Electricity Sector Planning for the Philippine islands: Considering Centralized and Decentralized Supply Options

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ABSTRACT

For archipelagic states such as the Philippines, it is important to evaluate centralized and decentralized approaches to electricity supply to ensure that the many and far-flung islands receive affordable, reliable and sustainable electricity. This study compares the feasibility of (I) submarine cable interconnection and (II) renewable energy based hybrid system development for 132 islands. For (I), we conduct a geospatial analysis and use an algorithm to compute the optimized grid outline, taking into account bathymetric models. For (II) we apply an optimization tool that computes for each island the least-cost power generation option, taking into account diesel generator, solar photovoltaic systems, battery storage, and electricity demand. The results indicate that a grid extension of 2,239 km submarine cable and 1,752 km land cable would be required to connect all of the islands considered. The overall investment under the given cost assumptions amounts to more than 3 billion USD for submarine cable interconnection and more than 700 million USD for a hybridized system development. Nevertheless, submarine cable interconnection is the most economically feasible option for 35 islands and can reduce power generation costs by up to 0.21 USD/kWh. A sensitivity analysis reveals that submarine cable interconnection remains the cost-effective option for most of the identified islands, even with costs increasing by 90%. This study gives an initial assessment of centralized and decentralized electricity supply strategies, and finds renewable energy based hybrid systems most feasible for the majority of islands, and submarine cable interconnection more promising for a few larger islands.

KEYWORDS

Submarine power cable, hybrid electricity system, interconnection, island power supply, Philippines

1 INTRODUCTION

More than one billion people globally lack access to clean electricity, which is addressed under the sustainable development goal (SDG) 7: To ensure access to affordable, reliable, sustainable and modern energy for all [1]. Grid extension is the standard approach for providing access to electricity but with the prevalence of sustainable technologies, utilizing local renewable energy (RE) resources [2] in decentralized electricity systems emerges as an alternative option for remote areas [3], which previously were either insufficiently supplied by diesel generators, or not supplied at all [4]. To assess the cost-effectiveness of both decentralized and centralized solutions, least-cost electrification or electricity supply plans are required. Such plans often combine geospatial analysis with electricity system modelling to identify the optimal solution for a certain country or region [5]. Electrification plans have been developed for several territorial countries, such as Ethiopia [6] or Nigeria [7], but not yet for archipelagic countries or island states. Due to their insular character, decentralized options are often implemented without considering grid extension through submarine cables. This hinders the achievement of SDG 7 on remote islands, which are characterized by a low accessibility due to their inherent insular character [8].
While continental developing regions may benefit from the central grid extension of existing power networks, islands require submarine cable interconnections to achieve a connection to a larger power

network. Installing submarine cable interconnections is capital-intensive, but can provide electricity at a low price assuming that the main grid has sufficient generation capacity [9]. Therefore, submarine cable interconnections might stimulate local economic development. Decentralized RE-based hybrid systems on islands present a viable option to increase the renewable energy share and lower generation costs [10], but upfront costs are high and hinder a wider deployment of RE on islands [11]. Nevertheless, this may change in the near future due to the decreasing costs of various technologies, such as solar photovoltaic systems [12]**,** battery storage technologies [13], or innovative finance mechanisms [14].

Assessing and comparing the feasibility of both centralized and decentralized options for electricity supply is important for large archipelagic states such as Indonesia and the Philippines, and also applicable for smaller island states, including the small island developing states (SIDS). Being very vulnerable to extreme weather events and sea level rise [15], both types of countries face specific development challenges and climate change impacts. Low-carbon strategies are essential to mitigating the continuing impact of climate change through electrification and increasing electricity demand [16]. From an electricity access planning perspective, island landscapes are more complex than not archipelagic countries given that assessing centralized and decentralized supply options requires more detailed information (such as that supplied by seabed analysis). With this study, we present an approach for pre-assessing the cost-effectiveness of submarine power cable interconnection and RE-based hybrid electricity system development. We apply our methodology using the case of 132 decentral island electricity systems in the Philippines. The specific purpose of this study is threefold: (a) to identify the required submarine cable and land cable length necessary for island interconnection, (b) to compare the costs of decentralized and centralized electricity system development, (c) to derive a cost assessment for each of these options for each island group.

1.1 The electricity sector in the Philippines

The Philippines are one of the fastest-evolving countries in Southeast Asia. With both economic [17] and demographic growth [18] exceeding the world average, the country is expected to become a upper-middle income country by 2040 [18]. The country's electricity demand is increasing rapidly, contributing to Southeast Asia's enormous hunger for energy which is expected to triple by 2050 [19]. Given that it is also one of the countries most affected by the impacts of climate change [18], it is in the Philippines' inherent interest to increase power generation capacities in an environmentally sustainable manner [17]. In archipelagic states like this one [20], geographical character determines infrastructural development. A huge developmental gap between metropolis and periphery is typical for such countries. Today the bulk of the country's economic wealth is generated in and around the National Capital Region (NCR) of Manila [21], whereas many other parts of the country lag far behind in terms of living standards, education, public health provisions, and economic opportunities. To overcome such disparities, it is imperative that the Philippines develop a secure, sustainable and affordable power supply in all parts of the country.

Currently the main island groups of Luzon, Visayas and Mindanao are connected to two separately operating major electric grids [22], which supply electricity to most of its population and economically prosperous regions. At least another 132 decentralized electricity systems, referred to as small isolated island grids (SIIG), which basically generate electricity through diesel generators [23], are operated on medium- to smaller-sized islands. For these islands, researchers have identified a high potential for the use of RE [24]. Additionally, for a large number (1,500 – 2,000) of small and very small islands, power generation is either not officially regulated or not in place [25]. Diesel-based power generation fails to meet the economic and environmental targets of the country for several reasons: (1) Since fuel must be imported, it increases the country's dependency on global oil markets and price fluctuations [23]; (2) Diesel power generation is relatively costly, with average generation costs of 0.39 USD/kWh (compare section 3.2). For privately-operated diesel generators, the reported costs to the customer can even be as high as 1 USD/kWh [26]. Additionally, electricity tariffs in remote regions are subsidized through the universal charge for missionary electrification (UCME) scheme, thereby increasing the costs of electricity on a national scale [23]. (3) Diesel power generation leads to environmental pollution through the emission of greenhouse gases (GHG) and other pollutants, and the risk of oil spills [18]. For the remote islands, the country faces the same energy security, equity and sustainability trilemma as Viña et al. have described for the country's main islands [18]. To avoid path dependencies and a lock-in dilemma, it is important to carefully assess all possible development options in the electricity sector from a number of different perspectives [27]. In this context, the question arises whether to interconnect the remote islands to the main electric grids, or upgrade the decentralized electricity system with RE. Both options present advantages and disadvantages: Connecting islands through submarine power cables is considered capital-intensive, but would allow for economies of scale. Developing RE-based hybrid systems can lead to an increased electricity autarky but requires higher maintenance efforts. As of today, no systematic assessment and comparison of both approaches has been conducted for the Philippines.

1.2 Submarine power cables and hybrid electricity systems

Submarine cables connect islands close to the shore usually on a medium-voltage level (<52 kV) [9]. For longer distances high voltage direct current (HVDC) cables are favored over high voltage alternating current cables (HVAC) due to lower power losses and less required material [28]. Once deployed into the sea the cables are buried in the seabed or armored to avoid damages by other marine activities such as fishing [29]. Interconnections by submarine cables are already realized in the Philippines both by AC and DC cables at different voltage levels. The most important interconnection of the country is the high voltage direct current (HVDC) submarine cable link (440 MW/350 kV capacity) connecting the Luzon and Visayas main grids between Luzon and Leyte (21 km) [29]. According to the National Grid Corporation of the Philippines (NGCP), submarine power cable interconnections potentially increase the efficiency of the overall electricity system by lowering operation and maintenance costs through economies of scale and achieving a higher coincidence factor. This factor makes it easier to forecast the demand for electricity for a larger customer group, due to a statistical balancing effect that compensates for fluctuations of the assumed demand. Considering this, electricity demand is easier to assess for larger settlements than for small villages due to a higher volatility of the load [30]. Electricity exports from the main grid to remote islands support economic development on these islands by enabling them to access relatively cost-competitive electricity prices. However, the planning and realization of such projects requires both high upfront capital investments and that uncertainties such as seabed currents be considered [31]. While high and inestimable costs are stated as the main barriers for submarine cable expansion, recently developed probabilistic cost models may increase the accuracy of submarine power cable cost projections [27]. So far, only a few studies on an international scale have analyzed the impact of submarine cable interconnection on electricity sector development, and none of these studies have focused on the Philippines. Ahmed et al. [28] studied the feasibility of HVAC and HVDC submarine interconnection for the ASEAN member states and concluded that HVDC is competitive over HVAC from distances of 160 km onwards. For the case of Greece, studies highlighted that the interconnection of islands would allow for a higher RE share in the electricity mix on the national scale [32] and lower electricity costs on the island scale [33]. Another study, examining the techno-economic feasibility of interconnecting the European and the US electricity sector, concluded that the socio-economic benefits would alleviate the high investment costs [34].

