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The role of inter-island transmission in full decarbonisation scenarios for Indonesia's power sector

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Abstract

Indonesia has large renewable energy resources that are not always located in regions where they are needed. Sub-sea power transmission cables, or island links, could connect Indonesia's high-demand islands, like Java, to large-resource islands. However, the role of island links in Indonesia's energy transition has been explored in a limited fashion. Considering Indonesia's current fossil fuel dependency, this is a critical knowledge gap. Here we assess the role of island links in Indonesia's full power sector decarbonisation via energy system optimisation modelling and an extensive scenario and sensitivity analysis. We find that island links could be crucial by providing access to the most cost-effective resources across the country, like onshore photovoltaics (PV) and hydropower from Kalimantan and geothermal from Sumatera. In 2050, 43 GW of inter-island transmission lines enable 410 GW_p of PV providing half of total generation, coupled with 100 GW of storage, at levelised system costs of 60 US$(2021)/MWh. Without island links, Java could still be supplied locally, but at 15% higher costs due to larger offshore floating PV and storage capacity requirements. Regardless of the degree of interconnection, biomass, large hydro, and geothermal remain important dispatchable generators with at least 62 GW and 23% of total generation throughout all tested scenarios. Full decarbonisation by 2040 mitigates an additional 464 $MtCO_2e$ compared to decarbonisation by 2050, but poses more challenges for renewables upscaling and fossil capacity retirement.

1. Introduction

Indonesia is a fast growing country that currently relies on abundantly available domestic coal to meet the increasing local electricity demand (62% in 2020) [1]. The country pledged to become carbon-neutral by 2060 [2] and can draw from diverse and extensive renewable energy resources [3]. Renewables only supplied 18% of electricity in 2020 [1], so the transformation towards a carbon-neutral, or even fully decarbonised, power system would be substantial and requires careful planning.

Energy System Optimisation Models (ESOMs) are powerful tools to support energy planning decisions. They allow exploring different energy systems and their technical, economic, and environmental trade-offs. State-of-the-art ESOMs, like Calliope [4] and PyPSA [5], are able to capture the spatial and temporal fluctuations of variable renewables and consist of nodes and interconnections between them. Each node contains location-specific, temporally resolved profiles for electricity demand and power production, while interconnections represent the power transmission lines connecting these nodes. These ESOMs can cover different sectors of the energy systems, like the power, industry, and transportation sector, and the generation, exchange, storage, and consumption of various energy carriers, like electricity and heat. In this study, however, we only focus on the power sector and electricity as energy carrier.

There is already a rich body of ESOM literature for Indonesia's power sector. Earlier modelled power systems were often based on official targets and policies, like the Nationally Determined Contributions to the Paris Agreement [6–9] and still contained high shares of fossil-fuel-based capacity. Only recently, the focus shifted to the modelling of 100% renewable power systems with [10–13] and without [14] nuclear power. Except in Reyseliani and Purwanto's [11] scenario with nuclear power, solar *photovoltaics (PV)* is the dominant generation technology in Indonesia's fully decarbonised power system with generation shares between 78% [10] and 99% [14] in 2050.

However, there are two main limitations in contemporary literature. First, most studies [6, 8, 10–12, 15–19] assume a national copperplate approach, meaning that all demand and supply occur in a single node without interconnections within and between islands, thereby disregarding the complexity of Indonesia's current grid topology of several, disconnected systems. This approach also does not reflect the regional mismatch between electricity demand and renewable energy resources, as is the case for Indonesia's economic centre Java where available land for onshore renewables is limited [20]. To balance this regional mismatch, sub-sea power transmission cables, or *island links*, have been suggested as a promising solution for Indonesia [10] and island states in general [21]. As of now, only two pairs of islands are connected in Indonesia, namely Java and Bali and Bangka and Sumatera [2], and there are opposing views on the benefit of further interconnections. One study [13] recommended further research into island links for Indonesia's future power system to supply Java with electricity from Sumatera and Kalimantan. Then again, another study [14] finds that island links are not advantageous for a solar-dominant power system in terms of levelised system costs.

Second, we found almost no academic study on Indonesia that assesses the parametric uncertainty of the used economic assumptions. The disregard for uncertainty is critical considering the recent cost reductions of renewables [22]. Studies that use historic high costs for renewables portray fuel switching from coal to natural gas [8–10] and carbon capture and storage [16, 18, 19] as more cost-effective for emission reductions than renewables. In contrast, studies [12–14, 17, 23, 24] that consider more recent cost data and future cost reductions find high shares of renewables, like solar PV, to be cost-effective. Only Silalahi *et al* [14] performed a sensitivity analysis for discount rate and generation, storage, and transmission costs. However, their systems rely heavily on solar PV (99% generation share) and mostly exclude non-solar renewable and nuclear alternatives Indonesia could draw from [3]. Consequently, studies on Indonesia lag behind global ESOM literature that uses a variety of approaches beyond scenario and sensitivity analyses to study parametric uncertainty. As reviewed by Yue *et al* [25], these approaches include Monte Carlo analysis, stochastic programming, and robust optimisation. Besides parametric uncertainty, recent literature also focusses on the structural uncertainty of ESOM, e.g. via modelling to generate alternatives, where near-optimal, but highly diverse, alternative solutions are collected [26, 27]. Since the focus of this paper lies on the role of island links in power system decarbonisation, we only address parametric uncertainty via an extensive scenario and sensitivity analysis, which is already novel within this context. In the future, our findings could be further refined with the more advanced approaches above to bring Indonesian ESOM literature closer to the global state of the art.

The two knowledge gaps above prevent the provision of technically sound and uncertainty-aware insights for the urgent planning of the Indonesian energy transition. Moreover, it is unclear whether, how, and under what conditions island links could provide technical and economic benefits to Indonesia's decarbonised power system and what their impact is on solar PV's and other technologies' cost-effectiveness.

This paper aims to address these gaps by exploring the role of inter-island sub-sea power transmission for a broad range of full decarbonisation scenarios for Indonesia's power system. We use spatially and temporally explicit demand and renewable resource data as well as up-to-date cost projections. We model fully decarbonised least-cost electricity systems under various decarbonisation rates, costs, electricity demand growth rates, demand profiles, power production profiles, and available renewable energy resources, amongst others. We explore the trade-offs between the resulting system designs in terms of installed generation and storage capacity, generation mix, and system costs. The 2050 designs are benchmarked against the current 2020 system. Beyond Indonesia, this paper is globally relevant as our findings could be scaled to other island and archipelagic states as well as other fast-growing, fossil-fuel-dependent economies.

2. Methods and materials

We use the open-source ESOM Calliope [4] to model the full decarbonisation of Indonesia's electricity system. Calliope has already been used to model a variety of energy systems across geographical contexts (e.g. in Africa [28] and India [29]) and scales (e.g. for cities [30], countries [31], and entire continents like Europe [32]), demonstrating high versatility while ensuring high spatial and temporal resolution and customisable technical detail. Calliope is tested in a comprehensive suite of automated tests, which cover around 90% of all code, and 100% of the core code. This means that the implementation of the mathematical formulation and of the code which generates the mathematical model, solves it, and returns results, are tested against known-good outcomes to ensure they function as intended [4]. Calliope uses nodes and interconnections to establish model regions and their production, consumption, storage, and exchange of energy carriers. In this study, we only focus on electricity and omit other energy carriers like heat and hydrogen, which keeps the model's complexity and runtime computationally feasible but omits sector-coupled solutions for the entire energy system. Each of Indonesia's 34 provinces is represented by one node. For the grid, we consider two network topologies, one with and one without island links. All used time series data is resampled to 3 hour time steps to compromise between computational tractability and the need to capture intra-daily fluctuations of renewable generation and demand (see appendix A for impact of temporal downsampling). We assume a location- and technology-independent discount rate of 10% as commonly used for Indonesia [11, 24, 33, 34]. Calliope determines the necessary generation, storage, and transmission capacities to meet demand within the user-defined boundaries. The optimisation process in Calliope aims to minimise overall system costs.

First, we model pathways from 2020 until 2050 where full power system decarbonisation is achieved by 2040 and 2050, respectively. It is assumed that existing 2020 fossil-fuel-based capacity [1, 35] is retired linearly without any new capacity additions. For full decarbonisation by 2040, for example, we assume that fossil capacity in 2030 is half of 2020 fossil capacity, and zero in 2040. The 2020 system generation costs are taken from PLN's statistics report [36]. While retiring fossil capacity, the model deploys renewable generation capacity in order to cost-effectively meet electricity demand at every location and 3-hourly timestep within the modelled year. We assemble the decarbonisation pathways by separately modelling the years 2030, 2040, and 2050 with their respective sets of techno-economic inputs. Each of these modelled years represents one decade of planning. This means that the planning of capacity expansion in each modelled decade is myopic with respect to changes in boundary conditions in the future, e.g. projected future costs. The capacities and costs of each previous decade's installations are fed as inputs to the next decade's model (e.g. 2030 capacities and their costs are inputs to the 2040 model, and 2030 and 2040 capacities and costs are inputs to the 2050 model).

In addition, we conduct a scenario and sensitivity analysis exclusively for the year 2050, i.e. omitting past installations and their costs. This allows us to study a broad and diverse range of fully decarbonised power systems within manageable time. As shown in appendix B, the difference between the 2050 systems with and without past installations is relatively small as most capacity is deployed between 2040 and 2050. The 2050 system from the decarbonisation-by-2050 pathway serves as the reference to which all other modelled systems and the existing 2020 configuration are compared in terms of installed generation and storage capacity, electricity generation, and levelised system costs.

In the following sub-sections, we elaborate on the methods and materials for demand, generation, storage, and transmission.

2.1. Demand

Time series data on Indonesian electricity demand is currently not openly available. We were able to obtain 2019 demand data for Kalimantan used in an earlier study [37] via a formal request to Indonesia's state utility company PLN. Kalimantan is situated on Borneo island and will host Indonesia's new capital city [38]. For the sake of transparency and replicability, we use publicly available Malaysian 2020 national demand data [39] scaled to the annual demand of each Indonesian province, which is available via public records [36]. Malaysia and Indonesia are similar in terms of local climate, but less so in other terms, such as economic activity, with Malaysia having a higher national GDP per capita of 12 000 US$(2022) compared to Indonesia's 4800 US$(2022) [40]. Hence, the Malaysian time series data might reflect the demand profiles of Indonesian provinces more or less well based on the local conditions. We assess the impact of the demand profile shape by running an alternative scenario that uses the abovementioned Kalimantan profile (see figure 1). Below, we describe the steps with which the Malaysian and Kalimantan data is further processed.

First, we convert the time zone from Malaysian/ West Indonesian time to Coordinated Universal Time. Then, we resample the data to hourly steps and fill empty time steps via linear interpolation (necessary for 1.2% of the Malaysian data). Next, we scale the data to the demand of Indonesia's provinces [36] with a time-invariant scaling factor. For example, if an Indonesian province has a 50% lower total annual electricity demand than Malaysia, all values are reduced by 50%. We also incorporate nationwide distribution losses of 7.2% [36] to all demand profiles to reflect how much electricity must be generated to meet end-user demand. For the demand in 2030, 2040, and 2050, we multiply the scaled demand profiles by constant, region-specific growth rates taken from PLN's 2021–2030 business plan [2], meaning that the growth rates apply until 2050. The growth rates vary from 4.0% p.a. in Java-Bali-Madura to 8.3% p.a. in Maluku, Nusa Tenggara, and Papua. The national weighted average growth rate is 4.8% p.a., using regional 2021 electricity

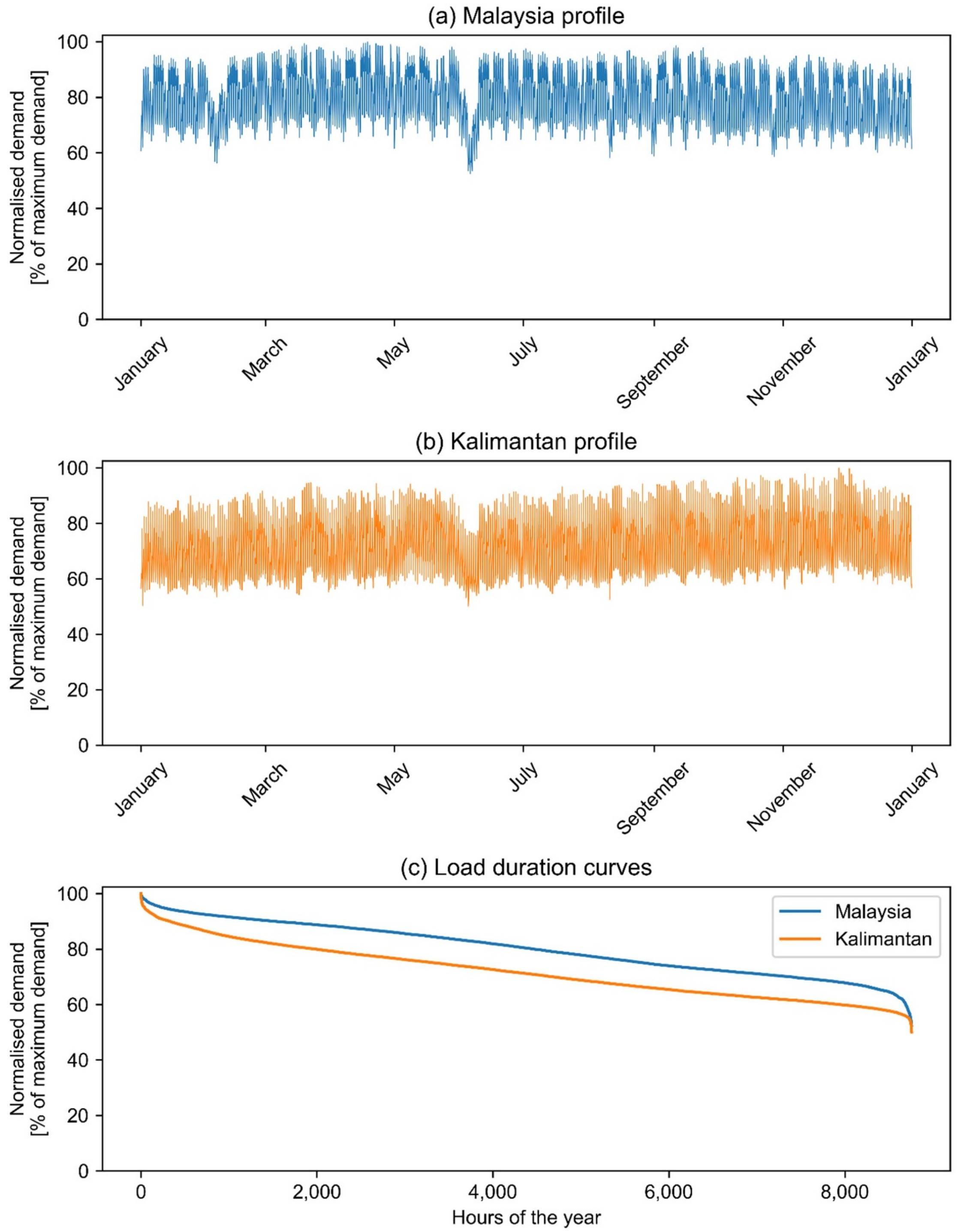

Figure 1. Normalised, hourly demand profiles from (a) Malaysia and (b) Kalimantan used in this study as well as (c) their relationship to each another (loads of profiles sorted in descending order).

demands as weights. To study the impact of demand growth, we assess alternative scenarios with a nationwide growth rate of 8.3% p.a.

