Statistics of Indonesia 2025.

80% from Indonesia's current grid-connected installed capacity of 80 GW.⁴⁷ Around 42 GW of this new capacity is planned to come from renewables, including 17 GW of solar PV, 12 GW of hydropower and 7 GW of wind, alongside smaller additions of geothermal and other renewable technologies, e.g., bioenergy. Around 17 GW is expected to come from fossil-fuel generation, primarily coal and gas. The plan also includes around 10 GW of storage, comprising 6 GW of battery energy storage system (BESS) and 4.2 GW of pumped hydro storage (PHS).

In the plan, fossil-fuel additions are front-loaded, with most gas and coal capacity scheduled for 2025–2029. By contrast, renewables and storage are largely back-loaded. The largest renewable additions occur after 2030, while only around 3.5 GW of the planned 10 GW of storage is targeted for delivery by 2030. Renewable capacity accounts for only around 30% of total capacity by 2035, with the remainder dominated by coal and gas plants. Delivering the 100 GWp solar programme on top of this baseline would represent a major acceleration in renewable deployment, as examined in Section 2.5.

⁴⁷ Only includes on-grid PLN supply. Source: MEMR (2026), *Handbook of Energy & Economic Statistics of Indonesia 2025*.

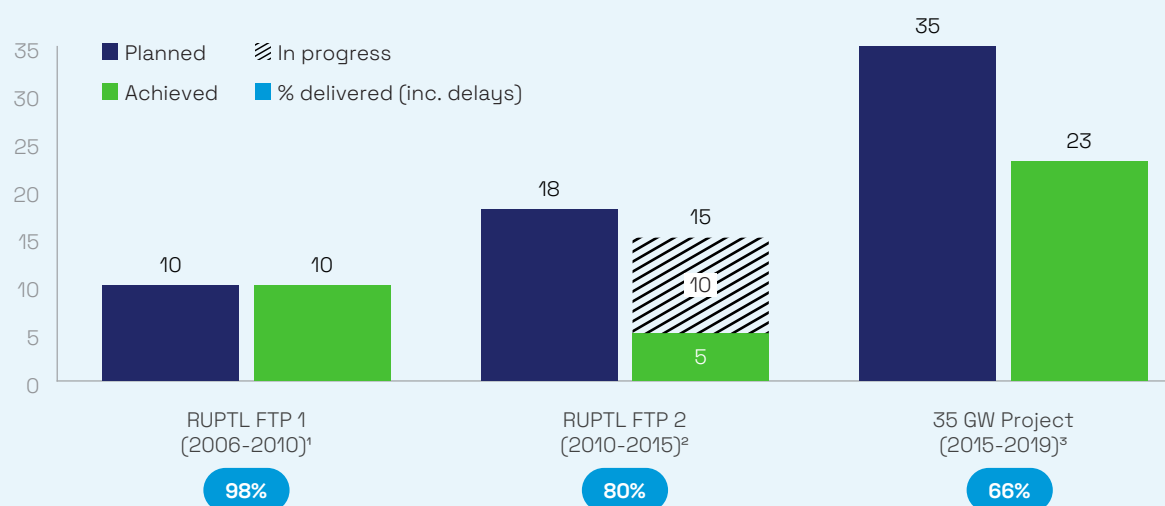
In theory, the capacity additions outlined in the RUPTL are sufficient to accommodate electricity demand growth under both BAU and High Electrification through 2035. In practice, delivery is uncertain. The previous 35 GW programme launched for 2015–2019 delivered only around 66% of planned capacity, including projects completed after significant delays. Earlier programmes, including Fast Track Programmes I and II, faced similar issues, although they achieved higher completion rates. Permit bottlenecks, financing constraints and project development challenges have repeatedly slowed delivery relative to plan [Figure 11].

Back-loading renewables and storage also concentrates delivery risk in the renewable build-out. Because most renewable additions are planned for the later period of 2029–2034, while most coal and gas additions are scheduled for 2025–2029, they are more exposed to delay, deprioritisation or cancellation if financing, permitting or system planning challenges emerge.

Figure 11 | Previous RUPTL programs have underdelivered and faced delays.

RUPTL has historically faced delays and under-delivery

Realisation of historic RUPTL's, in GW



- All three programmes have faced **significant delays** in meeting their targets. The FTP 1 target was met four years behind schedule and, as of 2023, FTP 2 was still in the process of meeting its target.
- The 35 GW programme **has prioritised coal power plants**, delaying renewable energy development.
- Note on the most recent plans: The 2019–2028 plan was in force for only two years before being replaced by the 2021–2030 plan, making its delivery difficult to assess. The 2021–2030 plan is still ongoing, but underdelivery appears likely: by early 2025, only 1.6 GW had been commissioned, compared with around 10 GW planned⁵.

Notes: 1) IEEFA (2024); 2) No official data are available on FTP 2 delivery; figures are based on IEEFA estimates; 3) Inside Indonesia (2020); 4) CREA and RUPTL; 5) IESR (2025), Government Needs to Ensure Strategy to Achieve Renewable Energy Target in RUPTL.

2.2

Indonesia has strong renewable resources, but deployment is lagging

Indonesia has the resource potential to scale renewables far beyond the levels planned in the RUPTL. Technical potential is estimated at over 7,700 GW of solar PV,⁴⁸ 155 GW of wind,⁴⁹ 95 GW of hydropower,⁵⁰ 24–2,160 GW of geothermal,⁵¹ 30 GW of biomass power and approximately 7,300 gigawatt-hours (GWh) of pumped hydro storage.⁵² These resources play different roles in the power system. Geothermal and biomass can operate continuously, allowing them to provide firm baseload power and replace coal in that role. Solar and wind are variable but can be paired with storage to provide firmer supply.

Geothermal and hydropower warrant particular attention as a round-the-clock, low-carbon baseload resources. The section below looks more deeply into their resource potential, currently deployment in Indonesia and what would be needed to scale them further.

Geothermal and hydropower warrant particular attention as a round-the-clock, low-carbon baseload resources.

Geothermal in Indonesia: the baseload renewable that remains largely untapped

The government estimates 24 GW of geothermal potential in Indonesia, while the IESR estimates 2,160 GW when next-generation potential is included, which is the largest untapped geothermal resource base in the world.⁵³ If fully realised, geothermal could help meet process-heat demand in key manufacturing sectors, strengthen firm capacity in a renewable power system and reduce reliance on coal and imported fuels. Yet only 2.7 GW of geothermal capacity is operational today, equivalent to around 10% of the 24 GW government estimate.⁵⁴

The strategic case for accelerating development is strong. Unlike solar or wind, geothermal delivers firm, dispatchable power. Its capacity factors exceed 90%, making it capable of replacing coal as a baseload source without storage or backup. One megawatt of geothermal capacity can therefore generate roughly twice as much electricity annually as one megawatt of solar capacity. The 2025–2034 RUPTL reflects this value, targeting an additional 5.2 GW of geothermal capacity over the next decade. Delivery, however, has historically lagged. In 2025, Indonesia added only 113 MW, compared with the 500–600 MW per year implied by the RUPTL pathway.

48 IESR (2025), *Unlocking Indonesia's Renewables Future*.

49 Energy Transition Partnership (2024), *Roadmap Onshore Wind Energy Development in Indonesia*.

50 MEMR (2023), *Percepat Upaya Transisi Energi, Menteri ESDM Dorong Pemanfaatan Tenaga Hidro*.

51 Potential includes next-generation potential from hot dry rock. Source: IESR and Project InnerSpace (2025), *The Future of Geothermal in Indonesia*.

52 IESR (2025), *Unlocking Indonesia's Renewables Future*.

53 Antara News (2025), *Illuminating the Future with Geothermal Power*.

54 Think Geoenergy (2025), *Indonesian Government sets Direction for Geothermal Growth at IIGCE 2025*.

Three structural barriers explain the delivery gap:

- **Exploration risk.** Upfront resource exploration can cost US\$30–50 million with no recourse if the resource proves insufficient, while full development of a 100 MW site can cost US\$400 million. This can reduce the internal rate of return (IRR) to 8–9%, well below the 10–12% required by developers, creating a financing gap before a single kilowatt-hour is generated.
- **Land access.** Much of Indonesia's geothermal potential lies in or adjacent to forest areas, where forestry borrow-to-use permits can involve costly offsetting requirements and coordination across multiple government agencies, adding years to permit acquisition timelines.
- **Social licence.** In several cases, including Flores and Mount Lawu, community opposition over water sources, land disruption and sacred sites has stalled projects, in part because of limited consultation at project outset.

Accelerating geothermal development requires three targeted interventions. First, **reduce upstream exploration risk** through a permanent, capitalised facility that provides contingent financing for drilling, with proven sites subsequently auctioned to private developers, building on the World Bank-backed Geothermal Resource Risk Mitigation (GREM) facility. Second, **scale permitting reform**. Pilot cases have reduced licensing timeline from up to 18 months to as little as one week, which could be replicated more widely. Third, **integrate standardised benefit-sharing frameworks and mandatory early consultation** into the licensing process. This should be supported by **public education on geothermal development, its benefits and the mitigation of its environmental impacts** to help communities make informed decisions and reduce the project-by-project negotiations that have repeatedly extended development timelines by years.^{55,56}

Hydropower in Indonesia: the Swiss Army knife of the power generation mix

Indonesia has approximately 95 GW of technical hydropower potential, concentrated primarily in Papua, Kalimantan, Sumatra and Sulawesi. As of December 2025, total installed capacity was around 6.3 GW, consisting of 5.1 GW of large hydropower plants (PLTA) and 1.2 GW of mini- and micro-hydropower plants across Indonesia, equivalent to less than 7% of total potential. The 2025–2034 RUPTL targets 16 GW of new hydropower capacity, the second-largest planned renewable addition after solar.

Indonesia has approximately 95 GW of technical hydropower potential, concentrated primarily in Papua, Kalimantan, Sumatra and Sulawesi.

⁵⁵ World Bank (2019), *Indonesia: Scaling Up Geothermal Energy by Reducing Exploration Risks*.

⁵⁶ ThinkGeoEnergy (2024), *Indonesia Aims to Shorten Geothermal Permit Process to Just Five Days*.

Hydropower is uniquely versatile: it can provide dispatchable firm power without battery storage, serve as baseload or distributed supply, support electricity storage through pumped hydro and host floating solar PV on existing reservoirs. The latter is demonstrated in the Cirata Solar PV Plant, where a 192 MW floating solar is installed on an existing reservoir, creating one of Southeast Asia's largest hybrid renewable systems without requiring additional land.

Large-scale hydropower offers transformational capacity but carries significant environmental and social risks. Flagship projects in the pipeline, including the 9 GW Kayan Cascade in North Kalimantan and the 1.3 GW Mentarang plant, involve potential impacts, including reservoir inundation of High Conservation Value (HCV) forests, displacement of Indigenous communities and permanent alteration of river ecosystems.

Mini- and micro-hydropower plants (with a capacity below 10 MW) have a structurally different profile. Run-of-river configurations avoid large-scale inundation, generally have smaller environmental footprints and are well suited to remote eastern Indonesia, where grid extension can be uneconomic and diesel dependence is high. Mini-hydropower is Indonesia's fourth-largest source of renewable capacity, with approximately 486 MW installed, yet represents only a fraction of the available potential.

Targeted interventions are needed to unlock further hydropower growth. For large-scale projects, the priority is to front-load environmental and social assessment before site selection, using spatial planning to identify and avoid sensitive areas before projects are tendered rather than addressing conflicts later in development. This will also be important for attracting international capital. Floating solar should be mainstreamed as a standard co-development option within PLN's tendering process for existing and planned reservoirs, given its low marginal cost and near-zero land footprint.

Targeted interventions are needed to unlock further hydropower growth.

The bottlenecks for mini-hydropower deployment are economic and regulatory. Local developers face limited financing access and high borrowing costs, which significantly increase project costs. At the same time, PLN ceiling tariffs are widely regarded as too low, while price-only competitive processes can push tariffs to commercially unviable levels. This leaves many technically viable projects uncontracted. In addition, the equity and partner requirements attached to PLN and sub-holding development schemes can complicate participation for smaller developers.⁵⁷ A revised feed-in tariff reflecting actual remote-area development costs, simplified permitting for run-of-river schemes and standardised PPAs could help unlock technically viable projects that have been commercially stranded.

57 The RUPTL provides three routes for project development: PLN, PLN sub-holding and an IPP. Under the PLN scheme, engineering, procurement and construction may be carried out directly by PLN or assigned to a subholding. A sub-holding may execute 100% of the project (P.100) or 51% while a partner executes the remaining 49% (P.51). Under the IPP scheme with mandatory partnership, the PLN sub-holding's participation is capped at 30%. Mini-hydropower projects developed under the IPP scheme does not involve a PLN sub-holding participation (100% IPP).

Wind plays a more limited role in Indonesia's power system

Indonesia's technical wind power potential of 155 GW does not indicate how much of that resource is commercially viable. Sitting close to the equator, Indonesia has relatively low average wind speeds. At around 4 metres per second at a height of 100 metres,⁵⁸ this speed is less than half the level of high-resource markets such as Denmark or the United Kingdom. Resources are concentrated in pockets, primarily East and West Nusa Tenggara, southern Sulawesi, southern Java and parts of Aceh and Papua. Only 154 MW is currently installed, across two wind farms in South Sulawesi, Sidrap and Tolo.⁵⁹ Wind can play a useful role in specific high-resource locations but is unlikely to scale to the same extent as solar.

Solar is the largest and fastest-to-build renewable opportunity, supported by continued global cost declines

Among Indonesia's renewable alternatives, solar stands out for three reasons:

- **Solar has by far the largest technical potential** at over 7,700 GW, with around 166 GW already estimated to be at commercially viable sites.⁶⁰ Its modularity allows deployment across diverse geographies and use cases, from utility-scale plants to rooftop and distributed systems. Previous IESR analysis suggests that **solar could in principle supply 88% of Indonesia's electricity demand by 2060, underlining the potential scale of this alternative.**⁶¹
- **Solar can be built quickly.** Utility-scale solar PV projects can be constructed within six months to two years, particularly when land access and grid connection are secured in advance. New coal-fired power plants (CFPP), by contrast, typically take four to six years from the start of construction to commercial operation. With electricity demand growing by 5–7% per year, this shorter construction period gives solar an important advantage in responding quickly to new demand compared to coal, geothermal and hydropower [Figure 12]
- **Globally, solar costs have fallen dramatically over the past decade and continue to decline.** Solar generation is intermittent, so scaling it requires storage and other solutions for system flexibility. Battery costs are also declining rapidly, making round-the-clock generation with solar plus batteries more affordable. Section 3.1 examines these global trends in more detail, and the direction of travel is clear. Solar is becoming one of the lowest-cost sources of new generation across many sunny markets, and Indonesia's high solar irradiation gives it a natural advantage in capturing that trend.

Solar could in principle supply 88% of Indonesia's electricity demand by 2060, underlining the potential scale of this alternative.

58 Plain et al. (2022), *How Offshore Wind Could Become Economically Attractive in Low-Resource Regions Like Indonesia*, iScience.

59 ETP (2024), *Roadmap for Onshore Wind Energy Development in Indonesia*.

60 IESR (2025), *Unlocking Indonesia's Renewables Future*.

61 IESR (2021), *Deep Decarbonization of Indonesia's Energy System*.

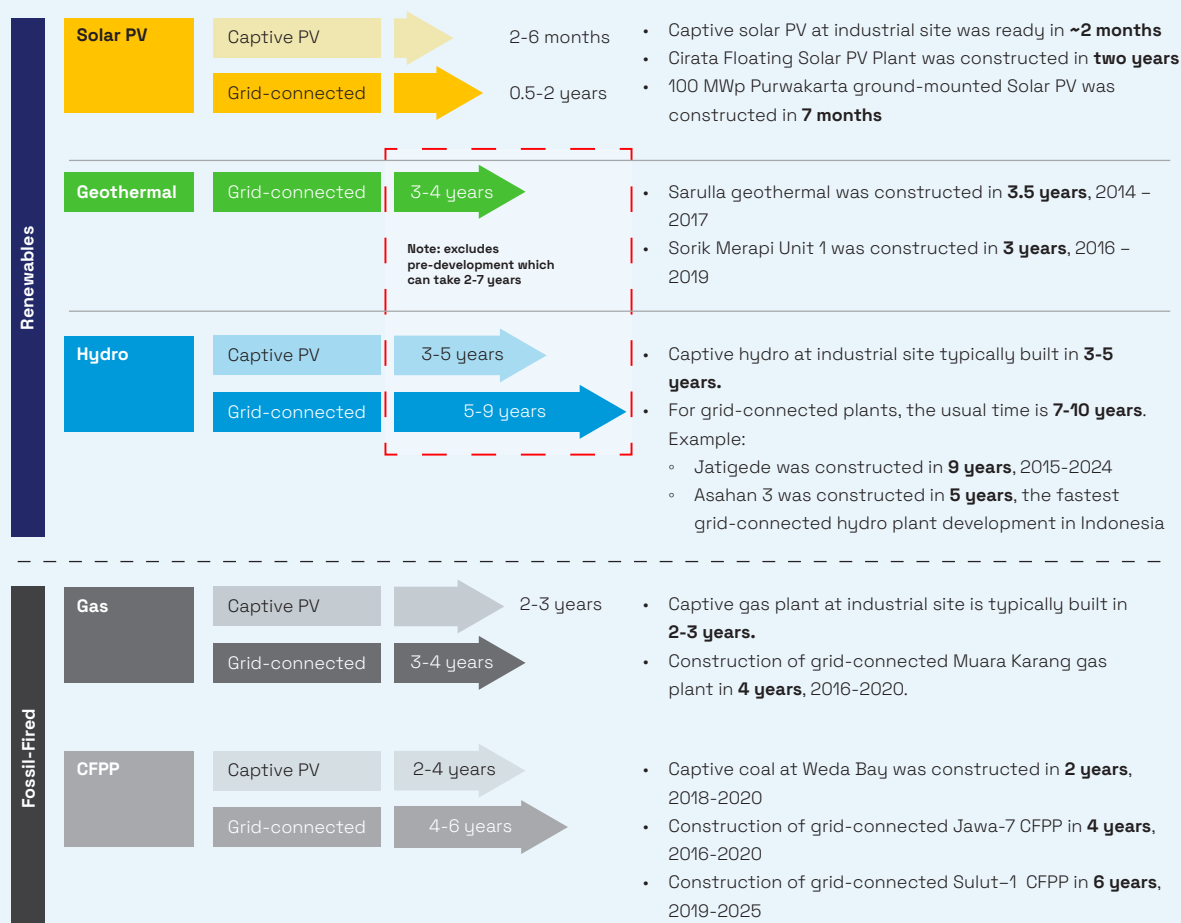
Figure 12 | Solar PV projects have the shortest construction time among renewable and fossil generation option.

Construction timelines of solar PV can be faster than coal, especially when captive

Typical Construction Time for RES Projects vs Fossil-fired Power Plants

Recent Examples

Time between start of construction and start of commercial operation



Sources: NS Energy Business; CNN Indonesia; expert interviews, Global Energy Monitor Wiki; Gumber et al. (2024), A Global Analysis of Renewable Energy Project Commissioning Timelines; Newposkommando; Boltim; Power Technology; Nippon Koei (2025).

Solar's advantages come with one important qualification: generation is limited to when the sun is available, so realising its full potential requires flexibility to shift some of that electricity to other times. How challenging this is depends heavily on geography. Low-latitude sunbelt countries such as Indonesia benefit from relatively consistent solar output across the year, meaning the challenge is primarily within the day rather than across seasons. By contrast, higher-latitude wind-belt countries can face greater seasonal variation, making balancing more complex and potentially more costly. Batteries and demand-side flexibility can help shift midday generation into evening demand, with costs continuing to decline (see Chapter 3). In sunbelt countries, the total system costs of solar-and-battery systems can be equal, or even fall below today's fossil-fuel systems.⁶² Expanding storage will also help maintain the reliability of Indonesia's power grid as solar accounts for a larger share of electricity generation.

Box C | Rooftop Solar

Rooftop solar can scale quickly, but Indonesia's quota system is constraining growth.

Pakistan shows how rapidly distributed solar can expand when the economics are compelling. Between 2023 and 2025, Pakistan deployed 27 GW of distributed solar, roughly equivalent to the combined capacity of all its operating coal, gas and oil power plants.⁶³ This boom was driven by the lower cost and greater availability of solar plus storage compared with grid electricity.

Indonesia remains far behind, with total installed rooftop solar capacity of 775 MW in 2025.⁶⁴ Growth is constrained not by the availability of rooftop space but by regulation. Under MEMR Regulation 2/2024, grid-connected rooftop solar projects require prior approval and are subject to system-based quotas.⁶⁵

This framework sets a quota allowance of 5.7 GW for 2024–2028,⁶⁶ divided across PLN's 11 power systems and allocated annually: 901 MW in 2024, 1,004 MW in 2025, 1,065 MW in 2026, 1,183 MW in 2027 and 1,593 MW in 2028.⁶⁷ More than 70% of the 2024 quota was allocated for Jamali, with the remainder distributed across Sumatra, Sulawesi, Kalimantan and the eastern islands. Within each system, capacity is allocated on a first-come, first-served basis through two application windows a year, in January and July. PLN has cited grid stability as the rationale for the gradual increase of the quotas, given the variability of rooftop solar generation.

63 Ember (2026), *The Solarization of Pakistan's Energy Economy*.

64 PLN (2025), *PLN Presentation: Sosialisasi Prosedur Permohonan Pembangunan dan Pemasangan PLTS Atap Januari 2026*.

65 Ashurst (2024), *Indonesia's New Rooftop Solar PV Regulation: A Difficult Balancing Act*.

66 Quota data as of July 2026; future changes are possible.

67 IESR (2024), *Efforts to Encourage the Effectiveness of Rooftop Solar Quota Fulfillment*.

62 ETC (2025), *Power Systems Transformation*.

Industry and analyst commentary points to three recurring issues with the current framework.

First, the annual quotas remain small relative to Indonesia's broader solar ambitions. The cumulative 5.7 GW quota represents only a small fraction of the 100 GWp solar programme and is far below existing demand. In the January 2026 application round, 304 MW of the 485 MW available was allocated to applicants already on the waiting list from the previous round, leaving less capacity for new applicants.⁶⁸ Second, MEMR Regulation 2/2024 abolished net metering. Customers can no longer offset electricity exported to the grid against their electricity bills, weakening the economics of rooftop solar.⁶⁹ Third, in high-demand systems, failing to secure an allocation will delay projects by six months until the next application window.

Stakeholders have repeatedly highlighted these constraints, and some expect significant increase (GW range) to the available quotas in near future.

68 Katadata (2026), *War Kuota PLTS Atap di Tengah Mimpi Kemandirian Energi*.

69 ABNR (2024), *Indonesia Issues New Rules on Operation of Rooftop Solar, Abolishes Net Metering*.

BOX D | Floating solar: a promising opportunity to scale solar on Indonesia's reservoirs

Floating solar is particularly well suited to Indonesia. Java is home to around 56% of the country's population on just 7% of its land area. Population density in the island is around 1,200 people per square kilometre (km²), which is around 2.5 times that of India, four times that of Vietnam and eight times that of China.⁷⁰ Solar deployment on Java therefore faces intense competition for land. Floating solar avoids much of this constraint by using reservoir surfaces instead. Much of Indonesia's near-term floating solar pipeline is located on existing hydropower reservoirs, allowing projects to share existing hydropower and grid infrastructure. Government officials estimate that Indonesia could host at least 28 GW of floating solar across its reservoirs and lakes.⁷²

Cirata provides the first proof point for large-scale floating solar in Indonesia. The 192-megawatt-peak (MWp) Cirata Floating Solar PV Plant in West Java was inaugurated in November 2023 as a joint venture between Masdar and PLN Nusantara Power. It is currently Southeast Asia's largest floating solar facility.⁷³ The site also illustrates the complementarity between floating solar and hydropower: hydropower generation is typically higher during the rainy season, while solar generation is higher during the dry season, helping stabilise output across the year.

70 BPS (2024), *Population Statistics 2024*.

71 World Bank (2024), *Population Density Indicator*.

72 Reuters (2021), *Indonesia Begins Work on Southeast Asia's Largest Floating Solar Plant*.

73 ANTARA News (2024), *Cirata Floating Solar Power Plant: Indonesia's Green Energy Milestone*.

The pipeline extends beyond Cirata. Several floating solar projects are now under development. The 92 MWp Saguling Project in West Java, developed by PLN Indonesia Power and ACWA Power, began construction in October 2025,⁷⁴ with commercial operations targeted for November 2026.⁷⁵ Three further 100 MW projects, Gajahmungkur, Kedung Ombo and Jatigede, are progressing through PLN's project pipeline.^{76,77} PLN and ACWA are also developing a 48 MW project on Lake Singkarak in West Sumatra.⁷⁸ The 2025–2034 RUPTL identifies other sites in the pipeline, including Sutami in East Java and Jatiluhur in West Java.⁷⁹

Two barriers are slowing the scale-up of floating solar. First, **reservoirs often have competing uses, creating potential concerns for surrounding communities.** Many of Indonesia's reservoirs support floating net-cage aquaculture, a primary source of livelihoods for local communities, and floating solar projects may require relocating these cages. Cirata's design allowed aquaculture to continue elsewhere on the reservoir, but this approach has yet to be standardised for wider replication.⁸⁰ At Lake Singkarak, the only large project in the pipeline located on a natural lake, local fishers have raised concerns about potential impacts on fish populations, amid existing mistrust following an earlier hydropower-related flash flood.⁸¹ Securing social licence for floating solar will therefore require credible early consultation and equitable benefit-sharing.

