1. Submitted to the journal “ENERGY” via the online submission system: Email received on submission confirmation (30 April 2023 – Indonesia time)
    - Confirmation email
    - Full manuscript draft
    - Cover letter
    - Declaration of interest statement
2. Email received from ENERGY Editor-in-Chief: Review results -- asking for revision (24 August 2023 – Indonesia time)
3. Submitted the revised manuscript via the online submission system
    - Response to editors’ and reviewers’ comments (22 September 2023 – Indonesia time)
    - The full manuscript draft (22 September 2023 – Indonesia time) consists of:
        - Highlight
        - cover letter
        - CRediT author statement
        - Declaration of interests
        - Revised manuscript without track changes
        - Revised manuscript with track changes
        - Point-to-point response to reviewers
4. Email received: Submission accepted (16 October 2023 – Indonesia time) and notification of production for typesetting (16 October 2023 – Indonesia time)
5. Email received: Production begun (17 October 2023 – Indonesia time)
6. Email received: Journal Proof for review (17 October 2023 – Indonesia time)
7. Email received: Pre-proof article is available online (18 October 2023 – Indonesia time)
    - Result of the Journal Pre-proof (18 October 2023 – Indonesia time)
8. Email received: Final article is published online (22 October 2023 – Indonesia time)

1. Submitted to the journal “ENERGY” via the online submission system: Email received on submission confirmation (30 April 2023 – Indonesia time)
    - Confirmation email
    - Full manuscript draft
    - Cover letter
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Cost-reliability trade-offs for grid-connected rooftop PV in emerging economies: a case of Indonesia’s urban residential households

--Manuscript Draft--

Manuscript Number:	
Article Type:	Full length article
Keywords:	on-grid; rooftop PV; emerging economies; reliability-cost; trade-offs.
Corresponding Author:	Yusak Tanoto, Ph.D. Petra Christian University INDONESIA
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Order of Authors:	Yusak Tanoto, Ph.D.
Abstract:	This paper explores the potential of grid-connected rooftop PV in terms of how the systems can be better planned and utilised through understanding possible trade-offs between cost and reliability, while recognising challenges to the security of utility supply in the context of emerging economies. The implications of three factors on rooftop PV planning, i.e., unserved energy targets, PV capacity, and billing deduction factors, are analysed to determine possible trade-offs in terms of total net present cost and realised unserved energy (capacity shortage). Four residential customer segments in an Indonesia’s urban area are considered in this study, where four cases in each segment, representing scenarios on PV capacities and billing deduction factors, are analysed through simulations using HOMER. The analyses highlight the role of cost components in the trade-offs involving possible cases of PV capacity. While optimisations have maximised the PV capacity across all realised unserved energy and according to the scenarios, higher unserved energy resulted in lower grid capacity required by the system to meet the demand according to the maximum unserved energy limit of the system. This study has provided insights not only to the residential customers but also to stakeholders involved in issuing and implementing rooftop PV policies.
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Cost-reliability trade-offs for grid-connected rooftop PV in emerging economies: a case of Indonesia's urban residential households

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Abstract

This paper explores the potential of grid-connected rooftop PV in terms of how the systems can be better planned and utilised through understanding possible trade-offs between cost and reliability, while recognising challenges to the security of utility supply in the context of emerging economies. The implications of three factors on rooftop PV planning, i.e., unserved energy targets, PV capacity, and billing deduction factors, are analysed to determine possible trade-offs in terms of total net present cost and realised unserved energy (capacity shortage). Four residential customer segments in an Indonesia's urban area are considered in this study, where four cases in each segment, representing scenarios on PV capacities and billing deduction factors, are analysed through simulations using HOMER. The analyses highlight the role of cost components in the trade-offs involving possible cases of PV capacity. While optimisations have maximised the PV capacity across all realised unserved energy and according to the scenarios, higher unserved energy resulted in lower grid capacity required by the system to meet the demand according to the maximum unserved energy limit of the system. This study has provided insights not only to the residential customers but also to stakeholders involved in issuing and implementing rooftop PV policies.

Keywords: on-grid, rooftop PV, emerging economies, reliability-cost, trade-offs.

1. Introduction

The utilisation of solar photovoltaic (PV) systems has significantly increased in recent years [1, 2]. In many urban areas in emerging economies and jurisdictions, rooftop solar PV has been seen growing [[3], [4], [5], [6], [7]], with grid-connected rooftop PV has been seen as one of the viable options for supplying electricity in residential households [8]. Grid-connected rooftop PV has been found to be less expensive and easier to install with almost no maintenance involved compared to hybrid systems [9]. While residential sector can contribute to the reduction of CO_2 emissions and sustainable energy transition through adoption of low cost, green technologies such as PV [10, 11], customer choices for grid-connected rooftop PV are influenced by performance expectations, socio-environmental beliefs, and price-value beliefs, among others [12]. In the context of emerging economies, however, it is important to note that the development of rooftop PV has been both economically and technically driven by rising electricity rates and the challenges faced by utilities in providing reliable supply, even in urban distribution networks.

Special attention should be given to the relatively poor reliability of urban distribution networks [13], which has notable significance for energy users in the residential sector, especially when it comes to choosing an appropriate size for grid-connected rooftop PV. Given a grid connected system, without any capacity shortage – as to represent the reliability – it would require a larger size, and of course at a higher cost, to meet all demands including very high peak loads even in a short time. On the other hand, a smaller and less expensive system may be able to be installed while allowing some capacity shortage but still reasonably meeting a reasonable portion of the load.

Many studies have explored various aspects of the techno-economic feasibility of rooftop solar PV systems in the context of emerging economies and developing countries, particularly for grid-connected residential applications using various techniques and tools. Some studies have focussed on system planning through simulations while others on performance evaluation of installed systems, either focussing on one location or several sites.

Gabr et al. [9] assessed the techno-economic feasibility of a grid-connected rooftop PV system in Egypt. The authors considered ongoing electricity retail prices and net-metering policy applied in three types of housing rates with different levels of demand. This study measured net present value of energy cost, payback period, and bill savings using HOMER. Laib et al. [14] evaluated the performance of a grid-connected solar PV system and its energy balance in Algeria. The authors developed a Matlab-Simulink model to carry out optimisations, rationalisations, and energy saving approaches in assessing the energy performance and energy balance of the system. Dondariya et al. [15] predicted grid-connected rooftop PV performance in Ujjain, India. The authors compared PV*SOL, PVGIS, SolarGIS, and SISIFO to analyse system performance in terms of energy generation, performance ratio, and solar fraction. Al Garni et al. [16] assessed the optimal design of grid-connected PV by considering various PV tracking systems as applied in Makkah, Saudi Arabia. The authors considered horizontal-axis, vertical-axis, and a two-axis tracking system using HOMER. Earlier studies by Lau et al. [17] analysed the pricing mechanism for grid-connected PV projects in the Malaysian residential sector. The authors assessed the impact of component costs, feed-in tariffs, and carbon taxes using HOMER.

Duman and Güler [18] analysed the economic feasibility of 5 kW grid-connected solar PV in nine provinces of Turkey. The authors examined the discounted payback period, internal rate of return, and profitability index using HOMER, and found that the system would not be feasible for two provinces under the practiced feed-in tariff. Bakhshi and Sadeh [19] investigated the economic feasibility of grid-connected rooftop PV systems, including net present value, internal rate of return, payback period, and levelized cost of energy, under dynamic feed-in tariff strategy. The authors used PVsyst software to estimate the annual generated energy of different cities in Iran through the analysis of a typical 5 kWpeak system. Li et al. [8] evaluated and compared the techno-economic performance of grid-connected rooftop PV systems and other alternatives in five climate zones in China using HOMER. The authors found that grid/PV systems would be the best choice among other studied systems, considering that Kunming is the most economical among other regions. Tomar and Tiwari [20] discussed the feasibility of grid-connected rooftop PV for three different residential households. The authors used HOMER to simulate the impact of feed-in tariffs/net-metering along with a tariff-of-day policy in New Delhi, India, and found that systems without energy storage is both technically and economically feasible for decentralised households.

While these studies, whether focussing on single household analysis or involving multiple sites, have certainly brought useful insights for the stakeholders regarding possible techno-economic impacts of grid-connected rooftop PV and its deployment opportunity, less explored, however, has been the impacts of different capacity shortage, i.e., different reliability targets at different sizes, and in particular, the potential trade-offs between system reliability and costs.

This paper aims to explore the potential of grid-connected rooftop PV in terms of how the systems can be better planned and utilised through understanding possible trade-offs between system reliability and cost while recognising challenges to utility supply security in the context of emerging economies. While residential rooftop PV systems can be enhanced by other generation technologies such as wind or diesel, gas, and energy storage, aiming to improve system reliability and efficiency [21], this paper particularly focusses on the grid-connected PV systems in urban household applications in emerging economies, with Surabaya, Indonesia, is taken as a case study.

As it is generally the case in some emerging economies and jurisdictions, rooftop PV has to date seen only modest deployment in Indonesia, despite its overall competitiveness and current supportive regulations that have been implemented. On the customer side, the decision whether to implement grid-connected rooftop PV or simply continue with the existing power connections from the utility grid is, in many cases, not supported by adequate techno-economic analyses, especially when focussing on reliability and cost implications due to system setting and regulations.

This paper provides a new perspective to ongoing techno-economic rooftop PV studies by presenting the reliability-cost trade-off for such systems. Such trade-offs may arise because of the possibility of alternative sizes due to a range of unserved energy targets, i.e., related to the level of reliability achieved that is generally experienced in emerging economies jurisdictions, and hence has impacted the system costs. This paper models unserved energy targets by allowing for some capacity shortages in the supply side.

The rest of this paper is organised as follows. A brief overview of the status of solar PV deployment focussing on rooftop solar PV systems in Indonesia is discussed in Section 2. Section 3 describes the method applied in this study, overview of the simulations, including input data and assumptions for modelling. Results and discussions are presented in Section 4, and finally the conclusion of the paper is presented in Section 5.

2. Brief Status of Rooftop Solar PV Deployment for Residential Households in Indonesia

Despite the enormous technical potential derived from excellent solar irradiation coverage across the Indonesian archipelago, and amidst the declining cost of solar PV systems, the development of rooftop solar PV for residential customers in Indonesia has been perceived as very slow. As of October 2022, of the 6,261 PLN (Perusahaan Listrik Negara, i.e., Indonesia's state-owned electricity company that is solely responsible for electricity generation, transmission, and distribution) customers who have installed rooftop PV with the total capacity of 71.35 MW, there were 4,676 residential customers, or 75%, mostly with on-grid system [22]. The rooftop PV systems installed in the residential sector have a total capacity of 15,2 MW, or around 22% of the total rooftop PV capacity in all PLN customers, namely residential, commercial, social, government, and industrial [23]. The Java-Bali area accounted for around 80% of the total national capacity of the rooftop solar PV in 2021 [24].

There are challenges pertaining to the slow deployment of residential rooftop PV in Indonesia which affect all PLN customers. While several of these matters have been acknowledged in the PLN Electricity Supply Business Plan (RUPTL) 2021-2030, such as: 1) several PLN electricity networks are currently not ready to accept penetration from distributed renewable energy based generation due to oversupply conditions caused by decreased demand; 2) relatively massive penetration of rooftop PV will require PLN to add more generation plants to increase system flexibility; and 3) more capital and operational costs due to additional investment in generation control and forecasting, dispatch system, and grid code enforcement [[25], [26], [27]], other challenges are related to the lack of alignment on how regulations have been implemented.

In high level regulations, the Indonesian government through the Ministry of Energy and Mineral Resources (MEMR) has made efforts to support the implementation of rooftop solar PV, including by issuing the Ministerial Regulation No. 49/2018, which was revised by the Ministerial Regulation No. 26/2021 [28], aimed to reach 3.6 GW of rooftop PV capacity. While the later has been perceived as a tremendous advance in terms of regulation, including the recognition of 100% export of electricity back to the PLN grid and other easier procedures, implementation has been quite the opposite. PLN has reluctant to approve applications submitted for rooftop PV installations up to the maximum allowable capacity quota per customer due to utility oversupply issues. The main problem is that PLN must pay for coal-based electricity produced by Independent Power Producers (IPP) in large quantities according to ongoing contract, especially with the take or pay scheme. Currently, deliberations involving stakeholders, led by the Ministry of Energy and Mineral Resources, are being held to discuss possible options that can be taken to deal with the ongoing situation, especially to revise the Ministerial Regulation No. 26/2021 [22].

3. Methods

In this study, on-grid rooftop solar PV systems are modelled using HOMER software. Possible system sizes with different load profiles are simulated along with its economic parameters, i.e., Net Present Cost (NPC) and Levelized Cost of Energy (LCOE). Four different residential households daily load profiles have been constructed for households with electricity contract of 2,200 Volt Ampere (VA), 3,500 VA, 5,500 VA, and 6,600 VA, respectively. These load profiles are presented in Figure 1.

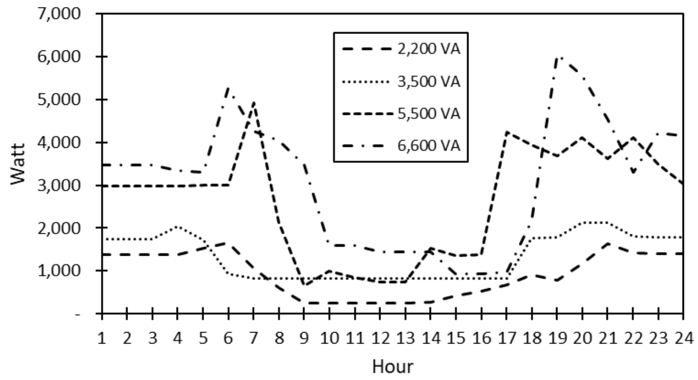

Figure 1. Surveyed hourly based daily load profile for four residential households.

While a preliminary survey has been carried out to obtain the load profiles (as shown in Figure 1) owned by different households in different locations in Surabaya – to represent different residential customer segments – this study considers only one location to allow the same solar irradiation data to be used in all simulations. It should be noted that all load profiles surveyed as shown in Figure 1 are for weekdays. Weekend patterns for most residential segments, nevertheless, show similar base load values to weekdays but have slightly higher peak load, over a short period of time, than weekdays. One thing to note is that the surveyed load profiles have ruled out the impact of Covid-19 pandemic which has recently subsided, where people spent more time at home due to restrictions on outdoor activities or working from home.

Meanwhile, several loading parameters such as the base load, maximum (peak) load, demand factor, and load factor for all residential segments are presented in Table 1. The demand factor is defined as the ratio of maximum demand to the connected load while load factor is defined as the ratio of the average load to maximum load, or for a day (24 hours), load factor is the ratio of energy consumed for 24 hours and maximum load recorded times 24 hours.

Table 1. Loading parameters for all surveyed residential households

Parameter	Residential household segments			
	2,200 VA	3,500 VA	5,500 VA	6,600 VA
Base load	240 Watt	820 Watt	657 Watt	935 Watt
Maximum load	1,655 Watt	2,127 Watt	4,915 Watt	6,056 Watt
Demand factor	0.53	0.32	0.48	0.43
Load factor	0.56	0.63	0.53	0.51

As shown in Table 1, the surveyed households are characterised by a fairly low to medium range of demand factors and rather low load factors, i.e., around 0.5 – 0.6. This, however, is a typical household situation in many urban areas in Indonesia, such as Surabaya. Demand for electricity drops between 7 AM – 4 PM as most people spend their day outside their homes studying or working. In addition, electricity has not been used for kitchen appliances except for refrigerator whereas stoves and ovens mostly use gas, and microwaves is not very common in Indonesia.

3.1. Solar resource data

Solar resource data is needed to calculate the hourly PV array power throughout the year. HOMER uses the average daily irradiance value (kWh/m^2/d) and the average clearness index for each month. Surabaya, the second largest urban area in Indonesia, has huge untapped potential for rooftop PV. Located on the east coast of the Java Sea, this 300 km^2 city area has quite high solar resources. The mapping of daily and yearly long-term average of global horizontal irradiation (GHI) of Indonesia, including Surabaya [29], is presented in Figure 2.

The long-term average daily irradiation in Surabaya, as shown in Figure 2, has reached about 5.4 kWh/m^2. This value is higher than Indonesia's daily average irradiation, which is 4.8 kWh/m^2 [29], in terms of global horizontal irradiation. This study employs the average daily radiation values for each month from NASA. The data is obtained for the latitude and longitude of 7°19' South and 112°47' East, respectively. The clearness index for each month is then calculated by HOMER, with the annual average of this clearness index being 0.53. The annual average daily radiation for the selected location is 5.3 kWh/m^2/day, or almost no different form the long-term average daily radiation value for Surabaya, as shown in Figure 2. Graphical illustration of daily radiation and clearness index for each month as used in HOMER is presented in Figure 3.

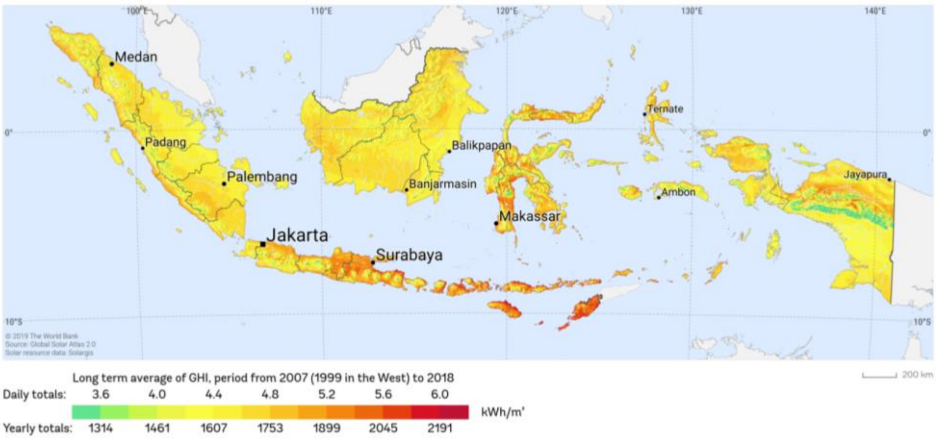

Figure 2. Mapping of daily and yearly long-term average of GHI (kWh/m^2) in Indonesia [29].

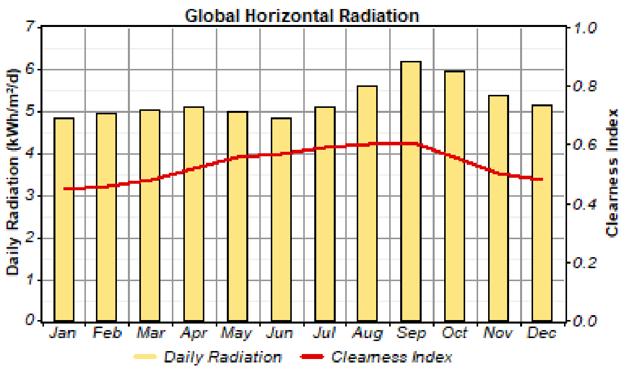

Figure 3. Monthly daily radiation and clearness index for the specified location as used in HOMER.

3.2. Reliability-cost trade-offs

In the context of residential grid-connected rooftop PV analysis, the cost-reliability trade-offs shall show residential customers the importance of knowing the options available and its potential two-sided impacts. This impact is arguably caused by a range of PV sizes that customers may consider due to budget or other constraints, including daytime power requirements and supply reliability. In contrast to the load profiles of commercial buildings in general – with loads that are relatively flat during the day, the load profiles for all surveyed households as shown in Figure 1, especially the shape of a deep valley during 7AM-4PM, can provide more choices to all customers, but also different consequences, in terms of installing any PV size that suits their needs and limitations, not only maximizing the size allowed by regulations, that is, up to whatever amount of power is contracted.

The cost-reliability trade-offs analysis in this study is carried out based on the range of maximum annual capacity shortage values assigned to the simulation. HOMER defines the total capacity shortage as the total amount of capacity shortage throughout a year, expressed in kWh/year. The value is used to calculate capacity shortage fraction. This fraction is a ratio between total capacity shortage and total electric load, both are expressed in kWh/year. The simulated systems may end up with a situation where there is an unmet load, or unserved energy when the electrical load exceeds the supply. Therefore, the total unmet load as well as unmet load fraction can be calculated accordingly for the system. Four different values of maximum annual capacity shortage, or we can say as maximum unserved energy, are applied in this study, i.e., 0%, 5%, 10%, and 15%.

3.3. System modelling, economic parameters, and assumptions

This study considers four different load profiles corresponding to the four residential customer segments. Simulations are carried out for each load profile by considering the electricity export deduction factor. The applicable electricity kWh export deduction factor determines the proportion of kWh exported to the grid that can be claimed as an electricity bill reduction factor. Two different billing deduction factors are employed in this study, i.e., 65% deduction factor as stipulated in Ministerial Regulation No. 49/2018, and 100% deduction factor according to Ministerial Regulation No. 26/2021. The first deduction factor shows that only 65% of the kWh exported to the grid can be claimed by customers as a deduction factor for electricity bills. The second factor indicates all of the kWh exported to the grid can be claimed by the customer to reduce the amount of kWh purchased from the grid.

These two conditions can be treated differently at HOMER. If net metering is not applied, i.e., using the 65% deduction factor, HOMER calculates the total energy charge by multiplying the total energy purchased from the grid by the electricity rate applicable to that household segment minus the amount of energy sold to the grid times the prevailing sellback rate. Using 100% deduction factor (HOMER defines this as net metering) and if there are net kWh purchases (more energy purchased from grid than is exported back to the grid), HOMER calculates the total energy charge by multiplying the amount of net kWh purchased from the grid with the electricity rate that applies to the household segment.

Currently, there is no Time of Use and demand charge applied to customers in Indonesian residential sector. The electricity rate for households with a 2,200 VA power contract (R1) is Rp. 1,444.70 per kWh while households with power of 3,500 VA or above (R2/R3) are charged Rp. 1,699.53 per kWh [30, 31]. Assuming the exchange rate is Rp. 15,000 per 1 US$, this gives us a US$ 0.096 per kWh for 2,200 VA customers, and US$ 0.113 per kWh for 3,500-6,600 VA ones. The simulation, therefore, applies different electricity rates between 2,200 VA and higher segments.

The simulation also takes demand uncertainty into account by allowing for up to 5% day-to-day variability, i.e., the standard deviation in the sequence of daily averages and up to 5% time-step-to-time-step, i.e., the standard deviation in the difference between the hourly data and the average daily profile, depending on the contract. Such an arrangement results in a system with a higher peak load than that obtained from the survey. For example, a 2,200 VA household with 22 kWh/d and a peak load of 1.65 kW is simulated to have a peak load of 2.1 kW due to the 5% day-to-day variability and time-step-to-time-step variability. Other than that, electricity demand is assumed to remain unchanged over the lifetime of the PV. The complete system configuration for all households in HOMER is illustrated in Figure 4.

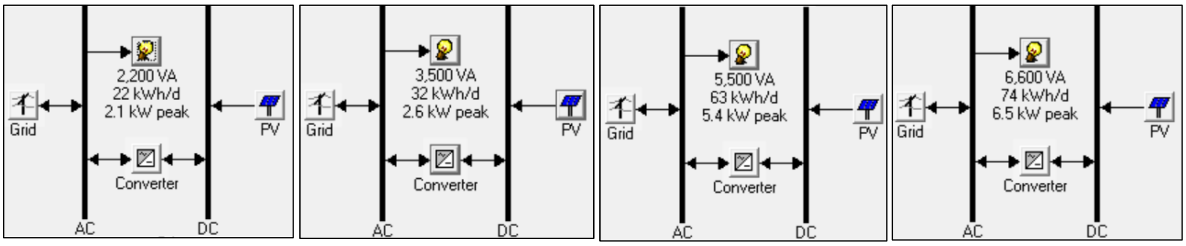

Figure 4. (Left to Right) System configurations for residential household with 2,200 VA, 3,500 VA, 5,500 VA, and 6,600 VA electricity contract in HOMER.

Solar PV array and converter

Since the effect of temperature on the PV array is not considered, HOMER calculates the power output generated by the solar PV array P_{PV} according to the following equation.

$$P_{PV} = Y_{PV} \times f_{PV}\left(\frac{G_T}{G_{T,STC}}\right) \tag{1}$$

where Y_{PV} is the rated capacity of the PV array (kW), f_{PV} is the derating factor (%), G_T is the solar radiation incident on the PV array in the current time step (kW/m^2), and $G_{T,STC}$ is the incident radiation at standard test condition (1 kW/m^2).

Capital and replacement costs for the 0.1 kW PV module are assumed to be US$ 50 each. This study assumes no annual O&M cost for the PV arrays. The cost of additional or replacement modules is assumed to increase linearly. The derating factor is assumed to be 80%, and the ground reflectance is 20%. Given an expected lifetime of 25 years, the PV arrays are installed without tracking. The slope is specified in the same degree as the location's latitude, which is 7.3°, while the azimuth is specified at 180° (due North).

