# Are High Renewable Energy Shares In Large Power Grids In Indonesia Too Expensive?

#### Matthias Günther<sup>a\*</sup>

<sup>a</sup>Swiss German University, Indonesia \*mguenther.germany@gmail.com

Abstract: High shares of power from renewable resources in large power supply grids do not imply insurmountable technical problem anymore. A question is rather whether, besides the technical feasibility, it is also economically viable to go for a high share of power from sun, wind, water, geothermal resources and biomass. This paper scrutinizes the costs of a renewable-energy based power supply in the Java-Bali grid, by far the largest grid in Indonesia. The study refers to a challenging power supply scenario in which 100% of the power in the Java-Bali grid comes from renewable resources. This scenario is expressed in a one-year modeling of the load and the respective power supply in the grid. The modeling identifies possible sets of installed capacities of the different power plant types and storage systems that allow the supply of the required electricity. A cost scenario is applied to these sets, which renders the system costs, and finally the power generation costs. All scenarios refer to the year 2050. The results show that, assuming moderate financing costs, the cost of the electricity generation in the possible supply systems would not be higher than that in currently existing systems in developed countries; and it would even not be far away from the power generation cost in the current Java-Bali grid. A secondary result of the study is that the usage of special long-term storage systems for the balancing of seasonal power supply fluctuations, additionally to pumped storages and batteries, is not economically necessary in the considered grid.

Keywords: renewable energy, cost scenario, cost optimization, Java-Bali grid

#### 1. Introduction

The generation of power from sun, wind, water, geothermal heat and biomass has obvious advantages over the generation of electricity from coal, petrol, other fossil resources, and uranium: The first group consists of renewable resources, while the latter group contains limited non-recoverable resources the excessive usage of which implies their depletion. Additionally, the usage of the resources in the first group has, if done properly, verly limited environmental effects, while the usage of the resources in the second group generally comes along with negative and in some cases potentially very dangerous environmental effects. Furthermore, any country or region possesses some of the resources in the first group. This is not the case for the resources in the second group; if countries and other geoeconomic units base their power supply on them, then their energy supply may depend on importing these resources, which may compromise foreign trade balances and create political dependencies.

There are, hence, obvious reasons to increasingly make use of renewable energy resources, and consequently there is a worldwide tendency to increase the share of renewable energy resources and to decrease the dependency especially on fossil fuels. This tendency refers to all types of usable energy, but it is especially notorious for electrical energy. However, as electrical energy is a commodity, in fact a very important and fundamental one, the economic implications of the specific design of a power supply system, in particular the power generation cost, must be a central concern. In some grids, the usage of some types of renewable resources has been cost competitive for a long time. This holds especially for hydropower wherever large rivers are available. In other grids this was not the case. However, the cost development of some renewable energy technologies is very dynamic. In particular solar energy and wind energy technologies have seen enormous cost reductions in the last decades, which opens more and more opportunities of their economically competitive application.

The changing economic conditions not only in the sense of reduced renewable energy technology costs, but also in the sense of varying - and in the long run increasing - fossil fuel costs,



require a continued economic reconsideration of the competitiveness of the different renewable-energy based power supply solutions. Additionally, the economic evaluation has to be done for any specific given grid individually. The results concerning one grid cannot be applied to other grids with their own economic and geographical conditions. The applicability and economic competitiveness of renewable energy technologies depend on the given natural conditions, the access to the technology markets, financing conditions, the access to fossil resources and the cost of them, and other conditions that are specific to the particular grid area.

The present study refers to the by far largest grid in Indonesia, the Java-Bali grid. This grid comprises about three fourth of the national power consumption. The renewable energy share, basically from hydropower and geothermal power, does currently not even reach 10%. The present paper is based on a scenario published in Günther et al. (2018), in which different options of a future 100% renewable energy supply in the Java-Bali grid are studied. This scenario is combined with a cost scenario for the involved power supply technologies, which allows the calculation of the system cost and the related power generation cost. As the power supply scenario contains some open parameters, a determination of the economically optimal supply system configurations must be included.

