Danish Energy Agency

EMBASSY OF DENMARK
Jakarta

South Kalimantan Regional Energy Outlook

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Disclaimer

The present report was developed with the support of National Energy Council (NEC), PLN Kalsel and Dinas ESDM South Kalimantan. However, the results, the simulations setup and the views expressed in the report do not represent any official statement or position of the aforementioned institutions. The results are to be ascribed solely to the main authors, i.e. Ea Energy Analyses and the Danish Energy Agency.

Foreword

These studies have been developed in a fruitful cooperation between Indonesian partners the Danish Embassy and the Danish Energy Agency. It is part of our long-standing and successful cooperation on energy, which is a step in the right direction towards reaching Indonesia's renewable energy targets. The cooperation and dialogue between a variety of stakeholders from both Indonesia and Denmark including national and regional governmental agencies, PLN, universities has led to a great product. We have shared a lot of information, knowledge and experience about low carbon energy planning. The studies and added capacities are of great value for the current and future energy planning in these regions. I am very pleased to see that the regions show a great potential for large-scale renewable energy. It is my hope that we move into the implementation phase for the Regional Energy Outlook. These studies, including the Lombok Energy Outlook from 2018, can hopefully inspire investors to visit these regions and will enable them to explore the vast renewable energy potential that can be utilized.

Saleh Abdurrahman

Secretary General,
National Energy Council

I would like to extend my gratitude to Children's Investment Fund Foundation for their financial contribution, enabling us to execute this study as part of our successful strategic sector cooperation between Denmark and Indonesia in the area of energy. As we hope to be able to assist Indonesia in its path towards a green and sustainable future with lessons learned from the Danish energy transition, I am pleased to see our countries exchanging knowledge and building ties in an important sector for the future. Apart from strengthening our bilateral relationship further, it is my belief that this study will contribute to Indonesian initiatives in accelerating renewable energy in Indonesia. Modelling and energy planning can play an important part in sparking the needed low carbon transition. It lays the foundation for sound policymaking and hopefully can inspire policy makers to turn targets into action. I remain confident that this study, as well as our other regional studies, could serve as excellent showcases for Indonesia to kick off a green transition. Once these regions have taken the first step in realizing their renewable energy potential, it is my wish that other provinces will follow suit and replicate those endeavours.

Rasmus Abildgaard Kristensen

Ambassador,
Danish Embassy in Indonesia

The Danish Energy Agency has a valuable cooperation with the Indonesian partners based on Danish experiences in long-term energy planning, integration of renewable energy and energy efficiency. In 2018, we initiated a new cooperation about provincial energy planning with focus on Lombok. This cooperation turned out very well with an Energy Outlook and prefeasibility studies for specific energy projects in Lombok showing a more detailed path to a greener and cheaper energy system. Since this cooperation turned out successful, we agreed to scale the provincial activities to four new provinces. These new provinces have very different characteristics and resources, which justifies the provincial approach. However, they all have a large potential for renewable energy and once again, our long-term planning approach based on economic optimization shows promising results for all of them. It is my strong hope that these valuable results will be considered in the regional energy planning in the provinces so the Danish experiences will be applied to ensure an affordable, resilient and environmentally friendly development of the power system in the provinces and stimulate the green transition in Indonesian.

Martin Hansen

Deputy Director General,
Danish Energy Agency

Danish Energy Agency

Ea Energy Analyses

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Executive summary

The **South Kalimantan Regional Energy Outlook** explores the potential development of the power system in the medium (2030) and long (2050) term analysing least-cost alternatives to address key questions, namely:

- How can South Kalimantan province ensure an affordable, resilient and environmentally friendly development of the power system?
- Can renewable energy (RE) become a competitive and cost-effective alternative to a development solely based on fossil fuels?

The province of South Kalimantan is part of the larger power system in Kalimantan (Borneo island) and is characterized by a moderately high average generation cost (1,682 Rp/kWh in 2018, compared to an average of 1,119 Rp/kWh for Indonesia). The power demand – today around 2.6 TWh/year – is expected to more than double in the next 10 years, requiring large infrastructure investments in both generation and transmission capacity.

In the current plans, the development of the generation mix for the next 10 years is almost exclusively based on new coal and natural gas plants, with limited investments on renewable energy. The picture is even more extreme towards 2050 in the regional energy plan RUED, which expects the additional demand to be covered almost exclusively by new coal power plants. The target for RE contained in RUED is only 14% in 2025 and 9% in 2050.

Among the reasons for this limited ambition for RE deployment is the fact that South Kalimantan is **one of the provinces with the largest coal reserves** and the contribution of coal mining to GDP is prominent. However, Kalimantan will also home to one of the first wind farms in Indonesia, a 70 MW project in Tanah Laut regency which is expected to be commissioned in 2021 and further expanded in the years to come. The province features not only a **good potential for competitive wind power**, with some of the best wind resources in the country, but also a large potential for solar and biomass-based power supply.

This report presents three *"what-if"* scenarios for 2030 which provide insights into the potential impacts and dynamics of the energy system's evolution under certain conditions. A **Business-as-Usual** (BaU) scenario serves as a reference and is based on plans from RUPTL 2019. Two least-cost alternatives supplement the BaU: the **Current Conditions** (CC) scenario which allows least cost investment in capacity from 2020 and the **Green Transition** (GT) scenario which demonstrates the impact of lower cost of finance for RE (8% WACC) compared to coal (12% WACC), thanks to international support against climate change, and consideration of pollution cost in the cost optimisation.

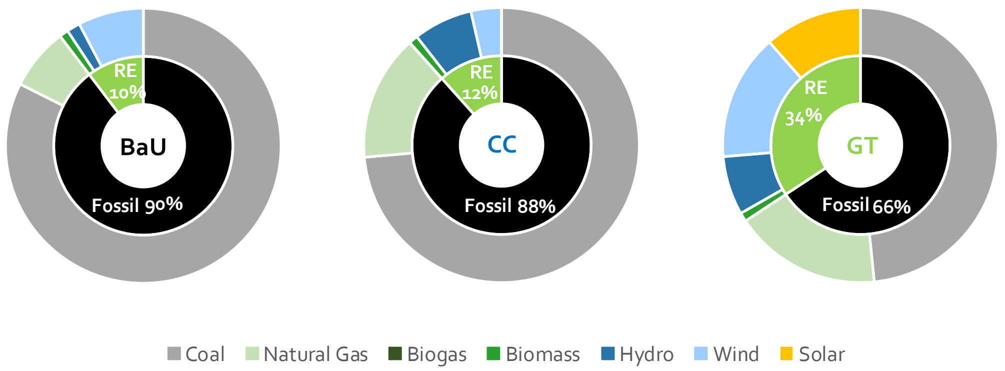


Figure: Power generation shares in the three scenarios shows the opportunity to increase RE penetration from 8% in BaU to 34% in 2030.

In addition, an assessment of the 2050 perspective has been carried out, comparing the expectations from the RUEDs of Kalimantan provinces to a scenario based on least-cost optimization with the aim to assess what would be the cheapest long-term system development path, disregarding the future targets currently in place.

The potential for South Kalimantan province to supplement the coal pipeline with affordable RE is tangible, especially after 2024 when overcapacity resulting from the commissioning of 400 MW of coal is reduced. This would lead the province towards a more sustainable development pathway. The opportunity to develop economically feasible hydro, wind and solar projects is enabled by the declining cost of RE technologies over time and access to cheaper capital.

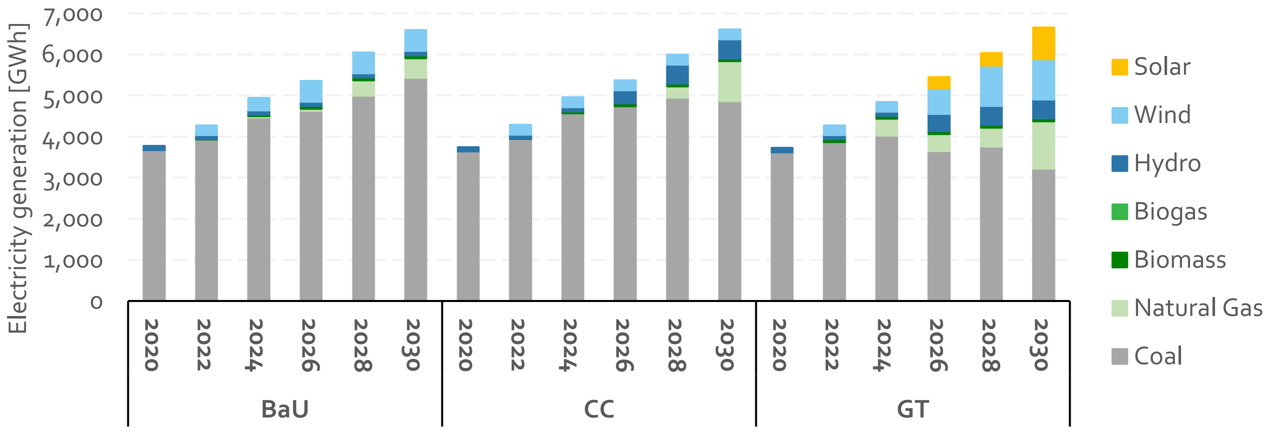


Figure: Power generation development in the three scenarios in South Kalimantan province.

The **large pipeline of coal projects under construction (400 MW)** guarantees the supply of most of the power demand increase in the coming years, making the province a net exporter and requiring only minimum additional investments before 2026. After that, in both optimized scenarios additional hydro and gas plants are added, while in the Green Transition scenario a large amount of wind and solar is further installed reducing coal generation.

A power system with 34% RE can be achieved while saving a cumulative ~3 trillion IDR by 2030 relative to BaU. Both Green Transition and the Current Condition scenarios have lower power costs than BaU (1,042 Rp/kWh). The Green Transition scenario (average generation cost of 1,016 Rp/kWh) has a minor extra cost of 13 IDR/kWh compared to the Current Conditions scenario (985 Rp/kWh). When including the estimated pollution cost, the GT scenario is by far the cheapest pathway, with an additional cumulative saving of 2 billion IDR in health-related costs compared to the other two scenarios.

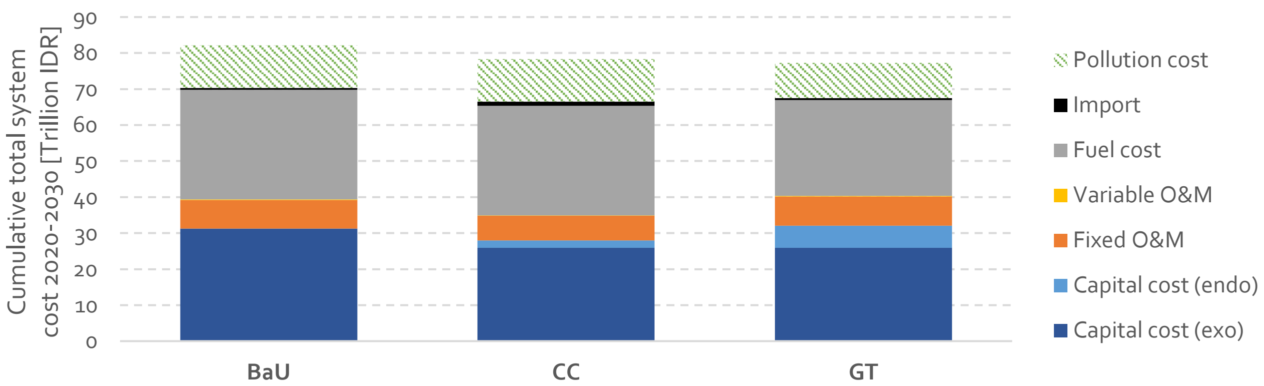
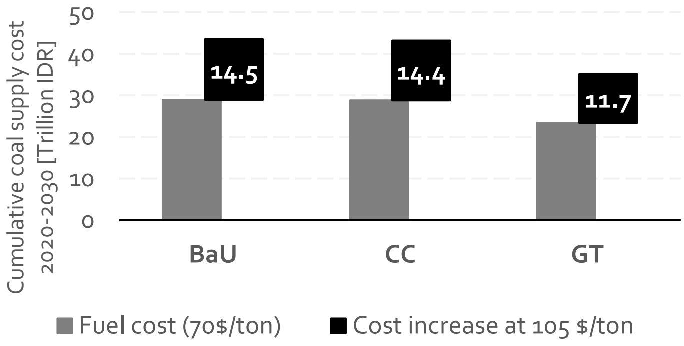


Figure: Cumulative total system costs in the three scenarios for the period 2020-2030.

If the Domestic Market Obligation capping the price to 70 $/ton is not renewed and coal price returns to around 105 $/ton, **the 2020-2030 system cost could increase by more than 14 trillion IDR in the BaU and Current Conditions scenarios**, while it would increase only 11.7 trillion IDR in the Green Transition scenario, materializing savings of 2.7 trillion IDR due to higher **diversification of the supply** and more RE in the system. This testifies to the risk of overreliance on coal. With such a high coal price, capacity factors of coal decline as **combined cycle gas power plants provide consistently cheaper bulk power generation** with a generation cost of 876 Rp/kWh compared to the 1,300 Rp/kWh of coal. In case the gas pipeline from East Kalimantan, expected to be operational after 2023, is not built, South Kalimantan province **would have the opportunity to install more RE to cover the increased demand**: an additional 100 MW of solar, 200 MW of wind and 40 MW of geothermal would be installed under Green Transition conditions.

Figure: Total cost increase 2020-2030 if the coal price returns to 105 $/ton.



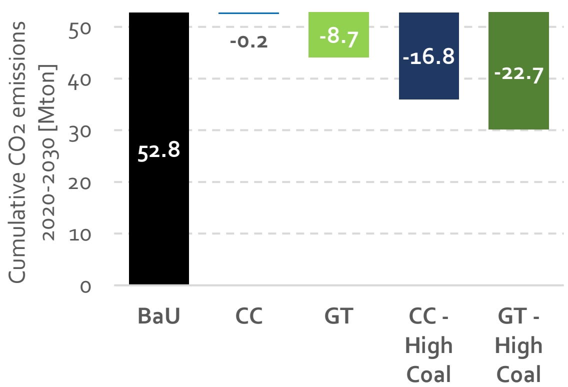


Figure: Cumulative emissions by scenario (incl. high coal price)

Today's CO_2 emissions from the power sector total 2.7 Mtons/year. The reliance on coal power and the power plants in the pipeline will almost double the emissions by 2022 and almost triple them by 2030 in BaU. A **combination of more RE and natural gas** (optimal in case of high coal prices) **can reduce cumulative emissions by an impressive 43%** and allow South Kalimantan province to supply a more than double of 2018 demand with the same emissions as today.

Toward 2050, **substitution of coal with natural gas and large deployment of solar and wind can reduce 2050 CO_2 emission by 60% and save on average 3.3 trillion IDR per year**, plus an additional 2.4 trillion IDR per year in health-related costs compared to what is planned in RUED. **The optimal share of RE is found to be 24% in 2050** (only 9% in RUED).

Following the analysis' results, the **key recommendations** to achieve an affordable and environmentally friendly development of the power system include:

- *Look beyond coal: start considering not only wind power, but also solar PV as potential sources of cheap power, especially under good financing. The identification of suitable sites for both technologies and the preparation of pre-feasibility studies can help attract investments.*
- *Start factoring in the risk of a discontinuation of the Domestic Market Obligation and a potential surge in coal price. Renewable energy and combined cycle gas turbines represent cheap options to diversify the power supply and increase the resilience of the power supply with respect to the generation cost.*
- *Carefully reassess the case for additional coal power plants to avoid technology lock-in and overcapacity.*
- *Map and monitor loan and financing option and attract international finance through the commitment to a RE project pipeline, the increase of the RE ambition of South Kalimantan province and an improved communication of these targets.*
- *Revise long-term RUED targets upward for RE and natural gas. Consider technology development and cost reduction potentials, with an eye on worldwide solar and wind market.*

Table of content

Table of figures

Nomenclature

Abbreviations

BaU	Business-as-Usual
BPP	Biaya Pokok Penyediaan (average generation cost)
CC	Current Conditions scenario
CF	Capacity Factor
COD	Commissioning Date
DEA	Danish Energy Agency
Dinas ESDM	Dinas Energi Sumber Daya dan Mineral
DMO	Domestic Market Obligation
EBT	Energi Baru Terbarukan (New and Renewable Energy)
EVA	Economic Evaluation of Air pollution
FLH	Full Load Hours
GDP	Gross Domestic Product
GHG	Green House Gas
GHI	Global Horizontal Irradiation
GT	Green Transition scenario
HSD	High Speed Diesel
IDR	Indonesian Rupiah (= Rp)
IPP	Independent Power Producer
KEN	Kebijakan Energi Nasional
LCoE	Levelized Cost of Electricity
LEAP	Long-range Energy Alternatives Planning
LNG	Liquified Natural Gas
MEMR	Ministry of Energy and Mineral Resources, Indonesia
MMSCF	Million Standard Cubic Feet
MIP	Mixed-Integer Problem
MFO	Marine Fuel Oil
MPP	Mobile Power Plant
NEC	National Energy Council, Indonesia
NDC	Nationally Determined Contribution
OPEX	Operational cost
PLN	Regional Power Company
PPA	Power Purchase Agreement
PPP	Purchasing Power Parity
PV	Photovoltaics
RE	Renewable Energy
RES	Renewable Energy Sources
RUED	Rencana Umum Energi Daerah (regional plan for energy system development)

Rp	Indonesian Rupiah (= IDR)
RUEN	Rencana Umum Energi Nasional (National Energy General Plan)
RUPTL	Rencana Usaha Penyediaan Tenaga Listrik (electricity supply business plan)
RUPTL19	RUPTL published in 2019 covering the period 2019-2028
SSC	Strategic Sector Cooperation
TSO	Transmission System Operator
VRES	Variable Renewable Energy Sources (wind and solar)
WACC	Weighted Average Cost of Capital

Power plant and fuel definition

PLTU	Coal
PLTUMT	Coal mine-mouth
PLTG	Gas
PLTGU	Combined cycle gas turbine
PLTS	Solar
PLTA	Hydro
PLTM	Mini/Micro hydro
PLTMG	Gas engine
PLTP	Geothermal
PLTB	Wind
PLTSa	Waste
PLTBm	Solid biomass
PLTBio	Liquid biomass
PLTBg	Biogas
PLTD	Diesel

1. Introduction

1.2 BACKGROND AND OBJECTIVES

This report is part of a larger project aiming at supporting the four provinces of South Kalimantan, Riau, North Sulawesi and Gorontalo in the development of their regional/provincial energy plans (RUEDs) and as a result assist them in their policy making. A regional energy outlook is developed for each province which includes in-depth analysis of the power systems, scenario analyses of pathways for optimizing the energy mix using a least cost approach and providing strategic policy recommendations.

The province of South Kalimantan, which is the focus of this report, is part of the larger power system in Kalimantan (Borneo island) and is characterized by a moderately high average generation cost (1,655 Rp/kWh in 2018, compared to an average of 1,119 Rp/kWh for Indonesia). South Kalimantan has the second largest coal reserves in Indonesia and coal mining industry accounts for 19-26% of the provincial GDP in the last five years (IESR 2019). The province has some of the best wind sites in the entire country, second only to South Sulawesi. South Kalimantan is home to the second largest wind farm in Indonesia – a 70 MW project which will be built in 2021 in Tanah Laut regency.

The RUED sets long-term targets for the use of RE, gas and coal in the province up to 2050. The ambition level of the province in terms of renewable energy deployment[1] is among the lowest in Indonesia, despite the favourable conditions and potential for wind, solar and biomass. Provincial RUED sets a target of 14% RE in 2025 and only 9% in 2050. With this starting point, the objectives of the study here presented here are:

- Assess power system planning in South Kalimantan province in the medium term (2030) and evaluate alternative development paths potentially including more RE generation;
- Analyse the plan for the power sector included in the RUED and evaluate a least-cost alternative to provide affordable, resilient and environmentally friendly development up to 2050.

1.3 GENERAL INFORMATION ON SOUTH KALIMANTAN

South Kalimantan is one of the six provinces of Kalimantan, the Indonesian part of Borneo island. It borders East Kalimantan in the north and Central Kalimantan toward west, while it faces the Makassar strait in the East (Figure 1). The total area is 37,378 km^2.

The capital, Banjarmasin, is located at the delta of Barito and Martapura rivers and is home to around 700,000 inhabitants. In the 2010 decennial census, the population recorded was at just over 3.6 million inhabitants.

South Kalimantan has two different climates: Tropical rainforest climate (Köppen climate classification Af) dominates but at the province border the tropical monsoon climate reigns. The climate is very much dictated by the surrounding sea and the prevailing wind system. Temperatures are relatively consistent throughout the year, averaging about 27 °C and the rainfall is on average high (Wikipedia 2019).

[1] The national and regional targets are formulated in terms of "new and renewable energy" (EBT in Bahasa), which, besides all renewable energy sources, includes also municipal solid waste and potentially nuclear.

Figure 1. Map of South Kalimantan. Source: Google Map.

South Kalimantan province has the second largest coal reserves in Indonesia, following East Kalimantan province. Coal contributes substantially to the local economy of the province, since coal mining industry accounted for 19-26% of the provincial GDP the last five years (IESR 2019).

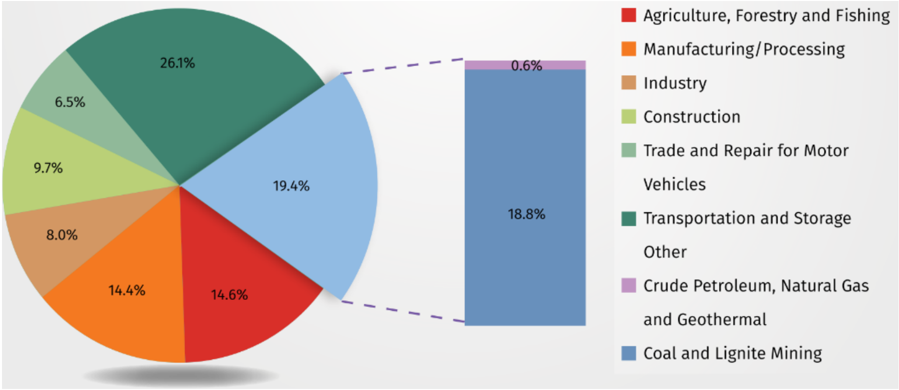


Figure 2: Breakdown of 2017 GDP in South Kalimantan.

