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The present report was developed with the support of National Energy Council (NEC), PLN Nusa Tenggara Barat (NTB) and Dinas ESDM NTB. 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.

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Foreword

The Danish Energy Agency is having a valuable cooperation with the Indonesian partners in long-term energy planning, integration of renewable energy and energy efficiency. Previous activities have focused on national energy planning, but in this study we continue the cooperation at province level in order to address more specific challenges and opportunities for low carbon transition in Lombok. The Lombok Energy Outlook 2030 shows a promising potential for renewable energy, reduction of local pollution and reduction of energy costs for the population of Lombok. We are looking forward to continue the successful cooperation with our Indonesian partners in the future.

Martin Hansen

Deputy Director General

Danish Energy Agency

These studies have been developed in a fruitful cooperation between Indonesian partners and the Danish Energy Agency, and we have shared a lot of information, knowledge and experiences about low carbon energy planning. The studies and added capacities are of great value for the current and future energy planning in Lombok. I am very pleased to see that Lombok shows a great potential for large scale renewable energy. Now we need to move into the implementation phase and I hope that Lombok Energy Outlook will inspire investors to come to Lombok.

Pak Saleh Abdurrahman

Secretary General

National Energy Council

I am pleased to see how the modelling and energy planning can contribute to spark an interesting and needed low carbon transition. It lays the foundation for sound policy making and hopefully can inspire policy makers to turn targets into action. I remain confident that Lombok could be an excellent showcase for Indonesia to kick off a green transition. Once Lombok takes the bold decisions to move forward on a green path my wish is that other provinces will follow in their footstep and replicate those endeavours.

Rasmus Abildgaard Kristensen

Ambassador

Danish Embassy in Indonesia

Lombok Energy Outlook 2030 clearly documents the potential for an accelerated green transition for the benefit of people, business and the environment. The Danish Energy Industry sees Indonesia as a great partner country with a large potential for further collaboration in many fields. We are ready to engage further, sharing Danish experience in energy planning and to provide partnership, technologies and investment to the green transition in Lombok and beyond

Troels Ranis

Director

Confederation of Danish Industries - Energy

Executive summary

As part of the engagement between Denmark and Indonesia under the Strategic Sector Cooperation, the Danish Energy Agency and the National Energy Council chose Lombok as a pilot area to study how the expected increase in electricity demand can be met in a cost-efficient and sustainable way. The study in particular focuses on the potential benefits and challenges related to large-scale deployment of variable renewable energy technologies.

Lombok is an island in the West Nusa Tenggara province, located between Bali and Sumbawa. The power system on the island is not interconnected to the main Java-Bali system and today most of the power supply is based on diesel generation, resulting in an average generation cost among the highest in Indonesia (13.9 c$/kWh). The demand has been growing at a fast pace and the expectation is that this growth will continue, driven by electrification and economic development, resulting in more than doubling of annual power consumption by 2030. The island is blessed with a rich and diverse potential for renewable energy, including geothermal, cheap biomass residues, a good irradiation suited for solar PV, fairly windy sites on the south coast, as well as opportunities for hydro power plants, pumped-hydro, biogas and a consistent amount of municipal solid waste.

The **Lombok Energy Outlook 2030** explores the potential evolution of Lombok power system from a planning and techno-economical perspective using least cost optimization, across a number of different scenarios. The objective of the study is to assess what is the most cost-efficient development of the power system in Lombok, considering local resources available, the cost of technologies and fuel availability/price. Furthermore, the objective is to assess what would be the cost of increasing renewable energy deployment in Lombok.

To answer these questions, the economic optimization model Balmorel is applied for optimizing capacity expansion and merit order dispatch on a least cost basis. The representation of the Lombok power system in the model, including details about current generation fleet, resource potentials and technology costs and characteristics, has been developed in close collaboration with PLN NTB and Dinas ESDM.

Four main scenarios are analysed and compared throughout the report, all of them assuming the power demand will increase in accordance with the official projections. The Business-as-Usual scenario, which is based on the capacity expansion plans of the RUPTL, almost exclusively relies on new coal and gas power capacity to satisfy the growing power need while in the three other scenarios, the model determines future deployment of capacity on a least cost basis under different framework conditions regarding fuel prices and cost of pollutants:

1. **Business-as-Usual (BaU):** developed based on the latest assumptions in RUPTL 2018-2027 from PLN. No investments in additional capacity and no costs for externalities are considered in the dispatch mechanisms.

2. **Least cost development under current conditions (Current Condition):** capacity from RUPTL is considered only until 2019 (projects already committed or under construction), while the rest of the development of power capacity is optimized by the model.

3. **Least cost development with no fossil fuel subsidies (No Fossil Subsidies):** considers the market-based fuel price for coal and gas, simulating a discontinuation of the domestic market obligation and price caps set by the government for coal and gas.

4. **Socioeconomic least cost development (Socioeconomic):** in addition to removing the subsidies to coal and gas, the health costs related to the emission of pollutants from power plants, such as NO_x, SO_2 and $PM_{2.5}$ are considered in the investment and dispatch optimization.

The model analyses show that there is a large potential for developing economically feasible renewable energy projects; a potential that increases over time as the cost of renewable energy technologies are expected to continue declining.

Biomass power, based on rice husk and corn residues, appears to be the most cost-efficient option for new capacity, coming into play already in 2020-2022 across all three least cost scenarios. Geothermal power also appears very competitive and provides a significant share of generation in all three least cost scenarios by 2030. Solar PV is not cost-efficient under the current conditions where fuel prices are capped, but in the No Fossil Subsidies scenario where subsidies to coal and gas are removed there is considerable deployment of solar PV. In the Socioeconomic scenario, where the cost of pollution is also considered in the optimization, the deployment of solar is further increased, along with wind power deployment.

All the least cost scenarios simulated have a substantially higher renewable energy share than the BaU with the Socioeconomic scenario reaching 58% renewable energy of the total generation by 2030 (Figure 1).

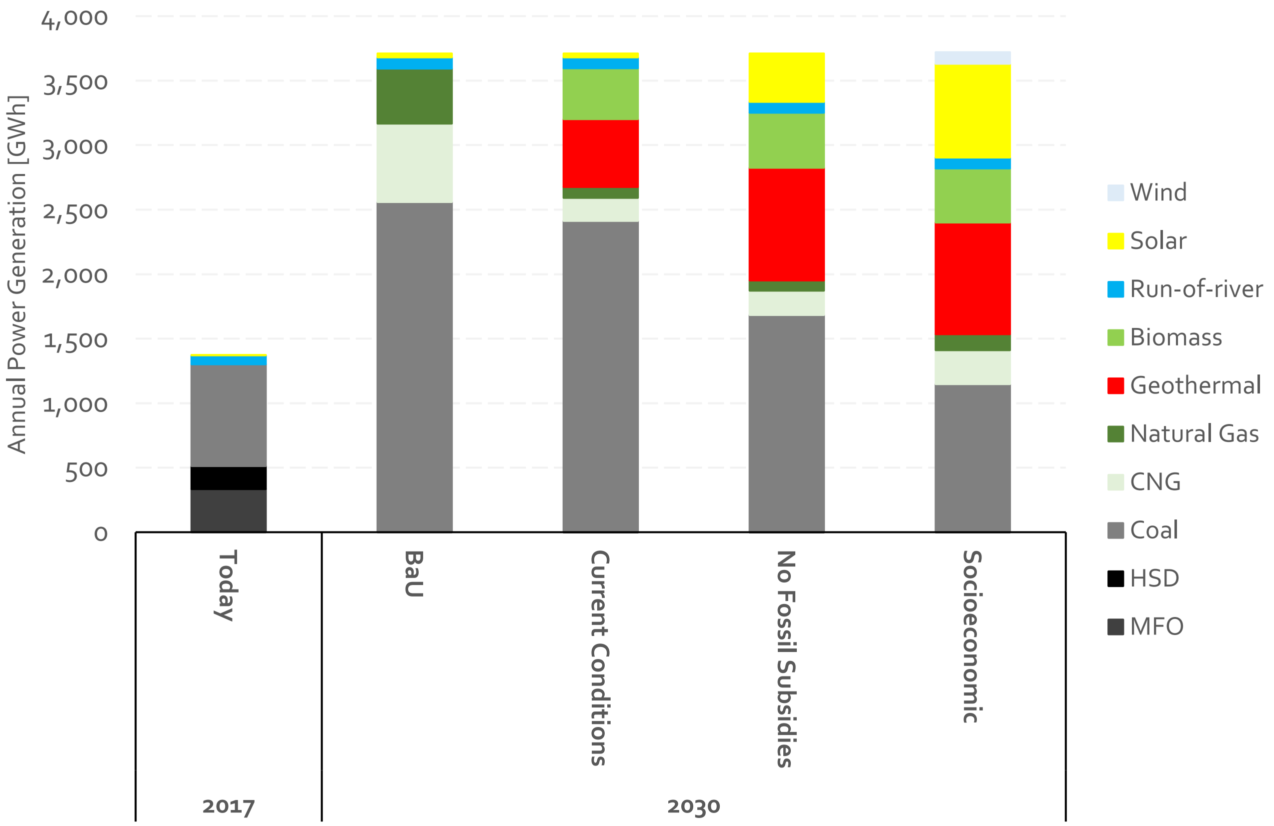

Figure 1: Generation in the Lombok power system in 2017 and 2030, across the scenarios simulated.

When the total economy of each of the scenarios is compared using the capped fossil fuel prices, and disregarding the costs of local pollution, the difference in total cost between all four scenarios is less than 10%. When considering market based fossil fuels price, i.e. adding the fuel price subsidies to cost, the BaU scenario stands out as the most costly option for Lombok, demonstrating total costs that by 2030 are approx. $50 million higher per annum than the three least cost scenarios that are almost on par. Adding pollution related health costs to the equation make the Socioeconomic and No Fossil Subsidies scenarios appear even more attractive relative to the Current Condition scenario and in particular the BaU scenario.

In other words, the study shows that reaching a share of almost 60% renewable energy is cost-efficient from a socioeconomic perspective. Even if pollution costs are ignored, it is still significantly cheaper than the BaU path relying on fossil fuels.

Since renewable energy technologies are generally quite investment heavy, but low on operating expenses, capital cost dominating in the scenarios with higher share of renewable energy. The model optimization is based on a real discount of 10% per annum, representing a commercial investor's perspective. If cheaper financing would be available, for example through an international carbon financing mechanism, this would significantly benefit the scenarios with high renewable energy shares. As an example, decreasing the real discount rate to 5%, reduces the capital cost of the Socioeconomic scenario by $54 million whereas the cost of the BaU only decreases $25 million.

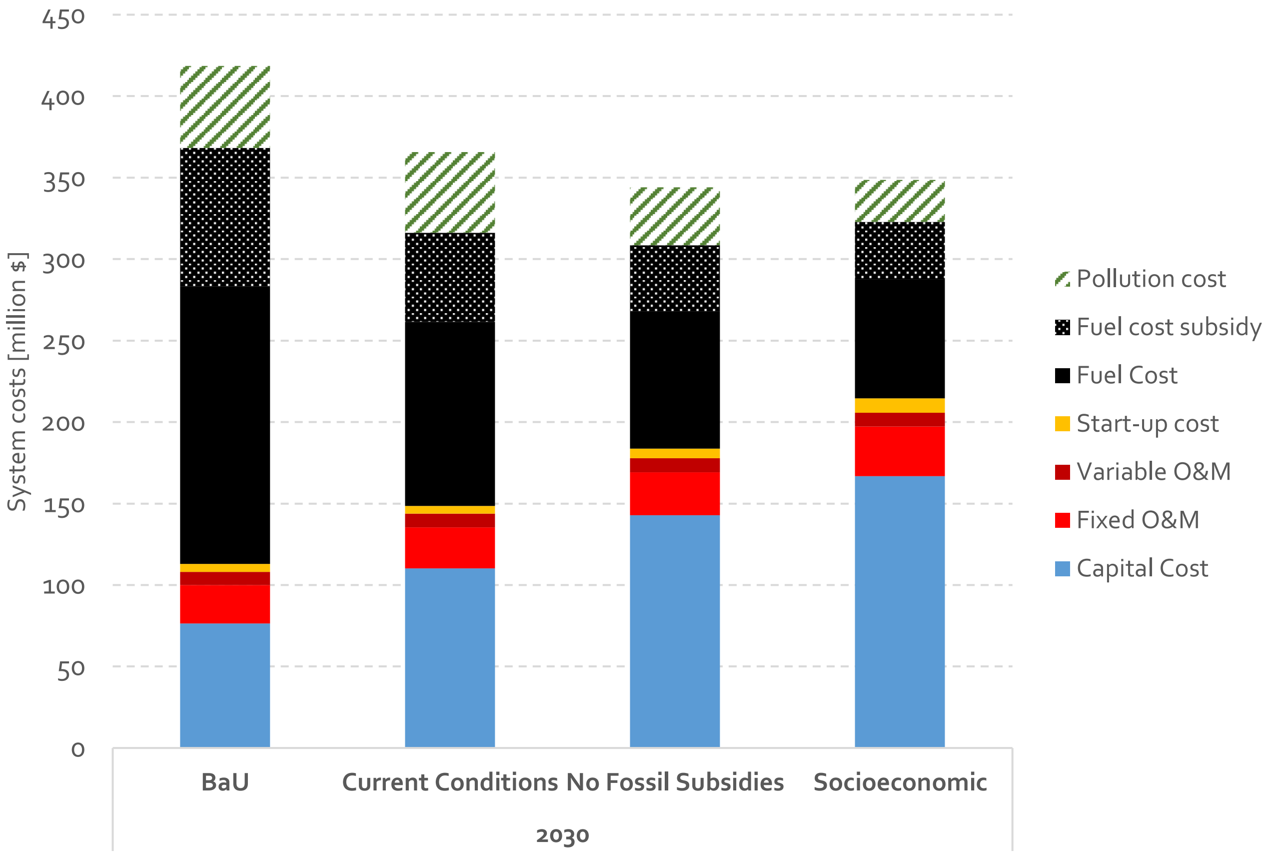

Figure 2: Total system costs in 2030 by cost component, with the addition of the cost of fuel subsidy and pollution cost.

The choice of one of the two paradigms for the development for the power system in Lombok – fossil fuel or renewable energy based – poses both challenges and opportunities.

A fossil fuel dominated system is more exposed to the risk of fuel price fluctuation, has higher emissions of harmful pollutants and faces the risk of technology lock-in. On the other hand, it is less complex and easier to operate, as well as having a slightly lower generation cost.

Conversely, a future with large share of variable renewable generation will face a higher inherent complexity and a stronger focus on integration measures, such as improved flexibility of power plants, forecasting system and advanced operational practices. On the other hand, the system would be more resilient to fuel price fluctuation, emit less pollutants and could potentially create local jobs and increase of touristic value of the island. CO_2 emissions are currently not regulated in Indonesia, however, this may change in the future, as a means for Indonesia to fulfil its obligations under the Paris agreement. Adding for example a moderate cost of $25 per tonne CO_2, increases the cost of the BaU scenario by $82 million whereas the cost of the Socioeconomic scenario only goes up by $36 million.

In the coming years, local as well as national stakeholders, will face important decisions to ensure affordable, reliable and accessible electricity for the people of Lombok. We hope that this report and other related activities can help support these decisive planning choices for the future Lombok power system.

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Nomenclature

Abbreviations

BPP	Biaya Pokok Penyediaan (average generation cost)
CF	Capacity Factor
CNG	Compressed Natural Gas
COD	Commissioning Date
DEA	Danish Energy Agency
Dinas ESDM	Dinas Energi Sumber Daya dan Mineral
DMO	Domestic Market Obligation
EVA	Economic Evaluation of Air pollution
FLH	Full Load Hours
GDP	Gross Domestic Product
GHI	Global Horizontal Irradiation
HSD	High Speed Diesel
IPP	Independent Power Producer
KEN	Kebijakan Energi Nasional
LcoE	Levelized Cost of Electricity
LNG	Liquified Natural Gas
MEMR	Ministry of Energy and Mineral Resources, Indonesia
MIP	Mixed-Integer Problem
MFO	Marine Fuel Oil
MPP	Mobile Power Plant
mmscf	Million standard cubic feet
mmscfd	Million standard cubic feet per day
NEC	National Energy Council, Indonesia
NTB	Nusa Tenggara Barat (West Nusa Tenggara)
OPEX	Operational cost
PLN NTB	Lombok Regional Power Company
PPP	Purchasing Power Parity
PV	Photovoltaics
RE	Renewable Energy

RES	Renewable Energy Sources
RUED	Rencana Umum Energi Daerah
RUPTL	Rencana Usaha Penyediaan Tenaga Listrik (electricity supply business plan)
SSC	Strategic Sector Cooperation
SWOT	Strengths-Weaknesses-Opportunities-Threats
TSO	Transmission System Operator
VRES	Variable Renewable Energy Sources (wind and solar)

Power plant and fuel definition

PLTU	Coal
PLTG	Gas
PLTGU	Combined cycle gas plant
PLTS	Solar
PLTA	Hydro
PLTM	Mini/Micro Hydro
PLTP	Geothermal
PLTB	Wind
PLTSa	Waste
PLTBM	Biomass
PLTD	Diesel

1. Introduction

Indonesia and Denmark are cooperating through a Strategic Sector Cooperation, which facilitates government-to-government collaboration in areas where Denmark has decades of experience, which is valuable to rapidly emerging economies. The Strategic Sector Cooperation program is embedded in the Ministry of Foreign Affairs with technical support from different ministries and agencies in Denmark. The Danish partner of the Strategic Sector Cooperation (SSC) program is the Danish Energy Agency (DEA) and the main partners in Indonesia are the Ministry of Energy and Mineral Resources (MEMR) and the National Energy Council (NEC), who are both represented in the steering committee. At the same time, the Danish Energy Agency also cooperates with the state-owned Indonesian electricity company (PLN).

During the period from 2016 to 2018, the DEA has cooperated with the Indonesian counterparts in order to share Danish lessons learned from the transition into a renewable energy (RE) system and identify where and how these lessons learned could be useful in an Indonesian context.

The Lombok Energy Outlook report is a regional case study of the power system in the island of Lombok, part of the West Nusa Tenggara province. The objective of the study is to assess cost-efficient developments of the power system in Lombok, taking into account available local resources, cost of technologies and fuel availability/price, thus providing support to the local stakeholders in the development of the future regional energy planning.

The study is part of a larger engagement in supporting the island of Lombok in the field of energy planning and integration of RE. Another activity related this engagement is the preparation of Prefeasibility studies of potential RE projects in the island [1], including a biomass power plant, a solar PV power plant, a wind power plant, and a waste incineration power plant. In addition, an analysis of three technologies that can support integration of fluctuating energy sources (Interconnector to Bali from Lombok, Hydro pumped storage, and Large-scale battery) has been carried out, as well as an assessment of an off-grid PV/battery hybrid solution on the island of Medang.

The partners behind the project are:

- **Dewan Energi Nasional (DEN)**, also referred to as National Energy Council (NEC), is a national, independent and permanent institution that is responsible for national energy policy. National Energy Council is in charge of designing and formulating national energy policies to be determined by the government, establishing national energy general plans and supervise the implementation of cross-sectoral policies.
- **Perusahaan Listrik Negara (PLN) NTB**, the local branch of the national vertically-integrated power utility, which is responsible for the planning and operation of the power system of Lombok, Sumbawa and Bima.
- **Dinas Energi Sumber Daya dan Mineral (ESDM) NTB**, the local office of the Ministry of Energy and Mineral Resources (MEMR), responsible among other thing for regional energy planning in the province of West Nusa Tenggara.
- **The Danish Energy Agency (DEA)**, which is partnering with 12 countries around the world to create a clean, prosperous and low-carbon energy future by sharing experience, expertise and innovation from the green transition in Denmark. In Indonesia the Danish Energy Agency works closely with NEC and PLN.
- **Ea Energy Analyses** is a Danish company that provides consulting services and undertakes research in the fields of energy and climate mitigation and adaption. Ea Energy Analyses has been working with NEC and PLN in a number of projects related to energy modelling and RE integration in Indonesia.

1.1 BACKGROUND, CONTEXT AND OBJECTIVE

The NEC has proposed that the SSC program should study a pilot area in Indonesia in more detail in order to show how a long-term energy strategy with a high variable renewable energy (VRE) penetration technically could be possible and what the cost would be.

Given the current RE regulation and market conditions, the offered price for RE supplied to the grid is high in Lombok compared to Java/Bali, which makes Lombok more attractive for developing financially viable RE projects. As a result, it has been proposed to carry out an assessment for the Lombok system as a more detailed and realistic case of a regional study. Findings from this analysis could be applied in other regions as well. The current average production cost for electricity in Lombok is 13.68 cent$/kWh. In the light of international and national experience, several RE solutions could therefore be financially viable. The size of Lombok is 4,725 km^2 with approximately 3.4 million inhabitants. According to the National Energy Plan (RUEN), there is a large potential for especially photo-voltaic (PV) power production in the NTB province.

The objective of the study is to carry out a comprehensive and detailed power system analysis using case-specific data for a relatively small isolated energy system, namely the NTB province. The analysis will function as a separate regional case study which findings and recommendations will complement other DEA energy planning activities on a national level. Focus of this study is on the power system of Lombok and not the entire West Nusa Tenggara. Model setup for the Sumbawa-Bima system has been nonetheless initiated, in order to provide solid model representation for future exploration, in connection with RUED.

1.2 GENERAL INFORMATION ON LOMBOK

The island of Lombok is part of the Lesser Sunda Islands chain, with the Lombok Strait separating Bali to the west and Sumbawa to the east. It has a total area of 4,725 km^2 and belongs to the West Nusa Tenggara province (Nusa Tenggara Barat) of Indonesia. The provincial capital and largest city is Mataram, in the western part of the island.

Situated just south of the Equator, Lombok enjoys consistent hours of sunlight and warm temperatures throughout the year, ranging from a low of 24°C to a high of 34°C during the hot months and 20°C to 31°C during cooler months. There are two seasons: the dry season, from April to September, and the rainy season from October to March [2].

