Rural electrification through village grids - Assessing the cost competitiveness of isolated renewable energy technologies in Indonesia

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Abstract

Isolated grids in rural areas powered by independent renewable energy sources ('renewable energy based village grids') are widely considered a clean and sustainable solution for Indonesia's rural electrification challenge. Despite the advantages of renewable energy based village grids, the number of conventional rural electrification solutions – such as costly grid extension (on-grid) or diesel powered village grids (off-grid) which are characterized by high operating costs and high greenhouse gas emissions – is much larger. One reason for the low diffusion of renewable energy based village grids can be attributed to the lack of private sector investments, leaving the responsibility of rural electrification predominantly on the shoulders of the government who often prefer the centralized and conventional solutions. To better understand this situation in this paper we perform a literature review on the economics of renewable energy based village grids in Indonesia, which reveals a gap in terms of cost data. Therefore, we calculate the levelized cost of electricity (LCOE) of solar photovoltaic (solar PV) and micro hydro powered village grids, and compare them to the conventional diesel solution. For solar PV, we additionally investigate different system configurations including a reduced supply contingency and a hybridization approach. Finally, we determine the CO_2 emission abatement costs and reduction potentials. Our results show that micro hydro powered village grids are more competitive than diesel powered solutions (at least when taking out Diesel and other subsidies). Solar PV powered solutions increase their competitiveness with the remoteness of the village grid is and when reduced supply contingency is applied. From an environmental perspective, micro hydro powered village grid solutions are found to have negative abatement costs with significant potential to reduce emissions. We conclude by discussing our results addressing the question which measures could support private investments into renewable energy-based village grids.

Key Words: Rural electrification, Micro hydro, Solar photovoltaic, Levelized cost of electricity (LCOE), Abatement cost, Off-grid

1 Introduction

As an emerging economy Indonesia needs to respond to multi-faceted challenges in its growing energy sector. This includes providing modern energy services to the poor, reducing oil dependency, and decoupling economic growth from greenhouse gas emissions [1–3]. Today Indonesia's electrification rate is 71%[1] [4]. Of the remaining 29%, about 80% reside in rural areas and almost all outside of the most populated islands, Java and Bali [3, 5]. Most of Indonesia's poor are living in regions which are difficult to access; either located in the countryside or on small islands, and therefore they have limited access to reliable and affordable electricity services. At the same time, rural electricity demand is rapidly growing[2].

Currently, the responsibilities for electrification are borne almost solely by the state-owned utility Perusahaan Listrik Negara (PLN), which owns and operates the country's entire transmission and distribution network, as well as a large proportion of the generation plants. PLN itself has long faced many challenges associated with being the dominant actor in the monopolized electricity sector. First, the expansion of the electricity network is very capital-intensive due to the geographically challenging nature of the archipelagos of Indonesia. Options for grid extension to remote areas or deployment of submarine cables into remote islands are typically very expensive [6] . Second, a large proportion of PLN's budget is dedicated to relieving the pressure of aging infrastructure, leaving little allowance for access expansion[3]. Despite these facts, some remote rural areas are already being electrified by the PLN, yet these electrification attempts are mainly based on diesel generators. Third, the Indonesian low grid electricity tariff is set by the government, in a bid to provide affordable electricity to the general population. This eventually caps PLN's revenue from electricity sales, making it difficult to recover the high production and distribution costs [7, 8].

Recognizing the urge for electricity access in remote areas and for replacing conventional by renewable energy sources, the Government of Indonesia recently set the target of 90% electrification by 2020, as a subset of its "Vision 2025: Building New Indonesia strategy"[4] and aims at implementing policies which foster renewable energy technologies. In recent years, a number of promising reforms have taken place designed to invite the participation of local government and the private sector in renewable energy based rural electrification efforts. This includes amongst regulations on small scale power purchase agreements [9], proposed US$43m program to increase renewable-based rural electrification and reduce diesel content[5], a framework which coordinates budgetary contribution of central and local governments to rural electrification advancement [3, 10, 11], and a 1000 remote island PV electrification program [10].

[1] This number reflects general access to electricity, but does not reflect the quantity and quality of the accessed electricity.

[2] PLN's projections and findings from our own in-depth interviews with a number of Indonesian renewable-energy based rural electrification project developers suggest that demand growth is expected to be 10% per year until 2018 [72].

[3] PLN's 2009 – 2018 supply plan outlines a proposed spending of $32b in generation, $14b in transmission and $13b in distribution [72].

[4] Vision 2025 Building New Indonesia lists a set of targets to achieve by 2025 focusing in the areas of economics, poverty eradication, and equal access to vital utilities across the nation [73].

[5] Diesel currently serves as the conventional solution for remote rural electrification due to its perceived low cost, scalability and accessibility. PLN statistics show that they operate 936 decentralized diesel power plants (50kW – 500kW) with a total capacity of 987MW across Indonesia [74].

Due to its geography, most non-electrified villages in Indonesia are too remote, complex and expensive for grid extension to take place[6]. Hence, off-grid solutions (predominantly diesel) become the basic electrification solution for these areas. As an alternative to diesel, renewable energy based village grids are widely considered as a feasible solution to improve rural electrification access which provides a platform to encourage rural economic growth [11–14] and do not result in additional greenhouse gas emissions [15]. However, despite the aforementioned efforts in improving rural electrification access and the benefits of renewable energy based village grids, only a small number have been realized. Efforts are still needed to scale up the diffusion of these solutions.

According to Indonesian rural electricity practitioners (who we interviewed during our study), investments in remote, renewable energy based rural electrification are almost entirely dependent from grants or charities from socially-inclined private organizations, aside from PLN. The literature review we perform (see Section 2) reveals a lack of data on the economics of renewable energy based village grids in Indonesia, making it difficult for decision makers to implement measures that foster their diffusion and attract private investments. In this study, we therefore address this data gap by tackling the following main research question: How competitive are isolated renewable energy based village grid solutions compared to the standard conventional solution? Specifically, we analyze two sub-research questions; first, what are the levelized costs of electricity generation (LCOE) of various solutions? and second, what are the costs and potentials of CO_2 emission abatement of these solutions?

To this end, first, we develop two electricity demand scenarios for a generic Indonesian village, reflected through daily load profiles. Second, we design standalone conventional, renewable and hybrid power generation systems to supply the village grid. Third, we calculate the LCOE for the baseline (conventional diesel powered village grid) and compare it to different micro hydro powered and solar PV powered solutions. Fourth, we calculate the abatement cost (AC) and emission reduction potentials of the renewable energy based and the hybrid solutions, compared to the diesel baseline.

The paper is structured as follows. While Section 2 reviews recent literature on the economics of RVGs in Indonesia, Section 3 describes the method applied in the study. This includes the quantitative approach to estimating Indonesian village electricity demand estimation, generation plant technical parameter sizing, and the calculation of LCOE, AC and emission reduction potentials. Section 4 outlines the results of our techno-economic model, followed by a discussion and conclusion in Section 5.

2 Literature review on the economics of RVGs in Indonesia

A review of literature published in the past five years on the economics of RVGs (or micro-/mini-/island-grids) in Indonesia resulted in eight documents (including scientific articles, reports and a presentation). The overview given in Table 1 shows that the eight papers differ regarding several aspects, e.g., in terms of technologies considered or economic indicator(s) provided.

[6] Based on our Indonesian field interviews with practitioners, the ideal distance between independent power plants and PLN's grid needs to be between 5 – 10km to guarantee project profitability.

Table 1 | Overview of studies investigating the economics of RVGs in Indonesia

Authors (Year)	Model (Generic vs. Specific)	Renewable Energy source to power village grids	Conventional	Economic indicator(s)	Details of calculation provided
USAID (2007) [16]	Generic	– Solar PV – Micro hydro – Biomass	– Diesel	Estimated generation costs	No
Holland & Derbyshire (2009) [6]	Specific	– Solar PV – Micro hydro – Biomass – Wind – Geothermal – Hybrid: Diesel/wind/battery	– Diesel	LCOE	Yes
Feibel (2010) [17]	no Model	– Micro hydro	– none	Cash flow	No calculation, but primary data of real projects
Tumiwa and Rambitan (2010) [18]	no Model	– Micro hydro	– none	Investment costs and real net profit	No calculation, but primary data of real projects
van der Veen (2011) [19]	Specific	– Solar PV – Hydro – Biomass – Wind	– Diesel	Generation cost	Yes
Abraham et al. (2012) [20]	No Model (LCOE) Specific (IRR, NPV)	– Solar PV – Micro hydro – Biomass – Wind	– Diesel (un- and subsidized)	LCOE Internal Rate of Return (IRR), Net Present Value (NPV)	LCOE: No IRR, NPV: Yes
Hivos (2012) [21]	no Model	– Micro hydro	– Diesel	Generation costs	No calculation, but secondary data
van Ruijven et al. (2012) [22]	Generic	– Hybrid: Wind/diesel		Generation costs	Yes

Out of the eight studies, Feibel [17] and Tumiwa and Rambitan [18] provide cost performance data on five real-life micro hydro based village grids in Indonesia. Both studies do not compare RVG cost to the conventional diesel based solution. Contrarily, Abraham and colleagues [20] and Hivos [21], while also referring to real project data, perform comparisons of RVGs and conventional village grid solutions (diesel-based), sourced from primary and secondary data. The remaining four studies are based on techno-economic models. USAID [16] lists in-house estimates of generation costs for different rural electrification options. In a report from 2009 Holland and Derbyshire [6] calculate the LCOE for different electrification options, among them RVGs, and compare them to the LCOE of grid extension. However, as both reports were written in 2007 and 2009 respectively, cost data might be outdated due to fast cost reductions of renewable energy technologies in recent years. Van der Veen [19] investigates the least-cost investment options to electrify the island of Sumba based on 100%

renewable energy sources. While the study focuses on a larger island grid and does not explicitly calculate generation costs for village grids, some results are still comparable to village grids as the sizes of single installed plants partly match village grid requirements. Finally, van Ruijven and colleagues [22] model global rural electrification trends and investment requirements and also apply their model to several regions and countries– including Indonesia. To do so, they calculate (amongst others) the generation cost of wind/diesel based village grids and compare it to grid-based electricity in a generic model.

