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Riau Regional Energy Outlook

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Disclaimer

The present report was developed with the support of National Energy Council (NEC), PLN Riau and Dinas ESDM Riau. However, the results, simulations setup and views expressed in the report do not represent any official statement or position of the aforementioned institutions and it is 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

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Executive summary

The **Riau Regional Energy Outlook** explores the potential development of the power system in the medium (2030) and long (2050) term, analysing least-cost scenarios which addresses the following key questions:

- How can Riau ensure an affordable, resilient and environmentally friendly development of the power system?
- What role can bioenergy play in displacing fossil fuels? Which other sources can actively contribute to achieving the RE goals?

Riau province is part of the larger power system in Sumatra 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). The power demand - today 4.4 TWh/year - is expected to double in the next 10 years, requiring large infrastructure investments in both generation and transmission. In the long term, the aim of increasing life standards and achieving a consumption per capita of 7,200 kWh/year (1,900 kWh/year in 2015) will increase the power demand even further.

RUPTL expects that new generation capacity will be almost exclusively based on new coal and natural gas investments, with a limited focus on RE in the next ten years. Meanwhile, the regional plan contained in RUED has a target of 34% RE in 2025 and 47% in 2050 and presents bioenergy as the main contributor to the power sector development, making the province more ambitious than the national goals contained in RUEN.

Riau has an **extensive potential for bioenergy** use in the power sector, namely biomass and biogas from existing waste of palm oil residues, as it is one of the provinces with the highest palm oil production. Using these waste products would also avoid their decay and prevent climate-harming methane emissions. Riau has limited potential for wind, geothermal and hydro. Solar irradiation is high enough for Riau to have economically feasible PV plants, albeit lower compared to other parts of Indonesia.

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.

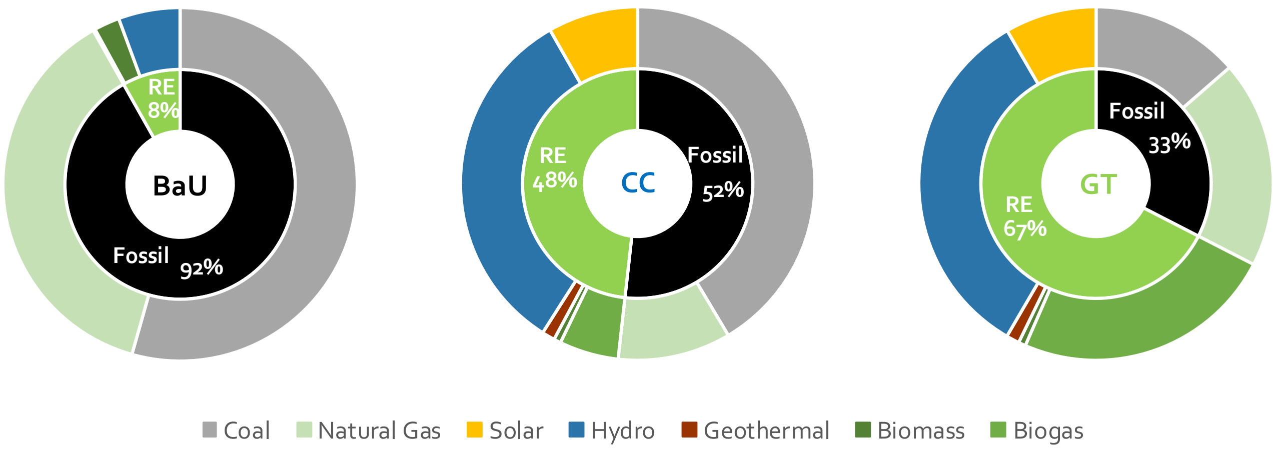

Figure: Generation share in the three scenarios shows the opportunity to increase RE penetration from 8% in BaU to 48-67% in 2030.

An assessment of the 2050 perspective is also carried out comparing the expectations from the RUEDs of all Sumatra provinces to a scenario based on least-cost optimization with the aim of assessing what would be the cheapest long-term system development, disregarding the future targets currently in place.

Riau, and Sumatra as a whole, can embark on a more sustainable development pathway. There are immediate opportunities to develop economically feasible RE projects. This potential will grow enabled by the declining cost of RE technologies over time and the possibility to access cheaper capital. The RE share of generation can reach 58% under Current Conditions and 67% in the Green Transition in 2030.

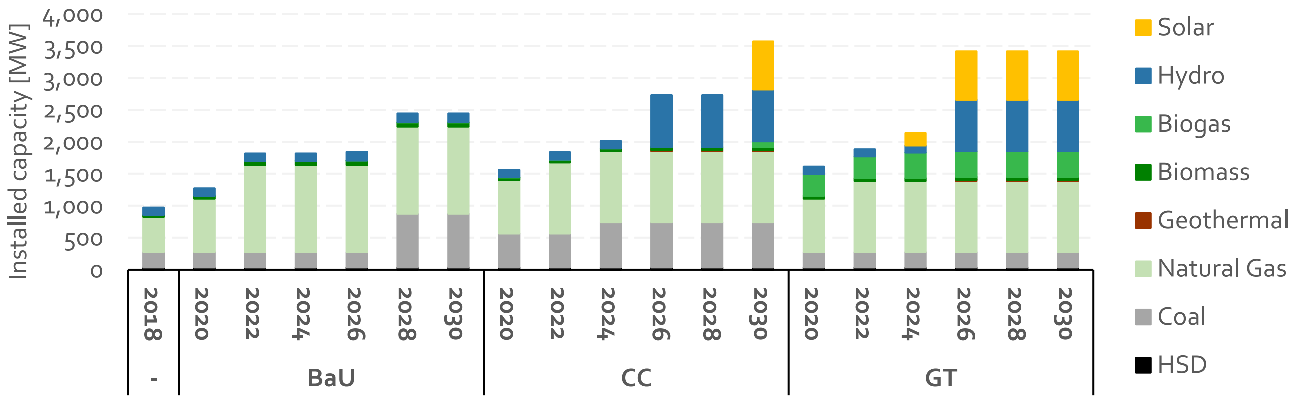

Figure: Capacity development in Riau in the three scenarios.

Planned gas power plants face the risk of low utilisation in all simulated scenarios. Cheaper generation from coal, imports and higher RE penetration are factors contributing to this risk. Coal also has a reduced role in the optimized scenarios compared to RUPTL. The addition of a large coal plant (600 MW) in the late 2020s would result in significantly increased emissions, displacing cheaper and cleaner alternatives. The least-cost optimised scenarios feature larger RE deployment, which allows Riau to reduce power imports from neighbouring provinces.

In Riau, a power system with two thirds RE can be achieved while saving a cumulative ~13 trillion IDR by 2030 relative to BaU. Both the Green Transition and the Current Condition scenarios have lower power costs than the BaU scenario (1,093 Rp/kWh). The Green Transition scenario (average gen. cost of 1,004 Rp/kWh) has a minor extra cost of 13 IDR/kWh if compared to the Current Condition (991 Rp/kWh). Including estimated pollution cost makes the Green Transition scenario by far the cheapest pathway, with an additional cumulative saving of 7-11 trillion IDR in health costs.

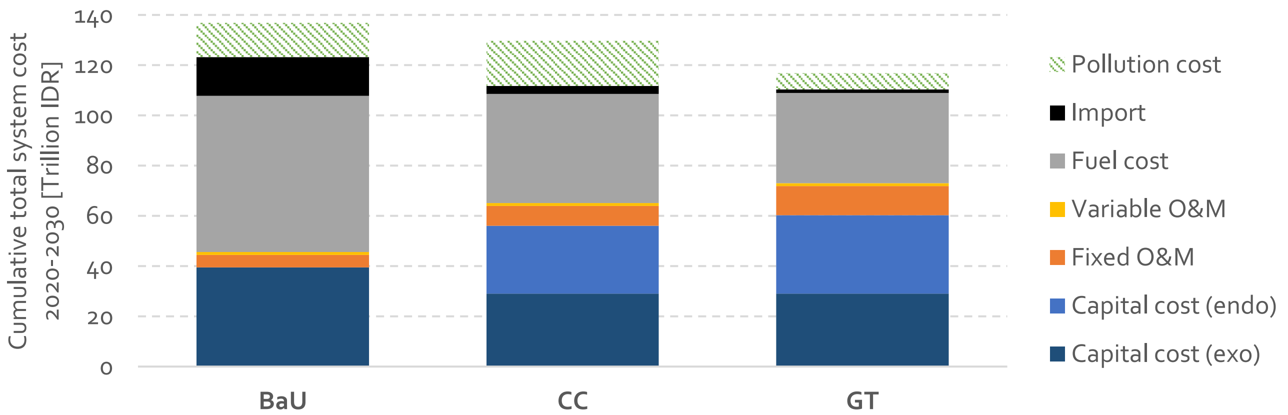

Figure: Cumulative total system costs in the three scenarios for the period 2020-2030.

Biogas, biomass and solar are all potentially competitive decarbonisation options. Their relative economics depends on the cost of bio-feedstock and the cost of capital. Availability of palm oil residues and price largely determines the cheapest option. Solar power, driven by large investment cost reduction over time, can become a competitive alternative for Riau from the mid-2020s, despite the slightly lower resource quality than neighbouring provinces.

Figure: Comparison of generation cost of biomass, biogas and solar (2030).

Toward 2050, larger deployment of solar supported by battery storage, together with biomass and biogas can save 17-18 trillion IDR per year compared to that planned under RUED and **increase the 2050 RE share from 47% to above 60%**. Further power sector decarbonization is challenging, due to the high projected demand growth and the relatively limited RE potential in Riau. Energy efficiency and decoupling of economic growth from power use will be key to reduction of GHG emissions.

The contribution of solar power is largely underestimated both in the medium term and especially in the long term. The solar potential originally estimated in RUEN should be revised. The expected 753 MW of solar potential would only occupy less than 0.01% of the total area of the region, while the scenarios indicate that up to 1.7 GW in 2030 and 13 GW in 2050 would be optimal and provide cost savings to the power supply.

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

- *Look beyond bioenergy: Start considering solar PV as a potential source of cheap power already in the early 2020s, especially under favourable international financing conditions for RE (otherwise from mid 2020s). Identification of suitable sites, preparation of pre-feasibility studies and increasing the ambition regarding solar in the policy and planning documents can help attract investments;*
- *Map and monitor loan and financing option and attract international finance through commitment to a RE project pipeline, increasing the RE ambition of Riau province and improving communication of these targets;*
- *Carefully reassess the case for additional coal power plants and large combined cycle gas plants to avoid technology lock-in and overcapacity. There is apparent risk of stranded assets and increased electricity tariffs in Riau;*
- Align main assumptions, such as RE potentials and power demand projections, across official planning documents such as RUEN, RUED and RUPTL to help ensure consistency in the information and in the process of policy making;
- *Revise the solar potential of the province by conducting a detailed mapping of space available and solar (for both rooftop and stand-alone PV);*
- *Conduct a study of bioenergy potential (considering among others palm oil mill position, distance to grid, feedstock transportation cost) and prioritize sites. Another critical point is to ensure the sustainability of bio residues used, in order to avoid the risk of deforestation and land use change.*

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Nomenclature

Abbreviations

BaU	Business-as-Usual
BPP	Biaya Pokok Penyediaan (average generation cost)
CC	Current Conditions scenario
CF	Capacity Factor
COD	Commissioning Date
CPO	Crude Palm Oil
DEA	Danish Energy Agency
Dinas ESDM	Dinas Energi Sumber Daya dan Mineral
DMO	Domestic Market Obligation
FFB	Fresh Fruit Branches
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
MFO	Marine Fuel Oil
MEMR	Ministry of Energy and Mineral Resources, Indonesia
MIP	Mixed-Integer Problem
MMSCF	Million Standard Cubic Feet
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
Rp	Indonesian Rupiah (= IDR)
RUED	Rencana Umum Energi Daerah (regional plan for energy system development)
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
PLTG	Gas
PLTGU	Combined cycle gas plant
PLTS	Solar
PLTA	Hydro
PLTM	Mini/Micro hydro
PLTMG	Gas engine
PLTP	Geothermal
PLTB	Wind
PLTSa	Waste
PLTBm	Biomass
PLTBg	Biogas
PLTD	Diesel

1. Introduction

1.1 BACKGROUND AND OBJECTIVE

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 Riau, which is the focus of this report, is part of the larger power system in Sumatra and is characterized by a medium-high average generation cost (1,655 Rp/kWh in 2018, compared to an average of 1,119 Rp/kWh for Indonesia), driven up by the use of natural gas and the fact that some areas which are not yet interconnected still use diesel. Riau the province with the highest production of palm oil and has a substantial potential for bioenergy use in the power sector, namely biomass and biogas. On the other hand, the wind speeds are low and the solar irradiation lower than in other parts of Indonesia. In the long term, the RUED sets targets for the use of RE, gas and coal in the two provinces up to 2050. The ambition of the province is higher compared to the national goals set in KEN and RUEN, with a target of 34% RE in 2025 and 47% in 2050, mainly due to a large deployment of biomass and biogas. With this starting point, the objective of the study presented here is twofold:

- Assess power system planning in Riau province in the medium term (2030) and evaluate alternative potential developments;
- Analyse the plan for the power sector included in RUED and evaluate least-cost alternatives to provide affordable, resilient and environmentally friendly development up to 2050.

1.2 GENERAL INFORMATION ON RIAU

Riau is the second largest province of Indonesia in terms of area and is located on the island of Sumatra. The neighbouring provinces are West Sumatra, North Sumatra and Jambi in the south, while in the east the Strait of Malacca separates it from Malaysia and Singapore. The capital and largest city is Pekanbaru.

The provincial population was 5.54 million at the 2010 census and according to the estimate for January 2014 this had risen to 6.36 million.

In general, Riau Province has a wet tropical climate that is influenced by two seasons, namely the rainy and dry seasons. The average rainfall received by Riau Province is between 2,000-3,000 mm/year with an average annual rainfall of 160 days. The average air temperature of Riau is 25.9 °C with maximum temperatures reaching 34.4 °C and minimum temperatures reaching 20.1 °C (Wikipedia 2019).

With 8.59 million tons of palm oil produced in 2018, corresponding to roughly 21% of the national total, Riau is by far the largest producer of palm oil in Indonesia (Badan Pusat Statistik 2019). Palm oil industry is also among the largest sources of provincial GDP, next after mining and quarrying.

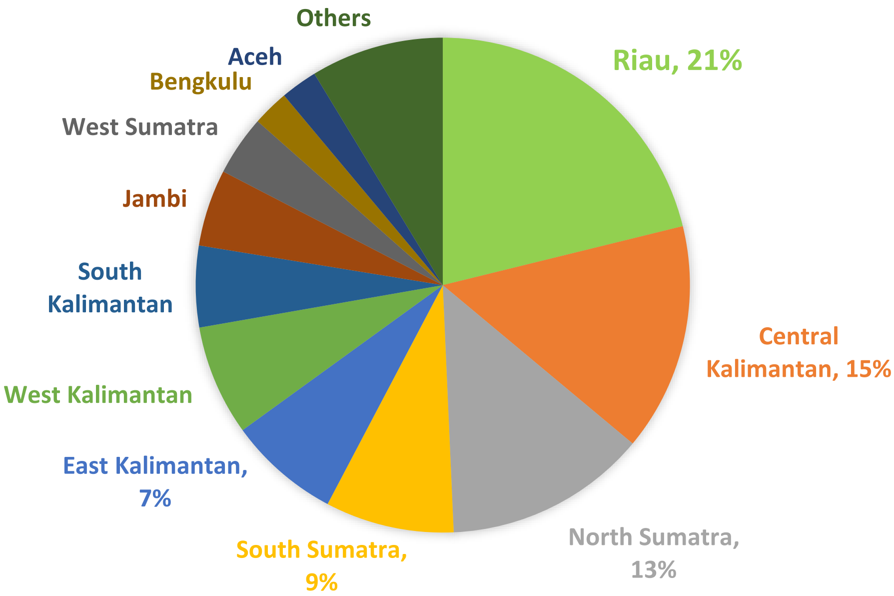

Figure 1: Share of total Indonesian palm oil production by province, 2018. Source: (Badan Pusat Statistik 2019)

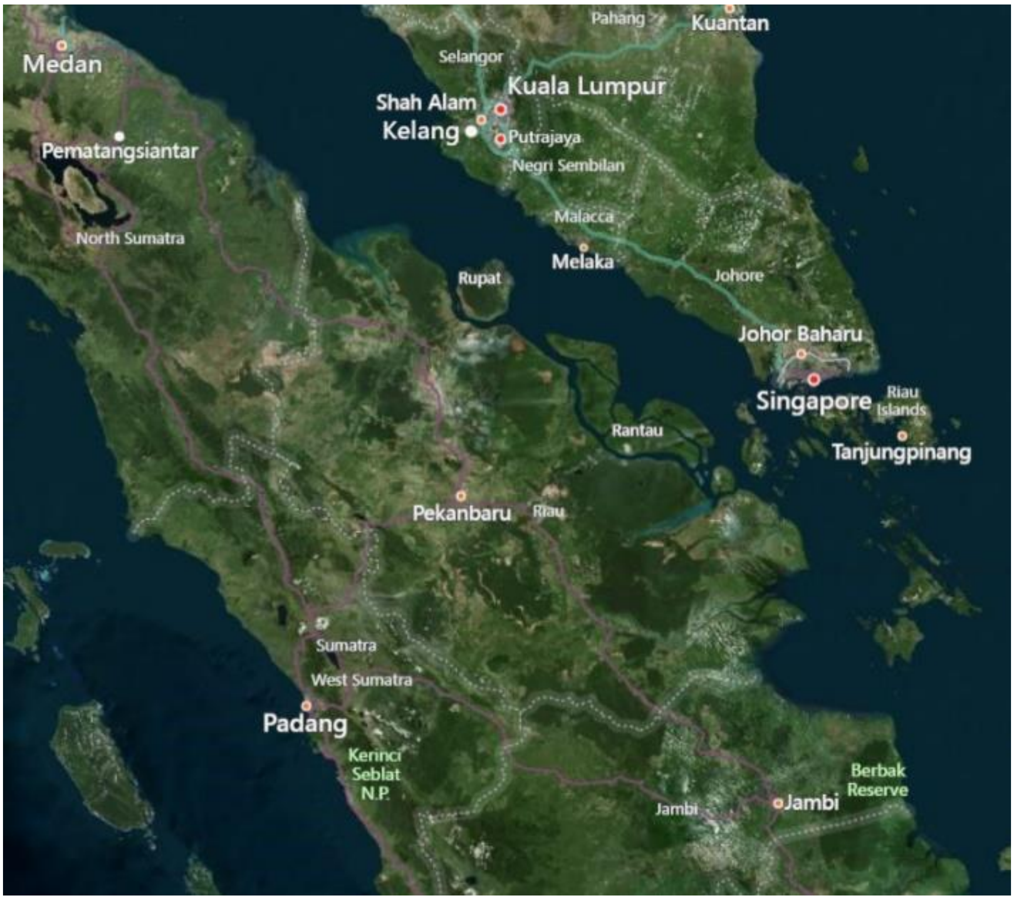

Figure 2. Map of Riau. Source: Bing Map.

1.3 POWER SYSTEM OVERVIEW

The power system in Riau is part of the south and central interconnected system of Sumatra named PLN SBST (Sistem Sumatra Bagian Selatan dan Tengah) and is electrically interconnected to West and North Sumatra, from which it imports power on a regular basis, to complement the local generation mainly fuelled by natural gas. The electrification rate in Riau Province in 2018 has reached 99%. There are districts that still have a ratio below 90%, but are planned to be completely electrified by 2020 (PT PLN Persero 2019).

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[1].

In Riau, the 2018 BPP was **1,655 Rp/kWh** (11.61 c$/kWh), which is among the highest registered in Sumatra if excluding islands and non-interconnected systems. As a reference, in the southern part of the island, in the S2JB (Sumatera Selatan Jambi dan Bengkulu) system, the BPP is 1,061 Rp/kWh, approximately 36% lower. Among the reasons for the high cost of generation in the Riau system is the fact that some areas are not yet connected to the main PLN system and use diesel as the main source of power. PLN expects that within the 2020 timeframe, most of the areas of Riau will be connected to the main system.

