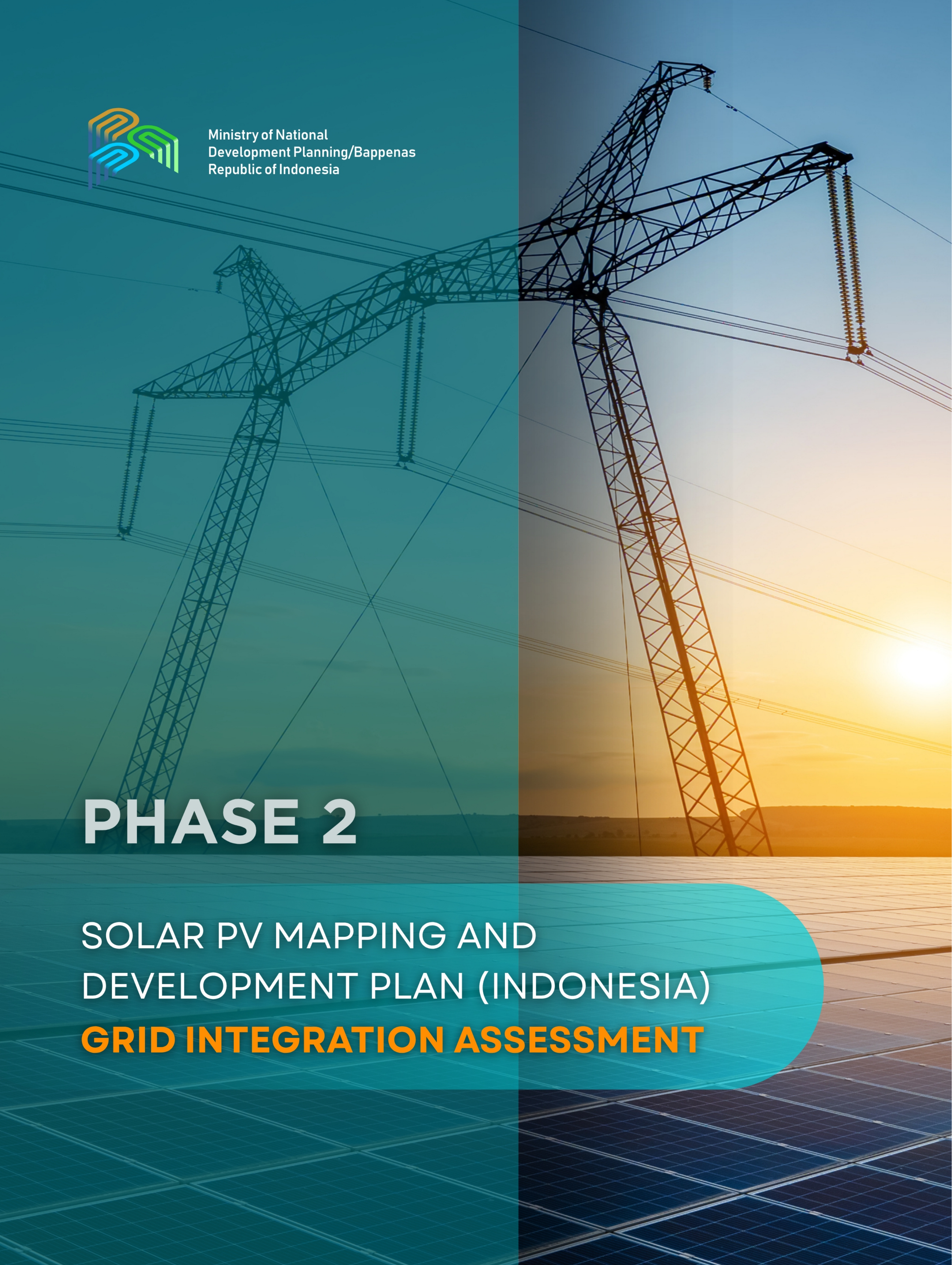

Ministry of National
Development Planning/Bappenas
Republic of Indonesia

PHASE 2

SOLAR PV MAPPING AND DEVELOPMENT PLAN (INDONESIA)

GRID INTEGRATION ASSESSMENT

October 2024

ENERGY
TRANSITION
PARTNERSHIP

UNOPS

1 GW SOLAR MAPPING AND DEVELOPMENT PLAN (INDONESIA)

Deliverable 3. Grid Integration Assessment

Prepared by:

tta

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Project: 1 GW SOLAR MAPPING AND DEVELOPMENT PLAN (INDONESIA)	Client: United Nations Office for Project Services, UNOPS
Consultant: Trama Tecnoambiental, S.L. (TTA), in collaboration with PT Inovasi Dinamika Pratama (Inovasi), Solargis, Environmental Resources Management (ERM) and PT Quadran Solusi Enjinering (Quadran)	
Financed by: UNOPS	PRESENTATION This report contains the deliverable #3 of the project. The authors of this report are Maryam Karimah (TTA), Solene Gondrexon (TTA), Roger Sallent (TTA), Justinus Alwie C (Quadran), Andre Susanto (Inovasi), Arryati Ramadhani (ERM), Juraj Betak (Solargis) and Martin Opatovsky (Solargis).

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GLOSSARY

Acronym	Definition
BAPPENAS	Ministry of National Development Planning
BOT	Built Operate Transfer
BOO	Built Own Operate
CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
CFPP	Coal-Fired Power Plants
C&I	Commercial and Industrial
DAK	Dana Alokasi Khusus (Special Allocation Budget)
DMO	Domestic Market Obligation
DRUPTL	The National Electricity Supply Business Plan Draft
ED	Economic Dispatch
E&S	Environmental and Social
ETP	Energy Transition Partnership
GE	Gas Engine
GHG	Greenhouse Gas
GHI	Global Horizontal Irradiance
GI	Gardu Induk (Substation)
GJ	Giga-Joule
GIS	Geographical Information System
GW	Gigawatt
GWh	Gigawatt-hour
HBA	Harga Batubara Acuan
Hz	Hertz
IBT	Inter-Bus Transformer
IFC	International Financial
IRR	Internal Rate Return
JRC	Joint Research Centre
kA	Kilo Ampere
kCal	Kilo Calory
kg	Kilo Gram
kV	Kilo Volt
kWh	Kilowatt-hour
kWp	Kilowatt-peak (installed power)

Acronym	Definition
JAMALI	Java, Madura, Bali
JMB	Java Madura Bali
LCOE	The Levelized Cost of Electricity
LNG	Liquefied Natural Gas
MCDM	Multi-Criteria Decision Matrix
MEMR	Ministry of Energy and Mineral Resource
MMBtu	Millions of British Thermal Units
MW	Megawatt
OCGT	Open Cycle Gas Turbines
O&M	Operation and Maintenance
OPEX	Operational Expenditure
Perpres	Peraturan Presiden (Presidential Decree)
PLN	National Electricity Company
PLTU	Pembangkit Listrik Tenaga Uap (Coal-Fired Power Plant)
PPA	Power Purchase Agreements
PSs	Performance Standards
PV	Photovoltaic
PVOUT	PV power production (Output)
RE	Renewable Energy
Rp	Rupiah (Indonesian Rupiah)
RUKN	Draft National Electricity General Plan
RUPTL	The National Electricity Supply Business Plan
SDG	Social Development Goals
TOP	Take Or Pay
TML	Thermal Minimum Loading
TWG	Technical Working Group
TWh	Terawatt-hour
UC	Unit Commitments
USD	United State Dollar
VRE	Variable Renewable Energy

1. EXECUTIVE SUMMARY

The Southeast Asia Energy Transition Partnership (ETP), hosted by the United Nations Office for Project Services, is driving renewable energy initiatives in Southeast Asia to accelerate the transition from fossil fuels to cleaner energy sources. In collaboration with Indonesia's Ministry of National Development Planning (BAPPENAS), ETP is advancing solar photovoltaic (PV) technology to help the nation meet its renewable energy targets and achieve net-zero emissions by 2060.

Despite Indonesia's vast potential for solar PV, the deployment is still minimal; only around 1 GW of solar power plants had been installed by 2024. ETP's 1 GW Solar Mapping and Development Project addresses these challenges by providing technical expertise to key stakeholders, including BAPPENAS, Ministry of Energy and Mineral Resources (MEMR), and State Electricity Company (*Perusahaan Listrik Negara*/PLN), to facilitate investments in large-scale solar PV projects.

This report, the third deliverable of the project, evaluates the technical and economic feasibility of integrating additional solar PV into the JAMALI grid in addition to the one planned in RUPTL. Furthermore, as continuation from the previous report, the analysis in this report includes a hosting capacity study and grid impact assessment, focusing on grid stability on the prioritized sites. Key findings include:

1. **Technical Feasibility:**
   - The JAMALI grid can absorb an additional 2.2 GW of solar PV by 2030 without significant battery storage requirements.
   - Larger substations (150 kV) offer better integration potential compared to smaller (70 kV) substations, but targeted grid upgrades may be needed in certain areas to maintain long-term stability.
2. **Economic and Environmental Impact:**
   - Integrating solar PV reduces fossil fuel reliance, with coal-based generation decreasing by 0.9% and gas generation by 1.2% by 2030. This shift increases the renewable energy mix from 4.6% to 5.9%.
   - Emissions are reduced by an average of 0.93 million tons of CO2 annually, underscoring the environmental benefits of solar PV integration.
   - While initial costs raise the Levelized Cost of Electricity (LCOE), the long-term economic benefits are clear. By replacing higher-tariff gas generation with 1.66 GW of solar PV, PLN can achieve immediate savings while maintaining system stability.
3. **Policy and Market Alignment:**
   - Removing indirect subsidies like the Domestic Market Obligation (DMO) would make solar PV more competitive.
   - By 2030, as coal phases down, the JAMALI system is likely to rely more on higher-cost gas. Solar PV, with a lower tariff than gas, can offset this impact, ensuring a more affordable energy mix.
   - Introduce a carbon tax to disincentivize coal generation and promote renewable energy.
   - Grant developers access to environmental attributes (e.g., carbon credits or RECs) to lower PPA tariffs and reduce overall LCOE.

In conclusion, integrating solar PV into the JAMALI system presents a viable path for Indonesia to transition to renewable energy, reduce emissions, and align with its national energy goals. Strategic actions, such as optimizing PV integration and adopting supportive policies, will ensure a cost-effective and sustainable energy future.

2. INTRODUCTION

2.1. Project Background

The Southeast Asia Energy Transition Partnership is a technical assistance programme, hosted by the United Nations Office for Project Services. ETP partners with governments, philanthropies, private sector and civil society to harness the vast untapped potential of renewable energy into the energy mix in the Southeast Asian region.

The programme mobilizes and coordinates the necessary technical and financial resources to create an enabling environment for renewable energy, energy efficiency, and sustainable infrastructures to support the transition from using fossil fuels to renewable sources of energy to advance climate action in Southeast Asia. In Indonesia, ETP collaborates with the Ministry of National Development Planning (BAPPENAS) to advance solar PV technology, aiming to accelerate the implementation of solar PV projects and help the country achieve net-zero emissions in the power sector by 2050. Indonesia has set a target of generating 23% of its energy from renewable sources by 2025 and 52% of new capacity by 2030[1], which will require an additional 8.8 GW of renewable energy capacity and $8 billion in annual investment[2].

Despite Indonesia's potential to generate solar power, based on the 2025-2060 National Electricity General Plan/Rencana Umum Ketenagalistrikan Nasional (RUKN), only around 1 GW of solar power plants had been installed by 2024[3]. The development of solar PV in Indonesia faces significant challenges, necessitating the implementation of risk-reduction measures to overcome these obstacles and advance renewable energy.

The 1 GW Solar Mapping and Development project will provide technical expertise to key stakeholders, including BAPPENAS, the Ministry of Energy and Mineral Resources (MEMR), and the state-owned electricity company (PLN). This initiative will support decision-making regarding investments in large-scale solar PV development within the JAMALI grid, while also offering insights applicable to other grids in Indonesia. The project builds upon ETP's previous initiative, the Upgrading PLN JAMALI Load Dispatch Centre, leveraging the newly designed system capabilities to better integrate Variable Renewable Energy (VRE) into the grid.

The project will generate a comprehensive study and assessment that addresses both technical and non-technical aspects, informing investment decisions for developing 1 GW (or more) of solar energy infrastructure in the JAMALI grid. Additionally, it will provide guidance on mechanisms for engaging with financiers and investors, with a focus on private-sector stakeholders. This work will serve as a key reference for PLN and the Government of Indonesia (MEMR and BAPPENAS) as they work to increase the share of renewable energy in the country's energy mix and accelerate the transition to clean energy.

[1] Electricity Supply Business Plan (RUPTL) 2021-2030 by PLN

[2] Indonesia Must Quadruple its Annual Renewable Investment Target to Reach its Climate Objectives I International Institute for Sustainable Development (iisd.org) accessed on 3 May 2024

[3] https://www.mordorintelligence.com/industry-reports/indonesia-renewable-energy-market/market-trends. Accessed on November 15, 2024.

2.2. About the Report

As part of the 1 GW Solar Development and Mapping Project in Indonesia, and specifically Phase 1 Report: Solar Irradiance Mapping, a total of 137 potential sites have been identified as suitable for ground-mounted, utility-scale solar PV projects in the JAMALI region. Phase 1 employed a multi-criteria decision-making (MCDM) process that incorporated geospatial, environmental, and social assessments and a preliminary grid integration analysis. Initially, the aim was to integrate 1 GW of renewable energy into the existing JAMALI grid. However, this study will analyze the maximum solar PV that can be integrated into the system by 2030 (potentially more than 1 GW). Therefore, the project's scope for the total PV capacity is expanded to the potential PV capacity that the system can absorb. This report represents the third deliverable of the project and the second phase of its development.

The report seeks to validate whether these sites can be technically integrated into the JAMALI system. The 137 potential sites collectively represent a total capacity of 14 GW. This report will conduct a grid integration assessment focusing on top-ranked sites based on MCDM scoring from previous deliverables and additional financial factors. The overall deliverable´s output is identifying a selection of technically viable sites to achieve the maximum potential PV penetration.

The report is structured into two main parts: the hosting capacity analysis of the JAMALI grid and the grid impact analysis. It aims to answer the following questions:

- **How much solar PV can be integrated into the JAMALI system?**

- **What are the technical consequences of integrating PV plants into the JAMALI system?**

- **What could be the economic impact of PV integration on the JAMALI system?**

Finally, the report provides technical insights to key stakeholders, including BAPPENAS, MEMR, and the state-owned electricity company (PLN). This information will support decision-making on investments in large-scale solar PV development in the JAMALI grid and offer lessons learned for other grids in Indonesia.

3. SYSTEM MODELING

This report focuses on Phase 2 of the project, which examines the technical and economic impacts of integrating PV systems into the JAMALI grid. Figure 1 illustrates the overall methodology for this phase, which is interconnected with Phases 1 and 3. During Phase 2, the selection of 137 potential sites will be refined to assess their viability and select the top-ranked sites based on the hosting capacity and grid impact analyses. The top-ranked sites will be chosen to meet the maximum PV penetration target and will undergo further analysis in the next deliverable.

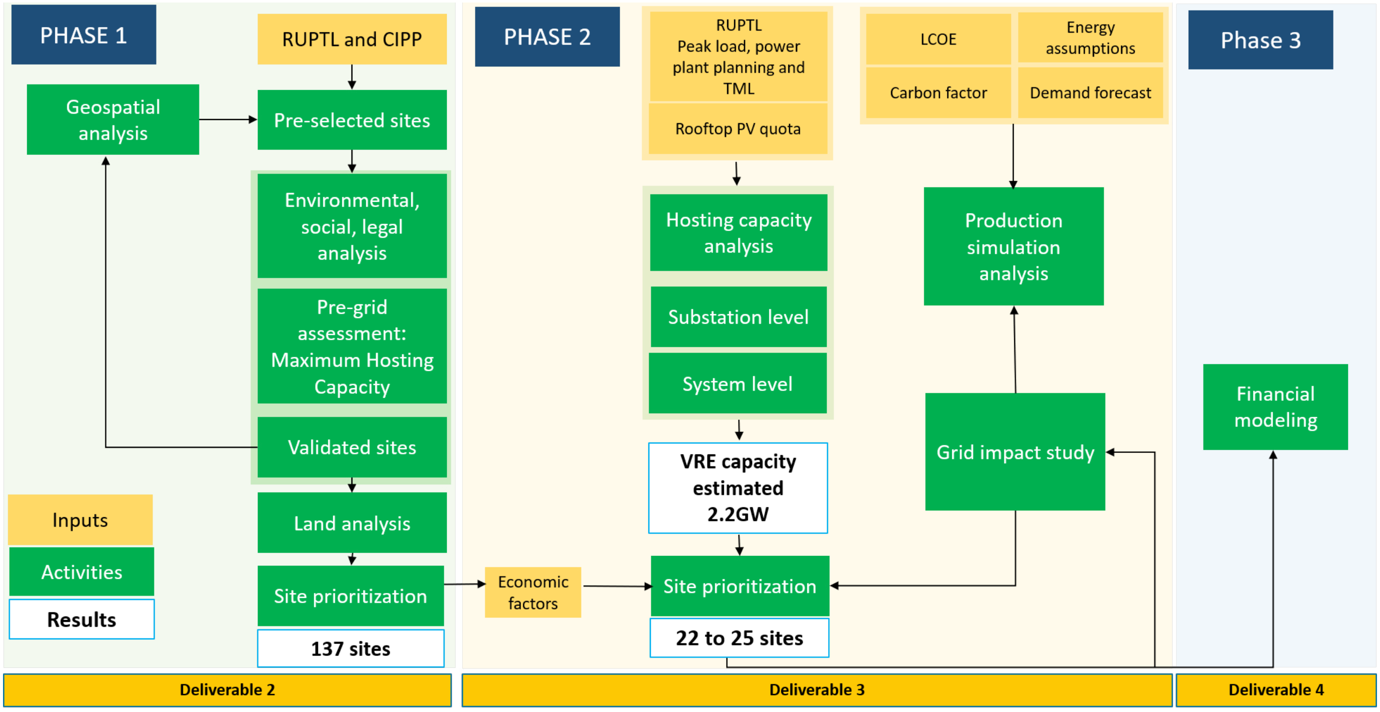


Figure 1. Phase 2 methodology

As preparatory steps, the system will be modelled, and assumptions regarding power system topology, demand forecasts, primary energy, and carbon factors will be established to proceed with the hosting capacity and grid impact analyses.

Grid integration assessment involves two main activities, namely the hosting capacity analysis and the grid impact study, as summarized below:

- ### Hosting capacity analysis of the JAMALI Grid: System modelling and variable renewable energy (VRE) capacity

This section assesses the potential for connecting solar PV within the JAMALI system from 2024 to 2030. It evaluates the overall maximum capacity for solar penetration while ensuring grid stability. The section details how the maximum Variable Renewable Energy (VRE) capacity was determined and the limits for integration into the system without compromising stability:

- At the substation level, the focus is on identifying the maximum renewable energy capacity that can be connected to individual substations. The purpose is to define the maximum hosting capacity for each substation.
- At the system level, the goal is to establish the maximum renewable energy capacity that can be integrated into the grid. This analysis will yield the total capacity available for integration, serving as the basis for prioritizing development sites.

The JAMALI power system was modeled using **DigSILENT PowerFactory** for technical analysis and **PLEXOS** for economic analysis. The input data includes information on each subsystem's load profile and demand forecast up to 2030. Other key data utilized include the primary energy model, fuel costs, RUPTL PLN, peak load, power plant planning, TML, demand forecasts, and rooftop PV quotas.

Based on the output data, which includes capacity estimates for VRE and various economic factors, the site rankings among the 137 potential sites will be adjusted, and the top-ranked sites will be updated. A new list of sites will be generated based on these top-ranked entries. This list of 22-25 sites will be validated in the next step, which includes the grid impact analysis of integrating these sites to the JAMALI grid.

- Grid impact analysis

Once the priority sites are selected, they will be incorporated into the model for further grid integration assessment. This assessment will be divided into two key areas:

- The technical analysis involves evaluating the behaviour of the power system before and after PV integration, ensuring that the system continues to operate within permissible limits.
- The economic grid impact analysis includes a production simulation that assesses the economic implications of grid integration. It examines how system operations change following PV integration, focusing on generation mix, emissions reduction, and generation costs. Key data includes LCOE, energy assumptions, carbon factors, and demand forecast.

Based on the output of the production simulation and grid impact study, the analysis will enable validation of the latest list of top-ranked sites. If the totality of the sites is not validated, the list of sites among the 137 potential sites can be changed, and the grid impact study can be re-conducted.

The outcome of this report will determine whether the additional PV capacity specified in a list of 22 to 25 sites can be safely and efficiently integrated into the JAMALI grid from both technical and economic perspectives amounting a total of 2.2GW.

3.1 Topology

The electricity system of the JAMALI grid was modelled to represent five distinct regions: Banten and Jakarta, West Java, Central Java and Yogyakarta, East Java, and Bali. This regional division captures the primary transmission network that interconnects these regions, ensuring efficient power transfer and facilitating a comprehensive analysis of the system's capacity.

At a more detailed level, the JAMALI grid is modelled as 25 subsystems operating at 150 kV. These subsystems are spread across the five regions and are connected to a 500 kV high-voltage transmission backbone. The connection between the 500 kV and 150 kV systems is facilitated through 500/150 kV Inter-Bus Transformers (IBTs), ensuring seamless power flow between regional subsystems and the broader grid. This detailed topology enables accurate intra-regional and inter-regional electricity transmission, providing insights into the power system's operational dynamics.