While the above literature is very valuable for understanding the economics of rural electrification in Indonesia, we see four reasons why further work is required: First, the role of variable demand and fluctuating supply over the day or the season (which is typical for intermittent renewable energy sources) is under-researched. Of the eight studies, only van der Veen [19] matches hourly demand curves with hourly supply – however on a larger island grid level. Second, the role of different electrification scenarios reflecting different economic developments, which is especially important from a policy perspective, needs more attention. Only van Ruijven and colleagues [22] (but only for a wind/diesel hybrid system) and van der Veen [19] (again for the island) look into different demand developments. Third, the competitiveness of RVGs compared to diesel generators is strongly influenced by the distance of the village to the diesel source and the electricity grid. Only Holland & Derbyshire [6] include the distance aspect explicitly (however, their cost assumptions might be outdated). Fourth, the role of subsidies for diesel, which is crucial when comparing RVGs to the conventional diesel based solution, has to be scrutinized in more detail. Only Abraham and colleagues [20] in their presentation provide numbers on the role of subsidies but do not provide a model. Therefore, in the remainder of the paper we will calculate the LCOE of different RVGs considering all four aspects simultaneously. In Section 4 we will compare our modelling results with the data provided by the above studies.

3 Method and Data

We answer the research question in a four step approach (see Figure 1), based on the principals of matching the demand side to the supply side model of a rural electricity sector in a generic Indonesian village. In step one, we estimate the electricity demand of the generic Indonesian village. For this village two electrification scenarios and different end-user consumer sectors are considered. In steps 2-4, we model the three supply side variables (power generation system capacities, LCOE and abatement costs) for conventional, renewable energy based and hybrid village grids. In step two, we model the capacities of conventional (baseline), renewable and hybrid electricity systems such that they meet the demands modelled in step one. In step three, we perform a cost analysis in which we consider capital expenditures (equipment investment, engineering, civil, construction and physical contingency), operating and maintenance expenditures (fixed and variable) of each system [17, 23], and appropriate discount and inflation rates. This step results in LCOE for each demand scenario and each power generation system and with this addresses the sub-research question 1. In step four, we calculate the abatement cost of the renewable and hybrid options compared to the conventional baseline and with this target sub-research question 2. The method and data section is structured along these four steps.

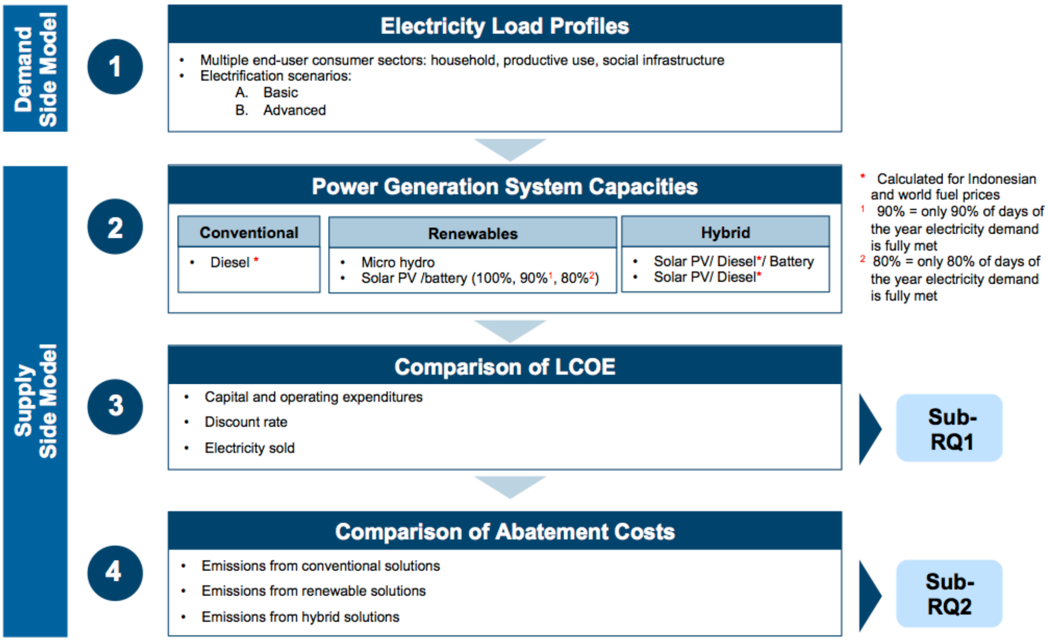

Figure 1 | Overview of research outline. Step 1. Demand model which calculates the village electricity load profile, based own a basic and an advanced electrification scenarios Step 2. Determination of required power generation system capacities to meet village electricity demand according to the load profiles and scenarios. We consider conventional (baseline), renewable energy based and hybrid village grids. Step 3. Calculation of LCOE for both electrification scenarios for all power generation options. This step answers to sub-research question 1. Step 4. Calculation of emissions abatement costs from implementation of renewable energy based and hybrid village grids. This step answers to sub-research question 2.

3.1 Electricity Load Profiles

In the first step we estimate the village electricity demand by defining the size of a generic Indonesian village, two electrification strategies, and the corresponding village load profiles. Based on a study of 10 remote, un-electrified villages in Sulawesi and Sumatra [17] and our own investigations during field visits, the size of a generic village is estimated to establish a baseline of a typical Indonesian village. Our generic village consists of 1475 people in 350 households, with 4.5 people per household on average.

While previous rural electrification studies have typically only considered household electricity demand [13, 14], to reflect the variability of villages across Indonesia and incorporate potential demand growth for rural electricity (compare van der Veen [19]), we define two types of electrification scenarios as classified in Table 2, considering three categories of end-user consumers: household, productive use and social infrastructure.

Table 2 | Two types of rural village electrification scenarios are considered in this study to reflect the variability of villages across Indonesia.

	Scenario A **Basic Electrification**	**Scenario B** **Advanced Electrification**
Overview of village	Remote rural village, with agriculture as the main economic activity.	Rural village with established or growing economic activities, beyond agriculture.
Power availability and end-consumer sectors	Electricity is available 18:00 – 06:00 for: • Household sector (night)	Electricity is available 24 hours for: • Household sector (day and night) • Productive use (majority during daytime) • Social infrastructure (majority during daytime)

Based on the proposed electrification scenarios for the generic village, in the next step we determine the load profile for both scenarios. As meters are often not employed in small off-grid electricity networks there is a lack of empirical data on electricity consumption from Indonesian villages [24]. Therefore, the load profile is estimated by determining the demand for electricity for each end-user category at hourly intervals during a typical day. The demand for electricity is estimated by identifying the electricity appliances required by consumers in each end-user category and the times of usage[7]. All assumptions to the demand model side are outlined in Appendix B, based on previous studies and our own Indonesian field investigations and interviews.
For scenario A, which is intended to serve remote rural villages with only the household sector as the end-users, the electricity demand per household is outlined in Appendix B. The village's total daily electricity consumption accounts to 162.5 kWh under this scenario. The peak demand periods for this strategy occur between 18:00 – 23:00 when villagers are home and use electricity for lighting and recreational purposes. During the day no electricity demand is generated as villagers perform their faming activities (see Figure a).