Capital and replacement costs of the 1 kW converter are assumed to be US$ 400 and US$380, respectively, without annual O&M cost. The expected converter life is 15 years with 90% efficiency on the inverter side, and 85% efficiency on the rectifier side. Capital and replacement costs are assumed to increase linearly with respect to size.

System economic

This study considers a project life of 25 years and assumes an annual interest rate of 5%. Other important assumptions include system fixed capital cost and system fixed O&M cost. Considering the current total installed cost of solar PV for Indonesian residential sector, i.e., US$ 1,000/kWp [32, 33], and the cost of solar PV modules and converters, the system fixed capital cost and the fixed O&M cost are set at US$ 200 and US$ 20/year, respectively.

There are three types of costs identified in HOMER. They are total net present cost (Total NPC), operating cost, and cost of energy (COE). The Total NPC, expressed in $, is used in economic analysis to show the system's life cycle cost. It is calculated as follows.

$$C_{NPC} = \frac{C_{ann,tot}}{CRF(i,R_{proj})} \tag{2}$$

$$CRF(i,N) = \frac{i(1+1)^N}{(1+i)^N - 1} \tag{3}$$

where $C_{ann,tot}$ is total annualised cost ($/year), CRF is capital recovery factor, i is interest rate (%), and R_{proj} is project lifetime (year).

Operating costs, expressed in $/year, are the sum of the annual O&M costs, and annualised replacement cost minus annualised salvage value. For grid-connected systems, it includes the annualised cost of electricity purchased from grid (grid purchases) minus electricity sold unto the grid (grid sales). Salvage value S is calculated based on the component's replacement cost C_{rep}, and is assumed to be proportional to the remaining component life as follows.

$$S = C_{rep} \times \frac{R_{rem}}{R_{comp}} \tag{4}$$

$$R_{rem} = R_{comp} - (R_{proj} - R_{rep}) \tag{5}$$

where R_{rem} is the remaining life of the component at the end of the project lifetime, R_{comp} is lifetime of the component, and R_{proj} is project lifetime.

Lastly, the COE in HOMER is defined as the average cost per kWh produced by the system. To calculate the COE, HOMER divides the total annualised cost of the system $C_{ann,tot}$ by the total electricity produced $E_{prim,AC}$, including total grid sales $E_{grid,sales}$, as follows.

$$COE = \frac{C_{ann,tot}}{E_{prim,AC} + E_{grid,sales}} \tag{6}$$

Scenarios and cases

This study considers two main scenarios regarding the selection of solar PV size candidates for the simulation. The first scenario is identified as Maximum-PV-Capacity (MPVC). This basically refers to the maximum solar PV capacity a customer is allowed to install, i.e., up to the contracted power (VA), as per regulations. For example, households with 2,200 VA power are allowed to install solar PV panels up to 2.2 kWpeak. In this case, HOMER is equipped with solar PV panels up to 2.2 kWpeak in fractions of 0.1 kW, and similarly for the rest of the household segments. These size candidates will be simulated by HOMER along with the fraction of capacity purchased from the grid. Optimisation will result in a system configuration with the least Total NPC, among other alternative results.

The second scenario is called Half-PV-Capacity (HPVC). In this scenario, a 6,600 VA household, for example, is simulated using solar PV panels up to 3.3 kW, or half the allowed size, in 0.1 kW fractions, and similarly for other households considered in this study. Basically, this scenario is implemented based on the finding of low load during the day, i.e., between 7AM to 4PM. Subsequently, the total NPC obtained in the MPVC and HPVC scenarios for each household segment are compared in the analysis. For these two main scenarios, the maximum capacity shortages of 5%, 10%, and 15% are considered as an indicator of reliability, that is equal to maximum unmet load in a year, as described in Section 3.2. This paper uses the terminology of capacity shortage and unserved energy (unmet load) interchangeably, expressed either in a percentage or kWh/year.

Four cases are considered for each residential household customer, or in other words two cases for each scenario as described earlier. The first scenario (MPVC) consists of 100%-MPVC and 65%-MPVC, while the second one (HPVC) consists of 100%-HPVC, and 65%-HPVC. In this regards, 100% and 65% refer to the applicable deduction factor according to the regulations. In a similar way, the analysis can be also classified into four groups with respect to the household's contracted power, with each group consists of 4 cases, i.e., 100%-MPVC, 100%-HPVC, 65%-MPVC, 65%-HPVC.

4. Results and Discussion

The simulation results for each case of the 2,200 VA household surveyed are shown in Figure 5 to Figure 8, respectively. In the 100%-MPVC case, the total NPC has reached \$9,175 for no unserved energy and has fallen to \$7,987 or 13% for up to 11% realised unserved energy (capacity shortage). As for no-unserved energy, the total NPC increased to \$10,031, \$10,371, and \$10,661 for the 65%-MPVC, 100%-HPVC, and 65%-HPVC cases, respectively. Operating costs, which mostly include the cost of electricity purchased from grid less electricity sold into the grid, varied within a considerably narrow range, i.e., between \$432 - \$577, for MPVC cases, and between \$570 - \$675 for HPVC cases.

It is interesting to note that the total NPCs for 100%-MPVC in the realised unserved energy range, are found to be the lowest among other cases. From the simulations, it is revealed that the total NPC of 0% capacity shortage for 100%-MPVC, that is \$9,175, cheaper than the total NPC of 7% capacity shortage for 65%-MPVC and the total NPCs of 11% capacity shortage for HPVC cases. This implies potential benefits to households with 2,200 VA power from rooftop PV installations up to the maximum permitted capacity and under a 100% billing deduction factor policy over various options in terms of possible unserved energy, possible installed rooftop PV capacity, and billing deduction factors.

The reliability-cost trade-offs can be seen in all four cases between the total NPCs and realised capacity shortages. In a 2,200 VA, 100%-MPVC case study, for example, it is found that the unmet load are 283kWh/year, 542 kWh/year, and 881 kWh/year, for 4%, 7%, and 11% realised capacity shortages, respectively. While the total NPCs have shown a noticeable decrease of around \$350 - \$450 every 3-4% additional unmet load, the COEs are found to be relatively similar. Other cases have shown similar characteristics, with constant COEs particularly for the cases with a deduction factor of 65%.

Max. Cap. Shortage (%)				PV (kW)	Conv. (kW)	Grid (kW)	Initial Capital	Operating Cost (\$/yr)	Total NPC	COE (\$/kWh)	Ren. Frac.	Capacity Shortage
0.0				2.2	1.5	1.8	\$ 1,900	516	\$ 9,175	0.081	0.33	0.00
5.0				2.2	1.5	1.4	\$ 1,900	489	\$ 8,796	0.081	0.34	0.04
10.0				2.2	1.5	1.3	\$ 1,900	464	\$ 8,446	0.080	0.35	0.07
15.0				2.2	1.5	1.2	\$ 1,900	432	\$ 7,987	0.079	0.36	0.11

Figure 5. Simulation results for 2,200 VA: 100%-MPVC

Max. Cap. Shortage (%)				PV (kW)	Conv. (kW)	Grid (kW)	Initial Capital	Operating Cost (\$/yr)	Total NPC	COE (\$/kWh)	Ren. Frac.	Capacity Shortage
0.0				2.2	1.5	1.8	\$ 1,900	577	\$ 10,031	0.089	0.33	0.00
5.0				2.2	1.5	1.4	\$ 1,900	550	\$ 9,652	0.088	0.34	0.04
10.0				2.2	1.5	1.3	\$ 1,900	525	\$ 9,302	0.088	0.35	0.07
15.0				2.2	1.5	1.2	\$ 1,900	493	\$ 8,842	0.088	0.36	0.11

Figure 6. Simulation results for 2,200 VA: 65%-MPVC

Max. Cap. Shortage (%)	PV (kW)	Conv. (kW)	Grid (kW)	Initial Capital	Operating Cost ($/yr)	Total NPC	COE ($/kWh)	Ren. Frac.	Capacity Shortage
0.0	1.1	1.0	1.8	$ 1,150	654	$ 10,371	0.092	0.19	0.00
5.0	1.1	1.0	1.4	$ 1,150	627	$ 9,987	0.092	0.20	0.04
10.0	1.1	1.0	1.3	$ 1,150	602	$ 9,636	0.091	0.21	0.07
15.0	1.1	1.0	1.2	$ 1,150	570	$ 9,177	0.091	0.21	0.11

Figure 7. Simulation results for 2,200 VA: 100%-HPVC

Max. Cap. Shortage (%)	PV (kW)	Conv. (kW)	Grid (kW)	Initial Capital	Operating Cost ($/yr)	Total NPC	COE ($/kWh)	Ren. Frac.	Capacity Shortage
0.0	1.1	1.0	1.8	$ 1,150	675	$ 10,661	0.094	0.19	0.00
5.0	1.1	1.0	1.4	$ 1,150	648	$ 10,277	0.094	0.20	0.04
10.0	1.1	1.0	1.3	$ 1,150	623	$ 9,926	0.094	0.21	0.07
15.0	1.1	1.0	1.2	$ 1,150	590	$ 9,467	0.094	0.21	0.11

Figure 8. Simulation results for 2,200 VA: 65%-HPVC

As shown in Figure 5 to Figure 8, optimisation results provide other insight into the role of the cost components in the trade-off analysis. While the initial capital costs are certainly found to be lower in HPVC cases compared to MPVC ones due to less PV module involved, i.e., $1,150 versus $1,900, it is found that the total NPCs of MPVC cases are found cheaper than those in HPVC cases with respect to the same realised capacity shortage, mainly due to cheaper annualised operating cost.

Meanwhile, the renewable energy fraction, i.e., the total contribution of electricity energy generation from renewable energy, has reached 33-36% in the cases of MPVC and 19-21% in the cases of HPVC, all within the range of 11% realised unserved energy. It should be noted that limiting the installed capacity of solar PV module to half of the maximum allowable capacity will affect the penetration rate of solar PV in the systems.

The cost-reliability trade-off in terms of total NPC versus realised unserved energy (capacity shortage) for all cases in 2,200 VA and 3,500 VA, as well as 5,500 VA and 6,600 VA households, are depicted in Figure 9 and Figure 10, respectively. For all households, there is a relatively large difference in total NPCs between the 100%-MPVC cases and the 65%-MPVC cases with respect to the all realised capacity shortages (up to maximum 15% capacity shortage), while insignificant differences of the total NPCs are found between those in the 100%-HPVC cases and the 65%-HPVC cases.

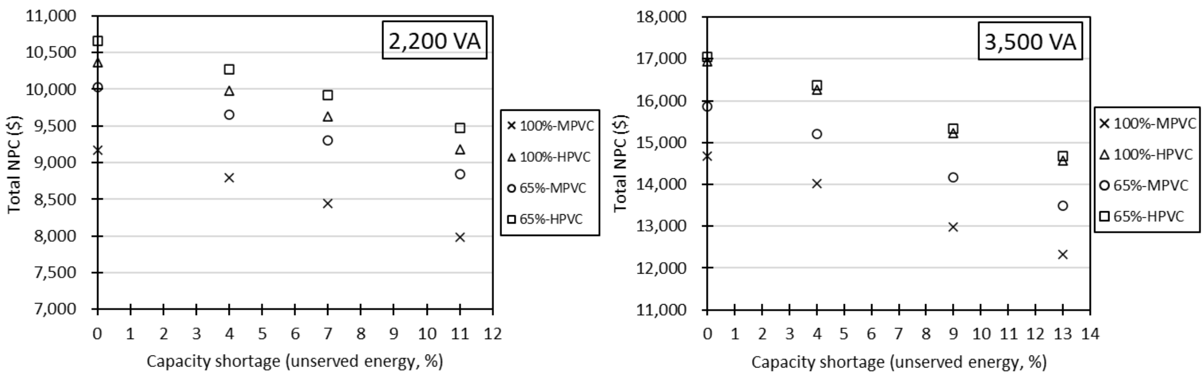

Figure 9. Total NPCs versus capacity shortage in all cases for 2,200 VA (left) and 3,500 VA (right)

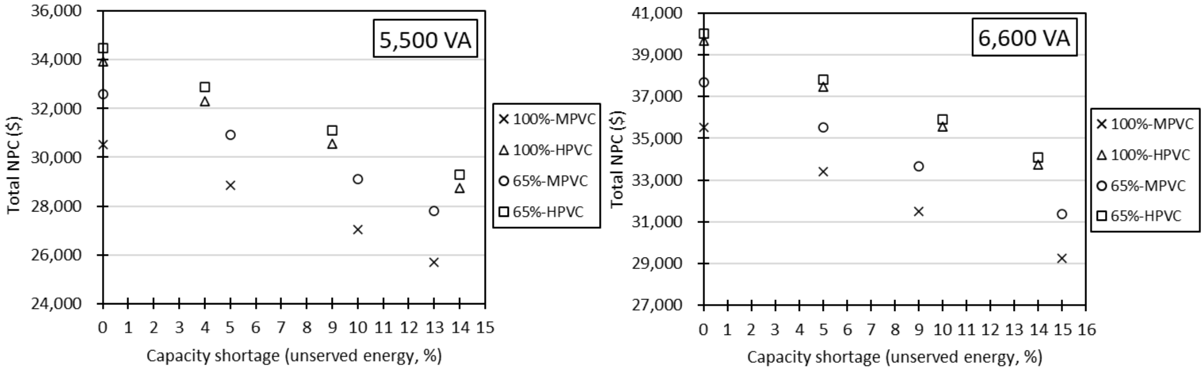

Figure 10. Total NPCs versus capacity shortage in all cases for 5,500 VA (left) and 6,600 VA (right)

Further analysis is carried out to determine which households exhibited the lowest cost per watt of PV installed capacity, in addition to exploring and comparing common economic parameters such as total NPC, operating cost, and COE. Among all considered household segments, the lowest cost per watt of PV installed capacity can be determined by comparing the values of total system cost (total NPC) with the PV installed capacity. Comparing all cases of 100%-MPVC and 65%-MPVC, as well as 100%-HPVC and 65%-HPVC without unserved energy, the variation in cost per watt of PV installed capacity is presented in Table 2.

Table 2. The cost per watt of PV installed capacity with 0% unserved energy.

Household	The cost per watt of PV installed capacity ($/Watt)			
	100%-MPVC	65%-MPVC	100%-HPVC	65%-HPVC
2,200 VA	4.17	4.56	9.43	9.69
3,500 VA	4.20	4.53	9.68	9.74
5,500 VA	5.55	5.93	12.34	12.54
6,600 VA	5.38	5.71	12.02	12.12

As shown in Table 2, the total NPC per watt of PV installed capacity, under 0% unserved energy, varied from $4.14/Watt to $12.54/Watt in all cases across all households. The results show similar costs in the MPVC cases with respect to 2,200 VA and 3,500 VA households and slightly more than double in the HPVC cases, and similar for 5,500 VA and 6,600 VA households. It is also found that the costs per watt of PV installed capacity are not affected by the applicable billing deduction factors but by the PV capacity. Nevertheless, it should be noted that the values obtained in Table 2 are largely influenced by the household's daily electricity load profile, among other related scenarios.

The simulation results in terms of possible system capacity, consisting of grid and PV capacity across all realised capacity shortages (unserved energy) in all cases of all households, are depicted in Figure 11 and Figure 12.

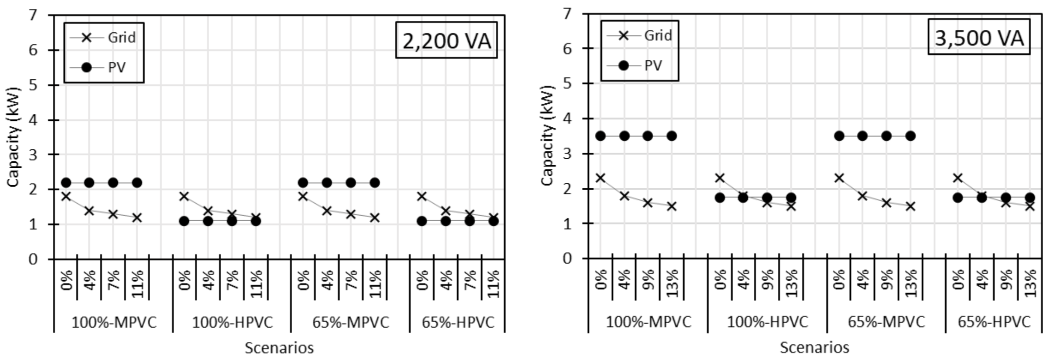

Figure 11. System capacity across all realised capacity shortage for 2,200 VA (left) and 3,500 VA (right)

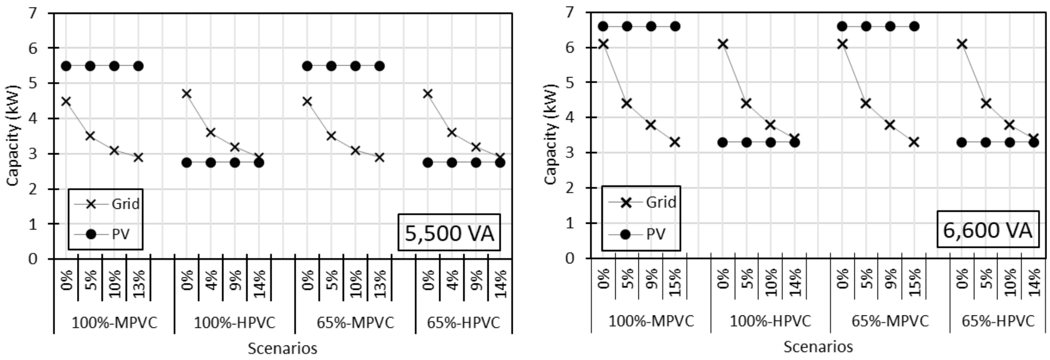

Figure 12. System capacity across all realised capacity shortage for 5,500 VA (left) and 6,600 VA (right)

As seen in Figure 11 and 12, while the optimisations have maximised the PV capacity across all realised unserved energy and according to the scenarios, higher unserved energy have resulted in lower grid capacity required by the system to meet the demand according to system's maximum unserved energy constraint. Moreover, it is interesting to note that the PV capacities across all MPVC cases are always higher than the grid ones. On the other hand, the grid capacities are mostly higher than those of PV in most HPVC cases, except in 3,500 VA for 9% and above unserved energy. In all cases of each household, the grid capacities have varied decreasingly across similar values within the realised unserved energy range. For example, in 2,200 VA (see Figure 11 left), the grid capacities are found at 1.8 kW, 1.4 kW, 1.3 kW, and 1.2 kW with respect to increasing realised unserved energy, in all cases, and similarly in other households.

It should be noted that, despite the possible variations and differences in terms of households' daily loading profiles among the surveyed residential sector segments, along with other affecting factors, which may cause different results and interpretations, this study has sought to explore possible cost-reliability trade-offs in Indonesia's urban residential rooftop PV applications due to factors such as possible unserved energy, PV capacity, and billing deduction factors. The significance of these three factors have been shown in the analysis considering residential households as to represent the customer side, and therefore, should be considered not only by customers who are willing to apply on-grid rooftop PV but also by stakeholders such as government and utility company according to their role in supporting more on-grid rooftop PVs connected to the power systems.

There is no doubt about the techno-economic potential of on-grid rooftop PV in accelerating distributed renewable energy penetration. Nevertheless, as the deployment of this rooftop PV seems to be modest status, some significant changes on the existing set of regulations are required. More encouraging, innovative policies should be adopted and introduced to address barriers and challenges faced by customers and industry towards more progressive status of rooftop PV deployment.

5. Conclusions

This paper aims to explore the potential of grid-connected rooftop PV in terms of how the systems can be better planned and utilised through understanding possible trade-offs between system reliability and cost while recognising challenges to utility supply security in the context of emerging economies. This study has assessed the trade-offs between cost and reliability for grid-connected rooftop PV in emerging economies. Simulations were carried out using HOMER for a case study of urban household customers in Indonesia, with the surveyed households located in Surabaya. The implications of three factors, namely unserved energy, PV capacity, and billing deduction factors, have been analysed to determine possible cost-reliability trade-offs, in terms of total NPC and realised unserved energy (capacity shortage). Four residential customer segments have been considered in the analysis, i.e., 2,200 VA, 3,500 VA, 5,500 VA, and 6,600 VA, and four cases in each segment that represent scenarios on PV capacities and billing deduction factors.

The optimisation results show that the reliability-cost trade-offs are observable in all four cases of each household segment between the total NPCs and realised capacity shortages. Moreover, the analyses have highlighted the role of cost components in the trade-off involving HPVC and MPVC cases, of which pertaining to initial capital costs and total NPCs. For example, relatively large gaps in terms of the total NPCs for all households are identified between 100%-MPVC cases and 65%-MPVC cases with respect to the all realised capacity shortages up to maximum 15% shortage, while insignificant differences are found between those in 100%-HPVC cases and 65%-HPVC cases.

The analysis also highlights the lowest cost per watt of PV installed capacity, which can be determined by comparing the values of the total system cost (total NPC) to the PV installed capacity. It is found that the costs per watt of PV installed capacity are not affected by the applicable billing deduction factors but rather by the capacity of PV. It is also found that the PV capacities have been maximised at all unserved energy levels according to the scenarios, whereas higher unserved energy have resulted in lower grid capacity required by the system to meet the demand according to the maximum unserved energy limit of the system. Residential customers should be thoughtful when planning their on-grid rooftop PV amidst the potential trade-offs between cost and reliability while paying attention to changing regulations which might be affecting customers overall benefits. Finally, the analysis conducted in this study has provided insights not only to the residential customers but also to stakeholders involved in issuing and implementing rooftop PV policies.

Acknowledgement

The author would like to thank profusely to the reviewers who have taken the time and effort necessary to review the manuscript. All valuable comments and suggestions, which help in improving the quality of the manuscript, are greatly appreciated.

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28 April 2023
Dear Professor Henrik Lund,
Editor-in-Chief Energy-Elsevier

Please consider the attached manuscript entitled " Cost-reliability trade-offs for grid-connected rooftop PV in emerging economies: a case of Indonesia's urban residential households" authored by Yusak Tanoto, for publication in Energy.

The utilisation of solar photovoltaic (PV) systems has significantly increased in recent years. In many urban areas in emerging economies and jurisdictions, rooftop solar PV has been seen growing, with grid-connected rooftop PV has been seen as one of the viable options for supplying electricity in residential households. In the context of emerging economies, however, it is important to note that the development of rooftop PV has been both economically and technically driven by rising electricity rates and the challenges faced by utilities in providing reliable supply, even in urban distribution networks.

Rooftop PV has to date seen only modest deployment in many emerging countries, despite the technological overall competitiveness and progressive regulations that have been implemented in those jurisdictions. On the customer side, the decision whether to implement grid-connected rooftop PV or simply continue with the existing power connections from the utility grid is, in many cases, not supported by adequate techno-economic analyses, especially when focussing on reliability and cost implications due to system setting and regulations. Special attention should also be given to the relatively poor reliability of urban distribution networks, which has notable significance for energy users in the residential sector, especially when it comes to choosing an appropriate size for grid-connected rooftop PV.

This study addresses the complexities for residential rooftop PV planning studies that have been less explored to date. While residential rooftop PV systems can be enhanced by other generation technologies such as wind or diesel, gas, and energy storage, aiming to improve system reliability and efficiency, this paper particularly focusses on the question of how residential customers can be more thoughtful about how the systems can be better planned and utilised through understanding possible trade-offs between system reliability and cost, while recognising challenges to utility supply security in the context of emerging economies. This study considers grid-connected PV systems in urban household applications in Surabaya, Indonesia, as a case study.

This paper's contribution is to explore the implications of three factors, i.e., different reliability targets, possible PV installed capacity, and billing deduction factors, on the trade-offs between total net present costs and realised unserved energy, and possible system configurations for various residential segment's on-grid rooftop PV in a developing country context. The analyses are carried out using HOMER that models on-grid rooftop PV considering scenarios that are related to those three factors.

This paper demonstrates the approach for the case of Indonesia's urban residential rooftop PV. Similar to a number of other developing countries, Indonesia has significant demand growth, a present reliance on fossil-fuel generation yet excellent renewable resources - particularly solar. While the study uses the Indonesian residential households as the case study, the method used, and insights obtained from the analyses presented in this paper are highly relevant to other jurisdictions with similar contexts.

I believe that this article will attract the readership from both popular and scientific audiences interested in the residential rooftop PV planning in the context of developing countries. I confirm that this manuscript has not been published elsewhere and is not under consideration by another journal. I am also available as a reviewer for Energy.

Thank you very much and I am looking forward to hearing from you soon.

Sincerely yours,

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Declaration of interests

☒The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

☐The authors declare the following financial interests/personal relationships which may be considered as potential competing interests:

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Thank you very much for expressing your interest in ENERGY.