Second, **water-surface fees vary significantly between sites.** This adds another layer of cost uncertainty for developers and financiers, similar to the uncertainty created by land acquisition for ground-mounted solar.

74 Reuters and SolarBytes (2025), *Indonesia Begins 92 MW Floating Solar Project in West Java*.

75 Renewables Now (2025), *ACWA, PLN Secure USD 60m for Floating Solar Project in Indonesia*.

76 Asian Infrastructure Investment Bank (2025), *Indonesia: Proyek Hijaunesia Staple Financing – Gajahmungkur 100 MW Floating Solar PV Project*.

77 ANTARA News (2025), *Floating Solar Power Plants to Energize Central Java*.

78 Mongabay Indonesia (2025), *Tragedy Haunts Community on Shore of Sumatra's Largest Solar Farm*.

79 IESR (2025), *The Big Role of Floating Solar Power Plants in Realizing RUPTL 2025–2034*.

80 ESA Global Development Assistance (2025), *Understanding the Planning Challenges for Floating Solar PV in Indonesia*.

81 Mongabay Indonesia (2025), *Tragedy Haunts Community on Shore of Sumatra's Largest Solar Farm*.

Despite immense potential, renewable deployment continues to lag regional peers

While Indonesia has abundant renewable resources, large-scale deployment has yet to take off. At the end of 2025, Indonesia had around 10 GW of on-grid renewable capacity, including 0.5 GW of solar, 0.1 GW of wind, 6 GW of hydropower and 2.8 GW of geothermal.⁸² Compared with regional peers, installed renewable capacity per capita remains low, at only 54 MW per million people, compared with 90 MW in the Philippines, 173 MW in India and 502 MW in Vietnam [Figure

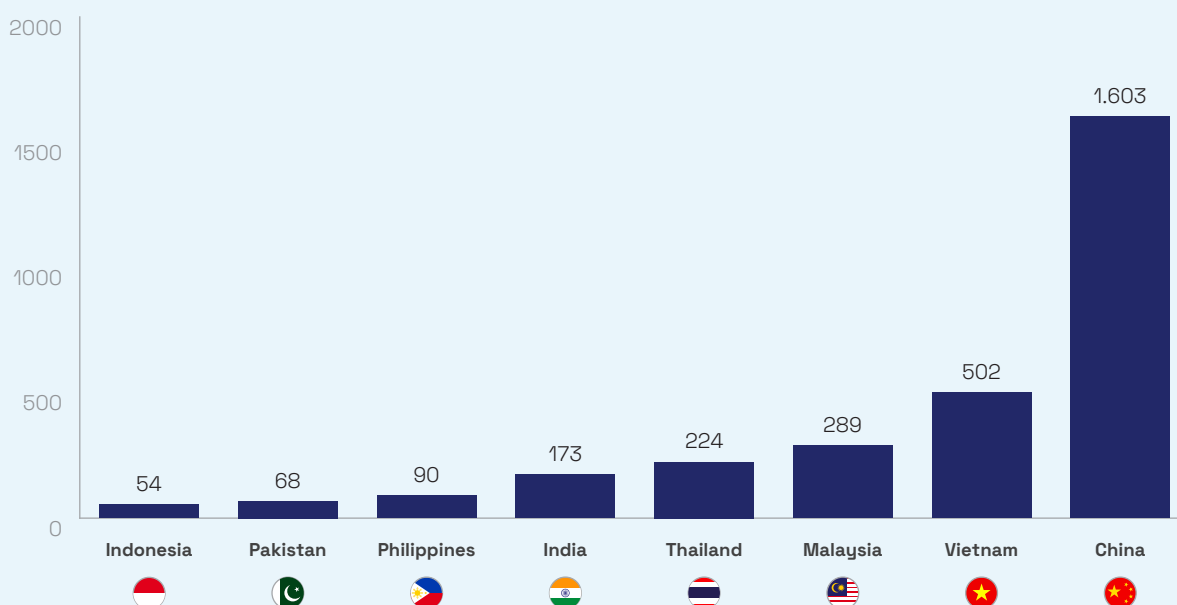
82 MEMR (2026), *Handbook of Energy & Economic Statistics of Indonesia 2025*.

13]. Despite having one of the largest renewable resource bases in Southeast Asia, Indonesia has so far developed only a small fraction of its potential. The constraint is not resource availability, but the conditions needed for projects to be commercially viable at scale. So far, those conditions have aligned for only a small number of strategic projects, as discussed in Section 2.3.

Figure 13 | Renewable deployment in Indonesia lags regional peers.

Indonesia is lagging behind regional peers in the deployment of renewable capacity

Renewable capacity per capita, MW per million people, 2025



Source; World Bank (2026), Population total; IRENA (2026), Renewable Capacity Statistics 2026.

Looking specifically at solar, regional peers show that there is a big opportunity to speed up Indonesia's deployment rate [Figure 14]. The 2025–2034 RUPTL targets around 17 GW of on-grid solar capacity by 2035, equivalent to roughly 1.7 GW per year. By comparison, India installed 38 GW in 2025 alone, while China installed 315 GW that year and is targeting more than 2,000 GW by 2030.⁸³ Pakistan, which has a comparable population and significantly lower GDP per capita than Indonesia, imported more than 15 GW of solar panels in 2024 despite having no formal national deployment programme.⁸⁴

Figure 14 adjusts these deployment rates for population. At around 2 MW per million people per year, Indonesia's current solar deployment rate is less than one-tenth of India's and less than one-hundredth of China's. Even the increase to 4 MW as planned under the current RUPTL would leave Indonesia well behind these deployment rates. Under the 100 GWp solar programme,

⁸³ pv magazine (2026), China Adds 315 GW Solar in 2025.

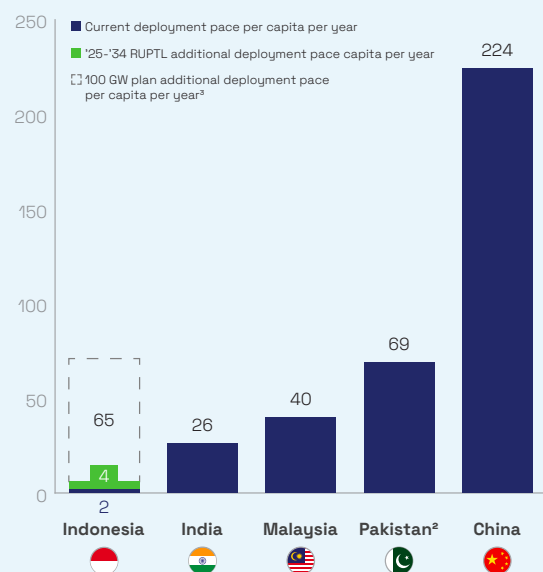
⁸⁴ Import data is used since no reliable data on installed capacity is available for Pakistan.

however, deployment would rise to around 65 MW per million people per year. This is a move in the right direction, although the target remains highly ambitious relative to Indonesia's deployment track record.

Figure 14 | Regional peers show what is possible in the pace of solar deployment.

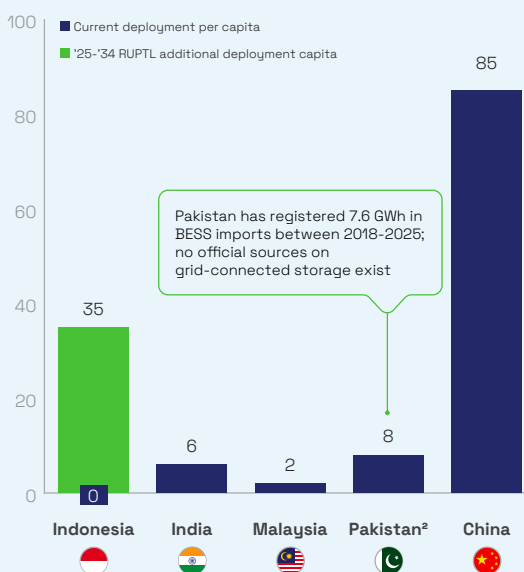
Regional peers show what is achievable regarding the deployment pace of solar capacity

Solar capacity installation per capita per year, MW per million people, 2024/2025¹



No significant storage capacity in Indonesia today, but RUPTL is planning a large increase for the next decade

Storage capacity installed⁴, MW per million people, 2024/2025¹



Notes: 1. Most recent available year used: 2024 or 2025. 2. No reliable annual installation figure is available for Pakistan; figures are based on reported imports. 3. Assumes the 100 GWp is realised over five years. 4. Includes PHS and BESS. 5. Assumes a four-hour storage duration for all imported BESS.

Sources: Solar: Indonesia: MEMR/IESR (2026), reported in pv magazine; India: MNRE (2026), reported in pv magazine; China: NEA (2026), reported in pv magazine; Pakistan: Ember and WRI (2025); Malaysia: IEA and PVPS (2026). Storage: China: CNESA (2024); China Daily/State Grid (2025); India: pv magazine (2026); Malaysia: Energy-Storage.News (2025); Pakistan: IEEFA (2025); pv magazine (2026); Indonesia: IESR/PLN RUPTL (negligible operational storage). Population: UN (2024), World Population Prospects 2024.

Storage deployment shows a similar gap. Indonesia's operational grid-scale electricity storage, i.e. PHS and BESS, remains at pilot scale,⁸⁵ while regional peers are scaling rapidly. Pakistan imported 7.6 GWh of battery capacity between 2018 and 2025, with imports tripling between 2024 and 2025.⁸⁶ India is moving even faster: it added 4.6 GWh of battery capacity in the first quarter of 2026 alone, bringing installed capacity to 8.5 GWh by mid-2026.⁸⁷ Without a corresponding acceleration in storage deployment, Indonesia risks underutilising its abundant renewable resource base.

⁸⁵ At the time of publication, Indonesia had only one operational grid-scale BESS: a 14 MWh system at IKN's 50 MW solar PV project.

⁸⁶ pv magazine (2026), *Pakistan Imports 4.6 GWh of BESS in 2025*.

⁸⁷ Mercom India (2026), *India Adds 4.6 GWh of Battery Energy Storage Capacity in Q1 2026*.

2.3

Renewables are approaching cost parity with new coal but remain more costly than existing coal

Indonesia's power system relies on a mix of generation technologies at different costs and with different benefits. Coal-fired generation dominates the current generation mix and provides baseload power at low cost under the DMO, which caps the coal price at US\$70 per tonne (see Box E). At this capped fuel price, the marginal generation cost of existing CFPP is around 3.5 US cents per kWh. Without DMO pricing, power from new CFPP would cost around 8 US cents per kWh. Gas provides flexible, dispatchable capacity, but at a higher cost than coal [Figure 15].

Indonesia's power system relies on a mix of generation technologies at different costs and with different benefits.

Renewables span a wider cost range, reflecting differences in resource quality, project scale and site characteristics. Hydropower and geothermal provide firm, low-carbon power and already play an established role in Indonesia's generation mix, but both face site constraints and long development timelines. New geothermal projects deliver power at around 8 US cents per kWh and new hydropower projects at around 6–8 US cents per kWh, both above the marginal cost of running existing CFPP. Solar generation can already be delivered at around 5–10 US cents per kWh. In favourable locations, costs can fall towards the lower end of the range, while the median is around 7.5 US cents per kWh, broadly comparable to new coal without DMO pricing. Wind is more limited in scope and currently delivers power at around 9 US cents per kWh in Indonesia's better wind-resource locations.

Renewables span a wider cost range, reflecting differences in resource quality, project scale, and site characteristics.

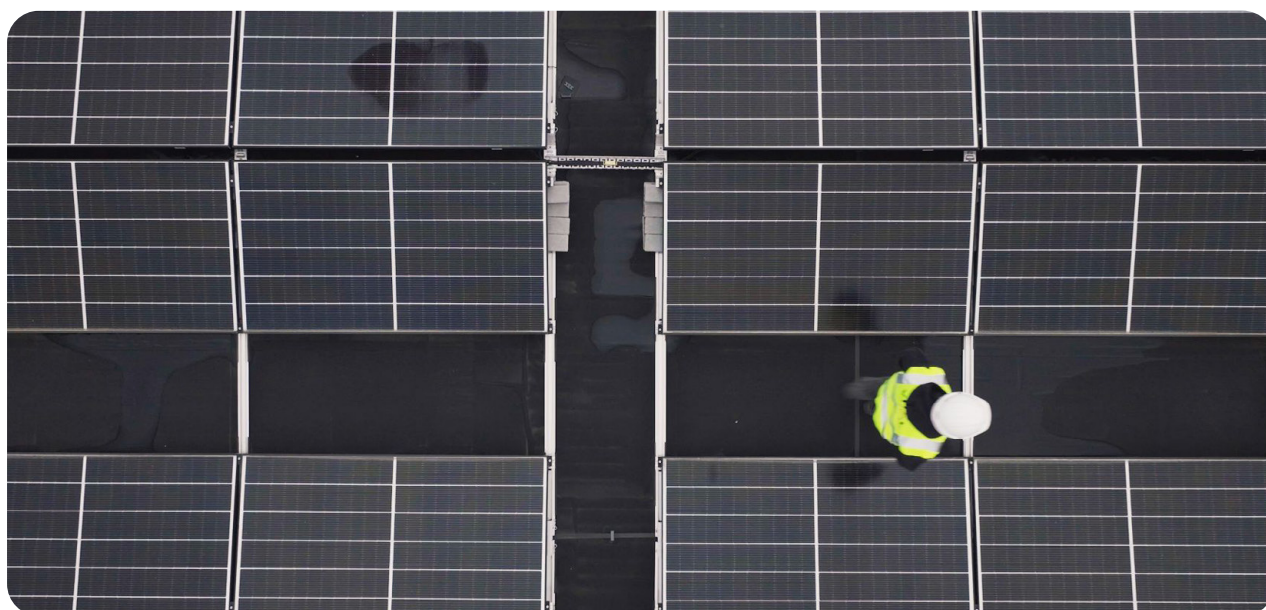
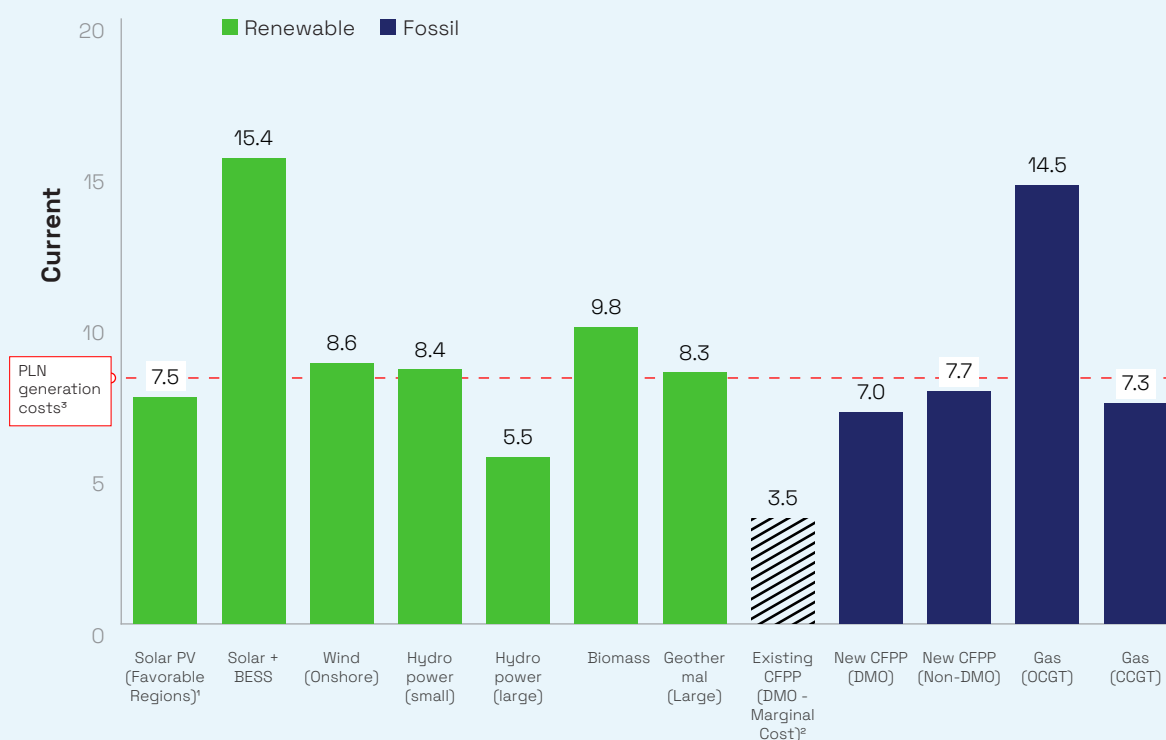


Figure 15 | Renewable generation costs are currently above the marginal cost of existing CFPP

Levelised cost of electricity per generation type

in c\$/kWh, median



Notes: 1) Favorable regions incl. Java, Sumatra; 2) Marginal cost includes fuel cost and variable O&M; 3) Biaya Pokok Produksi (BPP) based on PLN Statistics 2023; 7) Based on last reverse auction result in Q4 2025

Direct comparison between renewables and coal does not capture the full cost of operationalising them to deliver reliable power. CFPP can generate around the clock, while solar and wind generate only when the resource is available. For a fair comparison, the cost of variable renewables needs to account for storage where it is required to shift generation to periods of higher demand and provide firmer supply. For example, solar plus battery can deliver power at around 15 US cents per kWh today, significantly above current fossil generation costs.⁸⁸ Battery costs are falling rapidly, however, and the gap is narrowing (see Chapter 3).

⁸⁸ Based on a four-hour storage system and top-down modelling. Project-level data are not yet available, as only one utility-scale solar plus battery project is currently operational in Indonesia, as of September 2026.

BOX E | DMO lowers the prices of coal-fired generation

Indonesia applies a DMO that requires coal mining companies to sell **at least 25% of their annual production to the domestic market**, primarily for power generation by PLN.

Coal supplied domestically is also subject to a **Domestic Price Obligation (DPO)**, which caps the price for specified uses. For power generation, coal is capped at **US\$70 per tonne**, while selected industrial users face a cap of **US\$90 per tonne**. These regulated prices can be **well below international coal market prices**, particularly when global commodity prices are high. By limiting the fuel cost of coal-fired generation, the DMO-DPO system **makes electricity from existing CFPP cheaper** than it would be at market-based coal prices. Based on current coal export prices, the DMO reduces the marginal generation cost of existing CFPP by around 30%, from approximately 5 US cents per kWh to 3.5 US cents per kWh.⁸⁹

The system therefore acts as an implicit subsidy for coal-fired generation, shielding the electricity system from global coal price volatility and helping to stabilise electricity tariffs. At the same time, it distorts price signals in the power sector by making coal-fired generation appear cheaper than it would under market-based fuel prices.

89 Based on the difference between the DPO of US\$70 per tonne and the average official benchmark price for coal of the same grade in the first quarter of 2026 (US\$103.6 per tonne), assuming 35% efficiency for existing CFPP. Source: MEMR, *Harga Acuan*.

2.4**First-mover utility-scale projects show what is possible, but cost-competitiveness remains challenging**

The feasibility of utility-scale renewables under Indonesian conditions has been demonstrated in practice. Projects such as the **Cirata, Kota Bukit Indah, IKN** and **East Bali Solar PV Plants** show that utility-scale solar installations can be financed, permitted and delivered within commercially viable timelines [Figure 16].

These strategic projects succeeded because specific enabling conditions were in place, but these conditions are not yet systematically available across the wider market [Figure 16].

Common success factors included early access to suitable land, timely confirmation of grid connection, alignment with national or regional development priorities, clear long-term offtake arrangements and strong strategic partnerships between local and international developers or investors. Where these conditions align, renewable projects can progress relatively quickly, i.e. one to two years for solar.

However, these have largely remained strategic or first-mover projects that have yet to trigger a broader market replication. Commercial scalability remains the core challenge. Several developers have been able to deliver a successful solar project, but follow-on projects remain difficult to justify because the economics are weak given the achievable market prices. Project economics are also affected by regulatory hurdles. Industry experts cite greater regulatory certainty as an important lever for increasing developer interest, improving project economics

and reducing perceived project risk. This is particularly important in a market where project costs remain high, driven by module and balance-of-system (BoS) costs that are elevated by local content requirements (LCR), as well as land and grid-connection costs (see Chapter 3).

At the same time, **the revenues available to renewable projects are often too low to support attractive returns**, driven by three structural factors. First, the DMO keeps domestic coal prices well below international market levels, reducing the marginal generation cost of existing CFPP by around 30%, from approximately 5 US cents per kWh to 3.5 US cents per kWh (see Box E). This lowers the cost benchmark against which renewable projects compete, creating a structurally uneven playing field for unsubsidised developers. Second, the tariffs PLN is typically willing to offer to independent power producers (IPPs) can fall below the level required to make solar projects commercially viable, particularly where development costs are elevated by land constraints, permitting complexity or local content requirements. Third, most CFPP PPAs include take-or-pay clauses, while previous solar PV PPAs have included an annual contracted energy cap on the amount of electricity that can be sold to the grid. Together, these contractual structures can favour CFPPs in the dispatch order.

Policy and regulatory uncertainty compounds these problems. Procurement processes are unpredictable, while bankable offtake routes outside PLN remain limited. Together, these factors weaken project economics and make follow-on investment difficult to justify, even where technical potential is strong.

As a result, Indonesia is stuck in a low-volume equilibrium: **projects do not scale because economics are weak, and economics remain weak because the market has not yet scaled.**

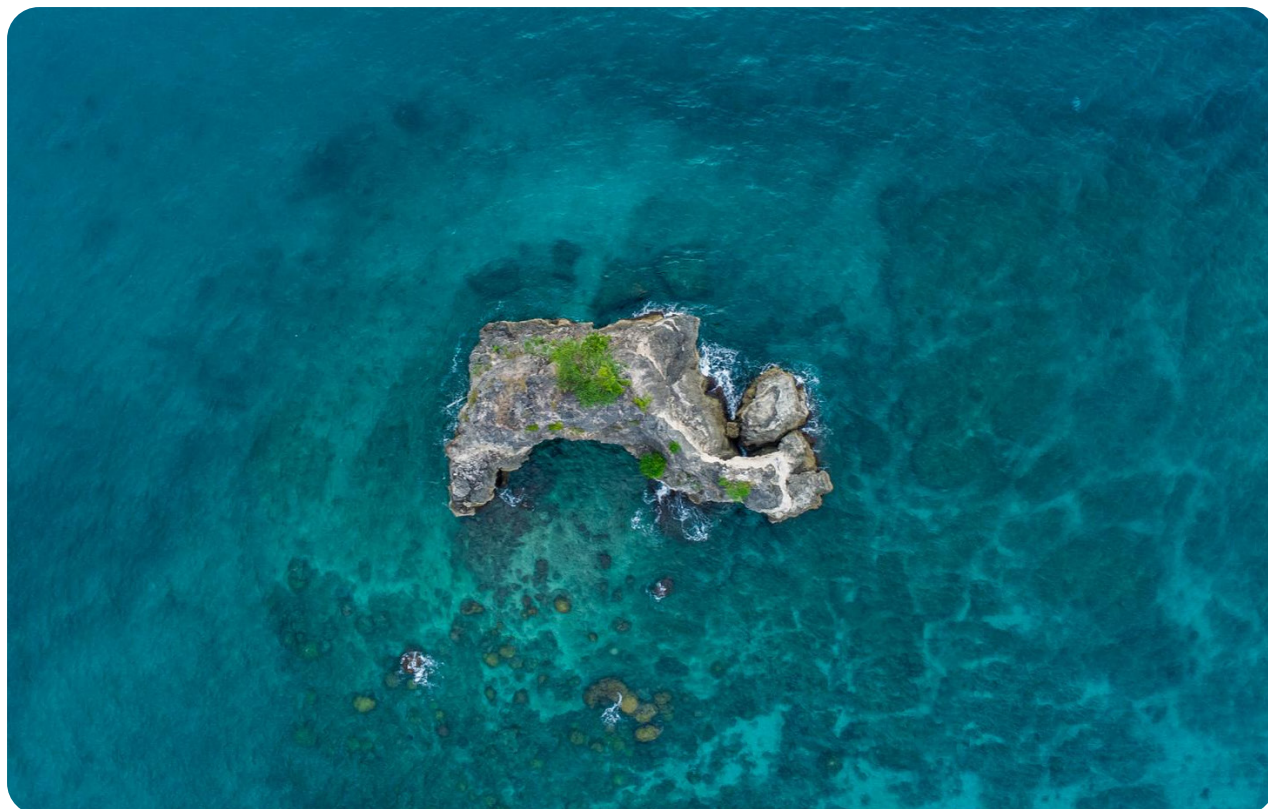
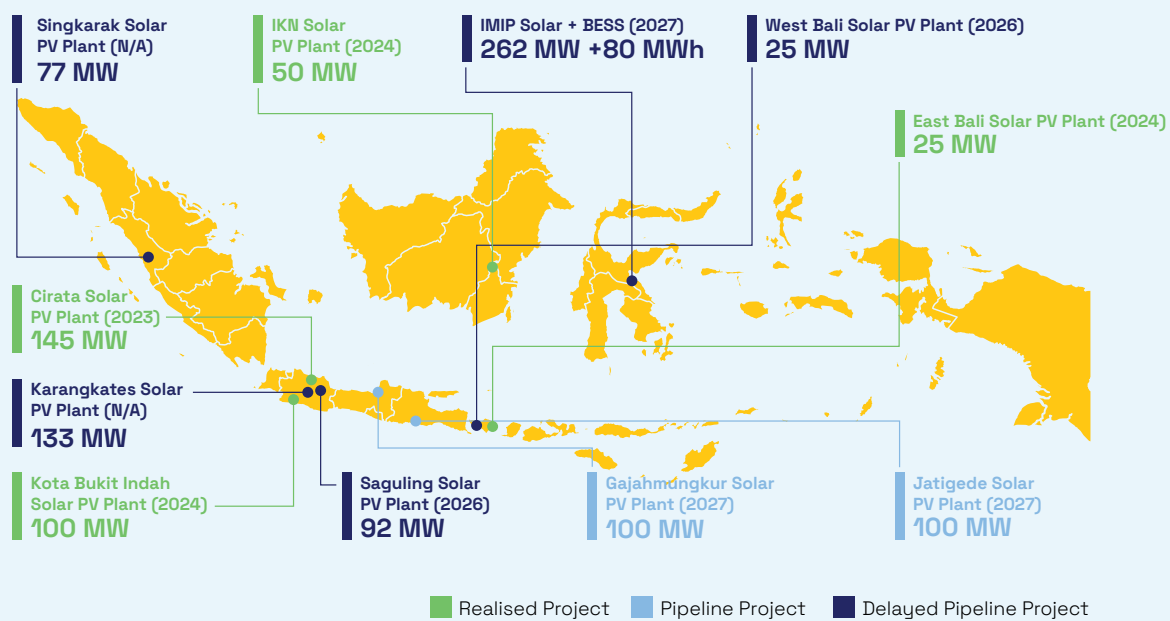


Projects do not scale because economics are weak, and economics remain weak because the market has not yet scaled.