1.4 POWER SYSTEM OVERVIEW

The power system in South Kalimantan is integrated with that of Central Kalimantan and together they are referred to as Kalselteng. In South Kalimantan, the largest interconnected system is Barito, while the largest isolated system is Kotabaru. Kotabaru is currently supplied with around 16 MW local diesel plants and is planned to be interconnected to the main system via a 150 kV line (PT PLN Persero 2019). In 2018, the electrification rate of the province was equal to 93.86%. In June 2018, it has been interconnected to East Kalimantan system via a 150kV power line.

The average generation cost for the different regional systems in Indonesia is commonly referred to as BPP (Biaya Pokok Pembangkitan) and its value for the past year is published by the Ministry of Energy and Mineral Resources in Spring (MEMR 2019). BPP represents an important metric both in terms of prioritization of investments and for regulation purposes. Indeed, since Ministerial Regulation 12/2017 (and following amendments), the potential tariffs for Power Purchase Agreements (PPA) with Independent Power Producers (IPP) have to be anchored to the value of the average generation cost of the system[2].

In Kalselteng, the 2018 BPP was of **1,682 Rp/kWh** (11.61 c$/kWh), the highest registered in Kalimantan region if excluding islands and non-interconnected systems. As a reference, the national average of BPP in 2018 was 1,119 Rp/kWh.

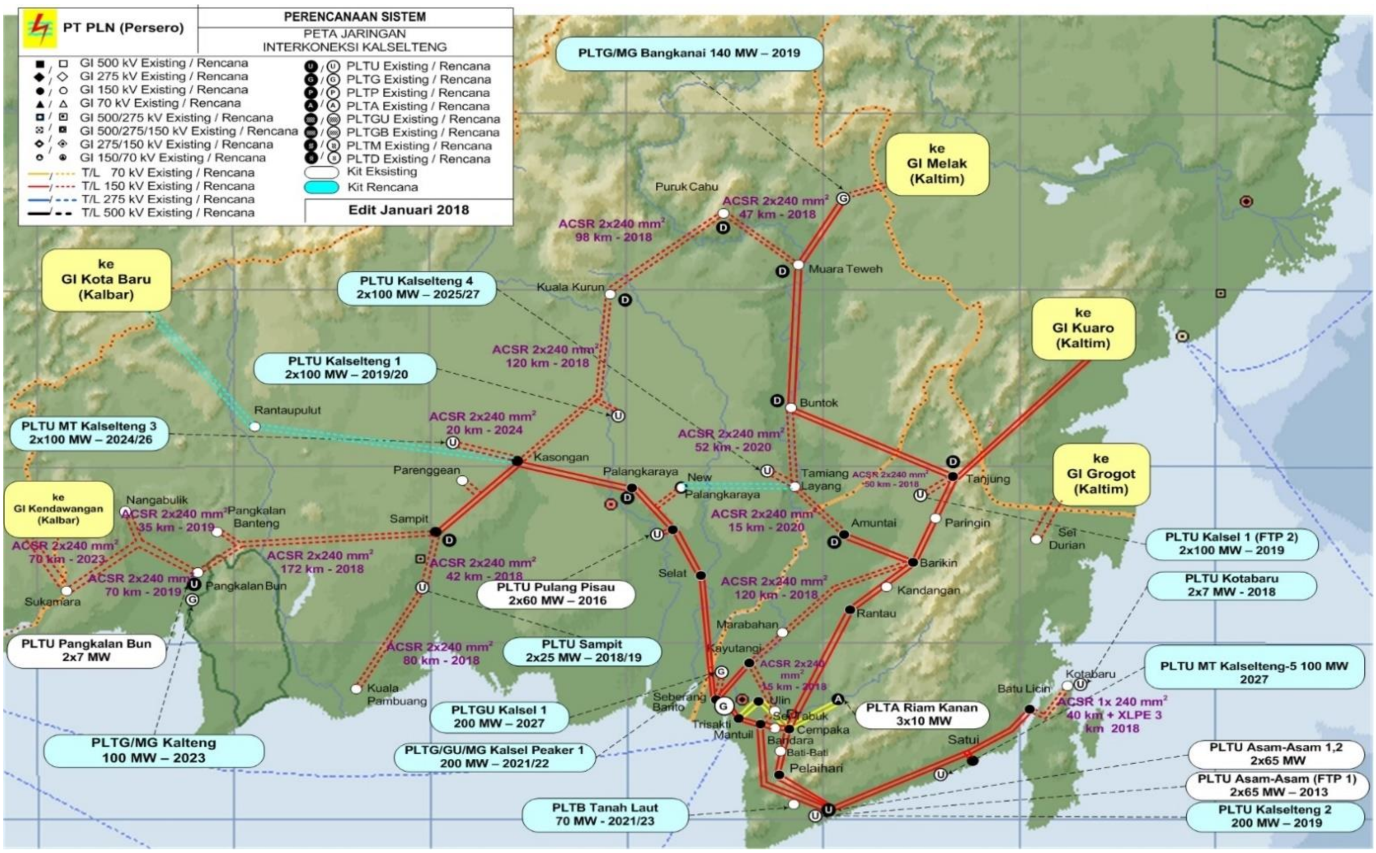


Figure 3: Overview of PLN Kalsel power system, including existing and planned generation. Source: (PT PLN Persero 2019)

[2] More specifically, the maximum permitted tariff for RE projects is set to 85% of the BPP of the region. For more info, see e.g.: (NEC; Danish Energy Agency; Ea Energy Analyses 2018).

Power demand

The RUPTL (PT PLN Persero 2019) reports a power demand in 2018 equal to 2,597 GWh, with an expectation for the South Kalimantan demand to grow to 5,581 GWh in 2028, corresponding to about twice the current demand. The growth expectations for the near future are mainly driven by an increased industrial activity, in particular in relation to coal mining and palm oil plantations. However, the regional plan contained in RUED (Dinas ESDM Kalimantan Selatan 2019) projects a much higher power demand, reaching 10 TWh by 2030 and corresponding to a value that is 60% higher in 2028 compared to RUPTL.

Looking at the average power load profile (Figure 4), the average daily peak load in Kalsel is around 550 MW and happens around 18-19 at night.

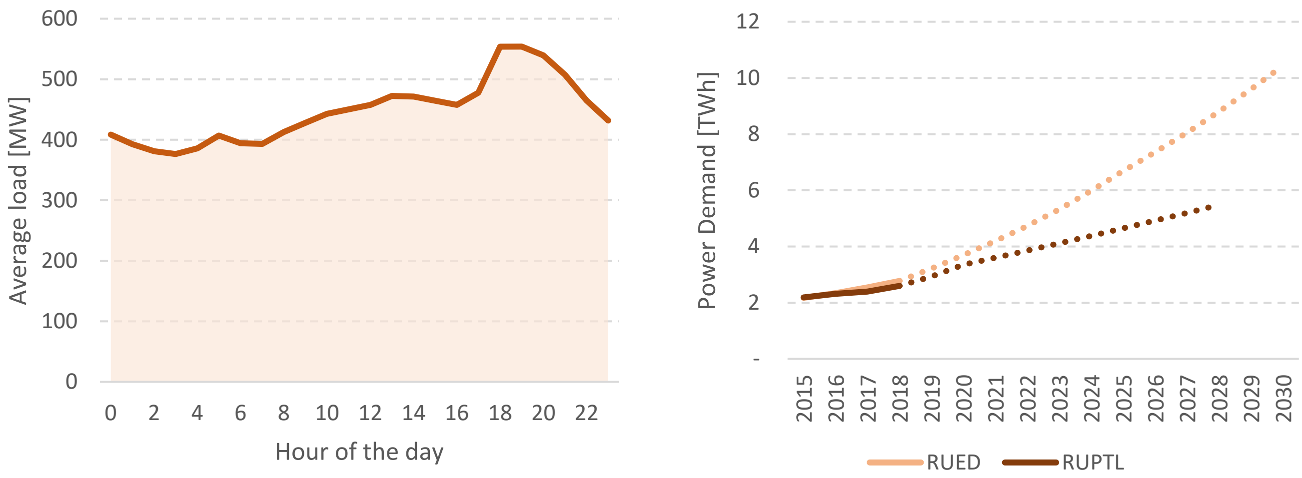


Figure 4: Daily load profile for 2018 (left) and total demand including projection to 2028 in RUED and RUPTL (right).

Current fleet overview

The total installed capacity in the Barito system stands today at 460 MW. The largest capacity by fuel is coal power with 260 MW installed plus 70 MW of excess power from a captive power plant[3], followed by diesel plants around 100 MW. Among the diesel plants there are both gas turbine using diesel due to lack of gas supply (21 MW of PLTG Trisakti) and a captive power plant of 12 MW. The only RE generator in the system is represented by a 30 MW hydro power plant in Riam Kanan (Figure 5).

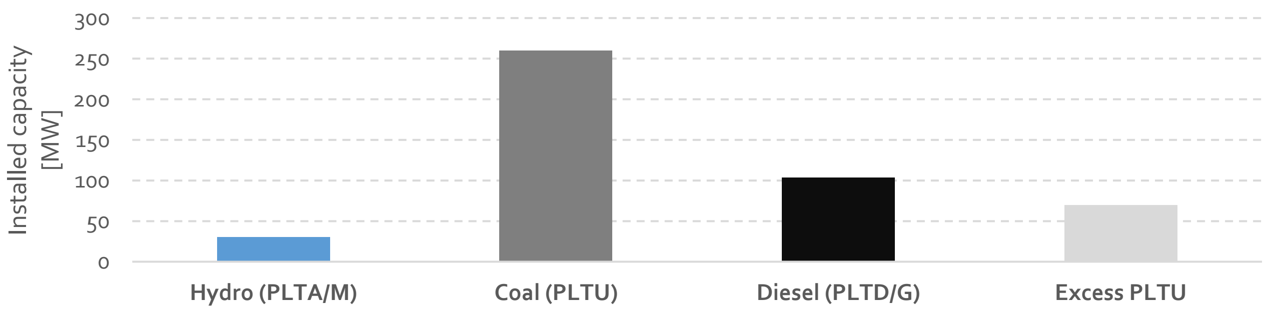


Figure 5: Installed capacity in 2018 in South Kalimantan – Barito system.

[3] Captive power plants are facilities dedicated to providing a localised source of power typically to an industry or palm oil plantation. Some of these plants operate in grid parallel mode with the ability to export excess power to the local electricity distribution network.

RUPTL: PLN plan for the next 10 years

Every year PLN, the national vertically integrated utility, publishes the national electricity supply business plan named RUPTL (Rencana Usaha Penyediaan Tenaga Listrik). The most recent version, published in 2019 (PT PLN Persero 2019), covers the period 2019-2028 and includes demand projections based on GDP evolution in each province, and planned expansion of the transmission network and the generation capacity.

The plan for investment in new generation capacity in South Kalimantan (Figure 6)[4] includes a large amount of coal plants, some gas plants and modest amount of RE units.

Two large coal power plants of 200 MW each, Kalsel and Kalselteng2, are under construction and will be commissioned in 2019 and 2020, respectively. With the addition of these two plants South Kalimantan will have power in excess and will most likely export it to neighbouring provinces. A 200 MW gas peaker will be fully operational from 2022, while an additional 100 MW combined cycle gas turbine and 100 MW mine mouth coal-fired power plant are planned to be added in 2027 and 2028, respectively.

As for RE, PLN signed a letter of intent with Total Eren to build the second wind farm of Indonesia, located in Tanah Laut, featuring a rated capacity of 70 MW and expected to be commissioned in 2021 (Total Eren 2017). Further bioenergy projects for a total of 12.4 MW are included in the plan. The local office of Dinas ESDM has explained that the plan is to build more wind power capacity before 2025, most likely an additional 80-130 MW.

While the listed projects include some RE, the planned development of the system is largely based on fossil fuels and in particular coal power plants.

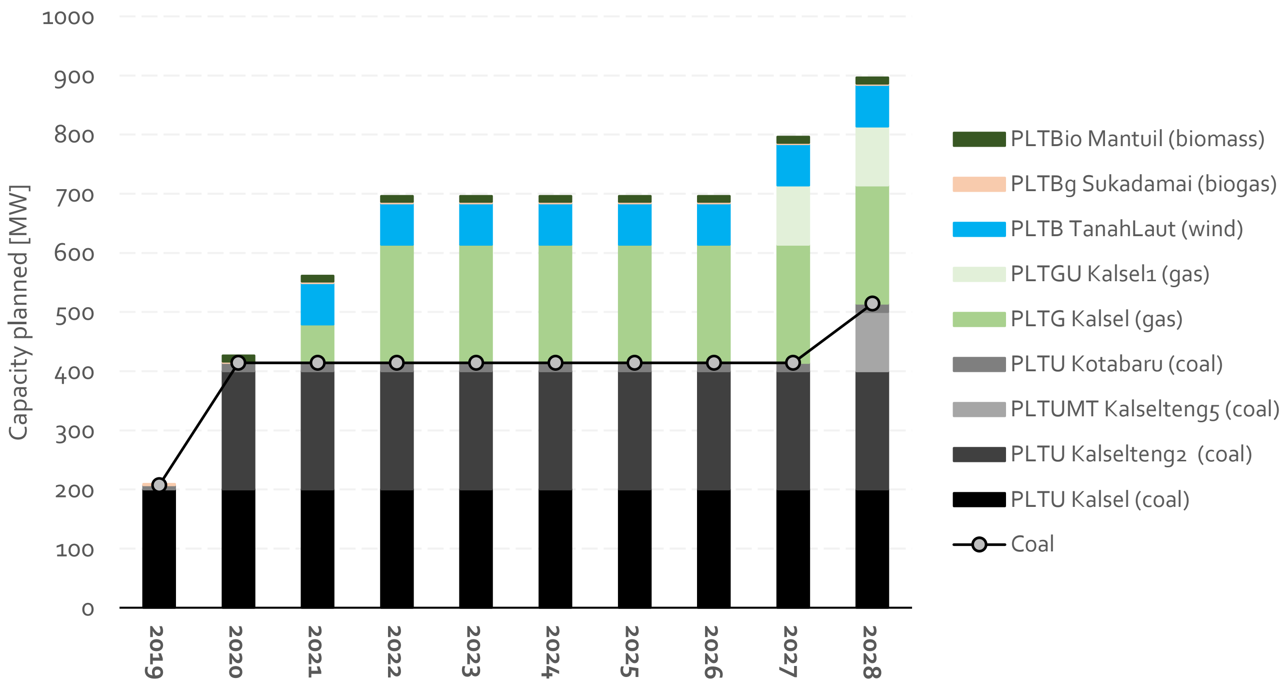


Figure 6: PLN plan for system development contained in RUPTL19 (PT PLN Persero 2019).

[4] A list of all planned power plants from RUPTL19 including location, size, expected commissioning date (COD) and ownership is available in Appendix B.

RUED: the regional planning document

RUED is part of the energy planning documents required by National Energy Law 30/2007, together with KEN and RUEN. While KEN and RUEN guide the development at national level, RUED focuses on the provincial level and how each province will contribute to the national targets. The preparation of the document involves different actors and the responsibility resides with the RUED taskforce, with the main actor being the regional office of the Ministry of Energy (Dinas ESDM). As a regional regulation, the final version must be approved by the provincial parliament.

Table 1: RUED targets for the RE share of primary energy.

	Entire energy system	Power system
	[%]	*[%]*
2015		6.4
2025	19.6	14.1
2050	24.7	9.0

The RUED document covers the development of the entire energy sector and, in several provinces, it has become common practice to use the LEAP[5] model (Stockholm Environment Institute 2019) to develop an overview of the energy system development towards 2050.

The overall targets for renewable energy contained in the latest draft version of RUED are indicated in Table 1. South Kalimantan aims at reaching a 24.7% RE share of primary energy in the entire energy system in 2050, which falls short of the 31% target set by KEN and RUEN at national level.

The focus of this study is on the contribution from the power sector to the regional targets set in the RUED document of South Kalimantan. The approach currently used in RUED to determine the evolution of the power system is not based on optimization and does not consider the expected cost developments of new technologies, nor the power system dynamics. South Kalimantan expects the power sector to contribute relatively less than other sectors, with the RE share only equal to 14% in 2025 and 9% in 2050. This very low target is because the province expects almost all the additional capacity in the 2050 perspective to be supplied by coal, with 7 GW of installed capacity in 2050. The capacity development assumed in RUED for the power system are summarized in Figure 7 and original tables from RUED can be found in Appendix B (Dinas ESDM Kalimantan Selatan 2019).

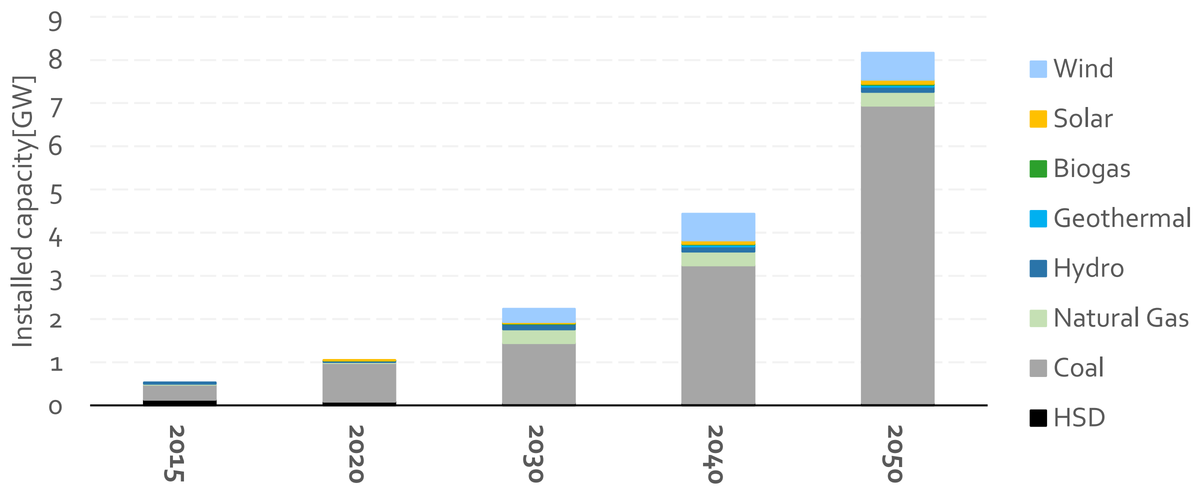


Figure 7: Expected capacity development in RUED in South Kalimantan.

[5] Long-range Energy Alternatives Planning System (LEAP)

RE potentials

The development of RE projected in RUED is strictly related to the potentials available in the province. An overview of the potentials can be found in RUEN (Presiden Republik Indonesia 2017), which describes how much capacity of hydro, geothermal, wind, solar and bioenergy can be installed in each Indonesian province. Figure 8 shows the assumed potentials for the analysis[6] and Full Load Hours (FLH) of generation[7]. South Kalimantan has a very large potential for solar power, totalling around 6,030 MW, followed by biomass (1,266 MW) and wind (1,400 MW). Hydropower resource is modest (280 MW) and with low capacity factors.

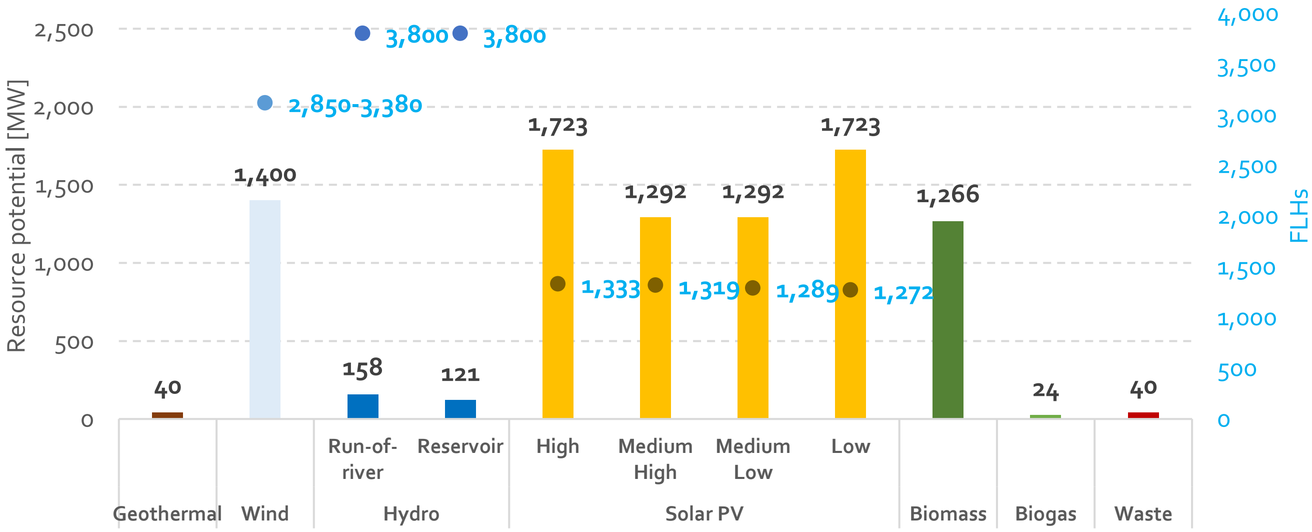


Figure 8: Potential RE sources and estimated Full Load Hours.

The potential of wind power, originally equal to 1,006 MW in RUEN, has been revised upwards to 1,400 MW by Dinas ESDM in RUED, therefore this value has been considered in the analysis.

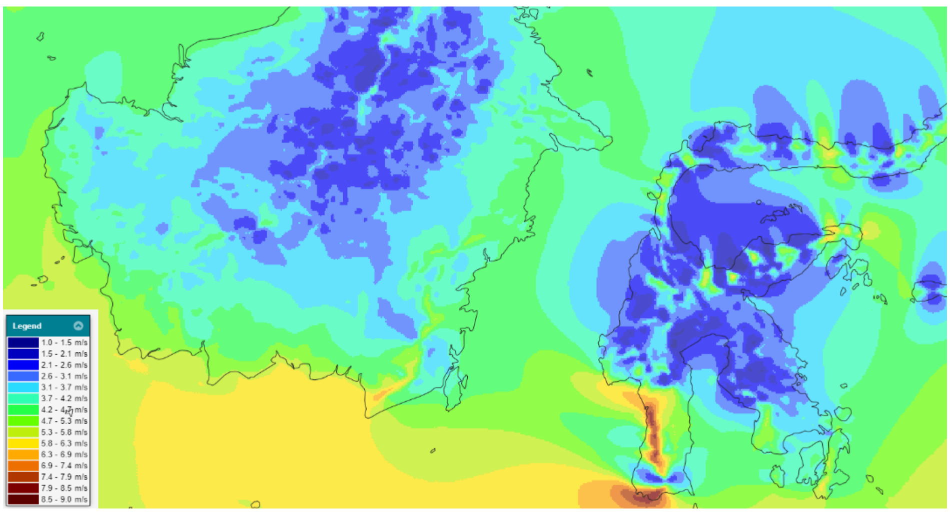


Figure 9: Wind speed map at 150m height. Source: (EMD International 2017)

Looking at wind maps of Indonesia (Figure 9), apart from the high wind speeds achieved in South Sulawesi, South Kalimantan also stands out compared to other regions as an exploitable area with wind speeds above 5-6 m/s. Our calculations based on hourly wind data indicates that with low specific power and high towers wind turbines with proper hub heights, it would be possible to achieve around 3,100 FLH (36% capacity factor).

