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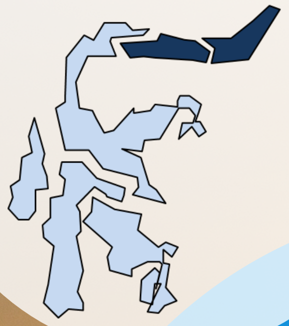

North Sulawesi and Gorontalo Regional Energy Outlook

November 2019

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Disclaimer
The present report was developed with the support of National Energy Council (NEC), PLN Sulutgo and Dinas ESDM Gorontalo and Sulawesi Utara. 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 **North Sulawesi and Gorontalo Regional Energy Outlook** explores the potential development of the power system in the medium (2030) and long (2050) term analysing least-cost scenarios to address the following key questions:

- How can North Sulawesi and Gorontalo ensure an affordable, resilient and environmentally friendly development of the power system?
- Are there alternatives to coal expansion? Which role can renewables play in displacing fossil fuels?

The two provinces of North Sulawesi and Gorontalo are part of the same power system, Sulutgo, and are characterized by a high average generation cost (1,918 Rp/kWh, compared to an average of 1,119 Rp/kWh for Indonesia). Power demand for 2018 registered by RUPTL is 2,180 GWh for the Sulutgo system, this demand is expected to rise to 5,300 GWh, **2.5 times today's demand.**

The plan in RUTPL is to meet this increased demand towards 2028 by relying heavily on coal expansions, with natural gas and hydro generation playing a supporting role. In the long term, the regional plan, RUED, sets targets for the use of RE, gas and coal in the two provinces up to 2050. The ambitions of the two provinces are different**: North Sulawesi expects a higher RE deployment** (46% in 2025, 49% in 2050) while **Gorontalo falls short** of the overall national target of 41% RE in 2050 (expecting 15.5% in 2025 and 35% in 2050).

North Sulawesi and Gorontalo have a large and diverse potential for renewable power. While North Sulawesi has an extensive potential for reservoir hydro as well as local geothermal, Gorontalo has good solar resources on top of a limited run-of-river hydro potential. Both provinces have modest, but exploitable wind resources.

The report presents three *"what-if"* scenarios towards 2030 which are used to provide insights on the potential impacts and dynamics of the energy system's evolution under particular conditions. A **Business-as-Usual** (BaU) scenario serves as a reference and is based on official plans from RUPTL 2019. Two least-cost alternatives supplement the BaU: The **Current Conditions** (CC) scenario is based on reference assumptions and the **Green Transition** (GT) scenario 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 the consideration of pollution cost into the planning process.

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

The Sulutgo power system can embark on a green pathway with a high RE share, by exploring the diverse opportunities available to both provinces in terms of RE potential. Least cost scenarios suggest that cost-efficient capacity buildout brings about high shares of RE generation. Under standard conditions, RE can supply up to 59% of the demand. When assuming financing favouring RE and internalizing pollution cost, **85% of the generation becomes based on RE in 2030**. North Sulawesi can take advantage of its large hydro potential, which can provide base-load generation and flexibility, thereby assisting with integration of variable RE generation. Additional baseload can be provided by tapping the substantial geothermal potential.

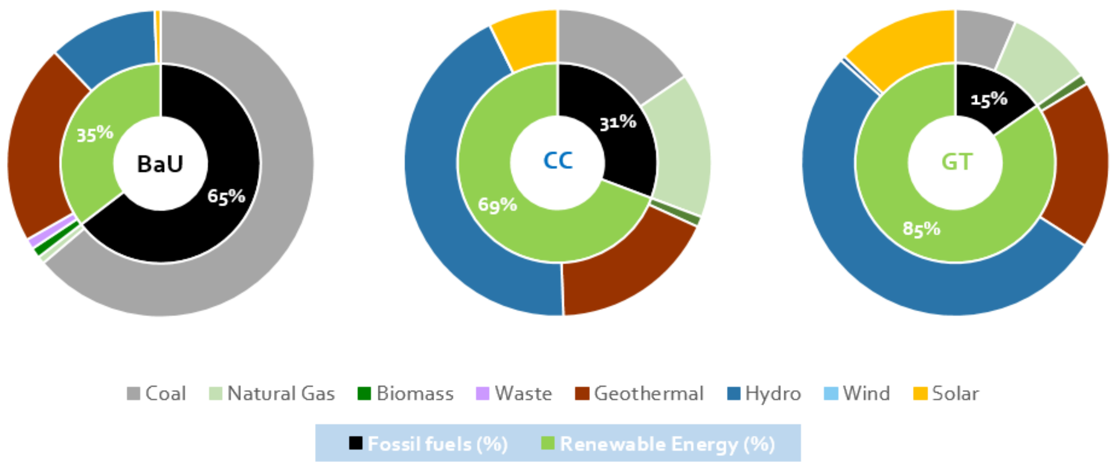

Figure: Generation share in the three scenarios shows that Sulutgo system can achieve a very high RE penetration.

North Sulawesi and particularly Gorontalo can benefit from the declining cost of solar generation, allowing the provinces to exploit their good solar irradiation. In recent years, cost of solar power plants has been decreasing rapidly and this trend is expected to continue in the years ahead. By 2030, solar PV levelized cost of electricity is expected to drop below that of coal plants, making solar an attractive investment for cost-efficient as well as climate-friendly and local electricity generation. Solar power can be a significant contributor to the power supply in 2030**:** Gorontalo can integrate up to 21% of solar generation, while North Sulawesi has solar irradiation sufficient to reach 11% solar penetration.

Planning restrictions or lack of suitable sites could limit the reservoir hydro buildout in North Sulawesi. In case, the reservoir hydro buildout is restricted, wind power can complement additional natural gas buildout and the Sulutgo system can reach **wind penetration levels of up to 6%.**

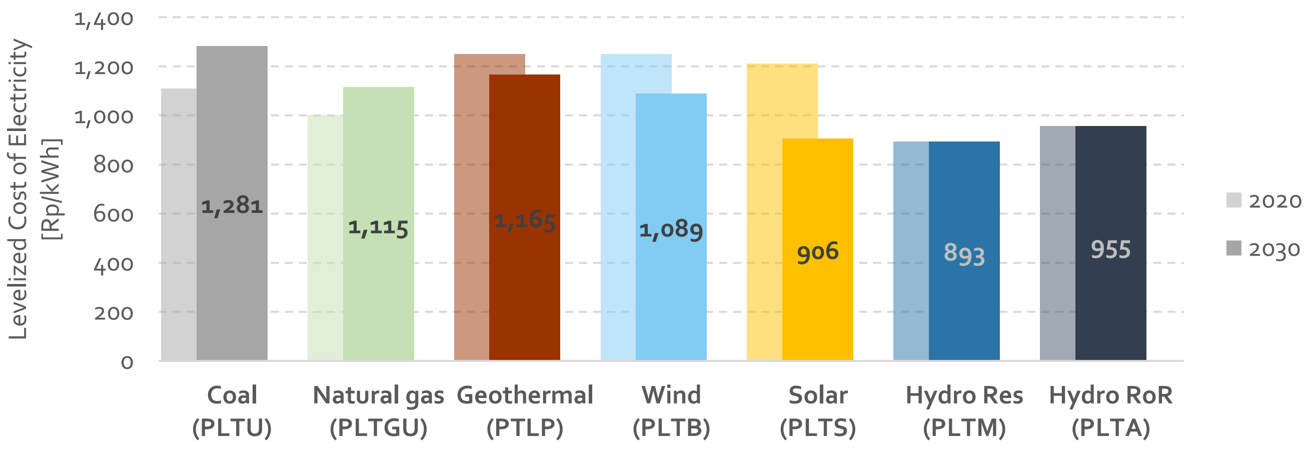

Figure: LCoE comparison for relevant power sources in Sulutgo in 2030 and comparison to 2020.

Coal generators risk stranded assets. Since geothermal, hydro, wind and solar have low short-term marginal costs, increased RE penetration might reduce dispatch from coal power plants. Additional investments in coal capacity therefore risk being under-utilized and might thus turn out excessively expensive. This risk is especially high for coal power as 40% of its generation costs are CAPEX. While also natural gas turbines risk low utilization, the financial risk of large sunk investment cost is lower, as the CAPEX share of total cost for gas turbines averages just around 23%. Coal replacement by natural gas is therefore seen in the cost-optimised scenarios.

In Sulutgo, a power system with 85% RE can be achieved while cumulatively saving ~12.6 trillion IDR by 2030 relative to BaU (~17.4 trillion IDR when considering pollution-related health costs). The Green Transition and the Current Conditions scenarios have very similar average generation costs (1,044 and 1,017 Rp/kWh respectively – pollution cost not included). The Green Transition scenario reduces the CO_2 emissions with 50% compared to the Current Conditions scenario at a minor additional cost of 27 IDR/kWh. Furthermore, health-related savings of about 1.2 trillion IDR can be achieved in the 10 years period if health damage costs resulting from pollution are considered in the GT scenario.

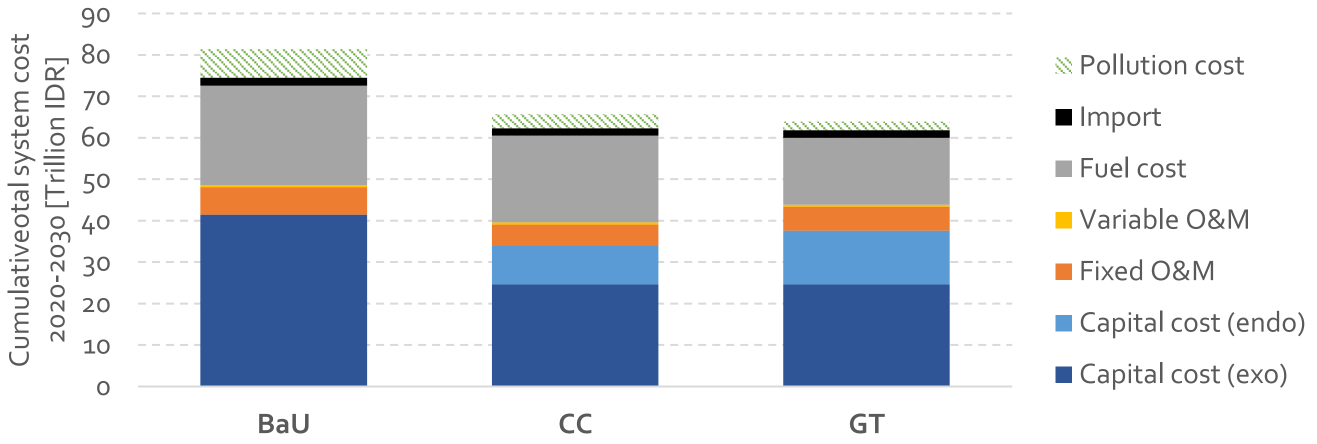

Figure: Cumulative total system costs in the three 2030 scenarios for the period 2020-2030.

When comparing the Least Cost scenario to RUED in the 2050 timeframe, **large potential savings can be made by steering away from a largely fossil-based generation fleet** to a diversified RE generation mix consisting of large solar capacity, some wind capacity and both geothermal and hydro capacity. A 19% cost reduction can be achieved compared to the RUED scenario while at the same time decreasing emissions by 76%. The resulting power mix overshoots the RUED RE targets for both provinces with a combined **83% RE generation**, suggesting the RUED target could be revised upwards.

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

- *Conduct a study of North Sulawesi's reservoir hydro and geothermal potential and prioritize sites. A clear overview of the province's best potential for hydro and geothermal projects based on feasibility studies and environmental assessments will allow for realistic planning;*
- *Look beyond hydro and geothermal power: Start considering solar PV as a potential source of cheap power from the mid-2020s, especially under good financing conditions (otherwise from 2030). Wind can also contribute in case of lack of sites or in case planning restriction limits the amount of hydro and geothermal;*
- *Examine the solar potential of the provinces by conducting a detailed mapping of resources and space availability (both rooftop and stand-alone PV). The identification of suitable sites, preparation of pre-feasibility studies and increasing the solar ambition in the policy and planning document can help attract investments;*
- *Map and monitor loan and financing options and develop a strategy to attract international finance. In order to attract capital, a commitment to a RE project pipeline, an increase in the RE ambition of North Sulawesi and Gorontalo provinces and an improved communication of these targets can be enabling factors;*
- *Carefully reassess the case for additional coal power plants to avoid technology lock-in and under-utilized. There is apparent risk of stranded assets and increased electricity tariffs for the Sulutgo system.*

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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
DEA	Danish Energy Agency
Dinas ESDM	Dinas Energi Sumber Daya dan Mineral
DMO	Domestic Market Obligation
EBT	Energi Baru Terbarukan (New and Renewable Energy)
EVA	Economic Evaluation of Air pollution
FLH	Full Load Hours
GDP	Gross Domestic Product
GHG	Green House Gas
GHI	Global Horizontal Irradiation
GO	Gorontalo
GT	Green Transition scenario
HSD	High Speed Diesel
IDR	Indonesian Rupiah (=Rp)
IPP	Independent Power Producer
KEN	Kebijakan Energi Nasional
LCoE	Levelized Cost of Electricity
LEAP	Long-range Energy Alternatives Planning
LNG	Liquified Natural Gas
MEMR	Ministry of Energy and Mineral Resources, Indonesia
MIP	Mixed-Integer Problem
MFO	Marine Fuel Oil
MPP	Mobile Power Plant
NEC	National Energy Council, Indonesia
NDC	Nationally Determined Contribution
NS	North Sulawesi
OPEX	Operational cost
PLN	Regional Power Company
PPA	Power Purchase Agreement
PPP	Purchasing Power Parity
PV	Photovoltaics
RE	Renewable Energy

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

Power plant and fuel definition

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

1. Introduction

1.1 BACKGROUND AND OBJECTIVE

This report is part of a larger project aiming at supporting the four provinces of, North Sulawesi and Gorontalo, Riau Province and South Kalimantan 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, mapping of RE resources in the province, scenario analyses of pathways for optimizing the energy mix using a least cost approach and providing strategic policy recommendations.

The two provinces of North Sulawesi (NS) and Gorontalo (GO), which are the focus of this report, are part of the same power system, Sulutgo, and are characterized by a high average generation cost (1,918 Rp/kWh, compared to an average of 1,119 for Indonesia as a whole). The high average generation cost of Sulutgo is driven by a large use of diesel. The extensive potential for RE in the NS and GO provinces and the regulation framework which is beneficial for areas with higher generation cost are two enabling factors for a larger deployment of RE in the short-to-medium term. In the long term, the regional plan, RUED, sets targets for 2050 for the use of RE, gas and coal in the two provinces. The ambitions of the two provinces is influenced by their different potentials: North Sulawesi expects a higher RE deployment (46% in 2025 and 49% in 2050) than the overall national target of 41% RE in 2050 while Gorontalo falls short expecting 15.5% in 2025 and 35% in 2050. In both provinces, the projections underestimate the cost-competitive potential for RE and downplays the role of the power sector in contributing to the national RE target in RUED. With this starting point, the objective of the study here presented is twofold:

- Assess power system planning in North Sulawesi and Gorontalo provinces in the medium term (2030) and evaluate alternative development paths potentially including more RE generation;
- Analyse the RUED plan for the Sulutgo and evaluate least-cost alternatives to provide affordable, resilient and environmentally friendly development up to 2050.

1.2 GENERAL INFORMATION ON NORTH SULAWESI AND GORONTALO

Sulawesi, formerly known as Celebes, is one of the four Greater Sunda Islands of the Malay Archipelago. It is composed of six provinces, namely South, South-East, West, Central, and North Sulawesi plus Gorontalo. The population and economic activity are more concentrated in the Southern part of the island, with Makassar being the largest city.

The two provinces of Gorontalo and North Sulawesi are located in the northern arm of Sulawesi Island, also known as the Minahasa Peninsula, dividing the Celebes Sea from the Molucca Sea and the Gulf of Tomini. Being located near the equator, the area has a fairly hot and constant air temperature, on average between 20 and 30 °C in both provinces. Air humidity is relatively high (73-86%) and rains quite abundant in all seasons (200-300 mm per month). In the 2010 decennial census, the population of the two provinces stood at 2.27 and 1.12 million inhabitants for North Sulawesi and Gorontalo, respectively.

Figure 1. Map of North Sulawesi and Gorontalo. Source: (Bing Map).

1.3 POWER SYSTEM OVERVIEW: SULUTGO

Gorontalo and North Sulawesi share a joint regional power system, **Sulutgo** (Figure 2). As of 2019, it is not interconnected to the rest of the Sulawesi, even though a power interconnection to Central Sulawesi via Tolitoli is in the pipeline. The power demand in North Sulawesi settled around 1.6 TWh in 2018, around three times larger than the one in Gorontalo, equal to 0.5 TWh (PT PLN Persero 2019). The largest load center in the area is in Manado, followed by Gorontalo and consequently the southern part of North Sulawesi, Kotamobagu. The island archipelago of Sangihe, north of Manado, is also part of the system, even though it is not connected to mainland, and is fueled entirely by diesel engines. A plan to switch to gas engines is in the pipeline, based on the latest PLN plan.

The electrification rate is relatively high compared to other parts of the country, with Gorontalo (91.83% electrified as of May 2019) on the way to reach the level of North Sulawesi (98.76%).

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 linked to the value of the average generation cost of the system[1].

In the Sulutgo system, the 2018 BPP was **1,918 Rp/kWh** (7.86 c$/kWh), which is among the highest registered if excluding small remote and non-interconnected systems. It is almost double the national BPP which settled at 1,119 Rp/kWh (13.46 c$/kWh) in 2018. The main reason for the high cost of generation in the Sulutgo system is the large dependency on diesel, which covers around 40% of the generation in NS and 60% in GO in 2018.

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

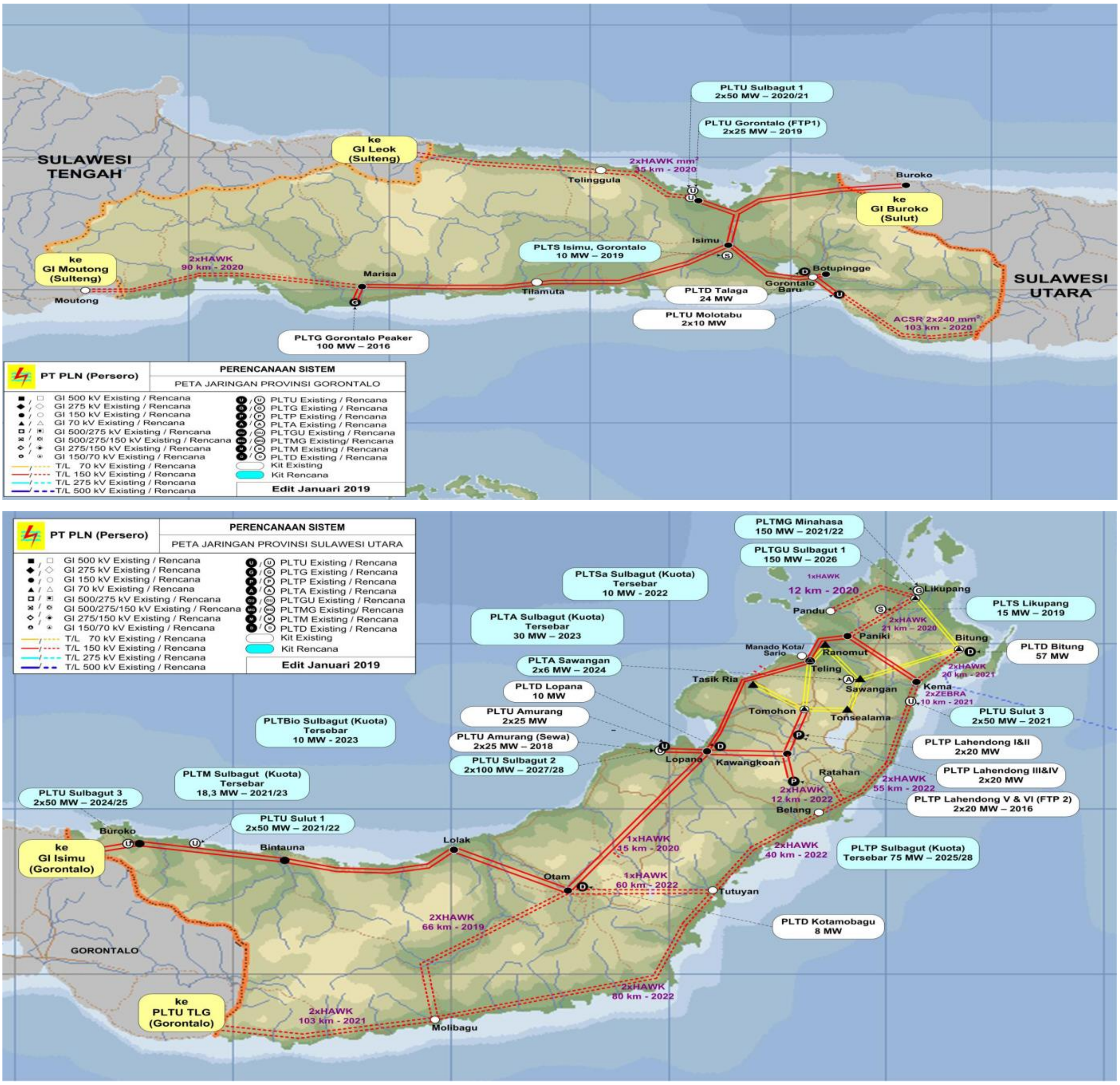


Figure 2: Overview of PLN Sulutgo system, including existing and planned generator. Source: (PT PLN Persero 2019)

Power demand

RUPTL (PT PLN Persero 2019) reports a power demand in 2018 equal to 1,677 GWh for North Sulawesi and 503 GWh for Gorontalo, with the former expected to grow at a higher rate throughout 2028. The expectation for the Sulutgo system in 2028 is of more than 5,300 GWh corresponding to approximately 2.5 times the demand today.