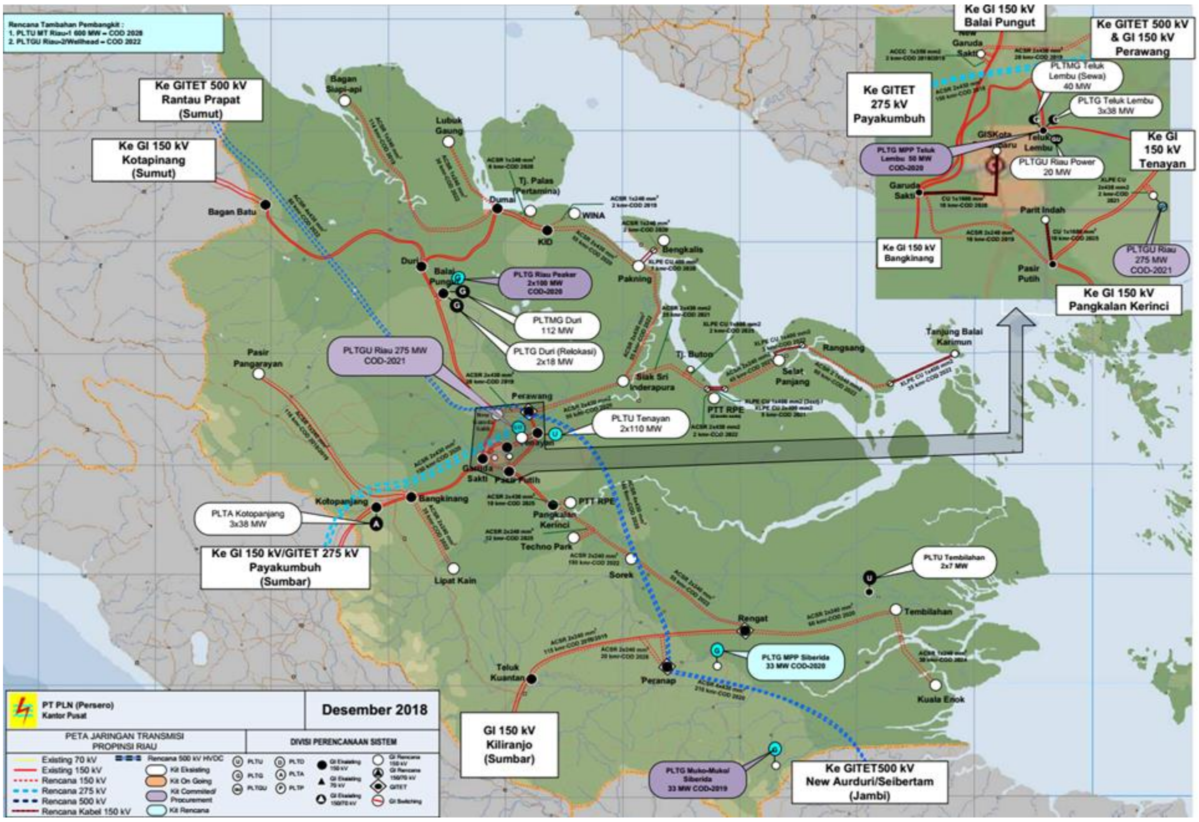

Figure 3: Overview of PLN Riau system, including existing and planned generation. Source: (PT PLN Persero 2019)

[1] More specifically, the maximum allowed 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 power demand in Riau province varies a lot depending on what is the boundary considered. In RUPTL, the 10-year plan from the electrical utility (PLN), only the PLN grid is considered. However, the total power demand in the province is higher when including all industrial areas and palm oil plantations. These areas have local generators, also called captive power plants, to supply the power and some of them even sell the excess power to PLN through PPAs. The total installed capacity of captive power plants is very large, reaching approximately 1 GW and most of these plants, in particular serving palm oil and pulp/paper industries, uses diesel captive plants (GIZ 2013). The capacity of these plants is roughly equal to the current capacity installed in the main PLN grid.

Figure 4 (below right) shows the difference in power demand historically for RUPTL (considering PLN grid) and RUED (considering the total electricity consumption of Riau). It can be seen that PLN grid power demand is less than half the total demand of Riau. In this analysis, PLN grid is the focus of the medium-term analysis until 2030, while in the 2050 simulations, RUED demand is considered instead.

Looking at PLN grid, power demand has been growing steadily in the period 2012-2018, with an impressive average annual increase of 9.4%. RUPTL (PT PLN Persero 2019) reports a power demand in 2018 equal to 4,414 GWh, with an expectation for the Riau system to grow to 9,648 GWh in 2028, corresponding to around twice the demand today. The main drivers for the power demand increase are expected to be the economic growth and development of new industrial areas.

Looking at the daily load profile averaged over the year (Figure 4), the peak demand in Riau reached around 735 MW in 2018 and occurs around 19:00 at night. One interesting thing to note from the profile, is that the load is quite constant with a high baseload consumption and a limited ramp up at night.

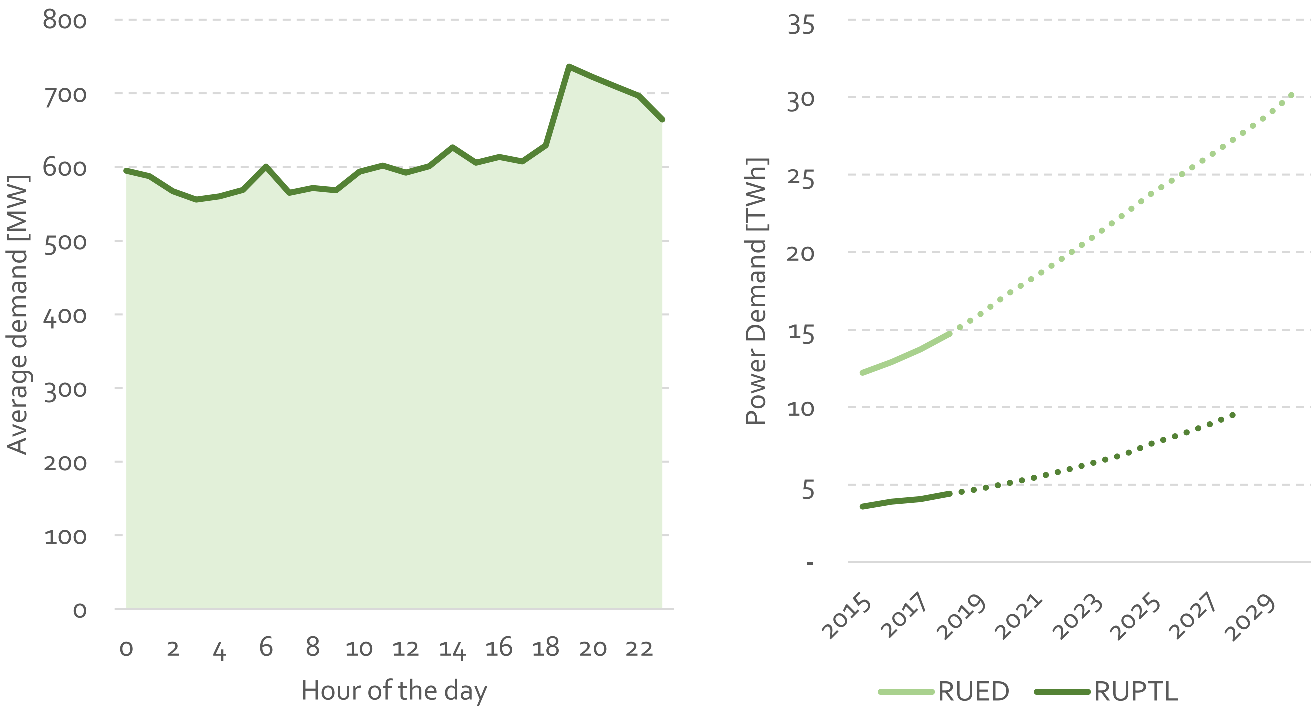

Figure 4: Load profile for 2018 and total demand including projection to 2028 [1].

Current fleet overview

The total installed capacity in the Riau PLN system stands at 1,196 MW. The largest capacity type is by far natural gas with 580 MW installed; coal follows with 234 MW and diesel with 203 MW. The only RE capacity present in the Riau power system is 114 MW of reservoir hydro power (Figure 5).

PLN also buys excess power from captive power plants, namely a coal plant (10 MW), some gas engines (25 MW) and a biomass plant (30 MW).

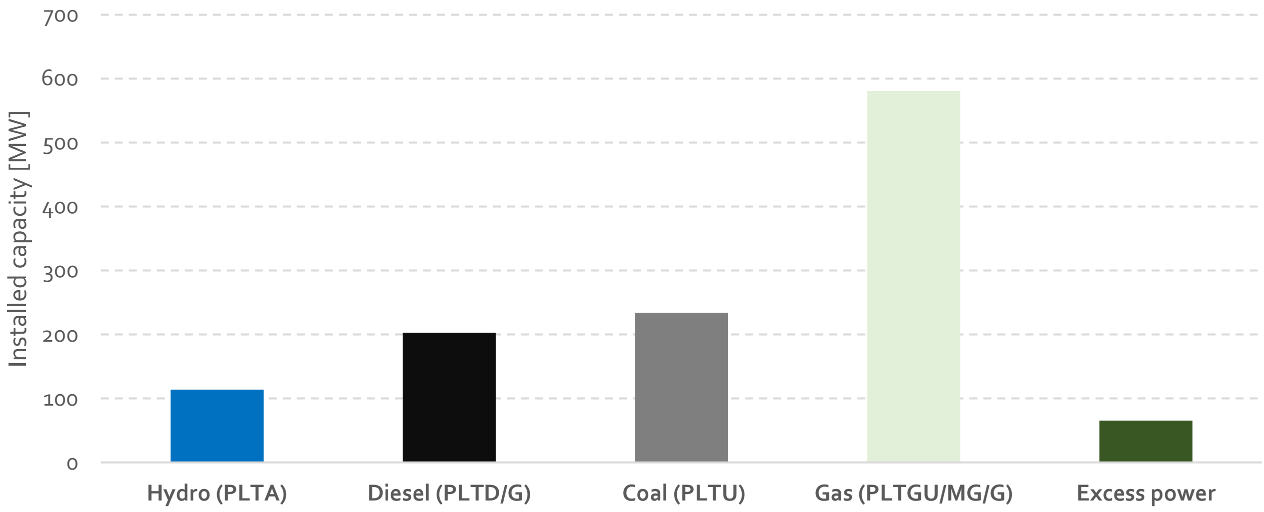

Figure 5: Installed capacity 2019 in Riau, by fuel type. Source: (PT PLN Persero 2019)

RUPTL: PLN expectations 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 as well as planned expansion of the transmission network and of the generation fleet.

The plan for the expansion of generation capacity in Riau (Figure 6)[2] includes substantial amount of natural gas, both gas peakers (PLTMG/PLTG) and combined cycle gas turbines (PLTGU) which are intended to provide the bulk power generation. A total of 288 MW of peakers will come online in 2020, while 525 MW of combined cycles will become operational between 2021 and 2022 (PLTGU Riau 275 MW and PLTGU Riau2 250 MW). It is also expected that a large mine-mouth coal power plant of 600 MW (Riau1) will be installed in 2028.

Additional 14 MW of bioenergy projects (11 MW of biomass and 3 MW of biogas) have secured a PPA or are under construction. A PPA for a 3 MW biogas plant in Ujung Batu has been signed with commissioning date 2020 at 1,147 Rp/kWh (Jonan 2018).

RUPTL lists also various projects for power plants that are planned but not yet allocated to any specific province, and therefore are specified as distributed (Tersebar, in Bahasa). For this analysis these plants have been allocated

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

to the various areas based on the power balance of each province and as a result only part of biomass (20 MW, 2022) and hydro run-of-river (20 MW, 2028) are allocated to Riau[3].

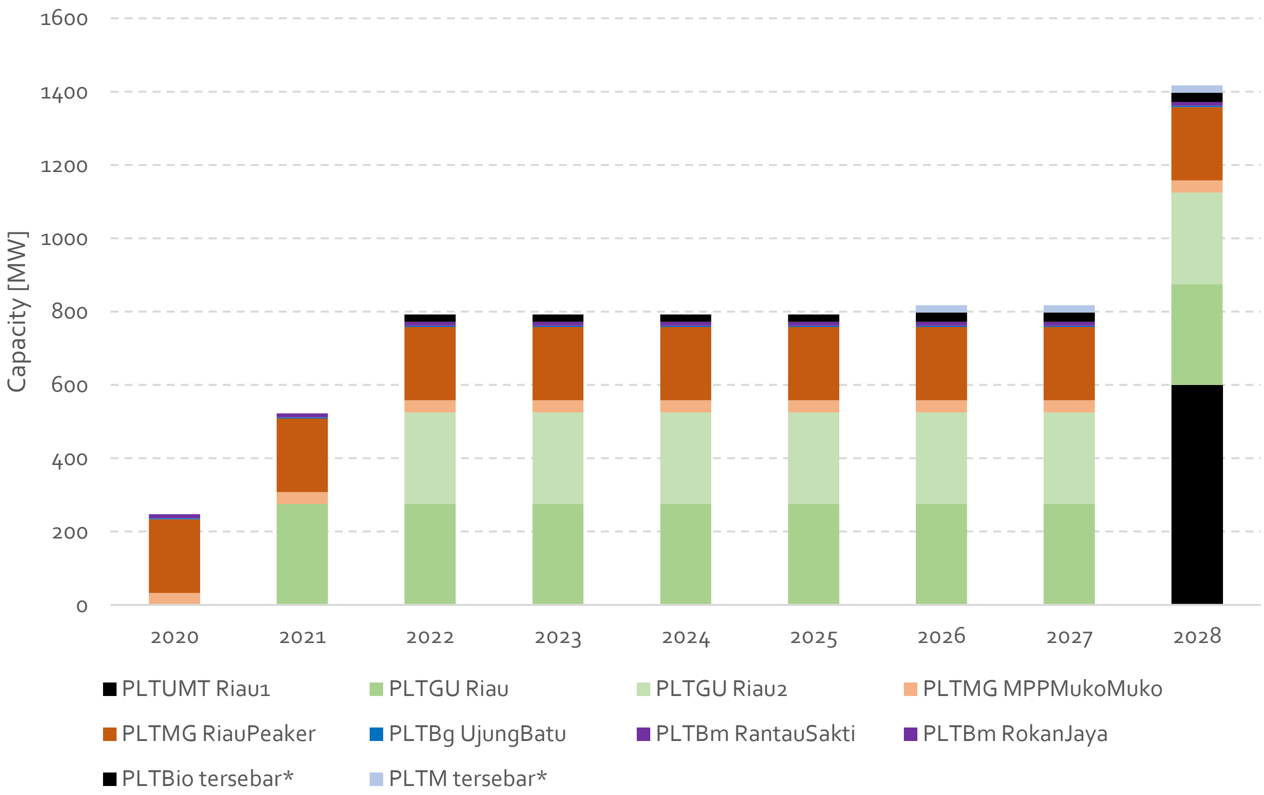

Figure 6: PLN plan for system development contained in RUPTL19 (PT PLN Persero 2019) [3].

RUED: The regional planning document

RUED together with KEN and RUEN forms part of the energy planning documents required by the National Energy Law 30/2007. While KEN and RUEN guide the development at national level, RUED is focused on the provincial level and how each province is expected to contribute to the national targets. The preparation of the document involves different actors and the responsibility resides within 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.

The RUED document covers the development of the entire energy sector and, in several provinces, it has become common practice to use the LEAP[4] model (Stockholm Environment Institute 2019) to develop an overview of the energy system development towards 2050.

[3] The distributed quota allocated to Riau is indicated with an asterisk (*) in the Figure.

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

Table 1. RUED targets for the RE share of primary energy. Sources: (Dinas ESDM Riau 2019)

	Entire energy system	Power system
	[%]	*[%]*
2015	1.0	14.2
2025	16.7	34.4
2050	41.8	46.9

The overall targets for RE[5] contained in the latest draft version of RUED are indicated in Table 1. Riau aims at reaching a 16.7 RE share of primary energy in 2025 and 41.7% in 2050. While the short-term target falls short of the national KEN/RUEN objective of achieving 23% of primary energy from RE, in the long term the RUED indicates a more ambitious target than the national one (31% RE in 2050).

The focus of this study is on the contribution from the power sector to the regional targets set in the RUED document of Riau. 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. Riau expects the power sector to contribute relatively more than other energy sectors, namely 34.4% RE in 2025 and above 46% in 2050.

The expectations for power capacity development under RUED plan are summarized in Figure 7 and original tables from RUED can be found in Appendix B (Dinas ESDM Riau 2019). Given the extensive bioenergy potential related to the large palm oil production in the province, RUED expects bioenergy and in particular biomass to be the main contributor to the power sector development going forward, together with natural gas.

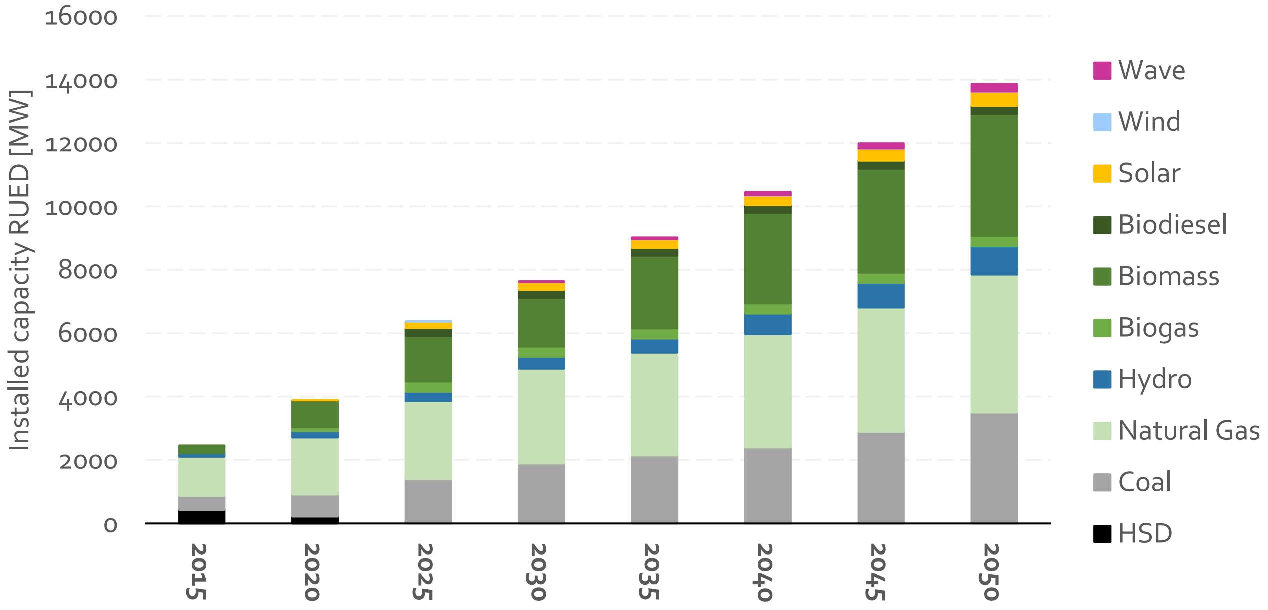

Figure 7. Expected power capacity development in RUED in Riau.

[5] 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.

RE potentials

The development in capacity expansion that is expected in RUED is strictly related to the potential for RE in the province. The RE potentials considered in RUED are originally from the national planning document 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 potential for the two provinces[6] and the Full Load Hours (FLH) of generation[7].

The Riau province features a very large potential of biomass (and biogas), related to bio residues from the palm oil production which could be used to produce electricity. Besides, Riau features 960 MW of potential of hydropower and 753 MW of solar PV. Wind speeds are very low and not strong enough to be exploited, limiting the potential to 22 MW. The geothermal potential is also very modest, with only 20 MW capacity.