The significant potential that RE holds out for the island context has been intensively discussed in the scientific literature. Kuang et al. [35] provided an overview of the development status of renewable energy on islands, stressing that hybrid electricity systems, based on one or more RE technologies combined with battery storage solutions and/or fossil back-up generators, are one of the most feasible solutions. The global techno-economic potential of such systems, and their significant potential for the Pacific region, was outlined by Blechinger et al. [10]. These findings are supported by Meschede et al. [2], who applied a cluster analysis of islands. Neves et al. [36] presented an overview of case studies of hybrid electricity systems in which different RE and conventional technologies were applied. For the Philippines, a study of the techno-economic potential of transitioning from diesel-based systems to

low-carbon electricity systems in order to achieve SDG 7 [24], taking into account site-specific data and recent cost predictions, was conducted by the authors in two publications [24] and [37].
In conclusion, there is a lack of research on least-cost electricity supply or renewable energy planning for the context of small islands and island states in which submarine cable interconnection are compared to RE-based hybrid system development. In this study, we address this knowledge gap by comparing the economic feasibility of submarine interconnection to the central grid with the development of RE-based hybrid systems for 132 decentral island systems in the Philippines. To assess the economic potential of submarine interconnection, we use a geospatial optimization routine to outline provisional submarine cable routes, taking into account digital elevation models and bathymetric maps. Based on the identified required cable length, we derive necessary investment costs. We then analyze the potential for RE-based hybrid system development by applying an electricity system simulation model. Investment costs are projected based on least-cost power generation, considering recent technology cost assumptions. Finally, we compare and discuss both options in terms of the levelized cost of electricity (LCOE), investment costs, and benefits to the development of the overall electricity sector.

2 METHODS

The methods chapter provides key information on the studied island grids (section 2.1), projected electricity demands (section 2.2), and introduces the approach we use to assess submarine cable interconnection (section 2.3) and RE-based hybrid system development (section 2.4).

2.1 Small isolated island grid landscape

In the Philippines, decentralized electricity systems rely mainly on diesel generators for power generation. The objective is to study the feasibility of grid interconnection through submarine power cables for the aforementioned electricity systems and to derive the related investment and power supply costs by applying a geospatial analysis. Subsequently, the feasibility of RE integration in the existing systems is studied as an alternative pathway by applying an electricity system optimization tool. Finally, the viability of both approaches is compared and discussed.
For this study, 132 small isolated island grids are considered. SIIGs are operated by the local electric cooperative (EC) in charge of transmission and distribution. Power generation assets are operated by either the former national power operator NPC-SPUG[1] (86%) or by independent power producers (14%). In early 2018, key data on these SIIGs were collected from the Philippine Department of Energy (DoE) [38] and NPC SPUG [39], covering their location, grid name, region, operator, distributor, power plant capacities, fuel prices, efficiency rate and electricity demand. We assume that the applied dataset covers the most relevant and largest SIIGs in the Philippines. The following table provides key information on the SIIGs we considered within the three main regions of Luzon, Visayas and Mindanao (Table 1).

Table 1. Key information for considered small isolated island grids per region.

Region	No. of grids	No. power plants	Daily operating hours	Rated capacity	Fuel price	Peak demand	Annual demand
[name]	[#]	[#]	[hours]	[MW]	[USD/l]	[MW]	[GWh/a]
Luzon	67	99	16.5	356.2	0.55	190.7	1,022.6
Visayas	46	48	12.8	26.6	0.51	13.1	59.7
Mindanao	19	22	16.2	67.1	0.63	29.8	177.5

[1] National Power Corporation – Small Power Utilities Group (https://www.spug.ph/)

Total	132	169		449.9		233.6	1,259.8
Average			15.2		0.56		

Table 1 reveals the heterogeneity of the SIIG landscape of the Philippines. Most of the SIIGs (67), and diesel power plants (99), with the highest capacity (>356 MW), are located in Luzon. The peak demand of 190 MW and annual electricity demand of 1,022 GWh are also highest in Luzon, reflecting the larger number of grids and longer average operating hours. Peak and annual demand in the Mindanao region amounts to 30 MW and 177 GWh, followed by those for the Visayas region, with a peak demand of 13 MW and an annual demand of 60 GWh. However, the three largest SIIGs in Luzon (Oriental Mindoro, Palawan main grid, Masbate main grid) comprise 46% of the annual demand for electricity for all SIIGs. Adding the next three largest SIIGs (Occidental Mindoro, Catanduanes, Marinduque) in Luzon to the selection increases the share to 61%. For the regions of Visayas and Mindanao, the total installed power capacities in the SIIGs are much lower (27 MW and 67 MW, respectively). In most of the SIIGs for the two regions, the distribution grid is supplied by only one diesel power plant; by contrast, in the larger grids in Luzon, several plants are supplying the local distribution grids. Average daily operating hours are approximately 16 hours in the Luzon and Mindanao grids, as contrasted to the grids of the Visayas region where smaller grids, in particular, have shorter service hours leading to an average service hour duration of only around 12 hours per day. Figure 1 illustrates the SIIGs considered.

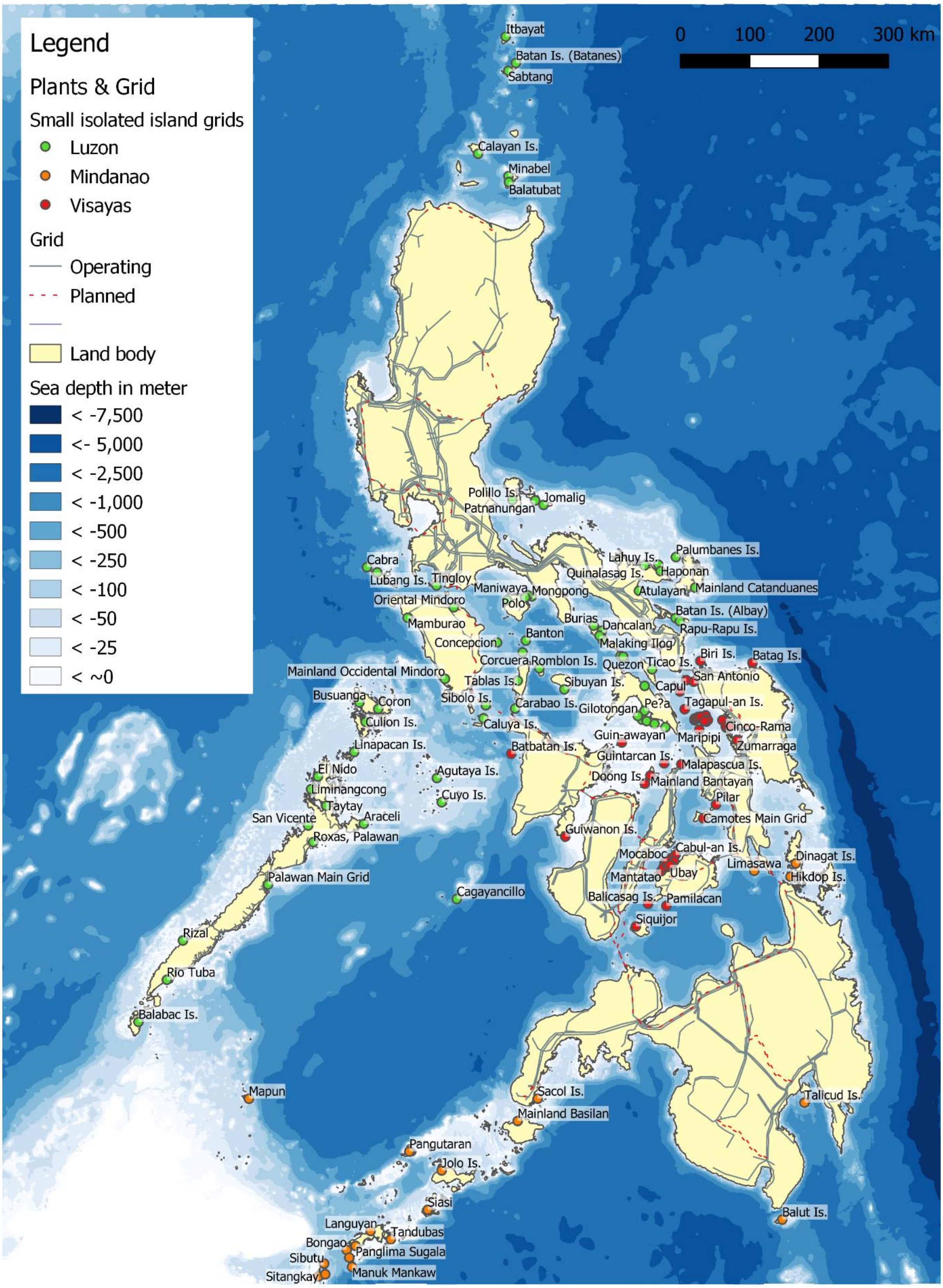

Figure 1. Location of 132 small isolated island grids and transmission grid in the Philippines.