#### 2. 100% renewable energy scenario

The 100% renewable energy scenario in Günther et al. (2018) refers to the year 2050. A consumption of 640 TWh is assumed, compared to a demand of about 152 TWh in 2015 (PLN, 2017). The scenario assumes that 90% of the power is delivered by photovoltaics (PV), 6% from geothermal power plants, 3% by hydropower plants and 1% by biopower plants. The numbers result from an estimation of possible future installed capacities of geothermal and hydropower plants, and a conservative estimation of the power potential from agricultural waste. PV is dimensioned such that it covers the load that is not yet covered by the other power plants. The installed PV capacity is an open parameter because it does not only depend on the remaining load it has to cover, but also on the installed storage capacities: Smaller installed storage capacities require larger PV capacities, and larger storage systems allow for a lower installed PV capacity.

Three system logics are distinguished in the mentioned text (system logics I, II and III). All logics have the following in common: geothermal power is permanently delivered; solar power is supplied whenever it is available, and it is stored when available in excess; hydropower is used for peak load shaving. The difference between logics I and II on the one hand and logic III on the other hand is that the latter contains a synthetic gas (methane) storage system (storage II), additionally to the storage system consisting of pumped storages and batteries (storage I) that is included in all three system logics. The difference between logics I and II is that bioenergy is used for seasonal balancing in logic II, while it is used for peak load shaving in logic I.

The inclusion of a second storage system in system logic III follows the idea of the distinction between short-term and long-term storages. This distinction between short-term and long-term storages is reasonable in the following sense: A complete storage cycle consists basically of three stages: storage charging, keeping the energy in the storage, and storage discharging. Each of these stages is associated with costs. These costs come from the technical installations that are needed and also from energy losses that may happen in any of these three stages. There is no perfect universal storage system that has minimum costs for all three stages of the storing cycle. There are storages, for instance, the capacity of which is not expensive such that large amounts of energy can be stored without running into high costs. If additionally the self-discharge rate is very low, these storages are appropriate for long-term storing of large amounts of energy. There are other storage systems that have high capacity costs but lower charging and discharging costs. These storage systems are appropriate for short-term storing. The high capacity cost can be easier accepted if there is a high energy throughput through the capacity during its lifetime. If the storage is frequently used, the high cost is distributed among a large amount of energy that flows through the storage.

Battery storage capacities are quite expensive; charging and discharging processes however are not expensive at all (not much additional equipment is needed, and there are no high charging and discharging energy losses). Batteries are, hence, convenient short-term storage systems the high capacity costs of which can be more easily justified if it is used frequently during its lifetime. The same

holds for pumped storages. The storage capacity is expensive, but the additional cost for charging and discharging is not high with long-lasting not too costly pumps and turbines and low charging and discharging energy losses. Pumped storages are, hence, also appropriate short-term storage systems the high capacity cost of which can be borne if a high energy throughput is achieved during their lifetime.

On the other hand, a synthetic gas storage is a typical long-term storage. The storage capacity itself is inexpensive. Large amounts of gas can be stored in cheap storage spaces. The charging and discharging processes however are costly. First, the additional infrastructure is expensive. Second, the energy losses are high. It is hence most probably no favourable option for a regular usage for frequent power supply balancing, for instance, for day-night balancing. The losses are high, at frequent charging and discharging these losses sum up to large amounts of lost energy. This type of storage is more appropriate for low-frequency usage, for rather exceptional deficit situations. For a rare usage, batteries and pumped storages are not appropriate due to their high capacity costs that can be justified only if the capacities are regularly used.