Looking at power daily load profiles (Figure 3 left), the peak load in North Sulawesi is around 3 times higher than in Gorontalo and the load ramp at night is larger. For both areas, the peak is around 19 at night.

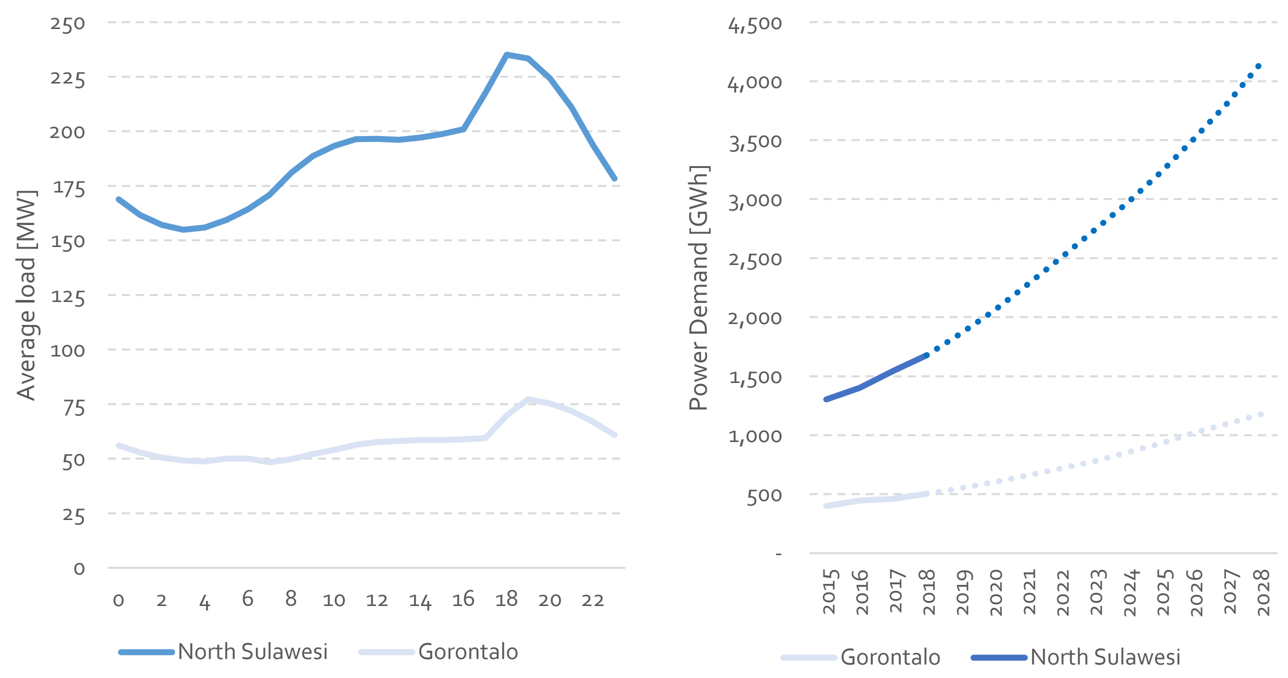


Figure 3: Load profile for 2017 and total demand including projection to 2028 [1].

Current fleet and generation overview

The total installed capacity in the Sulutgo system stands at 591 MW. The largest capacity by fuel is based on diesel (HSD) with 147 MW installed in North Sulawesi and 111 MW in Gorontalo[2]. Coal follows with 121 MW of installed capacity, with the largest PLTU unit located in Amurang (4x25 MW).

As for RE, a large geothermal power plant consisting of 6 units of 20 MW each, a total of 120 MW is located in Lahendong, North Sulawesi, and additional 56 MW of hydro, both small (PLTM) and large (PLTA) are installed in the same province. In addition to the 2.3 MW existing solar power plants (PLTS), two larger units are negotiating a PPA and are close to being grid-connected in Likupang (15 MW, NS) and Isimu (10 MW, GO). The tariff for these new solar power plants has been lower than the regional BPP, settling at 1,424 and 1,481 Rp/kWh, respectively (Jonan 2018).

Due to power shortage in North Sulawesi, a 120 MW marine vessel powerplant (MVPP) has since 2016 been rented by PLN and stationed in Amurang. The plant, currently fuelled by heavy fuel oil, has the option to switch to gas, in case supply is present. A PPA has been signed guaranteeing a utilization corresponding to 75-80% capacity factor, locking the agreement until 2020.

Figure 4: 120 MW mobile power plant currently stationed in Amurang.

Source: (Karpowership)

[2] 96 MW of the 111 MW installed in Gorontalo are from a PLTG unit (Gorontalo Peaker) currently running on HSD. The plan of PLN is to switch the fuel to natural gas when the supply of this source will be available in the province.

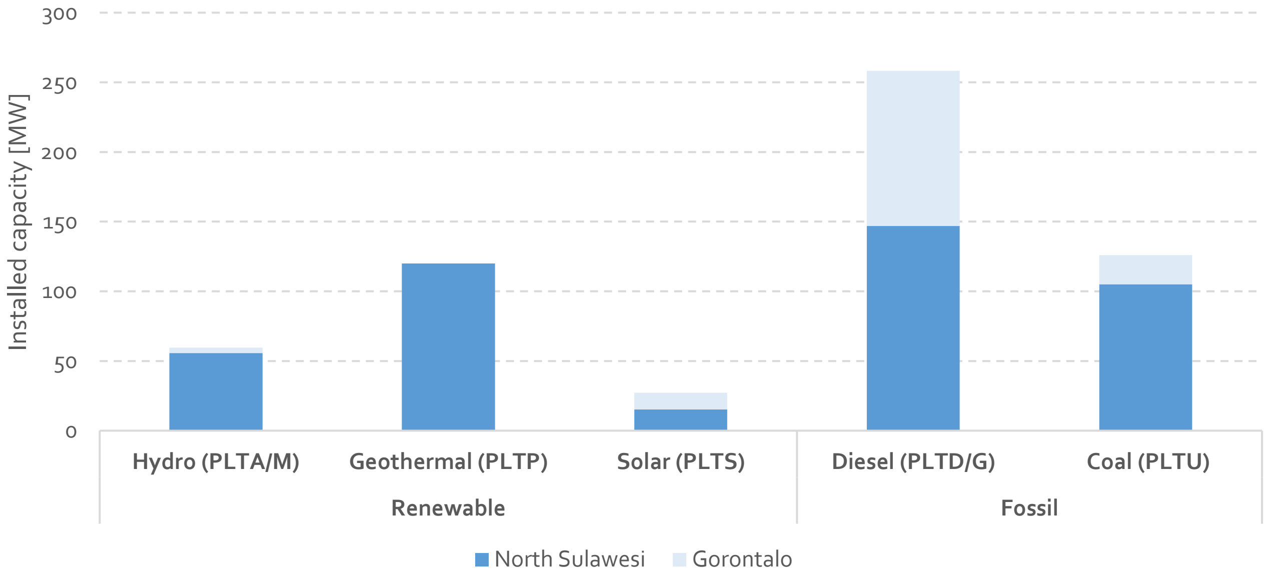


Figure 5: Installed capacity in Gorontalo and North Sulawesi, by fuel type.

The yearly generation in Gorontalo and North Sulawesi the last three years according to data from the local PLN (PLN Sulutgo 2019) is displayed in Figure 6. Looking at the values in GWh most of the generation takes place in North Sulawesi, which is dominated by diesel (40-56% in average across the three years). However, around 40% of the final supply is based on RE, with the largest contribution from geothermal. In Gorontalo, around 90% of the supply is based on diesel and coal and the rest from hydro, with a small contribution from solar PV.

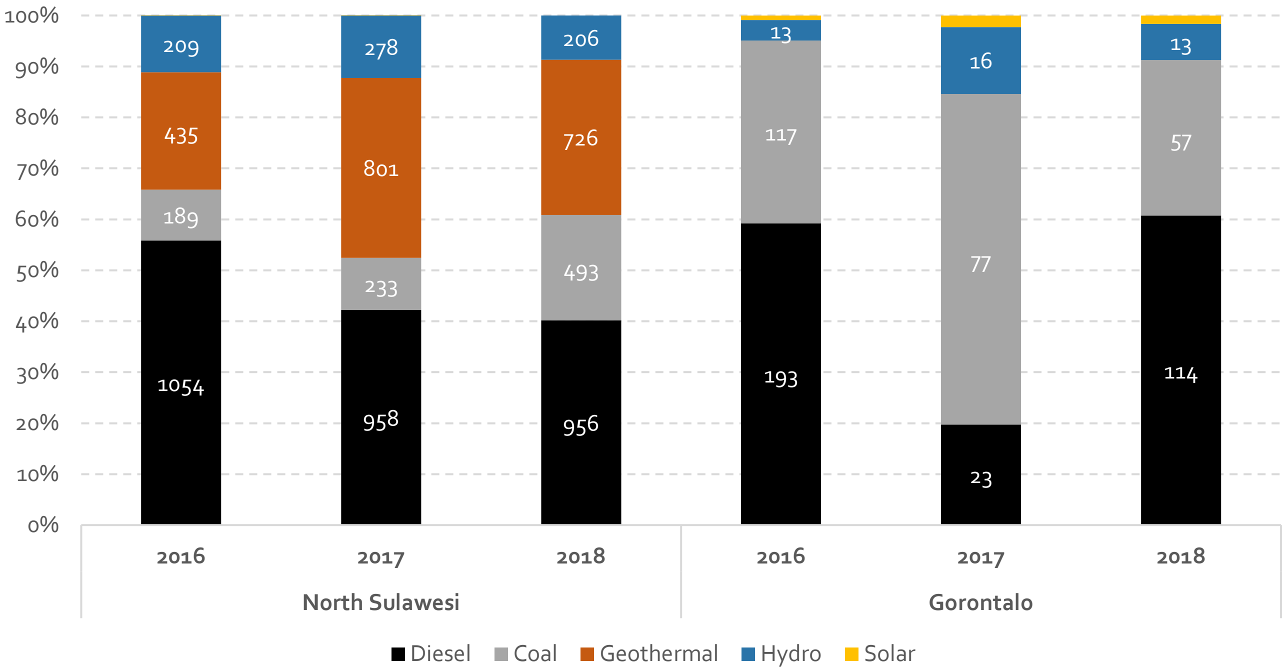


Figure 6: Generation share (%) by fuel type of total yearly generation for NS and GO. Labels indicate the value in GWh.

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, and planned expansion of the transmission network and the generation capacity.

The expectations for the expansion of generators in North Sulawesi (Figure 7)[3] include 200 MW coal in 2021 (Sulut 3 and Sulut 1), 150 MW natural gas engines in Minahasa in 2021, and a long term plan for a combined cycle in 2026 (Sulbagut 1) and further 300 MW coal between 2024 and 2028 (Sulbagut 3, Sulbagut 2). Beside this, a number of smaller scale RE plants are expected to come online, namely a biomass plant (10 MW), a municipal solid waste plant in Manado (10 MW), a hydro power plant with reservoir (30+12 MW), and a number of micro/mini hydro plants (totalling 33.4 MW).

As for Gorontalo, besides a 50 MW coal plant under construction (FTP1), additional 12 MW hydro and 100 MW coal (Sulbalgut 1) are planned for 2020/2021.

With the planned additions, the reserve margin in the system would increase significantly from the current 22% to 54% already in 2021, with the value being stable above 39% throughout 2028. The additional capacity should be enough to slowly phase-out diesel and to guarantee the supply of the increasing demand, with the expected peak doubling from 500 MW (2019) to around 1,000 MW in 2028.

While the listed projects include RE, the expected development of the system is largely based on coal power and, to a lower extent, natural gas and only marginally on RE. This is in contrast with both the large potential for RE, especially in North Sulawesi, and the expectations contained in the regional plans (RUED), which envision a larger contribution from natural gas.

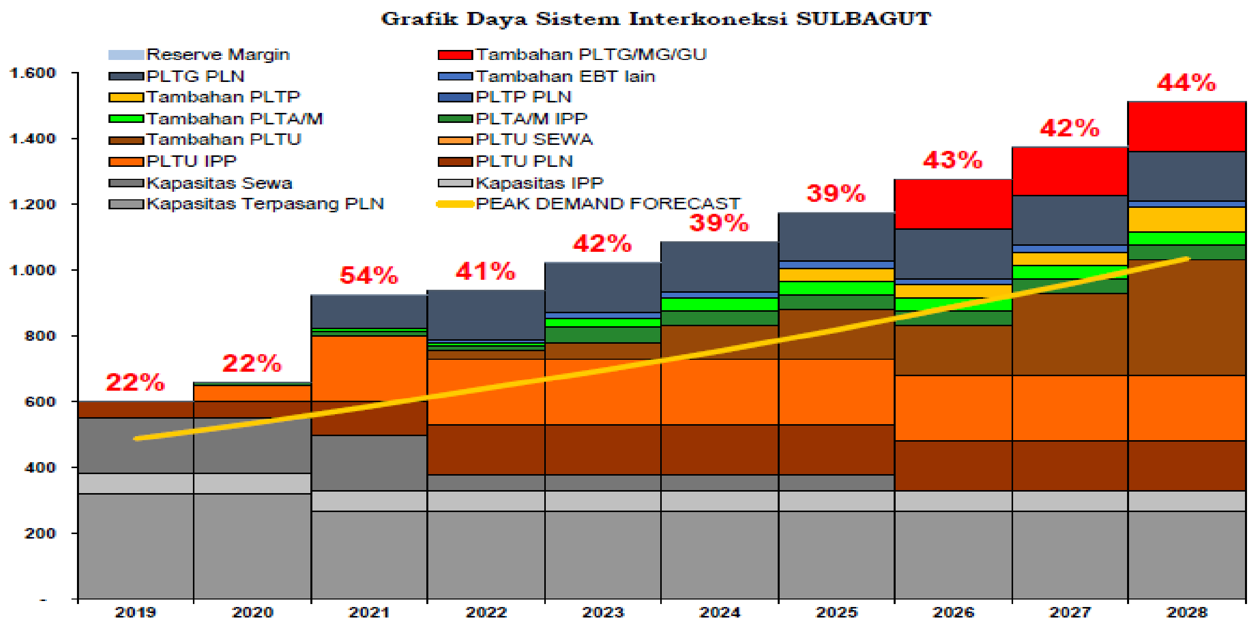


Figure 7: PLN plan for system development contained in RUPTL19 (PT PLN Persero 2019).

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

RUED: The regional planning document

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

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.

Table 1: RUED targets for the RE share of primary energy. Sources: (Dinas ESDM Gorontalo 2018; Dinas ESDM Sulawesi Utara 2018)

	Entire energy system		Power system	
	North Sulawesi	Gorontalo	North Sulawesi	Gorontalo
	[%]	*[%]*	*[%]*	*[%]*
2015	17.0	1.0	46.7	1.3
2025	33.2	16.7	46.2	15.5
2050	41.6	41.8	49.3	35.0

The overall targets for RE[5] contained in the latest draft version of RUEDs for the two provinces are indicated in Table 1. Both provinces aim at reaching a RE share in the entire energy system of around 41% in 2050, with Gorontalo a bit less ambitious in the 2025 timeframe (16.7% against 33.2%) due to a very low starting point in 2015.

The focus of this study is on the contribution from the power sector to the regional targets set in the RUED documents of North Sulawesi and Gorontalo. Indeed, the approach currently used to determine the evolution of the power system is not based on cost-optimization and does not consider the expected cost developments of new technologies, nor the power system dynamics. North Sulawesi expects the power sector to contribute relatively more than other sectors, with the RE share constantly above 46% until 2050. On the other hand, Gorontalo expects the power system to be less decarbonized than the overall energy system.

The expectations for capacity development in the power system are summarized in Figure 8 and original tables from RUED can be found in Appendix B (Dinas ESDM Gorontalo 2018; Dinas ESDM Sulawesi Utara 2018). As can be seen, the largest development in North Sulawesi is related to coal power plants, reaching almost 1.5 GW by 2050, while in Gorontalo it is expected that most of the demand increase will be covered by natural gas power plants (750 MW by 2050). The RE development is very substantial in North Sulawesi but mainly starting from 2030, reaching 1.5 GW of RE capacity by 2050. Gorontalo on the other hand, expects up to 400 MW RE in 2050.

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

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

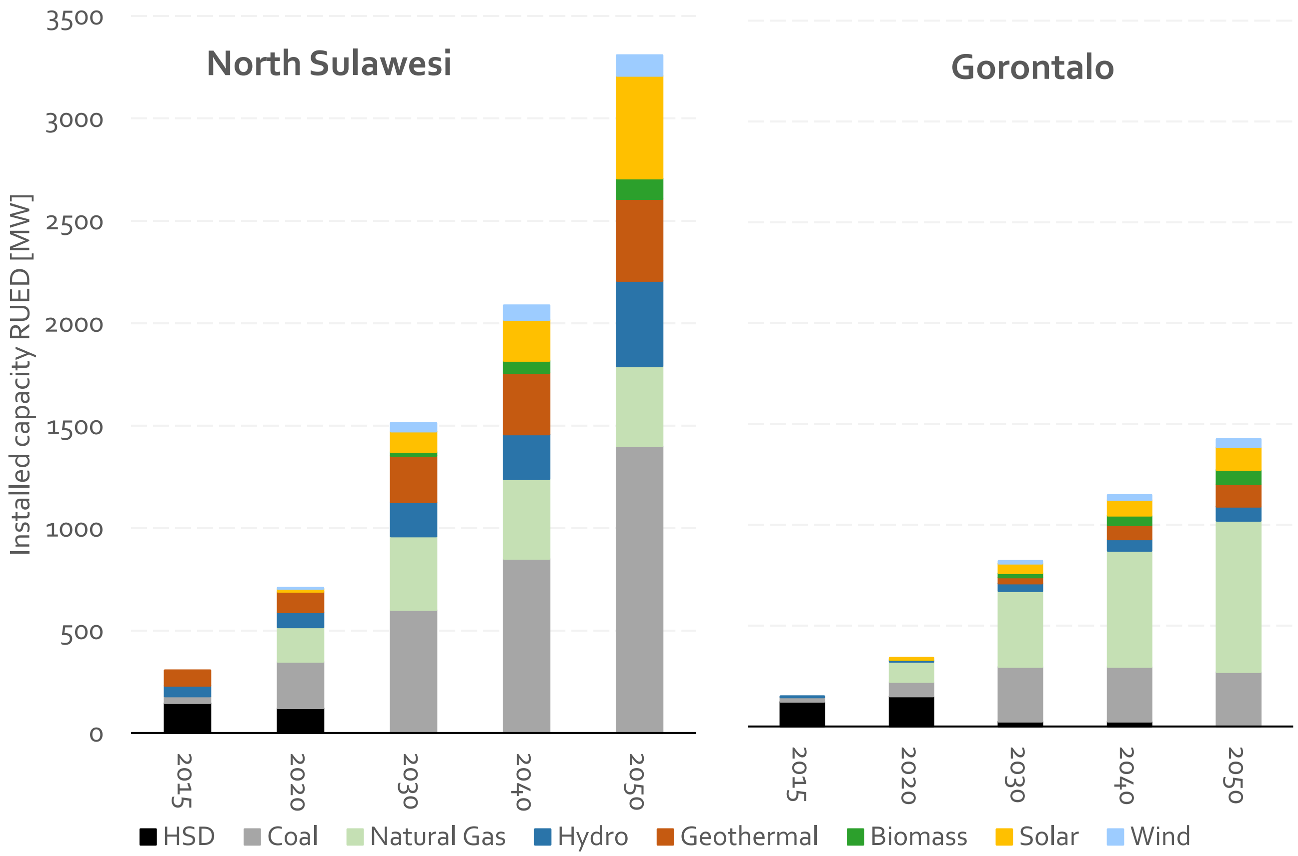
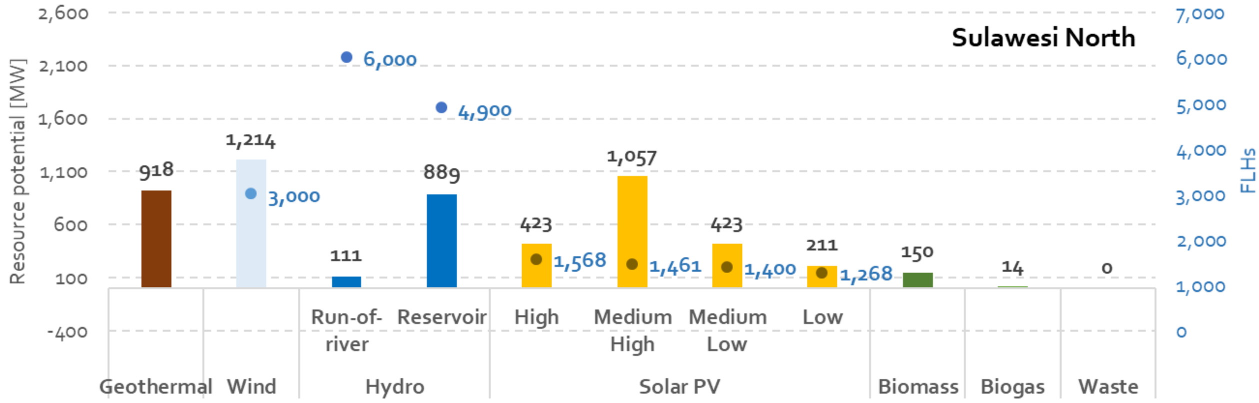


Figure 8: Expected capacity development in RUED in North Sulawesi and Gorontalo. Source: (Dinas ESDM Gorontalo 2018; Dinas ESDM Sulawesi Utara 2018)

RE potentials

The development in capacity expansion that is expected in RUED is closely related to the estimated potential for RE in the two provinces. 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 9 shows the assumed potentials for each of the two provinces[6] and the Full Load Hours (FLH) of generation[7].