2.2. Generation and storage

In this study, we use a set of 14 generation and two storage technologies. The technical and economic assumptions of the technologies are listed in appendices C and D, respectively.

In our model, the maximum installable capacity of most renewable energy technologies is restricted by their technical potential per region. For small hydro [41], solar PV [20], onshore wind [42], offshore wind [43], and *ocean thermal energy conversion (OTEC)* [44], we use publicly available data sets for the potentials, while we use official data from the Indonesian government for the technologies for which open data is not

Table 1. Constraints and further remarks regarding the implementation of renewables and nuclear energy in this study. The implementation of battery storage is not constrained in the model and thus not listed here. For biomass, geothermal, and large hydro, we refer to the resource assessments from official sources by the Indonesian government.

Technology	References	Constraints	Remarks
Biomass	[46]	See reference	Sourced from agricultural waste (mainly from palm oil, rice, and rubber production) as well as municipal waste
Geothermal	[45]	See reference	Maximum installable capacity equals sum of possible, proven, and expected reserves as well as currently installed capacity
Small hydro	[41]	• Distance to coastline $\geqslant$ 15 km (see Appendices E and F) • Outside of protected and natural-catastrophe prone areas	Mean and minimum power production profiles generated from hourly ERA5 reanalysis (years 2018 and 2010, respectively)
Large hydro	[46]	See reference	• Ratio between energy and storage capacity: 0.15 (i.e. reservoir can deliver rated power for 6.67 h) [53] • Mean and minimum power production profiles generated from 20 years of hourly ERA5 reanalysis (years 2018 and 2010, respectively)
PV	[20, 54, 55]	*Ground-mounted utility-scale PV* • Outside of water bodies, built-up infrastructure, agricultural land, forests, as well as protected and natural-catastrophe prone areas • Slope $< 15°$ *Offshore floating PV* • Outside of shipping and subsea cable routes, as well as protected and natural-catastrophe prone areas • Inside exclusive economic zone • Visual impact buffer of 10 km around coastlines • Water depth $<$ 55 m	• Capacity density: 60 MWp km^{-2} for ground-mounted utility-scale PV, 110 MW$_p$ km^{-2} for offshore floating PV • Mean and minimum power production profiles generated from 20 years of hourly ERA5 reanalysis (2001–2020)
Onshore wind	[42]	• Outside of water bodies, built-up infrastructure, as well as protected and natural-catastrophe prone areas • Slope $< 30°$ • Altitude $<$ 2000 m • Average 100 m wind speed $\geqslant$ 6 m s^{-1}	• Rated turbine power and rotor diameter: 2.5 MW and 116 m (median of turbine set studied in source) • Spacing of turbines: 5D $\times$ 10D (D being the rotor diameter) • Mean and minimum power production profiles generated from hourly ERA5 reanalysis (years 2018 and 2010, respectively)
Offshore wind	[43]	• Outside of shipping and subsea cable routes, as well as protected and natural-catastrophe prone areas • Inside exclusive economic zone • Visual impact buffer of 10 km around coastlines • Water depth $<$ 55 m • Average 100 m wind speed $\geqslant$ 6 m s^{-1}	• Low-wind-speed offshore turbine • Rated turbine power and rotor diameter: 2.1 MW and 114 m (median of turbine set studied in source) • Spacing of turbines: 10D $\times$ 10D (D being the rotor diameter) • Mean and minimum power production profiles generated from hourly ERA5 reanalysis (years 2018 and 2010, respectively)
Nuclear	[47, 48]	• Only West Kalimantan and Bangka Belitung Island • Total installed capacity capped at 35 GW	35 GW based on official press release
OTEC	[44]	• Outside of protected and natural-catastrophe prone areas • Inside exclusive economic zone • Water depth $>$ 1000 m and $\leqslant$ 3000 m	• Plant size: 136 MW$_{gross}$ • OTEC plants models using the pyOTEC model [49] • Mean and minimum power production profiles generated from daily Global Ocean Physics reanalysis (years 2018 and 2010, respectively)
Pumped hydro	[53]	Outside of protected and natural-catastrophe prone areas	—

available, namely for geothermal [45], large hydro, and biomass [46]. For nuclear, we draw from recent official plans [47, 48] for West Kalimantan and Bangka island. Table 1 lists the constraints imposed on each technology, while table 2 lists the resulting maximum installable capacity per technology and region. The

Table 2. Maximum installable generation and storage capacity per technology and region. 'var' under column 'Nuclear' stands for 'variable' and means that there is no hard limit on installed nuclear capacity in Sumatera and Kalimantan, as long as total installed nuclear capacity does not exceed 35 GW. Battery storage implementation is not constrained and thus not listed here. The maximum installable capacity accounts for the capacities already installed today.

		Maximum installable capacity [GW]									
Region	Biomass [46]	Geothermal [45]	Small hydro [41]	Large hydro [46]	Onshore PV [20]	Floating PV [this study]	Onshore wind [42]	Offshore wind [43]	Nuclear [47, 48]	OTEC [44]	Pumped hydro [53]
Java & Bali	7.4	4.4	2.9	4.4	50.0	7433	1.7	0	0	26.9	513
Sumatera	15.2	5.3	12.1	15.6	1953	19 960	0.3	0	Var	40.1	832
Kalimantan	5.0	0.01	32.5	21.6	3999	14 162	0.3	0	Var	8.7	1796
Sulawesi	1.8	1.2	5.7	10.3	1005	1834	5.3	0	0	54.0	2193
Nusa Tenggara, Papua, and Maluku	0.7	1.3	17.4	23.2	1961	5559	9.9	200	0	109	2582
Indonesia (total)	30.1	12.2	70.7	75.1	8969	48 947	17.5	200	35	239	7915

technical potentials of ground-mounted and offshore floating solar PV (8969 and 48 947 GW_p) stretch over roughly 150 000 km^2 of land area and 445 000 km^2 of marine area, and occupy roughly 8% and 7% of Indonesia's total land and marine area, respectively.

For the power production profiles, there are variable and dispatchable generators. For dispatchable generators like coal, nuclear, and geothermal, Calliope dispatches these plants in the most cost-effective way to meet demand. For variable generators, like PV and wind power, we prepared hourly capacity factors as shown in figure 2 and described below. Studies like [20, 42, 43, 49] use exclusion criteria, like nature conservation zones, to map technically feasible sites per technology across Indonesia and calculate site-specific power production profiles with a method called bias correction (see appendix E for explanation). Using bias correction, we prepare the hydropower profiles for this study using the datasets by Hoes *et al* [41] and the methods by Liu *et al* [50], see appendix F. The technical potentials and power production profiles for offshore floating solar PV are described in appendix G. All power production profiles used here are publicly accessible [20, 42, 43, 49] and are calculated based on open datasets, like ERA5 reanalysis [51] and the Global Solar Atlas [52].

The outputs of the site selection and bias correction are hundreds of technically feasible sites with 20 years (2001–2020) of hourly power production profiles across Indonesia and its provinces. For Calliope, we resample the power production profiles per province by aggregating the profiles of all sites inside a province based on averages weighted by the occupied area (for PV and wind power) or installed capacity (for hydropower and OTEC). As a result, each province has a distinct power production profile for each variable generation technology. In this study, we do not use the entire 20 year dataset, but only a single year. By default, we use the profiles from 2018 as its annual PV power production comes closest to the average annual PV production of the 20 year dataset. For the scenario analysis, we also run one case where we use the profiles from 2010, where the annual PV production was the lowest within the 20 year period (5% below average). The choice of years is based on PV because its technical potential is by far the largest in most parts of Indonesia, see table 2. To ensure the computational feasibility of the study, the hourly profiles are downsampled to a 3 hourly resolution, which has a limited impact on the studied key metrics as shown in appendix A.

We exclude rooftop solar PV due to a lack of mapped potentials and power production profiles in Indonesia. For the former, there are estimations [56] based on residential floor space per household, i.e. assuming that all buildings only have one floor. This method could lead to significant deviations if buildings have several floors and neglects commercial and industrial rooftops. Using such low-fidelity approaches would also lead to methodological imbalances given the high spatial and temporal detail of all other variable RET included in this study. Nonetheless, we still consider rooftop PV a relevant technology to involve Indonesian residents and businesses in the energy transition and thus boost social acceptance.

For storage, we consider battery and closed-loop pumped hydroelectric energy storage (pumped hydro for the remainder of the paper), as well as the reservoirs of large hydro. While battery storage is not constrained by location and storage capacity, we limit pumped hydro's maximum installable capacity to areas outside of nature conservation zones using the global pumped hydro dataset by Stocks *et al* [53]. For battery storage and pumped hydro, respectively, we assume a round-trip efficiency of 96% and 80%, storage losses of 0.1% per day and 0%, and a lifetime of 30 and 50 years [57]. For the large hydro reservoirs, we assume the same storage efficiencies as for pumped hydro.

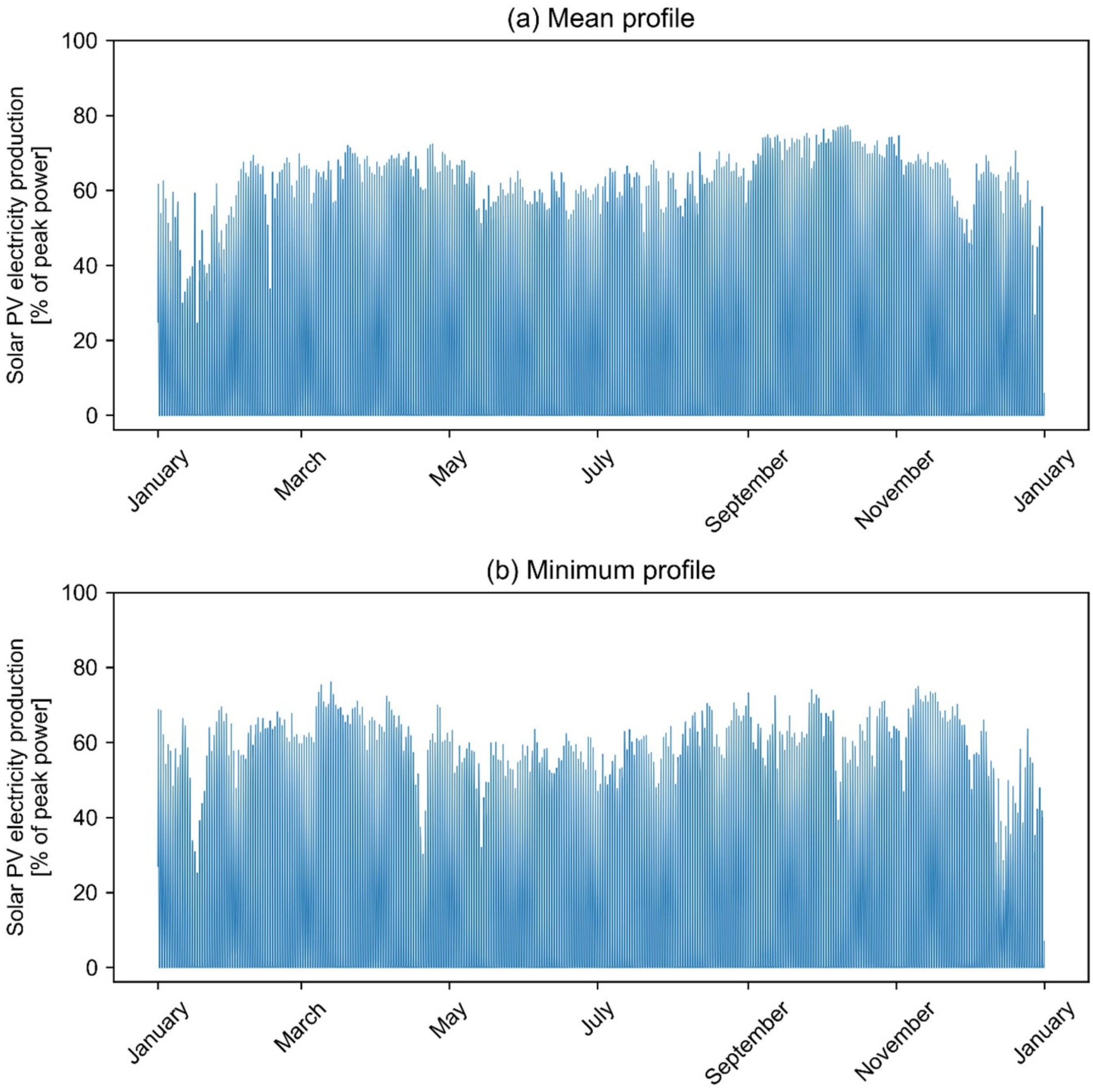

Figure 2. Example of hourly renewable power production profile showing the average PV production in East Nusa Tenggara, Indonesia. Note that each provinces uses unique, location-specific profiles for each variable generation technology.

Regarding *Capital Expenses (CAPEX)* and fixed and variable *Operational Expenses (OPEX)*, we use the 2030 and 2050 costs and their uncertainty ranges from the 2024 Indonesia technology catalogue [57], which provides up-to-date ranges of current and future costs based on literature and focus group meetings with local stakeholders. The 2040 costs are estimated via linear interpolation between 2030 and 2050 values. We use the reference costs for the default scenarios and scenarios unrelated to costs. For the sensitivity analysis and minimum and maximum cost scenarios, we use the uncertainty ranges from the Indonesia technology catalogue [57]. See appendix D for an overview of the cost assumptions used in this study. For geothermal [58], offshore floating PV [59], and OTEC [60] (see appendix H), we use different references as these technologies are not included in the catalogue (it includes small binary or condensing geothermal and onshore floating PV, but not large flash or dry geothermal and offshore floating PV).