Renewable power supply is in many cases characterized by a twofold pattern of power supply fluctuation. First, if the solar power share is sufficiently large there is the daily rhythm of day power excess and night deficit. Second, if there are sufficiently large seasonal fluctuations in any type of the renewable energy resources - varying insolation, wind speeds, river runoff or biomass supply - there can be corresponding seasonal power supply fluctuations. Both types of fluctuation, the high-frequency day-night fluctuation, and the low-frequency seasonal fluctuation may require appropriate storage systems that shift energy from excess periods to deficit periods, daily balancing and seasonal balancing. Due to the very different time structure of this possible twofold balancing need the combination of an appropriate short-term storage system and a different appropriate long-term storage may be necessary.

In the case of the Java-Bali grid the daily balancing is essential because of the given high dependence on solar power. The necessity of seasonal balancing is less obvious. Due to Indonesia's location around the equator yearly weather cycles are not as clearly marked as in countries that are located at higher latitudes. Nevertheless there are fluctuations in solar radiation due to the change between dry and rainy season. In Java, the driest month has about 40% more irradiation than the rainiest month. There are furthermore quite opposite fluctuations in the river runoff. But, as solar power is by far the most important component in the power mix, the total power generation is larger in the dry season and consequently there is a need to shift energy from the dry season to the rainy season.

However, taking a synthetic methane storage as long-term storage option, it is not clear at all whether such a storage is really economically favourable. On the one hand the inclusion of storage II reduces the necessary storage I capacity. But on the other hand, the installation of storage II also comes along with high costs. Additionally the usage of the gas storage requires a larger PV capacity because the cycle efficiency is lower; much power gets lost when it is stored in the gas storage and released from it. More power has to be generated if a gas storage is used. A tradeoff has to be made, hence, between the installed capacities of storage I, storage II, and PV. The definition of sets of these three system components that are necessary and sufficient to supply the needed power (together with the non-variable system components) is one of the main results in Günther et al. (2018). It is represented in figure 1. The installed storage I capacity is shown on the abscissa, the installed PV capacity on the ordinate, and storage II size is a discrete parameter. Observe that the storage II size is represented as the charging capacity, while the storage I size is represented as the storage capacity (i.e. the energy content of the full storage system). The reason for this difference is the following: For storage I, the maximum charging and discharging powers are considered to be strictly related to the capacity, so that a quantification of the charging and discharging powers besides the storage capacity is not necessary. For storage II there is no such interrelation. As mentioned above, the costs of the storage II capacity are low and can even be neglected compared to the costs of the charging and discharging infrastructure. The storage II capacity is therefore taken to be unlimited. The charging infrastructure, electrolyzers and methanation units, is costly and therefore taken as the size parameter.



Figure 1. Necessary and sufficient installed PV, storage I and, if applies, storage II capacities for the different system logics.

The scenario in Günther et al. 2018 defines hence, besides a set of fixed installed capacities for geothermal power plants, hydropower plants and biopower plants, a three-dimensional space of possible combinations of PV, storage I, and storage II capacities. The economic evaluation of the scenario, therefore, requires the identification of the economic optimum point within this space.

Concerning the storage I capacity, a capacity of 100 GWh is assumed for pumped storages. Currently (2018) a pumped storage capacity of 20 GWh is planned or under construction (PLN, 2017). The remaining storage I capacity is assumed to be covered by batteries.

As already mentioned, we do not take the gas storage as limiting factor for the storage II capacity, but rather the charging capacity. Charging happens in two steps: electrolysis of water into hydrogen and oxygen, and methanation of hydrogen and carbon dioxide into methane in the Sabatier process. We assume that the two process steps are arranged such that no large hydrogen storages are needed. Contrary to methane storages, hydrogen storages are quite expensive. It is more economic to adapt the installed capacity of methanation units to the installed capacity of electrolyzers and to abstain from the installation of hydrogen storages than to reduce the capacity of methanation units at the expense of the installation of hydrogen storages. Consequently, the size of the storage II system is fully characterized by the capacity of the electrolyzers.

The methane is used in combined-cycle power plants. The capacity of these power plants is considered to be such that it is sufficient to deliver the power whenever it is necessary. Their capacity is hence a function of the whole system design. Due to the fact that peak shaving is done with hydropower and biopower these power plants do not need to cover high peaks. Their operational profile is rather flat and does not need large capacities.