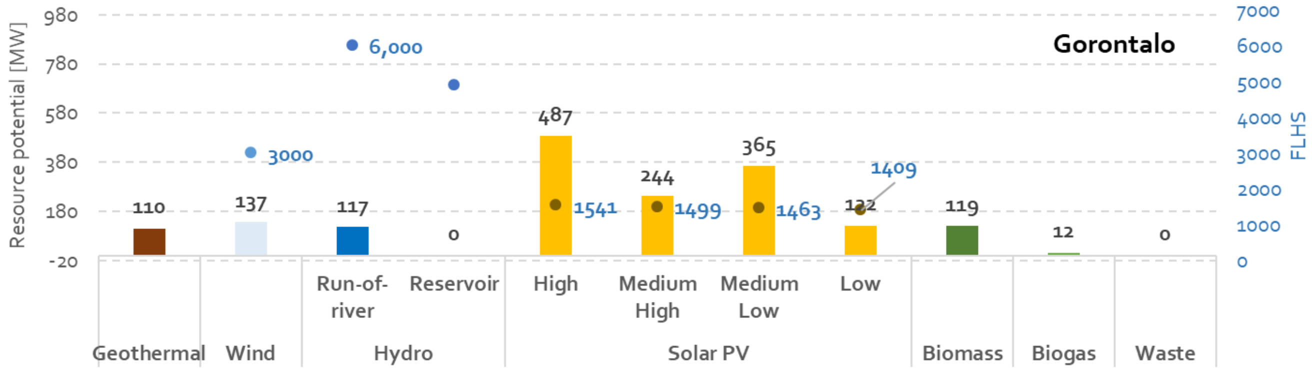


Figure 9: Estimated potentials and Full Load Hours for RE sources.

North Sulawesi has a very high and diversified potential for both dispatchable (geothermal, hydro) and variable (wind and solar) RE, while Gorontalo has a very high solar potential but lower potential for other RE. Solar power plants in this part of Indonesia can achieve very high FLH (1,270-1,570 h) due to the good level of irradiation, making them more profitable compared to other parts of Indonesia.

Figure 10: FLH in the area in kWh/kW based on (Global Solar Atlas 2019).

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

2. Scenario Framework and Approach

2.1 RESEARCH 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 Sulutgo power system in the medium term (2030)?
- What is the most competitive mix of RE plants that could help decarbonize the system and achieve the targets at lowest possible 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 two 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).

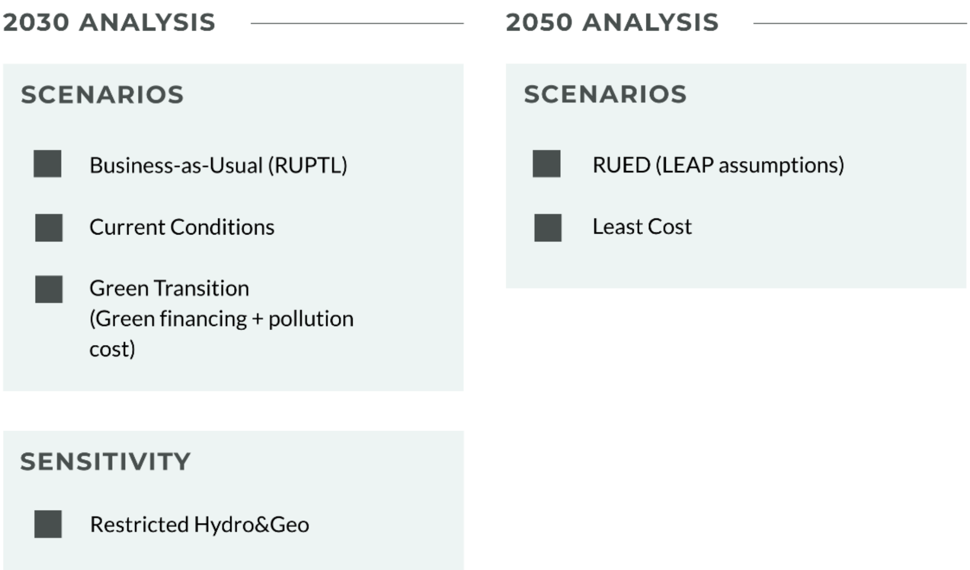


Figure 11: Two steps: 2030 analysis and 2050 analysis.

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 Sulawesi 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 Gorontalo and North Sulawesi 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 Sulawesi, disregarding the fuel mix targets in the RUED documents.

An overview of the scenarios can be found in Table 2.

Table 2: Overview of main scenarios and assumptions.

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

Sensitivity analyses

In addition to the main scenarios, two sensitivity analyses are performed to assess the impact of certain assumptions and parameters on the 2030 results. Specifically, in this analysis, the following sensitivities are assessed:

- **Restricted Hydro&Geo**: Given the challenge in planning and building large hydro and geothermal projects and the larger uncertainty regarding the resource quantity and quality, a sensitivity analysis is performed assuming **no additional hydro nor geothermal** can be built apart from the ones already planned in RUPTL19. This sensitivity scenario is simulated for both CC and GT conditions.

2.2 DRIVERS OF THE GREEN TRANSITION SCENARIO

The GT scenario represents a case in which conditions for RE development improves in two ways: Firstly, it is assumed that financing RE projects becomes easier than financing coal power plants, due to international climate commitments of countries and institutions worldwide. Furthermore, it is assumed that power system planning takes into account the cost of the local pollution caused by combustion of coal, natural gas and biomass.

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.

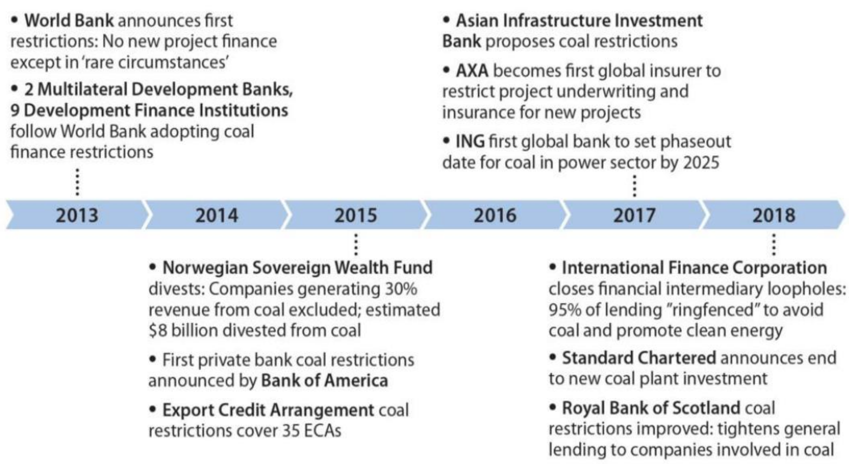


Figure 12: List of institutions announcing their restriction on coal financing. Source: (IEEFA 2019)

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 85% of the total lifetime cost of solar (with the remaining related to O&M costs), while it represents only 39% of the total lifetime cost of coal (around 50% is related to fuel cost).

Having access to cheap financing is a key for the success of capital-intensive technologies like 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 21%, while it reduces the LCoE of coal (PLTU) by only 13%. In 2020, with a cost of capital of 5%, wind generation becomes cheaper than coal.

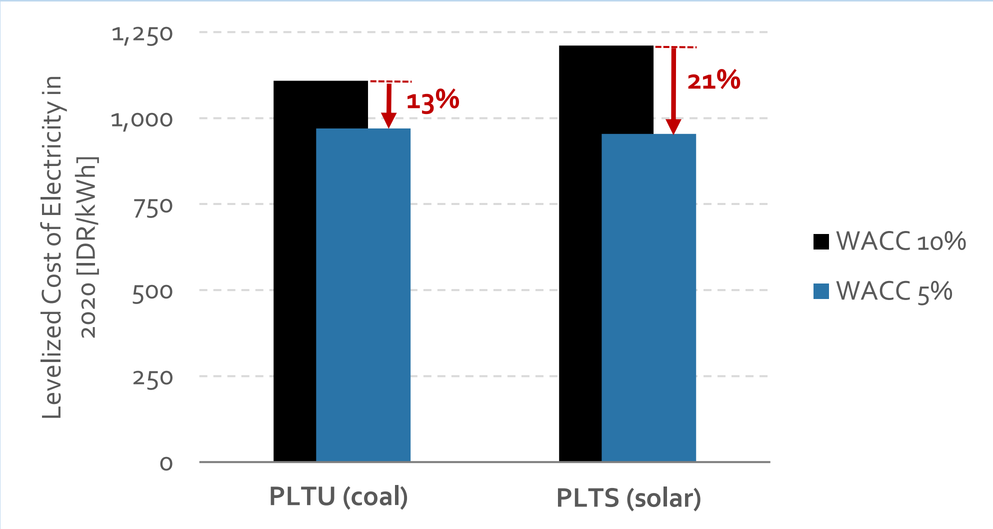


Figure 13: Effect of reduction of cost of capital (WACC) on coal and solar in 2020.

Cost of pollution

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

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

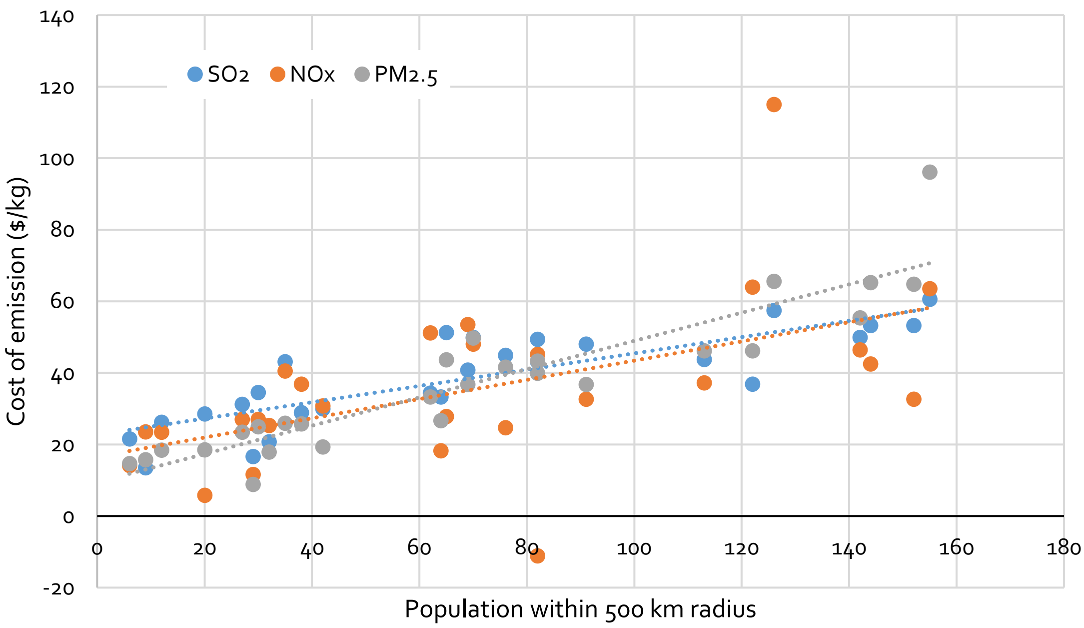


Figure 14: Correlation between the cost of pollution from SO_2, NO_x and PM2.5 from each of the 27 EU Member States and the population within a 500 km radius from the country's geographical centre.

An overview of the SO_2 costs in Indonesia for each province is shown in Figure 15. For North Sulawesi and Gorontalo, the figure used are 4.5 $/kg of SO_2, 3.4 $/kg of NO_x and 2.2 $/kg of PM2.5, based on the population density of North Sulawesi, Gorontalo and the surrounding region. These values are much lower compared to more populated islands such as Java and Sumatra.

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 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. More information on the model can be found in Appendix A.

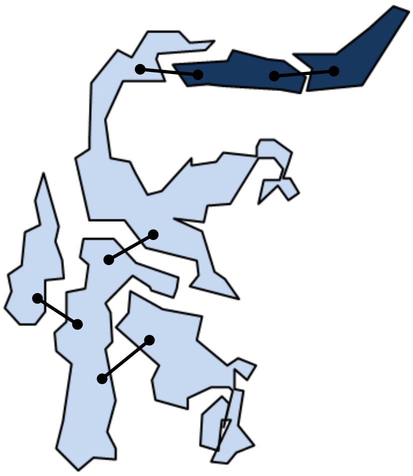


Figure 16: Balmorel representation of Sulawesi. Focus area highlighted.

For the analysis, a representation of the power system in Sulawesi has been developed based on public sources and on data from PLN and Dinas ESDM of both Gorontalo and North Sulawesi. The power system in Sulawesi is divided in the six provinces and contain a representation of the interconnection capacity between provinces. In all simulations, the entire system has been considered and optimised, even though most of the focus will be placed upon the provinces of Gorontalo and North Sulawesi.

The Sulutgo system, currently not connected to Central Sulawesi, will be connected within the next decade via power interconnectors. In all simulations, Sulawesi's seven provinces are simulated simultaneously to ensure a consistent representation of the two provinces under focus 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 THE ENTIRE SULAWESI ISLAND

Coal investments in Sulawesi are likely overestimated *in RUPTL and face the risk of becoming stranded assets. Cost-optimization shows that* ***reservoir hydro will play a crucial role*** *in the power expansion on the Sulawesi island. In additional,* ***small amounts of cost-competitive solar generation*** *appear in all provinces.*

In the BaU scenario, based on RUPTL capacity expansions, the Sulawesi power system will meet the rapidly increasing power demand by means of coal generation, hydro expansions and geothermal power from North Sulawesi. By 2030, roughly half of the power demand is met by coal and 40% by hydro (Figure 17).

A cost-optimised Sulawesi power system relies even heavier on the hydro potential on the island. In the CC scenario, where conservative financing is assumed, the share of hydro generation increases to 60%, decreasing Sulawesi's dependency on coal power. The introduction of modest amounts of natural gas generation further replaces coal.

When considering the costs of pollutants and the increasing concerns about climate and its impact on financing possibilities, coal generation is drastically reduced to a meagre 8% of total power generation while hydro and modest amounts of solar dominate the power mix in 2030. In the GT scenario, 90% of the generation is RE in 2030, compared to only 48% in the BaU scenario.

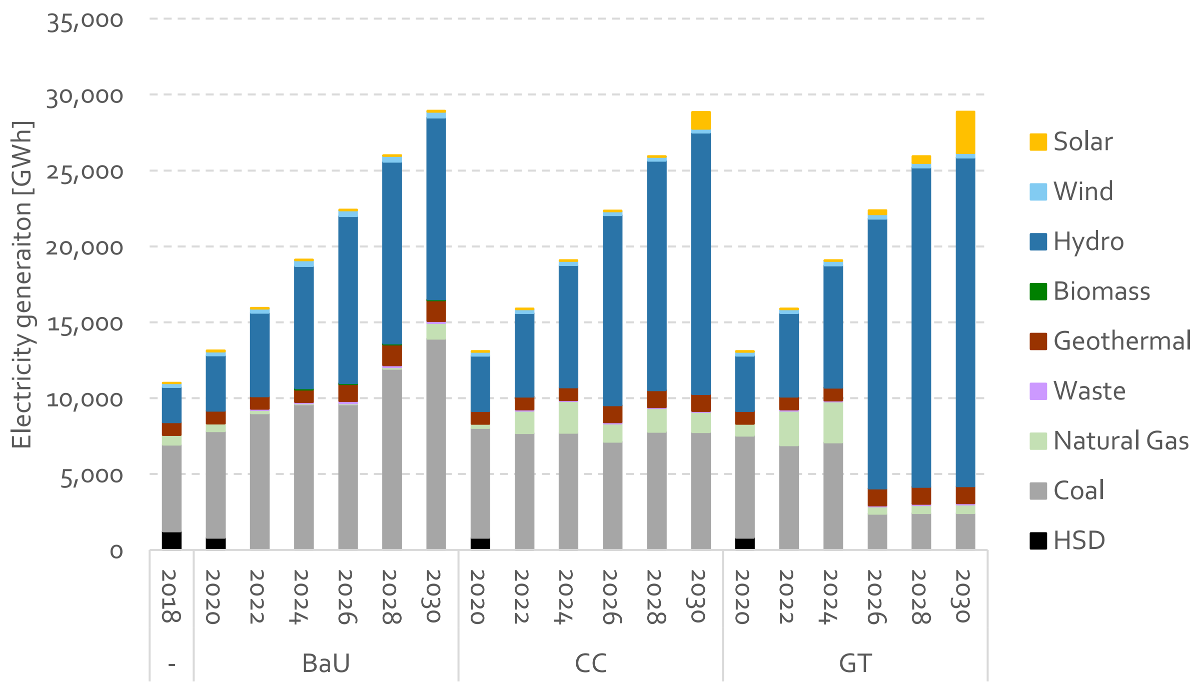


Figure 17: Power generation development in the entire Sulawesi island for the three main scenarios.

Figure 18 shows the share of generation for coal, natural gas or variable RE in 2030 for the BaU scenario and the GT scenario. North Sulawesi is the only province with geothermal potential. The South of Sulawesi relies on coal and hydro. Sulawesi South province sees some wind expansion. In all provinces, the RE share increases significantly in the GT scenario compared to the BaU scenario. North Sulawesi and Central Sulawesi have the highest share of RE generation; Gorontalo has the lowest due to limited hydro resources.

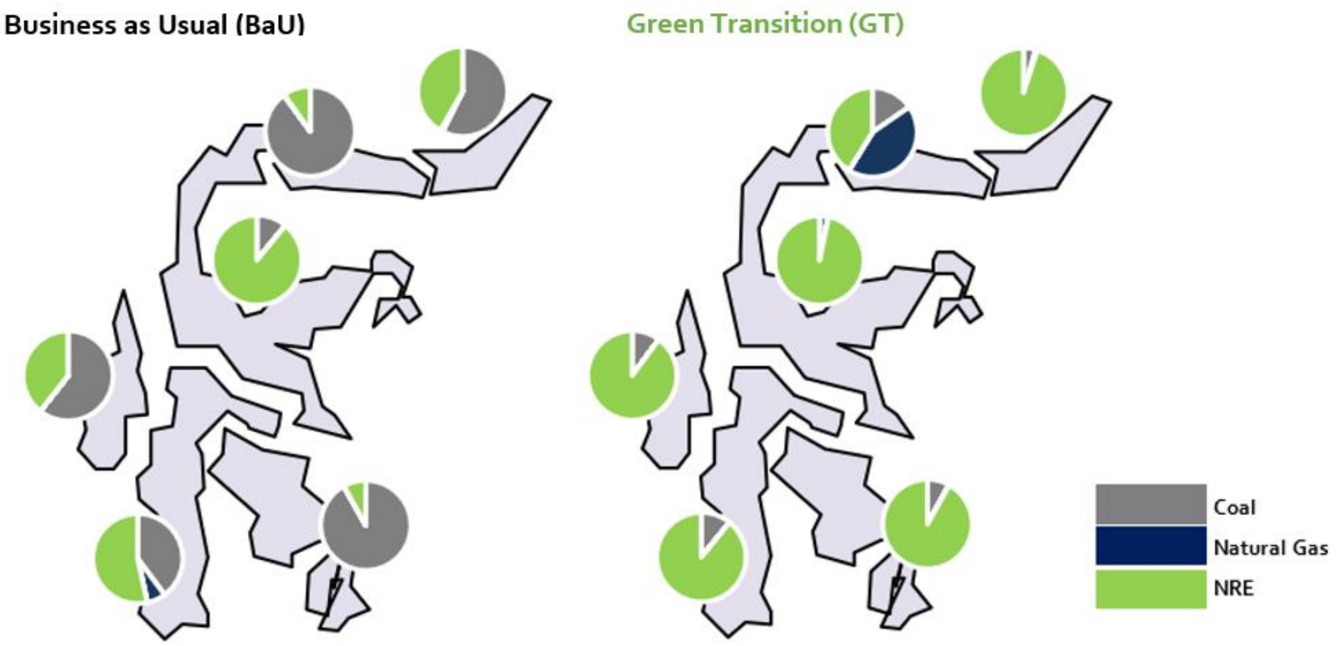


Figure 18: Overview of the generation share per province in 2030 in BaU vs GT.