Sincerely,

Henrik Lund
Editor-in-Chief
Energy
Data in Brief (optional):

We invite you to convert your supplementary data (or a part of it) into an additional journal publication in Data in Brief, a multi-disciplinary open access journal. Data in Brief articles are a fantastic way to describe supplementary data and associated metadata, or full raw datasets deposited in an external repository, which are otherwise unnoticed. A Data in Brief article (which will be reviewed, formatted, indexed, and given a DOI) will make your data easier to find, reproduce, and cite.

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Note: While submitting the revised manuscript, please double check the author names provided in the submission so that authorship related changes are made in the revision stage. If your manuscript is accepted, any authorship change will involve approval from co-authors and respective editor handling the submission and this may cause a significant delay in publishing your manuscript.

Comments from Editors and Reviewers:

Reviewer responses to questions:

Reviewer's Responses to Questions

Note: In order to effectively convey your recommendations for improvement to the author(s), and help editors make well-informed and efficient decisions, we ask you to answer the following specific questions about the manuscript and provide additional suggestions where appropriate.

1. Are the objectives and the rationale of the study clearly stated?

Please provide suggestions to the author(s) on how to improve the clarity of the objectives and rationale of the study. Please number each suggestion so that author(s) can more easily respond.

Reviewer #1: Yes.

Reviewer #2: see comment 2

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2. If applicable, is the application/theory/method/study reported in sufficient detail to allow for its replicability and/or reproducibility?

Please provide suggestions to the author(s) on how to improve the replicability/reproducibility of their study. Please number each suggestion so that the author(s) can more easily respond.

Reviewer #1: Mark as appropriate with an X:
Yes [] No [x] N/A []
Provide further comments here:
No verifiable data.

Reviewer #2: Mark as appropriate with an X:
Yes [X] No [] N/A []
Provide further comments here:

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3. If applicable, are statistical analyses, controls, sampling mechanism, and statistical reporting (e.g., P-values, CIs, effect sizes) appropriate and well described?

Please clearly indicate if the manuscript requires additional peer review by a statistician. Kindly provide suggestions to the author(s) on how to improve the statistical analyses, controls, sampling mechanism, or statistical reporting. Please number each suggestion so that the author(s) can more easily respond.

Reviewer #1: Mark as appropriate with an X:
Yes [] No [x] N/A []
Provide further comments here:
It uses software that does most of the calculations.

Reviewer #2: Mark as appropriate with an X:
Yes [] No [] N/A []
Provide further comments here:
see comment 12

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4. Could the manuscript benefit from additional tables or figures, or from improving or removing (some of the) existing ones?

Please provide specific suggestions for improvements, removals, or additions of figures or tables. Please number each suggestion so that author(s) can more easily respond.

Reviewer #1: Yes, the manuscript needs to present tables describing the data used such as solar irradiance.

Reviewer #2: (No Response)

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5. If applicable, are the interpretation of results and study conclusions supported by the data?

Please provide suggestions (if needed) to the author(s) on how to improve, tone down, or expand the study interpretations/conclusions. Please number each suggestion so that the author(s) can more easily respond.

Reviewer #1: Mark as appropriate with an X:
Yes [x] No [] N/A []
Provide further comments here:

Reviewer #2: Mark as appropriate with an X:
Yes [X] No [] N/A []
Provide further comments here:

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6. Have the authors clearly emphasized the strengths of their study/theory/methods/argument?

Please provide suggestions to the author(s) on how to better emphasize the strengths of their study. Please number each suggestion so that the author(s) can more easily respond.

Reviewer #1: No

Reviewer #2: (No Response)

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7. Have the authors clearly stated the limitations of their study/theory/methods/argument?

Please list the limitations that the author(s) need to add or emphasize. Please number each limitation so that author(s) can more easily respond.

Reviewer #1: No

Reviewer #2: The conclusion should put more emphasis on the benefits of rooftop PV supported by the findings of the paper.

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8. Does the manuscript structure, flow or writing need improving (e.g., the addition of subheadings, shortening of text, reorganization of sections, or moving details from one section to another)?

Please provide suggestions to the author(s) on how to improve the manuscript structure and flow. Please number each suggestion so that author(s) can more easily respond.

Reviewer #1: Yes.

Reviewer #2: (No Response)

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9. Could the manuscript benefit from language editing?

Reviewer #1: Yes

Reviewer #2: Yes

Reviewers' comments on the manuscript:

Editor #: Please make sure that your paper is clear in the description of the scientific novelty in comparison to what have previously been published in ENERGY within the same topic. Introduction and literature review should be revised by looking at recent papers published in this field within the scope of Energy Journal.

Reviewer #1: The manuscript cannot be published in this presentation, it needs to be improved.

Here are my recommendations:
1. It should be defined how decimals are going to be separated, in some cases they use comma as decimal separator and in others they do not, please check well the text.
2. Present a table with the solar irradiance data obtained by NASA, frequency of registration.
3. Demonstrate how the data were calibrated for use in HOMER.
4. Figure 2 should be improved, the legend is not distinguishable.
5. Describe what the clearness index is.
6. Present the equations for calculating the Solar PV array and converter section.
7. Present the source of the data in the System economic section.

The authors present a study with two scenarios using the HOMER software, much of the method is done through this software, it is recommended to the authors to add a model, or more scientific method, to use HOMER and enrich it with the proposal of a model that improves it.

Reviewer #2: Thank you for the submission of the paper. The paper can be considered for publication after a major revision.
Main comment:
1) Before resubmitting the revised version, a thorough language check has to be done.
2) section2: When describing the current situation, it is of importance to describe the development of the massive oversupply of coal fired power stations from 2015 on. In addition, it should be mentioned that PLN is very reluctant to modify its plans for additional coal fired power stations, which are not yet build. A quantification of the oversupply in the different Indonesian regions as well as the still planed capacity additions should be show to explain the situation. In this context it would be of interest to add a more detailed description of the actual barriers for PV implementation and how this could eventually be solved.
3) currencies should always written in ISO code, eg. IDR, USD
4) CAPEX and OPEX should be given in IRD to make it comparable with kWh prices.
5) All abbreviation should be spelled out at the first use in the text.
detailed comments
6) ref 1,2: Here the IEA PVPS Snapshots could be added: https://iea-pvps.org/snapshot-reports/snapshot-2023/
7) page1, line 46-49: The uptake of PV rooftop systems due to rising electricity prices is a world wide phenomena, not only in emerging economies. Eg. Australia, Netherlands and many others
8) page 2, line 11 and 15: reference to the respective software programmes, eg. where to find it, is missing
9) page 3, line 5: Various publications and organssations like ISER mention: missing permits, administrative barriers, perception of high costs
10) page 3, line 45 -50: Here some of the arguments a contradicting each other. E.g. if an oversupply in the form of coal exists, no additional flexibility reserve is needed.
11) Figs 5 to 8: These are actually tables. Please avoid the term operating costs, because you are effectively describing the costs for the PV generated and grid bought electricity.
12) a sensitivity analysis of the economic variable would be helpful.

3. Submitted the revised manuscript via the online submission system
   - Response to editors' and reviewers' comments (22 September 2023 – Indonesia time)
   - The full manuscript draft (22 September 2023 – Indonesia time) consists of:
     - Highlight
     - cover letter
     - CRediT author statement
     - Declaration of interests
     - Revised manuscript without track changes
     - Revised manuscript with track changes
     - Point-to-point response to reviewers

Response to editor's and reviewers' comments and review report:

Ref. No.: EGY-D-23-04810

Title:
Cost-reliability trade-offs for grid-connected rooftop PV in emerging economies: a case of Indonesia's urban residential households

I thank the editor and reviewers for their thoughtful criticisms and helpful suggestions on how to improve the paper. I have addressed these with extensive revisions to the paper, as outlined below, and believe the work has been greatly strengthened as a result. I hope that it is now suitable for publication in ENERGY.

Editor #:

Please make sure that your paper is clear in the description of the scientific novelty in comparison to what have previously been published in ENERGY within the same topic. Introduction and literature review should be revised by looking at recent papers published in this field within the scope of Energy Journal.

Author's response: Thank you for this suggestion. I have improved the introduction section (Section 1) and updated the literature review up to Section 2. The revised paper now has 15 references from ENERGY journal (marked up with yellow in the references section of the revised paper), and this includes 6 additional papers on the topic from ENERGY as detailed below:

[22] K. Mohammadi, M. Naderi, M. Saghafifar. Economic feasibility of developing grid-connected photovoltaic plants in the southern coast of Iran. Energy, 156 (2018), pp. 17-31.
[24] Á. X. C. de Jesus, D. P. Neto, E. G. Domingues. Computational tool for technical-economic analysis of photovoltaic microgeneration in Brazil. Energy, 271 (2023), 126962.
[30] Z. Xin-gang, X. Yi-min. The economic performance of industrial and commercial rooftop photovoltaic in China. Energy, 187 (2019), 115961.
[31] A. Orioli, A.D. Gangi. Six-years-long effects of the Italian policies for photovoltaics on the pay-back period of grid-connected PV systems installed in urban contexts. Energy, 122 (2017), pp. 458-470.
[33] G.G. Pillai, G.A. Putrus, T.Georgitsioti, N.M. Pearsall. Near-term economic benefits from grid-connected residential PV (photovoltaic) systems. Energy, 68 (2014), pp. 832-843.
[46] D. Wang, D. Liu, C. Wang, Y. Zhou, X. Li, M. Yang. Flexibility improvement method of coal-fired thermal power plant based on the multi-scale utilization of steam turbine energy storage. Energy, 239 (2022), 122301.

In addition to references previously included in Section 1 and Section 2 of the submitted draft, I have added additional literature from sources other than the ENERGY journal, marked up with grey, as follows:

[3] PVPS: Snapshot of Global PV Markets 2023. Available: https://iea-pvps.org/snapshot-reports/snapshot-2023/ [Accessed 1 September 2023].
[15] HOMER software. Available: https://www.homerenergy.com/ [Accessed 29 August 2023].
[18] PV*SOL software. Available: https://pvsol.software/en/ [Accessed 30 August 2023].

[19] Photovoltaic Geographical Information System (PVGIS). Available: https://joint-research-centre.ec.europa.eu/photovoltaic-geographical-information-system-pvgis_en [Accessed 2 September 2023].
[20] SOLARGIS PV planner. Available: https://solargis.info/pvplanner/#tl=Google:hybrid&bm=satellite [Accessed 2 September 2023].
[21] SISIFO. Available: https://www.sisifo.info/es/default [Accessed 1 September 2023].
[22] K. Mohammadi, M. Naderi, M. Saghafifar. Economic feasibility of developing grid-connected photovoltaic plants in the southern coast of Iran. Energy, 156 (2018), pp. 17-31.
[23] RETScreen software. Available: https://natural-resources.canada.ca/maps-tools-and-publications/tools/modelling-tools/retscreen/7465 [Accessed 15 September 2023].
[29] PVsyst Photovoltaic Software. Available: https://www.pvsyst.com/ [Accessed 7 September 2023].
[35] Regulatory Support: Key to Unlock Indonesia's Solar Potential. Available: https://iesr.or.id/en/regulatory-support-key-to-unlock-indonesias-solar-potential [Accessed 2 September 2023].
[36] Technical issue is not the main barriers to the renewable energy transition; financial and regulatory issues are. Available: https://iesr.or.id/road-to-energy-transition [Accessed 9 September 2023].
[37] Indonesia's Solar Policies Designed to Fail? Available: https://ieefa.org/wp-content/uploads/2019/02/Indonesias-Solar-Policies_February-2019.pdf [Accessed 3 September 2023].
[38] Market Potential of Rooftop Solar PV in Surabaya: A Report. Available: https://iesr.or.id/wp-content/uploads/2019/08/IESR-Market-Potential-of-Rooftop-Solar-PV-in-Surabaya.pdf [Accessed 15 September 2023].
[39] Residential Rooftop Solar: Technical and Market Potential in 34 Provinces in Indonesia. Available: https://iesr.or.id/wp-content/uploads/2019/07/IESR-Technical-Note-Residential-Rooftop-Solar-Potential-in-34-Provinces-ID.pdf [Accessed 9 September 2023].
[47] Flexible Thermal Power Plant: An Analysis of Operating Coal-Fired Power Plants Flexibly to Enable the High-Level Variable Renewables in Indonesia's Power System. Available: https://iesr.or.id/wp-content/uploads/2022/06/IESR-Flexible-Thermal-Power-Plant-2022.pdf [Accessed 29 August 2023].
[49] Rooftop PV users cannot sell electricity to PLN (in Bahasa Indonesia). Available: https://www.cnbcindonesia.com/news/20230308131539-4-419924/pemakai-plts-atap-tak-bisa-jual-listrik-ke-pln-ini-alasannya [Accessed 12 September 2023].
[50] Not Yet Extinct, PLN Adds 13,819 MW Coal Power Plants Until 2030 (in Bahasa Indonesia). Available: https://www.cnbcindonesia.com/news/20211005154444-4-281622/belum-punah-pln-tambah-13819-mw-pltu-batu-bara-hingga-2030 [Accessed 5 September 2023].

New references included in Section 3 of the revised paper are as follows.

[52] Page, J. (2012). The Role of Solar-Radiation Climatology in the Design of Photovoltaic Systems. Practical Handbook of Photovoltaics, 573–643.
[53] NSRDB: National Solar Radiation Database. Available: https://nsrdb.nrel.gov/data-viewer [Accessed 31 August 2023].
[56] Solar PV Inverter DC to AC 1000-Watt price in Indonesia. Available: https://www.tokopedia.com/baterailab/thinkpower-grid-tie-ongrid-inverter-1-6k-sseries-with-limiter-wifi-1000w?extParam=ivf%3Dfalse&src=topads [Accessed 10 September 2023].
[57] Solar PV panel 100-Watt peak price in Indonesia. Available:

https://www.tokopedia.com/asia-teknindo/solar-panel-surya-solar-cell-100-wp-100-wattpolycrytalline-maysun [Accessed 9 September 2023].
[60] Rooftop PV system fixed capital and maintenance cost in Indonesia (in Bahasa Indonesia). Available: https://www.kompas.com/properti/read/2022/06/04/080000221/berapa-biaya-pemasangan-plts-atap-di-rumah-simak penghitungannya?page=all#:~:text=Adapun%20total%20biaya%20pemasangan%20PLTS%20sebesar%20Rp%2033.703.900%2C%20rinciannya,Beton)%3A%20Rp%203.060.000 [Accessed 11 September 2023].

I have also presented a clearer description of the scientific novelty and new perspectives provided by the study in comparison to this existing work, as follows.

Introduction – paragraph 9:
While studies focussing on single household analysis or involving multiple sites have provided useful insights for stakeholders regarding the potential techno-economic impacts of grid-connected rooftop PV and its deployment opportunity, less explored, however, has been the impacts of different capacity shortages (unserved energy targets), PV capacity, and billing deduction factors. In particular, there has been little attention of the potential trade-offs between system reliability and costs.

Introduction – paragraph 11:
This paper offers a new perspective on the ongoing rooftop PV studies from a techno-economic standpoint. It introduces the concept of reliability-cost trade-offs that may arise due to different energy targets and the resulting variations in PV system sizes. These trade-offs are particularly relevant in emerging economies given the level of reliability and associated costs can vary significantly. The paper models unserved energy targets by accounting for potential capacity shortages on the supply side.

Reviewer #1:

The manuscript cannot be published in this presentation, it needs to be improved. Here are my recommendations:

1. It should be defined how decimals are going to be separated, in some cases they use comma as decimal separator and in others they do not, please check well the text.

   Response: Thank you for this constructive feedback. In the revised paper, the separator between the decimals is a dot (point), and the thousands separator is a comma. I double-checked that this arrangement is applied consistently.

2. Present a table with the solar irradiance data obtained by NASA, frequency of registration.

   Response: Thank you for this comment. I should have been clearer on this issue. The solar irradiance data presented in the paper, i.e., the GHI and / or Clearness Index, were obtained from NASA database through HOMER. I have now added some discussions in the revised paper regarding the two options that users can choose in entering the solar irradiation data into HOMER software. In summary, the data can be either downloading from HOMER or from the NREL National Solar Radiation Database (NSRDB) data viewer website. The complete descriptions are provided in Section 3.1 paragraph 2 (including the steps to access the data in NSRDB website), paragraph 3 (including description about time interval of the data), and paragraph 4, as follows.

Section 3.1 – paragraph 2:

HOMER allows users to enter GHI and/or Clearness Index values using one of the two possible approaches, i.e., by downloading GHI and/or Clearness Index values from HOMER or by obtaining the NASA/MERRA2 hourly-based datasets of GHI and/or Clearness Index from the NREL National Solar Radiation Database (NSRDB) viewer [53]. While the first approach allows users to directly obtain 'ready to use' monthly average values of GHI and/or Clearness Index by specifying the location's latitude and longitude, the second approach lets users explore the data using the following steps: (1) entering the location's latitude and longitude; (2) selecting available datasets; (3) selecting appropriate attributes; (4) selecting year(s); (5) selecting time interval of the data; (6) selecting data formatting options; (7) typing an email for receiving the data; and (8) submitting the request.

Section 3.1 – paragraph 3:

While obtaining the GHI and/or Clearness Index data from the NREL NSRDB data viewer website may provide users with flexibility and options of getting the preferred data granularity (10-minute, 30-minute, or 60-minute time intervals for Asia, Australia, and Pacific regions during 2016 – 2020), HOMER detects the time step of the imported data file based on the number of lines. If, for example, the imported data file contains 8,760 lines, HOMER assumes it contains hourly data. Subsequently, HOMER will convert the data into monthly averages, i.e., a single value for each month. Users, however, should first convert the GHI from hourly-based W/m^2 into daily-based kW/m^2 for a particular year before importing the data into HOMER. In addition, if the year selected on the NREL data viewer website is more than one specific year, users must produce an average value for each time step within all considered years.

Section 3.1 – paragraph 4:

This study applies the first approach, i.e., downloading the 'ready to use' GHI and Clearness Index data for a location having a South Latitude of 7°19' and an East longitude of 112°47'. While the considered latitude in this study is slightly different from that in [51], the location provides an average daily GHI of 5.26 kWh/m^2, similar to that in [51]. Table 2 presents numerical values of the monthly average GHI, and Clearness Index obtained for this study, while Figure 3 shows how HOMER depicts the values graphically.

In addition, a table regarding the GHI and Clearness Index used in the study has been included in the revised paper, as follows.

Table 2. Monthly average GHI and clearness index for the specified location

Month	Clearness index	Global Horizontal Index (kWh/m^2/day)
January	0.45	4.84
February	0.46	4.97
March	0.48	5.05
April	0.52	5.09
May	0.56	5.00
June	0.57	4.82
July	0.59	5.10
August	0.60	5.62
September	0.61	6.21
October	0.56	5.96
November	0.50	5.34
December	0.48	5.13

Average	0.53	5.26

3. Demonstrate how the data were calibrated for use in HOMER.

Response: Thank you for this valuable comment. In case of utilising the data from NSRDB data viewer website, the data needs to be converted from its original temporal into HOMER's hourly-based temporal data. Users should first adjust the unit of GHI from Wh/m^2 into kWh/m^2 once it is converted into hourly-based temporal data. The complete discussion is presented as follows.

Section 3.1 – paragraph 3:
While obtaining the GHI and/or Clearness Index data from the NREL NSRDB data viewer website may provide users with flexibility and options of getting the preferred data granularity (10-minute, 30-minute, or 60-minute time intervals for Asia, Australia, and Pacific regions during 2016 – 2020), HOMER detects the time step of the imported data file based on the number of lines. If, for example, the imported data file contains 8,760 lines, HOMER assumes it contains hourly data. Subsequently, HOMER will convert the data into monthly averages, i.e., a single value for each month. Users, however, should first convert the GHI from hourly-based W/m^2 into daily-based kW/m^2 for a particular year before importing the data into HOMER. In addition, if the year selected on the NREL data viewer website is more than one specific year, users must produce an average value for each time step within all considered years.

4. Figure 2 should be improved; the legend is not distinguishable.

Response: Thank you for this comment and suggestion. Figure 2 has been enhanced by displaying the entire country of Indonesia in the upper portion and zooming out Java in the lower portion, where Surabaya is situated. I used arrows to indicate both Surabaya location and the associated daily long-term average GHI of 5.3 kWh/m^2. The figure is presented as follows.

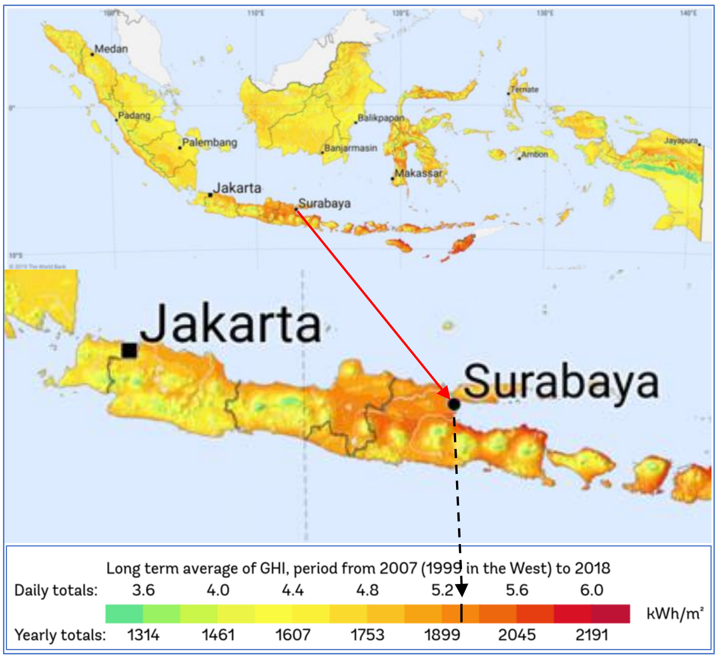

Figure 2. A map showing daily and yearly long-term average GHI (kWh/m^2) in Indonesia and Surabaya [51].

5. Describe what the clearness index is.

   Response: Thank you for this comment. I should have been clearer on this term. Description of the Clearness Index has been included in the 2nd paragraph of Section 3.1 (Solar resource data) as follows.

   Section 3.1 – paragraph 2:
   HOMER uses either the average daily GHI or the average Clearness Index for each month to calculate PV power for each hour of the year. The Clearness Index, a dimensionless number between 0 to 1, is obtained by dividing the horizontal surface global radiation by the extraterrestrial horizontal radiation for the same period [52]. HOMER divides GHI by the extraterrestrial horizontal radiation to find the clearness index. A low value of the clearness index, for example, 0.25, indicates a very cloudy month, while 0.85 indicates a very sunny month.

6. Present the equations for calculating the Solar PV array and converter section.

   Response: Thank you for this important suggestion. In addition to the equation for calculating the power output generated by the solar PV array, the equations for calculating the Solar PV array and converter section have been added in the revised paper, particularly in Section 3.3 under the specific section of Solar PV array and converter, as follows.

   Section 3.3 >> Solar PV array and converter:
   In HOMER, the rated capacity of the PV array Y_{PV} is specified by users as one of the input variables to Eq. 1. Users can either enter at least one size of solar PV module and the capital cost associated with that particular size, for example, 2 kW, or in fractions, for example, 0.1 kW PV. If the second option were selected, the user must enter several PV module capacities in multiples of 0.1 kW to 2 kW or up to the maximum capacity considered. HOMER simulates possible supply configurations to meet hourly-based energy demand and displays the system's Y_{PV} in the simulation results. Therefore, if users enter Y_{PV} as fractions, the number of solar PV arrays N_{PV} can be obtained using the following equation.

   $$N_{PV} = \frac{calc\_Y_{PV}}{frac\_Y_{PV}} \qquad (2)$$

   where cal_Y_{PV} is the calculated system's rated capacity of the PV array (kW), and $frac\_Y_{PV}$ is the fraction of the rated capacity of the PV entered by users (kW).

   HOMER models a converter, commonly known as an inverter, to convert DC electricity generated by solar PV arrays to AC electricity by considering the user-specified efficiency η of the inverter side. HOMER calculates the performance of a converter on an annual basis according to the following equation.

   $$\eta = \frac{kWh/year_{in}}{kWh/year_{out}} \qquad (3)$$

   where $kWh/year_{in}$ is the DC electricity generated by PV arrays (kWh/year), and $kWh/year_{out}$ is the AC electricity produced by inverter (kWh/year).

7. Present the source of the data in the System economic section.

Response: Thank you for this comment. The source of the data for system's economic, such as electricity rates, capital and replacement costs for converter, capital and replacement costs for PV modules, system capital cost and the fixed O&M cost for the context of Indonesia market have been added in the revised paper, as follows.

Section 3.3 – paragraph 5:

………………… The electricity rate for households with a 2,200 VA power contract (R1) is IDR 1,444.70 per kWh, while households with power of 3,500 VA or above (R2/R3) are charged IDR 1,699.53 per kWh [[54], [55]]. Assuming the exchange rate is IDR 15,000 per USD 1, this gives us USD 0.096 per kWh for 2,200 VA customers and USD 0.113 per kWh for 3,500-6,600 VA ones. The simulation, therefore, applies different electricity rates between 2,200 VA and higher segments.