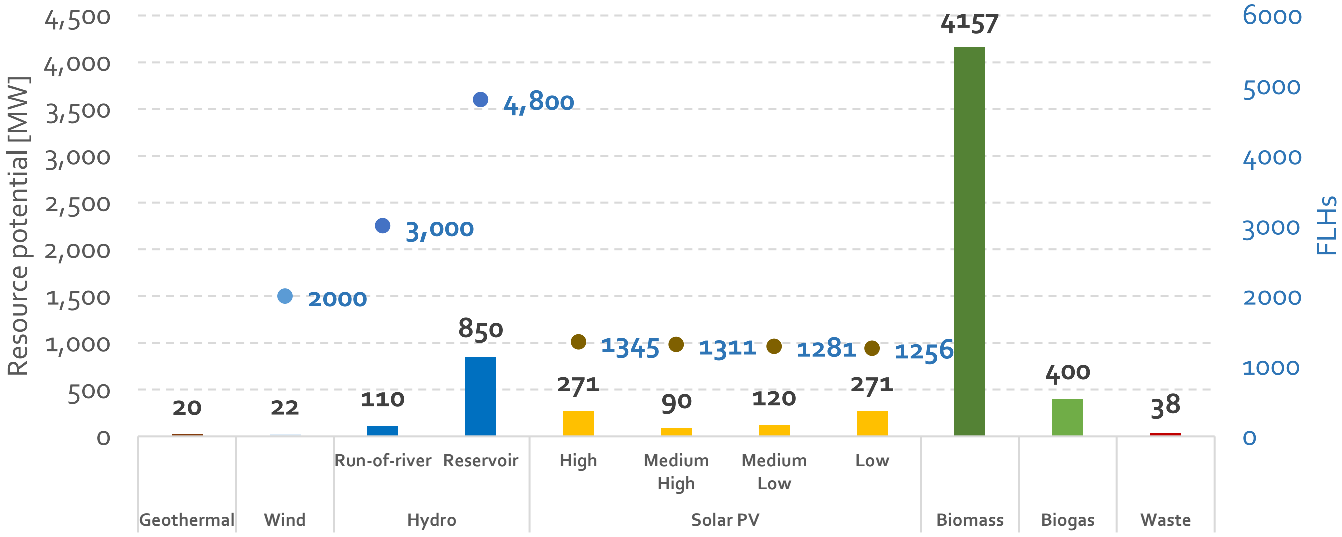

Figure 8. Potentials of RE sources based on RUED and estimated Full Load Hours.

Several differences exist between the potentials expressed in the various planning documents. For example, RUED indicates a lower solar potential (450 MW) compared to what expressed in RUEN (753 MW) without explaining the reason behind the reduction. In this analysis, the original potential from RUEN is considered.

Another exception has been done regarding the potential of biogas. RUEN indicates a potential of just 38 MW, while a previous draft of RUED expected a contribution above 3,000 MW. For this reason, a revision of the amount of biomass available in relation to the plantations of palm oil has been performed in this study.

The total biomass available in Sumatra, based on the feedstock database of the Directorate General of RE and Energy Conservation (EBTKE 2014), has been divided into two categories: Solid palm oil crop residues (palm shells, fibre, stems and midribs) for biomass plant use, and palm oil mill effluent (POME) and fruit branches (anaerobic composting) for use in biogas plants. The total potential in Sumatra has been divided by region based on the distribution of palm oil mill capacity (Directorate General of Estate Crops - Ministry of Agriculture of Republic Indonesia 2016), with 35% of the total located in Riau.

[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.

This results in a total biomass potential for Sumatra (assuming a calorific value of 14 GJ/ton) of 11.9 GW and a total biogas potential of around 1.1 GW. This means that, based on these calculations, the **potential of Riau is approximately 400 MW biogas plants** and 4,100 MW biomass plant.

Similar figures for biogas result assuming that for every mill with a capacity of 45 ton of fresh fruit brunches per hour, a 1.5 MW biogas plan can be built with additional ~1 MW in case of anaerobic composting of empty fruit branches (Hasanudin et al. 2015).

Biomass database in Sumatra

Sumatera	Unit	Feedstock	GJ
Palm oil residues			
Serat (Fiber)	ton	9,494,873	134,420,758
Cangkang (Shell)	ton	4,541,026	80,317,415
Tandan Kosong (EFB)	ton	17,751,284	87,618,998
Limbah Cair (POME)	m^3	33,490,990	25,663,249
Midrib	ton	49,417,062	693,112,838
Tanan Ulang (Midrib and stem)	ton	7,036,297	103,108,495

Distribution Fresh Fruit Brunches Mill capacity

	tons FFB/h	%
North Sumatra	3,815	20%
Riau	**6,660**	**35%**
West Sumatra	1,645	9%
Jambi	2,245	12%
Bengkulu	990	5%
Lampung	375	2%
South Sumatra	3,555	18%

Figure 9: Biomass in Sumatra and distribution of palm oil mills by region. Sources: (EBTKE 2014), (Directorate General of Estate Crops - Ministry of Agriculture of Republic Indonesia 2016)

Figure 10: Example of biogas plant, PLTBg in the area Pabrik Kelapa Sawit PTPN V, Riau. Source: (BPPT)

2. Scenario framework and approach

2.1 RESEARCH QUESTION 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 Riau province in the medium term (2030)?
- What role can bioenergy play under different cost assumptions? Is there room for other RE to substitute fossil fuel 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).

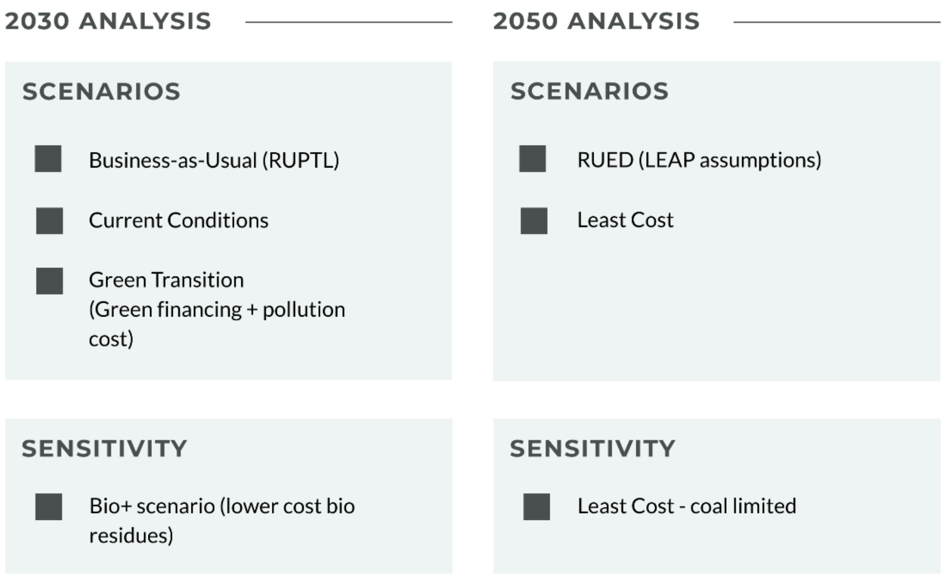

Figure 11. Two steps: 2030 analysis and 2050 analysis.

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 Sumatra 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 Riau 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 Sumatra, disregarding the fuel mix targets in the RUEDs. Solar buildout is assumed not to be limited by potential in RUEN.

Moreover, since the demand in the 2050 scenarios includes all the non-interconnected areas, especially all palm oil plantations, the price of biomass in this simulation is assumed to be 50% lower compared to the 2030 simulations. Indeed, biomass can be used directly to supply the demand in the palm oil plantations, with a reduction in the transportation and handling cost. 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 and Least cost development. Solar buildout not limited by RUEN

Sensitivity analyses

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

- **Bio+**: given the large bioenergy potential and the uncertainty on the cost of raw biomaterials, a sensitivity is performed assuming **50% less expensive raw material**, namely POME and other palm oil residues. This sensitivity analysis is simulated for both CC and GT conditions.

For the 2050 scenarios, a sensitivity analysis is carried out with respect to Least Cost scenario:

- **Least Cost – coal limited**: Riau province showed the ambition of limiting the coal deployment going forward and RUED plan for more natural gas compared to coal. A least-cost scenario **limiting the deployment of coal to what is planned in RUED** is analysed.

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 pollution caused by combustion of coal, natural gas and biomass.

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 12). 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.

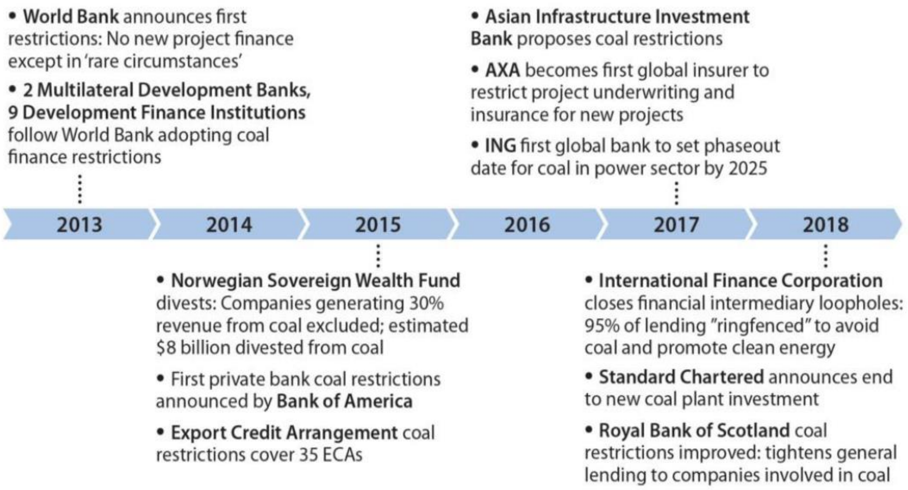

Figure 12: List of institutions announcing their restriction on coal financing. Source: (IEEFA 2019)

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%.

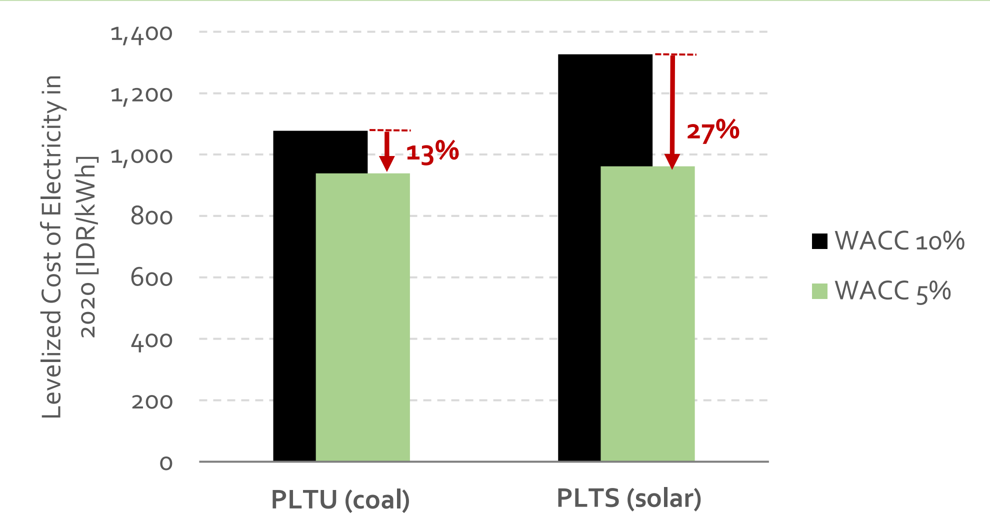

Figure 13: Effect of reduction of cost of capital (WACC) on cola and solar in 2020.

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.

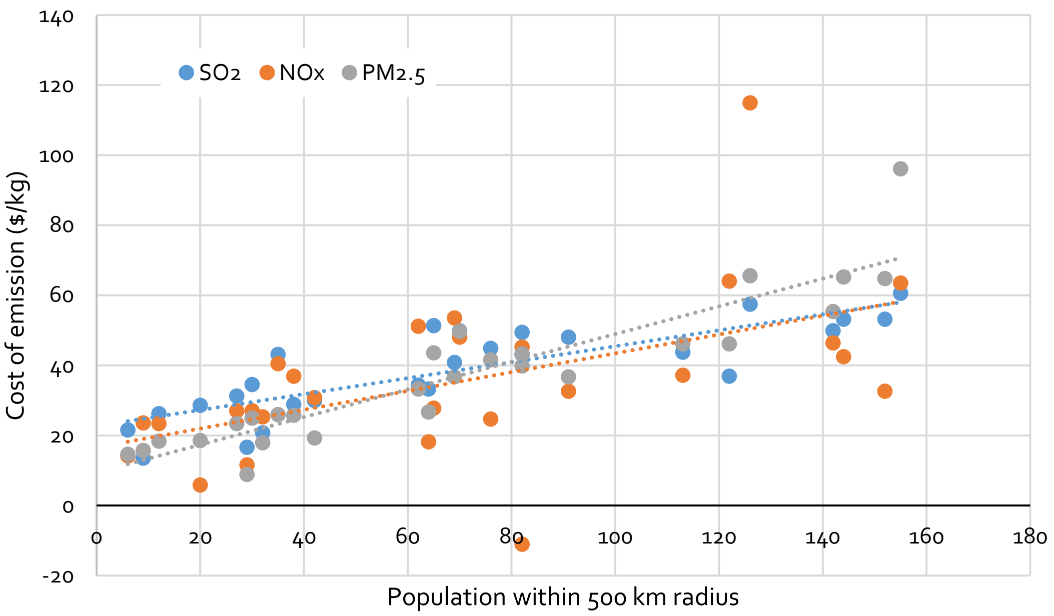

Figure 14: Correlation between the cost of pollution from SO_2, NO_x and PM2.5 from each of the 27 EU Member States and the population within a 500 km radius from the country's geographical centre.

An overview of the SO_2 costs in Indonesia for each province is shown in Figure 15. For Riau, the figure used are 6.3 \$/kg of SO_2, 5.5 \$/kg of NO_x and 5.3 \$/kg of PM2.5. It can be noted that, while the values are still lower than those in Java island, the pollution cost is among the highest in Indonesia; indeed, Sumatra is a quite populated island in which the emission of polluting particles will potentially affect a large population.

Figure 15: 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.

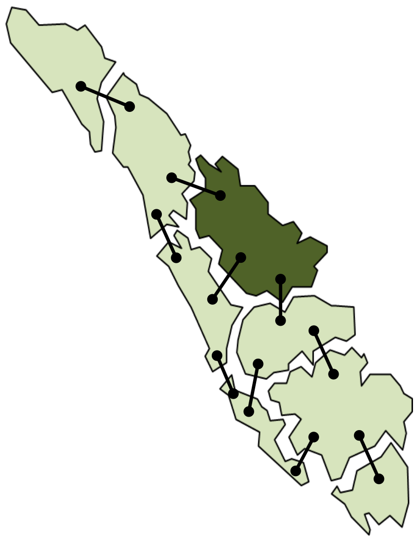

Figure 16: Balmorel representation of Sumatra. Focus area highlighted.

For the analysis, a representation of the power system in Sumatra has been developed based on public sources and on data from PLN and DINAS ESDM Riau. The power system in Sumatra is divided in the eight provinces and contain a representation of the interconnection capacity between provinces. In all simulations, the entire system has been considered and optimized, even though most of the focus will be placed upon the province of Riau.

Riau is connected to neighbouring provinces, namely Jambi, North and West Sumatra, via power interconnectors. In all simulations, Sumatra's eight provinces are simulated simultaneously to ensure a consistent representation of Riau 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 SUMATRA ISLAND

***Coal investments in Sumatra are likely overestimated** in RUPTL and face the risk of becoming stranded assets. Optimised scenarios suggest hydro and geothermal can play a larger role than anticipated in RUPTL. Moreover, solar power and biogas are potentially competitive already in the short term with access to good financing. The addition of more RE can also make Riau province **energy independent**.*

In the 2030 perspective, the total installed **coal capacity is less than half in the optimised scenarios** compared to what is expected in the BaU (Figure 17) and it is not substituted by more natural gas, but instead more RE generation. Indeed, natural gas capacity is also slightly lower than BaU in the scenarios analysed.

Figure 17: Coal and gas capacity additions in Sumatra.

Despite the addition of a sizable amount of RE, the BaU scenario expects a very large contribution from coal power at roughly 50% of the power supply of Sumatra in 2030. In the optimised scenarios, the role of coal is decreased, especially in the GT scenario, which consider the pollution cost (Figure 18).

In the CC scenario, **more hydropower is installed**, providing more than a third of the generation, together with 1.2 GW of solar power in 2030. The level of geothermal generation is similar to BaU.

In the GT scenario, inclusion of pollution cost reduces the generation of coal power, making room for more natural gas generation in the short term and much more RE from 2025. **Capacity factors of coal power plant plummet** to around 2,000 Full Load Hours a year, resulting in much of the investment becoming stranded assets. With low interest rates, solar PV is competitive already from 2022, with 500 MW installed, which grows to more than 3,000 MW by 2030. Large biogas investments are taking place from 2020, in regions with palm oil plantations. Hydropower capacity is even higher than the CC scenario and more geothermal is installed compared to the other scenarios, again due to the lower cost of capital. Overall, the system has a very high penetration of RE already after 2025, reaching 87% in 2030 due to the very significant contribution from the large hydro and geothermal potentials of Sumatra.

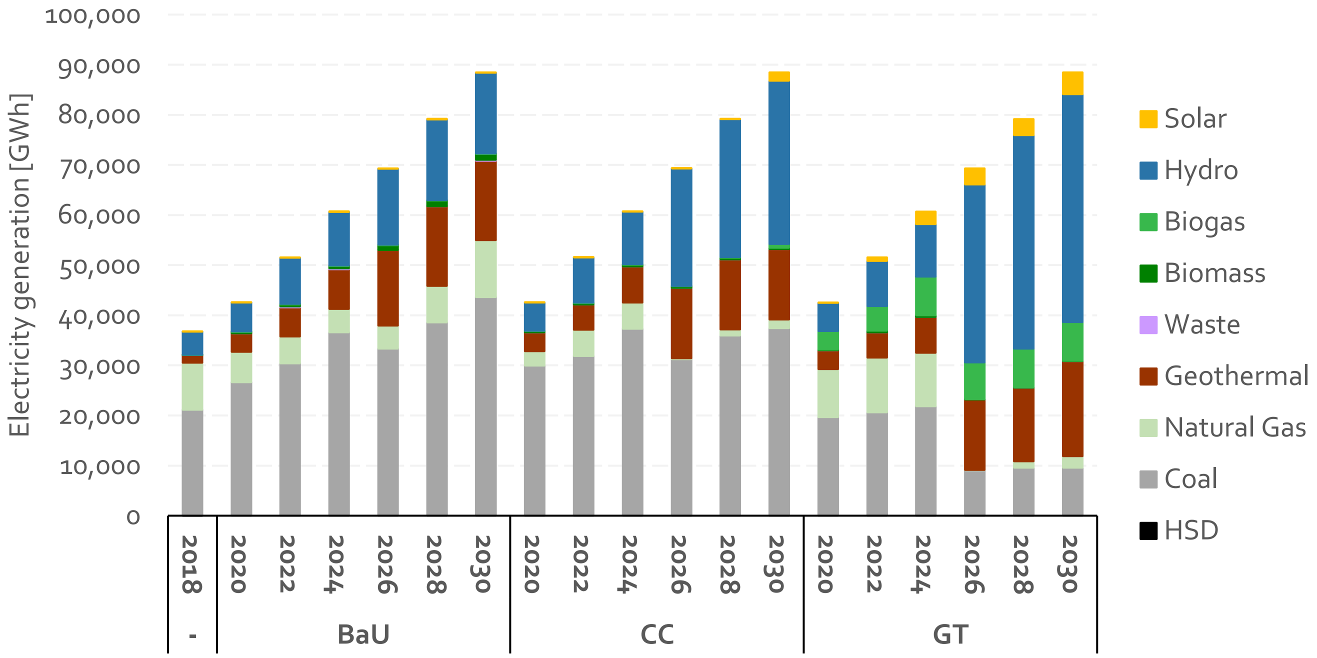

Figure 18: Power production development in the entire Sumatra island for the three main scenarios.

Looking at the generation share per province in the BaU and GT scenarios in 2030 (Figure 19), two things stands out. Firstly, the difference in the share of RE between the two scenarios is remarkable in every province. Secondly, provinces in the Southern part of Sumatra already have a quite high RE penetration in the BaU scenario, primarily due to the large hydro and geothermal buildout and are almost fully decarbonized in GT. In both cases, however, **Riau is the province in the region with lowest amount of RE** due to the limited potential for hydro and geothermal.