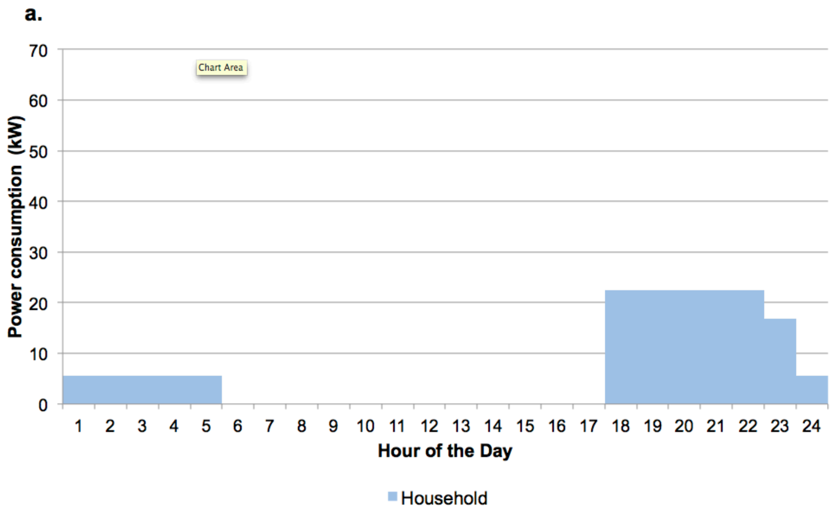

Figure 2a | Total village hourly load profile for end-user sector under Scenario A (basic electrification scenario) where demand is requested during 15 hours per day.

[7] Due to the geographical location of Indonesia, we assume no seasonality effect on the demand.

For scenario B, the household, productive use and social infrastructure sectors are considered as end-users. The total village daily electricity demand under this strategy for the generic village is 558.5 kWh. A breakdown of electrical appliances and power consumption for each sector is given in Appendix B. The resulting hourly load profile for both electrification strategies applied to our generic village is given in Figure 2b.

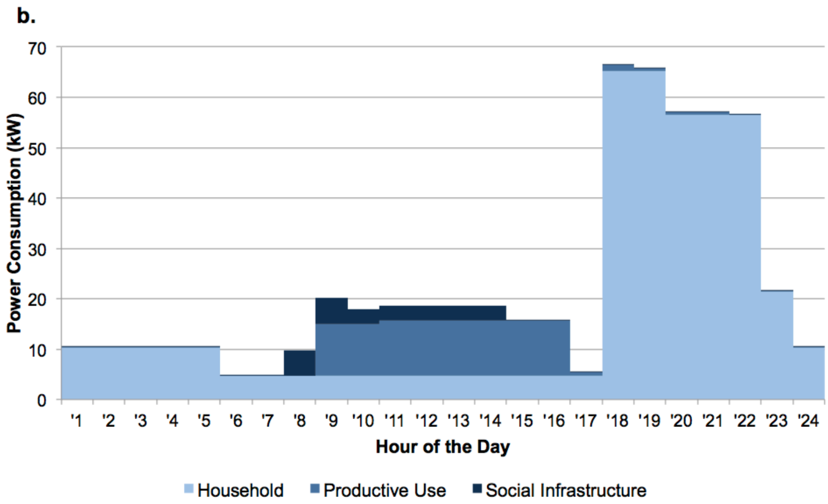

Figure 2b | Total village hourly load profiles for each end-user sector under Scenario B (advanced electrification scenario) where electricity is requested during 24 hours per day.

3.2 Power Generation System Capacities

Having determined the demand for electricity in the generic Indonesian village, in the second step, we calculate the required capacities of power generation systems to meet the electricity demand levels for each scenario as defined in the hourly load profiles. As the village grid in question is assumed to be an isolated network, electricity is produced independently by the power generation systems and distributed through the grid to the end-use consumers. The results of this sizing process can be found in Table 3. Assumptions relevant to the modelling of power generation system capacities are outlined in Appendix A.

3.2.1 Conventional (diesel powered) village grid

The required diesel engine capacity is determined by matching the peak demand of the village for both electrification scenarios, including the distribution losses and diesel generator system efficiency. The system's load factor adjusted efficiency is dependent on the capacity factor, which is deduced from our load profile[8].

The most important drawback of diesel generators is its high operating costs due to dependence to diesel fuel. In Indonesia, this effect is even more prominent in rural areas and remote islands where fuel prices increase with transportation costs and distance to distribution centers. This location-dependence factor is reflected by three diesel retail price categories determined by the Indonesian Oil and Gas Distribution Agency (BHP Migas) [9]

[8] We calculate the hourly capacity factors based on the estimated load profile and take a daily average to obtain the overall capacity factor. By utilising a diesel engine efficiency-load map we obtain the load factor adjusted engine efficiency [66].

[9] BHP Migas official prices show Sumatra and Nusa Tenggara prices as being the lowest (1x), compared to Java-Bali (1.04x) and Borneo-Sulawesi-Papua (1.06x) [26]. In practice, the accessible retail prices can reach up to 3.3 times official prices [75].

Therefore, as a fair proxy to reflect this location-dependence variability, we assume three categories of transport cost variation of low (1.0x lowest official diesel price), medium (2.0x) and high (2.73x) [10].

Furthermore, we differentiate the subsidized and unsubsidized diesel prices in Indonesia (compare Abraham et al. [20]). First, we consider the discrepancy between the Indonesian diesel fuel oil prices which has remained since 15 March 2009 at 3,578 IDR/liter (0.29$€_{2012}$/liter) [25] with the global price of 0.61€/liter in 2012 [26]. To both prices, we also apply a diesel fuel price growth projection over the lifetime of the diesel power system [27, 28] (Appendix D).

3.2.2 Renewable energy based village grids

As a first alternative to conventional diesel powered village grids, we consider micro hydro and solar PV/battery based solutions.

3.2.2.1 Micro hydro

In areas with sufficient natural resources (flow rate, water availability and head), micro hydro is a proven reliable and low-maintenance technological option to address rural electrification access [10, 15]. Through our interviews with industry practitioners, we discover that micro hydro popularity in Indonesia is also underpinned by the strong local technical knowledge base, mature domestic micro hydro industry and manufacturing capability. However, currently only 19% capacity of Indonesian estimated 450MW micro hydro potential have been tapped [29][11]. Similarly to the estimation method for diesel, the micro hydro power plant capacity in this study is sized such that it matches the peak load of the village, including distribution losses.

3.2.2.2 Solar PV/battery

Solar PV systems, which directly convert solar energy into electricity, offer a number of additional benefits; including high modularity, zero noise, and particularly the availability of high solar resources in almost all developing countries [12]. Previous studies have concluded that standalone solar PV off-grid networks are still less competitive when compared to other more mature renewable energy technologies, driven by high investment costs [12, 22]. The main challenge concerning the use of an intermittent power generation source such as solar PV/battery is that all electricity can only be produced during day time, leaving night time or cloudy day consumption reliant on battery storage. However, this peak production pattern does not match the demand curve, where peak demand occurs at night time, where the solar PV panels do not produce electricity (compare van der Veen [19]). For an isolated network, this significantly raises the need for battery storage to meet electricity demand during non-daylight hours. We assume a solar PV system configuration which consists of crystalline silicon (cSi) based solar PV power plant connected to advanced lead-acid battery storage. The electricity produced by solar PV panels is used directly to satisfy demanded levels of electricity at that point in time. Excess electricity production during daylight-hours will be stored, and discharged at night or during cloudy days to meet the requested demand.

[10] Multipliers obtained on the basis of analysis of PLN's official cost of electricity supply across the entire network [38].

[11] Due to the location-dependence nature of micro hydro, the overall investment and O&M costs are not as scalable as diesel power plants. As practitioners suggest from interviews we conducted, the main cost drivers are either construction cost (for low head situations) or generator cost (for high head situations). However, for modeling purposes this effect is assumed negligible.

To determine the appropriate solar PV and battery system sizes, data of the solar irradiation potential for the target location is required. Hourly solar irradiation data from a Typical Meteorological Year (TMY) derived from multi-year measurements is used as it provides a more robust overview of solar energy potential corrected for a standard year [30] [12]. Our analysis based on the data set results in an average global horizontal irradiation of 4214 Wh/m^2 [13]. We calculate the solar PV and battery system size through an optimization approach. To this end, the sizes of the solar PV field and battery capacity are optimized to reduce the LCOE of the entire system. Complete details on the formulation of this optimization process are outlined in Appendix E.

3.2.2.3 Solar PV/battery with 90% and 80% reduced supply contingencies

To reduce the LCOE of the higher renewable energy based village grid solution, the solar PV/battery (see results on Figure 4); we consider an alternative solution with reduced supply contingencies. We argue that since the SAIDI (System Average Duration Interruption Index) of PLN is 6.96[14] [31] and based on practitioners' advice from our own field interviews, an isolated village grid with sub-100% availability can be acceptable, provided that it is explicitly covered in a community agreement approved by the villagers. We therefore consider two levels of reduced supply contingency approach to the solar PV configuration. First, under a 90% reduced supply contingency the power generation system configuration is able to supply sufficient electricity to fully meet the demanded levels as reflected by the load profiles. In the remaining 36 days (10% of the days in the year), a shortage of electricity supply may be expected. Second, under the 80% configuration, there are 72 days (20% of the days in the year) where electricity supply shortage may be expected.