Besides OTEC, offshore floating PV is another technology for which future costs are highly uncertain. With 405 US$(2021)/kW$_p$ in 2050 [59], the costs of offshore floating PV in this paper are only 9% higher than those of ground-mounted PV [57], which is a low deviation compared to the up to 94% of cost difference observed in 2018 [61]. Then again, this assumption could be justified by the stronger expected cost reductions of floating PV over ground-mounted systems [59, 62], as well as the relatively mild offshore conditions in most of Indonesia's waters that could enable lower installation, floating structure, and mooring costs. Between Java and Kalimantan, for example, wind speeds at 10 m height are below 4 m s^{-1} [63], wave resources are low [64], and due to the islands' location on the continental Sunda shelf, water depths are less than 50 m even far offshore [65]. Nonetheless, we acknowledge that the cost assumptions used in this study might favour offshore floating PV over other technologies, which is why we also use substantially higher costs

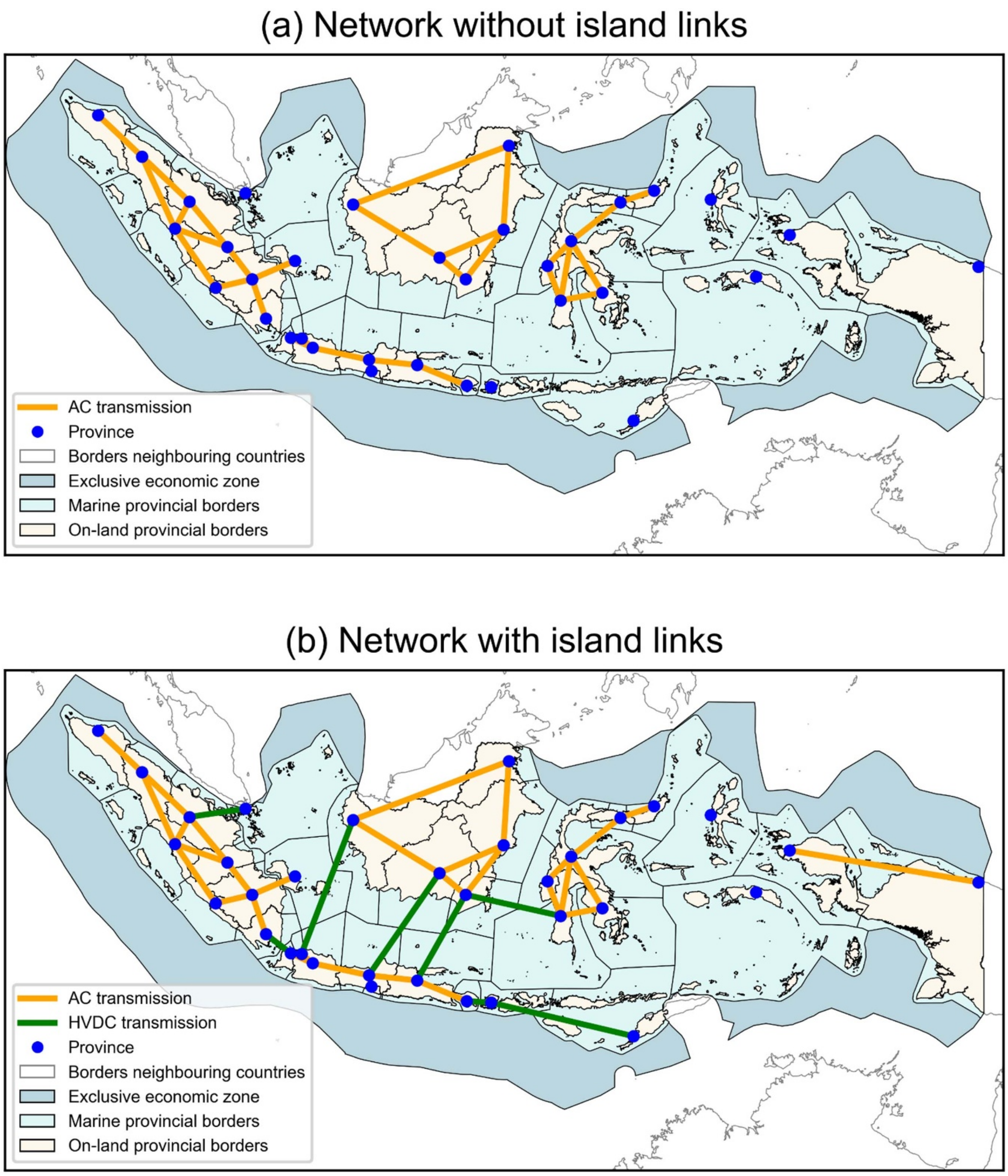

Figure 3. Transmission network representations studied in this paper, based on (a) PLN's 10 year business plan (RUPTL) until 2030 without island links (besides Java-Bali), and (b) a concept for Indonesia's 'super grid' (Pemodelan Tim NZE KESDM, presented at the Institute of Technology, Bandung, Indonesia, 18 October 2022).

during the scenario and sensitivity analysis (930 US$(2021)/kW$_p$, i.e. twice the maximum 2050 costs of ground-mounted PV [59] to reflect the currently observed cost difference above [61]).

Due to the lack of consistent fuel cost data applicable to Indonesia, we use the same fuel costs for coal, diesel, natural gas [36], uranium (nuclear power) [66], and biomass [58] for all modelled years and scenarios.

All costs are converted to US$(2021) using the currency conversion rates in appendix I.

2.3. Power transmission

The studied network topologies are shown in figure 3. They are simplifications based on the current network and its potential development. The network without island links is based on PLN's 2021–2030 business plan [2]. The interconnected system is a concept [67] from the G20 meeting in 2022 hosted by Indonesia. We assume *alternating current (AC)* lines for land-based power lines and sub-sea *high-voltage direct current (HVDC)* lines for island links. We only consider the lines' active power flows, thus omitting aspects like voltage, frequency, and apparent power. Since national data on maximum active line capacity is not available,

Table 3. Scenarios studied in this paper and their properties.

Scenario	Time horizon	Properties/ changes from reference scenario
Reference	2030–2050	Demand growth: regionally varying from RUPTL (i.e. 4.8% p.a. on average) Demand profiles: Malaysia Power profiles: 2018 (year with power production closest to the 20 year average) Costs: 2030, 2040, 2050 based on projections
High demand growth	2050	Demand growth: 8.3% p.a. nationwide
Alternative demand profiles	2050	Kalimantan demand profile
Alternative power profiles	2050	Power profiles from the year 2010 (year with lowest PV production in 20 year dataset)
Maximum 2050 costs	2050	Costs of all technologies set to maximum
Minimum 2050 costs	2050	Costs of all technologies set to minimum
Solar only	2050	Only solar-based generators

Table 4. Parameters that are studied for the sensitivity analysis.

Parameter	Range of analysed variations
Renewable generation and HVDC transmission costs	Tested technology: varied between minimum and maximum 2050 costs Rest: fixed at reference 2050 costs
Maximum installable generation capacity (geothermal, biomass, and large hydro)	Between −50 and +50% of default capacities (see table 2)
Maximum HVDC transmission capacity	5–50 GW

we let Calliope optimise the transmission capacities to up to 50 GW per link and test this decision during the sensitivity analysis.

For HVDC and AC lines, we use an efficiency of 96.5% per 1000 km (beeline) [68] and 98% [36], respectively. The HVDC lines' efficiency is distance-dependent as we know the distance between islands. In contrast, we do not know the total length of AC connections between nodes so we use the efficiency of the total transmission system [36]. That is also why we calculate CAPEX of onshore AC lines per unit of installed active capacity rather than per unit of length. The CAPEX of the HVDC lines consists of a distance-dependent component in US$(2021)/MW/km for cables and a capacity-dependent component in US$(2021)/MW for the inverter pairs onshore. The costs used in this study are listed in appendix D and the references and assumptions underlying the HVDC costs are shown in appendix J.

2.4. Scenario and sensitivity analysis

The assumptions and setups described so far are default values used for the reference scenarios with and without island links. Besides the reference cases, we also perform a scenario and sensitivity analysis. With these analyses, several (scenario analysis) or single inputs (sensitivity analysis) are replaced with alternative values, while all other inputs remain unchanged. Table 3 shows the studied scenarios, and table 4 shows the inputs being investigated for the sensitivity analysis. The reference and alternative scenarios are compared with each other and to the 2020 system in terms of installed generation and storage capacity, electricity generation [1], and levelised system costs [36]. The sensitivity and scenario analysis serve the purpose of (1) addressing the implications of inputs that are either uncertain (e.g. future cost) or not publicly available (e.g. transmission line data), and (2) sharpening our key findings and the conditions under which they apply.

3. Results and discussion

3.1. Island links reduce system costs via lower generation and storage capacity needs

Figure 4 shows the full decarbonisation pathways by 2040 and 2050 with and without island links. Panels (a) and (b) display the installed generation capacity. In 2030, island links are limitedly deployed because it is more cost-effective to meet demand locally with the remaining fossil capacity. After 2030, the impact of island links becomes significant as fossil capacity is further retired, which harmonises with previous work [13]. The system without island links mainly uses offshore floating PV as available land on Java for onshore solar parks is limited. With island links, there is less solar-based capacity and more dispatchable capacity from biomass, large hydro, and geothermal.

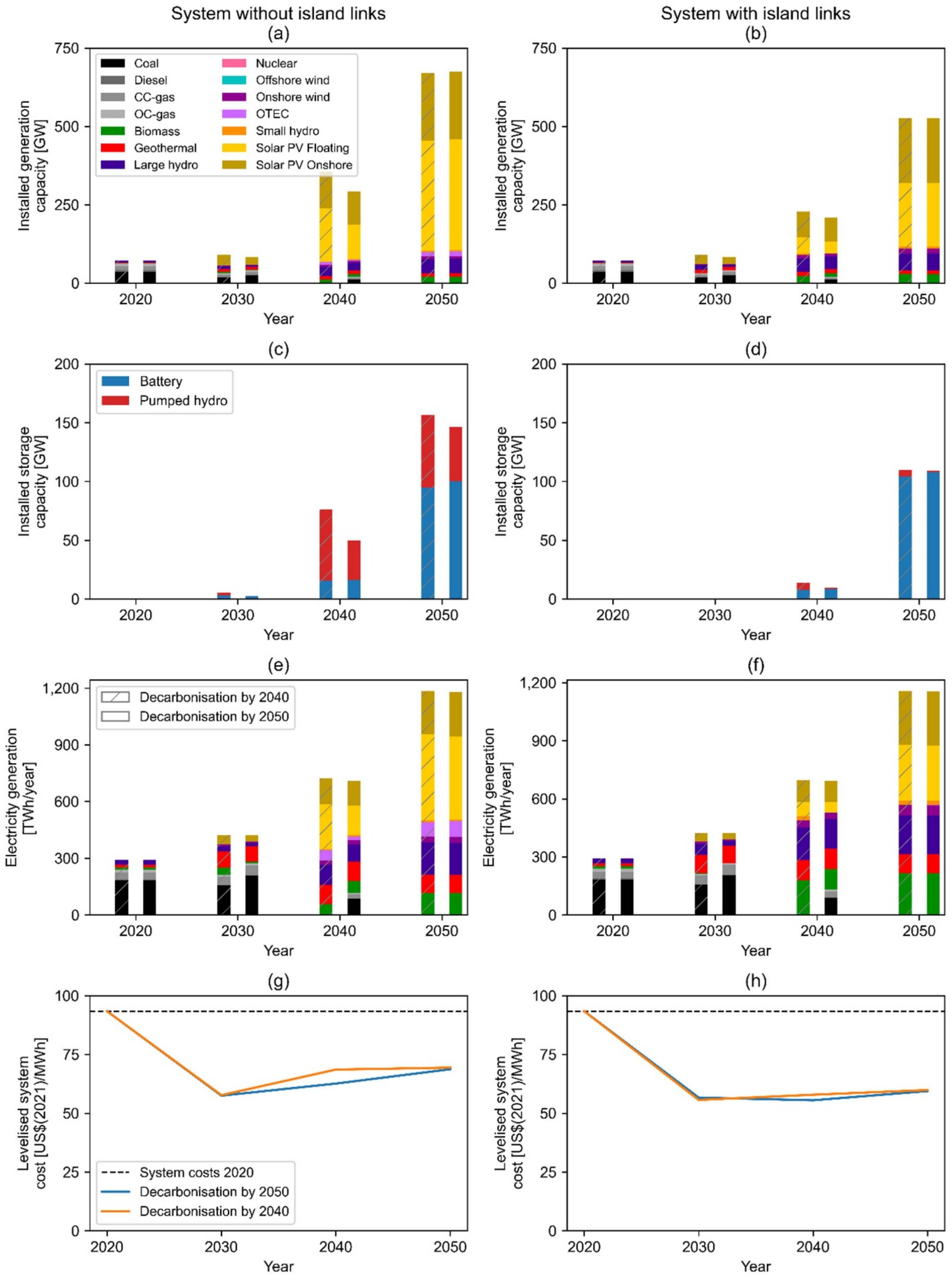

Figure 4. Installed (a), (b) generation and (c), (d) storage capacity, (e), (f) electricity generation, and (g), (h) levelised system costs of the decarbonisation pathways until 2040 (hatched bars) and 2050 (solid bars) without (left column) and with (right column) island links.

Panels (c) and (d) show the installed storage capacity. By 2050, the system without island links deploys roughly 150 GW of storage starting from 2030. Meanwhile, the system with island links only uses roughly 100 GW starting from 2040 as Java can tap into the abovementioned dispatchable capacity from neighbouring islands to meet demand. Panel (c) shows the effects of future cost reductions on the preference of storage options over time. Until 2040, pumped storage is more cost-effective and sees significant deployment, especially in the decarbonisation-by-2040 pathway. After 2040, battery storage becomes more cost-effective as its costs are expected to decline sharply in the future, while the costs of pumped hydro are expected to stay the same. This shows that a long-term focus and awareness for future cost reductions is important when planning any future power system considering pumped hydro's operational lifetime of 50 years [57].

Panels (e) and (f) show the generated electricity to meet electricity demand. Fossil-fuelled generators still dominate the generation mix in 2030, despite their capacity being reduced by 33%–50% and national demand growing by 4.8% p.a. This reflects the current fossil overcapacity in Indonesia's electricity system. In recent years, Indonesia overestimated future demand growth and consequently installed large amounts of coal power capacity, which now could potentially become stranded assets [23, 69]. The current fossil overcapacity poses a significant barrier for Indonesia's energy transition, as the addition of renewable energy capacity would exacerbate the problem. Once fossil-fuelled generators are fully phased out, the 2050 systems without island links would utilise 569 GW_p of PV generating 57% of total generation. Besides 382 TWh from biomass, geothermal, and large hydro (32% of total generation), OTEC would provide 84 TWh or 7% of total generation, thus making it a cost-effective technology if local electricity production is preferred. With island links, PV's role is less prominent with 410 GW_p and 49% of total generation as Indonesia can tap into diverse cost-effective sources to meet Java's electricity demand.