Section 3.3 >> Solar PV array and converter:

…………. Capital and replacement costs of the 1 kW converter are assumed to be USD 400 (IDR 6,000,000) [56] and USD 380 (IDR 5,700,000), respectively, without annual O&M costs. ………….

This study assumes capital and replacement costs for the 0.1 kW peak PV module in Indonesia to be USD 50 each (equal to around IDR 750,000) [57], and no annual Operating and Maintenance (O&M) costs for the PV arrays. ……………………

Section 3.3 >> System economic:

………………… Considering the current total installed cost of solar PV for the Indonesian residential sector, i.e., USD 1,000/kW peak (IDR 15,000,000/kW peak) [[58], [59]], and the cost of solar PV modules and converters, the system fixed capital cost and the fixed O&M cost are set at USD 200 (IDR 3,000,000) [60] and USD 20/year (IDR 300,000/year), respectively.

All sources for system's economic have been included in the revised paper's references, as follows.

[54] Tarif Adjustment (in Bahasa Indonesia). Available: https://web.pln.co.id/pelanggan/tarif-tenaga-listrik/tariff-adjustment [Accessed 24 February 2023]

[55] Good News! Electricity Tariffs for The Next 3 Months Don't Increase. Available: https://voi.id/en/economy/241919 [Accessed 24 February 2023].

[56] Solar PV Inverter DC to AC 1000-Watt price in Indonesia. Available: https://www.tokopedia.com/baterailab/thinkpower-grid-tie-ongrid-inverter-1-6k-sseries-with-limiter-wifi-1000w?extParam=ivf%3Dfalse&src=topads [Accessed 10 September 2023].

[57] Solar PV panel 100-Watt peak price in Indonesia. Available: https://www.tokopedia.com/asia-teknindo/solar-panel-surya-solar-cell-100-wp-100-wattpolycrytalline-maysun [Accessed 9 September 2023].

[58] How much does it cost to install a solar PV roof at home? (in Bahasa Indonesia). Available: https://www.kompas.com/properti/read/2022/06/04/080000221/berapa-biaya-pemasangan-plts-atap-di-rumah-simak-penghitungannya?page=all [Accessed 21 February 2023].

[59] Should I install solar panels at home? Available: https://www.thejakartapost.com/business/2022/02/04/should-i-install-solar-panels-at-home.html [Accessed 20 February 2023].

[60] Rooftop PV system fixed capital and maintenance cost in Indonesia (in Bahasa Indonesia). Available: https://www.kompas.com/properti/read/2022/06/04/080000221/berapa-biaya-pemasangan-plts-atap-di-rumah-simak penghitungannya?page=all#:~:text=Adapun%20total%20biaya%20pemasangan%20PLTS%20sebesar%20Rp%2033.703.900%2C%20rinciannya,Beton)%3A%20Rp%203.060.000 [Accessed 11 September 2023].

Additional comment from Reviewer #1:
The authors present a study with two scenarios using the HOMER software, much of the method is done through this software, it is recommended to the authors to add a model, or more scientific method, to use HOMER and enrich it with the proposal of a model that improves it.

Response:
Thank you for this thoughtful comment and suggestion. Additional explanations and discussions on the model and specific method to improve HOMER utilisation have been added in the revised paper, as follows.

Introduction – paragraph 10:
…………………. In particular, this study suggests a method for applying billing deduction factors in HOMER optimisation while taking into account the implications of setting and regulation through different unserved energy targets, PV capacity, and billing deduction factors on the assessment of cost-reliability trade-offs.

Section 3.3 – paragraph 1:
This study assesses the grid-connected rooftop PV systems for residential households by using HOMER software to model system configurations for four residential household segments with their associated load profiles in the urban area of Surabaya, Indonesia, as a case study. The complete model consists of an electricity grid, the household's loading pattern, and the main components consist of PV array and converter. While much of the simulations are performed in HOMER, this study takes into account the implications of setting and regulation through different unserved energy targets, PV capacity, and billing deduction factors on the assessment of cost-reliability trade-offs.

Section 3.3 – paragraph 2:
In particular, this study suggests a method for incorporating billing deduction factors in HOMER optimisation since the software does not account for billing deduction cases in in its direct calculations. In HOMER, varying sell-back rates for energy sold to the grid can be used to account for various billing deduction factors. To simulate a billing deduction factor of 65%, for instance, the model multiplies the amount of electricity sold to the grid by 65% of the electricity full rate for customers.

Reviewer #2:

Thank you for the submission of the paper. The paper can be considered for publication after a major revision.

Main comment:

1. Before resubmitting the revised version, a thorough language check has to be done.

Response: Thank you for this comment. The revised paper has been checked in terms of its language and thoroughly.

2. Section 2: When describing the current situation, it is of importance to describe the development of the massive oversupply of coal fired power stations from 2015 on. In addition, it should be mentioned that PLN is very reluctant to modify its plans for additional coal fired power stations, which are not yet build. A quantification of the oversupply in the different Indonesian regions as well as the still planed capacity additions should be show to explain the situation. In this context it would be of interest to add a more detailed description of the actual barriers for PV implementation and how this could eventually be solved.

   Response: Thank you for this constructive feedback. The revised paper has now included more comprehensive description (as written in Section 2, paragraph 3 – 5) on the challenges to the slow deployment of residential rooftop PV in Indonesia, especially regarding the actual barriers due to PLN's unchanging plan for ongoing development of coal-fired power plants, financial implication of electricity oversupply, and updated status of regulatory approach, as follows.

   Section 2 – paragraph 3:
   Through the Ministry of Energy and Mineral Resources (MEMR), the Indonesian government has made efforts to encourage the implementation of rooftop solar PV. This includes the issuance of Ministerial Regulation No. 49/2018, revised by Ministerial Regulation No. 26/2021 [48]. These regulations aim to achieve a rooftop PV capacity of 3.6 GW. Although the revised regulation is seen as a positive step, especially regarding the recognition of 100% export of electricity back to the PLN grid, implementation has been challenging.

   Section 2 – paragraph 4:
   As the grid operator, PLN is hesitant to approve applications for rooftop PV installations up to the maximum allowable capacity quota per customer due to oversupply and financial issues, mainly caused by the ongoing take-or-pay scheme derived from the Power Purchase Agreement (PPA) of large quantities of coal-based electricity from Independent Power Producers (IPP). To address the situation, MEMR has consulted with stakeholders to discuss various options, focusing on revising Ministerial Regulation No. 26/2021. Due to the current oversupply situation, rooftop PV users will most likely not be allowed to export electricity to the PLN grid, according to the newly revised regulation that has yet to be published [49].

   Section 2 – paragraph 5:
   Despite the positive efforts on the regulatory framework, the ongoing 35 GW coal power plant mega-project started in 2015 has become a problem for Indonesia's energy transition. The unchanging plans for additional coal power plants, which are not yet built, are arguably seen as one of the main barriers that hinder the massive development of PV, including rooftop systems – that require a comprehensive solution. While the share of coal in electricity generation is expected to decrease from around 56 GW to 40 GW, the capacity of coal-fired power plants is proposed to increase by 13 GW in the RUPTL 2021-2030. It has come to light that there are still plans to construct coal power plants in 2027, as per the 2015-2019 PPA [50].

3. Currencies should always be written in ISO code, eg. IDR, USD.

Response: Thank you for this valuable comment. The revised paper has now adopted ISO 4217 for currency codes. I have double-checked that all monetary values have applied IDR for Indonesian Rupiah and USD for United States Dollar.

4. CAPEX and OPEX should be given in IRD to make it comparable with kWh prices.

   Response: Thank you for this comment. I have now added the monetary values in IDR for economic variables of the system in the revised paper. Those can be found in Sub-Section 3.3 System modelling, economic parameters, and assumptions, particularly in the following parts.

   - Solar PV array and converter:

     .... Capital and replacement costs of the 1 kW converter are assumed to be USD 400 (IDR 6,000,000) [56] and USD 380 (IDR 5,700,000), respectively, without annual O&M costs. Capital and replacement costs are assumed to increase linearly concerning size.

     This study assumes capital and replacement costs for the 0.1 kW peak PV module in Indonesia to be USD 50 each (equal to around IDR 750,000) [57], ...

   - System economic:
     .... Considering the current total installed cost of solar PV for the Indonesian residential sector, i.e., USD 1,000/kW peak (IDR 15,000,000/kW peak) [[58], [59]], and the cost of solar PV modules and converters, the system fixed capital cost and the fixed O&M cost are set at USD 200 (IDR 3,000,000) [60] and USD 20/year (IDR 300,000/year), respectively.

5. All abbreviation should be spelled out at the first use in the text.

   Response: Thank you for this comment. I have double-checked that all abbreviations are spelled out the first time they are use in the text of the revised paper.

Detailed comments:

6. Ref 1, 2: Here the IEA PVPS Snapshots could be added: https://iea-pvps.org/snapshot-reports/snapshot-2023/

   Response: Thank you for this valuable suggestion. I agreed with the reviewer and have added the suggested reference (Ref. [3]) to support the first sentence – along with the other two references – as follows.

   [3] PVPS: Snapshot of Global PV Markets 2023. Available: https://iea-pvps.org/snapshot-reports/snapshot-2023/ [Accessed 1 September 2023].

   Emphasising on the recent global PV capacity growth, the first sentence of the revised paper now becomes:

   The utilisation of solar photovoltaic (PV) systems has increased significantly in recent years, with global capacity growth reaching 1.2 TW by 2022 [[1], [2], [3]].

7. Page 1, line 46-49: The uptake of PV rooftop systems due to rising electricity prices is a worldwide phenomena, not only in emerging economies. Eg. Australia, Netherlands and many others.

   Response: I agreed with this thoughtful comment and could have been clearer with this issue. The uptake of rooftop PV systems due to rising electricity prices in many countries, including the developed ones, has been included in the revised paper, now at the 2nd paragraph, as follows.

   Introduction – paragraph 2:
   Rising electricity prices in developed countries like Australia, the Netherlands, Germany, and many others have fuelled the adoption of residential rooftop PV systems along with the growth in capacity. However, it is worth noting that rooftop PV development in emerging economies has been influenced by both economic and technical factors. Increasing electricity rates and challenges utilities face in providing a reliable power supply, particularly in urban distribution networks, have contributed to the rise of rooftop PV in these countries.

8. Page 2, line 11 and 15: reference to the respective software programmes, e.g., where to find it, is missing.

   Response: Thank you for this feedback. I have now added the ref. number for all software used by previous studies in the revised paper (now are mentioned in paragraph 5 and paragraph 6) and included them in the references as follows.

   Introduction – paragraph 5 and 6:

HOMER:	[15] HOMER software. Available: https://www.homerenergy.com/ [Accessed 29 August 2023].
PV*SOL:	[18] PV*SOL software. Available: https://pvsol.software/en/ [Accessed 30 August 2023].
PVGIS:	[19] Photovoltaic Geographical Information System (PVGIS). Available: https://joint-research-centre.ec.europa.eu/photovoltaic-geographical-information-system-pvgis_en [Accessed 2 September 2023].
SolarGIS:	[20] SOLARGIS PV planner. Available: https://solargis.info/pvplanner/#tl=Google:hybrid&bm=satellite [Accessed 2 September 2023].
SISIFO:	[21] SISIFO. Available: https://www.sisifo.info/es/default [Accessed 1 September 2023].
RETScreen:	[23] RETScreen software. Available: https://natural-resources.canada.ca/maps-tools-and-publications/tools/modelling-tools/retscreen/7465 [Accessed 15 September 2023].
SolarEnergy:	[24] Á. X. C. de Jesus, D. P. Neto, E. G. Domingues. Computational tool for technical-economic analysis of photovoltaic microgeneration in Brazil. Energy, 271 (2023), 126962.

9. Page 3, line 5: Various publications and organisations like ISER mention: missing permits, administrative barriers, perception of high costs

   Response: Thank you for this constructive comment. I agreed with the reviewer and have now added a reference by IESR (ref. [38]) to complement the 'on customer side's barrier' as follows.

Introduction – Paragraph 12:

On the customer side, on the other hand, the decision regarding whether to implement grid-connected rooftop PV or rely solely on electricity from the utility grid, in many cases, has not been supported by sufficient knowledge of techno-economic aspects, particularly on reliability and cost implications due to different system settings and regulations. In addition, lack of product knowledge, complicated permit requirements, and perception of expensive systems were identified as the main barriers to adopting rooftop PV for households [38].

10. Page 3, line 45 -50: Here some of the arguments a contradicting each other, eg. if an oversupply in the form of coal exists, no additional flexibility reserve is needed.

    Response: Thank you for this critical comment. While the paragraph has been improved grammatically as well as its readability and delivery of the sentences, a sentence has been added into the last part of the paragraph to critically comment the PLN's contradicting arguments by presenting the opportunity for coal-fired power plants in providing the grid with required flexibility, as follows.

    Section 2 – paragraph 2:

    There are challenges to the slow deployment of residential rooftop PV in Indonesia that are currently affecting all PLN customers. Some of these challenges have been acknowledged in the PLN Electricity Supply Business Plan (RUPTL) 2021-2030 [43]. These include: 1) several PLN electricity networks are currently not prepared to handle distributed renewable energy-based generation due to oversupply conditions caused by decreased demand; 2) there will be a need for PLN to add more generation plants to increase system flexibility if there is a relatively massive penetration of rooftop PV; and 3) there will be additional investment costs in generation control and forecasting, dispatch system, and grid code enforcement [[44], [45]]. While the challenges may delay large-scale PV deployment, oversupply of system capacity, including from coal-fired power plants, can present an opportunity to provide the grid with increased flexibility [[46], [47]].

11. Figs 5 to 8: These are actually tables. Please avoid the term operating costs, because you are effectively describing the costs for the PV generated and grid bought electricity.

    Response: Thank you for this valuable comment and suggestion. In the revised paper, Figures 5 to 8 have been modified into Tables 3 to 6 and have been placed after the 3rd paragraph of Section 4 (Results and Discussion). A screenshot of Table 3 is presented below.

Table 3. Simulation results for 2,200 VA: 100%-MPVC

Maximum annual unserved energy (%)	PV (kW)	Converter (kW)	Grid (kW)	Initial Capital (USD)	Total NPC (USD)	COE (USD/kWh)	RE share (%)	Unserved energy (%)
0	2.2	1.5	1.8	1,900	9,175	0.081	33	0
5	2.2	1.5	1.4	1,900	8,796	0.081	34	4
10	2.2	1.5	1.3	1,900	8,446	0.080	35	7
15	2.2	1.5	1.2	1,900	7,987	0.079	36	11

I have replaced the term 'maximum capacity shortage' with 'maximum annual unserved energy' to better represent the system reliability constraints and capacity shortage' with 'unserved energy' for the reliability results of the optimised configurations.

As suggested, the term 'operating costs' has now been avoided in Tables 3 to 6, also in the revised paper. To exclude the term 'operating costs' in the analysis, the text has been modified as follows.

***Section 3.3 >> System economic* (*last sentence*)**

…………………. While the term operating costs is useful in providing the user with some insights into the contribution of these types of costs on the total NPC and typically decreases at higher unserved energy, this study rules out the term operating costs in the analysis due to the focus of this study on analysing the possible trade-off between the system cost, which is already well represented by the total NPC, and unserved energy.

12. A sensitivity analysis of the economic variable would be helpful.

Response: Thank you for this suggestion. The revised paper has now included sensitivity analyses described at paragraphs 16, 17, and 18. The study has used 'maximum annual unserved energy' as the sensitivity variable. The descriptions are accompanied by sensitivity results presented in Figures 13, 14, and 15. These include: 1) possible trade-offs on total NPC versus unserved energy fraction; 2) net grid purchases (electricity purchased from the grid minus electricity sold to the grid) versus maximum annual unserved energy; and 3) total NPC versus total electricity production. Overall, the sensitivity analysis parts are as follows.

Results and Discussion – paragraph 13:

A sensitivity analysis of the techno-economic factors influencing system performance would benefit stakeholders, particularly residential customers. While focusing on system reliability, this study uses only a 5% annual interest rate and fixed electricity rates associated with household segments. As a result, the sensitivity variable used in HOMER is maximum annual unserved energy.

Results and Discussion – paragraph 14:

Taking a 2,200 VA household with 100%-MPVC as an example, a graphical sensitivity result depicting possible trade-offs on total NPC versus unserved energy fraction and a sensitivity result of net grid purchases (electricity purchased from the grid minus electricity sold to the grid) versus maximum annual unserved energy are presented in Figure 13 and Figure 14, respectively. Meanwhile, a sensitivity result of total NPC versus total electricity production is shown in Figure 15.

Results and Discussion – paragraph 15:

Maximum annual unserved energy constraints have varying effects on total NPC, total electricity production, and nett grid purchases. As shown in Figure 13, total NPC cannot be less than USD 8,500 when unserved energy is kept at or below 6%. According to Figure 15, a 10% unserved energy would result in approximately 9,700 kWh/year of electricity production, which would equal approximately USD 8,500 in total NPC.

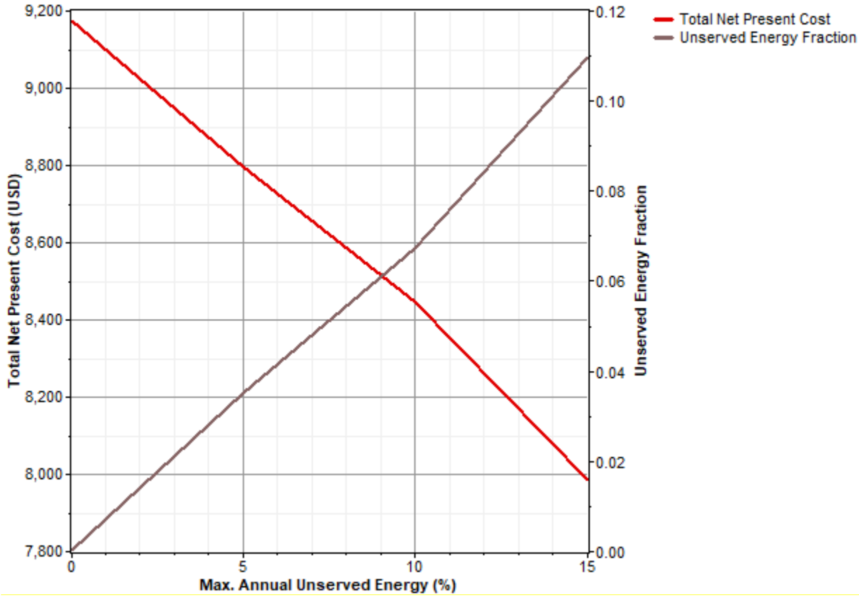

Figure 13. Sensitivity result of total NPC versus unserved energy fraction in a 2,200 VA household with 100%-MPVC.

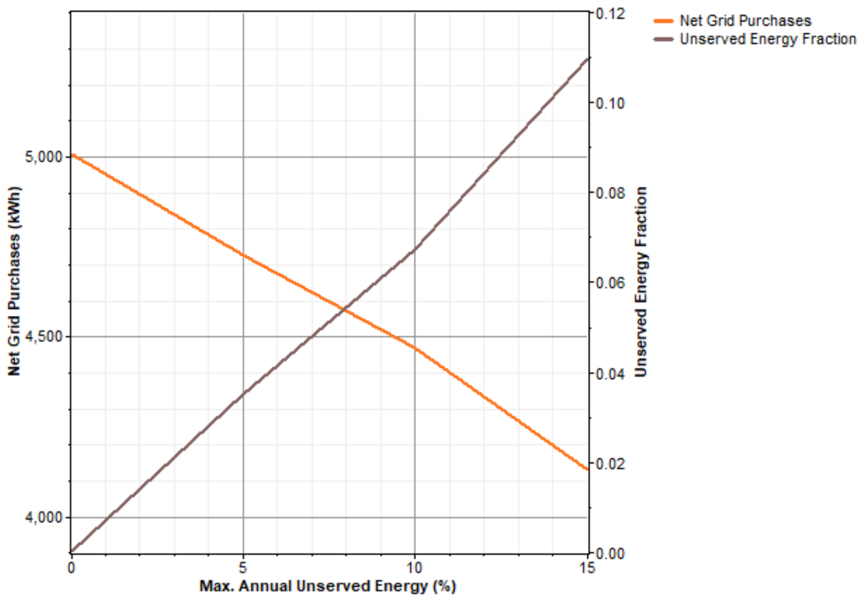

Figure 14. Sensitivity result of net grid purchases versus maximum annual unserved energy in a 2,200 VA household with 100%-MPVC.

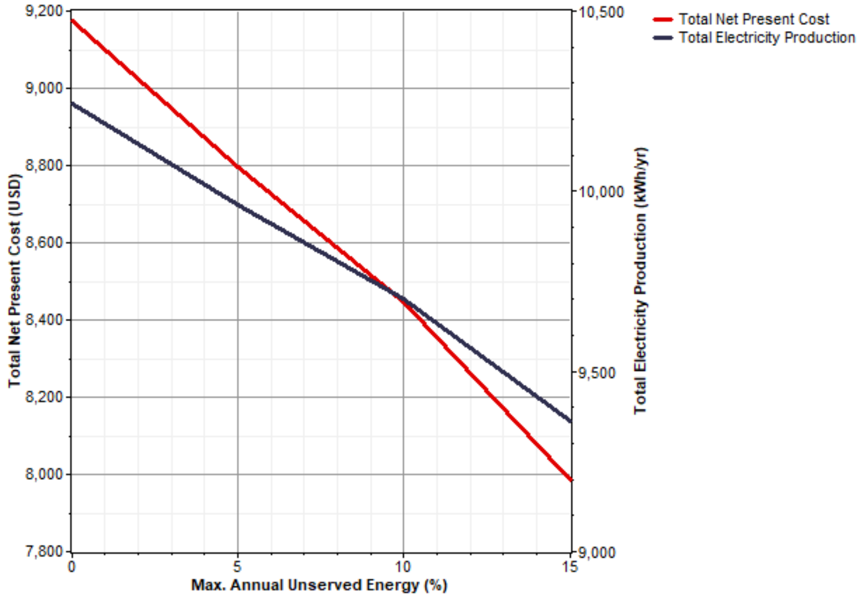

Figure 15. Sensitivity result of total NPC versus total electricity production in a 2,200 VA household with 100%-MPVC.

Additional comment from Reviewer #2:

- The conclusion should put more emphasis on the benefits of rooftop PV supported by the findings of the paper.

  Response: Thank you for this valuable suggestion. I could have been clearer in this part. In the revised paper, I have modified sentences in paragraph 2 and added a specific paragraph (paragraph 3) to put more emphasis on the benefits of grid-connected rooftop PV by highlighting important findings from the case study as follows.

  Conclusions – paragraph 2:

  In all four cases of each household segment, i.e., 100%-MPVC, 65%-MPVC, 100%-HPVC, and 65%-HPVC, the optimisation results show reliability-cost trade-offs between the total NPC and all unserved energies. Furthermore, the role of cost components in the trade-offs between HPVC and MPVC cases in terms of initial capital costs and total NPC was highlighted in the analyses. The findings revealed a relatively large difference in total NPC for all households between 100%-MPVC cases and 65%-MPVC cases for all unserved energies, while differences between those in 100%-HPVC cases and 65%-HPVC cases are insignificant. The simulation results implied potential benefits of rooftop PV installation up to the maximum permitted capacity and a 100% billing deduction scheme for households with 2,200 VA, taking into account different options for unserved energy, installed capacity, and billing deduction percentage.

  Conclusions – paragraph 3:

  Among the significant results of this study that highlight the benefits of grid-connected rooftop PV are the following: 1) higher renewable energy penetration for MPVC systems compared to HPVC systems regardless of the billing deduction factors; 2) cheaper total NPC are shown by MPVC cases than those of HPVC cases within the same unserved energy; 3) lower shares of energy charge to the annual total cost in MPVC cases compared to those in HPVC ones; and 4) Over the project lifetime, the cost per kWh consumed (USD/MWh consumed) showed only a slight variance between the system with no-unserved energy and the system with the poorest reliability, given 100%-MPVC cases in 2,200 VA as an example;

5) All households with a 15% maximum limit on unserved energy have the lowest costs per watt of installed PV capacity, and these costs are unaffected by billing deduction factors; 6) based on the system's maximum unserved energy limits, higher unserved energy has led to a decrease in the amount of grid capacity needed by the system to meet demand, and the PV capacities are maximised across all unserved energies in various scenarios; and 7) Sensitivity analyses have revealed a range of impacts of maximum annual unserved energy constraints on various parameters, including total NPC, total electricity production, and net grid purchases.

Author's additional response to the revised paper:

- All revisions in terms of language and/or additional sentences in the revised paper are marked up in yellow. Grammatical errors have been corrected and additional sentences have been added throughout the text's body, either by rewriting existing paragraphs or adding new ones, to improve readability and manuscript delivery.