Figure 16 | While some utility-scale solar projects in Indonesia are moving forward, others remain delayed or stalled in the pipeline.

While Some Large-Scale Solar PV Have Been Built, Some Are Delayed and Stuck in the Pipeline

List of solar projects (Commercial Operation Date)



Shared enabling themes behind successful solar projects in Indonesia

List of Realised Solar Projects and Their Enablers

Solar Projects	Enablers
Cirata Solar PV Plant	- Strategic partnership between foreign investor (Masdar) and PLN that unlocks international capital and expertise. - Designated as National Strategic Project (PSN), which fast-tracked regulatory approvals and given priority support. - Long-term PPA with PLN.
Kota Bukit Indah Solar PV Plant (Industrial Estate)	80 hectares of industrial estate land in the Kota Bukit Indah Industrial Estate were secured early - Clear industrial offtake: the plant directly links solar generation to local industry demand
IKN Solar PV Plant Solar + BESS	- Land and grid connection were secured early - High political support, tied to national development priority of developing a net-zero emissions capital city and the President's vision - Strategic partnership between Sembcorp and PLN
East Bali Solar PV Plant	- Long-term PPA with PLN, providing commercial certainty - Strategic corporate collaboration between Medco Power Indonesia and Solar Philippines - Enabling local government policies

Realized Projects

Cross-project Enabling Themes



Strategic partnership with foreign and local investors



Early securing of land and site control



Early grid access and interconnection



Alignment with government strategic vision and policies



Clear long-term power offtake or demand assurance

Sources: PLN (2023, 2024); PwC (2025); Medco (2025); Systemiq Analysis.

List of Pipeline Solar Projects and Their Status & Blockers

Cross-project Blockers

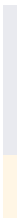
Solar Projects	Status and blockers	
Delayed Pipeline Projects	Karangkates Solar PV Plant - Land-clearing conflicts with local fish farmers - Operation was initially planned in 2025; developers are currently reassessing land use and social impact	
	West Bali Solar PV Plant - Initially planned during G20 Summit Bali in 2022 - Land clearing issue delayed the development	
	Singkarak Solar PV Plant Land-clearing conflicts with local fish farmers; concerns regarding potential effects on the local fish population	 Uncleared land or space leads to social conflicts and delays
	IMIP Solar + BESS Long permitting and negotiation process; in discussion since 2022	 Long permitting and negotiation process
	Saguling Solar PV Plant - Long permitting and negotiation process: tender process began in 2019 and reached financial close in 2025 - Saguling Solar PV Plant is expected to operate in 2026	
Pipeline Projects	Jatigede Solar PV Plant - Still in pre-development stage - Commercial structure is currently not finalised	
	Gajahmungkur Solar PV Plant - Developers are strategic international organizations (ADB and AIB) - Detailed environmental and social impact assessment to address community concerns	 Note: These projects are currently still in the development phase. Both projects are planned for operation in 2027.

Sources: PLN (2022, 2025); Times Indonesia (2025); Kabupaten Malang (2025); PwC (2025), Bisnis.com (2025), Nickel Industries (2023); Systemiq Analysis.

2.5

Indonesia's ambition is now accelerating with the 100 GWp solar programme

Indonesia's solar ambition is accelerating, as signalled by the 100 GWp solar programme. In August 2025, the government announced a target to deploy 100 GWp of solar by 2030, across off-grid systems for remote areas, rooftop solar and grid-scale projects. Compared with the 17 GW of on-grid solar additions planned by 2035 under the current RUPTL, this represents a step change in ambition. As Figure 14 shows, delivering the programme would bring Indonesia close to Pakistan's current deployment pace, a significant acceleration from today's rate.



Indonesia's solar ambition is accelerating, as signalled by the 100 GWp solar programme.

The near-term push is significant. For utility-scale projects, only around 6 GW of on-grid solar is currently targeted by 2030 in the RUPTL. Full delivery of 100 GWp would represent a major increase in solar deployment within just five years. It would also more than double Indonesia's installed generation capacity by 2030 from 96 GW in 2024.

While the design and composition of the full 100 GWp solar programme are still being finalised, previous IESR analysis identified around 20 GW of decentralised solar that could be developed before 2030, mainly by replacing diesel generators through de-dieselisation and improving electricity access in remote regions.⁹⁰

Whether 100 GWp is achievable by 2030 depends on two mutually reinforcing conditions:

- **On the supply side, the cost of solar plus batteries needs to fall sufficiently** to compete with existing coal-fired generation. Physical deployment capacity exists, but it is constrained by cost competitiveness (see Chapter 3).
- **On the demand side, electricity demand needs to grow quickly** enough to absorb the additional generation without curtailment risk. As Chapter 1 shows, accelerated electrification across the industrial, transport and residential sectors, combined with new demand from electricity exports and data centres, could generate an additional 160 TWh of demand by 2035 compared with BAU, creating room for more on-grid solar generation.

90 IESR (2026), *The Solar Archipelago: Indonesia's 100 GWp Leap to Energy Sovereignty*.

The two conditions reinforce each other. Faster electrification supports more solar by absorbing additional generation, while lower-cost solar can accelerate electrification by reducing the cost of switching away from fossil-fuel technologies.

The two conditions reinforce each other. Faster electrification supports more solar by absorbing additional generation, while lower-cost solar can accelerate electrification by reducing the cost of switching away from fossil-fuel technologies. The case for moving quickly has been strengthened further by the 2026 Iran conflict, which pushed oil prices above US\$100 per barrel, making the replacement of diesel generators with solar plus batteries more economically attractive and highlighting the fiscal cost of Indonesia's continued dependence on oil imports (see Chapter 5).

Getting the policy response right matters as much as the headline ambition. Without targeted interventions to bring down solar costs, the 100 GWp solar programme could increase overall system costs. Without parallel action to scale demand and storage, some solar generation could be curtailed if supply grows faster than the system can absorb it. The enabling conditions required on both fronts are set out in Chapter 6. If the government's 2030 timeline is to be met, those interventions will need to be pursued with urgency.

Electricity demand could triple in the long term

Over a longer horizon, the demand-side question is more about timing than the risk of insufficient demand. ETC projects that global electricity demand will roughly triple by 2050 as transport, heating, industry and hydrogen production electrify. Indonesia is likely to experience the same broad trend.⁹¹ The longer-term challenge is therefore to align new supply with the pace of demand growth and to utilise early sources of demand to support new projects until broader demand catches up.

91 ETC (2025), *Power Systems Transformation: Delivering Competitive, Resilient Electricity in High-Renewable Systems*.





Chapter 3

Solar's path to cost-competitiveness in Indonesia

Chapter 2 showed that Indonesia has abundant solar resources, but that commercial deployment is stuck in a low-volume equilibrium. This chapter examines the current economics of solar in Indonesia. It shows that there is a significant cost gap between Indonesia and leading markets, driven largely by addressable cost components rather than fundamental constraints. The gap is largely explained by elevated module and balance-of-system costs partly driven by local content requirements, high land and grid-connection costs and unpredictable permitting and financing. With targeted action on each component, Indonesia's solar LCOE could fall by 30–50% from today's level by 2035, from 5–10 US cents per kWh to 4–7 US cents per kWh, approaching leading-market levels.

The chapter comprises three sections. Section 3.1 outlines the global solar and battery revolution that has reset what is possible. Section 3.2 diagnoses the cost gap between Indonesia and leading solar markets, breaking it down into specific addressable components. Section 3.3 explores how each cost component can be lowered and at what pace.

3.1

The global solar and battery revolution is happening now

The most significant energy development of the past decade has been the dramatic decline in the global cost of solar PV and batteries. Since 2010, global solar PV module costs have declined by around 20% per year and battery system costs by an average of 16% per year, driven by technical innovation, economies of scale in manufacturing and learning curve effects [Figure 17].

These cost declines are transforming the economics of electricity systems. **In many regions, solar is already among the cheapest sources of new-build generation.** BloombergNEF (BNEF) estimates global benchmark LCOE of around 4 US cents per kWh for solar PV, compared with around 8 US cents per kWh for coal-fired generation and 10 US cents per kWh for combined-cycle gas turbine (CCGT) generation.⁹² **Batteries are the second half of this shift, with costs falling particularly rapidly over the past two years.** BNEF's global benchmark cost for a four-hour battery project fell 27% year on year to US\$78 per megawatt-hour (MWh) in 2025, a record low, and BNEF projects a further 25% reduction by 2035.⁹³ Lower battery costs allow solar generation to be stored and shifted into evening demand periods at lower cost, maintaining power system reliability.



Solar is already among the cheapest sources of new-build generation.

Solar plus batteries are becoming the default option for power system expansion in sunbelt countries. In 2025 alone, developers commissioned around 87 GW of co-located solar and battery projects globally, delivered at an average of 5.7 US cents per kWh. Recent auctions

92 BNEF (2026), *Battery Storage Costs Hit Record Lows as Costs of Other Clean Power Technologies Increased: BloombergNEF*.

93 BNEF (2026), *Levelized Cost of Electricity Update 2026*.

confirm the trajectory: Saudi Arabia is procuring 5 GW/20 GWh of battery storage in dedicated tenders, alongside solar tenders clearing near 1.3 US cents per kWh, while India's first auction for solar plus batteries with six hours of storage in early 2026 cleared at around 3.4 US cents per kWh.⁹⁴ Solar plus batteries can therefore provide low-cost and reliable electricity supply beyond daylight hours, at prices that are increasingly competitive with, often lower than, new fossil generation.

Figure 17 | The costs of solar modules and batteries have been falling dramatically in the last 15 years.

Solar PV Module Costs

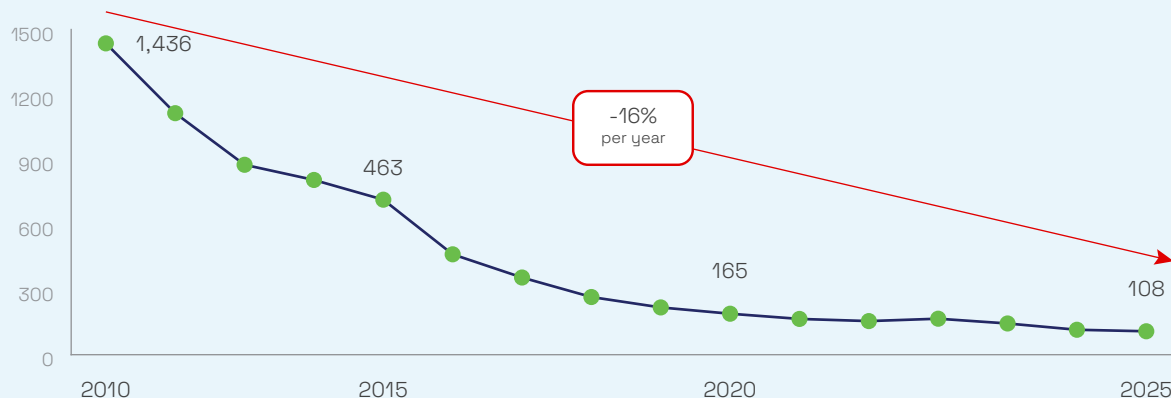
\$ per watt



Note: Module element of benchmark capex for a typical fixed-axis utility-scale PV project.
Source: BNEF (March 2025), Solar Modules Are Cheap and Will Become Even Cheaper

Lithium-ion Battery Price Survey Results: Global Average Pack Price

\$/kWh, real 2024



Source: BNEF (2025), Lithium-ion battery price survey December 2025

For sunbelt countries such as Indonesia, with strong solar irradiation and large resource potential, this cost decline presents a significant opportunity. Yet Indonesia's current solar costs remain well above leading-market levels.

94 Chambers and Partners (2026), *Power Generation, Transmission & Distribution 2026 – Middle East*.

3.2

Indonesia's solar LCOE is above leading-market levels, driven by addressable cost components

Solar stands out as Indonesia's most promising renewable technology (see Chapter 2). The question is how close solar is to being commercially competitive at scale and what it would take to close the remaining gap.

Indonesian solar electricity can already be delivered at around 5–10 US cents per kWh, comparable to new coal-fired generation without DMO pricing but remains significantly above the marginal cost of existing CFPP with DMO pricing. Coal and solar generation, however, cannot be compared fully like-for-like: coal can generate around the clock, whereas standalone solar generates only during daylight hours. Pairing solar with batteries can provide firmer supply by shifting daytime generation into the evening, but this raises the cost to 15 US cents per kWh, significantly above current fossil generation costs.⁹⁵

Indonesian solar electricity can already be delivered at around 5–10 US cents per kWh, comparable to new coal-fired generation without DMO pricing but remains significantly above the marginal cost of existing CFPP with DMO pricing.

A more useful reference point is the cost already achieved in leading solar markets. China and Vietnam can deliver solar generation for around 5 US cents per kWh [Figure 18]. India has reached around 3 US cents per kWh for standalone solar and 4.5 US cents per kWh for solar plus batteries on an almost round-the-clock basis (see Box F). These leading solar markets also have one thing in common: solar LCOE is below prevailing electricity tariffs, making deployment more economically attractive. For Indonesia, both the cost gap with leading markets and the gap relative to the current average electricity tariff remain significant. The strategic implication is significant: every year Indonesia delays scaling solar, peers are achieving lower generation costs and strengthening the competitiveness of their industrial electricity supply.

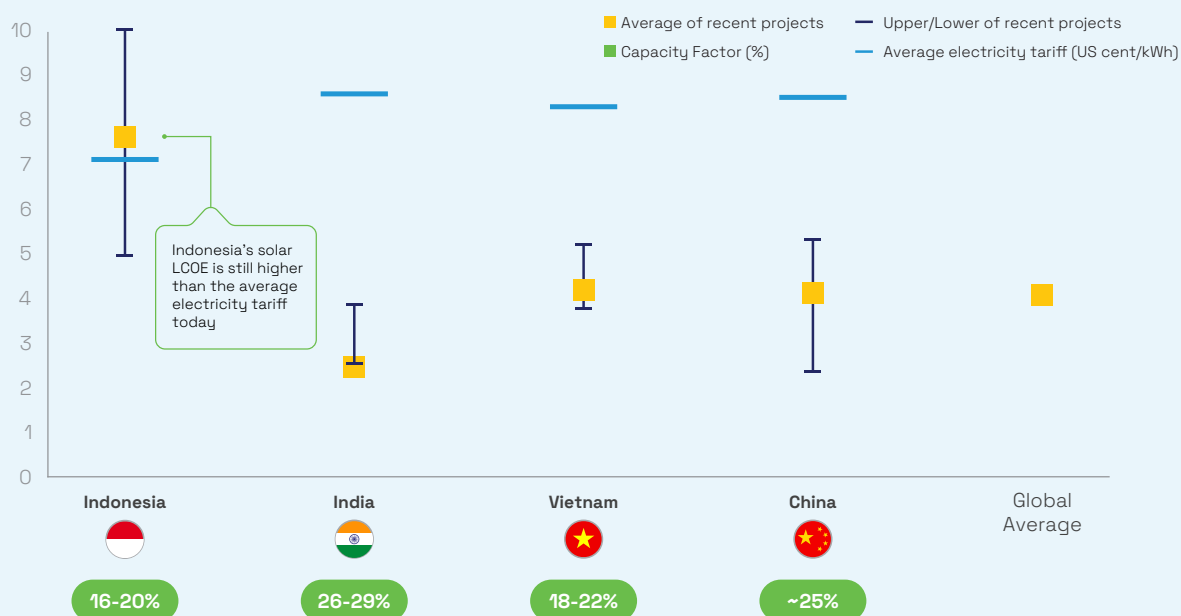
⁹⁵ This is a top-down estimate as no project-level data was available at the time of this report's publication.

Figure 18 | Indonesia's current solar generation costs are high compared to regional peers and its average electricity tariff.

Indonesia's solar PV generation costs are much higher than those of regional peers

LCOE of utility-scale solar PV generation, 2024-2025¹

in \$/kWh



Notes: 1. Most recent available year used: 2024-2025 for most countries. India is based on competitive auction outcomes, China and Vietnam are based on support mechanism frameworks, and Indonesia LCOE is based on developer interviews. 2. Lower range based on 2024 data; upper range based on RUPTL 2025-2034 plans.

Sources: Central Electricity Regulatory Commission India (2024-2025), Solar Tariff Adoption Orders (SECI/SJVN); National Development and Reform Commission China (2025), Renewable Mechanism Pricing Framework and Provincial Results; Ministry of Industry and Trade Vietnam (2025), Decision 988/QĐ-BCT Solar Price Framework; Energy Regulatory Commission Thailand (2024), Renewable FIT Procurement Framework; Solar Quarter (2026); Berkeley (2025), Implications of India's Solar + Storage Auctions; IRENA (2025), Renewable Power Generation Costs in 2024.

BOX F | Solar PV cost reductions in India

Over the past decade, delivered solar generation costs have fallen by roughly 50% in India, showing how quickly costs can fall when scale, competitive auctions, stronger supply chains and lower financing costs reinforce one another. For projects with six hours of battery storage, auction prices recently fell to around US\$34 per MWh.⁹⁶ Recent Indian auctions for almost round-the-clock⁹⁷ renewable electricity, using solar plus batteries, have achieved prices of around US\$50 per MWh.⁹⁸ Because these contracts are typically fixed in nominal terms over long durations, the real value of the electricity price declines over time, falling to the equivalent of below US\$25 per MWh by the end of the contract period in 2045. This illustrates how rapid deployment and supportive market frameworks can drive renewable electricity costs to extremely low levels.

⁹⁶ Ember (2026), *Battery Storage is Now Cheap Enough to Unleash India's Full Solar Potential*

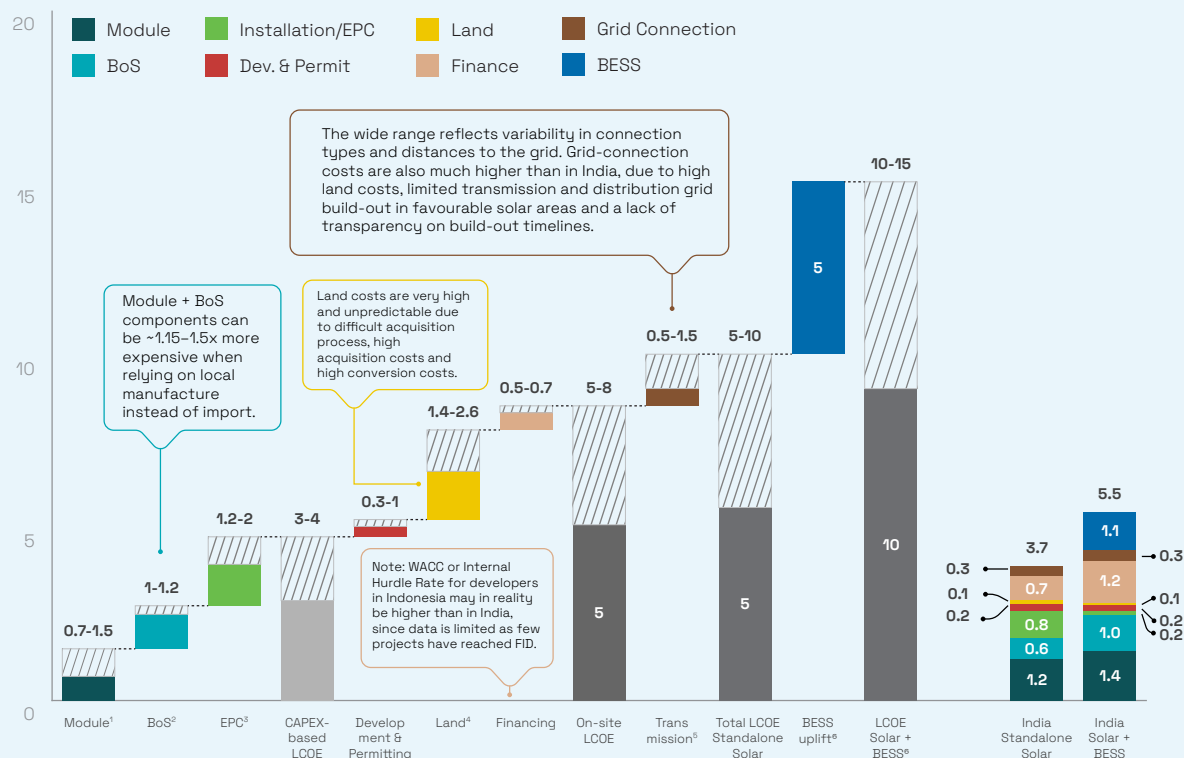
⁹⁷ Round-the-clock refers to 95% availability.

⁹⁸ Chojkiewicz et al. (2025), *Plummeting Solar + Storage Auction Prices in India Unlock Affordable, Inflation-proof 24/7 Clean Power*.

Figure 19 | India's lower solar LCOE components show what Indonesia could achieve.

Solar and solar + storage LCOE in Indonesia vs. India

In US cents/kWh, favourable Solar locations



Notes: 1. Survey results range from 12 to 20 cent/Wp. The upper end reflects locally manufactured prices, while the lower end reflects import prices, excluding logistics. 2. BoS includes inverters, electrical components, mounting or floaters (where applicable) and other components. 3. Includes EPC services and civil works. The upper end of the range reflects projects in remote areas. 4. Based on average land prices and additional land-conversion costs across five major islands modelled in the study (Java, Sumatera, Kalimantan, Sulawesi and MPNT). The upper end of the range corresponds to Java and the lower end to Kalimantan. 5. The wide range reflects differences in connection type (e.g. subsea or overland) and distance to the transmission grid. Assumes transmission lines only, with no new substations. 6. Based on four-hour BESS.

Source: Expert input based on actual projects in Indonesia and India.

The cost gap between Indonesia and leading solar markets is driven by three major, addressable cost components. Two additional factors add smaller direct cost premiums but can prevent projects from advancing altogether [Figure 19]:

- Module and BoS costs:** Local content requirements restrict access to the lowest-cost global modules and components, keeping hardware costs above international benchmarks. Developers indicate that component costs vary between 12-20 US cents per watt-peak (Wp), with locally manufactured modules at the higher end of the range and imported modules at the lower end. As a result, the contribution of component cost can be around 10-50% higher than global benchmarks. Domestic manufacturing capacity for the required module technology exists in Indonesia, including from Tier 1 manufacturers, but differences in scale, incentives and technology ownership mean local prices cannot yet match Chinese export levels. The MEMR is targeting a maximum premium of 15% over Chinese reference prices, though developers report a larger gap in practice.

- **Land-acquisition costs:** Land prices are high and further elevated by regulatory complexity, the absence of pre-zoned land for renewable development and protracted acquisition processes in which developers must deal with many individual landowners. The land-cost component of Indonesian solar projects can be around 14–26 times the cost in India.
- **Grid-connection costs:** Projects are often located far from the transmission network, and developers may need to fund grid connections upfront, including transmission lines to the main network and, in some cases, new substations.⁹⁹ Land acquisition challenges along transmission corridors compound these costs further, adding to their variability.