For the PV system we assume a conservative rooftop capacity of 60 GW, which is equivalent to a roof area of 2  $m^2$  per person (in a study about Germany a usable roof area of 12  $m^2$  per person was estimated (Lödl et al., 2010)).

Table 1 shows the installed capacities of the components with fixed installed capacities and it mentiones the components the installed capacities of which are either an independent or a dependent open parameter.

Component	Capacity [GW, *GWh]			
Geothermal power plants	5.5			
Hydropower plants	5.8			
Biopower plants	4			
PV rooftop	60			
Pumped storages	100*			
PV ground-mounted	independent open parameter			
Batteries	independent open parameter			
Electrolyzers	independent open parameter			
Methanation units	open parameter, depending on electrolyzer capacity			
Methane storage	open parameter, depending on system design			
Combined cycle power plants	open parameter, depending on system design			

### Table 1: Installed capacities.

### 3. Methodological considerations

The economic evaluation refers only to the power *generation*. The study does not cover transmission and distribution. The economic parameters are the annual generation system cost and the related power generation cost.

We assume a static system, which means two things: First, the study is not about the phase of transition from one type of system to another, the renewable-energy based system is rather taken to be already installed and running. Second, all system components exist in an age continuum in the system such that every year the same share of the installed capacity of a component has to be renewed or modernized. For instance, if the lifetime of PV systems is taken to be 25 then 4% of the installed capacity is renewed every year. The approach of assuming a constant system has the advantage of constant annual costs. Every year is exactly the same in terms of operation, maintenance, renovation and modernization costs, as well as in terms of power generation. This simplifies the calculation considerably.

We will distinguish between what we call the annual system *running* costs and the *total* annual system costs. The *running* costs are the sum of the operation and maintenance costs, and the component renovation and modernization costs. The *total* costs include additionally the capital costs. The power generation cost is the annual total generation system cost with respect to the annually generated power.

A major challenge is the estimation of the future cost of the system components and their lifetime. As the year 2050 is considered, cost and lifetime assumptions are more or less vague, at least for some of the system components. There are mature technologies the costs of which can be assumed to be constant. This holds for instance for combined-cycle power plants and hydropower plants. Other technologies underlie a dynamic cost development, and the estimation of their future costs cannot be but vague. For components that are particularly critical for the system cost calculation in the double sense that they imply a high share of system cost and that the estimation of their future costs is vague, a sensitivity analysis of the system cost with respect to the cost of that component is interesting. We will include a sensitivity analysis for the battery cost.

### 4. Economical assumptions

Table 2 shows the economical assumptions concerning the system components. It contains assumptions about the costs of the investments and modernizations as well as the operation and maintenance costs, and it includes assumptions about the component lifetime. The cost estimations are for 2050. The

monetary unit is  $\varepsilon_{2018}$ . The references that are taken into account for the cost estimations are shown in the respective line in the table.

Component		Cost [€/kW], *[€/kWh]	Lifetime, *modernization [a]	O&M [€/(kWa), *€/(kWha)]
PV ground-mounted (Fraunhofer ISE, 2015)	System without inverter	275	25	10
	Inverter	25	15	
PV rooftop (Fraunhofer ISE, 2015)	System without inverter	350	25	12
	Inverter	25	15	
Pumped storage	Investment	510*	40*	10.2*
(IRENA, 2015, Conrad, 2014)	Modernization	75*		
Battery (Agora Energiewende, 2014)	(25% higher than nameplate capacity due to aging)	125*	12	2.5*
Electrolyzer (Albrecht et. al. 2013)		700	30	28
Methanation unit (Albrecht et al. 2013)		550	25	11
Combined cycle power plant (Agentur für Erneuerbare Energien, 2012, Hartmann, 2014)	Power plant	750	30	17
	CO <sub>2</sub> recovery	450	30	20
Hydropower plant (IRENA, 2012a)	Investment	2000	40*	40
	Modernization	270		
Geothermal power plant	Investment	4000	_ 30*	80
(IRENA, 2015)	Modernization	500		
Biopower plant (IRENA, 2012b)		2000	20	120

Table 2: Component assumptions for 2050.