In the BaU scenario, the Central Sulawesi region has by far the highest RE generation share, most of its generation being hydro and exports about 8% of its generation to Gorontalo, West and South Sulawesi. While in the GT scenario, West and South Sulawesi develop more hydro capacity, Central Sulawesi decreases its annual export to 5% - the main part of these 5% is exported to Gorontalo, which has the lowest RE shares (see Figure 19).

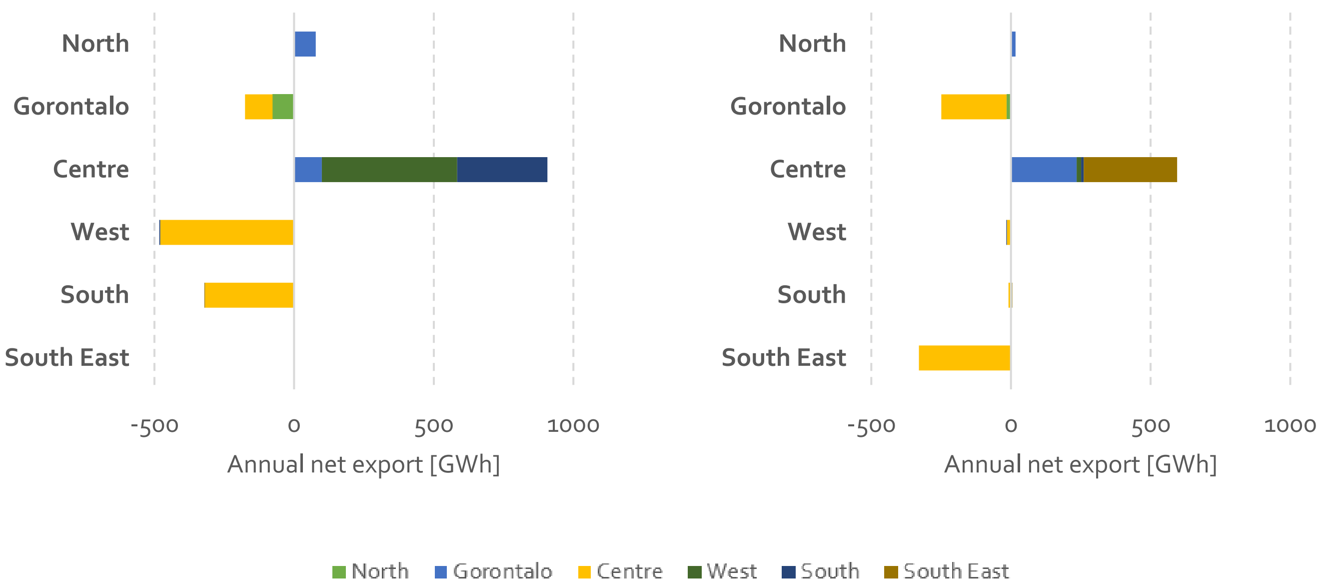


Figure 19: Annual net export in 2030 for the BaU scenario and the GT scenario.

3.2 NORTH SULAWESI AND GORONTALO: SYSTEM DEVELOPMENT

***Coal dependency in North Sulawesi and Gorontalo reduces drastically** in the cost-optimised scenarios, implying that cheaper power generation is available independently of financing schemes or consideration of pollution costs**.** **Coal is substituted in the power mix by natural gas and RE**, mainly hydro and solar. The **geothermal potential in North Sulawesi** is utilized in all three scenarios.*

RUPTL development plans for North Sulawesi and Gorontalo, consider a relatively high reliance on geothermal power and notably less hydro generation compared to the entire Sulawesi island. **The geothermal potential** of the island is concentrated in North Sulawesi province and **provides cost-efficient and clean power generation**, which is utilized in the CC and the GT scenarios.

An overview of the total generation in 2030 in the three scenarios is shown in Figure 20. Apart from hydro and geothermal, RUPTL envisions the bulk of the Sulutgo demand to be met by coal (up to 65%). This coal-dominated picture is changed considerably in the optimised scenarios CC and GT, where coal generation makes up only 15% in the CC scenario and as low as 6% in the GT scenario. **Two main alternatives for coal replacement are seen – natural gas and RE** (mostly hydro and solar generation – geothermal already plays an important role in the BaU scenario)**.**

Natural gas plays a negligible role in the power generation in the BaU scenario. However, in the least cost scenarios, gas generation becomes a cheaper alternative to coal. In 2030, the CC scenario sees 15% natural gas generation. The GT also sees natural gas in its power mix; however, RE takes up a large share of the generation, leaving natural gas just 9% of total generation.

In the CC scenario, hydro generation and solar together make up half of the power generation in the Sulutgo system, with 43% generated by hydro turbines and 7% by solar PV. Including geothermal and small amounts of biomass generation, the **CC scenario has a 69% RE share.** Favorable financing and including pollution costs result in a **RE share of 85% in the GT scenario**, composed of 50% hydro, 18% geothermal, 13% solar power and small amounts of wind and biomass.

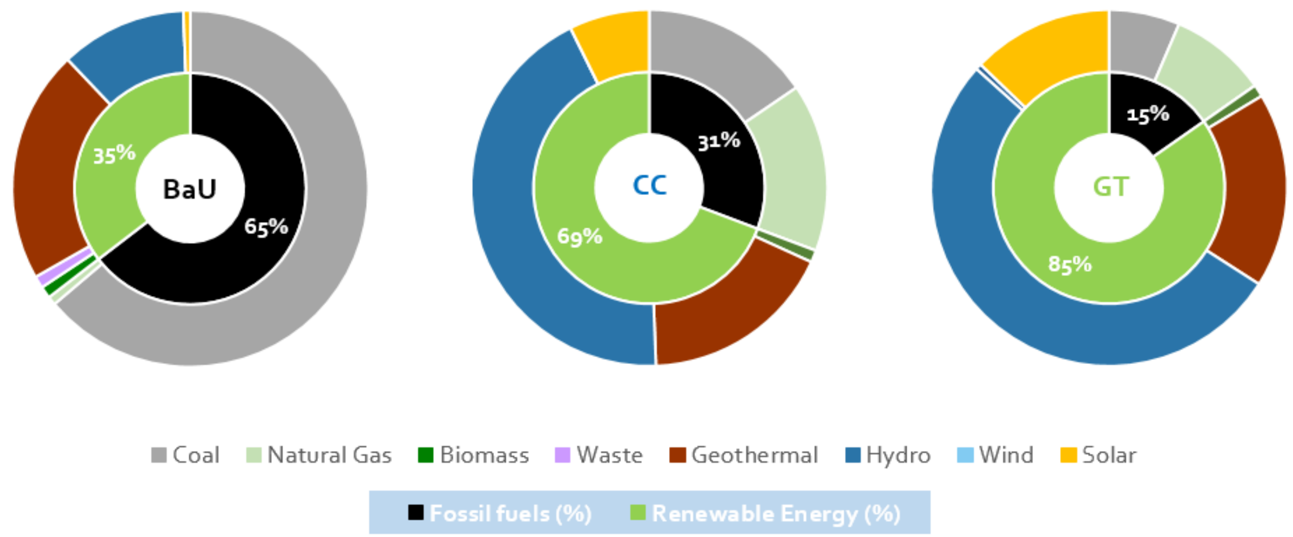


Figure 20: Generation shares in 2030 in the three scenarios (outer circle) and share of fossil fuels and RE (inner circle).

North Sulawesi and Gorontalo can count on a diversified RE potential

As both North Sulawesi and Gorontalo see a decrease in coal-based generation, they utilise different domestic power sources for meeting demand. ***North Sulawesi exploits its good geothermal and large hydro potential****, whereas* ***Gorontalo can rely on higher solar full load hours*** *to generate about a fifth of the demand.*

In Figure 21, the power mix of North Sulawesi and Gorontalo are shown for the three analysed scenarios. North Sulawesi has the advantage of both an excellent potential for reservoir hydro as well as good geothermal potential. In the CC scenario, almost half of the generation in North Sulawesi is based on hydro and about 22% on geothermal. Less than a quarter of generation is fossil-based. Financing favouring RE and including pollution cost optimization result in a 95% RE share in 2030 for the GT scenario.

Gorontalo, on the other hand, has neither reservoir hydro nor geothermal potential and therefore has a higher share of fossil generation (64% in the CC scenario and 58% in the GT scenario). However, Gorontalo has better solar resources and especially in the GT scenario, lower WACC for RE increases solar generation to 21%. The increase in the WACC for coal increases natural gas generation, while decreasing coal generation to only 15% and allowing natural gas to supply 43% of generation.

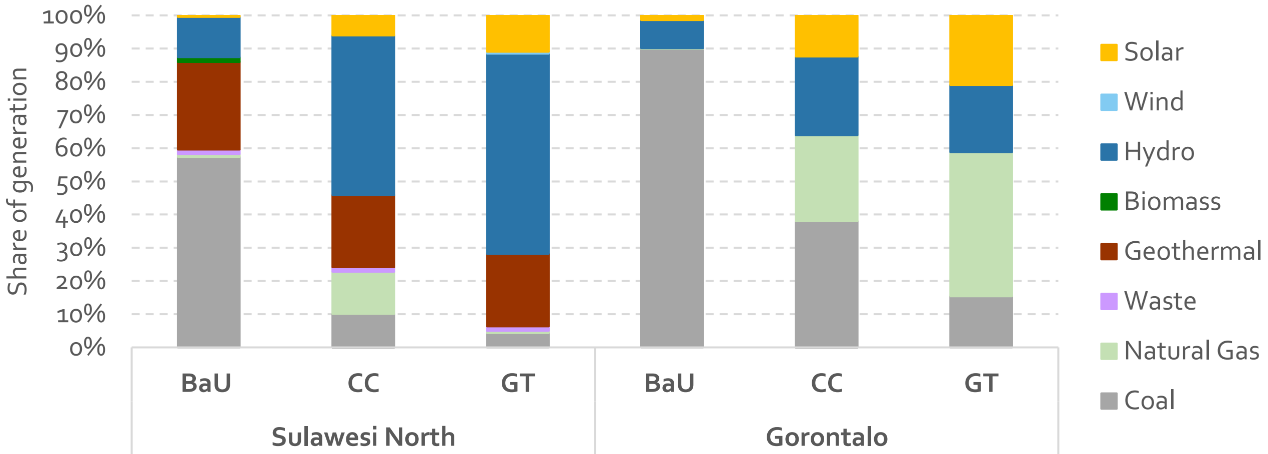


Figure 21: Share of generation for North Sulawesi and Gorontalo in 2030 in the CC and GT scenarios.

Figure 22 shows model-optimised investments in hydro and solar in 2026, 2028 and 2030. In the CC scenario, solar generation comes in with 270 MW in 2030, as the LCoE is low enough for solar to compete with natural gas and other RE sources such as reservoir hydro. With financing favouring RE investments, investments in solar are already seen in 2026 with 125 MW. **By 2030, the solar capacity in quadruples to about 500 MW**, almost matching the new investments in hydro capacity.

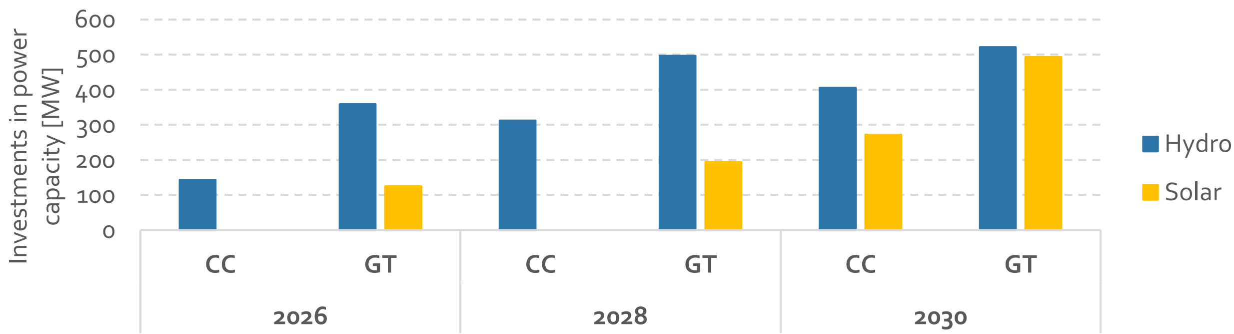


Figure 22: Model-based investments in hydro and solar capacity in 2026, 2028 and 2030.

RE is becoming cost competitive with fossil fuels

As testified by the large RE deployment toward 2030, RE is cost competitive in the Sulutgo system, where ***reservoir hydro generation can provide cost-efficient and flexible generation already in 2020.*** *Large and rapid cost reductions for solar result in* ***solar generation costs below 1,000 IDR/kWh by 2030****. This is significantly lower than coal and natural 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 must be sold for the power plant to cover all its cost and the LCoE is therefore an indication of the tariff (PPA) a technology requires to be competitive.

Figure 23 shows the LCoE of all relevant generation technologies in the provinces of North Sulawesi and Gorontalo for 2030, with a comparison to the 2020 cost (transparent column). As seen, 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. Solar, has the largest cost reduction potential in the period considered and this is well in line with worldwide trends and PV market (see Text box 2).

It is interesting to note that in 2030 almost all RE technologies have a cost comparable to or lower than that of coal and natural gas. Indeed, while these two traditional technologies see a slight cost increase from 2020 to 2030 (higher projected fuel costs), **RE can rely on a cost reduction due to larger deployment and learning rates.**

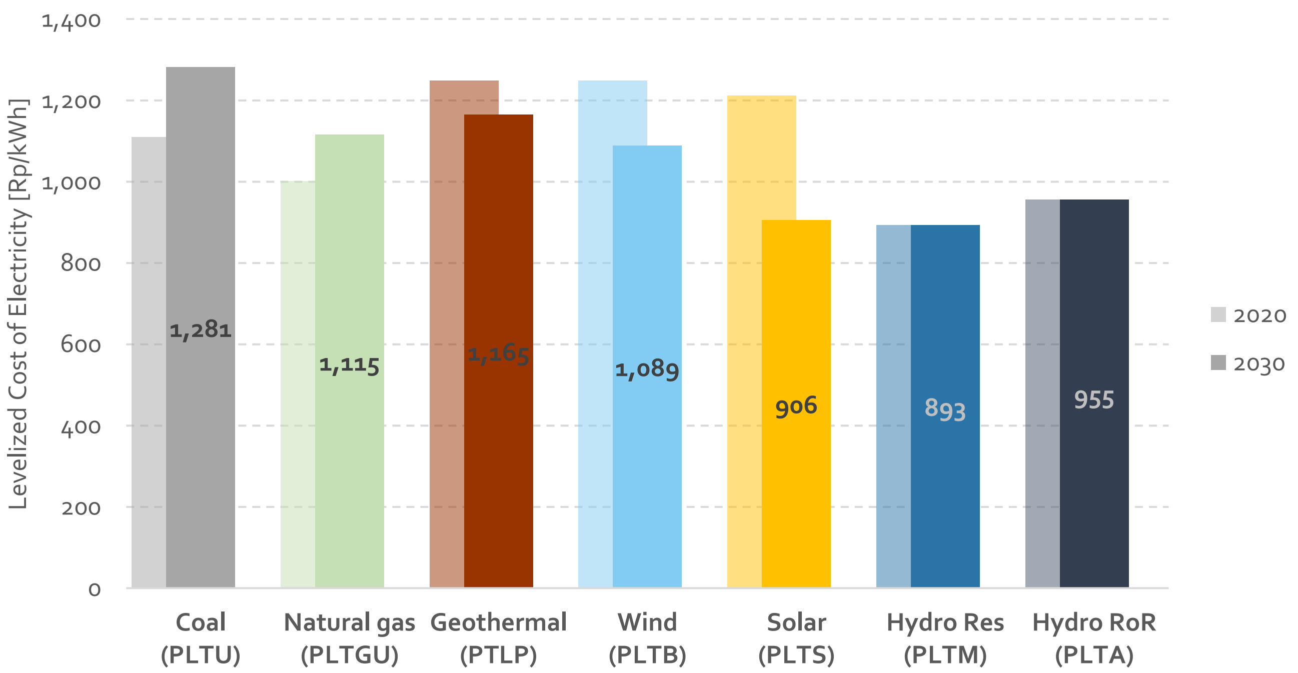


Figure 23: LCoE comparison for relevant power sources in Sulutgo in 2030 (solid) compared to 2020 (light)[9]. Numbers indicated represent 2030 LCoE.

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

[9] To calculate LCoE, a number of assumptions has been made: WACC is 10% for all technologies, economic lifetime is 20 years, assumed FLHs for PLTU, PLTP, PLTBm and PLTBg are 7000h, PLTGU has 6,000 h while for wind solar and hydro FLH used are from Figure 9. Fuel cost and technology costs are from 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.

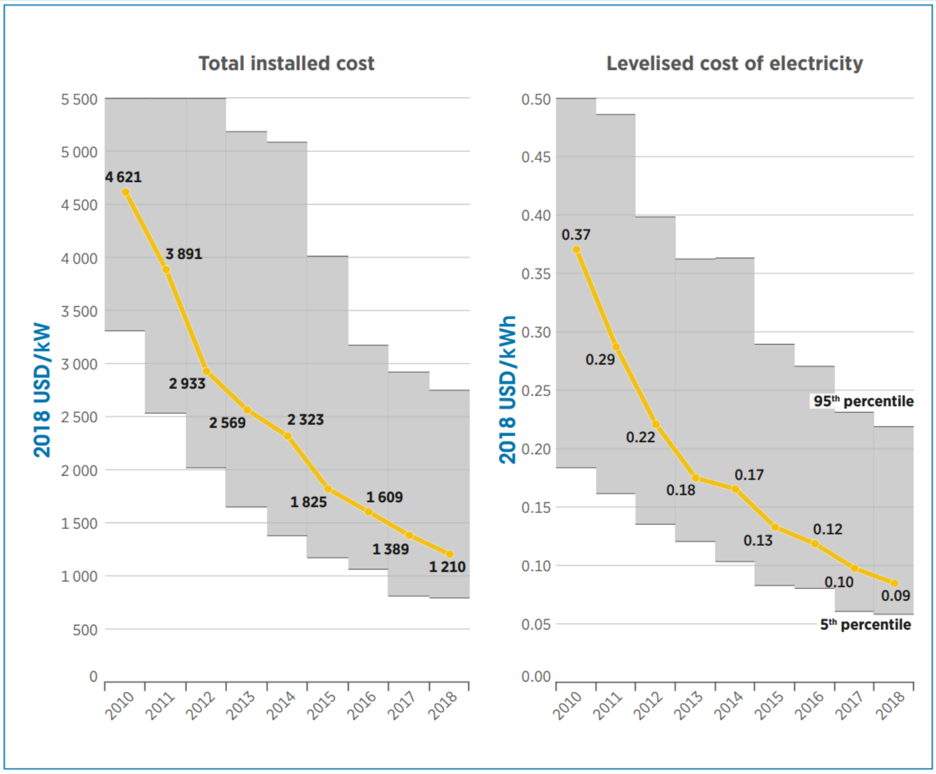


Figure 24: Total installed cost and levelized cost of electricity of solar power from 2010 to 2018. Source: (IRENA 2019)

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.

Gas can outcompete coal

*The **high efficiency of combined cycles and the relatively higher coal price** in Northern Sulawesi make natural gas more competitive than coal for bulk power generation and cover the need of dispatchable generators. The introduction of increased shares of variable RE results in **decreased full load hours for fossil generators**, making **capital intensive coal even less attractive and at risk of becoming stranded asset.***

As previously shown, natural gas generation is cheaper than coal generation in both 2020 and 2030. This is due to the high efficiency assumed for combined cycle natural gas turbines and a relatively high coal price in Sulutgo. Nonetheless, RUPTL projects more than a quadrupling of coal capacity in coal capacity between 2020 and 2030 (from 180 MW to 780 MW in 2030 – see Figure 25). The RUPTL sees the same quadrupling for natural gas capacity (100 MW in 2020 increasing to 400 MW in 2030).

Model results indicate that the RUPTL natural gas capacity is close to the optimal, with both the CC and the GT scenario resulting in about 400 MW gas turbines. On the other hand, least-cost optimization suggests that no additional investments in coal are justified as neither the CC nor the GT scenario include any coal investments in the period 2020-2030.