The JAMALI grid is expected to interconnect with the Sumatra grid by 2029, as planned in the RUPTL draft 2024-2033. In anticipation of this future connection, the study includes simulations of remote power generation in Sumatra, focusing primarily on geothermal and hydropower resources. As a result, the flow of electricity from Sumatra to JAMALI only depends on the energy output of the power plants. This interconnection is projected to enable energy transfers of approximately 3.6 terawatt-hours (TWh) annually, highlighting the increasing role of renewable energy in supporting regional grid integration and strengthening energy security. Additionally, this interconnecting lowers the overall JAMALI system LCOE due to the reduction of gas consumption.

The detailed topology and system modeling for the JAMALI grid, as developed in the PLEXOS software, are presented in Figure 2 and Figure 3. These figures provide a comprehensive visual representation of the Java-Bali electricity system, highlighting key transmission corridors and substations that form the grid's backbone.

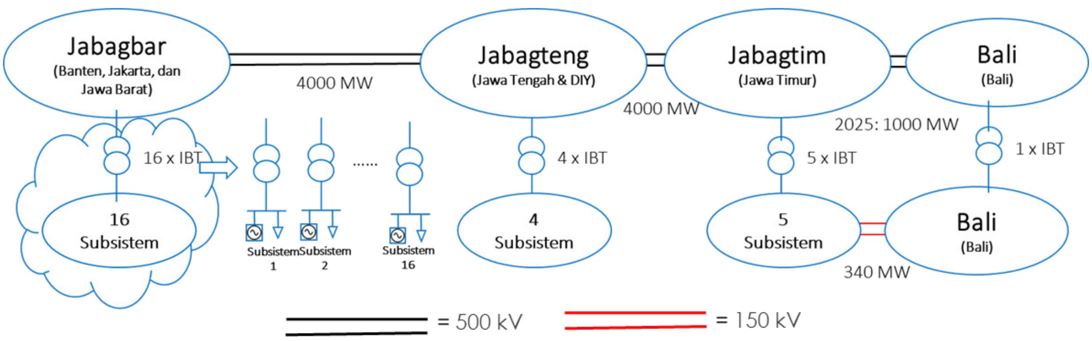


Figure 2. Modelling diagram of JAMALI power system

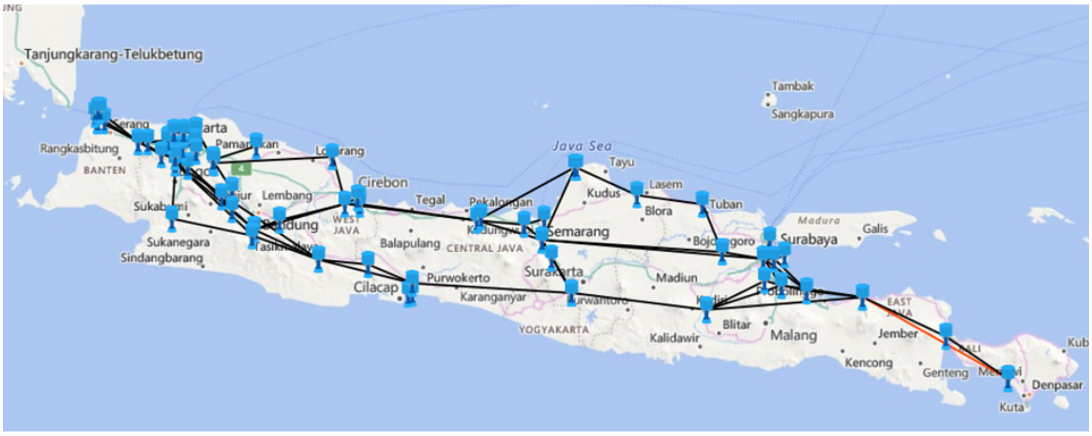


Figure 3. JAMALI Power system model in PLEXOS

3.2. Demand Forecast

The demand forecast used in this study is based on the latest draft RUPTL2024-2033, which serves as the input for the model. This data includes detailed information on the load profile of each subsystem and the demand forecast extending to the year 2030. The study horizon spans from 2024 to 2030. The process follows these steps:

1. The demand profile of each subsystem is analyzed to understand its characteristics.
2. The proportionality of each subsystem relative to the total system demand is calculated, ensuring that each subsystem's demand is represented as a proportion of the overall system demand.
3. The energy and peak demand forecast for the JAMALI System is determined, providing an outlook on future system requirements. For this study, the Sumatra system interconnection is not modelled.
4. The data is processed into load curves for each subsystem, detailing the projected demand growth from 2024 to 2030. Load growth data is provided by PLN through the RUPTL draft 2024-2030.

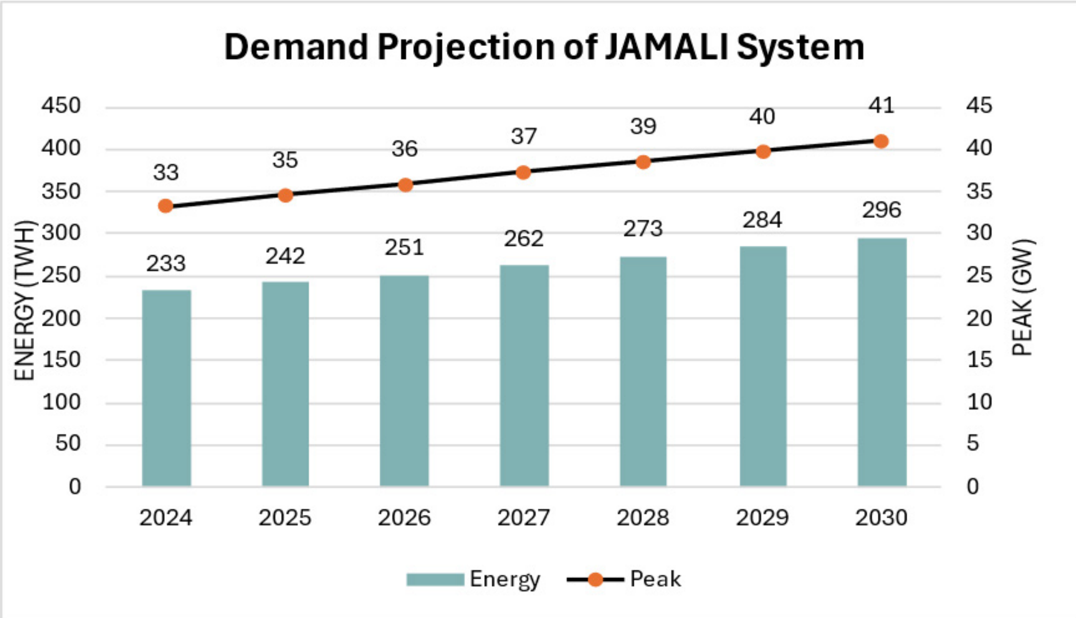


Figure 4. Demand projection curve

The graph in Figure 4 presents the projected energy consumption within the JAMALI System. The bars represent cumulative energy consumption in TWh, while the line illustrates the maximum instantaneous demand in gigawatts (GW). Both metrics exhibit a clear upward trend, indicating an increasing reliance on the system and the need for capacity expansions to meet future demand.

- In 2024, the peak demand is forecasted to reach 32 GW, while the energy consumption is expected to be 233 TWh.
- By 2030, the peak demand is projected to rise to 40 GW, with energy consumption increasing to 296 TWh.

This rising trend underscores the importance of planning for adequate capacity and infrastructure to support the growing energy needs.

3.3. Primary Energy

Various fuel types are modelled in PLEXOS, including coal, natural gas, diesel, liquefied natural gas (LNG), fuel oil, and biomass. Among these, coal and natural gas are the most widely utilized primary energy sources for electricity generation in the JAMALI Power Systems. Fuel price is one of the key parameters used in the generation expansion optimization and simulation production study. The data and assumptions regarding fuel prices are elaborated in the following sections.

3.3.1. Coal

Indonesia possesses significant coal reserves, with production levels that consistently exceed the domestic consumption requirements for Coal-Fired Power Plants (CFPPs). As a result, Indonesia has become a major coal exporter. However, domestic coal prices, particularly those in the electricity sector, are regulated differently from global market prices due to government intervention. As a major domestic buyer, the electricity sector benefits from price controls under the Domestic Market Obligation (DMO) policy. This policy ensures that domestic coal prices are insulated from fluctuations in global markets.

Under Indonesia's DMO policy, domestic coal prices are capped at $70/ton for coal with a heat value of 6,332 kcal/kg. This regulated price is then adjusted according to the specific heat values of individual CFPPs, with transportation costs factored in, which are estimated to range between $12 and $18 per ton for Java, depending on the distance from mining sites. The DMO policy is designed to provide price stability for the electricity sector, and thus, domestic coal prices are assumed to remain constant throughout the study period.

For the sensitivity analysis, coal market prices are modelled based on the World Bank's commodity market outlook, released in April 2024. In this scenario, the base heat value of 6,332 kcal/kg is applied, and the price is adjusted according to the specific heat values of the CFPPs, including transportation costs. According to the World Bank's projections, the coal price is expected to decrease from $125/ton in 2024 to $110/ton in 2025, which is anticipated to remain stable until 2030, the end of the study horizon.

The comparison between the regulated DMO price and the market price objectively assesses the benefits of solar PV systems by removing the indirect subsidies provided to coal through the DMO mechanism. Table 1 presents the projected coal market prices based on the World Bank commodity market outlook for April 2024[4].

[4] World Bank. (2024). Commodity Markets Outlook: April 2024. Washington, DC: World Bank. https://www.worldbank.org/en/research/commodity-markets

Table 1. Coal market price

	PRICES (in nominal US Dollars)					
COMMODITY	Unit	2021	2022	2023	2024f	2025f
Coal, Australia	$/mt	138.1	344.9	172.8	125.0	110.0
Crude Oil, Brent	$/bbl	70.4	99.8	82.8	84.0	79.0
Natural gas, Europe	$/mmbtu	16.1	40.3	13.1	9t.5	10.5
Natural gas, U.S	$/mmbtu	3.9	6.4	2.5	2.4	3.5
Liquefied natural gas, Japan	$/mmbtu	10.8	18.4	14.4	12.5	13.5

3.3.2. Gas and LNG

The JAMALI system connects several gas providers via gas pipelines and LNG facilities. The operation of these pipelines and LNG suppliers is governed by the MEMR Regulation No. 135.K/HK.02 MEM.M/2021, which outlines the maximum available quantities of LNG and gas, as well as the regulated pricing structure.

It is assumed that gas and LNG suppliers typically secure Take-Or-Pay (TOP) contracts for approximately 90% of the available fuel quantity. Under these contracts, gas power plants, particularly Combined-Cycle Gas Turbine (CCGT) plants, must purchase and consume a minimum volume of gas, even if their actual consumption is lower. This ensures the power plants' steady offtake of gas, obliging them to operate at a minimum load level to meet the contractual offtake requirement. As a result, nearly all gas power plants are constrained to run at their minimum output levels in compliance with these agreements.

The regulation is effective until 2024. Therefore, for this study, it is assumed that from 2025 onward, the quantity of available gas, the TOP contracts, and the prices for pipeline gas will remain unchanged, based on the last applicable values under the 2021 regulation. For LNG, it is assumed that starting in 2025, the price will be set at USD 12/MMBtu, and reserves will remain stable for the duration of the study.

3.3.3. Oil

In the JAMALI system, some power plants—including diesel power plants, Gas Engines (GE), CCGT, Open-Cycle Gas Turbines (OCGT), and CFPPs—continue to utilize oil as a fuel source. The pricing for oil in this study is based on Pertamina's Region 1 pricing data as of June 2023 and is assumed to remain stable throughout the analysis period.

3.3.4. Biomass

In addition to fossil fuels, biomass is used as a fuel source in the JAMALI system. A number of biomass power plants are in operation, and several of PLN's CFPPs have adopted co-firing schemes that integrate biomass into their energy production processes. The pricing for biomass fuel in this study is derived from PLN's data projections, which extend until 2030.

The specific fuel prices, expressed in standard units, are presented in Table 2, while their corresponding values in USD/GJ are depicted in Figure 5.

Table 2. Fuel price data in commonly used unit[5]

Year	Coal (USD/ ton) HBA 6332 kCal/kg	LNG and Gas Pipe (USD/ MMBTu)			Buffer	HSD (USD / liter)	MFO (USD / liter)	Nuclear (USD / kG)	Biomass (USD / ton)
		Ave.	Min.	Max.					
2023	70	6.5	4.0	8.4	-	1.4	1.2	1978	52.7
2024	70	6.5	4.0	8.4	-	1.4	1.2	1978	53.7
2025	70	7.5	4.0	12	-	1.4	1.2	1978	60.8
2026	70	7.5	4.0	12	-	1.4	1.2	1978	62.3
2027	70	7.5	4.0	12	-	1.4	1.2	1978	63.8
2028	70	7.5	4.0	12	-	1.4	1.2	1978	65.4
2029	70	7.5	4.0	12	-	1.4	1.2	1978	67.1
2030	70	7.5	4.0	12	-	1.4	1.2	1978	68.7

Figure 5 presents a comparison of current fuel prices across various energy sources. As shown, since the JAMALI system does not yet utilize nuclear energy, coal remains the cheapest option when based solely on the fuel cost, especially when the regulated DMO price is applied. However, fuel cost is not the only factor to consider.

When environmental and social costs are considered, coal's substantial negative impact disqualifies it as a climate-friendly option and makes it one of the largest contributors to climate change. In fact, the overall cost of coal can be significantly higher when externalities such as health impacts, environmental degradation, and carbon emissions are included. Studies have shown that the hidden costs of coal, including healthcare expenses from air pollution and the long-term effects of climate change, can exceed the direct economic costs of coal generation.

[5] Source: Coal prices are determined based on the DMO regulation and adjusted according to the specific heat value of coal used by CFPPs. LNG and gas pipe refer to Minister Regulation Number 135.K_MG.04-MEM.M-2021. Biomass prices are based on "Permen 12 tahun 2023"

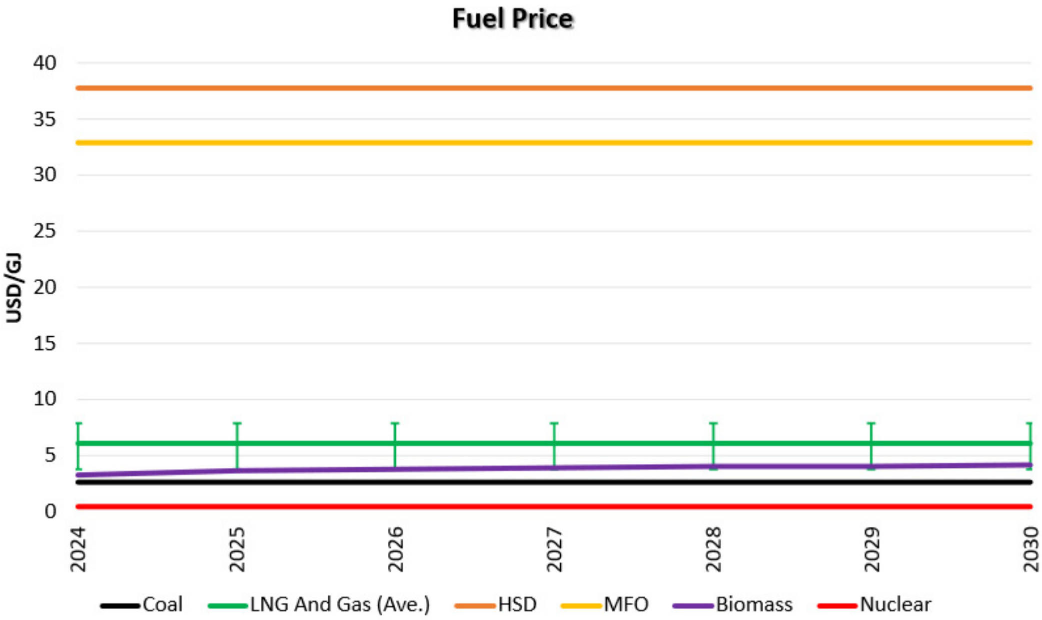


Figure 5. Fuel price data in USD/GJ Unit

3.4. Carbon Emission Factor

The carbon emission factor represents the amount of carbon dioxide (CO2) emitted when one gigajoule (GJ) of energy is produced from burning a specific fuel. In this model, a carbon tax of $2 per ton, as outlined in Undang-Undang No. 7, 2021, is applied as a disincentive for coal usage, addressing the external costs associated with CO2 emissions. For comparison, according to data from carbon tax rates in selected jurisdictions worldwide as of April 2024, Statistica.com, the carbon tax in the global market reaches $167 per ton of CO2 in Uruguay. This indicates that Indonesia has significant potential to increase its carbon tax valueTable 3 shows the carbon factor per type of fuel based on *Pedoman Perhitungan dan Pelapooran Inventarisasi Gas Rumah Kaca, APPLE-GATRIK*.

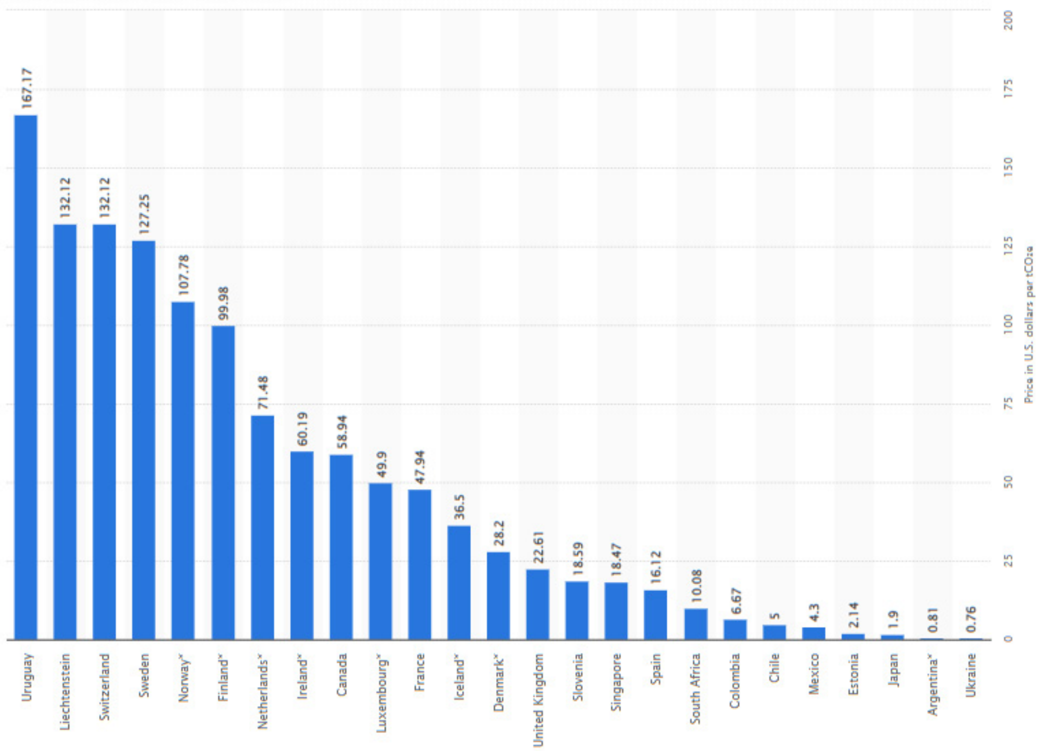


Figure 6. Carbon tax comparison in global market

CFPPs are modelled in detail, with the carbon intensity of each plant based on data from PLN. The results show that coal, including sub-bituminous, lignite, and peat, has the highest carbon factor, leading to the largest CO2 emissions. Implementing a carbon tax raises the overall cost of coal-based generation, making it less economically viable for PLN.

Natural gas and petroleum have lower carbon factors compared to coal but still contribute to greenhouse gas emissions. Interestingly, biomass is assumed to have a zero-carbon factor, as it is considered a net-zero emissions fuel due to the assumption that the CO2 released during combustion is offset by the CO2 absorbed during plant growth. Replacing coal with renewable energy sources like solar PV, which is exempt from carbon taxes, can lead to significant cost savings for PLN over time by reducing the financial impact of carbon taxation. This data is important for evaluating the environmental and economic effects of different energy sources, further supporting the shift toward cleaner, low-carbon alternatives.

Table 3. Table of carbon factor[6]

Fuel	Carbon Factor (kg/GJ)
Sub Bituminous	96.1
Lignite	101
Peat	106
Gas	56.1
Oil	74.1
Biomass	0

[6] Kementerian Energi dan Sumber Daya Mineral Republik Indonesia. (2018). Pedoman Perhitungan dan Pelaporan Inventarisasi Gas Rumah Kaca, APPLE-GATRIK. Jakarta, Indonesia: Direktorat Jenderal Ketenagalistrikan.

3.5. Variable Renewable Energy (VRE) Power Plant total capacity

VRE power plants have dispatch profiles based on natural conditions. PV and wind power plants are included in the VRE category. The dispatch profile for these power plants depends on wind and solar irradiation, which vary over time, leading to fluctuations in energy production.

JAMALI has three voltage levels for transmission: 500 kV, 150 kV, and 70 kV. The 500 kV level serves as the backbone of the entire JAMALI system, while the 150 kV and 70 kV levels focus on subsystem-level distribution within smaller areas. The scope of this grid modeling study for the JAMALI system includes a transmission backbone with a capacity of 500 kV. For the system-level modeling, the model focuses primarily on the 500 kV transmission backbone network to simplify the simulation. Power generation planning is based on the power balance from 2024 to 2030, particularly for PV power plants.