Figure 3: Lombok is situated between Bali and Sumbawa. Source: Bing Maps.

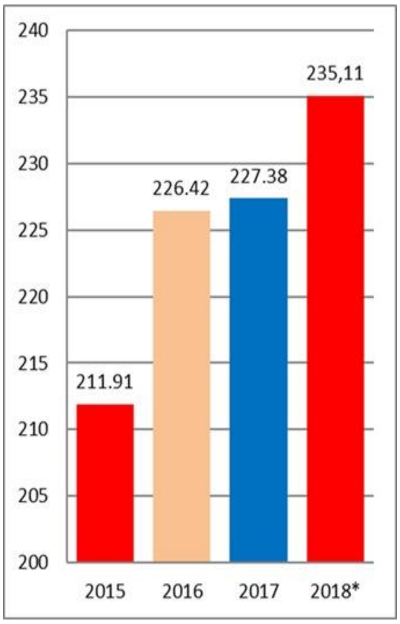
According to the 2014 census, the population of Lombok Island was 3.35 million. Between 2010 and 2014 the population average annual growth rate has been 1.1%, which is lower than the national population growth rate of 1.38% per annum between 2010 and 2015 [2].

1.3 LOMBOK POWER SYSTEM

The power system in Lombok today is almost entirely based on fossil fuels, with diesel being the main fuel in the mix, followed by coal. A small amount of generation from hydropower and solar power completes the current power supply (Figure 2).

The fuels used for the power supply are medium grade coal, High Speed Diesel (HSD) and Marine Fuel Oil (MFO). The coal used in the PLTU power plants on the island is medium grade with a calorific value of around 4,500 kcal/kg. While HSD is a distillate product with cetane number 45, used in a large range of application including transportation, MFO is an oil fuel which is not a distillate, but includes a type of residue that is thicker at room temperature and solid black. The use of this type of fuel is generally confined to direct combustion in large industries and it is economically cheaper than HSD.

The power demand on the island has been growing steadily in the last few years (Figure 4), with the peak consumption expected to total 260 MW by the end of 2018 [3]. The demand curve is relatively flat with a sharp increase in the load around 18:00 in the afternoon, with the peak lasting until roughly 21:00.



No	Energi Primer	2015 (GWh)	2016 (GWh)	2017 (GWh)	2018 (GWh)
1	HSD	588.66	486.77	344.38	113.77
2	MFO	272.75	464.76	450.74	204.23
3	BIODIESEL	-	38.76	29.63	-
4	AIR	49.04	63.70	58.96	30.27
5	BATUBARA	267.02	284.63	488.65	251.80
6	SURYA	0.64	0.99	1.07	0.41

Figure 4: Evolution of peak demand and generation in the period 2015-2018 (2018 provisional). Source: PLN NTB.

The electrification rate in the entire province of West Nusa Tenggara is 77%, with the lowest level of electrification to be found in Sumbawa-Bima. Lombok, however, has a total electrification rate of 87.7% as of October 2018 and only 3 villages are yet to be electrified.

The existing fleet, totalling 306 MW, consists of 3 coal power plants, 7 diesel power plants, a number of small hydro power plants scattered around Mount Rinjani and three solar power plants totalling 800 kW located in the Gili islands. Most of the power supply and demand occurs in the western part of the island, where the capital Mataram is located. The lower consumption centre is to be found on the East coast and is primarily supplied by local diesel power plants.

The transmission system is well developed and enables a single dispatch system without major congestions. The main system is a 150 kV network stretching from Mataram to East Lombok, which serves the city of Mataram, West Lombok district, Central Lombok district, East Lombok district and North Lombok district. Two medium 20 kV systems, as well as several small isolated systems (small islands) completes the power network of Lombok [3].

The power systems on three islands, Gili Trawangan, Gili Meno and Gili Air have been connected through a 20 kV sea cable to the mainland Lombok system since 2012. Recently, also the island of Gili Gede in the south west has been connected through a sea cable, enabling the reduction of local diesel generation and the provision of power 24 hours per day.

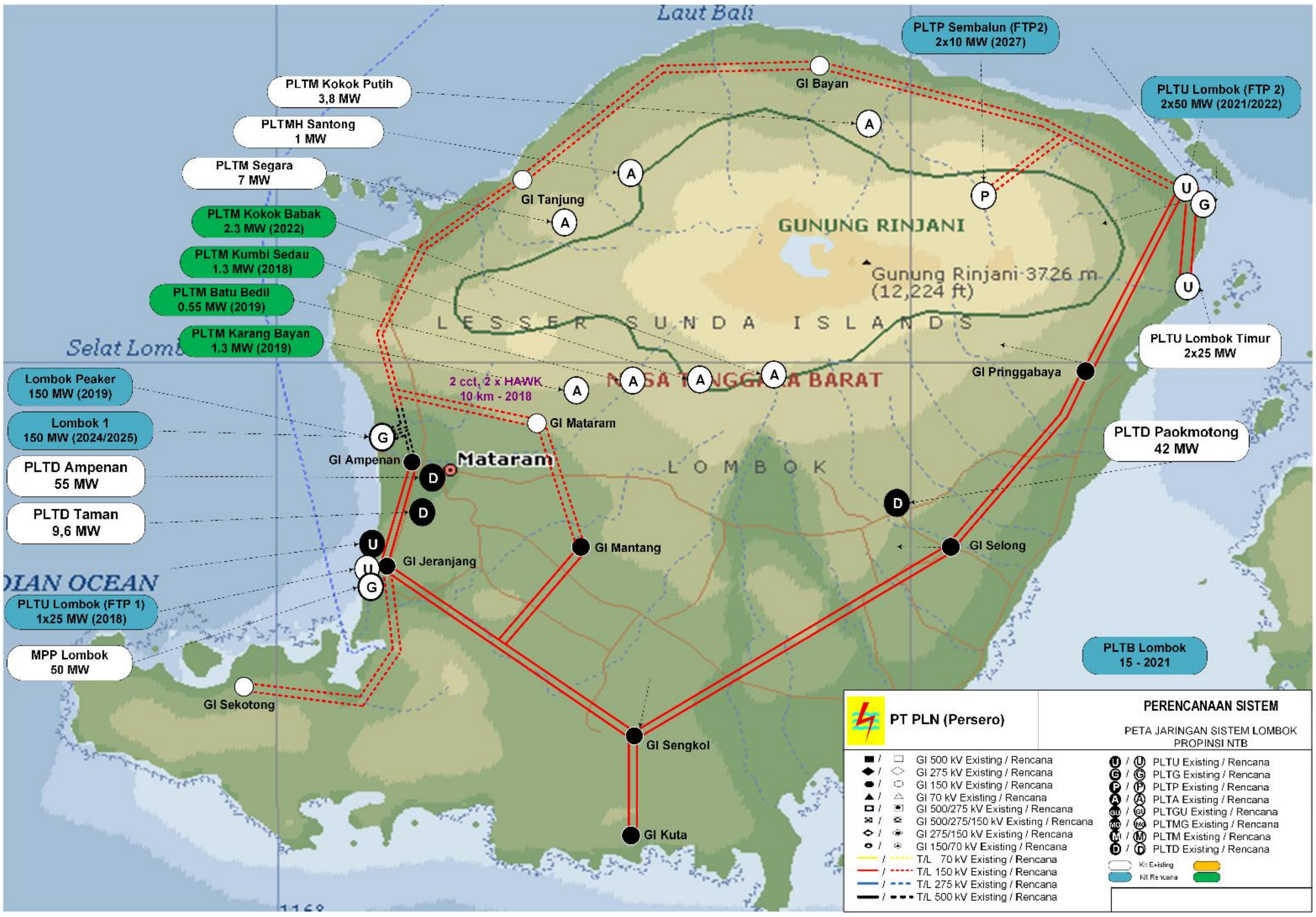


Figure 5: Lombok power system. Representation of transmission system, current generators and planned capacity expansion as for RUPTL. Source: PLN NTB

Due to the large share of power supplied by diesel plants and engines, the average generation cost (BPP) of the island is among the highest in all of Indonesia. In 2017, the generation cost was 1,861 IDR/kWh corresponding to 13.9 c$/kWh, while the cost in Java-Bali system, which is largely dominated by coal power, was 6.81 c$/kWh and the national average 7.66 c$/kWh [4].

The distribution of power sales for 2018, shown in RUPTL, clearly indicates that the largest consumer segments are households and private businesses (including touristic hotels and resorts). The industrial consumption is very low and is not expected to increase drastically in the near future.

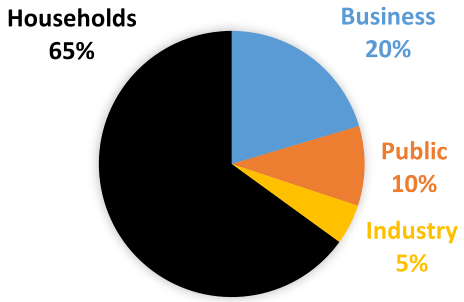


Figure 6: Power sales 2018 by consumer segment. Source: RUPTL.

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 during 2018 [3], covers the period 2018-2027 and includes demand projections based on GDP evolution in each province, and planned expansion of the transmission network and of the generation fleet.

The chapter related to the island of Lombok projects a steady increase of the demand, followed by an expansion of the generation fleet. Figure 7 shows the development of both peak demand and installed capacity in MW and the expected reserve margin for each year.

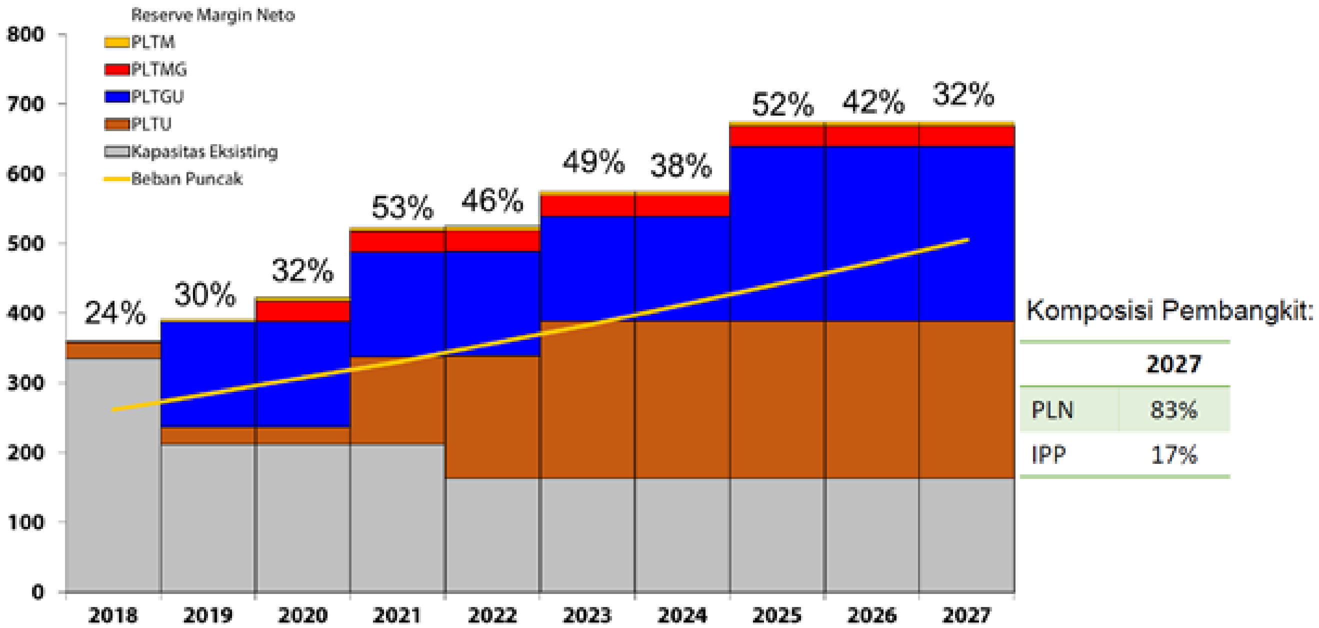


Figure 7: Development of peak demand and capacity expansion in MW in Lombok based on RUPTL 2018. Percentage for each year indicates the reserve margin in the system [3].

The main strategic power plant projects in the Lombok system include four new coal units in the Eastern part of the island (4x50 MW, PLTU Lombok FTP2 and PLTU Lombok 2) to meet the increasing demand and a 150 MW CNG gas peaker (Lombok PLTGU/MGU) to meet peak load.

An additional 15 MW of distributed RE projects (spread between Lombok and Sumbawa) are included in the list of unallocated projects. The capacity stated is solar (PLTS) with the possible alternative listed being hydro power (18 MW, Sumbawa), geothermal (20 MW, Lombok and Sumbawa) and wind power (15 MW).

The main observations from Figure 7are the following:

- Large gas capacity (blue) is planned to substitute the expensive bulk diesel generation on the island;
- The level of reserve margin in the system is projected to remain high with more than 30% in 2027 and more than 50% in some of the years.
- Despite the good RE potential on the island, the amount of RE projects considered by PLN in RUPTL remains low for the coming 10 years.

The following table, adapted from RUPTL, provides an overview of all projects in Lombok including the expected commissioning date (COD) and status.

Table 1: Planned generation units for the island of Lombok included in RUPTL 2018 [3].

Project number	System	Type	Fuel	Location/Name	Capacity (MW)	COD	Status	Ownership
2	Lombok	PLTU	Coal	Lombok (FTP 1)	25	2018	Under Construction	PLN
6	Lombok	PLTM	Hydro	Sedau Kumbi	1,3	2018	Under construction	IPP
7	Lombok	PLTS	Solar	Pringgabaya	5	2019	Procurement	IPP
8	Lombok	PLTS	Solar	Selong	5	2019	Procurement	IPP
9	Lombok	PLTS	Solar	Sengkol	5	2019	Procurement	IPP
10	Lombok	PLTS	Solar	Kuta	5	2019	Procurement	IPP
11	Lombok	PLTGU	Gas	Lombok Peaker	150	2019	Procurement	PLN
13	Lombok	PLTM	Hydro	Karang Bayan	1,3	2019	Under construction	IPP
14	Lombok	PLTM	Hydro	Batu Bedil	0,6	2019	Under construction	IPP
15	Lombok	PLTM	Hydro	Koko Babak	2,3	2020	Procurement	IPP
16	Lombok	PLTMG	Gas	MPP Sambelia	30	2020	Planned	PLN
19	Lombok	PLTU	Coal	Lombok (FTP 2)	100	2021	Procurement	PLN
21	Lombok	PLTU	Coal	Lombok 2	50	2022	Planned	PLN
22	Lombok	PLTU	Coal	Lombok 2	50	2023	Planned	PLN
24	Lombok	PLTGU/ MG	Gas	Lombok 1	100	2025	Planned	*Unallocated*
20	Distributed	PLTS	Solar (or other RE)	Distributed	15	2021	Planned	*Unallocated*

Challenges going forward

The isolated power system of Lombok faces several challenges today and in its next future development. These challenges have been identified in a dialogue with both PLN NTB and Dinas ESDM NTB, as well as based on a broader stakeholder discussion.

1. Affordable power supply to the island

In order to provide cheap electricity to the inhabitants of the island, actions need to be taken to reduce the high average generation cost (BPP). Among the potential measures to achieve a lower cost of electricity, the two most frequently mentioned solutions are:

- **Reduction of fuel oil in the mix:** the plan is to reduce the supply from diesel, mainly in order to reduce the supply cost, but also to limit pollutants in the mix and to reduce national import dependency. The planned 150 MW gas peaker is a step in this direction and it is expected to almost entirely offset the generation from diesel in the main grid system.
- **Interconnection to Java**: the interconnection of Lombok system to Java-Bali through a marine cable to Bali has been a topic of discussion. This would allow lowering the retail price and might support further integration of RE as well as improve grid stability. The project comes however with challenges which include high investment costs and deploying the cable in the deep strait which also has strong currents and occasional earthquakes [1].

2. Uncertain supply of gas and coal

Based on the projections from RUPTL, the power system of Lombok will rely largely on natural gas and coal.

Unlike other locations in Indonesia, Lombok does not have access to natural gas directly from the fields through a gas pipeline. For the new Lombok Peaker power plant, the gas is to be supplied in the form of CNG obtained from the gas supplier in Gresik (East Java). The gas is first compressed in Gresik's facilities, then transported to Lombok using a CNG vessel and finally decompressed in a local facility close to the power plant, located in the Tanjung Karang area, close to Mataram city.

The CNG vessel, transporting the gas to Lombok, is the first-of-its-kind in the world, and will have the capacity to transport as many as 23 mmscf per trip (21.6 BBTU per trip). The total supply available from compression facility of Gresik should be around 40 mmscfd (41 BBTU/day) and only part of this will be supplied to Lombok. The vessel takes 4 days to load, reach Lombok and unload. The daily supply to Lombok is therefore limited to around 5.4 BBTU/d and it is not clear whether it would be possible to expand this in the next future. The maximum daily supply of CNG using the vessel, corresponds to roughly 6 hours of operation at full load for the 150 MW power plant.

Two additional power plants are also supposed to be fueled with natural gas, in this case in the form of LNG: the existing MPP Power plant (50 MW) close to Mataram which is currently fueled with HSD and the planned Sambelia 30 MW power plant in the eastern part of the island. The original project is expecting mini LNG regassification facilities to be built on site, but no action has been taken so far and the government seems to be evaluating the actual increase in the power demand before investing in new LNG facilities [5].

As for the coal supply to the island, it is affected by two sources of uncertainty: price and supply.

Through the domestic market obligation (DMO) 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 and 43 $/ton for lower grade coal. This price is locked until late 2019 and the confirmation of this subsidy is highly uncertain [6]. As a reference, the market price of high graded coal averaged around 103 $/ton between August and November 2018 (HBA index) [7], which is 50% higher than the price cap for PLN.

Moreover, the amount of coal output from mines is capped nationally to maintain the internal supply stable in the future and Lombok is assigned a certain quota of this total national output. It is uncertain how this cap will evolve in the future and whether Lombok can increase the coal use indefinitely in the future years.

3. Long commissioning process and difficulties with land acquisition

PLN and Dinas ESDM have stated that long commissioning process for power plant development and buildout is one of the key factors limiting the local capacity expansion. It has for example taken 7 years to receive the final approval of for 50 MW coal power plant on the island.

Several elements contribute to the slowing down of project development, with the land acquisition process being one of the major barriers. Contributing to the difficulties of the land acquisition is the importance of agriculture which is the major GDP contributor to the island economy, the heritage value of land for farmers, as well as the lack of clarity regarding the ownerships of some lands, due to the lack of clear documentation.

4. Technical challenges for integration of more RE in the system

As mentioned earlier, the Lombok power system is a non-interconnected system, with a relatively weak electrical grid, posing challenges to the development of VRE projects. Concerns regarding voltage and frequency stability problems at the distribution grid level as a result of increased solar and wind penetration were the main reasons for limiting the installed capacity of the new solar power plants under construction in Lombok to 5 MW each.

Another barrier to a larger RE penetration in the grid is the current dispatch mechanism. The power dispatch is organized with a day-ahead scheduling followed by a manual power plant dispatch via radio. In case the power from a certain plant has to increase, the control center contacts the power plant via radio to request an increase in the power output. This communication channel is very fast to e.g. cover the fluctuation of solar power in the grid. Moreover, the dispatch is conducted without deploying any forecasting system. Currently, the solar power plants in the system are scheduled the day-ahead using the full rated capacity and the difference between the scheduled rated capacity (5 MW) and the actual generation (e.g. 3 MW) is to be covered by diesel power plant running as spinning reserve. With this mechanism and the lack of forecasting, the backup needed for RE is 1:1, i.e. for each 1 MW of VRES installed there is a need of 1 MW of reserve.

Another aspect that constitutes a reason for concern and which could be exacerbated by a higher solar generation is the ramping of the load at night.

Due to these and other reasons, for example the preference for not ramping down baseload generation, the limit to VRES penetration is indicatively set in Lombok to 20% of the hourly power demand, for every hour of the year. This is a major barrier for additional fluctuating RE in the system of Lombok, as well as other regional systems in Indonesia.

5. Reconstruction after the earthquakes of summer 2018

During July-August 2018, a number of earthquakes shook the island of Lombok. The strongest quakes (6.4 and 6.9 Richter) hit the North Lombok, a more rural area with lower income compared to the capital Mataram, and caused more than 460 casualties [8].

While the cost in terms of human lives and damage is high, especially for an area of low income like North Lombok, it seems that the power system has not been strongly affected by the event. PLN mentioned that rebuilding and electrical connection of all villages is well in progress and the expectation is that the event will not negatively affect the next step of the planned evolution of the system, nor the economic development of the island.

Potential concern regarding the future risk of infrastructure damage, might affect the willingness to invest in new power plants, in particular for IPPs. The effect is, however, difficult to estimate at this point in time.

2. Methodology

2.1 RESEARCH QUESTION AND SCENARIOS ANALYSED

Starting from the current power sector conditions and taking into consideration all the challenges faced in the development of the power sector in Lombok, a number of questions arise:

- What is the most **cost-efficient development** of the power system in Lombok, taking into account available local resources, cost of technologies and fuel availability/price?
- How do **subsidies to fossil fuels** and **externality cost** of pollutants affect the least cost development?
- What is the cost of increasing **RE** deployment in Lombok?

In order to answer these questions and explore the potential future development of the power system in Lombok, a set of scenarios is designed and analysed. All scenarios, apart from BaU, look at least cost development of the system, each assuming different boundary conditions.

1. **Business-as-Usual (BaU)**
   The BaU scenario is based on the most recent assumptions in RUPTL 2018-2027 from PLN. No investments in additional capacity and no costs for externalities are considered in the dispatch mechanisms. The model optimizes only the dispatch on an hourly level based on the marginal generation cost of the power plants, taking into account the current fuel price structure. The level of ambition in terms of RE of this scenario is limited to 20 MW of solar power coming online in 2019 and additional 8 MW small hydro.

2. **Least cost development under current conditions (Current Conditions)**
   In this scenario, only capacity specified in RUPTL as projects already committed or under construction projects already committed or under construction[1] is considered until 2019, while the rest of the investment in power capacity development is optimized by the model. The model optimizes the capacity development with no consideration of external costs of pollution and using the current capped price for coal and gas.