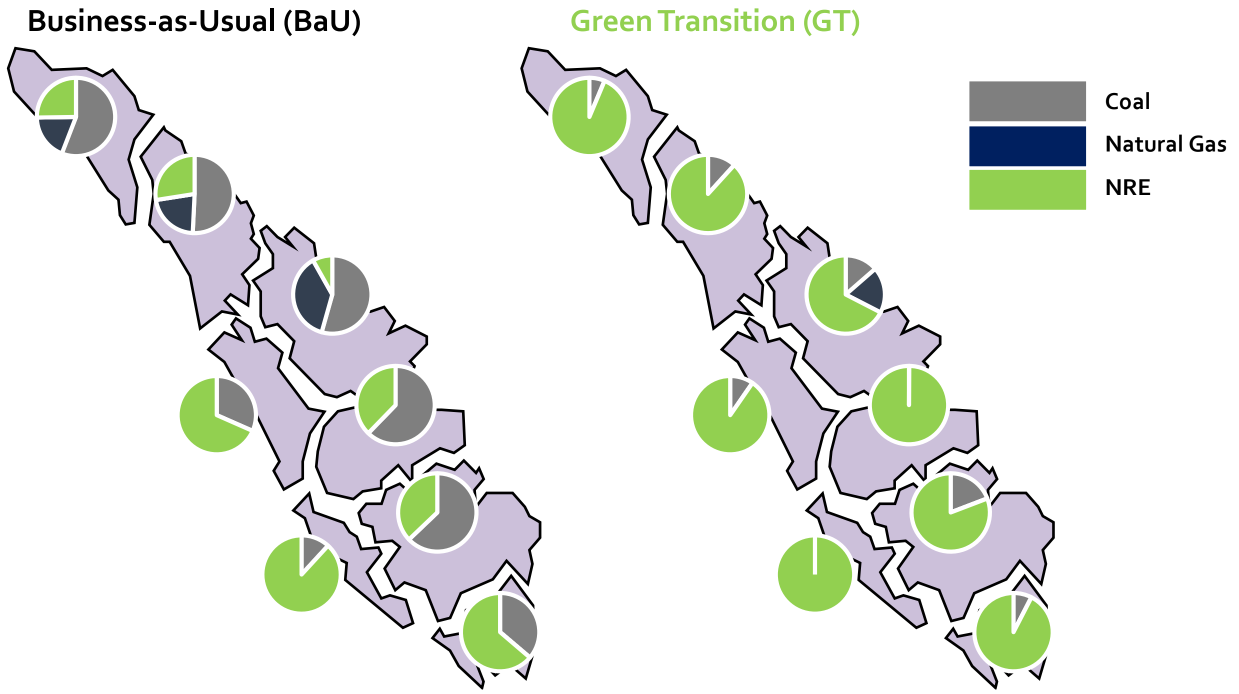

Figure 19: Share of generation in 2030 in BaU vs GT in all Sumatra.

When larger shares of low-cost bulk RE generators, for example hydro and geothermal, are added to the system, power flows between regions are affected. The map in Figure 20 shows the transmission flow between provinces in Sumatra for BaU scenario in 2026, when large hydro and geothermal capacities are added to the system. Provinces with a larger share of hydro (Jambi, Bengkulu, West Sumatra) and geothermal (South Sumatra, Lampung) tend to **export the largest amount of power** to the northern provinces that see relatively lower amount of RE. Indeed, these RE sources have very low short-term marginal cost of generation, since they have no fuel cost, and tend to produce for a large number of hours during the year.

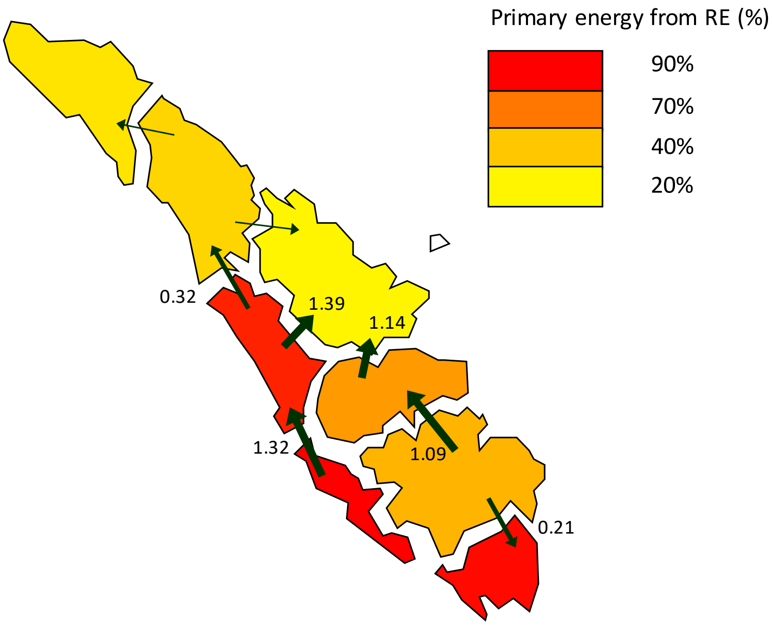

Figure 20: Flow dynamics in TWh in 2026 for BaU scenario. The level of RE is indicated by color as shown in the scale.

Figure 21 shows that Riau is a net importer in almost all scenarios and years, especially in the BaU scenario, in which it reaches 2.5 TWh of imported energy in 2026 (from Jambi and West Sumatra). In both optimised scenarios, Riau reduces the level of imports, becoming **almost independent in the GT scenario**.

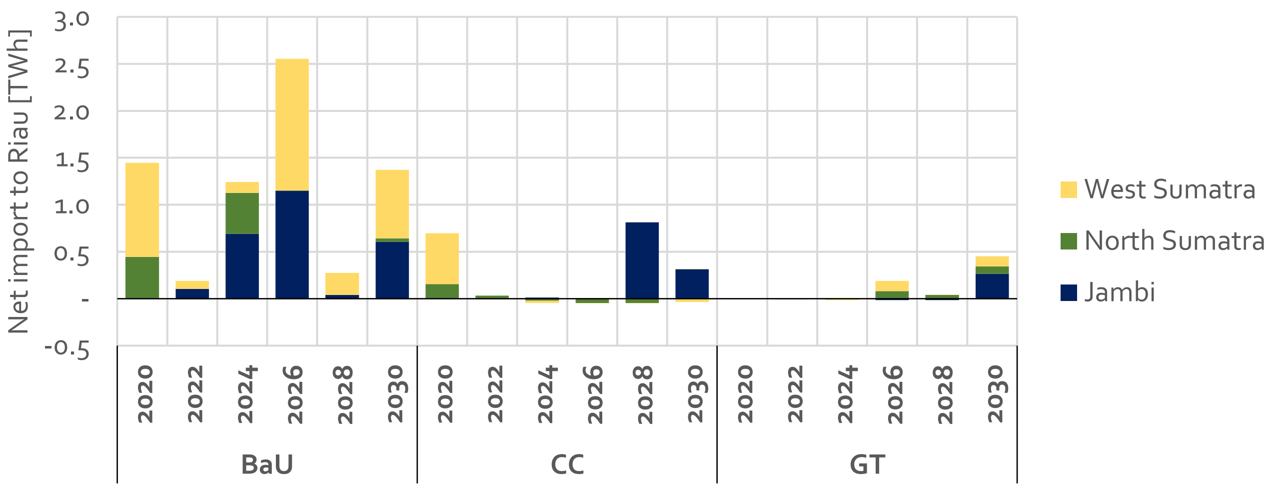

Figure 21: Net yearly power import in Riau across scenarios.

3.2 POWER SYSTEM DEVELOMENT IN RIAU PROVINCE

RE is becoming increasingly competitive with fossil fuels

Following worldwide cost reductions, solar generation cost drops below 1,000 IDR/kWh by 2030. Hydropower, geothermal and biogas are also on the way to become cheaper than coal and gas generation.

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 has to be sold for the power plant to cover all its cost and is therefore an indication of the tariff (PPA) a technology requires to be competitive.

Figure 22 shows the LCoE of all potential generation technologies in the province of Riau for 2030, with a comparison to the 2020 cost, using technology assumptions from the Indonesian Technology Catalogue (NEC 2017). As can be noted, hydropower is 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 as hydro. Solar, followed by wind, has indeed the largest cost reduction potential in the period consider and this is well in line with worldwide trends and 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 and natural gas. Indeed, while these two technologies see a slight cost increase from 2020 to 2030 (due to a higher projected fuel cost), RE can count on a cost reduction resulting from a larger deployment and learning rate.

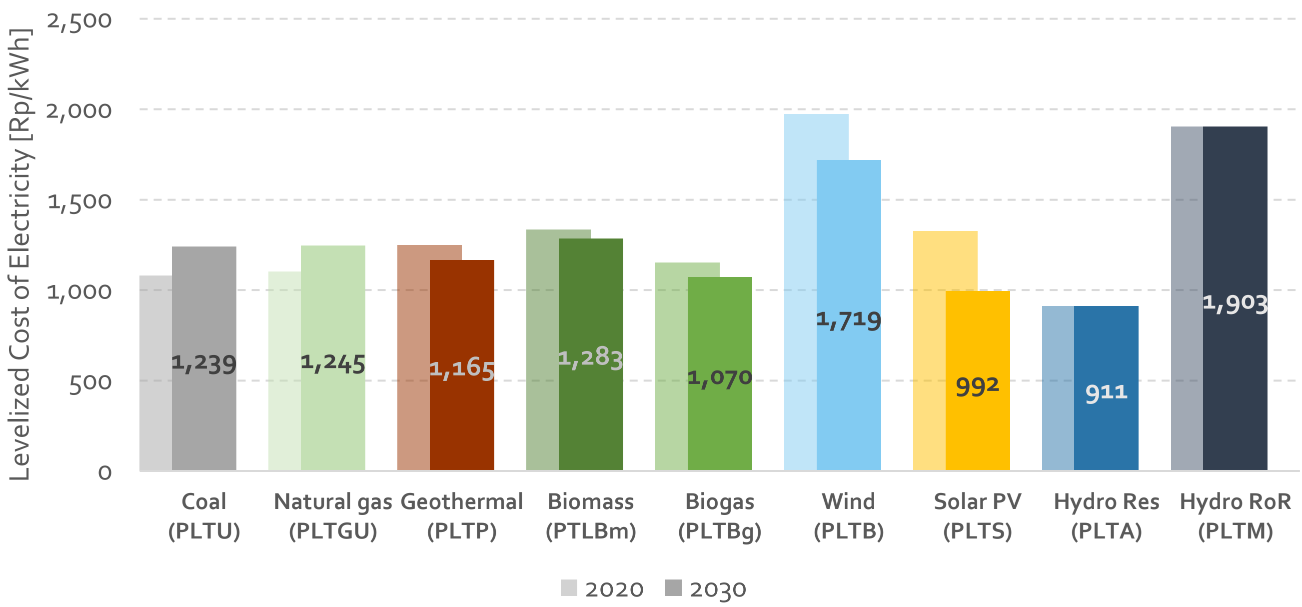

Figure 22: LCoE comparison for relevant power sources in Riau in 2030 (solid) compared to 2020 (light)[9].

[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.

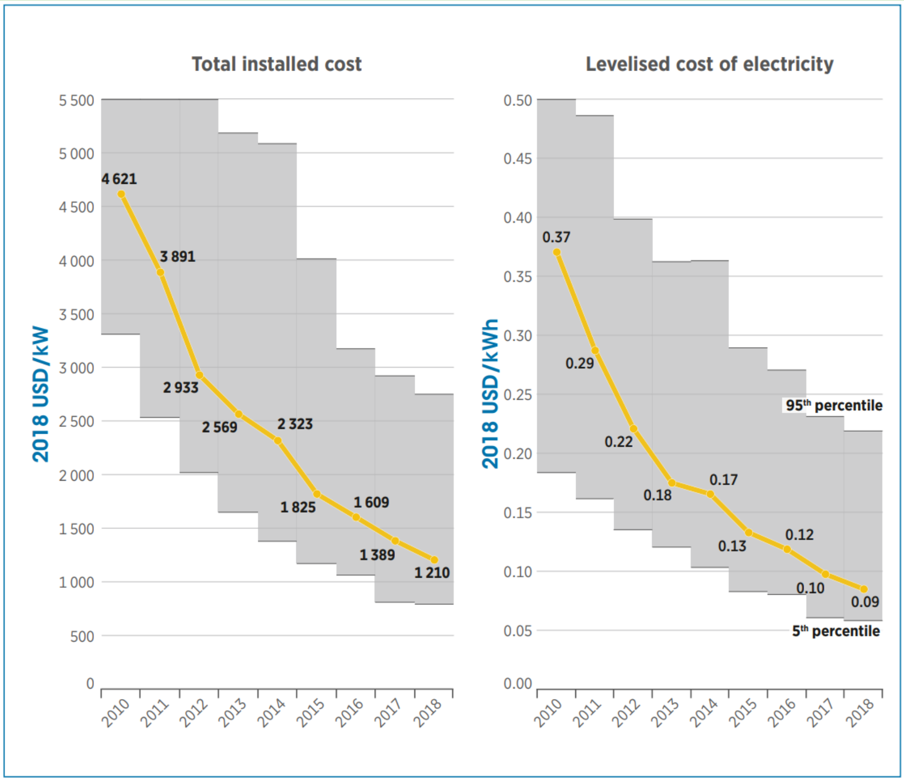

Figure 23: Total installed cost and levelized cost of electricity of solar power from 2010 to 2018. Source: (IRENA 2019)

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 for more RE in Riau power system

***Hydropower additions are the cheapest source of new power** also in Riau, but it takes several years to plan and build new hydro plants. **Solar and biogas** are competitive from 2030, but in case of cheap financing biogas is economically feasible already in 2020 and solar in 2024.*

The optimal power plant development in the optimised scenarios indicates a very different system compared to the BaU case. In both CC and GT scenarios the model chooses to **invest in more hydro, solar and biogas**.

Despite the assumed constraints in the deployment of hydropower (i.e. investment in new plants only possible after 2025), the model finds hydro power the cheapest option for new capacity, signalling that it would be beneficial to exploit the hydro potential in order to reduce power system cost.

In the CC scenario, coal power plants are prioritized over combined cycle gas turbines in the short term and additional coal plants are present already from 2024, even though in 2030 the total coal capacity is 135 MW lower than in BaU. Solar power becomes competitive from 2030, to the point where it reaches the maximum potential of 753 MW in one single year. In addition to this, 92 MW of biogas power plants are added to the system in 2030.

In the GT scenario, the combined impact of pollution cost and lower cost of finance for RE, drastically reduces the fossil fuel capacity, with no additional coal power plant built. A combination of hydropower, solar PV and biogas supplies the additional power demand, with biogas feasible already in 2020 and solar in 2024. The profitability of these two sources causes them to reach their respective resource potential already in 2026 (400 MW for biogas and 753 MW for solar).

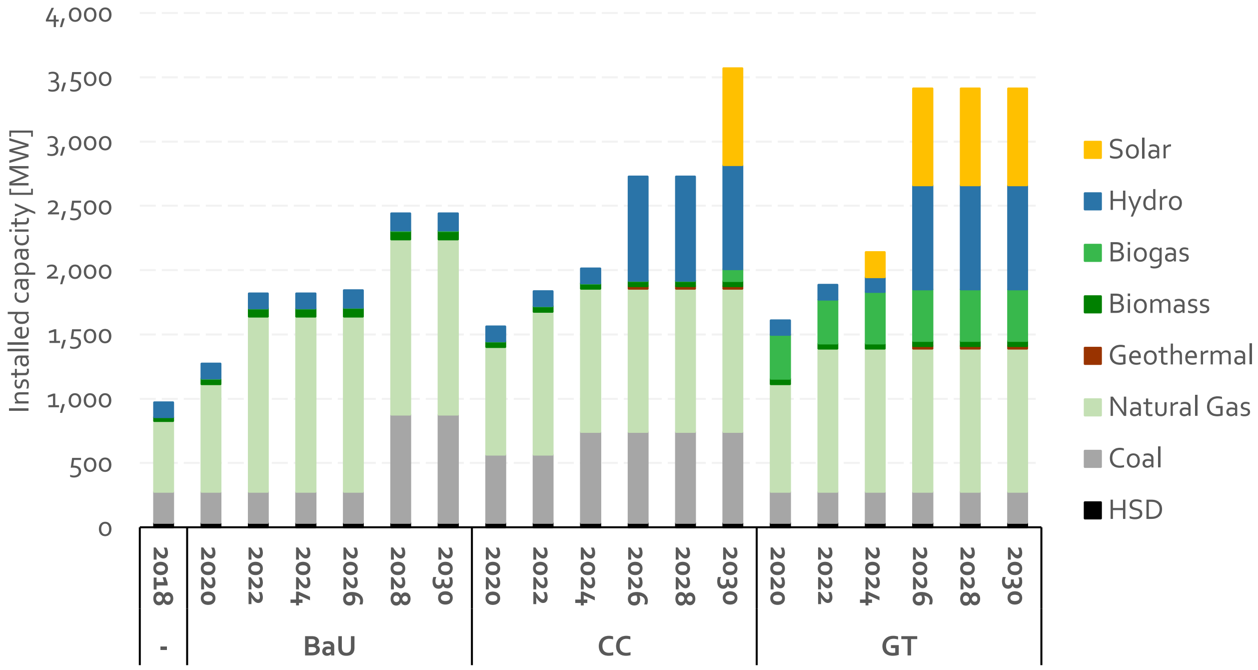

Figure 24: Power generation capacity development in Riau for the three main 2030 scenarios.

An overview of the total generation in 2030 in the three scenarios is shown in Figure 26. The share of RE generation in 2030, is a mere 8% in the BaU, but reaches 48% in CC and 67% in GT, indicating that there is a **large room to supply the demand with more RE** in the power system of Riau.

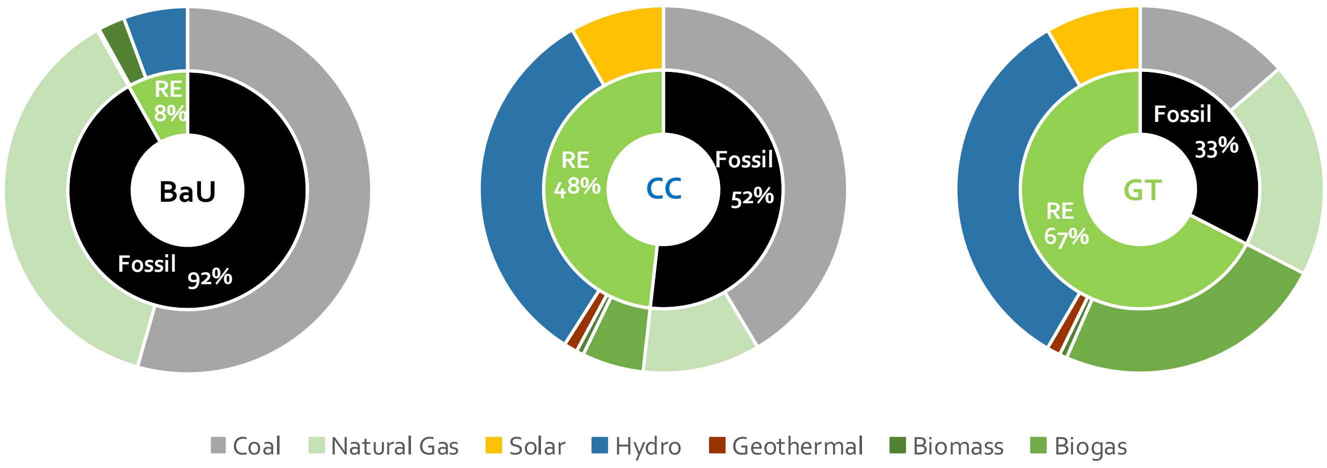

Figure 26: Generation in 2030 in the three scenarios and share of fossil fuels (black) and RE (green).

Text box 3. Cheap financing vs pollution cost. What is the most impacting measure?

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.

Surprisingly, the **system in 2030 is very similar in the three cases** (GT, only WACC considered, only Pollution Cost considered), with the same amount of renewable energy. The only difference is that when pollution cost is not considered, there are 200 MW of additional coal power which in the short term pushes out RE and in 2030 reduces gas generation. This underlines that renewable energy is very close to be competitive with fossil fuels and, since the cost gap is small, the efforts required for a green transition are limited and different measures can achieve the same result.

The additional coal generation from this 200 MW plant emits a large amount of CO_2 over the simulated period. Figure 21 shows the cumulative CO_2 emission reduction (2020-2030) from implementing measures separately: considering pollution cost has a larger overall climate effect than a favorable WACC.