2.2 Estimation and projection of electricity demand

To accurately assess the potential of electricity supply options, the impact of electricity demand must be considered for each option. This is especially important for mini-grids [40] and rural electrification in developing countries [41], as electricity demand tends to evolve after electricity access has improved [42]. Furthermore, for the potential of intermittent RE sources such as solar photovoltaics (PV), the temporal distribution of electricity demands can be decisive. To address this we carried out a detailed estimation and projection of electricity demands, based on an approach we applied in a recently published work [24]. Electricity demand patterns were collected on an hourly basis for the majority (126 of 132) of the considered SIIGs from the Philippine DoE [38] and NPC SPUG [39]. This resulted in an annual electricity demand of approximately 1,260 GWh (see Table 1). Nevertheless, 87 out of the 132 considered SIIGs supply electricity for less than 24 hours per day. Increasing daily service hours to 24 for all consumers is one of the targets of the Philippines government [38], and is in line with its objective to achieve the SDG 7. We have reflected this target by applying 24-hour load profiles for all SIIGs through filling the not supplied service hours according to typical demands. By applying the approach we outlined in a recent publication [24], 24/7 load profiles were derived for each identified 132 SIIG with realistic hourly values, resulting in an increase of 2% to 1,287 GWh/a of the total demand for electricity.

2.3 Submarine power cable interconnection – Geospatial analysis

Spatial modelling of submarine interconnection to the selected SIIGs assesses the economic feasibility and estimated investment costs of this option. The approach optimizes the overall grid extension path to all considered SIIGs under the constraint of following the shortest and flattest possible route instead of only considering the shortest linear distance [43]. The key parameters considered are sea depth and elevation, derived from bathymetric and topographic maps. Hence, the identified grid extension reflects the optimized plan for the interconnection of all SIIGs based on their location-specific characteristics, such as seabed bathymetry and distance to neighboring islands—independently of characteristics such as annual electricity demand. Such a geospatial network planning for insular frameworks requires the following datasets: (1) the location and course of the existing transmission grid as starting point for the grid extension, (2) the location of the SIIGs as the ending point for grid extension, (3) information on sea depth and elevation, to assess the feasibility of spanning the grid over specific routes. Dataset (1) is derived by creating polyline shapefiles of the existing grid and planned grid extension, as published by NGCP [31]. For the subsequent analysis, only the existing grid is considered due to the uncertainty of project realization of the planned grid. Dataset (2) is derived by creating a point shapefile of SIIG locations taken from [38] and [39]. For dataset (3), we applied gridded bathymetric and elevation data for ocean and land in a resolution of one square kilometer covering the Philippine archipelago, provided by the British Oceanographic Center [44]. Figure 2 visualizes the aforementioned datasets for a sample region and highlights the applied approach.

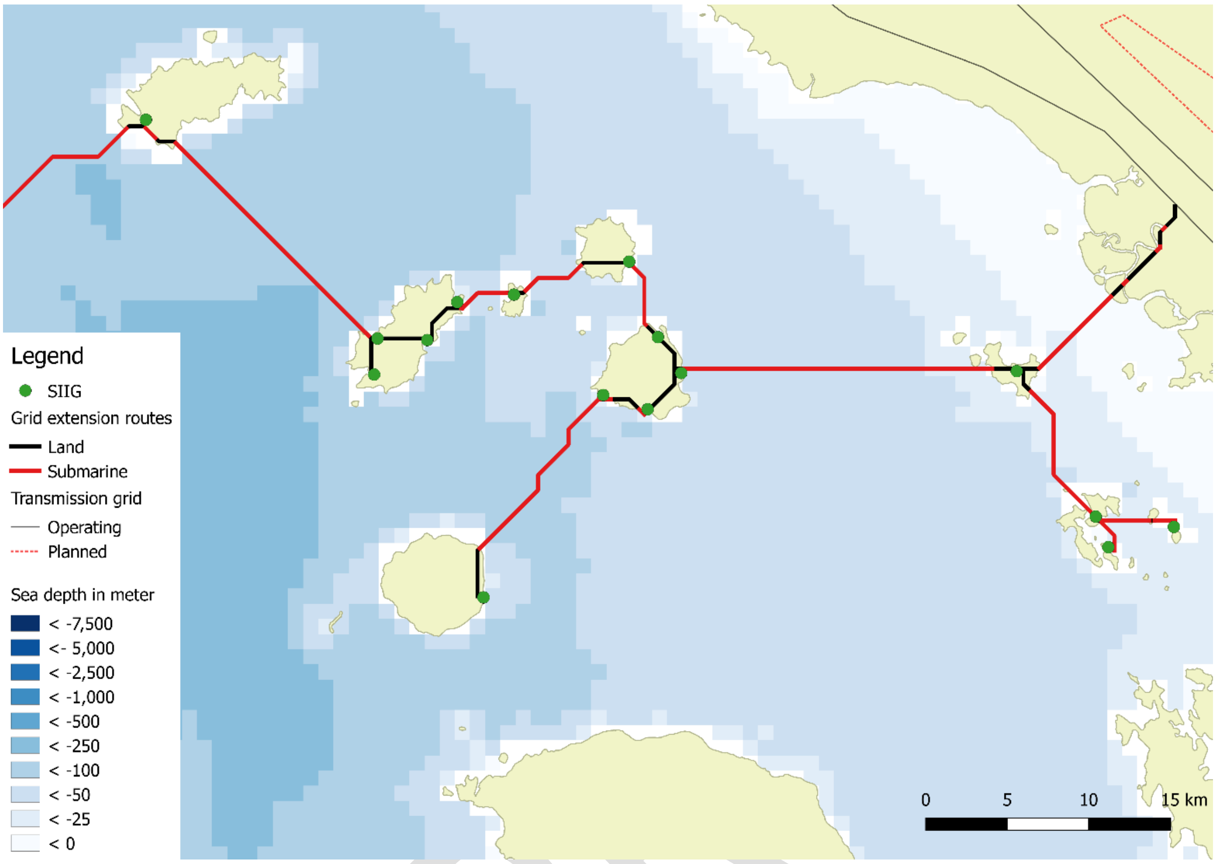

Figure 2. Example for optimized grid extension via submarine and land cable taking into account local bathymetry and a minimum spanning tree.

Based on the described datasets, a decision raster dataset was created by converting terrain information for both ocean and land into slope values based on dataset (3). To allow the optimization algorithm to use the complete existing grid as starting point for grid extension and SIIG locations as ending points, dataset (1) and (2) were added to the decision raster with zero weighted costs. As relative costs increase with higher slopes, the tool optimizes the routes by identifying a route minimizing the bypassing slopes. Additionally, cable routes over land are favored over sea routes. Under these assumptions, an optimum connection pathway to extend the grid to all SIIGs was derived by applying a minimum spanning tree. The minimum spanning tree considers all possible options and connects the locations by minimizing the required connections between all new grid extension lines. Finally, a least-cost grid extension outline was extracted, as highlighted for the sample region in Figure 2.

The identified grid outline was further processed to differentiate the segments in grid extension through submarine or land cable. The required cable length for each segment was then calculated. Additionally, for all submarine cable segments, the extra cable requirement based on sea depth was derived. This was necessary to accurately estimate investment costs, since submarine power cables need to be buried or fixed in the seabed as illustrated in Figure 3. For each submarine cable segment, the sea depth was identified in one kilometer-steps and the accumulated depth calculated based on the corresponding elevation difference. To specifically calculate the investment costs for each submarine segment, the accumulated depth was added to the required length.