PV power plants are categorized into two types: utility-scale, which can be ground-mounted or floating, and PV rooftop systems. These two categories exhibit different solar irradiation patterns, with utility-scale installations showing more fluctuation due to their larger capacity for each area, whereas PV rooftop systems have smaller capacities but wider distribution.

According to the latest draft of the RUPTL, both PV categories will be implemented using a phased approach with varying capacities. Figure 7 below illustrates the cumulative capacity for both types of PV. The total capacity for utility-scale PV is projected to grow from 375 MW in 2024 to 3100 MW by 2030. There is no wind power plants included in the latest draft of RUPTL.

Ministerial Regulation of Energy and Mineral Resources (Permen ESDM) No. 2 of 2024 regulates the installation and operation of rooftop solar power systems, which constrains the expansion of PV rooftops through yearly quotas. According to PLN data, PV rooftop capacity is expected to increase from 825 MW in 2024 to 2050 MW in 2030.

Overall, the total PV capacity in the JAMALI system is forecasted to rise from 1,200 MW in 2024 to 5150 MW by 2030.

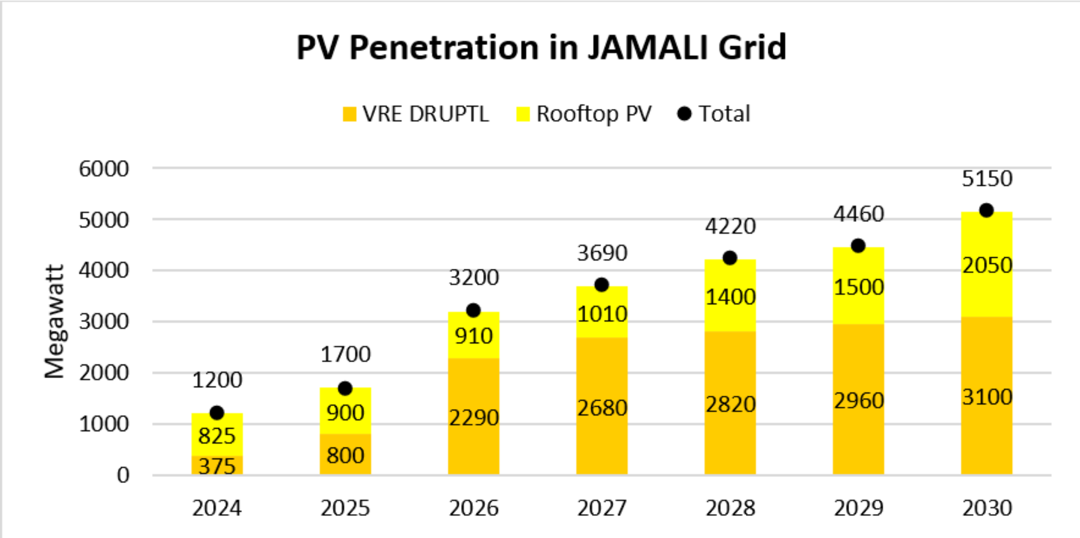


Figure 7. VRE Total Capacity in RUPTL and Rooftop PV Quota until 2030

4. HOSTING CAPACITY ANALYSIS

This section aims to provide the maximum VRE Hosting capacity analysis capacity, particularly solar PV, that can be safely integrated into the power grid while ensuring system stability. The grid's ability to accommodate additional renewable energy sources will be assessed by considering key factors such as peak load, existing power generation capacity, and planned renewable energy integration. The relevance of this analysis lies in its ability to provide insights into the upper limits of solar PV integration without causing grid instability.

Two levels of analysis are performed here: substation and system. The process entails progressively raising PV generation and monitoring the grid's response in different operational scenarios to ensure that grid limitations, like voltage stability and line loads, are not surpassed. The results are essential for strategic planning, guiding decisions on how much renewable energy can be added to the system to meet future energy goals while maintaining grid reliability and compromising stability and providing guidance for future renewable energy expansion plans.

4.1. Hosting capacity analysis: substation level

4.1.1. Methodology

The hosting capacity analysis at the substation level was conducted as part of Phase 1: Solar Irradiance Mapping report. The purpose of this assessment was to determine the maximum hosting capacity of each substation that the proposed Solar PV systems will be connected to (the 137 sites). By conducting this analysis, the maximum Solar PV capacity that can be integrated into each specific substation is identified, ensuring that the substation can accommodate the added generation without exceeding operational limits.

To analyze the capacity of PV systems connected to a substation (Gardu Induk, or GI), the process involves progressively increasing the PV capacity while monitoring for operational constraints such as load flow limits, voltage levels, line loading thresholds, and Inter-Bus Transformer (IBT) loading. The steps involved in this process are outlined below:

1. **Data Collection**: The first step involves collecting detailed data on the substation, the PV systems, and the overall transmission grid configuration. This includes information on the substation's technical specifications, its connection to the grid, and the expected PV generation profile. The data is then used to build a comprehensive model of the substation in DIgSILENT PowerFactory, a power system simulation software.
2. **Base Case Validation**: After building the model, the base case scenario (without additional PV capacity) is validated to ensure that the model accurately reflects the substation's real-world operating conditions.
3. **Incremental PV Capacity Addition**: Once the base case is validated, PV capacity is incrementally added to the model in stages. For each incremental increase, a load flow analysis is conducted to evaluate the impact on key operational parameters,

including voltage levels, line loading, and IBT capacity.

4. **Operational Constraints Monitoring:** At each stage, the system's response is carefully monitored. The goal is to ensure that voltage levels remain within permissible limits, transmission lines are not overloaded, and IBTs continue to operate within their thermal limits. If any operational constraints, such as voltage deviations, line overloading, or transformer overloading, are encountered, these issues are recorded.
5. **Capacity Adjustment:** If operational constraints are detected, the PV capacity is adjusted by reducing the amount of PV generation until the system stabilizes. This ensures that all operational parameters, including voltage, line loading, and IBT operation, remain within acceptable limits.

This process of incremental PV capacity addition, monitoring, and adjustment is repeated until the maximum PV capacity that can be safely integrated into the substation is determined. The final capacity ensures grid stability and operational safety, allowing for the maximum amount of Solar PV generation that can be supported by the substation.

4.1.2. Results

The result of this analysis has been presented in the Phase 1 report, providing the maximum hosting capacity for the nearest substation to each selected site, encompassing 67 substations assessed. Table 4 below are details of the maximum hosting capacity of these 67 substations.

Table 4. Maximum hosting capacity per substation

No	HubName	Maximum Hosting Capacity (MW)
1	GI 150 kV Bayah	160
2	GI 150 kV Rangkasbitung	260
3	GI 150 kV Tigaraksa	560
4	GI 70 kV Serang	145
5	GIS 150 kV PLTU Labuan	480
6	GI 150 kV Ciamis	950
7	GI 150 kV Cianjur	245
8	GI 150 kV Haurgeulis	140
9	GI 150 kV Jatibarang	270
10	GI 150 kV Juishin	420
11	GI 150 kV Karangnunggal	650
12	GI 150 kV Kutamekar	425
13	GI 150 kV Mandirancan	330
14	GI 150 kV Mekarsari	730
15	GI 150 kV Pabuaran	460

No	HubName	Maximum Hosting Capacity (MW)
16	GI 150 kV Patuha	290
17	GI 150 kV PLTU Cirebon	380
18	GI 150 kV Purwakarta	500
19	GI 150 kV Semen Baru	510
20	GI 150 kV Semen Jawa	70
21	GI 70 kV Babakan	80
22	GI 70 kV Cianjur	245
23	GI 70 kV Kadipaten	65
24	GI 70 kV Kuningan	80
25	GI 70 kV Lembursitu	35
26	GI 70 kV Pameungpeuk	85
27	GI 70 kV Pangandaran	80
28	GI 70 kV Parakan	70
29	GI 70 kV Sumadra	100
30	GIS 150 kV PLTU Pelabuhan Ratu	60
31	GI 70 kV Sumedang	100
32	GI 150 kV Batang	1050
33	GI 150 kV Blora	50
34	GI 150 kV Jelok	180
35	GI 150 kV Kedungombo	170
36	GI 150 kV Majenang	200
37	GI 150 kV Mojosongo	1050
38	GI 150 kV Palur	970
39	GI 150 kV Pemalang	390
40	GI 150 kV PLTU Rembang	240
41	GI 150 kV Rembang	240
42	GI 150 kV Semen Indonesia	760
43	GI 150 kV Weleri	650
44	GITET 500 kV Tanjung Jati	650
45	GI 150 kV Bangkalan	230
46	GI 150 kV Banyuwangi	520
47	GI 150 kV Bojonegoro	255
48	GI 150 kV Cepu	190
49	GI 150 kV Genteng	280

No	HubName	Maximum Hosting Capacity (MW)
50	GI 150 kV Gondangwetan	870
51	GI 150 kV Kerek	360
52	GI 150 kV Mliwang	1350
53	GI 150 kV Pier	1080
54	GI 150 kV Purwosari	850
55	GI 150 kV Sampang	680
56	GI 150 kV Sementuban	240
57	GI 150 kV Situbondo	560
58	GI 150 kV Sumenep	310
59	GI 150 kV Tanjung Awar Awar	250
60	GI 150 kV Tuban	1100
61	GI 70 kV Magetan	75
62	GI 70 kV Pandaan	90
63	GI 70 kV Siman	65
64	GI 70 kV Sukorejo	50
65	GI 150 kV Baturiti	240
66	GI 150 kV Negara	350
67	GI 150 kV Pemaron	210

4.2. Hosting capacity analysis: JAMALI system level

4.2.1. Methodology

At the system level, similarly to the substation level, the hosting capacity analysis aims to determine the maximum amount of VRE specifically solar PV that the JAMALI grid can accommodate while maintaining overall system stability. Figure 8 illustrates the methodology for the system-level simulation.

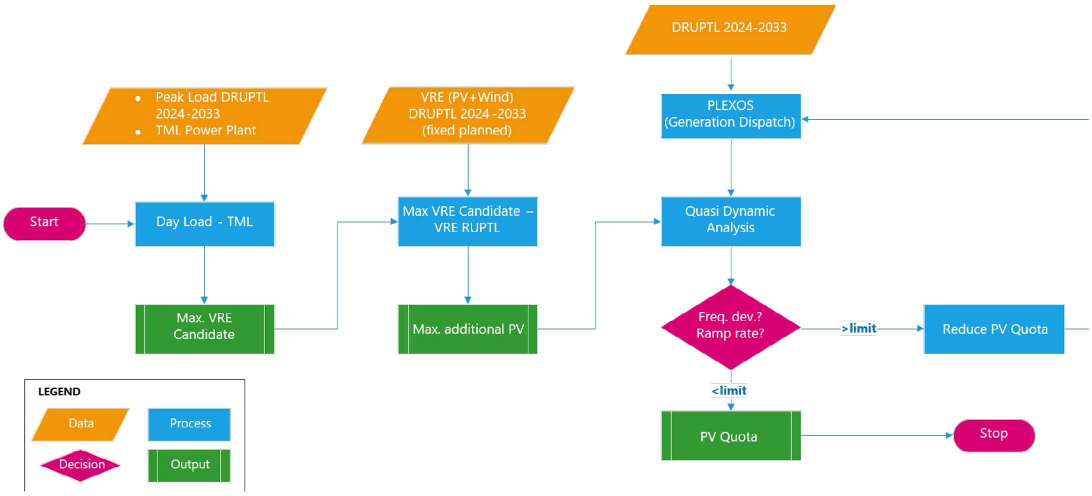


Figure 8. Methodology of system level hosting capacity analysis

The analysis involves several key steps:

1. **Initial Data Collection:** The process begins by collecting key input data, including the peak load from the draft of RUPTL 2024–2033 (PLN's electricity supply business plan), which provides an estimate of the maximum demand the grid will face. Additionally, the Thermal Minimum Loading (TML) of existing power plants is assessed to understand the minimum operational capacity that thermal power plants must maintain during low-demand periods.
2. **Day Load Profile Calculation:** Using the peak load and TML data, the day load profile is calculated, reflecting the grid's load throughout the day. This profile indicates how much renewable energy, such as solar PV, can be integrated without exceeding grid limits, particularly during periods of high renewable generation and low demand.
3. **Maximum PV Capacity Candidate:** The day load profile is used to estimate the maximum PV capacity that can be technically accommodated by the system. This initial estimation provides a baseline before accounting for dynamic stability factors.

4. **Consideration of fixed VRE Capacity:** The next step involves factoring in the fixed VRE capacity from the RUPTL 2024–2033 draft, which represents renewable energy projects that are either planned or already in progress. This capacity serves as a baseline for further VRE integration.
5. **Maximum potential additional PV:** The difference between the maximum potential PV capacity candidate and the fixed VRE capacity determines the additional PV capacity that can be added to the system.
6. **Simulation to determine PV Quota into the grid:** The potential maximum PV capacity is then input into the PLEXOS generation dispatch tool, considering the load profile and renewable energy generation. The results of this simulation are fed into a quasi-dynamic analysis to assess the grid's stability. This analysis focuses on two critical parameters: frequency deviation, which measures how much the grid frequency fluctuates due to variable renewable generation, and ramp rates, which evaluate how quickly the system needs to adjust generation to match demand as solar generation fluctuates. If either the frequency deviation or ramp rates exceed acceptable limits, it indicates that the grid cannot safely accommodate the calculated PV capacity, and thus the PV quota must be reduced. Conversely, if these parameters remain within acceptable limits, the system is deemed stable, and the maximum PV capacity can be maintained. Through iterative assessments and adjustments based on stability results, the process concludes with a final determination of the maximum PV capacity that can be integrated into the grid without causing instability. This final PV quota ensures that solar energy can be added to the system in a way that optimizes renewable integration while preserving grid stability.

The term PV quota is used to indicate the maximum quota for PV to be injected into the JAMALI grid. Thus, after the system-level hosting capacity analysis, the maximum additional PV capacity that can be safely integrated into the grid is determined.

4.2.2. Results

This analysis determined the maximum capacity of PV systems that can be integrated into the power grid at a system-wide level while maintaining overall grid stability. It provides a comprehensive understanding of how renewable energy integration affects grid performance, including the impact on transmission lines, transformers, and stability across all regions. The findings helped identify the additional PV capacity that could be safely integrated beyond what is already included in the strategic planning for the JAMALI power system through 2030. Table 5 outlines the forecasted VRE capacity in the JAMALI region from 2024 to 2030. It provides three key sections:

1. **PV Maximum Candidate:** This section presents the maximum potential PV capacity to be integrated into the grid each year, starting from 1,325 MW in 2024 and increasing to 6,340 MW by 2030. The maximum level of VRE candidate is determined by reducing the daytime load to the TML of the power plant. This approach enables higher penetration of solar power plants without forcing other power plants, especially conventional ones, into a daily 'start-stop' operation mode.

2. **Candidate:** This category is divided into two parts: VRE RUPTL, which shows the projected VRE capacity based on the National Electricity Plan draft (DRUPTL 2024-2033), starting at 375 MW in 2024 and reaching 3,100 MW by 2030; and PV Utility, which reflects the expected utility-scale PV capacity for each year, beginning at 264 MW in 2024 and growing to 3,240 MW by 2030.
3. **Maximum Penetration:** This section breaks down the total VRE integration into different categories. VRE Scale Utility shows the utility-scale contribution of VRE, starting at 375 MW in 2024 and increasing to 3,100 MW by 2030. PV Rooftop displays the projected capacity of rooftop solar installations, growing from 825 MW in 2024 to 2,050 MW by 2030. PV Utility refers to utility-scale PV capacity, starting at 1,100 MW in 2024 and reaching 2,200 MW by 2030. The final row, VRE Total, sums the total VRE capacity, starting at 2,300 MW in 2024 and rising to 7,350 MW by 2030.

Table 5. JAMALI maximum RE penetration

JAMALI System		Unit	2024	2025	2026	2027	2028	2029	2030
PV Maximum Candidate		MW	1325	1636	2354	2983	3878	4913	6340
Candidate	VRE RUPTL	MW	375	800	2090	2680	2820	2960	3100
	PV Utility	MW	264	264	264	303	1058	1953	3240
Maximum Penetration	VRE Utility Scale	MW	375	800	2090	2680	2820	2960	3100
	PV Utility (Quota for additional PV)	MW	1100	1100	1100	1100	1200	1900	2200
	PV Rooftop	MW	825	900	910	1010	1400	1500	2050
	VRE Total	MW	2300	2800	4040	4530	5420	6360	7350

As presented in Table 5, the maximum PV that can be integrated into the JAMALI grid is shown cumulatively for each year until 2030. By 2030, the system is projected to accommodate an additional 2,200 MW, or 2.2 GW, beyond what has already been integrated into the DRUPTL 2024-2033. Therefore, this analysis provides a framework for site prioritization. The total capacity of the selected sites must align with the system's available capacity, which amounts to 2.2 GW. This study should prioritize site selection based on strategic importance and geographical diversity within the JAMALI regions, ensuring that top sites are chosen from each province and that the total capacity of these sites meets the system's capacity availability.

The maximum additional PV capacity that can be integrated into the grid in 2024 is 1,100 MW, with no increase until 2027, followed by a slight increment of 100 MW in 2028. To avoid concentrating all additional site plans at once, this study proposes a proportional distribution of the PV capacity to be added from 2024 to 2028. Instead of integrating the full 1.1 GW in 2024, the study suggests adding 300 MW of solar PV capacity per year over this period. The remaining 1,000 MW increase, scheduled between 2029 and 2030, is distributed equally across these two years, with 500 MW added each year. The additional PV utility capacity per year is presented in Table 6.

Table 6. Additional PV utility capacity per year

PLTS	Unit	2023	2024	2025	2026	2027	2028	2029	2030
Additional PV Utility Capacity per Year	MW	-	-	300	300	300	300	500	500

5. GRID IMPACT STUDY

5.1. Methodology

5.1.1. Power System Analysis

Several key parameters are assessed during power analysis through load flow studies to ensure the safe integration of PV systems. This includes monitoring the minimum and maximum voltage levels at each grid interconnection (GI) point across five areas, ensuring that voltage remains within permissible limits. The maximum loading of inter-bus transformers (IBT) and transmission lines is also recorded. Short-circuit levels at each GI connected to PV systems are calculated, ensuring that protection systems can handle potential faults without exceeding their capacity. Additionally, a transient stability analysis is performed to evaluate the system's response to disturbances such as faults or outages, ensuring the grid remains stable and returns to normal operation.

To proceed with power system analysis, this study used **DIgSILENT Power Factory** to perform load flow analysis, short circuit calculation, dynamic/transient stability analysis, and quasi-dynamic analysis.

5.1.1.1. Load flow analysis

A load flow analysis, also known as power flow analysis, is a key technique used to determine how electrical power moves through the grid from generation sources to consumers. It calculates the voltage at different points in the network, the amount of power flowing through transmission lines, and the loading of transformers and other equipment. This analysis helps ensure the power system operates within its safe limits, avoiding overloading or unstable voltage conditions.

Load flow analysis provides a detailed understanding of the grid's ability to handle current and future electricity demand. It identifies whether the grid can handle the load without exceeding the capacity of transmission lines, transformers, or generating units. By identifying potential issues like voltage drops or overloaded equipment, it can ensure the grid remains stable and reliable, and determine whether upgrades or adjustments are necessary, especially when integrating new energy sources like solar.

For this specific load flow analysis, the data used includes several key elements to model the power flow most accurately and identify constraints or potential issues during the integration of new energy sources namely:

- Peak load forecasts that provide the maximum expected electricity demand at various points in the grid, helping to determine how much power the system needs to handle.

- TML from power plants is used to ensure that thermal generators are operating at their minimum output levels to maintain grid stability.
- The fixed VRE capacity from the DRUPTL 2024-2033 plan which outlines the planned integration of renewable energy sources like solar and wind into the system.
- Network data to incorporate the grid's physical configuration, including line impedance, transformer ratings, and bus voltage limits.

A load flow analysis typically involves creating a detailed model of the power grid, including generation sources, substations, transmission lines, and loads. The software DigSILENT is used to input the network configuration, along with generation and load data, to simulate how power flows through the grid. The analysis calculates the voltage at each bus (connection point), power flows along transmission lines, and the loading of critical equipment like transformers. It also verifies whether the system is operating within safe voltage and thermal limits.

In this part of the analysis, the grid model is adjusted to include the integration of additional PV systems. The process begins by using peak load forecasts and the minimum operational requirements of thermal plants to calculate the overall day load. The model then assesses how much additional PV capacity can be accommodated while maintaining safe voltage levels, line loading, and IBT capacity. The analysis also considers the fixed VRE capacity from the national plan and runs simulations to determine the maximum PV capacity that can be added without exceeding these limits.

5.1.1.2. Short circuit calculation

A short circuit analysis is performed to determine the electrical fault currents that may occur in the grid when an abnormal connection or fault happens, such as a line-to-ground or line-to-line fault. It calculates the amount of current that flows through the system under fault conditions and ensures that protective equipment (such as circuit breakers) can handle these fault currents without being damaged.