Panels (g) and (h) show the levelised system costs. Up until 2030, costs decline regardless of transmission network due to the reduction of fossil overcapacity and the increased cost-effectiveness of the remaining plants. After 2030, system costs increase again for both networks, but less so for the system with island links. The system costs in 2050 are 69 US$(2021)/MWh without island links and 60 US$(2021)/MWh with island links, mainly due to the former's larger need for solar-based generation and storage capacity. The target year for full decarbonisation only has a minor impact on system costs in 2050 (deviation $<1\%$).

Indonesia's power system could be fully decarbonised much faster than 2060 as currently pledged [2]. Both 2040 and 2050 are feasible targets, provided that decarbonisation starts now. The 2040 target would lead to fewer emissions in total, but poses more technical and economic challenges. The interconnected system would require 38 GW of sub-sea lines and 133 GW_p of PV capacity by 2040. For PV, that would mean a growth rate of 41% p.a. from 2020 onwards (versus 32% p.a. globally between 2010–2021 [22]). Without island links, no sub-sea lines are needed, but in turn larger shares of PV (286 GW_p, required growth rate 46% p.a.) and 9 GW of OTEC by 2040, which is still at a pre-commercial level today. Moreover, 74% of current coal capacity [70] would need to be retired up to twelve years earlier than initially planned (assuming 30 years of planned useful lifetime [57]), which might lead to high compensation costs to coal power plant owners.

Conversely, achieving the 2050 target would require a PV growth rate of 30% p.a. in line with global observations [22]. Also, only 36% of the 2020 coal capacity [70] would need to be decommissioned up to seven years earlier than planned, thus accruing lower compensation costs. Then again, the 2050 target would allow for 464 $MtCO_2e$ of greenhouse gas emissions after 2040 and is thus less ambitious in terms of climate change mitigation.

Figure 5 compares our 2050 systems with other fully decarbonised systems in literature. There are considerable differences between all depicted systems, which underlines the challenges of comparing energy system models and their outcomes. None of the systems in figure 5 can be labelled as right or wrong, not only because it is impossible to predict how Indonesia's actual power system will develop in the future, but also because the modelled systems are the products of numerous assumptions and choices made by the modellers. These choices encompass electricity demand growth (2050 values ranging between 950 TWh [12] and >3000 TWh [13, 14]), included technologies (e.g. nuclear being included [10–13] or not [14]), spatial and temporal granularity, and costs, amongst others. Therefore, it is important to acknowledge these differences and to make the used models and data as transparent and openly accessible as possible, as seen for Hersaputri *et al*'s [10] open-source OSeMOSYS model for Indonesia and our Calliope model [71] and output datasets [72]. Despite the abovementioned differences, we also see commonalities between our results and recent literature. First, solar PV is the dominant generation technology in almost all scenarios and its generation share increases with demand. Second, dispatchable generation from biomass, large hydro, and geothermal remains important, albeit to a larger extent in our work than in other studies most likely due to our model's high spatial granularity with transmission network representation, broad set of included technologies, and differences in technical and economic assumptions.

3.2. Dispatchable generators remain important in an interconnected, solar-dominated power system

This section starts elaborating on the results of the scenario and sensitivity analysis, using the year 2050 from the decarbonisation-by-2050 pathway as reference.

Figure 6 compares the results of the alternative scenarios listed in table 3. Solar-based generation remains dominant in almost all scenarios, except for the 'alternative power profiles' and 'maximum 2050 costs—all technologies' scenarios. The 'alternative power profiles' scenario uses the power profiles from 2010, which is the year with the lowest PV and wind, but also highest hydropower productivity in the underlying 20 year

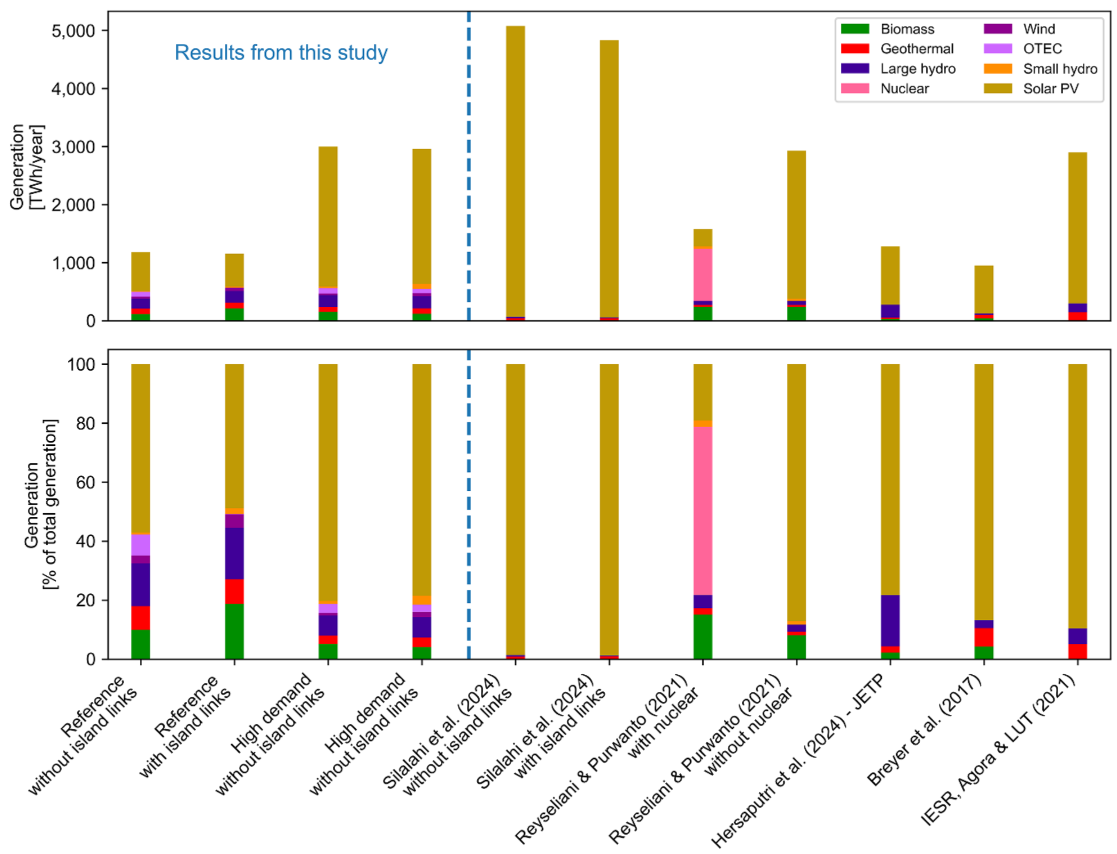

Figure 5. Comparison of generation mixes of fully decarbonised 2050 power systems from recent literature. 'Solar PV' comprises both offshore floating and ground-mounted utility-scale solar PV. 'Wind' refers to onshore wind power.

dataset. This underlines the importance of a diversified generation portfolio that is hedged against times of varying sunshine, wind, and rainfall.

The 'maximum 2050 costs—all technologies' scenario shows that island links could help Indonesia tapping into cost-effective resources even if costs decline less strongly, especially those of offshore floating PV. Without island links, offshore floating PV's generation share is only slightly reduced in favour of OTEC as there are limited cost-effective alternatives that Java could resort to. With island links, offshore floating PV is not present in the system anymore as Indonesia can draw from a broad set of more cost-effective generation technologies. Hence, offshore floating PV's role in Indonesia's power system decarbonisation is mainly tied to the extent of future cost reductions and interconnectivity between islands. As mentioned in section 2.2, rooftop PV is not included as an option in our model. Depending on the costs of floating and rooftop PV, the latter's inclusion may lead to a partial replacement of floating PV by rooftop PV in the optimised model outcomes.

Besides PV's dominance, another commonality of the alternative scenarios is the significance of dispatchable generators regardless of inter-island connections. Excluding the 'solar only' scenario, the combined capacity and generation of biomass, large hydro, and geothermal is at least 62 GW in figure 6(a) and 284 TWh/year, or 23% of total generation, in figure 6(c). The 'solar only' scenario, in turn, shows that a power system fully based on solar PV is technically possible with and without island links, but at twice the storage capacity requirements and 37%–45% higher system costs compared to the reference scenarios. Then again, such a system might still be interesting if the large-scale implementation of technologies like large hydro, geothermal, and biomass is not desired or socially accepted due to their potentially negative environmental and social impacts, e.g. seismic activity, competition with food production, and the relocation of native residents [73].

Figure 6(d) shows that the benefits of island links outweigh their costs. Even if the costs of island links are increased while all other technologies' costs are unchanged, levelised system costs only increase by 2% compared to the reference scenario with island links and are still 12% lower than the costs of the reference system without island links.

The shape of the demand profiles ('alternative demand profiles' scenario) has a relatively small influence on the systems' key indicators, thus justifying the use of scaled Malaysian data.

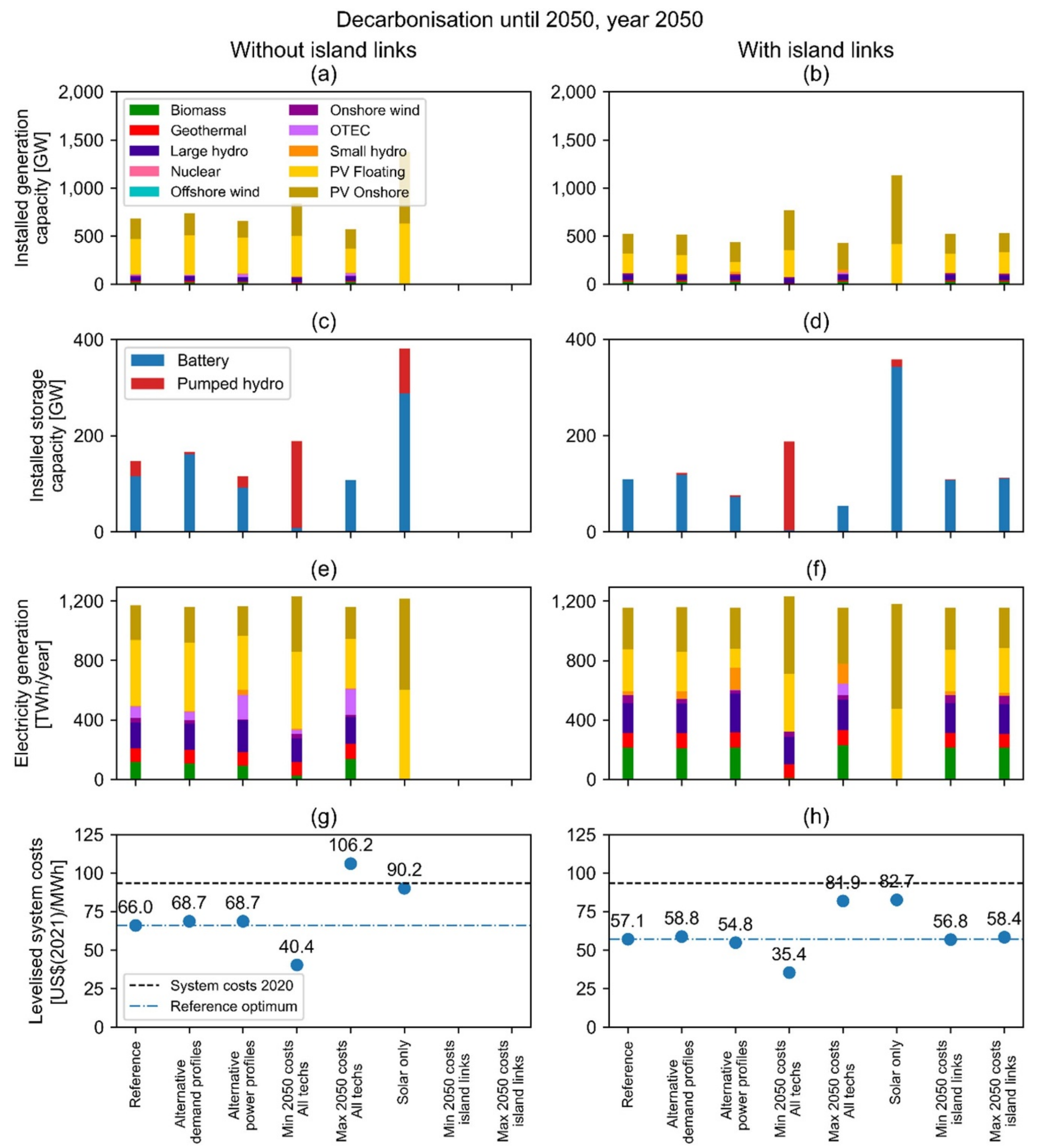

Figure 6. Installed (a), (b) generation and (c), (d) storage capacity, (e), (f) electricity generation, and (g), (h) levelised system costs of the alternative scenarios without (left column) and with (right column) island links.

So far, our results indicate that island links foster the utilisation of dispatchable generators. This is further supported by figure 7, which shows that island links would enable the utilisation of more than 60% of available large hydro, biomass, and geothermal resources even if they are increased by 50%. Then, dispatchable generators would account for more than half of total electricity generation in figure 7(d). Without island links, ramping up available resources is less impactful as most of them are located outside of Java on islands with far lower electricity demand. The official sources [45, 46] used for the reference potentials of geothermal, biomass, and large hydro tend to underestimate available renewable resources [3]. Therefore, we recommend further research to better understand the potentials of biomass and geothermal, and refine their role in Indonesia's energy transition, also with their abovementioned potential environmental impacts in mind [73].