Two additional factors contribute smaller cost premiums that can become significant barriers to project delivery:

- **Development and permitting costs:** Costs are estimated at 0.1–0.3 US cents per kWh higher in Indonesia than in India. Long and unpredictable permitting timelines increase pre-construction expenditure. More critically, absent or delayed permits can prevent projects from reaching financial close entirely.
- **Financing:** Because financing costs apply across total CAPEX, even a small change in the weighted average cost of capital (WACC) can materially affect LCOE. For example, for solar PV projects in India, a 1 percentage point increase in the cost of capital increases project LCOE by around 6%.¹⁰⁰ Beyond the cost, financing access is also a constraint. When procurement, permitting and licensing are unpredictable and prone to delays, projects struggle to secure financing. Limited data are available on the actual cost of financing for Indonesian utility-scale solar projects, as few projects have reached final investment decision (FID). The financing component shown in Figure 19 may therefore understate the true cost.

In practice, some cost components are also highly connected: land, grid connection and engineering, procurement and construction (EPC) costs trade off against one another depending on location. Sites where land costs are low tend to be remote and sparsely populated. In these sites, limited grid infrastructure drives up transmission costs, and a lack of local supply chains and logistics raises EPC costs. Denser, more developed areas show the reverse: transmission and EPC costs are lower because infrastructure is already in place, but land is scarcer and more expensive. Developers note that finding sites where all three costs are low is therefore difficult, if not impossible.

In practice, some cost components are also highly connected: land, grid connection and engineering, procurement and construction (EPC) costs trade off against one another depending on location.

⁹⁹ Cost allocations between developers and PLN differ per project and depend on the project structure.

¹⁰⁰ The number is based on interviews with developers.

The same addressable cost pressures also affect solar plus batteries.

Projects in Indonesia are estimated to cost around 10–15 US cents per kWh today with a four-hour battery, assuming the same module, land, grid and financing premiums diagnosed above. Globally, co-located solar and battery projects that became operational in 2025 already deliver power at an average of around 5.7 US cents per kWh.¹⁰¹ The cost-reduction actions set out in Section 3.3 therefore apply to solar plus batteries as well as standalone solar. As those actions bring down module, land, grid and financing costs, and as battery costs continue their steep global decline, Indonesia's cost gap with leading markets for solar plus batteries could narrow alongside the gap for standalone solar.

3.3**Indonesia's solar costs can fall significantly through targeted action on specific LCOE components**

The cost components identified in Section 3.2 can each be reduced through targeted action. More than adjustments in future tenders or market forces alone, closing the gap will require interventions across each of these cost components, which need to begin now. Chapter 6 sets out the specific interventions in detail, while this section describes their intended outcomes.

If delivered together, these interventions could reduce Indonesia's solar LCOE from around 5–10 US cents per kWh today to around 4.5–9 US cents per kWh by the end of Phase 1 and 4–7 US cents per kWh by the end of Phase 2, approaching leading-market levels [Figure 20]. Beyond lowering costs overall, these actions could also narrow the wide variation in costs across projects and locations, making solar viable in more places and easier to replicate at scale. Further reductions are likely beyond these phases if global solar costs continue their downward trend in the past 10 years.

The same addressable cost pressures also affect solar plus batteries.

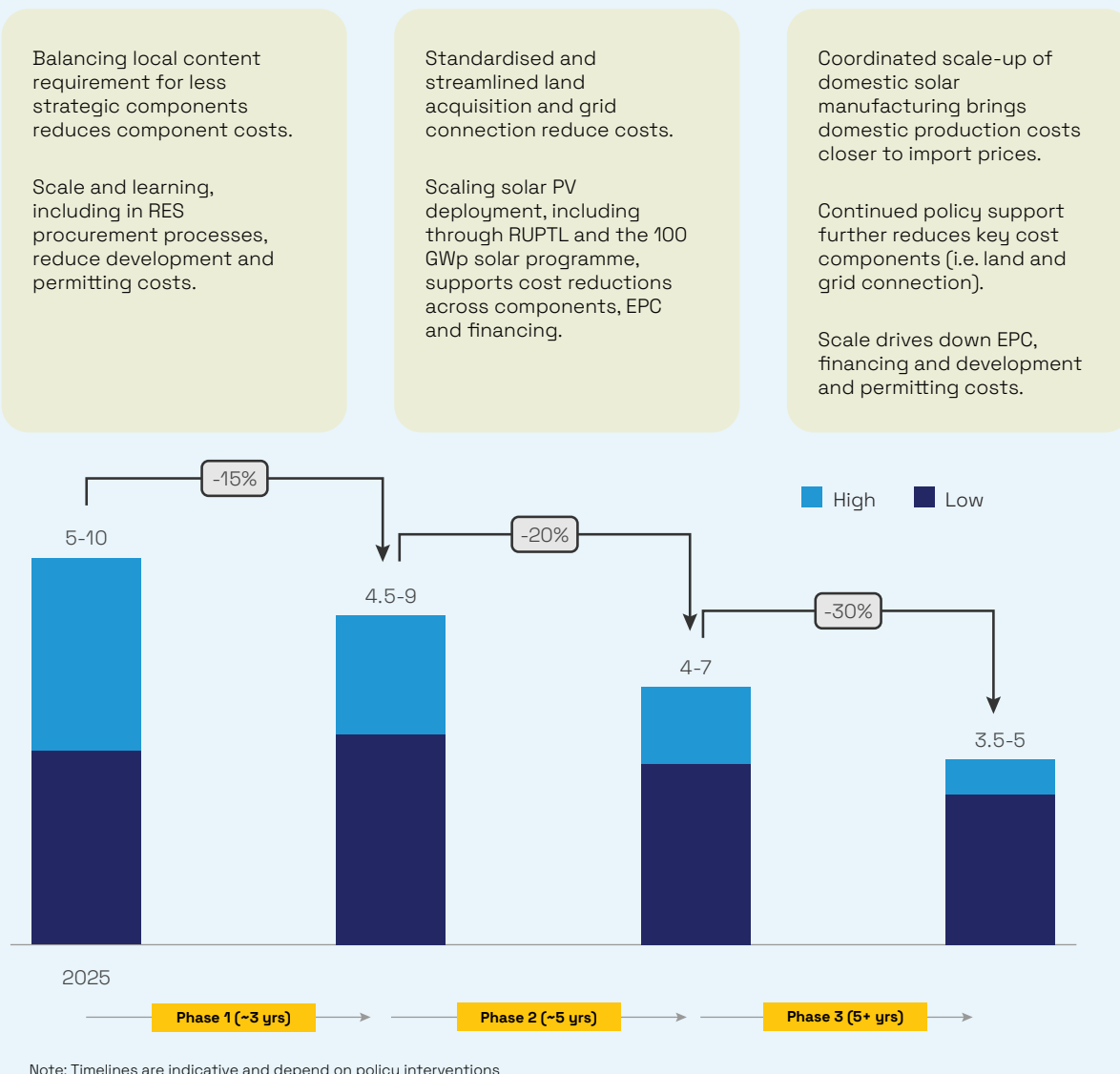
Beyond lowering costs overall, these actions could also narrow the wide variation in costs across projects and locations, making solar viable in more places and easier to replicate at scale.

101 BloombergNEF (2026), *Levelized Cost of Electricity 2026*.

Figure 20 | Indonesia's solar LCOE can be lowered with targeted interventions.

Indicative outcomes of interventions on Indonesia's solar LCOE

In US cents/kWh, average high-low across five modelled areas



Module and BoS costs can move towards import parity through a phased local content strategy.

A time-bound import exemption tied to credible domestic investment commitments would bring near-term hardware costs closer to international benchmarks while preserving a pathway for domestic manufacturing to scale. As domestic capacity reaches competitive volumes, local content requirements can progressively move upstream, from cells to wafers and ingots. This phased approach, which is set out in detail in Chapter 6, builds on Indonesia's 2024 local content requirement relaxation under MEMR Regulation 11/2024 and India's Approved List of Models and Manufacturers (ALMM) framework. The near-term effect would be a meaningful reduction in module and BoS costs. However, the MEMR does not expect domestic module production to reach Chinese price levels in the near term because of differences in production scale, incentives and technology ownership. The full impact on domestic solar PV manufacturing capacity will therefore take longer to be seen.

Land-acquisition costs can be reduced through a centralised land mechanism and pre-zoning of renewable development areas. A dedicated government entity or land bank, supported by clear renewable development zones and standardised acquisition processes, could reduce one of Indonesia's largest cost premiums, currently around 65–80% above India. Detailed design choices and policy steps are set out in Chapter 6. Stakeholders have also identified two viable routes to expand the land available for solar PV: combining solar with agriculture through agrovoltatics (AgriPV) and repurposing former mining areas for solar generation. Box I in Chapter 6 explores these options further.

Grid-connection costs can be reduced by aligning transmission planning with renewable deployment.

Accelerating transmission expansion while explicitly planning for renewable integration, combined with the land acquisition reforms described above, could reduce grid-connection costs and increase timely grid accessibility across projects.

Grid-connection costs can be reduced by aligning transmission planning with renewable deployment.

Development and permitting costs can be reduced through a standardised procurement process for solar, including structures for premium buyers and catalytic projects. This includes a time-bound permitting process, which would reduce pre-construction expenditure and, more importantly, lower the risk of projects being blocked altogether.

Financing costs can decline as the broader ecosystem matures. The direct cost differential may be modest, but access to finance is constrained when permitting, licensing and procurement are unpredictable. Permitting reforms and more bankable projects as precedents would increase access to competitive financing options.

These cost reductions depend on four coordinated areas of intervention, detailed in Chapter 6.

A near-term wave of fast-tracked catalytic projects, including projects with premium buyers and the first phase of the 100 GWp solar programme, could drive early scale and establish bankable precedents. Removing barriers to rooftop solar could further increase deployment volumes across the country. Targeted action on land, grid and permitting could address structural cost drivers, while a phased local content strategy could bring module and BoS costs closer to import parity and progressively move Indonesia's manufacturing industry up the value chain [Figure 20].

If solar costs follow this trajectory, a more renewable supply mix could meet Indonesia's electricity demand at a significantly lower total system cost than the current RUPTL pathway. Chapter 4 examines what that supply mix could look like.



Chapter 4

The supply mix opportunity: lower cost, more renewables

The previous chapters showed that Indonesia's renewable build-out challenge is not one of resource availability, but of cost and scalability, and outlined a staged path through which solar generation costs could fall to competitive levels by 2035. Chapter 4 assesses two supply pathways and their implications for total power system costs. The modelling indicates that a Least-Cost supply mix could deliver 5–15% lower system costs by 2035 than the 2025–2034 RUPTL pathway, while meeting increased demand without adding new coal or gas capacity over the period.

The chapter is structured in three sections. Section 4.1 introduces the RUPTL and Least-Cost supply pathways, which are paired with the BAU and High Electrification demand pathways set out in Chapter 1. Section 4.2 breaks down the RUPTL supply pathway, which delivers a gradual shift anchored in continued fossil generation. Section 4.3 breaks down the Least-Cost supply pathway, which integrates more renewable capacity, and compares its system-cost implications with the RUPTL pathway.

4.1

Two supply pathways

To test how different supply strategies could shape the power system and its associated costs, this report models two supply pathways [Figure 22]. The first is **the RUPTL supply pathway**, in which capacity additions, technology mix, commercial operation dates and grid expansion **follow the 2025–2034 RUPTL**. Project lead times are based on prevailing assumptions for conventional and renewable assets, while technology costs evolve in line with MEMR projections [Figure 21].

The second is the Least-Cost supply pathway, which does not follow technology mix or build-out schedule set in the current RUPTL. Instead, it is based on the generation capacity and associated grid infrastructure needed to meet projected demand at the lowest total system cost while maintaining reliability, even under High Electrification. The capacity build-out is technology agnostic, to be adjusted as needed. The cost of additional network infrastructure is included in the optimisation, and the same government cost trajectories for generation technologies are applied. Exception is made for solar, where costs decline faster between 2025 and 2035 in line with the trajectory set out in Chapter 3 [Figure 21]. The DMO price cap for coal is assumed to remain stable across both pathways.

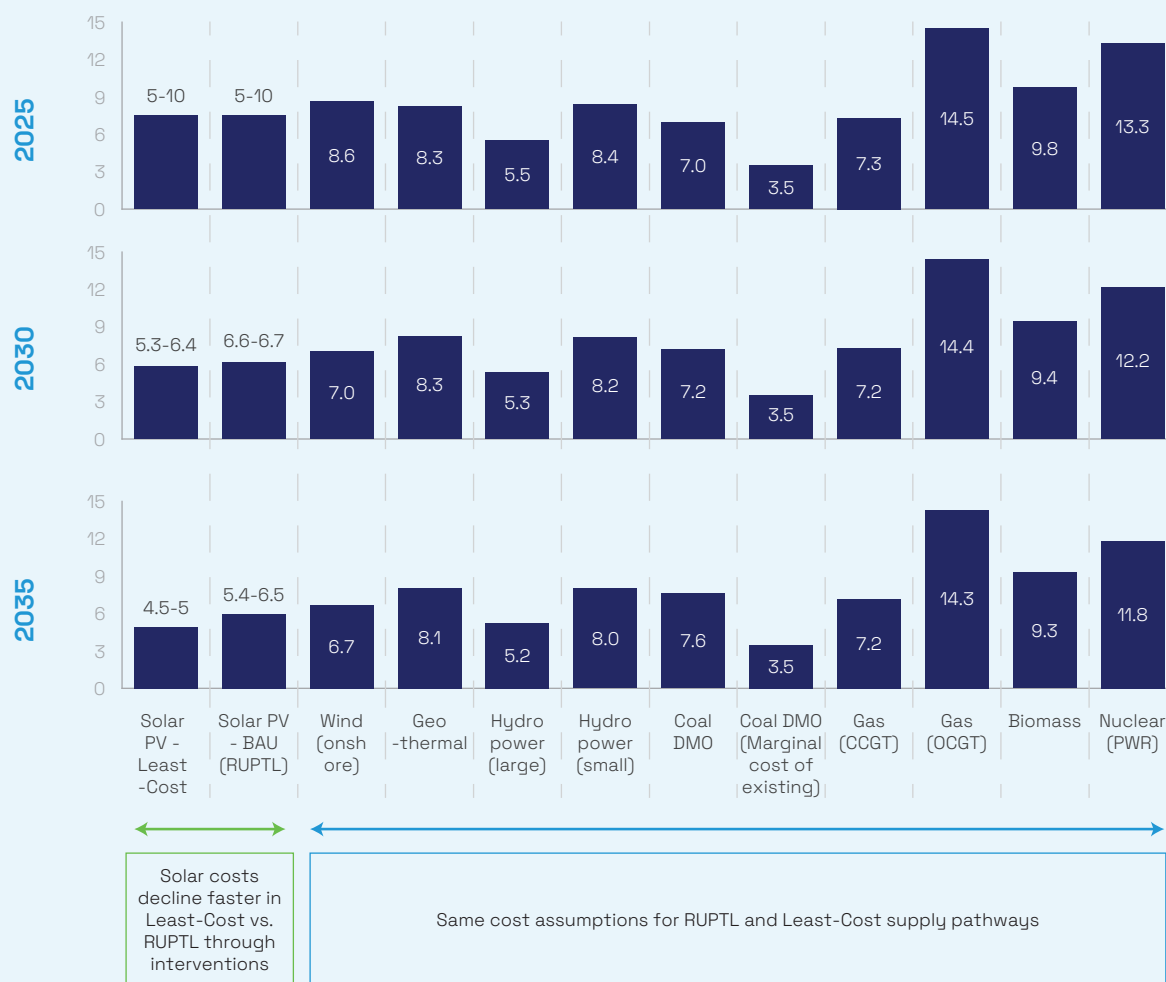


The capacity build-out is technology agnostic, to be adjusted as needed.

Figure 21 | Solar LCOE is assumed to decline more significantly in the Least-Cost pathway.

LCOE for the main generation types included in the supply modelling

In US cents/kWh, range of solar costs based on regional cost differences¹



Notes: 1) Favorable regions incl. Java, Sumatra, unfavorable regions incl. Papua.
Source: IESR PLEXOS Model

The distinction between the RUPTL and Least-Cost pathways matters because the RUPTL is not designed as a pure least-cost optimisation. It is a strategic planning document that balances multiple objectives, including supply security, policy priorities, delivery risk, existing plans, committed projects, contractual obligations and the practical constraints of the existing system. The Least-Cost pathway is therefore not presented as an alternative to the RUPTL but as a benchmark for assessing the implications of the current pathway. It shows how the system could evolve if solar costs decline and grid investment is focused on minimising long-term system costs while still maintaining reliability. The comparison helps distinguish justified trade-offs from avoidable cost inefficiencies, particularly as renewable technology costs continue to fall faster than expected in many markets.

Figure 22 | The modelling uses two supply pathways combined with two demand scenarios

Assumptions for the two supply pathways

Parameter	RUPTL PATHWAY	LEAST-COST PATHWAY
	Optimised for 2025–2034 RUPTL project development plans	Optimised for least-cost power system, technology agnostic
Power Mix	Based on RUPTL COD date, only on-grid demand and supply are modelled	The generation mix is determined for a least-cost power system, with no constraints on which technology to build and when, provided that total demand is met every year. Only on-grid demand and supply are modelled.
Capacity buildout limit	Based on RUPTL COD date and grid improvement/development plan	Unconstrained build-out to meet increased power demand, automatically building additional infrastructure. The required additional grid from RUPTL plans will be treated as a key takeaway of the model.
LCOE improvement	Using LCOE projections from MEMR for all generation technologies	Same as BAU, except Solar PV LCOE improves faster with interventions
Demand scenario combinations	Combined with both BAU and High Electrification demand : A Baseline B RUPTL High Electrification	Combined only with high electrification demand : C Least-Cost High Electrification



Box G | Supply scenarios cover on-grid supply only: captive demand is a significant additional opportunity

The supply pathways modelled in this chapter cover on-grid generation only. As highlighted in Chapter 1, a significant share of Indonesia's electricity demand is met by captive generation outside the grid: 23% under BAU and 20% under High Electrification. Across the two demand pathways, captive electricity demand reaches around 150–170 TWh by 2035.

This captive demand represents a significant additional opportunity for renewable deployment that is not captured in the modelling for the Least-Cost pathway. Industrial sites that rely on captive power typically require continuous power. This cannot be substituted by solar in the near term, as standalone solar without storage does not have the capacity to deliver. However, on-site solar can meet an increasing share of daytime industrial demand, particularly when paired with batteries.

Meeting 10% of captive demand by 2035 would require roughly 11 GW of additional solar capacity.¹⁰² This would be in addition to the on-grid capacity modelled in Sections 4.2 and 4.3 and represents a conservative entry point for captive renewable deployment that could scale considerably further as costs fall and storage solutions mature.

Realising this opportunity depends on the same cost reduction actions and enabling conditions required for on-grid solar, as set out in Chapter 6. One important difference is that captive solar competes against the all-in cost of on-site coal or diesel generation, which may be higher than the PLN tariff.

¹⁰² This number is based on the assumption that 10% of the 165 TWh captive demand is met by solar at a capacity factor of 17%. Land availability may limit actual deployment.

4.2

Business-as-Usual (RUPTL) supply across two demand scenarios

The current RUPTL build-out is sufficient to meet both demand scenarios through 2035. The same capacity additions are deployed under both BAU and High Electrification scenarios: around 18 GW of solar PV, 8 GW of wind, 15 GW of geothermal, 8 GW of new gas and 1 GW of new coal between 2025 and 2035 [Figure 24].¹⁰³ A further 10 GW of storage is added, comprising 7 GW of BESS and 3 GW of PHS. No additional capacity is required under High

The current RUPTL build-out is sufficient to meet both demand scenarios to 2035.

¹⁰³ These capacity additions are slightly higher than the RUPTL targets because the RUPTL runs only through 2034, while the modelling extends the supply pathway through 2035.

Electrification despite the higher demand. As the RUPTL (supply) and BAU (demand) combination broadly represents the baseline pathway, it is referred to hereafter as the Baseline scenario.

The main difference between the Baseline and RUPTL High Electrification scenarios is the utilisation extent of existing fossil fleet. The additional demand under High Electrification is met largely by running existing coal and gas plants at higher load factors rather than by adding more capacity. As a result, renewables account for a slightly smaller share of generation, falling from 36% under BAU to 32% under High Electrification by 2035 [Figure 23].

The cost difference between the two demand scenarios is significant. Total system cost falls from 9.7 US cents per kWh under BAU to 8.9 US cents per kWh under High Electrification by 2035, as fixed capital and grid costs are spread across a more sizeable demand base [Figure 25].

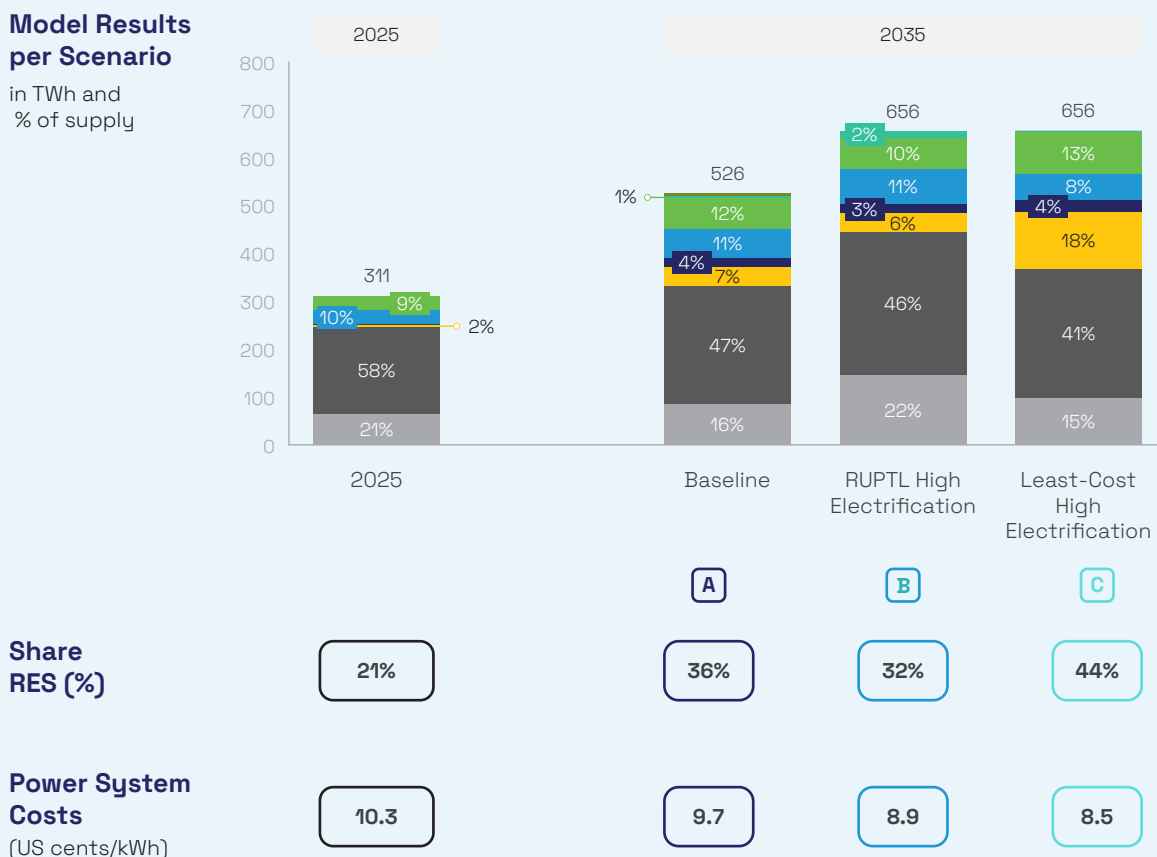
Figure 23 | The Least-Cost pathway reduces power-system costs and increases the share of renewables to 44% by 2035

Electricity generation mix by scenario, on-grid demand

■ Gas ■ Solar ■ Hydro ■ Other RE¹
■ Coal ■ Wind ■ Geothermal ■ Other fossil

Model Results per Scenario

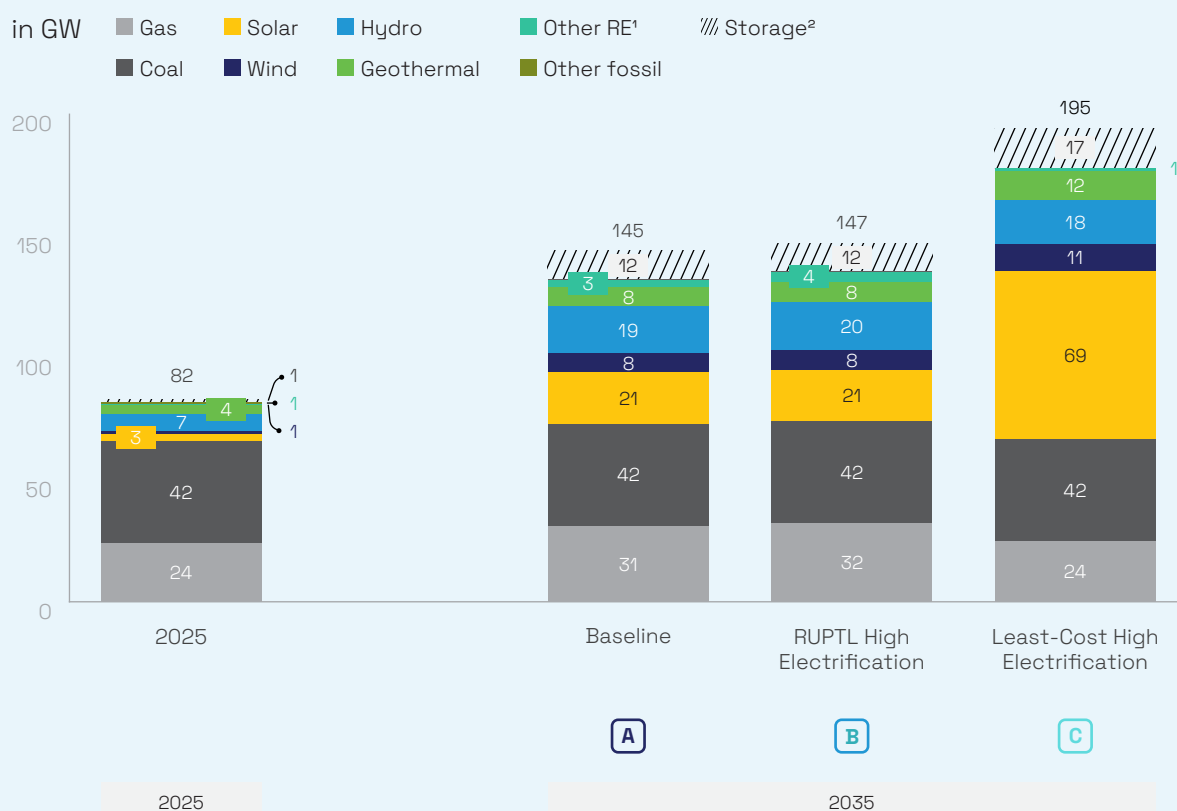
in TWh and % of supply



Source: IESR analysis using PLEXOS.
Notes: 1) Includes bio-energy and nuclear.