This analysis is necessary because electrical faults can cause excessive currents that may damage equipment, reduce system stability, or even result in prolonged outages. Identifying fault levels helps grid operators select the appropriate protection settings and design safeguards to minimize the impact of these faults. Ensuring that equipment can withstand, and interrupt fault currents is vital for maintaining the grid's reliability and safety. The breaking current, which represents the maximum fault current that a circuit breaker can safely interrupt, must comply with grid regulations. For instance, the breaking capacities for 500 kV, 150 kV, and 70 kV systems are set at 63 kA, 40 kA, and 25 kA, respectively. Ensuring circuit breakers are rated accordingly is essential for preventing equipment failure and ensuring safe operation. The data used for short circuit analysis are the Nominal Voltage of each substation and the breaking current of the short circuit current.

In a short circuit analysis, the grid's electrical configuration is modeled, including generators, transformers, and transmission lines. Different types of faults (like three-phase, phase-to-phase, and phase-to-ground faults) are simulated at various locations in the grid. The analysis calculates the fault current levels and compares them to the ratings of the equipment, particularly the capacity of circuit breakers to interrupt the current.

5.1.1.3. Dynamic/Transient stability analysis

Dynamic, or transient stability analysis, is the study of a power system's ability to maintain synchronism and recover after a disturbance, such as the loss of a major generation unit or a sudden decrease in renewable energy output. It examines how the system reacts to these disturbances in terms of voltage, frequency, and overall stability over a short time frame (seconds to minutes) to ensure the system can return to a stable operating condition without collapsing.

Transient stability analysis helps to validate the reliability of the power system during sudden disturbances. If the system cannot maintain stability after an event like the sudden loss of a generator or a dip in solar power output, it could lead to cascading failures, blackouts, or equipment damage. The analysis helps grid operators understand how resilient the system is and what actions or protections need to be in place to avoid instability, which is especially important as renewable energy sources like solar and wind are integrated, which can introduce variability in generation.

In this specific analysis, key data used includes the largest generation unit (PLTU JAWA-10) with a capacity of 1000 MW. PV Plant data, including their total installed capacity and variations in active power output due to changes in solar irradiation and Irradiation levels used in the simulation, specifically drops from 1000 W/m² to 500 W/m² and 800 W/m² and Frequency response data during these events, to track how the system handled disturbances.

In general, transient stability analysis involves simulating various disturbances in the power system, such as the sudden loss of generation or load. The simulation models the system's dynamic response, focusing on key parameters like voltage, frequency, and the interaction between generators. It then determines whether the system can return to a stable operating state or if further disturbances could cause instability or outages. The analysis looks at factors like how fast the frequency recovers and whether the voltage returns to normal levels after the disturbance.

5.1.1.4. Quasi-dynamic analysis

A quasi-dynamic analysis evaluates how a power system behaves over time, focusing on gradual changes in load and generation. It bridges static and dynamic analyses by simulating how the grid handles fluctuating conditions, such as renewable energy generation and monitors key parameters like frequency deviation. Quasi-dynamic analysis is important because it helps predict how a power system responds to time-varying conditions, particularly in terms of maintaining frequency stability. This type of analysis contributes to validating that, even with changes in power generation (like solar power fluctuations), the grid remains within safe operational limits, avoiding frequency instability that could lead to blackouts or equipment damage.

The key data used in this analysis is the frequency deviation of the Jamali System over 24 hours. This data shows how the system's frequency responds to changing conditions throughout the day, with specific attention to staying within the acceptable deviation range of ±0.2 Hz.

5.1.2. Production Simulation

Production simulation is conducted to estimate the allocation of electric energy production across generating units to meet system load at any given time, while also calculating the associated production costs. This simulation involves performing Unit Commitment (UC) and Economic Dispatch (ED), with both processes subject to specific security constraints to ensure system reliability.

5.1.2.1. Unit commitment and economic dispatch

UC determines which generating units must operate (i.e., be committed) to meet the system load at each hour. In contrast, ED optimizes the loading of the committed generating units, aiming to minimize the overall variable costs of the system. These two methodologies are fundamental to production simulation and are explained as follows:

- **Unit Commitment (UC)**: UC is carried out on an hourly basis, taking into account the commitment category of each unit—such as must-run, economic, or peak—as predefined by the user. Generating units are ranked based on their category and operating costs, which include variable operation and maintenance (O&M) costs, along with startup costs. The commitment sequence is designed to determine which units to activate to meet the system load, including the necessary spinning reserve, while also accounting for constraints such as minimum up and down times for each unit.
- **Economic Dispatch (ED)**: Once the UC process has identified which units should be committed, ED is performed every hour to determine the optimal distribution of load among the committed units. The dispatch follows a merit-order principle, where units in the must-run category are dispatched first, followed by economic units, and finally peak units. Within each category, generating units are evaluated based on their heat-rate curves to ensure that all generators within the same category operate at the same marginal cost. This process takes into consideration the minimum and maximum output limits of the generating units.

This simulation requires input, including system load in the form of energy (GWh), peak load, and daily load curve, as well as techno-economic parameters of the generating units, such as the heat rate curve, fuel availability and price, as well as the physical operating limitations of the generating unit (like minimum loading, lean rate, minimum up and down time, startup time, etc.).

The simulation is performed using PLEXOS, as energy modelling software. The output of the production simulation provides valuable insights into several key aspects which are generation mix, emissions reduction calculation, and an economic impact analysis.

5.1.2.2. Generation mix

The generation mix refers to the evaluation and modeling of the contribution of different energy sources (e.g., coal, natural gas, renewables like wind and solar) over a specific timeframe to the overall electricity supply. This analysis helps in understanding how various energy sources contribute to the grid and how these contributions may change due to factors such as policy shifts, market dynamics, or technological advancements.

In this study, generation mix analysis is particularly important to illustrate the role of load-following power plants, such as gas power plants, in meeting electricity demand. The increasing penetration of solar PV energy will first affect the need for load-following power plants before impacting baseload power plants. Furthermore, this analysis helps quantify the effect of expanding the share of renewable energy in the overall generation mix.

Generation mix analysis plays a critical role in energy planning, offering insights into the current energy landscape and supporting informed decision-making for future investments and infrastructure development. A diversified generation mix can mitigate the risks associated with over-reliance on a single energy source. For this analysis, the power generation data for each plant is required, covering the period from fiscal year 2024 through 2030. This data includes the total power generation in megawatts (MW) for each plant, accounting for multi-unit generators by aggregating the output across all units.

5.1.2.3. Emission reduction calculation

Emission reduction calculations are a key component of climate change mitigation efforts. They involve quantifying the decrease in greenhouse gas emissions resulting from specific actions or policies. This data could contribute to tracking progress, setting targets, and evaluating the effectiveness of climate strategies. Power plants are major contributors to greenhouse gas emissions, primarily due to the burning of fossil fuels like coal, natural gas, and oil. Therefore, accurate emission reduction calculations are needed for regulatory compliance, carbon market participation, environmental responsibility, competitive advantage, technological advancement, and risk management. The data used in the emission reduction calculations at power plants can vary depending on the specific methodology and the level of detail required. However, some common data types include fuel consumption data, emission factors, plant efficiency data, emission monitoring data, and operational data.

5.1.2.4. Economic impact analysis

Economic Impact Analysis assesses the potential effects of a project, policy, or event on a region or nation’s economy. One of the key metrics used in this context is the Levelized Cost of Energy (LCOE), which calculates the average cost of electricity production over the study horizon. LCOE accounts for both capital costs (e.g., plant construction) and operational costs (e.g., fuel and maintenance), enabling a comprehensive cost assessment for each power plant in the system.

LCOE is particularly valuable for cost comparison, as it allows for direct comparisons between different power generation technologies, such as geothermal, coal, gas, and renewable energy. It also supports investment decisions, guiding policymakers and investors in identifying the most economically viable energy sources. Additionally, for energy planning, LCOE helps determining the optimal mix of power generation technologies for a reliable and cost-effective energy system.

The data used for economic impact analysis includes investment costs, fixed operations and maintenance (O&M) costs, fuel costs, and the installed capacity for each scenario within the JAMALI system.

LEVELIZED COST OF ELECTRICITY (LCOE)

LCOE represents the average cost of producing each unit of electricity (typically measured in kilowatt-hours, kWh) from a power plant over its lifetime. It is a key metric used to evaluate the cost-effectiveness of different energy generation technologies by considering all relevant costs.

According to PLN's system for calculating the LCOE, several cost components are factored in:

- **Component A**: Investment costs, including capital expenditures for equipment, installation, and infrastructure.
- **Component B**: Fixed operation and maintenance (O&M) costs, which remain constant regardless of energy production.
- **Component C**: Fuel costs (applicable mainly to fossil-fuel plants), which do not apply to Solar PV but are included in the general LCOE framework for consistency.
- **Component D**: Variable operation and maintenance costs, which depend on the amount of electricity generated.
- **Component E**: Investment cost for transmission line assets constructed from the electricity generation power plant asset to PLN's interconnection point.

These cost components are then divided by the expected annual energy output to derive the LCOE. This method provides a comprehensive view of the cost per unit of electricity produced, enabling comparisons across different generation technologies and helping decision-makers determine the most cost-efficient options.

Presidential Regulation Number 112 of 2022 introduces a two-stage pricing scheme for renewable energy projects, including Solar PV. The first stage covers the initial ten years of the plant's operation, followed by a reduced price for the subsequent years. For this study, the ceiling price of 6.95 c$/kWh applies to the first ten years, as the Solar PV plants are expected to be built and operational within this timeframe. This pricing structure based on Technology Data for Indonesia Power Sector 2024 by Energy Ministry Indonesia, reflects the emphasis on encouraging early investments in renewable energy through favorable pricing in the initial years of operation. LCOE assumptions taken for this study are shown in the Figure 9:

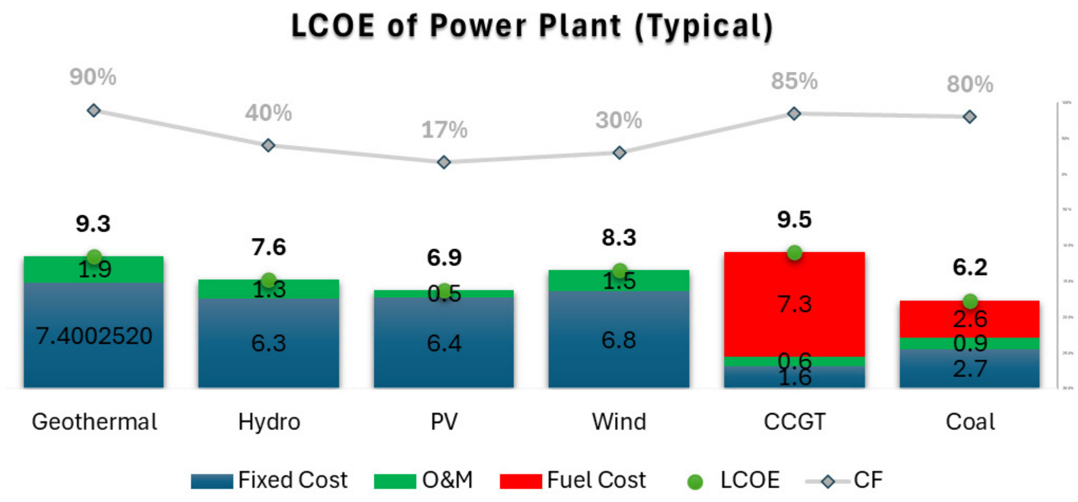


Figure 9. Power plants LCOE assumptions

SCENARIOS AND SENSITIVITY ANALYSIS

Sensitivity analysis is a relevant tool in energy planning and economic modeling, as it allows for the evaluation of how changes in key variables—such as fuel prices, investment costs, and regulatory measures—impact the performance and cost-effectiveness of the energy system. Analyzing various scenarios allows for the evaluation of each key parameter's impact on the outcome.

Scenarios for economic analysis

Three scenarios are analyzed in this economic study:

- Scenario 1: The base case scenario includes PV plants as planned under RUPTL draft (2024-2033)
- Scenario 2: The scenario includes the base case scenario with an additional 2.2 GW of PV capacity to be integrated
- Scenario 3: A carbon tax of $2/ton is applied

Scenarios for sensitivity analysis

In this analysis, the primary focus is on how changes in coal and PV prices affect the LCOE and the total system cost. The sensitivity analysis provides valuable insights into the financial implications of adjusting coal and PV prices, helping to inform decisions about energy policy and investments. Four scenarios are analyzed for the sensitivity analysis, namely:

- Scenario 1: Coal price under DMO, and PV price capped at 6.95 IDR/kWh as per Presidential Regulation No. 112.
- Scenario 2: Coal price under DMO, and PV price at the lower end of 5.5 IDR/kWh.
- Scenario 3: Coal price at market value, and PV price capped at 6.95 IDR/kWh.
- Scenario 4: Coal price at market value, and PV price at the lower end of 5.5 IDR/kWh

5.2. Sites Prioritization

Based on the output data, which includes capacity estimates for additional VRE of 2.2 GW and various economic factors, the site rankings among the 137 locations were adjusted primarily to incorporate economic parameters such as land prices and distance to the grid. Using the updated top-ranked sites and ensuring geographical diversification. The sites for the additional solar PV systems, a new list of 25 sites, will be selected partially for their diversity of location throughout Java and Bali. This list will be validated in the next step, which involves a grid impact analysis. Figure 10 presents the overall methodology where site prioritization is performed.

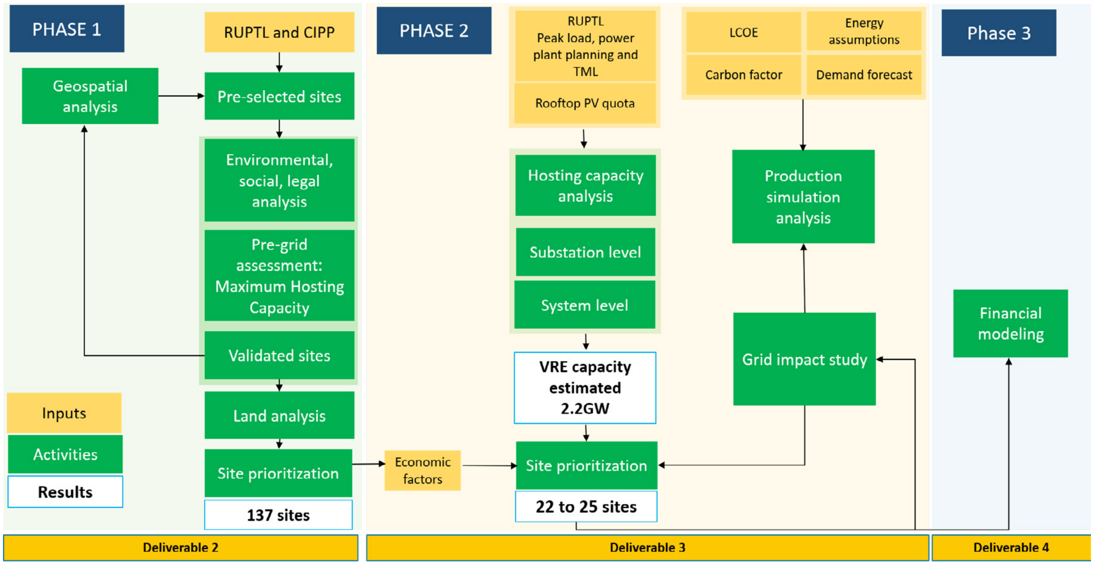


Figure 10. Phase 2 sites prioritization

The capacity assigned for the selected sites is divided into four assigned capacities: 25 MW, 50 MW, 75 MW, and 100 MW. The maximum of 100 MW was determined, considering the risk of securing the land and other environmental risks for higher capacity. Therefore, the number of sites selected to achieve 2.2 GW must be at least 22 sites of 100MW. This maximum of 100 MW be re-evaluated at the next deliverable, taking into account the financial factor and viability.

Table 7. List of prioritized sites

No.	ADM1	ADM2	ADM3	ADM4	Hub Name	Assigned Capacity (MW)	Maximum Hosting Capacity (MW)	Solar PV Potential (MW) by Land Availability
1	Jawa Tengah	Pati	Dukuhseti	Wedusan	GITET 500 kV Tanjung Jati	100	650	110

No.	ADM1	ADM2	ADM3	ADM4	Hub Name	Assigned Capacity (MW)	Maximum Hosting Capacity (MW)	Solar PV Potential (MW) by Land Availability
2	Jawa Tengah	Rembang	Sale	Tengger	GI 150 kV Semen Indonesia	100	760	121
3	Jawa Timur	Tuban	Bancar	Siding	GI 150 kV Mliwang	100	1350	103
4	Jawa Timur	Sumenep	Dasuk	Dasuk Timur	GI 150 kV Sumenep	100	310	190
5	Jawa Tengah	Sukoharjo	Polokarto	Genengsari	GI 150 kV Palur	100	970	332
6	Jawa Timur	Bojonegoro	Tambakrejo	Dolokgede	GI 150 kV Cepu	100	190	157
7	Jawa Timur	Situbondo	Arjasa	Bayeman	GI 150 kV Situbondo	75	560	82
8	Jawa Barat	Cianjur	Sindangba-rang	Kertasari	GI 150 kV Patuha	75	290	76
9	Jawa Tengah	Kendal	Patean	Sidodadi	GI 150 kV Weleri	100	650	111
10	Jawa Timur	Sumenep	Ambunten	Tambaagung Barat	GI 150 kV Sumenep	75	310	87
11	Jawa Tengah	Brebes	Banjarharjo	Cikakak	GI 70 kV Babakan	75	80	80
12	Jawa Tengah	Rembang	Sale	Joho	GI 150 kV Semen Indonesia	75	760	91
13	Jawa Timur	Tuban	Kerek	Trantang	GI 150 kV Sementuban	75	240	84
14	Jawa Tengah	Rembang	Sedan	Sambong	GI 150 kV PLTU Rembang	100	240	101
15	Banten	Pandeglang	Panimbang	Citeureup	GI 150 kV Tanjung Lesung	100	480	382
16	Jawa Timur	Banyuwangi	Glenmore	Karangharjo	GI 150 kV Genteng	100	280	206

No.	ADM1	ADM2	ADM3	ADM4	Hub Name	Assigned Capacity (MW)	Maximum Hosting Capacity (MW)	Solar PV Potential (MW) by Land Availability
16	Jawa Timur	Banyuwangi	Glenmore	Karangharjo	GI 150 kV Genteng	100	280	206
17	Jawa Barat	Indramayu	Terisi	Cikawung	GI 70 kV Parakan	50	70	70
18	Jawa Barat	Karawang	Telukjambe Barat	Wanasari	GI 150 kV Mekarsari	100	730	141
19	Jawa Barat	Ciamis	Jatinagara	Cintanagara	GI 150 kV Ciamis	100	950	105
20	Jawa Barat	Indramayu	Gantar	Bantarwaru	GI 150 kV Haurgeulis	75	140	97
21	Jawa Barat	Tasikmalaya	Cipatujah	Cipatujah	GI 150 kV Ka-rangnunggal	100	650	219
22	Banten	Lebak	Maja	Pasir Kecapi	GI 150 kV Tigaraksa	100	560	104
23	Banten	Lebak	Curugbitung	Sekarwangi	GI 150 kV Rangkas-bitung	100	260	260
24	Bali	Buleleng	Tejakula	Sembiran	GI 150 kV Baturiti	100	240	214
25	Bali	Buleleng	Kubutamba-han	Bukti	GI 150 kV Baturiti	25	240	45

The latest list of top-ranked sites should be validated based on the output of the production simulation and grid impact study. If the totality of the sites is not validated, a new list of sites can be generated from 137 sites, and then the grid impact study should be re-conducted.

5.3. Power System Analysis

The power system analysis assesses how electricity moves through the interconnected network of power generation, transmission, and distribution systems. It helps to understand the flow of electricity across the grid, ensuring efficient and reliable delivery to customers. The analysis focused on key aspects such as voltage levels, power flow, and equipment capacity to ensure the grid remains stable and can meet electricity demand. In this section, the analysis evaluated whether the system can maintain normal operation with the integration of 2200 MW additional PV capacity.

5.3.1. Load Flow Analysis

The JAMALI system comprises 25 subsystems, which are categorized into 5 distinct areas.

- **Area 1**: the subsystems include Bekasi24-Cawang1, Cibinong12-Depok2, Cilegon12, Kembangan2-Balaraja34, Gandul13-Kembangan2, Balaraja12, Bekasi13-Cibinong3, Cawang23-Depok1, Gandul24, and Suralaya-Cilegon3
- **Area 2**: the subsystems include Bandung S, Cibatu12, Cibatu34-Mandirancan, Cirata, and Tasikmalaya.
- **Area 3**: the subsystems include the Pedan12, Tanjungiati-Ungaran3, Ungaran12-Kesugihan, and Pedan34 subsystems.
- **Area 4**: the subsystems include Krian12-Gresik, Ngimbang, Paiton-Grati, Kediri, and Krian34. Lastly
- **Area 5**: the subsystems include Bali subsystem.

Thus, the load flow study was conducted for all areas to identify the substations with the highest and lowest voltage levels, the lines with the highest loading in each area, and the IBTs with the largest loading in each area. Overall, the technical results show in Table 9 that the grid is generally stable regarding voltage levels but has certain regions where the transmission lines and IBT are lower than their capacity limits.