Figure 8 shows how changes in costs of individual technologies affect their generation share. Biomass, geothermal, and large hydro are only limitedly sensitive to changes in costs, which reflects their cost-effectiveness in a fully decarbonised power system, but also their limitations in terms of resource availability. If onshore PV's costs are set to maximum 2050 levels, its generation share drops to almost zero as widely available floating PV becomes more cost-effective. Vice versa, floating PV is fully replaced by onshore PV at maximum 2050 costs. In contrast to existing work (see figure 5), there are small, but not insignificant,

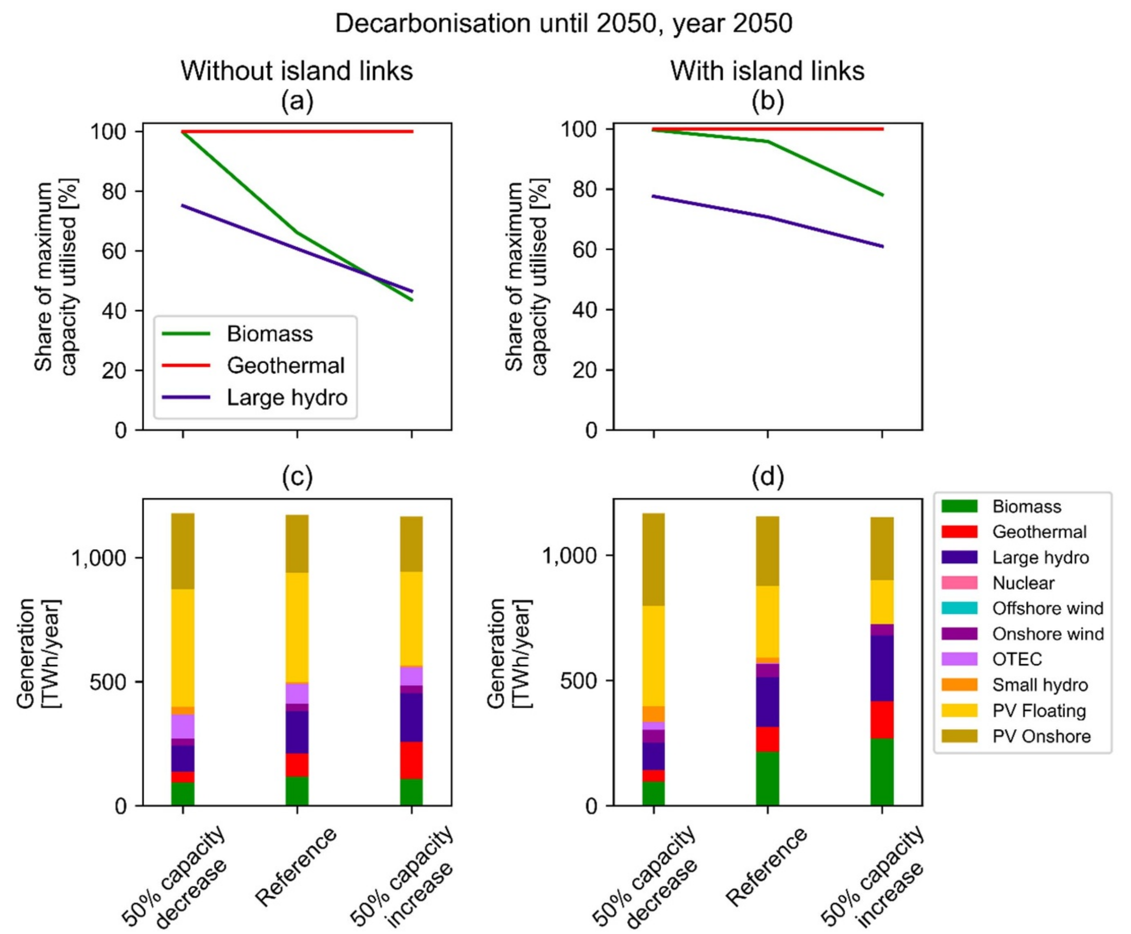

Figure 7. Sensitivity of resource utilisation and generation to changes in available biomass, geothermal, and large hydro resources without (left column) and with (right column) island links.

shares of onshore wind power even at maximum 2050 costs. This is due to the high spatial granularity of the underlying wind resource data, which revealed local hotspots with average wind speeds above 6 m s^{-1} at 100 m hub height. Therefore, our earlier finding [42] of onshore wind being an interesting solution for Indonesia's sub-provincial energy transition is further strengthened.

Figure 8 further shows that nuclear and OTEC would only have noticeable generation shares in an interconnected system if they experience extreme cost reductions until 2050 (i.e. minimum 2050 costs). For OTEC, we see a hen-and-egg problem as it needs strong and sustained cost reductions to be considered by the model, but these cost reductions are only achieved if there are early adopters who implement OTEC at its pre-commercial, high costs. Therefore, OTEC's commercialisation might require public support to encourage early adoption. Then again, OTEC does see implementation in the system without island links (see figure 4), so OTEC could be commercialised as a local generator if large-scale island link implementation is not being pursued. At minimum 2050 costs, 13.5 GW of nuclear could provide 10% of total electricity generation. This contrasts the 121 GW of nuclear capacity from Reyseliani and Purwanto's [11] 100% RET + nuclear scenario, which used different costs and implementation restrictions.

3.3. Kalimantan could become the key power exporter to Java even at high island link costs

This section focusses on the island links and their sensitivity to more conservative technical and economic assumptions. Figure 9 illustrates the installed transmission capacity between islands in 2050 for the (a) reference (b) high demand, (c) 5 GW HVDC transmission limit, (d) solar only, and (e) minimum and (f) maximum HVDC costs scenario.

In the reference scenario, total installed inter-island transmission capacity amounts to 43 GW, with 27 GW between Kalimantan and Java. For comparison, the sub-sea transmission capacity installed on the European continent in 2015 was already about 14 GW [74], and is expected to grow substantially by 2050, despite Europe not being an archipelagic entity. Therefore, the obtained numbers can be deemed plausible. Under high demand growth (8.3% p.a.) in panel (b), 116 GW of inter-island transmission capacity would be necessary, including one 50 GW link from West Kalimantan to Jakarta.

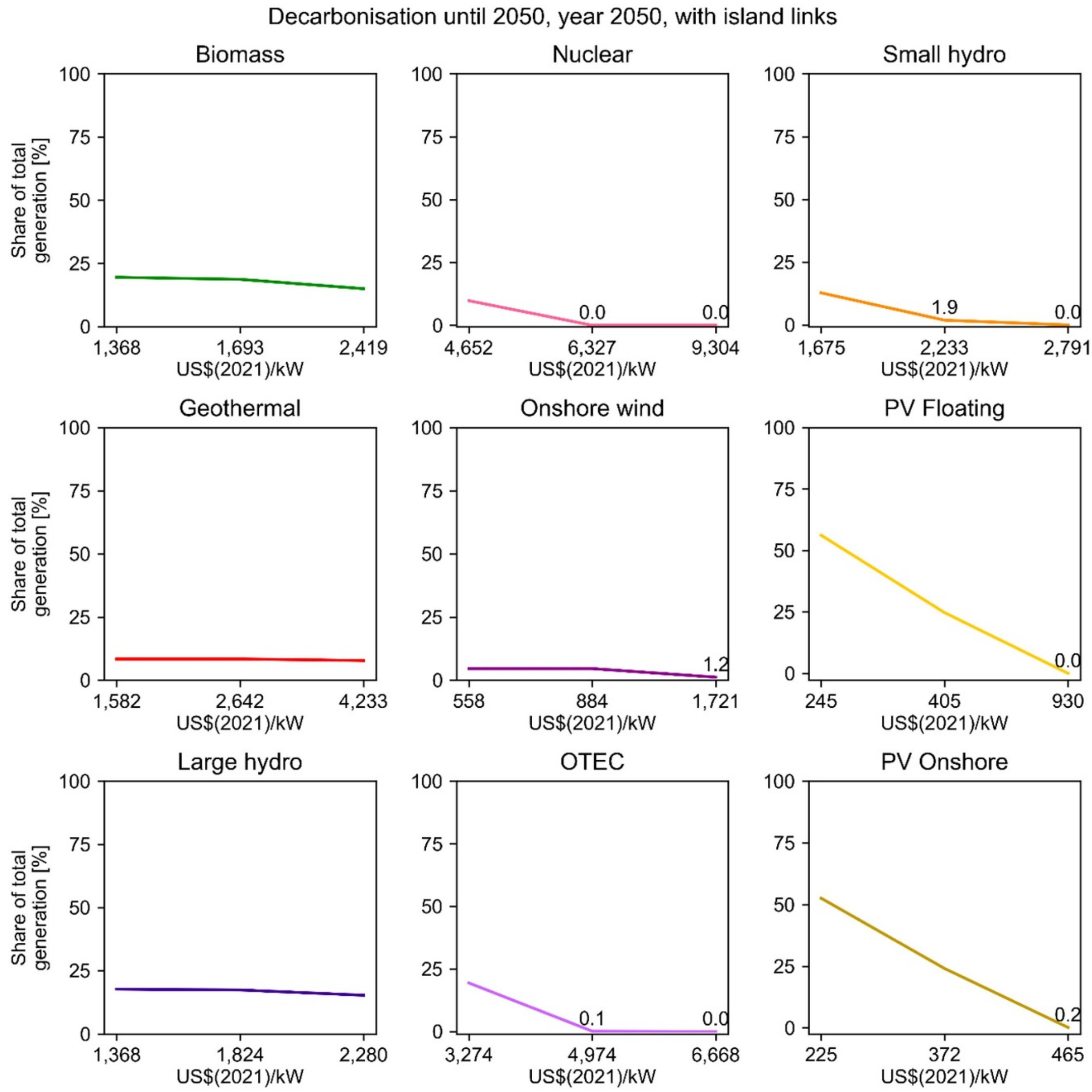

Figure 8. Sensitivity of generation shares to changes in individual technology costs. The three cost values on the x-axis of each panel reflect the minimum, reference, and maximum 2050 costs. For each panel, we change the costs of the studied technology, while keeping the costs of all other technologies at reference levels. Offshore wind is not shown here as its generation share is 0.2% at minimum 2050 costs.

Line capacities of up to 50 GW as reported above are mainly the result of setting the maximum installable capacity per island link to that value. As shown in panel (c) in figure 9, the reference scenario deploys lines of up to 16 GW and distributes the total needed transmission capacity over more lines if maximum capacity per line is capped to lower thresholds. If electrification and sector-coupling progresses and electricity demand grows more strongly than in the reference scenario, Indonesia has several options to distribute the transmission capacity to avoid too large transmission links.

Panel (d) indicates that island links are also useful in the absence of dispatchable generators in the ‘solar only’ scenario. Due to the cost differences between onshore and floating PV, it is cost-effective to source more than half of total generation from onshore PV, mainly situated on Kalimantan, to supply Java, in addition to some generation from local floating PV plants.

Panel (e) illustrates how island links remain relevant even under significantly higher costs. At maximum 2050 levels, the capacity of most links is reduced, except for the Banten–Lampung link which increases from 3.4 to 4.4 GW. In the maximum 2050 costs scenario, mainly the distance-dependent cost component is increased (from 293 to 1261 US$(2021)/MW/km), so shorter links become more cost-effective. The link from West Kalimantan to Java is only moderately affected by the cost increase, with its capacity decreasing from 15.8 GW to 14.0 GW. This underlines the pivotal role of that link in Indonesia’s full power system decarbonisation. With minimum HVDC costs, the total island link transmission capacity only increases slightly to 44 GW compared to the reference case.

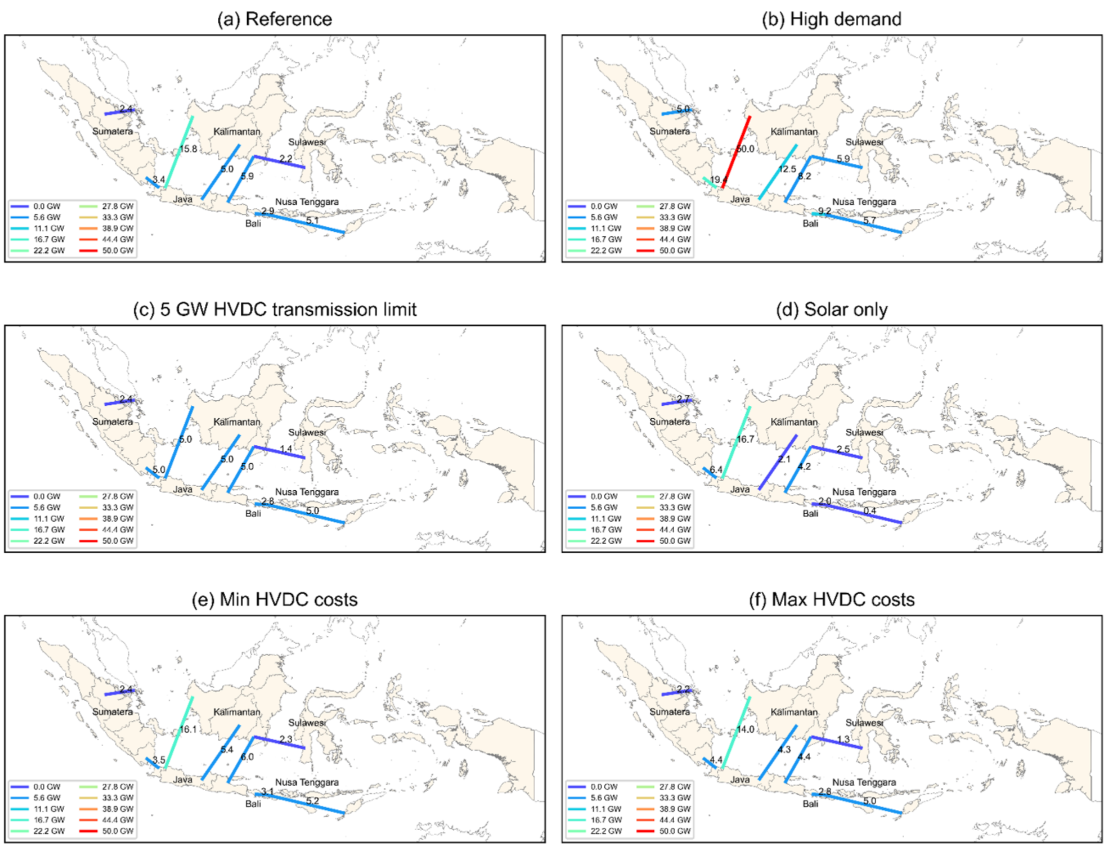

Figure 9. Active power flows of island links for the (a) reference, (b) high demand, (c) 5 GW HVDC transmission limit, (d) solar only, and (e) minimum and (f) maximum HVDC costs scenarios. The line colours reflect the rated line capacities.

What our model does not capture are the non-technical challenges of island links. Indonesia consists of more than 17 000 islands with different cultural, political, and institutional contexts. Setyowati and Quist [75, p 9] showed that 'energy planning processes are not neutral technical exercises but constitute political processes [...] at national and subnational levels'. Therefore, national interconnections might stand in contrast with the desire of subnational islands to maintain their energy independence, amongst others. Since interconnections could be a source of income for regions like Kalimantan, our results could be used to highlight the mutual benefits of such interconnections and to reconcile them with local values.

Furthermore, our study does not consider the intricacies of sub-sea cable routing with regards to seismic activity, shipping routes, etc and their impact on power system planning. Indonesia is on a high tectonic setting with many seismic faults that can cause devastating earthquakes and tsunamis, like the Palu Earthquake in 2018 on Sulawesi [76]. Thus, high seismic design criteria need to be considered carefully to ensure the sustainable and long-lasting operation of both sub-sea links (especially the links connecting Java–Sumatera, South Kalimantan–East Java, and Java–Bali–West Nusa Tenggara) and on-land links, especially considering the seismic activity on Sumatera (Great Semangko Fault), Sulawesi (Palu–Koro Fault), Java (Baribis Fault), and East Kalimantan [77].

Nonetheless, our results show that island links are key for Indonesia's energy security once power system decarbonisation gains momentum as demand could be met domestically, reliably, and affordably. Beyond Indonesia, our findings could be relevant for the planned ASEAN power grid [78] connecting Indonesia to neighbouring countries like Singapore and Malaysia, as well as for other island and coastal states. For example, small islands like Aruba and Curaçao could be connected to their continental neighbours Colombia and Venezuela, which are both rich in hydropower resources [79, 80]. Then, island links could significantly improve the energy security of these islands as they would become less reliant on Diesel generators and high, volatile fuel prices [81].