3. **Least cost development with no fossil fuel subsidies (No Fossil Subsidies)**
   This scenario builds on the *Current Conditions* scenario but considers the market based fuel price for coal and gas, simulating a discontinuation of the DMO and the price cap set by the government for coal and gas. To represent this, the prices of coal and gas are increased 50% compared to the other scenarios. As a reference, the PLN capped price for high grade coal (>6,000 kcal/ton) is set to 70 $/ton, while the current market price for high grade coal is around 105 $/ton, exactly 50% higher.

[1] Specifically, the power plants included in the scenarios are those with COD until 2019: 25 MW PLTU, 20 MW PLTS, 150 MW PLTGU Lombok Peaker, 3.3 MW PLTA.

4. **Socioeconomic least cost development (Socioeconomic)**
   In the Socioeconomic scenario, not only the subsidy to coal and gas is removed, but the external costs of pollution from NO_x, SO_2 and $PM_{2.5}$ are considered in the investment and dispatch optimization. No externalities related to the emissions of CO_2 are considered in the scenario.

The timeframe chosen for all scenarios is 2020-2030 with simulations for every two years, while the year 2017 will serve as a base year for comparison. An investment simulation is carried out, considering full time resolution (hourly) and an annual horizon for the optimization. The investments in most power plants are optimized on a discrete basis, considering a standard size of the power plants. The optimization is therefore a Mixed-Integer Problem (MIP). For more modular technologies like wind, solar and storage, the capacity is instead optimized on a continuous basis. Based on the investment simulation results, a more detailed dispatch optimization run is carried out, with a time horizon of one week and unit commitment constraints related to the technical capability of power plants, i.e. including online/offline status, ramping limits of units, minimum load and start-up cost.

The following table summarizes the scenario setup based on the three main elements and assumptions that differentiate them: initial capacity assumed, specific fuel targets, external cost of pollution.

Table 2: Applied scenario assumptions.

Scenario	Initial capacity	Externality cost of pollution	Fossil fuel cost
BaU	All RUPTL18 capacity No additional investments	None	Capped price
Current Conditions	RUPTL18 only until 2019 Then optimal investments	None	Capped price
No Fossil Subsidies	RUPTL18 only until 2019 Then optimal investments	None	Coal and gas price follow market
Socioeconomic	RUPTL18 only until 2019 Then optimal investments	Externality cost on NO_x, SO_2 and PM2.5	Coal and gas price follow market

Sensitivity analyses

In addition to the main scenarios just described, in which the power demand is equal to the development expected in RUPTL, an additional sensitivity analysis is performed to assess the potential effect of a **lower power demand**, as a result of lower energy intensity. The sensitivity is carried out on the basis of the BaU scenario.

The assumptions behind the alternative power demand scenario are as follow: it is assumed that the same economic growth in West Nusa Tenggara can be achieved with a lower power consumption. Specifically, the average power demand growth in the period 2018-2027 is reduced from an average of 7.6% to an average of 6%. This corresponds to a reduction in the power intensity (ratio between the increase of power demand and the increase of GDP) from 1.6 to 1.22. The value of 1.22 also corresponds to the average power intensity in Indonesia between 2009 and 2016, based on figures provided in the RUPTL.

This resultant power demand projection in the Low Demand sensitivity is 6% lower in 2020 and 13% in 2030 compared to the RUPTL assumptions used in the rest of the scenarios.

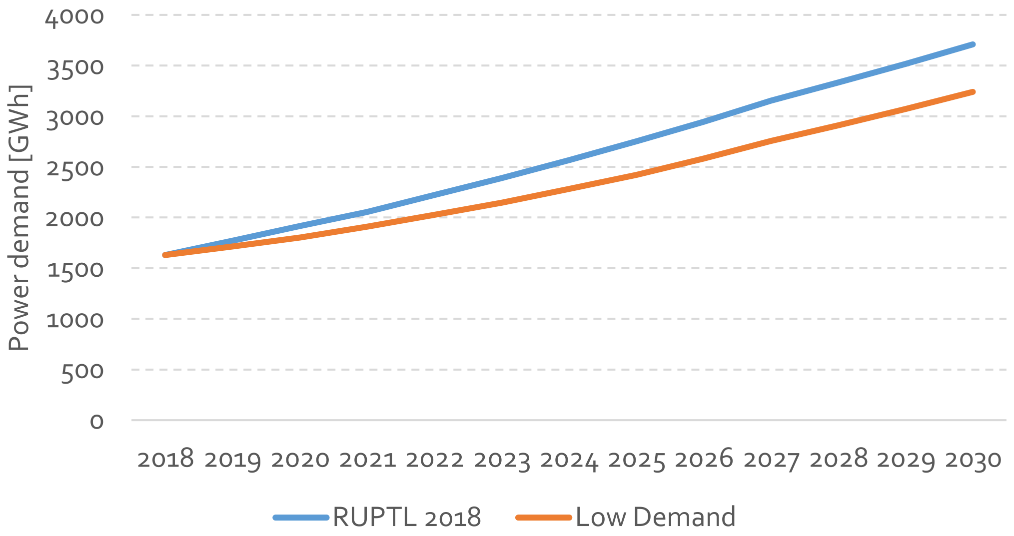


Figure 8: Demand projection in the Low Demand sensitivity compared to RUPTL 2018.

An additional sensitivity scenario is carried out to analyse the effect of a potential interconnection to Java-Bali system with a sea cable through the Lombok strait.

The **Interconnection** sensitivity scenario looks at how would the dispatch and the integration of RE changes in case Lombok would be connected to Java-Bali system, in the case of Socioeconomic scenario. The analysis looks at the change in the dispatch schedule with and without interconnection, to draw conclusions on the potential benefits of the interconnection in comparison to its cost.

2.2 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.

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 1.

2.3 MAIN DATA AND ASSUMPTIONS

The modelling of the Lombok power system, as well as the assumptions behind, have been prepared and reviewed in collaboration with the teams of PLN NTB and Dinas ESDM during the training session in Lombok and training in PLN Kantor Pusat DIV SIS.

Additional data for specific RE projects on the island has been included from the Prefeasibility studies project [1], which studied the business case of 7 RE projects in Lombok and West Nusa Tenggara.

Current generation fleet

To represent the current power system, each existing power plant has been modelled individually, with information about the efficiency (heat rate), variable and fixed operational cost, as well as emission data.

The total installed capacity as of November 2018 is 306 MW, most of which is HSD and MFO fuel oil plants, followed by coal power plants and a small amount of run-of-river hydro and solar, like depicted in Figure 5 [3].

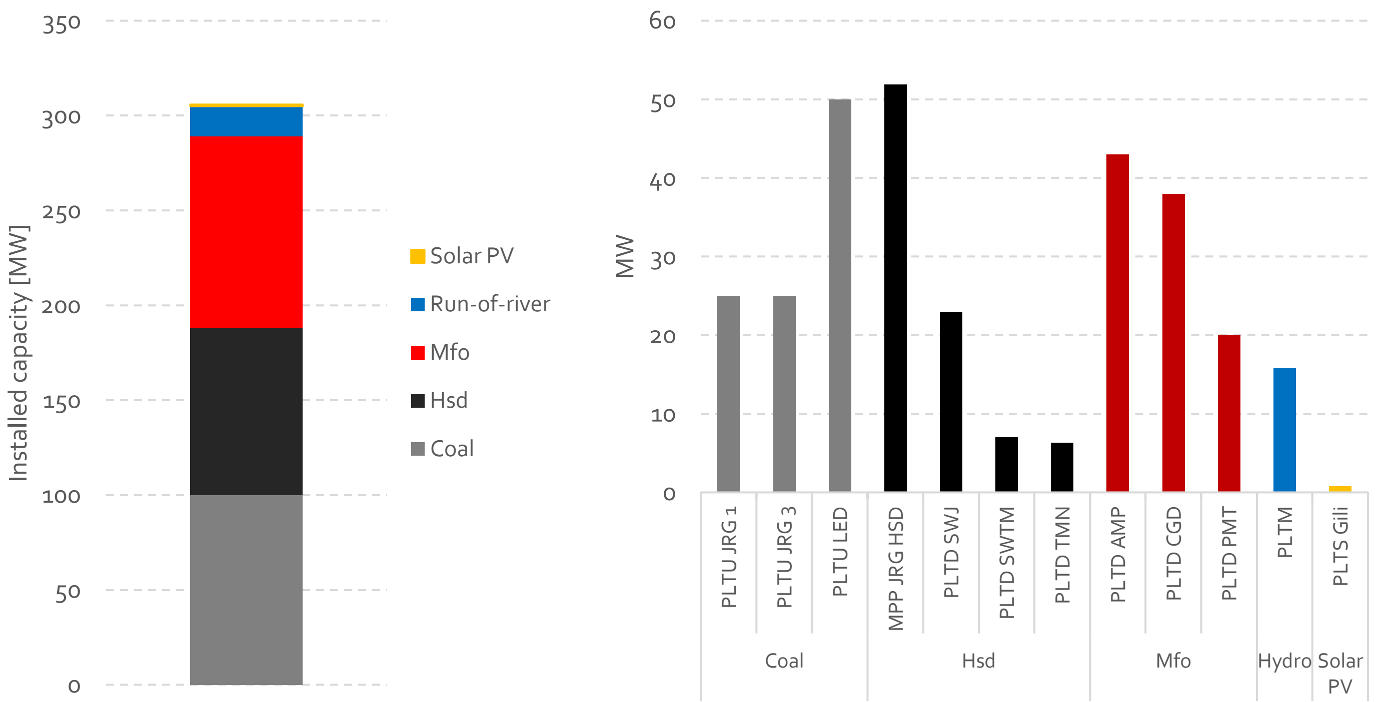


Figure 9: Existing capacity in Lombok power system.

Currently, PLN is stipulating contracts to lease diesel power plants. This has been modelled with agreed capacity factors (CF) throughout the year and dispatch cost per kWh. The average minimum CF agreement with leased power plants is 60% (5,300 FLH). The minimum CF as for the contract are enforced in the model only until 2019, after which PLN is planning to install Lombok Peaker unit (150 MW, PLTGU).

Power demand

The peak power of the island of Lombok has been increasing throughout the past few years, from around 211 MW in 2015 to the current 235 MW, with expectations for the peak power to reach 260 MW by the end of 2018 (based on RUPTL).

The demand profile, represented in Figure 10 as average daily load, is relatively flat during the day with a sharp peak surge in the late afternoon, around 18, when the sun sets and customers switch on lighting and other power equipment. This sudden load ramp is one of the challenges in the system, due to the need of fast ramping units to pick up load increases. Following the effect that has been famously described as the “duck curve” in California, the integration of more and more PV in the system, exacerbates this challenge, since the effect on the residual demand curve is relatively higher. One other characteristic worth noting is the morning peak related to people waking up and early morning prayer time.

Figure 10 (right) shows also the historical development of power demand until 2017 and the projection assumed in the study toward 2030. The power demand projection assumed is from RUPTL 2018-2027, with trendline assumption between 2027 and 2030.

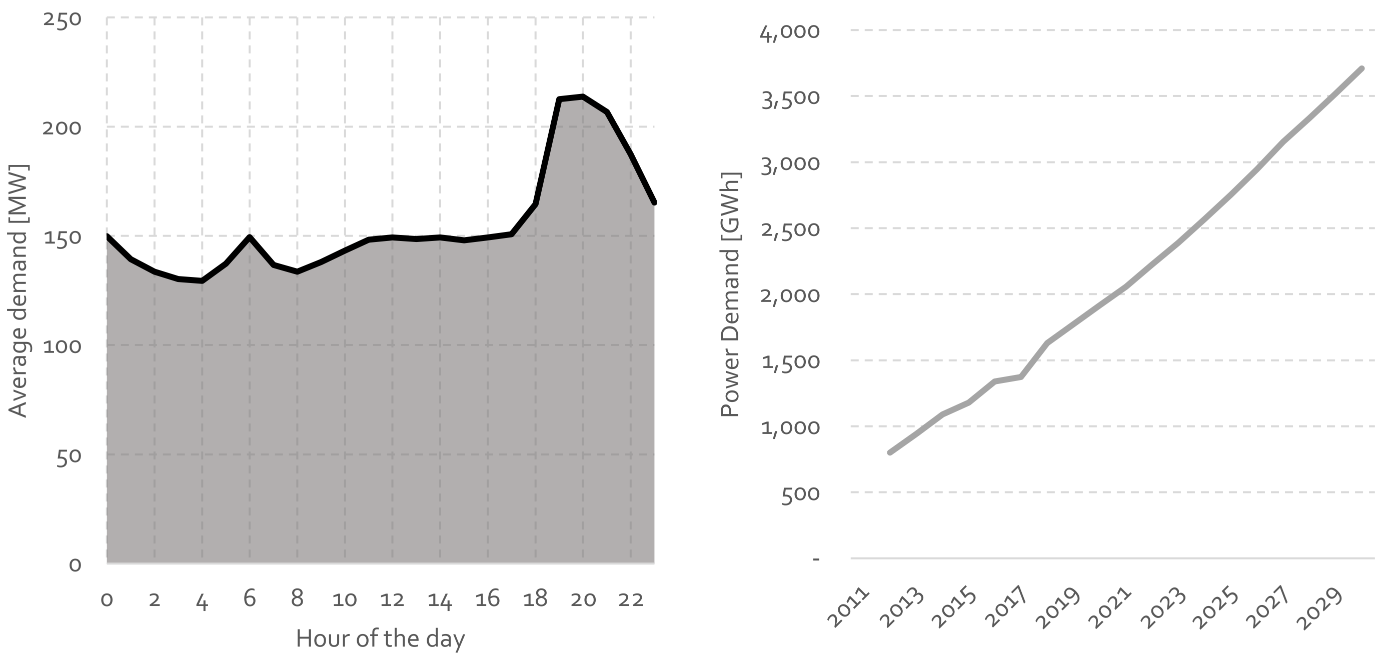


Figure 10: Average hourly load in Lombok system (left) and assumptions for demand projection (right).

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 [9].

The assumptions applied in this study use the Technology Catalogue as a starting point and adapt some of the assumptions to the context of the island of Lombok, also using the feedback received from the Prefeasibility studies and discussions with local PLN and Dinas ESDM[2].

The weighted average cost of capital assumed in the study for new investment in generation capacity is 10.2%, based on the assessment done for the Prefeasibility studies.

Table 3 summarizes the technologies available for investments and the main technical and financial assumptions:

Table 3: 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%	-

Fuel supply and prices

The island of Lombok does not have access to local coal, gas nor oil resources. For this very reason, the current and future supply of fossil fuels in Lombok is of critical importance to the power system planning.

Coal

As mentioned in Chapter 1, the DMO sets the price of coal for PLN at 70 $/ton for high grade coal and 43 $/ton for lower grade coal.

Based on feedback from PLN, the price of coal (including transportation cost) is set to around 50 $/ton for 2018 and 2019, corresponding to 2.8 $/GJ (assuming heating value of 4,218 kcal/kg) and increases following World Energy Outlook 2017 [10] development in the coming years. No restrictions to the amount of coal supplied to the island are assumed in this analysis.

[2] The data used as a basis for the analyses has been the Technology catalogue, slightly revised based on various feedback. The figures shown are not given directly by PLN, nor should they be considered as the de-facto assumptions behind PLN planning.

CNG and LNG

As described in the introduction, the supply of CNG will be secured starting from 2019-2020 with a marine vessel from the port of Gresik. The total amount of CNG has been capped in the model to a value of 3.9 PJ per year, corresponding to 5.4 mmsfc a day. This is based on the projected PLN use from RUPTL that is assumed to be limited by the transport capability of the vessel.

With regard to LNG, there are discussions undergoing regarding the construction of a small LNG regassification facility close to MPP power plant, currently running on HSD. The plan is to exchange the power plant supply from HSD to gas, but it is still uncertain whether the plant will keep running on HSD, supplied by a dedicated LNG regassification facility or through a pipe from the decompression facility of Lombok Peaker power plant. In the model, it is assumed that the MPP power plant will be converted to LNG in 2020.

As for the CNG and LNG prices, for 2019 and 2020 the value is set to 8.1 $/mmbtu corresponding to 7.67 $/GJ, based on the regulation from the MEMR Regulation from 2017 (58,11,45). Their future development is based on the trend from World Energy Outlook 2017.

No subsidies scenario

In the No Fossil Subsidies scenario, the price of coal and gas (both CNG and LNG) is increased by 50% to represent market conditions.

As a reference, the subsidized cost for high grade coal (>6,000 kcal/ton) is today capped at 70 $/ton while the market price for the same coal, identified with the HBA index (Harga Batubara Acuan), has averaged around 103 $/ton in the last 4 months (August-November 2018), corresponding to a 50% increase in the value [7]. As for gas, the market price for natural gas in Indonesia is in the range of 12-15$/mmbtu, compared to a value of 8.1 $/mmbtu set by the MEMR for PLN.

Figure 11 shows the development of fossil fuel prices in the two cases, namely with and without subsidy.

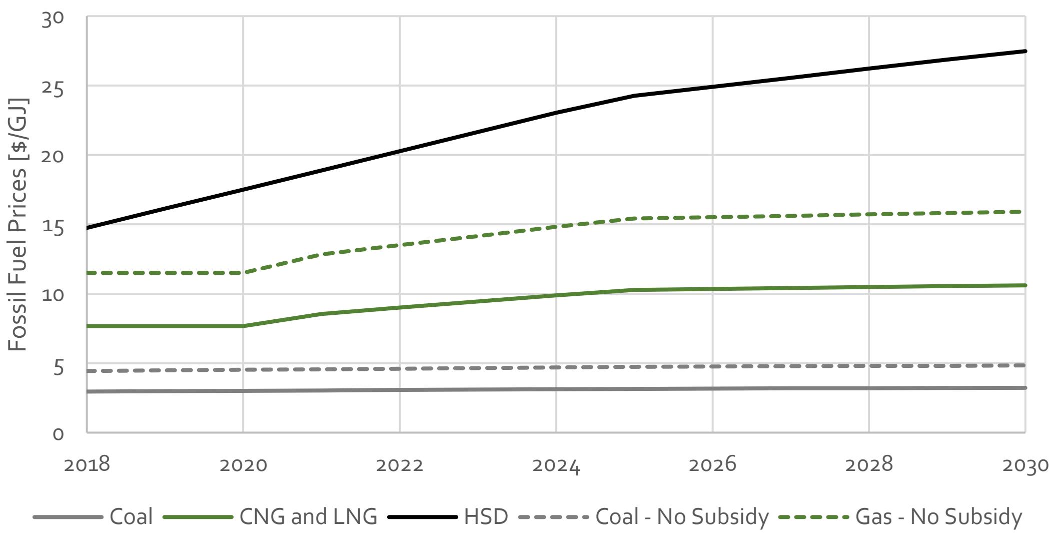


Figure 11: Development of fossil fuel prices overtime, following the trend from WEO17. No subsidy scenarios assume a 50% increase in price of coal and gas.

Externality cost

Combustion of fuels such as coal, oil and gas lead 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 Socioeconomic scenario these costs are considered as part of the overall societal cost of power generation.

Calculating these impacts, and the cost for society, requires comprehensive and complex atmospheric modelling – such as EVA (Economic Valuation of Air pollution). The EVA model system 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 [11]. 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 and the application of the cost to each province in Indonesia. European costs are then translated to Indonesian costs using purchasing power parity (PPP) figures from the World Bank.

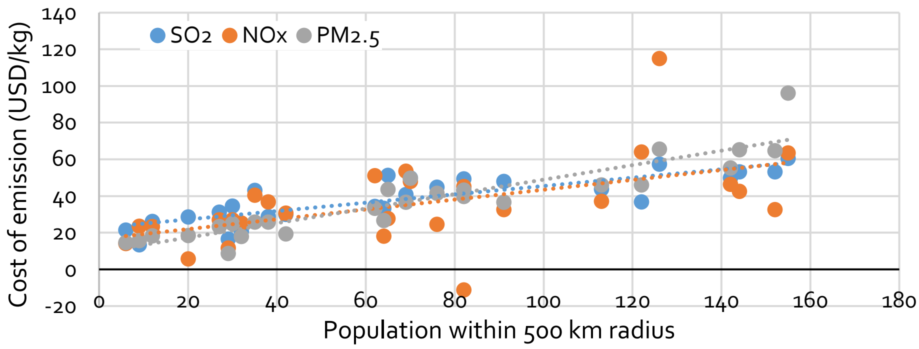


Figure 12: Correlation between the cost of pollution from SO_2, NO_x and PM2.5 from each of the 27 EU members and the population within a 500 km radius from the country's geographical center.

An overview of the SO_2 costs in Indonesia for each province is shown in Figure 13. For West Nusa Tenggara, the figure used are 4.8 \$/kg of SO_2, 3.8 \$/kg of NO_x and 2.8 \$/kg of PM2.5.

A study on the hidden cost of power generation in Indonesia has estimated figures of a similar range [12].