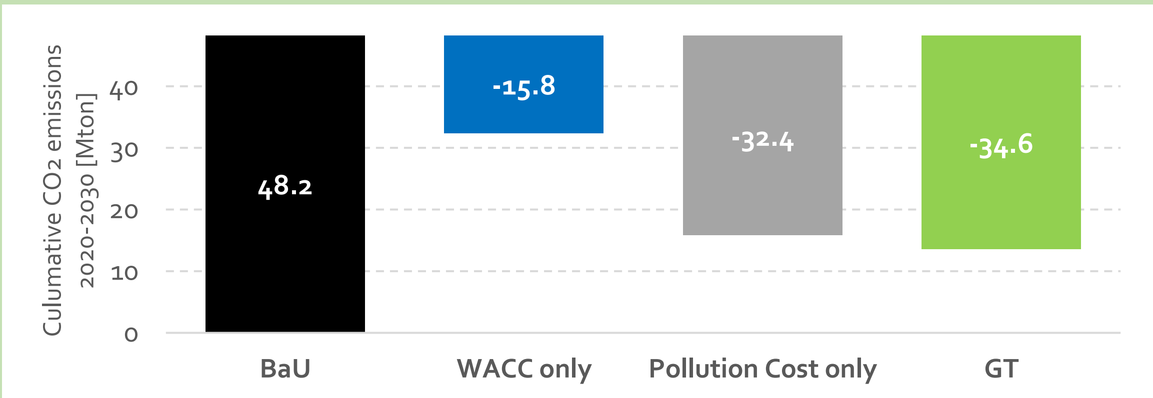

Figure 25: Emission reduction from GT scenario vs implementing the two measures separately.

A greener and more climate-friendly supply with no additional cost

*In a scenario with favourable conditions for RE it is possible to achieve **a much larger RE penetration and emission reduction while reducing cost compared to BaU**, with an average generation cost of 1,004 Rp/kWh vs 1,093 in BaU. A more RE-based system also reduces risks of cost surge, due to fluctuating and uncertain cost of fuel 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 optimised by the model[10]), fixed and variable operation and maintenance cost (O&M), fuel cost and cost of power imported from other regions.

The three analysed scenarios have more or less the same cost of supplying the power demand of Riau (Figure 27). The **BaU scenario is, nevertheless, the most expensive** of the three scenarios, meaning that the realisation of planned power plants is not the path providing the most affordable electricity. In the GT scenario, the cumulative cost saving is around 13 trillion IDR over the 10 years analysed if the damage cost of pollution is excluded from the GT calculation[11].

Table 3: Average generation cost by scenario.

	Rp/kWh
BaU	1093
CC	991
GT	1004

The CC scenario, featuring 48% RE in 2030, has an average cost of 991 Rp/kWh while the **GT scenario, with 67% RE, has an average cost of 1,004 Rp/kWh (excluding damage cost of pollution)**. The cost of basing generation on two thirds RE is thus only marginally higher than the CC scenario and much lower than the generation cost of today (Table 3).

When the damage cost of pollution is included, the GT scenario ends up being much cheaper than the other two scenarios, guaranteeing an additional cumulative saving of 7-11 trillion IDR in health-related costs.

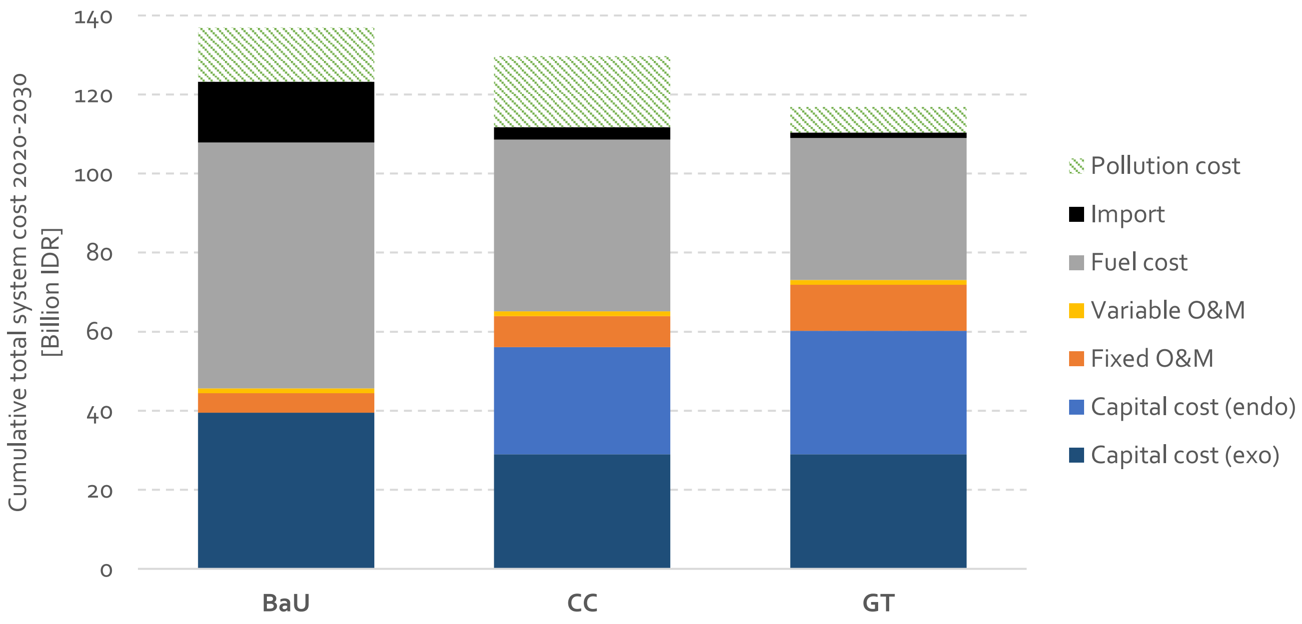

Figure 27: Cumulative total system costs in the three 2030 scenarios for the period 2020-2030[8].

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[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 of emissions.

Another important factor is that the portion of the total costs related to fuel expenditure is only 32% in the GT scenario compared to 50% in BaU. A system with much 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 future fuel price fluctuations**. For example, the price of coal fluctuated considerably in the last five years, from a minimum of around 50 $/ton (March 2016) to a maximum of 110 $/ton (August 2018) (ESDM 2019).

Gas plants risk low utilization

***Gas power plants could run for less than anticipated** as coal is cheaper to be dispatched as baseload. While capacity factors of coal remain generally around 75-80%, combined cycle gas turbines are dispatched for a capacity factor around 35% in BaU, plummeting down to around 10-20% in CC and GT.*

The gas engines and combined cycle pipeline in Riau, based on RUPTL 2019 (PT PLN Persero 2019), totals 758 MW (with 525 MW of combined cycle gas turbines and 233 MW of gas engines). Most of these plants are already under construction, apart from Riau 2 (250 MW)[12].

Model results suggests that in scenarios in which capacity is optimised and more RE is added to the mix, there is a risk for gas plants to have low amount of running hours (Figure 28). While in the BaU scenario, gas plants have capacity factors around 35%, in the CC and the GT scenarios the value is reduced to 10-20% indicating that those power plants would be underutilized.

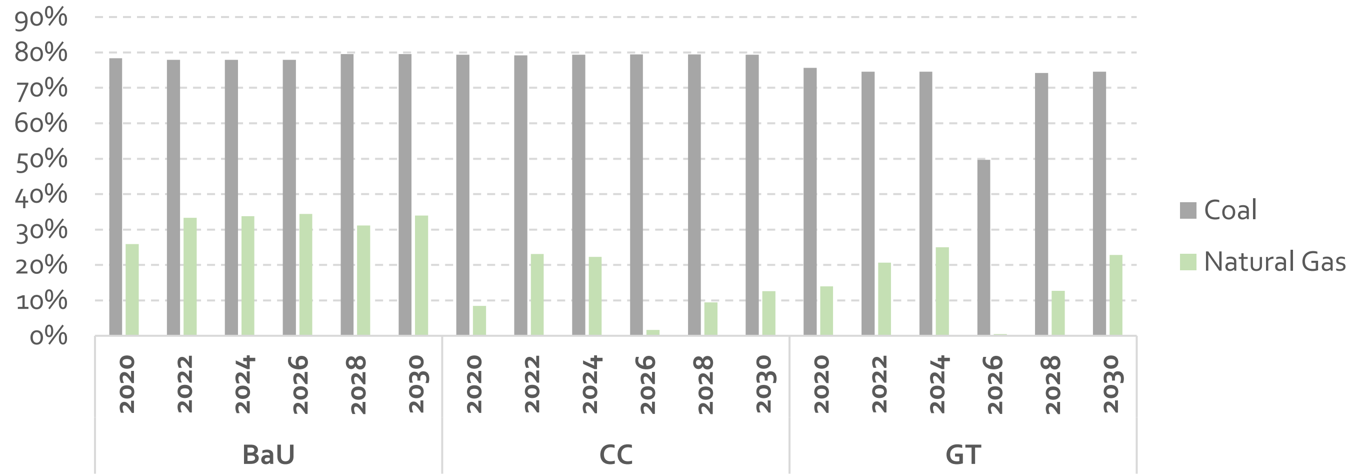


Figure 28: Capacity factors of coal and gas power plants by scenario and year.

The effect is even stronger in 2026: After new hydropower projects are built in all regions of Sumatra, the utilization of gas goes down to almost zero to then picks up again in the following years as load increases. Hydro power is the largest competitor to gas-fired power plants in providing flexibility and intermediate/peak services.

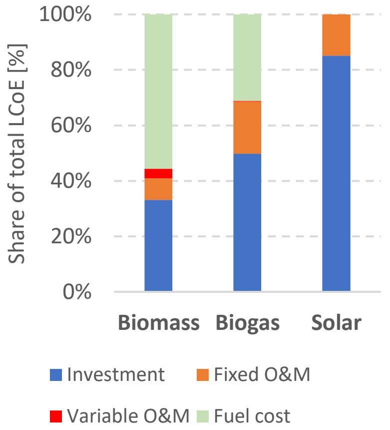
This situation occurs in case large hydro facilities are built in Sumatra. In case hydro power projects cannot be completed due to difficulties in the planning or lack of exploitable sites, natural gas can be a substitute and achieve higher running hours. However, additional gas power plants should be carefully considered also in relation to the potential expansion of RE.

[12] See Appendix B for a detailed list of planned plants under RUPTL 2019, including status and COD.

Lower prices of feedstock make biomass competitive

***Biomass benefit more from having access to cheap feedstock** compared to biogas, since fuel cost cover a larger share of the total. Its LCoE would reduce down to around 930-970 Rp/kWh. In case low cost bio residues are available, biomass can play a sizable role in the power supply already before 2030, substituting coal, gas and some hydro/solar generation.*

The cost structure of generation technologies is very different. While solar LCoE mainly depends on the investment cost, biogas and biomass have a consistent share that depends on fuel cost. For biomass, this share reaches around 55%.



As a consequence, in a scenario where bio feedstock in the form of POME and palm oil residues is available at very low cost (assumed 50% lower than in the original assumptions), biomass is the one that benefit the most, reducing its LCoE to 970 Rp/kWh in 2020 and 930 Rp/kWh in 2030. A "Bio+" variation of the CC and GT scenarios is therefore analysed.

Under this condition, biomass contribution to the power supply of Riau province can increase significantly, reaching 3 TWh in 2030 in both CC-Bio+ and GT-Bio+ scenarios (Figure 29). The generation increase reduces investment and production from coal, gas and to a lower extent also hydro and solar. Furthermore, biogas benefits from the lower POME cost, resulting in the full potential of biogas utilized already in 2020 in the GT-Bio+ scenario, instead of 2024.

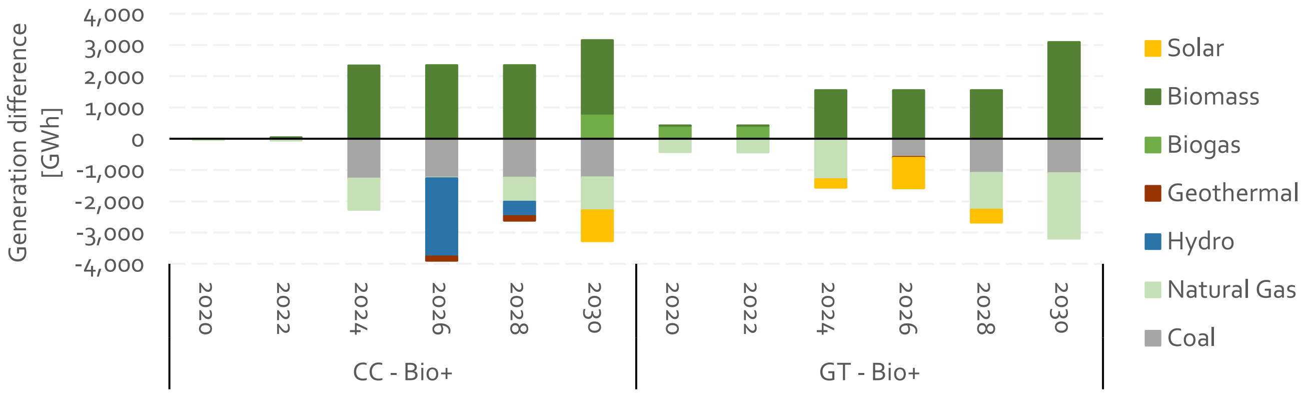


Figure 29: Change in generation for Bio+ scenarios compared to the respective base scenarios.

Large biomass capacity additions in the Bio+ scenarios start from 2024 and the total capacity installed reaches 375 MW in CC and 482 MW in GT by 2030, while in the original CC and GT scenarios no additional biomass plants are installed apart from the existing/planned 41 MW (Table 4). The installed capacity is still only around 10% of the potential, equal to more than 4 GW.

Table 4: Installed biomass capacity in the scenarios.

Biomass capacity	Original assumptions		Lower feedstock price	
	CC	GT	CC - Bio+	GT - Bio+
	MW	*MW*	*MW*	*MW*
2022	41	41	47	41
2026	41	41	375	262
2030	41	41	375	482

What are the implications for CO2 emissions and climate change?

*If commissioned, planned coal power plants for 2028 will cause the province's CO_2 emissions to **more than double**. On the other hand, Riau province has the chance to **almost eliminate CO_2 emission in 2030**, due to the potential for a significant RE penetration and the offsetting effect of biogas.*

Today, emissions from Riau's power generation stands at 3 Mtons. The evolution of the generation fleet and the power dispatch will determine the pathway for the development of the provincial climate footprint. One factor that has a large impact is the expected increase in power demand in 2030: If Riau 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 in the BaU scenario remain constant until 2026, due to increased power import and a larger use of natural gas, which has a smaller CO_2 impact than coal. However, CO_2 emission **dramatically increases in 2028 due to the planned new 600 MW coal power plant**, resulting in doubling emissions compared to 2018 (Figure 30).

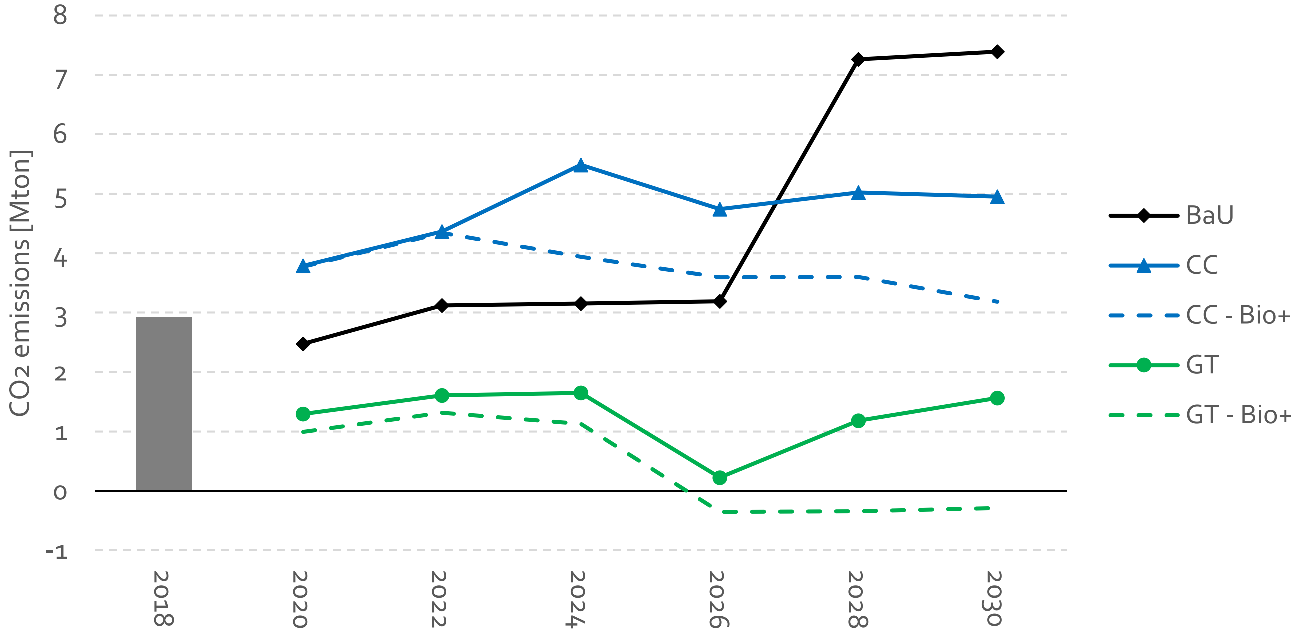


Figure 30: CO2 emissions from power generation in Riau in the analysed 2030 scenarios.

In the CC scenario, the CO_2 emissions are in the short term higher than BaU due to a larger deployment of coal power but starts to decline in 2024 and then becomes lower than BaU due to the additional hydro and solar installed. As for the GT scenario, the large generation of solar and biogas offsets the CO_2 emissions from coal and gas. In this scenario, Riau can **power more than double the current demand and at the same time reduce the CO_2 emissions** compared to today.

In 2030, the annual emissions in the BaU Scenario reaches 7.4 Mtons, while the reduction in the CC and the GT scenarios equals 2.4 Mtons and 5.8 Mtons, respectively, corresponding to almost 80% reduction (Figure 31).

The utilization of more biomass in the two Bio+ scenarios means that emissions are reduced by more than 35% in CC-Bio+ compared to CC and become negative[13] in the GT-Bio+.

[13] See Text box 4 for explanation.

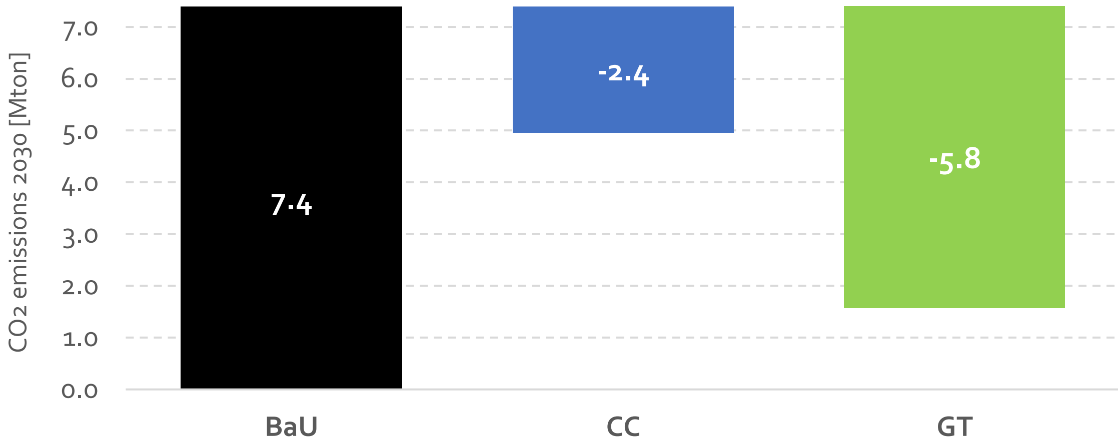


Figure 31: CO2 emissions reduction in CC and GT scenarios in 2030.

Text box 4. Climate impact of POME and biogas production.

The reason why emissions of CO_2 can be negative is that the deployment of biogas is often considered to have a positive GHG effect. **POME treated in open lagoons is the second largest single source of greenhouse gas emissions in the palm oil industry**, after the emissions from land-use change. Degradation of organic content in POME releases into the atmosphere methane gas, an even more powerful GHG than CO_2.POME has an average methane yield of 0.39 m3/kg of volatile solids, which is higher than other common feedstock sources such as dairy manure and municipal solid wastes. Capturing the methane released from POME translates directly into GHG emissions reductions, which is a goal in the environmental sustainability pillar (USAID; WINROCK Int. 2015). In this report it is assumed that burning 1 GJ of biogas saves 29 kgCO_{2eq}.

Equivalent CO_2 emissions from different phases of crude palm oil (CPO) production for a plantation with new land use is shown in Figure 32.