[6] Total solar potential has been split into four categories (High, Medium High, Medium Low, Low) depending on the level of irradiation.
[7] Full Load Hours (FLH) are another way of expressing the Capacity Factor of a power plant. While Capacity Factor is defined in %, Full Load Hours is expressed in hours in the year or kWh/kW. 100% capacity factor corresponds to 8,760 hours.

2. Scenario framework and approach

2.1 RESEARCH QUESTIONS AND SCENARIOS ANALYSED

Given the expectations from both the official power system planning contained in RUPTL and the long-term targets expressed in RUED, the current study aims at exploring the following questions:

- What is the least-cost development of the power system in South Kalimantan province in the medium term (2030)?
- Is there room for RE to substitute some coal generation at low cost?
- Is the development assumed in RUED toward 2050 the optimal plan for the power system? How does it compare to a least-cost alternative scenario?

In order to answer the questions, the study is divided into two steps. First, a medium-term analysis towards 2030 is carried out using RUPTL19 as a reference. It is composed of three main scenarios. Next, a 2050 analysis is carried out considering 2 pathways: a RUED baseline and a least-cost alternative scenario. The Balmorel model is used to analyse the scenarios (see Appendix A for more model information).

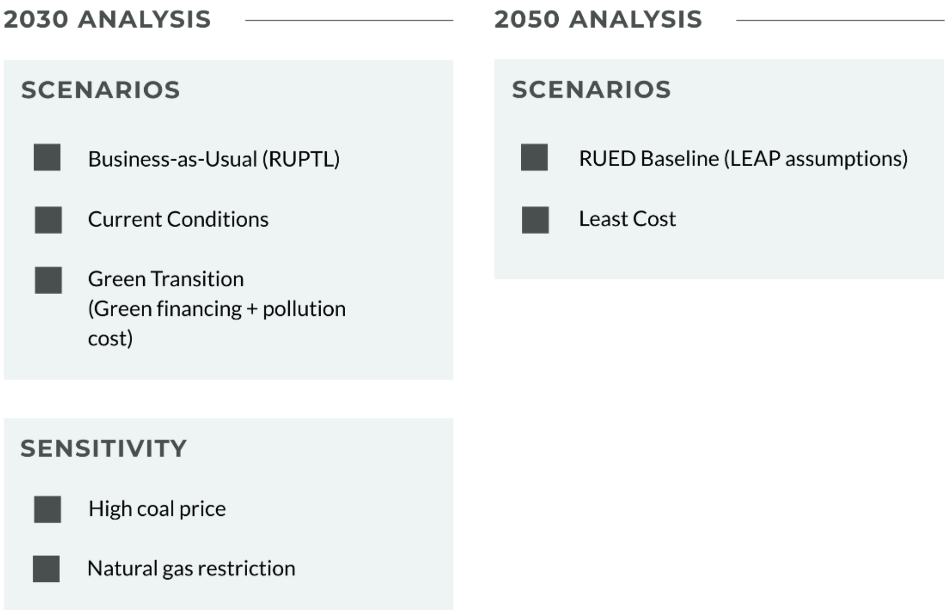


Figure 10. Two steps: 2030 analysis and 2050 analysis.

More in detail, the scenarios analysed for 2030 are the following:

- **Business-as-Usual (BaU)**
  The BaU scenario assumes no change in existing and planned capacity. It is based on the most recent assumptions in RUPTL19 from PLN regarding the period 2019-2028. No investments in additional capacity and no costs for externalities are considered in the dispatch mechanisms. The model optimizes only the dispatch of the existing and planned power plants based on their marginal generation cost and taking into account fuel prices.

- **Current Conditions (CC) – Least cost development under current conditions**
  In the CC scenario, only capacity specified in RUPTL as projects already committed or under construction in 2019 is considered, while the rest of the investment in power capacity development is optimized by the model. The model optimizes the generation capacity development using the BaU assumptions regarding technology cost, weighted average cost of capital (WACC) (10%) and fuel prices and does not consider external costs of pollution.

- **Green Transition (GT) – Least cost development with favourable conditions for RE**
  This scenario is similar to the CC scenario except for the fact that external costs of pollution are included and that the WACC is assumed lower for RE (8%) and higher for coal (12%). The GT scenario optimizes capacity additions towards 2030 thus supplementing existing capacity and projects under construction.

As for the 2050 scenarios, the following scenarios are considered:

- **RUED Baseline**
  In this scenario the latest RUED plans for all the provinces in Kalimantan are considered in terms of demand projections and fuel mix targets (as applied in LEAP). Moreover, only the capacities specified in the RUED for the detailed evolution of the generation fleet in South Kalimantan are considered in the model. No additional capacity can be invested in.

- **Least Cost**
  Here capacity development is dictated by RUED until 2020 after which, the model determines the optimal least-cost investment in additional capacity for both generation and transmission from 2020 to 2050 in all provinces of Kalimantan, disregarding the fuel mix targets in the RUED documents.

An overview of the scenarios can be found in

Table 2.

Table 2: Main scenarios overview and assumptions.

	Scenario	Initial capacity	Demand	Main assumptions
2030 scenarios	**BaU**	All RUPTL 19 capacity No additional investments	RUPTL	Reference assumptions
	Current Conditions (CC)	RUPTL19 only until 2020 Then optimal investments	RUPTL	Reference assumptions
	Green Transition (GT)	RUPTL19 only until 2020 Then optimal investments	RUPTL	International finance prioritizes RE (**8% WACC**) over coal (**12% WACC**). Cost of pollution considered in the optimization
2050 scenarios	**RUED baseline**	Fixed to RUED until 2050	RUED	RUED targets for all provinces
	Least Cost	RUED until 2020, then optimal investments	RUED	No fuel mix target for the provinces. Least cost development based on cost

Sensitivity analyses

In addition to the main scenarios, a number of sensitivity analyses are performed to assess the impact of assumptions and parameters on the 2030 results. Specifically, the following sensitivities are investigated:

- **High coal price**: The price of coal fluctuated significantly in the last five years, from a minimum of around 50 $/ton (March 2016) to a maximum of 110 $/ton (August 2018). All scenarios assume the current price of coal (around 70 $/ton) and a long-term development following WEO18). In this sensitivity analysis, a **50% increase of coal price**, equivalent to an increase of today's price from 70 to 105 $/ton, is simulated. This is performed for both the CC and GT scenario;

- **Natural gas restriction**: Given the uncertainty regarding the gas pipeline to be built from East to South and Central Kalimantan supplying natural gas to the two provinces, a sensitivity analysis is performed assuming **no additional gas supply in the two provinces** apart from the current availability of wellhead gas. This sensitivity analysis is simulated for both CC and GT conditions.

2.2 DRIVERS OF THE GREEN TRANSITION SCENARIO

The GT scenario represents a case in which conditions for RE development improves in two ways: Firstly, it is assumed that financing RE projects becomes easier than financing coal power plants, due to international climate commitments of countries and institutions worldwide. Furthermore, it is assumed that power system planning takes into account the cost of the local pollution caused by combustion of coal, natural gas and biomass. No costs on GHG emissions are assumed.

Financing coal vs RE projects

Coal financing is becoming more and more challenging in Indonesia, as well as worldwide. Globally, over 100 financial institutions and 20 large insurers divested from coal projects and now have restrictions on financing new coal (Figure 11). Recently, the Deputy Chief Executive Officer of Indonesia's PT Adaro Power (power generation unit of the country's second-largest coal mining company) stated that "coal power plant financing is very challenging. About 85% of the market now doesn't want to finance coal power plants" (Reuters 2019). The decreasing competition in financing of fossil fuel assets could lead to a rising expected rate of return for the remaining financing institutions.

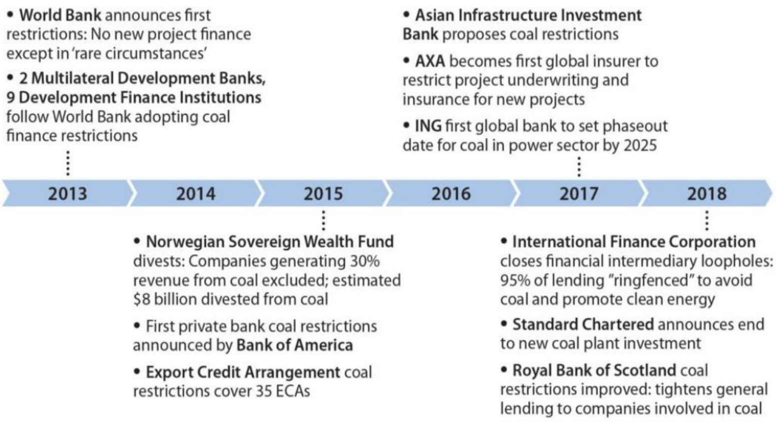


Figure 11: List of institutions announcing their restriction on coal financing. Source: (IEEFA 2019)

On the other hand, with the undersigning of the Paris agreement, Indonesia expects international support in order to achieve the conditional GHG emission reduction targets, which could come in the form of access to cheaper finance. The First Nationally Determined Contribution (NDC) – Republic of Indonesia stated that "Indonesia could increase its contribution up to 41% reduction of emissions by 2030, subject to availability of international support for finance, technology transfer and development and capacity building" (Republic of Indonesia 2016).

Cheaper financing could be available through international financial institutions such as World Bank, Asian Development Bank, etc. Indeed, there are already examples of such funding from the Asian Development Bank, which for example supported the development of hybrid plants based on wind and solar in North Sulawesi, in the form of 600 million IDR result-based loan (RBL) program (PT PLN Persero 2019).

Text box 1: Effect of financing cost on the LCoE of power plants

The generation cost (LCoE) of more capital-intensive technologies such as solar, wind and biogas, depends to a higher extent on the cost of capital, compared to technologies in which the investment cost represents a less prominent share of total project costs. A reduction in the financial cost of capital (WACC) can greatly affect the LCoE of these technologies. Conversely, technologies with a higher cost of fuel and O&M cost, which consequently have a lower portion of their cost related to capital expenditures, have less dependency on the finance-related costs.

For example, the investment cost makes up around 82% of the total lifetime cost of solar (with the remaining related to O&M costs), while it represents only 32% of the total lifetime cost of coal (more than 50% is related to fuel cost).

Having access to cheap financing is key to the success of capital-intensive technologies such as wind and solar. For example, considering the year 2020, a reduction in the weighted average cost of capital (WACC) from 10% to 5% reduces the LCoE of solar PV plant (PLTS) by 27%, while it reduces the LCoE of coal (PLTU) by only 13%.

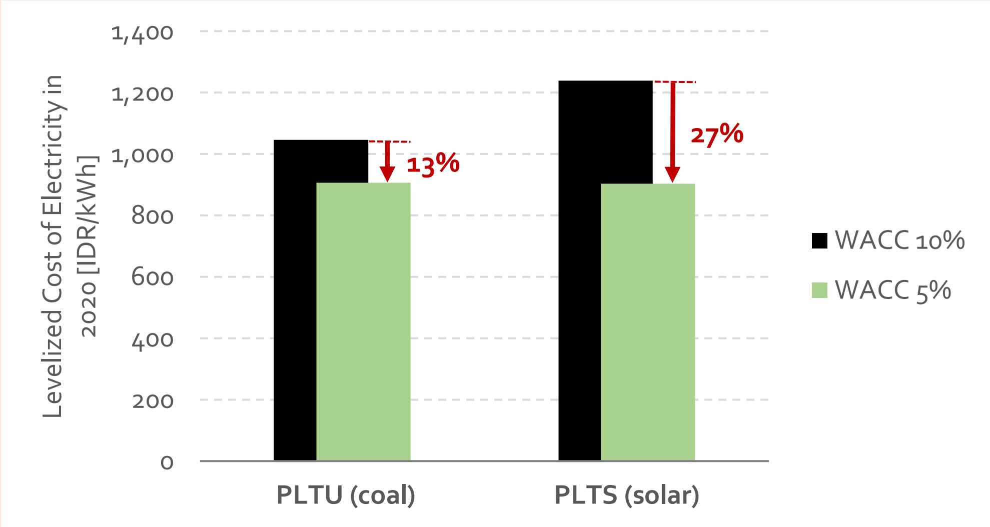


Figure 12: Effect of reduction of cost of capital (WACC) on coal and solar in 2020.

Cost of pollution

Combustion of fuels such as coal, oil and gas leads to emissions of SO_2, NO_x, and $PM_{2.5}$ which have a considerable impact on human health, causing premature death and illness. In the GT scenario these costs are considered part of the overall societal cost of power generation and thus included in the optimization. By doing so, power plants using coal and to a lower extent natural gas and biomass, will have a higher cost than alternatives that produce no emissions. Indirectly, this favours RE technologies such as geothermal, hydro, wind and solar, for which the production of electricity involves no combustion-related emission of pollutants. In this study, no additional externality for the emissions of CO_2 is consider.

Calculating the pollution impacts of combustion, and the cost for society, requires comprehensive and complex atmospheric modelling – such as EVA (Economic Valuation of Air pollution). The EVA model uses the impact-pathway chain to assess the health impacts and health-related economic externalities of air pollution resulting from specific emission sources or sectors. Since no detailed study for Indonesia is available, figures have been estimated in the context of a previous power system study for Indonesia (Ea Energy Analyses 2018). The methodology consisted of elaboration of health-related cost for Europe to assess the cost depending on the population living in a radius of 500 km from the source of emissions. European costs were then translated to Indonesian costs using purchasing power parity (PPP) figures from the World Bank. A study on the hidden cost of power generation in Indonesia (Ery Wijaya 2010) has estimated figures of a similar range as those calculated in the 2018 study by Ea Energy Analyses.

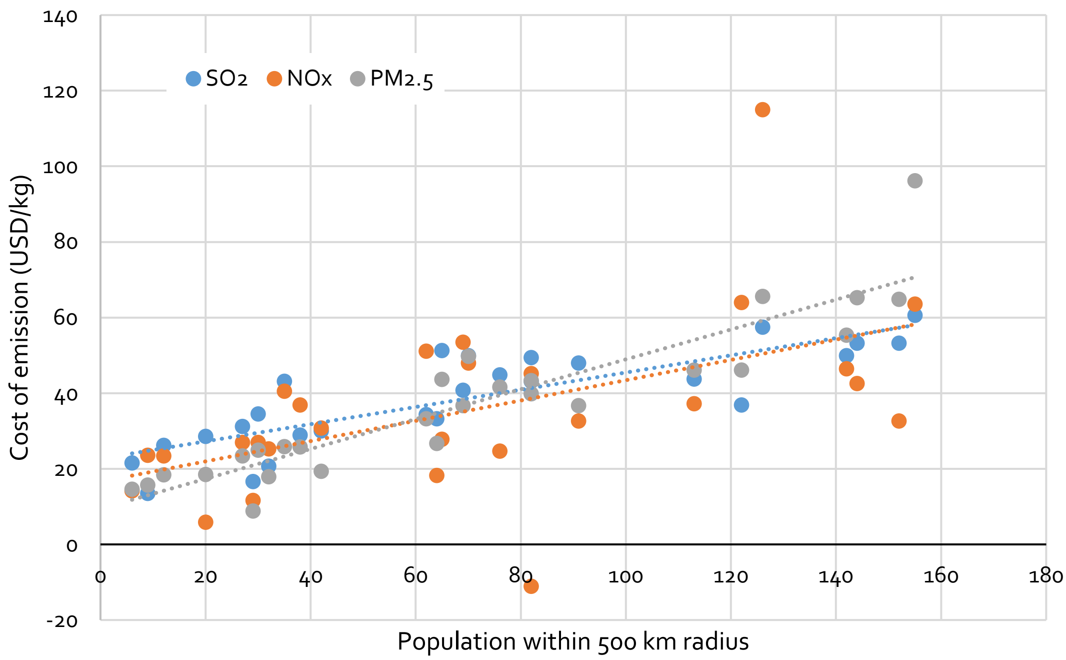


Figure 13: Correlation between the cost of pollution from SO_2, NO_x and PM2.5 from each of the 27 EU Member States and the population within a 500 km radius from the country's geographical centre.

An overview of the SO_2 costs in Indonesia for each province is shown in Figure 14. For South Kalimantan, the figures used are 4.7 \$/kg of SO_2, 3.7 \$/kg of NO_x and 2.6 \$/kg of $PM_{2.5}$, based on the population density of South Kalimantan and surrounding region. It can be noted that the values are lower than those in Java and Sumatra island; indeed, Kalimantan is much less densely populated than other areas in Indonesia meaning that the emission of polluting particles potentially affect a smaller population.

Figure 14: Health damage cost of SO_2 emissions in Indonesia, resulting from the assessment. Source: (Ea Energy Analyses 2018)

2.3 THE BALMOREL MODEL

Balmorel is a model developed to support technical and policy analyses of power systems. It is a bottom-up partial equilibrium model which essentially finds economical dispatch and capacity expansion solution for the represented energy system, based on a least cost approach (Ea Energy Analyses 2019).

To find the **optimal least-cost outcome in both dispatch and capacity expansion**, Balmorel considers developments in electricity demand, grid constraints, technical and economic characteristics for each kind of production unit, fuel prices, and spatial and temporal availability of RE. Moreover, policy targets in terms of fuel use requirements, environmental taxes, CO_2 limitations and more, can be imposed on the model. More information on the model can be found in Appendix A.

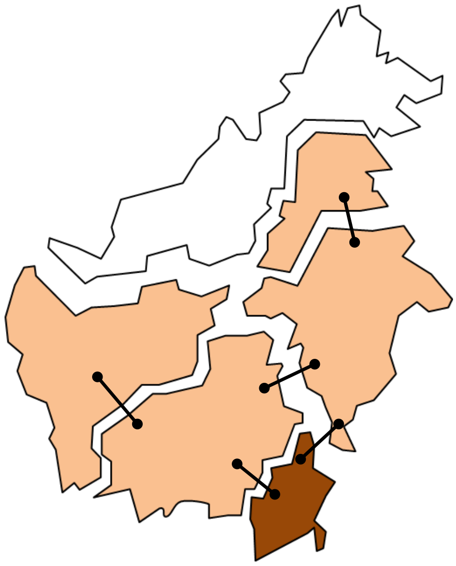


Figure 15: Balmorel representation of Kalimantan. Focus area highlighted.

For the analysis, a representation of the power system in Kalimantan has been developed based on public sources and on data from PLN and Dinas ESDM South Kalimantan. The power system in Kalimantan is divided in the five provinces and contain a representation of the interconnection capacity between provinces.

Today, South Kalimantan is connected to neighbouring provinces, namely Central and East Kalimantan via power interconnectors. In all simulations, Kalimantan's five provinces are simulated simultaneously to ensure a consistent representation of South Kalimantan in context of the regional power system. The model minimizes the cost of suppling power demand considering options for importing and exporting electricity between interconnected regions, accounting for resource potentials, fuel prices and regional characteristics.

3. 2030 scenarios

3.1 OVERVIEW OF ENTIRE KALIMANTAN SYSTEM

***Coal investments in Kalimantan are likely overestimated** in RUPTL and face the risk of becoming stranded assets. Optimized scenarios suggest that solar, wind and natural gas can play a larger role than anticipated in RUPTL. Solar power, with access to cheap finance, reaches installation of 3 GW in 2030 in the GT scenario and provides up to 15% of the total generation.*

The conventional power plant additions in the entire region in the 2030 perspective varies greatly across scenarios. New coal power plants reach a total of almost 1,600 MW in the BaU scenario, while the **optimized scenarios CC and GT show almost no additional coal**, with only 250 MW added across Kalimantan system in CC and a mere 30 MW installed in GT (Figure 16). In the CC scenario, natural gas capacity substitutes coal. In the GT scenario more RE capacity is installed, while natural gas capacity is more or less similar to BaU.

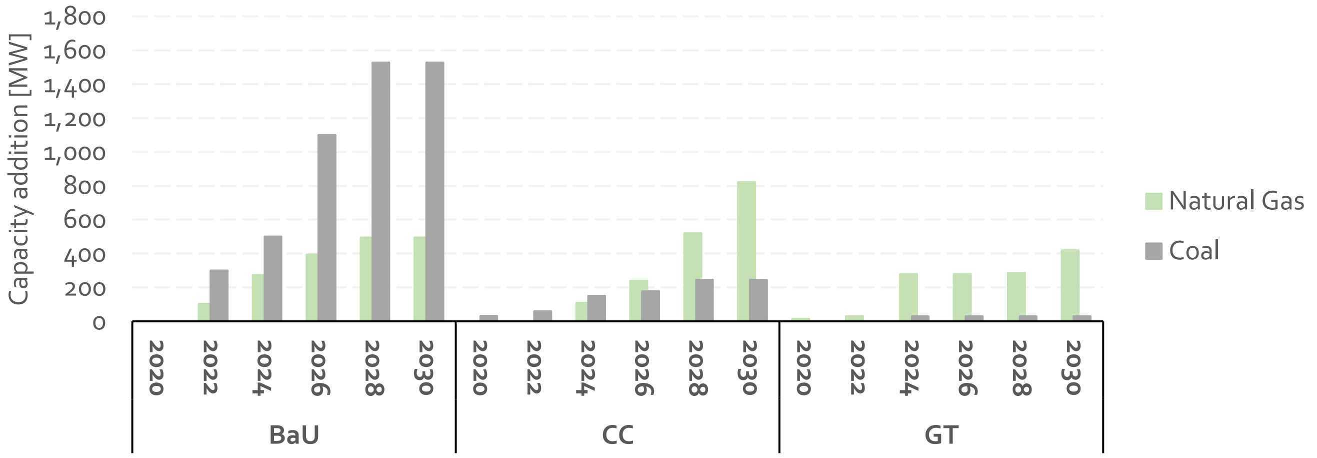


Figure 16: Coal and natural gas capacity additions in Kalimantan, excluding capacity already under construction.