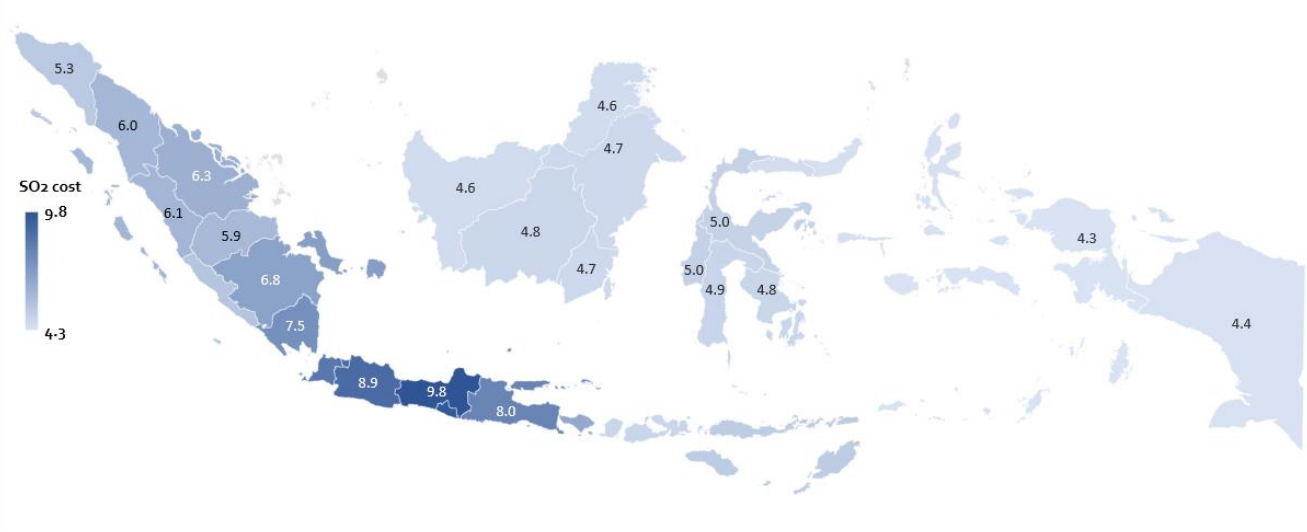


Figure 13: Health damage cost of SO_2 emissions in Indonesia, resulting from the assessment. Source: [12]

Resource mapping

RE potentials

The island of Lombok is blessed with diverse and abundant RE potential. More or less all the renewable technologies with potential to provide electricity are present on the island – geothermal and hydro, good solar irradiation, sufficient wind speeds to be exploited with new low wind speed turbines, wave power, and biomass/biogas.

The main source for estimation of the potentials is RUED [13], which states the values for the entire West Nusa Tenggara (NTB). Where a potential is stated directly for Lombok in RUED, the number is used. This is the case for geothermal, hydro, wave, and biomass/biogas resources. However, for resources such as wind and solar, the distribution of the potentials between Lombok, Sumbawa and Bima has been assumed.

In most of the cases, the potential of RES is so high that it does not constitute itself a limitation to the amount of RE based power that can be established (Figure 14). Other factors, such as competition with cheap coal supply, land availability and challenges in integrating variable RE, are the main limiting factor for a higher RE penetration.

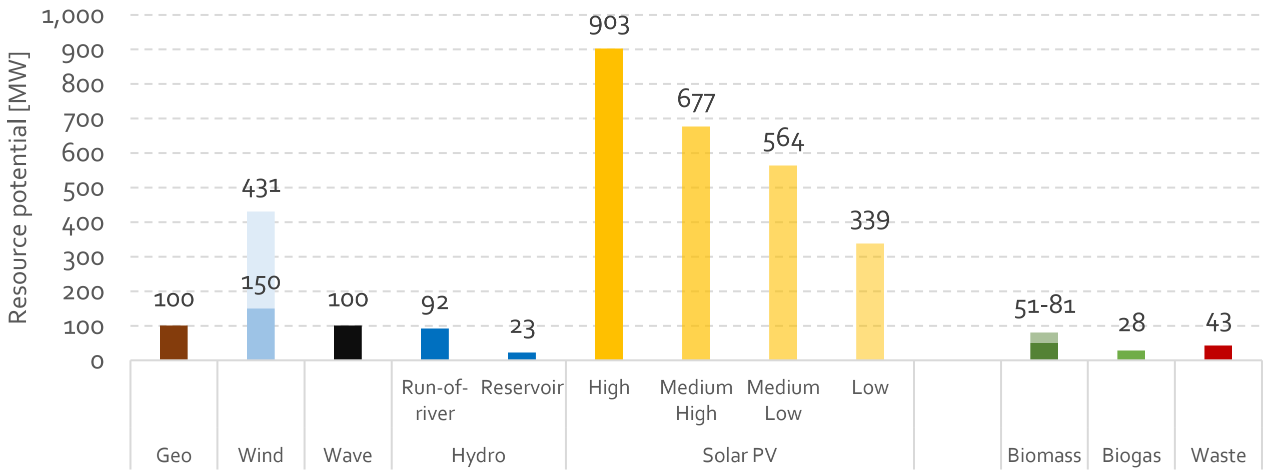


Figure 14: Potentials for RE in the island of Lombok. Biomass, biogas and waste are expressed in maximum fuel consumption (GJ), but here transformed in MW by using power plant efficiency and FLH (5,000-7,000 for biomass, 8,000 for biogas and waste). Wind has 150 MW of potential in high wind (3000 FLH) and the rest in lower wind (2,400 FLH).

Solar irradiation and FLH

The solar resource in Lombok is among the highest in Indonesia, with an average daily global horizontal irradiation (GHI) between 3.3 to 5.6 W/m^2. All the island, excluding the area around Mount Rinjani (which anyway is a national park and protected area), has exploitable solar resource between 1,400 and 1,800 FLH in a year (Figure 15Figure 15: Distribution of PV output in kWh/kW (FLH) on the left and locations chosen to calculate distribution on the right.**Error! Reference source not found.**). The areas with highest irradiation are located in the South and East of the island, where the four 5 MW plants are currently under construction.

To represent the diversity of solar resources, 54 locations distributed around the island have been selected (Figure 15) and the FLH at the location calculated on the Global Solar Atlas by the World Bank (reference). 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 has then been distributed accordingly, resulting in the following: High solar area with 1,667 FLH (903 MW), medium-high area with 1,592 FLH (677 MW), medium-low area with 1,517 FLH (564 MW) and low solar area with 1,441 FLH (339 MW)[3].

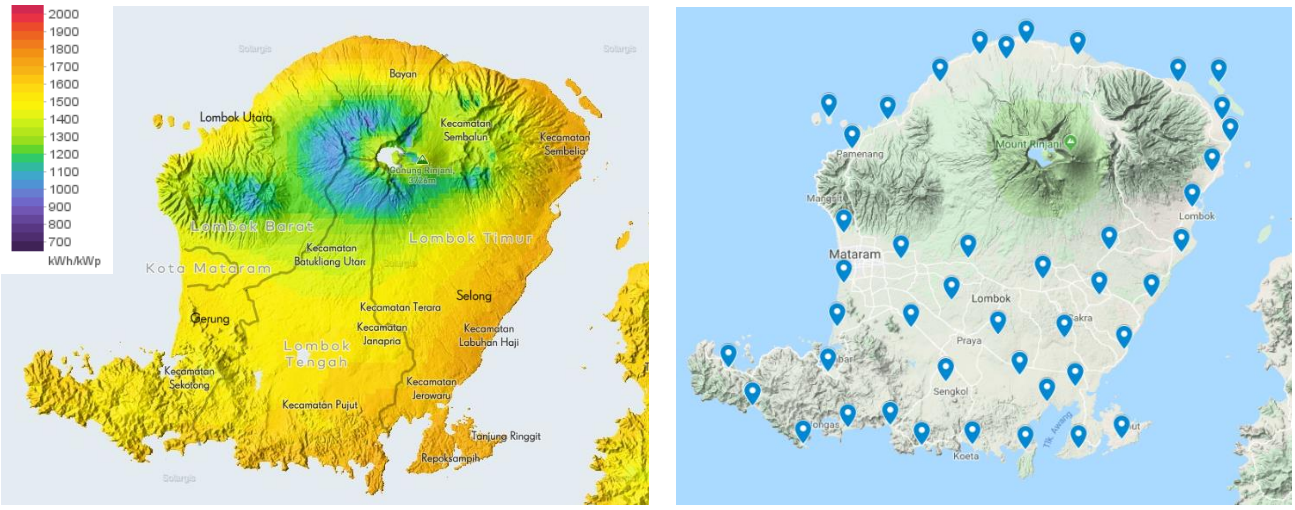


Figure 15: Distribution of PV output in kWh/kW (FLH) on the left and locations chosen to calculate distribution on the right.

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 [14]. To create the final profile, hourly profiles from 6 locations distributed throughout the island (including the 4 new solar plants) have been combined (Figure 16).

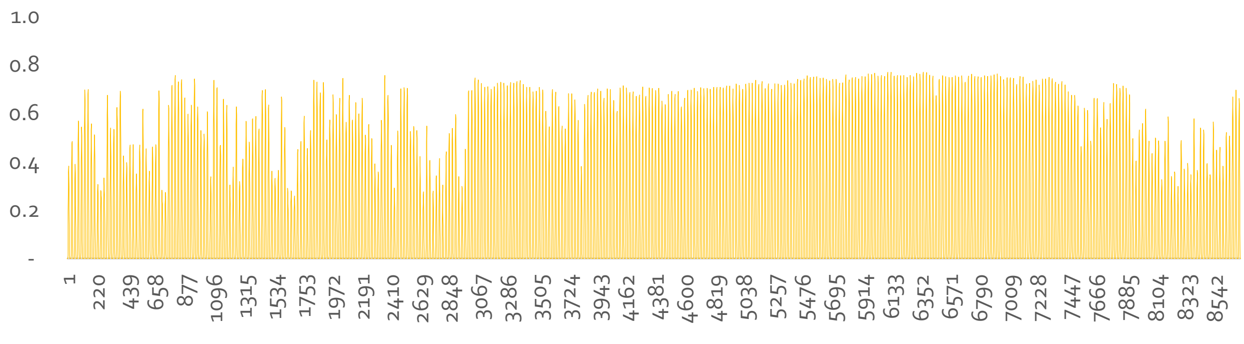


Figure 16: Hourly solar profile considered in the model.

[3] The solar FLH indicated here are referring to the capacity of the panels in DC, i.e. before the inverter. In case of sizing factor above, FLH should be multiplied by the sizing factor, and expressed with reference to the capacity in AC. In the Prefeasibility study the sizing factor is assumed 1.1, and the FLH 1,800, which is equivalent to the assumption here.

Wind speeds and FLH

Wind speeds in Indonesia are generally on average much lower than other countries in the area and the majority of locations show wind speed with values below 4-5 m/s. However, combining the fact that selected locations, generally closer to the coast, have slightly more favourable wind conditions and that commercially available turbines are evolving to be able to exploit lower wind speeds, the island have some selected spots in the southern part where wind power plants could potentially be feasible. Both BPPT, the Indonesian technology institute, and a commercial wind project developer conducted or are conducting measuring campaigns in the Jerowaru area, south east of Lombok.

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 [15]. The assumed turbine model, Vestas V150, has relatively low specific power and could result in 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 17).

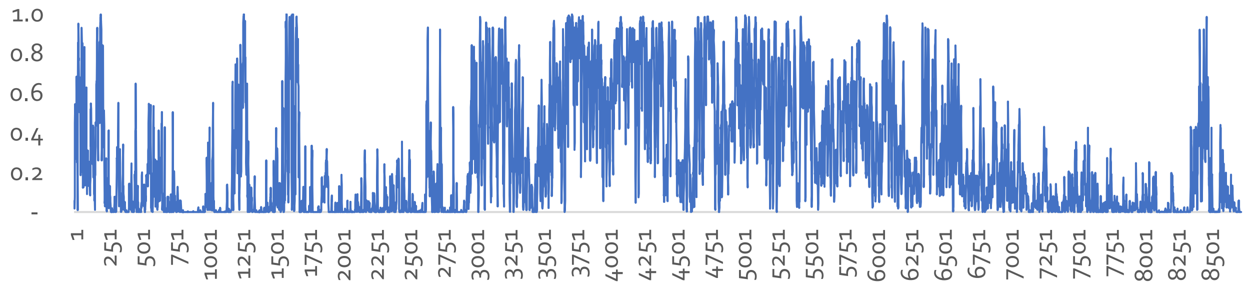


Figure 17: Hourly profile of wind generation used in the model.

Hydro profile and FLH

As for hydro power plants – both run-of-river and reservoir – an inflow profile has been created assuming precipitation data from climate-data.org [16] as a proxy for hydro generation in each month of the year and converting it to an hourly profile. As for the annual generation, a value of 4,426 FLH is used based on the average generation from all existing hydro plants on the island for the years 2013-2014.

Biomass and biogas resources

The assumption regarding the potential for biomass and biogas in Lombok is based on figures from RUED [13]. For biomass, only rice husk and corn residues are considered. Considering a heating value of 13 GJ/ton (typical for this type of biomass) [9], the total resource corresponds to an annual resource of 4.7 PJ/year. This would correspond to a total of 51-81 MW of biomass power plants considering FLH in a range of 5,000-7,000 hours.

Potentially, the biomass resource could be higher if considering resources from crops dedicated to growing wood biomass for pellets, but as a study for Java [17] showed, the creation of pellets from wood biomass sources would make the fuel too expensive to burn in a power plant. Instead it would be channelled to the lucrative Asian wood pellets markets.

The price assumed for biomass is from the Prefeasibility study, that carried out interviews with a number of hellers'owners. The biomass cost assumed is equal to 3.3 $/ton (50,000 IDR) plus transportation and additional costs totalling 7.7 $/GJs (final biomass cost of 11 $/ton), a significant cost top-up due to the scattered nature of the biomass potential in the island.

As for biogas, the resource is very large due to the many cattle farms on the island. The potential capacity of biogas plants, assuming a utilization of 7,000 FLH, is equal to 28 MW. Whether this potential is actually practically possible to exploit remains unclear. Regardless, the technology is still too expensive to be a competitive short-term solution.

Municipal solid waste

In the pre-feasibility study, the total amount of waste for each Regency of Lombok has been estimated (Figure 18).

In the model, Lombok is divided into three areas: North-West, East and Central-South and each area is assigned waste resources in GJ (assuming a heating value of 10 GJ/ton). For the estimation of waste ending up at sea, the lower value of 200,000 ton has been included in the North-West area.

The gate fee assumed in the model is equal to 3.3 $/ton corresponding to 50,000 IDR/ton.

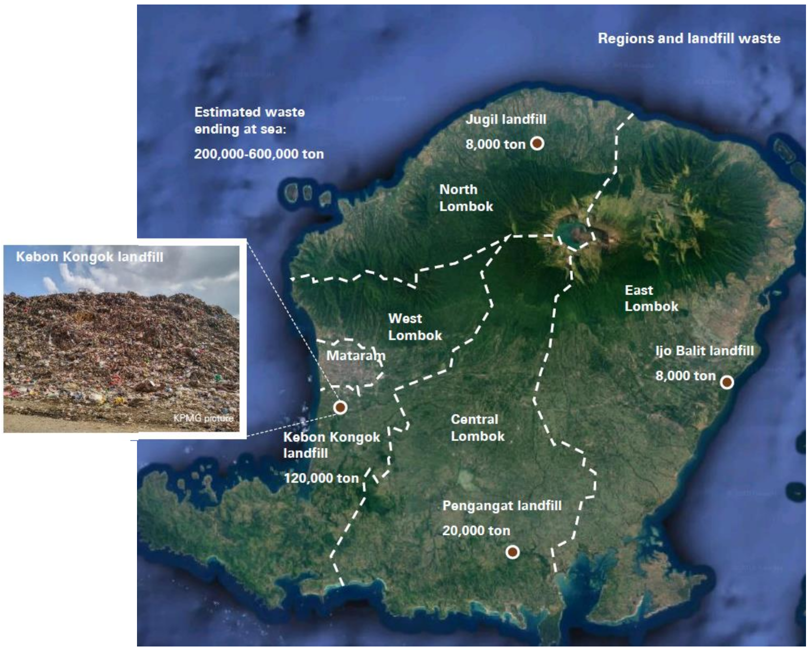


Figure 18: Waste potential in Lombok. Source: Prefeasibility Studies [1]

Levelized cost of electricity

The Levelized Cost of Electricity (LCoE) indicates the lifetime cost of power generation from a specific power plant, including all the costs incurred by the power plant (capital cost, O&M cost, fuel cost). It is a good indicator for comparison of generation technologies and assessing the cheapest source of generation. Based on the assumption explained above, the LCoE is calculated for the years 2020, 2025, 2030, for illustrative purposes. The results are shown in Figure 19.

The FLH assumed for coal and biomass are 7,000 (80% capacity factor), while for geothermal they are assumed to be 8,000 (91% capacity factor). The extra cost that coal and gas would incur if the fossil fuel subsidies are removed is indicated with the shaded area on top of the two columns in the figure.

As it is possible to note, the LCoE of coal is quite constant while LCoE of RE sources is reduced overtime. In 2020, only biomass is competitive with subsidized coal, while geothermal might compete only if subsidies to coal prices are removed. Wind and solar have a very similar LCoE, around 10 c$/kWh.

Solar power experiences the largest generation cost reduction over the period and reaches a cost of 6.6 c$/kWh in 2030, lower than coal power, even if subsidized. Also, power from geothermal sources, at 6.9 c$/kWh, is more affordable than coal based generation. Wind power's LCoE, which experiences a reduction in the period 2020-2030 even if less dramatic than that of solar, is more or less at the same level as the LCoE of coal without subsidies in 2030.

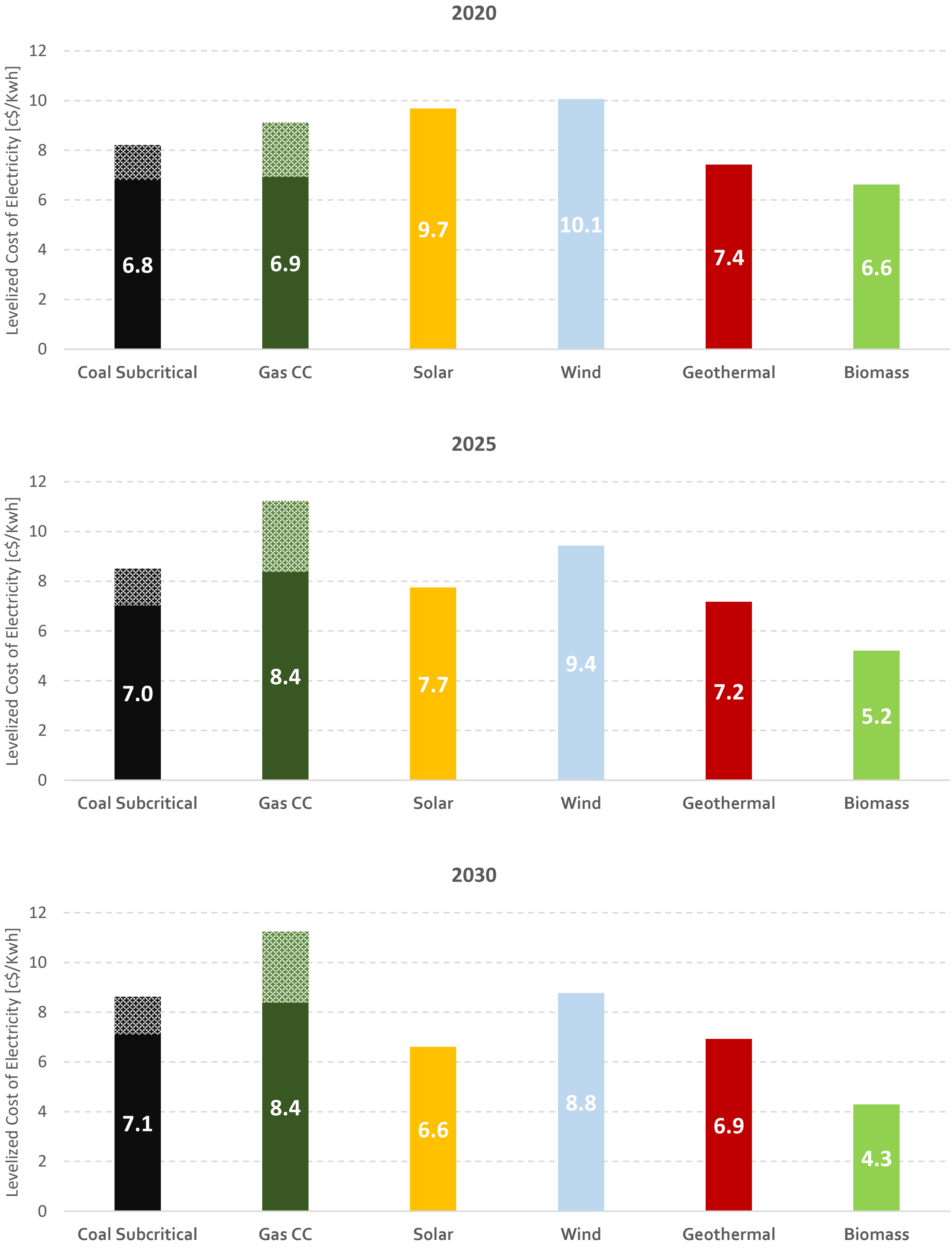


Figure 19: LCoE development from 2020 to 2030 for the main generation options in Lombok. Shaded area for Coal and Gas represents the extra cost in case fossil fuel price is not capped.

3. Results

In this chapter, the results of the analysis will be presented for the main scenarios, as well as for the demand sensitivity and interconnection analysis.

3.1 MAIN SCENARIO RESULTS

As mentioned in the introduction, BaU scenario simulates the system based on the RUPTL development and serves as reference for the other scenarios. The Current Conditions scenario, in which no specific assumption has been made regarding fuel cost or pollution externalities, is the optimized system development suggested by the Balmorel model considering the assumptions on cost and resources described in Chapter 2.

In the third scenario, the price cap on coal and gas, which represent a de-facto subsidy, is discontinued. As the last step, in the Socioeconomic scenario, the externality cost of emissions of local pollution (SO_2, NO_x, $PM_{2.5}$) are added, making the scenario a socioeconomic assessment of the most cost-effective development of the power system in Lombok.

Capacity expansion

Figure 20 shows the development of the installed capacity in the three least cost scenarios compared to BaU, while Table 4 details the investments optimized by the model in each of the simulated years.