Table 8. Load flow simulation result before connection of 2200 MW PV 2030

Area	GI Min	Voltage (kV)	Voltage (pu)	GI Max	Voltage (kV)	Voltage (pu)	IBT	Loading (%)	Line	Loading (%)
AREA 1	1_CIKANDE7	487,2	0,97	1_SURALAYA7	494,6	0,99	1_ IBT75_ IDMY #1	94,7	1_DKSB - 1_KBJR #4	89,8
	1_TELUK NAGA5	144,9	0,97	1_GIS GANDARIA5	157,3	1,05				
AREA 2	2_CIBI-NONG1-7	492,0	0,98	2_MATENG-GENG/PLTA PS7	501,2	1,00	2_ IBT75_ CBNG #3	75,7	2_CWBR - 2_SLLM #1	77,5
	2_KIARAPA-YUNG5	146,0	0,97	2_CIRATA FPV5	158,2	1,05				
AREA 3	PEDAN-TSK-BR 1	497,5	1,00	3_SWITCH-ING GRINDU-LU7	507,5	1,02	3_ IBT75_ PDAN #4	80,6	3_PWDD - 3_ KDMB #1	72,6
	3_PUDAK-PAYUNG5	144,6	0,96	3_BATANG2/ LIMPUNG5	157,0	1,05				
AREA 4	4_GRESIK BARU7	503,6	1,01	4_ WATUDODOL/ KALIPURO7	518,1	1,04	4_ IBT54_ DRYO #1	98,3	4_SWHN - 4_ UDAN #1	89,9
	4_BULUKAN-DANG5	146,3	0,98	4_SURABAYA BARAT/KRI-AN5	156,1	1,04				
AREA 5	5_ ANTOSARI7	517,9	1,04	5_ ANTOSARI7	518,1	1,04	5_ IBT75_ ASRI #1	27,5	5_PBWG - 5_ PMRN #1b	66,3
	5_ PAYANGAN5	150,6	1,00	5_ ANTOSARI5	155,1	1,03				

Table 9 Load flow simulation result after connection of 2200 MW PV 2030

Area	GI Min	Voltage (kV)	Voltage (pu)	GI Max	Voltage (kV)	Voltage (pu)	IBT	Loading (%)	Line	Loading (%)
AREA 1	1_CIKANDE7	487,1	0,97	1_SURALAYA7	494,5	0,99	1_ IBT75_ IDMY #1	93,3	1_DKSB - 1_KBJR #4	91,8
	1_TELUK NAGA5	144,9	0,97	1_GIS GANDARIA5	157,3	1,05				
AREA 2	2_CIBI-NONG1-7	491,9	0,98	2_MATENG-GENG/PLTA PS7	501,0	1,00	2_ IBT75_ CBNG #3	75,2	2_BKSI - 2_PDKL #1a	90,2
	2_KIARAPA-YUNG5	146,0	0,97	2_CIRATA FPV5	158,1	1,05				
AREA 3	PEDAN-TSK-BR 1	497,5	1,00	3_SWITCH-ING GRINDU-LU7	508,4	1,02	3_ IBT75_ PDAN #4	78,8	3_PWDD - 3_ KDMB #1	89,1
	3_PUDAK-PAYUNG5	144,6	0,96	3_PEDAN5	157,2	1,05				
AREA 4	4_GRESIK BARU7	503,6	1,01	4_ WATUDODOL/ KALIPURO7	517,9	1,04	4_ IBT54_ DRYO #1	98,3	4_SWHN - 4_ UDAN #1	93,3
	4_BULUKAN-DANG5	146,3	0,98	4_SURABAYA BARAT/KRI-AN5	156,2	1,04				
AREA 5	5_ ANTOSARI7	517,9	1,04	5_ ANTOSARI7	517,9	1,04	5_ IBT75_ ASRI #1	23,7	5_PBWG - 5_ PMRN #1b	58,1
	5_ PAYANGAN5	150,6	1,00	5_ ANTOSARI5	155,0	1,03				

5.3.2. Short Circuit Calculation

For this analysis, faults were calculated for various substations in the grid, as shown in Table 9. The simulation focuses exclusively on three-phase faults, as they are the most severe type of fault that can occur in a power system. By analyzing this worst-case scenario, it can ensure that protective equipment, such as circuit breakers, is capable of handling even the most extreme conditions. If the system can manage a three-phase fault, it will also be able to handle less severe faults, making this analysis a comprehensive approach to ensuring grid safety and reliability.

Before the connection of 2200 MW PV (Table 10), the short-circuit current levels across various substations remained within the safe operational limits, ensuring that protective devices, such as circuit breakers, could handle the fault currents effectively. The system could manage any three-phase faults caused by the additional 2200 MW PV, which represent the worst-case scenario in power systems, without exceeding equipment capacity.

Table 10. Short circuit calculation result before connection of 2200 MW PV 2030

Substation	Nominal Voltage (kV)	Ib (kA)	ikss (kA)	Iks (kA)	Ip(kA)
1_TIGARAKSA5	150	32,77	35,55	32,52	93,26
3_TANJUNG JATIB7	500	33,85	34,34	33,80	81,94
1_RANGKASBITUNG BARU5	150	30,91	31,87	30,82	75,02
4_TUBAN5	150	28,89	30,03	28,79	75,34
4_SITUBONDO5	150	26,13	28,31	25,93	70,60
1_PLTU BANTEN5	150	24,54	27,16	24,30	66,24
3_WELERI5	150	25,60	26,17	25,55	60,23
2_CIAMIS5	150	22,40	22,99	22,35	58,57
3_SLUKE/PLTU REMBANG5	150	18,96	20,98	18,78	52,36
2_KARANGNUNGGAL5	150	18,66	19,22	18,61	48,47
2_MEKARSARI5	150	17,53	18,52	17,44	44,03
3_SEMEN INDONESIA5	150	18,04	18,18	18,03	47,93
4_MLIWANG5	150	15,55	16,13	15,50	36,76
2_PATUHA5	150	14,73	15,44	14,66	37,31
3_PALUR5	150	13,62	13,78	13,60	30,33
5_BATURITI5	150	12,25	13,15	12,17	26,30
3_CEPU5	150	7,96	8,16	7,94	17,03
4_GENTENG5	150	6,88	6,96	6,87	15,22
4_SUMENEP5	150	4,99	5,03	4,99	10,36
2_BABAKAN4	70	4,81	4,89	4,80	9,46
2_HAEURGEULIS5	150	4,16	4,18	4,16	9,99
2_PARAKAN4	70	3,34	3,47	3,33	6,65

After connection of 2200 MW PV (Table 11), the short-circuit current levels increased slightly at some substations but remained within acceptable limits. For instance, the fault current at Tigaraksas5 reached 32,9 kA, indicating that, while the short-circuit levels increased, they were still within the capabilities of the protective equipment.

Table 11. Short circuit calculation result after connection of 2200 MW PV 2030

Substation	Nominal Voltage (kV)	Ib (kA)	ikss (kA)	Iks (kA)	Ip(kA)
1_TIGARAKSA5	150	32,99	35,56	32,76	93,30
3_TANJUNG JATIB7	500	34,28	34,29	34,28	81,82
1_RANGKASBITUNG BARU5	150	31,37	31,79	31,33	74,83
4_TUBAN5	150	29,47	30,06	29,42	75,42
4_SITUBONDO5	150	26,76	28,33	26,62	70,65
1_PLTU BANTEN5	150	25,05	27,19	24,86	66,32
3_WELERI5	150	26,05	26,18	26,04	60,26
2_CIAMIS5	150	23,11	23,00	23,12	58,60
3_SLUKE/PLTU REMBANG5	150	19,91	20,91	19,82	52,18
2_KARANGNUNGGAL5	150	19,27	19,22	19,28	48,47
2_MEKARSARI5	150	18,72	18,44	18,75	43,85
3_SEMEN INDONESIA5	150	18,46	18,17	18,48	47,88
4_MLIWANG5	150	16,06	16,13	16,05	36,76
2_PATUHA5	150	15,06	15,44	15,02	37,30
3_PALUR5	150	13,71	13,78	13,71	30,35
5_BATURITI5	150	12,79	13,16	12,76	26,33
3_CEPU5	150	8,57	8,18	8,60	17,08
4_GENTENG5	150	7,29	6,94	7,32	15,18
4_SUMENEP5	150	5,72	5,03	5,79	10,36
2_BABAKAN4	70	5,50	4,90	5,55	9,48
2_HAEURGEULIS5	150	4,48	4,18	4,51	9,98
2_PARAKAN4	70	3,75	3,44	3,78	6,60

5.3.3. Dynamic/ Transient Stability Analysis

In this analysis, three events were simulated for the year 2030:

1. **Event 1:** The first event involved removing the largest generation unit, PLTU JAWA-10, from the system and simulating the impact of removing the largest generation unit from the grid. This simulation is critical for assessing the system's ability to maintain stability and balance supply and demand when a significant generation source becomes unavailable. By removing PLTU JAWA-10, this simulation evaluates the system's response to a major frequency disturbance and determines the effectiveness of contingency measures, such as reserve deployment and frequency control mechanisms
2. **Event 2:** The second event simulated the effect of a 50% reduction in active power output from all PV Plants in Area 3, caused by a decrease in solar irradiation from 1000 W/m^2 to 500 W/m^2. The purpose of this simulation is to analyse the impact of solar irradiance variability and intermittency. It analyzes the impact of solar variability and intermittency, modeling scenarios like heavy cloud cover or adverse weather conditions.
3. **Event 3:** The third event modelled a 20% reduction in active power output from the same PV plants, due to a smaller decrease in solar irradiation from 1000 W/m^2 to 800 W/m^2 and so simulating the effect of a 20% reduction in PV power output on the system. The purpose of this simulation is to simulate minor weather-induced fluctuations. Such events are more frequent in areas with high PV penetration. This simulation is designed to test the system's resilience to smaller-scale variability and assess its ability to maintain frequency stability without significant disruptions. It also highlights the role of advanced grid management techniques in mitigating less severe, but routine, renewable generation fluctuations

Each event was evaluated to assess the grid's stability under varying conditions. These simulations were conducted over specific periods, with the rate of power reduction adjusted to reflect the speed of cloud movement and the corresponding rate of power output decrease for each PV plant.

The results of the transient stability analysis revealed the system's response to different events. When the largest generation unit, PLTU JAWA-10, was removed from the grid as shown in Figure 11, the frequency dropped to 49.85 Hz. Although this was a significant decrease, it remained within the safe frequency deviation limit.

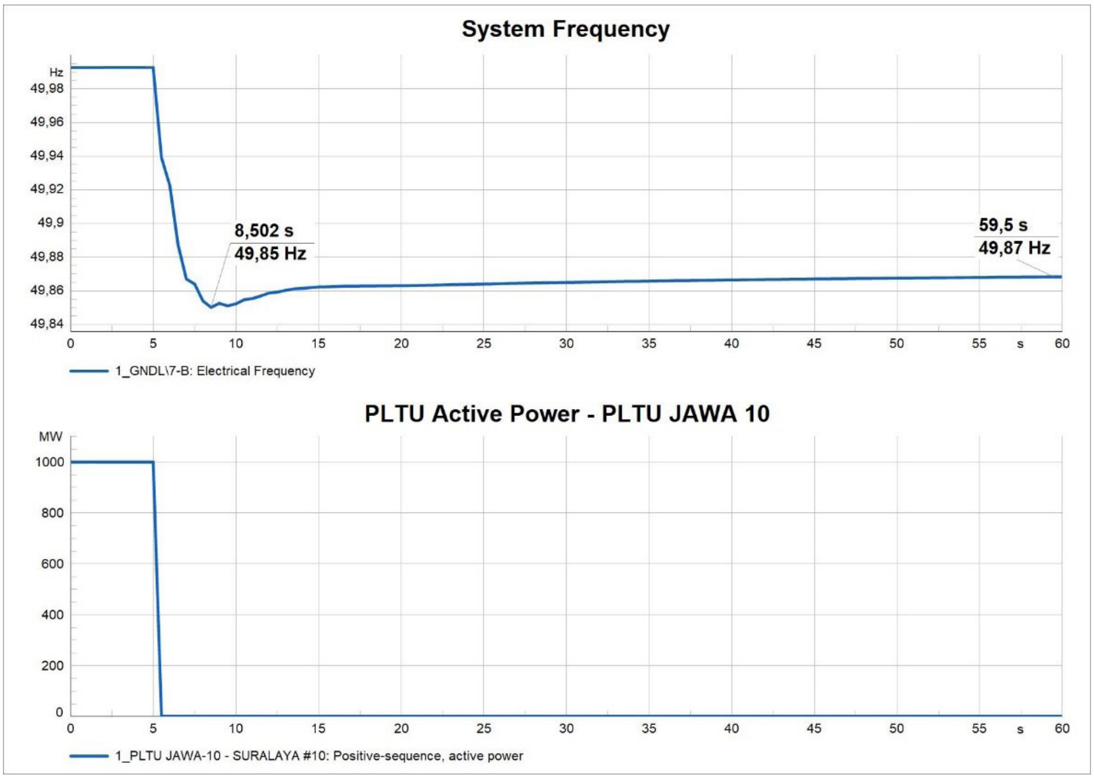


Figure 11. Transient stability analysis -Largest generation unit stepped out causes frequency decrease

In the second scenario shown in Figure 12, where the power output of PV plants in Area 3 was reduced by 50%, dropping from 655 MW to 300 MW over 68 seconds, the frequency decreased to 49.95 Hz.

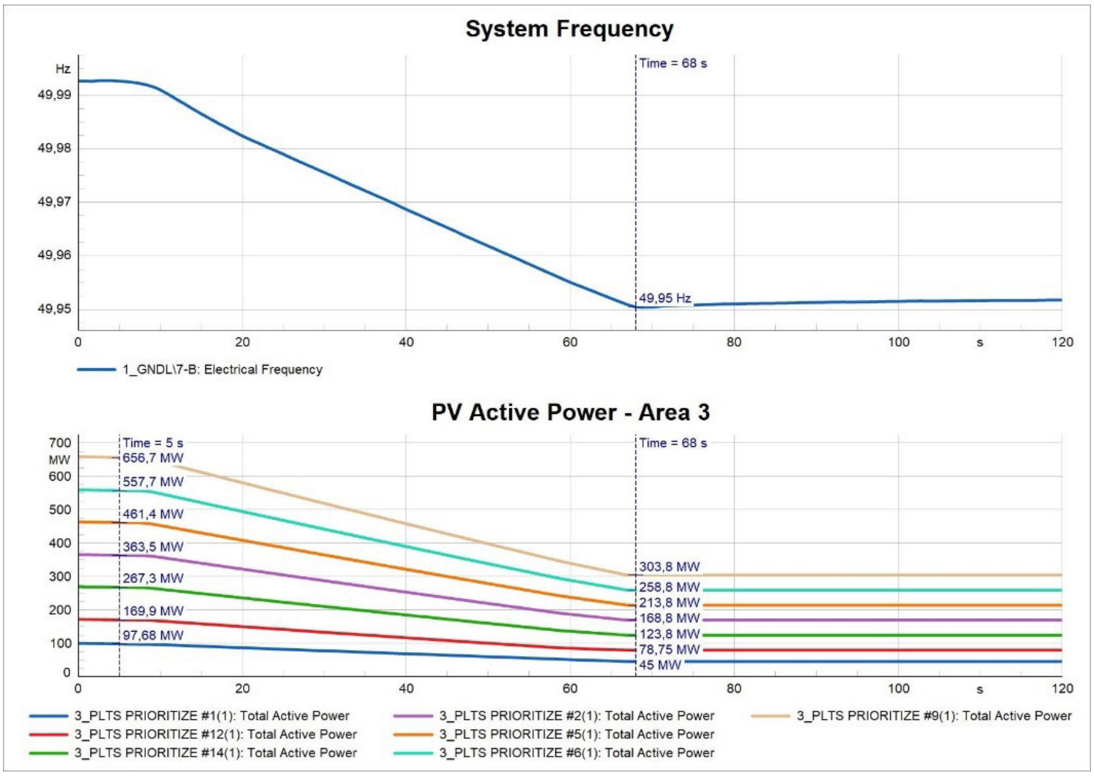


Figure 12. Transient stability analysis – PV plant area 3 50% power reduction due to Solar Irradiation decrease causes frequency decrease

Finally, in the third event shown in Figure 13, a 20% reduction in PV power output, from 655 MW to 520 MW over 31 seconds, caused the frequency to drop slightly to 49.98 Hz, still within the acceptable range. These results demonstrate the system's resilience in maintaining stability despite significant changes in generation.

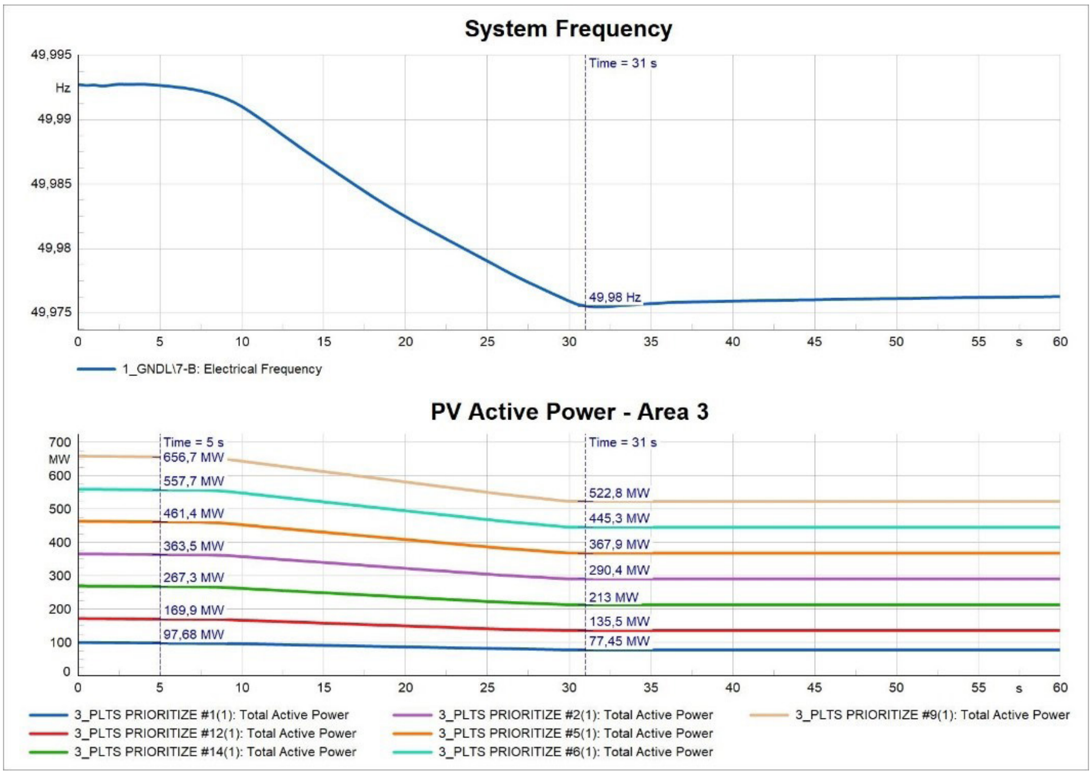


Figure 13. Transient stability analysis – PV plant area 3 80% power reduction due to solar irradiation decrease causes frequency decrease

In practical terms, these results demonstrate that the grid is well-prepared to handle both planned and unplanned events, such as the sudden loss of a generator or fluctuations in solar power due to weather changes. This is particularly important as renewable energy becomes a larger part of the energy mix, ensuring that even with variations in solar output, the grid can remain stable and reliable without the risk of blackouts or the need for immediate interventions.

5.3.4. Quasi-dynamic Analysis

In this case, the analysis tracked the frequency deviation of the JAMALI system over the course of a day. The goal was to observe how the grid's frequency responded to changes in power generation and load, ensuring that these deviations remained within safe limits—specifically within a range of ±0.2 Hz. As shown in Figure 14, the frequency deviation stayed within this range throughout the day, indicating that the system remained stable despite varying conditions.

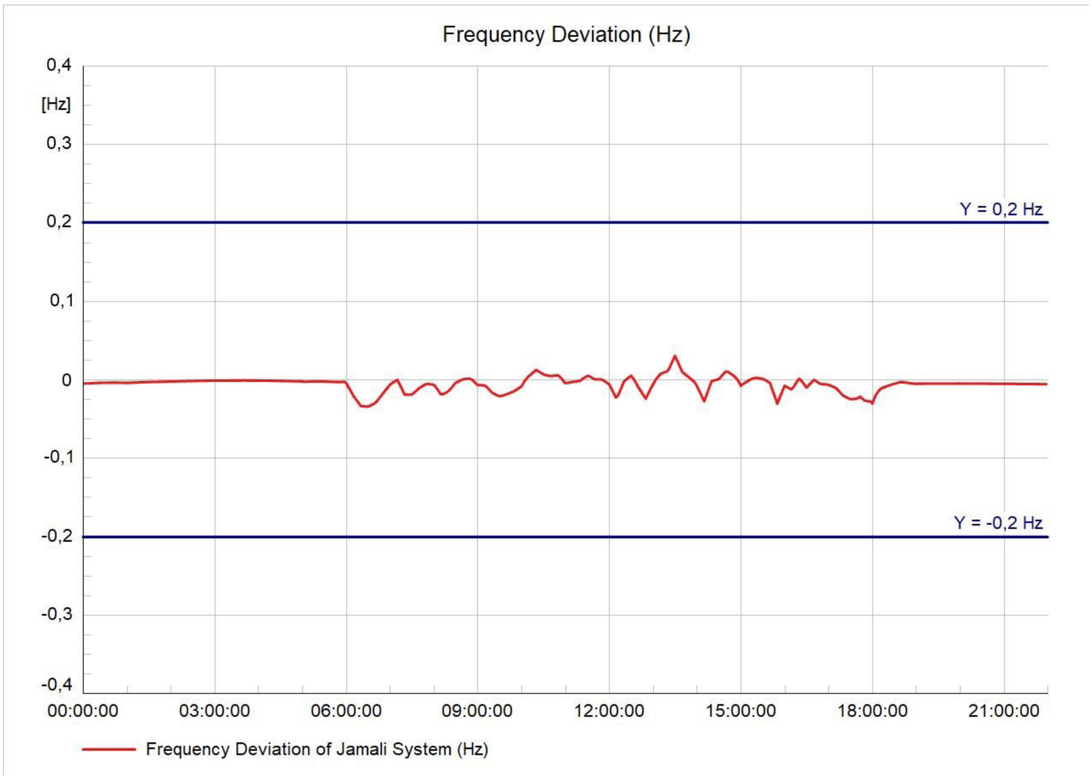


Figure 14. JAMALI Grid frequency deviation (Hz) after 2200 MW PV penetration 2030

These results demonstrate that the grid can handle fluctuations in demand and renewable energy generation without significant issues. Although there were slight frequency fluctuations during the day, they stayed well within safe limits, confirming the system's ability to maintain frequency stability under normal operating conditions. The frequency stayed within the safe range of ±0.2 Hz, this confirms that the grid can manage demand and renewable energy fluctuations without significant issues, maintaining reliable frequency stability, which is vital for supporting the integration of renewable sources like solar power.