4. Summary and conclusions

This paper explores the role of sub-sea inter-island power transmission, or island links, in full power system decarbonisation scenarios for Indonesia. We address current limitations in Indonesian modelling literature by using the spatially and temporally resolved state-of-the-art ESOM Calliope. The model considers various techno-economic assumptions, electricity network topologies, and scenario designs. We use the model to explore pathways for Indonesia's full power system decarbonisation by 2040 and 2050 and assess the diversity of 2050 system configurations via a scenario and sensitivity analysis. Despite its focus on Indonesia, the paper is globally relevant as our findings might translate to other island and archipelagic states, as well as the ASEAN region.

We show that the role of island links is mainly the connection of islands where electricity demand and available renewable energy resources are mismatched. With 43 GW of island link capacity, Indonesia could supply high-demand regions like Java with low-cost electricity from neighbouring islands with vast resources and lower demand, e.g. with onshore PV and hydropower from Kalimantan, geothermal from Sumatera, and onshore wind power from East Nusa Tenggara and Sulawesi. Java could also meet its demand locally without island links, but only with offshore-based generators, like floating PV and OTEC, as available land for onshore renewables is limited there. Together with an increased need for storage capacity, the costs of the system without island links are 15% higher than the costs of the interconnected system (69 vs 60 US$(2021)/MWh). Throughout the scenario and sensitivity analysis, the interconnected system was more cost-effective than the disconnected one, even if the costs of island links are substantially increased.

Furthermore, Indonesia has the potential to achieve full decarbonisation of its power system well before the currently pledged 2060 timeline provided that decarbonisation starts now. The 2040 target would avoid 464 $MtCO_2e$ of emissions compared to the 2050 target, but also poses greater technical and economic challenges in terms of renewable generation and transmission capacity upscaling and premature phase-out of existing fossil-based capacity. If cost projections hold true, 410 GW_p of solar PV would produce roughly half of total electricity in 2050, coupled with roughly 100 GW of storage mainly from batteries. Biomass, large hydro, and geothermal are another key element of Indonesia's decarbonised power system with a combined capacity and generation share of at least 62 GW and 23% of total generation. These technologies, especially geothermal and biomass, are mainly limited by local resource availability rather than economic limitations, so we recommend further research into the scouting of further resources and the technologies' large-scale deployment considering potential environmental impacts. Moreover, the large generation shares of offshore floating PV reported here, especially for the system with island links, are tied to strong future cost reductions. Under more conservative costs, offshore floating PV is only deployed in the system without island links due to a lack of alternatives.

We conclude that Indonesia's energy transition is not primarily a matter of technology and resources, but of investment, political will, and commitment. Once the main islands are interconnected, Indonesia's decision makers may have the luxury of deciding between a diverse set of similarly technically viable system configurations of their preference. However, there will be challenges. Indonesia must provide a conducive environment for domestic and international investments into new, renewable generation, storage, and transmission infrastructure, as well as the retirement of fossil capacity. Moreover, the energy transition must be socially just and inclusive. Regions currently reliant on the coal industry must not be left behind and included in a decarbonised world, e.g. as a hub for renewable energy services in the case of Kalimantan. The sovereignty of subnational islands must be respected, and the establishment of island links must be based on mutual benefits.

This paper already offers a diverse set of solutions for Indonesia's power system decarbonisation. Nonetheless, the model can be further improved by addressing the limitations of our work. First, we used the same demand pattern from Malaysia's and Kalimantan's system for all Indonesian provinces, albeit scaled to fit local annual demand. This leads to an oversizing of capacity as dips and peaks in demand occur in all provinces at the same time. This could be addressed by incorporating location-specific demand profiles from Indonesia's state-owned utility company PLN, or by modelling synthetic demand profiles. Second, the model could be expanded to other energy carriers (e.g. hydrogen) and sectors (e.g. transportation and industry),. Further research into these matters might strengthen the benefits of island links, not only for electricity, but other gaseous and liquid energy carriers. Third, technologies like rooftop PV, carbon capture and storage, wave power, and tidal power could be included to offer more options for Java to meet demand locally besides offshore floating PV. Fourth, the sub-sea cable routing of the island links could be researched in more detail, considering limitations from areas with seismic activity and shipping routes, amongst others. Lastly, more advanced methods could be used to assess the parametric and structural uncertainty of our model and to further strengthen our findings, e.g. via modelling to generate alternatives.

Data availability statement

The data that support the findings of this study are openly available at the following URL/DOI: https://doi.org/10.4121/acc15d6d-d851-4519-a483-7e25fc810124 and https://github.com/JKALanger/calliope_indonesia.

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Author contributions

JL: Conceptualization; Data curation; Formal analysis; Investigation; Methods & Materials; original draft

FL: Contributions to methodology; Supervision; Methods & Materials; Validation; Writing—review & editing

SP: Supervision; Validation; Writing—review & editing

HPR: Methods & Materials; Validation; Writing—review & editing

MIAI: Methods & Materials; Validation; Writing—review & editing

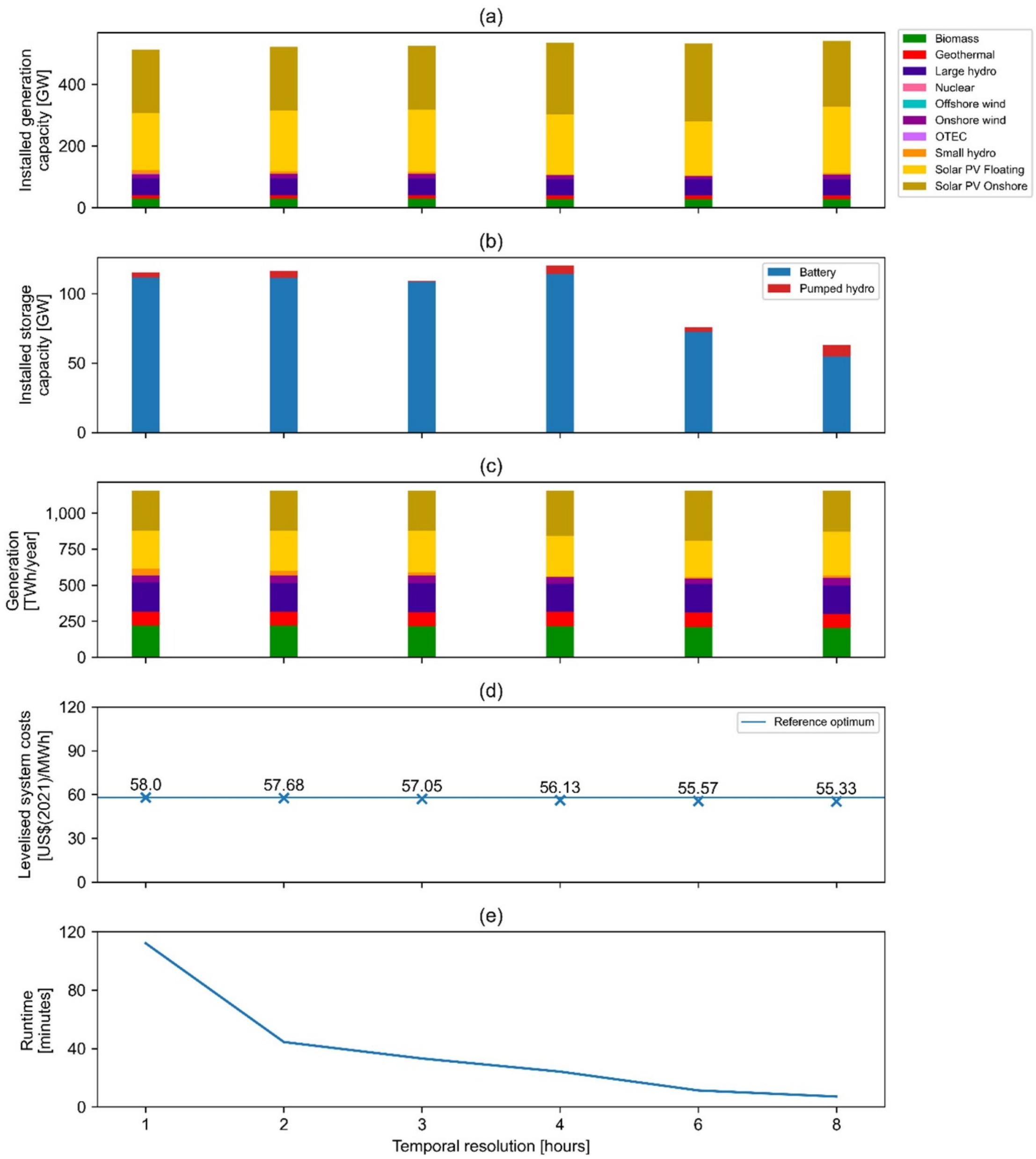
KB: Contributions to methodology; Supervision; Methods & Materials; Validation; Writing—review & editing

Conflict of interest

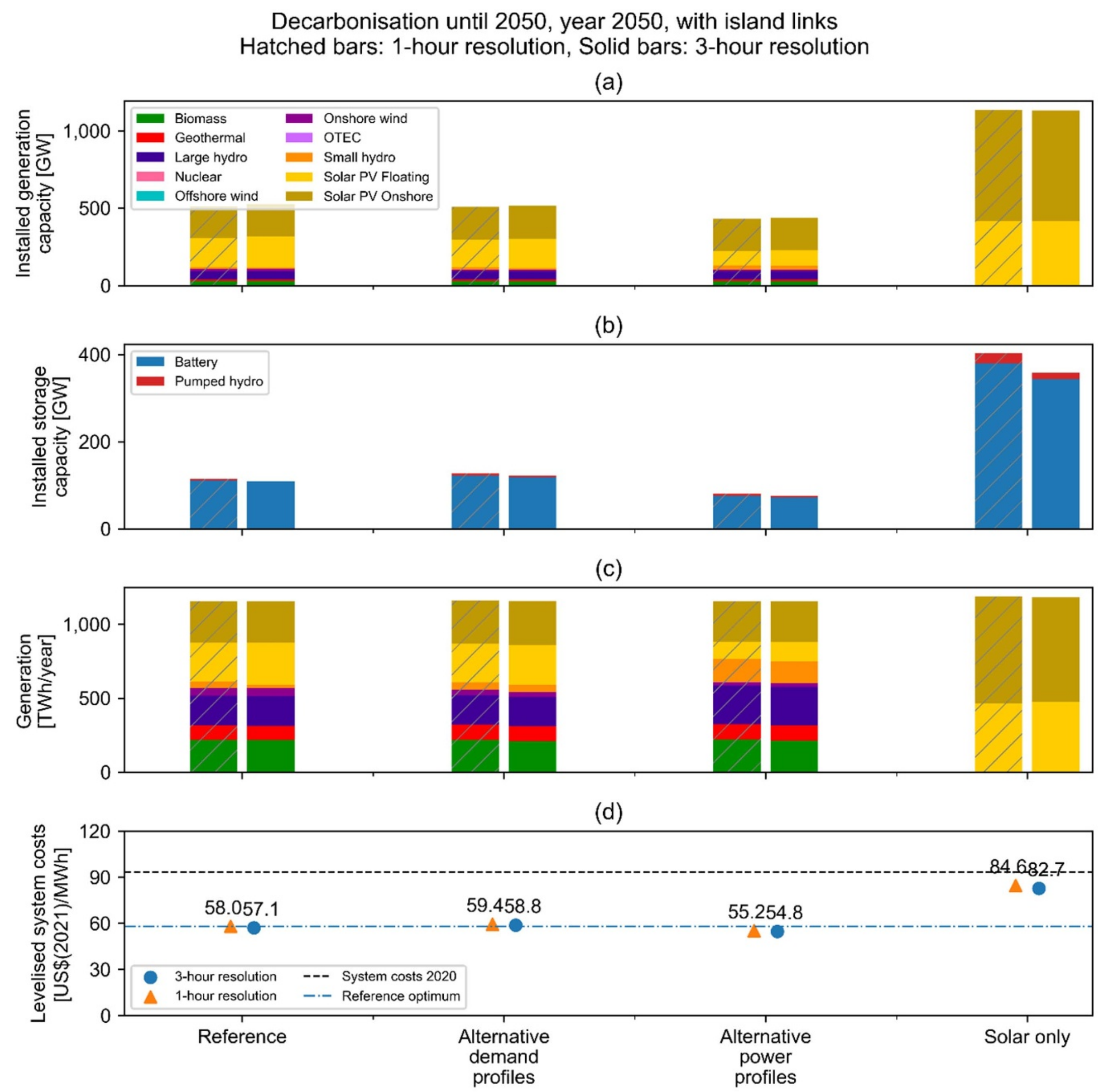
The authors declare no competing interest.