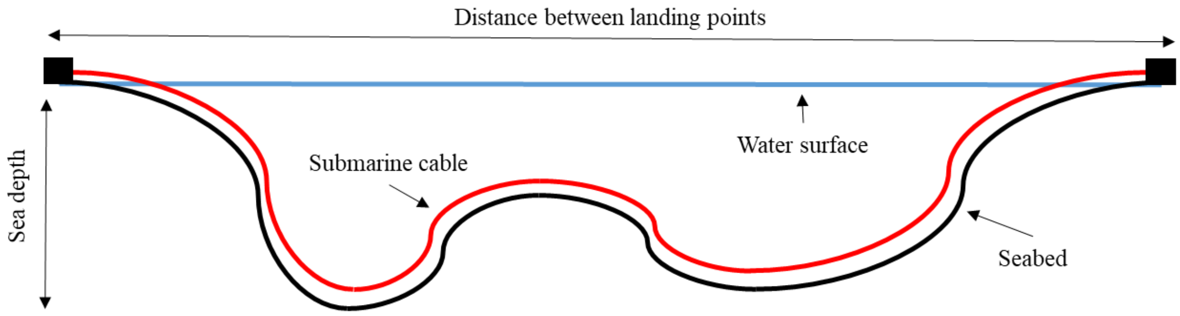

Figure 3. Sketch of submarine cable route reflecting sea depth.

2.3.1 Submarine power cable interconnection cost estimation

Submarine power cable interconnections are major infrastructure projects that require significant planning, labor force, stakeholder dialogues, and investment capital. The assessment of probable costs is crucial for decision makers to advance the planning of such infrastructure projects. It is therefore necessary to assess costs in an early project stage. For submarine power cable projects, cost assessments are very difficult due to the lack of historical data, site-specific conditions, preplanning requirements, and uncertainty of project conditions. An approach based on probabilistic cost prediction for submarine power cables has been introduced [27], but the model is not sufficiently calibrated with data from the focus region. Ultimately, a simplified cost assumption model based on the required submarine and land cable length and voltage level was implemented and applied for this study. The length of the grid extension was derived from the optimum grid extension path, as described above. The voltage level per submarine project was defined based on submarine route length and electricity demand of the islands to be connected, excluding additional electro-technical characteristics for a simplified approach. Finally, the highest required voltage level based on demand or length was applied. The scheme presented in Table 2 was applied to assign adequate voltage levels to each of the submarine cables.

Table 2: Assigned voltage levels per peak demand and submarine length

Voltage level (kV)	Peak demand (kW)	Submarine length(km)
13.2	200	<5
34	1,000	<10
69	5,000	<20
138	10,000	<50
230	>10,000	>50

Investment costs were calculated by multiplying the identified required cable length by the applied cost value for the respective voltage level for each submarine power cable. For the required land power cable, a fixed cost value of 12,000 USD/km is assumed [45]. Table 3 provides an overview of the applied cost assumptions. These cost assumptions are based on discussions with representatives of the Philippine DoE and the National Electrification Administration (NEA), and reflect costs assumed for submarine cable development in the Philippines. It is certain that costs per kilometer may differ in accordance with technology and voltage level, as well as to the specific project conditions (seabed currents, marine surface, etc.). The power generation costs for the central power supply were not specifically modeled in this paper; instead, we used a generic cost of 0.09 USD/kWh for this variable. Thus, the modeled grid extension pathways should only be implemented if power generation capacity is increased to meet the additional demand.

Table 3. Applied cost values for grid extension, taking into account capital expenditures, operational expenditures, interest rates, power generation costs, and lifetime of components

Category	Parameter	Unit	Value
Submarine power cable	CAPEX (13.2 kV)	USD/km	350,000
	CAPEX (34 kV)	USD/km	500,000
	CAPEX (69 kV)	USD/km	750,000
	CAPEX (138 kV)	USD/km	1,000,000
	CAPEX (230 kV)	USD/km	1,500,000
	OPEX	USD/y	0.005% CAPEX Invest
	Lifetime	yearsYears	40
Land power cable	CAPEX	USD/km	12,000
	OPEX	USD/y	0.05% CAPEX Invest
	Lifetime	years	40
Economic	Project lifetime	years	40
	Interest rate	%	10
	Power generation costs (main grid)	USD/kWh	0.09

Finally, the levelized cost of electricity (LCOE) for each of the required infrastructure investments was calculated, as described in equations 1 and 2.

$$LCOE = \frac{IC*CRF(WACC,N)+OPEX}{E_{consumed}} + LCOEgrid \qquad (1)$$

Equation 1: LCOE for submarine power cables. The abbreviations stand for Initial costs (IC), capital recovery factor (CRF), weighted average cost of capital (WACC), project lifetime (N), operation and maintenance expenditures per year (OPEX), and consumed electricity per year ($E_{consumed}$).

$$CRF(WACC, N) = \frac{WACC*(1+WACC)^N}{(1+WACC)^N - 1} \qquad (2)$$

Equation 2: Capital recovery factor (CRF). CRF is set according to the weighted average cost of capital (WACC) and project lifetime in years (N).

2.4 Renewable energy- based hybrid system development: electricity system optimization

In this study, the potential for RE-based hybrid electricity systems for each SIIG is analyzed using an electricity system simulation and optimization tool. This approach is based on model used in a recent study by the authors, focusing on the hybridization potential in the Philippines [24]. The applied tool optimizes the system design in terms of lowest LCOE, considering renewable energy (solar PV), fossil fuel resources, and battery storage capacities. The tool is implemented in the Python programming language [46] and was applied in peer-reviewed studies on a global scale [10] and to the Philippine case specifically [37]. It was also validated with HOMER Energy [47]. The approach simulates electricity flows in hourly increments for one reference year, taking into account diesel generator, PV, battery storage, and the electricity demand. The application of components is based on a published dispatch strategy [24], which aims to maximize the use of solar power plant-derived electricity. To ensure the stability of the system, however, at each time-step a stability criterion of 40% of the respective hourly load must be fulfilled by the battery storage or the diesel generator. The feasibility of meeting this criterion while supplying the load entirely by solar power is checked. In the case of insufficient solar power, the system discharges the battery to its allowable lowest state-of-charge (SOC) before activating the diesel generator. The optimization algorithm minimizes the LCOE by using iteration to vary the sizes of the components. PV and battery storage systems are the variable parameters for this study, since the diesel capacities are already in place and are set equal to the SIIG peak demand. The final LCOE takes into account the annualized initial costs; operational costs per year and fuel costs per year and are divided by the overall electricity demand to provide LCOE per kWh (Eq. 3 and Eq. 4) [14]. The tool feedbacks the configuration of the electricity supply system, leading to minimized LCOE considering the local resources—in this case, solar irradiation.

$$LCOE = \frac{IC*CRF(WACC,N)+OPEX+Costs_{fuel}*Fuel}{E_{consumed}} \qquad (3)$$

Equation 3: Levelized cost of electricity (LCOE) for power systems. The abbreviations stand for Initial costs (IC), capital recovery factor (CRF), weighted average cost of capital (WACC) pro,ject lifetime (N), operation and maintenance expenditures per year (OPEX), cost of diesel per liter ($Costs_{fuel}$), consumed diesel per year (Fuel), and consumed electricity per year ($E_{consumed}$).

$$CRF(WACC,N) = \frac{WACC*(1+WACC)^N}{(1+WACC)^N-1} \qquad (4)$$

Equation 4: Capital recovery factor (CRF). CRF is set according to the weighted average cost of capital (WACC) and project lifetime in years (N).

2.4.1 Resource, technical and economic input parameter

To assess the local potential for PV power generation, site-specific values for global horizontal irradiation (GHI) were obtained from GHI datasets [48] and converted into PV power generation based on a published conversion model [49]. Combining the aforementioned models lead to an individual PV yield in hourly time steps for each considered electricity system (SIIG). Besides the available renewable resources, it is necessary to define the technical and economic parameters of each component. A summary of all input parameters is given in Table 4.