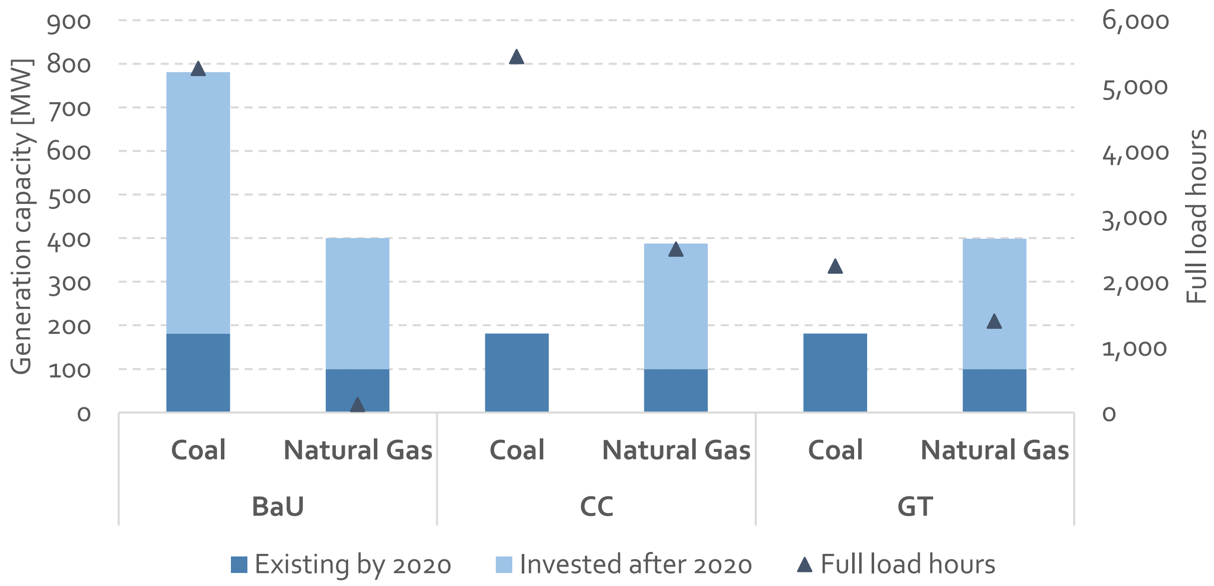


Figure 25: Installed coal and natural gas capacity in 2030, shown as existing capacity (installed before or by 2020) and additional invested capacity after 2020 as well as the corresponding full load hours.

Figure 25 also shows coal and natural gas full load hours for 2030. In the BaU scenario, combined coal and natural gas capacity is largely overestimated for generation needs, as short-term costs for coal are lower, all generation is coal based and natural gas shows exceptionally low full load hours.

In the CC scenario, coal capacity is much lower and a balanced generation profile between coal and natural gas is seen. However, in the GT scenario, the increased RE generation in the Sulutgo system reduces the need for fossil-based power, showing low full load hours for natural gas as well as for coal. Coal turbines are capital intensive and need a high number of full load hours in order to be profitable. With lower annual generation, the LCoE of coal increases faster than that of natural gas, which has lower capital costs but higher variable costs (Figure 26). Investments in coal thus risk becoming underutilized capacity when a large share of RE is introduced in the Sulutgo power system.

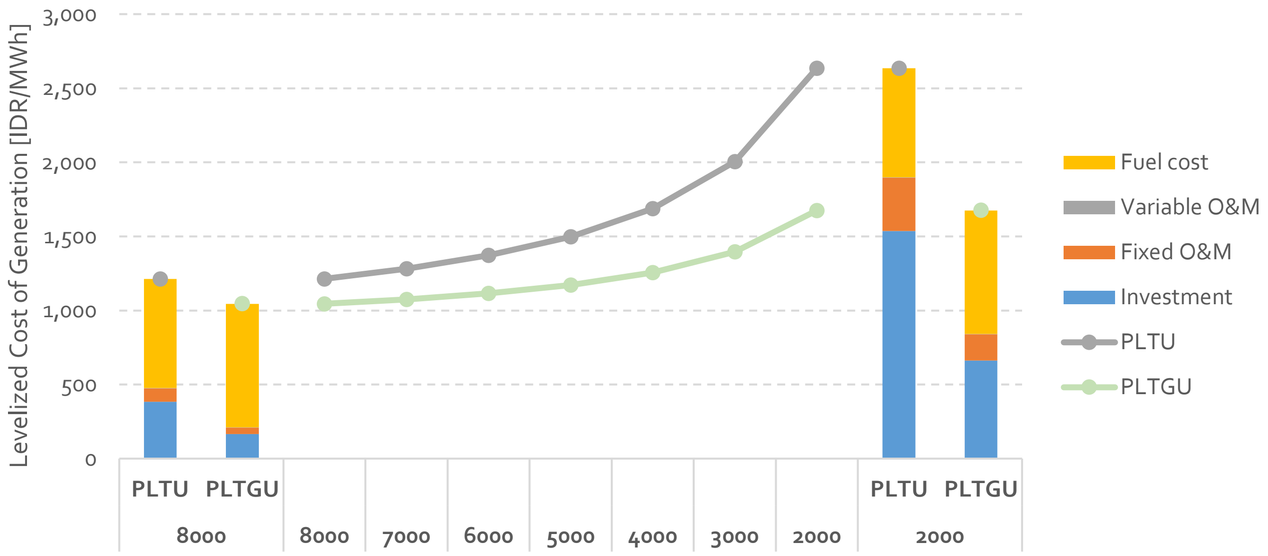


Figure 26: LCoE of coal and natural gas at different full load hours. Cost components shown at full load hours of 8,000 and 2,000.

What if planning constraints reduce the hydro and geothermal buildout?

*The long planning process as well as the challenges related to resource uncertainty and availability of locations, make **large additions of hydro and geothermal uncertain** in the short to medium term. If planning constraints limit the deployment of these resources, **gas would play a larger role, together with additional solar and wind generation**, coupled with the use of storage.*

The constraints faced to develop the potential of geothermal energy and the considerable potential for reservoir hydro power are land status issues since most of the potential is in the forest area of the Gunung Ambang nature reserve in Bolaang Mongondow Regency. Some large potential hydropower projects are Poigar II and III (20+50 MW), Minut I-II-III (53 MW), Ranoyapo I-II (108 MW) and Mongondow (37 MW). Based on RUPTL, the potential of hydro energy that can be utilized for power generation is estimated to around 278.4 MW spread over 33 locations (PT PLN Persero 2019).

A sensitivity analysis of the CC and GT scenarios is performed where the hydro and geothermal capacity buildout is assumed equal to what planned in RUPTL. The differences in power capacity are shown in Figure 27. For geothermal power, this means a slight increase compared to the least-cost optimizations, however, the sensitivity results in a strong restriction to hydro power buildout.

In the CC scenario, a restriction on hydro buildout would result in higher natural gas generation. By 2030, however, additional solar capacity and even a small amount of wind capacity replace the hydro power. This increase in variable RE capacity is higher in the GT scenario, where already in 2026, wind and solar capacity replace hydro.

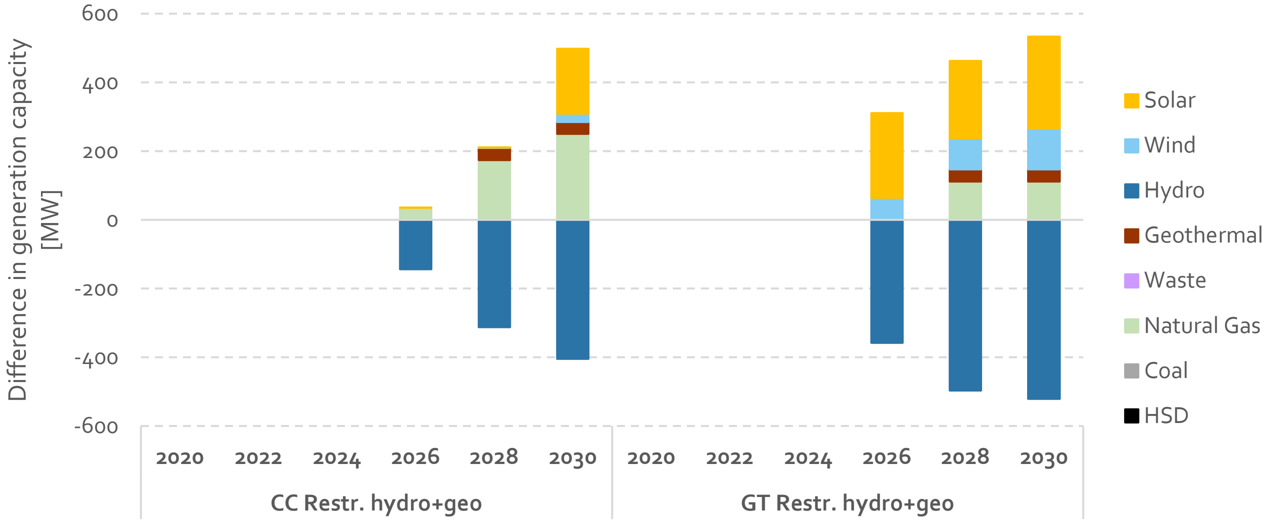


Figure 27: Differences in power capacity development between the sensitivity analyses and the respective main scenarios.

In both sensitivity analyses, the restriction on hydro buildout reduces the RE share in 2030. In the restricted CC scenario, only just 47% of generation is from RE (69% in the main CC scenario). While in the restricted GT scenario, hydro is replaced by solar generation and some wind generation, leading to a decreased in the high natural gas contribution from 85% to 58%.

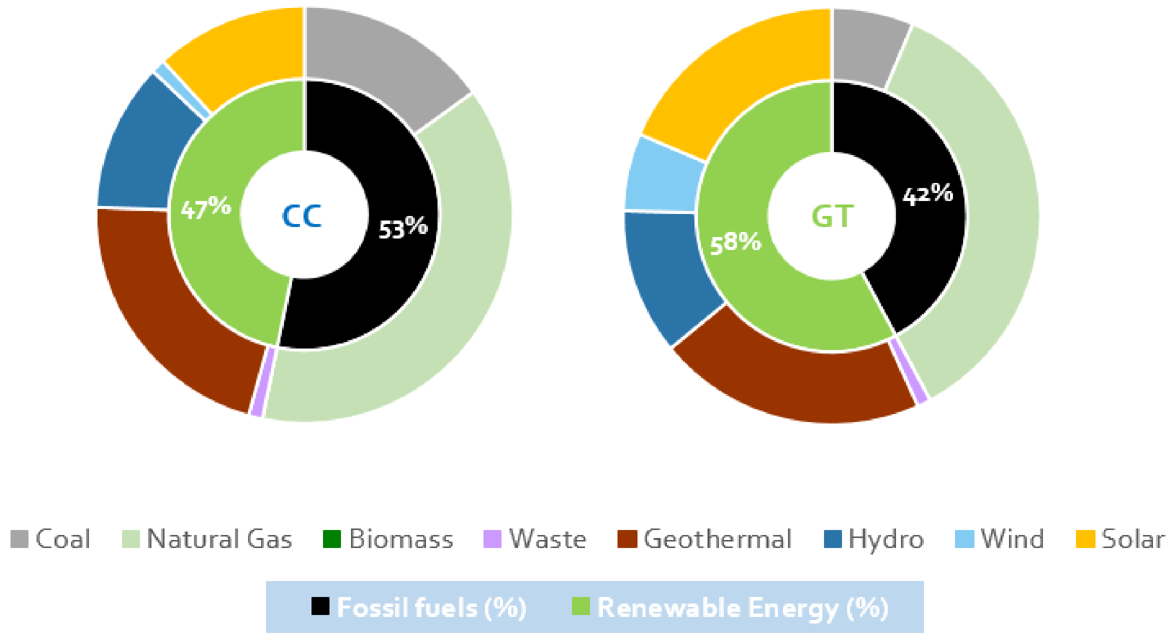


Figure 28: Generation shares (outer circle) in 2030 in the restricted CC and restricted GT scenarios and share of fossil fuels and RE (inner circle).

Greener scenarios have comparable cost

*The scenario with favourable conditions for RE investment has a cost similar to the BaU, meaning that it is possible to achieve **a larger RE penetration and emission reduction at virtually no extra cost**, and an average generation cost of 1,044 Rp/kWh. A more RE-based system also reduces risks of cost surge, due to fluctuations in future fuel cost.*

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 the power imported from other regions.

The BaU scenario has a significantly higher total cost than the CC and GT scenarios (+/-24% or about 16 trillion IDR on-cost) as it includes investments in expensive coal generation and under-used natural gas capacity. Total costs for the CC and GT scenarios are similar and are around 65 trillion IDR over the period 2020-2030.

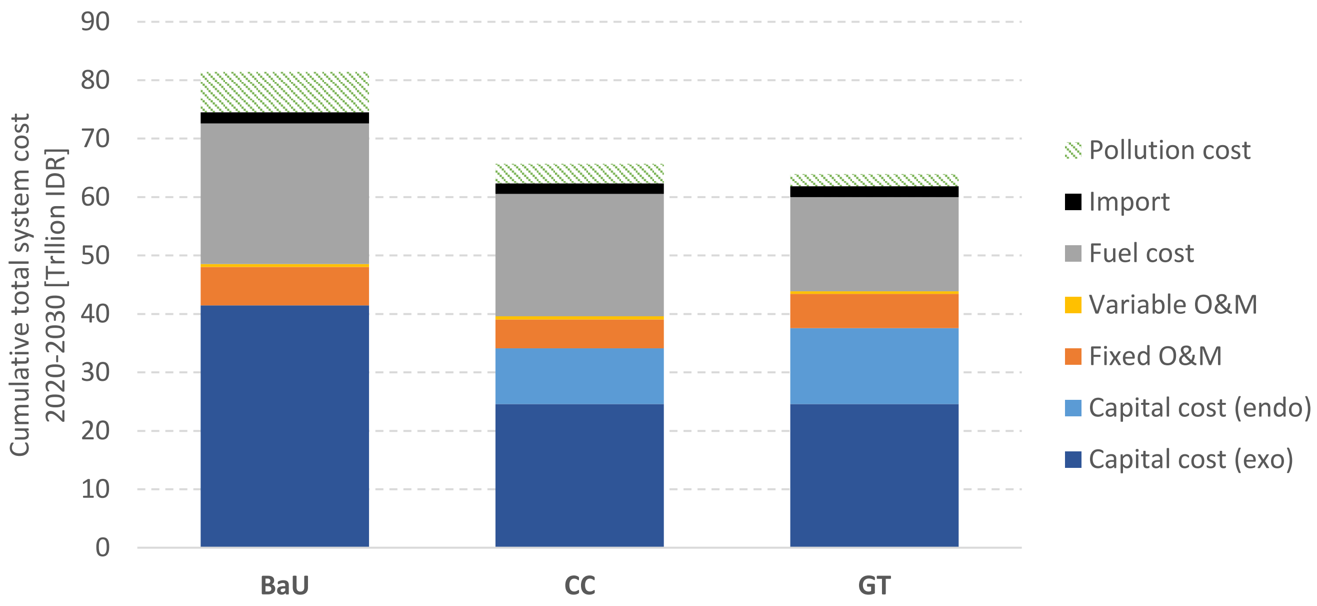


Figure 29: Cumulative total system costs in the three scenarios for the period 2020-2030[8].

The costs of generating electricity in the three scenarios is shown in Table 3. While the power mix of the two scenarios is quite different, the cost differences between the CC scenario and the GT scenario are marginal. The CC scenario has a generation cost of 1,017 Rp/kWh and 69% RE share, while the GT scenario has a generation costs of 1,044 Rp/kWh and 85% RE. These results suggest that in the Sulutgo power system, the costs of introducing RE technologies come at a very low additional cost.

Table 3: Average generation cost by scenario.

	Rp/kWh
BaU	1,216
CC	1,017
GT	1,044

Furthermore, savings related to health costs sum up to about 1.2 trillion IDR between 2020 and 2030.

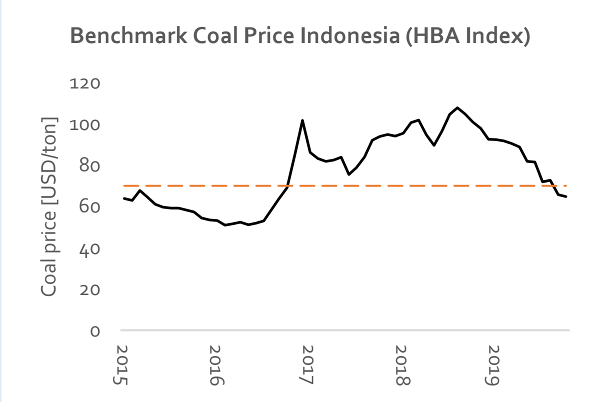
Another important factor is the portion of the total costs related to fuel expenditure, which is only 24% in GT scenario compared to 34% in the CC scenario. A system with more RE, while increasing the capital requirement,

[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.

significantly 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).

Text box 3. 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 with other power sources, is shown in Figure 30Figure 30: Generation cost of coal at 70$/ton vs 110 $/ton and comparison with other sources at 8 and 10% WACC.. With a coal price of 70 $/ton (and considering no further transportation cost for the fuel), the generation cost of coal-based power 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, combined cycle gas turbines and solar would have a lower generation cost. With a cost of capital (WACC) of 8%, both wind and PV cost fall to around 1,100 Rp/kWh, making them cheaper than coal plants already in 2020.

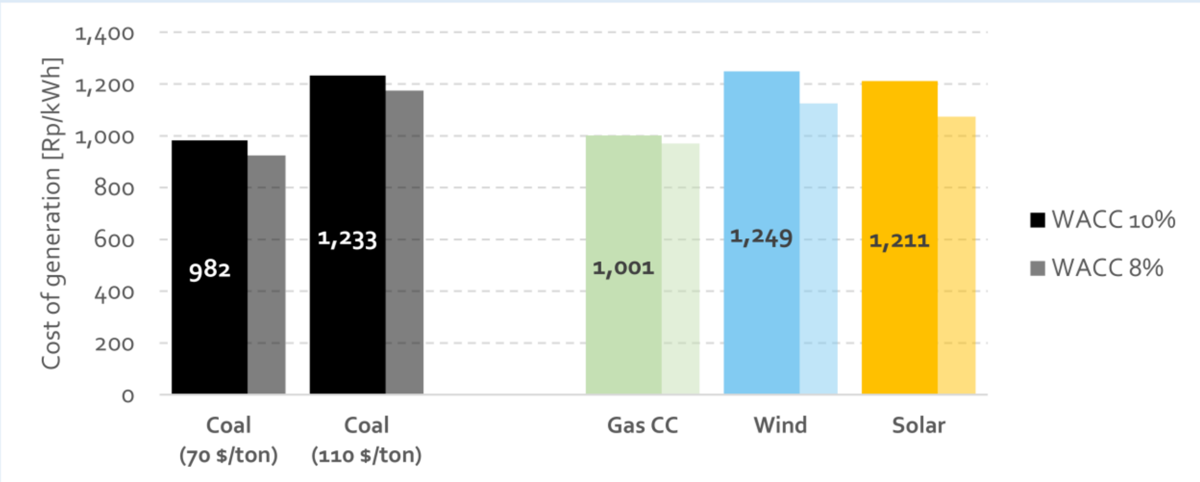
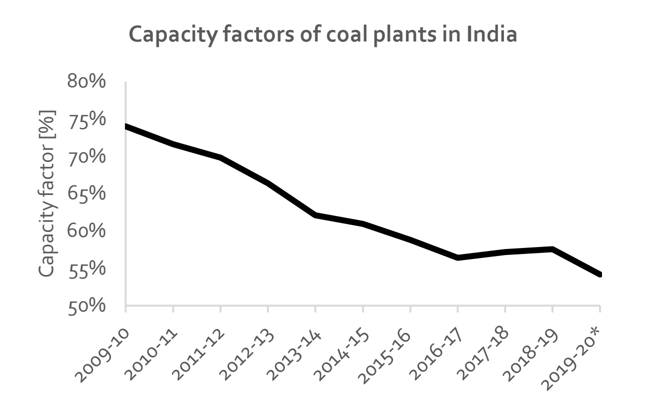


Figure 30: Generation cost of coal at 70$/ton vs 110 $/ton and comparison with other sources at 8 and 10% WACC.

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

As the share of RE grew, China and India experienced **collapsing utilization rates of coal power plants**. China's 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 in Indonesia, expressed in term of declining capacity factor, is shown in Figure 31. At low coal prices, the capacity factor must drop below 55% to make solar and wind cheaper. If coal price reaches 110 $/ton, already at full utilization wind and solar can compete. The lowest the coal capacity factor, the largest the cost saving from using variable RE. **At high price and 50% coal capacity factor, the generation cost of coal is 30% higher than solar 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 variable RE competitive already in 2020, even without considering the great cost reduction potential that technologies such as solar and wind are experiencing worldwide.