5.4. Production Simulation

5.4.1. Generation Mix

As mentioned in the section 5.1.2.4, the scenarios simulated are:

- **Scenario 1**: The base case scenario, which includes PV plants as planned under RUPTL.
- **Scenario 2**: An additional 2.2 GW of PV capacity is integrated.

Figure 15 presents the generation mix curve categorized by fuel type for each power plant under the scenario 1

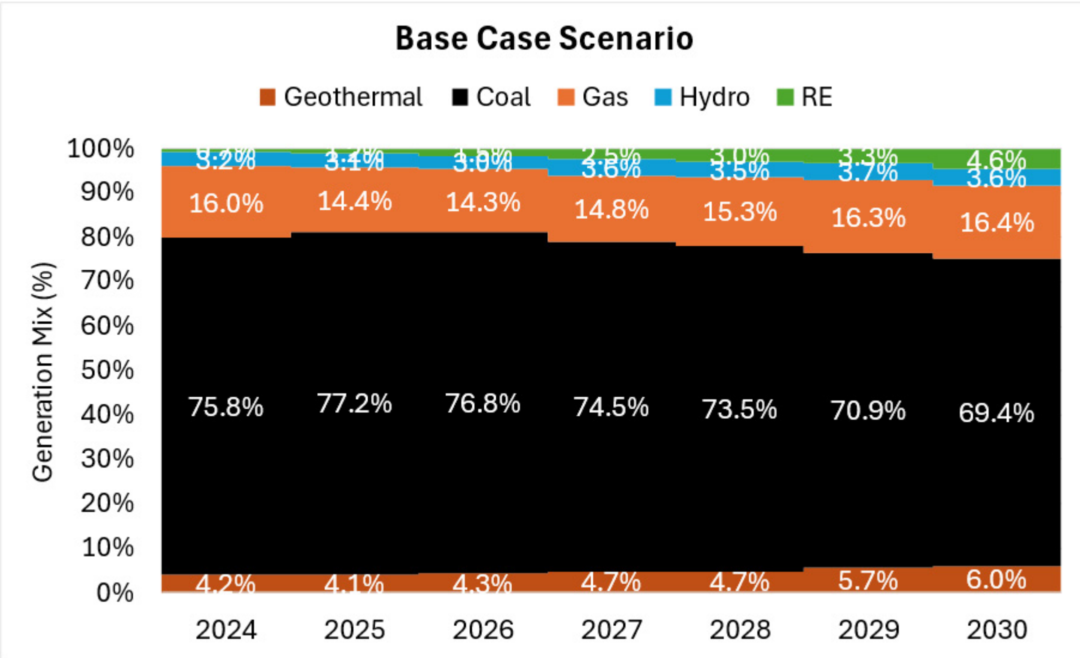


Figure 15. Generation mix curve of base case scenario

Figure 16 illustrates the generation mix under scenario 2, where additional solar PV plants are implemented as planned (see Table 6)

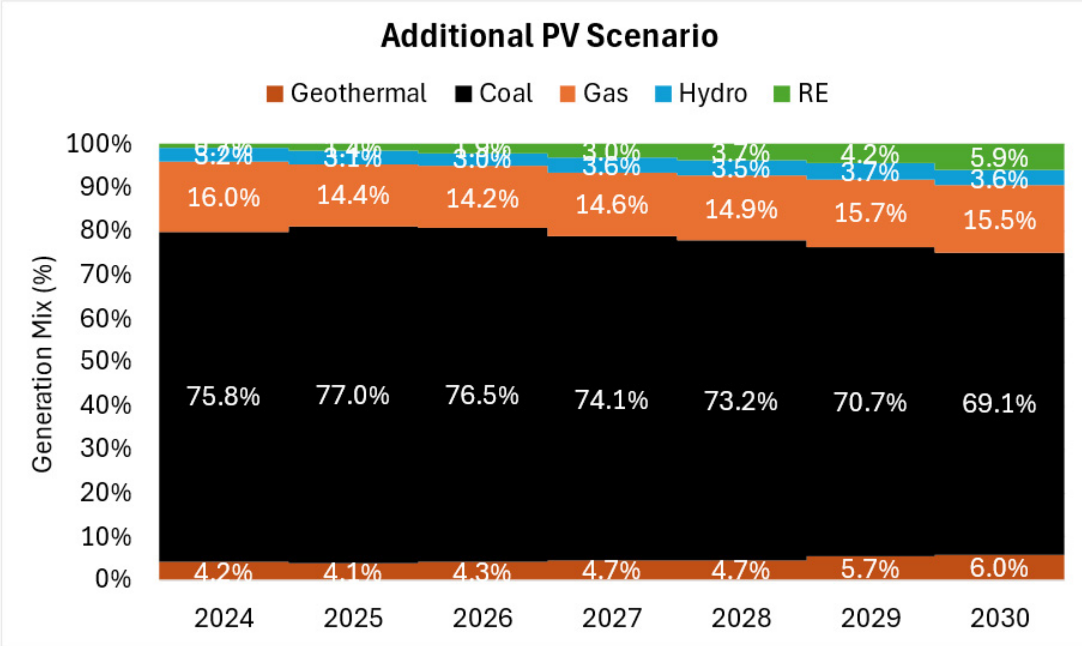


Figure 16. Generation mix curve of additional PV scenario

The addition of solar PV plants (beyond those planned in DRUPTL) as per Scenario 2 results in a gradual increase from 0.2% in 2025 to 1.2% in 2030. This is accompanied by a reduction in energy coming from gas and coal.

The figures representing the two scenarios show how coal's generation share remains the largest. Although the price of VRE is more affordable, there is a limited ability to supply energy sources due to its unstable quantity. Gas is more expensive than coal. Consequently, the utilization of CFPP is maximized first, and then CCGT is utilized.

Under scenario 2, a decline of 0.3% in coal-based generation between 2025 and 2030 can be noticed. During this period, gas-based power generation is projected to gradually decline by 0.1% to 0.9%. In contrast, RE generation is expected to steadily increase, from 0.4% in 2024 to 1.2% by 2030 after the additional solar PV plants.

While the increase in the RE mix resulting from the addition of solar PV may appear modest, it represents a significant rise—from 4.6% to 5.9% by 2030—compared to the baseline scenario, an increase of over 26.5%. This shift highlights the growing contribution of renewables to the overall energy mix, despite coal remaining the largest generation source.

Figure 17 shows the energy transition occurring due to the integration of solar PV into the system. Between 2024 and 2030, coal and gas energy gradually decrease as renewable energy sources grow. However, renewables cannot fully replace gas generation due to limitations in primary energy availability. During this period, coal is the primary source being displaced by additional PV capacity.

From 2025 to 2027, coal energy decreases gradually due to the constraints on gas supply (Take Or Pay TOP Contract). Thevolume of gas that must be absorbed by gas power plants prevents them from shutting down, forcing them to operate at minimum load. Therefore, given the demand conditions during these years, gas power plants cannot significantly reduce their output because they are already at the lower limit of their operating capacity.

From 2028 to 2030, gas power plants respond to growing demand, allowing gas to take on a larger role as they adjust to load conditions. This shift creates an opportunity for PV energy to replace more gas generation than in previous years, as it is often associated with lower variable costs. As can be seen in Figure 17, gas and coal energy are replaced by solar power plants with the same amount of combined coal and gas with solar energy.

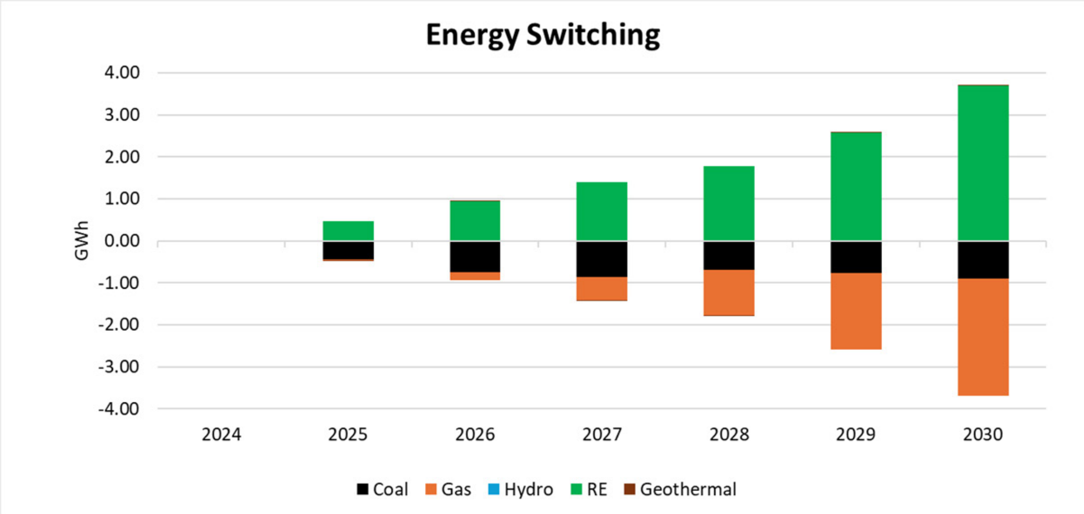


Figure 17. Energy switching curve

Coal's low fuel cost contributes to a lower LCOE. However, replacing coal with more expensive solar PV, as reflected in this case, increases the overall system LCOE. To mitigate this increase, the amount of additional solar PV capacity should be carefully calibrated to replace only gas. Since the capacity factor of solar PV is approximately 18%, it can be used to estimate how much gas energy can be displaced by solar, minimizing the reduction in coal usage. Table 12 outlines the recommended additional solar PV capacity needed to displace gas generation without impacting coal.

Table 12. New additional PV without reducing coal

Powerplant	Unit	2024	2025	2026	2027	2028	2029	2030
Solar PV	MW	-	15	129	356	728	1194	1663

Nevertheless, with the government's current ambition to phase down coal and transition towards green energy, future regulations will likely aim to cap or reduce the share of coal in the energy mix. This shift may lead to a greater reliance on gas as an alternative and given the higher cost of gas, solar PV will become more competitive. Figure 19 shows that the system LCOE decreases from 1,063.3 Rp/kWh to 1,061.3 Rp/kWh by adding 1.663 GW of additional PV instead of 2.2 GW, optimizing the reduction of gas without decreasing coal usage.

A separate study should be conducted to determine the real cost of coal to PLN based on the PPA price, fuel pass-thorough costs (when applicable throughout the operational period to date), and any penalties (if applicable throughout the operational period to date). Because of the fluctuating fuel costs, it is possible that coal power plants will not remain the lowest LCOE power plant. Additionally, when the operational limitations of coal power plants (slow ramp up/ramp down rates) are considered, it may cause additional costs to the grid operations in order to provide frequency and voltage balancing due to demand fluctuations.

5.4.2. Emission Reduction Calculation

As mentioned in the section 5.1.2.4, the scenarios simulated are:

- **Scenario 1**: The base case scenario, which includes PV plants as planned under RUPTL.
- **Scenario 2**: An additional 2.2 GW of PV capacity is integrated.

Figure 15 presents the generation mix curve categorized by fuel type for each power plant under the scenario 1

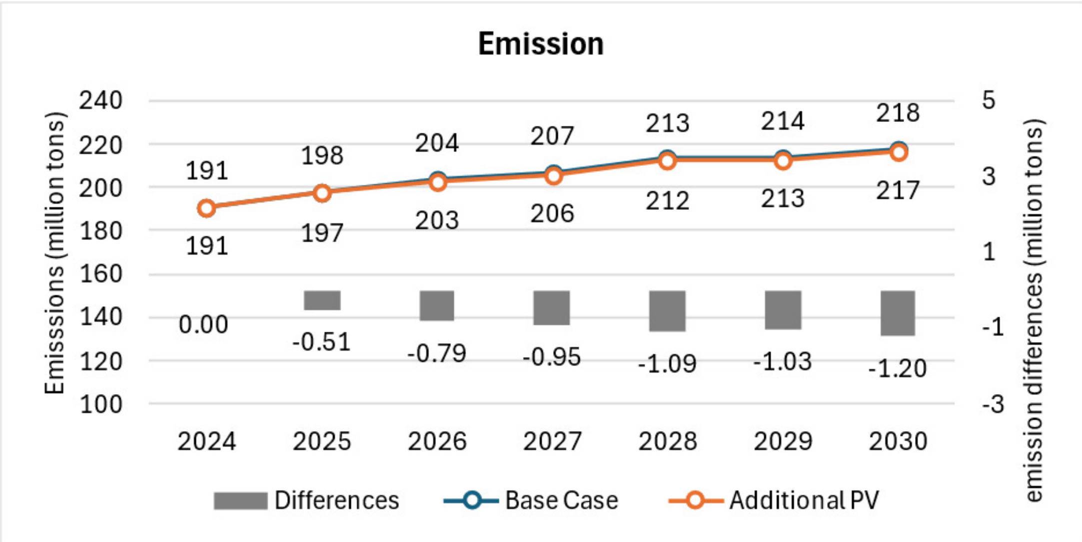


Figure 18. Curve of emissions

Figure 18 above shows emission levels from 2024 to 2030. It highlights three key trends: the blue line represents emissions in millions of tons under current conditions, the orange line represents emissions in a scenario where PV systems are added, and the grey bars indicate the difference between the two emission levels. The addition of solar PV systems results in an average annual reduction of 0.93 million tons of CO_2, contributing significantly to the shift towards a cleaner energy mix.

In 2029, the emission reduction is smaller compared to the previous year due to the addition of 1,800 MW of new gas capacity, which is necessary to meet growing demand. As a result, the additional PV capacity in 2029 displaces more gas-generated energy than in previous years, leading to a smaller reduction in coal-generated energy. This smaller decrease in coal usage results in a lower overall reduction in emissions.

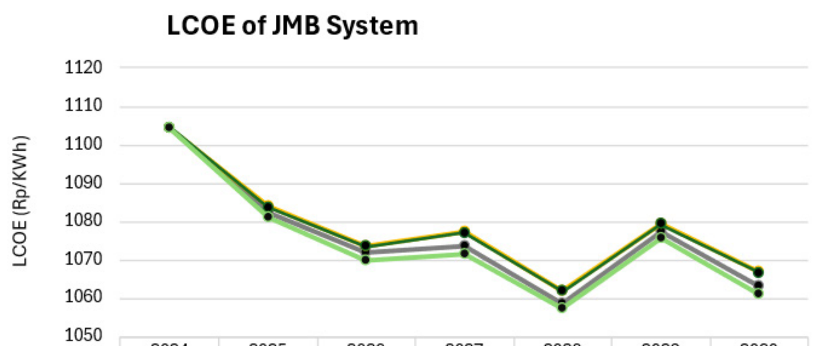
5.4.3. Economic Impact Analysis

In this study, economic analysis uses a grid perspective. The main parameter is the system's LCOE. This LCOE calculates the total cost based on the cost needed by all of the power plants in the grid, including thermal and renewable power plants. The LCOE calculates all of the power plant components, which are component investment, fixed O&M, fuel cost, and variable O&M. The total cost is divided by all of the electric demand in the grid.

In terms of total cost per kWh (that includes all cost component ABCD) in each powerplant, diesel power plants are the most expensive at US$0.166/kWh. This is followed by gas turbine power plants at US$0.099/kWh due to the lower efficiency of the power plant when compared to CCGT plants. On the other hand, CCGT power plants have a cost of generation at US$0.082/kWh. CFPP plants have a cost of generation at US$0.077/kwh. Solar PV projects currently are at a lifetime low at US$0.0695/kWh in Indonesia. Hydro power and wind power at good locations can also generate electricity at relatively low costs of generation at US$0.085/kWh and US$0.092/kWh respectively. The key difference here is that renewable energy power plants such as solar PV, wind, hydro, geothermal, and others do not rely on the availability and price volatility of fuel prices.

The integration of new PV systems into the energy grid has wide-ranging economic implications, especially concerning the potential replacement of fossil fuels and the resulting reduction in CO2 emissions. Conducting a thorough economic impact analysis could help to assess the feasibility of this transition. The economic impact analysis on this deliverable remains at a high level and will be detailed further in the next phases of the project. It is important to note that in this study, all existing power plants are assumed to remain operational, with additional PV systems being integrated into the grid. As a result, the fixed costs of existing power plants do not impact the cost assessment for the new power generation capacity. This means that PLN must still cover the same fixed costs, regardless of whether additional PV capacity is added. On the other hand, the production cost simulation used in this analysis considers only variable costs (components C and D) such as fuel prices, power plant efficiency, and variable O&M costs associated with different types of power plants, including the newly integrated PV systems.

The results from a seven-year horizon study indicate slight variations in the power plant mix due to the scheduled operation of committed power plants. The economic impact of adding new PV plants is contingent on the overall power plant composition within the system.



	2024	2025	2026	2027	2028	2029	2030
Base Case	1104.5	1082.3	1071.9	1073.6	1058.8	1077.2	1063.3
Additional PV	1104.5	1083.9	1073.7	1077.2	1062.0	1079.4	1066.8
Additional PV with carbon tax 2 $/ton	1104.5	1083.8	1073.6	1077.1	1061.9	1079.3	1066.7
New Solar PV Capacity (1663 MWp)	1104.5	1081.0	1070.0	1071.4	1057.4	1075.5	1061.3

Figure 19. LCOE of JAMALI system curves

Three scenarios are analyzed in this economic study:

- **Scenario 1:** The base case scenario, which includes PV plants as planned under RUPTL.
- **Scenario 2:** An additional 2.2 GW of PV capacity is integrated.
- **Scenario 3:** A carbon tax of $2/ton is applied.
- **Scenario 4:** New PV adjustment purpose to reduce the gas energy only.

As a result, in Scenario 2, the LCOE value increases by an average of 2.7 Rp/kWh. This increase is primarily due to the higher investment costs associated with the additional PV plants, which outweigh the energy savings achieved. Consequently, the overall total cost rises because the upfront capital expenditures for solar PV installation exceed the operational cost reductions generated from reduced fossil fuel consumption. However, the cost will be significantly lower after ten years of Solar PV operation.

In Scenario 3, the application of a carbon tax of 2 $/ton results in potential cost savings. The carbon tax increases the cost of CFPP generation, thereby making the replacement of CFPP energy with solar PV more economically favorable for PLN considering the following points:

- The carbon tax to disincentivize fossil fuel is a different mechanism than the solar PV project developer earning additional revenue from the environmental attributes (in this case selling the carbon credits earned by producing solar PV electricity)
- The carbon tax implementation on fossil fuel power plants will add cost to PLN (whether it's a PLN-owned power plant or IPP's owned). If the amount of MWh generated from those power plants is reduced because they are being replaced by some of solar PV generation, then it can be considered as savings to PLN as an avoided cost (both in the MWh PPA tariff from fossil fuel power plants, and in the carbon tax attached to those MWhs).
- The carbon credit sales (or REC sales) based on the MWh produced by the solar PV plant are separate revenue for the project developer (if allowed). This additional revenue allows the solar PV project developer to lower the PPA tariff to PLN while keeping the financial returns attractive to continue developing solar PV projects in Indonesia.

These savings from the carbon tax could translate into a reduction of approximately 0.2 Rp/kWh, or an estimated savings of around 100 billion Rupiah, due to the decreased reliance on coal-based generation and the shift to cleaner solar energy.

When the solar PV capacity is reduced to a total of 1,663 MWp as scenario 4, it is assumed that only gas energy is impacted, as explained earlier. For the economic analysis, the investment cost of adding solar PV is offset by the savings from reduced gas energy. The results show that replacing gas energy with solar PV, at an LCOE of 6.95 c$/kWh, will decrease the LCOE by 1.7 Rp/kWh on average over 5 years, or a total of 2.8 trillion Rupiah

If the additional PV capacity's purpose is to prevent or to offset from an increase in the LCOE, then the carbon price should align with the value presented in Table 13, as modeled in Scenario 3. In this case, the LCOE remains comparable to the base scenario, ensuring that the cost of electricity does not significantly rise, while still achieving environmental benefits through the reduction of CO2 emissions. However, this study of carbon tax is very high level, and further detail study is needed.