Not all the individual cost assumptions can be discussed here, but it is worth to call the attention to the battery cost, which is particularly crucial for the system cost calculation. Battery prices have dropped rapidly in the last decade, especially due to the development efforts in e-mobility. Currently (2018), the cost amounts to about 300  $\epsilon$ /kWh. In a mid-term perspective, manufacturers and market observers expect further strong price reductions (Agora Energiewende, 2014). In the present study we assume battery costs of 100  $\epsilon$ /kWh for the year 2050. However, as the battery cost is so decisive for the economic evaluation of the scenario, we will add a corresponding sensitivity analysis below.

### 5. Annual system running cost

The annual system running costs come from the permanent renovation and modernization of system components and from operation and maintenance. The calculation of the system running costs is based on the system configuration represented in table 1 and in figure 1, and on the assumptions shown in table 2.

A comparison of systems I and II should show that system II as lower costs because the seasonal balancing function of bioenergy reduces the demand both for storage capacity and PV capacity. The cost difference is represented in figure 2.



Figure 2. Annual system running costs for systems I and II in dependence on the storage capacity.

The minimum annual costs of system I are around 29 bn  $\in$ , while the minimum costs of system II are around 26.5 bn  $\in$  per year. That means, the allocation of the available bioenergy for seasonal balancing reduces the annual costs by 2.5 bn  $\in$ . The minimum cost for system II is achieved at an installed storage I capacity of 1030 GWh and, according to figure 1, at an installed PV capacity of about 485 GW. If the storage gets smaller, the cost increase due to a larger PV capacity exceeds the storage cost reduction; and if the storage gets larger, the possible PV capacity decrease is not sufficient to compensate the increased storage cost. As system II is clearly more economic than system I, the latter is no considered anymore in the following.

For the comparison of system II and system III, the additional parameter of the storage II parameter, specified in terms of the electrolyzer capacity, has to be taken into account. Figure 3 shows the annual running cost of system III in dependence on the storage I capacity and the electrolyzer capacity.



Figure 3. Annual system running costs for system III in dependence on storage I capacity and electrolyzer capacity.

As figure 3 shows, the minimum costs of system III are in the same range as the minimum costs in system II if storage II is small. That means that under the given cost assumption, in particular under the given battery cost scenario, the integration of gas storages does not provide any economic benefit compared to the exclusive usage of pumped storages and batteries. For instance, if a storage II system



with a charging capacity of 5 GW is integrated into the supply system, the necessary storage I capacity is reduced by around 80 GWh. But the saved costs due to the smaller battery system just compensate for the storage II costs that have to be added. A larger gas storage system even increases the system costs and is therefore neither necessary nor recommendable.

**IC WNIET** 2018

Figure 4 shows the breakdown of the system costs for system II and III, i.e. for the system without gas storage and for the system with gas storage with different capacities. The cost breakdown considers four cost items: PV, storage I, storage II, and non-variable costs. The non-variable costs refer to the system components with a fixed capacity, i.e. geothermal power plants, hydropower plants, and biopower plants.



Figure 4. Breakdown of the annual system running costs for the supply system without and with storage II with different charging capacities.

The assumed battery costs of 100 C/kWh are such that an additional storage II investment is not economically advantageous. Only higher battery costs imply that it is economically favourable to integrate a gas storage into the system. Indeed, just slightly above a battery cost of 100 C/kWh the integration of gas storages allow for lower system running costs. The cost difference starts to be noticable at a battery cost of around 200 C/kWh, where the difference amounts to about 4%. The higher the battery cost is, the larger is the economic benefit of such an additional gas storage, which is illustrated in the diagram in figure 5. With increasing battery costs the abolute and relative cost difference increases in favour of the system design *with* a gas storage.