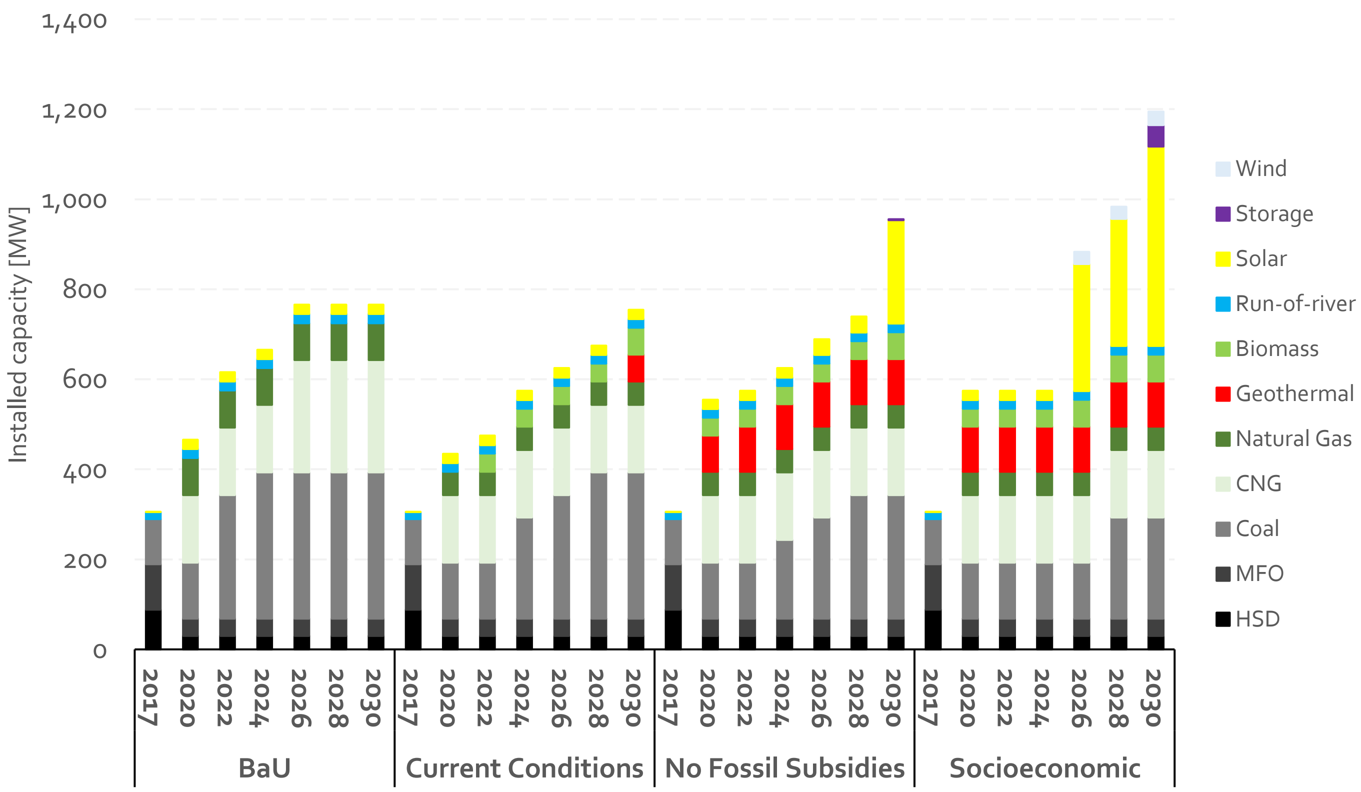


Figure 20: Capacity evolution in the main scenarios.

Table 4: Installed capacity by fuel for each optimized scenario and year.

	Coal	Biomass	Geothermal	Solar	Wind	Storage
Current Conditions						
2022		40				
2024	100					
2026	50					
2028	50					
2030		20	60			
No Fossil Subsidies						
2020		40	80			
2022			20			
2024	50					
2026	50			15		
2028	50					
2030		20		194		2
Socioeconomic						
2020		40	100			
2022						
2024						
2026		20		261	27	
2028	100					
2030				161	3	48

As can be seen, there are major differences in what type of power plants are prioritized by the model and deemed optimal compared to the BaU scenario.

The main observation is that much more RE is coming online in all three least cost scenarios compared to RUPTL and this reduces the need for fossil fuel plants. Moreover, diesel power plants are already decommissioned in 2020, as a result of the 150 MW of CNG gas coming online in 2019 and the conversion of MPP plant to LNG in 2020.

As for RE, 40 MW biomass plants are considered competitive in the model already from 2020 or 2022 depending on the biomass price and power plant cost assumed, even with no consideration of externality cost or higher fossil fuel prices. The model also finds investment in geothermal capacity feasible in all scenarios, with a minimum of 60 MW installed across scenarios and years.

In the two scenarios, No Fossil Subsidies and Socioeconomic, solar power becomes competitive in 2026. In the No Fossil Subsidies scenario, the total solar capacity in 2030 equals 229 MW and only 2 MW of storage is needed to integrate this large solar capacity. On the other hand, in the Socioeconomic scenario, in which the solar capacity in the system reaches a total of 443 MW, storage in the form of large lithium-ion batteries is added to better manage the integration of the solar generation and use some of the energy to cover the late afternoon ramps and peak. The total suggested storage capacity in the Socioeconomic scenario is 192 MWh (48 MW, with a 4-hour storage capacity), equal to roughly 10% of the installed solar capacity.

Generation

Figure 21 shows the development of generation in the main scenarios from 2017 to 2030.

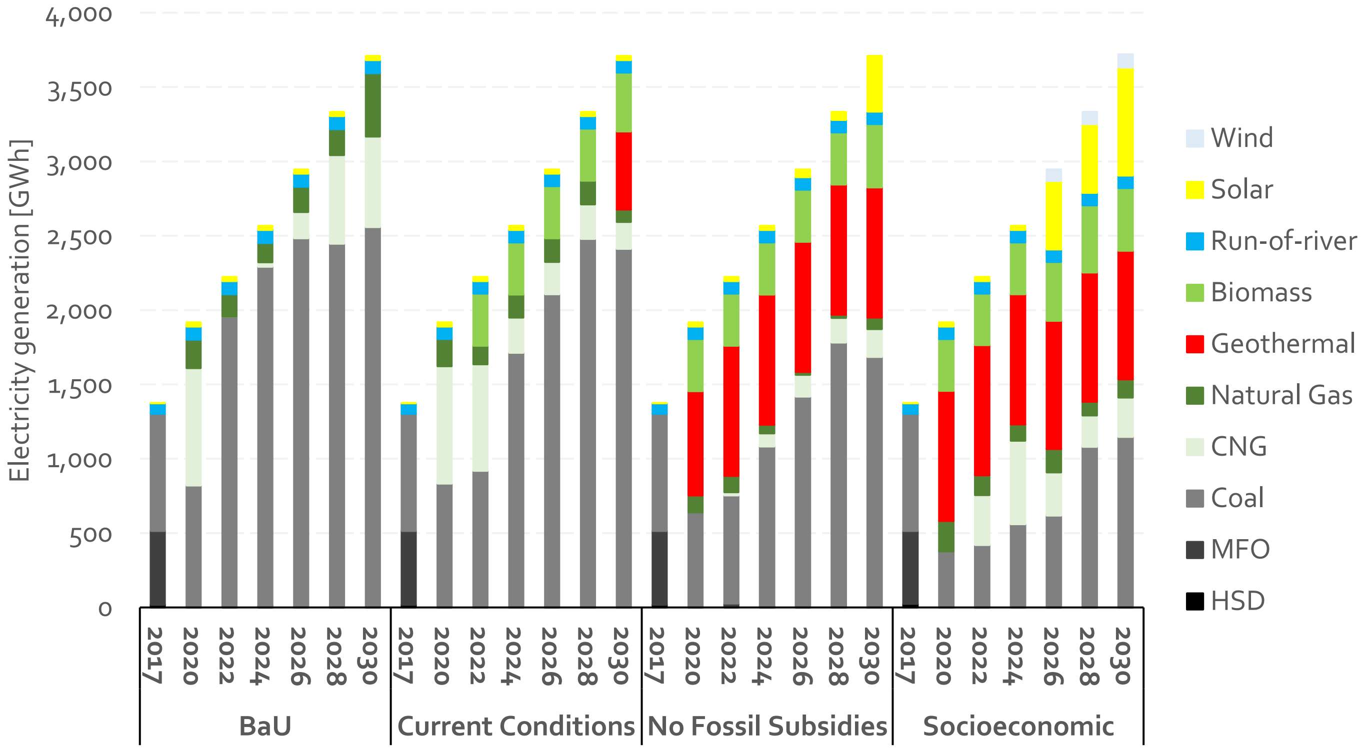


Figure 21: Generation evolution in the main scenarios.

The total RE penetration that is reached in 2030 is only 3% in BaU and 28% in the Current Conditions scenario, while it grows to 47% in the No Fossil Subsidies scenario and 58% in the Socioeconomic.

The VRES penetration (wind and solar) is negligible in the first two scenarios, while equal to 10% and 20% in the No Fossil Subsidies scenario and the Socioeconomic scenario, respectively.

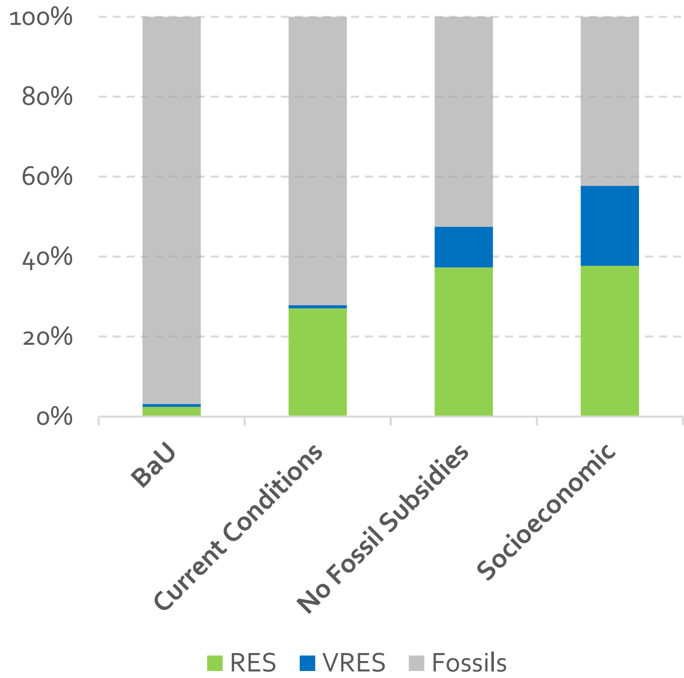


Figure 22: Generation share in 2030 in the main scenarios. RES (hydro, biomass, geothermal) and VRES (wind, solar) share highlighted.

Detailed dispatch and average day in 2030

In order to better understand the system conditions and how the available generators are dispatched, the average daily dispatch throughout the year 2030 in the four main scenarios can be compared, visualized in Figure 23.

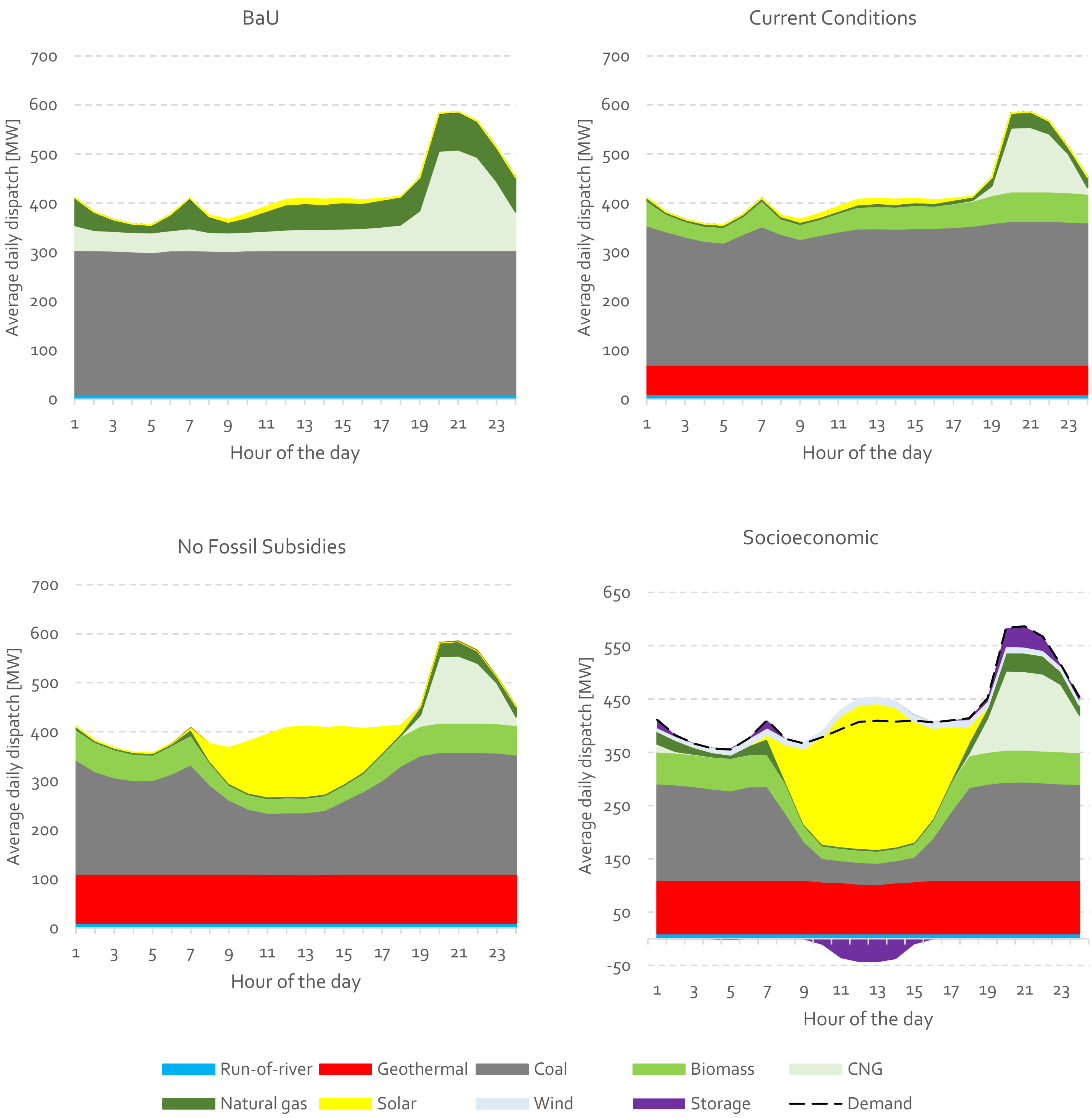


Figure 23: Average daily dispatch in the four main scenarios in 2030.

In the BaU and Current Conditions scenarios, coal power plants provide the baseload generation with limited or no ramping required, due to the very low solar penetration. The peak is covered by CNG and LNG plants, with Biomass in the No Externalities scenario acting as an intermediate generator, and geothermal providing part of the baseload.

In the two scenarios with higher RE penetration, the dispatch is radically changed. First of all, geothermal power plants provide a stable source of baseload due to its dispatchability and very low variable/fuel cost. Coal power plants still provide the bulk power generation, but due to the high penetration of solar in the middle of the day, coal generation is ramped down to make room for a zero marginal cost generation, to reduce the cost of power supply. Similar to the previous scenarios, the peak is supplied by CNG and LNG with few additional differences. In the Externalities scenarios, the higher solar penetration makes it convenient to install energy storage capacity which load during hour with high irradiation and then releases the energy in the late afternoon, both to help with the load ramping and to supply part of the peak.

The following graphs shows the weekly dispatch for the BaU scenario and the Socioeconomic scenario for a week in December (wet season) and a week of July (dry season).

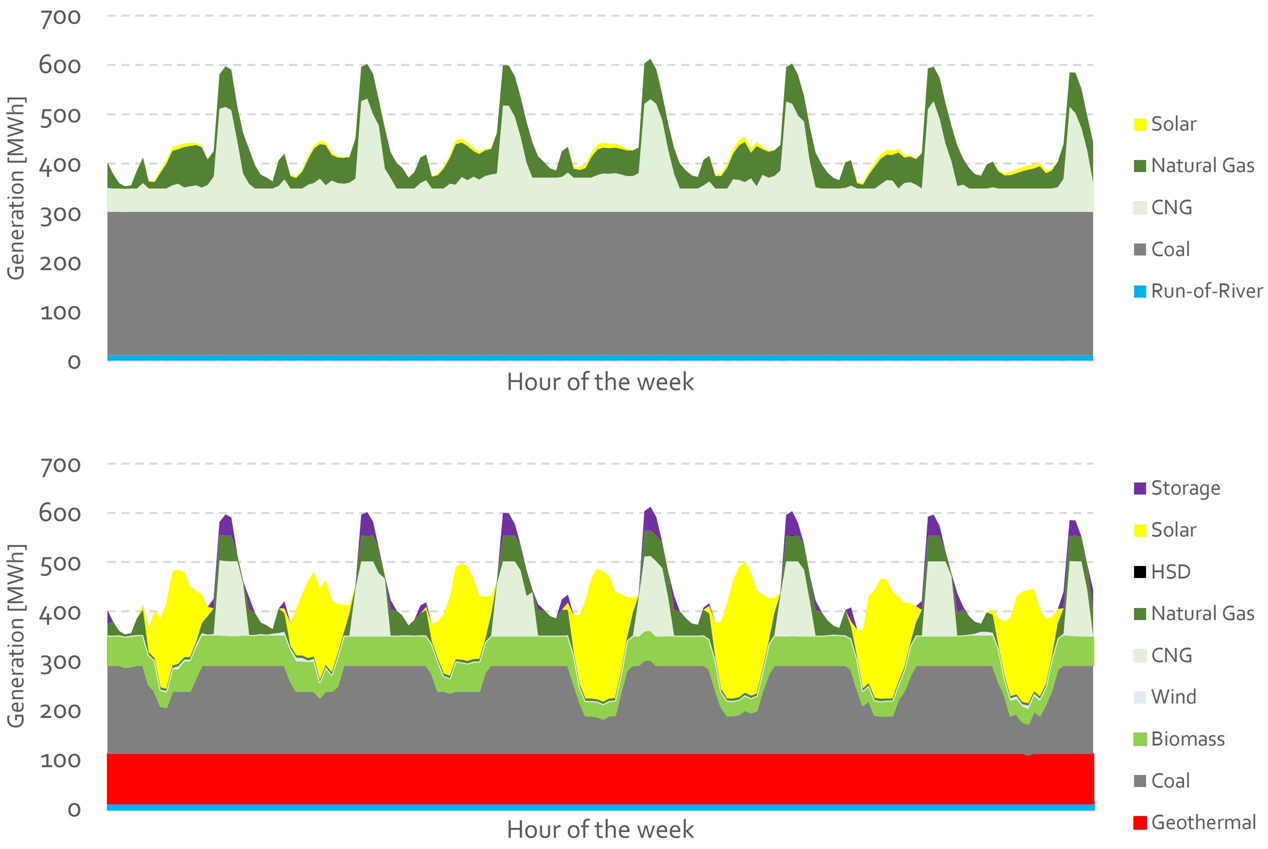


Figure 24: Power supply by fuel during a week of December in the BaU scenario (above) and the Socioeconomic scenario (below).

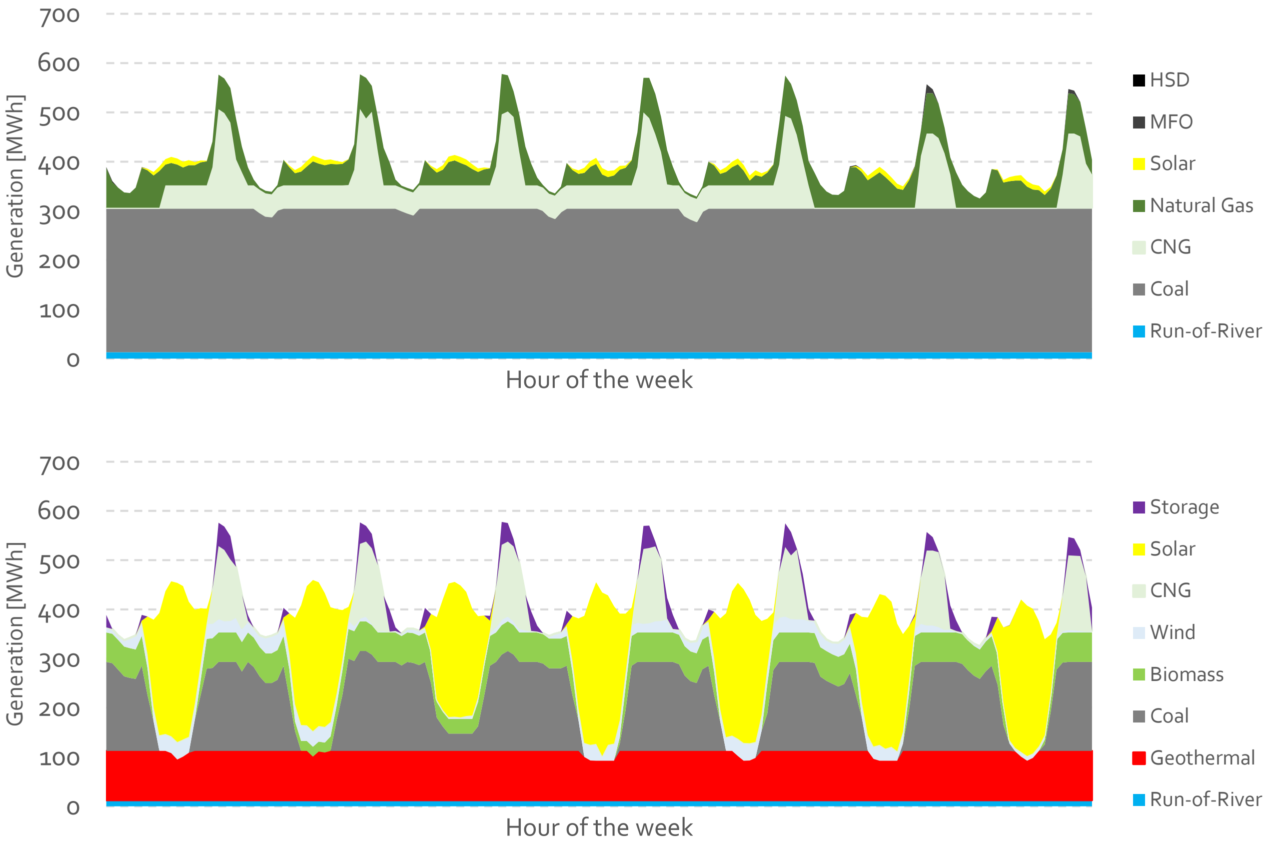


Figure 25 Power supply by fuel during a week of July in the BaU scenario (above) and the Socioeconomic scenario (below).