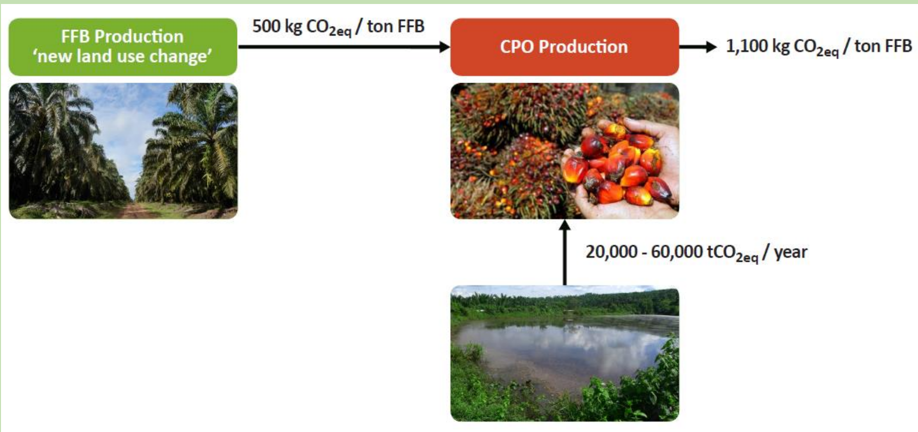


Figure 32: CO2 equivalent emissions from fresh fruit branches (FFB) and crude palm oil (CPO) production. Source: (USAID; WINROCK Int. 2015)

Solar PV vs bioenergy: Which wins?

Bioenergy is cheaper than solar PV in the short term, but cost reduction potential for solar PV makes it cheaper in 2030. At low feedstock prices, biomass can be the cheapest source of power generation in Riau. ***A clear mapping of potential sites for biogas and biomass plants, as well as a better understanding of residue availability and cost is necessary to determine the way forward.***

In the scenarios and Bio+ sensitivity analysed, solar PV, biogas and biomass are found to be feasible in Riau within different timeframes and with different prioritization depending on conditions such as cost of fuel, financing cost and bioenergy source potential. As discussed above, solar PV and biogas are more capital-intensive technologies than biomass, which in turn has higher fuel costs.

When looking at the 2020 perspective (Figure 33, left), **power from biogas is cheaper** than solar and biomass, which has more or less the same cost. The PV technology is not yet mature in Indonesia and suffers from high investment cost and high cost of capital. When comparing biogas and biomass, the former has a lower cost of generation since it has lower fuel cost: POME is cheaper per GJ than other palm oil residues, which need transportation and processing. When considering low feedstock prices (Bio+ sensitivity), biomass results in slightly lower generation cost than both competing technologies.

In 2030, **solar PV becomes the best alternative** at reference feedstock prices (assumed in CC and GT scenarios) with biogas following very closely. Under Bio+ conditions, with low price of fuel, both bioenergy sources become slightly cheaper than PV.

Given the large dependency of generation cost of biogas and biomass from the cost of the feedstock, it is very important to **understand both the availability and the potential cost of a steady and economical supply of residues** to the power plants. A clear mapping of sites and fuel supply logistics is needed to determine the prioritization between technologies and to prepare a realistic project pipeline.

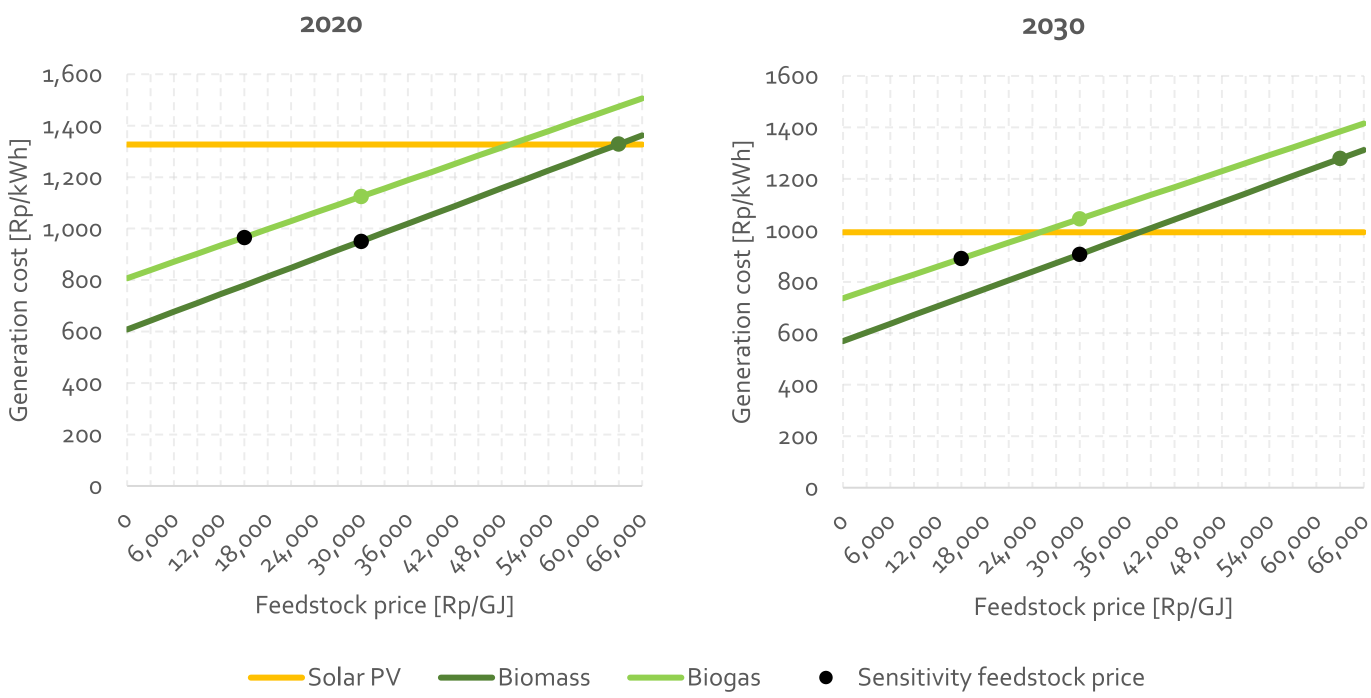


Figure 33: Comparison of solar PV, biogas and biomass cost for different feedstock prices. Dots indicate the price level assumed in the analysis (black dots represent the values in the Bio+ variation).

Solar power in Riau, an underestimated potential?

*The **solar power potential of Riau is most likely underestimated**, at 753 MW. In case the solar potential is disregarded, **up to 1.7 GW are optimal in 2030**, increasing the RE level from 67% to 78%.*

The solar power potential estimated in RUEN for the province of Riau is 753 MW (Presiden Republik Indonesia 2017). In regional RUED, this number is further reduced to 450 MW with no apparent explanation for the discrepancy. The value appears very low given that Riau is the second largest province in Sumatra after South Sumatra, which has a potential of 17 GW.

One of the reasons for the low potential could however be the relatively lower solar irradiation that characterises Riau, compared to other provinces in Sumatra and the rest of Indonesia. Nevertheless, the full load hours that can be achieved in Riau, according to the Global Solar Atlas, is not low enough to justify such a low estimate (Figure 34).

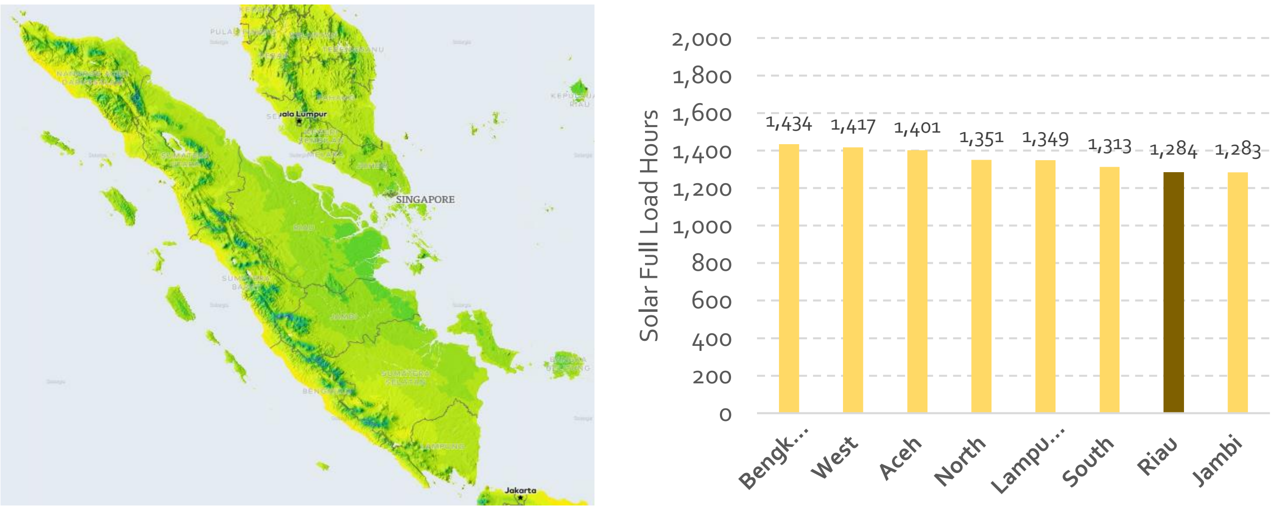


Figure 34: Map of solar irradiation of Sumatra (left) and solar FLH for the various provinces, Source: (Global Solar Atlas 2019)

For this reason, a model simulation for both CC and GT has been carried out to assess the sensitivity to removing the solar potential limitation. When looking at solar power investments (Figure 35), it is clear that without the max 753 MW restriction on solar power installation, **solar can play an even larger role in Riau power system, with a capacity of 1 GW in CC and 1.7 GW in GT in 2030**. With such a solar PV addition, the share of RE in the GT scenario would increases from 67% to 78%.

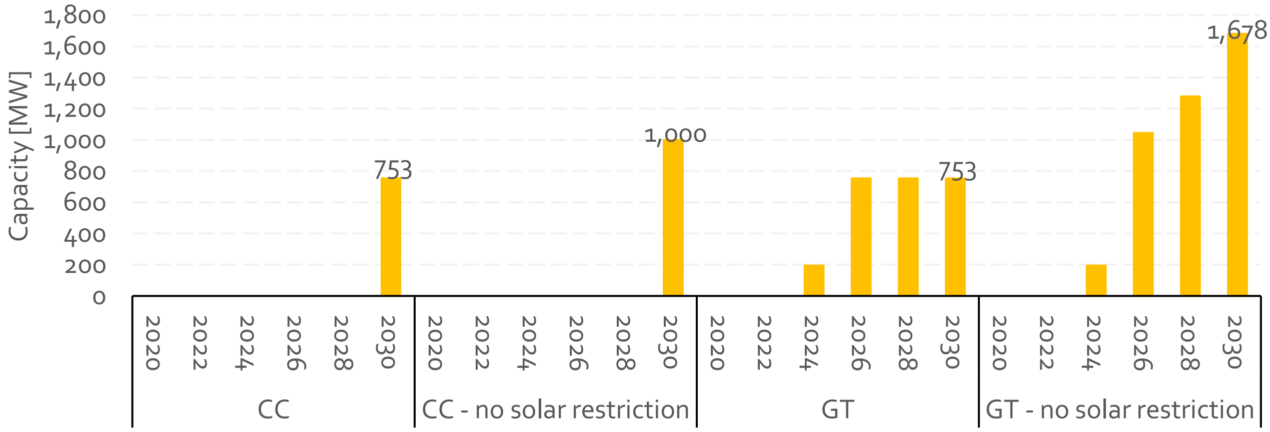
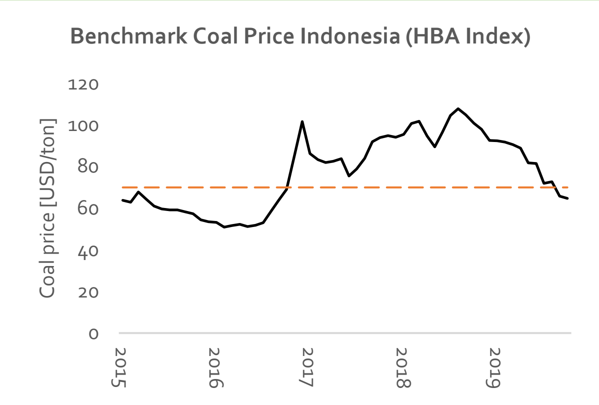


Figure 35: PV capacity additions with and without the 753 MW restriction, for CC and GT scenarios.

Text box 5. Coal price surge and low capacity factors make coal power much more expensive.

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 generation cost of coal plants and consequently on the end user tariffs.

The variation of the cost of generation for coal plants in 2020, together with a comparison to other power sources, is shown in Figure 36. With a coal price of 70 $/ton (and considering no further transportation cost for the fuel), the generation cost of coal is just below 1,000 Rp/kWh. If the price of coal at the power plant increases to 110 $/ton, the **generation cost increases by 26% reaching 1,233 Rp/kWh**.

At this cost level, various other sources would be competitive, for example natural gas and biogas would have a lower generation cost. Solar power would still be slightly more expensive, but with a cost of capital (WACC) of 8%, PV would also fall below 1,200 Rp/kWh, making it cheaper than coal plants already in 2020.

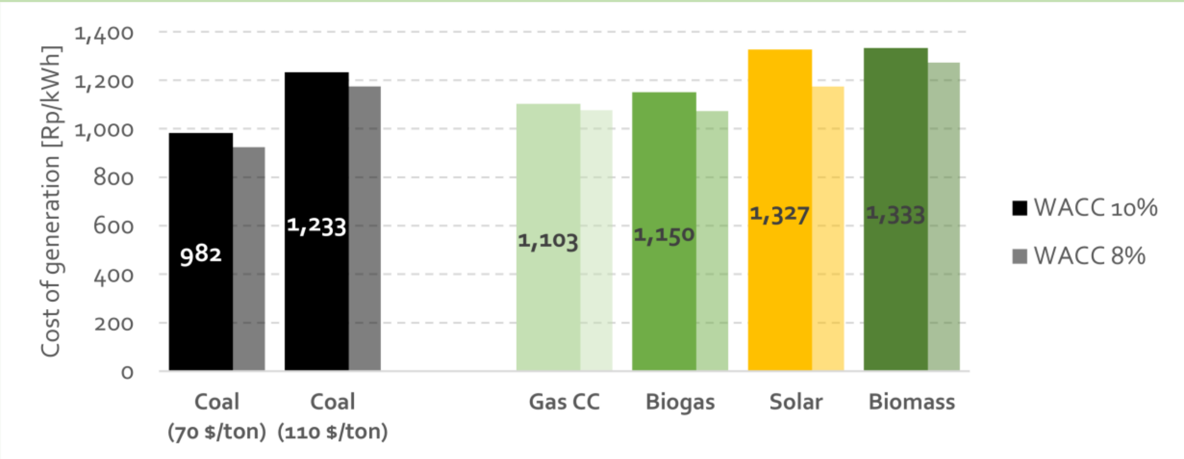
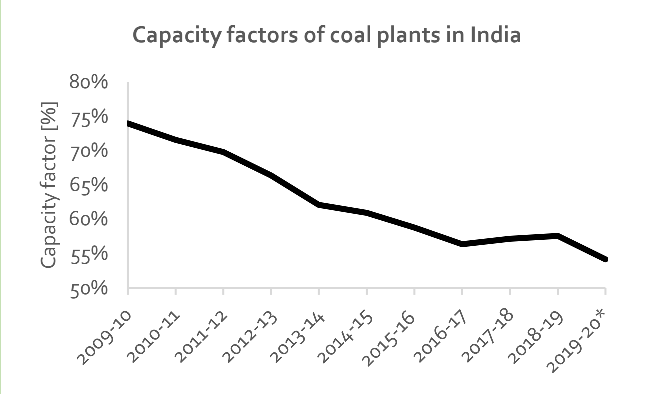


Figure 36: Generation cost of coal at 70$/ton vs 110 $/ton and comparison with other sources at 8 and 10% WACC.

Another factor to consider is that coal generation cost largely **dependent on how many hours the power plant is running**. The fixed costs (investment and fixed O&M) impacts less the total generation cost when coal plant has high capacity factors. The lower the capacity factor, the more expensive is to generate with the plant.

As RE share grew, China and India experienced **collapsing utilization rates of coal power plants**. China utilization of thermal plants fell below 50% in 2016 (China Electricity Council 2018), while in India, despite the projected 70-80% utilization rate, capacity factors plummeted from around 75% in 2010 to less than 55% today (Ministry of Power - Government of India 2019).



The effect of lower utilization rate of coal plants for Indonesia, expressed in term of declining capacity factor, is shown in Figure 37. At almost full plant utilization (80% CF), coal plants produce at a lower cost compared to both solar and biogas. When coal price is at 110 $/ton, biogas is cheaper regardless of the coal CF and **solar PV is cheaper if coal power has CF below 70% already in 2020.**

Looking at domestic and international markets, the risk of both surging coal prices and lower utilization of coal are tangible. The combined effect of these two factors would largely increase coal prices and make renewable energy sources competitive already in 2020, even without considering the great cost reduction potential that technology like solar and wind are experiencing worldwide.

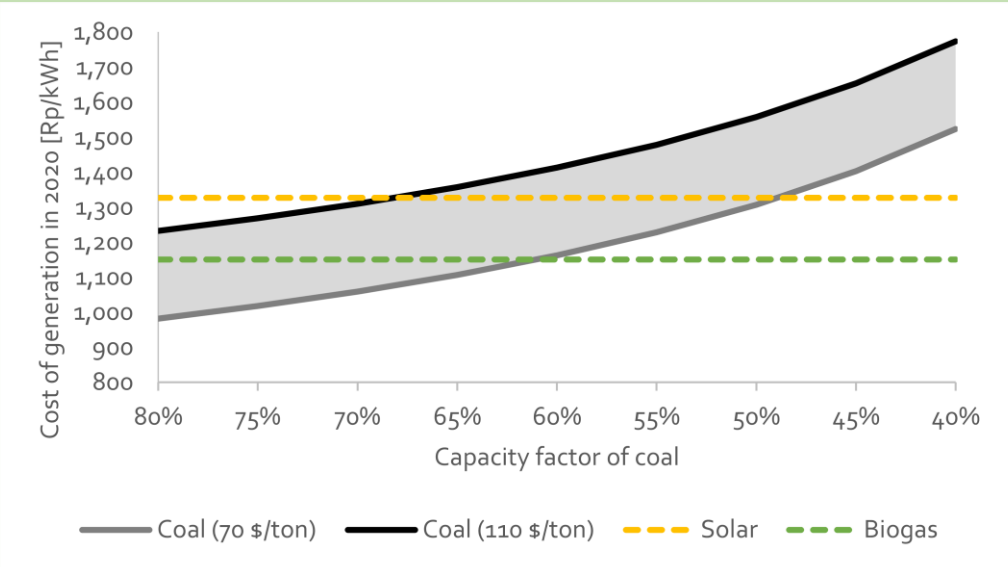


Figure 37: Coal generation cost at declining capacity factor, for a coal price of 70 $/ton and 110 $/ton.

4. 2050 scenarios

Alternative least cost development features much more RE than RUED

*The optimization of the power sector additions towards 2050 leads to **more RE than anticipated in RUED**. Solar power, supported by battery storage, has a larger role after 2030 with up to 11 GW in 2050. Least cost scenarios show it is possible to **achieve a share of 61-72% RE in the primary energy** in 2050.*

To analyse the long term perspective and the potential development of the power system in Riau, two scenarios are analysed: in the scenario "RUED" the buildout of power plants follows the plans under regional energy policy (RUED), including the target in terms of share of natural gas, coal and RE. In addition, a "Least Cost" scenario is analysing what would be the development of the generation fleet on a pure cost minimization basis, disregarding existing policies and plans. Given the likely underestimation of solar potential in RUED and RUEN, the potential of solar in the Least Cost scenario is assumed unlimited, in order to find out the optimal level in the system from an economical perspective.

Figure 38 shows the capacity buildout in the two 2050 scenarios. The most striking difference is that in the **Least Cost scenario a massive deployment of solar is envisioned** starting from after 2030, which supplies a large part of the demand. The optimal PV capacity in the system reaches 4.9 GW in 2040 and 8.6 GW in 2050. In order to enable integrating 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 0.25 MW of battery storage in 2040 and around 0.33 MW in 2050**. Indeed, it is only after a large solar capacity is operational, that the solar penetration becomes challenging from a system-operation perspective. While the penetration remains below 5-10%, solar can be easily integrated in the system, especially in a system with flexible gas power plants.

Besides these large investments in solar and storage, the system features a very similar level of biomass and hydropower (reaching maximum potential in 2050). In the short term, even more biomass is deployed in the Least Cost scenario compared to RUED while less natural gas capacity is installed.