Figure 5. Annual minimum system running costs for a sytem with and without storage II.

Each point on the curves in figure 5 corresponds to a specific optimum system configuration, i.e. the system component sizes of the variable system components (PV, storage I, storage II) vary from point to point on the shown curves. In particular, storage II should be larger the higher the battery cost gets. Figure 6 shows the optimum electrolzyer capacity for the different battery cost levels, i.e. the electrolyzer capacities, for which the system running costs are minimal.



Figure 6. Electrolyzer capacity at the economic optimum in dependence on the battery cost.

### 6. Total annual system cost and power generation cost

The costs discussed in chapter 5 do not represent yet the complete system cost. One cost component is still left out: the capital cost. The fact that the system binds financial resources that require some return is still neglected. The advantage of leaving the capital costs out is to reduce the speculative character of the calculation. The drawback is that an error is accepted because most probably a return on the investment will be required. However, the problem is that it is impossible to know how big this error is because it is impossible to have a reliable idea about the financing conditions in the year 2050. Financing conditions vary and are literally unpredictable for the timeframe we consider. What makes things worse, interest rates can vary for different system components because different risk premiums may have to be paid.

Even if it is impossible to acquire a reliable idea about future financing costs, it may be a useful way to take them into consideration in an *exemplary* way. However, the chosen example should at least be realistic from the current point of view. For the exemplary calculation of the financing costs we assume a unique interest rate of 4% that is applied to the capital bound in all system components. 4% sounds low compared to current interest rates in Indonesia. On the other hand it is not low in Europe where current (2018) interest rate levels generally are historically low. The chosen interest rate is a reasonable assumption considering current interest rates and rates in the last decades.

With this interest rate and the addition of the financing costs, a minimum total annual system cost of aound 41 bn  $\in$  is calculated. The 26.5 bn  $\in$  running cost is complemented with 14.5 bn  $\in$  financing cost. Figure 7 shows the breakdown of the costs for the difference system configurations.



Figure 7. Power generation cost for system with and without storage II for a battery cost of 100 €/kWh.

## **IC WIET** 2018

Again, the inclusion of a gas storage infrastructure reduces the costs again if the battery cost is higher than  $100 \notin kWh$ . However, the cost must be quite considerably higher in order to allow for a noticable system cost decrease. Even at a battery cost of  $200 \notin kWh$  the system cost decrease amounts only to 3%. For a battery cost of  $300 \notin kWh$  the system cost savings are already 10% (figure 8). Only if the battery cost is high, the investment in an additional gas storage infrastructure, which binds quite a high amount of financial resources, makes sense.



Figure 7. Total annual system cost of the system with and without gas storage.

For comparison to figure 6, figure 8 shows the cost breakdown for a battery cost of  $300 \notin kWh$ . At this cost, which corresonds to the current (2018) cost level, the breakdown shows an optimum at a medium size gas storage system with an electrolyzer capacity in the range of 25 to 50 GW.



Figure 9. Power generation cost for system with and without storage II for a battery cost of 300  $\notin$ /kWh.

Figure 8 shows the contribution of the different cost blocks to the total system costs.

Knowing the total annual system costs and the generated power, the power generation costs can be determined. Figure 9 shows the result.



Figure 9. Power generation cost for system with and without storage II.

For a probable future battery cost of 100  $\epsilon$ /kWh the power generation costs are about 6.5  $\epsilon$ ct/kWh. And for a pessimistic battery cost scenario of 200  $\epsilon$ /kWh the power generation costs amount to about 9  $\epsilon$ ct/kWh. The cost of 6.5  $\epsilon$ ct/kWh is comparable to the current power generation costs in many countries (Institute for Energy Research, 2017; Kost, 2018), and it is close to the current generation cost in the Java-Bali grid of about 5.3  $\epsilon$ ct/kWh (MEMR, 2017).