Table 13. Yearly recommended minimum carbon price

Item	unit	2024	2025	2026	2027	2028	2029	2030
Carbon Price	$/tonCO2	0	48	36	61	50	38	55

5.5. Power System Analysis

In the context of Indonesia, two important regulatory factors influence energy pricing: the DMO policy, which regulates coal prices, and Presidential Regulation Number 112 of 2022, which caps the price of PV energy at 6.95 c$/kWh. This sensitivity analysis adjusts these factors to reflect potential market conditions. Specifically, coal prices are referenced from the World Bank's market data, and the PV price is updated to reflect the lower end being 5.5 c$/kWh. The objective is to assess how these price changes influence the LCOE and total system cost under different scenarios. The summary of the sensitivity analysis can be found in Table 14.

Table 14. Sensitivity scenarios

Sensitivity	Fuel Price		PV Price	
	Regulated Price	Market Price	Ceiling Price	Anon. Private Project Price
1	✓		✓	
2	✓			✓
3		✓	✓	
4		✓		✓

The scenarios are defined as follows

- **Scenario 1**

  This scenario aims to reflect the real conditions in Indonesia, where the coal price is regulated by the government with a DMO cap, and the price of PV is set at 6.95 c$/kWh according to Presidential Regulation No. 112. This scenario can serve as a benchmark for comparison with other sensitivity scenarios.

- **Scenario 2**

  According to various literature, including technology data for Indonesia's power sector in 2024, there will be a decreasing trend in PV prices in future years. Based on this, there is a possibility that the price of PV could fall below 6.95 c$/kWh. The potential market is reflected by a lower PV price of 5.5 c$/kWh. The coal price still refers to the DMO cap.

- **Scenario 3**

  The DMO policy regulates the coal price in Indonesia with 70 $/ton cap. On the other hand, the global coal price is expected to remain above $100 per ton at least until 2026, according to the World Bank's Commodity Price Forecasts for 2024. This scenario will explore the potential impact of applying global coal market prices in Indonesia. The PV price sill refer to Presidential Regulation No. 112 with 6.95 c$/KWh

- Scenario 4

  This scenario will combine Scenario 2 and Scenario 3, using the global coal market and a lower PV price to assess the economic impact on the JAMALI system

Table 15. Delta LCOE for four sensitivity scenarios

Delta LCOE (Additional PV - Base Case)									
Number	Scenario	Unit	2024	2025	2026	2027	2028	2029	2030
1	DMO + PV (Perpres) Price	Rp/KWh	0.0	1.6	1.8	3.6	3.2	2.2	3.6
2	DMO + PV (Anon. Private Project)	Rp/KWh	0.0	1.2	0.9	2.3	1.6	0.1	0.6
3	Market Coal Price + PV (Perpres) Price	Rp/KWh	0.0	1.1	1.1	2.4	2.5	1.5	2.9
4	Market Coal Price + PV (Anon. Private Project)	Rp/KWh	0.0	0.7	0.2	1.1	0.9	-0.7	-0.1

Table 16. Delta cost for four sensitivity scenarios

Delta Total Cost (Additional PV - Base Case)										
Number	Scenario	Unit	2024	2025	2026	2027	2028	2029	2030	Total
1	DMO + PV (Perpres) Price	Triliyun Rupiah	0.0	0.4	0.5	0.9	0.9	0.6	1.1	4.3
2	DMO + PV (Anon. Private Project)	Triliyun Rupiah	0.0	0.3	0.2	0.6	0.4	0.0	0.2	1.8
3	Market Coal Price + PV (Perpres) Price	Triliyun Rupiah	0.0	0.3	0.3	0.6	0.7	0.4	0.9	3.1
4	Market Coal Price + PV (Anon. Private Project)	Triliyun Rupiah	0.0	0.2	0.0	0.3	0.2	-0.2	0.0	0.5

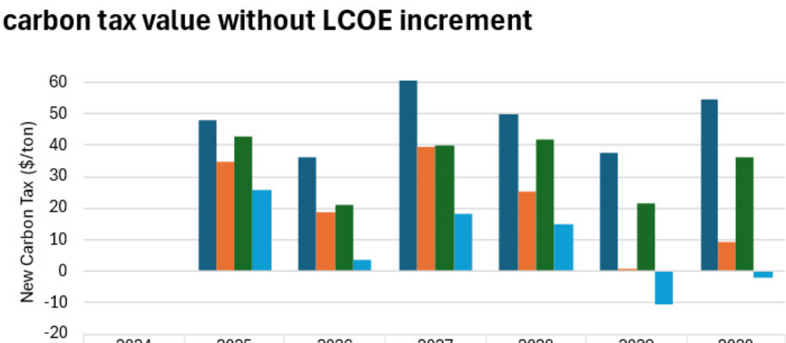
The first and third scenarios demonstrate the varying impacts of coal prices. In Scenario 1, coal prices follow DMO scheme, while in Scenario 3, market coal prices are used, with a USD 40/ton difference. The market coal price results in higher costs for CFPPs, leading to an increase in LCOE. In this case, reducing CFPP energy generation allows for greater penetration of PV energy, which results in larger cost savings compared to the DMO scenario. Higher market coal prices lead to a greater reduction in coal use, replaced by cheaper PV energy, thereby reducing both LCOE and total system costs.

When comparing DMO and market coal price sensitivities, lowering the PV price has a more significant positive effect on reducing delta LCOE and delta total system cost. The incremental cost of LCOE is smaller when the lower PV price is applied, whether under DMO or market coal price conditions.

In Scenario 4, which covers the years 2029 and 2030, negative delta values are observed, indicating that adding PV energy positively impacts reducing LCOE. During these years, around 1.8 GW of CCGT capacity and 1.7 GW of additional capacity are committed, while CFPP are already operating at maximum capacity. As a result, demand growth will be met primarily by gas generation. With the decreasing costs of PV, these conditions allow for more gas energy to be displaced by PV, further reducing LCOE.

Analysis on Carbon Tax

To avoid increases in LCOE when adding new PV capacity, implementing a carbon tax on thermal power plants, particularly CFPPs is recommended. A carbon tax would raise the variable costs of thermal generation, creating a disincentive for the CFPPS and giving indirect economic incentives to increase PV penetration. Figure 20 demonstrates the differences in total costs across the scenarios with and without a carbon tax.



	2024	2025	2026	2027	2028	2029	2030
DMO Fuel Price & Ceiling PV Price	0	48	36	61	50	38	55
DMO Fuel Price & PV Price 5.5 c$/kWh	0.0	34.9	18.6	39.7	25.3	0.9	9.1
Market Fuel Price & Ceiling PV Price	0.0	43.0	21.0	39.9	41.8	21.6	36.2
Market Fuel Price & PV Price 5.5c$/kWh	0.0	26.0	3.8	18.5	15.0	-10.4	-1.8

Figure 20. Differences in total cost of 3 Scenarios

The first and third scenarios, which reflect differences in coal prices, suggest that a higher carbon tax should be implemented to offset the higher costs associated with coal generation. A carbon tax would mitigate the increased costs and help balance the overall system impact. In contrast, the second and fourth scenarios suggest that a lower carbon tax could suffice. However, Scenario 4 clearly demonstrates that even with a lower carbon tax, the addition of PV capacity leads to significant cost reductions and a lower LCOE. This reduction is primarily driven by the displacement of gas energy by cheaper PV, resulting in cost savings, reduced dependency on fossil fuels, and lower emissions.

Nevertheless, implementing a lower carbon tax is not recommended. The analysis underscores that when a carbon tax is applied at higher levels, PV becomes far more favorable in the long term. A higher carbon tax enhances the economic viability of PV, accelerating the transition toward cleaner energy while reducing the financial burden of fossil-fuel-based generation.

An alternative to consider is to allow the project developers the rights to the environmental attributes, which could generate additional revenue to be defined for these actors. Overall, it can result in a lower PPA tariff to PLN. Generally, the project developers have access to the carbon credit/REC market, where they can earn more on the environmental attributes than PLN or other government agencies. It would be worth studying further a combination of a carbon tax for fossil fuel-based power plants and allowing the developers to have the rights to the environmental attributes, which will result in lower PPA tariffs to PLN so that it can have a lower LCOE in electricity generation.

6. RESULTS ANALYSIS AND CONCLUSION

6.1. Result Analysis

This section highlights the results of three major analyses in this report: hosting capacity analysis, grid impact study, and production simulation analysis.

1. Hosting Capacity Analysis

To ensure the projects enable safe, efficient, and reliable RE deployment while aligning with future grid expansion plans and maintaining system integrity, the hosting capacity analysis provided three key sets of analysis: first, on the maximum RE penetration, second, on which substations should be connected to future solar PV developments and lastly the solar PV development constraints linked with the maximum hosting capacity. This analysis was conducted at both the system and substation levels and was critical for identifying potential grid bottlenecks and areas requiring upgrades to accommodate additional RE integration.

It was found through the hosting capacity analysis of the JAMALI grid that in addition to the draft RUPTL planned VRE installations, an additional 2.2 GW of solar PV can be added to the grid on top of the existing VRE plan outlined in the DRUPTL by 2030. This can be achieved without significant BESS installations. The total hosting capacity of the JAMALI grid per year for the next 6-7 years (2025-2030) is presented in Table 6

Understanding this maximum RE penetration is essential for ensuring overall grid stability and preventing issues such as voltage fluctuations or frequency deviations. These insights support safe, efficient, and reliable RE deployment while aligning with future grid expansion plans from PLN.

At the substation level, the analysis revealed a distinction between 70 kV and 150 kV substations. The results showed that 70 kV substations are limited in their capacity to integrate solar PV compared to 150 kV substations. Therefore, it is recommended that future large solar PV development plans prioritize connections to 150 kV substations, which offer greater capacity for accommodating generated power and better support large-scale solar projects. Additionally, while some areas may have ample land available for large-scale solar PV plants, the development potential may be constrained by the substation's maximum hosting capacity unless there is a project to upgrade the current substations.

2. Grid Impact Study

Site prioritization

Locations of the shortlisted sites (25 locations for a total of 2200 MW) were validated by the grid impact study. Solar PV installations at those locations will not affect the grid stability. In the next assignment's stage, a detailed financial viability study of the 25 sites will be conducted. The grid impact study will be adjusted to accommodate any potential changes to the final list of the solar PV sites and ensure that the final list of the solar PV installation sites continues to have no effect on grid stability.

Power system analysis

The power system analysis found that the grid can handle the integration of an additional 2200 MW of PV capacity with few transmission lines and substation upgrades required to maintain long-term stability and reliability.

The grid impact study results show that while the system is generally stable, certain areas, particularly in Area 1 and Area 4 (see definition of the areas 5.3.1), have transmission lines and transformers operating near or above 90% capacity, indicating potential limitations for further PV integration without upgrades. The short circuit analysis confirmed that fault currents across substations, such as 44.2 kA at Tigaraksas5 and 41.0 kA at Tanjung JatiB7, remain within the safe breaking capacity limits (63 kA for 500 kV, 40 kA for 150 kV, and 25 kA for 70 kV), ensuring protective equipment can manage faults. In the transient stability analysis, the removal of the largest generation unit (PLTU JAWA-10, 1000 MW) caused a frequency drop to 49.85 Hz, while power reductions of 50% and 20% in PV plants in Area 3 resulted in frequency drops to 49.95 Hz and 49.98 Hz, all within acceptable limits. The quasi-dynamic analysis revealed that the Jamali system's frequency deviation remained within ±0.2 Hz, indicating the grid can handle fluctuations in power generation and load, even after integrating 2.2 GW of PV capacity. Overall, the study indicates the grid can support further renewable energy integration, but certain areas may require upgrades to maintain long-term stability and reliability.

Production Simulation Analysis

The production simulation results highlight the impact of adding 2.2 GW of solar PV capacity to the JAMALI system, focusing on three main areas: generation mix, emission reduction, and economic impact analysis.

- Generation mix

Integrating the additional PV capacity reduces reliance on fossil fuels. By 2030, coal-based generation decreases by 0.9%, and gas generation falls by 1.2%, while the RE mix increases from 4.6% to 5.9% with the addition of 2.2 GW of solar PV. However, due to minimum load requirements and TOP contracts for coal and gas, these constraints limit the reduction in fossil fuel usage.

In years of growing demand, such as 2028 and 2030, fossil fuel generation—particularly gas—rises to meet the increased load, providing more flexibility for solar PV to displace gas-fired generation. This shift reduces gas consumption, as PV plants have lower variable costs and can replace a larger portion of gas-based energy.

As an alternative, the maximum PV capacity that can be integrated into the grid without replacing coal generation is estimated at 1.663 GW by 2030. However, this would limit the integration of additional PV capacity and miss the opportunity to reduce coal usage in the context of the government's commitment to phase down coal .

- Emission reduction

It was also found that by 2030, coal-based generation decreases by 0.9%, while gas generation falls by 1.2% lowering CO2 emissions by 0.93 million tons per year. This underscores the positive impact of replacing fossil fuels with renewable energy, highlighting the environmental benefits of solar PV integration.

- Economic impact analysis

The economic implications of integrating 2.2 GW of PV capacity are significant. While solar PV helps reduce emissions and fossil fuel dependence, the initial integration adds to the system's total costs, increasing the LCOE. This increase is largely influenced by the mix of coal and gas generation displaced by PV. The simulation reveals that coal price sensitivity, driven by the DMO subsidy, and PV price changes both significantly impact the LCOE.

In scenarios where the coal price follows the DMO and the PV price is capped at 6.95 c$/kWh (as set by Presidential Regulation No. 112), the system experiences the highest LCOE increase, with an average annual delta of 2.7 Rp/kWh. However, if coal prices reflect market values and PV costs decrease to 5.5 c$/kWh (as a lower end of PV LCOE), the LCOE increase is significantly reduced, averaging just 0.3 Rp/kWh. Moreover, in 2029 and 2030, the addition of PV results in an actual reduction in LCOE of 0.7 and 0.1 Rp/kWh, respectively. This reduction occurs as a larger share of more expensive gas generators are displaced by cheaper PV energy, leading to substantial cost savings.

To maximize the economic benefits of solar PV integration, injecting 1.663 GW of PV—enough to replace higher-cost gas generation—could yield immediate savings without the same initial cost pressures associated with displacing coal. However, this approach means the grid is not fully maximizing renewable energy potential by not replacing coal, which remains cheap due to the DMO regulation. Additionally, as stipulated by Presidential Regulation No. 112, after 10 years, the PV tariff will drop significantly to 4.17 c$/kWh /kWh, making it increasingly competitive against traditional generation sources.

> **“ Looking ahead, aligning with government plans to reduce CFPP by 2030, the regulation to phase down coal may drive the system to rely more on gas, which has a higher tariff than coal. This shift could lead to an increase in the system's LCOE. However, adding solar PV—at a lower tariff than gas—can offset the economic impact, allowing PLN to replace coal with more cost-effective renewable energy, thus supporting the long-term affordability and sustainability of the energy mix.**

To further balance the cost increases associated with PV integration, the promotion of a carbon tax could be a strategic option. The level of the carbon tax would depend on the specific scenario. This would help to disincentivize coal and mitigate the overall economic impact of transitioning from coal to renewable energy. An alternative is to grant project developers the rights to environmental attributes, allowing them to generate additional revenue through carbon credit or RECs, potentially leading to lower PPA tariffs for PLN and reducing the overall LCOE in electricity generation. Both scenarios need further study and analysis.

6.2. Conclusion

In conclusion, integrating solar PV into the JAMALI grid offers a viable path to reducing fossil fuel reliance while achieving economic and environmental benefits. By 2030, the grid can accommodate an additional 2.2 GW of solar PV beyond the RUPTL plan without compromising stability, accelerating Indonesia's renewable energy targets and climate goals.

Solar PV demonstrates strong competitiveness with other generation sources, particularly if indirect subsidies, such as the DMO for coal, are removed. While PV prices are higher during the first 10 years, they decline significantly thereafter, making PV the most cost-effective option in the long term. Unlike fossil fuels, PV prices are stable, offering economic security against fluctuating fuel markets. These findings emphasizing the need for policy reforms such as carbon taxes or granting environmental attributes to developers to lower LCOE and PPA tariffs.

The integration of solar PV also brings substantial economic optimization. While initial costs raise the LCOE, the long-term economic benefits are clear; injecting an additional 1.66 GW of solar PV—rather than the full 2.2 GW—focuses on replacing higher-tariff gas power plants. This approach yields immediate cost savings while maintaining grid stability, achieving an optimized balance between renewable energy deployment and system affordability. Additionally, the alignment with Indonesia's plans to phase down CFPPs further underscores the importance of solar PV. While gas may become the primary alternative as coal is reduced, its higher costs could increase the system's LCOE. By integrating solar PV, Indonesia can achieve a more affordable, stable, and environmentally friendly energy mix in the future.

7. NEXT STEPS

7.1. Economic Analysis

The economic analysis will be performed further in the next deliverable to identify the most economically feasible locations for solar PV development by estimating the incurred costs of the solar PV development and potential incentives or facilities based on prevailing regulations. The economic analysis will consider the following:

- Land Acquisition Costs
- Social and Environmental Costs, including potential social and environmental costs in the analysis (e.g., costs required to mitigate any environmental and/or social risks, such as resettlement costs).
- Capital expenditures (CAPEX) for solar PV, covering costs of installing the solar PV
- Capital expenditures (CAPEX) for transmission line infrastructure as well grid integration costs (if any)
- Operational expenditure (OPEX), costs required to operate and maintain the system, including both preventive and corrective maintenance
- Contingency costs, covering estimated costs required to mitigate potential risks, such as estimated resettlement costs, costs to cover potential delay in the construction
- Revenue to the solar PV project owner from electricity sales, by considering the estimated total demand per system, tariff based on the prevailing regulations, estimated generated electricity, and length of Power Purchase Agreement period.
- Financial feasibility parameters, such as Project Internal Rate of Return ("IRR"), Debt Service Coverage Ratio, and payback period

Given the carbon market/REC market that can be available as additional revenue streams for solar PV projects, the financial impact of environmental attribute sales will also be considered. When the additional revenues are considered in parallel to PPA revenues, potentially the PPA tariffs can be reduced while keeping the project IRR the same. The reduction in PPA tariffs will benefit PLN so it can purchase solar PV based electricity from the project developers at a lower cost while keeping the financial returns of the project developers attractive.

If one or more of the analysis scenarios found that the PPA tariff must be higher than the current ceiling price, an additional analysis will be performed. This analysis will calculate the PLN consumer tariff increase that is required by PLN (for all electricity sales except the subsidized consumers) in order to pay for the gap between the required tariff to keep the project IRR attractive to project developers and the ceiling price.

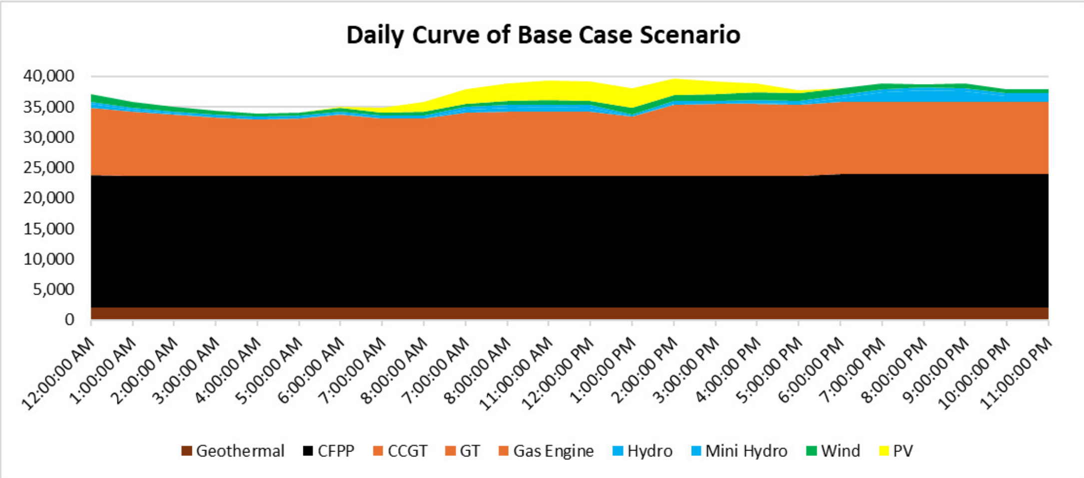
In addition to the parameters above, available facilities or incentives relevant to solar PV development will also be assessed. The available facilities will be assessed based on applicable regulations at the national or regional levels, such as Special Allocation Budget/ Dana Alokasi Khusus/"DAK". However, since facilities and/or incentives will not be certainly obtained, the analysis will only be done on a high-level basis. Further discussions with relevant stakeholders will be required if any of the facilities/incentives are applied to any of the developments.

To complement the economic analysis, further analysis of potential financing and investment mechanisms will also be done by considering potential suitable business models for the selected solar PV development. The business model development will consider the following aspects:

- Stakeholders involved in the solar PV development and their respective roles and responsibilities
- Procurement mechanism for public infrastructure
- Project scheme (e.g. Build-Operate-Transfer/BOT, Build-Operate-Own/BOO)
- Available relevant facilities and/or incentives for respective procurement method
- Contractual arrangement among the stakeholders
- Foreign ownership limitation
- Local content requirement

ANNEX A: GENERATION MIX

The figures below compare the daily generation curves between the scenario 1: Base Case scenario and scenario 2 with additional PV capacity. In the additional PV scenario, output from CCGT and hydro during the daytime decreases, while PV generation increases. Output from other power plants remains unchanged.