- In addition to presenting all of the corrected sections in response to the reviewers' comments, Section 4 (Results and discussion) has undergone significant improvement. This is done expanding the analyses and discussions pertaining to the grid-connected rooftop PV model in the case study, including: the potential role of the system cost components on the cost-reliability trade-offs, the trade-offs between annualised total cost and unserved energy, the cost per MWh energy consumed during the project lifetime, the cost per watt of PV installed for all unserved energies, sensitivity analysis of the techno-economic factors due to different maximum annual unserved energy. All additional analyses and discussions in Section 4 of the revised paper have been marked up with yellow as well.

Energy

Cost-reliability trade-offs for grid-connected rooftop PV in emerging economies: a case of Indonesia’s urban residential households

--Manuscript Draft--

Manuscript Number:	EGY-D-23-04810R1
Article Type:	Full length article
Keywords:	on-grid; rooftop PV; emerging economies; reliability-cost; trade-offs.
Corresponding Author:	Yusak Tanoto, Ph.D. Petra Christian University INDONESIA
First Author:	Yusak Tanoto, Ph.D.
Order of Authors:	Yusak Tanoto, Ph.D.
Abstract:	This study explores the potential of grid-connected rooftop photovoltaic (PV) systems in terms of how they can be better planned and utilised by understanding possible trade-offs between cost and reliability while acknowledging challenges to utility supply security in the context of emerging economies. The study particularly examines the implications of unserved energy targets, PV capacity, and billing deduction factors on grid-connected rooftop PV’s trade-offs in terms of total net present cost and unserved energy. This study considers four residential household segments in Indonesia’s urban area as a case study, with four cases applied in each segment representing scenarios on PV capacities and billing deduction factors. Using HOMER software, the analyses highlight the role of cost components in trade-offs involving potential PV capacity cases. Systems with maximum PV capacity exhibit cheaper total net present costs than those of half PV capacity within the same unserved energy. While the optimisations pushed PV capacity up to the maximum size across all unserved energies, higher unserved energy resulted in lower grid capacity required to meet demand associated with the system’s maximum unserved energy limit. This study provides residential customers and stakeholders with insights to better plan and implement grid-connected rooftop PV systems and policies.

Highlights:

- Cost-reliability trade-offs are assessed for grid-connected rooftop PV models.
- Reliability is expressed in HOMER optimisation by capping annual unserved energy.
- Impacts of unserved energy targets, PV capacity, and sell-back rates are examined.
- Cheaper net present costs are achieved by systems with maximum PV capacity.
- Higher unserved energies lowered the costs per watt of PV installed capacity.

21 September 2023
Dear Professor Henrik Lund,
Editor-in-Chief ENERGY-Elsevier

Please consider attached a revised manuscript entitled "Cost-reliability trade-offs for grid-connected rooftop PV in emerging economies: a case of Indonesia's urban residential households" authored by Yusak Tanoto, for publication in Energy.

The revised manuscript is submitted after carefully addressing the editor's and reviewers' comments. Among the author's responses, the revised paper now has 15 references of recent papers published in ENERGY journal and additional literature from other resources. It also has presented a clearer description of the scientific novelty and new perspectives contributed by the study in comparison to existing work, as introduced in Section 1 (Introduction) and elaborated more in Section 3.3 (System modelling, economic parameters, and assumptions).

The manuscript has been improved significantly by enhancing the analyses and discussing more on findings, including the potential role of the system cost components on the cost-reliability trade-offs, the trade-offs between annualised total cost and unserved energy, the cost per MWh energy consumed during the project lifetime, the cost per watt of PV installed for all unserved energies, sensitivity analysis of the techno-economic factors due to different maximum annual unserved energy. Significant results of the study that highlight the benefits of grid-connected rooftop PV have been emphasised in the conclusions.

I believe this article will attract readership from both popular and scientific audiences interested in the role of high variable renewable energy penetrations on sustainable electricity industry planning in emerging economies. The language of this manuscript has been thoroughly checked by an English expert, and I hereby confirm that this manuscript has not been published elsewhere and is not under consideration by another journal.

Finally, I would like to thank the editor and reviewers for their thoughtful criticisms and helpful suggestions on how to improve the paper. I do hope that it is now suitable for publication in ENERGY. Thank you very much and I am looking forward to hearing from you soon.

Sincerely yours,

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CRediT author statement

Yusak Tanoto: Conceptualisation, Methodology, Data preparation, Simulation, Analysis, Visualisation, Writing – Original draft preparation, Review and Editing.

Declaration of interests

☒The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

☐The authors declare the following financial interests/personal relationships which may be considered as potential competing interests:

Cost-reliability trade-offs for grid-connected rooftop PV in emerging economies: a case of Indonesia's urban residential households

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Abstract

This study explores the potential of grid-connected rooftop photovoltaic (PV) systems in terms of how they can be better planned and utilised by understanding possible trade-offs between cost and reliability while acknowledging challenges to utility supply security in the context of emerging economies. The study particularly examines the implications of unserved energy targets, PV capacity, and billing deduction factors on grid-connected rooftop PV's trade-offs in terms of total net present cost and unserved energy. This study considers four residential household segments in Indonesia's urban area as a case study, with four cases applied in each segment representing scenarios on PV capacities and billing deduction factors. Using HOMER software, the analyses highlight the role of cost components in trade-offs involving potential PV capacity cases. Systems with maximum PV capacity exhibit cheaper total net present costs than those of half PV capacity within the same unserved energy. While the optimisations pushed PV capacity up to the maximum size across all unserved energies, higher unserved energy resulted in lower grid capacity required to meet demand associated with the system's maximum unserved energy limit. This study provides residential customers and stakeholders with insights to better plan and implement grid-connected rooftop PV systems and policies.

Keywords: on-grid, rooftop PV, emerging economies, reliability-cost, trade-offs.

1. Introduction

The utilisation of solar photovoltaic (PV) systems has increased significantly in recent years, with global capacity growth reaching 1.2 TW by 2022 [[1], [2], [3]]. In several emerging economies and jurisdictions, the installation of rooftop solar PV has witnessed significant growth [[4], [5], [6], [7], [8]]. Grid-connected rooftop PV is a feasible option for providing electricity in residential households in many urban areas [9]. Installing grid-connected rooftop PV is simpler, cheaper, and requires almost no maintenance compared to hybrid systems [10]. Adopting low-cost, green technologies like PV can reduce CO_2 emissions and support sustainable energy transition [[11], [12]]. However, when choosing grid-connected rooftop PV, customers consider various factors, including the system's performance expectations, socio-environmental beliefs, and price-value beliefs, among others [13].

Rising electricity prices in developed countries like Australia, the Netherlands, Germany, and many others have fuelled the adoption of residential rooftop PV systems along with the growth in capacity. However, it is worth noting that rooftop PV development in emerging economies has been influenced by both economic and technical factors. Increasing electricity rates and challenges utilities face in providing a reliable power supply, particularly in urban distribution networks, have contributed to the rise of rooftop PV in these countries.

It is of importance to pay special attention to the low reliability of urban distribution networks [14]. This is particularly essential for households choosing the appropriate size of rooftop PV components. A grid-connected system without any capacity shortage, representing excellent reliability, would require a larger supply capacity to meet high peak loads during a short period. This, of course, would come at a

higher cost. On the other hand, a smaller and less expensive system may meet a reasonable portion of the load while allowing for some capacity shortage.

Many studies have investigated different aspects of the techno-economic feasibility of rooftop solar PV systems in the context of emerging economies and developing countries. These studies have primarily focused on grid-connected residential applications and have used various techniques and tools. Some studies have concentrated on system planning through simulations, while others have evaluated the performance of installed systems, either at a single location or across several sites.

Gabr et al. [10] assessed the techno-economic feasibility of a grid-connected rooftop PV system in Egypt, considering the ongoing electricity retail prices and net-metering policy applied to three types of housing rates with different demand levels. They used HOMER (Hybrid Optimization of Multiple Energy Resources) software [15] to measure the net present value of energy cost, payback period, and bill savings. Laib et al. [16] evaluated the performance of a grid-connected solar PV system and its energy balance in Algeria. The authors developed a Matlab-Simulink model to optimise, rationalise, and implement energy-saving approaches to evaluate the system's energy performance and balance.

Dondariya et al. [17] predicted the performance of grid-connected rooftop PV systems in Ujjain, India. The authors compared PV*SOL [18], PVGIS [19], SolarGIS [20], and SISIFO [21] to analyse system performance in terms of energy generation, performance ratio, and solar fraction. Mohammadi et al. [22] analysed the impact of different tracking options on the potential of grid-connected PV development in Iran using RETScreen software [23]. Jesus et al. [24] proposed SolarEnergy, a new optimisation tool for the techno-economic analysis of PV microgeneration. The authors conducted a techno-economic analysis of grid-connected PV systems in Brazil, providing decision-making indicators such as net present value, modified internal rate of return, discounted payback period, and sensitivity analysis of key techno-economic parameters. In another study, Al Garni et al. [25] assessed the optimal design of grid-connected PV by considering various PV tracking systems applied in Makkah, Saudi Arabia. The authors used HOMER to examine the horizontal axis, vertical axis, and a two-axis tracking system. Earlier study by Lau et al. [26] analysed the pricing mechanism for grid-connected PV projects in the residential sector of Malaysia by evaluating the impact of component costs, feed-in tariffs, and carbon taxes using HOMER.

Duman and Güler [27] assessed the economic feasibility of 5 kW grid-connected solar PV in nine provinces of Turkey. Using HOMER, the study evaluated the discounted payback period, internal rate of return, and profitability index, and found that the system would not be feasible in two provinces under the practiced feed-in tariff. Bakhshi and Sadeh [28] examined the economic feasibility of grid-connected rooftop PV systems in Iran. They used PVsyst software [29] to estimate the annual energy generation of a 5-kW peak system in different cities. Their analysis included Net Present Value (NPV), Internal Rate of Return (IRR), payback period (PP), and Levelised Cost of Energy (LCOE), and employed a dynamic feed-in tariff strategy. Similar indicators, i.e., NPV, LCOE, IRR, and static PP and dynamic PP, were used by Xin-gang and Yi-min [30] in building a cost-benefit model to evaluate the economic performance of China's rooftop PV industry. Meanwhile, Orioli and Gangi [31] considered the effects of time variation on the PP assessment of grid-connected rooftop PV systems in Italy.

Li et al. [9] conducted a study to evaluate and compare the techno-economic performance of grid-connected rooftop PV systems and other alternatives in five climate zones in China using HOMER. The study found that grid/PV systems were the most cost-effective option among all the studied systems, and Kunming is the most economical among other regions. Tomar and Tiwari [32] discussed the feasibility of grid-connected rooftop PV for three residential households. The authors used HOMER to simulate the impact of feed-in tariffs/net metering along with a tariff-of-day policy in New Delhi, India. They concluded that systems without energy storage are technically and economically viable for

decentralised households. An earlier study by Pillai et al. [33] developed an economic evaluation methodology to assess the near-term benefits of grid-connected residential PV systems in the United Kingdom and India. The authors developed a metric called 'Prosumer Electricity Unit Cost' (PEUC) and used it to examine the effects of solar input, financial mechanisms, and demand profiles in the near-term time frame of the project.

While studies focussing on single household analysis or involving multiple sites have provided useful insights for stakeholders regarding the potential techno-economic impacts of grid-connected rooftop PV and its deployment opportunity, less explored, however, has been the impacts of setting and regulation through different unserved energy targets, PV capacity, and billing deduction factors. In particular, there has been little attention of the potential trade-offs between system reliability and costs.

This paper aims to explore the potential benefits of grid-connected rooftop PV in terms of how the systems can be better planned and utilised through understanding possible trade-offs between system reliability and cost while also recognising the challenges to utility supply security in the context of emerging economies. While system reliability and efficiency of residential rooftop PV can be enhanced by incorporating other technologies such as wind or diesel, gas, and energy storage [34], this paper focuses on the grid-connected PV systems in urban households in emerging economies. In particular, this study suggests a method for incorporating billing deduction factors in HOMER optimisation while taking into account the implications of setting and regulation through different unserved energy targets, PV capacity, and billing deduction factors on the assessment of cost-reliability trade-offs. The city of Surabaya, Indonesia, is considered a case study.

Despite high-level supportive legislation, rooftop PV has only seen modest deployment in Indonesia mainly due to non-technical barriers and challenges, such as missing permits, lack of regulatory certainty, lack of alignment and synchronisation of implementing regulations, project bankability issues, and cost burden for PLN (Perusahaan Listrik Negara, i.e., Indonesia's state-owned electricity company that is solely responsible for electricity generation, transmission, and distribution) as the sole off-taker, among others [[35], [36], [37]].

On the customer side, on the other hand, the decision regarding whether to implement grid-connected rooftop PV or rely solely on electricity from the utility grid, in many cases, has not been supported by sufficient knowledge of techno-economic aspects, particularly on reliability and cost implications due to different system settings and regulations. In addition, lack of product knowledge, complicated permit requirements, and perception of expensive systems were identified as the main barriers to adopting rooftop PV for households [38].

This paper offers a new perspective on the ongoing rooftop PV studies from a techno-economic standpoint. It introduces the concept of reliability-cost trade-offs that may arise due to different energy targets and the resulting variations in PV system sizes. These trade-offs are particularly relevant in emerging economies given the level of reliability and associated costs can vary significantly. The paper models unserved energy targets by accounting for potential capacity shortages on the supply side.

The paper is organised as follows. Section 2 provides a brief overview of the current status of solar PV deployment, with a focus on rooftop solar PV systems in Indonesia. Section 3 explains methods used in this study, including an overview of the simulations, input data, and modelling assumptions. Results and discussions are presented in Section 4. Finally, the conclusion of the paper is presented in Section 5.

2. Brief Status of Rooftop Solar PV Deployment for Residential Households in Indonesia

The potential for rooftop solar PV systems in Indonesia is immense due to the country's vast solar irradiation coverage and large market [39]. Despite this, the development of residential rooftop PV systems has been slow. As of October 2022, 75% of the 6,261 PLN customers who installed rooftop PV were residential customers with mostly on-grid systems [40]. The residential sector has installed rooftop PV with a total capacity of 15.2 MW, representing approximately 22% of the total rooftop capacity for all PLN customers [41]. The Java-Bali area has the largest share of the national rooftop PV capacity, accounting for around 80% in 2021 [42].

There are challenges to the slow deployment of residential rooftop PV in Indonesia that are currently affecting all PLN customers. Some of these challenges have been acknowledged in the PLN Electricity Supply Business Plan (RUPTL) 2021-2030 [43]. These include: 1) several PLN electricity networks are currently not prepared to handle distributed renewable energy-based generation due to oversupply conditions caused by decreased demand; 2) there will be a need for PLN to add more generation plants to increase system flexibility if there is a relatively massive penetration of rooftop PV; and 3) there will be additional investment costs in generation control and forecasting, dispatch system, and grid code enforcement [[44], [45]]. While the challenges may delay large-scale PV deployment, oversupply of system capacity, including from coal-fired power plants, can present an opportunity to provide the grid with increased flexibility [[46], [47]].

Through the Ministry of Energy and Mineral Resources (MEMR), the Indonesian government has made efforts to encourage the implementation of rooftop solar PV. This includes the issuance of Ministerial Regulation No. 49/2018, revised by Ministerial Regulation No. 26/2021 [48]. These regulations aim to achieve a rooftop PV capacity of 3.6 GW. Although the revised regulation is seen as a positive step, especially regarding the recognition of 100% export of electricity back to the PLN grid, implementation has been challenging.

As the grid operator, PLN is hesitant to approve applications for rooftop PV installations up to the maximum allowable capacity quota per customer due to oversupply and financial issues, mainly caused by the ongoing take-or-pay scheme derived from the Power Purchase Agreement (PPA) of large quantities of coal-based electricity from Independent Power Producers (IPP). To address the situation, MEMR has consulted with stakeholders to discuss various options, focusing on revising Ministerial Regulation No. 26/2021. Due to the current oversupply situation, rooftop PV users will most likely not be allowed to export electricity to the PLN grid, according to the newly revised regulation that has yet to be published [49].

Despite the positive efforts on the regulatory framework, the ongoing 35 GW coal power plant mega-project started in 2015 has become a problem for Indonesia's energy transition. The unchanging plans for additional coal power plants, which are not yet built, are arguably seen as one of the main barriers that hinder the massive development of PV, including rooftop systems – that require a comprehensive solution. While the share of coal in electricity generation is expected to decrease from around 56 GW to 40 GW, the capacity of coal-fired power plants is proposed to increase by 13 GW in the RUPTL 2021-2030. It has come to light that there are still plans to construct coal power plants in 2027, as per the 2015-2019 PPA [50].

3. Methods

In this study, HOMER software is used to model grid-connected rooftop solar PV systems. Possible system sizes with various load profiles are simulated, as are their economic parameters, such as total Net Present Cost (NPC) and Cost of Energy (COE). Four different daily load profiles for residential households with electricity contracts of 2,200 Volt-Ampere (VA), 3,500 VA, 5,500 VA, as well as 6,600 VA have been created. Figure 1 depicts these load profiles.

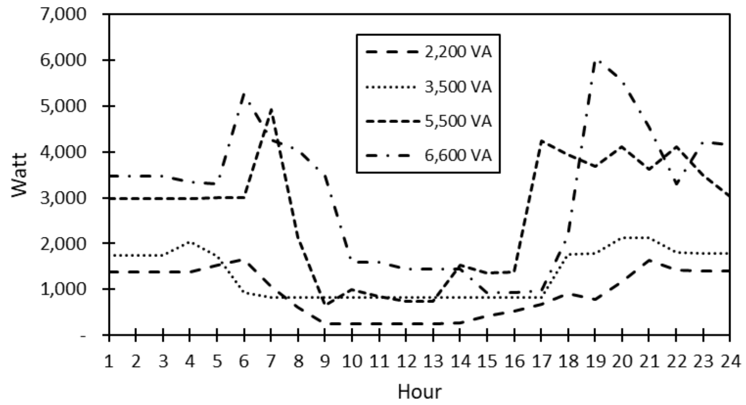

Figure 1. Surveyed hourly based daily load profile for four residential households.

While a preliminary survey has been carried out to obtain the load profiles (as shown in Figure 1) owned by different households in different locations in Surabaya – to represent different residential customer segments – this study considers only one location to allow the same solar irradiation data to be used in all simulations. It should be noted that all load profiles surveyed, as shown in Figure 1, are for weekdays. Nevertheless, weekend patterns for most residential segments show similar base load values to weekdays but have slightly higher peak load, over a short period, than weekdays. One thing to note is that the surveyed load profiles have ruled out the impact of the Covid-19 pandemic which has recently subsided, where people spent more time at home due to restrictions on outdoor activities or working from home.

Meanwhile, Table 1 shows several loading parameters for all residential segments, including the base load, maximum (peak) load, demand factor, and load factor. The demand factor is defined as the maximum demand divided by the connected load. The load factor is the ratio of average to maximum load for a 24-hour period.

Table 1. Loading parameters for all surveyed residential households

Parameter	Residential household segments			
	2,200 VA	3,500 VA	5,500 VA	6,600 VA
Base load	240 Watt	820 Watt	657 Watt	935 Watt
Maximum load	1,655 Watt	2,127 Watt	4,915 Watt	6,056 Watt
Demand factor	0.53	0.32	0.48	0.43
Load factor	0.56	0.63	0.53	0.51

As shown in Table 1, the surveyed households have a fairly low to medium range of demand factors and relatively low load factors, i.e., around 0.5 – 0.6. This, however, is a typical household situation in many Indonesian urban areas, including Surabaya. Between 7 a.m. and 4 p.m., demand for electricity falls because most people spend their days outside their homes studying or working. Furthermore, with the exception of refrigerators, electricity has not been used for kitchen appliances. While gas is commonly used in stoves and ovens, microwaves are uncommon in Indonesia.

3.1. Solar resource data

Surabaya has huge untapped potential for rooftop PV. Located on the east coast of the Java Sea, Surabaya is Indonesia's second-largest urban area of around 300 km^2 and has relatively high solar resources. According to a World Bank report that selected a geographical site of -7.32° (7°19') South Latitude and 112.68° (112°40') East Longitude, the long-term average daily Global Horizontal Irradiation (GHI) in Surabaya has reached 5.29 kWh/m^2 [29], higher than Indonesia's average daily GHI

of 4.8 kWh/m^2. Figure 2 presents the map of daily and yearly long-term averages of GHI values in Indonesia, including Surabaya, from 1999-2018 [51].

HOMER allows users to enter GHI and/or Clearness Index values using one of the two possible approaches, i.e., by downloading GHI and/or Clearness Index values from HOMER or by obtaining the NASA/MERRA2 hourly-based datasets of GHI and/or Clearness Index from the NREL National Solar Radiation Database (NSRDB) viewer [53]. While the first approach allows users to directly obtain 'ready to use' monthly average values of GHI and/or Clearness Index by specifying the location's latitude and longitude, the second approach lets users explore the data using the following steps: (1) entering the location's latitude and longitude; (2) selecting available datasets; (3) selecting appropriate attributes; (4) selecting year(s); (5) selecting time interval of the data; (6) selecting data formatting options; (7) typing an email for receiving the data; and (8) submitting the request.

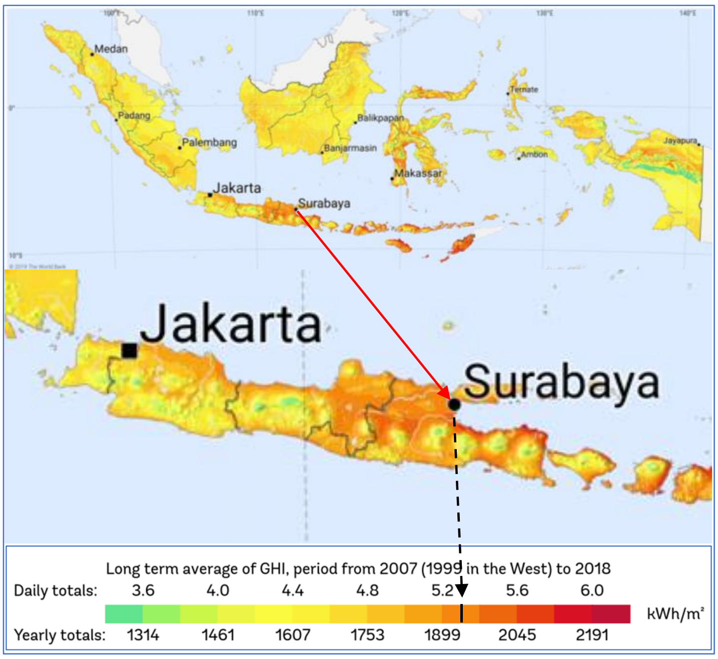

Figure 2. A map showing daily and yearly long-term average GHI (kWh/m^2) in Indonesia and Surabaya [51].

While obtaining the GHI and/or Clearness Index data from the NREL NSRDB data viewer website may provide users with flexibility and options of getting the preferred data granularity (10-minute, 30-minute, or 60-minute time intervals for Asia, Australia, and Pacific regions during 2016 – 2020), HOMER detects the time step of the imported data file based on the number of lines. If, for example, the imported data file contains 8,760 lines, HOMER assumes it contains hourly data. Subsequently, HOMER will convert the data into monthly averages, i.e., a single value for each month. Users, however, should first convert the GHI from hourly-based W/m^2 into daily-based kW/m^2 for a particular year before importing the data into HOMER. In addition, if the year selected on the NREL data viewer website is more than one specific year, users must produce an average value for each time step within all considered years.

This study applies the first approach, i.e., downloading the 'ready to use' GHI and Clearness Index data for a location having a South Latitude of 7°19' and an East longitude of 112°47'. While the considered latitude in this study is slightly different from that in [51], the location provides an average daily GHI of 5.26 kWh/m^2, similar to that in [51]. Table 2 presents numerical values of the monthly average GHI, and Clearness Index obtained for this study, while Figure 3 shows how HOMER depicts the values graphically.

Table 2. Monthly average GHI and clearness index for the specified location

Month	Clearness index	Global Horizontal Index ($kWh/m^2/day$)
January	0.45	4.84
February	0.46	4.97
March	0.48	5.05
April	0.52	5.09
May	0.56	5.00
June	0.57	4.82
July	0.59	5.10
August	0.60	5.62
September	0.61	6.21
October	0.56	5.96
November	0.50	5.34
December	0.48	5.13
Average	0.53	5.26

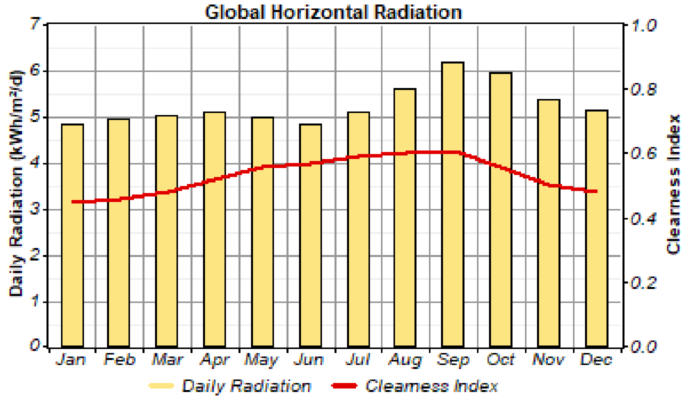

Figure 3. HOMER visualisation of monthly average GHI and Clearness Index for the specified location.