Figure 24 | Additional demand is increasingly met by renewables in the Least-Cost supply pathway.

Capacity Mix for All Scenarios, On-grid Demand Only



Notes: 1. Includes bio-energy and nuclear. 2. Based on PHS and a four-hour BESS.
Source: IESR modelling using PLEXOS

4.3

The Least-Cost supply pathway under High Electrification demand

In the Least-Cost pathway, additional demand under High Electrification can be met without adding new coal or gas capacity. Between 2025 and 2035, the pathway adds around 65 GW of solar PV, 10 GW of wind and 10 GW of geothermal. It also increases storage capacity by 17 GW, including 13 GW of BESS and 3 GW of PHS [Figure 24]. By 2035, renewables account for 44% of total generation, compared with 32–36% in the RUPTL pathway [Figure 23] under the same demand scenario. This shows that a more renewable mix is also potentially the more affordable one.

Total power system costs under High Electrification are also lower in the Least-Cost pathway, reaching around 8.5 US cents per kWh compared with 8.9 US cents per kWh in the RUPTL pathway. In Baseline, the total system cost is higher, at around 9.7 US cents per kWh. Most of the savings in the Least-Cost pathway come from lower fossil-fuel consumption, as cheaper solar displaces coal and gas generation.

This cost advantage is conservative because the modelling assumes that coal continues to benefit from DMO pricing. If the DMO were reduced or removed, coal power would become more expensive, strengthening solar's cost advantage and widening the gap further.

Faster reductions in solar costs would allow even greater deployment. In a sensitivity analysis in which the cost-reduction trajectory set out in Chapter 3 is accelerated by five years, on-grid solar capacity reaches around 90 GW by 2035, compared with 69 GW in the main Least-Cost scenario. The renewable share rises to 26% by 2030 and 46% by 2035 (see Box H).

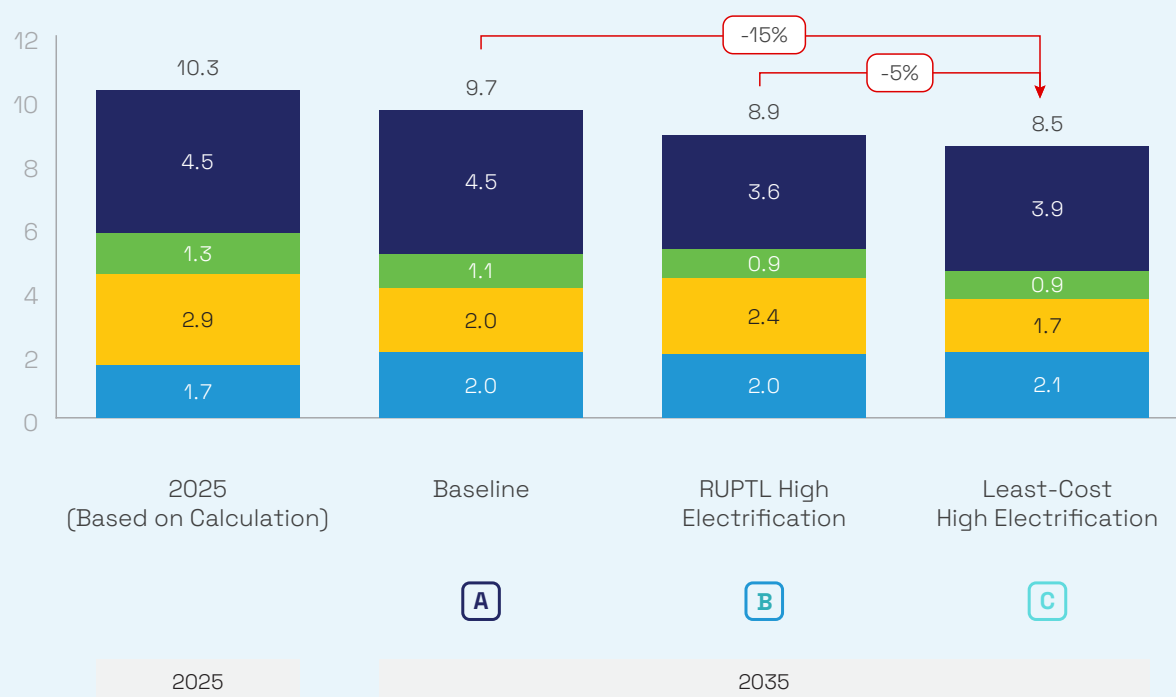
Across the full scenario set, Least-Cost High Electrification delivers the lowest system cost. By 2035, the cost falls by around 12% from 9.7 US cents per kWh under Baseline to 8.5 US cents per kWh under Least-Cost High Electrification [Figure 25]. The savings are driven by two factors. High Electrification creates a more diverse demand base across which fixed capital and grid costs are spread, while the Least-Cost supply pathway increases the share of lower-cost renewables and reduces the more expensive fossil fuel.

Figure 25 | Total power system costs are around 15% lower under Least-Cost High Electrification by 2035.

Projected Total Power System Costs¹ for Scenarios

In US cents/kWh supply

■ Capital ■ Labor and O&M ■ Fuel ■ T&D



BOX H | What it would take to deliver the 100 GWp solar programme

As set out in Chapter 2, the government's 100 GWp solar programme spans on-grid utility-scale, captive and rooftop solar, while the supply modelling covers on-grid supply only.

Even so, the modelling confirms that the 100 GWp ambition is physically achievable.

In the Least-Cost pathway, on-grid solar capacity reaches around 70 GW by 2035, rising to around 95 GW if solar costs fall faster.¹⁰⁴ This represents a step change from the 17 GW envisaged under the current RUPTL. When the additional potential from rooftop and captive solar is considered, the overall opportunity is consistent with the 100 GWp ambition, particularly if solar costs fall faster. Reaching this scale, however, depends on two conditions: coordinated policy actions to remove barriers and reduce solar costs and rapid electrification across Indonesia to ensure sufficient demand.

The pace at which this can be achieved depends almost entirely on how fast Indonesia brings down solar costs. The cost-reduction trajectory set out in Chapter 3 takes time to materialise, with moderate reductions in the early years and steeper declines later as scale, learning and supply-chain effects compound. Project development timelines also matter. Although utility-scale solar can be constructed within six months to two years (see Section 2.2), permitting, land acquisition and grid connection processes typically add several years under the current framework. As a result, most of the solar deployment would only occur in 2030–2035, rather than before 2030 as targeted by the 100 GWp solar programme.

¹⁰⁴ All cost reductions are accelerated by five years in this sensitivity scenario.

Figure 26 | Solar capacity under Least-Cost High Electrification and two sensitivity scenarios

Solar Installed Capacity and Storage Volumes, Sensitivity Scenarios



Notes: 1. PHS and BESS. For BESS, assuming a four-hour storage duration. 2. Scenario C assumes a solar LCOE of 4.5–9 US cents per kWh in 2030 and 4–7 US cents per kWh in 2035. 3. Sensitivity 1 assumes a solar LCOE of 4–7 US cents per kWh in 2030 and 3.5–5 US cents per kWh in 2035. 4. Sensitivity 2 assumes a solar LCOE of 3.7 US cents per kWh in 2027 (India's current level, adjusted for Indonesia's lower capacity factor). 5. Sensitivity 2 assumes a coal LCOE increase of 30% to 4.5 US cents per kWh for existing assets and 9 US cents per kWh for new assets.

Source: IESR analysis.

A sensitivity analysis illustrates what aggressive policy actions could deliver by 2030. The 100 GWp solar programme becomes technically achievable on its original timeline if two conditions are met simultaneously:

- **Solar generation costs fall rapidly to leading-market levels.** Under this sensitivity scenario, Indonesia's solar generation cost reaches around 3.7 US cents per kWh by 2027.¹⁰⁵ Reaching this level so quickly requires implementing far-reaching policy interventions with urgency.
- **The cost advantage of coal is reduced.** Under this sensitivity scenario, coal costs rise by 30% from current DMO-supported levels, removing the structural cost distortion that gives coal an artificial advantage over solar.

Under these conditions, **more than 60 GW of on-grid utility-scale solar capacity could be deployed by 2030 in the Least-Cost pathway** [Figure 26]. Combined with the significant rooftop and captive solar potential discussed in Chapter 2, this could bring total solar deployment to or above the government's 100 GWp target by 2030

Two conclusions pertaining to the 100 GWp solar programme therefore emerge. First, the scale of the ambition is technically and economically viable. The modelling reaches around 70–95 GW of on-grid solar by 2035. Combined with rooftop and captive solar, the 100 GWp ambition could be delivered. Second, achieving 100 GWp by 2030 rather than 2035 depends critically on how quickly policy actions can bring down costs. Faster cost reductions accelerate deployment. Without them, deployment would likely only speed up after 2030.

¹⁰⁵ Based on the LCOE of utility-scale solar PV projects in India today, adjusted for Indonesia's lower solar capacity factor.





Chapter 5

A more electrified, more renewable Indonesia delivers stronger economic outcomes

A more electrified economy, served by a more renewable power system, can contribute meaningfully to Indonesia's growth ambitions. **The Least-Cost High Electrification scenario could deliver around 8–10% of the growth needed to move Indonesia** from its current annual GDP growth rate of around 5% towards the 8% ambition [Figure 27]. This represents around US\$160 billion more GDP than the Baseline scenario between 2025 and 2035. Of this contribution, approximately US\$25 billion comes from future-proofing investment across the energy system, electrification and clean manufacturing, US\$13 billion from investment in data centres and electricity export projects and US\$125 billion from reduced oil and diesel imports and new regional electricity export revenues.

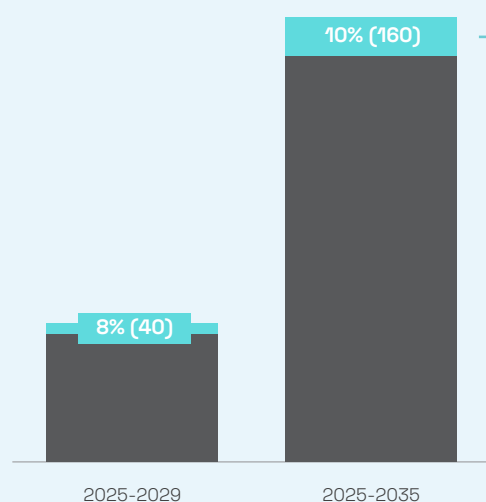
Figure 27 | Least-Cost High Electrification could deliver around 8–10% of the required additional GDP for the targeted 8% GDP.

Illustrative Comparison | High-Electrification, Least Cost Pathway Could Represent ~8-10% Of Indonesian's Required Additional GDP Expansion 8% Growth Pathway, In Addition To Indirect Impact

Direct impact of Least-Cost High Electrification vs. required GDP growth

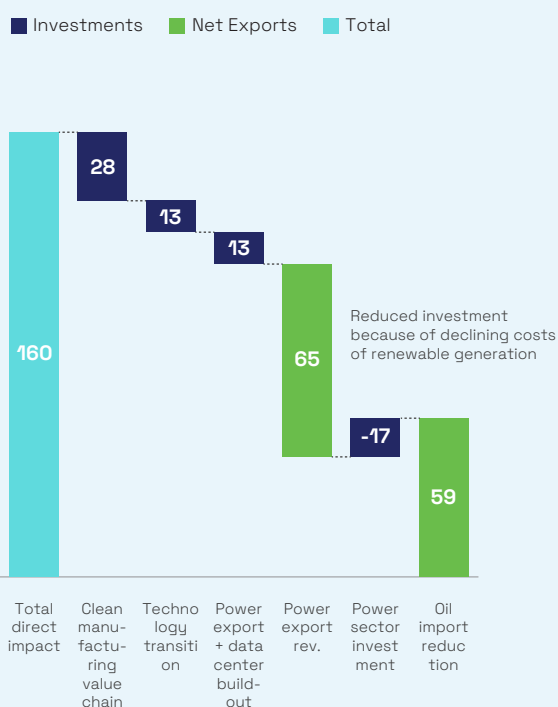
Additional GDP growth required per year to move from 5% annual growth to 8% annual growth, \$ Billion

C ■ Additional growth in Least-Cost High Electrification vs. Baseline
■ Other sources of additional GDP growth



Additional GDP impact of Least-Cost High Electrification vs. Baseline

C vs **A** Total change, 2025-2035, \$ Billion



Build More
adds to GDP

Spend Less
Reduces imports and investment need

Source: INDEF Analysis

The direct GDP impact of Least-Cost High Electrification estimated in this chapter is just an approximation, only covering additional investment and net exports. It does not include potentially significant spillover effects such as additional manufacturing jobs, higher spending from wage growth, foreign direct investment (FDI) beyond the sectors identified or avoided health and environmental costs. The estimated 8–10% contribution is therefore conservative. Moreover, its contribution towards the 8% GDP growth ambition should be seen as complementary to, rather than a substitute for, the broader policies and investment required to achieve it.

Beyond these direct GDP effects, higher electrification and a more renewable power system could free up fiscal space by reducing fossil-fuel subsidy expenditure by around US\$20 billion between 2025 and 2035, create around 48,000 future-proof jobs by 2035 and deliver structural gains that support sustained growth. This includes stronger industrial competitiveness in a greening global economy, reduced exposure to energy price volatility, greater resilience to supply shocks and improvements in public health, air quality and climate credibility [Figure 27].

Beyond these direct GDP effects, higher electrification and a more renewable power system could free up fiscal space by reducing fossil-fuel subsidy expenditure by around US\$20 billion between 2025 and 2035, create around 48,000 future-proof jobs by 2035 and deliver structural gains that support sustained growth.

Figure 28 | Least-Cost High Electrification also delivers significant indirect benefits.

Subsidy savings

\$20 Bn

Between 2025–2035

Jobs

48,000

Additional, future-proof jobs in the power system



Source: INDEF Analysis

This chapter comprises three sections. Section 5.1 sets out the direct GDP impact through net exports, including lower oil imports, the largest single economic benefit identified in the analysis. Section 5.2 examines the direct GDP impact from additional investment. Section 5.3 explores the indirect economic gains.

5.1

Direct GDP impact: higher net exports as oil imports decline and electricity exports increase

Least-Cost High Electrification delivers around US\$23 billion in additional net exports per year by 2035 compared with Baseline. This is equivalent to around US\$125 billion cumulatively between 2025 and 2035. Two factors contribute to this: oil and oil-product imports decline by around US\$15 billion per year by 2035 and regional electricity exports increase to around US\$8–9 billion per year. Lower oil consumption also reduces government subsidy expenditure, a related fiscal benefit that will be separately discussed in Section 5.3.

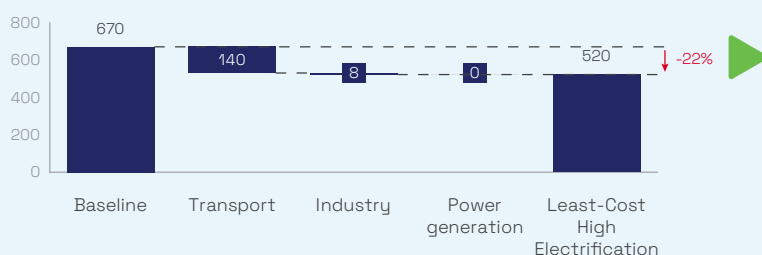
5.1.1 Lower oil imports is the largest single economic benefit of the pathway

As a net oil importer, Indonesia’s dependence on imported oil creates a structural fiscal vulnerability. Domestic oil production fell to around 580,000 barrels per day in 2024 as domestic consumption reached approximately 1.6 million barrels per day.¹⁰⁶ Domestic refining capacity meets only around 60% of national demand.¹⁰⁷ This import dependence has become a growing fiscal concern. The 2026 Iran conflict, for example, pushed oil prices above US\$100 per barrel, compared with the government’s budget assumption of US\$70 per barrel. Each additional dollar in the oil price adds approximately Rp6.8 trillion, or around US\$380 million, to government spending.¹⁰⁸

Figure 29 | Higher electrification and renewables can materially reduce oil demand.

Oil Demand Reduction by Sector¹

Million barrels per year, 2035



Cumulative demand reduction
(million barrels, 2025–2035)

550

35

1

Economic Effects

Avoided oil imports²

US\$60-75

billion (cumulative), 2025–2035

US\$15-17

billion (annual) by 2035

Notes: 1. Includes oil and oil products, including diesel. For transport, which commonly uses B40/B50 biodiesel, B40 diesel was assumed in 2025 and B50 diesel assumed for the rest of the years. For industry, specific biodiesel consumption numbers were incorporated. The volume of bio-fuel has been subtracted from this total to get a diesel-only total. 2. Assumes a government-projected oil price of US\$80 per barrel and a diesel import price of US\$145 per barrel.

Sources: INDEF and IESR analysis; APBN (2026), Kerangka Ekonomi Marko dan Pokok-Pokok Kebijakan Fiskal 2026, S&P Global Platts.

¹⁰⁶ Indonesia Investments (2024), *Crude Oil Indonesia: Production & Consumption*.

¹⁰⁷ Asia Times (2025), *Why Oil-Rich Indonesia Imports Most of Its Fuel*.

¹⁰⁸ IDN Financials (2026), *Oil Hits USD 100, Indonesia to Keep Fuel Subsidies through 2026*.

By 2035, oil consumption under High Electrification is 22% lower than under BAU, equivalent to almost 150 million barrels of avoided demand in 2035 alone and around 585 million barrels cumulatively between 2025 and 2035 [Figure 29].¹⁰⁹ Transport is the dominant driver, accounting for around 140 million of the 150 million barrels avoided in 2035, as E2Ws and passenger cars replace petrol-fuelled and diesel-fuelled vehicles¹¹⁰. The industrial sector contributes a smaller reduction, with cumulative savings of around 8 million barrels between 2025 and 2035 through the electrification of industrial heat and the replacement of diesel generators with grid-connected and on-site renewable supply.

While oil use in on-grid power generation is limited, the gains from reducing it are greater than the number suggests. Displacing diesel is an important part of delivering the 100 GWp solar programme, as diesel remains among the most expensive sources of generation in the system. The total potential from de-dieselisation is likely to be greater than Figure 29 shows, along with the associated cost and reliability benefits. This is because the modelling captures only on-grid demand, while many remote communities still rely on off-grid diesel generators.

In total, lower oil demand translates into around US\$60 billion in cumulative avoided oil import expenditure between 2025 and 2035, with annual savings reaching around US\$15 billion by 2035. These savings also help preserve hard currency reserves, reduce pressure on the rupiah and lower Indonesia's exposure to global commodity volatility. To put the scale in context, US\$15 billion per year is broadly equivalent to half of Indonesia's palm oil export value in 2024.¹¹¹ If oil prices remain at US\$100 per barrel, cumulative avoided import expenditure rises to around US\$75 billion, 25% above the central case, along with annual subsidy savings. In a more volatile oil-price environment should the Iran conflict persist, the resilience benefits would grow in value over time.

Lower oil consumption also reduces Indonesia's fossil-fuel subsidy bill.

Because subsidy expenditure is a fiscal flow rather than a direct GDP component, this benefit is discussed separately in Section 5.3. The modelling indicates cumulative savings of around US\$16 billion in oil-product subsidies between 2025 and 2035, reaching around US\$3–4 billion per year by 2035, equivalent to around a third of the 2026 budget for the free nutritious meal (MBG) programme.¹¹² Reduced oil consumption therefore creates benefits through both the trade balance and the public budget, creating the single largest fiscal and economic benefit of the pathway.

Lower oil consumption also reduces Indonesia's fossil-fuel subsidy bill.

¹⁰⁹ This chapter combines oil and oil-product results into a single data point; a breakdown is provided in the Technical Appendix. Total oil demand has been adjusted for biodiesel's contribution, assuming B50 from 2026 onwards.

¹¹⁰ The uptake of EVs and E2Ws in the high electrification scenario is ambitious and needs policy support. The uptake of EVs and E2Ws under High Electrification is ambitious and will require policy support. Realising only half of the uptake will cut 70 mboe of oil and save US\$8 billion per year.

¹¹¹ GAPKI (2025), *Production Drops, Indonesian Market Shrinks*.

¹¹² Reuters (2026), *Indonesia Cuts Budget of President's Free Meals Programme*.

5.1.2 Regional electricity exports could generate around US\$8–9 billion per year by 2035

Indonesia is already exploring dedicated renewable generation projects for export to Singapore, supported by subsea interconnection. Under Least-Cost High Electrification, around 46 TWh of low-carbon electricity could be exported to neighbouring countries each year by 2035, generating approximately US\$8–9 billion in annual export revenues. This is equivalent to around 4% of Indonesia's total export value in 2025, at around US\$300 billion.¹¹³ Beyond the headline revenue, electricity exports could strengthen Indonesia's export profile in two ways. First, electricity exports typically involve multi-decade PPAs, providing more stable foreign-exchange earnings than commodity exports that are exposed to global price cycles. Second, electricity exports could generate export revenues with greater domestic value added by building on renewable generation and grid infrastructure, rather than relying primarily on raw extracted materials.

5.2

Direct GDP impact: additional future-proofing investment and new growth sectors

Least-Cost High Electrification directs around US\$25 billion in additional cumulative future-proofing investment between 2025 and 2035 [Figure 27] through the energy system, end-use electrification and domestic clean energy manufacturing. A further US\$13 billion in additional investment is mobilised in two new growth sectors enabled by access to low-carbon power: regional electricity exports and data centres. The economic impact of these investments depends on how much of their value is captured domestically. Greater use of domestically produced equipment, materials and services can increase the impact on GDP. However, requiring higher local content before competitive domestic capacity is available can also raise costs and reduce competitiveness. These investment opportunities are explained below.

1. Energy system

Least-Cost High Electrification delivers a more efficient use of capital for the energy system than Baseline, requiring around US\$190 billion of power system investment between 2025 and 2035. This is US\$17 billion lower than the US\$205 billion investment required under Baseline, while meeting higher electricity demand. Faster deployment of solar PV, combined with structural cost interventions, lowers the unit cost over time. In other words, this option results in the lowest total system cost, freeing up capital to be used elsewhere in the economy.

113 BPS (2026), *Exports and Imports of Indonesia in December 2025*.

2. Electrification of end-use sectors

Electrifying transport, households and industry requires an estimated US\$13 billion in cumulative investment between 2025 and 2035, across three areas:

- o **Transport: US\$7–8 billion** for the deployment of almost 2 million additional EVs, around 9 million E2Ws and around 11,000 electrified mining trucks in place of internal combustion engine (ICE) alternatives between 2025 and 2035.¹¹⁴ Although upfront purchase prices can be higher than fossil-based alternatives, the total cost of ownership of E2Ws is already lower because of lower fuel and operating and maintenance costs. Early deployment in mining is also showing similar cost advantages (see Chapter 1). The investment estimate assumes further cost reductions in electric technologies over the next decade, as detailed in the Technical Appendix.
- o **Residential: US\$4 billion** for increased AC adoption, reaching 38% of households by 2035, and a limited transition to electric cooking, covering around 20 million units.
- o **Industry: US\$1.5–2 billion** for industrial electrification technologies including electric boilers, heat pumps and EAF.