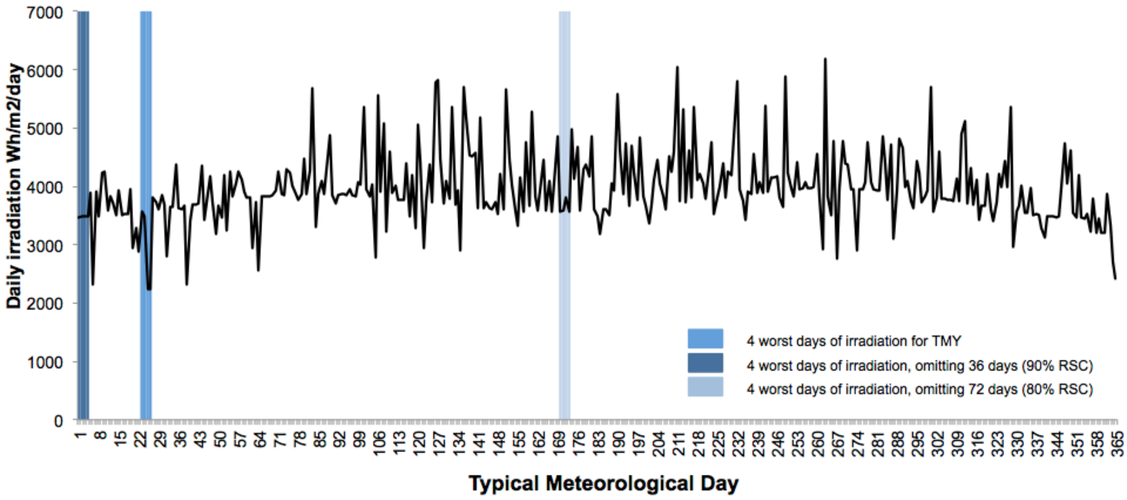

Figure 3 | TMY data [34] **showing daily irradiation** (Wh/m^2) representing the solar potential for electricity generation. The highlighted areas show four consecutive worst days under three system configurations (100% availability, 90% and 80% reduced supply contingencies). The solar PV and battery system capacities are determined through an optimization process such that using available irradiation from these sets of four consecutive days, village electricity demand will always be satisfied.

[12] Since no TMY data exists yet for any location in Indonesia, as a proxy we utilize TMY data for Kuching (Malaysia) which shares the region of north-western Borneo island with Indonesia, located at 01º33'N and 110º25'E [34].

[13] This figure is only slightly lower compared to results of a simulation study for Samarinda (East Borneo) of 4830 Wh/m^2 [76], which makes our assumption conservative.

[14] In comparison, according to IEEE Standard 1366 – 1998 the median value for North American utilities SAIDI is 1.5 hours per customer per year.

To estimate the 90% configuration, using TMY data we rank and omit the worst 36 days of irradiation (below 3633 Wh/m^2). From the reduced data set, we select the four worst irradiation days as a basis to determine the appropriate solar PV and battery capacities to fulfil electricity demand for 329 days in the year (see Figure 3). For the 80% configuration, we take a similar approach to the 90% reduced supply contingency approach. However, in this case we omit worst 73 days of irradiation (below 3741 Wh/m^2) from the data set. Subsequently, we size the solar PV/battery system to fully satisfy electricity demand for 292 days in the year (see Figure 3).

3.2.3 Hybrid village grid

As a second alternative to conventional diesel powered village grids, we model two hybrid options combining both conventional and renewable energy based village grid solutions. As our results (Figure 4) suggest that micro hydro already has the lowest LCOE compared to the conventional diesel powered village grid solution, we apply the hybridization strategy only for solar PV powered solutions.

3.2.3.1 Solar PV / battery / diesel hybrid

In this configuration, we utilize a 50% solar PV to 50% diesel electricity production mix, complemented by battery backup. During the day solar PV panels produce electricity for immediate consumption. Whenever excess electricity production occurs it is stored in the battery and discharged when required. A diesel generator is available for use at any time of the day to cover shortages in electricity supply which cannot be provided through solar PV production or discharging the battery.

3.2.3.2 Solar PV / diesel hybrid

In this configuration, battery backup is eliminated and any shortage of power not supplied by solar PV field is covered by diesel generator. In this configuration, we utilize a 30% solar PV to 70% diesel mix for electricity production [32]**.** Day time demand is supplied by solar PV production and supplemented by diesel generator. Due to absence of battery, the diesel generator produces electricity to fully supply night time electricity demand. This hybridisation strategy is applicable only for the scenario B, as scenario A does not demand electricity during the day. This configuration was planned to be installed in some PLN owned and operated village grid networks through the 1000 island program.

For all power generation systems, the results for the required capacities are outlined in Table 3.

Table 3 Resulting power generation system sizes for scenarios A and B under various configurations (conventional, renewable energy based and hybrid village grids).

Power generation type		Capacity for scenario A	Capacity for scenario B
Conventional	Diesel	23.4 kW	69.6 kW
Renewable	Micro hydro	23.4 kW	69.6 kW
	Solar PV	62.3 kWp	232.5 kWp
	Battery	300 kWh	716 kWh
	Solar PV at 90%	52.0 kWp	177.6 kWp
	Battery	219 kWh	517 kWh
	Solar PV at 90%	50.4 kWp	170.8 kWp
	Battery	216 kWh	516 kWh
Hybrid	Solar PV	8.9 kWp	32.4 kWp
	Battery	118.8 kWh	260.4 kWh

Diesel	8.9 kW	32.4 kW
Solar PV	-	29.8 kWp
Diesel		69.6 kW

3.3 LCOE calculation

To answer the sub-research question 1, we calculate the LCOE for all power generation system which had been sized above and both electrification scenarios via a non-linear dynamic cash-flow model. To assess the generation cost of the conventional, renewable and hybrid electrification technologies, the LCOE are calculated. Taking into account all discounted costs accrued throughout the system lifetime (n) including investment expenditure (I_t), operations and maintenance expenditure (M_t), and fuel expenditures (F_t), divided by the discounted value of electricity sold during the lifetime (E_t). We assume that the demand is always met by the generation. This approach is valid as the grid is isolated and electricity which is not consumed is also not sold and therefore presents no benefit from an economic point of view. The cost assumptions for all technological options are available in Appendix C. LCOE is defined as:

$$LCOE = \frac{\sum_{t=1}^{n} \frac{I_t + M_{t+} F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

[€/kWh][15]

3.4 Calculation of abatement costs and savings of CO2 emissions

To answer sub-research question 2, we calculate the emissions abatement costs for all renewable energy based and hybrid village grid options and for both electrification scenarios. Implementation of an alternative renewable energy based power generation system reduces greenhouse gas emissions that would otherwise have been caused by a conventional diesel generation system to power the village grid. The emissions abatement costs from these alternative technologies are defined by the difference in LCOE between diesel and renewable-based technologies and the associated emissions relative to the diesel plant that it would displace [33]. This formula is defined as:

$$Abatement\ cost\ (AC) = \frac{LCOE_{renewable\ based} - LCOE_{diesel}}{Emissions_{diesel} - Emissions_{renewsable\ based}}$$

[€/tCO_2]

Subsequently, we also calculate the savings in CO_2 emissions from opting for renewable energy based village grid solutions as opposed to diesel, given by the formula:

$$CO_2\ emissions\ savings = \frac{Yearly\ fuel\ input_{diesel} - Yearly\ fuel\ input_{renewable\ based\ alternative}}{Diesel\ fuel\ specific\ CO_2\ emission}$$

[tCO_2/year]

[15] Calculated in €/kWh instead of USD/kWh as carbon markets are more proliferated in Europe .

4 Results

In this section, we present the results for the LCOE and abatement costs and potentials for the two proposed electrification scenarios and the different technological solutions. The LCOE results are depicted in Figure 4, and the abatement costs and emission reduction potentials results in Figure 5.