Appendix

A. Impact of temporal downsampling

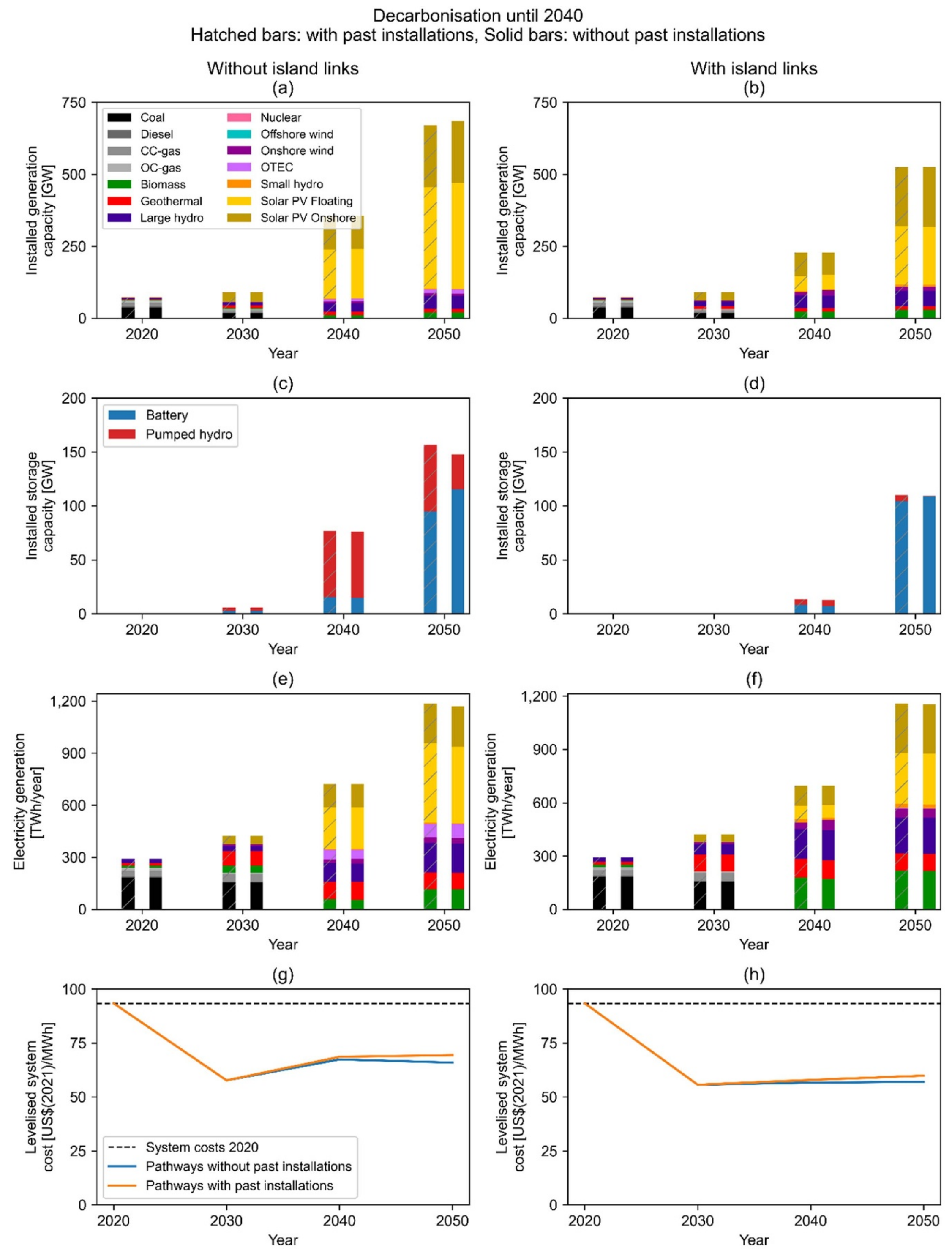


Supplementary Figure 1. The impact of temporal resolution on installed (a) generation and (b) storage capacity, (c) electricity generation, (d) levelised system costs, and (e) model runtime.

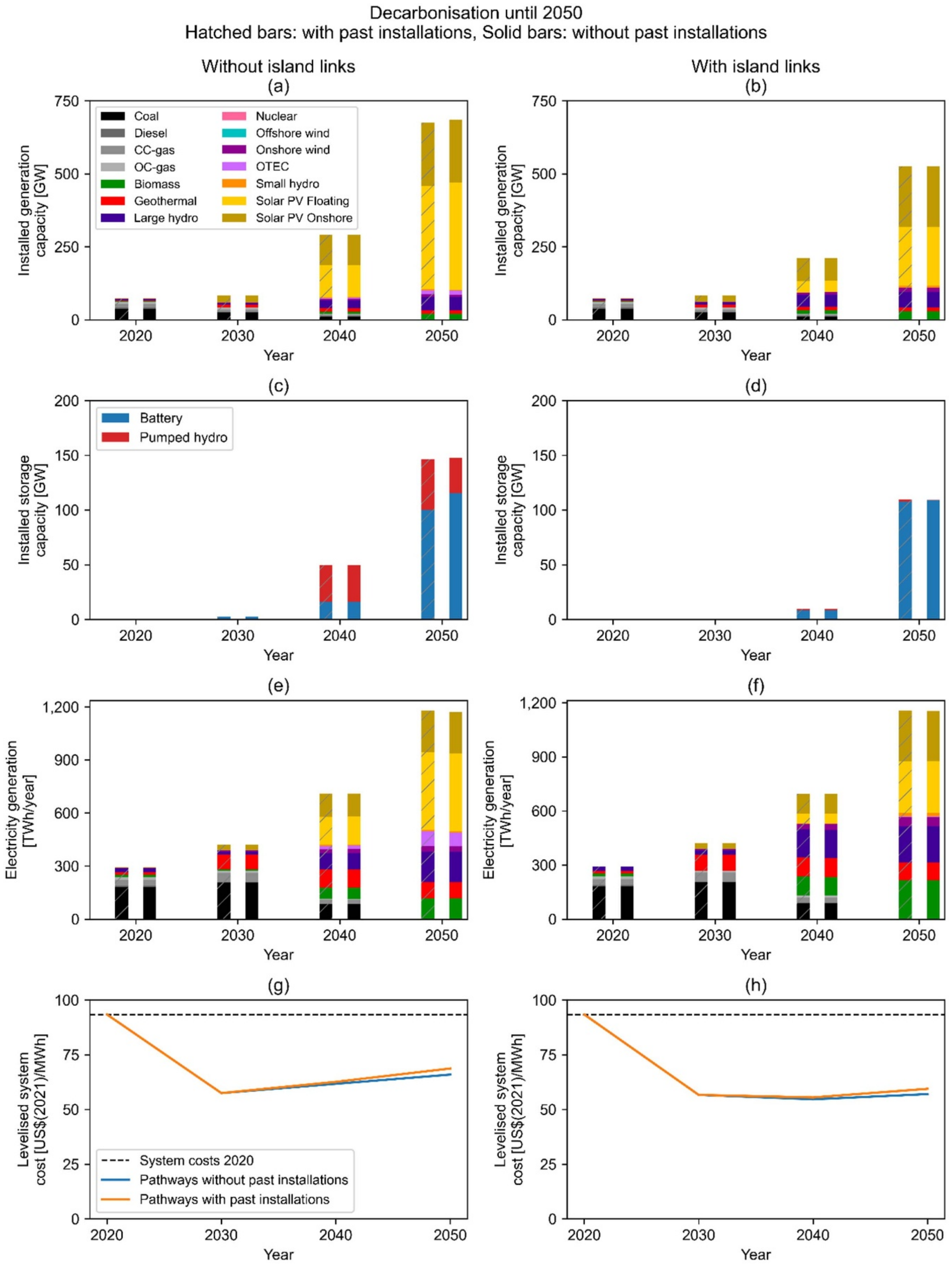


Supplementary Figure 2. Impact of temporal resolution on installed (a) generation and (b) storage capacity, (c) electricity generation, and (d) levelised system costs for a set of alternative scenarios studied in this paper.

B. Impact of modelling decarbonisation pathways with and without past installations



Supplementary Figure 3. The impact of considering past installations on installed (a) generation and (b) storage capacity, (c) electricity generation, (d) levelised system costs for the decarbonisation by 2040 pathway with and without island links.



Supplementary Figure 4. The impact of considering past installations on installed (a) generation and (b) storage capacity, (c) electricity generation, (d) levelised system costs for the decarbonisation by 2040 pathway with and without island links.

C. Technical assumptions for generation, storage, and transmission technologies

Technology	Parameter	Unit	Assumption	References
Coal (supercritical)	Efficiency	[%]	40	All [57]
	Lifetime	[years]	30	
	Minimum load	[%]	40	
Diesel (reciprocating engine)	Efficiency	[%]	48	All [57]
	Lifetime	[years]	25	
	Minimum load	[%]	6	
CCGT	Efficiency	[%]	61	All [57]
	Lifetime	[years]	25	
	Minimum load	[%]	15	
OCGT	Efficiency	[%]	40	All [57]
	Lifetime	[years]	25	
	Minimum load	[%]	15	
Large hydro (reservoir)	Efficiency	[%]	95	[57]
	Lifetime	[years]	50	[57]
	Ratio between storage and energy capacity	[-]	0.15	[31]
Biomass (direct combustion steam turbine)	Efficiency	[%]	32	All [57]
	Lifetime	[years]	25	
	Minimum load	[%]	30	
Geothermal	Efficiency	[%]	17	All [57]
	Lifetime	[years]	30	
Small hydro (run-of-river)	Efficiency	[%]	80	All [57]
	Lifetime	[years]	50	
Solar PV (ground-mounted, utility-scale)	Efficiency	[%]	X	[20]
	Lifetime	[years]	40	[57]
Solar PV (offshore floating PV)	Efficiency	[%]	X	This study
	Lifetime	[years]	25	[57]
Onshore wind	Efficiency	[%]	X	[42]
	Lifetime	[years]	30	[57]
Offshore wind	Efficiency	[%]	X	[43]
	Lifetime	[years]	30	[57]
Nuclear (heavy water reactor)	Efficiency	[%]	42	All [57]
	Lifetime	[years]	60	
	Minimum load	[%]	25	
OTEC	Efficiency	[%]	X	All [49]
	Lifetime	[years]	30	
Battery (Lithium-iron)	Round-trip efficiency	[%]	96	[57]
	Storage losses	[% per day]	0.96	[57]
	Ratio between storage and energy capacity	[-]	0.25	[31]
	Lifetime	[years]	30	[57]
Pumped hydro (closed-loop)	Round-trip efficiency	[%]	80	[57]
	Storage losses	[% per day]	0	[57]
	Ratio between storage and energy capacity	[-]	0.15	[53]
	Lifetime	[years]	50	[57]
Onshore power transmission (AC)	Efficiency	[%]	98	[36]
	Lifetime	[years]	40	[31]
	Maximum capacity per link	[GW]	50	This study
Sub-sea power transmission (HVDC)	Efficiency	[% per 1,000 km]	96.6	[68]
	Lifetime	[years]	40	[68]
	Maximum capacity per link	[GW]	50	This study

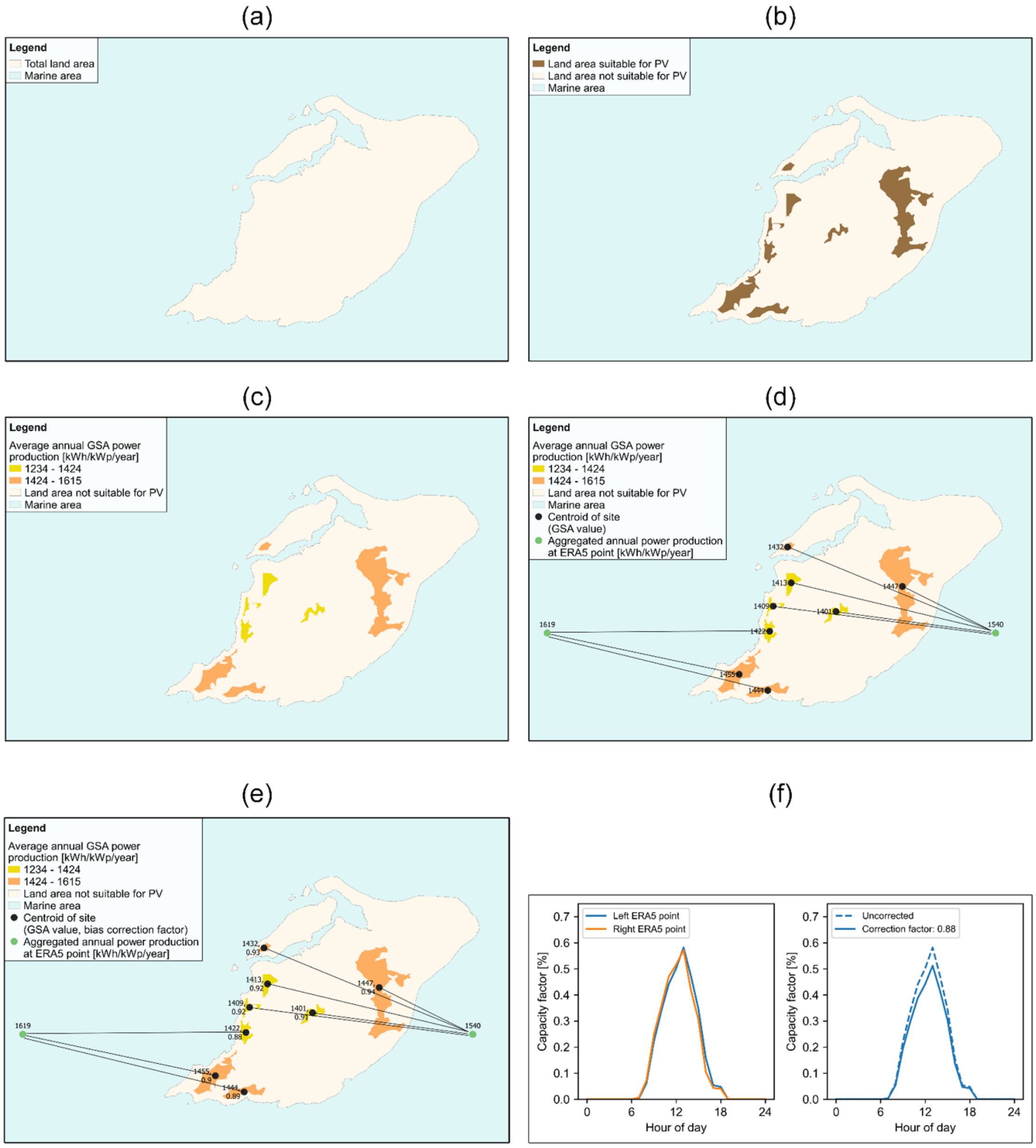
X refers to the power production profiles for which efficiency has already been accounted for in the underlying references.