3.2. Reliability-cost trade-offs

The cost-reliability trade-offs in the context of residential grid-connected rooftop PV analysis should demonstrate to customers the importance of understanding the options available and their possible two-sided impacts. This impact may be caused by different PV sizes that customers may consider due to budget or other constraints, such as daytime power requirements and supply reliability. In contrast to the load profiles of commercial buildings in general, which have relatively flat loads during the day, the load profiles for all surveyed households, as shown in Figure 1, can provide more options to all customers, particularly considering the shape of a deep valley from 7 a.m. – 4 p.m. However, there are different consequences for installing any PV size that suits their needs and limitations, not just only maximising the size allowed by regulations up to the contracted amount of power.

The cost-reliability trade-off analysis in this study is based on the maximum annual capacity shortage values assigned to the simulation. HOMER uses the term 'maximum annual capacity shortage' to express the system's reliability constraint. It defines the total capacity shortage as the total amount of capacity shortage throughout a year, expressed in kWh/year. The value is used to calculate the capacity shortage fraction. This fraction is a ratio between total capacity shortage and total electric load, expressed in kWh/year. The simulated systems may end up with a situation where there is an unmet load or unserved energy when the electrical load exceeds the supply. Therefore, the total unmet load and the unmet load fraction can be calculated accordingly. This study applies 0%, 5%, 10%, and 15% of the maximum annual capacity shortage (or maximum unserved energy). Hereafter, the

paper uses the term ‘maximum unserved energy’ as the system reliability constraint and ‘unserved energy’ as the result of system reliability.

3.3. System modelling, economic parameters, and assumptions

This study assesses the grid-connected rooftop PV systems for residential households by using HOMER software to model system configurations for four residential household segments with their associated load profiles in the urban area of Surabaya, Indonesia, as a case study. The complete model consists of an electricity grid, the household’s loading pattern, and the main components consist of PV array and converter. While much of the simulations are performed in HOMER, this study takes into account the implications of setting and regulation through different unserved energy targets, PV capacity, and billing deduction factors on the assessment of cost-reliability trade-offs.

In particular, this study suggests a method for incorporating billing deduction factors in HOMER optimisation since the software does not account for billing deduction cases in its direct calculations. In HOMER, varying sell-back rates for energy sold to the grid can be used to account for various billing deduction factors. To simulate a billing deduction factor of 65%, for instance, the model multiplies the amount of electricity sold to the grid by 65% of the electricity full rate for customers.

This study examined four load profiles corresponding to the four residential customer segments. Simulations are performed for each load profile, considering the electricity export deduction factor. The applicable kWh export deduction factor determines the proportion of kWh exported to the grid that can be used as a factor for reducing electricity bills. This study uses two different billing deduction factors, i.e., a 65% deduction factor according to Ministerial Regulation No. 49/2018 and a 100% deduction factor according to Ministerial Regulation No. 26/2021. The first deduction factor shows that only 65% of the kWh exported to the grid is permissible for customers to reduce electricity bills. The second factor indicates that the customer can use all kWh exported to the grid to reduce the amount of kWh purchased from the grid.

In HOMER, these two conditions can be treated differently. HOMER calculates the total energy charge without net metering, i.e., using the 65% deduction factor, by multiplying the total energy purchased from the grid by the electricity rate applicable to that household segment minus the amount of electricity sold to the grid times the applicable sell-back rate. Using a 100% deduction factor (net metering), HOMER calculates the total energy charge by multiplying the amount of net kWh purchased from the grid by the electricity rate that applies to the household segment.

No Time-of-Use (TOU) rate and demand charge is applied to Indonesian residential sector customers. The electricity rate for households with a 2,200 VA power contract (R1) is IDR 1,444.70 per kWh, while households with power of 3,500 VA or above (R2/R3) are charged IDR 1,699.53 per kWh [[54], [55]]. Assuming the exchange rate is IDR 15,000 per USD 1, this gives us USD 0.096 per kWh for 2,200 VA customers and USD 0.113 per kWh for 3,500-6,600 VA ones. The simulation, therefore, applies different electricity rates between 2,200 VA and higher segments.

The simulation also accounts for demand uncertainty by allowing for up to 5% day-to-day variability, i.e., the standard deviation in the sequence of daily averages, and up to 5% time-step-to-time-step variability, i.e., the standard deviation in the difference between the hourly data and the average daily profile, depending on the contract. This configuration results in a higher peak load than the surveyed households have. For example, a 2,200 VA household with 22 kWh/day and a peak load of 1.65 kW is simulated to have a peak load of 2.1 kW due to the 5% day-to-day and time-step-to-time-step variability. Aside from that, electricity demand is assumed to remain constant over the PV’s lifetime. The complete system configuration models for all households in HOMER is illustrated in Figure 4.

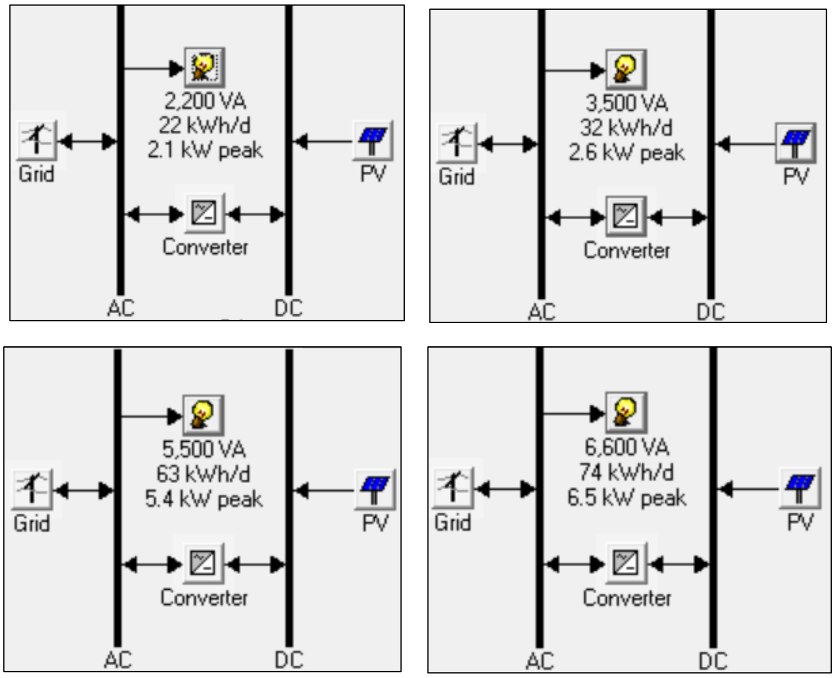

Figure 4. HOMER system configurations for residential households with 2,200 VA and 3,500 VA (top left to right), households with 5,500 VA and 6,600 VA (down left to right) electricity contracts.

Solar PV array and converter

Since the effect of temperature on the PV array is not considered, HOMER calculates the power output generated by the solar PV array P_{PV} according to the following equation.

$$P_{PV} = Y_{PV} \times f_{PV} \left(\frac{G_T}{G_{T,STC}} \right) \tag{1}$$

where Y_{PV} is the rated capacity of the PV array (kW), f_{PV} is the derating factor (%), G_T is the solar radiation incident on the PV array in the current time step (kW/m^2), and $G_{T,STC}$ is the incident radiation at standard test condition (1 kW/m^2).

In HOMER, the rated capacity of the PV array Y_{PV} is specified by users as one of the input variables to Eq. 1. Users can either enter at least one size of solar PV module and the capital cost associated with that particular size, for example, 2 kW, or in fractions, for example, 0.1 kW PV. If the second option were selected, the user must enter several PV module capacities in multiples of 0.1 kW to 2 kW or up to the maximum capacity considered. HOMER simulates possible supply configurations to meet hourly-based energy demand and displays the system's Y_{PV} in the simulation results. Therefore, if users enter Y_{PV} as fractions, the number of solar PV arrays N_{PV} can be obtained using the following equation.

$$N_{PV} = \frac{calc\_Y_{PV}}{frac\_Y_{PV}} \tag{2}$$

where cal_Y_{PV} is the calculated system's rated capacity of the PV array (kW), and $frac\_Y_{PV}$ is the fraction of the rated capacity of the PV entered by users (kW).

HOMER models a converter, or better known as an inverter, to convert DC electricity generated by solar PV arrays to AC electricity by considering the user-specified efficiency η of the inverter side.

HOMER calculates the performance of a converter on an annual basis according to the following equation.

$$\eta = \frac{kWh/year_{in}}{kWh/year_{out}} \tag{3}$$

where $kWh/year_{in}$ is the DC electricity generated by PV arrays (kWh/year), and $kWh/year_{out}$ is the AC electricity produced by inverter (kWh/year).

The expected converter life is 15 years, with 90% efficiency on the inverter side and 85% efficiency on the rectifier side. The converter-rated capacity candidates can be slightly higher than the solar PV capacity specified in the simulation search space, as HOMER does not consider the power factor of the load. Capital and replacement costs of the 1 kW converter are assumed to be USD 400 (IDR 6,000,000) [56] and USD 380 (IDR 5,700,000), respectively, without annual O&M costs. Capital and replacement costs are assumed to increase linearly concerning size.

This study assumes capital and replacement costs for the 0.1 kW peak PV module in Indonesia to be USD 50 each (equal to around IDR 750,000) [57], and no annual Operating and Maintenance (O&M) costs for the PV arrays. The cost of additional or replacement modules is assumed to increase linearly. The derating factor is considered 80%, and the ground reflectance is supposed to be 20%. Given an expected lifetime of 25 years, the PV arrays are installed without tracking. The slope is specified in the same degree as the location's latitude, 7.3°, while the azimuth is set at 180° (due North).

System economic

This study considers a project lifetime of 25 years and assumes an annual interest rate of 5%. Other important assumptions include system fixed capital cost and system fixed O&M cost. Considering the current total installed cost of solar PV for the Indonesian residential sector, i.e., USD 1,000/kW peak (IDR 15,000,000/kW peak) [[58], [59]], and the cost of solar PV modules and converters, the system fixed capital cost and the fixed O&M cost are set at USD 200 (IDR 3,000,000) [60] and USD 20/year (IDR 300,000/year), respectively.

In HOMER, the economic feasibility of the systems can be assessed by using total Net Present Cost (total NPC), Cost of Energy (COE), and operating costs. The total NPC, expressed in USD, is used in economic analysis to show the system's life cycle cost. It is calculated as follows.

$$C_{NPC} = \frac{C_{ann,tot}}{CRF(i, R_{proj})} \tag{4}$$

$$CRF(i, N) = \frac{i(1+1)^N}{(1+i)^N - 1} \tag{5}$$

where $C_{ann,tot}$ is total annualised cost (USD/year), CRF is capital recovery factor, i is interest rate (%), and R_{proj} is project lifetime (year).

HOMER defines COE as the average cost per kWh produced by the system. It is calculated by dividing the total annualised cost by the total electricity produced including total grid sales as follows.

$$COE = \frac{C_{ann,tot}}{E_{prim,AC} + E_{grid,sales}} \tag{6}$$

where $E_{prim,AC}$ the total electricity produced by all components of the system in a year, and $E_{grid,sales}$ is the total grid sales (electricity sold to the grid).

Operating costs, expressed in USD/year, are the sum of the annual O&M costs, and annualised replacement cost minus annualised salvage value. For grid-connected systems, it includes the annualised cost of electricity purchased from the grid minus electricity sold to the grid. While the term operating costs is useful in providing the user with some insights into the contribution of these types of costs on the total NPC and typically decreases at higher unserved energy, this study rules out the term operating costs in the analysis due to the focus of this study on analysing the possible trade-off between the system cost, which is already well represented by the total NPC, and unserved energy.

Scenarios and cases

This study considers two main scenarios in the simulation regarding the selection of solar PV-size candidates. The first scenario is called Maximum-PV-Capacity (MPVC). This basically refers to the maximum PV capacity a customer can install, i.e., up to the power (VA) contracted by a household, as per Ministerial Regulation No. 26/2021. For example, a household with 2,200 VA contracted power can install PV panels up to 2.2 kW peak capacity. In this case, the simulation considers up to 2.2 kW peak PV capacity in 0.1 kW PV arrays. This scenario considers PV sizes of up to 3.5 kW peak, 5.5 kW peak, and 6.6 kW peak for households with 3,500 VA, 5,500 VA, and 6,600 VA, respectively. HOMER simulates these size candidates and the fraction of electricity purchased from the grid. The optimisation will result in a system configuration with the least total NPC and other alternatives that exhibit higher total NPC.

The second scenario is called Half-PV-Capacity (HPVC). Under this scenario, simulations use up to half the maximum allowable PV capacity. For example, simulations for possible system configurations for a 2,200 VA household consider up to 1.1 kW peak capacity in 0.1 kW PV arrays. Other simulations for households with 3,500 VA, 5,500 VA, and 6,600 VA are carried out considering PV capacity of up to 1.75 kW peak, 2.75 kW peak, and 3.3 kW peak, respectively. This scenario is based on the low load during the day for all households, i.e., between 7 a.m. and 4 p.m. This study assesses the total NPC from both MPVC and HPVC scenarios for all household segments.

This study considers up to four cases for each household segment, i.e., 100%-MPVC, 100%-HPVC, 65%-MPVC, and 65%-HPVC. In this regard, either 100% or 65% refer to the applicable deduction factor according to the regulations mentioned earlier in Section 2. In other words, there are two cases for each scenario. The MPVC scenario consists of 100%-MPVC and 65%-MPVC, while the HPVC scenario consists of 100%-HPVC and 65%-HPVC.

4. Results and Discussion

Table 3 to Table 5 highlight the main results regarding important techno-economic aspects for all the cases considered in a 2,200 VA household. In the 100%-MPVC cases, the total NPC has reached USD 9,175 for 0% maximum unserved energy (no-unserved energy) and has declined to USD 7,987 or 13% for up to 11% simulated unserved energy. As for no-unserved energy, the total NPC has increased to USD 10,031, USD 10,371, and USD 10,661 for the 65%-MPVC, 100%-HPVC, and 65%-HPVC cases, respectively.

All the total NPC of 100%-MPVC is found to be the cheapest among other cases considering all unserved energy. From the simulations, it is revealed that the total NPC of 100%-MPVC with no-unserved energy is USD 9,175, cheaper than the total NPC of 65%-MPVC with 7% unserved energy and of HPVC cases with 11% unserved energy. The simulation results have implied potential benefits of rooftop PV installation up to the maximum permitted capacity and concerning a 100% billing deduction scheme for households

with 2,200 VA, considering different options regarding unserved energy, installed capacity, and percentage of billing deduction.

As shown in Table 3 to Table 6, renewable energy's contribution to electricity generation has reached 33-36% share in the cases of MPVC and 19-21% share in the cases of HPVC within the range of 11% unserved energy. As expected, reducing the installed capacity of PV modules to half the maximum allowable capacity will decrease PV penetration in the systems.

Table 3. Simulation results for 2,200 VA: 100%-MPVC

Maximum annual unserved energy (%)	PV (kW)	Converter (kW)	Grid (kW)	Initial Capital (USD)	Total NPC (USD)	COE (USD/kWh)	RE share (%)	Unserved energy (%)
0	2.2	1.5	1.8	1,900	9,175	0.081	33	0
5	2.2	1.5	1.4	1,900	8,796	0.081	34	4
10	2.2	1.5	1.3	1,900	8,446	0.080	35	7
15	2.2	1.5	1.2	1,900	7,987	0.079	36	11

Table 4. Simulation results for 2,200 VA: 65%-MPVC

Maximum annual unserved energy (%)	PV (kW)	Converter (kW)	Grid (kW)	Initial Capital (USD)	Total NPC (USD)	COE (USD/kWh)	RE share (%)	Unserved energy (%)
0	2.2	1.5	1.8	1,900	10,031	0.089	33	0
5	2.2	1.5	1.4	1,900	9,652	0.088	34	4
10	2.2	1.5	1.3	1,900	9,302	0.088	35	7
15	2.2	1.5	1.2	1,900	8,842	0.088	36	11

Table 5. Simulation results for 2,200 VA: 100%-HPVC

Maximum annual unserved energy (%)	PV (kW)	Converter (kW)	Grid (kW)	Initial Capital (USD)	Total NPC (USD)	COE (USD/kWh)	RE share (%)	Unserved energy (%)
0	1.1	1.0	1.8	1.150	10,371	0.092	19	0
5	1.1	1.0	1.4	1.150	9,987	0.092	20	4
10	1.1	1.0	1.3	1.150	9,636	0.091	21	7
15	1.1	1.0	1.2	1.150	9,177	0.091	21	11

Table 6. Simulation results for 2,200 VA: 65%-HPVC

Maximum annual unserved energy (%)	PV (kW)	Converter (kW)	Grid (kW)	Initial Capital (USD)	Total NPC (USD)	COE (USD/kWh)	RE share (%)	Unserved energy (%)
0	1.1	1.0	1.8	1,150	10,661	0.094	19	0
5	1.1	1.0	1.4	1,150	10,277	0.094	20	4
10	1.1	1.0	1.3	1,150	9,926	0.094	21	7
15	1.1	1.0	1.2	1,150	9,467	0.094	21	11

The optimisation results presented in Table 3 to Table 6 also provide customers with another insight into the potential role of the system cost components in shaping the cost-reliability trade-off. While the initial capital costs are of course found to be lower in HPVC cases compared to those in MPVC due to less PV array involved, i.e., USD 1,150 versus USD 1,900, it is found that the total NPC of MPVC cases are found to be cheaper than those of HPVC cases within the same unserved energy.

From the simulation results in 100%-MPVC cases, for example, it is found that 4% unserved energy is equal to 283 kWh/year of unmet electricity, while 7% and 11% unserved energies are equal to 542 kWh/year and 881 kWh/year, respectively. On the other hand, the total NPC of this particular case has shown a noticeable decrease of around USD 350 – USD 450 for every 3-4% additional unserved energy.

Table 7 to 10 shows the trade-offs between the total NPC, as expressed in annual total cost (USD/year), and unserved energy (kWh/year) of all simulations for a 2,200 VA household. The optimisation results show cheaper total annual costs as unserved energy increases. In addition, MPVC cases have shown more affordable yearly costs due to fewer energy charges (electricity bills) spent by the customers compared to those of HPVC.

It is of importance to observe the simulation results in terms of a range of shares of energy charge to the total (annual) cost of the systems. As presented in Table 7 to Table 10, all optimisation results in MPVC cases have shown lower shares of energy charge to the (annual) total cost compared to those in HPVC ones. It is found that the averaged shares of energy charge to the total cost are 70% and 74.6% for 100%-MPVC and 65%-MPVC, respectively, versus 83.9% and 84.3 for 100%-HPVC and 65%-HPVC, respectively.

As the finding compares MPVC and HPVC scenarios, it highlights the potential benefits of higher PV penetrations in reducing the energy charge component's share of the total annual cost within the same unserved energy range. In this regard, the lower applicable billing deduction factor indicates the smaller revenue that a customer can expect within the same scenario, which, of course, has an impact on the higher portion of energy charge in the total annual cost. While this paper highlights particular results for a 2,200 VA surveyed household, similar implications as obtained in Table 7 are also expected to occur for other households considered in this study, given the similarity of the households' daily load profiles.

Table 7. Trade-offs between annualised total cost and unmet energy for a 2,200 VA household

Scenario	Unserved energy (%)	Unmet energy (kWh/year)	Annual energy charge (USD/year)	Annualised total cost (USD/year)	Share of energy charge to total cost (%)	Averaged share of energy charge to total cost (%)
100%-MPVC	0	0	481	651	73.8	70
	4	283	454	624	72.8	
	7	542	429	599	71.6	
	11	881	396	567	69.8	
100%-HPVC	0	0	624	736	84.8	83.9
	4	287	597	709	84.2	
	7	546	572	684	83.6	
	11	886	539	651	82.8	
65%-MPVC	0	0	541	712	75.9	74.6
	4	283	515	685	75.2	
	7	542	490	660	74.2	
	11	881	457	627	72.9	
65%-HPVC	0	0	645	756	85.3	84.3
	4	287	617	729	84.6	
	7	546	592	704	84.1	
	11	886	560	672	83.3	

Figure 9 and Figure 10 depict the cost-reliability trade-offs in terms of total NPC versus unserved energy for all cases in 2,200 VA and 3,500 VA, as well as 5,500 VA and 6,600 VA households,

respectively. From the simulation results presented in Figure 9 and Figure 10, the total NPC of 100%-MPVC cases is the cheapest in every unserved energy. The finding indicates a comparative benefit of on-grid rooftop PV systems installing maximum PV capacity permitted combined with higher billing deduction factors (here is 100%) over other configurations. Moreover, there is a relatively large difference in total NPC between the 100%-MPVC cases and the 65%-MPVC cases concerning all unserved energies up to a 15% maximum annual unserved energy constraint, while insignificant differences of the total NPC are found between those in the 100%-HPVC cases and the 65%-HPVC cases, particularly in 3,500 VA and 6,600 VA households.

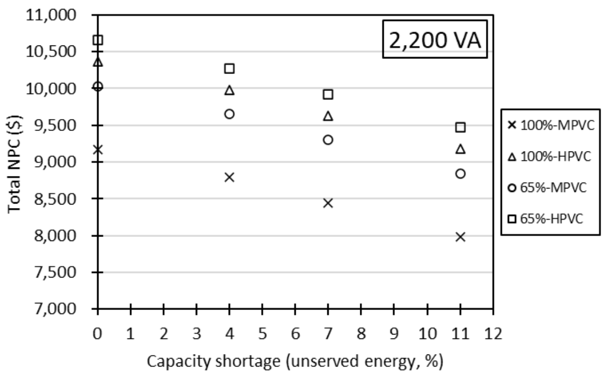

Figure 9. Total NPC versus unserved energy in all cases for 2,200 VA (left) and 3,500 VA (right)

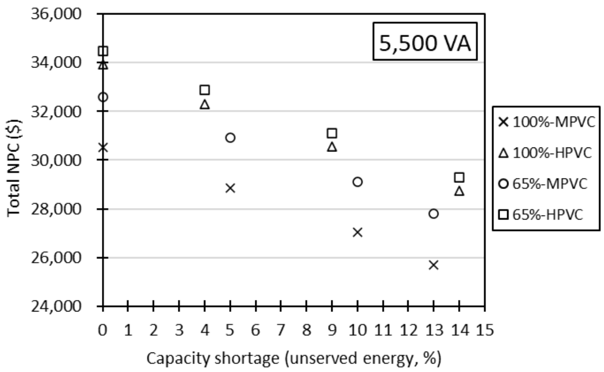

Figure 10. Total NPC versus unserved energy in all cases for 5,500 VA (left) and 6,600 VA (right)

Residential customers can further estimate one of the important indices for rooftop PV installation decision-making, i.e., the cost per MWh consumed (USD/MWh). Using 100%-MPVC cases in a 2,200 VA household as illustrations, and given the cost is the total NPC, as presented in Figure 9, the costs per MWh consumed during the project lifetime for 0%, 4%, 7%, and 11% unserved energies are USD 37.19/MWh, USD 36.70/MWh, USD 36.22/MWh, and USD 35.54/MWh, respectively, provided the total MWh consumed over the 25-year project lifetime are 246.68 MWh, 239,68 MWh, 233.20 MWh, and 224.73 MWh, respectively for the associated unserved energies.

From this particular analysis, it is found that, despite a considerably large difference in terms of total NPC between the system with no-unserved energy and that with the poorest reliability (USD 1,188 difference), the cost per MWh figures have shown a relatively small gap of cost difference during the project lifetime, i.e., USD 1.65/MWh, between no-unserved energy and 11% unserved energy.

In addition to merely exploring and comparing economic parameters such as total NPC, the share of energy charge to total annual cost, and COE, it is also of interest to assess the potential economic impact of the systems in terms of cost per watt of PV installed, i.e., through exploring which households exhibit the lowest cost per watt of PV installed capacity. The cost per watt of PV installed

can be used as one of the indicators for customers in deciding the capacity of PV to be installed while considering possible techno-economic scenarios, including the potential impact of applicable billing deduction factors and a range of different unserved energy.