### 7. Conclusion

The most important conclusion is that the power generation cost in the future renewable-resource based power supply system is not higher than the cost in currently existing systems, and not even much higher than in the current Java-Bali grid.

It should be emphasized that only the direct system costs are considered in the calculation. The macroeconomical and social side effects of the different system designs and the costs related to these side effects are not taken into consideration. It is not easy to quantify these effects. However, taking into account the side effects of the current coal-dominated power generation, like land consumption due to mining and pollution effects, and monetarizing them, would increase considerably the real costs of coal power (in Sanchez (2017) a doubling of the cost is estimated). Additionally, while power from renewable-energy technologies has the tendency to get cheaper, the same tendency cannot be assumed for coal power. The technology does not promise big cost reductions, and possible higher carbon dioxide prices as well as possible higher coal prices may even cause higher future coal power costs. It has become gradually clear that in a mid-term perspective the levelized cost of power from renewable resources will be lower than the power from fossil fuels (Greenpeace, 2017). However, the latter does not necessarily mean that the power supply is also cheaper, because a renewable-energy based supply system may need power storages that increase the power supply cost.

Indeed, in the Java-Bali grid, with a very limited share of dispatchable power generation in hydro and biopower plants, the situation is rather challenging. There is a very high demand for storage systems that increases the system cost considerably. Nevertheless, the result is that a renewable-resource based power supply is economically competitive.

A second result is that a synthetic gas storage is not economically necessary. This holds at least if the situation is considered from the point of view of the electricity supply alone. If other forms of energy are taken into account then the usefulness of the integration of synthetic gas storages may be evaluated in a different way. Synthetic gases can play an important role for transportation and for thermal uses. In the sense of an increasing coupling of the different energy sectors the generation of chemical energy carriers out of electricity can play an important role (Brown, 2018).