Load and residual load

The penetration of more and more variable RE brings along a number of transformations in the power system. One of the most immediate effects is the reduction in the load that has to be served by dispatchable power plants.

A convenient way to visualize this effect is to look at load duration curves[4] and compare the actual load to the residual load, i.e. the load minus the generation from variable RE such as solar and wind. To visualize the concept, the comparison in shown for 2030 in the Socioeconomic scenario, the scenario with the highest VRES penetration among the ones analysed (Figure 26).

As can be seen, the peak demand is not affected by the presence of solar capacity in the system: the peak hours occur at a moment of the day in which no sun is shining, therefore no solar generation can be dispatched.

On the other hand, the concentrated presence of solar in the central hours of the day reduces the room in the system for baseload power and requires more flexibility to the power plants, given the larger ramps in residual load. The room for baseload with very high capacity factor in the case represented is significantly reduced. The general role of baseload generators changes in the scenarios with high VRES penetration, with an advantage for the system to reduce the output in favor of zero-marginal cost generation from solar.

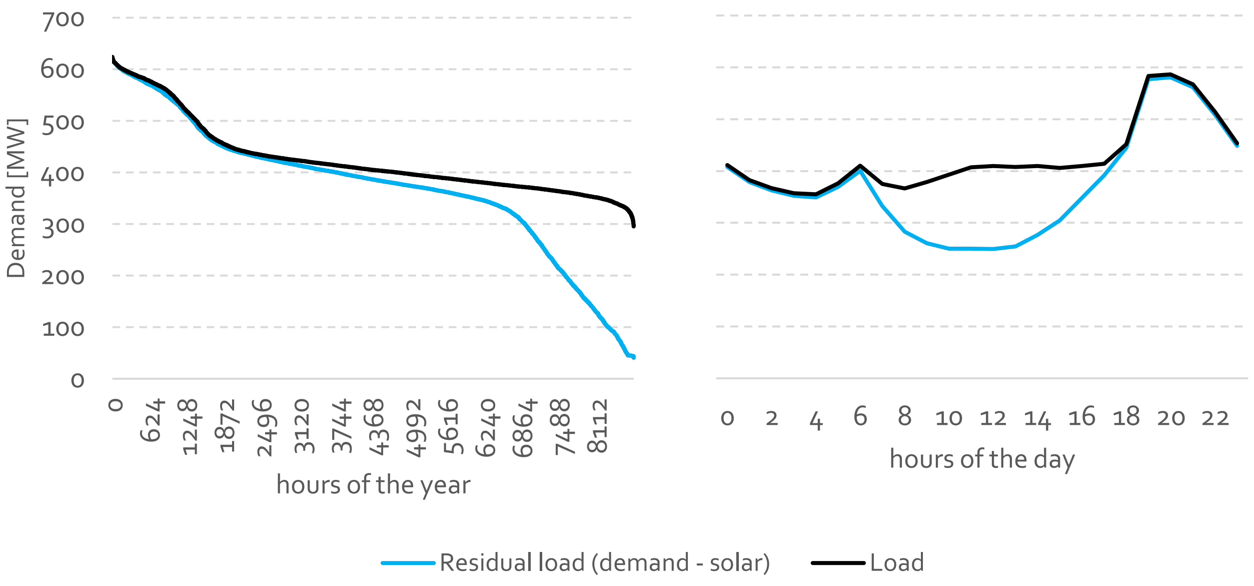


Figure 26: Residual load duration curve (left) and daily curve (right).

It must, however, be emphasized that the ramp in the residual load that the decreased generation from solar imposes in the afternoon, is somewhat smoother than the rapid load pick-up during peak hours, which remains the steepest load ramp.

To better demonstrate the increase in ramping that solar power causes, Figure 27 shows the duration curve of hourly ramping in the four scenarios in 2030. As can be noted, the largest hourly upward ramp in the system is around 200 MW, it is the same in each scenario and represents the hours of increased consumption at night. Therefore, solar power does not directly affect this specific requirement, since it will be served by CNG or LNG power plants, as seen in the dispatch graphs. The presence of higher solar capacity in the Socioeconomic scenario

[4] A duration curve shows the number of hours in the year (x-axis) when the load was above a certain power (y-axis). Basically, it shows hourly demand throughout the year on a descending order.

does, however, increase the intermediate ramps around 50 to 100 MW per hour. Specifically, these are the upward ramps of coal in the late afternoon. It is also discernible that solar capacity increases the downward ramps in the system (right side of the graph).

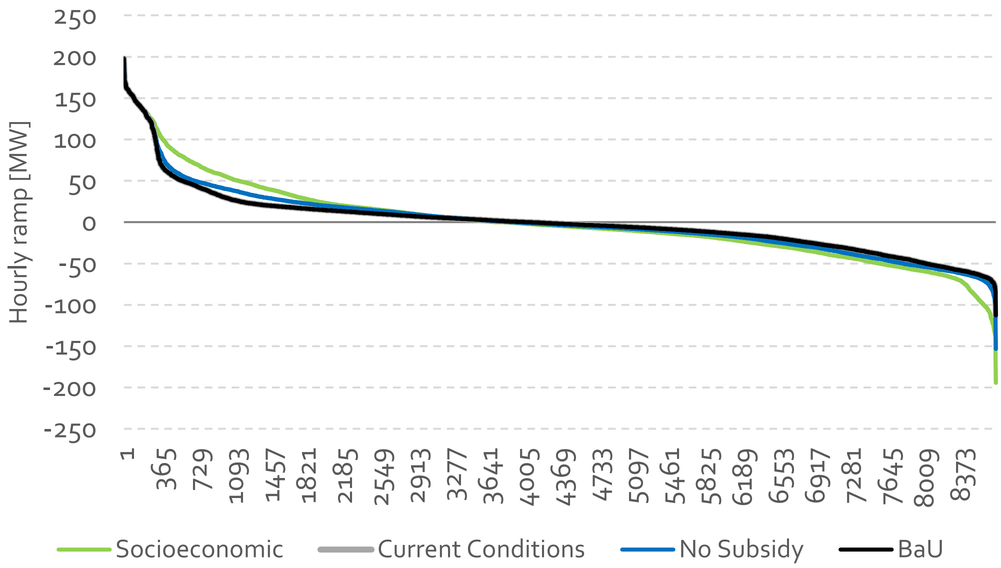


Figure 27: Duration curve of hourly ramps in the system across the four scenarios in 2030.

From what has been described, it is clear that one of the largest changes in the system resulting from a higher solar penetration, as for example in the Socioeconomic scenario in 2030, is the change in the role of coal power plants: Their running hours are reduced, and some upward and downward ramps are required to make room for solar power generation. It is evident from Figure 28, which presents the duration curve ramps of coal power plants expressed in percentage of the total coal fleet, that ramping is increased in the No Fossil Subsidies scenario and the Socioeconomic scenario. However, the maximum hourly ramp experienced in the Socioeconomic scenario is around 40-50% of the total coal capacity, which is within the technical limits of the coal power plants installed today in the Lombok power system (60% ramp up or down of the capacity within 1 hour).

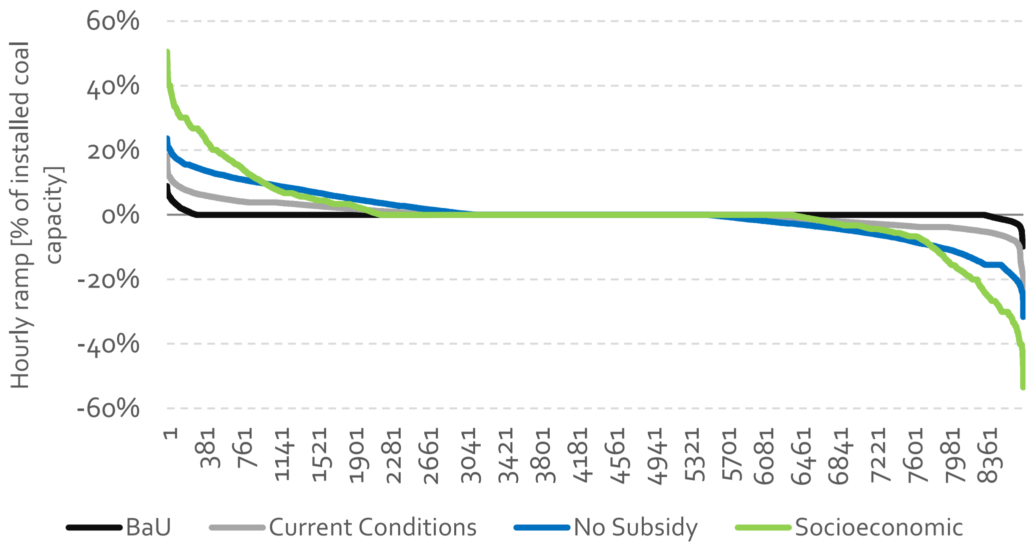
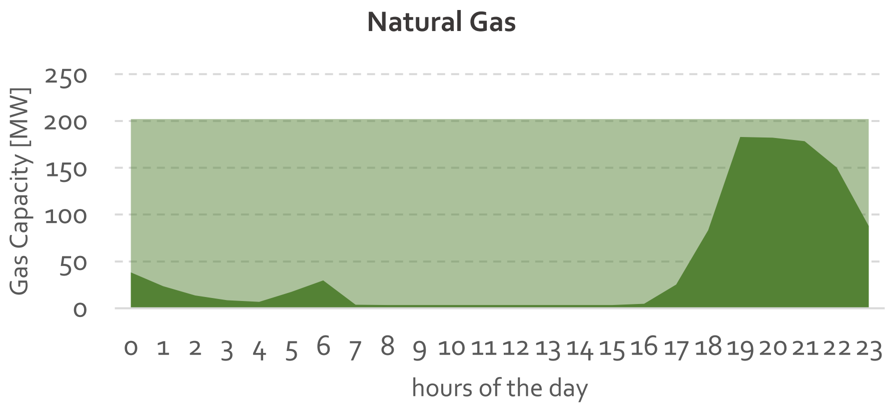


Figure 28: Duration curve of hourly ramps for coal power plants across scenarios in 2030.

A summary of the average behavior of natural gas and coal power plants in Lombok in the Socioeconomic scenario in 2030 is visualized in Figure 29. The 200 MW of available gas capacity is mainly utilized to cover the demand peak at night and ramped up steeply between 17:00 and 19:00. Conversely, the entire natural gas capacity is available during the day as a reserve to help coping with fluctuations and potential forecast errors of solar power generation. Coal power plants, on the other hand, start ramping down in the morning to make room for solar power generation and start ramping up again between 14:00 and 17:00.



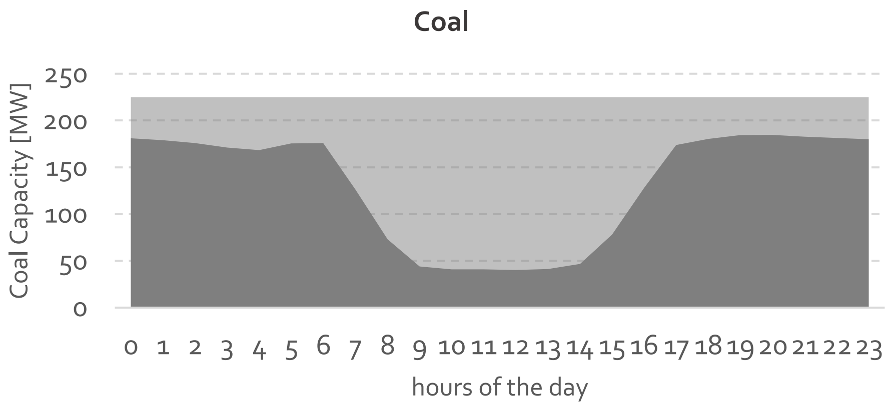


Figure 29: Available (light) vs dispatched (dark) capacity for natural gas and coal in the Socioeconomic scenario in 2030.

Emissions of pollutants and CO_2

As previously mentioned, combustion of fuels such as coal, oil and gas lead to emissions of SO_2, NO_x, and $PM_{2.5}$ which have a considerable impact on human health, causing premature death and illness. These negative effects result in a cost for society related to increase health cost. Some of these costs might be carried directly by PLN, for example in case a certain compensation is given to population living in the proximity of a coal power plant, or if future regulation will require the installation of environmental facilities to reduce the harming emissions from power plants.

It is interesting to compare the emissions of pollutants across scenarios. The highest pollutant emitted across scenarios is NO_x, which is emitted by both coal and natural gas. Overall, emissions in the Socioeconomic scenario, the only scenario including the aforementioned cost in the optimization, are 50% lower in 2030 compared to BaU and Current Conditions. The emission cost in the Socioeconomic scenario is therefore much lower, as will be pointed out later in the report.

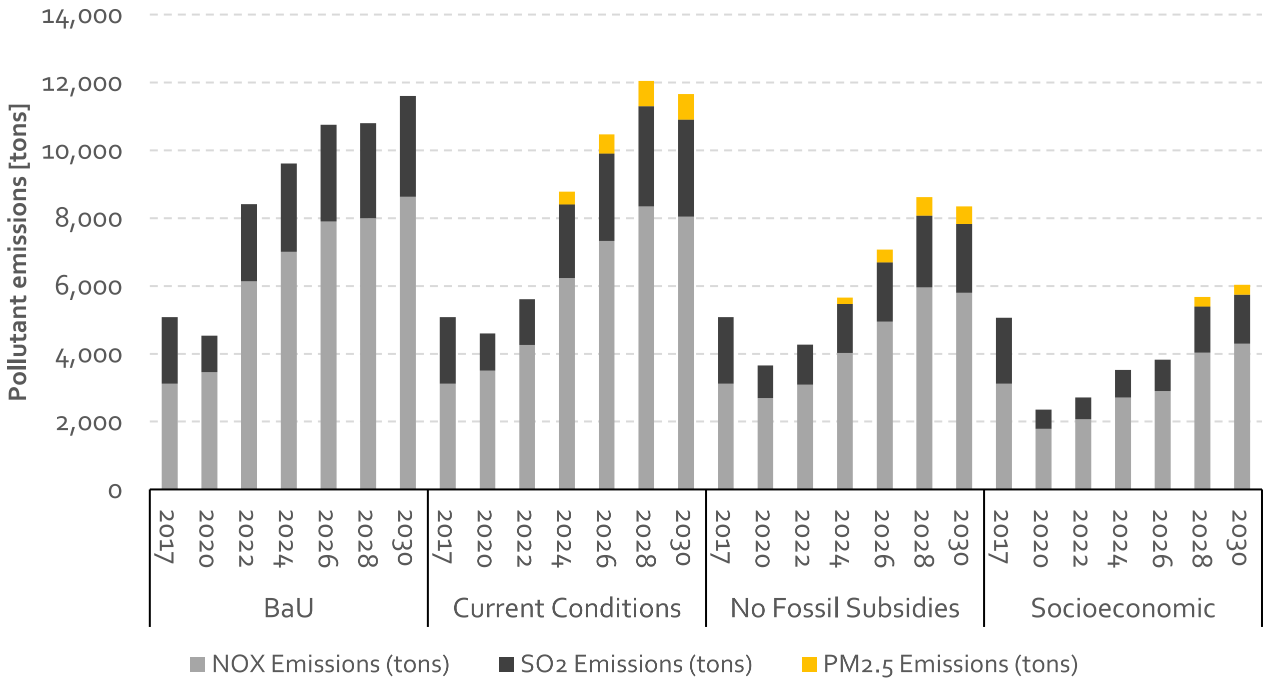


Figure 30: Emissions of pollutants related to power generation in the 4 scenarios.

As for the emissions of CO_2, no specific externality cost nor CO_2 emission tax has been considered in any of the modelled scenarios. However, Figure 31 shows a comparison of CO_2 emissions in the different scenarios. The BaU and Current Conditions scenarios have the highest level of CO_2 emissions, surging from a level of 1.5 Mton in 2017 to a value of around 3 Mton in 2030. On the other hand, removing fossil fuel subsidies results in much lower emissions for the power sector – it is almost halved compared to the first two scenarios and not much higher than today's level in spite of significantly higher power demand. In 2030, the Socioeconomic scenario emissions reach a value lower than that of 2017.

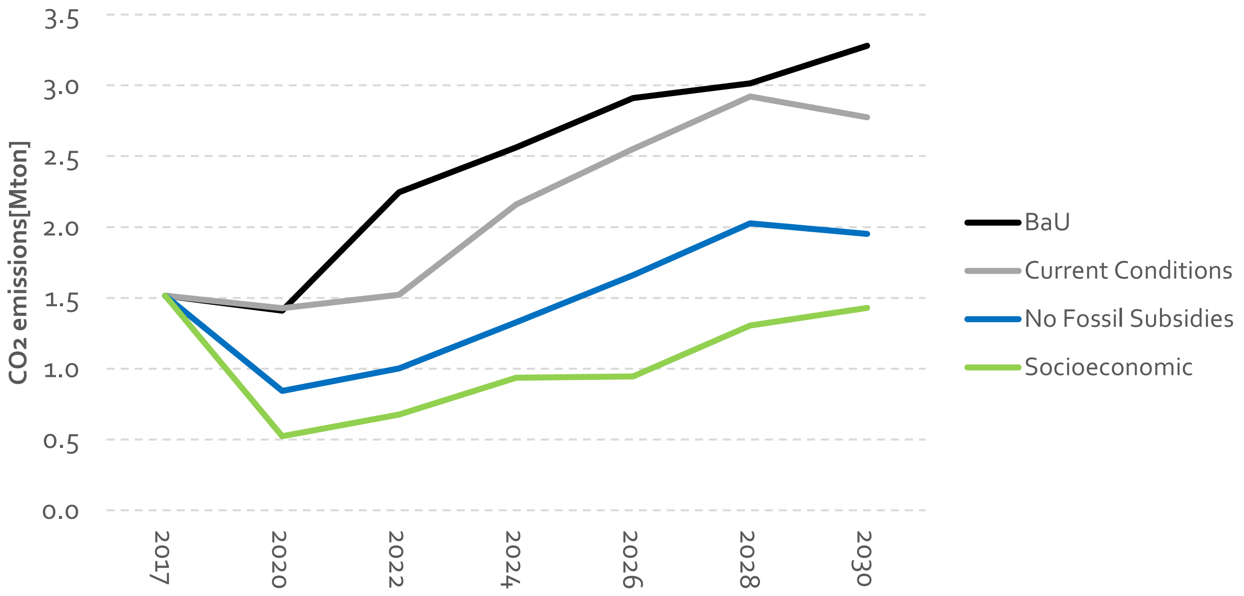


Figure 31: CO_2 emissions for the four main scenarios.

A look at the specific emissions measured in ton CO_2 per kWh of power generated, it is clear that first of all, the value is in all scenarios lower than that of 2017, due to the phase-out of diesel and introduction of natural gas. Secondly, even if emissions grow in total, the specific emissions are quite stable across time in all scenarios meaning that the increase of emissions is mostly related to a higher demand. The No Fossil Subsidies scenario and the Socioeconomic scenario have approximately half of the specific emissions compared to the scenarios BaU and Current Conditions.

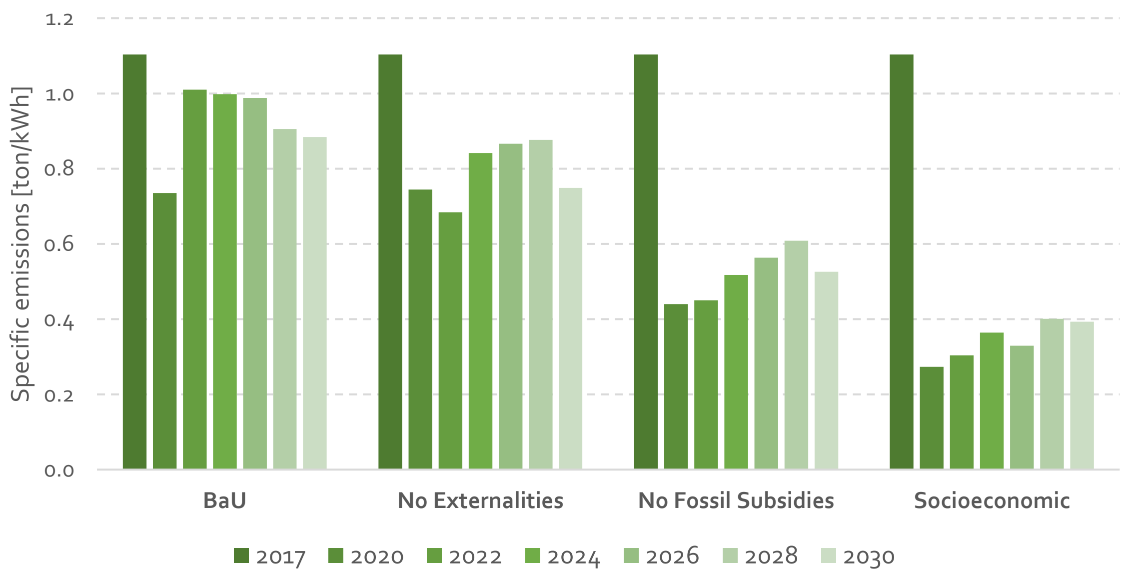


Figure 32: Specific emission of carbon dioxide in the scenarios.

Even if no externalities are considered for CO_2 in the scenarios, reducing CO_2 emissions might both contribute to fulfilment of the target of the Paris Agreement, which was ratified by Indonesia, and also attract international aid and support, in particular in the form of low-cost finance.