The lowest cost per watt of PV installed capacity can be obtained for all scenarios by comparing the total system cost (total NPC) with the PV installed capacity. Table 8 presents variations in cost per watt of PV installed capacity for all the optimisation results of 100%-MPVC and 65%-MPVC, as well as 100%-HPVC and 65%-HPVC given no-unserved energy (0% maximum unserved energy), while Tables 9 to 11 present variations of the cost per watt of PV installed capacity considering 5%, 10%, and up to 15% maximum unserved energy, respectively.

Table 8. The cost per watt of PV installed capacity with 0% maximum unserved energy.

Household	The cost per watt of PV installed capacity ($/Watt)			
	100%-MPVC	65%-MPVC	100%-HPVC	65%-HPVC
2,200 VA	4.17	4.56	9.43	9.69
3,500 VA	4.20	4.53	9.68	9.74
5,500 VA	5.55	5.93	12.34	12.54
6,600 VA	5.39	5.71	12.02	12.12

Table 9. The cost per watt of PV installed capacity with 5% maximum unserved energy.

Household	The cost per watt of PV installed capacity (USD/Watt)			
	100%-MPVC	65%-MPVC	100%-HPVC	65%-HPVC
2,200 VA	3.99	4.39	9.08	9.34
3,500 VA	4.00	4.34	9.30	9.36
5,500 VA	5.24	5.62	11.75	11.95
6,600 VA	5.06	5.39	11.36	11.46

Table 10. The cost per watt of PV installed capacity with 10% maximum unserved energy.

Household	The cost per watt of PV installed capacity (USD/Watt)			
	100%-MPVC	65%-MPVC	100%-HPVC	65%-HPVC
2,200 VA	3.84	4.23	8.76	9.02
3,500 VA	3.71	4.05	8.71	8.77
5,500 VA	4.91	5.29	11.11	11.31
6,600 VA	4.78	5.10	10.78	10.88

Table 11. The cost per watt of PV installed capacity with 15% maximum unserved energy.

Household	The cost per watt of PV installed capacity (USD/Watt)			
	100%-MPVC	65%-MPVC	100%-HPVC	65%-HPVC
2,200 VA	3.63	4.02	8.34	8.61
3,500 VA	3.52	3.86	8.32	8.38
5,500 VA	4.68	5.06	10.45	10.65
6,600 VA	4.43	4.76	10.23	10.33

As shown in Table 8, the total NPC per watt of PV installed capacity, under 0% unserved energy, varied from USD 4.14/Watt to USD 12.54/Watt in all cases across all households. The results show similar costs in the MPVC cases concerning 2,200 VA and 3,500 VA households, slightly more than double in the HPVC cases, and similar for 5,500 VA and 6,600 VA households. It is also found that the results are not affected by the applicable billing deduction factors but simply by the PV capacity. Nevertheless, it should be noted that the results obtained in Tables 8 to 11 are largely influenced by the household's daily electricity load profile and other applied scenarios.

The simulation results in terms of possible system capacity, consisting of grid and PV capacity across all unserved energy in all cases of all households, are depicted in Figure 11 and Figure 12.

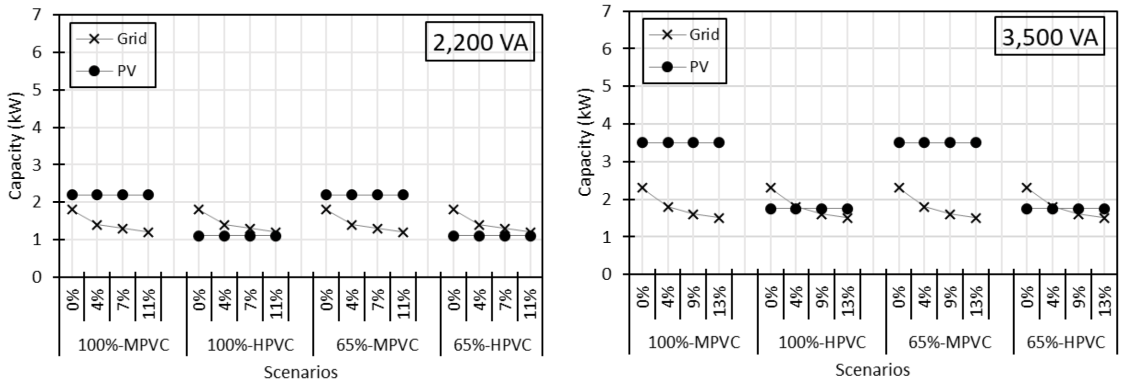

Figure 11. System capacity across all unserved energies for 2,200 VA (left) and 3,500 VA (right)

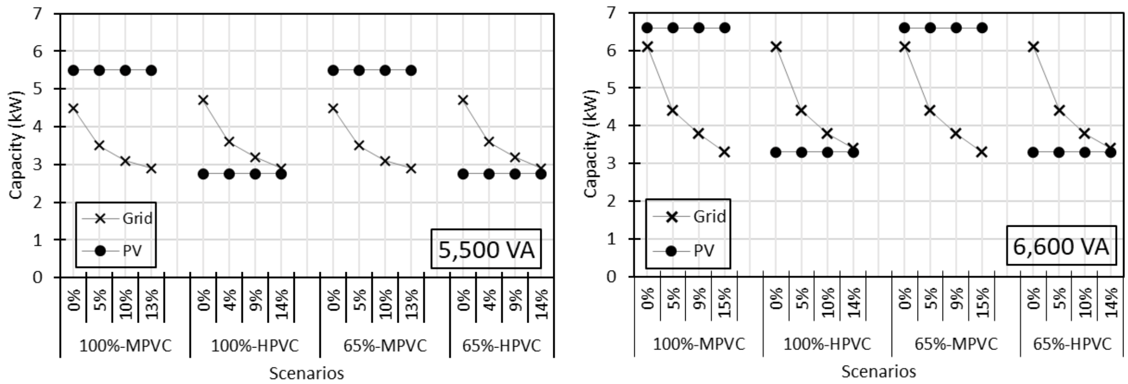

Figure 12. System capacity across all unserved energies for 5,500 VA (left) and 6,600 VA (right)

As seen in Figures 11 and 12, higher unserved energy has resulted in lower grid capacity required by the system to meet the demand according to the system's maximum unserved energy constraint, and the PV capacities are maximised across all unserved energies in different scenarios. Moreover, it is interesting to note that the PV capacities across all MPVC cases are always higher than the grid ones. On the other hand, the grid capacities are mostly higher than those of PV in most HPVC cases, except in 3,500 VA for 9% unserved energy and beyond. In all cases, the grid capacities have similarly decreased within the unserved energy range. For example, in 2,200 VA (see Figure 11 left), the grid capacities are found at 1.8 kW, 1.4 kW, 1.3 kW, and 1.2 kW for 0%, 4%, 7%, and 11% unserved energy, respectively, and similarly in other households.

A sensitivity analysis of the techno-economic factors influencing system performance would benefit stakeholders, particularly residential customers. While focusing on system reliability, this study uses only a 5% annual interest rate and fixed electricity rates associated with household segments. As a result, the sensitivity variable used in HOMER is maximum annual unserved energy.

Taking a 2,200 VA household with 100%-MPVC as an example, a graphical sensitivity result depicting possible trade-offs on total NPC versus unserved energy fraction and a sensitivity result of net grid purchases (electricity purchased from the grid minus electricity sold to the grid) versus maximum annual unserved energy are presented in Figure 13 and Figure 14, respectively. Meanwhile, a sensitivity result of total NPC versus total electricity production is shown in Figure 15.

Maximum annual unserved energy constraints have varying effects on total NPC, total electricity production, and nett grid purchases. As shown in Figure 13, total NPC cannot be less than USD 8,500

when unserved energy is kept at or below 6%. According to Figure 15, a 10% unserved energy would result in approximately 9,700 kWh/year of electricity production, which would equal approximately USD 8,500 in total NPC.

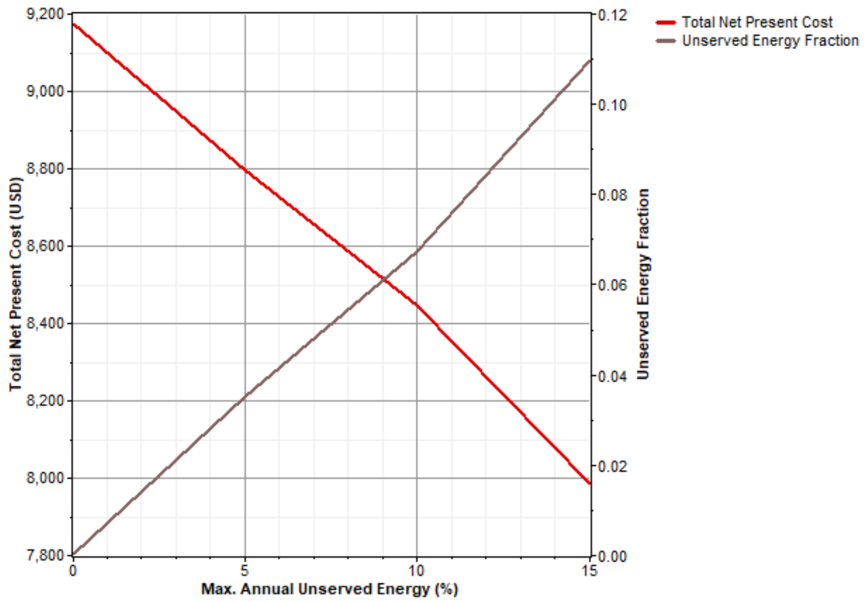

Figure 13. Sensitivity result of total NPC versus unserved energy fraction in a 2,200 VA household with 100%-MPVC.

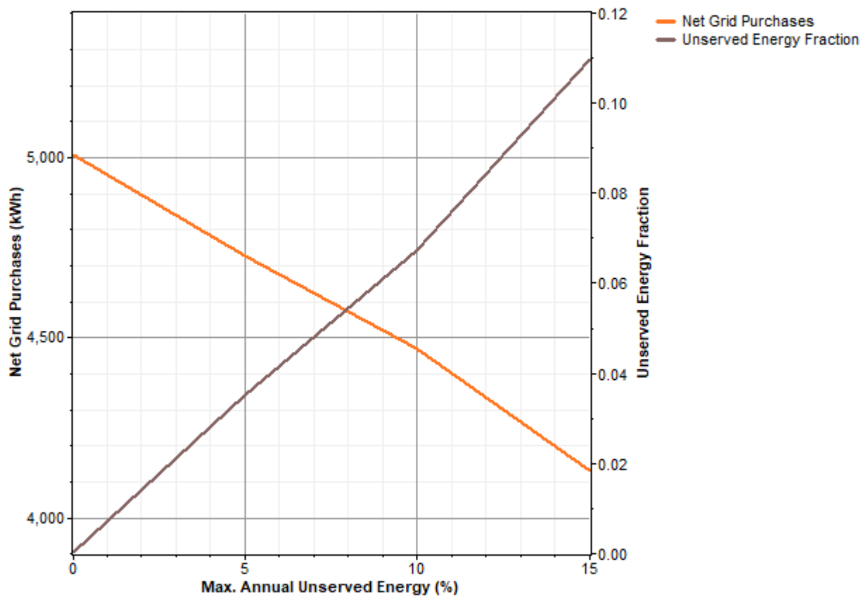

Figure 14. Sensitivity result of net grid purchases versus maximum annual unserved energy in a 2,200 VA household with 100%-MPVC.

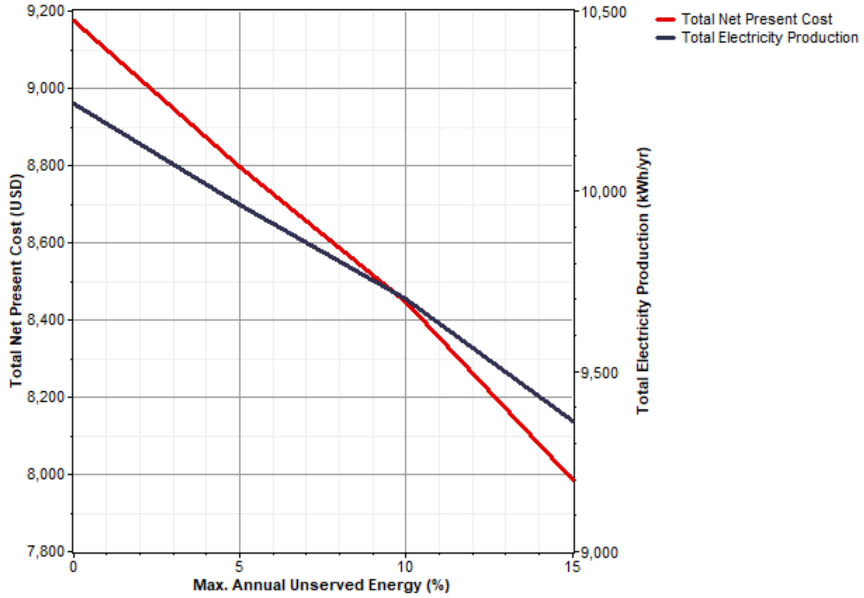

Figure 15. Sensitivity result of total NPC versus total electricity production in a 2,200 VA household with 100%-MPVC.

Despite possible variations and differences in households' daily loading profiles along with other affecting factors, which, of course, may provide different results and interpretations, this study has sought to explore possible cost-reliability trade-offs in Indonesia's urban residential grid-connected rooftop PV due to three key factors, namely potential unserved energy, PV capacity, and possible billing deduction scheme. The significance of these factors has been shown in the analysis considering different residential household segments, and therefore, should be considered not only by customers who are willing to apply on-grid rooftop PV but also by stakeholders such as government and utility companies according to their role in supporting more grid-connected rooftop PV capacity.

5. Conclusions

This paper explores the potential of grid-connected rooftop PV systems in terms of how they can be better planned and utilised by understanding the possible trade-offs between system reliability and cost while recognising challenges related to electricity supply security in the context of emerging economies. The effects of various unserved energy limits, PV capacities, and billing deduction factors (modelled in HOMER using different sell-back rates) on the systems' techno-economic parameters have been investigated in order to better understand possible cost-reliability trade-offs for total NPC and unserved energy. The analyses are carried out with the help of HOMER, with four different residential household segments in Surabaya, Indonesia, serving as a case study.

In all four cases of each household segment, i.e., 100%-MPVC, 65%-MPVC, 100%-HPVC, and 65%-HPVC, the optimisation results show reliability-cost trade-offs between the total NPC and all unserved energies. Furthermore, the role of cost components in the trade-offs between HPVC and MPVC cases in terms of initial capital costs and total NPC was highlighted in the analyses. The findings revealed a relatively large difference in total NPC for all households between 100%-MPVC cases and 65%-MPVC cases for all unserved energies, while differences between those in 100%-HPVC cases and 65%-HPVC cases are insignificant. The simulation results implied potential benefits of rooftop PV installation up to the maximum permitted capacity and a 100% billing deduction scheme for households with 2,200 VA, taking into account different options for unserved energy, installed capacity, and billing deduction percentage.

Among the significant results of this study that highlight the benefits of grid-connected rooftop PV are the following: 1) higher renewable energy penetration for MPVC systems compared to HPVC systems regardless of the billing deduction factors; 2) cheaper total NPC are shown by MPVC cases than those of HPVC cases within the same unserved energy; 3) lower shares of energy charge to the annual total cost in MPVC cases compared to those in HPVC ones; and 4) Over the project lifetime, the cost per kWh consumed (USD/MWh consumed) showed only a slight variance between the system with no-unserved energy and the system with the poorest reliability, given 100%-MPVC cases in 2,200 VA as an example; 5) All households with a 15% maximum limit on unserved energy have the lowest costs per watt of installed PV capacity, and these costs are unaffected by billing deduction factors; 6) based on the system's maximum unserved energy limits, higher unserved energy has led to a decrease in the amount of grid capacity needed by the system to meet demand, and the PV capacities are maximised across all unserved energies in various scenarios; and 7) Sensitivity analyses have revealed a range of impacts of maximum annual unserved energy constraints on various parameters, including total NPC, total electricity production, and net grid purchases.

When it comes to grid-connected rooftop PV, residential customers must be thoughtful, as there are potential trade-offs between cost and reliability. At the same time, attention must be paid to changing regulations that may have an impact on overall profitability. This study's analyses provided important findings and insights not only to the residential customers but also to stakeholders involved in the planning and implementation of rooftop PV policies.

Finally, there is no doubt about the grid-connected rooftop PV's techno-economic potential for accelerating distributed renewable energy penetration. Nonetheless, because rooftop PV deployment appears to be modest, especially in Indonesia, changes to the existing set of regulations are required. More encouraging, innovative policies should be introduced to address the barriers and challenges that customers and the industry face in moving rooftop PV deployment forward.

Acknowledgement

The author would like to thank the reviewers for their time and effort in reviewing the manuscript. All valuable comments and suggestions for improving the manuscript's quality are greatly appreciated.

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Cost-reliability trade-offs for grid-connected rooftop PV in emerging economies: a case of Indonesia's urban residential households

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Abstract

This study explores the potential of grid-connected rooftop photovoltaic (PV) systems in terms of how they can be better planned and utilised by understanding possible trade-offs between cost and reliability while acknowledging challenges to utility supply security in the context of emerging economies. The study particularly examines the implications of unserved energy targets, PV capacity, and billing deduction factors on grid-connected rooftop PV's trade-offs in terms of total net present cost and unserved energy. This study considers four residential household segments in Indonesia's urban area as a case study, with four cases applied in each segment representing scenarios on PV capacities and billing deduction factors. Using HOMER software, the analyses highlight the role of cost components in trade-offs involving potential PV capacity cases. Systems with maximum PV capacity exhibit cheaper total net present costs than those of half PV capacity within the same unserved energy. While the optimisations pushed PV capacity up to the maximum size across all unserved energies, higher unserved energy resulted in lower grid capacity required to meet demand associated with the system's maximum unserved energy limit. This study provides residential customers and stakeholders with insights to better plan and implement grid-connected rooftop PV systems and policies.

Keywords: on-grid, rooftop PV, emerging economies, reliability-cost, trade-offs.

1. Introduction

The utilisation of solar photovoltaic (PV) systems has increased significantly in recent years, with global capacity growth reaching 1.2 TW by 2022 [[1], [2], [3]]. In several emerging economies and jurisdictions, the installation of rooftop solar PV has witnessed significant growth [[4], [5], [6], [7], [8]]. Grid-connected rooftop PV is a feasible option for providing electricity in residential households in many urban areas [9]. Installing grid-connected rooftop PV is simpler, cheaper, and requires almost no maintenance compared to hybrid systems [10]. Adopting low-cost, green technologies like PV can reduce CO_2 emissions and support sustainable energy transition [[11], [12]]. However, when choosing grid-connected rooftop PV, customers consider various factors, including the system's performance expectations, socio-environmental beliefs, and price-value beliefs, among others [13].

Rising electricity prices in developed countries like Australia, the Netherlands, Germany, and many others have fuelled the adoption of residential rooftop PV systems along with the growth in capacity. However, it is worth noting that rooftop PV development in emerging economies has been influenced by both economic and technical factors. Increasing electricity rates and challenges utilities face in providing a reliable power supply, particularly in urban distribution networks, have contributed to the rise of rooftop PV in these countries.

It is of importance to pay special attention to the low reliability of urban distribution networks [14]. This is particularly essential for households choosing the appropriate size of rooftop PV components. A grid-connected system without any capacity shortage, representing excellent reliability, would require a larger supply capacity to meet high peak loads during a short period. This, of course, would come at a

higher cost. On the other hand, a smaller and less expensive system may meet a reasonable portion of the load while allowing for some capacity shortage.

Many studies have investigated different aspects of the techno-economic feasibility of rooftop solar PV systems in the context of emerging economies and developing countries. These studies have primarily focused on grid-connected residential applications and have used various techniques and tools. Some studies have concentrated on system planning through simulations, while others have evaluated the performance of installed systems, either at a single location or across several sites.

Gabr et al. [10] assessed the techno-economic feasibility of a grid-connected rooftop PV system in Egypt, considering the ongoing electricity retail prices and net-metering policy applied to three types of housing rates with different demand levels. They used HOMER (Hybrid Optimization of Multiple Energy Resources) software [15] to measure the net present value of energy cost, payback period, and bill savings. Laib et al. [16] evaluated the performance of a grid-connected solar PV system and its energy balance in Algeria. The authors developed a Matlab-Simulink model to optimise, rationalise, and implement energy-saving approaches to evaluate the system's energy performance and balance.

Dondariya et al. [17] predicted the performance of grid-connected rooftop PV systems in Ujjain, India. The authors compared PV*SOL [18], PVGIS [19], SolarGIS [20], and SISIFO [21] to analyse system performance in terms of energy generation, performance ratio, and solar fraction. Mohammadi et al. [22] analysed the impact of different tracking options on the potential of grid-connected PV development in Iran using RETScreen software [23]. Jesus et al. [24] proposed SolarEnergy, a new optimisation tool for the techno-economic analysis of PV microgeneration. The authors conducted a techno-economic analysis of grid-connected PV systems in Brazil, providing decision-making indicators such as net present value, modified internal rate of return, discounted payback period, and sensitivity analysis of key techno-economic parameters. In another study, Al Garni et al. [25] assessed the optimal design of grid-connected PV by considering various PV tracking systems applied in Makkah, Saudi Arabia. The authors used HOMER to examine the horizontal axis, vertical axis, and a two-axis tracking system. Earlier study by Lau et al. [26] analysed the pricing mechanism for grid-connected PV projects in the residential sector of Malaysia by evaluating the impact of component costs, feed-in tariffs, and carbon taxes using HOMER.

Duman and Güler [27] assessed the economic feasibility of 5 kW grid-connected solar PV in nine provinces of Turkey. Using HOMER, the study evaluated the discounted payback period, internal rate of return, and profitability index, and found that the system would not be feasible in two provinces under the practiced feed-in tariff. Bakhshi and Sadeh [28] examined the economic feasibility of grid-connected rooftop PV systems in Iran. They used PVsyst software [29] to estimate the annual energy generation of a 5-kW peak system in different cities. Their analysis included Net Present Value (NPV), Internal Rate of Return (IRR), payback period (PP), and Levelised Cost of Energy (LCOE), and employed a dynamic feed-in tariff strategy. Similar indicators, i.e., NPV, LCOE, IRR, and static PP and dynamic PP, were used by Xin-gang and Yi-min [30] in building a cost-benefit model to evaluate the economic performance of China's rooftop PV industry. Meanwhile, Orioli and Gangi [31] considered the effects of time variation on the PP assessment of grid-connected rooftop PV systems in Italy.

Li et al. [9] conducted a study to evaluate and compare the techno-economic performance of grid-connected rooftop PV systems and other alternatives in five climate zones in China using HOMER. The study found that grid/PV systems were the most cost-effective option among all the studied systems, and Kunming is the most economical among other regions. Tomar and Tiwari [32] discussed the feasibility of grid-connected rooftop PV for three residential households. The authors used HOMER to simulate the impact of feed-in tariffs/net metering along with a tariff-of-day policy in New Delhi, India. They concluded that systems without energy storage are technically and economically viable for

decentralised households. An earlier study by Pillai et al. [33] developed an economic evaluation methodology to assess the near-term benefits of grid-connected residential PV systems in the United Kingdom and India. The authors developed a metric called 'Prosumer Electricity Unit Cost' (PEUC) and used it to examine the effects of solar input, financial mechanisms, and demand profiles in the near-term time frame of the project.

While studies focussing on single household analysis or involving multiple sites have provided useful insights for stakeholders regarding the potential techno-economic impacts of grid-connected rooftop PV and its deployment opportunity, less explored, however, has been the impacts of setting and regulation through different unserved energy targets, PV capacity, and billing deduction factors. In particular, there has been little attention of the potential trade-offs between system reliability and costs.

This paper aims to explore the potential benefits of grid-connected rooftop PV in terms of how the systems can be better planned and utilised through understanding possible trade-offs between system reliability and cost while also recognising the challenges to utility supply security in the context of emerging economies. While system reliability and efficiency of residential rooftop PV can be enhanced by incorporating other technologies such as wind or diesel, gas, and energy storage [34], this paper focuses on the grid-connected PV systems in urban households in emerging economies. In particular, this study suggests a method for incorporating billing deduction factors in HOMER optimisation while taking into account the implications of setting and regulation through different unserved energy targets, PV capacity, and billing deduction factors on the assessment of cost-reliability trade-offs. The city of Surabaya, Indonesia, is considered a case study.

Despite high-level supportive legislation, rooftop PV has only seen modest deployment in Indonesia mainly due to non-technical barriers and challenges, such as missing permits, lack of regulatory certainty, lack of alignment and synchronisation of implementing regulations, project bankability issues, and cost burden for PLN (Perusahaan Listrik Negara, i.e., Indonesia's state-owned electricity company that is solely responsible for electricity generation, transmission, and distribution) as the sole off-taker, among others [[35], [36], [37]].