Table 4. Overview of technical and economic input values for electricity system simulation tool

Category	Parameter	Unit	Value
	CAPEX	USD/kW	1,400
PV	OPEX	USD/kW/y	28
	Lifetime	years	20

Battery	CAPEX (Capacity & Power)	USD/kWh	800
	OPEX	USD/kWh/y	8
	Lifetime	years	15
	maximum c-rate	kW/kWh	1
	depth of discharge	%	80
	charging efficiency	%	90
	discharging efficiency	%	90
	initial state of charge	%	50
Diesel	CAPEX	USD/kW	500
	OPEX (fix)	USD/kW/y	20
	OPEX (var)	USD/kWh	0.02
	Lifetime	years	20
	Rotating mass	%	40
	Efficiency	l/kWh	0.35
Economic	Diesel price	USD/l	0.75
	Project lifetime	years	20
	Annual Fuel Changings	%	3
	Interest rate	%	10

The system components are basically described by CAPEX, OPEX, lifetime and technical constraints. For solar PV, costs of 1,400 USD/kWp were applied [50], OPEX of 28 USD/kWp per year (2% of CAPEX), and a lifetime of 20 years. We consider the use of lithium-ion batteries as an electricity storage system, given its advantageous characteristics over other storage technologies [13]. Initial costs add up to 800 USD/kWh for capacity [51], combining the costs for capacity and power at a fixed c-rate of one as a modular unit. OPEX are 8 USD/kWh per year and the lifetime is 15 years. Other technical parameters are round-cycle efficiency of 90 % and a maximum depth of discharge of 80 %. No degradation rate is considered, since it is assumed that lithium-ion batteries are operated under stable temperatures (through cooling) and that the maximum depth of discharge is not violated, since temperature and state of charge have been identified as most influential factors for lithium-ion battery ageing and degradation [52]. For all SIIGs diesel generators are already in place. However, since most diesel generators have already operated for years or even decades and are facing the end of their lifetime, it might be necessary to implement new diesel generators—especially as modern diesel generators are more controllable and better harmonized with RE-based hybrid systems. Therefore, initial costs of 500 USD/kW are assumed for diesel generators. Operational costs are based on expenditures for maintenance or lubricant oils and amount to 0.02 USD per generated kWh and 20 USD per kW annually. The lifetime of the new diesel plants was set at 20 years. We introduced a system stability parameter of 40% of the hourly demand (compare section 2.4). This reflects the operating diesel capacity necessary to provide auxiliary services in case of insufficient supply by the battery storage system. The efficiency value for each SIIG was set at 0.35 l/kWh, reflecting the efficiency of modern diesel generators. The diesel fuel price was set to 0.75 USD/l, assumed as the average diesel cost in the Philippines in 2018. The diesel price growth rate is expected to be 3% annually. For each project, a lifetime of 20 years was applied. The weighted average costs of capital (WACC) are 10 %, based on an equity share of 40 %, equity costs of 15 %, and a loan interest rate of 6.6 %.

3 RESULTS

The results chapter outlines our findings with respect to our assessment of submarine cable interconnection (section 3.1) and hybrid electricity system development (section 3.2), concluding with a least-cost comparison (section 3.3) and sensitivity analysis (section 3.4).

3.1 Submarine cable interconnection

Based on the identified cable routes, interconnecting all considered SIIGs to the main grid of the Philippines requires a 2,239 km submarine power cable and a 1,752 km land power cable (“overhead” cable). The development of 321 segments of submarine power cable and 412 segments of land power cable is necessary to realize the said grid extension. Based on the considered input parameters the total investment costs add up to approx. 3.2 billion USD for submarine power cables and 21.0 million USD for land power cables. Table 5 gives an overview of the key result values derived by the geospatial analysis.

Table 5. Overview of the results on submarine power interconnection optimization for the three main regions of the Philippines

Region	**Length (km)**		**Investment (m. USD)**		**LCOE**
	Submarine	Land	Submarine	Land	USD/kWh
Luzon	1,193	1,047	1,691.8	12.6	0.28
Visayas	450	264	638.7	3.2	0.89
Mindanao	596	441	867.1	5.3	0.61
Total	2,239	1,752	3,197.6	21.0	0.37 (av.)

Since most of the required grid extension for both submarine and land cable would be implemented in the Luzon region, basically due to the larger number of SIIGs there, investment would be predominantly used for projects in that region. However, investment per SIIG is highest in Mindanao due to the lower number of SIIGs, less grid infrastructure in place, and higher remoteness of the islands there. As the geospatial analysis optimizes the submarine cable routes in terms of length and depth, the identified routes follow the shortest path in the shallowest water possible. The longest cable route identified has a length of 168 km and connects the southernmost island of Mapun to Balabac island, south of Palawan (Figure 4, number 30). Out of all submarine cable routes, only five exceed a length of 80 km, considered as the threshold for AC versus DC power cable deployment [29]. However, the average length of all submarine routes is 7.5 km. The average maximal depth per route of all identified routes is 209 meters, whereas the maximal depth exceeds 1,673 meters for the submarine route passing the Luzon strait towards the northernmost islands of the Batanes group (no. 1 in Figure 4). Since submarine cables need to be buried or fixed in the seabed to avoid suffering damage from other marine activities (such as fisheries), the depth for passing submarine routes is of importance as well. Therefore, for each route the accumulated depth is calculated to account for additional material requirement. On average, the accumulated depth adds 224 m to the overall cable requirement. For some routes that pass along deep trenches, however, the accumulated depth is significant; such is the case, for example, for the route passing the Luzon strait towards the Batanes group (no. 1 in Figure 4), where the added cable requirement is 5.7 km. The land power cables are mainly required to close the gap between the submarine cable landing station and the existing grid. The longest required cable is approximately 47.9 km in length, whereas the average length of all land power cables is 4.8 km. Figure 4 maps the optimized submarine and land power cable routes for interconnecting decentralized electricity systems.

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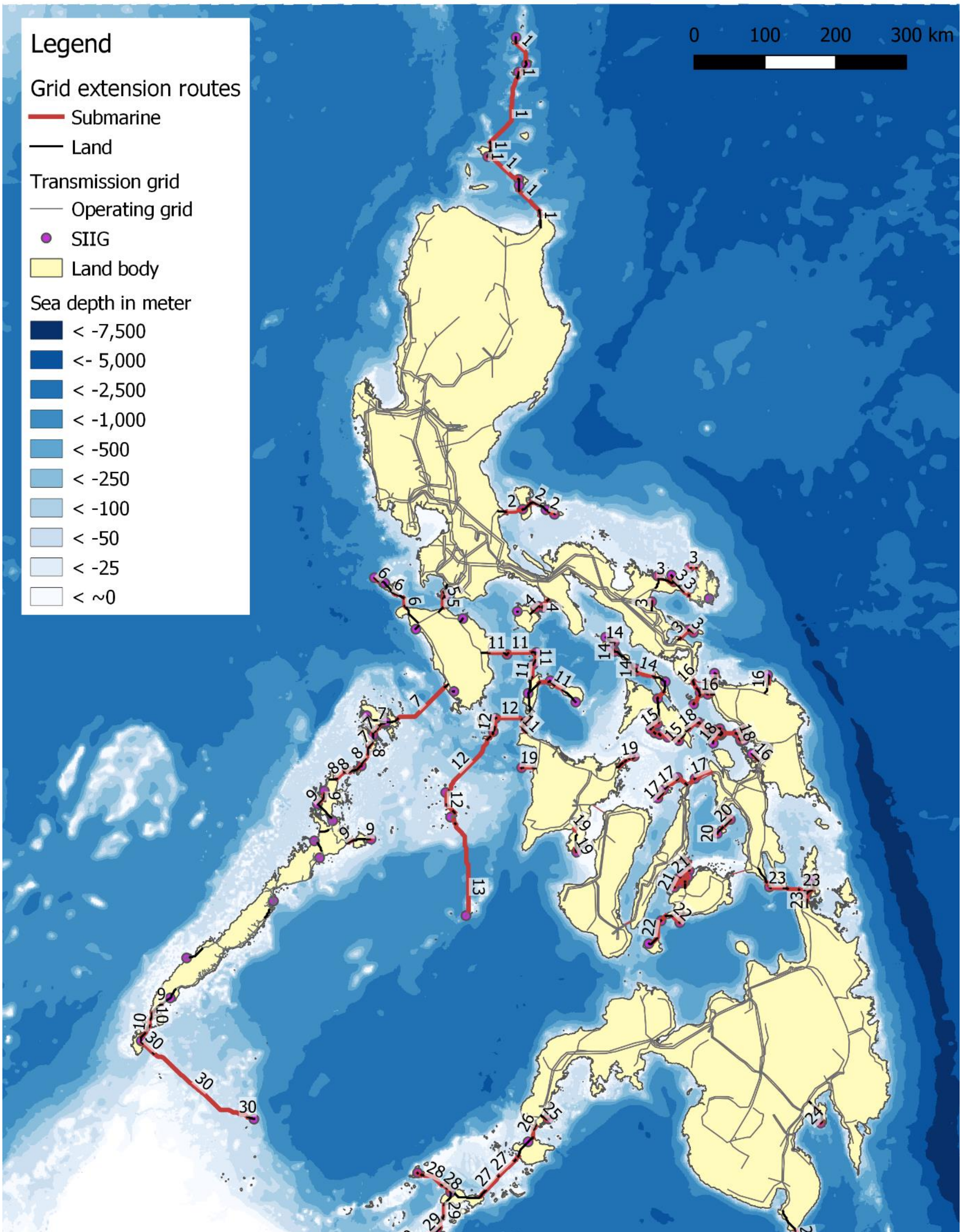

Figure 4. Optimized submarine and land power cable routes for interconnecting decentralized electricity systems

3.2 Renewable energy - based hybrid systems

The techno-economic modelling of RE-based hybrid electricity systems reveals a significant potential for integrating renewable energy into the existing SIIG. Table 6 provides an overview of key result values identified for the three island regions.