Despite the low additional investments, coal remains the dominant source of power in all scenarios, thanks to the large existing fleet. In the GT scenario, the consideration of pollution cost reduces the generation of coal power, making room for more natural gas generation in the short term and significantly more RE from 2025 (Figure 17).

In the CC scenario, coal generation is more or less at the same level compared to BaU and the hydro generation is lower than BaU. On the other hand, natural gas generation is much higher due to the commissioning of a large amount of combined cycle power plants. RE has a hard time competing with low cost bulk production from coal and gas.

In the GT scenario, RE becomes competitive from 2024. Solar power provides the largest contribution, with 3 GW installed capacity in 2030 corresponding to 15% of generation. Wind generation is doubled compared to the BaU scenario, and most of the capacity is located in South Kalimantan.

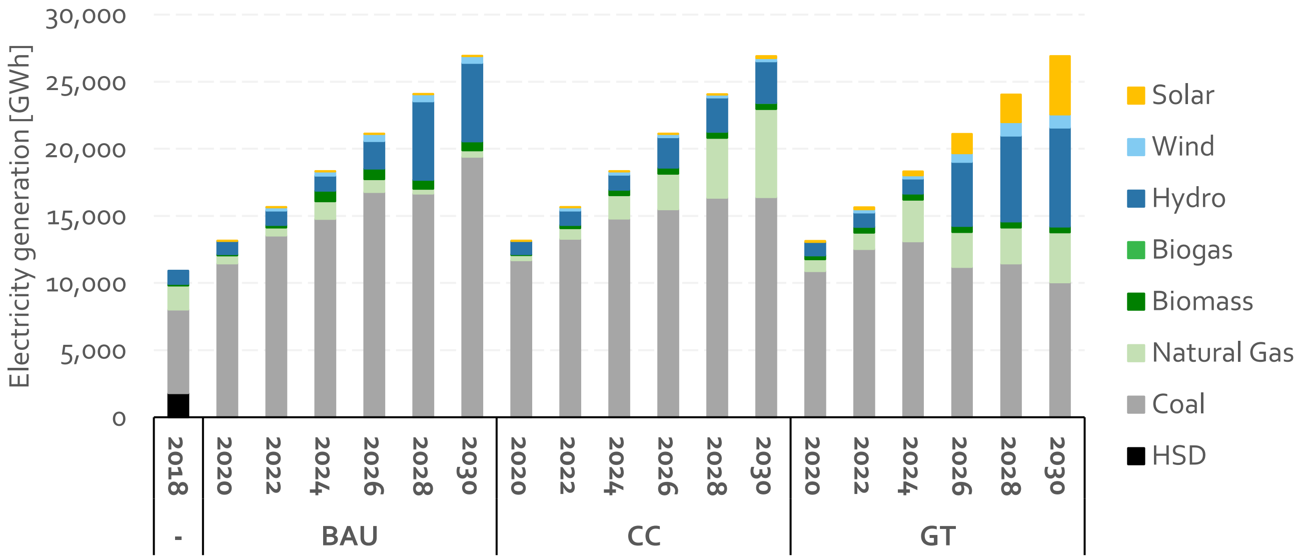


Figure 17: Power generation development in the entire Kalimantan system for the three main scenarios for 2030.

Looking at the generation share per province in the BaU and GT scenarios in 2030 (Figure 18), the difference in the share of RE between the two scenarios is remarkable in every province.

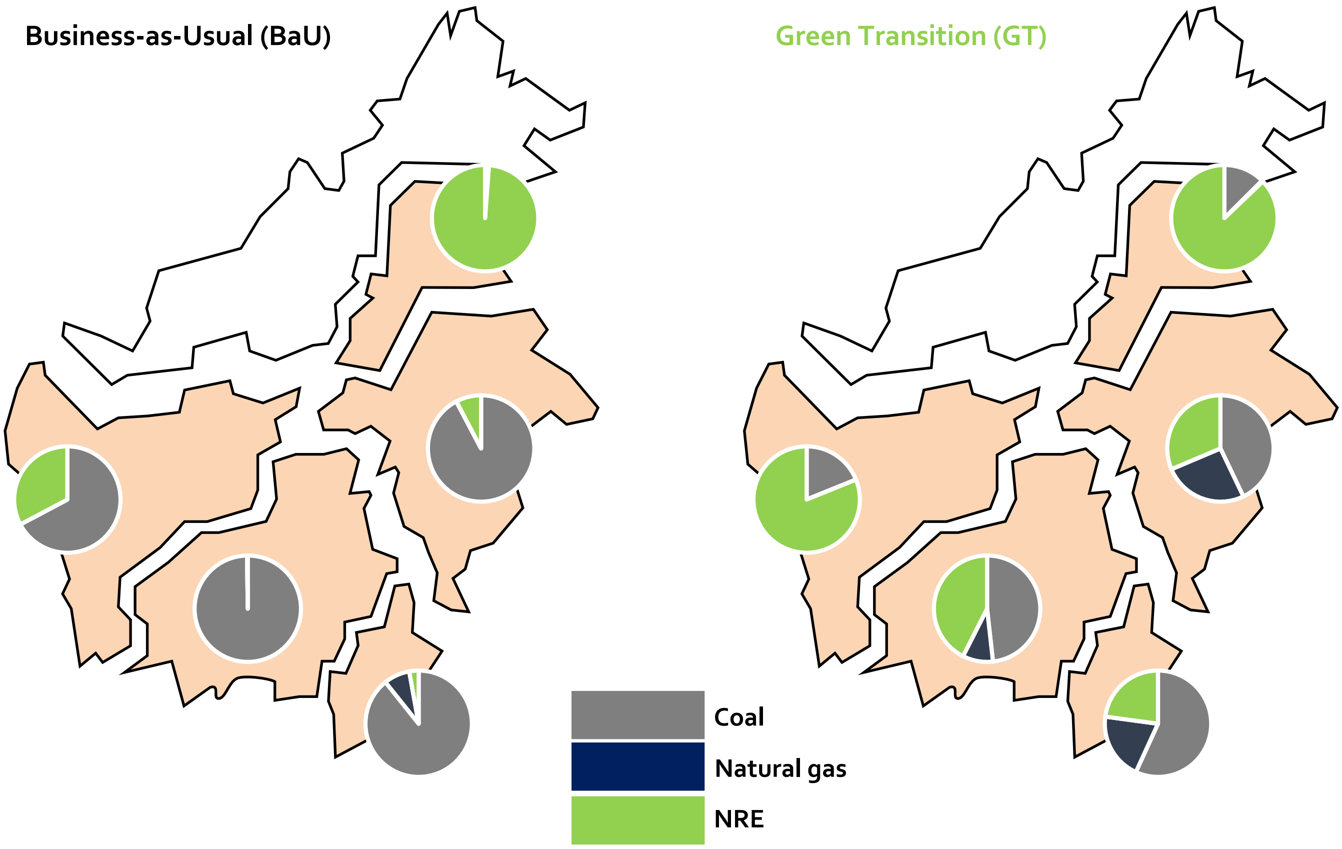


Figure 18: Overview of the generation share per province in 2030 in BaU vs GT.

In the BaU, most of the power is based on coal and only North Kalimantan, due to the installation of a large hydro reservoir plant, has a large share of RE, while in the GT scenario all provinces feature a sizable RE share. Moreover, natural gas is used more broadly. In the GT scenario, **South Kalimantan is the province with the lowest RE penetration** and the largest use of coal.

Figure 19 shows the power flow dynamics over time in the Kalimantan system, as an average across each scenario. The most significant power flow happens between Kalimantan North and East. Until 2026, North is importing power from East, which has a largest fleet and cheap coal power. After the construction of 1 GW hydro reservoir in 2027, North Kalimantan becomes net exporter of a large amount of power.

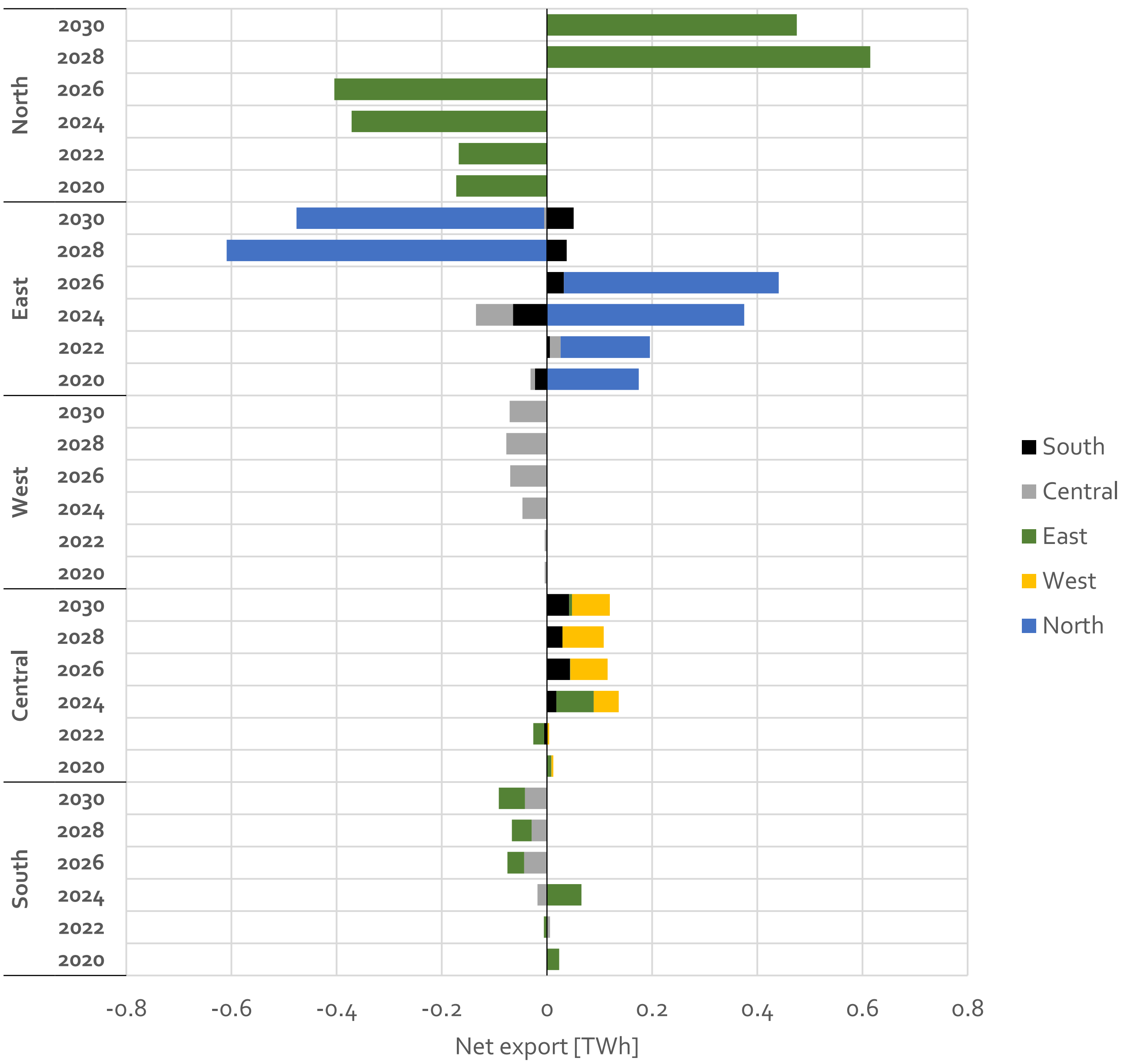


Figure 19: Net yearly power export between regions in Kalimantan (average across each scenario).

3.2 POWER SYSTEM DEVELOMENT IN SOUTH KALIMANTAN PROVINCE

RE is getting more and more competitive with fossil fuels

Following worldwide cost reductions, solar generation cost drops below 1,000 IDR/kWh by 2030. Wind, hydropower and biomass are also on the way to becoming cheaper than coal generation in South Kalimantan.

The best way to compare the cost of generation for different technologies is using a metric called Levelized Cost of Electricity (LCoE)[8], which expresses the cost of the megawatt-hours generated during the lifetime of the plant, including all costs (Investment cost, O&M costs, Fuel costs). It corresponds to the minimum price at which the energy must be sold for the power plant to cover all its cost and the LCoE is therefore an indication of the tariff (PPA) a technology requires to be competitive.

Figure 20 shows the LCoE of all potential generation technologies in the province of South Kalimantan for 2030, with 2020 costs shown for comparison, using technology assumptions from the Indonesian Technology Catalogue (NEC 2017). Combined cycle gas turbines result the cheapest source of power in both years, but in 2030 **solar breaks the 1,000 Rp/kWh mark** and reaches almost the same level. Solar, followed by wind, has indeed the largest cost reduction potential in the period considered and this is well in line with worldwide trends and the PV market (see Text box 2).

It is interesting to note that almost all RE technologies have a cost in 2030 comparable to that of coal power plants, despite the relatively low coal price. Indeed, while coal sees a slight cost increase from 2020 to 2030 (due to a higher projected fuel cost), RE can count on a cost reduction related to larger deployment and learning rate.

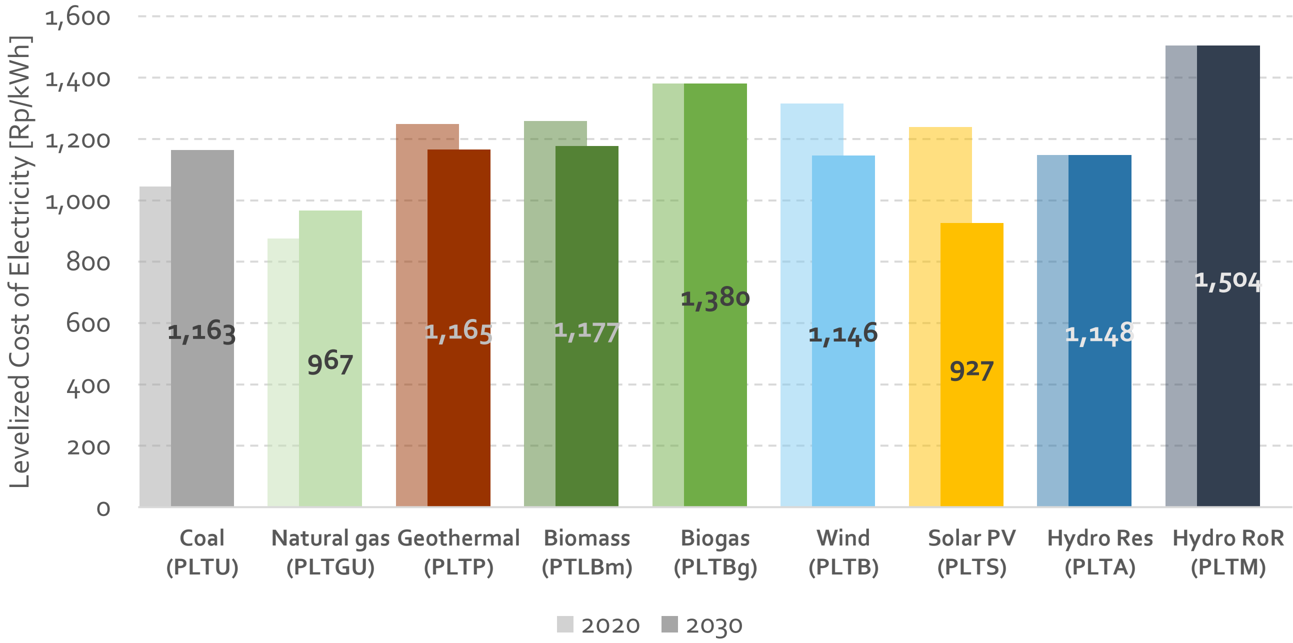


Figure 20: LCoE comparison for relevant power sources in South Kalimantan in 2030 (solid) and comparison to 2020 (light)[9].

[8] A definition of the LCoE is available in the Glossary.

[9] To calculate LCoE, several assumptions have been made: WACC 10% for all technologies, economic lifetime 20 years, FLH of PLTU, PLTGU, PLTP, PLTBm/Bg is 7,000 hours, while for wind, solar and hydro FLH used are from Figure 8. Technology costs are from Indonesian Technology Catalogue (NEC 2017) and fuel cost assumptions are specified in Appendix B.

Text box 2. Solar power on its way to become the cheapest source of power worldwide

During 2019, several solar PV auctions attracted international attention for the record-breaking results. A Portuguese auction on 1.15 GW of solar power received bids as low as 1.64 c$/kWh (230 Rp/kWh) and an auction in Dubai received a similar low bid of 1.69 c$/kWh (237 Rp/kWh) (PV Magazine 2019).

As testified by worldwide cost of new PV installation and illustrated in Figure 19, solar power has dropped dramatically in cost and is now becoming the cheapest source of energy. Between 2010 and 2018 the levelized cost of solar has dropped 75% and is today well below 10 c$/kWh in most of the countries worldwide.

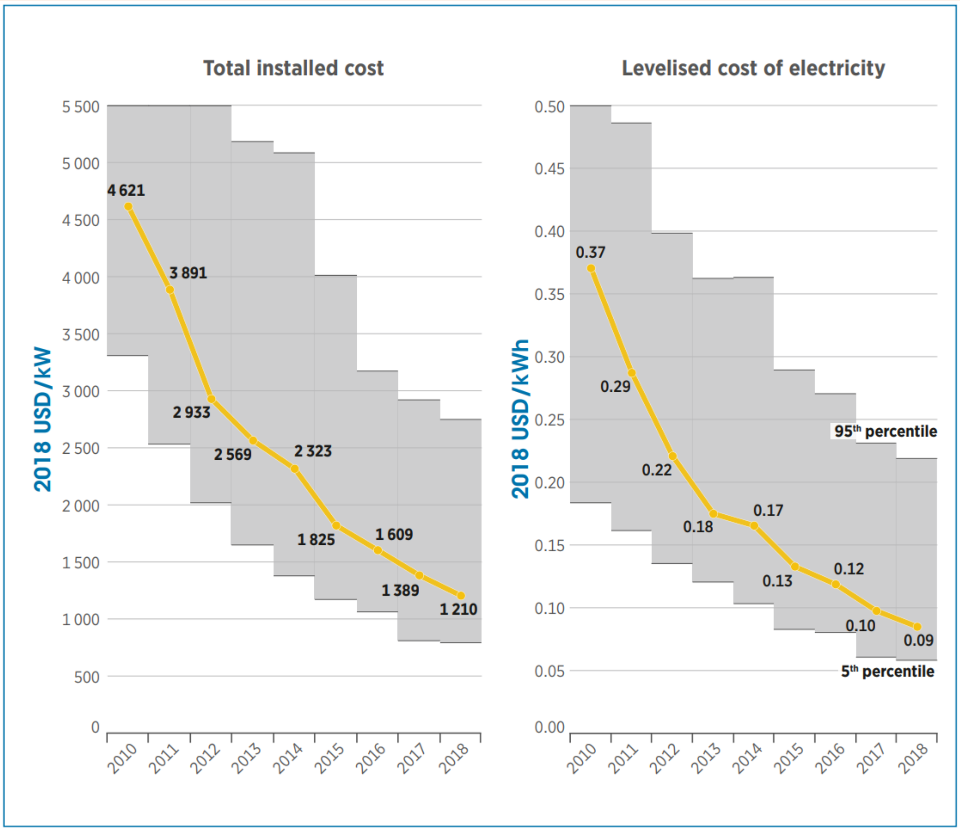


Figure 21: Total installed cost and levelized cost of electricity of solar power from 2010 to 2018. Source: (IRENA 2019)

During 2018-19, a number of PPAs for solar power have been signed across Indonesia, landing an average tariff of 10 c$/kWh (1,432 Rp/kWh) based on a capital cost around 1.38 M$/MW$_p$ (Jonan 2018). As of today, the cost of solar power in Indonesia is higher compared to other parts of the world due by a combination of factors, such as very low installation volumes, the combination of local content requirement and a non-existing PV industry, artificially low electricity prices, lack of infrastructure and trained personnel, and difficulties in securing financing (NEC; Danish Energy Agency; Ea Energy Analyses 2018).

Based on the values achieved by many auctions worldwide, in both developed and developing countries, there is a large cost reduction potential for solar PV in Indonesia. The Indonesian technology catalogue expects a cost of 0.89 M$/MW$_p$ by 2020, which is lower than today but still higher than what is expected in other countries. As an example, the Danish technology catalogue predicts an installation cost of 0.66 M$/MW$_p$ by 2020 (Danish Energy Agency; Energinet 2019), i.e. more than 25% lower.

There is room to reduce coal generation in South Kalimantan power system

*Coal generation is dominating the supply in South Kalimantan province in all scenarios. However, **natural gas, wind and solar emerge as alternatives in the late 2020s**, when overcapacity due to coal currently under construction is reduced. When considering cost of pollution and cheaper RE financing, **RE can supply 1/3 of the power** in 2030.*

In all scenarios, **coal generation is dominating the supply** in South Kalimantan. However, combined cycle gas turbines, wind and solar, emerge as cheap alternatives to substitute part of the coal-based generation.

The **large pipeline of coal projects under construction (400 MW)** guarantees the supply of the majority of power demand increase in the coming years, making the province a net exporter and requiring only minimum additional investments before 2026 in all scenarios. In the two optimized scenarios (CC and GT), additional hydro and natural gas plants are added to the system when the power demand increases above what the new coal power plants can supply.

In the CC scenario, limited additional investments are found optimal: Investment in 121 MW of reservoir hydro and 166 MW of combined cycle gas turbines are done by 2030. In the GT scenario, the **combined effect of pollution cost and lower cost of finance for RE makes variable RE such as wind and solar competitive** with fossil fuels on a pure cost-basis. In this case, the fleet is expanded with 195 MW of solar and 190 MW wind power in 2026 and grows to 570 MW and 290 MW, respectively, by 2030.