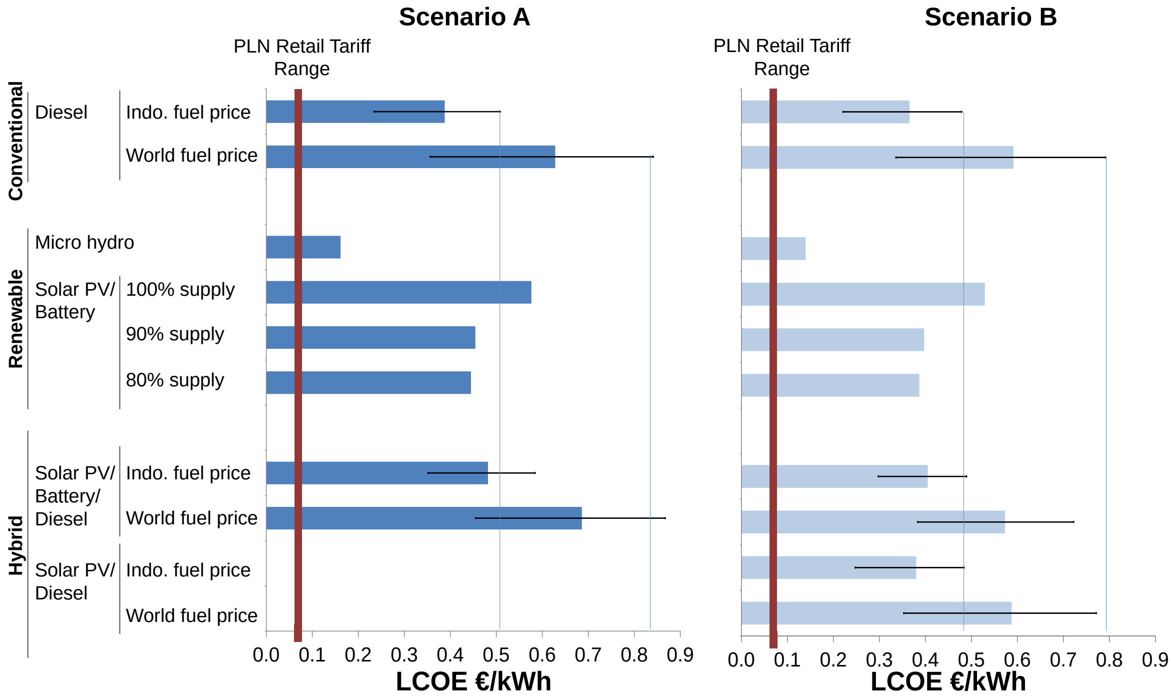

Figure 4 | LCOE for generic Indonesian village grid with various power generation configurations, applying a basic (A) and advanced (B) electrification scenario. For each technological option, the LCOE are quantified in by the horizontal axis in €/kWh. The black lines represent the range of LCOE for any village grid configuration with diesel components, demonstrating the influence of fuel costs due to remoteness of the village. The most left (smallest) LCOE within a variation represent locations close to distribution centres, the most right (highest) represent the furthest locations. Additionally, we compare the LCOE results to the PLN retail tariff range depicted by the red vertical bars. A range of tariff exists as retail prices differ for household, productive use and social infrastructure consumers [35].

The first observation from Figure 4 is that the cost of all technologies decreases when advanced electrification scenario are applied instead of basic electrification. This is driven by a higher capacity factor, achieved through daytime utilization of electricity for productive use and social infrastructure. In the basic scenario (Scenario A), as electricity is demanded only at night time during which villagers return home, the power generation systems are idle throughout the day and therefore no electricity can be sold. In the advanced scenario (Scenario B), during the day the demand pattern is smoother, the power generation system never reduces to an idle state and proportionately more electricity can be sold to multiple end-user sectors. During the day electricity demand predominantly comes from social infrastructure and productive use, while at night time demand stems from household sector.

Second, we find strong differences for the LCOE of the various solutions. Starting from the conventional solution, we observe that the diesel powered village grid option has the second lowest LCOE (at low and medium remoteness) when considering the Indonesian diesel fuel prices. However, when we consider world diesel fuel prices, the LCOE are 62% higher. The dependence of diesel powered village grids on an external factor – the transportation of diesel from a distribution centre to the generation site – affects the operating cost throughout its lifetime strongly. Particularly in more remote areas diesel prices can be much higher than in distribution centres. When considering this sensitivity to location we observe a large range of variation in LCOE. For scenario A we observe LCOE between 0.23 – 0.51€/kWh (at Indonesian diesel prices) and 0.36 – 0.84 €/kWh (at world diesel prices). For scenario B we observe LCOE between 0.22 – 0.48 €/kWh (Indonesian fuel prices) and 0.34 – 0.79 €/kWh (world fuel prices). This is in a similar range to the findings of Holland & Derbyshire [6] and shows that diesel powered village grid is the most expensive option for very remote area application, particularly when no subsidies are assumed. However, results by van der Veen [19] and real project data by Hivos [21] and Abraham et al. [20] show lower figures, which can be explained by the fact that the studies neglect future diesel price development in the case of Hivos [21] and Abraham et al. [20] and lower investment and operational cost assumptions in combination with a longer lifetime for the diesel generator in the case of van der Veen [19]. Furthermore, we observe no significant difference in LCOE with change in electrification strategies. This demonstrates the scalability of the diesel generation system, where costs are driven primarily by purchase of diesel fuel and its expected price growth throughout the asset lifetime.

In the set of results for renewable energy based village grid solutions, we observe that micro hydro consistently has the lowest LCOE compared to other technologies, for both scenarios at 0.16€/kWh (A) and 0.14€/kWh (B). However, these results, which are also very comparable to those by Holland & Derbyshire [6], are only valid when sufficient hydro resources are available. USAID [16], van der Veen [19], Hivos [21] and Abraham et al. [20] report lower generation cost, which stems from higher capacities, favourable local specifics and lower discount rates. Solar PV/battery is considered to have the least restrictions for application and can be placed almost anywhere in Indonesia due to the abundance of solar potential [29, 34]. In alignment with results of previous studies in other countries [10, 22, 32, 33], our analysis demonstrates that solar PV is however still the most expensive technological option to power village grids. For scenario A we obtain LCOE of 0.58 €/kWh and for scenario B 0.53€/kWh. However, for solar PV in scenario B we observe that the solar PV battery LCOE is already lower than a diesel engine at world fuel prices, even at medium remote places. Interestingly, these results are higher than those obtained by Holland & Derbyshire [6] four years ago, despite the fact that PV cells experienced strong cost reductions, and also higher than newer results by van der Veen [19]. The reason for this is that we assume a higher discount rate and that we size the system so that it can provide electricity even in the least sunny period of the year and therefore include large battery storage investments. In evaluating the effects of alternative configurations to solar PV powered village grids, first, we observe the reduced supply contingency strategy, which proves to be successful in reducing LCOE. At 90% configuration the LCOE of a solar PV/battery powered village grid is reduced to 0.45€/kWh (A) and 0.40€/kWh (B), indicating a total reduction between 21% - 25%. Furthermore, at 80% configuration the LCOE is reduced to 0.44€/kWh (A) and 0.39€/kWh (B), indicating a reduction between 22% - 27%. The LCOE reduction between 100% to 90% configuration is more effective than the step between 90% to 80%, as the worst irradiation days (mostly outliers) are already eliminated from the calculation in the first reduced supply contingency step.

In the hybridisation strategy, firstly, for solar PV/battery/diesel hybrid configuration, scenario A results in LCOE ranging from 0.35 – 0.58 €/kWh (at Indonesian diesel prices) indicating an average reduction of 17% compared to the original solar PV/battery configuration and only 4% higher than diesel (similar to Holland & Derbyshire's results [6]). At world prices the LCOE of this configuration is 0.46 – 0.87€/kWh. This demonstrates that in locations close to diesel distribution centres, such configuration may increase the competitiveness of solar PV powered village grids compared to a solar PV/battery configuration. However it is not ideal and relatively more expensive for application in more remote areas due to increased transportation cost of diesel. For scenario B, the solar PV/battery/diesel hybrid proves to be even more expensive than standalone solar PV/battery with relatively higher LCOE of 0.30 – 0.49€/kWh (Indonesian fuel prices) and 0.38 – 0.72€/kWh (world fuel prices). Secondly, the results for the solar PV/diesel hybrid village grid (30% solar PV and 70% diesel), the results for advanced electrification strategy are slightly more competitive than solar PV/battery/diesel. We observe LCOE between 0.25 – 0.48 €/kWh (Indonesian fuel prices) and 0.35 – 0.77 (world fuel prices). Hybrid technologies which combine diesel and solar PV are only cheaper than pure solar PV/battery options, if diesel subsidies are assumed and/or the village location is not remote. Their application might be interesting in places where diesel generators already exist but more generation capacity is needed due to the development of the village.