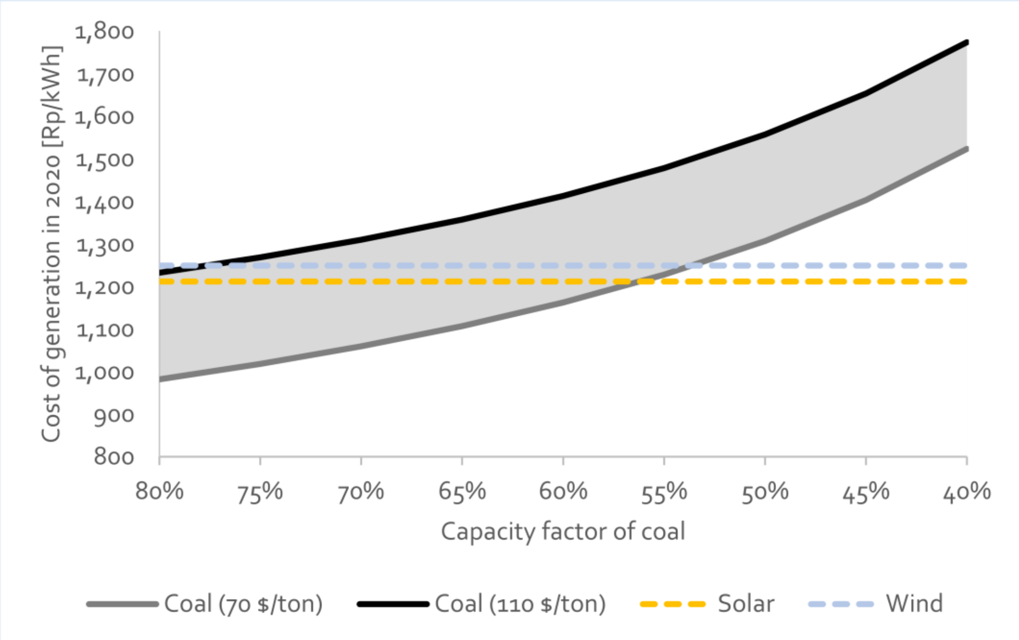


Figure 31: Coal generation cost at declining capacity factor, for a coal price of 70 $/ton and 110 $/ton.

What is the impact on CO2 emissions and pollution?

The replacement of coal with natural gas and RE generation such as hydro, solar and in some cases wind generation, ***drastically reduces the CO_2 emissions in 2030 to less than half compared to the BaU scenario.*** *Planning constraints on hydro buildout could pose a challenge to reducing emissions to the optimal level.*

In all scenarios considered, the large share of coal generation in the BaU scenario is replaced by both natural gas generation and varying levels of RE. This change in energy mix, effectively **reduces total emissions in the Sulutgo region in 2030 from 4.3 Mtons to 2 - 0.7 Mtons**. The GT scenario being more ambitious in CO_2 abatement by 2030, has more solar and hydro generation compared to the CC scenario. The emissions in the GT scenario are about half the emissions in the CC scenario, even though the increase in cost of generation is only 2.5%.

Hydro planning constraints might have a negative effect on the emission abatement and increase the total emissions with 38% in the restricted CC scenario and almost 100% in the restricted GT scenario.

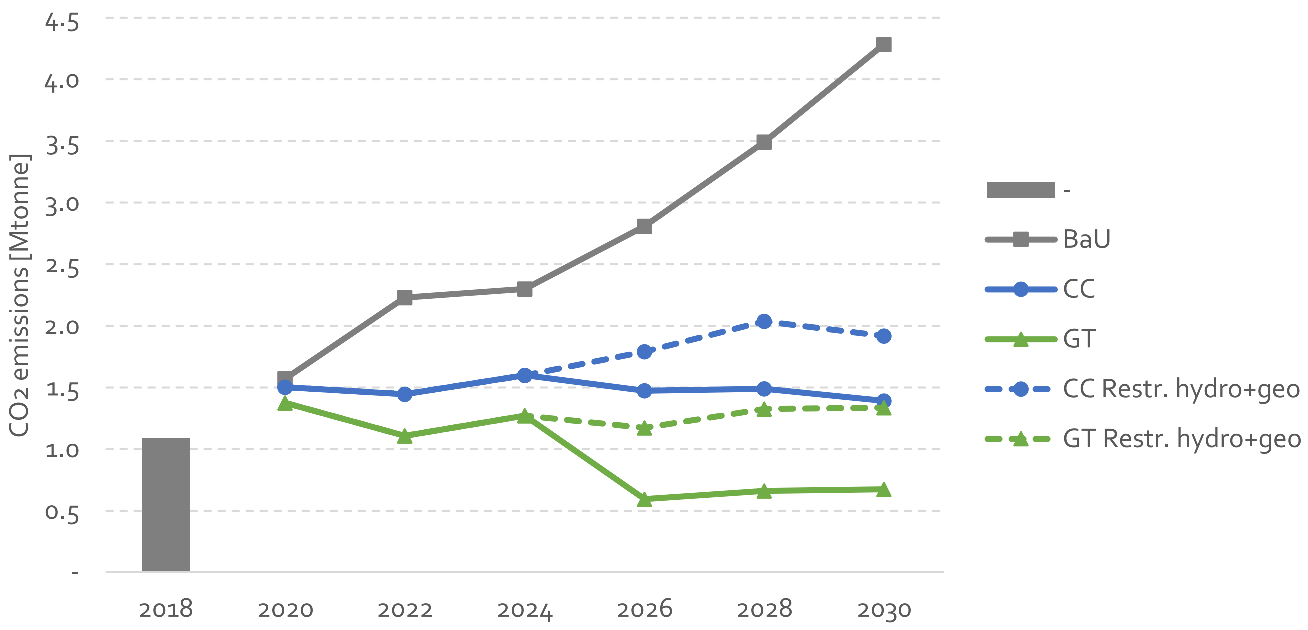


Figure 32: CO2 emissions in the scenarios in the period 2020-2030.

Integration of RE can be done without drastic changes in dispatch

The presence of solar power modifies the dispatch around midday, but the integration of these amounts of variable RE are not challenging for the system operation. ***The large amount of dispatchable RE such as reservoir hydro, geothermal as well as small amounts of storage systems (batteries) makes the transition to a less carbon intensive system smooth****.*

In the BaU scenario less than 1% of generation is based on variable RE, while the GT scenario exhibits a solar share of 13%. This share of variable generation can easily be integrated in the power mix especially in the Sulutgo system as enough flexible generation sources are available to balance the system in hours of low solar generation.

Figure 33 shows the generation of an average day in 2030 in the BaU scenario and the GT scenario.

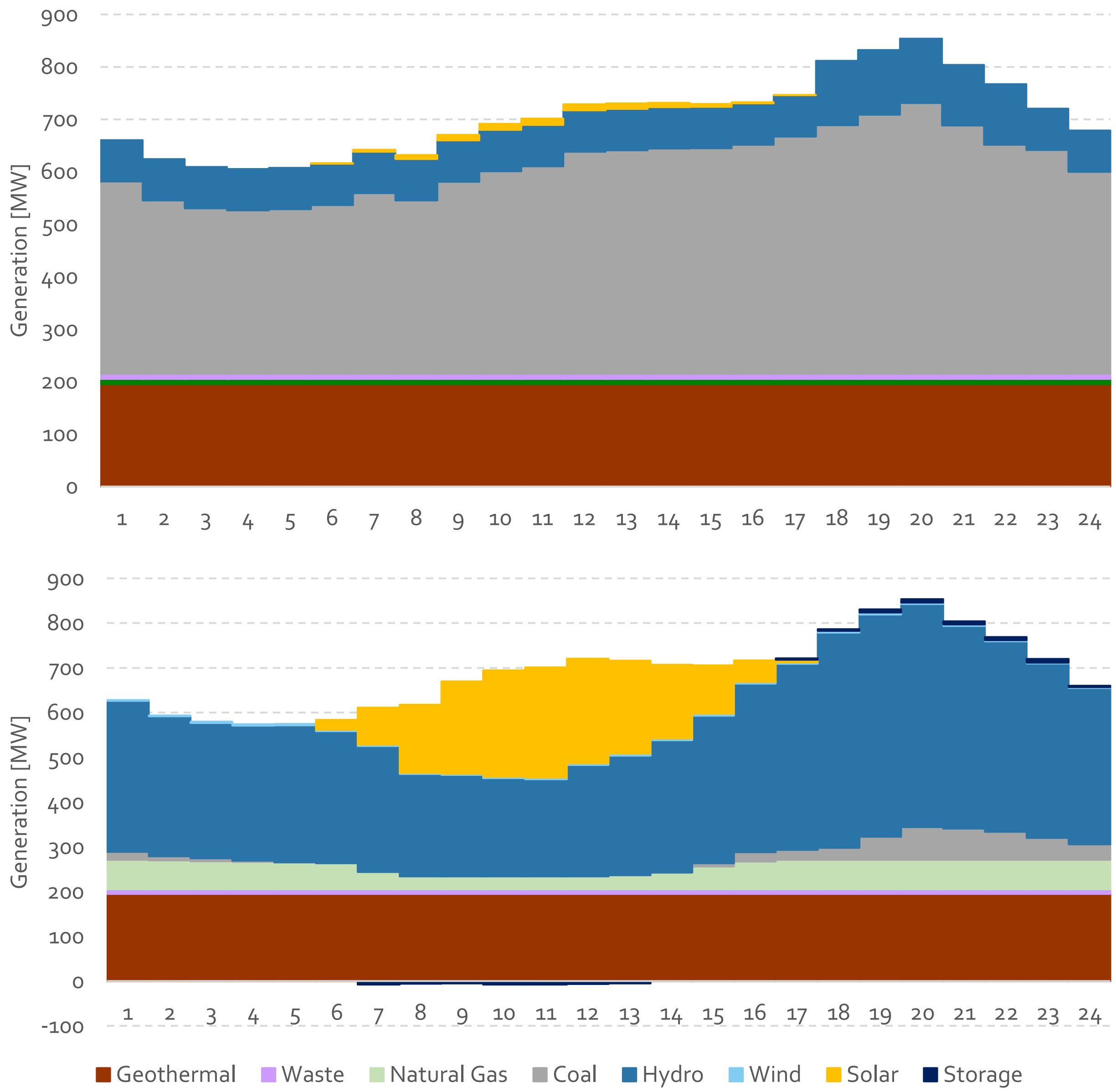


Figure 33: Generation pattern of an average day in 2030 for the BaU (above) and GT (below) scenarios.

In the BaU scenario, geothermal, biomass and waste form the baseload generation. Coal, for the large part also generates baseload, but together with hydro shows small variations in generation to follow demand fluctuations.

In the GT scenario, solar power takes over a large part of day-time generation. **The large capacity of reservoir hydro generation ensures enough flexibility to reduce generation during solar peaks and ramp up in the evening peak.** The baseload generation from the BaU scenario, geothermal and waste, remain as constant generation during the day together with natural gas. The small amount of coal generation is only used in peak hours.

Storage and reservoir as enablers of VRES

***Hydro can play a pivotal role in helping to balance the fluctuating nature of VRES**. In absence of large additions of hydro to the system, storage can be a viable option already before 2030. For every MW of solar and wind, only 0.2 MW of storage are needed.*

In the GT scenario, small amounts of battery storage are seen in the power system in 2030. Their generation and charging pattern show obvious correlation to the solar generation as well as the load profile (Figure 34). During the daily solar peak, the batteries are being charged with the excess of power from solar generation, around 10 hours later, from 16:00 in the afternoon, the batteries generation to contribute to the evening peak.

The hydro generation pattern has a similar pattern with less generation during mid-day and higher output in the evening.

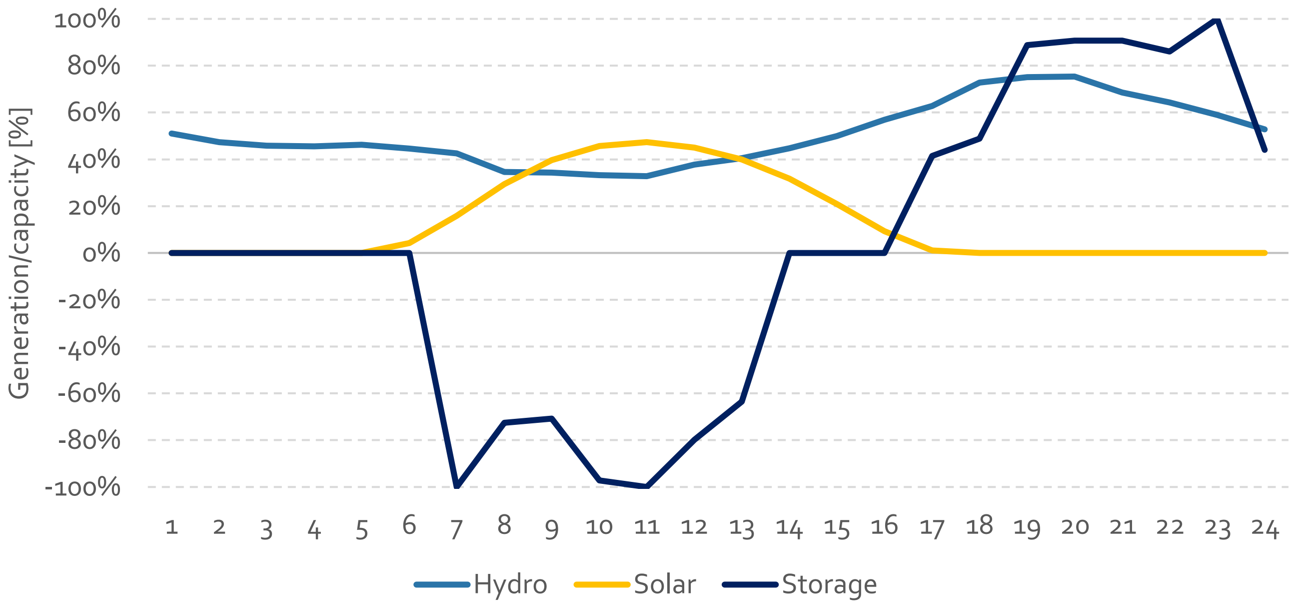


Figure 34: Generation (and charging) of hydro, solar and storage on an average day in 2030 in the GT scenario.

In the restricted GT scenario, where hydro buildout is restricted, solar and wind generation combined make up almost 25% of the total generation. With this increased share of RE and reduced hydro capacity, battery capacity becomes more important for balancing the system. In this scenario, for every MW of wind or solar, 0.2 MW of battery capacity is added to the power system.

4. 2050 scenarios

Alternative least cost development features much more RE than RUED expectations

*Least cost optimization of the power sector leads to **much more RE than anticipated in RUED**. Cost decline of technologies and a large RE potential allow for an 83% RE penetration in 2050. **Solar, combined with storage plays, an essential role**: By 2050, almost 3.3 GW solar capacity is combined with 1.3 GW battery storage. About 700 MW wind capacity also enters the system.*

In order to assess the long-term perspective and the potential development of the power system in the Sulutgo system, two scenarios are analysed: In the scenario "RUED" the buildout of power plants follows the plans of the regional energy policy, (RUED), including the targets for the share of natural gas, coal and RE. For North Sulawesi and Gorontalo, this corresponds to a system that is largely based on coal power. A "Least Cost" scenario analyses, what would be the development of the generation fleet on a pure cost minimization basis, disregarding existing policies and plans.

The capacity buildout in both scenarios is shown in Figure 35 showing a large difference in generation fleet. The RUED scenario sees a large expansion in coal capacity (up to 1.7 GW by 2050) as well as natural gas buildout (1.1 GW), investments in RE capacity are limited to 600 MW solar, 500 MW hydro and 140 MW wind.

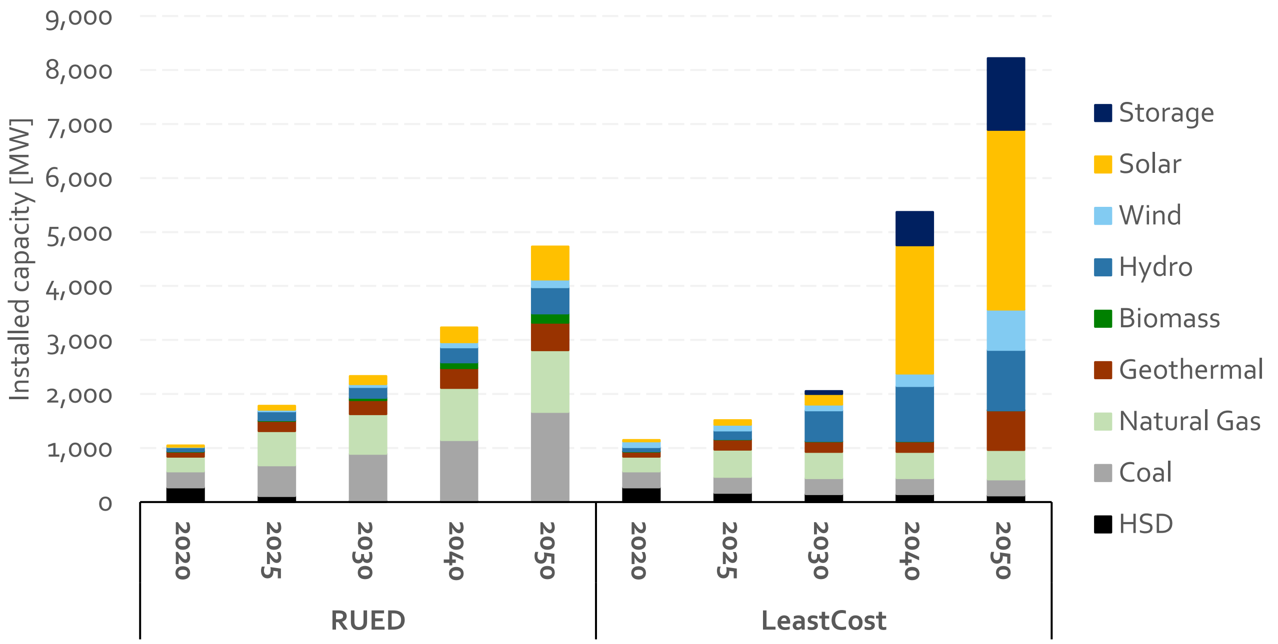


Figure 35: Installed capacity in North Sulawesi and Gorontalo in the Least Cost scenario compared to RUED plans.

The Least Cost scenario does not show any new investments in coal capacity. **In the medium-term (until 2030), the main developments are natural gas or hydro capacity**, with a limited amount of solar capacity. **In the long-term (up to 2050) the largest expansions in the Least Cost scenario are in RE and battery storage.** By 2050, almost 3.3 GW solar capacity is combined with 1.3 GW batteries. About 750 MW of wind capacity also enters the system.

With a strongly reduced fossil-based capacity, other technologies fulfil the balancing role for wind and solar. The Sulutgo power system can rely on the flexibility of hydro capacity to balance the variable RE generation. Additional battery storage appears from 2040 onwards. **For every MW solar power, 0.26 MW and 0.4 MW of battery capacity appears in 2040 and 2050, respectively.**

As shown in Figure 36, the RE share as envisioned by the RUED scenario (41%) is much lower than the total RE share in the Least Cost scenario, indicating that increasing the RE ambitions in the Sulutgo system could actually reduce costs for North Sulawesi and Gorontalo provinces. **Cost-minimized scenarios show that the optimal RE share for the system lies around 83%.**

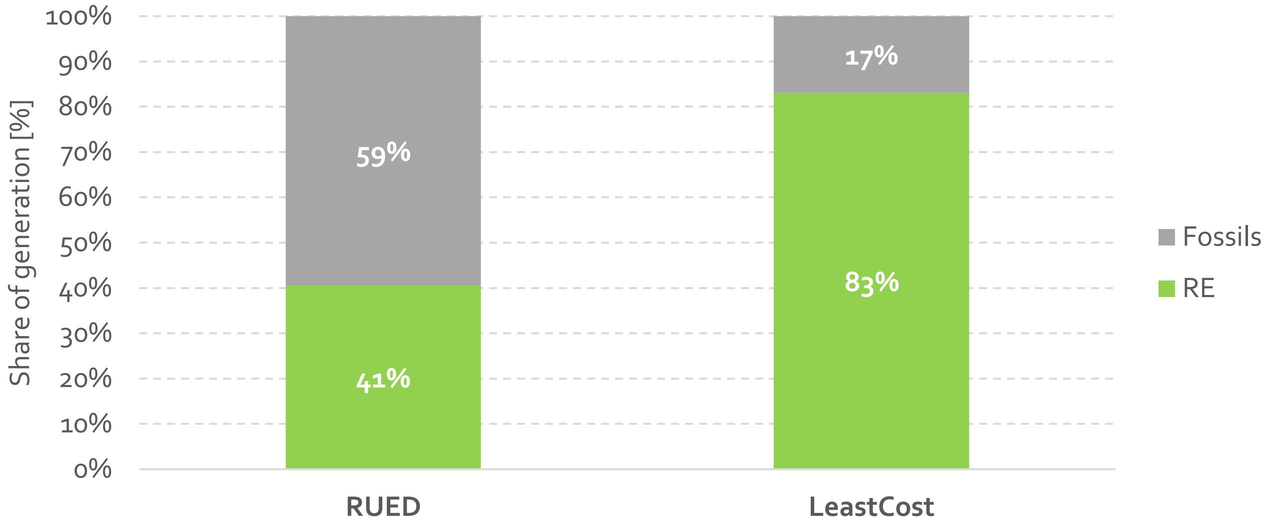


Figure 36: Share of generation in the Sulutgo system by 2050 in the RUED and the Least Cost scenarios.