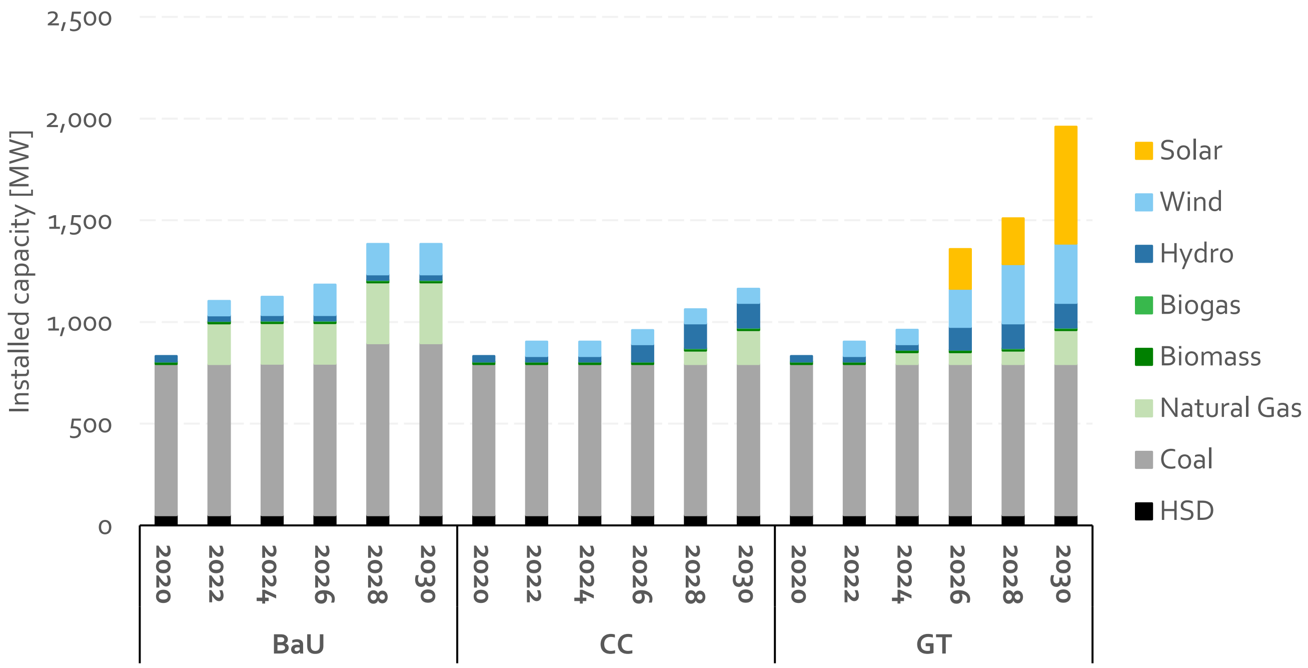


Figure 22: Power generation capacity development in South Kalimantan for the three main scenarios for 2030.

An overview of the total generation in 2030 in the three scenarios is shown in Figure 24. The share of RE generation in 2030 is 10% in BaU and only slightly higher in the CC scenario (12%) but rises to 34% in the GT scenario, indicating that there is a **large potential to supply the demand with more RE** in a cost-effective way in the power system of South Kalimantan.

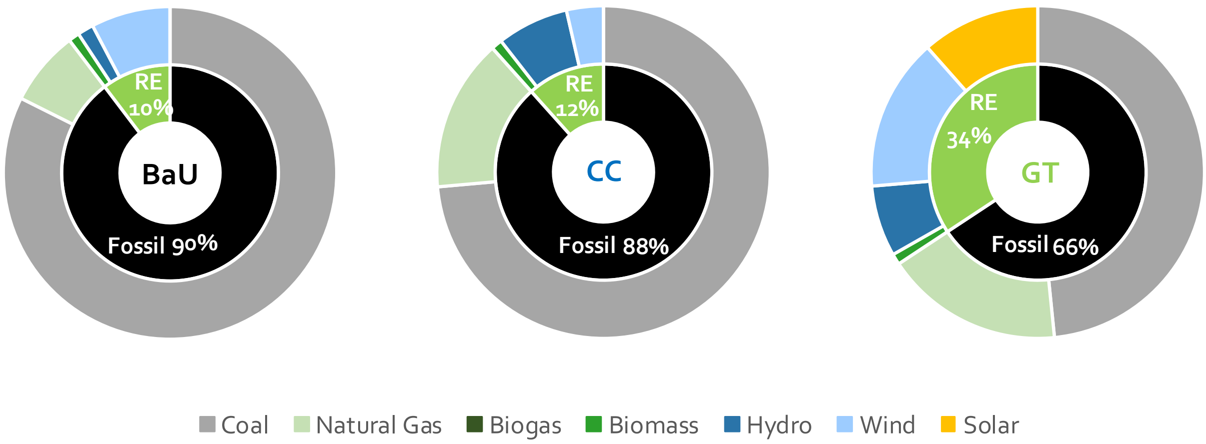


Figure 24: Generation in 2030 in the three scenarios and share of fossil fuels (black) and RE (green).

Text box 3. Cheap financing vs pollution cost. What measure provides most impact?

In the GT scenario, the combination of more advantageous financing conditions for RE and the consideration of pollution cost is simulated, however it is important to understand the effect of each of the two measures better.

The measure with the highest effect in South Kalimantan is the consideration of pollution cost in the planning optimization. By considering it, dispatching coal generation incurs additional costs and thus becomes more expensive, increasing the competitivity of other sources such as solar and wind. On the other hand, decreasing the WACC of RE by 2% is not enough to drive the investment in much more RE. Combining the two measures has an additional combined effect, since the increase in coal cost and the reduction in RE financing costs makes solar and wind competitive.

Figure 21 shows the CO_2 reduction in 2030 from implementing measures separately: Considering pollution cost has a larger overall climate effect alone than a favorable WACC for RE.

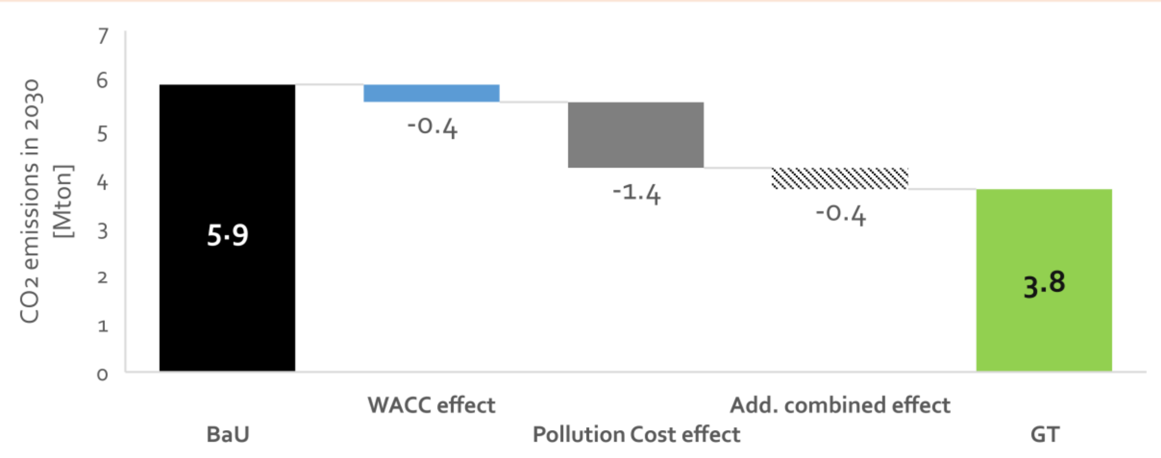


Figure 23: Emission reduction contribution from the two measures contained in GT scenario.

A greener and more climate-friendly supply with virtually no cost top-up

The scenario with favourable conditions for RE has a similar cost compared to a scenario with much lower RE deployment, meaning that it is possible to achieve ***a 34% RE penetration and reduce emissions at virtually no extra cost****, with an average generation cost of 1,016 Rp/kWh. A more RE-based system also reduces risks of cost surge, due to fluctuating and uncertain price of coal in the future.*

To assess the cost of the different scenarios, cumulative costs in the period 2020-2030 are computed, including all cost components: capital cost of units (both planned and optimized by the model[10]), fixed and variable operation and maintenance cost (O&M), fuel cost, cost for the power imported from other regions.

Based on these cost components, **the three scenarios analysed arrive at more or less the same cost** of supplying the power demand of South Kalimantan (Figure 25). The **BaU scenario is, however, the most expensive** of the three scenarios. In the two optimized scenarios (CC and GT), the cost saving is around 2.8 - 3.8 trillion IDR over the 10 years analysed.

The CC scenario, with only 12% RE, has an average cost of 985 Rp/kWh while the **GT scenario, featuring 34% RE, has an average cost of 1,016 Rp/kWh**. The cost of a scenario with 1/3 RE generation is only marginally higher and anyway lower than the generation cost of today (Table 3).

Table 3: Average generation cost by scenario.

	Rp/kWh
BaU	1042
CC	985
GT	1016

Moreover, when we consider the damage cost of pollution[11], the GT scenario ends up being cheaper than the other two scenarios, guaranteeing an additional cumulative avoided 2 trillion IDR in health-related costs.

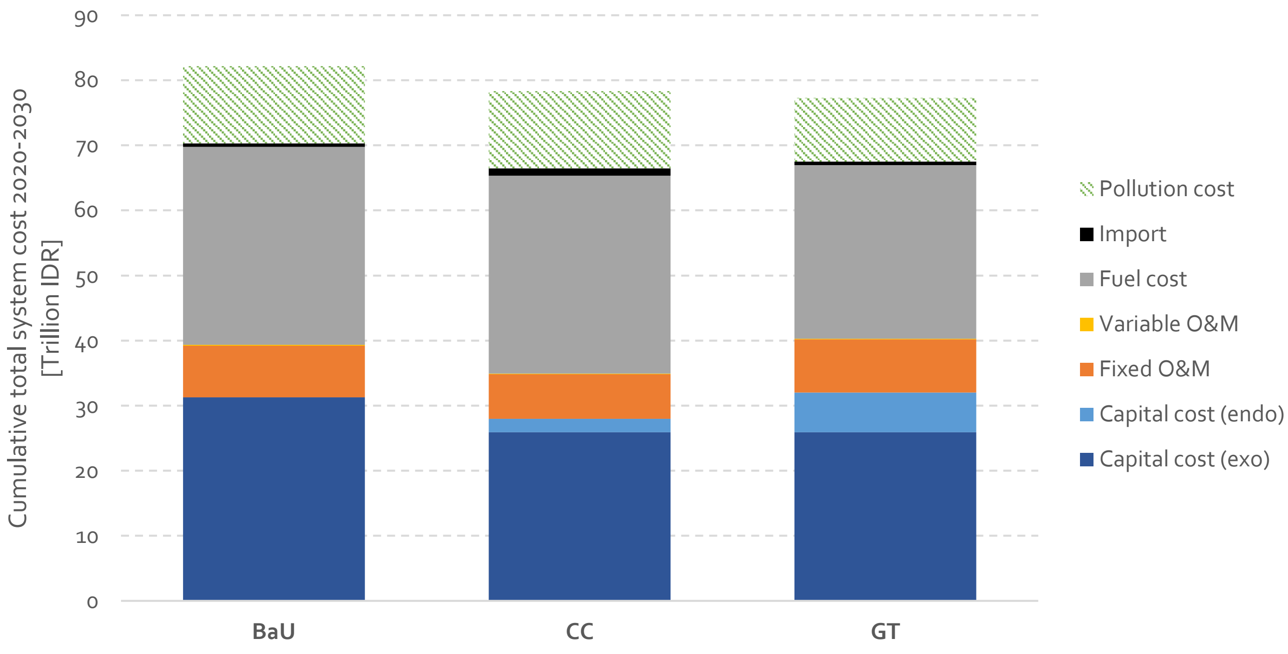


Figure 25: Cumulative total system costs in the three scenarios for the period 2020-2030[8].

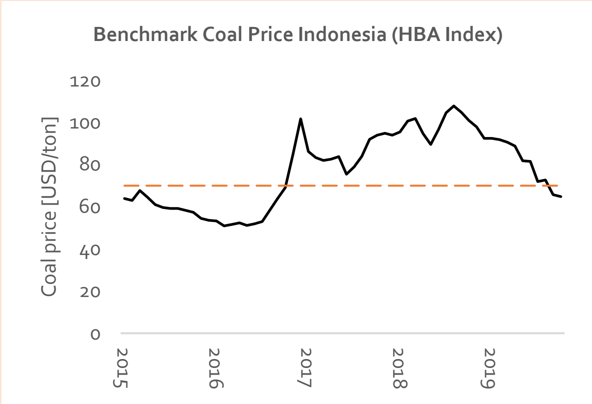
[10] Capital costs are divided into exogenous (exo) and endogenous (endo). The former expresses the cost for the units that are considered outside the model optimization, i.e. imposed as assumption. This includes all power plants for BaU, while only those already under construction for the other two scenarios. Conversely, the power plants added endogenously are those that are found optimal by the model.

[11] Cost of pollution is calculated multiplying emissions of SO_2, NO_x and $PM_{2.5}$ by the corresponding specific damage cost per gram emissions.

Another important factor is that the portion of the total costs related to fuel expenditure is 39% in the GT scenario compared to around 45% in the BaU and CC scenarios. A system with more RE, while increasing the capital requirement and the need to finance projects, largely reduces the fuel cost required to run the system, consequently **reducing the risk related to fuel price fluctuations in the future**. Indeed, while coal for power generation purposes is safeguarded by the current Domestic Market Obligation (DMO), the market price of coal has fluctuated significantly in the last five years. In case the DMO would not be extended in the future, this would potentially translate into a higher risk for increased electricity tariffs (more details in Text box 4).

Text box 4. Coal price risk: What would happen if coal price increases?

The price of coal fluctuated a lot in the last five years, from a minimum of around 50 $/ton (March 2016) to a maximum of 110 $/ton (August 2018). Today, price of coal for power supply is controlled through the domestic market obligation (DMO), with which the Indonesian government forces local coal miners to supply part of their coal production to the domestic market, specifically to coal-fired power plants as there is a real need for an increase in the nation's power supply.



The price of coal for PLN, through the DMO quotas, is capped at 70 $/ton for high grade coal. If DMO is discontinued in the future, a sudden surge of coal price in the market could have serious impacts on the cost of supply and the end user tariffs in South Kalimantan.

Based on the scenario analysed, a 50% increase in the coal price (corresponding today to an increase from the current level of 70 $/ton to a level of 105 $/ton) would increase the cumulative cost of supply by more than 14 trillion IDR in BaU and CC, more dependent on coal generation (+22% total generation cost), while it would increase the cost by only 11.7 trillion IDR in GT (+17%), the scenario with more renewable energy.

In this case, i.e. in case of coal price surge, **the cumulative cost savings by having more renewable energy in the system would be 2.7 trillion IDR** over the 2020-2030 period.

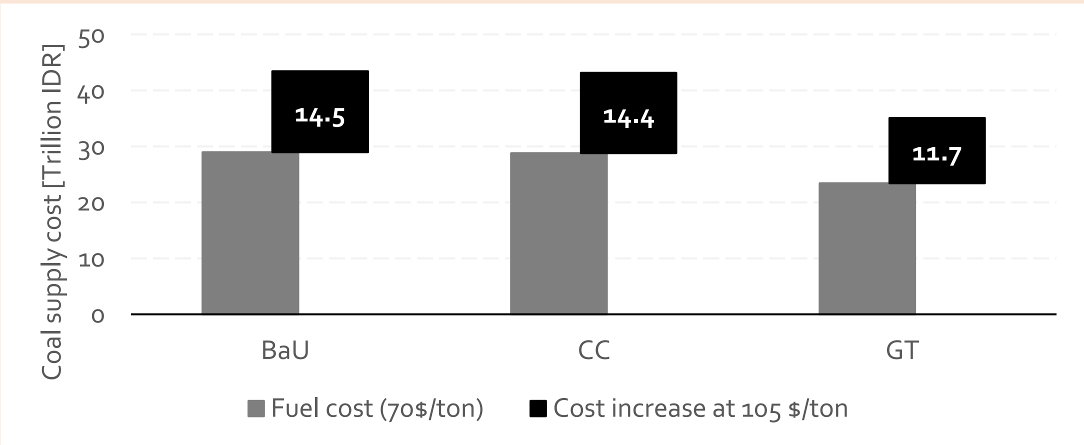


Figure 26: Effect of surge in coal price in the cost of supply.

How would the optimised system look like if the coal price was higher?

In case the coal price returns to its highest level, just above 100 $/ton, ***combined cycles powered by natural gas would become more competitive than coal power plants****. In such a scenario, coal generation would be reduced by 60-70% and would also make room for additional wind power in the GT scenario.*

All scenarios assume the current price of coal (around 70 $/ton) and a long-term development following WEO18. A sensitivity analysis was performed assuming an increase of coal price to 105 $/ton, roughly equivalent to a 50% increase, to assess the change in the power system development (see Text box 4 for background on historical coal price levels).

In case of such coal price development and assuming that the system can react by investing in additional power plants, the generation in South Kalimantan would change dramatically with **coal generation reduced by up to 60-70% between 2024 and 2030** (Figure 27). Around 300-500 MW of additional combined cycle gas turbines would be installed to reduce the generation from coal, which becomes expensive to dispatch. In the GT, also 350 MW of wind power becomes competitive from 2022, helping to displace coal in the short term. All these short-term capacity additions also reduce the need for additional hydro and solar capacity after 2025.

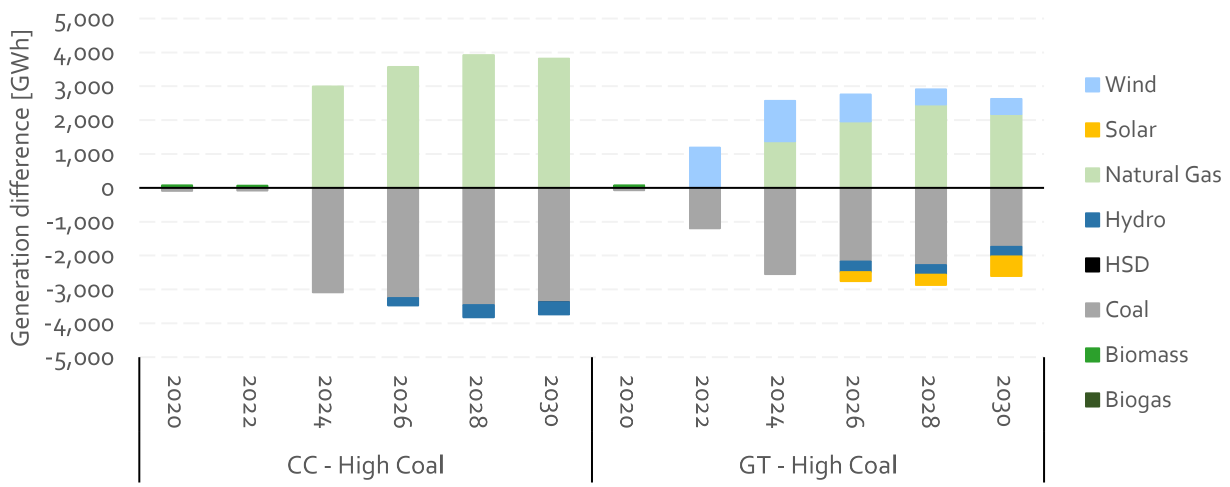


Figure 27: Change in generation after an increase in coal price to 105 $/ton.

These results show that the **competitivity of coal power plants compared to natural gas combined cycles depends significantly on the cost of fuel**. The variation of the generation cost of these two types of power plants depending on the cost of fuel is examined in Figure 28 considering the cost in 2020. The central point represents the baseline assumption in this study for both coal (1,118 Rp/kg, 70 $/ton) and natural gas (82,442 Rp/MMSCF[12]), while the upper and lower values represent the generation cost with -50% and +50% fuel cost.

The baseline generation cost of subcritical coal is 1,048 Rp/kWh while supercritical coal plant cost is 931 Rp/kWh. If the coal price increases to 1,677 Rp/kg, corresponding roughly to the value achieved by the HBA index in August 2018, the LCoE of subcritical coal plants reaches 1,300 Rp/kWh.

Combined cycle gas turbines have a baseline cost of 876 Rp/kWh in 2020, due to the relatively low natural gas price and the high efficiency of the combined cycle plant. The variation of +/-50% of the fuel price makes the generation cost vary in the range 586-1,166 Rp/kWh.

[12] Million Standard Cubic Feet (MMSCF) is a unit of measurement for gas, widely used in Indonesia to express the unit price of gas.

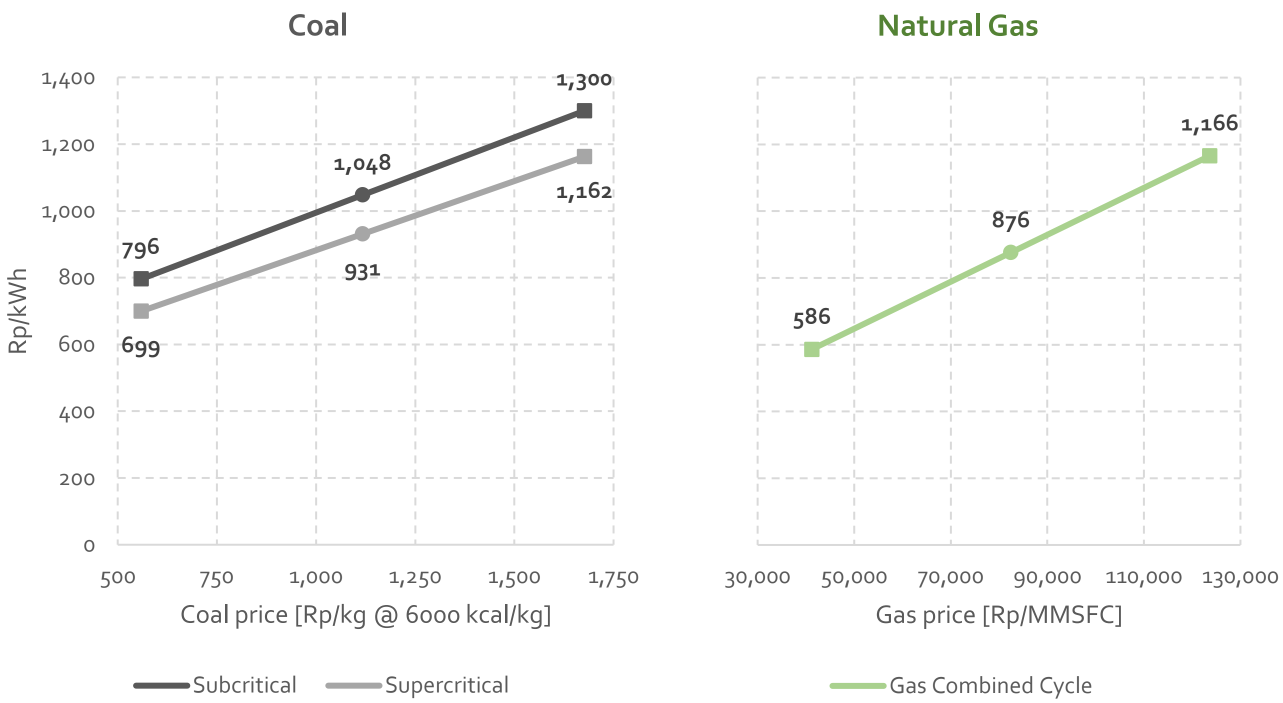


Figure 28: Generation cost of coal sub-/ supercritical plants and natural combined cycle gas turbines as a function of fuel cost.