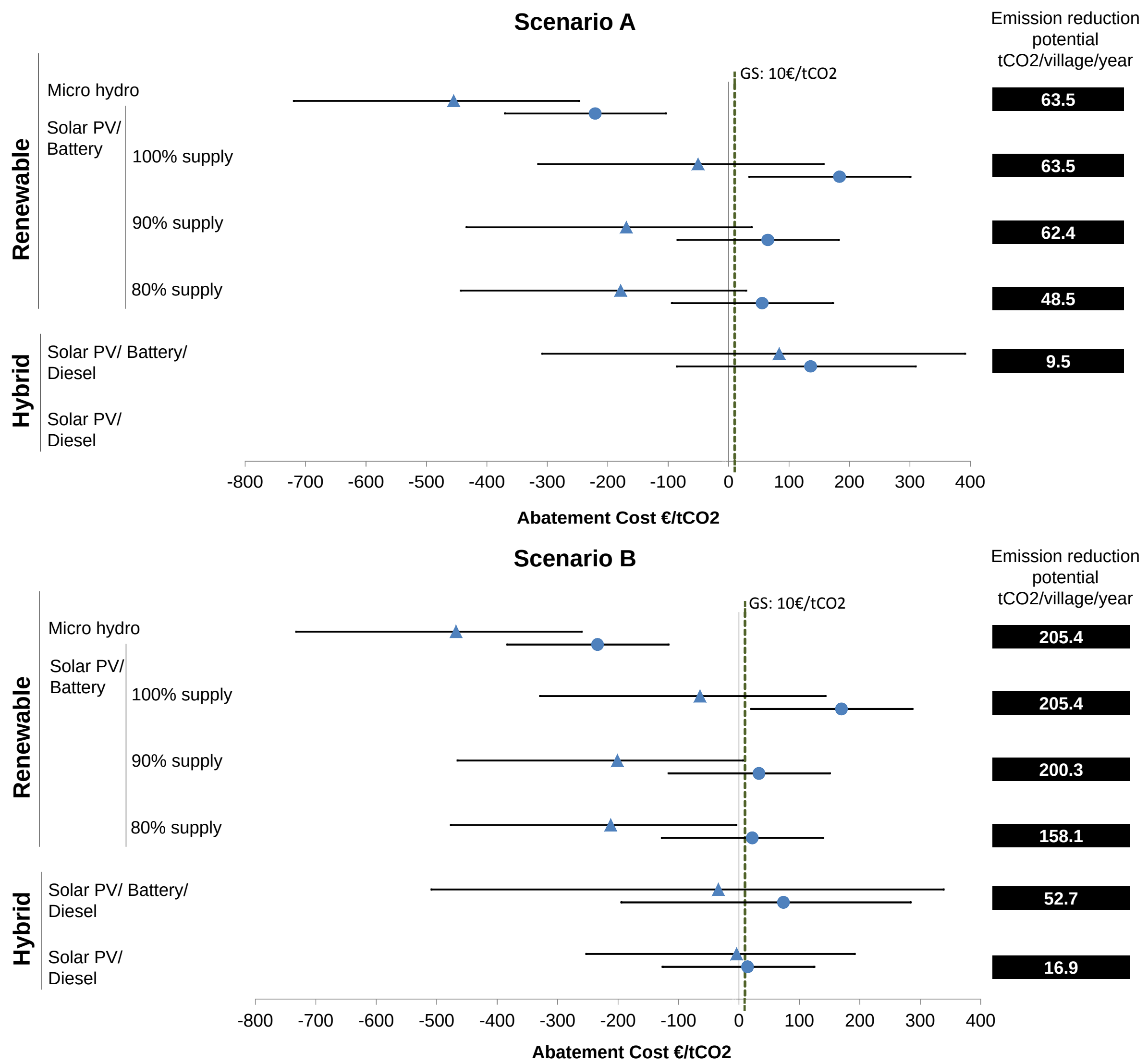

Figure 5 | Abatement costs and emission reduction potentials of renewable energy based and hybrid village grids compared to the conventional diesel baseline. The abatement costs are quantified by the horizontal axis, measured in €/tCO_2. For each technological option, we calculate the abatement costs considering world unsubsidized prices (symbolized by the triangle symbol) and Indonesian subsidized prices (symbolized by the circle symbol). We also consider a range (black lines) of abatement costs to differing remoteness levels of the village. We compare these abatement costs to the current Gold Standard (GS) carbon price of 10€/tCO_2, depicted by the dotted line[16]. For each technological option, we also calculate the emissions reduction potential by choosing a renewable energy based or hybrid village grid as an alternative to the conventional diesel solution (black boxes).

By law, all end-users to the PLN grid are entitled to the official PLN tariffs. For completeness, we compare the LCOE of the village grids to PLN retail tariffs (red band in Figure 4). PLN tariffs differ according to the end-use category as determined by Ministerial Decree 4/2010 [35]. On average the lowest tariff is for consumers in the social sector (0.06€/kWh). This is followed by household (0.07€/kWh) and industrial consumers who use for productive use (0.08€/kWh). The PLN retail tariff band is thus far lower than all the LCOE of the analysed village grid options.

The abatement cost analysis shows a wide range of emission abatements and costs. Generally, the influence of fuel subsidies is quite high. We observe that abatement costs for micro hydro solutions are in any case negative, when compared to diesel solutions. This implies that savings can actually incur by choosing micro hydro over diesel powered village grid option while at the same time emissions can be reduced by 63.5 tCO_2/year/village (scenario A) respective 205.4 tCO_2/year/village (scenario B). The abatement costs for all power systems which contain solar PV components are higher. However, we observe in all cases (except for solar PV/battery/diesel in scenario A), when considering unsubsidized world diesel fuel prices, abatement costs are negative. In terms of emissions reductions, as expected the renewable energy only solutions (micro hydro and solar PV/battery at different configurations) yield the highest volume of CO_2 emission avoided. The hybrid solutions result in 75%-84% (solar PV/battery/diesel/) and 91% (solar PV/diesel) less emission reductions due to the presence of the diesel content. Finally, the Gold standard carbon price of 10€/tCO_2 is small compared to the wide range of abatement costs. However, it becomes obvious that for several options a carbon price could (partially) financially support the diffusion of renewable energy based village grids sufficiently.

5 Discussion and conclusion

In order to reach Indonesia’s 90% electrification target, high investments are needed. The US$43m provided by the government and the grants from international organizations will not be sufficient. Additional resources stemming from private investors are urgently required [36] . In this section we discuss why only little private investment into village grids takes place and how the diffusion of renewable energy based village grids can be ramped up strongly by providing incentives for private investors. We commence our discussions from micro hydro and then solar PV powered solutions.

Our results highlight that micro hydro powered village grid is the solution with the lowest generation costs and negative abatement costs in all cases (even when assuming subsidized non-remote diesel prices). Despite this fact and many studies identifying locations with sufficient natural resources [7, 37] the diffusion of micro hydro village grids is still low. This is related to the extremely low electricity retail tariff determined by the government. While PLN’s average network costs of electricity supply at €0.16/kWh [38] also exceed this range of tariff , the resulting gap is covered by the government. This represents a second, indirect, form of subsidy

[16] While the retail price for GS projects is above these 10€/tCO_2, interviews we conducted with carbon market actors indicate that 10€/tCO_2 is the maximum that is passed through to the project.

(additional to the direct fuel price subsidies), which becomes a hindrance to private investments (unless private investors would be bailed out by the Indonesian government like PLN – a rather unrealistic and socially doubtful scenario)[17]. Previous studies suggest that the deterrent of private investors in rural electrification projects may be caused by a number of reasons, including national electricity tariffs that are lower than the cost of decentralized-produced electricity [6] and from the high (transaction) cost associated with rural electrification projects [11] and regulatory, technological and counterparty uncertainty [37]. Therefore, it's essential to create an investment environment that is conducive to increase village grid private investment; one option is for the government to remove the electricity "price cap". With this retail tariffs would reflect cost of electricity supply more closely and fairly. While this first option may result in higher prices for consumers and potentially a significant burden to the lower income earners, studies show that in other countries rural poor are willing to pay higher electricity prices [13, 20]: e.g., in Cambodia rural electricity prices are much more flexible and reach from 37 to 74 €/kWh [39]. The second option to increase private investments is to remove the electricity price cap, and concurrently re-distribute fuel subsidies. In case the Indonesian government wants to keep end-user prices very low, one option is to shift current fuel subsidies in such way that micro hydro solutions get subsidized. Electricity subsidies in Indonesia, when measured by price-gap methodology[18] are among the highest in non-OECD countries, in particular for oil [40]. These subsidies have increased significantly from 2005 (€0.7b) to 2008 (€6.3b) driven by increase of international oil prices and high dependence on diesel based generation systems [41]. Gradually lowering the subsidies from emission intensive technologies and increasing those for hydro would be a feasible solution[19]. Additionally, when the electricity subsidy removal is implemented simultaneously with fuel subsidy redistribution, the adverse effects on household levels may be dampened, compared to an electricity subsidy removal alone [42]. In the case of village grids, the LCOE of diesel is much higher than the retail price when compared to micro hydro. Hence, if hydro is installed instead of diesel, the total amount of required subsidies is reduced, resulting in savings for the government. Another consideration is that micro hydro capacity and capabilities are already advanced in Indonesia, with a number of manufacturing centers across the country[20] [42, 43]. This is in contrast with solar PV technology, where manufacturing takes place mainly in industrialized or threshold countries. Hence, strengthening this technology could also create jobs and economic development in the country (additional to the development that can be expected due to the existence of power in the villages) and thereby be a contribution to an Indonesian green growth strategy.

While micro hydro is the cheapest option and should be chosen where the natural potential is available, solar PV based options are much more expensive but nevertheless can be interesting for villages where the hydro potential is lacking. For an overview on different electrification options for different remote environments, see a recent IEA-RETD report [44]. Solar PV technology has very high technical potential and is expected to experience rapid reduction in costs [14, 42, 43]. Especially in very remote villages, solar PV/battery options can be cheaper than diesel. This trend will reinforce itself with raising diesel prices [45]. Hence, the same reasons for non-investments from the private sector as discussed for micro hydro hold for solar PV options. However, the role of diesel subsidies is even more precarious. Without diesel subsidies, solar PV based options are also attractive in

[17] These indirect subsidies of course also impede private investments in fossil fuel-based rural electrification.

[18] Price-gap methodology calculates the gap between regulated retail tariffs and regulated benchmark price [40].

[19] In a promising step, the government has already announced plans for subsidy reforms between September 2012 – April 2013, following a failed attempt in April 2012 [42].