More RE can lead to large cost savings and emission reductions

*The deployment of larger shares of RE can lead to **2 trillion IDR/year savings on average**. The system is much more capital intensive, with lower risk of cost fluctuations due to fuel prices as a result. At the same time, 75% emissions reduction can be achieved in the Least Cost scenario.*

The large increase in RE generation in the Least Cost scenario has clear impacts on both the total system costs and the CO_2 emissions in the Sulutgo system.

Figure 37 shows the system costs for each year in the RUED and Least Cost scenarios, capital cost being annualized. The RUED capital costs are 3.3 trillion IDR lower than in the Least Cost scenario in 2050 (excluding pollution costs). On average **the Least Cost scenario savings are 2 trillion IDR per year (13%). Additional savings of average 0.8 trillion IDR per year result from lower health related costs due to reduced pollution** (see Table 4).

Table 4: Saved annual system costs and pollution damage costs in the Least Cost scenario.

	Total cost savings *[Trillion IDR]*	Additional pollution savings *[Trillion IDR]*
2020	0.0	0.0
2025	0.8	0.2
2030	1.8	0.5
2040	2.7	1.0
2050	3.3	1.9
Yearly average	**2.0**	**0.8**

Furthermore, the fuel share of the total costs in the RUED scenario is 38% while it is only 13% in the Least Cost scenario. **Lower fuel cost reduces the vulnerability to fluctuations in fossil fuel prices.**

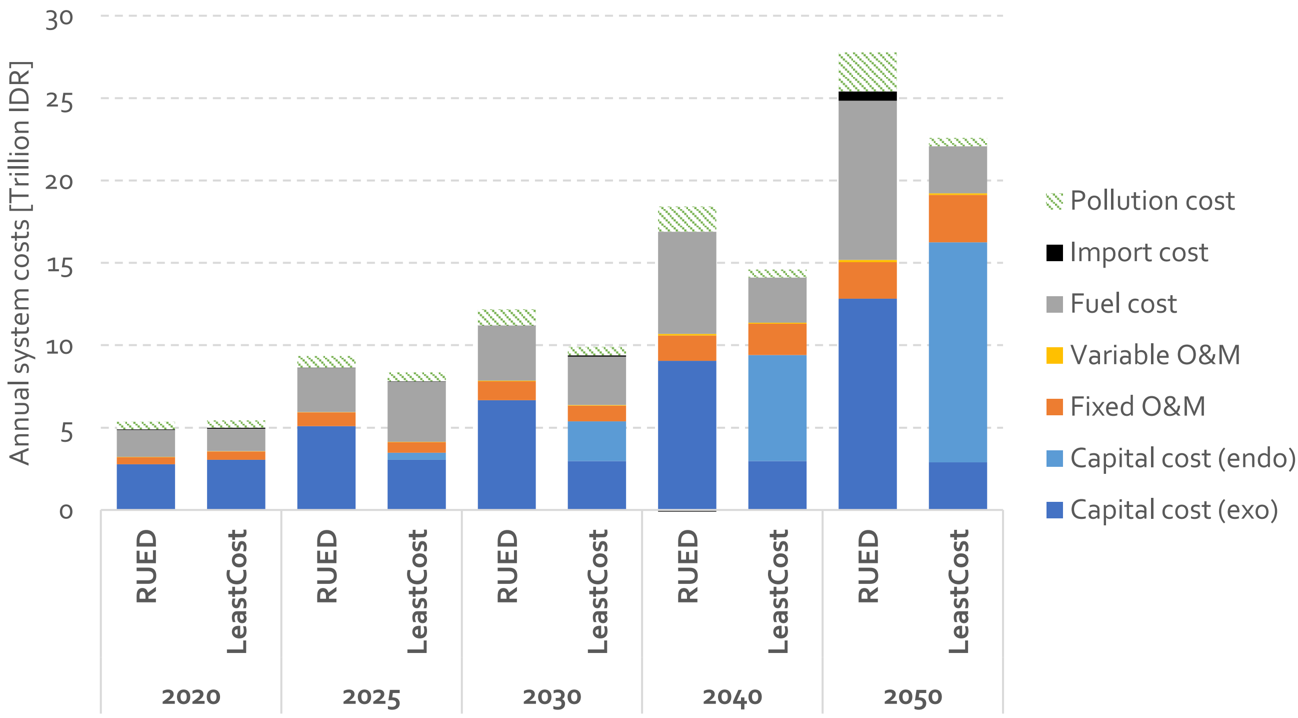


Figure 37: Comparison of total system cost by scenario and year.

The expected surge in CO_2 emissions in the RUED scenario, the result of a large increase in demand and a capacity buildout relying on fossil fuels, is shown in Figure 38. Between 2020 and 2050, the annual emissions almost quintuple and **reach 10.6 Mtons in 2050.**

The introduction of large shares of RE generation and reductions in coal generation in the Least Cost scenario result in emissions remaining relatively constant over the years with **emissions in 2050 only 2.6 Mtons – a reduction of 75% compared to the RUED scenario.**

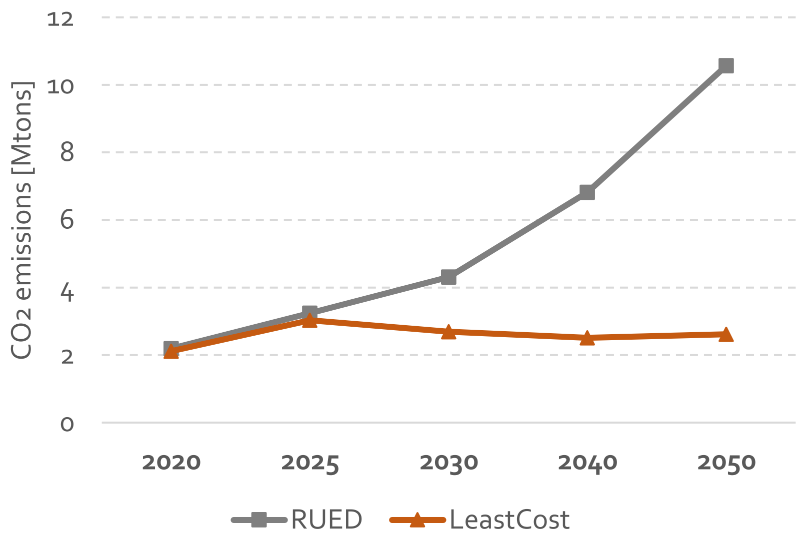


Figure 38: Annual CO2 emissions in the Sulutgo system for the RUED and Least Cost scenarios.

Is the long-term RUED target ambitious enough?

The high RE potential and the cost-competitiveness of RE, which is not considered in the RUED projections, demonstrate that the ***cheapest possible power system in 2050 has a much larger share of RE compared to current plans.*** *Not increasing the ambition on RE can be costly for both Gorontalo and North Sulawesi.*

The primary energy mix in the power system in 2025 and 2050 is shown for both scenarios and both provinces in Figure 39. For Gorontalo, the Least Cost scenario shows a RE share in primary energy of 53% in 2025, which grows to 74% in 2050. Both these renewable shares surpass the RUED goals, expecting 15.5% in 2025 and 35% in 2050.

For North Sulawesi, the renewable primary energy already surpasses the goal for 2025, 58% instead of the expected 46%. This difference between target and least cost RE share increases by 2050, **the Least Cost scenario overshoots the goal by far, 92% compared to 49% in RUED.**

This illustrates that from a cost-optimisation perspective, RE expansion can be the best option in the long term for both North Sulawesi and Gorontalo provinces. This is due to their good potential for geothermal, hydro and solar.

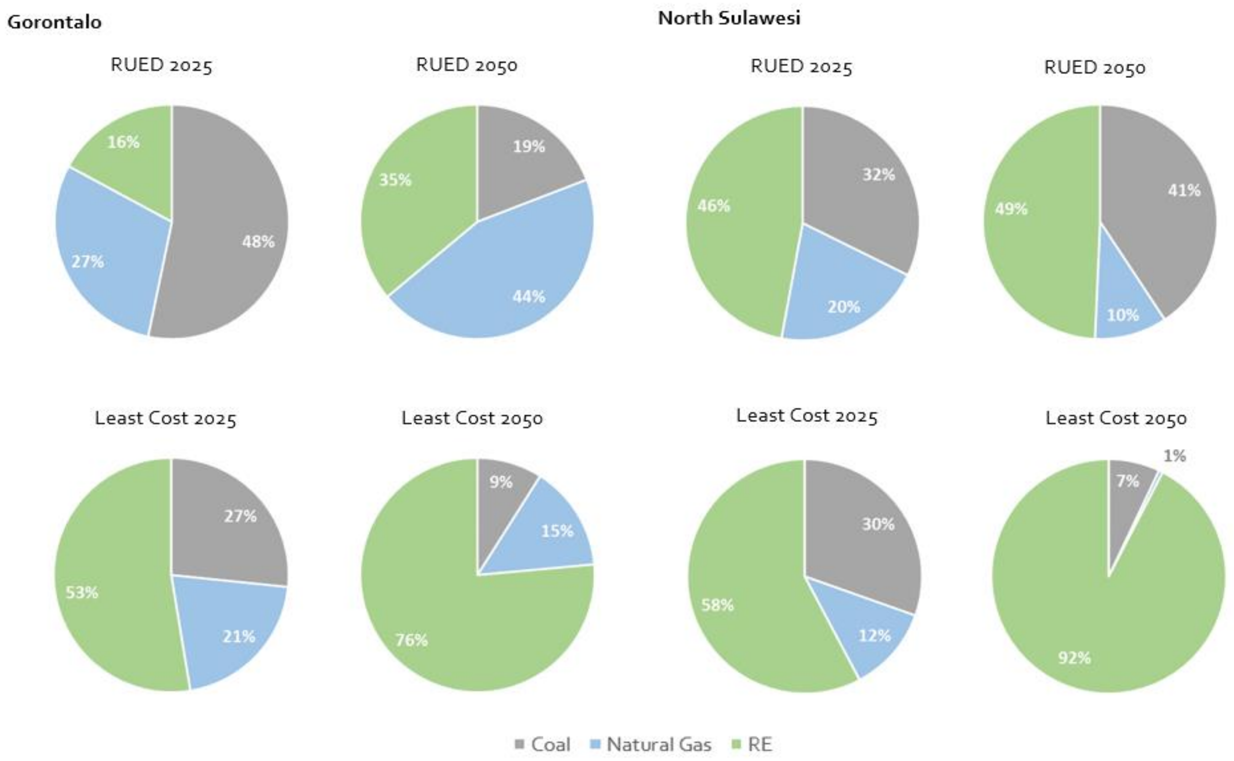


Figure 39: Primary energy by source in the RUED and Least Cost scenarios in 2025 and 2050.

5. Conclusions and recommendations

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

The results of the analysis for both medium term and long term showed that coal capacity development does not provide cost-efficient power neither in the short nor long term due to high capital costs and low utilization. Failing to consider other sources could lead to a higher cost of supply and increased power tariffs. RE generation such as hydro, geothermal and solar (and even wind) power are the best choices for capacity expansions. Hydro and natural gas generation are the best technologies to complement the RE generation as they can be dispatched in a flexible manner. Furthermore, large amounts of solar capacity require battery investments to help hydro and natural gas power to balance the system.

A higher deployment of RE and natural gas could result in large cost savings and in consistent reduction of the climate impact and the emissions.

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

- Conduct a study of North Sulawesi's reservoir hydro and geothermal potential and prioritize sites. A clear overview of the province's best potential for hydro and geothermal projects based on feasibility studies and environmental assessments will allow for realistic planning;
- Look beyond hydro and geothermal power: Start considering solar PV as a potential source of cheap power from the mid-2020s, especially under good financing conditions (otherwise from 2030). Wind can also contribute in case of lack of sites or in case planning restrictions limit the amount of hydro and geothermal potential to be exploited;
- Examine the solar potential of the provinces by detailed mapping of resources and space availability (both rooftop and stand-alone PV). The identification of suitable sites, preparation of pre-feasibility studies and increasing the solar ambition in the policy and planning documents can help attract investments;
- Assumptions across official planning documents, such as RUEN, RUED and RUPTL (but also RUKN and RUKD) differs both in terms of energy sources potentials and power demand projections. Aligning main assumptions across documents can help ensure consistency in the information and in the process of policy making;
- Map and monitor loan and financing options and develop a strategy to attract international finance. The results show that with foreign aid and international financing at lower rates due to interest in the global fight against climate change, RE can become an attractive option. In order to attract capital, a commitment to a RE project pipeline, an increase in the RE ambition of North Sulawesi and Gorontalo provinces and an improved communication of these targets can be enabling factors;
- Carefully reassess the case for additional coal power plants to avoid technology lock-in and under-utilised capacity. There is apparent risk of stranded assets and increased electricity tariffs for the Sulutgo system.

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Appendix A. Balmorel model

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

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

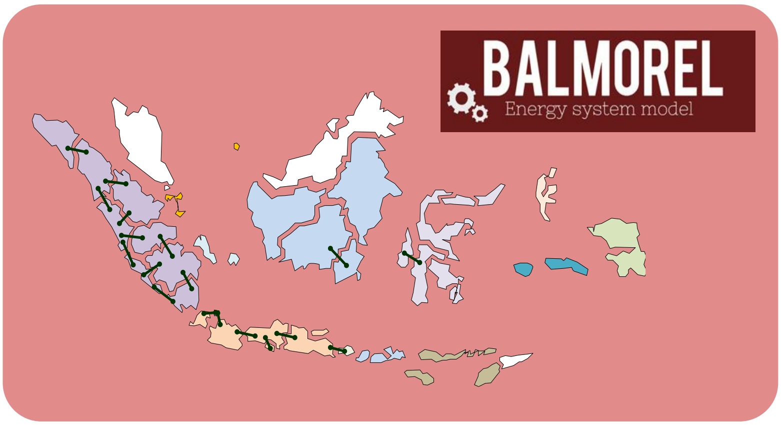


Figure 40: Balmorel model, Indonesian setup.

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 41). 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).

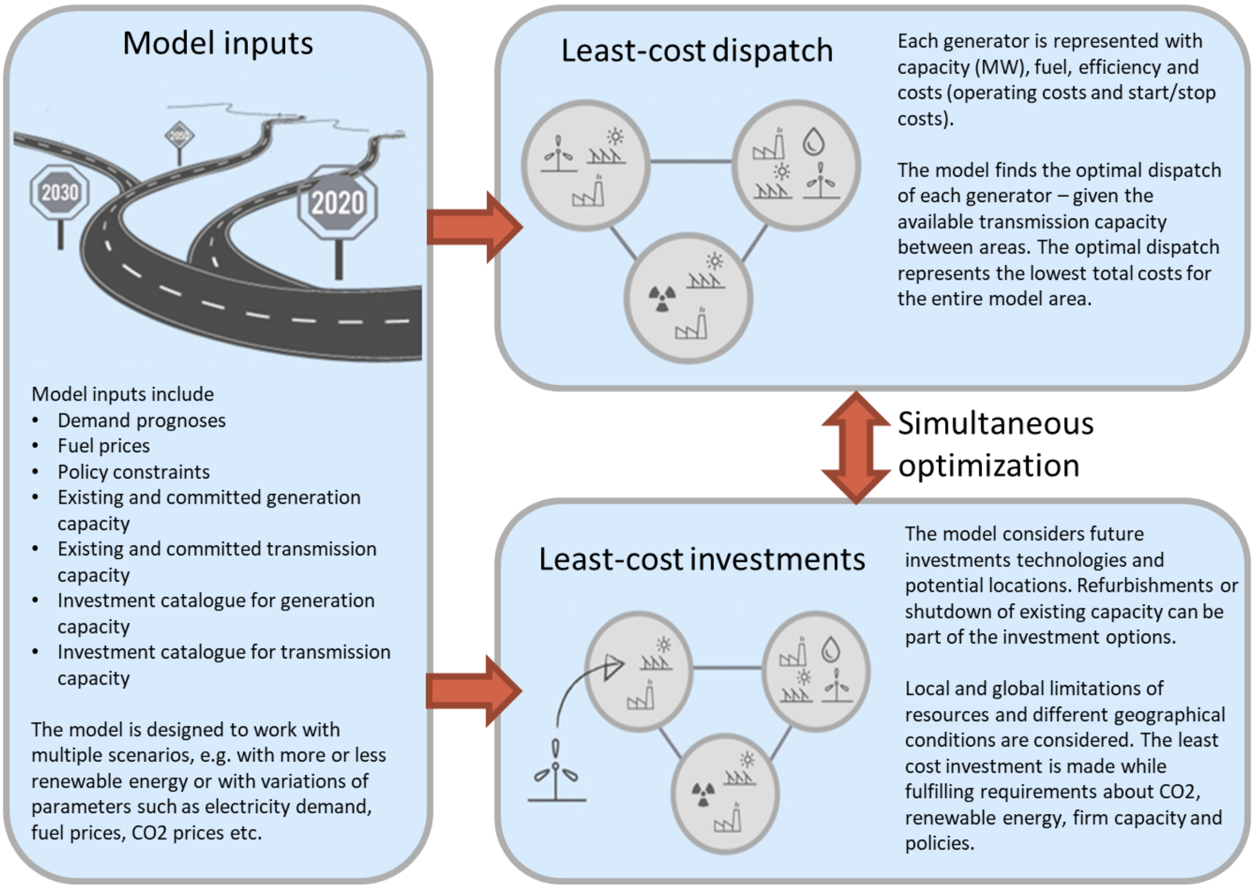


Figure 41: Balmorel model inputs and optimization logic.

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

B-I. GEOGRAPHICAL RESOLUTION

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

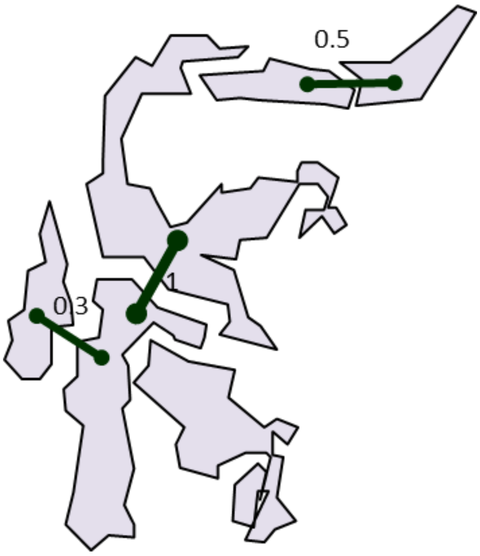


Figure 42: Sulawesi Island represented in 5 transmission regions. Interconnector capacity shown (in GW) for 2018.

The island is represented in the Balmorel model as 5 dispatch-regions, each with its own electricity consumption. The transmission regions are connected by electricity transmission lines with fixed capacity. As of 2018, only the power systems of Gorontalo and North Sulawesi are connected, via a 500 MW power line as well as South Sulawesi with West and Centre Sulawesi (300 MW and 1 GW respectively)

While the focus of this study is on North Sulawesi and Gorontalo, 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 North Sulawesi and Gorontalo, each unit is represented separately, while for the other regions groups of power plants are represented depending on the fuel type.

B-II. TIME RESOLUTION AND UNIT COMMITMENT

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

To limit the computation time, not all hours of the year are included in the simulation. The dispatch and investment optimisation, both in generation capacity and in transmission capacity, are performed with 25 hourly time segments and 26 seasons (25x26 = 2,526) time-steps. The 26 seasons represent two-week periods in the year, where the hours are aggregated into 25 intervals representing evening peak demand, afternoon solar peaks, nights, morning etc. A more accurate dispatch optimization is analysed in an hourly representation (52x168 =8760 time-steps).

Unit commitment

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

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

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

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

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

B-III. EXISTING AND COMMITED GENERATION CAPACITY

As a starting point, the existing generation fleet in 2018 is implemented in the Balmorel model. To represent the current power system, each existing power plant has been modelled individually, with information about the efficiency, variable and fixed operation and maintenance cost, as well as emission and unit commitment data. As of 2018, the total generation capacity in the Sulutgo system was about 620 MW.

Planned projects under RUPTL19

For all model-optimised 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 BaU scenario, all buildout in the RUPTL is included until 2028. The generation capacity included in the model for North Sulawesi and Gorontalo is shown Figure 43.