What are the implications for CO2 emissions and climate change?

*The commissioning of the 400 MW of **coal plants under construction almost doubles the CO_2 emissions** of South Kalimantan in the short term. BaU conditions will bring emissions to 6 Mtons, but the **deployment of more wind and solar or a large reliance on combined cycle gas turbines can keep emissions below the 4 Mtons threshold.***

Today, emissions from South Kalimantan's power generation stands at 2.7 Mtons. The evolution of the generation fleet and the power dispatch will determine the pathway for the climate footprint of the province. One factor that has a large impact is the increase in the power demand expected in the 2030 perspective: If South Kalimantan wishes to reduce its climate footprint, then the province must not only fulfil the increased demand for power with more sustainable sources, but also use them to reduce the generation from existing polluting capacity.

Emissions increase significantly in the all three scenarios in the short term (until 2022) due to the commissioning and the bringing into operation the 400 MW of coal power plants currently under construction (Kalsel FTP2 and Kalselteng). These **two power plants alone almost double the CO_2 emissions in the province compared to 2018** (Figure 29), with the emissions in 2024 in BaU and CC close to 5 Mtons.

The path undertaken in both BaU and CC scenarios, i.e. large reliance on coal plants and small addition of gas power plants, brings emissions to almost 6 Mtons by 2030 and **emits almost 29 Mtons over the 10-year period analysed**. In order to at least partially avoid this surge in climate-related emissions, important steps have to be taken.

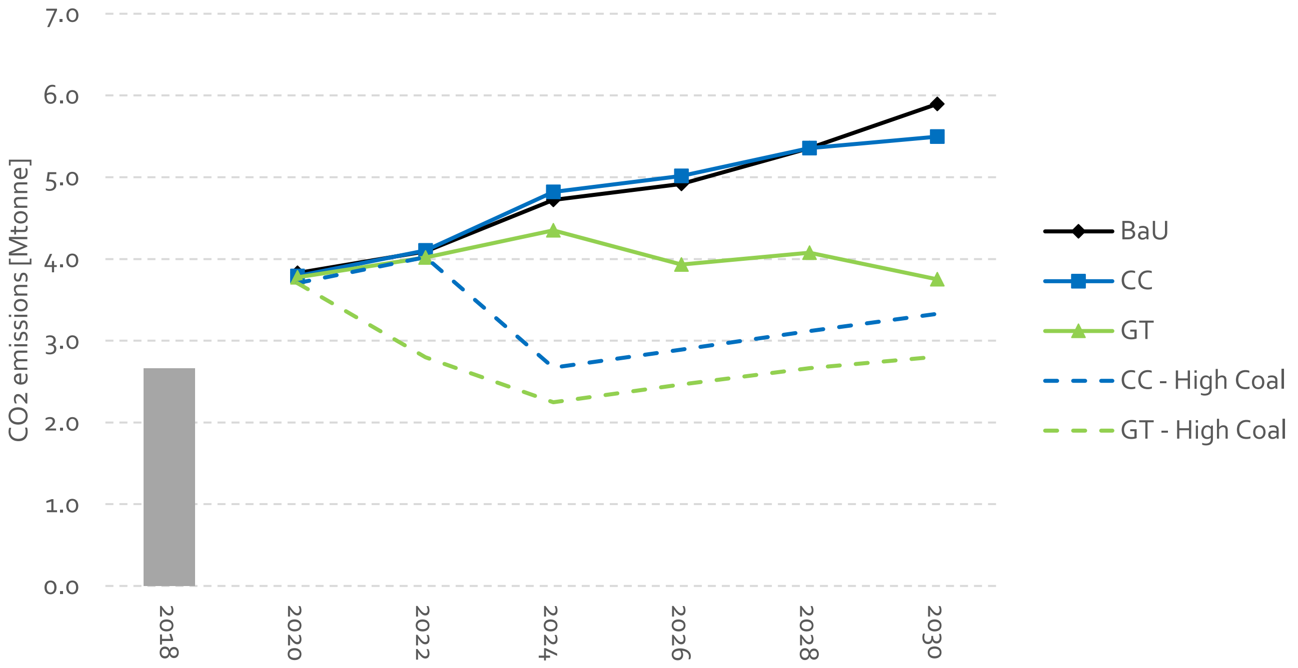


Figure 29: CO2 emissions from power generation in South Kalimantan in the scenarios analysed.

The deployment of larger shares of wind and solar, as found optimal under the GT conditions, can **keep emissions below the 4 Mtons threshold** in 2030 and avoid 8.7 Mtons emissions cumulated in the period analysed (-17%), as shown in Figure 30.

A similar impact can be achieved if a large amount of coal is substituted by combined cycle gas turbines, in the scenarios with high coal price. In this case, the **combination of RE and natural gas can reduce cumulative emissions by an impressive 43%** (-22.7 Mtons) **and allow South Kalimantan to meet more than double the demand with the same emissions as today**.

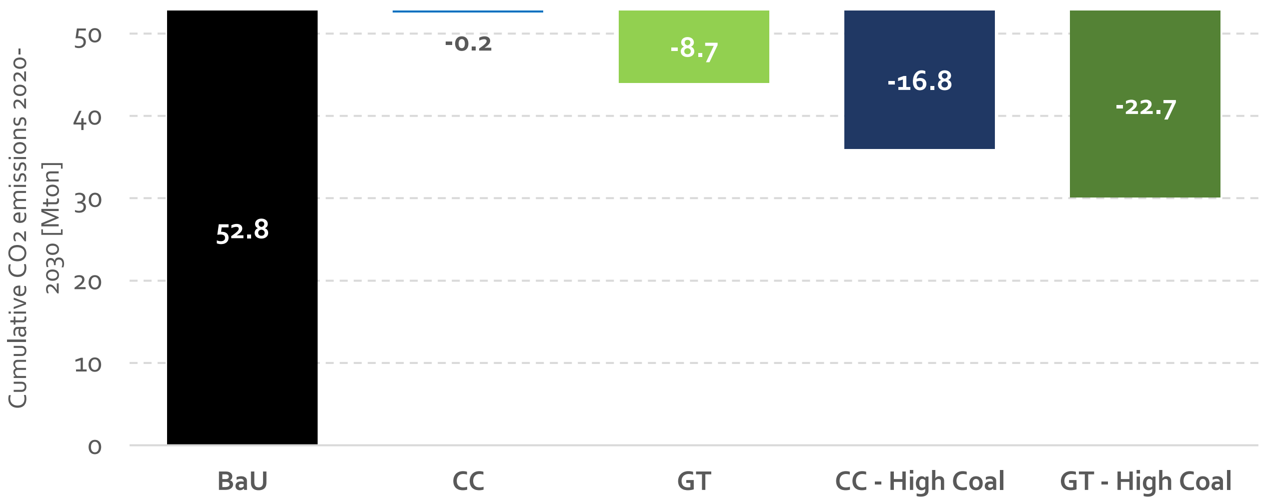


Figure 30: Cumulative emissions by 2030 in BaU and reduction in optimized scenarios.

Coal plants could experience low capacity factors

Coal power plants run as baseload in the BaU scenario and the CC scenario with 66-68% capacity factors on average, which is potentially lower than anticipated, while ***capacity factors drop to 50% in the GT scenario****. Gas power plants, in particular combined cycles, sees larger utilization in the optimized scenarios CC and GT with capacity factors reaching full utilization (70-80% CF) in 2030.*

Model results suggest that in scenarios in which capacity is optimized and more RE comes into the mix, there is a risk that coal plants have a low amount of operating hours (Figure 31). In the BaU and CC scenarios coal plant have capacity factors around 50-60% in the short term due to overcapacity. In 2030 the factors reach 70%. Conversely, in the GT scenario, due to the cost of pollution and the additional capacity coming in the system, **coal capacity factors plummet down to 50% in 2030.**

On the other hand, **combined cycle gas turbines achieve very high capacity factors** in both CC (after 2028) and GT (since 2024) making them more competitive in terms of cost of generation.

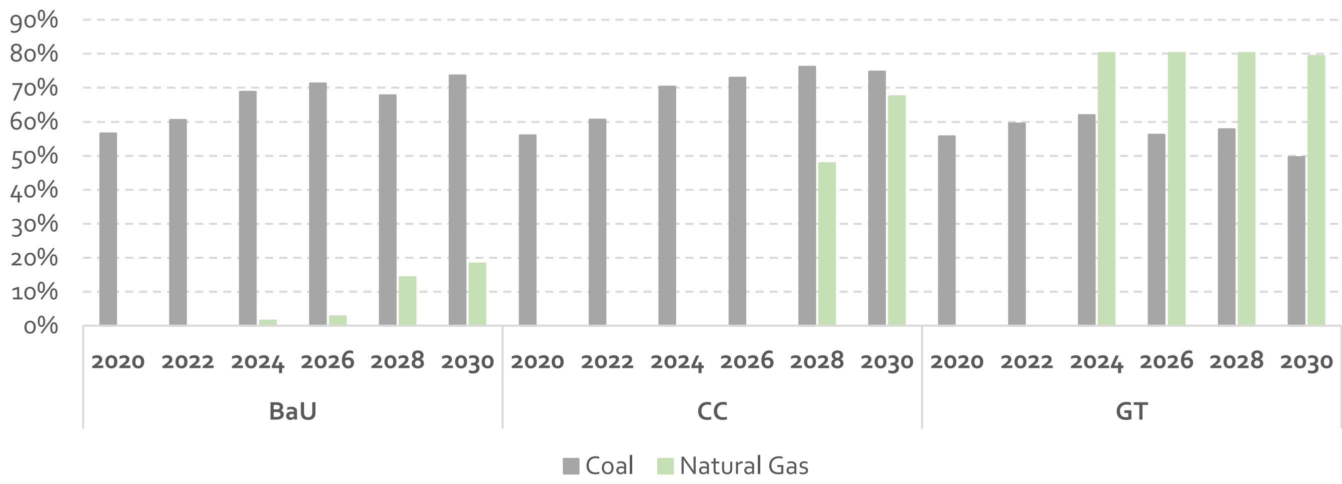


Figure 31: Capacity factors of coal and gas power plants by scenario and year.

In case the East Kalimantan gas pipeline does not materialize, what would happen?

If the gas pipeline currently under pre-feasibility study is not built, de facto limiting the additional gas supply in Central and South Kalimantan, ***RE can supply the missing power in the GT****, with additional 100 MW solar (supported by 100 MW batteries), 200 MW wind and 20 MW geothermal capacity.*

A gas pipeline between East Kalimantan and Kalselteng system is currently under pre-feasibility study and in the best case it would become operational by 2023. While this assumption is applied in all scenarios analysed, a sensitivity analysis is carried out evaluating the potential impact of a cancellation of the project or a delay post 2030. In this case, the only option to deploy natural gas plants in South Kalimantan would be to use liquified natural gas (LNG), which is assumed to be more expensive.

Under this condition, the 160 MW additional combined cycle gas turbines that appeared in the CC and GT scenarios by 2030 would be substituted by different investments (Figure 32). In the CC scenario, coal power capacity would be added to the system to make up for the lost supply. On the other hand, under the GT conditions, more RE capacity would be optimal: 200 MW wind power plants, 40 MW geothermal and 100 MW additional solar power.

The high wind and PV capacity, surpassing 1,000 MW in the "GT No gas" scenario, would be integrated with the addition of a 100 MW – 400 MWh battery storage plant. In addition, a 25 MW LNG capacity is found optimal.

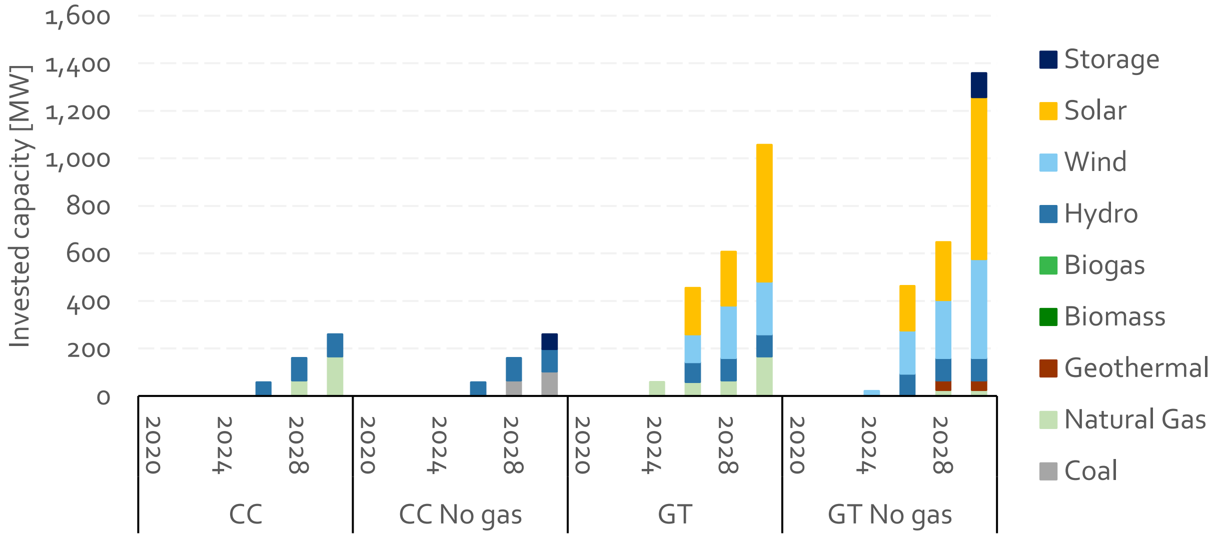


Figure 32: Investments in new capacity in the No Natural Gas sensitivity, compared to the CC and GT scenarios.

4. 2050 scenarios

Alternative least cost development features much more RE and gas than RUED

*The optimization of the power sector additions towards 2050 leads to **much more RE than anticipated in RUED** and to the **deployment of combined natural gas cycles rather than coal plants**. 700 MW of wind power and 2.4 GW of solar PV are deployed in 2050 together with 1.35 GW of battery storage. Least cost scenario achieves a share of renewables in terms of primary energy of 24% in 2050.*

To analyse the long-term perspective and the potential development of the power system in South Kalimantan, two scenarios are analysed: in the "RUED" scenario the buildout of power plants follows the plans under regional energy policy (RUED), including the target in terms of capacity mix of natural gas, coal and RE. For South Kalimantan, this corresponds to a system that is largely based on coal power. In addition, a "Least Cost" scenario is used to analyse what would be the development of the generation fleet on a pure cost minimization basis, disregarding existing policies and plans.

Figure 33 shows the capacity buildout in the two cases. The difference in how the fleet evolves is striking: In the **Least Cost scenario minimal coal capacity is added to the system and the increase in power demand is covered by natural gas and RE.** In the medium term (until 2030), it is combined cycle gas turbines that see the largest increase, while **from 2040 massive deployment of solar** supply a large portion of the demand. The optimal PV capacity in the system reaches 1.7 GW in 2040 and 2.4 GW in 2050.

Contextually, in order to integrate this large solar capacity and provide partially-dispatchable generation, battery storage capacity is added to the system. **For every 1 MW of solar capacity, the model adds 0.2 MW of battery storage in 2040 and around 0.55 MW in 2050**. Solar penetration becomes challenging from a system-operation perspective only for a large deployment of solar power. While the penetration remains below 5-10%, solar can be easily integrated in the system, especially in a system with large flexible gas power plants.

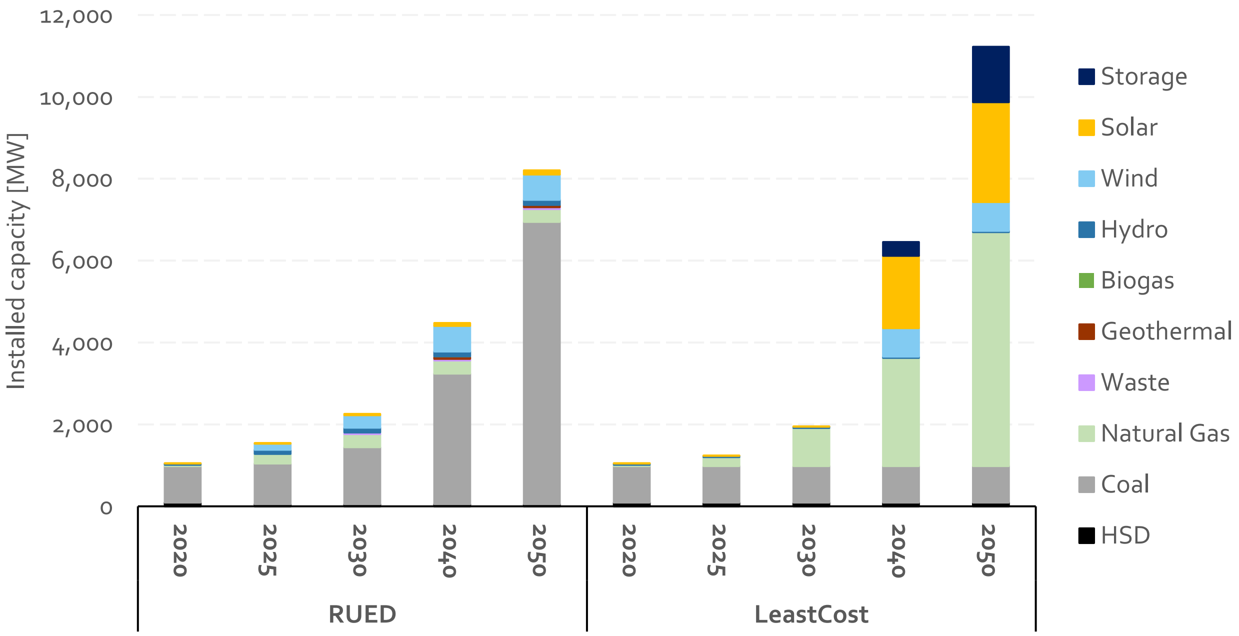


Figure 33: Installed capacity in South Kalimantan in Least Cost scenario compared to RUED scenario.

South Kalimantan's optimized system sees a high share of natural gas generation (72%) in 2050. This generation together with 12% of variable RE replace a large amount of coal generation compared to the RUED scenario. Wind power is also part of the mix, reaching a capacity of 700 MW in 2050, which is portion of the estimated wind potential that is situated in locations with high capacity factor (CF). The rest of the potential is assumed to be at lower CF and cannot compete with the low cost of solar in the 2040-2050 perspective.

The primary energy mix in the two 2050 scenarios is shown in Figure 34. In the RUED scenario the amount of RE is 15% in 2025 and 9% in 2050. On the other hand, the Least Cost scenario features a lower share in 2025 (2%) but in the long term, **the primary energy form RE in the system reaches 24%.**

While the analysis shows that South Kalimantan could be more ambitious in terms of deployment of RE, especially solar, it also testifies that due to the low potentials of hydro and geothermal it is hard for the province to cost-effectively reach very high levels of RE.

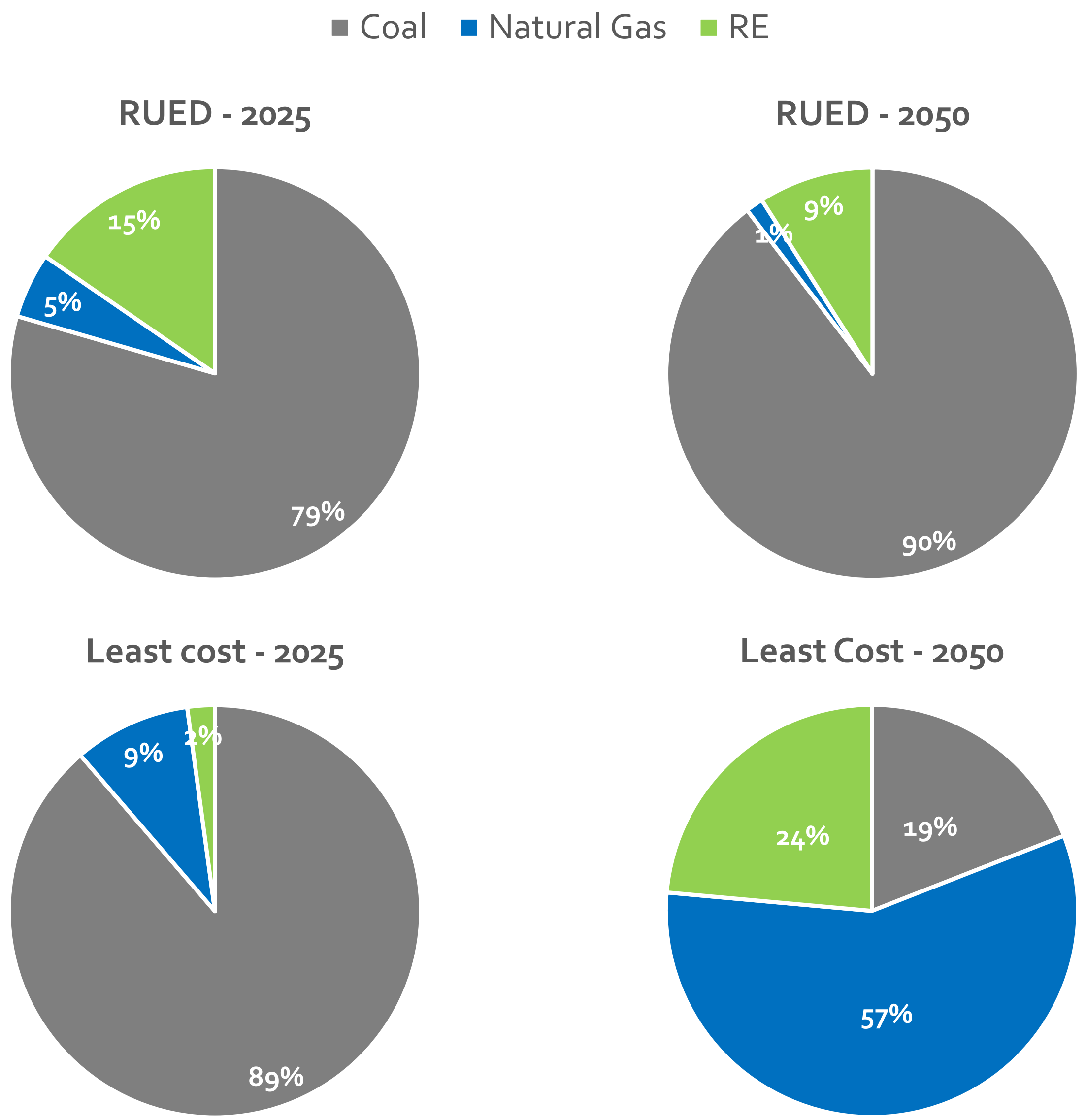


Figure 34: Primary energy by source in the two scenarios, 2025 and 2050.