Table 6. Results of techno-economic evaluation of renewable based hybrid electricity systems

Region	Demand	Investment	PV cap.	Battery cap.	LCOE	RE-share
	[GWh/a]	m. [USD]	[MWp]	[MWh]	[USD/kWh]	[%]
Luzon	1,011	566.5	291.4	82.5	0.32	30.9
Visayas	92	47.3	23.4	6.7	0.33	27.8
Mindanao	185	94.0	48.9	13.3	0.32	31.4
Total	1,288	707.8	363.6	102.5	0.33 (av.)	29.9 (av.)

Under the technical and economic assumptions outlined in Table 4, integrating RE into the existing SIIGs is beneficial, lowering LCOE compared to purely diesel-fueled electricity systems for each of the considered SIIGs. Average pure diesel LCOE are at 0.39 USD/kWh, as compared to hybrid LCOE of 0.33 USD/kWh. LCOE reduction per SIIG is between 4 – 8 USDcent/kWh, with an average reduction of 5 USDcent/kWh. A PV potential of 360 MW, coupled with a battery storage requirement of 100 MWh, must be installed. With such capacities in place, the RE share achieved in the SIIGs would average 30%, allowing for the mitigation of more than 1.3 million liters of diesel fuel and 400 thousand tons of CO_2 emissions annually as compared to pure diesel systems. To implement these systems, an investment of approximately 708 million USD in the existing SIIG power system infrastructure is required. Besides this investment, annual fuel costs of 221 million USD (over the 20-year project period fuel costs are expected to rise to 288 million USD on the annual average based on the expected diesel price) and annual operational expenditures of 32.5 million would accrue.

On a regional scale, its larger number of SIIGs means that Luzon would have the highest PV and battery storage potential and require the greatest investment. Figure 5 shows the potential RE share and necessary investment for each SIIG. Despite the high number of projects on smaller SIIGs, only a few large SIIGs would take up the most investment requirements. The majority of SIIGs have potential RE shares of between 25% and 35%. Higher RE sharers are simulated for larger SIIGs reflecting the higher daytime electricity demands; allowing for more direct consumption of PV power.

Altering the input parameters defined in Table 4 may significantly impact the overall results presented above. Essentially, dynamic cost developments for electricity storage and diesel fuel may affect the potential for RE-based hybrid systems, as outlined by Ocon and Bertheau [37]. The rapid decrease of electricity storage costs projected by recent studies [51] would allow for a higher share of renewable energy, since a larger battery capacity would replace diesel power generation through the storage of generated solar power. Additionally, the combination of electricity storage technologies for short-term and long-term electricity storage could lead to overall system cost reductions in the future. Lower diesel fuel costs or flatter fuel price growth rate would lead to lower RE shares, as less battery capacity would be installed in the cost optimized hybrid system configuration. However, the more likely increase of diesel costs would result in higher RE shares and a higher economic attractiveness of RE.

The implementation of a cost factor for greenhouse gas emissions (GHG) would significantly reduce the share of diesel generated electricity in the generation mix and thereby potentially increase the overall system costs. Since there are no observable political activities addressing the implementation of such a price on emissions cost, however, it is excluded from the analysis.

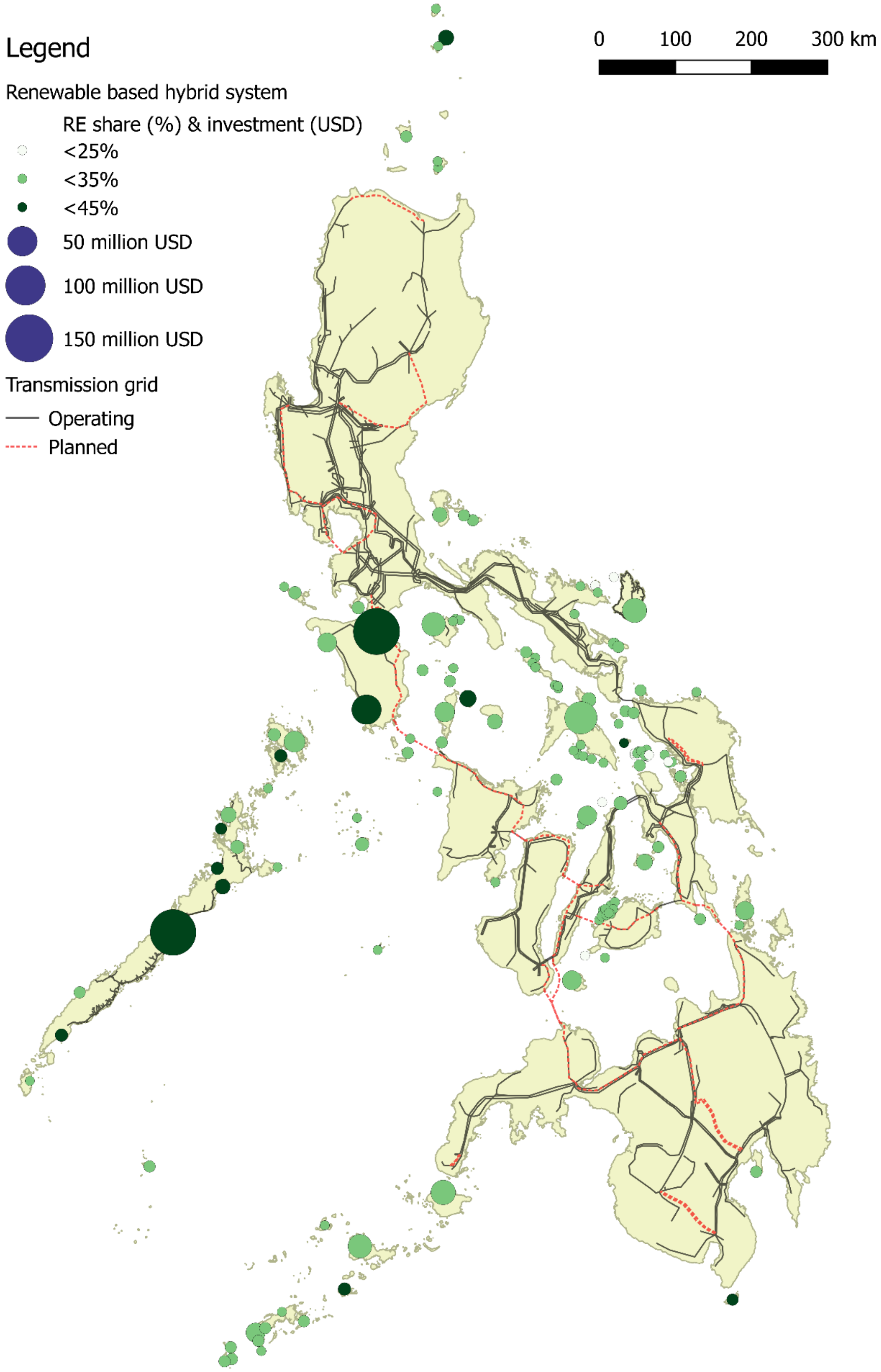
Legend
Renewable based hybrid system
RE share (%) & investment (USD)
<25%
<35%
<45%
50 million USD
100 million USD
150 million USD
Transmission grid
Operating
Planned
0
100
200
300 km

Figure 5. Overview map showing the overall investment necessary to develop SIIGs to renewable energy based hybrid grids.

3.3 Least-cost comparison: Recommendations for electricity sector development

As final step in least-cost planning, a comparison of the LCOE of submarine cable interconnection with the LCOE of RE-based hybrid systems was conducted. For this, all SIIGs were grouped into 30 island or project groups. Comparing the investment costs of both development options reveals that submarine power cable interconnection with approximately 3.2 billion USD would be substantially more capital intensive than the development of RE-based hybrid systems with approximately 708 million USD. Nevertheless, based on the applied cost assumptions, the average LCOE for submarine cable development in Luzon are lower than those for RE-based hybrid electricity systems (compare Table 5 to Table 6). A more detailed breakdown of disaggregated SIIG level highlights that submarine cable interconnection can be the more cost-effective option for some SIIGs and island groups (compare Table 8).