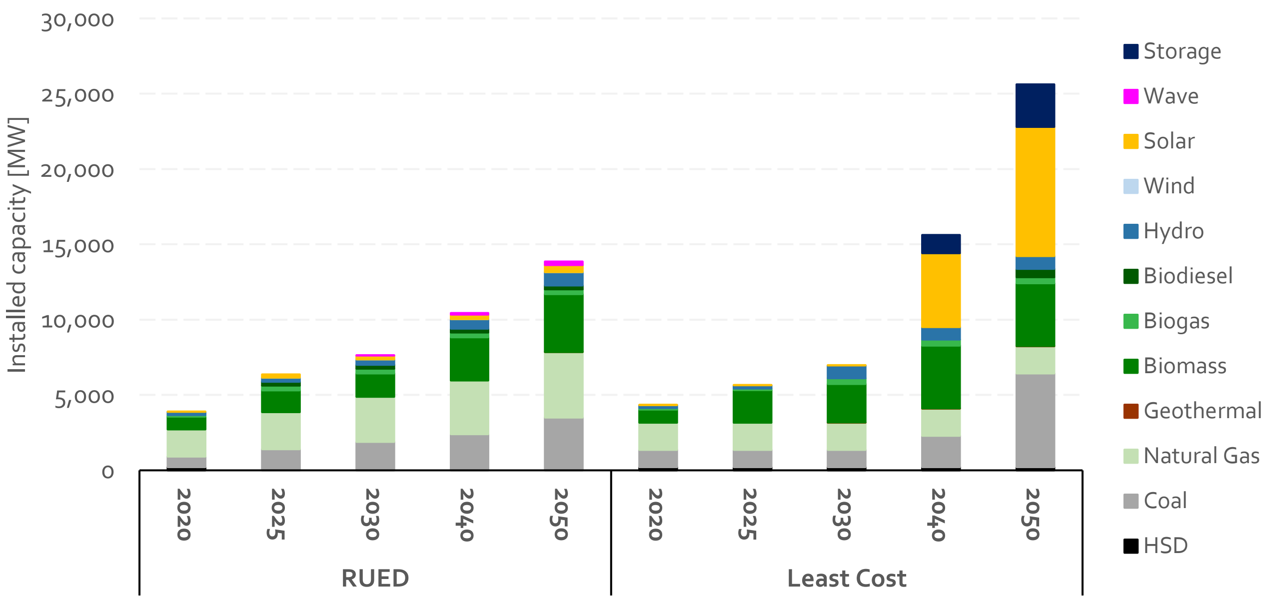


Figure 38: Installed capacity in Riau in Least Cost scenario compared to RUED plan.

In the long term, the Least Cost scenario features almost double the coal capacity compared to the plan of RUED. This is due to the fact, that once biomass, biogas and hydro potential is maximized, and a large solar generation is installed in the system, additional dispatchable capacity is needed and coal plants are cheaper than natural gas by 2050.

Since RUED expects a low contribution from coal to the future power supply, a sensitivity scenario named "**Least Cost – coal limited**" is simulated limiting the coal capacity to what is expected in RUED, i. e. 3.5 GW by 2050.

In such a scenario, the reduced coal capacity (-2.7 GW in 2050) is substituted with a combination of natural gas (+1.4 GW), solar PV (+6 GW) and storage (+1.3 GW).

When comparing the generation of the three scenarios, it appears that the **optimized scenarios feature less natural gas generation** compared to RUED, displacing it with more biomass in the medium term and with solar in the long term.

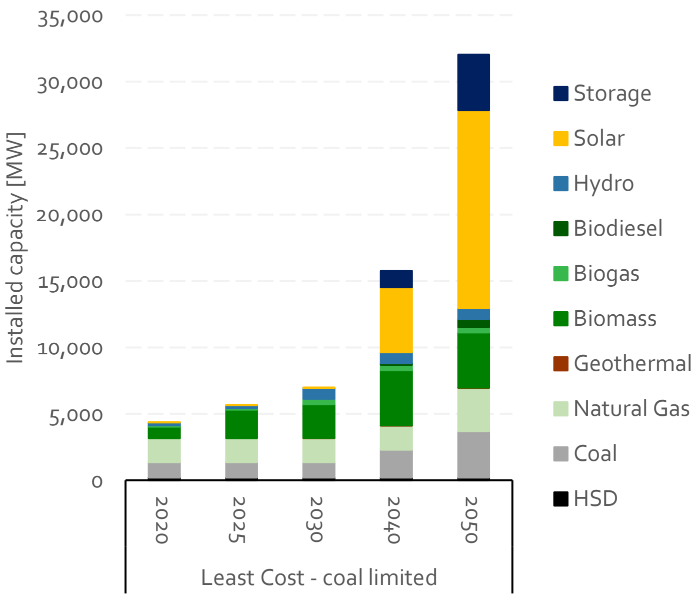


Figure 39: Capacity installed in case coal is limited to RUED level.

The primary energy mix in the three scenarios in 2050 are represented in Figure 40. In the RUED scenario, the amount of RE equals 47%. On the other hand, in the Least Cost scenarios **the primary energy from RE in the system reaches a value between 61% and 72%** depending on what role coal is expected to play.

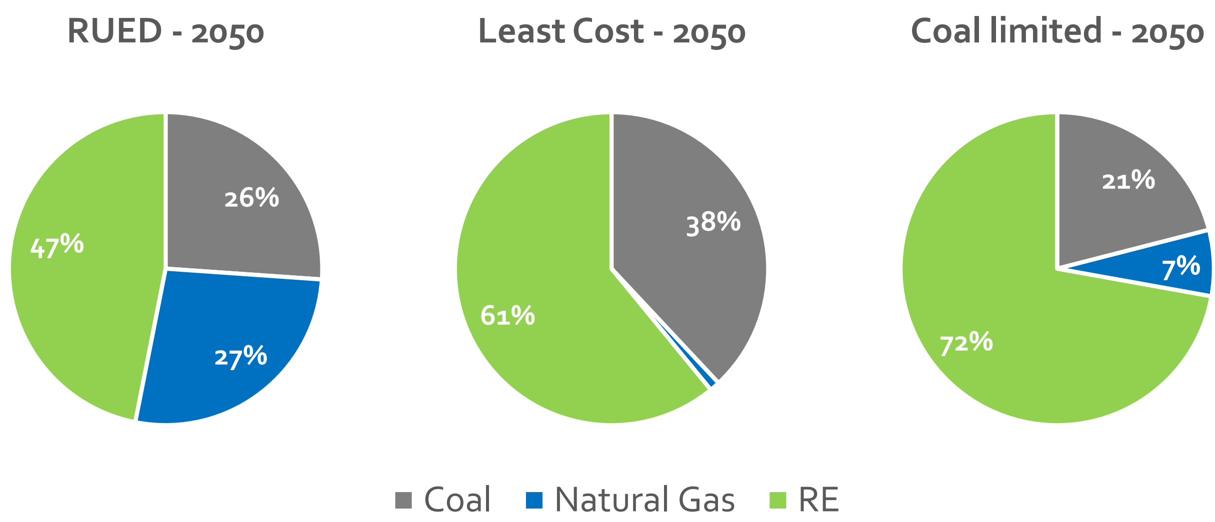


Figure 40: Primary energy by source in the power sector in 2050 in the three 2050 scenarios analysed.

Text box 6. Space requirement for solar power. How much is 14 GW, really?

As seen in the Least cost scenarios for 2050, the optimal level of solar PV in the system would be between 8.6 and 14.8 GW, between 11 and 20 times higher than the potential for solar indicated in RUEN, equal to 753 MW.

The space requirement for PV plants depends on a number of parameters, among which the efficiency of the cells is the most important. The higher the efficiency, the lower the area needed to accommodate a certain capacity. In utility-scale PV plants, in order to avoid shading between panels, the space between consecutive rows is sometimes increased, taking more space per kW compared to what it would take on a small residential application.

Based on data from the technology catalogue (NEC 2017), the **space requirement for large PV plants** varies between 9,000 m^2/MW_{peak} in 2020 to 7,000 m^2/MW_{peak} in 2050, when efficiency of modules will be higher.

Riau is the second largest province in the entire Indonesia with a total area of 87,000 km^2. Based on the aforementioned space requirement, the total area needed to accommodate the largest solar capacity seen in the scenarios, i.e. 14.8 GW, would be equal to around 104 km^2, corresponding roughly to **0.12% of the total area of Riau province**. As a reference, the original potential of 753 MW from RUEN would only take 0.007% of the total area of Riau.

Figure 41: Space requirement for 14.8 GW of solar is equal to just 0.12% of the total area of Riau. Source: (Google Earth)

More RE can lead to cost savings and emission reduction

*Toward 2050, the use of more solar in addition to biomass in the two Least Cost scenarios can **reduce the cumulative CO_2 emissions by 12-14% compared to RUED and save on average 17-18 trillion IDR per year** compared to RUED.*

The different power supply mix in the optimized scenarios impacts both system costs and the climate footprint in terms of CO_2 emissions.

Figure 42 shows a cost comparison between the three 2050 scenarios analysed, while Table 5 gives an overview of the total cost of each. In **both the RUEN scenario and the Least Cost scenario the potential for cost saving is large**, with a 71 trillion IDR total cost saving for the simulated years in the Least cost scenario (corresponding to an average yearly saving of 18 trillion IDR). In the scenario with a limit on coal buildout, the total system cost is very similar to the Least Cost case and so are the savings compared to the RUED scenario. Moreover, when considering cost of pollution, **the scenario with limited coal is even cheaper**, with a cost of 240 trillion IDR (compared to 243 trillion IDR of the Least Cost).

One large cost component in the RUED scenario is related to the import from neighbouring regions. The buildout assumed in the RUED scenario results in larger power imports, and thus an increase in the associated costs, compared to the two other scenarios.

Given the relatively modest coal deployment in the RUED scenario, the costs related to the emission of SO_2, NO_x and $PM_{2.5}$ are lower than in the Least Cost scenario and more or less similar to the Least Cost – Coal limited scenario.

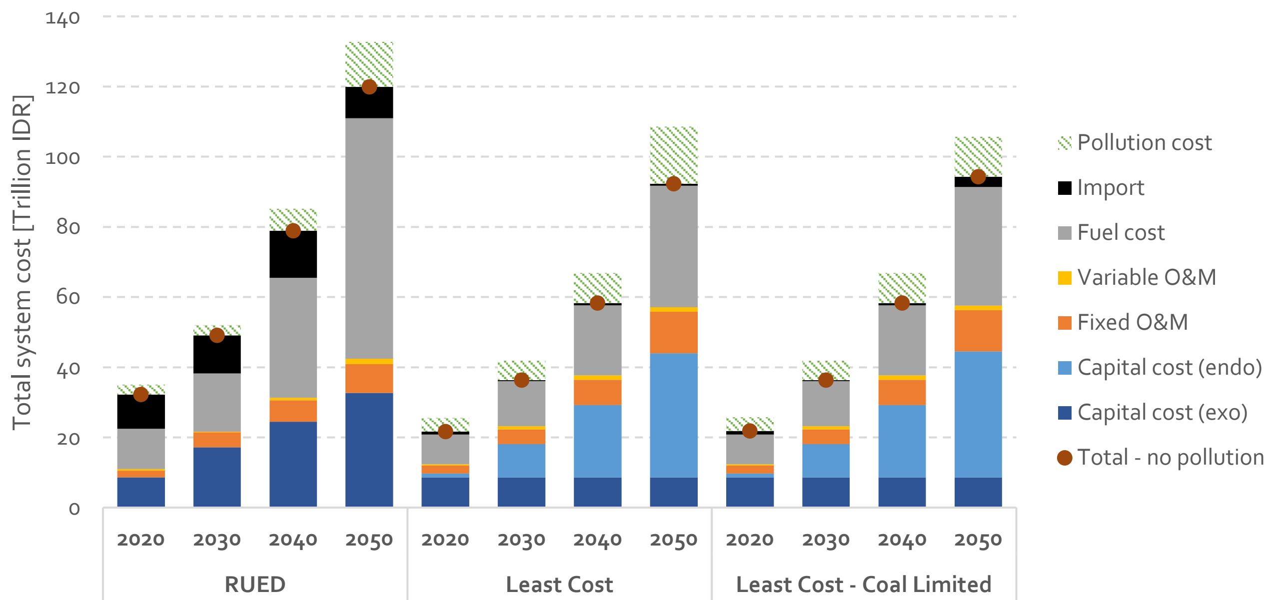


Figure 42: Comparison of total system cost by scenario and year.

Table 5: Total cost with and without pollution cost in RUED and Least Cost scenarios, cumulative for 2020, 2030, 2040, 2050.

	Total cost – no pollution	Total cost incl. pollution
	[Trillion IDR]	*[Trillion IDR]*
RUED	280	305
Least Cost	209	243
Least Cost - coal limited	211	240

The CO_2 emissions increases substantially overtime in all scenarios, due to the exponential growth in the power demand (Figure 43).

With the power plant pipeline suggested in the Least Cost, the emissions in 2050 are similar to those in the RUED scenario but lower in the medium term, due to higher biomass use. The limitation of coal capacity, combined with a larger deployment of solar power in the Least Cost – coal limited scenario reduces long-term emissions, with a value for 2050 that is 28% lower.

In terms of cumulative emissions from 2020 to 2050, a higher use solar power in addition to biomass and biogas can reduce emissions by **55 Mtons (-12%) in the Least Cost scenario over the 30 years analysed**. Furthermore, **if coal deployment is limited to what planned in RUED the cumulative emissions are reduced by 66 Mtons (-14%)** compared to RUED**.**

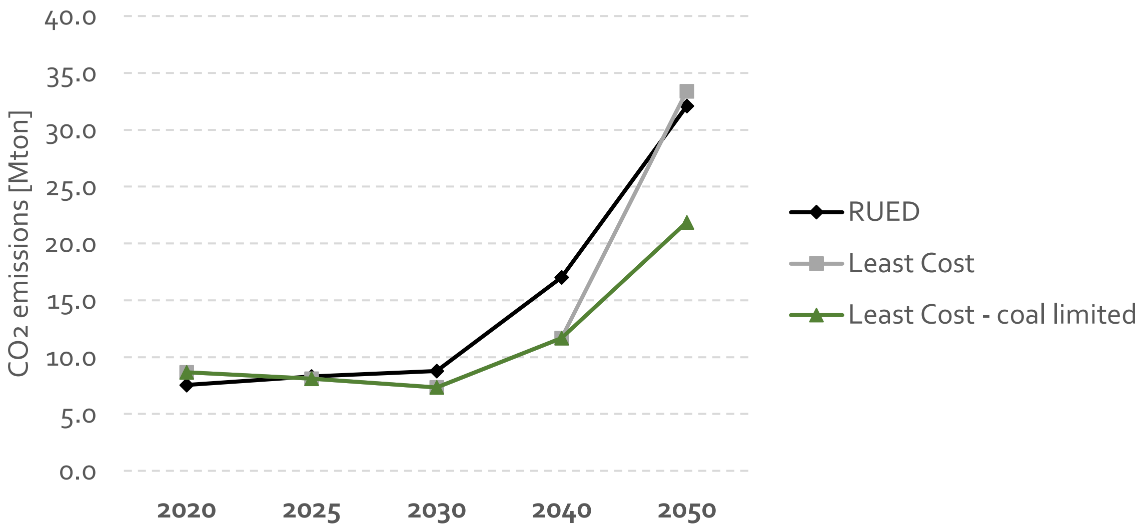


Figure 43: CO2 emissions in the three 2050 scenarios.

Given the limited RE potential in Riau, it is under none of the scenarios analysed economically feasible to reduce further emissions. If Riau province wishes to curb its climate change impact resulting from the power sector, other measures such as **energy efficiency and decoupling of economic growth from power use will be key**.

5. Conclusions and recommendations

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

The results of the analyses for both medium term and long-term show that solar power contribution to the supply in Riau is underestimated, as well as the provincial potential. The combination of biogas, biomass and solar can bring about higher shares of RE in both 2030 and 2050, while reducing emissions and cost of supply. A full and accelerated exploitation of hydro potential in Riau can also help reduce cost and provide affordable clean power.

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

- Look beyond bioenergy: Start considering solar PV as a potential source of cheap power already in the early 2020s, especially given the favourable international financing conditions for RE (otherwise from mid 2020s). Identification of suitable sites, preparation of pre-feasibility studies and formulating an increased ambition regarding solar in the policy and planning documents can help attract investments;
- As testified by the results of auctions worldwide, solar is quickly becoming the cheapest sources of power. Even though Indonesia is lagging behind in terms of its deployment of solar and still experiences higher costs today, ultimately the cost will be brought down thanks to larger volumes and cost drop as the local industry develops;
- 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 such as solar PV can become an attractive option. In order to attract capital, a commitment to a RE project pipeline, an increase in the RE ambition of Riau province and an improved communication of these targets can be enabling factors;
- Carefully reassess the case for additional coal power plants and large combined cycle gas plants to avoid technology lock-in and overcapacity. There is apparent risk of stranded assets and increased electricity tariffs in Riau;
- Assumptions across official planning documents, such as RUEN, RUED and RUPTL (but also RUKN and RUKD) largely differ 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;
- Revise the solar potential of the province by conducting a detailed mapping of space available and solar resource (for both rooftop and stand-alone PV);
- Conduct a study of the bioenergy potential (considering among others palm oil mill location, distance to grid, feedstock transportation cost) and prioritize sites. Another critical point is to ensure the sustainability of bio residues used, in order to avoid the risk of deforestation and land use change that would jeopardize the climate change mitigation efforts.

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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 8760 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 fundamental model which essentially finds economical dispatch and capacity expansion solution for the represented energy system.

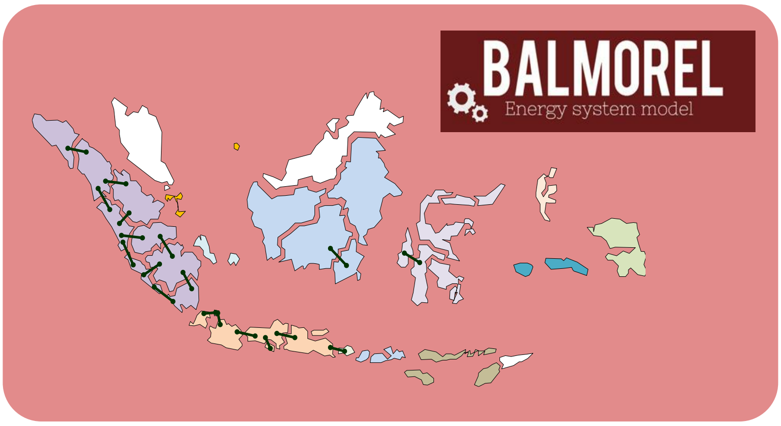

Figure 44: Balmorel model, Indonesian setup.

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 45). 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).

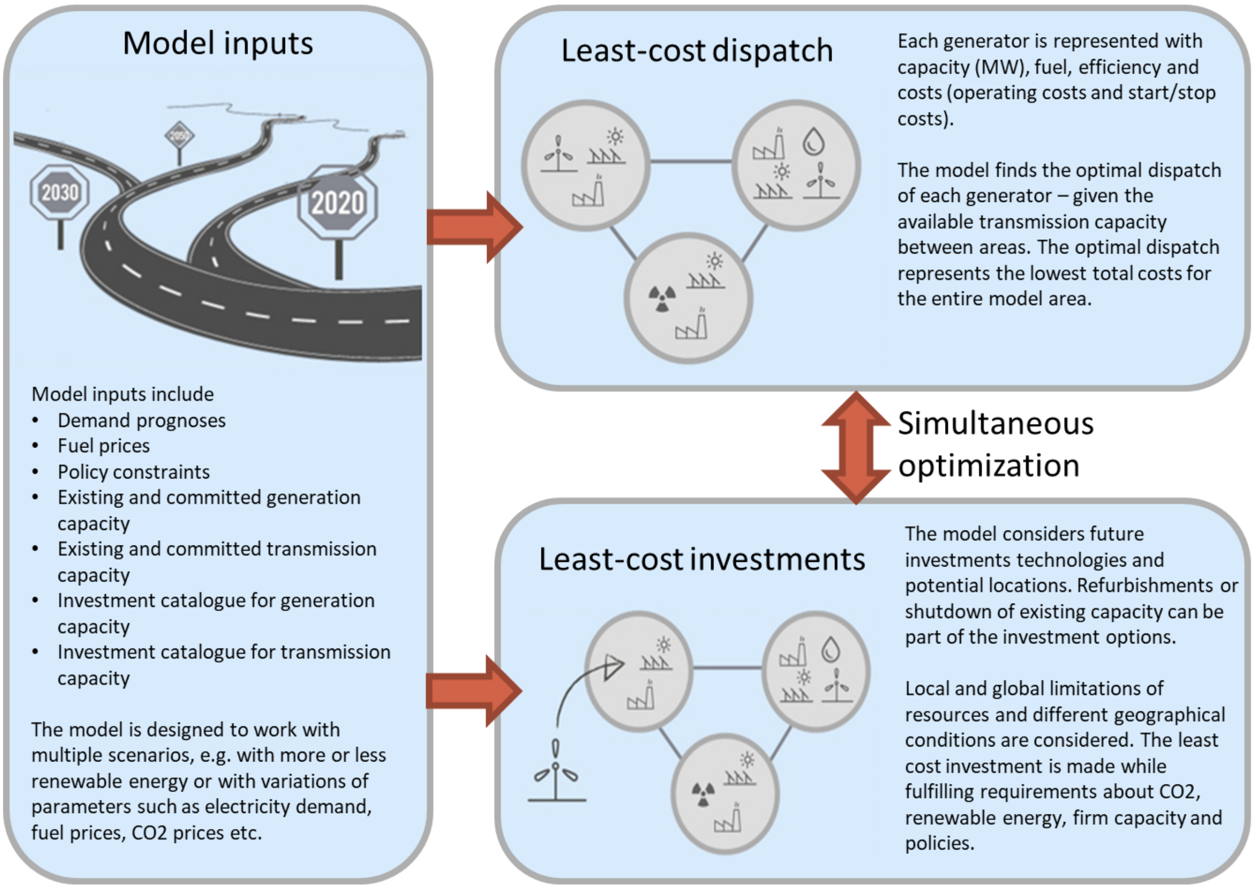

Figure 45: Balmorel model inputs and optimization logic.