More RE and natural gas can lead to cost savings and emission reductions

*Toward 2050, substitution of coal with natural gas and large-scale deployment of solar and wind can **reduce CO_2 emission by 60% and save on average 3.3 trillion IDR per year**, plus an additional 2.4 trillion IDR annually in health-related costs compared to RUED.*

The impact of the deployment of more natural gas and RE in the Least Cost scenario is tangible in both with respect to CO_2 emission and total cost of supply.

Figure 35 presents the cost comparison between the two scenarios, while Table 4 gives an overview of the cost savings per year. While in the short term, the cost difference is not very large, it grows substantially in the long term, when RUED meets the power demand with coal power and Least Cost scenario does so with cheaper generators. The cost savings averages 3.33 trillion IDR per year over the period 2020-2050 with a peak of 8.45 trillion in 2050.

In addition to this, there is also a large potential to reduce the costs related to the emission of SO_2, NO_x and $PM_{2.5}$ caused by the combustion of coal in power plants. On average the potential cost saving is equal to 2.41 trillion IDR annually.

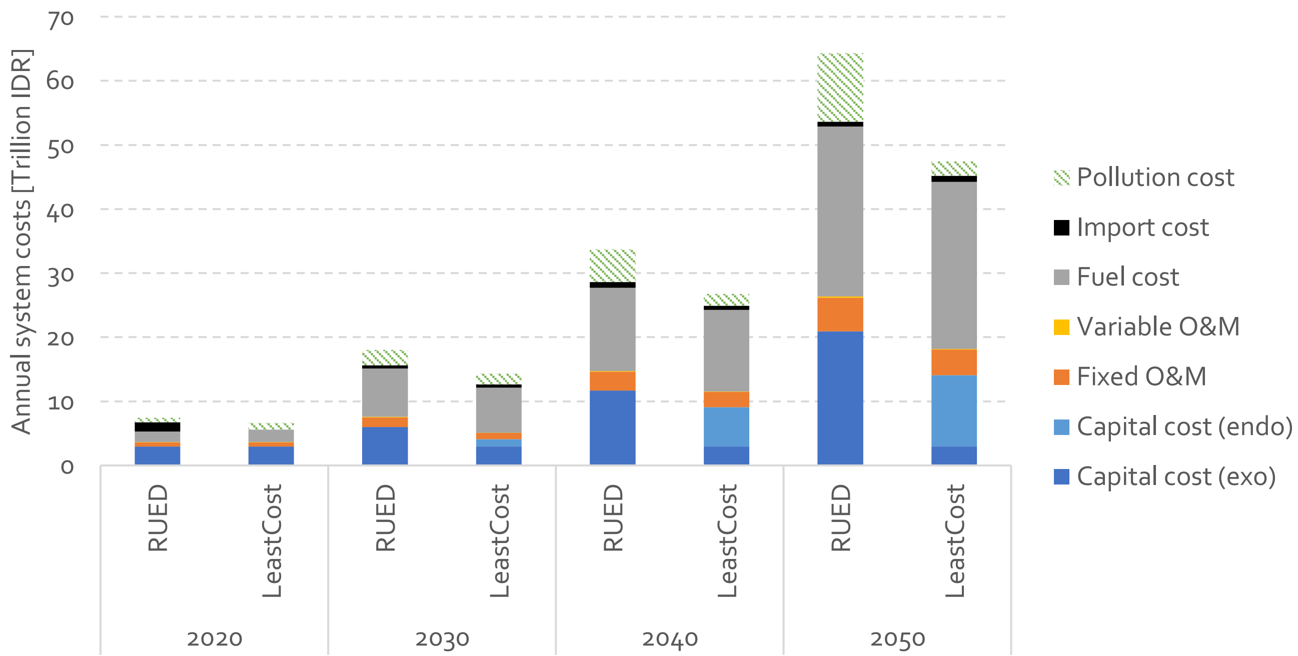


Figure 35: Comparison of total system cost by scenario and year.

Table 4: Savings in the Least Cost scenario from reduced system cost and reduced pollution cost per year.

	Total system cost savings [Trillion IDR]	Additional savings pollution [Trillion IDR]
2020	1.21	-0.33
2025	0.27	0.04
2030	2.99	0.67
2040	3.71	3.25
2050	8.45	8.43
Yearly average	**3.33**	**2.41**

The emissions of CO_2 caused by coal power plants are the largest among the different generation technologies. It is not a surprise that the almost exclusive coal deployment under the RUED scenario causes the **emissions to skyrocket to more than 40 Mton by 2050** (Figure 36).

With the power plant pipeline suggested in the Least Cost scenario, it is possible to reduce the emissions related to an increased power demand and reduce the emissions by 60% in 2050. This would correspond to a **cumulative reduction of 251 Mton (-45%) over the 30 years analysed**.

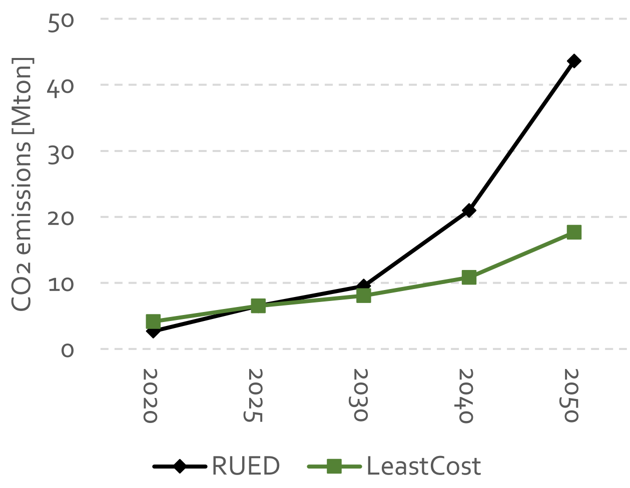


Figure 36: CO2 emissions in RUED and Least Cost.

5. Conclusions and recommendations

The ambition of the analyses carried out in this **South Kalimantan Regional Energy Outlook** has been to answer key questions related to power system planning in the province with the ultimate aim of indicating how South Kalimantan province can ensure an affordable, resilient and environmentally friendly development and on whether renewable energy could play a role.

The results of the analyses for both medium term and long term showed that while coal will still dominate the supply in the short term due to the large capacity already installed and the competitive dispatch cost, failing to consider other sources could lead to a higher cost of supply and increased power tariffs. Natural gas, solar and wind are the best candidates to supplement coal in meeting the expected power demand increase in the province.

A higher deployment of natural gas, solar and wind could result in large cost savings and in substantial reduction of the climate-related emissions.

The **key messages and recommendations** with regard to achieving an affordable and environmentally friendly development of the power system include:

- Look beyond coal: Start considering not only wind power, but also solar PV as potential sources of cheap power, especially if cheaper financing is possible. Identification of suitable sites for both technologies and the preparation of pre-feasibility studies can help attract investors. Carefully reassess the case for additional coal power plants to avoid technology lock-in and overcapacity in the future, as RE becomes more competitive and cost-effectively displaces coal generation;
- Start factoring in the risk of a discontinuation of the DMO and a potential surge in coal price. RE and combined cycle gas turbines represent cheap options for diversification of the power supply and increasing the resilience of the power supply with respect to the cost of power supply. Failing to do so could result in increased power tariffs;
- Assumptions across official planning documents, such as RUEN, RUED and RUPTL (but also RUKN and RUKD) differs both in terms of energy sources potentials and power demand projections. Aligning main assumptions across documents can help ensure consistency in the information and in the process of policy making;
- Map and monitor loan and financing options and develop a strategy to attract international finance. The results show that with foreign aid and international financing at lower rates due to interest in the global fight against climate change, RE can become an attractive option. In order to attract capital, a commitment to a RE project pipeline, an increase in the RE ambition of South Kalimantan province and an improved communication of these targets can be enabling factors;
- Revise long-term RUED targets upward for RE and natural gas. The 2050 Least Cost optimization scenario shows a dominant role for natural gas and a RE share reaching 24%. Consider technology development and cost reduction potentials for RE. As testified by the results of auctions worldwide, solar and onshore wind are becoming the cheapest sources of power. Even though Indonesia is lagging behind in terms of its deployment and still experiences higher costs today, ultimately the cost will be brought down due to larger volumes and cost drop as the local RE industry develops.

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Glossary

Levelized cost of electricity

This parameter expresses the cost of the MWh generated during the lifetime of the plant and it represent a life-cycle cost. It can be calculated as:

$$LCoE = \frac{I_0 + \sum_{t=1}^{N} \frac{V_t}{(1+i)^t}}{\sum_{t=1}^{N} \frac{E_t}{(1+i)^t}}$$

where:
I_0 *= Overnight cost or Investment cost [IDR]*
N = Technical lifetime of the plant [years]
V = Variable cost including O&M and fuel cost [IDR in year t]
E = Electricity produced in the year t [kWh in year t]
i = real discount rate [%]

Full Load Hours (FLH)

Full Load Hours (FLH) are another way of expressing the Capacity Factor of a power plant. While capacity factor is defined in %, Full Load Hours are expressed in hours in the year or kWh/kW. 100% capacity factor corresponds to 8,760 hours.

Appendix A. Balmorel model

The scenarios described are developed and analysed using the open source model Balmorel. The model has been developed and distributed under open source ideals since 2001. The GAMS based source code and its documentation is available for download on www.balmorel.com. While the code is free to access, a GAMS license is required.

Balmorel is a model developed to support technical and policy analyses of power systems. It is a bottom-up partial equilibrium model which essentially finds economical dispatch and capacity expansion solution for the represented energy system.

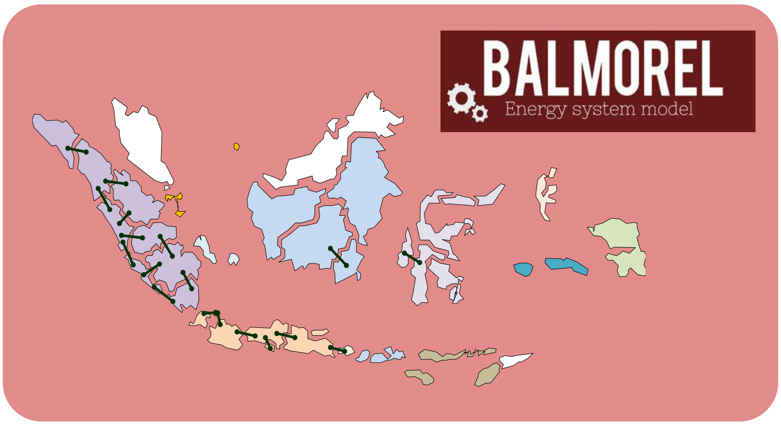

Figure 37: Balmorel model, Indonesian setup.

In investment mode, it is able to simultaneously determine the optimal level of investments, refurbishment and decommissioning of electricity and heat generation and storage technologies, as well as transmission capacity between predefined regions. In dispatch optimization mode, it determines the optimal utilization of available generation and transmission capacity at an hourly level, replicating the day-ahead scheduling of units in the dispatch centres, based on least cost dispatch.

To find the optimal least cost outcome in both dispatch and capacity expansion, Balmorel considers developments in electricity demand overtime, grid constraints, technical and economic characteristics for each kind of production unit, fuel prices, and spatial and temporal availability of RE. Moreover, policy targets in terms of fuel use requirements, environmental taxes, CO_2 limitations and more, can be imposed on the model (Figure 38). It is capable of both time aggregated, as well as hourly modelling, which allows for a high level of geographical, technical and temporal detail and flexibility.

The model has been successfully used internationally for long-term planning and scenario analyses, short-term operational analyses on both international as well as detailed regional levels. The typical stakeholders in the different countries ranges from TSOs, National Energy Authorities, vertically integrated utilities and other public/private bodies with responsibility over power system planning, energy regulation, power dispatch and market operation.

Currently, activities are ongoing in Mexico, Indonesia, China and Vietnam, where the model is used for renewable integration scenarios and countries Energy Outlooks from the responsible national agencies. In recent years, additional activities have been developed in the Eastern African Power Pool (Egypt, Sudan, Ethiopia, Kenya, South Sudan, Burundi, Rwanda, D.R. Congo) and South Africa, while smaller studies in Canada, Ghana and Mauritius have taken place before 2010 (Ea Energy Analyses 2019).

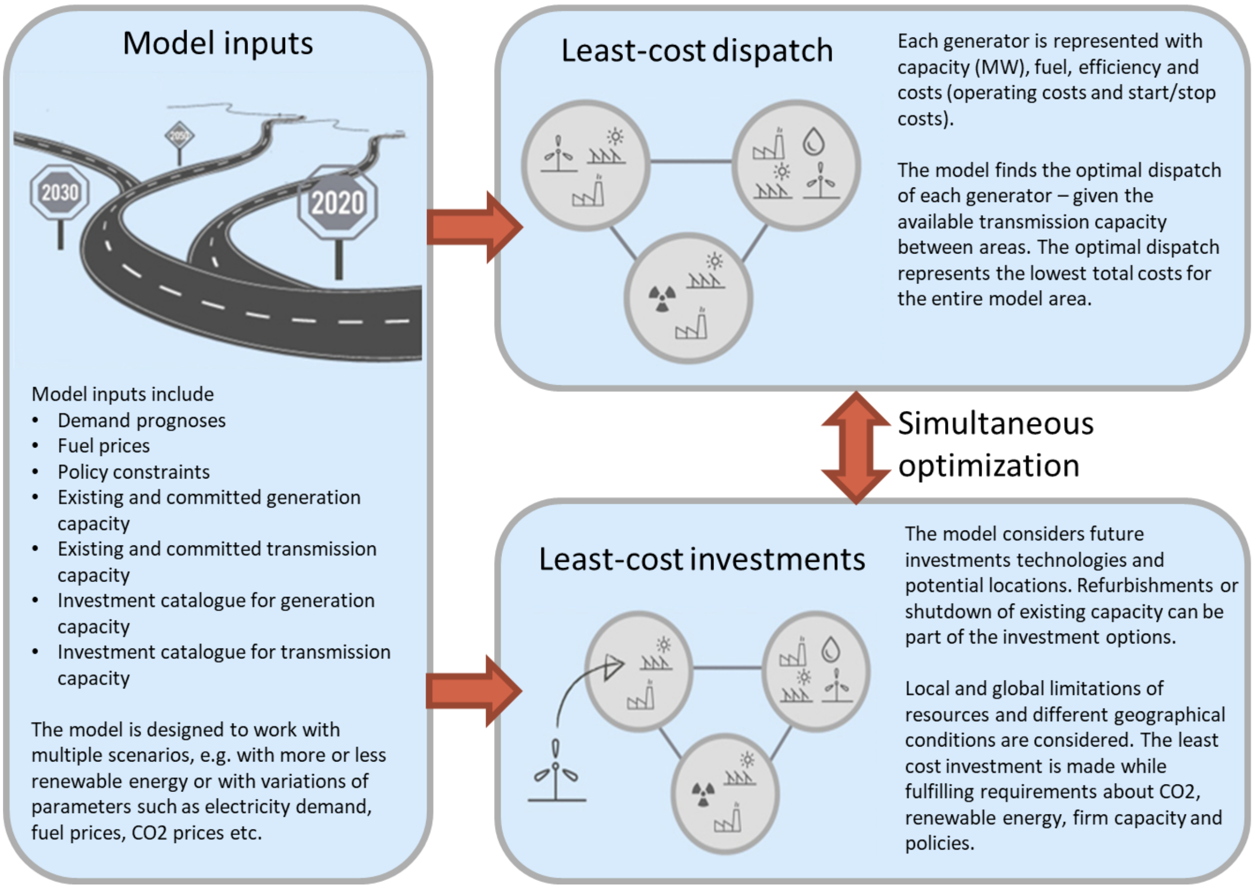

Figure 38: Balmorel model inputs and optimization logic.

Among the Balmorel model advantages compared to other planning tools available, are the following:

- Least cost optimization of dispatch on an hourly bases, simulating actual day-ahead scheduling of units
- Co-optimization of dispatch and new investments
- Non-marginal analysis of new capacity added to the system
- Co-optimization of new transmission and generation capacity
- Takes into account CF evolution of traditional plants
- Good representation of RE variability and impact on the residual load
- Flexible, customizable and scalable: it has been applied to entire countries like Indonesia, but also to smaller systems like Lombok.

Appendix B. Detailed assumptions

The Kalimantan power system analyses are carried out with the Balmorel model, described in Appendix A. The input to the Kalimantan Balmorel model and the set-up of the simulations is described in more detail in this Appendix.

B-I. GEOGRAPHICAL RESOLUTION

The model contains data of the electricity system of the Kalimantan island. The map below illustrates the interconnected power system in Kalimantan in 2018.

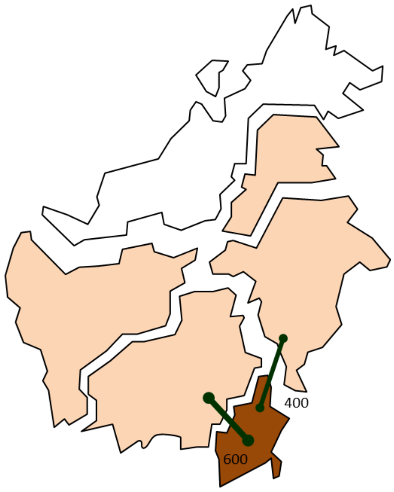

Figure 39: Kalimantan Island represented in 5 transmission regions. Interconnector capacity shown (in MW) for 2018.

The island is represented in the Balmorel model as five dispatch-regions, each with its own electricity consumption. The transmission regions are connected by electricity transmission lines with fixed capacity. As of 2018, only the power systems of East Kalimantan and Kalsenteng (Central and South Kalimantan) are connected, via a 400 MW power line.

While the focus of this study is on South Kalimantan, a representation of the other regions is included in the model optimization to reflect dependencies between regions and potentials for import/export. For the power system of South and Central Kalimantan, each power generation unit is represented separately, while for the other regions groups of power plants are represented depending on the fuel type.

B-II. TIME RESOLUTION AND UNIT COMMITMENT

The model is set up to analyse the year 2018 as reference year and the period 2020-2030 in 2-year intervals. For the 2050 scenarios, the calculations are performed on 2020, 2025, 2030, 2040 and 2050.

To limit the computation time, not all hours of the year are included in the simulation. The dispatch and investment optimisation, both in generation capacity and in transmission capacity, are performed with 25 hourly time segments and 26 seasons (25x26 = 2,526) time-steps. The 26 seasons represent two-week periods in the year, where the hours are aggregated into 25 intervals representing evening peak demand, afternoon solar peaks, nights, morning etc. A more accurate dispatch optimization is analysed in an hourly representation (52x168 =8,736 time-steps).

Unit commitment

The aggregated dispatch and investment runs have been carried out using investment simulations with unit commitment in its relaxed mixed integer formulation. Relaxing the unit commitment restraints means that variables which in the unrelaxed case would be binary values (0 or 1) are represented as linear values (e.g. a unit can be 56% online). Unit commitment constraints implemented in this case are

- Start-up costs
- Minimum generation requirement
- Increased marginal efficiency at higher generation levels

As the modelling includes many different units, the general impact of implementing unit commitment on a large scale in the relaxed form will be close to the realistic impact.

In the hourly dispatch runs, full (un-relaxed) unit commitment is implemented, where binary variables are strictly zero or one. In the hourly run additional unit commitment constraints are

- Minimum up and down time (e.g. a unit that is turned on, needs to stay on at least X hours, one that is shut down needs to stay shut down for Y hours)
- Maximum ramp-up and down time

B-III. EXISTING AND COMMITED GENERATION CAPACITY

As a starting point, the existing generation fleet in 2018 is implemented in the Balmorel model. To represent the current power system, each existing power plant has been modelled individually, with information about the efficiency, variable and fixed operation and maintenance cost, as well as emission and unit commitment data. As of 2018, the total generation capacity in South Kalimantan was about 400 MW.

Planned projects under RUPTL19

For all model-optimized 2030 scenarios (Current conditions, Green transition and the sensitivities), additional capacity from projects having started operation after 2018 or currently under construction, have been added for later years, as well as planned generation capacity in RUPTL19 until 2020. Planned hydro in RUPTL power capacity have been implemented until 2025. Hydro and geothermal projects generally require long planning horizons and therefore buildout until 2025 will likely not differ significantly from planned capacity.

In the BaU scenario, all buildout in the RUPTL is included until 2028. The generation capacity included in the model for South Kalimantan is shown Figure 40.

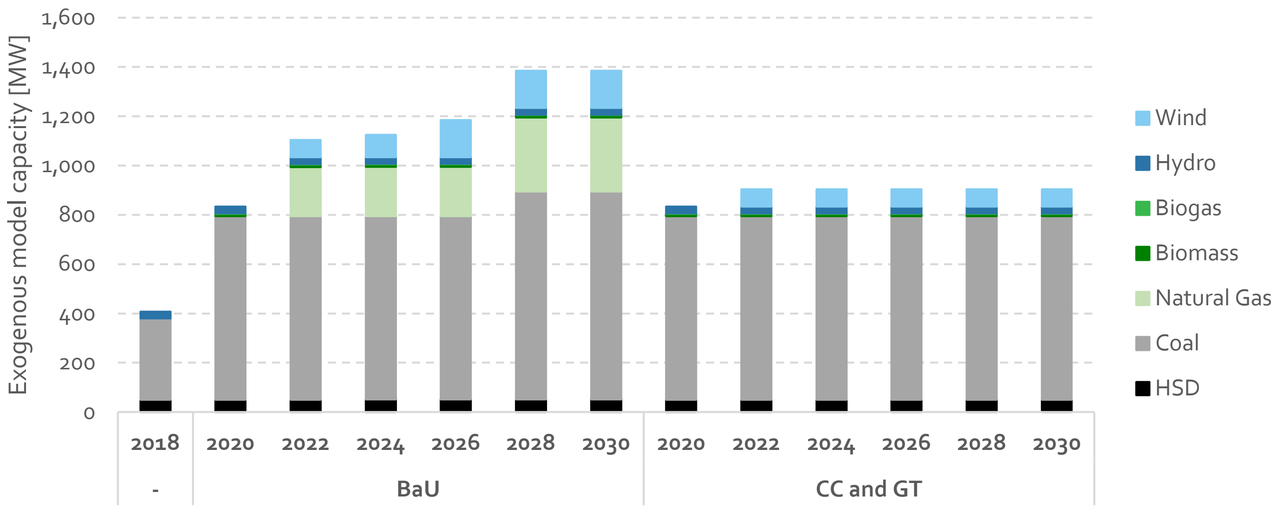

Figure 40: Existing and committed capacity entered in the Balmorel model as input in the BaU, CC and GT scenario.