#### References

- Agentur für Erneuerbare Energien (2012) Studienvergleich: Entwicklung der Investitionskosten neuer Kraftwerke.
- http://www.forschungsradar.de/uploads/media/AEE\_Dossier\_Studienvergleich\_Investitionskosten\_nov12.pdf. Access date: 13 July 2018
- Agora Energiewende (2014) Stromspeicher in der Energiewende: Untersuchung zum Bedarf an neuen Stromspeichern in Deutschland für den Erzeugungsausgleich, Systemdienstleistungen und im Verteilnetz.
- https://www.agora-energiewende.de/fileadmin/downloads/publikationen/Studien/Speicher\_in\_der\_Energiewend e/Agora\_Speicherstudie\_Web.pdf. Access date: 13 July 2018
- Albrecht, U. et al. (2013) Analyse der Kosten Erneuerbare Gase. Eine Expertise der Ludwif-Bölkow-Systemtechnik GmbH.
- http://www.lbst.de/download/2014/20131217\_BEE-PST\_LBST\_Studie\_EEGase.pdf. Access date: 13 july 2018
- Brown, T., Schlachtberger, D., Kies, A., Schramm, S., Greiner, M. (2018) Synergies of sector coupling and transmission reinforcement in a cost-optimized, highly renewable European energy system. https://arxiv.org/pdf/1801.05290.pdf. Access date: 20 July 2018
- Conrad, J., Pellinger, C., Hinterstocker, M. (2014) Gutachten zur Rentabilität von Pumpspeicherkraftwerken on behalf of the Bavarian State Ministry of Economy, Media, Energy and Technology.
- https://www.stmwi.bayern.de/fileadmin/user\_upload/stmwi/Themen/Energie\_und\_Rohstoffe/Dokumente\_und\_C over/2014-Pumpspeicher-Rentabilitaetsanalyse.pdf. Access date: 13 July 2018
- Fraunhofer ISE (2015) Current and Future Cost of Photovoltaics. Long-term Scenarios for Market Development, System Prices and LCOE of Utility-Scale PV Systems.
- https://www.ise.fraunhofer.de/de/veroeffentlichungen/studien/studie-current-and-future-cost-of-photovoltaics-lo ng-term-scenarios-for-market-development-system-prices-and-lcoe-of-utility-scale-pv-systems.html. Access date: 13 July 2018
- Greenpeace (2017) Comparing electricity production costs for renewable to fossil and nuclear power plants in G20 countries.
- https://www.greenpeace.de/sites/www.greenpeace.de/files/publications/20170705\_greenpeace\_studie\_comparin g\_electricity\_costs\_engl.pdf. Access date: 20 July 2018
- Günther, M., Ganal, I., Bofinger, S. (2018) A 100% Renewable-Energy Scenario for the Java-Bali Grid. International Journal of Renewable Energy Development, 7(1), 13-22
- Hartmann, C. (2014) Systemanalyse der CO<sub>2</sub>-Sequestrierung aus Biomasse-Heizkraftwerken: Technik, Wirtschaftlichkeit, Nachhaltigkeit.
- https://www.zhb-flensburg.de/fileadmin/content/spezial-einrichtungen/zhb/dokumente/dissertationen/hartmann/ 141024-dissertation-ch.pdf. Access date: 13 July 2018
- Institute for Energy Research (2018) Energy Generating Costs. https://instituteforenergyresearch.org/analysis/electric-generating-costs-a-primer/. Access date: 18 July 2018
- IRENA (2012a) Renewable Energy Technologies: Cost Analysis Series: Hydropower. https://www.irena.org/documentdownloads/publications/re\_technologies\_cost\_analysis-hydropower.pdf. Access date: 13 July 2018
- IRENA (2012b) Renewable Energy Technologies: Cost Analysis Series: Biomass. https://www.irena.org/DocumentDownloads/Publications/RE\_Technologies\_Cost\_Analysis-BIOMASS.pdf. Access date: 13 July 2018
- IRENA (2015) Renewable Power Generation Costs in 2014.
- https://www.irena.org/DocumentDownloads/Publications/IRENA\_RE\_Power\_Costs\_2014\_report.pdf. Access date: 13 July 2018
- Kost, C., Shivenes, S. Nguyen, H.-T., Schlegl, T. (2018) Stromgestehungskosten Erneuerbare Energien. Fraunhofer ISE.

https://www.ise.fraunhofer.de/content/dam/ise/de/documents/publications/studies/DE2018\_ISE\_Studie\_Str omgestehungskosten\_Erneuerbare\_Energien.pdf. Access date: 18 July 2018

- Lödl, M. (2010) Abschätzung des Photovoltaik-Potentials auf Dachflächen in Deutschland. 11. Symposium Energieinnovation Graz/Austria 2010. https://mediatum.ub.tum.de/doc/969497/969497.pdf. Access date: 13 July 2018
- MEMR (2017) Keputusan Menteri Energi dan Sumber Daya Mineral Republik Indonesia Nomor 1404 K/20/MEM/2017 tentang biaya pokok penyediaan pembangkitan PT Perusahaan Listrik Negera. http://jdih.esdm.go.id/peraturan/Kepmen-esdm-1404-Th2017.pdf. Access date: 19 July 2018
- PLN (2017) Rencana Usaha Penyediaan Tenaga Listrik PT Perusahaan Listrik Negara (persero), tahun 2013 s.d. 2022, 2015 s.d. 2024, 2016 s.d. 2025.

http://www.djk.esdm.go.id/index.php/rencana-ketenagalistrikan/ruptl-pln. Access date: 10 July 2018



Sanchez, L., Lontoh, L., Christensen, L.T. (2017) Case Study: What is the true cost of coal in Central Java? The International Institute for Sustainable Development. https://www.iisd.org/sites/default/files/publications/case-study-what-true-cost-coal-central-java.pdf Access

https://www.iisd.org/sites/default/files/publications/case-study-what-true-cost-coal-central-java.pdf. Access date: 19 July 2018