[20] The same holds true for several other developing countries, such as Nepal, Kenya or Nigeria.

medium remote villages. A gradual phase-out of subsidies could be coupled with a gradual build-up of solar PV/battery powered village grids. In order to limit additional costs during this transition phase, the solar PV/battery solutions can be designed in a way that they do not aim at 24 hour power delivery over 365 days. Smaller configurations can limit costs significantly (while still delivering major amounts of electricity; compare the LCOE results of our 90% configuration) and be installed in the beginning. The high modularity of solar PV and batteries allows a subsequent addition of generation and storage capacity (which will be even cheaper at the time of installation due to the learning curve of both solar PV and battery technologies [23]). Similarly to hydro, fuel and electricity "price cap" subsidies should be re-distributed to also support solar PV in places without hydro potential.

The findings underline renewable options can be cheaper than their fossil alternatives that typically represent the baseline. The public perception is often still dominated by idea that renewable-based options are far off from competitiveness with conventional generation options [46]. Schmidt et al. [27] show that for grid-connected large scale wind, abatement costs can be negative if the baseline is largely based on oil products. They, in line with other recent studies [46, 47], conclude that subsidies are a major issue. Our study confirms this for the case of village grids in Indonesia. Fuel subsidies can strongly deteriorate the competitiveness of renewables. Energy prices have been subsidized in Indonesia since 1967 and are determined through a government decree. Subsidies in diesel oil result in official retail prices which are 33% lower than the world market prices [41]. In the case of solar PV, these subsidies push the abatement cost from negative to as high as almost 200€/tCO_2. Additionally we find, that indirect subsidies, which allow for extremely low retail prices make private investments totally unattractive.

The results on the abatement cost show that a certain part of the additional costs of solar PV could be covered by carbon credits. While the United Nations Framework Convention on Climate Change talks are currently at a time of uncertainty, new market mechanisms, e.g., Nationally Appropriate Mitigation Actions (NAMAs), are looming, which can partially also be financed via carbon credits[21] [48]. For more details on the potential of new carbon finance mechanisms, see e.g., a series of recent UNDP papers [46, 47, 49, 50].

Overall it seems that rural electrification through renewable energy based village grids is hardly an issue of high additional costs of renewables but rather of the political economy of the country's energy sector. In order to remove the barriers for renewable electrification, political work is required. Agencies for technical and political assistance are required to support the Indonesian government in building an electrification strategy that targets five areas of development relevant to the Indonesian energy sector. First, such strategy must support the 90% electrification rate target at low or even zero emission growth. Second, such strategy can be created in a way that improves economic development through national value creation and capacity building in the village grid technology sector (e.g. scalable and high quality hydro manufacturing, installation and assembling of switch gears and solar PV panel production). Third, the strategy can also be geared towards establishing electricity as a basic commodity for rural economies; such that it stimulates productive use and subsequently boost rural economic development. This stimulation of electricity demand is akin to shifting from a basic electrification (scenario A) to advanced electrification (scenario B) in our study, which proved to be beneficial in lowering LCOE and making village grid electricity more affordable. An important issue is of course the phase out of fuel

[21] As our results show, NAMAs for different technologies have different financial needs.

subsidies, which can be intricate[22]. Fourth, such strategy must attract private equity and debt sponsors (beyond purely concessional finance). An analysis of the risks involved in rural electrification [49] and their transfer and reduction can lower the cost of renewables more than of conventional technologies. Their high capital intensity makes them more sensitive towards high discount rates (which are found in investment environments with high risks). Last but not least, such strategy has to involve stakeholders – from village residents, via potential investors, the financial sector, technology providers to PLN – in order to manage counterbalance interests.

Finally, we conclude with a statement of our main contributions and some limitations which call for further research. This study enriches the literature in rural electrification ─ with particular focus to Indonesia ─ in three ways. First, in contrast to previous studies, our analysis considers a holistic view of rural end-user consumer market including household, productive use and social infrastructure. This serves as a first valuation base for private sector when considering village grid investments. Second, we analyze the issues that are directly relevant in encouraging private sector investment in rural electrification sector. Third, our results contribute towards proposals for policy makers by showing the actual economic barriers (often the high costs of renewables are perceived as the main barrier – something, we clearly disprove).

Our study is clearly limited to techno-economic calculations. However, literature on the diffusion of renewable energies in developing countries has shown that further financial and non-financial barriers are highly relevant [10, 39, 40, 49]. Hence, we suggest four areas for future research: analyze the risks for private investors in order to derive appropriate de-risking strategies; analyze the socio-techno-economic barriers of village grid diffusion which goes beyond the pure cost calculations presented in this study; research on potential business models for renewable energy based village grids in Indonesia; and analyze on a country level to calculate the economic costs and benefits of the proposed rural electrification strategy.

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[22] The issue of Indonesian fuel subsidy is very sensitive. Adjustments of fuel prices seldom take place as the political impact and community backlash can be severe [42].

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Appendix A – Assumptions for Power Generation System Capacities

Table A.1 Assumptions relevant to the modelling of power generation system capacities

Section of Model - Technology			Technical assumptions			Economic assumptions		
			Factor	**Assumed value**	**Source**	**Factor**	**Assumed value**	**Source**
Demand model			Distribution losses	4%	[51]	Population	1497 people	[17]
			Voltage level	Low (under 1 kV)	[52–54]	Number of household	350 households	[17]
			Electrification scenarios	See Table	[14, 43, 55, 56] Supplemented by Indonesia in-field interviews			
			Demand by end-user sector	See Appendix B	[14, 43, 48, 49, 55, 57] Supplemented by Indonesia in-field interviews			
			Operating hours (scenario A)	18:00 – 06:00	Own assump.			
			Operating hours (scenario B)	00:00 – 00:00	Own assump.			
			Operating days	365 days (no seasonality)	Own assump.			
LCOE model						Discount rate	12.5%	[58]
						Inflation rate	2.1%	[59]
						Exchange rate USD/EUR	1.31269	[60]
						Exchange rate IDR/EUR	11779.8	[60]
Conventional generation model	Diesel		Efficiency (scenario A)	26%	[51, 52]	Diesel price (Indonesia)	0.29€$_{2012}$/litre See Appendix D	[25]
			Efficiency (scenario B)	27.64%	[51, 52]	Diesel price (World)	0.61€$_{2012}$/litre See Appendix D	[26]
			Diesel oil density	0.832 kg/litre	[61]	Diesel retail price multiplier, based on transport cost effect	Low: 1.0x, Medium: 2.0x, High: 2.7x	[24, 33, 54]
			Diesel oil calorific value	11.94 MWh/tonne	[62]	Investment cost	See Appendix C	[12]
			Diesel plant lifetime	20 years	[12]	O&M cost	See Appendix C	[12]
			Specific CO_2 emission	0.26674 tCO_2/MWh	[63]			
Renewable energy generation model	Micro hydro		Overall efficiency	85%	Based on an interview with a micro hydro power implementer	Investment cost	See Appendix C	[12]
						O&M cost	See Appendix C	[12]
	Solar PV/ Battery	Solar PV	Location	Kuching, Malaysia as proxy	[34]	Investment cost	See Appendix C	[12]
			Temperature factor	0.932	[17, 64, 65]	O&M cost	See Appendix C	[12]
			Tilt angle	20º	Own assump.			
			Nominal Operating Cell Temperature (NOCT)	45ºC	[17, 58]			
			Maximum temperature coefficient	-0.38%	[17, 59]			
			Inverter efficiency	95%	[60, 66]			
			Lifetime	25 years	[12]			
		Battery	Battery efficiency	90%	[66, 67]	Investment cost	See Appendix C	[12]
			Overall charging efficiency	81.23%	By calculation	O&M cost	See Appendix C	[12]
			Depth of discharge	20%	Own assump.			
			Initial rest capacity at start of optimization	10%	Own assump.			
			Lifetime	5 years	[61, 67]			
Hybrid generation model	Solar PV / Battery / Diesel		Diesel efficiency (scenario A)	35%	[51, 52]	Same Investment cost and O&M cost assumptions as above		
			Diesel efficiency (scenario B)	35%	[51, 52]			
			Other assumptions as above					
	Solar PV / Diesel		Diesel efficiency (scenario B)	26%	[51, 52]	Same Investment cost and O&M cost assumptions as above		
			Other assumptions as above					

Appendix B – Electric Appliances

Table B.1 Typical electrical appliances for household sector under Scenario A [11]**.** Data also supplemented by findings from Indonesian field trip.

Electrical Appliance	Power Consumption (W)	Quantity per household	Usage duration per day
Light bulb (indoor)	16	2	18:00 – 00:00
Light bulb (outdoor)	16	1	18:00 – 06:00
TV 19"	80	0.2 (1 every 5 households)	18:00 – 23:00

Table B.2 Typical electrical appliances for household sector under Scenario B [14, 43, 55, 56]**.** Data also supplemented by findings from Indonesian field trip.