3. Domestic clean energy manufacturing

Building domestic manufacturing capacity to serve a more electrified, more renewable economy represents around US\$30 billion of future-proofing investment opportunity between 2025 and 2035. This includes selected strategic elements of the clean energy manufacturing value chain, including EVs, E2Ws, electric mining trucks, batteries for EVs and the power system and solar panels.

EVs, E2Ws and electric heavy-duty trucks account for around US\$10 billion of the manufacturing investment, broadly comparable with investment in Indonesia's nickel smelting industry in 2024.¹¹⁵ Battery manufacturing for EVs and the power system contributes a further US\$17 billion, while solar PV manufacturing contributes around US\$3 billion. These estimates already apply existing local content requirements to projected demand. Chapter 6 sets out the case for a more phased approach to local content for solar. Further detail on the assumptions is provided in the Technical Appendix.

4. New growth sectors enabled by low-carbon power

Access to competitively priced low-carbon electricity could mobilise around US\$13 billion in additional investment in regional electricity exports and data centres between 2025 and 2035. This comprises:

¹¹⁴ This estimate reflects the incremental cost of purchasing equipment for EVs compared with for ICE alternatives. For passenger EVs, the price difference is assumed to become negligible from 2030 and for E2Ws from 2034.

¹¹⁵ BKPM (2025), *2024 Investment Realisation Press Conference: Nickel Smelting Received IDR 153.2 trillion of Investment Realisation in 2024*.

- o Regional electricity exports: around US\$9 billion¹¹⁶ for dedicated renewable generation and storage infrastructure (large-scale solar and BESS) for exports to neighbouring markets.
- o Data centres: around US\$4 billion in additional CAPEX for approximately 360 MW of additional capacity by 2035 compared with Baseline. This growth is supported by international hyperscalers that increasingly require access to renewable electricity as a condition for major investment (see Chapter 1).

The economic impact of these investments ultimately depends on how much value is captured domestically. A phased approach can help optimise the benefits. Competitive imports can initially reduce costs and accelerate build-out, while domestic manufacturing expands as market scale, policy support and investor confidence develop. Chapter 6 sets out recommendations for balancing solar generation costs with the growth of domestic manufacturing.

5.3

Indirect economic impact: fiscal savings, future-proof jobs and structural gains

Beyond the direct GDP impact set out in Sections 5.1 and 5.2, a more electrified, more renewable economy could deliver wider economic gains. Three benefits have been identified: fiscal space from lower energy subsidy spending, future-proof job creation in industries with long-term global growth and structural and strategic gains that strengthen Indonesia's competitiveness in the longer term.

5.3.1 Least-Cost High Electrification could reduce energy subsidy costs by around US\$20 billion over the next decade

Energy subsidies are among the largest and most volatile items in Indonesia's budget. In 2024, the government spent around US\$47 billion on energy subsidies, with roughly 90% directed at fossil fuels.¹¹⁷ This spending comes with significant exposure to global fuel-price movements due to reliance on imported fuels. Reducing fossil-fuel demand therefore does more than cut emissions. It reduces a persistent source of fiscal risk.

Under Least-Cost High Electrification, spending on selected energy subsidies falls by around US\$20 billion or 5% cumulatively between 2025 and 2035 compared with Baseline [Figure

¹¹⁶ Total project investment is approximately US\$45 billion. The analysis assumes that around 20% uses domestically manufactured content.

¹¹⁷ IISD (2026), *Indonesia's Energy Support Measures*.

30].¹¹⁸ Almost all of the savings come from explicit subsidies¹¹⁹ funded through the government budget, while the net change in implicit price-cap mechanisms is small.

Cumulatively over the decade, the US\$20-billion saving in explicit subsidies between is equivalent to close to one-tenth of a full year of state spending.¹²⁰ Transport accounts for by far the largest share. As electric vehicles replace petrol-fuelled and diesel-fuelled vehicles, oil and diesel subsidy spending falls by around US\$16 billion, accounting for roughly four-fifths of the total savings. Electricity compensation payments also decline by around US\$1.3 billion as a lower LCOE narrows the gap between the cost of generating electricity and the regulated selling price. Residential liquefied petroleum gas (LPG) subsidies fall by a further US\$1.5 billion as electric cooking replaces subsidised LPG.

As electric vehicles replace petrol-fuelled and diesel-fuelled vehicles, oil and diesel subsidy spending falls by around US\$16 billion, accounting for roughly four-fifths of the total savings.

Meanwhile, implicit subsidies do not draw on government budget but rather reflect the benefit of the price caps applied to coal and gas, mainly for power generation.¹²¹ The greater demand under Least-Cost High Electrification increases the value of the implicit subsidy coal by around US\$1 billion while reducing the implicit subsidy for gas by around US\$0.5 billion as gas use in power generation declines.

¹¹⁸ This analysis is not a comprehensive assessment of all energy and fuel subsidies in Indonesia. It focuses on the schemes most affected by higher electrification and greater renewable power deployment.

¹¹⁹ Explicit subsidies are funded through the government budget and include oil and diesel subsidies, including the diesel share of biodiesel assuming B50 blending from 2026, LPG subsidies and electricity compensation payments. Figures are cumulative between 2025 and 2035 and assume current subsidy arrangements continue at today's price levels. Price assumptions: crude oil at US\$78.6 per barrel (ICP) against a regulated consumer price of US\$70 per barrel; imported petroleum diesel at US\$148.6 per barrel and B50 biodiesel at US\$138.6 per barrel against a subsidised transport consumer price of US\$60.1 per barrel; LPG at US\$0.93 per kilogram supply cost against a consumer price of US\$0.35 per kilogram and electricity generation cost (BPP) of US\$87.6 per MWh against a regulated selling-price cap of US\$62.2 per MWh. Sources: fuel demand (LEAP); power dispatch and generation costs (PLEXOS); oil (ICP, MEMR); diesel and biodiesel (S&P Global Platts, HIP, Pertamina Patra Niaga); LPG (IMF); electricity (PMK 73/2025).

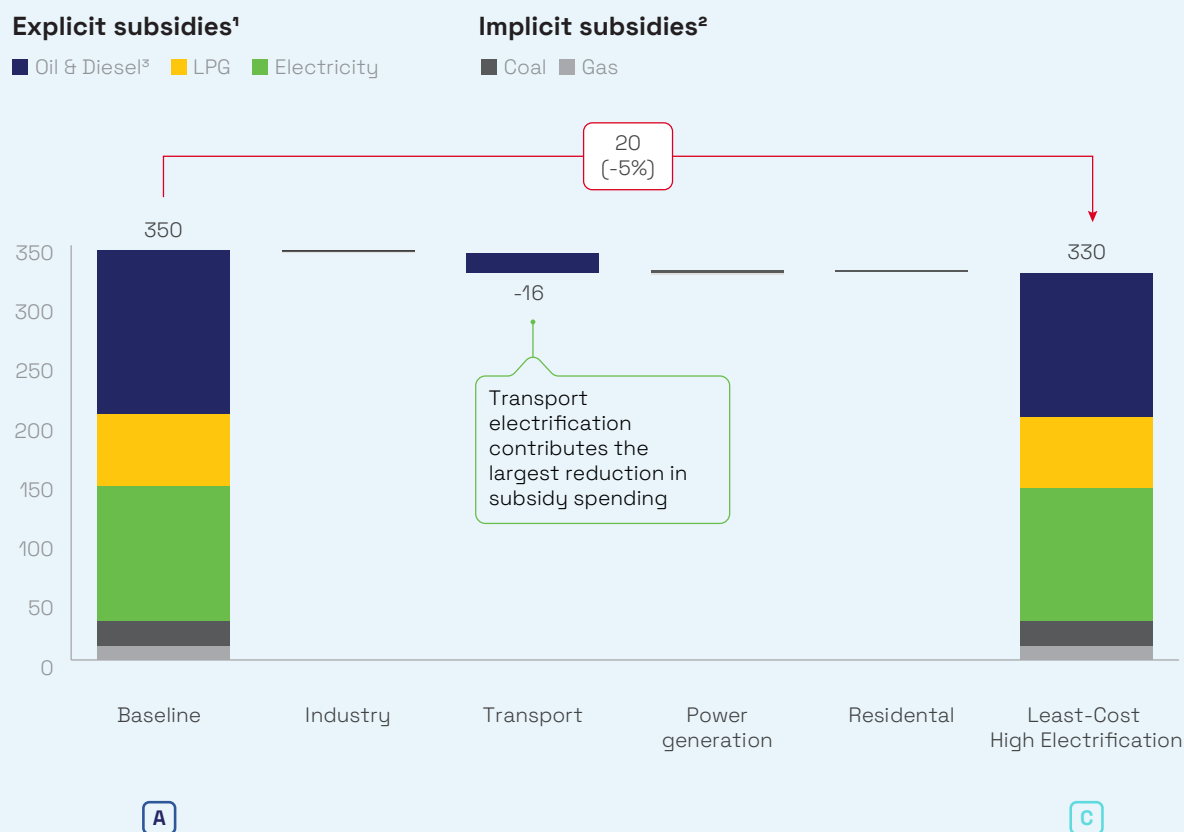
¹²⁰ MUC Consulting (2025), *House of Representatives Passes 2026 State Budget Law: Here are the Structure and Targets*.

¹²¹ Implicit subsidies are price-reducing measures that do not draw directly on the government budget, including regulated domestic prices for coal and gas used in power generation. See the Technical Appendix for the full methodology. Price assumptions: coal for power US\$77.9 per tonne (HBA) against a US\$70 per tonne cap, industrial coal US\$116.2 per tonne against a US\$90 per tonne cap and industrial gas US\$7.1/MMBtu against a US\$6/MMBtu cap. Sources: coal (HBA, Ditjen Minerba); gas (IMF); power and industrial demand (LEAP, PLEXOS); caps (MEMR Decrees 56/2022, 267/2022 and 76/2025).

Figure 30 | Savings on selected energy subsidies rise in a more electrified, more renewable energy system.

Selected energy system subsidies, cumulative

In US\$ billion, 2025-2035



Notes: 1. Explicit subsidies are funded by government budget. 2. Implicit subsidies are price-reducing incentives (e.g. the DMO price cap on coal) that are not funded by government budget. Current subsidies and incentives are assumed to continue at today's price levels. For full price assumptions, see Technical Appendix. 3. Includes the diesel in biodiesel and assumes B50 blending from 2026 onwards.

These savings create additional fiscal space in two ways. First, a lower subsidy bill reduces exposure to oil-price shocks such as those that prompted spending adjustments in 2022 and 2026, strengthening fiscal resilience through commodity-price cycles. Second, the savings can be redirected towards infrastructure, education or industrial support, turning lower fuel expenditure into investment for longer-term growth and further compounding the economic gains.

5.3.2 Power system investments create future-proof jobs

Under Least-Cost High Electrification, the build-out of a more renewable power system could create around 48,000 or 65% more power generation jobs than under Baseline [Figure 31]. By contrast, under RUPTL High Electrification, employment remains at around 73,000 jobs, broadly similar to Baseline, because the additional electricity demand is met largely through greater utilisation of existing fossil-fuel plants.

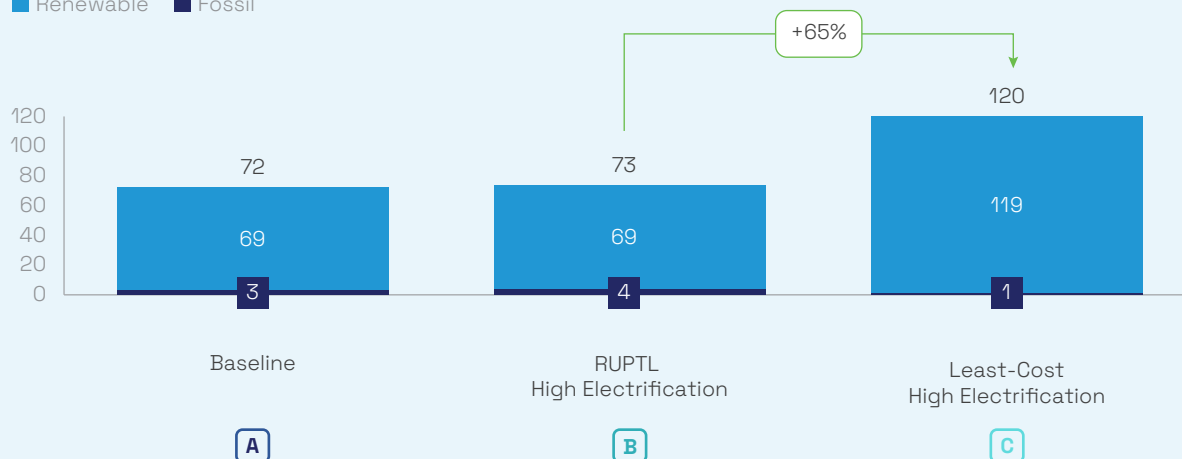
When the same High Electrification demand is instead met through the Least-Cost supply pathway with greater renewable deployment, power generation employment rises to around 120,000 jobs. The additional jobs come largely from investment in new renewable generation capacity. These estimates already account for a small decline of fewer than 1,000 jobs in fossil-fuel generation. The decline is small because the Least-Cost pathway does not involve significant retirement of existing fossil capacity. The estimates also exclude jobs associated with grid expansion and clean energy manufacturing, which could provide further employment gains (see Section 5.2).

Figure 31 | Least-Cost High Electrification delivers the largest jobs increase.

Net additional jobs across scenarios, 2025–2035

In thousands

■ Renewable ■ Fossil



These jobs are concentrated in industries that are growing globally. Renewable generation, electrification and distributed energy systems require electrotechnical skills that are increasingly in demand across Asia and globally, supporting higher wage, greater transferability and worker mobility. By contrast, earnings from coal-related employment are likely to weaken in the long-term as global power systems decarbonise. Investing in the renewable workforce now therefore better prepare Indonesian workers for the next decades of the energy transition.

Investing in the renewable workforce now therefore better prepare Indonesian workers for the next decades of the energy transition.

5.3.3 Structural and strategic gains reinforce the case for more electrification and renewables

Beyond fiscal savings and employment, a more electrified, more renewable economy can deliver broader structural and strategic second-order gains for Indonesia's economy. These include stronger competitiveness as customers and trading partners increasingly value low-carbon supply, greater attractiveness to foreign investors, improved energy resilience and benefits for air quality and public health.

5.3.4 A more renewable power system strengthens competitiveness in a greening global economy

Global competitiveness is increasingly influenced by the carbon intensity of production. The Carbon Border Adjustment Mechanism (CBAM) is the most developed example of this trend, with similar mechanisms being introduced or considered in other major markets, including the United Kingdom, Australia and Canada. From January 2026, CBAM imposes carbon costs on imports of steel, aluminium, cement, fertilisers and hydrogen. Around US\$760 million of Indonesian exports are estimated to be exposed to CBAM, equivalent to 5% of Indonesia's exports to the European Union in 2023.¹²² Iron and steel alone could face more than US\$300 million in charges because of their high emissions intensity relative to European benchmarks.¹²³

Carbon pricing is beginning to shape commodity markets. The London Metal Exchange has outlined plans to facilitate premiums for more sustainably produced metals,¹²⁴ while discussions are also emerging around differentiated pricing for lower-carbon nickel. As demand for green metals grows, producers are increasingly assessed on the carbon intensity of the electricity used in production. This creates a particular competitiveness risk for Indonesia, if access to low-carbon electricity does not improve. Nickel is a cornerstone of Indonesia's downstream industrial strategy. A nickel industry that relies on a fossil-dominated power system can lead to price discounts or even market exclusion in a greening global metals market.

Corporate investment decisions are adding to this pressure. Multinational manufacturers, particularly consumer-facing companies, increasingly consider access to low-carbon electricity when deciding where to invest [Figure 33]. In 2024, Tesla cited Indonesia's coal-heavy power mix as one factor behind its decision not to establish manufacturing operations in the country, as this would be inconsistent with its sustainability strategy.¹²⁵ H&M has committed to sourcing 100% renewable electricity across garment production by 2030 and phasing out coal boilers from its supply chain by the end of 2026.¹²⁶ Across sectors including metals, chemicals, manufacturing and data centres, Indonesia's fossil-dominated power system increases the risk of supply chain exclusion, commodity discounts and reduced foreign direct investment.

¹²² IESR (2024), *Indonesia Energy Transition Outlook*.

¹²³ Trade Expo Indonesia (2024), *CBAM dan Implikasinya*.

¹²⁴ Fastmarkets (2025), *LME Outlines Plan for 'Sustainable' Base Metal Premiums: LME Week 2025*.

¹²⁵ Kumparan (2024), *Terungkap, Ini Alasan Tesla Ogah Investasi di Indonesia*.

¹²⁶ H&M Group (2025), *Annual and Sustainability Report 2024*.

Figure 33 | Limited access to renewables and overreliance on coal is hurting Indonesia's global competitiveness.

Companies	Example	Impact
	Hyundai withdrew from an MoU with Adaro due to rising public pressure to reduce reliance on coal-based suppliers.	Adaro minerals loses 50–100 kt of aluminum sales to Hyundai per year due to reliance on coal power.
	Samsung sought to increase renewable energy use for phone production but had difficulty getting access to renewables.	Samsung shifted a majority of production to Vietnam , enabling power wheeling and significant growth in renewable energy use.
	Targeting 100% renewable energy for data centre operations, Amazon signed a 210 MW solar PV GEAS with PLN in 2022, but delivery has been significantly delayed.	The risk of future data centres choosing other regions where it is easier to secure renewable power (e.g., Malaysia) is increasing.
	Tesla was in discussions with the Government of Indonesia to invest in manufacturing but did not proceed, citing Indonesia's fossil-heavy electricity system as a concern for sustainable EV manufacturing.	Indonesia is facing the risk of reduced investment into and slower growth of the manufacturing industry.
	Indonesia has ~25 solar panel manufacturers with 6–11 GW/year of production capacity. With domestic demand too low to absorb output and US tariffs constraining exports, producers, including TMAI, warn of furloughs and layoffs.	Underused factories and job losses in a young solar-manufacturing sector will make it difficult for Indonesia to build a competitive domestic clean-energy supply chain.

Notes: GEAS = Green-Energy-as-a-Service
Sources: PROSPERA/BINS Research; BNEF (2025); Suruhanjaya Tenaga; Systemiq Analysis; Kumaran (2024); Bloomberg Technoz (2026).

5.3.5 Renewables and electrification improve energy cost predictability for industry

For energy-intensive and trade-exposed sectors, cost predictability is critical. In Indonesia's current system, industrial users remain exposed to global fossil-fuel markets, either through electricity tariffs or regulations around coal supply.

Grid-connected firms, such as light manufacturing facilities, rely on regulated electricity tariffs. While these tariffs can remain stable in the short term, they are influenced by fuel prices, exchange rates and inflation. For illustration, in July 2022, the government increased tariffs for certain non-subsidised household and government customers by around 18%.¹²⁷ Tariffs were

127 Antara News (2022), Hiking Electricity Rates Triggers 0.019-Percent Inflation: Official.

subsequently held flat for several quarters in 2024–2025 despite higher input costs, with the difference absorbed through higher compensation payments to PLN. In this case, tariff risk was merely deferred rather than removed. For energy-intensive sectors, the possibility of future tariff increases remains a material concern.

Industrial users relying on captive coal-fired generation

face a similar risk. Nickel processors, for example, rely on coal supplied under the DMO at capped prices. Industry stakeholders have raised concerns about whether DMO supply can keep pace with the rapid expansion of nickel processing. As smelting capacity grows and available DMO supply tightens, producers could become more exposed to international coal prices. This could increase coal input costs by up to 40% and nickel production costs by up to 15%.¹²⁸

For both grid-connected and captive power users, current cost stability ultimately depends on regulatory mechanisms that buffer exposure to fossil-fuel price volatility. Industrial energy costs are shaped not only by market fundamentals but also by decisions on tariffs, subsidies, domestic coal allocation and production quotas. Increasing the share of renewables in the power mix can reduce this exposure because renewable generation does not require ongoing fuel inputs and is therefore less affected by the global commodity market.

At the individual-site level, combining electrification with on-site solar plus storage is a risk management strategy. By replacing direct fossil-fuel use with electric processes and increasing on-site renewable generation, firms can reduce their exposure to tariff uncertainty, fuel supply constraints and regulatory shifts. As one industrial stakeholder noted, companies increasingly view electrification and on-site renewables as a critical measure to reduce risks they cannot directly control, including future changes in PLN tariffs and energy policy.

For energy-intensive sectors, the possibility of future tariff increases remains a material concern

Companies increasingly view electrification and on-site renewables as a critical measure to reduce risks they cannot directly control

¹²⁸ The DMO earmarks 25% of national coal production for domestic use at a capped price. Following the recent reduction in the annual coal production quota from 800 Mt to 600 Mt, available DMO supply falls from approximately 200 Mt to 150 Mt per year. Nickel-sector coal demand is approaching 100 Mt per year, equivalent to around two-thirds of available DMO supply. If DMO supply is insufficient, nickel producers may need to purchase coal at international market prices. The estimated cost impact assumes an export coal price of US\$130 per tonne (ICI 1, February 2026).

CASE STUDY | Electrification and rooftop solar at Haleon Indonesia

Haleon, a consumer healthcare manufacturer, has paired heat electrification with rooftop solar at its Pulogadung site in East Jakarta. The project illustrates both how quickly these technologies can be deployed and the practical factors that can affect implementation.

Haleon installed a rooftop solar system of around 417 kWp in just 69 days, which now supplies roughly 20–25% of the site's electricity demand. The permitting took longer than construction due to the biannual application windows and quota-allocation constraints (see Box C), and the grid connection was finally secured around six months later than initially planned. The current system uses around half of the available rooftop space and could have been larger, but under existing rules Haleon would not receive compensation for additional electricity exported to the grid.

On the demand side, the site replaced oil-based heat with electric steam generation and water heating. This reduced operating costs and lowered direct exposure to oil-price movements for its thermal processes.

Together, electrification and on-site solar also support a broader risk-management objective. While electricity tariffs and fuel prices are outside the company's control, on-site generation and electrified processes give the site greater control over a portion of its energy costs. The team also highlighted a broader motivation: demonstrating that practical steps towards decarbonisation are feasible for manufacturers in Indonesia to encourage wider adoption across the sector.

5.3.6 A more diversified power system is more resilient to fuel supply shocks and geopolitical disruption

A more diversified power mix on the supply side and lower oil dependence across the economy on the demand side ultimately reduce exposure to disruptions.

On the supply side, Indonesia's current heavy reliance on coal creates concentration risk. In January 2022, the government imposed an emergency coal export ban after domestic supply shortfalls left 20 PLN CFPP critically low on fuel.¹²⁹ The episode showed that even a coal-dominated system in a major coal-producing country is still vulnerable to domestic supply-chain disruptions. Renewable generation requires no ongoing fuel supply once built. Many renewable technologies can also be deployed across different locations and at different scales. This reduces the likelihood for a single disruption to affect the entire system.

On the demand side, electrification reduces Indonesia's exposure to oil-price shocks. Transport is the dominant consumer of oil products in Indonesia, accounting for 73% of consumption in 2023, while the industrial sector accounts for 9% and the residential sector for 15%.¹³⁰ A geopolitical oil-price shock can therefore simultaneously affect the trade balance, subsidy

¹²⁹ MEMR (2022), *Preventing Power Outages, Government Temporarily Bans Coal Export*.

¹³⁰ IEA (n.d.), *Indonesia – Oil, Countries & Regions*.

spending, cost of living and industrial production costs, as demonstrated by the 2026 price spike following escalation in the Iran conflict. As Chapter 1 showed, the cost of industrial heat from oil-fired boilers more than doubled in 2026. Electrification reduces this exposure by shifting transport and industrial power demand onto a grid with a more diversified and domestically produced supply mix. As illustrated in Figure 29, electrification of transport alone could reduce oil demand by around 140 million barrels per year by 2035.

5.3.7 Cleaner air, better health, and stronger climate credibility

Air pollution imposes substantial costs on Indonesia's economy and population. The World Bank estimated that air pollution costs approximately US\$220 billion in 2019.¹³¹ In Jakarta, annual average concentration of fine particulate matter (PM2.5) reached six times the World Health Organization (WHO) guideline in 2023. The IESR attributes around 10,500 premature deaths and US\$7.4 billion in annual health costs to CFPP. Accelerating the coal phase-out to 2040 could avoid 182,000 premature deaths and approximately US\$130 billion in associated health costs¹³².

A more electrified, more renewable system can reduce these health impacts through two reinforcing channels: lower supply-side emissions from power generation and lower demand-side emissions from replacing coal boilers, diesel generators and ICE vehicles with electric alternatives. The latter can have a particularly significant impact because many of these combustion sources are located in densely populated areas, where exposure to air pollution is highest.