Table 5: Planned generation units for South Kalimantan included in RUPTL 2019.

System	Type	Fuel	Location/Name	Capacity (MW)	COD	Status	Ownership
Barito	PLTU	Coal	Kalsel (FTP2)	2 x 100	2019	Under Construction	IPP
Barito	PLTBg	Biogas	Sukadamai	2,4	2019	Under Construction	IPP
Barito	PLTU	Coal	Kalselteng 2	2 x 100	2020	Under Construction	PLN
Mantuil	PLTBio	Biomass	Mantuil (Kuota) Tersebar	10	2020	Planned	IPP
Barito	PLTGU	Natural gas	Kalsel 1	100	2027	Planned	*Unallocated*
Barito	PLTU MT	Coal mine-mouth	Kalselteng 5	100	2028	Planned	IPP
Barito	PLTG/ MG/ GU/MGU	Natural gas	Kalsel	200	2021/22	Planned	PLN
Barito	PLTB	Wind	PLTB Tanah Laut	70	2021/23	Planned	IPP
Kotabaru	PLTU	Coal	Kotabaru	2 x 7	2019/20	Under Construction	PLN
Isolated Tersebar	PLTD	Diesel	PLTD Lisdes Kalsel	0,9	2024	Planned	PLN

RUED expectation for capacity development

For the 2050 scenarios, capacity development from RUED was implemented until 2020 for the Least-cost scenario. In the RUED scenario all RUED's capacity buildout for South Kalimantan was included until 2050. For the other provinces in Kalimantan, RUED generation targets were set (Table 7).

Table 6: Planned generation units for South Kalimantan included in RUED 2019.

Jenis	2015	2020	2025	2030	2040	2050
PLTUB	260	804	804	904	904	904
PLTUB Tambahan	-	-	100	400	2,200	5,900
PLTGU	-	-	-	100	100	100
PLTG	20	20	220	220	220	220
PLTD	50	50	50	50	50	50
PLTD Sewa	80	40	-	-	-	-
Beli Daya Lebih	90	90	90	90	90	90
PLTA/PLTMH	30	30	98	121	121	121
PLTB	-	-	150	300	600	600
PLTS	0.3	8	17	29	55	80
PLTSa	-	-	-	20	40	40
PLTBiogas	-	10	20	20	20	20
PLTP	-	-	-	-	40	40
PLTH	-	-	-	-	40	40
Total	530	1.053	1.549	2.254	4.480	8.205
Persen EBT (%)	5,7	4,6	18,4	21,7	20.4	11,5

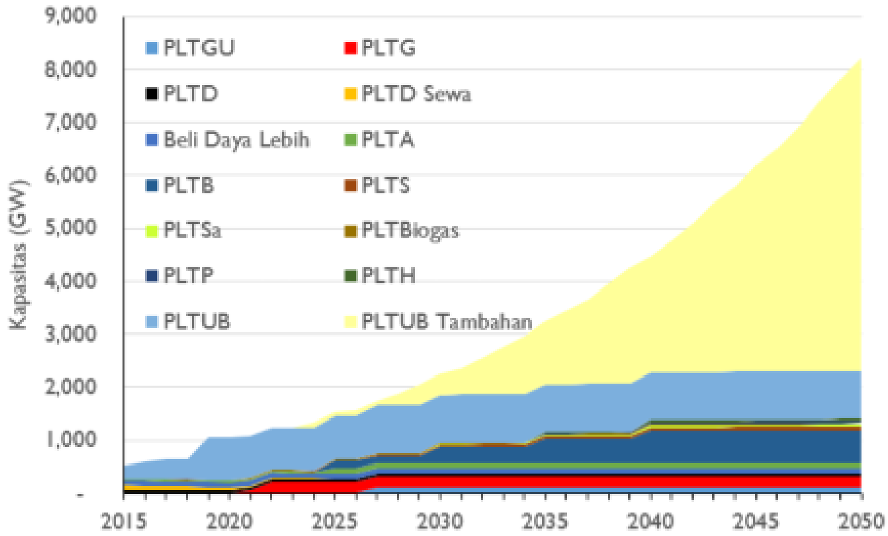

Figure 41: RUPTL capacity buildout expectations until 2050.

Table 7: Generation shares in the RUED scenario, for all provinces. Shares are implemented as minimum generation restrictions for all Provinces.

		2020	2030	2040	2050
Central Kalimantan	**RE share** [%]	18	41	54	67
	Coal share [%]	23	43	34	26
	Gas share [%]	7	13	10	7
East Kalimantan	**RE share** [%]	17	38	51	64
	Coal share [%]	37	46	37	27
	Gas share [%]	19	15	12	9
North Kalimantan	**RE share** [%]	42	81	89	96
	Coal share [%]	10	17	10	3
	Gas share [%]	18	2	2	1
South Kalimantan	**RE share** [%]	10	13	11	9
	Coal share [%]	80	81	85	89
	Gas share [%]	2	4	3	1
West Kalimantan	**RE share** [%]	14	30	32	35
	Coal share [%]	26	45	38	31
	Gas share [%]	7	17	23	28

B-IV. MODEL-BASED INVESTMENT APPROACH

The Balmorel model is myopic in its investment approach, in the sense that it does not explicitly consider revenues beyond the year of installation. This means that investments are undertaken in each year if the annual revenue requirement (ARR) in that year is satisfied by the market. Capacity appears in the beginning of the year of commissioning. This means that the decision for investment should be considered as taken in an earlier year (considering planning and construction).

A balanced risk and reward characteristic of the market is assumed, which means that the same ARR is applied to most technologies, specifically 0.1175, which is equivalent to 10% internal rate of return for 20 years. This rate should reflect an investor's perspective. For the Green Transition scenario, the ARR was differentiated depending of generation source (0.1019 for renewable generation and 0.1339 for coal generation). For transmission capacity this ARR becomes 0.1241 (12% internal rate of return for 30 years).

Technical and financial data

In order to be able to optimize future capacity expansion, it is of paramount importance to estimate the development of the cost and performance of generation technologies. For this reason, a Technology Catalogue for Power Generation technologies of has been developed in 2017 in collaboration with Danish Energy Agency (DEA), National Energy Council (NEC) and a number of power sector stakeholders (NEC 2017).

Table 8 summarizes the technologies available for investments and the main technical and financial assumptions in 2020. For some technologies, learning rates are assumed for years beyond 2020, resulting in decreased costs or increases efficiencies.

Table 8: Financial assumptions on technologies available for investment in the model in 2020.

Technology		Investment cost	Variable O&M cost	Fixed O&M cost	Efficiency
		$/MW	*$/MWh*	*k $/MW*	%
Subcritical coal	PLTU	1.65	0.13	45	34%
Combined cycle gas turbine	PLTGU	0.75	0.13	23	56%
Geothermal plant	PLTP	4.5	0.37	20	-
Biomass power plant	PLTMG	2.5	3	48	29%
Waste power plant	PLTSa	8.4	-	277	35%
Wind	PLTB	1.88	-	60	-
Solar	PLTS	1.25	-	15	-
Run of river hydro	PLTA/M	1.9	0.5	53	33%

Geothermal and hydro expansions have been included as input until 2025, following the plan under RUPTL19. Until after 2025, no additional model-based investments are allowed for those two technology types.

Availability of power plants and reserve requirements

The Balmorel model does not inherently consider reserve margin for the investment optimization, investing in just enough capacity to supply demand in all hours. However, planned and unplanned outages both in generation and transmission capacity as well as errors in the prediction in demand and VRE generation, might necessitate additional flexible capacity to be dispatch in critical hours. In the model, a certain average availability has been considered for each power plant (72% for existing coal plants and 80% for new coal and other thermal plants), de-facto reducing its available capacity and guaranteeing an intrinsic reserve margin. In addition, in order to ensure enough capacity regardless of the transmission level, it has been imposed that each province in Kalimantan should at any point have enough dispatchable capacity to cover its peak demand. Dispatchable capacity includes coal, diesel, natural gas, biomass, waste, geothermal, reservoir hydro and batteries.

B-V. FUEL SUPPLY AND PRICES

Fuel prices used for the simulations are based on PLN Statistics for 2017 (PT PLN Persero 2017), while the long-term projections follow the development of the New Policy scenario of the World Energy Outlook 2018 (International Energy Agency 2018) (Figure 42).

The coal price in South Kalimantan from 2017 statistics is 551 IDR/kg, which is 3% higher than East Kalimantan. The gas price in Kalimantan East is 73,109 IDR/MMSCF. For Kalimantan South, 5% cost is added to account for the cost of transport of natural gas from Kalimantan East to Kalimantan South, Kalimantan South not having local NG sources. In the sensitivities, when no pipelines from Kalimantan East to Kalimantan South are assumed, Kalimantan South can still import LNG, at a higher fuel cost (+/- 50% more expensive). The price for diesel in 2017 was 7,728 IDR/liter and is the fuel which price is growing the most in the future. The price assumed for biomass is from Perhepi and is around 700,000 Rp/ton with a calorific value for 15 GJ/ton.

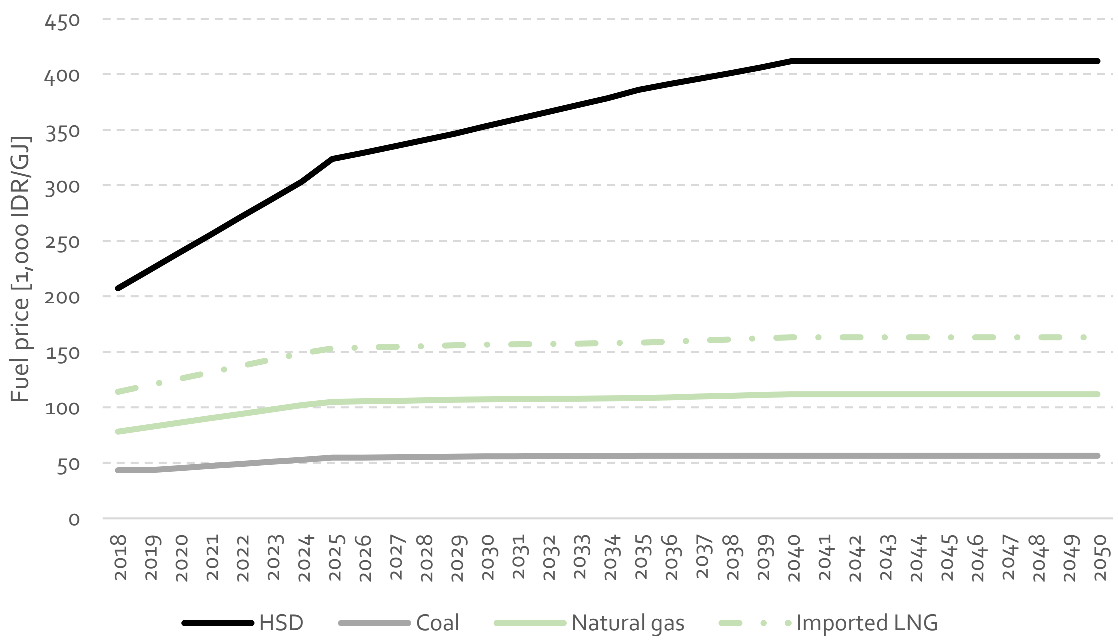

Figure 42: Fuel price projections for South Kalimantan.

B-VI. INTERCONNECTORS

Interconnectors until 2030 are included in the model as input and not optimized, due to difficult planning processes and long planning horizons. In 2018, connections exist only between East Kalimantan and South Kalimantan and between Central Kalimantan and South Kalimantan. From 2020, connections are planned between Kalimantan East and Central, Central and West and East and North as well, resulting in a better interconnected power system. The assumptions for the interconnectors expansion in the next future are from the 20-year plan of Directorate General of Electricity of the MEMR (Directorate General of Electricity 2019).

	Central	Central	Central	East	East
	East	**South**	**West**	**North**	**South**
2018	0	600	0	0	400
2019	400	600	0	400	400
2020	400	1000	400	400	400
2021	400	1000	400	400	400
2022	400	1000	400	400	400
2023	400	1000	400	400	550
2024	400	1000	550	400	700
2025	400	1000	700	400	700
2026	400	1000	700	400	700
2027	400	1000	700	400	700
2028	400	1000	700	400	700
2029	400	1000	700	400	700
2030	400	1000	700	400	700
> 2030	400	1000	700	400	700

Figure 43: Transmission capacity in Kalimantan. Source: (Directorate General of Electricity 2019)

In the Balmorel model, transmission of power can happen between the five dispatch-regions depending on the cost of generation at an hourly level, meaning that theoretically the flow could change direction every hour. In reality, in the power system in Indonesia, the flexibility of the transmission lines is not so high since the different dispatch centers are not fully coordinated in real-time, but the power across regions, when there is a sensible difference in the generation cost is set on a periodical basis. In order to represent transmission flow closer to reality, in the scenarios, a threshold of 350 IDR/kWh has been assumed, meaning that while the difference in the cost of generation is below this level, no power will be transmitted between the two area.

From 2030, onwards (in the 2050 scenarios), model-optimized transmission can be added to the interconnector grid. Transmission line investment costs are given in Table 9.

Table 9: Investments costs for additional transmission lines after 2030 (Million IDR/MW).

East	**Central**	10,794
North	**East**	12,028
South	**Central**	4,318
South	**East**	11,411
West	**Central**	18,505

B-VII. RE RESOURCES

Wind power resource

The hourly wind speed profile used is from *Wind Prospecting*, an open-source meso-scale model of wind developed by EMD International for the ESP3 program (EMD International 2017). The assumed turbine model, Vestas V150, has relatively low specific power and could result in more than 3,000 FLH at the site. Two sites have been used to calculate the potential production from the turbine. A location close to Tanah Laut with an average wind speed of 6.7 m/s at 100m which can achieve 3,380 FLH and slightly less windy site with average speed of 5.8 m/s at 100m, which can achieve 2,850 FLH.

Combining hourly wind speed with the power curve of the turbine permits calculation of an expected generation profile to be used in the model (Figure 44). As can be seen, wind speeds and consequently wind generation is higher during the dry season months.

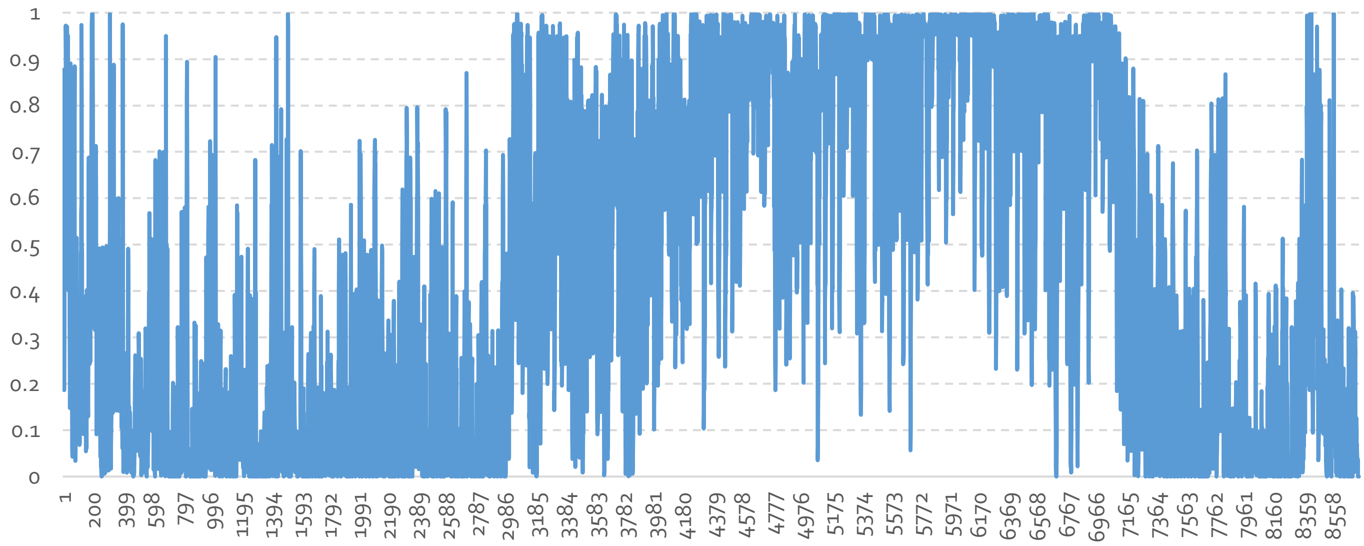

Figure 44: Wind variation profile considered in the model.

Solar power resource

To represent the diversity of solar resources, 52 locations distributed around the island have been selected (14 in South Kalimantan and 23 in Central Kalimantan – see Figure 45) and the FLH at the location calculated on the Global Solar Atlas by the World Bank (Global Solar Atlas 2019). The frequency distribution of FLH has been used to distinguish 4 resource classes and to determine the size of each class. The total solar potential for Kalimantan South has then been distributed accordingly, resulting in the following: High solar area with 1,333 FLH (1,723 MW), medium-high area with 1,319 FLH (1,292 MW), medium-low area with 1,289 FLH (1,292 MW) and low solar area with 1,272 FLH (1,723 MW).

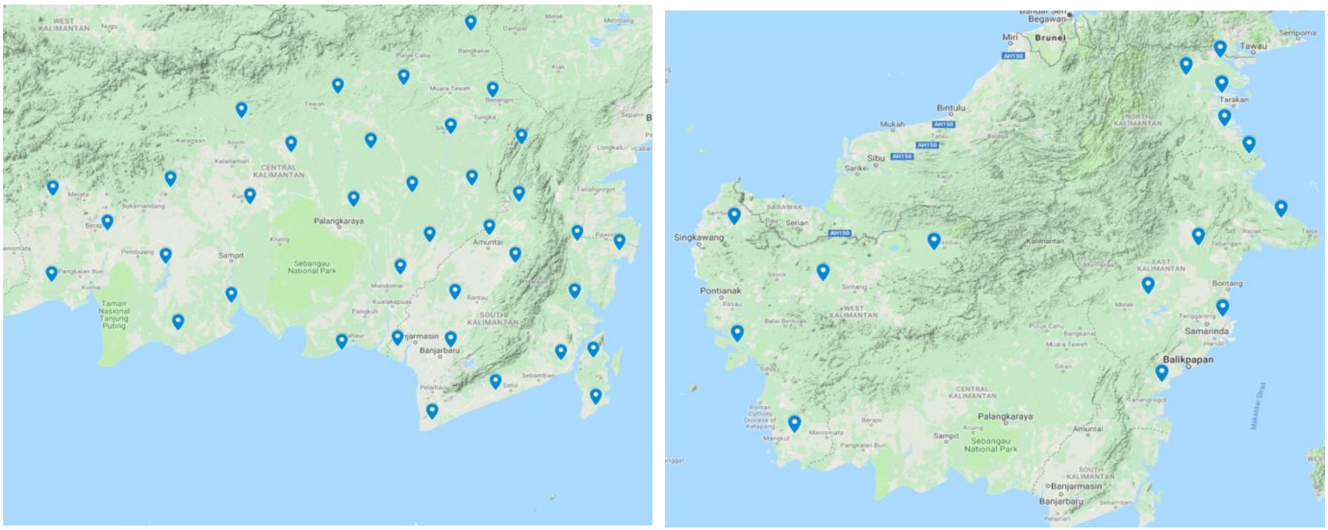

Figure 45: Locations used to estimate solar resource and total potential in South, Central and the rest of Kalimantan.

The hourly solar irradiation is quite constant throughout the year with a more constant irradiation during the dry season (May-October), making the low seasonality of solar attractive for the power system. The hourly profiles considered are based on the website Renewables Ninja (Pfenninger and Staffell 2019), see Figure 46.

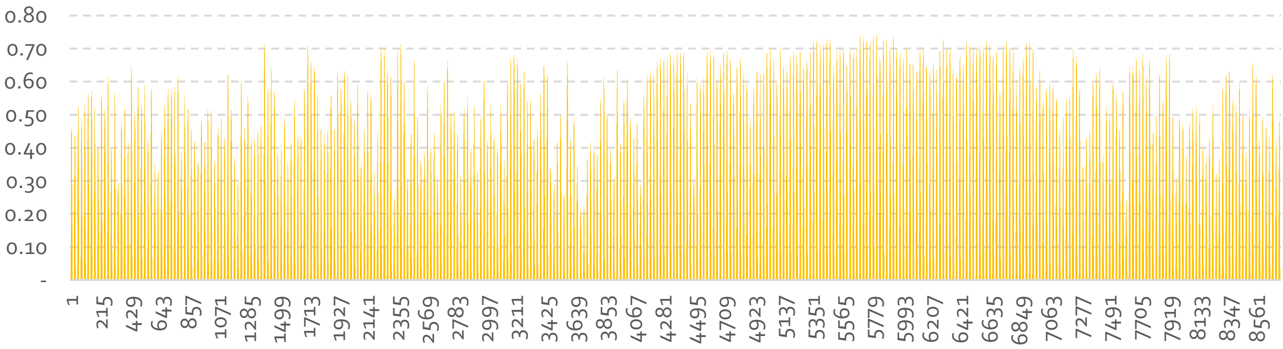

Figure 46: Solar variation profile considered in the model.

As solar power is a relatively new technology and investments in new solar might necessitate further investments in transmission and distributions grids, a maximum allowed additional investment per years has been assumed for solar power as shown in Table 10.

Table 10: Allowed expansion rate (MW/year) for solar power.

Central	188
East	375
North	63
South	313
West	250