System generation cost

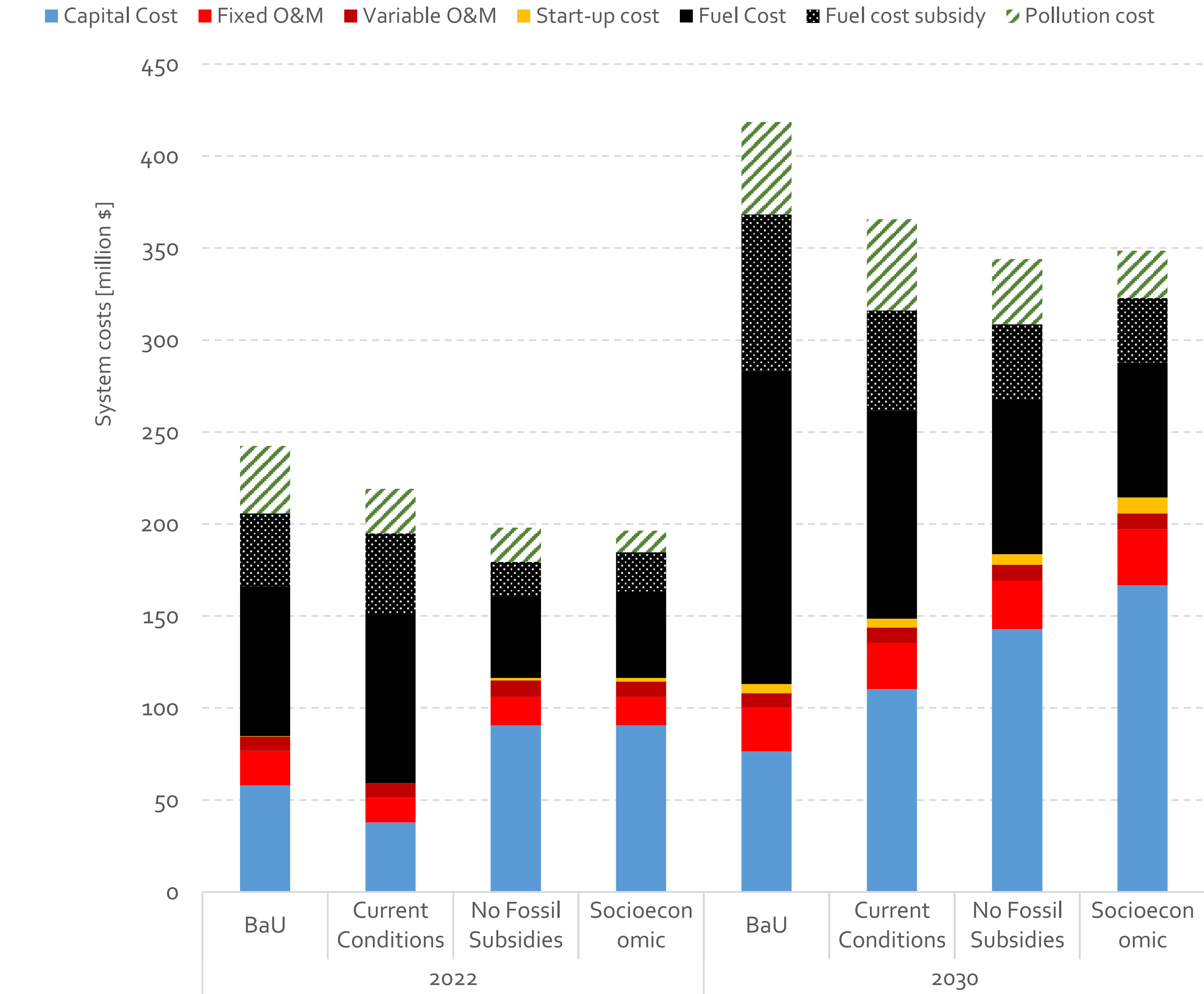
Figure 33 shows the development of the total system cost of the Lombok power system for the years 2022 and 2030, across the different scenarios, expressed in million $. The cost components considered are Capital cost, Fixed operation & maintenance cost, Variable operation & maintenance cost, Start-up cost of units, and finally Fuel cost. Furthermore, the fossil fuel subsidy – corresponding to 50% of the fuel cost of gas and coal – is shown. This represents the extra cost that the system incurs, in case the subsidies to fossil fuel prices are removed. Finally, the last cost component is the pollution cost related to the emissions of NO_x, SO_2 and $PM_{2.5}$.

The No Fossil Subsidies and Socioeconomic scenarios are much more capital intensive than the other two scenarios. This is typical for a system based on higher shares of RE, since it is characterized by higher upfront investment cost, but little-to-no fuel cost. This increases the required investment in the system compared to BaU scenario.

Conversely, the largest cost component in the BaU scenario is fuel cost. It is in 2030 more than double compared to that of the Socioeconomic scenario. A system with such high fuel cost has a higher risk of cost fluctuations depending on the international price of fossil fuels. Indeed, the potential extra cost related to the removal of subsidy is very high.

The Current Conditions scenario is the one with the lowest cost both in 2022 and in 2030, followed by the BaU scenario. However, in case the coal price subsidy is removed, the extra expenditure for fuel makes these two scenarios more expensive than the No Fossil Subsidies scenario. Finally, if the extra cost of pollution is included in the calculation, the Socioeconomic scenario turns out to be the cheapest.

Overall, the key message from the calculation of the total system cost is that all four scenarios have more or less the same generation cost. Therefore, it appears that having a system with much more RE, while increasing the capital requirement, largely reduces the fuel cost required to run the system. RE scenarios have a very little extra cost compared to BaU when considering subsidized coal and gas prices and no externalities, while a lower cost when considering the two aforementioned elements.



	2022 BaU	2022 Current Conditions	2022 No Fossil Subsidies	2022 Socioeconomic	2030 BaU	2030 Current Conditions	2030 No Fossil Subsidies	2030 Socioeconomic
Pollution cost	37	24	19	12	50	50	35	26
Fuel cost subsidy	40	44	19	22	85	55	41	35
Fuel Cost	81	92	44	47	170	113	84	73
Start-up cost	0	0	1	2	5	5	6	9
Variable O&M	8	8	9	8	8	8	9	9
Fixed O&M	19	13	15	15	24	25	27	30
Capital Cost	58	38	91	91	76	110	143	167

Figure 33: Total system cost across scenarios in 2022 and 2030[5].

[5] The total cost of the Socioeconomic scenario in 2030 appears slightly higher than No Fossil Subsidies, while it should be equal or slightly lower. Two are the main reasons: we are only displaying 2030, while for the previous years Socioeconomic has lower cost, and investment simulations over which capacity is optimized does not contain the full representation of power plants operational limits, like in the detail dispatch simulation from which these total costs are calculated.

3.2 POWER DEMAND SENSITIVITY SCENARIO

The reduction of the power demand assumed, i.e. 6% in 2020 and 13% in 2030, due to the lower power intensity, affects the power generation and dispatch in the Lombok power system.

In the Low Demand scenario, only the dispatch is optimized using the generation capacity evolution from RUPTL. The aim is to understand more about the dispatch and utilization of power plants in case the demand turns out to be lower than expected, and from there draw conclusions about the need for such investments in power capacity expansion.

Figure 34 shows the development of generation until 2030. It can be observed that a lower power demand reduces the generation from LNG and partly that from coal plants.

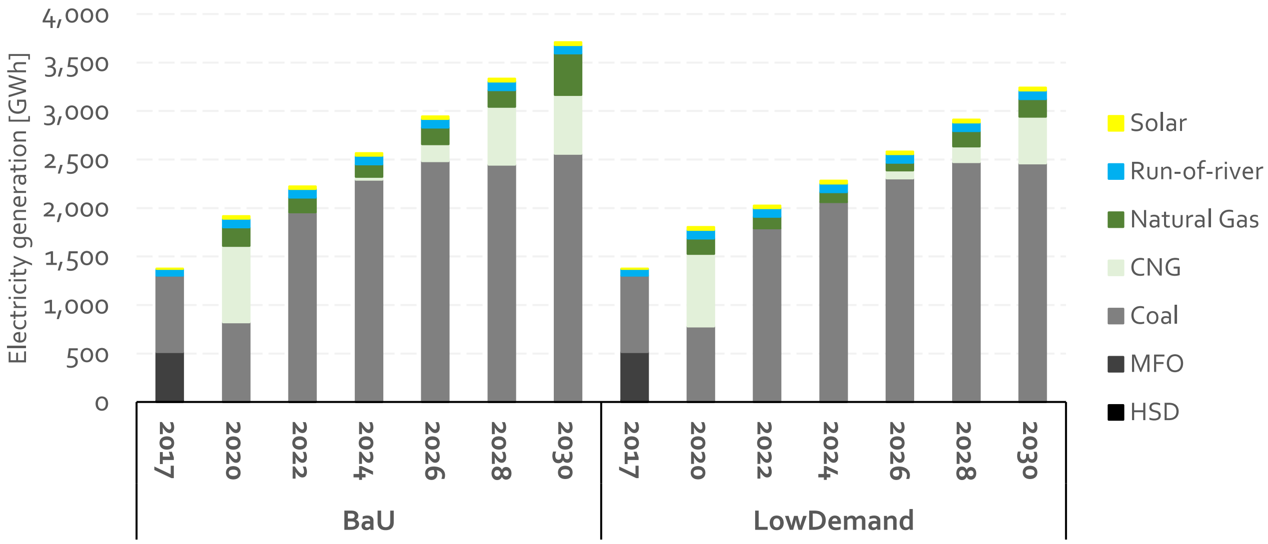


Figure 34: Development of annual generation in the Low Demand sensitivity compared to BaU.

If we focus on the Full load Hours (figure equivalent to capacity factors) of the generators, it can be observed that the power plants that reduce their output most are the JRG3 coal plant, the MPP power plant, the Lombok Peaker, and the JRG coal plant.

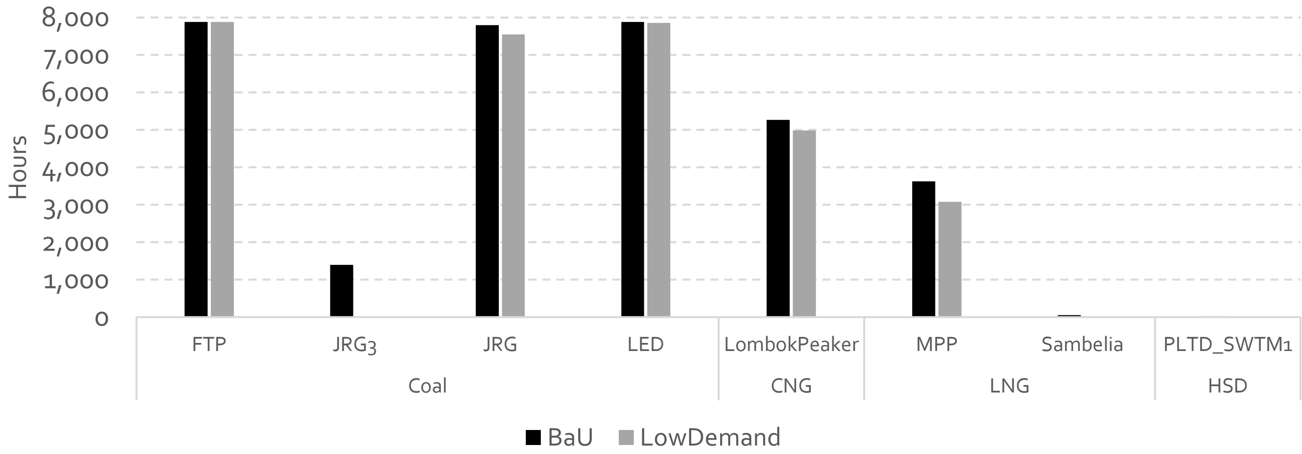


Figure 35: Full load hours of power plants in 2030 in the two scenarios.

3.3 INTERCONNECTION SENSITIVITY SCENARIO

The sensitivity of the socioeconomic scenarios to the interconnection of Lombok to the Java-Bali system is performed as a base scenario. Generation capacities from Socioeconomic scenario are used for Lombok, while for Java-Bali a similar investment optimization has been carried on, allowing investments in addition to the power plants assumed in RUPTL.

The project

The Pre-feasibility study [1] describes an interconnection project consisting of a submarine cable that connects Lombok to Bali with a capacity of 300 MW. There are two options for the connection (Figure 36): one direct connection and one through Nusa Penida. The cheapest option assessed is the connection trough Nusa Penida, which would utilize HVDC technology and cost $162-200 million.

The assumed commissioning year in this analysis is 2025.

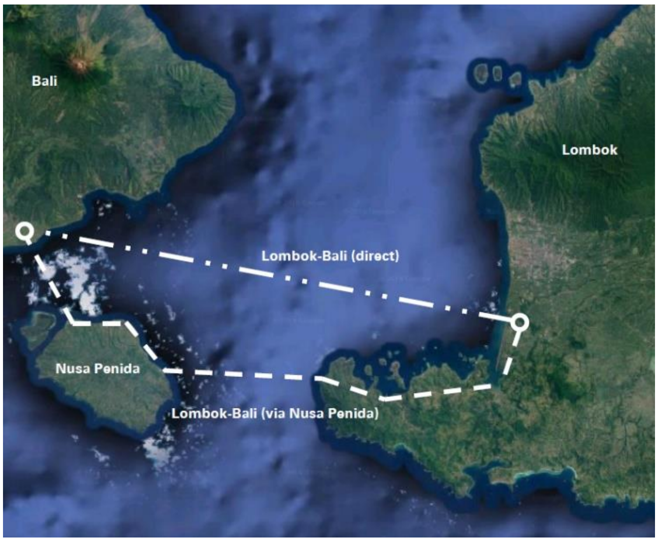


Figure 36: Interconnection options.

Source: Pre-feasibility studies [1].

Methodology

To simulate the interconnector sensitivity of the Socioeconomic scenario, a consistent development of the Java-Bali system, i.e. applying the market price of coal and gas and adding pollution cost, must be assessed. Starting from the RUPTL capacities, an investment run is simulated to determine the development of Java-Bali generation fleet under these conditions. The results for 2017, 2026 (first year in which the cable is available) and 2030 are shown in **Error! Reference source not found.**.

Similar to the development in Lombok, the modelled Java-Bali system features a high solar and geothermal capacity, alongside coal and natural gas.

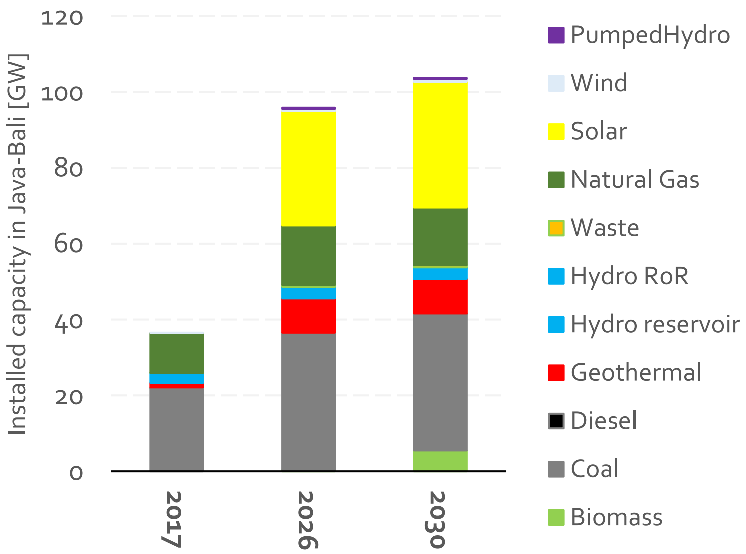


Figure 37: Development for Java-Bali system.

The impact of the interconnector is assessed by simulating the dispatch of the two power systems with and without the interconnector. Impacts on investment in generation capacity are not considered in this sensitivity. The interconnector can, however, potentially reduce the overall generation cost in the combined system by enabling more efficient dispatch.

Results

Figure 38 shows the generation in Lombok in the sensitivity analysis, i.e. if the 300 MW of cable to Bali is available, compared to the Socioeconomic scenario. The generation from power plants in Lombok decreases when the cable is added to the system. In the first year, 2026, the generation reduction is around 30% and it decreases further over time. The main effect of the cable addition is that cheaper generation from coal and geothermal plants in the Java-Bali system is imported to Lombok and more expensive or less efficient generators on Lombok reduce their output. The effect is particularly visible for coal and gas (CNG and LNG) generators. It is interesting to note that the generation from the CNG plant coming online in 2019 is significantly reduced.

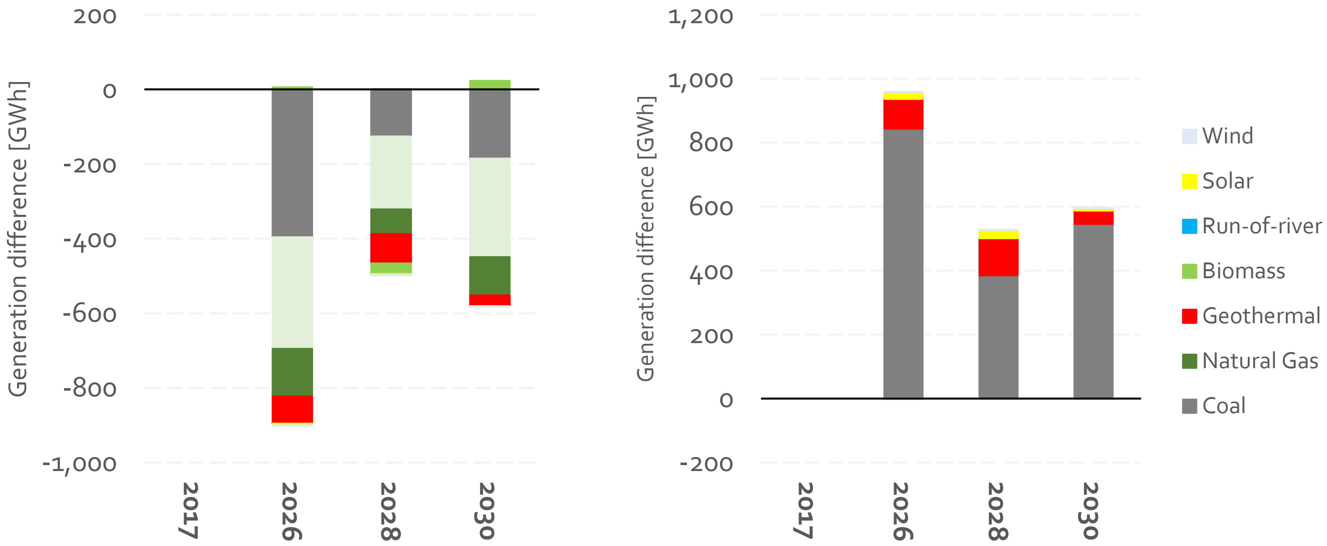


Figure 38: Generation difference in Lombok (left) and Java-Bali (right) in the scenario with cable, compared to the scenario without cable.

The new typical daily system dispatch in the Interconnector scenario is significantly different from the dispatch without the interconnector (Figure 39). Cheap energy sources like geothermal and biomass are largely unaffected by the presence of the interconnector and during the central part of the day, the large solar capacity is dispatched. On the other hand, in the morning and afternoon, the import from Java-Bali ensures the match between generation and demand, partly substituting coal and gas generation.

The presence of the interconnector also acts as an integration measure for the large solar capacity: the Lombok system exports power during the central part of the day and imports power during hours with less RE generation.

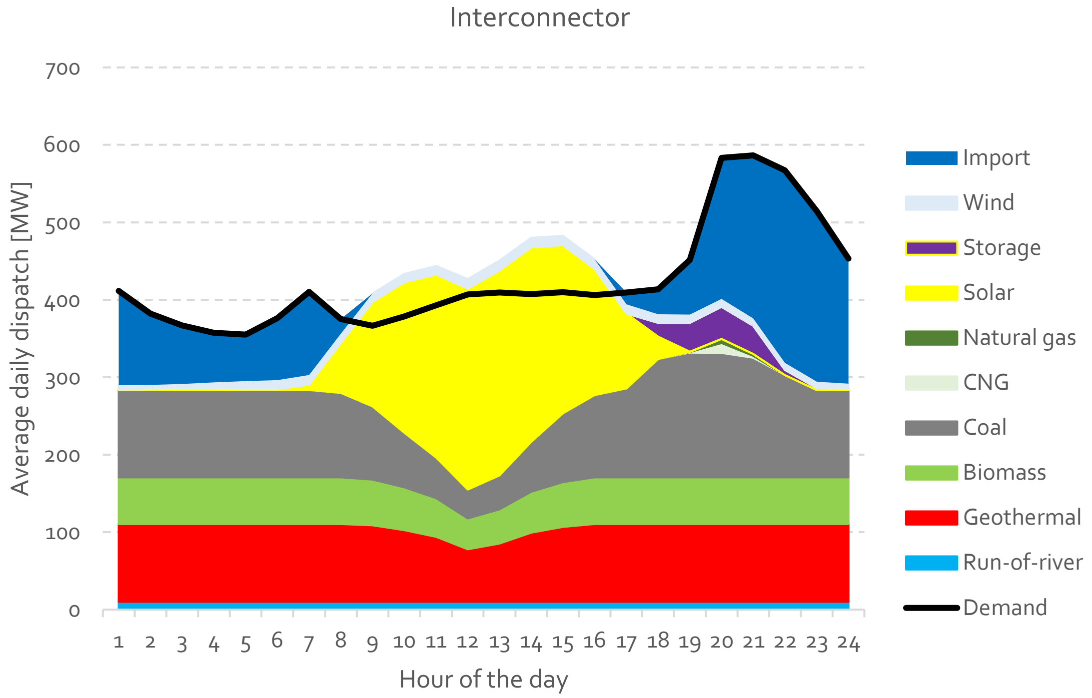


Figure 39: Average daily dispatch in Lombok in 2030, when the interconnector is available.

The marginal generation cost is a measure for the cost of generating one extra MWh in a given hour in a given power system, or the savings from reducing the generation in that hour. [6] Comparing the marginal generation cost of two interconnected systems in a given hour of the year determines whether the power flows in one direction or the other according to optimal power dispatch: if the marginal generation cost is lower in Bali than in Lombok, power will flow from Bali to Lombok and vice-versa. The higher the difference in the marginal generation cost throughout the year, the higher the value of the interconnector and the larger the potential savings on annual generation cost in the combined systems.