Renewable deployment also strengthens Indonesia's climate credibility. Indonesia has committed to reducing emissions by 32% below its NDC (Nationally Determined Contribution) baseline by 2030, rising to 43% with international support, and to net zero by 2060.¹³³ Credible progress in the power sector could strengthen Indonesia's standing as a Group of Twenty (G20) economy and major energy producer, broadening access to concessional finance, climate partnerships and international capital for industrial transformation.

¹³¹ World Bank (2022), *The Global Health Cost of PM2.5 Air Pollution: A Case for Action Beyond 2021*.

¹³² CREA and IESR (2023), *Health Benefits of Just Energy Transition and Coal Phase-Out in Indonesia*.

¹³³ Government of the Republic of Indonesia (2025), *Second Nationally Determined Contribution Republic of Indonesia*.



Chapter 6

Capturing Indonesia's solar and electrification opportunity: a roadmap for action

Capturing the economic gains set out in Chapter 5 depends on coordinated interventions across both supply and demand. One priority cuts across the recommendations that follow: **rebalancing incentives between fossil fuels and renewables**. As Chapter 5 showed, Indonesia currently spends around US\$47 billion a year on energy subsidies, with roughly 90% directed at fossil fuels.¹³⁴ These support mechanisms give fossil fuels an artificial cost advantage that can weaken the competitiveness of both renewables and electrified end uses.

Recommendations for rebalancing these supply-side incentives are well established and have been covered extensively in existing studies.^{135,136,137,138,139,140} Key measures include phasing down fossil-fuel price support, including the DMO coal price cap and the Designated Natural Gas Price (HGBT) mechanism, bringing captive coal-fired generation into the emissions trading system¹⁴¹, and redirecting the resulting fiscal space towards renewable generation and storage, grid investment and electrification. This is not a one-off reform but a progressive rebalancing that should scale as renewables and electrification reach tipping points: acting too slowly prolongs fossil-fuel lock-in, while acting too abruptly creates political and fiscal risks. Because these reforms are covered extensively in other studies, this report does not revisit them in detail.

Building on this foundation, the report focuses its recommendations on two areas where it can add the most: bringing down the cost of solar generation and accelerating demand electrification. On the supply side, solar costs need to come down materially, bringing them closer to levels already achieved in leading solar markets. Four categories of intervention can support this: **i) fast-tracking catalytic grid-scale projects** that anchor early demand and generate bankable precedents, **ii) removing barriers to rooftop solar**, **iii) policy support on key cost components**, particularly land and grid costs, to address structural drivers of Indonesia's solar cost gap and **iv) a phased local content strategy** that builds Indonesian manufacturing capacity while keeping deployment costs competitive.

Categories 1 and 3 are closely linked and are most effective when treated as a single project-development chain rather than separate interventions. Sites are identified, land requirements are standardised and sites pre-cleared, grid access is secured and projects are then tendered with these constraints already addressed. These supply-side interventions need to be paired with stable, long-term policies that accelerate demand electrification in the transport and industrial sectors.

The chapter comprises two sections. Section 6.1 sets out how to scale solar at lower cost through the four categories of intervention. Section 6.2 sets out how to accelerate electrification of demand, particularly in the transport and industrial sectors.

134 IISD (2026), *Indonesia's Energy Support Measures*.

135 IEA (2022), *An Energy Sector Roadmap to Net Zero Emissions in Indonesia*.

136 Ember (2025), *Response to Indonesia's Just Energy Transition Partnership (JETP) Progress Report 2025*.

137 IISD (2026), *Indonesia's Energy Support Measures*.

138 World Bank (2026), *Indonesia Economic Prospects, June 2026*.

139 World Bank (2024), *Indonesia's Fuel Subsidies Reforms*.

140 IESR (2025), *Indonesia Energy Transition Outlook 2026*.

141 Ember (2025), *Response to Indonesia's Just Energy Transition Partnership (JETP) Progress Report 2025*.

6.1

Scaling solar at lower cost: four categories of intervention

Closing Indonesia's solar generation cost gap with leading markets requires action across four categories of intervention [Figure 34]. As set out in Chapter 3, the gap is largely driven by elevated module and BoS costs linked to local content requirements, high land-acquisition costs driven by regulatory complexity and the absence of pre-zoned land and high grid-connection costs driven by long distances to the transmission network. Permitting and financing add further cost pressure and project-level risk.

These cost drivers are addressable, but bringing them down will require focused and organised action across four categories of intervention:

Category 1

Fast-track catalytic grid-scale projects that anchor early demand and generate bankable precedents, including projects serving premium buyers, e.g., data centres and electricity exports, and the first phase of the 100 GWp solar programme. This includes the quick wins discussed in Section 2.5, including projects that phase out diesel. These near-term projects can build deployment scale, reduce financing costs through improved procurement, set bankable precedents and unlock follow-on private capital.

Category 2

Remove barriers to rooftop solar by reforming the quota system that currently constrains distributed rooftop deployment. Faster rooftop uptake can scale capacity quickly and add to domestic module demand, helping reduce module and BoS costs for utility-scale projects as well.

Category 3

Policy support on key cost components, particularly to reduce land and grid-connection costs. A centralised land mechanism, pre-zoned renewable development areas and accelerated transmission expansion address the structural drivers of Indonesia's cost premium. These interventions benefit not only solar deployment but also other renewable generation technologies that face the same land and grid constraints.

Category 4

A phased local content strategy that brings module and BoS costs towards import parity in the near term while progressively moving Indonesian manufacturing up the value chain.

While these interventions focus on the 2025–2035 period covered by the modelling in this report, the solar cost-reduction trajectory does not end there. Global solar costs have fallen steeply over the past decade and are projected to continue declining, meaning Indonesia's solar generation costs could fall further beyond 2035.

Figure 34 | Interventions can bring down the cost of solar generation in Indonesia

Breakdown of Indonesia's versus India's solar LCOE today

\$c/kWh, grid-scale, favourable solar locations



Notes: 1. Survey results show 12-20 cents per Wp, with upper range representing locally manufactured prices, lower range represents import prices, excluding logistics. 2. BoS includes inverter, electrical components and mounting or floaters, if applicable. 3. EPC includes EPC services and civil works. Upper end of the range represents remote areas. 4. Based on average land price and additional land conversion cost across five major islands modelled in our study (Java, Sumatera, Kalimantan, Sulawesi and MPNT). Upper end of the range corresponds with Java, the lower end with Kalimantan. 5. The wider range is due to costs being dependent on connection type (e.g., subsea and overland) and distances to the transmission grid; assumed reliance on transmission lines with no new substations built.
Source: Expert input

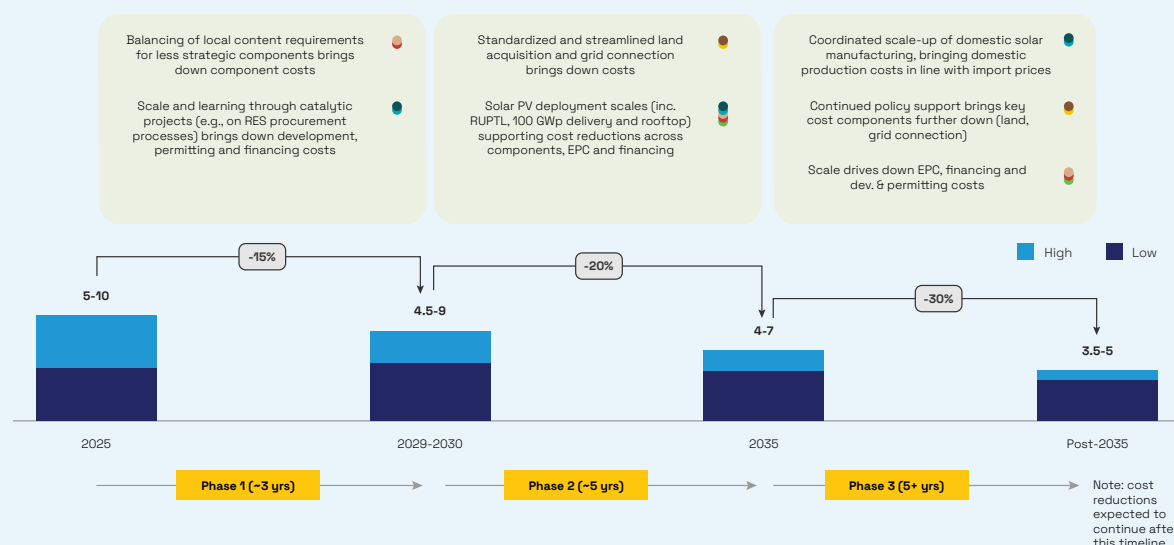
4 categories of interventions to bring down the cost of solar in Indonesia

Impact on LCOE component

Objective	Interventions	Timeline for impact on LCOE If implementation begins today
Intervention Categories		
1. Fast-tracking catalytic projects	- Unlock catalytic projects through two time-bound tracks: premium buyer projects (Singapore exports, data centres) and the first part of the 100 GWp programme (inc. de-dieselisation) - Allow for long-term export permits - Set up regular (e.g., annual) RES auction rounds, with clear bidding and contracting frameworks - Develop standard implementation for innovative RE procurement (e.g. PPA) - Relaxing LCR for catalytic projects	Short term (Before 2030)
2. Removing barriers to rooftop solar	Unlock scaling of rooftop solar across Indonesia - Reform solar quota system to enable easier deployment of larger volumes of rooftop solar and enable economies of scale	Short term (Before 2030)
3. Policy support on key cost components	Remove the structural cost and regulatory roadblocks behind Indonesia's cost gap with leading markets - Improve land acquisition process and support on land costs for utility-scale projects - Build out grid and improving access for utility-scale projects	Medium term (Before 2035)
4. Phased local content strategy	Move Indonesia's solar manufacturing progressively up the value chain without holding up near-term deployment and increasing component costs - Designing and implementing revised phased local content strategy for solar PV and other RES - Scaling up domestic manufacturing capacity and capability	Longer term (After 2035)

Indicative outcomes of the interventions on Indonesia's solar LCOE

\$c/kWh, grid-scale, average high-low across five modelled regions



6.1.1 Category 1: Fast-track catalytic grid-scale projects

Fast-tracking a catalytic wave of solar projects can create the demand pull and market precedent on which subsequent cost reductions depend. This report identifies two tracks of catalytic projects:

- **Track 1: Premium-buyer projects.** These are projects serving buyers willing to pay a premium and contract directly with IPPs at rates above PLN's current tariffs. The two most promising near-term routes are renewable electricity exports to Singapore and power supply for data centre developers with renewable energy commitments.
- **Track 2: Supporting the first phase of the 100 GWp solar programme,** planned for delivery in 2026–2027 as the quick-wins phase of the broader programme (see Section 2.5). This first wave combines rooftop solar deployment, projects to phase out diesel generators (e.g., with solar plus storage where the economics are already favourable), and utility-scale solar projects.

Four interventions can support the delivery of these catalytic projects, each targeting a specific driver of solar cost or project risk. Their effect on the solar LCOE is summarised in Figure 34.

- First, **unlocking electricity exports**, such as through long-term export permits for the planned export to Singapore. These projects are now moving forward and that momentum needs to be maintained. Scaling exports in line with the 100 GWp solar programme could support broader renewable deployment, creating access to premium export buyers for Track 1.
- Second, **developing standard implementation frameworks for innovative renewable procurement**, such as standardised PPAs and joint transmission utilisation arrangements, can reduce financing costs by establishing bankable precedent and reducing development risk for early projects. This should be done in step with the cost interventions outlined in Section 6.1.3. Together, they span the full project-development chain.
- Third, **Indonesia should move from one-off, single-project procurement to a regular, predictable renewable capacity auction calendar.** PLN's Giga One scheme¹⁴² is a step in the right direction. It bundles multiple projects into a single procurement round, giving the market a larger and clearer volume signal than project-by-project tendering. The task now is to make this cadence regular and predictable through an annual auction calendar with pre-announced volumes that ramp in line with the 100 GWp solar programme and the cost-reduction trajectory. Predictability can lower costs on three fronts: financing costs fall as lower development risk is priced in, supplier and EPC capacity can scale against the certainty of future demand and competition can drive tariffs down across successive

¹⁴² PLN has already begun moving in this direction. In 2026, it launched GIGA ONE, a new integrated procurement model that bundles 22 solar sites totalling 1.2 GW under the first tranche, Mentari Nusantara I, into a single consolidated tender rather than separate project-based tenders. This approach is intended to improve project bankability and streamline procurement through to construction. A second tranche, Mentari Nusantara II (1.1 GW), is planned for launch in the second half of 2026.

rounds. To ensure these gains are realised, bidding and contracting frameworks need to be clear and bankable. Post-award milestones should also be binding to keep projects moving from financial close through to commercial operation, preventing the stalls that sometimes follow tender wins in Indonesia. Storage should also be incorporated into the regular auction calendar through dedicated solar-plus-storage rounds, rather than added to projects on a case-by-case basis. Box J sets out why storage is critical to the build-out and the steps needed to scale it.

- Fourth, **balancing initial local content requirements for catalytic projects** can bring module and BoS costs towards import parity in the near term. Allowing imports of less strategic components can help keep early project costs competitive. At the same time, parts of the 100 GWp solar programme can provide a clear demand signal for domestic manufacturers as local capacity develops.

Together, these interventions should deliver visible cost reductions before 2030. Catalytic projects that access components at import parity can lower module and BoS costs, while unblocking export projects can reduce permitting and development costs. The resulting bankable precedents can then lower financing costs by reducing perceived project risk.

Together, these interventions should deliver visible cost reductions before 2030.

6.1.2 Category 2: Removing barriers to rooftop solar

Rooftop solar remains significantly underused in Indonesia despite its potential. As set out in Chapter 2, Indonesia had around 775 MW of rooftop solar capacity in 2025,¹⁴³ far behind regional peers such as Vietnam, where more than 9.5 GW has been deployed.¹⁴⁴ The constraint is not the availability of rooftop space or solar resources but the current quota-based permitting system, as introduced in Box C.

Three features of the current framework, set under MEMR Regulation 2/2024, hold deployment back. First, the cumulative 2024–2028 quota of 5.7 GW is very low, especially relative to the ambition level of the 100 GWp solar programme. Second, net metering was abolished under the same regulation, meaning customers can no longer offset electricity exported to the grid against their bills, weakening the economics of rooftop solar, particularly for residential users. Third, the biannual application windows can delay projects by up to six months if an application window is missed or the quota for a particular system has already been filled.

Two policy options could unlock greater rooftop solar deployment in Indonesia. The first is to significantly improve the existing framework. This includes raising annual quotas in line with the 100 GWp solar programme ambition and actual demand,

Two policy options could unlock greater rooftop solar deployment in Indonesia.

¹⁴³ PLN (2025), *PLN Presentation*.

¹⁴⁴ Earth Journalism Network (2026), *A Reporting Tipsheet on Renewable Energy in Vietnam*.

which exceeded available capacity by 40% in 2026.¹⁴⁵ Other options include restoring a form of net metering or compensation for exports,¹⁴⁶ publishing sub-system quota allocations transparently so developers can identify locations with available capacity¹⁴⁷ and replacing the biannual application windows with rolling applications. The second, more ambitious option is to **remove the quota requirement for systems below a defined size threshold**, such as residential and small commercial and industrial installations as well as installations combined with batteries. This would allow smaller, primarily self-consumption-based systems to proceed without prior PLN approval, while grid-impact assessments would be retained for larger installations that have clear engineering value. In both cases, stronger grid and storage planning would be essential to avoid system instability as rooftop deployment increases. One potential issue is reverse power flow, which can cause local voltage rise, particularly for installations that apply net metering.

Removing these barriers, while planning for grid and storage needs from the outset, could deliver two benefits. First, rooftop capacity can scale quickly because installations are small, modular and located on existing buildings, avoiding many of the land acquisition and grid connection challenges that have slowed utility-scale projects. Second, rooftop solar adds to domestic solar demand, which can drive reductions in the cost of modules and BoS through scale. Because these components are also used in rooftop and utility-scale projects, faster rooftop deployment can strengthen the demand base for domestic manufacturing under Category 4 and support the cost-reduction trajectory set out in Chapter 3.

6.1.3 Category 3: Policy support on key cost components

Removing the structural cost and regulatory roadblocks that account for much of the gap between Indonesia's solar generation costs and those in leading markets is critical to meeting the RUPTL renewable targets and delivering the 100 GWp solar programme. The interventions below target the two largest addressable cost premiums explained in Chapter 3, land acquisition and grid connection. These interventions can also benefit other renewable generation technologies, including geothermal and hydropower, which face many of the same structural constraints, and should deliver visible cost reductions before 2035.

Removing the structural cost and regulatory roadblocks that account for much of the gap

These interventions should be treated as consecutive stages of the same project-development chain, rather than standalone fixes. The chain culminates in the procurement and tendering process set out in Category 1. Pre-cleared sites, standardised land arrangements and grid access at the site boundary can allow projects to be tendered at lower cost and reach financial close more quickly.

¹⁴⁵ Bloomberg Technoz (2026), *Kuota PLTS Atap 2026 Sudah Habis, Bakal Ditambah 500 MW Lagi*.

¹⁴⁶ AESI and IESR (2023), *Joint Position Statement on the Proposed Revision of MEMR Regulation 26/2021*; IESR (2024), *MEMR Regulation No. 2/2024 Limits Public Participation to Support Energy Transition through Rooftop Solar PV*.

¹⁴⁷ IESR (2024), *Efforts to Encourage the Effectiveness of Rooftop Solar Quota Fulfillment*.

Land costs

Land acquisition and conversion are among the highest-impact areas for policy intervention on solar generation costs in Indonesia. They contribute directly to project costs and can also determine whether projects reach financial close at all.

Indonesia's land-access strategy for renewables should combine land-use planning and designation with faster permitting and financing and risk mitigation support.

India's experience shows the potential impact. State governments used powers under the Land Revenue Code to designate so-called wasteland, state-owned but unused land, as renewable energy development sites, avoiding the need for private land purchases and bypassing forest release requirements.

Stakeholder discussions identified four intervention options relevant to Indonesia's land constraints. They range from stronger state involvement to lighter regulatory facilitation and can be combined [Figure 35].

Implementation is not straightforward: key risks include social acceptance around land use, institutional capacity to aggregate land at scale and contestation over allocation.

Indonesia's land-access strategy for renewables should combine land-use planning and designation with faster permitting and financing and risk mitigation support.



Figure 35 | Intervention options to reduce land costs for renewables projects in Indonesia.**Four Intervention Options to Lower Land Costs for Renewables in Indonesia**

Intervention Option	Key Mechanism	Design Features	State Cost	Time to Impact
1. Direct state-led land bank The government brings down costs of land acquisition and conversion by securing land and leasing it to renewables developers	A dedicated state agency acts as a land bank, acquiring land at scale, holding title and leasing serviced plots to IPPs through long-term tenure, with control on lease fees.	A single agency holds land, financing and tendering authority. Land is acquired before renewable energy tenders, often with concessional finance, allowing developers to bid for plug-and-play sites with no land risk.	 High Direct acquisition + holding	 Long Substantial regulatory reform
2. State-aggregated re-designation zoning Government identifies priority areas and designates them for RES development, such as the newly introduced pre-approved Renewable Energy Zones.	Provincial or state governments identify existing public, degraded or non-agricultural land, undertake zoning and clearance and transfer serviced parcels to RES developers. This can be complemented by controls on land prices or lease fees.	Land is typically already state-owned or low-conflict (wasteland, salt pans or ex-mining). Central government supports detailed project report (DPR) preparation and grid infrastructure. The implementing agency aggregates land and auctions it to private developers at below-market prices.	 Med-High Zoning, clearance + DPR support	 Med-Long Some regulatory reform
3. Developer-led acquisition with state de-risking Government provides de-risking instruments (e.g., subsidies, financing and tax-exemption) to reduce the cost and risk of land acquisition.	Developers acquire land commercially, while a state vehicle partially finances upfront acquisition costs, covers biodiversity offsets and supports community benefit-sharing schemes to reduce social licence risk.	Land remains privately owned, while the state provides concessional finance for land assembly and offsets. Standardised landowner payment schemes reduce negotiation friction, while a statutory community benefit fund collects access fees from developers.	 Med Concessional finance + offsets	 Medium Setting up instruments
4. Permitting acceleration Government provides permitting support where land requires zoning release (e.g., forestry or agricultural land) and accelerates operational permitting.	Government designates priority renewable zones with fast-tracked permitting and master planning, while simplifying operational permits such as Environmental Impact Assessments (AMDAL) for solar PV projects. This shortens the project development cycle, since the AMDAL for solar PV should be less extensive than coal power plants.	Strategic zones are mapped in national power plans. Projects within these zones receive priority pricing, fast-tracked environmental approvals and grid-access guarantees. There is no additional fiscal expenditure on land; developers handle land acquisition.	 Low Regulatory only — no fiscal spending	 Short Designating zones

The first three options carry direct land acquisition or financing costs for the state. State-Aggregated Re-Designation (Option 2) and Permitting Acceleration (Option 4) are likely to be the most cost-efficient. Indonesia also has relevant institutional mechanisms already in place. The Ministry of Agrarian Affairs and Spatial Planning/National Land Agency (ATR/BPN) provides the institutional framework for the Detailed Spatial Plan (RDTR), which can support land-use designation. The existing legal framework allows sites to be prepared ahead of tender by confirming Other Use Area (APL) status, obtaining *Persetujuan Penggunaan Kawasan Hutan* (PPKH) under PP 23/2021 or completing Convertible Production Forest (HPK) release where required (e.g. unproductive HPK and in provinces with over 30 percent of forest cover). This process could help unlock around 10,000–25,000 hectares of potentially available land identified through ATR/BPN as of the writing of this report.¹⁴⁸

The next step is to consolidate a national catalogue of pre-cleared, auction-ready sites. The catalogue should also standardise how land enters auction. Today, land identification and acquisition vary from tender to tender, adding time and cost. A common template for due diligence, zoning status and lease or acquisition terms would allow each auction round to draw from ready parcels on consistent terms. In Indonesia, the catalogue could bring together sites with confirmed APL status, PPKH issuance or completed HPK release ahead of tender.

BOX 1 | Unlocking new land for solar: AgriPV and former mine sites could ease Indonesia's land constraint

Two approaches offer promising options to unlock new land areas for solar without having to compete for scarce greenfield land: AgriPV and mine site repurposing. AgriPV is the concept of co-locating solar panels and agricultural production on the same land. In Indonesia, it could significantly expand the area available for solar without taking land out of food production, although the scale of the opportunity still needs to be validated. In India, around 30% of cropland, or 47.5 million hectares, is found to be technically suitable for AgriPV. In a high-potential scenario, that land alone could generate more than twice India's projected electricity demand in 2050.¹⁴⁹ Indonesia may also have significant potential, given that agricultural land accounted for 29% of its total land area in 2023.¹⁵⁰ However, the scale of the opportunity needs to be assessed under Indonesia's own crop, climate and terrain conditions, particularly given its more mountainous landscape compared with the largely flat cropland assessed in the India study.

¹⁴⁹ ETC (2026), *Unlocking Solar at Scale*.

¹⁵⁰ World Bank (2023), *Agricultural Land (% of Land Area) – Indonesia*.

¹⁴⁸ This estimation is based on stakeholder input.

Repurposing mines sites is another viable route to free up land for solar. Studies suggest that retiring Indonesian coal mines could support up to 60 GW of solar capacity, with more than 100,000 hectares of coal-mining land potentially available for conversion to solar PV.¹⁵¹ This approach is already being implemented elsewhere. China currently leads the way with 90 operational coal mine-to-solar projects, with 14 GW delivered and a further 9 GW in planning. In Indonesia, around 430 MW is currently in the pipeline through cooperation between Pertamina New & Renewable Energy and PT Bukit Asam across Ombilin, Tanjung Enim and Bantuas.^{152,153}

Former mine sites can offer several advantages over greenfield locations, including clearer land ownership, proximity to substations and other power infrastructure and, in some cases, existing grid connections or electricity-supply arrangements with power export licenses. However, difficult terrain and rehabilitation requirements may increase development costs.

Repurposing former mines and expanding AgriPV could therefore help ease land constraints on solar development in Indonesia, but both would require appropriate regulatory frameworks and new ways of working. For AgriPV, this includes dual-use land classification, crop-specific standards and pilot programmes that safeguard agricultural production. The framework should also enable farmers to benefit from lower energy costs or electricity sales, supported by reliable PPAs and adequate local grid capacity. For former mine sites, renewable repurposing should be incorporated into mine-closure and rehabilitation plans, with clear post-mining land ownership, streamlined permitting and early coordination on grid access.

151 World Bank (2026), *Spatial Analysis of Coal Mining Lands for Renewable Energy Repurposing in Southeast Asia*.

152 PT Bukit Asam (2026), *PTBA dan PNRE Jajaki Pengembangan PLTS di Lahan Pascatambang*.

153 Global Energy Monitor (2025), *Bright Side of the Mine*.

Grid connection and transmission costs

Grid connection and transmission costs are a major component of the delivered cost of renewable electricity. They can be lowered through two main interventions. First, developers currently bear the cost of connecting their projects to the transmission grid, which increases with distance. As the grid expands closer to generation sites, connection distances and developer costs fall. Second, reducing the regulated tariff for using the grid can lower the wheeling cost included in the delivered electricity price. Both approaches depend on transmission expansion, which is costly and complex given Indonesia's distances and geography.