When comparing the investment costs for both options on the national, regional, or island scale, it is important to consider that the identified investment costs for submarine interconnection do not account for the increased power generation capacities in the main grid, which are probably necessary in order to meet the additional demand. Future research should fill these knowledge gaps. Despite these shortcomings, the approach can indicate where submarine cable interconnection should be favored over RE-based hybrid system development. For analyzing the results on a more detailed level, the SIIGs were partitioned into 30 island groups classified by region and proximity. The island groups, names, and number of comprised SIIG are shown in Table 7 for hybrid electricity systems and in Table 8 for submarine power cables; both are visualized in Figure 4 and Figure 5.

The last column of Table 8 compares the LCOE for submarine cable interconnection to RE-based hybrid system development and lists the difference. For seven island groups, reflecting 35 SIIGs, submarine interconnection is the more cost-effective option. The highest potential for submarine interconnection is identified for the island of Mindoro (island group 5) with a cost benefit of 0.21 USD/kWh as compared to hybridization. Given its high demand for electricity, high anticipated growth in demand, and short distance from the main grid (20.5 km submarine cable required), our result supports further research into a submarine interconnection, as already discussed by NGCP [31]. The second highest cost benefit is derived for Palawan (island group 9), with 0.10 USD/kWh LCOE for submarine power cables as compared to LCOE of 0.31 USD/kWh for RE-based hybrid electricity systems. Nevertheless, island groups 7 and 8 must be interconnected before Palawan can be connected to the main grid. When adding the investment costs for the aforementioned island groups to the one for Palawan, the LCOE increases to 0.21 USD/kWh, but is still lower than that for RE-based hybrid system development. Additionally, the islands of Busuanga and Culion, which are not viable for connection, could potentially be interconnected in order to connect Palawan to the main grid. However, the technical feasibility of such an interconnection needs to be assessed in detail, especially as one major submarine cable (101 km) passing deep sea would be required for connection between Mindoro and Busuanga. Another potential for interconnection is derived for Masbate (island group 15) via the connection of some smaller islands of island group 18. When considering the investment costs for both island groups (15 and 18), the economic advantage of submarine connection decreases to 0.35 USD/kWh, but would give 23 SIIGs access to the main grid. In the south of the Philippines, connecting the islands of Basilan (island group 26) with a cost-saving potential of 0.19 USD/kWh has a clear cost-reduction potential compared to RE-based hybrid electricity systems. For near Jolo island (island group 27) the potential for RE-based hybrid system development and submarine grid interconnection are nearly identical. However, the interconnection of Jolo is only cost-efficient if Basilan is interconnected. For connecting Marinduque (island group 4) to the main grid, a cost-saving potential of 0.18 USD/kWh is projected. Due to its short submarine cable route (23.9 km) and high electricity demand, this is one of the most attractive submarine connection projects. Finally, the interconnection of several SIIGs in the Bicol region, including Catanduanes (island group 3), with a cost-saving potential of 0.06 USD/kWh, and connecting the Camotes island group (no. 20) with a saving potential of 0.13 USD/kWh, might be feasible for submarine connection. However, in both cases the cost advantages as compared to RE-based hybrid system development are small, and changes in cost parameters may quickly offset the cost advantage.

This detailed breakdown offers some clear recommendations for the remote electricity development sector. First, given the short distances to overcome, the high electricity demand, and the high cost advantages for submarine cable interconnection to Mindoro, Marinduque and Basilan, the feasibility of interconnecting those islands should be individually studied in the near future. Second, the interconnection of Palawan (including Busuanga and Culion) and Masbate (with its several smaller surrounding islands) should be investigated. Once connected to the main grid, the areas could be excluded from the missionary electrification subsidy scheme to decrease the overall UCME burden. For the three suggested priority areas, this would decrease by 37% the annual electricity demand to be subsidized by the UCME. The remaining island groups reflect a high potential for clean energy technology deployment by the installation of RE-based hybrid systems. As outlined earlier, RE-based hybrid systems reduce power generation costs and can therefore help decrease UCME costs as compared to pure diesel power generation. Besides relieving the pressure on national funding, both centralized and decentralized electricity supply options can increase domestic employment opportunities through local construction jobs and the manufacture of necessary parts. This holds true for both RE-based solutions (given the current emergence of a solar power manufacturing industry in the Philippines), and submarine cable interconnection (given that the Philippines are a significant producer of electronics and electrical components).

Table 7: Renewable energy - based hybrid electricity systems potential for each island/project group

No	Project group	SIIIG	Load demand	Peak demand	PV size	Battery size	Investment	LCOE (Hy.)	RE share
[#]	[name]	[#]	[MWh/a]	[kW]	[kW]	[kWh]	Million [$]	[$/kWh]	[%]
1	Batanes	6	13,186	2,324	4,129	1,112	7.8	0.31	36%
2	Jomalig	3	12,427	2,307	2,928	800	5.9	0.33	29%
3	Bicol	8	60,820	11,606	16,145	4,898	32.3	0.32	33%
4	Marinduque	4	50,329	9,837	13,889	3,963	27.5	0.32	33%
5	Mindoro	4	362,367	62,453	108,210	29,963	206.7	0.31	36%
6	Lubang	2	5,027	902	1,174	334	2.4	0.32	29%
7	Busuanga	3	42,149	8,626	10,763	3,223	22.0	0.32	33%
8	Culion	1	735	132	196	60	0.4	0.32	33%
9	Palawan	9	274,006	49,728	81,643	23,365	157.9	0.31	37%
10	Balabac	1	898	176	228	69	0.5	0.31	34%
11	Romblon	6	55,144	10,903	15,653	4,258	30.8	0.32	32%
12	Cuyo	5	11,209	2,156	2,877	818	5.8	0.32	33%
13	Cagayancillo	1	658	133	170	51	0.3	0.31	35%
14	Ticao/Burias	8	10,657	2,278	2,589	735	5.4	0.33	30%
15	Masbate (main)	7	113,332	22,121	31,317	8,962	62.1	0.32	34%
16	Leyte	6	7,392	1,482	1,676	475	3.5	0.33	27%
17	North of Cebu	4	33,033	6,737	8,427	2,458	17.1	0.32	32%
18	Masbate (small is.)	16	4,620	1,003	1,077	310	2.3	0.33	29%
19	Panay	3	2,189	447	543	162	1.1	0.33	30%
20	Camotes	2	15,606	3,018	3,742	1,081	7.6	0.32	31%
21	Bohol	10	959	241	209	63	0.5	0.33	27%
22	Siquijor	3	24,965	5,069	6,856	1,899	13.7	0.32	33%
23	Dinagat	3	24,332	4,167	6,417	1,680	12.4	0.32	31%
24	Mindanao	2	2,749	480	745	201	1.4	0.32	33%
25	Sacol	1	477	94	115	37	0.2	0.32	30%
26	Basilan	1	58,882	8,680	15,948	4,146	30.0	0.31	33%
27	Jolo	1	53,402	9,200	14,012	4,001	27.4	0.31	34%
28	Pangturan	1	317	76	65	20	0.1	0.33	27%
29	Tawi Tawi	10	43,155	6,838	11,155	3,116	21.5	0.31	33%

30	Mapun	1	2,763	503	673	206	1.4	0.32	32%

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Table 8: Submarine power cable interconnection potential for each island/project group

No	Region	Sub. cab.	Voltage	Sub. cable invest	Land cable	Land cable invest	Total invest	Generation costs	LCOE (Su.)	LCOE Comp.
[#]	[name]	[km]	[kV]	Million [$]	[km]	Million [$]	Million [$]	[$/kWh]	[$/kWh]	[$/kWh]
1	Batanes	252.0	230	378.0	96.1	1.2	379.2	0.09	3.28	2.97
2	Jomalig	41.7	138	41.7	53.2	0.6	42.3	0.09	0.47	0.14
3	Bicol	59.9	230	89.9	83.5	1.0	90.9	0.09	0.26	-0.06
4	Marinduque	23.9	138	23.9	17.2	0.2	24.1	0.09	0.14	-0.18
5	Mindoro	20.5	230	30.7	37.9	0.5	31.2	0.09	0.10	-0.21
6	Lubang	22.9	138	22.9	79.5	1.0	23.8	0.09	0.62	0.29
7	Busuanga	101.2	230	151.7	92.2	1.1	152.8	0.09	0.49	0.18
8	Culion	47.7	138	47.7	41.0	0.5	48.2	0.09	7.37	7.05
9	Palawan	15.4	230	23.1	158.8	1.9	25.0	0.09	0.10	-0.21
10	Balabac	29.9	138	29.9	39.8	0.5	30.3	0.09	3.84	3.53
11	Romblon	141.5	230	212.2	167.5	2.0	214.2	0.09	0.52	0.20
12	Cuyo	191.1	230	286.7	25.4	0.3	287.0	0.09	2.93	2.62
13	Cagayancillo	137.9	230	206.9	0.7	0.0	206.9	0.09	35.00	34.69
14	Ticao/Burias	30.5	138	30.5	112.0	1.3	31.8	0.09	0.42	0.10
15	Masbate (main)	77.4	230	116.1	42.7	0.5	116.6	0.09	0.20	-0.11
16	Leyte	55.7	230	83.6	76.0	0.9	84.5	0.09	1.36	1.03
17	North of Cebu	78.0	230	116.9	23.1	0.3	117.2	0.09	0.48	0.16
18	Masbate (small is)	111.4	230	167.1	56.1	0.7	167.7	0.09	4.12	3.79
19	Panay	43.8	138	43.8	42.8	0.5	44.3	0.09	2.34	2.01
20	Camotes	18.7	69	14.0	27.7	0.3	14.4	0.09	0.19	-0.13
21	Bohol	73.5	230	110.2	10.0	0.1	110.4	0.09	12.87	12.53
22	Siquijor	68.7	230	103.1	28.0	0.3	103.4	0.09	0.55	0.23
23	Dinagat	72.4	230	108.5	67.7	0.8	109.4	0.09	0.59	0.27
24	Mindanao	25.1	138	25.1	70.8	0.8	25.9	0.09	1.14	0.82
25	Sacol	4.0	13	1.4	8.1	0.1	1.5	0.09	0.44	0.12
26	Basilan	18.6	138	18.6	18.2	0.2	18.8	0.09	0.13	-0.19
27	Jolo	71.7	230	107.6	35.9	0.4	108.0	0.09	0.31	0.00
28	Pangturan	55.3	230	82.9	53.4	0.6	83.6	0.09	29.35	29.03