Figure 40 shows the difference in the hourly marginal generation cost between the two regions. It highlights the fact that for most of the hours of the year, the price in Bali is 0.25 c$ cheaper for each kWh produced and therefore Lombok is importing power from Bali. There are some hours however, in which the cost of generation in Lombok is lower (negative value in Figure 40) and therefore Lombok is exporting power to Bali, this mainly happens when large solar generation in the central part of the day reduces the marginal generation cost to a very low level.

[6] In power systems organized through a day-ahead electricity market, the marginal generation cost in the hour represents the hourly price of electricity.

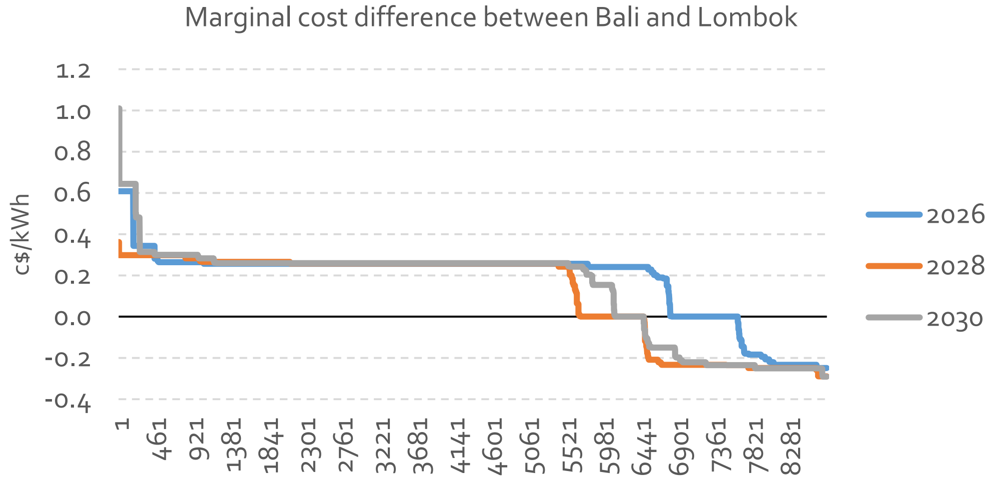


Figure 40: Hourly difference in the marginal generation cost of Bali and Lombok. A positive value indicates an advantage for Lombok to import power from Bali.

As a final consideration, generation costs are compared in the scenario with and without interconnector. When adding the cable between Lombok and Bali, the combined system experiences a cost saving of $31.2 million in 2026, $18 million in 2028 and $25.3 million in 2030. The largest saving is experienced in the power system on Lombok, due to the import of power produced by more efficient coal plants, the cheaper coal price in Java-Bali and the reduction of natural gas use on Lombok.

This corresponds to an average cost saving of $24.8 million per year. Considering that the investment cost for the Interconnector project has been assessed to $162-200 million, the corresponding simple payback time of the investment would be around 6½-8 years. This makes the investment in the cable feasible and represents a solid solution for the reduction of the generation cost and the integration of RE in the long term. However, some caveats, as well as further considerations, need to be underlined:

- The generation cost difference when the cable comes online in 2025 is already much lower than today's level. This is due to the fact, that expensive diesel generation in Lombok is phased out already in 2020 and low variable cost RE such as geothermal and biomass comes online in the meantime. It is important to assess the profitability of the Interconnector project considering how the system could look like in 2025 and after, across different scenarios.
- The assessment has been conducted as a sensitivity analysis for the Socioeconomic scenario. To evaluate the feasibility of such a large investment, the analysis should be expanded to a number of additional scenarios, starting with the official RUPTL projection.
- The Interconnector scenario explored the impact of the interconnector on the dispatch only. The presence of an interconnector could affect long-term investments in both Java-Bali and Lombok, which could potentially increase the value of the project.
- Additional benefits of the interconnector include a higher security of supply on Lombok and a more stable system frequency. However, with 300 MW being the largest contribution to the supply on the island, N-1 criteria might require a dedicated back-up in case of outage of the interconnector. The 150 MW CNG Peaker might be part of such a solution.

4. Conclusions and Recommendations

The research questions to which this analysis aimed to provide answers were the following:

- What is the most **cost-efficient development** of the power system in Lombok, taking into account available local resources, cost of technologies and fuel availability/price?
- How do **subsidies to fossil fuels** and **externality cost** of pollutants affect the least cost development?
- What is the cost of increasing **RE** deployment in Lombok?

The potential development of the power system in Lombok is very different across the scenarios analysed. The BaU scenario, based on assumptions from RUPTL 2018, is largely based on the addition of coal power plants and gas to supply the demand in the island. On the other hand, based on the assumption described and the least cost optimization from the model, there is the potential for RE sources to play a role in the development of the supply in the island.

Biomass and geothermal energy are the **cheapest sources of new generation** in the short term, as also confirmed by the calculation of the LCoE. However, some obstacles have to be overcome to make the installation of these sources a reality. For biomass, mainly in relation to the husk supply, which is in competition with agricultural use (as underlined in the Prefeasibility studies) and for geothermal, the challenges are technological complexity and precise localization of the resource.

In case subsidisation of coal and gas is removed and the **true cost of the fuel** elicited to the power system, other RE sources such as solar and wind can compete with coal and gas and help reduce the cost of generation. This is true in particular starting from 2026.

The zero-marginal cost generation from solar power displaces more expensive generators in the merit order dispatch during the central hours of the day, reducing system cost in particular due to the reduction of fuel consumption. The generation from solar becomes dominant in 2030 due to the continuous cost reduction and to the availability of cheaper energy storage. This large solar penetration poses some challenges to the operation of the system.

While solar is not significantly increasing the requirement for extreme **ramps** due to the night load surge, it does increase the requirement for more flexible baseload power plants: more flexibility will be required from existing and new coal plants. It is assessed that both the downward ramps of coal power plants in the late morning and the upward ramp in the late afternoon is within the operational limits of current power plants, with a maximum ramping requirement of 40-50% per hour. In some particularly sunny days in the dry season, some coal power plants might be required to shut down for 4-5 hours in the middle of the day to be started up again and ramped up in the late afternoon. In case this is not possible for the power plants, a higher level of solar curtailment could be accepted in order to keep power plants running at their minimum load or additional storage could be installed to exploit this excess energy and release it during the ramp up and peak at night, helping the system to balance.

Regarding **storage requirements**, the operational optimization with Unit Commitment in the No Fossil Subsidies scenario shows that around 230 MW of solar power could be dispatched without need for storage. During the central hours of the day, in which coal and solar covers the demand, natural gas and CNG power plants would be available to eventually covers the variability and uncertainty of solar power supply. If larger solar capacity is found to be feasible, for example to reduce pollution cost in the Socioeconomic scenario, storage is installed in combination with solar to reduce the strain on the system in the central part of the day and to store cheap energy to be released during the night peak, thus displacing also some natural gas generation. The MW capacity of storage installed, in the form of 4-hours lithium-ion batteries, is roughly 11% of the corresponding solar capacity and equal to 48 MW (192 MWh).

Solar power capacity in 2030 is relatively high in the two scenarios with higher RE, namely 229 MW (No Fossil Subsidies) and 443 MW (Socioeconomic). This large capacity will require large areas of land which might be in conflict with other activities on the island, in particular agriculture. The total required land area for 443 MW would be equal to 4.43 km^2, corresponding to roughly 0.1% of the total surface of the island. Moreover, part of this solar capacity could practically be furnished by rooftop PV, for which a new regulation has recently been published by the MEMR, and thus relieving the pressure on land. As a reference, the solar target mentioned in RUEN for the entire West Nusa Tenggara province is 292 MW in 2025.

Besides solar power, **wind power** has a competitive business case today considering the high tariff guaranteed based on the Regulation 50/2017, as shown in the Prefeasibility studies. The competitiveness of wind power relative to solar power becomes weaker in the longer term due to the expected large cost decrease for PV in the near future. However, the LCoE of wind is not much larger than that of solar and the installation of more wind power could alleviate some of the integration challenges related to a high solar penetration. Indeed, wind power generation is more distributed throughout the day and could reduce the need for coal ramping and contribute during hours with high load as well.

Additional projects might be relevant for the island of Lombok, even if not found feasible in the model analysis. A waste power plant on Lombok was found to not be feasible from a purely economic perspective and based on the current gate fee for the collection of waste. However, as underlined in the Prefeasibility studies report, the project might have a high environmental value in reducing the level of pollution of the coastline and sea around the island. The solution of a pumped-hydro power plant or a reservoir hydro plant might also be an interesting source of flexible generation and depending on the specific location and orography might also be more convenient than assessed in this analysis – especially, if the civil works related to the construction does not have to be carried by the power generation project, but instead as an environmental solution for irrigation.

Looking at the total cost of the system excluding externalities and considering subsidy, the most expensive scenario (Socioeconomic) is only 9% more costly than the cheapest (Current Conditions). When considering the extra cost of the subsidy to fossil fuel, the cheapest scenario (No Fossil Subsidies) is 3% below the Socioeconomic scenario. Finally, when also factoring in externalities, the difference in the total cost is only 6%.

The key message we can deduce is that the three different least cost scenarios optimized by the model have almost the same cost, which does not differ largely from the cost of the BaU. Basically, it is possible for Lombok to reach very high RE penetration, up to almost 60%, without a high extra cost and without jeopardizing the power system.

Since internalizing pollution cost and fuel price risk into the planning might be complicated, the island of Lombok (and more broadly the province of Nusa Tenggara) could consider implementing a more ambitious **RE target** instead, for example with a level of around 50-60% of the final electricity consumption. Setting a target for the final electricity consumption (or share of generation) is different from the way the target is currently set in RUEN and might be a more simple and transparent way of implementing a RE target, as briefly discussed in the Text Box below.

In case a more ambitious path is chosen, potential extra cost related to **integration of a high share of VRES** could materialize, for example in relation to the expansion and reinforcement of distribution grids, increasing flexibility of power plants, setting up a proper forecasting system and more advanced operational practices. On the other hand, contribution to climate change mitigation and reduction of emissions could potentially attract both cheap international finance and funding though development programs, not to mention the potential increase in tourism and international attention.

The following table presents a simplified SWOT analysis and summarizes the strengths/opportunities and the weaknesses/threats of a BaU development compared to a more ambitious RE development, such the one described in Socioeconomic scenario.

Table 5: SWOT analysis of the BaU scenario and the Socioeconomic scenario.

BaU - RUPTL	
Strengths / Opportunities	**Weaknesses / Threats**
Higher technological confidence in coal and gas	High risk of fuel price increase (large % of the system cost is related to fuel)
Less complex system operation	Larger emissions of pollutants (almost double)
	Risk of technology lock-in
	Difficult to secure financing to coal in the next future
	ow incentive to improve operational practices and modernize the system

More ambitious RE development	
Strengths / Opportunities	**Weaknesses / Threats**
Resilience with respect to risk of fuel price increase	Very large investment in new capacity needed
Lower emissions and health cost	Challenges with integration of RE, likely causing some extra cost
Opportunity for international funding, also in relation to decarbonization efforts	Risk that cost of RE does not develop as expected
Opportunity for local job creation and employment	Potential challenge in finding enough land
Opportunity to modernize the power system	
Potential increase in the touristic value of island	

Formulating RE targets in Primary Energy Use vs Final Energy Consumption

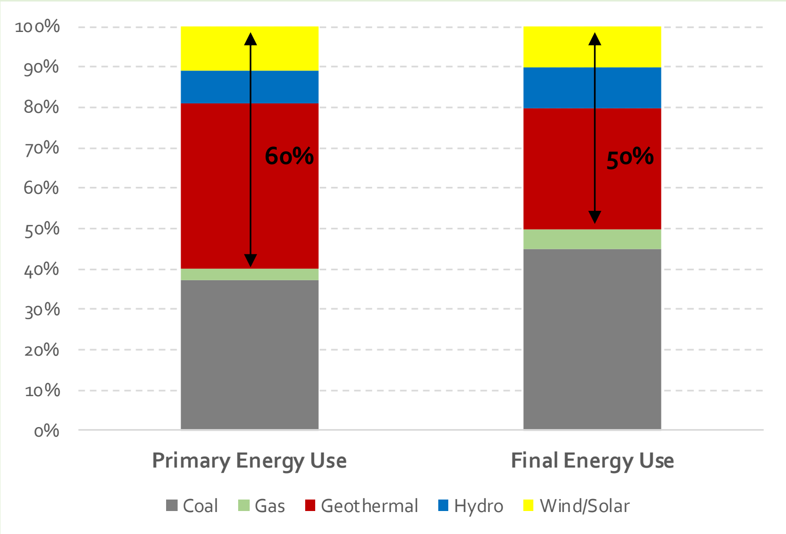
Policy documents like KEN and RUEN set a target for the Indonesian energy sector in terms of Primary Energy Use, equal to: 30% coal,20% gas and 23% RE in 2025.

There are different ways of setting policy targets for energy or fuel use. For example, targets can be set on **Primary Energy Use** like KEN, or in **Final Energy Consumption**, like it is commonly done in Europe.

The advantage of formulating targets in primary energy is that it provides a way to encompass the entire energy system and comparing contributions between sectors that are intrinsically different like transport, building and power sector. On the other hand, when solely looking at the power sector, a target on primary energy is less transparent, in particular when talking about RE sources like geothermal, solar and wind. Using primary energy use as a measurement requires assumptions regarding the conversion efficiency between power generation and primary energy use. For thermal power plants, this is relatively easy since the efficiency is known, as well as the total input of fuel, but for RE setting the efficiency is not trivial.

In Indonesia, these "accounting" efficiencies are set as follow: 20% for geothermal, 25% for solar and wind and 33% for hydro. This means e.g. that for every MWh generated from geothermal, 5 MWh are accounted for primary energy use, making it simpler to reach a certain target.

The result is the following: a certain RE target expressed in primary energy would result in a lower RE share in final energy use. The following figure, developed using the accounting efficiencies above, shows an example of how a target of 60% RE measured in primary energy corresponds to only a 50% RE share measured in final energy.



Other ways to set RE target includes for example **Targets on capacity**, which requires much less RE generation to fulfill the same percentage target since capacity factors of VRES such as solar and wind normally are lower than those of thermal generation based on fossil fuels (i.e. it takes more capacity of VRES to produce the same amount of annual generation).

4.1 POTENTIAL NEXT STEPS AND FUTURE WORK

Based on the results and model created in the course of the project, it would be relevant to initiate future modelling analyses which go more in detail with specific points raised in this report. For example:

- Analysis of the cost of an even more ambitious RE penetration on the island, for example exploring the case of a 100% RE power system;
- Sensitivity analyses on the operational limits, including an assessment of the extra cost of increased requirements on the flexibility of the power plants;
- Analysis of the effect of cheap financing available from, for example, international sources (effects of lower cost of capital);
- Expansion on the interconnector analysis, potentially evaluating the feasibility across different potential power system development scenarios and assessing the long term effect of the cable presence on the optimal capacity expansion.

Moreover, the model of the entire West Nusa Tenggara system has been developed during the various training sessions. Future work could cover the energy planning across different scenarios for the entire system, analyse the potential costs and benefits or an interconnection between Lombok and Sumbawa, as well as an assessment of the potential development of remote areas.

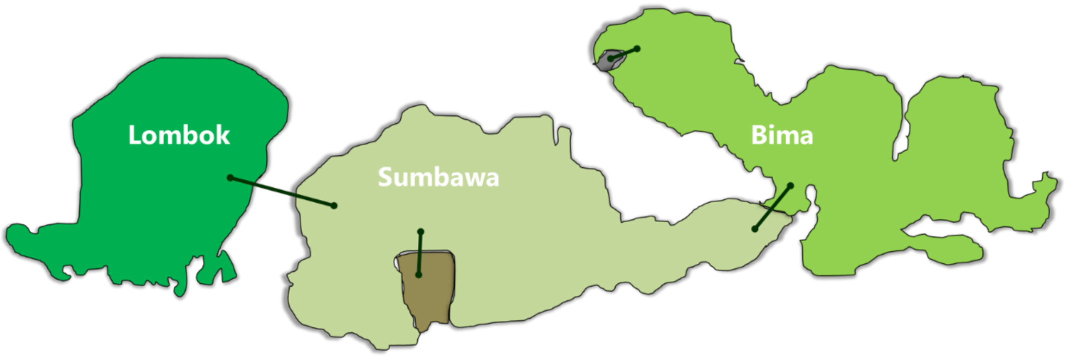


Figure 41: Geographical representation of West Nusa Tenggara in the preliminary Balmorel setup. Lombok, Sumbawa, Bima and the two isolated systems of Pekat and Lunyuk.

In particular, the Balmorel model could be used in the process of developing regional energy planning and the preparation of RUED. Currently, scenarios of future development of the energy system are modelled using LEAP, an energy modelling tool used to simulate the entire energy sector, with yearly time resolution.

The detailed power system optimization that Balmorel can offer, going down to dispatch at an hourly level, could complement the LEAP model and help analyse in more detail potential scenarios of the development of the power system in West Nusa Tenggara. European and international experiences indicate that increasing the RE share in the power sector is cheaper than in other sectors such as transportation or industry.

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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.

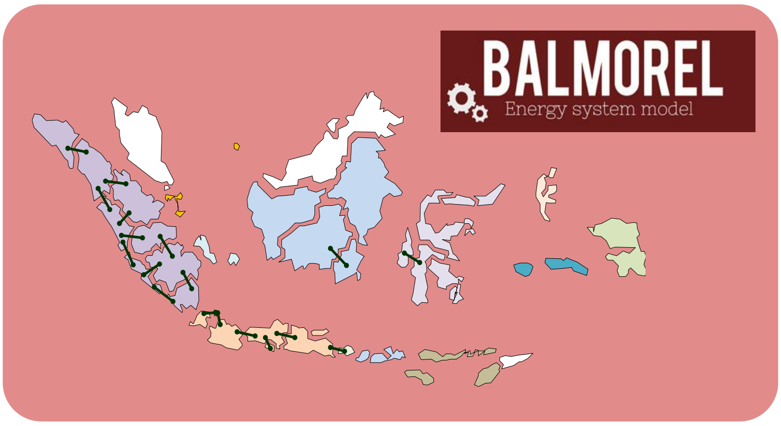

Figure 42: Balmorel model, Indonesian setup.

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 centers, 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 43). 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.

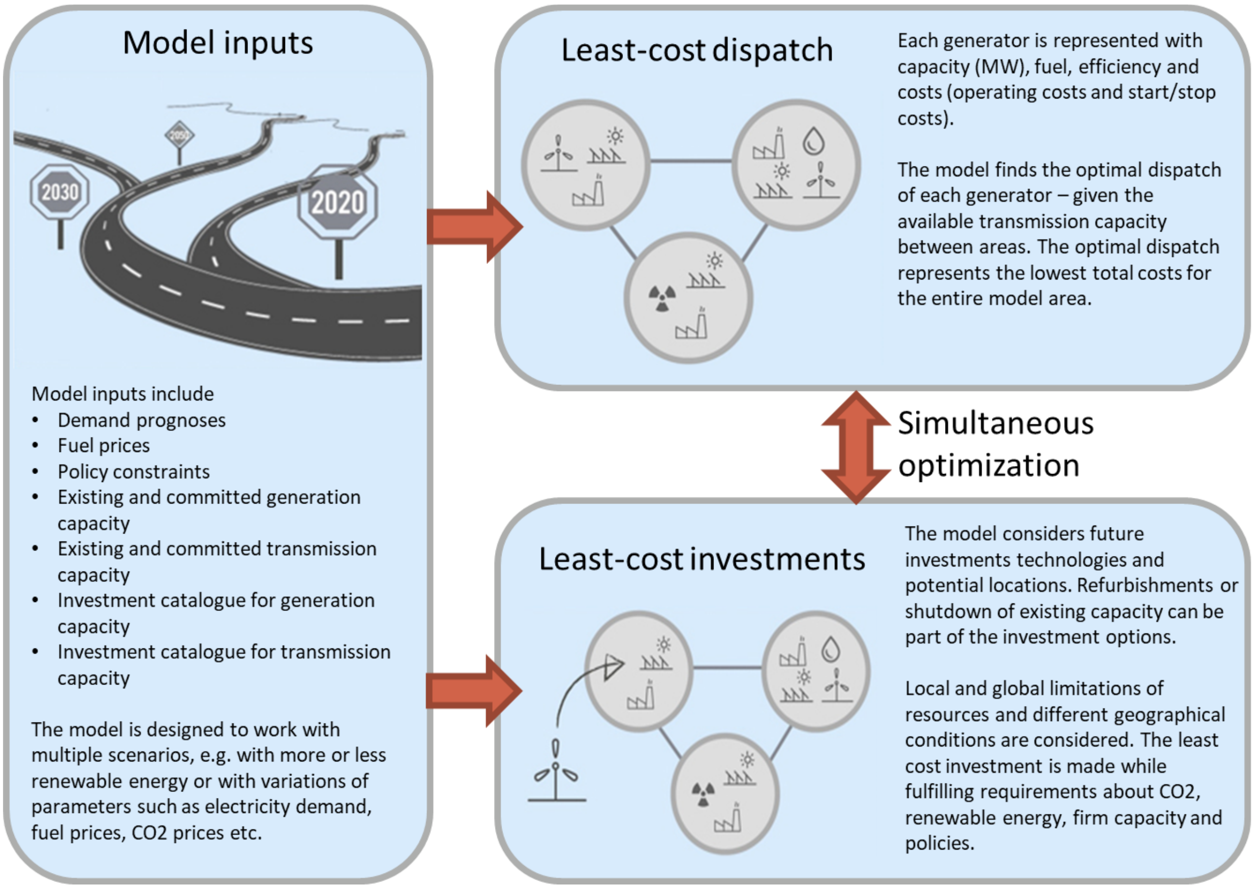

Figure 43: Balmorel model inputs and optimization logic.

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
- Potential co-optimization of new transmission and generation capacity (not used in this analysis for Lombok)
- 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.