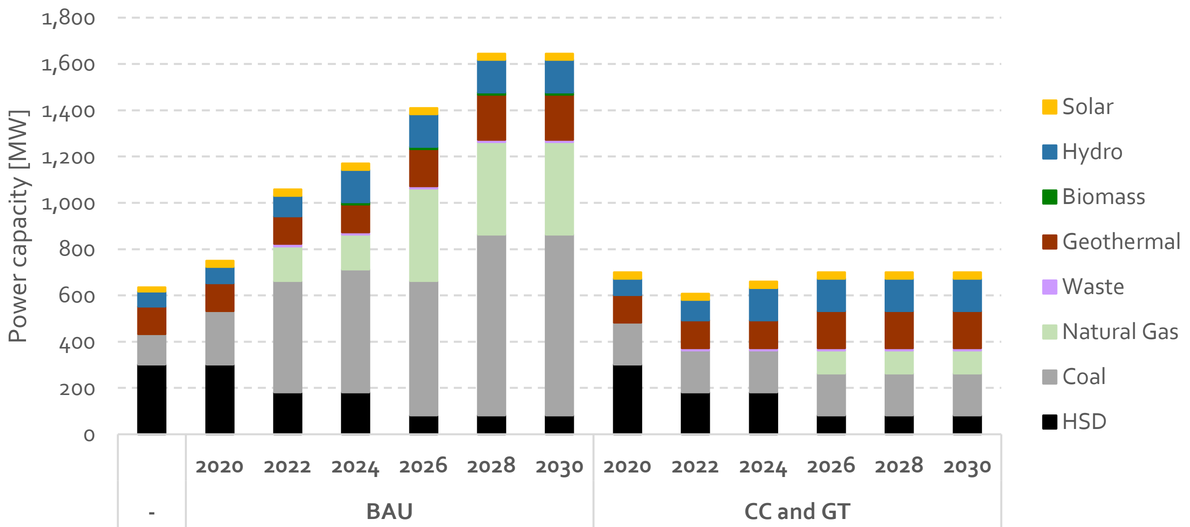


Figure 43: Existing and committed capacity entered in the Balmorel model as input in the BaU, CC and GT scenario for NS and GO.

Table 5: Planned generation units for North Sulawesi and Gorontalo included in RUPTL 2019.

System	Type	Fuel	Location/Name	Capacity (MW)	COD	Status	Ownership
North Sulawesi							
Talaud	PLTU	Coal		6	2019	Konstruksi	PLN
Sulbagut	PLTS	Solar	Likupang	15	2019	Konstruksi	IPP
Molibagu	PLTM	Hydro	Dominanga	3.5	2020	Pendanaan	IPP
Sulbagut	PLTM	Hydro	-	8	2021	Rencana	IPP
Sulbagut	PLTU	Coal	Sulut 3	2 x 50	2021	Pengadaan	IPP
Sulbagut	PLTSa	Waste	-	10	2022	Rencana	IPP
Sulbagut	PLTA	Hydro	-	30	2023	Rencana	IPP
Sulbagut	PLTM	Hydro	-	10	2023	Rencana	IPP
Sulbagut	PLTBio	Biomass	-	10	2023	Rencana	IPP
Sulbagut	PLTA	Hydro	Sawangan	12	2024	Rencana	PLN
Sulbagut	PLTP	Geothermal	-	40	2025	Rencana	IPP
Sulbagut	PLTGU	Natural gas	Sulbagut 1	150	2026	Rencana	Unallocated
Sulbagut	PLTP	Geothermal	-	35	2028	Rencana	IPP
Sulbagut	PLTMG	Natural Gas	Minahasa	150	2021/22	Rencana	PLN
Sulbagut	PLTU	Coal	Sulut 1	2 x 50	2021/22	Pengadaan	PLN
Sulbagut	PLTU	Coal	Sulbagut 3	2 x 50	2024/25	Rencana	IPP
Sulbagut	PLTU	Coal	Sulbagut 2	2 x 100	2027/28	Rencana	Unallocated
Gorontalo							
Sulbagut	PLTU	Coal	Gorontalo (FTP1)	2 x 25	2019	Konstruksi	PLN
Sulbagut	PLTS	Solar	Isimu, Gorontalo	10	2019	PPA	IPP
Sulbagut	PLTM	Hydro	Iya	2	2020	Pengadaan	IPP
Gorontalo	PLTM	Hydro	Bone Bolango	9.9	2021	PPA	1PP
Sulbagut	PLTU	Coal	Sulbagut 1	2 x 50	2020/21	Pengadaan	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 North Sulawesi and Gorontalo was included until 2050. For the other provinces in Sulawesi, RUED generation targets were set (Table 7).

Table 6 RUED expected capacity expansion.

Gorontalo (MW)

Pembangkit	2015	2020	2025	2030	2035	2040	2045	2050
PLTU Batubara	21.0	71.0	271.0	271.0	271.0	271.0	271.0	271.0
PLTGU Gas	-	100.0	200.0	300.0	400.0	500.0	600.0	700.0
PLTG Minyak	100.0	100.0	100.0	75.0	75.0	75.0	50.0	50.0
PLTD Minyak Solar	23.2	49.5	49.5	25.0	25.0	25.0	25.0	-
PLT Mini/Mikrohidro	6.2	8.2	28.0	38.0	48.0	58.0	65.0	70.0
PLT Panas Bumi	-	-	20.0	30.0	50.0	70.0	90.0	110.0
PLT Biomasa	-	2.0	12.0	22.0	37.0	47.0	62.0	72.0
PLT Surya	2.0	10.0	32.0	47.0	62.0	77.0	92.0	112.0
PLT Bayu	-	-	5.0	12.0	20.0	25.0	30.0	40.0
Total	152.4	340.7	717.5	820.0	988.0	1,148.0	1,285.0	1,425.0

North Sulawesi (MW)

No	Branches	2015	2020	2025	2030	2035	2040	2045	2050
1	PLTU Batubara	33.00	225.00	300.00	600.00	725.00	850.00	1,150.00	1,400.00
2	PLTGU Gas	-	-	150.00	150.00	150.00	150.00	150.00	150.00
3	PLTG Gas	-	150.00	150.00	150.00	150.00	150.00	150.00	150.00
4	PLTMG Gas	-	20.00	30.00	60.00	60.00	90.00	90.00	90.00
5	PLTD Minyak	146.00	121.67	60.83	-	-	-	-	-
6	PLTA	51.20	63.20	118.44	150.00	175.00	200.00	300.00	400.00
7	PLT Mini_Mikrohidro	0.20	9.25	17.60	17.60	17.60	17.60	17.60	17.60
8	PLT Panas Bumi_PLTP	75.00	100.00	175.00	225.00	275.00	300.00	350.00	400.00
9	PLT Biomasa	-	-	-	20.00	40.00	60.00	80.00	100.00
10	PLT Surya_PLTS	0.70	14.75	35.00	100.00	150.00	200.00	300.00	500.00
11	PLT Bayu_PLTB	-	4.17	25.00	40.00	55.00	70.00	85.00	100.00
	Total	306.10	708.03	1,061.88	1,512.60	1,797.60	2,087.60	2,672.60	3,307.60

Table 7: Generation shares in the RUED scenario, for all provinces.

		2020	2025	2030	2040	2050
Gorontalo	**RE share**	8%	16%	19%	27%	35%
	Gas share	13%	27%	30%	37%	44%
	Coal share	8%	48%	42%	31%	19%
North	**RE share**	46%	46%	47%	48%	49%
	Gas share	10%	20%	18%	14%	10%
	Coal share	24%	32%	34%	37%	41%
Centre	**RE share**	26%	33%	36%	41%	47%
	Gas share	4%	8%	13%	24%	34%
	Coal share	54%	58%	50%	34%	18%
South	**RE share**	57%	59%	61%	63%	66%
	Gas share	19%	16%	16%	17%	17%
	Coal share	21%	25%	23%	20%	17%
South East	**RE share**	5%	8%	12%	21%	30%
	Gas share	1%	2%	3%	5%	7%
	Coal share	48%	85%	80%	70%	60%
West	**RE share**	87%	90%	91%	93%	96%
	Gas share	5%	10%	9%	6%	4%

B-IV. MODEL-BASED INVESTMENT APPROACH

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

A balanced risk and reward characteristic of the market is assumed, which means that the same ARR is applied to most technologies, specifically 0.1175, which is equivalent to 10% internal rate of return for 20 years. This rate should reflect an investor's perspective. For the 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 8 summarizes the technologies available for investments and the main technical and financial assumptions in 2020. For some technologies, learning rates are assumed for years beyond 2020, resulting in decreased costs or increases efficiencies.

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

Technology		Investment cost	Variable O&M cost	Fixed O&M cost	Efficiency	Size
		$/MW	*$/MWh*	*k $/MW*	%	*MW*
Subcritical coal	PLTU	1.65	0.13	45	34%	50
Combined cycle gas turbine	PLTGU	0.75	0.13	23	56%	10
Geothermal plant	PLTP	4.5	0.37	20	-	20
Biomass power plant	PLTMG	2.5	3	48	29%	10
Waste power plant	PLTSa	8.4	-	277	35%	20
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 Sulawesi should at any point have enough dispatchable capacity to cover its peak demand. Dispatchable capacity includes coal, diesel, natural gas, biomass, waste, geothermal, reservoir hydro and batteries.

B-V. FUEL SUPPLY AND PRICES

Fuel prices used for the simulations are based on PLN Statistics for 2017 (PT PLN Persero 2017), while the long-term projections follow the development of the New Policy scenario of the World Energy Outlook 2018 (International Energy Agency 2018) (Figure 44).

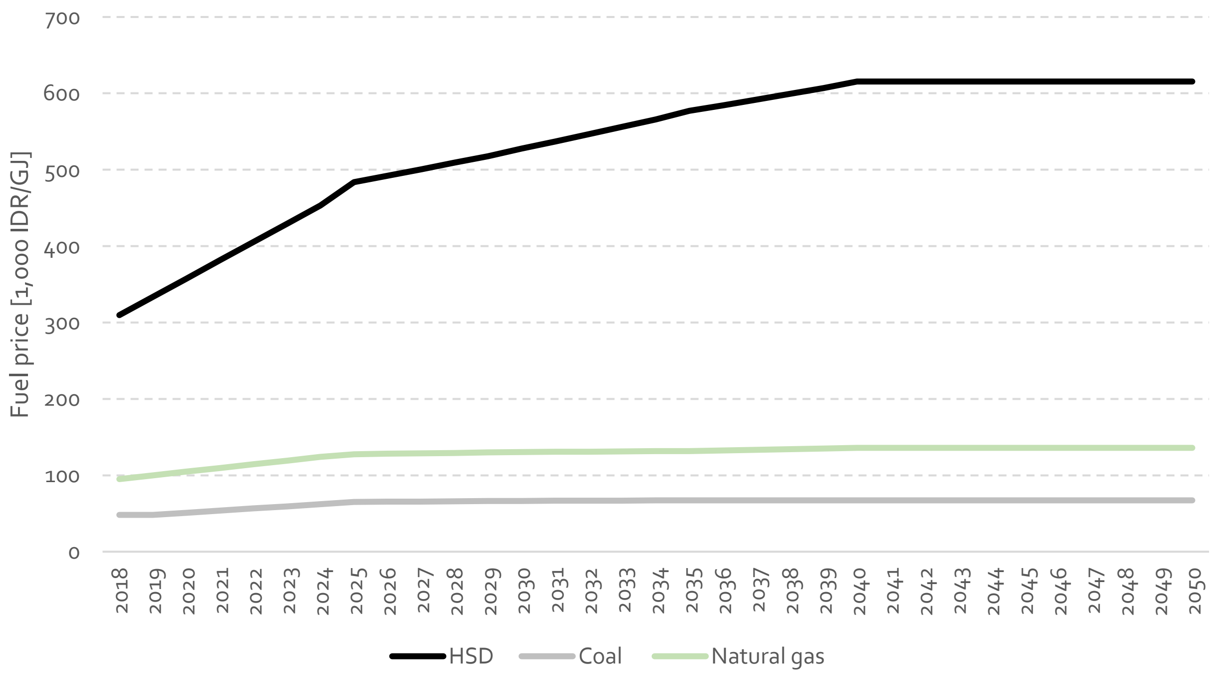


Figure 44: Fuel price projections for North Sulawesi and Gorontalo.

B-VI. INTERCONNECTORS

Interconnectors until 2030 are included in the model as input and not optimised, due to difficult planning processes and long planning horizons. 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) and feedback from local PLN (PLN Sulutgo 2019).

- Small interconnection between Gorontalo and Central Sulawesi (35 MW) assumed from 2024. Larger interconnection after 2030
- Interconnection between Gorontalo and North Sulawesi is gradually expanded from 500 MW to 1800 MW in 2030

Table 9: Transmission capacity in Sulawesi. Source: (Directorate General of Electricity 2019), (PLN Sulutgo 2019) .

	Centre Gorontalo	Centre South	Centre South East	Centre West	Gorontalo North	South South East	South West
2019		1000	3000	400	500	300	300
2020		1000	3000	400	500	300	300
2021		3000	3000	400	700	300	300
2022		3000	3000	400	900	300	300
2023		3000	3000	400	1100	300	300
2024	35	3000	3000	400	1300	300	3300
2025	35	3000	3000	400	1500	300	3300
2026	35	3000	3000	400	1600	300	3300
2027	35	3000	3000	400	1600	300	3300
2028	35	3000	3000	400	1700	300	3300
2029	35	3000	3000	400	1700	300	3300
2030	35	3000	3000	400	1800	300	3300
>2030	600	3000	3000	400	1900	300	3300

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-optimised transmission can be added to the interconnector grid. Transmission line investment costs are given in Table 10.

Table 10: Investments costs for additional transmission lines after 2030 (Million IDR/MW).

Gorontalo	**Centre**	15.347
North	**Gorontalo**	6.891
South	**Centre**	12.529
South East	**Centre**	9.710
South East	**South**	18.793
West	**Centre**	2.662
West	**South**	9.396

B-VII. RE RESOURCES

Wind power resource

The hourly wind speed profile used is from *Wind Prospecting*, an open-source meso-scale model of wind developed by EMD International for the ESP3 program (EMD International 2017). The assumed turbine model, Vestas V150, has relatively low specific power and could result in more than 3,000 FLH at the site.

Combining hourly wind speed with the power curve of the turbine permits calculation of an expected generation profile to be used in the model (Figure 45).

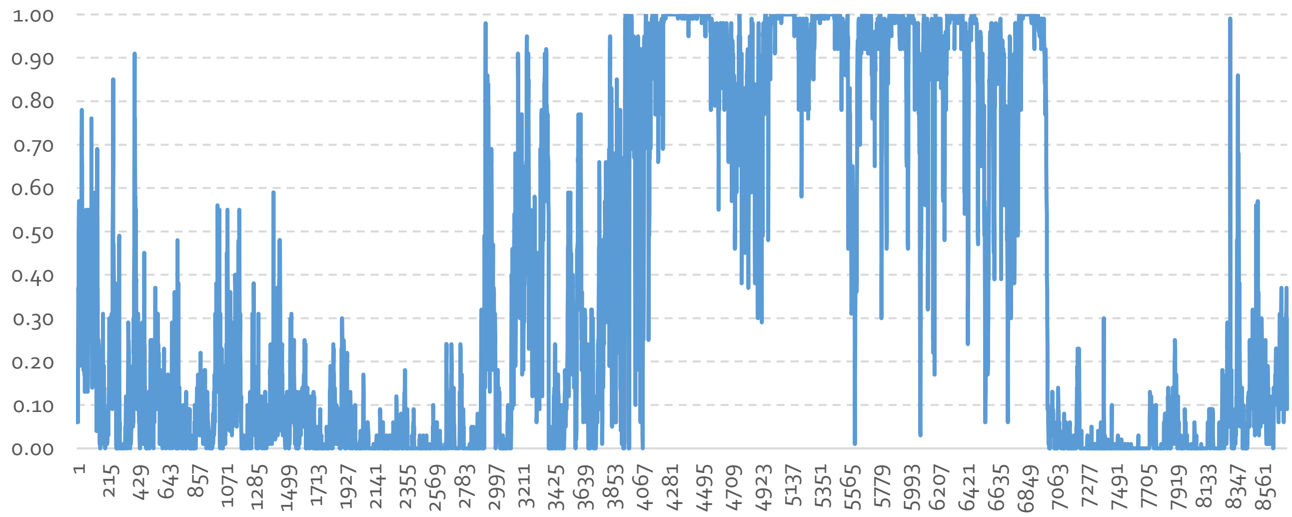
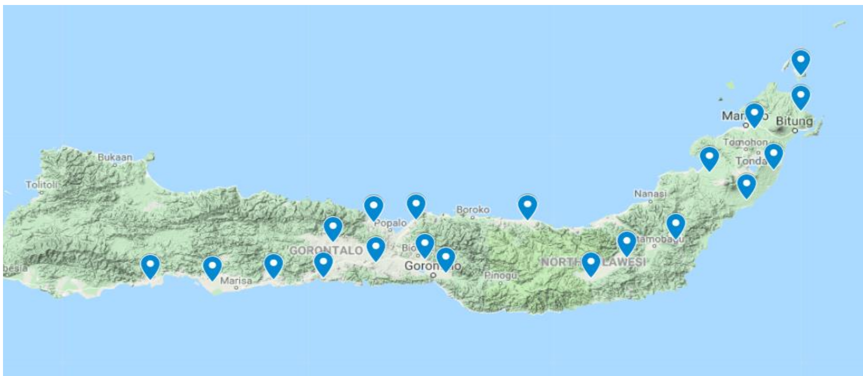


Figure 45: Wind variation profile considered in the model.

Solar power resource

To represent the diversity of solar resources, 40 locations distributed around the island have been selected (10 in North Sulawesi and 10 in Gorontalo – see Figure 46) 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 GO and NS has then been distributed accordingly.



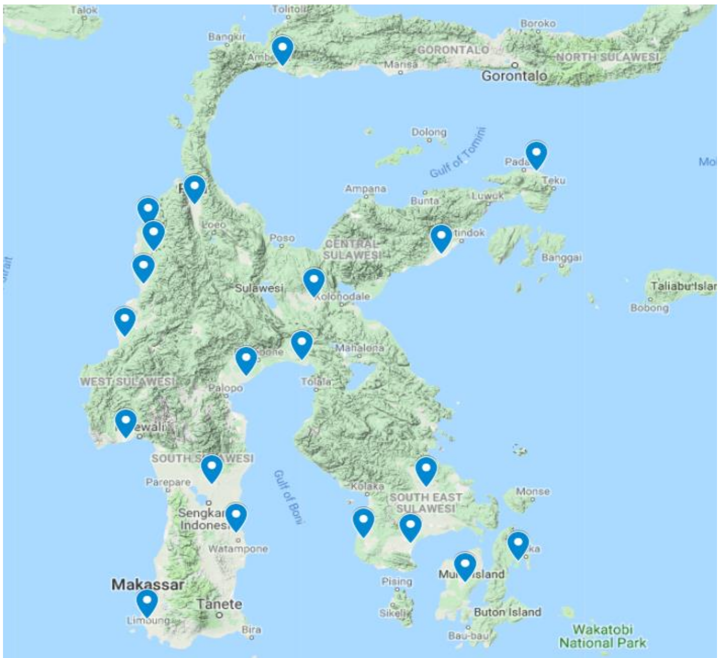


Figure 46: Locations used to estimate solar resource and total potential in North Sulawesi, Gorontalo and the rest of Sulawesi.

The hourly solar irradiation is quite constant throughout the year with a more constant irradiation during the dry season (May-October), making the low seasonality of solar attractive for the power system. The hourly profiles considered are based on the website Renewables Ninja (Pfenninger and Staffell 2019), see Figure 47.

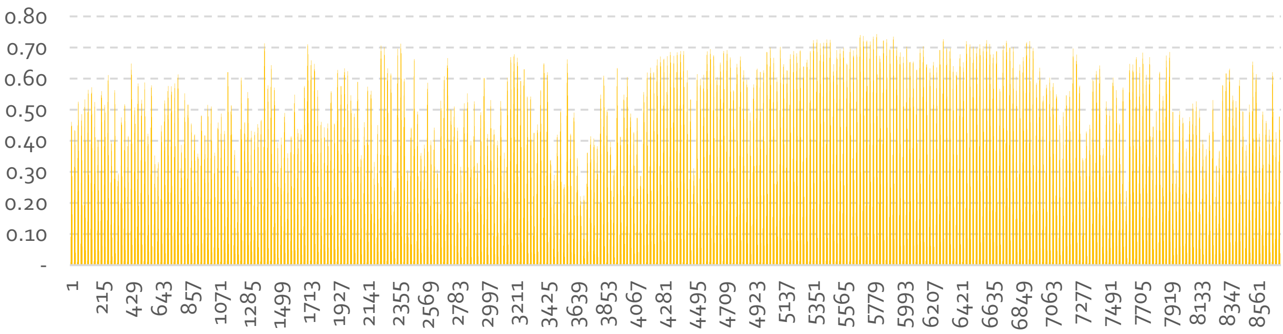


Figure 47: Solar variation profile considered in the model.

As solar power is a relatively new technology and investments in new solar might necessitate further investments in transmission and distributions grids, a maximum allowed additional investment per years has been assumed for solar power as shown in Table 11.

Table 11: Allowed expansion rate (MW/year) for solar power.

Gorontalo	125
North	375
Centre	250
South	1125
South East	250
West	125