Sector	Electrical Appliance	Power Consumption (W)	Quantity per consumer	Usage duration per day
Household	Fluorescent Lamp (inside house)	16	2	18:00 - 0:00
	Fluorescent Lamp (outside house)	16	1	18:00 - 6:00
	Color TV 19"	80	1	18:00 - 23:00
	Stereo (speakers)	20	1	18:00 - 23:00
	Refrigerator	100	4 per 30 household	17:00 - 9:00
	DVD/VCD Player	25	1	18:00 - 20:00
Productive Use	**Kiosk (4.5 per village)**			
	Light bulb	25	4	18:00 - 22:00
	Coffee milling (2 per village)			
	Coffee Huller	1000	1	9:00 - 17:00
	Coffee Grinder	2000	1	9:00 - 17:00
	Carpenter (1.7 per village)			
	Metal grinder	120	1	9:00 - 17:00
	Drilling machine	350	1	9:00 - 17:00
	Circular saw	1500	1	9:00 - 17:00
	Planer	450	1	9:00 - 17:00
	Tailor (1 per village)			
	Sewing Machine (dynamo)	120	1	9:00 - 17:00
	Restaurant (1 per village)			
	Refrigerator	100	1	0:00 - 0:00
	Mixer	100	1	11:00 - 19:00
	Blender	180	1	11:00 - 19:00
Social Infrastructure	**Hospital (1)**			
	Vaccine refrigerator	60	1	00:00 - 00:00
	Vaccine refrigerator / freezer	60	1	00:00 - 00:00
	Indoor lights (CFL)	15	10	10:00 - 17:00
	Outdoor lights (CFL)	15	4	10:00 - 17:00
	Microscope	15	1	2 hours per day
	Centrifuge nebulizer	150	1	2 hours per day
	Vaporizer	40	1	2 hours per day
	Oxygen concentrator	300	1	2 hours per day
	Overhead fan	40	4	10:00 - 17:00
	Water pump	100	1	2 hours per day
	Electric steriliser	1500	1	2 hours per day
	Desktop Computer	60	2	10:00 - 17:00
	15" LCD monitors	25	2	10:00 - 17:00
	Multi function scanner/ copier/ printer	17	1	2 hours per da
	Satellite phone	5	1	Only in emergencies
	Internet: Cisco Aironet Workgroup	0.05	1	10:00 - 17:00
	Internet: 4-port ethernet hub	7.5	1	10:00 - 17:00
	School (1)			
	Internet: Cisco Aironet Workgroup	0.05	1	08:00 - 15:00
	Internet: 4-port ethernet hub	7.5	8	08:00 - 15:00
	Desktop Computer	60	30	08:00 - 15:00
	Indoor lights (CFL)	15	24	08:00 - 15:00
	Outdoor lights (CFL)	15	12	08:00 - 15:00

Sector	Electrical Appliance	Power Consumption (W)	Quantity per consumer	Usage duration per day
	Internet: Cisco Aironet Workgroup	0.05	1	08:00 - 15:00
	Common communications infrastructures			
	Payphone	2	3	00:00 - 00:00
	Internet: Cisco Aeronet 350 Access	0.05	1	00:00 - 00:00
	Internet: Digital VSAT receiver	30	1	00:00 - 00:00

Appendix C – Costs of the different generation plants

Table C.1 | Costs of diesel generator plant [12]

Type of Cost	Value
Reference rated output	100 kW
Investment cost	
Engineering	7.62 €/kW
Equipment & material	457.08 €/kW
Civil	10.00 €/kW
Erection	7.62 €/kW
O&M cost	
Fixed O&M cost	0.02 €/kWh
Variable O&M cost	0.03 €/kWh

Table C.2 | Costs of micro hydro power plant [12]

Type of Cost	Value
Reference rated output	25 kW
Investment cost	
Engineering	152.35 €/kW
Equipment & material	3755.64 €/kW
Civil	746.55 €/kW
Erection	533.26 €/kW
Process contingency	533.26 €/kW
O&M cost	
Fixed O&M cost	0.00 €/kWh
Variable O&M cost	0.41 €/kWh

Table C.3 | Costs of solar PV and battery power plant [62, 67]

Type of Cost	Value
Investment cost	
Module sales price	0.87 €/Wp
Inverter sales price	0.21 €/Wp
Remaining balance of plant price	0.64 €/Wp
EPC margin	8%
O&M cost	
Fixed O&M cost	1.5% of total investment cost

Appendix D – Projected development of diesel fuel prices, under world (symbolized by quadrates) and Indonesian (diamonds) prices.

These projections are calculated based on multipliers advised by the International Energy Agency [27, 68].

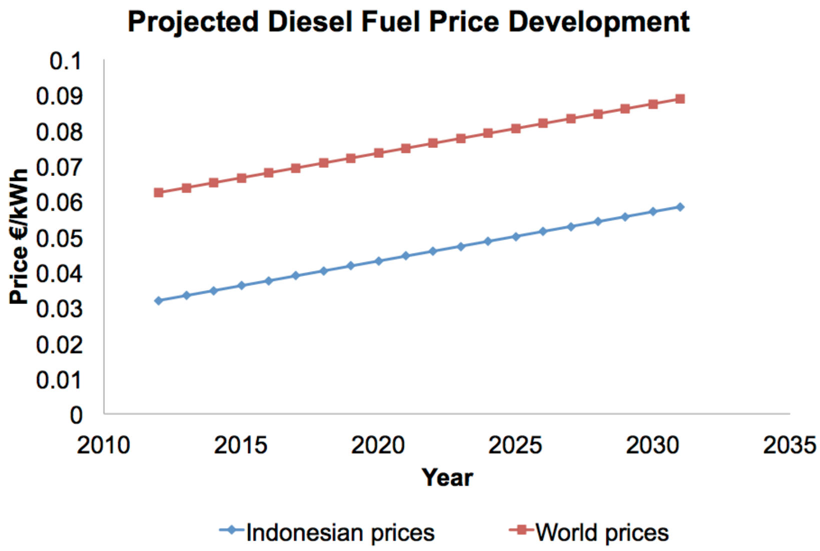

Figure D.1 | Projected Diesel Fuel Price Development

Appendix E – Calculation of solar PV/battery system capacities

First, using the hourly TMY data we calculate the tilt-adjusted global horizontal irradiation (I_{DHt}) to obtain the total irradiation (I_{Ct}) by adjusting for the assumed tilt angle (ϑ=20°), given by the equation

Eq, E.1 $$I_{C_t} = \frac{I_{DH}}{\cos(\vartheta)}$$ [Wh/m²]

We then calculate the weighted cell temperature derate factor (Tf) to account for performance variations in case the cell temperature (T_{cell}) differs from the 25°C at standard testing conditions, by incorporating the module Nominal Operating Cell Temperature (NOCT=45°C) and temperature coefficient (∇=-0.0038/°C) [23].

Eq. E.2 $$T_{cell_t} = \frac{NOCT - 20°C}{800\ Wh/m^2} I_{C_t}$$ [°C]

Eq. E.3 $$Tf_t = 1 + \left[(T_{cell_t} - 25°C)\nabla\right]$$ [-]

Eq. E.4 $$Weighted\ Tf = \frac{\sum_{t=1}^{8760} I_{C_t} Tf_t}{I_{C,annual}}$$ [-]

Eq. E.5 $$E_{PV_t} = Number\ of\ panels\ \times Rated\ power\ per\ panel \times Weighted\ Tf \times \frac{I_{C_t}}{1000}$$ [W]

The solar PV/battery system must operate such that the available power for village load consumption (E_{load}) at any time *t* can either be sourced from solar PV production (E_{PV}) or by discharging battery (E_{batt}).

Eq. E.6 $$E_{Load_t} = E_{PV_t} + E_{Batt_t}$$ [W]

We select the four consecutive days within the TMY with the lowest levels of irradiation as the basis of our model[23,24] (see Figure 3). A solar PV/battery system that fulfills hourly load consumption during these four ‘worst-case’ days should be able to generate sufficient electricity at 100% availability throughout other days of the year, which have higher solar irradiation levels. At any time *t* when the power produced from the solar PV panels exceeds the required demand at that time, the excess production can be stored in the battery which has a charging efficiency of 81.23% and 20% rest energy margin [69–71] . Consequently, the battery will be discharged to supply any shortages should the solar PV panels be unable to produce sufficient power to meet demand. These requirements are given by the following formulas.

Eq. E.7 $$E_{Batt_t} = \begin{cases} if\ (E_{PV_t} - E_{Load_t}) > 0, \eta_{Batt}\left[(E_{PV_t} - E_{Load_t}) + E_{Batt_{t-1}}\right] \\ if\ (E_{PV_t} - E_{Load_t}) < 0, E_{Batt_{t-1}} - (E_{Load_t} - E_{PV_t}) \end{cases}$$ [W]

Using a non-linear optimization method we then determine the combination of solar PV and battery capacities, which yields the lowest LCOE (objective function) and meets the demanded levels of power at any time t (constraint).

Eq. E.8 $$\min LCOE_{PV,batt}\quad s.t.\quad E_{PV_t} + E_{Batt_t} \geq E_{Load_t}$$

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[23] From the IWEC data this was determined to be between January 23rd and 26th 1990 which yielded global horizontal irradiation of 3794, 3712, 2373 and 2376 Wh/m² respectively.

[24] Industry practice recommends off-grid small-scale PV generation system ranges from 3 – 6 days [48, 54, 55, 77].