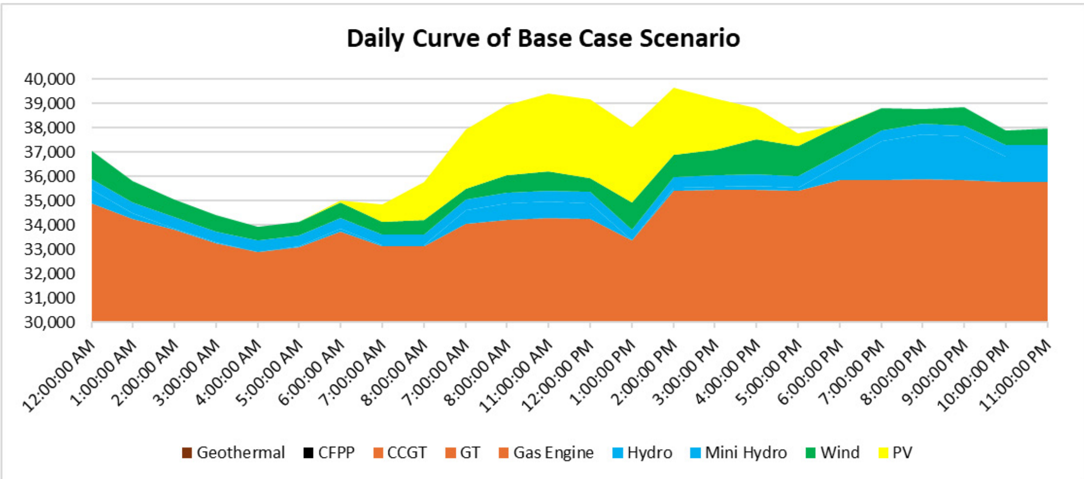
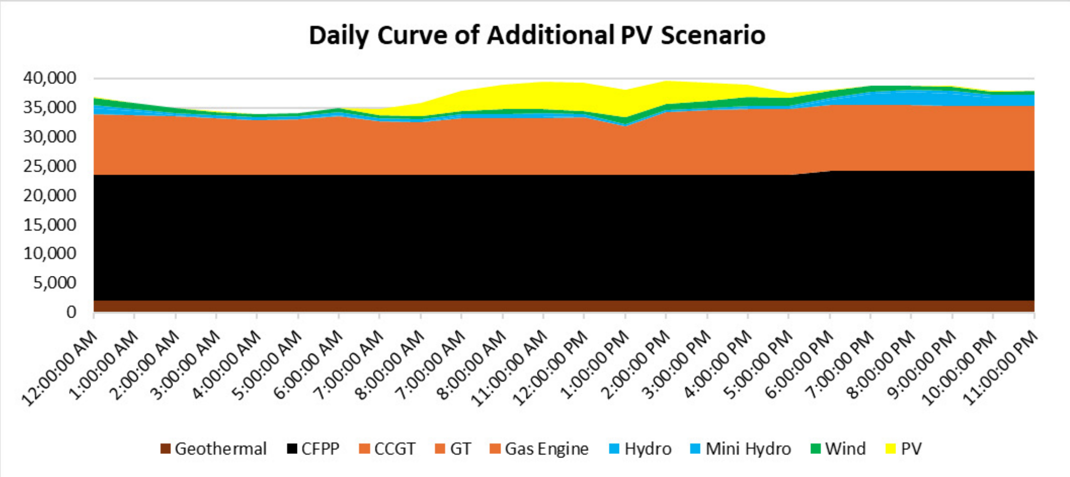


Figure 21. Generation mix: daily curve scenario 1



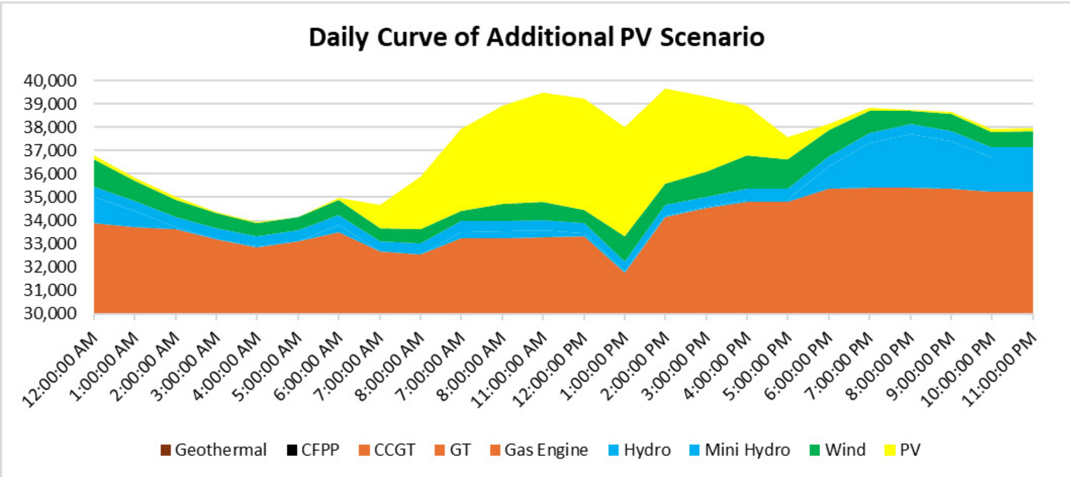


Figure 22. Generation mix: daily curve scenario 2

ANNEX B: CAPACITY FACTOR

Table 17. Capacity factor scenario 1

Category	Property	2024	2025	2026	2027	2028	2029	2030
CFPP	Capacity Factor	69%	72%	75%	75%	78%	78%	79%
CCGT	Capacity Factor	29%	28%	29%	30%	33%	33%	31%
GT	Capacity Factor	13%	19%	15%	24%	1%	2%	1%
Gas Engine	Capacity Factor	74%	60%	36%	37%	8%	10%	7%
Hydro	Capacity Factor	26%	26%	26%	26%	26%	27%	27%
Mini Hydro	Capacity Factor	63%	63%	63%	64%	64%	64%	64%
Wind	Capacity Factor	-	-	30%	30%	30%	29%	30%
PV	Capacity Factor	18%	18%	18%	18%	18%	18%	18%
Geothermal	Capacity Factor	90%	90%	89%	90%	90%	90%	90%
PS	Capacity Factor	-	-	-	-	0%	0%	0%

Table 18. Capacity factor scenario 2

Category	Property	2024	2025	2026	2027	2028	2029	2030
CFPP	Capacity Factor	69%	72%	74%	75%	77%	78%	79%
CCGT	Capacity Factor	29%	28%	28%	30%	33%	32%	29%
GT	Capacity Factor	13%	19%	15%	24%	1%	1%	1%
Gas Engine	Capacity Factor	74%	60%	36%	37%	9%	11%	8%
Hydro	Capacity Factor	26%	26%	26%	26%	26%	27%	27%
Mini Hydro	Capacity Factor	63%	63%	63%	64%	64%	64%	64%
Wind	Capacity Factor	60%	61%	59%	68%	74%	75%	79%
PV	Capacity Factor	-	-	30%	30%	30%	29%	30%
Geothermal	Capacity Factor	18%	18%	18%	18%	18%	18%	18%
PS	Capacity Factor	90%	90%	89%	90%	90%	90%	90%

ANNEX C: PRELIMINARY GRID INTEGRATION ANALYSIS

S_id	Latitude	Longitude	Available Land Coverage Area (ha)	Solar PV Potential by Land (MW)	HubName	Maximum Hosting Capacity (MW)	Solar PV Potential (MW) Individual	Solar PV Potential (MW) Clustered	Hub Distance (kmr)
S1	-6.93775	106.283811	876.70	877	GI 150 kV Bayah	160	160	160	34
S2	-6.446755	106.368132	931.05	931	GI 150 kV Rangkasbitung	260	260	260	14
S3	-6.425143	106.352366	531.82	532	GI 150 kV Rangkasbitung	260	260		11
S4	-6.318448	106.323406	20.24	20	GI 150 kV Rangkasbitung	260	20		78
S5	-6.38938	106.407981	104.41	104	GI 150 kV Tigaraksa	560	104	104	15
S6	-6.369875	106.415828	269.79	270	GI 150 kV Tigaraksa	560	270	270	12
S7	-6.082806	106.140263	71.62	72	GI 70 kV Serang	145	72	72	47
S8	-6.540033	105.703628	381.93	382	GIS 150 kV PLTU Labuan	480	382	382	2
S9	-7.185267	108.421359	10.57	11	GI 150 kV Ciamis	950	11	11	18
S10	-7.224362	108.411471	105.04	105	GI 150 kV Ciamis	950	105	105	13
S11	-6.721517	107.144888	21.27	21	GI 150 kV Cianjur	245	21	21	95
S12	-6.525476	108.137335	106.28	106	GI 150 kV Haurgeulis	140	106	140	23
S13	-6.574419	107.915029	97.14	97	GI 150 kV Haurgeulis	140	97		15
S14	-6.575333	107.920984	97.14	97	GI 150 kV Haurgeulis	140	97		15
S15	-6.573166	107.898683	110.49	110	GI 150 kV Haurgeulis	140	110		16

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S16	-6.546382	108.205422	184.03	184	GI 150 kV Jatibarang	270	184	184	17
S17	-6.46369	107.20107	86.31	86	GI 150 kV Juishin	420	86	355	1
S18	-6.508367	107.213365	22.34	22	GI 150 kV Juishin	420	22		61
S19	-6.560381	107.129157	246.75	247	GI 150 kV Juishin	420	247		15
S20	-7.727922	108.378377	185.51	186	GI 150 kV Karangnunggal	650	186	405	30
S21	-7.733974	108.038529	218.58	219	GI 150 kV Karangnunggal	650	219		15
S22	-6.407955	107.34291	39.07	39	GI 150 kV Kutamekar	425	39	39	23
S23	-6.80754	108.538932	360.02	360	GI 150 kV Mandirancan	330	330	330	60
S24	-6.363727	107.246842	141.32	141	GI 150 kV Mekarsari	730	141	141	0
S25	-6.549476	107.5913	766.58	767	GI 150 kV Pabuaran	460	460	460	11
S26	-7.336353	107.108033	13.85	14	GI 150 kV Patuha	290	14	290	39
S27	-7.343449	107.115982	61.46	61	GI 150 kV Patuha	290	61		38
S28	-7.416727	107.063116	76.34	76	GI 150 kV Patuha	290	76		5
S29	-7.387065	107.197134	174.33	174	GI 150 kV Patuha	290	174		34
S30	-7.460115	107.366101	58.35	58	GI 150 kV Patuha	290	58		3
S31	-6.801179	108.603961	106.19	106	GI 150 kV PLTU Cirebon	380	106	106	36
S32	-6.569329	107.491233	157.96	158	GI 150 kV Purwakarta	500	158	158	40
S33	-6.55169	107.046818	101.20	101	GI 150 kV Semen Baru	510	101	101	16
S34	-7.412025	107.007522	374.44	374	GI 150 kV Semen Jawa	70	70	70	51
S35	-7.423571	106.991565	241.52	242	GI 150 kV Semen Jawa	70	70		52
S36	-7.396133	106.867631	56.87	57	GI 150 kV Semen Jawa	70	57		47
S37	-7.164091	106.800571	220.12	220	GI 150 kV Semen Jawa	70	70		22

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S38	-7.133943	106.950902	37.00	37	GI 150 kV Semen Jawa	70	37	70	17
S39	-6.934184	108.695733	147.01	147	GI 70 kV Babakan	80	80	80	1
S40	-7.012972	107.104993	94.15	94	GI 70 kV Cianjur	245	94	94	61
S41	-6.812715	108.214043	126.10	126	GI 70 kV Kadipaten	65	65		15
S42	-6.776488	108.158431	340.68	341	GI 70 kV Kadipaten	65	65	65	30
S43	-6.66601	108.086401	162.49	162	GI 70 kV Kadipaten	65	65		15
S44	-7.064115	108.536559	138.55	139	GI 70 kV Kuningan	80	80	80	23
S45	-7.00293	108.608177	160.99	161	GI 70 kV Kuningan	80	80		60
S46	-7.013509	107.076605	32.11	32	GI 70 kV Lembursitu	35	32		0
S47	-7.223319	107.025116	19.94	20	GI 70 kV Lembursitu	35	20	35	11
S48	-7.211387	107.03726	84.84	85	GI 70 kV Lembursitu	35	35		39
S49	-7.501746	107.448508	45.87	46	GI 70 kV Pameungpeuk	85	46		38
S50	-7.536841	107.553677	167.67	168	GI 70 kV Pameungpeuk	85	85	85	5
S51	-7.677255	107.893422	292.44	292	GI 70 kV Pameungpeuk	85	85		34
S52	-7.699123	108.409613	118.45	118	GI 70 kV Pangandaran	80	80	80	3
S53	-6.636831	108.026444	210.10	210	GI 70 kV Parakan	70	70	70	36
S54	-7.501991	107.482838	61.55	62	GI 70 kV Sumadra	100	62	62	40
S55	-7.226885	106.487818	25.10	25	GIS 150 kV PLTU Pelabuhan Ratu	60	25	25	16
S56	-6.923886	109.819915	196.38	196	GI 150 kV Batang	1050	196	196	51
S57	-6.996164	111.246076	266.01	266	GI 150 kV Blora	50	50	50	52
S58	-7.214495	110.564115	123.78	124	GI 150 kV Jelok	180	124	124	47
S59	-7.285359	110.868949	163.35	163	GI 150 kV Kedungombo	170	163	163	22

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S60	-7.390214	108.764788	474.72	475	GI 150 kV Majenang	200	200	200	17
S61	-7.488894	110.66251	76.74	77	GI 150 kV Mojosongo	1050	77	77	1
S62	-7.638159	110.934651	331.64	332	GI 150 kV Palur	970	332	332	61
S63	-7.028522	109.507938	239.00	239	GI 150 kV Pemalang	390	239	390	15
S64	-7.093456	109.357606	262.3407	262	GI 150 kV Pemalang	390	262		30
S65	-6.728982	111.541064	101.27	101	GI 150 kV PLTU Rembang	240	101	101	15
S66	-6.801009	111.327478	82.23	82	GI 150 kV Rembang	240	82	82	23
S67	-6.81405	111.536483	121.24	121	GI 150 kV Semen Indonesia	760	121	339	60
S68	-6.861324	111.581306	91.22	91	GI 150 kV Semen Indonesia	760	91		0
S69	-6.848907	111.621764	127.15	127	GI 150 kV Semen Indonesia	760	127		11
S70	-6.924883	109.92602	42.42	42	GI 150 kV Weleri	650	42	215	39
S71	-7.063862	110.161113	61.60	62	GI 150 kV Weleri	650	62		38
S72	-7.056141	110.13914	110.97	111	GI 150 kV Weleri	650	111		5
S73	-6.985719	108.790202	499.05	499	GI 70 kV Babakan	80	80	80	34
S74	-6.463676	110.978186	110.45	110	GITET 500 kV Tanjung Jati	650	110	110	3
S75	-7.100333	113.017469	150.66	151	GI 150 kV Bangkalan	230	151	22	36
S76	-6.909194	112.994416	70.71	71	GI 150 kV Bangkalan	230	71		40
S77	-8.255255	114.263197	19.59	20	GI 150 kV Banyuwangi	520	20	20	16
S78	-7.037614	111.946113	41.85	42	GI 150 kV Bojonegoro	255	42	189	51
S79	-7.029902	111.934325	146.61	147	GI 150 kV Bojonegoro	255	147		52
S80	-7.251292	111.699117	157.13	157	GI 150 kV Cepu	190	157	157	47
S81	-8.379733	114.049428	206.47	206	GI 150 kV Genteng	280	206	280	22

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S82	-8.327976	114.051084	30.60	31	GI 150 kV Genteng	280	31	280	14
S83	-8.403846	114.072117	63.40	63	GI 150 kV Genteng	280	63		10
S84	-7.741457	112.859112	28.75	29	GI 150 kV Gondangwetan	870	29	29	72
S85	-6.926187	111.876359	120.99	121	GI 150 kV Kerek	360	121	275	80
S86	-6.936615	111.889799	154.16	154	GI 150 kV Kerek	360	154		83
S87	-6.813834	111.734607	141.71	142	GI 150 kV Mliwang	1350	142	245	17
S88	-6.800867	111.719162	103.33	103	GI 150 kV Mliwang	1350	103		19
S89	-7.672422	112.770756	49.15	49	GI 150 kV Pier	1080	49	49	68
S90	-7.740245	112.834374	77.59	78	GI 150 kV Purwosari	850	78	78	88
S91	-7.160636	113.035305	69.64	70	GI 150 kV Sampang	680	70	306	22
S92	-6.931467	113.099427	119.23	119	GI 150 kV Sampang	680	119		31
S93	-6.929501	113.114488	116.68	117	GI 150 kV Sampang	680	117		3
S94	-6.851106	111.875362	422.42	422	GI 150 kV Sementuban	240	240	240	38
S95	-6.906619	111.79984	150.98	151	GI 150 kV Sementuban	240	151		13
S96	-6.901331	111.823752	83.66	84	GI 150 kV Sementuban	240	84		10
S97	-7.79798	114.117181	82.16	82	GI 150 kV Situbondo	560	82	312	14
S98	-7.729317	114.03488	230.19	230	GI 150 kV Situbondo	560	230		23
S99	-6.888254	113.858622	190.13	190	GI 150 kV Sumenep	310	190	310	13
S100	-6.918821	114.012356	34.81	35	GI 150 kV Sumenep	310	35		22
S101	-6.940136	114.045873	105.07	105	GI 150 kV Sumenep	310	105		24
S102	-6.971228	113.985799	38.25	38	GI 150 kV Sumenep	310	38		17
S103	-6.921716	113.595546	23.42	23	GI 150 kV Sumenep	310	23		28

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S104	-6.95054	113.650841	79.49	79	GI 150 kV Sumenep	310	79	310	21
S105	-6.934192	113.641757	22.65	23	GI 150 kV Sumenep	310	23		23
S106	-6.92464	113.723392	89.98	90	GI 150 kV Sumenep	310	90		15
S107	-6.88439	113.86962	73.70	74	GI 150 kV Sumenep	310	74		14
S108	-6.88157	113.864133	58.24	58	GI 150 kV Sumenep	310	58		14
S109	-6.891748	113.968872	49.92	50	GI 150 kV Sumenep	310	50		19
S110	-6.897391	113.97715	29.52	30	GI 150 kV Sumenep	310	30		20
S111	-6.908124	114.004647	76.26	76	GI 150 kV Sumenep	310	76		21
S112	-6.919903	114.020474	30.43	30	GI 150 kV Sumenep	310	30		22
S113	-6.919549	113.786772	85.73	86	GI 150 kV Sumenep	310	86		11
S114	-6.924807	113.728822	86.76	87	GI 150 kV Sumenep	310	87		15
S115	-6.949569	113.653144	94.76	95	GI 150 kV Sumenep	310	95		21
S116	-6.886059	113.838383	47.09	47	GI 150 kV Sumenep	310	47		13
S117	-6.881294	113.848313	24.58	25	GI 150 kV Sumenep	310	25		14
S118	-6.879662	113.875716	33.20	33	GI 150 kV Sumenep	310	33		15
S119	-6.885831	113.924179	54.35	54	GI 150 kV Sumenep	310	54		16
S120	-6.768347	111.943708	46.60	47	GI 150 kV Tanjung Awar Awar	250	47	81	74
S121	-6.770969	111.968529	33.53	34	GI 150 kV Tanjung Awar Awar	250	34		54
S122	-6.936296	112.148195	6.99	7	GI 150 kV Tuban	1100	7	244	1
S123	-6.942557	112.146967	26.10	26	GI 150 kV Tuban	1100	26		14
S124	-6.940865	112.139568	51.44	51	GI 150 kV Tuban	1100	51		13
S125	-6.935325	112.156381	18.34	18	GI 150 kV Tuban	1100	18		14

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S126	-7.035883	111.95829	64.34	64	GI 150 kV Tuban	1100	64	244	2
S127	-6.986106	112.068169	78.39	78	GI 150 kV Tuban	1100	78		11
S128	-7.715003	111.34321	199.71	200	GI 70 kV Magetan	75	75	75	80
S129	-7.596396	112.67149	102.17	102	GI 70 kV Pandaan	90	90	90	58
S130	-7.715605	112.297694	217.87	218	GI 70 kV Siman	65	65	65	13
S131	-7.699438	112.767905	63.04	63	GI 70 kV Sukorejo	50	50	50	63
S132	-8.096548	115.250903	45.26	45	GI 150 kV Baturiti	240	45	240	20
S133	-8.102311	115.273379	51.84	52	GI 150 kV Baturiti	240	52		21
S134	-8.116732	115.27702	213.90	214	GI 150 kV Baturiti	240	214		20
S135	-8.409523	114.84328	324.77	325	GI 150 kV Negara	350	325	350	21
S136	-8.293214	114.577632	96.18	96	GI 150 kV Negara	350	96		12
S137	-8.091324	115.172601	19.36	19	GI 150 kV Pemaron	210	19	19	13
S138	-6.993032	108.701195	133.16	133	GI 70 kV Babakan	80	80	80	12
S139	-7.057922	108.479136	215.76	216	GI 70 kV Kuningan	80	80	80	10
S140	-6.849257	107.87823	40.91	41	GI 70 kV Sumedang	100	41	41	36