D. Cost assumptions for generation, storage, and transmission technologies

			Year				
Technology	Cost	Unit	2030	2040	2050—min	2050—ref	2050—max
Coal (supercritical)	CAPEX	[US$(2021)/kW]	1442	1418	—	—	—
	Fixed OPEX	[US$(2021)/kW/year]	42	42	—	—	—
	Variable OPEX	[US$(2021)/MWh/year]	1.3	1.2	—	—	—
	Fuel costs	[US$(2021)/MWh$_{thermal}$]	12.1	12.1	—	—	—
Diesel (reciprocating)	CAPEX	[US$(2021)/kW]	847	837	—	—	—
	Fixed OPEX	[US$(2021)/kW/year]	8.5	8.4	—	—	—
	Variable OPEX	[US$$(2021)/MWh/year]	6.4	6.3	—	—	—
	Fuel costs	[US$(2021)/MWh$_{thermal}$]	38.7	38.7	—	—	—
CCGT	CAPEX	[US$(2021)/kW]	958	921	—	—	—
	Fixed OPEX	[US$(2021)/kW/year]	24	24	—	—	—
	Variable OPEX	[US$(2021)/MWh/year]	2.3	2.3	—	—	—
	Fuel costs	[US$(2021)/MWh$_{thermal}$]	23.3	23.3	—	—	—
OCGT	CAPEX	[US$(2021)/kW]	986	954	—	—	—
	Fixed OPEX	[US$(2021)/kW/year]	24	24	—	—	—
	Variable OPEX	[US$(2021)/MWh/year]	3.3	3.3	—	—	—
	Fuel costs	[US$(2021)/MWh$_{thermal}$]	23.3	23.3	—	—	—
Large hydro (reservoir)	CAPEX	[US$(2021)/kW]	1963	1893	1368	1824	2280
	Fixed OPEX	[US$(2021)/kW/year]	38	37	27	35	44
	Variable OPEX	[US$(2021)/MWh/year]	0.7	0.6	0.5	0.6	0.8
Biomass (direct combustion steam turbine)	CAPEX	[US$(2021)/kW]	1926	1810	1396	1693	2419
	Fixed OPEX	[US$(2021)/kW/year]	46	43	34	40	57
	Variable OPEX	[US$(2021)/MWh/year]	2.9	2.7	2.2	2.5	3.6
	Fuel costs	[US$(2021)/MWh$_{thermal}$]	9.0	9.0	—	9.0	—
Geothermal	CAPEX	[US$(2021)/kW]	3201	2921	1582	2642	4233
	Fixed OPEX	[US$(2021)/kW/year]	40	37	25	33	41
	Variable OPEX	[US$(2021)/MWh/year]	0.2	0.2	0.1	0.2	0.2
Small hydro (run-of-river)	CAPEX	[US$(2021)/kW]	2410	2321	1675	2233	2791
	Fixed OPEX	[US$(2021)/kW/year]	54	52	38	50.2	63
	Variable OPEX	[US$(2021)/MWh/year]	0.5	0.5	0.4	0.5	0.6
Solar PV (ground-mounted, utility-scale)	CAPEX	[US$(2021)/kW$_p$]	519	446	225	372	465
	Fixed OPEX	[US$(2021)/kW$_p$/year]	5.3	5.0	2.4	4.7	7.1
Solar PV (floating PV)	CAPEX	[US$(2021)/kW$_p$]	848	473	245	405	930
	Fixed OPEX	% of CAPEX	2	2	2	2	2
Onshore wind	CAPEX	[US$(2021)/kW$_p$]	1116	1000	558	884	1721
	Fixed OPEX	[US$(2021)/kW$_p$/year]	33	31	23	28	56
Offshore wind (fixed-bottom)	CAPEX	[US$(2021)/kW]	3322	2996	1442	2670	2977
	Fixed OPEX	[US$(2021)/kW/year]	93	84	57	76	88
	Variable OPEX	[US$(2021)/MWh/year]	4.5	4.1	2.5	3.6	4.0
Nuclear (heavy water reactor)	CAPEX	[US$(2021)/kW]	7350	6839	4652	6327	9304
	Fixed OPEX	[US$(2021)/kW/year]	112	108	19	105	167
	Variable OPEX	[US$(2021)/MWh/year]	2.1	2.1	1.5	2.1	2.6
	Fuel costs	[US$(2021)/MWh$_{thermal}$]	2.9	2.9	—	2.9	—
OTEC (closed-cycle)	CAPEX	[US$(2021)/kW$_{gross}$]	6048	5511	3274	4974	6668
	Fixed OPEX	% of CAPEX	3	3	3	3	3
Battery (Lithium-ion)	CAPEX	[US$(2021)/MWh$_{stor}$]	298 125	252 955	153 580	207 784	406 535
	Fixed OPEX	[US$(2021)/MWh$_{stor}$/year]	2442	2076	582	1710	3490
	Variable OPEX	[US$(2021)/MWh/year]	1.7	1.6	1.5	1.5	2.1
Pumped hydro (closed-loop)	CAPEX	[US$(2021)/kW$_{stor}$]	1116	1116	558	1116	5582
	Fixed OPEX	[US$(2021)/kW$_{stor}$/year]	17	17	3.7	17	28
	Variable OPEX	[US$(2021)/MWh/year]	0.9	0.9	0.5	0.9	2.8
Onshore power transmission (AC)	Fixed CAPEX	[US$(2021)/kW]	522	522	—	522	—
	Variable OPEX	[US$(2021)/MWh/year]	1.3	1.3	—	1.3	—
Sub-sea power transmission (HVDC)	Fixed CAPEX	[US$(2021)/MW]	171 000	171 000	148 000	171 000	207 000
	CAPEX per distance	[US$(2021)/MW/km]	293	293	171	293	1261
	Variable OPEX	% of CAPEX	1.7	1.7	0.7	1.7	3.5

E. Brief overview of bias correction

Supplementary figure 5 gives a general overview of the renewable energy potential mapping process deployed in [20, 42, 43, 49], demonstrated for ground-mounted, utility-scale solar PV. We start with the entire land area in panel (a). Using Geographic Information System software, we then remove any unsuitable areas, e.g. nature conservation zones and water bodies. The remaining, suitable areas are shown in panel (b). Next, we determine the resource availability at these sites using resource maps, like *Global Solar Atlas (GSA)* [52].



Supplementary Figure 5. Steps of the general renewable energy potential mapping methodology used in this dissertation, starting with panel (a) and ending with panel (e), demonstrated for solar PV on Boano Island, West Seram, Maluku, Indonesia. The left graph of panel (f) visualises the power production profiles of the two ERA5 points shown in panels (d) and (e), and the right graph of panel (f) shows how the effect of the bias correction factor for the left ERA5 datapoint in panels (d) and (e).

The GSA has a fine resolution of 250 m $\times$ 250 m, and all pixels inside the PV sites are sampled to obtain the average annual power production per site in panel (c).

The downside of resource maps like GSA is that they are not temporally resolved, meaning that they only show the average annual power production. They do not show the intraday and seasonal fluctuations, which is important when modelling the power production of variable RET. There are meteorological datasets that contain data like solar irradiation in hourly timesteps for many decades, e.g. ERA5 *reanalysis*. These datasets, however, have a low spatial resolution (30 km $\times$ 30 km for ERA5) and do not capture the detailed local orography [42]. Hence, GSA and reanalysis are complimentary and would, if coupled, enable the modelling of renewable power production at high spatial and temporal resolution. This coupling is achieved via a method called *bias correction*, which we explain below.

As shown in panel (d), we first generate the centroids of the PV sites containing the GSA power production. Then, we add the ERA5 datapoints to the map and determine the closest ERA5 point for each centroid. Next, the GSA power production of the centroids are compared to the power production of the

ERA5 datapoint closest to them. The latter is calculated using a PV system model with ERA5 reanalysis as input. From the comparison, we obtain a time-invariant scaling factor for each centroid, called *bias correction factor*. For example, if the GSA power production at a site is 1455 kWh/kW_p/year and the aggregated annual power production at the closest ERA5 point is 1619 kWh/kW_p/year, then each hourly value of the ERA5 power production profile is multiplied by a bias correction factor of $1455/1619 = 0.9$, as shown in panels (e) and (f). Applying this correction factor, the power production profiles from ERA5 match the site-specific GSA values on an annual basis.

F. Hourly hydropower production profiles using bias correction

For hydropower, we use the publicly available dataset for hydropower plant locations and their mean river discharge and hydraulic head by Hoes *et al* [41]. To convert the single-value river discharge into hourly time series, we use ERA5 runoff data and the methods by Liu *et al* [50] as follows.

First, we detect the upstream basins of each hydropower plant using the HydroBASINS dataset [82] and Pfafstetter coding system. Put simply, this system assigns identification numbers to basins based on their location on the river, see supplementary figure 6. If the code's last digit is odd, the basin contains the river's main stem. If the last digit is even, the basin contains the tributary of the main stem (i.e. a branch of the main river). If the last digit is zero, the basin is not connected to the main stem at all. The higher the last digit, the more upstream the basin is located on the river (1: most downstream; 9: most upstream). The basins can be subdivided into smaller basins and then coded in the same way for higher precision. In that case, the applicable number is appended to the original basins' code. For example, the most downstream sub-basin of basin *858* (level 3) has the code *8581* (level 4).

Upstream basins can be determined by iteratively checking the last digit of a basin's Pfafstetter code and removing its last digit. Liu *et al* [50] did this for levels 5–7. After trial-and-error and in line with Gøtske and Victoria [83], we use level 8 basins to detect upstream basins without iterating to lower levels.

After obtaining the upstream basins, we aggregate the hourly runoff profiles of all ERA5 points that overlap with these basins. If an ERA5 point only partially covers a basin, we calculate the fraction of the overlapping area. For example, if only 25% of an ERA5 point overlaps with a basin, only 25% of the respective runoff data is used for aggregation.

After this step, we know the total runoff across each basin, but not yet the river discharge at the plant's location. For this, we aggregate the runoff of all upstream basins and then calculate the annual mean. Then, we compare the mean with the mean discharge value at the plant's location calculated by Hoes *et al* [41] to obtain a correction factor. Each time step of the runoff data is then multiplied with the correction factor.

Next, we calculate the hydropower plant's rated power P_{rated} using equation (1) with water density $\rho = 1000$ kg m^{-3}, gravity $g = 9.81$ m s^{-2}, mean river discharge Q, and hydraulic head H.

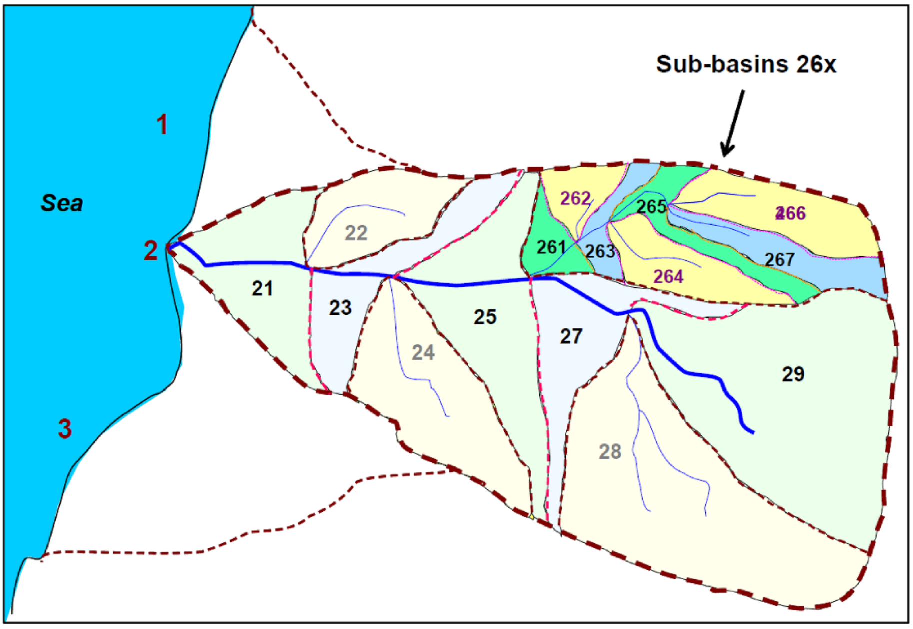
$$P_{\text{rated}} = \rho * g * Q * H \quad . \tag{1}$$

The hourly power production P_t is also calculated with equation (1), but then with the hourly river discharge Q_t. If $P_t > P_{\text{rated}}$, the power production at that time step is capped to P_{rated}.

This approach captures the essence of what leading open-source ESOM like PyPSA [85] are doing. Nevertheless, we acknowledge that this method only delivers ballpark numbers on hourly hydropower production profiles. Liu *et al* [50] found correction factors beyond 1000 when comparing their modelled runoff with empirically measured river data. Our main goal is to capture seasonal fluctuations in hydropower availability, especially during Indonesia's dry season, and we perceive a limited level of accuracy as acceptable.

G. Technical potential and power production profiles for offshore floating solar PV in Indonesia

We use the geographic information system software QGIS 3.18 Zürich [86] to map the technical potential of offshore floating solar PV across Indonesia. The local technical potentials are necessary as a maximum implementation constraint for the electricity system model. We start with a map of Indonesia's exclusive economic zone [87], and remove unsuitable sites based on site selection criteria. For this study, technically feasible sites must be situated (a) outside of marine protected areas [88], (b) outside of natural-catastrophe-prone areas [89], (c) at locations with water depths [65] above 55 m (own assumption), and (d) outside of major shipping routes [90]. For the technical potential per province, we multiply the technically suitable area with a capacity density of 110 MW_p km^{-2} [55].



Supplementary Figure 6. Pfafstetter coding system [84].

Supplementary Table 1. Upscaling scenario for OTEC towards full commercial scale based on the original upscaling scenarios for Indonesia by Langer *et al* [60].

Year	Global installed OTEC capacity (GW_{gross})	Cost reduction (% of 2021 CAPEX)	CAPEX (US\$(2021)/kW_{gross})
2023	0.01	100%	6668
2025	0.02	93%	6202
2030	0.07	81.3%	5421
2035	0.24	71.6%	4774
2040	0.85	63.1%	4208
2045	2.92	55.7%	3714
2050	9.95	49.1%	3274

Underlying assumptions include a learning rate of 7% per doubling of installed capacity, and an installation growth rate of 22% p.a. from a global starting capacity of 10 MWgross. CAPEX were re-calculated with the pyOTEC model [49], which did not exist yet at the time of the upscaling study [60].

For the hourly power production profiles, we use the profiles for ground-mounted, utility-scale solar PV from our earlier work [20]. With this, we assume that the 12% higher power production of floating systems due to the seawater's cooling effect and higher irradiance [57] is counterbalanced by the higher net losses from soiling from bird droppings (2.5%), panel mismatch due to waves (6.2%), transmission losses from plant to shore (1.5%), and a greater need for maintenance and thus lower availability (1.5%) [52].

H. OTEC upscaling scenario

For OTEC, costs and their development are highly uncertain due to its early development stage. Based on earlier work on OTEC's upscaling towards commercial scale [60], we estimate its future cost with three cases. The first case assumes that OTEC will not be upscaled globally and that present costs also apply in 2050. The second case assumes that OTEC will be upscaled globally to an aggregated installed capacity of 10 GW by 2050 at a cost reduction rate, or *learning rate*, of 7% per doubling of installed capacity [60], and 2021 costs are adjusted for these learning effects to estimate 2030, 2040, and 2050 costs see supplementary table 1 for the OTEC upscaling senario. The third case takes the median 2030, 2040, and 2050 costs from the two previous cases, which we use as default costs for most scenarios.

I. Currency conversion rates

Year	US$(year) to US$(2021) [91]	EUR(year) to US$(year) [92]
2024	0.85	—
2022	0.93	—
2021	1	1.2
2020	1.01	1.14
2019	1.04	1.12
2018	1.06	1.18
2017	1.08	1.13
2016	1.10	1.11

J. Costs of HVDC transmission

	CAPEX		
References	Cable [US$(2021)/MW/km]	Inverter pair [US$(2021)/MW]	OPEX [% of CAPEX]
[68]	293	147 741	3.5
[14]	171	170 557	—
[5]	1261	207 386	0.7–1.7[a]
Minimum	171	147 741	0.7
Median	293	170 557	1.7
Maximum	1261	207 741	3.5

[a] The OPEX in [5] comprises 2% of inverter pair CAPEX and 0.35% of cable CAPEX. The OPEX range above is calculated assuming a line capacity of 50 GW and shortest and longest HVDC cables of 30 km (Banten–Lampung) and 520 km (Kalimantan Barat–Jakarta), respectively.

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