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

A-I. GEOGRAPHICAL RESOLUTION

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

Figure 46: Sumatra Island represented in 8 transmission regions.

The island is represented in the model as eight dispatch-regions, corresponding to the provinces in Sumatra, each with its own electricity consumption. The transmission regions are connected by electricity transmission lines with fixed capacity. While the focus of this study is on Riau, 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 Riau, each power generation unit is represented separately, while for the other regions groups of power plants are represented depending on the fuel type.

A-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.

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.

A-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.

Planned projects under RUPTL19

For all model-optimized 2030 scenarios (CC, GT 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 and geothermal 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 Business as Usual scenario, all buildout in the RUPTL is included until 2028.

The list of projects included in RUPTL 2019 for Riau is summarized in Table 6.

Table 6: Planned generation units for Riau included in RUPTL 2019.

System	Type	Fuel	Location/Name	Capacity (MW)	COD	Status	Ownership
Sumatera	PLTBg	Biogas	Ujung Batu	3	2019	PPA	IPP
Sumatera	PLTBm	Biomass	Rantau Sakti (EBTKE)	1	2019	Under Constr.	IPP
Sumatera	PLTG	Natural gas	Teluk Lembu	55	2020	Procurement	PLN
Sumatera	PLTMG	Natural gas	MPP Muko-Muko	33	2020	PPA	PLN
Sumatera	PLTMG	Natural gas	Riau Peaker	100	2020	Under Constr.	PLN
Sumatera	PLTMG	Natural gas	Riau Peaker	100	2020	Under Constr.	PLN
Sumatera	PLTBm	Biomass	Rokan Jaya	10	2020	Under Constr.	IPP
Sumatera	PLTGU	Natural gas	Riau	275	2021	Under Constr.	IPP
Sumatera	PLTGU	Natural gas	Riau-2	250	2022	Procurement	IPP
Sumatera	PLTU-MT	Coal	Riau-1	300	2028	PPA	IPP
Sumatera	PLTU-MT	Coal	Riau-1	300	2028	PPA	IPP

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 Riau was included until 2050. For the other provinces in Sumatra, only RUED generation targets were set (Table 8).

Table 7: Planned generation units for Riau included in RUED 2019.

Power plant	2015	2016	2017	2018	2019	2020	2025	2050
PLTU Batubara	449	449	449	696	696	696	696	696
PLTU Batubara Bersih_USC	-	-	-	-	-	-	700	2,800
PLTU Gas	-	-	-	-	-	-	-	-
PLTU Minyak	-	-	-	-	-	-	-	-
PLTGU Gas	26	76	126	176	226	364	1,001	2,051
PLTGU LNG	-	-	-	-	-	-	-	250
PLTGU Minyak	-	-	-	-	-	-	-	-
PLTG Gas	918	929	940	951	1,084	1,084	1,084	1,400
PLTG Minyak	-	-	-	-	-	-	-	-
PLTMG Gas	287	298	309	320	353	358	381	500
PLTMG Minyak	-	-	-	-	-	-	-	-
PLTD Minyak	426	384	341	298	256	213	-	-
PLTD BioSolar	-	-	-	-	-	-	250	250
PLT Gasifikasi Batubara_PLTGB	-	-	-	-	-	-	-	250
PLTA	114	114	114	114	114	114	214	793
PLT Mini_Mikrohidro	0	0	0	0	0	0	10	101
PLT Panas Bumi_PLTP	-	-	-	-	-	-	4	4
PLT Biomasa	700	700	700	700	777	854	1,437	3,844
PLT Biogas	2	5	8	11	14	114	325	325
PLT Sampah PLTSa	-	-	-	-	-	-	10	30
PLT Surya_PLTS	1	1	1	1	1	1	200	450
PLT Bayu_PLTB	-	-	-	-	-	-	2	5
PLT Laut	-	-	-	-	-	-	-	241
Total	2,924	2,956	2,989	3,268	3,522	3,798	6,315	13,990

Table 8: Generation shares in the RUED scenario, for all provinces. Shares are implemented as minimum generation restrictions.

		2025	2050
Riau	RE share [%]	34.4%	46.9%
	Coal share [%]	29.1%	24.1%
	Gas share [%]	34.7%	28.2%
Sumatra North	RE share [%]	52.5%	47.7%
	Coal share [%]	27.3%	22.0%
	Gas share [%]	20.2%	30.3%
Sumatra West	RE share [%]	72.2%	88.3%
	Coal share [%]	20.9%	5.1%
	Gas share [%]	5.9%	6.6%
Jambi	RE share [%]	37.8%	59.6%
	Coal share [%]	44.4%	27.7%
	Gas share [%]	17.7%	12.7%
Bengkulu	RE share [%]	73.4%	75.8%
	Coal share [%]	25.7%	23.9%
	Gas share [%]	0.0%	0.0%
Sumatra South	RE share [%]	23.0%	39.6%
	Coal share [%]	60.4%	42.3%
	Gas share [%]	16.6%	18.1%
Lampung	RE share [%]	75.9%	74.8%
	Coal share [%]	15.2%	8.8%
	Gas share [%]	9%	16%
Aceh	RE share [%]	62.5%	80.8%
	Coal share [%]	24.5%	9.3%
	Gas share [%]	13.0%	9.9%

A-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 GT 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 9 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 9: Financial assumptions on technologies available for investment in the model in 2020. Main source: (NEC 2017)

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 Sumatra 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.

A-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 47).
The coal price in Riau from 2017 statistics is 620 IDR/kg, 16% higher than East Kalimantan (for which HBA index is defined), while the gas price is 112,362 IDR/MMSCF.

The prices for bioenergy have been calculated based on the PPA prices achieved by biogas and biomass (Jonan 2018) presented in Table 10. Starting from the expected capital costs and technical characteristics of technologies based on Table 9 and the average achieved tariff for the two technologies, the fuel price has been estimated. The resultant values are a price of around 4 $/GJ for solid palm oil residues and 2 $/GJ of POME.

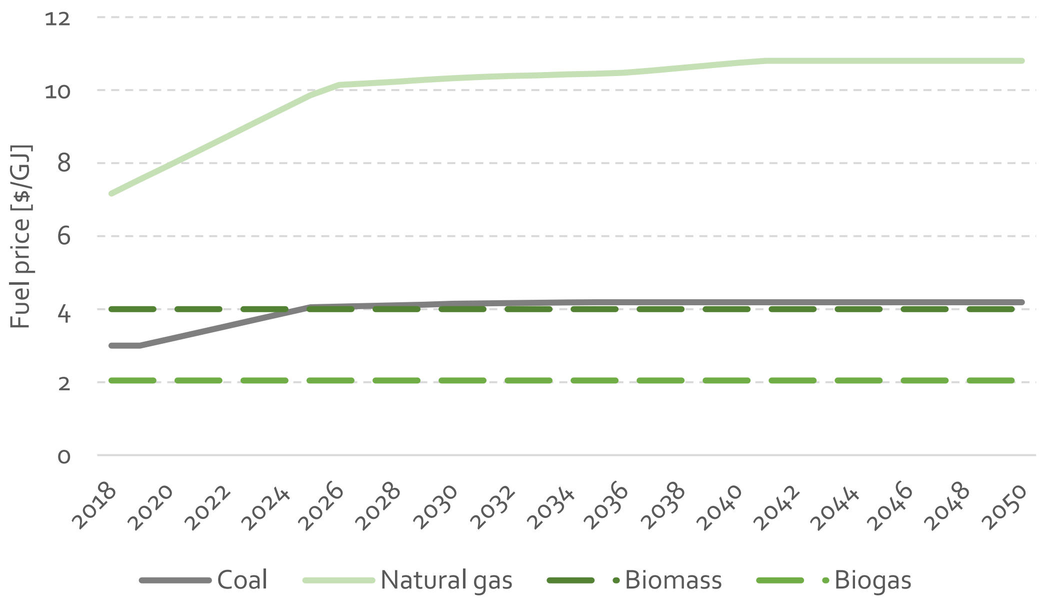

Figure 47: Fuel price assumptions and projections for Riau.

Table 10: Tariffs for biogas and biomass projects for PPAs signed in 2018-19.

Projects	Location	Capacity (MW)	Price (IDR/kWh)
Biogas			
PLTBg Mitra Puding Mas (Excess Power)	Sumatera Selatan	2	889
PLTBg Pagar Merbau	North Sumatra	1	1,050
PLTBg Kwala Sawit	North Sumatra	1	1,050
PLTBg Aceh Tamiang (Geso)	Aceh	3	1,176
PLTBg Ujung Batu	Riau	3	1,147
Biomass			
PLTBm Tempilang	Bangka Belitung	6	1,544
PLTBm Aceh Tamiang / Langsa	Aceh	10	1,176
PLTBm Mersam	Jambi	3	889
PLTBm Sentosa Jaya Purnama	Bangka Belitung Islands	10	1,544
PLTBm Siantan	West Kalimantan	10	1,495

A-VI. INTERCONNECTORS

Interconnectors until 2030 are included in the model as input and not optimized, due to difficult planning processes and long planning horizons. From 2020, connections expansions are planned all across Sumatra, 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).

	Riau	Riau	Riau	Aceh	Bengkulu	Jambi	Jambi	Lampung	West	West
	Jambi	North	West	North	South	South	West	South	Bengkulu	North
2018	0	400	700	700	700	1800	1500	1100	0	1500
2019	3000	400	700	1100	700	1800	1500	1100	0	1500
2020	3000	400	1450	2600	700	1800	1500	1100	200	1500
2021	3000	400	2,200	2600	700	1800	1650	1850	400	1800
2022	3000	1900	2,200	2600	700	3300	1800	2600	400	1800
2023	3000	3400	2,200	2600	700	4800	1800	2600	400	1800
2024	3000	3400	2,200	2600	700	4800	1800	2600	400	1800
2025	3000	3400	2,200	2600	700	4800	1800	2600	400	1800
2026	3000	3400	2,200	2600	700	4800	1800	2600	400	1800
2027	3000	3400	2,200	2600	700	6800	1800	2600	400	1800
2028	3000	3400	2,200	2600	700	8800	1800	2600	400	1800
2029	3000	3400	2,200	2600	700	8800	1800	2600	400	1800
2030	3000	3400	2,200	2600	700	8800	1800	2600	400	1800
> 2030	3000	3400	2,200	2600	700	8800	1500	1100	0	1500

Figure 48: Transmission capacity expansion in Sumatra. 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 11.

Table 11: Investments costs for additional transmission lines between provinces after 2030 (Million IDR/MW)

North	**Aceh**	15,704
North	**West**	12,215
Riau	**West**	6,980
Riau	**North**	27,919
Riau	**Jambi**	9,074
Jambi	**Bengkulu**	5,584
South	**Bengkulu**	3,490
South	**Jambi**	6,631
South	**Lampung**	8,027
West	**Bengkulu**	12,912
West	**Jambi**	12,215
Lampung	**Bengkulu**	8,725

A-VII. VRES RESOURCES

Wind power resource

In order to assess the resource quality of wind power, as well as the hourly wind speed profiles, the platform *Wind Prospecting is used.* It is an open-source meso-scale model of wind developed by EMD International for the ESP3 program (EMD International 2017). Unfortunately, the wind resource in Riau and more generally in Sumatra is very low and is hardly exploitable for economically-feasible projects, even with Class III turbines more suitable to low wind conditions. Indeed, the wind speed is consistently below 4 m/s.

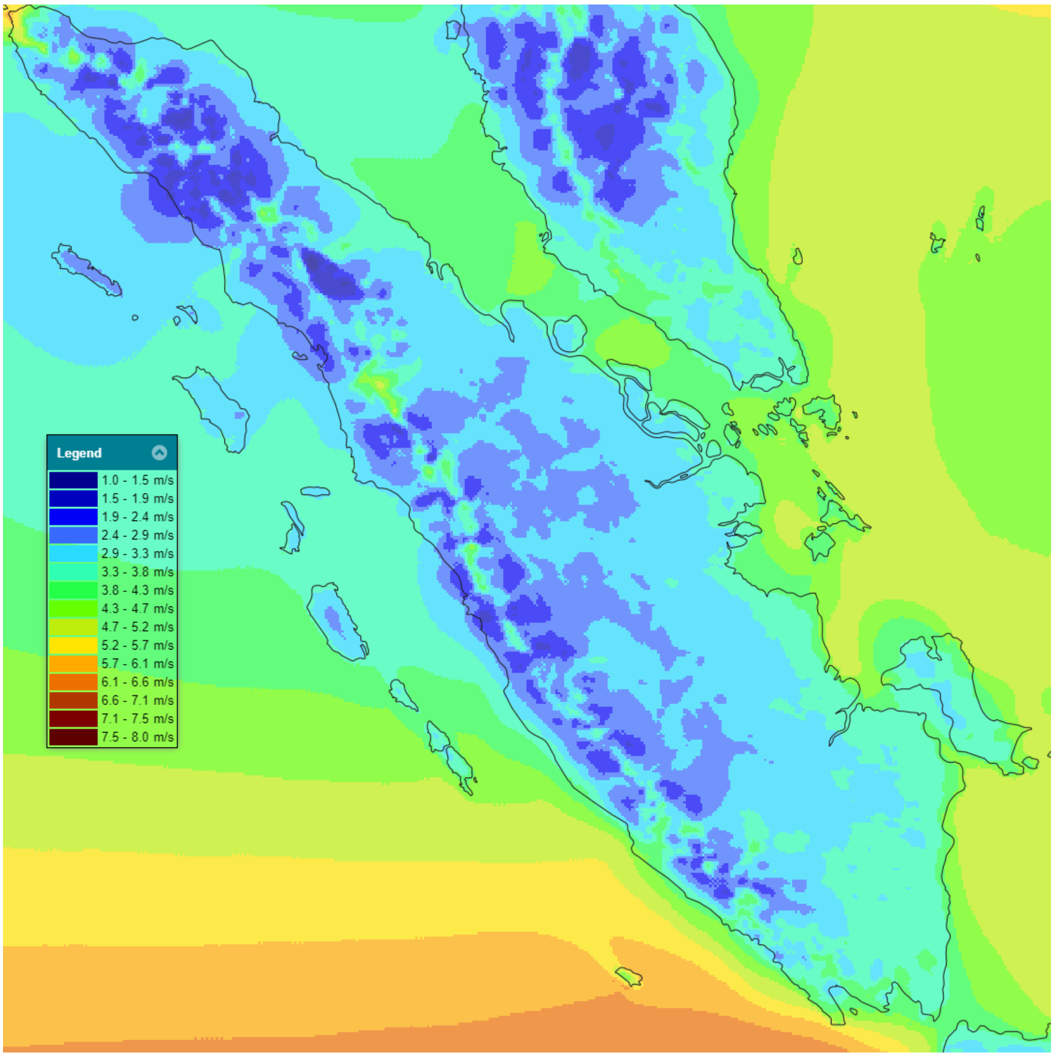

Figure 49: Wind speed at 50m, overview for Sumatra. Source: (EMD International 2017)

Solar power resource

To represent the diversity of solar resources, 60 locations distributed around the island have been selected (25 in Riau and 35 in the rest of Sumatra – see Figure 50) 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 Riau has then been distributed accordingly, resulting in the following: High solar area with 1,345 FLH (90 MW), medium-high area with 1,311 FLH (120 MW), medium-low area with 1,281 FLH (271 MW) and low solar area with 1,256 FLH (271 MW).

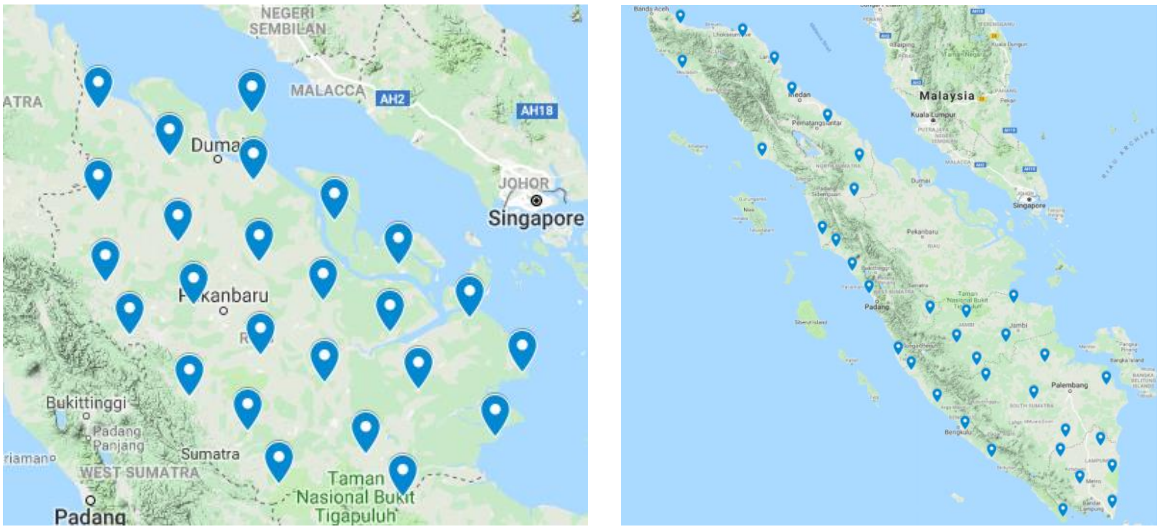

Figure 50: Locations used to estimate solar resource and total potential in Riau and Sumatra.

The hourly solar irradiation is quite constant throughout the year with, 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 51.

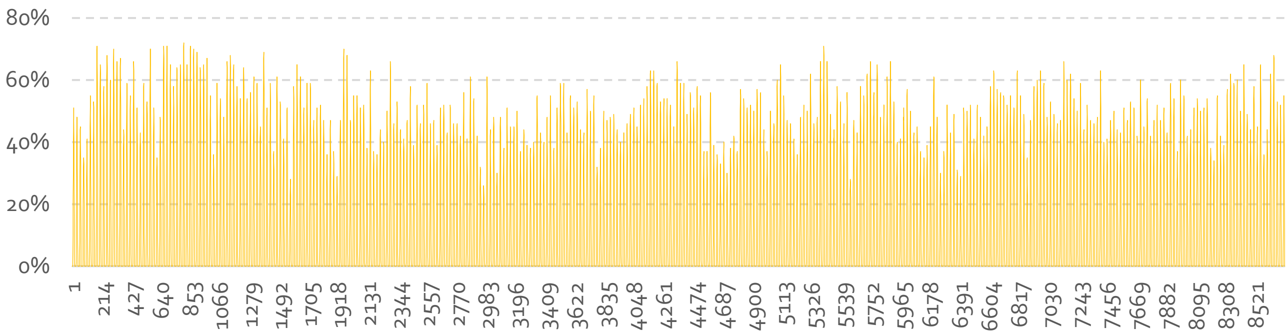

Figure 51: Solar variation profile considered in the model for Riau

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 12.

Table 12: Allowed expansion rate (MW/year) for solar power

Aceh	313
Bengkulu	125
Jambi	250
Lampung	500
North	1,125
Riau	500
South	563
West	375