29	Tawi Tawi	157.3	230	236.0	174.0	2.1	238.1	0.09	0.70	0.39
30	Mapun	191.3	230	287.0	12.6	0.2	287.1	0.09	11.63	11.32

3.4 Sensitivity analysis of submarine cable costs and electricity demand

The input parameter most difficult to define is the submarine cable cost per kilometer, due to the paucity of published research data or publicly available project data. In order to understand its impact, we conducted a sensitivity analysis on the chosen values to understand their significance for the overall comparison of submarine cable costs for the decentralized options. We increased and decreased the assumed capital expenditure for the submarine cables stepwise from -90% to +90%. Our findings (Table 9) show that the derived least-cost options for the 30 island regions are very robust, specifically for an increase in costs. Another input parameter considered as influential for the potential of submarine cable interconnection is the electricity demand. Here, a similar pattern is observed when focusing on the impact of decreasing or increasing electricity demand on the potential for decentral and central electricity supply options (Table 10). In a range of +- 25%, the findings are very robust. More submarine cable interconnections become viable with the more likely scenario of an increasing electricity demand. In the other case, which assumes a lower electricity demand, the decentral solutions (RE-based hybrid systems) are the most economic pathways in most cases.

Table 9: Resulting changes in the least-cost electricity supply option after changing the assumed capital costs for submarine cables

Cost change %	**- 90%**	**- 50%**	**- 30%**	**- 20%**	**- 10%**	**0**	**+ 10%**	**+ 20%**	**+ 30%**	**+ 50%**	**+ 90%**
Decentral	10	16	22	22	22	23	23	23	23	24	24
Central	20	14	8	8	8	7	7	7	7	6	6

Table 10: Resulting changes in the least-cost electricity supply option after changing the projected electicity demand

Demand change %	**-75%**	**-50%**	**-25%**	**0%**	**+25%**	**+50**	**+75%**
Decentral	26	25	23	23	22	21	18
Central	4	5	7	7	8	9	12

4 DISCUSSION

This study offers a preliminary assessment of development options for the electricity sector of remote islands in the Philippines. Given its pioneering and novel approach, the study opens up opportunities for further refinement and improvement.

When seeking to optimize submarine cable routes, it is important to consider further marine activities and threats in future works. Shipping channels and areas of intense fishing activity can damage submarine power cables and thus pose a high threat to these materials [53]. The potential impact of submarine power cables on marine life (e.g. on crabs [54] and other coral fauna [55]) must also be taken into account. In the Philippines, seabed currents and unexploded warfare material can threaten the feasibility of submarine cable interconnection, as described by the grid operator [31].

With this study, we have successfully adapted an approach, originally developed for electrification planning with overhead lines [43], for the case of island interconnection with submarine power cables. The identified optimized submarine cable routes are based on bathymetric maps and the estimated investment costs are based on cost values collected through expert interviews. Nevertheless, the costs of submarine power cable projects are difficult to assess in detail, given that costs are sensitive to a variety of parameters. Among other factors, type of seabed (rocky/sandy), use of AC or DC technology, and voltage level have a significant impact on costs [27]. To obtain a more detailed cost benefit analysis, future research work must assess input parameter in more detail. Furthermore, electro-technical aspects need to be studied in more detail. Here, only an assumption on the most suitable voltage level for required electricity generation was possible. A detailed electricity flow

model can shed light on the electro-technical feasibility of supply options discussed in the present study, which focused on route estimation and identifying optimal connection pathways.
With regard to assessing the potential for RE-based hybrid electricity systems, the assumed cost parameters clearly influence the LCOE and investment costs and thus affect the applied results. Another study revealed that diesel and battery storage costs have the highest impact on LCOE and investment costs [37] of all cost factors. Future research needs to address sensitivity analyses that focuses on cost assumptions for technologies, and should consider the cost of transporting material to remote islands in the Philippines. The uncertainty surrounding how electricity demand will develop in the future is another factor that significantly affects the derived potential for renewable energy integration [41].
Despite these limitations, we obtained valuable results for electricity sector planning in the Philippines. The main submarine interconnection lines proposed are similar to the grid expansion plans of NGCP. Still, for each new interconnection project it is necessary to conduct a least-cost comparison with a RE-based hybrid system to avoid investments into submarine cables when the RE-based hybrid system would be the more cost-effective option. Currently, submarine cable deployment is also being analyzed by local electric cooperatives, who are responsible for supplying their franchise areas with electricity. Findings from those studies as well as lessons-learnt of implemented submarine cable interconnection projects can be used to validate the cost findings for submarine interconnection.

5 CONCLUSION

The main objective of this study is to compare the viability of submarine power cable interconnection and RE-based hybrid system development for 132 small isolated island grids in the Philippines that currently rely on diesel power generation. The results discussed above provide key information about electricity sector planning that will help decision makers develop and implement the most suitable electricity supply option for island contexts.
By optimizing the spatial grid extension outline for the interconnection of all SIIGs, we identify a grid extension potential of 2,239 km by submarine cable and 1,752 km by land cable. The overall investment for the given cost assumptions amounts to more than 3.2 billion USD for grid infrastructure alone, not considering the power generation capacity required to meet the demand on the newly connected islands. For hybridizing the considered systems, the overall investment for the given cost assumptions amounts to 708 million USD. Such an investment would allow for the implementation of 363 MW of PV and 102 MWh of battery storage capacity, leading to an average RE share of 30%.
On the island scale, we reveal that submarine interconnection of the Catanduanes, Marinduque, Mindoro, Palawan, Masbate, Camotes, and Basilan island groups is the least-cost option and should be further studied for its potential implementation in the near future. Priority should be given to submarine power cable connection to Mindoro, Marinduque and Basilan, based on their close proximity to the main grid and the high electricity demand on these islands. However, additional power generation capacities are needed in the main grid to meet the additional annual electricity demand of 935 GWh/a (for all islands with potential for submarine interconnection) or 471 GWh/a (for three recommended submarine interconnections). Nevertheless, connecting the recommended islands would allow for a graduation from the UCME subsidy scheme and reduce the amount of national funding needed to subsidize future electricity tariffs. A portion of the money saved could be invested in RE-based hybrid system development on islands where submarine connection is not viable. Going beyond submarine cable interconnection the development of RE-based hybrid systems hold out enormous potential for cleaner energy supply and reducing expenses for the subsidy schemes in place. This underlines that improving the enabling framework for RE-based hybrid system development can lead to more sustainable, affordable and reliable electricity supply while submarine power cable interconnection might be a viable option for islands with high electricity demands and high growth potential. Our findings and the developed methodology may be of interest to countries with a topography, insular character, and increasing demand for electricity similar to the Philippines.

ACKNOWLEDGEMENT

P. Bertheau is grateful to the PhD Scholarship of the Reiner Lemoine Foundation. This work is also supported by the Research Project entitled, “Ener-PHIL – Research Cooperation supporting the Energiewende on the Philippine Islands” funded by the BMBF. The authors are grateful to staff of the Philippine Department of Energy and National Electrification and Administration (NEA) for the data provisioned and advice.

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