International experience shows land and transmission interventions to scale renewables are well precedented (see Appendix I). Across markets, deployment has accelerated and tariffs have fallen sharply where a single empowered entity has aggregated land, coordinated transmission and structured procurement. India's solar park scheme achieved record-low tariffs by combining pre-cleared land with shared transmission at the edge of designated parks, resolving land and

grid constraints before projects were tendered. South Africa's Renewable Energy Independent Power Producer Procurement Programme (REIPPPP) mobilised more than US\$17 billion in private investment through a similar model of coordinated state facilitation. Appendix I sets out case studies from India, Australia, South Africa, Vietnam and Morocco.

Figure 36 | Intervention options to reduce transmission costs for renewable projects in Indonesia.

Two Design Choices And Interventions To Lower The Costs Of Using The Grid In Indonesia

Intervention Option	Key Mechanism	Design Features	Cost Borne By
Who pays for grid use?			
Full cost socialisation "All ratepayers Pay"; all costs for building/upgrading transmission lines are charged across the full consumer base	Transmission infrastructure for renewables is built by the state or regulated utility, and the entire cost is recovered through a uniform tariff levied across all grid users, similar to PLN's existing Biaya Pokok Produksi (BPP, or Cost of Generation).	Regulator authorises the build before generation is committed, breaking the chicken-and-egg dynamic. Transmission costs are spread over millions of consumers, making per-customer impact small; generators face zero transmission capex, improving project IRRs.	ALL RATEPAYERS Uniform tariff on every grid user via PLN, as with the current BPP mechanism.

How are transmission projects financed and structured?

Transmission acceleration fund Transmission projects are accelerated via a state-led fund/facility, involving low-rate financing/instruments from development finance institutions or government bonds.	A (state-owned) green bank or Development Finance Institution (DFI) provides concessional debt to transmission builders (state-owned or private), lowering the financing-cost component of the line and the regulated tariff that recovers it.	Concessional finance is provided at sub-commercial rates and longer tenors than markets offer, often paired with grants for early works. The transmission asset remains regulated and revenue-determined; subsidy is purely on the cost of capital. Mechanism can be paired with competitive procurement of the transmission build.	STATE / DFIS Concessional public finance subsidises the cost of capital not the asset.
Deep-vs-shallow connection split Transmission lines are split between deep (transmission backbone or interconnection) and shallow (connecting backbone to nearest step-down transformers). Both have different investors and entities in charge of the end-to-end building out process.	A pre-defined and regulated boundary divides transmission costs: defined entities (e.g., developers, PLN) fund only the line and substation upgrades from their generation site to the nearest existing grid node ("shallow" connections), while another entity (e.g., INA or Danantara) funds all reinforcement of the backbone ("deep" connections).	The shallow/deep boundary is regulator-defined and binding; CAPEX and focus of responsible organisations improve versus current full-connection responsibility. A deep-vs-shallow investment split between Danantara (new sovereign wealth fund) and PLN could allow for burden sharing. Danantara could lease back the infrastructure to PLN for operational control of the asset.	SHARED Danantara funds backbone (deep); developers and PLN fund site-to-node lines (shallow).

Note: 1. BPP = Biaya Pokok Produksi (Cost of Generation). 2. DFI = Development Finance Institutions

For Indonesia, several intervention models could bring down transmission costs, with the cost allocated differently between developers, the state and ratepayers [Figure 36]. Learning from global experience, one option is a deep-versus-shallow investment split between Danantara, the sovereign wealth fund, and PLN, which could share the transmission investment burden currently carried largely by PLN. This could be combined with a lease-back model, under which Danantara leases the assets to PLN for operation. This would allow PLN to retain control of the grid while reducing its investment burden.

These interventions should form one delivery chain, moving from pre-development site identification and land pre-clearance and standardisation, through grid access, and finally into the regular auction calendar under Category 1. Indonesia's renewable energy processes are

currently spread across MEMR, the Ministry of Environment (MoE), ATR/BPN, PLN and the Ministry of Investment and Downstream Industry/Investment Coordinating Board (BKPM), with no single entity holding integrated authority. A state-owned enterprise (SOE) with a real-estate or land-banking mandate could play this coordinating role for the power sector. Danantara could play a similar role for key parts of transmission deployment, e.g., backbone infrastructure and inter-island connectors.

Scaling storage can also reduce the amount of transmission investment required. By shifting solar output away from congested periods, batteries can relieve transmission and distribution constraints and improve utilisation of existing lines, deferring or avoiding some grid reinforcement while maintaining reliability. Storage is a complement to the transmission interventions above, not a substitute. It can reduce near-term investment at specific congestion points, but lowering wheeling costs still depends on the transmission-financing models outlined in this section. Box J sets out why storage is critical to Indonesia's build-out and the steps needed to scale it.

BOX J | Unlocking utility-scale storage as a system asset

Storage is integral to the renewable build-out modelled in this report. In the Least-Cost pathway, around 17 GW of storage capacity is added by 2035, including 13 GW of BESS and 3 GW of PHS, alongside 65 GW of solar capacity. This allows daytime solar generation to be shifted to the evening peak and helps firm the system without adding new coal-fired or gas-fired capacity (see Chapter 4). Two barriers currently limit utility-scale storage in Indonesia. First, solar plus storage remains expensive relative to existing coal-fired generation. Second, Indonesia lacks a regulatory framework that allows storage to capture its full value. Both need to be addressed for storage to scale alongside the 100 GWp solar programme.

The cost gap is significant but could narrow. With four-hour storage, solar plus batteries delivers power at around 15 US cents per kWh, compared with around 3.5 US cents per kWh for existing DMO coal (see Chapter 2). Three factors could bring the cost of solar plus batteries down:

- Global battery system costs have fallen by around 16% per year since 2010 and continue to decline (see Chapter 3)
- Interventions to reduce solar LCOE outlined in Chapter 3 would ultimately lower the combined cost of solar plus storage.
- The interventions that reduce solar project costs can also benefit co-located storage, which shares the same site and grid connection. Lower land-acquisition and grid-connection costs, more competitive and predictable procurement and an updated local content strategy can all reduce the combined cost.

Lower costs are necessary but not sufficient. Storage will not scale until the regulatory framework is updated to recognise its value. Three gaps stand out:

- Existing regulation has yet to recognise storage. MEMR Regulation 19/2025 recognises batteries within hybrid power plants, but only below 10 MW, while the tariff decree is still being finalised. This leaves no clear commercial framework for standalone or co-located utility-scale storage.^{154,155}
- The ancillary-services market is not established and, in most regions, batteries are not recognised by grid codes, so batteries cannot be paid for the frequency response, reserves, and peaking capacity they provide, and depend on bilateral deals with PLN¹⁵⁶.
- No dedicated procurement route is available. Operational utility-scale storage is currently limited to one flagship project in Indonesia's new capital (IKN), the 50 MW/14.2 MWh IKN Solar PV Plant, alongside small pilots. The flagship project was directly assigned rather than competitively tendered.¹⁵⁷

To drive storage scaling, government could take three steps: i) define storage as a distinct system asset and extend the hybrid-plant tariff rules beyond the current scope of projects below 10 MW to utility-scale standalone and co-located batteries; ii) create a revenue route for system services, starting with a capacity or availability payment and a basic ancillary-services mechanism and (iii) incorporate storage into PLN's GIGA ONE auction calendar through dedicated solar-plus-storage rounds, which PLN has indicated will follow its first 1,225 MW solar tender.¹⁵⁸

154 ECADIN (2026), *MEMR Regulation No. 19 of 2025 and the Role of Hybrid Power Plants in Indonesia's Energy Transition*.

155 ESS News (2026), *Indonesia to Announce New Government Regulation to Encourage BESS, Hydrogen in Remote Locations*.

156 Wibowo et al. (2026), *Comparative Analysis of Grid Code Recognition of Energy Storage in Southeast Asian Single-Buyer Electricity Systems*.

157 Energy-Storage.News (2025), *Sembcorp Launches Indonesia Solar-Plus-BESS Project with State-Owned Power Company PLN*.

158 pv magazine (2026), *Indonesia Tenders 1.2 GW of Solar*.

6.1.4 Category 4: Phased local content strategy to balance domestic manufacturing with cost competitiveness

A phased local content strategy can help Indonesia move solar manufacturing further up the value chain without increasing near-term deployment costs. The core policy mechanism is a time-bound local content requirement, under which temporary access to lower-cost imported components can be linked to binding commitments to establish domestic capacity at the next stage of the value chain. This should be phased along with the 100 GWp deployment trajectory so that domestic manufacturing scales alongside the build-out. In practice, requirements could progress upstream, from cells to wafers and then ingots, with each stage taking effect only when domestic producers can supply the required volumes at costs close to import parity. Each

step should also be announced well in advance, giving manufacturers a clear demand signal for investment.

Indonesia already has a precedent for this approach. MEMR Regulation 11/2024 allows imported modules for a defined period, but only from manufacturers committed to establishing domestic module production by the end of 2025. The mechanism offers short-term cost relief for longer-term domestic capacity development. A similar mechanism could be replicated for cells, wafers and ingots.

Indonesia can draw on India's experience (see Box K), which provides a clear success story for progressive upstream integration. India progressively moved local content requirements upstream, from modules in 2021 to cells in 2026 and then wafers and ingots from 2028. Each extension was announced years in advance, taking effect only once sufficient domestic capacity was in place. Indonesia's starting point, however, is more advanced than India's was at a comparable stage. Indonesia already has an investment-linked import framework under MEMR Regulation 11/2024 and substantial downstream capacity in place, at around 10.6 GW of module and 9.5 GW of cell assembly, although much of this capacity is underused because domestic demand remains low.¹⁵⁹ The near-term task is therefore less about building assembly capacity from scratch, as India did, and more about using the 100 GWp build-out to absorb this idle capacity before extending the local content requirement to upstream stages Indonesia still lacks: wafers, ingots and polysilicon. With the 100 GWp commitment approaching, the timing is right to review the local content requirement so that the programme can help reshape Indonesia's clean-technology manufacturing landscape.

BOX K | India's domestic solar manufacturing strategy

India's solar manufacturing strategy followed a clear principle: use imported components initially to scale demand, then progressively move domestic production requirements upstream, moving from final assembly backwards toward raw materials. At each stage, domestic requirements were introduced only once domestic capacity was sufficient to supply the market without driving costs up significantly.

India initially allowed unrestricted module imports to scale deployment through competitive auctions. Once the market had expanded, it introduced the ALMM framework, requiring domestically assembled modules in government-backed projects from 2021. This was supported by the Production Linked Incentive scheme, which provided around US\$2.8 billion in output-linked subsidies to manufacturers.¹⁶⁰ Module manufacturing capacity

160 IEEFA and JMK Research (2025) Assessing the effectiveness of India's solar Production Linked Incentive scheme

159 SR (2025), *Indonesia Must Seriously Develop an Integrated Solar Industry*.

grew from 8 GW in 2021 to more than 120 GW by mid-2025.¹⁶¹ The requirement was then extended one step upstream. Domestically manufactured cells became mandatory for eligible projects from June 2026, by which point domestic cell capacity had reached 29 GW.¹⁶² A further requirement covering wafers is scheduled from 2028, subject to at least three independent manufacturers with a combined capacity of 15 GW being operational.¹⁶³

The lesson for Indonesia is not to replicate India's sequence exactly, but to apply the same principle: let incentives lead mandates, move requirements up the value chain step by step and avoid introducing local content requirements faster than competitive domestic capacity can absorb it.

161 CEEW (2025), *Unlocking Solar Manufacturing Potential with Solar PV Modules*.

162 IEEFA and JMK Research (2025), *Assessing the Effectiveness of India's Solar Production Linked Incentive Scheme*.

163 SolarQuarter (2026), *MNRE Expands ALMM Framework to Include Solar Wafers, Strengthening Domestic Supply Chain*.

6.2 Supporting demand-side electrification

As set out in Chapter 2, electrification delivers substantial benefits beyond decarbonisation. It reduces dependence on oil and gas imports, lowers long-term energy costs for industry and consumers and strengthens export competitiveness. For most sectors, electrified alternatives become the lower cost option once their efficiency advantage outweighs any price gap between electricity and the fuel they replace (see Chapter 1). Falling electricity prices bring this crossover forward.¹⁶⁴ The crossover comes soonest where the displaced fuel is expensive, like in the case of industrial heat using imported oil, and latest where fossil fuels remain cheap, like in the case of DMO coal. This is why rebalancing incentives and bringing down solar costs can both accelerate electrification.

Scaling renewable supply and electrifying demand reinforce each other. Higher electricity demand spreads grid and generation CAPEX over a larger volume of consumption and reduces the risk of temporary overcapacity, supporting greater scale and further cost reductions in renewables. In turn, lower-cost renewables can reduce electricity prices and accelerate the crossover for electrified solutions.

Realising these benefits requires policy action across the two segments where electrification has the biggest near-term impact: transport and industry. The remainder of this section sets out the policy interventions needed in each.

164 Michael Libreich (2026), *The Electrification Staircase*

Transport. Indonesia's transport electrification has progressed unevenly across vehicle segments, while the direction of incentives has become increasingly unclear. Three segments require distinct policy responses:

- Passenger EVs.** Indonesia's passenger EV uptake was on a strong trajectory until recent policy shifts. EVs' share of new car sales rose from around 1% in 2023 to around 15% in 2025,^{165,166} driven by rapid global cost reductions and a coherent national incentive package combining import duty exemptions, luxury tax waivers and reduced value-added tax (VAT) for fully assembled EVs. This framework gave consumers, manufacturers and investors a clear signal, putting the EV market on the track for a step expansion from 2026 onwards. The incentive landscape has since become more volatile. Import incentives for fully assembled EVs expired at the end of 2025 and were not renewed, while in April 2026 the government withdrew nationwide EV tax breaks and transferred authority over vehicle tax rates to regional governments.¹⁶⁷ It has since begun reintroducing national support on a new basis, with a phased VAT and luxury-tax package rolled out from mid-2026, restricted to battery EVs and weighted towards locally assembled, nickel-battery models.¹⁶⁸ While this is the right direction, the terms have changed repeatedly, rollout has been delayed and regional discretion continues to fragment the market. **The priority is to settle a stable, nationally coherent EV incentive framework and hold it in place long enough to rebuild investor and consumer confidence.**
- E2Ws.** While Indonesia is the largest two-wheeler market in Southeast Asia, E2Ws account for only 0.7% of its total two-wheeler stock and 1.3% of sales in 2025, despite having a lower total cost of ownership than ICE two-wheelers (see Chapter 1).¹⁶⁹ Policy support has followed a stop-start pattern. A national subsidy of Rp7 million per unit launched in 2023 was hampered by a complex application process and ended abruptly in late 2024.¹⁷⁰ Replacement schemes promised for 2025 never materialised and sales fell by around 80% that year. A smaller subsidy of Rp5 million per unit, covering an initial 100,000 units, is being introduced in 2026, but its launch has been repeatedly delayed, and the implementing regulation was still pending in mid-2026.¹⁷¹ **The priority is to introduce a stable, targeted and long-term E2W scheme** rather than year-by-year subsidies subject to political cycles, with two specific levers:

¹⁶⁵ IEA (2026), *Global EV Outlook 2026*.

¹⁶⁶ A. A. Huda, R. Bridle and A. Suharsono (2025), *Indonesian Electric Vehicle Boom: A Temporary Trend or a Long-Term Vision?*

¹⁶⁷ Until the end of 2025, imported completely built-up EVs benefited from import duty exemptions, luxury tax waivers and reduced VAT. From January 2026, these incentives apply only to locally assembled EVs meeting an LCR of at least 40%, which remain eligible for a 1% VAT rate. The LCR threshold rises to 60% by 2029 and 80% by 2030.

¹⁶⁸ In April 2026, the Government of Indonesia withdrew nationwide EV tax breaks and transferred authority over vehicle tax rates to regional governments (Eco-Business, 2026; ANTARA, 2026). From mid-2026, it began reintroducing national support on a different basis, including government-borne VAT support of 40–100% for electric cars, a 100% luxury tax waiver and a direct subsidy of Rp5 million per electric motorcycle. The motorcycle subsidy initially covered around 200,000 units and was later expanded. Support is restricted to battery EVs and weighted towards models using nickel-based batteries and assembled locally, with final terms still being confirmed in mid-2026 (Indonesia Business Post, 2026; ANTARA, 2026).

¹⁶⁹ IEA (2026), *Global EV Outlook 2026*.

¹⁷⁰ A. A. Hermawan (2025), *Time to Ride, Indonesia Electric Motorcycle Diaries*.

¹⁷¹ ANTARA (2026), *Indonesia's Rp5M E-Motorcycle Incentive Awaits Finance Regulation*.

First, **structured financing support** to address upfront costs and secondary-market barriers, despite favourable total cost of ownership. China's 2025 national consumer trade-in programme provides a working template at scale. Its e-bike component committed RMB1 billion, approximately US\$140 million, in trade-in subsidies, reaching 1.65 million consumers and supporting 1.66 million new electric scooter purchases within months, with subsidies applied directly at the point of sale.¹⁷² Indonesia could adapt this approach through dedicated E2W financing windows, alongside a de-risking facility for Indonesian financiers that assign little or no value to E2Ws at end of life.

Indonesia could adapt this approach through dedicated E2W financing windows, alongside a de-risking facility for Indonesian financiers that assign little or no value to E2Ws at end of life.

Second, **targeted incentives for fleet operators**. Gojek, Grab and delivery platforms have high daily mileage, making the cost-of-ownership case for electric vehicles particularly strong at fleet level.¹⁷³ Fleet conversion can reach scale several years ahead of private adoption, providing a stable demand anchor for the domestic E2W manufacturing sector.

- Trucks and heavy-duty vehicles. Electrification of heavy-duty transport is still at an early stage, but deployment is beginning to grow in mining and remote operations as the cost advantage becomes clearer. Vale Indonesia signed a strategic cooperation agreement to deploy more electric trucks in April 2026, following a trial of all-electric mining trucks at its Sulawesi nickel sites that reportedly reduced energy costs by over 50%.¹⁷⁴ Indika Energy's Kideco coal mine in East Kalimantan began EV dump-truck trials in September 2024 with Sany,¹⁷⁵ and mining contractor Saptaindra Sejati received 15 heavy-duty electric trucks in May 2026 following successful trials in tropical mining conditions.¹⁷⁶ The priority is to scale these early deployments by focusing on off-grid and remote mining operations where high diesel costs make the economics most favourable. Indonesian retail diesel prices reached Rp26,000 per litre (around US\$1.47 per litre) in May 2026, the highest on record.¹⁷⁷ This creates a substantive operating-cost gap with electric alternatives. Policy levers to accelerate deployment include accelerated permitting for mining operators piloting electric fleets and dedicated concessional finance for the upfront capital premium.

¹⁷² Mordor Intelligence (2025), *China E-Scooter Market Size, Share & 2030 Trends Report*.

¹⁷³ IESR (2023), *Indonesia Electric Vehicle Outlook 2023*.

¹⁷⁴ International Mining (2026), *Boonray Signs Cooperation Deal with Vale Indonesia Following Successful Electric Mining Truck Trial. Trial Numbers May Not Represent Actual Full Deployment of Electric Mining Trucks*.

¹⁷⁵ Indika Energy (2025), *Eco-Innovation in Mining: EV Dump Truck Trials at Kideco*.

¹⁷⁶ Electrify (2026), *Indonesia: Sany Delivers 15 Electric Trucks to Saptaindra Sejati*.

¹⁷⁷ GlobalPetrolPrices.com (2026), *Indonesia Diesel Prices, 18-May-2026*.

Across all three segments, charging infrastructure remains a critical enabler. Expanding charging and battery-swap networks beyond Java through dedicated public funding for intercity corridors, while establishing interoperability standards to prevent network fragmentation, is essential to sustain the deployment trajectory in each vehicle category.

Across all three segments, charging infrastructure remains a critical enabler.

Industry. The cross-cutting incentive rebalancing set out earlier, i.e. phasing down the DMO, HGBT and other fossil-fuel supports and including captive coal in the emissions trading system, would go a long way in incentivising industries to switch from fossil fuels to electricity. CAPEX support and concessional finance for shifting from fuel-based to electricity-based processes can further accelerate the transition. This would reinforce the renewable build-out in two ways: industrial electrification creates the catalytic on-grid demand needed to absorb additional renewable supply at scale, while on-site solar and storage at industrial sites can support distributed renewable deployment to complement utility-scale capacity. These measures can be targeted at industries where the economics of electrification are strongest today, i.e. textiles, food and beverage, glass and ceramics, so that public capital supports both end-use decarbonisation and renewable deployment.

Appendix I:

The land and grid interventions set out in Section 6.1.3 have clear international precedents. The table below summarises how government and quasi-government entities across several markets have used land acquisition, pre-zoning and shared transmission mechanisms to unlock renewable deployment and the outcomes achieved. These cases informed the intervention options proposed for Indonesia. They illustrate what integrated state coordination can deliver rather than serving as direct templates, as each reflects its own regulatory and market context.

Country	Vehicle / Programme	Land Intervention	Transmission Intervention	Key Outcome
India	MNRE Solar Park Scheme + SECI (since 2014)	State governments identify and pre-acquire contiguous “wasteland”; CFA of up to Rs20 lakh/MW or 30% of project cost ¹⁷⁹	State Transmission Utility builds shared evacuation infrastructure before park development; CFA covers grid-connectivity cost ¹⁷⁹	50 parks, ~38 GW sanctioned; 5 acres/MW model standardised; tariffs hit historic lows (Rs2.44/kWh, Bhadla) ^{178,179}
Australia (NSW)	EnergyCo + Rewiring the Nation + REZ framework	EnergyCo budget includes Commonwealth concessional finance’s AU\$490 million for land acquisition and biodiversity offsets in Central-West Orana REZ ¹⁸⁰	AU\$2.1 billion Transmission Acceleration Facility for 2025–2026; ¹⁸¹ AU\$750 million from federal CEFC for CWO REZ transmission ¹⁸²	First REZ plan was state-approved in 2024; 4.5 GW network capacity by 2028; 35-year concession awarded to the ACERES consortium ¹⁸³
South Africa	REIPPPP + IPP Office (DBSA-hosted)	Developer-led but with state coordination; deep-versus-shallow connection cost split ¹⁸⁴	Eskom bears deep connection costs for transmission strengthening; IPP only pays shallow costs for connection to the nearest substation	R209.7 billion (~US\$12–20 billion, depending on exchange rate) in private investment; ¹⁸⁵ 6.4 GW awarded to 112 IPPs; tariffs fell 70% across bid windows ¹⁸⁵

178 MNRE (2025), *Development of Solar Parks and Ultra Mega Solar Power Projects*.

179 PBI Delhi (2023), *50 Solar Parks of Nearly 37.5 GW Sanctioned Since 2014; Capacity of 10.2 GW Established: Union Power and New & Renewable Energy Minister*.

180 Australia Energy Regulator (2025), *CWO REZ Network Project - Remade Revenue Determination - Summary Report*.

181 NSW Government (2023), *Further \$1.8 Billion to Power NSW to a Clean Energy Future*.

182 CEFC (2025), *CEFC Commits \$750 Million to Development of Landmark NSW Energy Transformation Project*.

183 Ministry for Energy and Climate Change, NSW Government (2025), *Deal is Sealed for Australia’s First Renewable Energy Zone*.

184 Eberhard, Kolker and Leigland (2014), *South Africa’s REIPPPP: Success Factors and Lessons*, PPIAF/World Bank; Eberhard, Kolker & Leigland (2014)

185 Global Infrastructure Hub (2021), *South Africa’s Renewable Energy IPP Case Study*.

Country	Vehicle / Programme	Land Intervention	Transmission Intervention	Key Outcome
Vietnam	DPPA Decree 57/2025 + EVN + PDP8	No state land aggregation, but PDP8 designates capacity per region with priority approvals ¹⁸⁹	Two tracks: EVN-grid wheeling or fully-private transmission lines (regional first) ^{186,187}	US\$18 billion in transmission CAPEX for PDP8; ¹⁸⁸ private capital can bypass state-grid bottlenecks
Morocco	MASEN, a state agency, 2010	MASEN directly acquires land at scale (3,043 hectares for Noor Ouarzazate) and leases to IPPs ¹⁸⁹	A tripartite agreement between the government-MASEN-ONEE defines transmission terms before tender; an existing 225kV line is leveraged ¹⁹⁰	~US\$2.3 billion for Noor complex; world's largest CSP; first project enabled by a single-window state agency

186 Venture North Law (2025), *Vietnam Refines the Framework for Direct Power Purchase Agreement with Decree 57/2025*.

187 Arcus Energy (2025), *Vietnam's Direct Power Purchase Agreement Framework, in Force Since 3 March 2025*.

188 Vietnam International Law Firm (2025), *Vietnam's Revised PDP-8: A Strategic Path for National Electricity Development*.

189 African Development Bank Group (2025), *Summary Environmental and Social Impact Assessment (ESIA) for Ouarzazate Solar Power Station Project II*.

190 Power Technology (n/a), *Noor Ouarzazate Solar Complex - Project Webpage*.

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