On the customer side, on the other hand, the decision regarding whether to implement grid-connected rooftop PV or rely solely on electricity from the utility grid, in many cases, has not been supported by sufficient knowledge of techno-economic aspects, particularly on reliability and cost implications due to different system settings and regulations. In addition, lack of product knowledge, complicated permit requirements, and perception of expensive systems were identified as the main barriers to adopting rooftop PV for households [38].

This paper offers a new perspective on the ongoing rooftop PV studies from a techno-economic standpoint. It introduces the concept of reliability-cost trade-offs that may arise due to different energy targets and the resulting variations in PV system sizes. These trade-offs are particularly relevant in emerging economies given the level of reliability and associated costs can vary significantly. The paper models unserved energy targets by accounting for potential capacity shortages on the supply side.

The paper is organised as follows. Section 2 provides a brief overview of the current status of solar PV deployment, with a focus on rooftop solar PV systems in Indonesia. Section 3 explains methods used in this study, including an overview of the simulations, input data, and modelling assumptions. Results and discussions are presented in Section 4. Finally, the conclusion of the paper is presented in Section 5.

2. Brief Status of Rooftop Solar PV Deployment for Residential Households in Indonesia

The potential for rooftop solar PV systems in Indonesia is immense due to the country's vast solar irradiation coverage and large market [39]. Despite this, the development of residential rooftop PV systems has been slow. As of October 2022, 75% of the 6,261 PLN customers who installed rooftop PV were residential customers with mostly on-grid systems [40]. The residential sector has installed rooftop PV with a total capacity of 15.2 MW, representing approximately 22% of the total rooftop capacity for all PLN customers [41]. The Java-Bali area has the largest share of the national rooftop PV capacity, accounting for around 80% in 2021 [42].

There are challenges to the slow deployment of residential rooftop PV in Indonesia that are currently affecting all PLN customers. Some of these challenges have been acknowledged in the PLN Electricity Supply Business Plan (RUPTL) 2021-2030 [43]. These include: 1) several PLN electricity networks are currently not prepared to handle distributed renewable energy-based generation due to oversupply conditions caused by decreased demand; 2) there will be a need for PLN to add more generation plants to increase system flexibility if there is a relatively massive penetration of rooftop PV; and 3) there will be additional investment costs in generation control and forecasting, dispatch system, and grid code enforcement [[44], [45]]. While the challenges may delay large-scale PV deployment, oversupply of system capacity, including from coal-fired power plants, can present an opportunity to provide the grid with increased flexibility [[46], [47]].

Through the Ministry of Energy and Mineral Resources (MEMR), the Indonesian government has made efforts to encourage the implementation of rooftop solar PV. This includes the issuance of Ministerial Regulation No. 49/2018, revised by Ministerial Regulation No. 26/2021 [48]. These regulations aim to achieve a rooftop PV capacity of 3.6 GW. Although the revised regulation is seen as a positive step, especially regarding the recognition of 100% export of electricity back to the PLN grid, implementation has been challenging.

As the grid operator, PLN is hesitant to approve applications for rooftop PV installations up to the maximum allowable capacity quota per customer due to oversupply and financial issues, mainly caused by the ongoing take-or-pay scheme derived from the Power Purchase Agreement (PPA) of large quantities of coal-based electricity from Independent Power Producers (IPP). To address the situation, MEMR has consulted with stakeholders to discuss various options, focusing on revising Ministerial Regulation No. 26/2021. Due to the current oversupply situation, rooftop PV users will most likely not be allowed to export electricity to the PLN grid, according to the newly revised regulation that has yet to be published [49].

Despite the positive efforts on the regulatory framework, the ongoing 35 GW coal power plant mega-project started in 2015 has become a problem for Indonesia's energy transition. The unchanging plans for additional coal power plants, which are not yet built, are arguably seen as one of the main barriers that hinder the massive development of PV, including rooftop systems – that require a comprehensive solution. While the share of coal in electricity generation is expected to decrease from around 56 GW to 40 GW, the capacity of coal-fired power plants is proposed to increase by 13 GW in the RUPTL 2021-2030. It has come to light that there are still plans to construct coal power plants in 2027, as per the 2015-2019 PPA [50].

3. Methods

In this study, HOMER software is used to model grid-connected rooftop solar PV systems. Possible system sizes with various load profiles are simulated, as are their economic parameters, such as total Net Present Cost (NPC) and Cost of Energy (COE). Four different daily load profiles for residential households with electricity contracts of 2,200 Volt-Ampere (VA), 3,500 VA, 5,500 VA, as well as 6,600 VA have been created. Figure 1 depicts these load profiles.

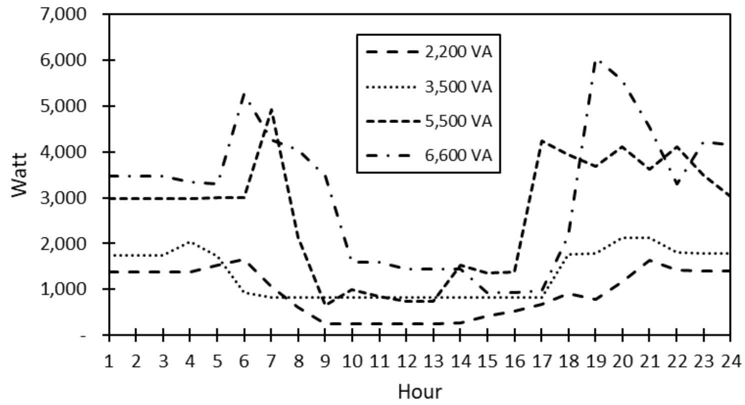

Figure 1. Surveyed hourly based daily load profile for four residential households.

While a preliminary survey has been carried out to obtain the load profiles (as shown in Figure 1) owned by different households in different locations in Surabaya – to represent different residential customer segments – this study considers only one location to allow the same solar irradiation data to be used in all simulations. It should be noted that all load profiles surveyed, as shown in Figure 1, are for weekdays. Nevertheless, weekend patterns for most residential segments show similar base load values to weekdays but have slightly higher peak load, over a short period, than weekdays. One thing to note is that the surveyed load profiles have ruled out the impact of the Covid-19 pandemic which has recently subsided, where people spent more time at home due to restrictions on outdoor activities or working from home.

Meanwhile, Table 1 shows several loading parameters for all residential segments, including the base load, maximum (peak) load, demand factor, and load factor. The demand factor is defined as the maximum demand divided by the connected load. The load factor is the ratio of average to maximum load for a 24-hour period.

Table 1. Loading parameters for all surveyed residential households

Parameter	Residential household segments			
	2,200 VA	3,500 VA	5,500 VA	6,600 VA
Base load	240 Watt	820 Watt	657 Watt	935 Watt
Maximum load	1,655 Watt	2,127 Watt	4,915 Watt	6,056 Watt
Demand factor	0.53	0.32	0.48	0.43
Load factor	0.56	0.63	0.53	0.51

As shown in Table 1, the surveyed households have a fairly low to medium range of demand factors and relatively low load factors, i.e., around 0.5 – 0.6. This, however, is a typical household situation in many Indonesian urban areas, including Surabaya. Between 7 a.m. and 4 p.m., demand for electricity falls because most people spend their days outside their homes studying or working. Furthermore, with the exception of refrigerators, electricity has not been used for kitchen appliances. While gas is commonly used in stoves and ovens, microwaves are uncommon in Indonesia.

3.1. Solar resource data

Surabaya has huge untapped potential for rooftop PV. Located on the east coast of the Java Sea, Surabaya is Indonesia's second-largest urban area of around 300 km^2 and has relatively high solar resources. According to a World Bank report that selected a geographical site of -7.32° (7°19') South Latitude and 112.68° (112°40') East Longitude, the long-term average daily Global Horizontal Irradiation (GHI) in Surabaya has reached 5.29 kWh/m^2 [29], higher than Indonesia's average daily GHI

of 4.8 kWh/m^2. Figure 2 presents the map of daily and yearly long-term averages of GHI values in Indonesia, including Surabaya, from 1999-2018 [51].

HOMER allows users to enter GHI and/or Clearness Index values using one of the two possible approaches, i.e., by downloading GHI and/or Clearness Index values from HOMER or by obtaining the NASA/MERRA2 hourly-based datasets of GHI and/or Clearness Index from the NREL National Solar Radiation Database (NSRDB) viewer [53]. While the first approach allows users to directly obtain 'ready to use' monthly average values of GHI and/or Clearness Index by specifying the location's latitude and longitude, the second approach lets users explore the data using the following steps: (1) entering the location's latitude and longitude; (2) selecting available datasets; (3) selecting appropriate attributes; (4) selecting year(s); (5) selecting time interval of the data; (6) selecting data formatting options; (7) typing an email for receiving the data; and (8) submitting the request.

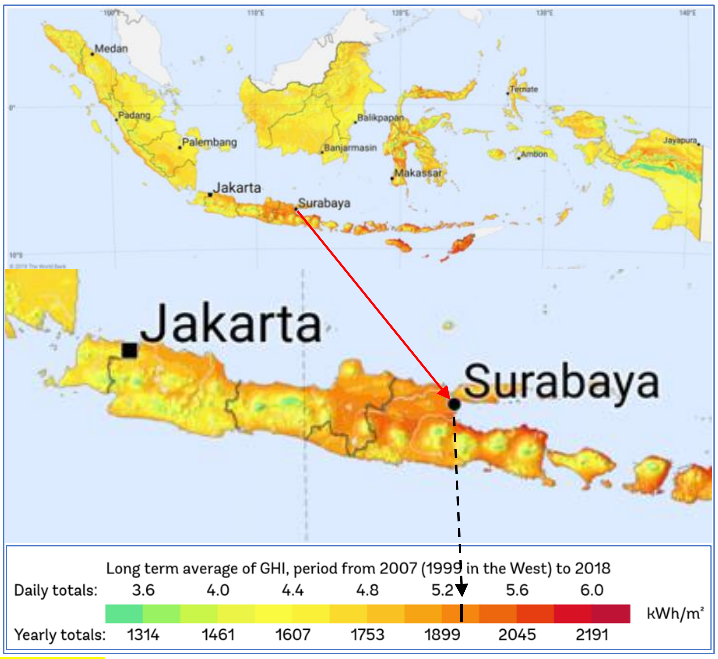

Figure 2. A map showing daily and yearly long-term average GHI (kWh/m^2) in Indonesia and Surabaya [51].

While obtaining the GHI and/or Clearness Index data from the NREL NSRDB data viewer website may provide users with flexibility and options of getting the preferred data granularity (10-minute, 30-minute, or 60-minute time intervals for Asia, Australia, and Pacific regions during 2016 – 2020), HOMER detects the time step of the imported data file based on the number of lines. If, for example, the imported data file contains 8,760 lines, HOMER assumes it contains hourly data. Subsequently, HOMER will convert the data into monthly averages, i.e., a single value for each month. Users, however, should first convert the GHI from hourly-based W/m^2 into daily-based kW/m^2 for a particular year before importing the data into HOMER. In addition, if the year selected on the NREL data viewer website is more than one specific year, users must produce an average value for each time step within all considered years.

This study applies the first approach, i.e., downloading the 'ready to use' GHI and Clearness Index data for a location having a South Latitude of 7°19' and an East longitude of 112°47'. While the considered latitude in this study is slightly different from that in [51], the location provides an average daily GHI of 5.26 kWh/m^2, similar to that in [51]. Table 2 presents numerical values of the monthly average GHI, and Clearness Index obtained for this study, while Figure 3 shows how HOMER depicts the values graphically.

Table 2. Monthly average GHI and clearness index for the specified location

Month	Clearness index	Global Horizontal Index (kWh/m^2/day)
January	0.45	4.84
February	0.46	4.97
March	0.48	5.05
April	0.52	5.09
May	0.56	5.00
June	0.57	4.82
July	0.59	5.10
August	0.60	5.62
September	0.61	6.21
October	0.56	5.96
November	0.50	5.34
December	0.48	5.13
Average	0.53	5.26

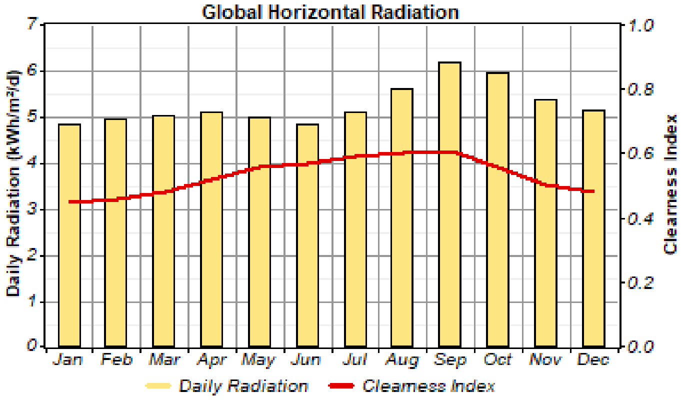

Figure 3. HOMER visualisation of monthly average GHI and Clearness Index for the specified location.

3.2. Reliability-cost trade-offs

The cost-reliability trade-offs in the context of residential grid-connected rooftop PV analysis should demonstrate to customers the importance of understanding the options available and their possible two-sided impacts. This impact may be caused by different PV sizes that customers may consider due to budget or other constraints, such as daytime power requirements and supply reliability. In contrast to the load profiles of commercial buildings in general, which have relatively flat loads during the day, the load profiles for all surveyed households, as shown in Figure 1, can provide more options to all customers, particularly considering the shape of a deep valley from 7 a.m. – 4 p.m. However, there are different consequences for installing any PV size that suits their needs and limitations, not just only maximising the size allowed by regulations up to the contracted amount of power.

The cost-reliability trade-off analysis in this study is based on the maximum annual capacity shortage values assigned to the simulation. HOMER uses the term 'maximum annual capacity shortage' to express the system's reliability constraint. It defines the total capacity shortage as the total amount of capacity shortage throughout a year, expressed in kWh/year. The value is used to calculate the capacity shortage fraction. This fraction is a ratio between total capacity shortage and total electric load, expressed in kWh/year. The simulated systems may end up with a situation where there is an unmet load or unserved energy when the electrical load exceeds the supply. Therefore, the total unmet load and the unmet load fraction can be calculated accordingly. This study applies 0%, 5%, 10%, and 15% of the maximum annual capacity shortage (or maximum unserved energy). Hereafter, the

paper uses the term ‘maximum unserved energy’ as the system reliability constraint and ‘unserved energy’ as the result of system reliability.

3.3. System modelling, economic parameters, and assumptions

This study assesses the grid-connected rooftop PV systems for residential households by using HOMER software to model system configurations for four residential household segments with their associated load profiles in the urban area of Surabaya, Indonesia, as a case study. The complete model consists of an electricity grid, the household’s loading pattern, and the main components consist of PV array and converter. While much of the simulations are performed in HOMER, this study takes into account the implications of setting and regulation through different unserved energy targets, PV capacity, and billing deduction factors on the assessment of cost-reliability trade-offs.

In particular, this study suggests a method for incorporating billing deduction factors in HOMER optimisation since the software does not account for billing deduction cases in its direct calculations. In HOMER, varying sell-back rates for energy sold to the grid can be used to account for various billing deduction factors. To simulate a billing deduction factor of 65%, for instance, the model multiplies the amount of electricity sold to the grid by 65% of the electricity full rate for customers.

This study examined four load profiles corresponding to the four residential customer segments. Simulations are performed for each load profile, considering the electricity export deduction factor. The applicable kWh export deduction factor determines the proportion of kWh exported to the grid that can be used as a factor for reducing electricity bills. This study uses two different billing deduction factors, i.e., a 65% deduction factor according to Ministerial Regulation No. 49/2018 and a 100% deduction factor according to Ministerial Regulation No. 26/2021. The first deduction factor shows that only 65% of the kWh exported to the grid is permissible for customers to reduce electricity bills. The second factor indicates that the customer can use all kWh exported to the grid to reduce the amount of kWh purchased from the grid.

In HOMER, these two conditions can be treated differently. HOMER calculates the total energy charge without net metering, i.e., using the 65% deduction factor, by multiplying the total energy purchased from the grid by the electricity rate applicable to that household segment minus the amount of electricity sold to the grid times the applicable sell-back rate. Using a 100% deduction factor (net metering), HOMER calculates the total energy charge by multiplying the amount of net kWh purchased from the grid by the electricity rate that applies to the household segment.

No Time-of-Use (TOU) rate and demand charge is applied to Indonesian residential sector customers. The electricity rate for households with a 2,200 VA power contract (R1) is IDR 1,444.70 per kWh, while households with power of 3,500 VA or above (R2/R3) are charged IDR 1,699.53 per kWh [[54], [55]]. Assuming the exchange rate is IDR 15,000 per USD 1, this gives us USD 0.096 per kWh for 2,200 VA customers and USD 0.113 per kWh for 3,500-6,600 VA ones. The simulation, therefore, applies different electricity rates between 2,200 VA and higher segments.

The simulation also accounts for demand uncertainty by allowing for up to 5% day-to-day variability, i.e., the standard deviation in the sequence of daily averages, and up to 5% time-step-to-time-step variability, i.e., the standard deviation in the difference between the hourly data and the average daily profile, depending on the contract. This configuration results in a higher peak load than the surveyed households have. For example, a 2,200 VA household with 22 kWh/day and a peak load of 1.65 kW is simulated to have a peak load of 2.1 kW due to the 5% day-to-day and time-step-to-time-step variability. Aside from that, electricity demand is assumed to remain constant over the PV’s lifetime. The complete system configuration models for all households in HOMER is illustrated in Figure 4.

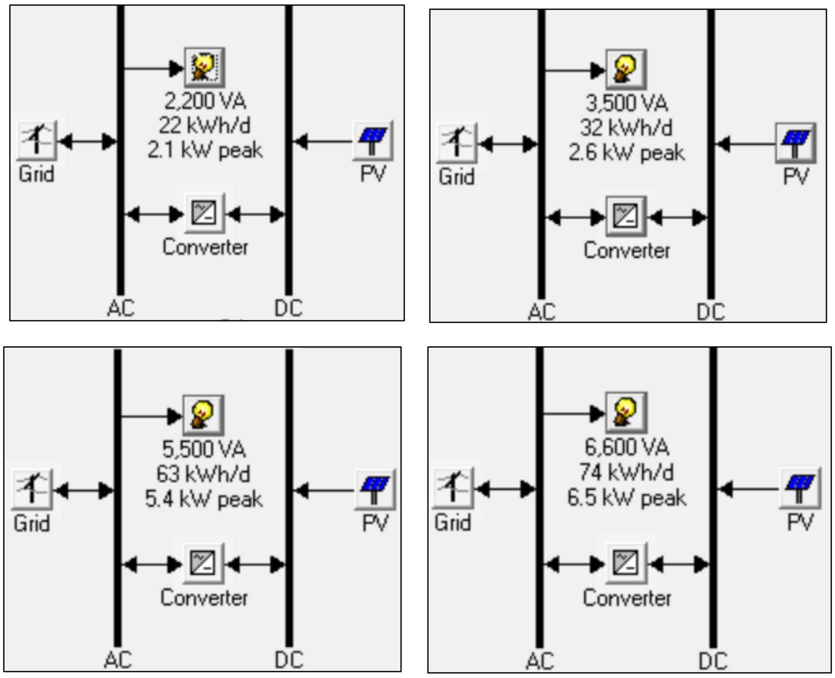

Figure 4. HOMER system configurations for residential households with 2,200 VA and 3,500 VA (top left to right), households with 5,500 VA and 6,600 VA (down left to right) electricity contracts.

Solar PV array and converter

Since the effect of temperature on the PV array is not considered, HOMER calculates the power output generated by the solar PV array P_{PV} according to the following equation.

$$P_{PV} = Y_{PV} \times f_{PV} \left(\frac{G_T}{G_{T,STC}} \right) \quad (1)$$

where Y_{PV} is the rated capacity of the PV array (kW), f_{PV} is the derating factor (%), G_T is the solar radiation incident on the PV array in the current time step (kW/m^2), and $G_{T,STC}$ is the incident radiation at standard test condition (1 kW/m^2).

In HOMER, the rated capacity of the PV array Y_{PV} is specified by users as one of the input variables to Eq. 1. Users can either enter at least one size of solar PV module and the capital cost associated with that particular size, for example, 2 kW, or in fractions, for example, 0.1 kW PV. If the second option were selected, the user must enter several PV module capacities in multiples of 0.1 kW to 2 kW or up to the maximum capacity considered. HOMER simulates possible supply configurations to meet hourly-based energy demand and displays the system's Y_{PV} in the simulation results. Therefore, if users enter Y_{PV} as fractions, the number of solar PV arrays N_{PV} can be obtained using the following equation.

$$N_{PV} = \frac{calc\_Y_{PV}}{frac\_Y_{PV}} \quad (2)$$

where cal_Y_{PV} is the calculated system's rated capacity of the PV array (kW), and $frac\_Y_{PV}$ is the fraction of the rated capacity of the PV entered by users (kW).

HOMER models a converter, or better known as an inverter, to convert DC electricity generated by solar PV arrays to AC electricity by considering the user-specified efficiency η of the inverter side.

HOMER calculates the performance of a converter on an annual basis according to the following equation.

$$\eta = \frac{kWh/year_{in}}{kWh/year_{out}} \quad (3)$$

where $kWh/year_{in}$ is the DC electricity generated by PV arrays (kWh/year), and $kWh/year_{out}$ is the AC electricity produced by inverter (kWh/year).

The expected converter life is 15 years, with 90% efficiency on the inverter side and 85% efficiency on the rectifier side. The converter-rated capacity candidates can be slightly higher than the solar PV capacity specified in the simulation search space, as HOMER does not consider the power factor of the load. Capital and replacement costs of the 1 kW converter are assumed to be USD 400 (IDR 6,000,000) [56] and USD 380 (IDR 5,700,000), respectively, without annual O&M costs. Capital and replacement costs are assumed to increase linearly concerning size.

This study assumes capital and replacement costs for the 0.1 kW peak PV module in Indonesia to be USD 50 each (equal to around IDR 750,000) [57], and no annual Operating and Maintenance (O&M) costs for the PV arrays. The cost of additional or replacement modules is assumed to increase linearly. The derating factor is considered 80%, and the ground reflectance is supposed to be 20%. Given an expected lifetime of 25 years, the PV arrays are installed without tracking. The slope is specified in the same degree as the location's latitude, 7.3°, while the azimuth is set at 180° (due North).

System economic

This study considers a project lifetime of 25 years and assumes an annual interest rate of 5%. Other important assumptions include system fixed capital cost and system fixed O&M cost. Considering the current total installed cost of solar PV for the Indonesian residential sector, i.e., USD 1,000/kW peak (IDR 15,000,000/kW peak) [[58], [59]], and the cost of solar PV modules and converters, the system fixed capital cost and the fixed O&M cost are set at USD 200 (IDR 3,000,000) [60] and USD 20/year (IDR 300,000/year), respectively.

In HOMER, the economic feasibility of the systems can be assessed by using total Net Present Cost (total NPC), Cost of Energy (COE), and operating costs. The total NPC, expressed in USD, is used in economic analysis to show the system's life cycle cost. It is calculated as follows.

$$C_{NPC} = \frac{C_{ann,tot}}{CRF(i,R_{proj})} \quad (4)$$

$$CRF(i,N) = \frac{i(1+1)^N}{(1+i)^N-1} \quad (5)$$

where $C_{ann,tot}$ is total annualised cost (USD/year), CRF is capital recovery factor, i is interest rate (%), and R_{proj} is project lifetime (year).

HOMER defines COE as the average cost per kWh produced by the system. It is calculated by dividing the total annualised cost by the total electricity produced including total grid sales as follows.

$$COE = \frac{C_{ann,tot}}{E_{prim,AC}+E_{grid,sales}} \quad (6)$$

where $E_{prim,AC}$ the total electricity produced by all components of the system in a year, and $E_{grid,sales}$ is the total grid sales (electricity sold to the grid).

Operating costs, expressed in USD/year, are the sum of the annual O&M costs, and annualised replacement cost minus annualised salvage value. For grid-connected systems, it includes the annualised cost of electricity purchased from the grid minus electricity sold to the grid. While the term operating costs is useful in providing the user with some insights into the contribution of these types of costs on the total NPC and typically decreases at higher unserved energy, this study rules out the term operating costs in the analysis due to the focus of this study on analysing the possible trade-off between the system cost, which is already well represented by the total NPC, and unserved energy.

Scenarios and cases

This study considers two main scenarios in the simulation regarding the selection of solar PV-size candidates. The first scenario is called Maximum-PV-Capacity (MPVC). This basically refers to the maximum PV capacity a customer can install, i.e., up to the power (VA) contracted by a household, as per Ministerial Regulation No. 26/2021. For example, a household with 2,200 VA contracted power can install PV panels up to 2.2 kW peak capacity. In this case, the simulation considers up to 2.2 kW peak PV capacity in 0.1 kW PV arrays. This scenario considers PV sizes of up to 3.5 kW peak, 5.5 kW peak, and 6.6 kW peak for households with 3,500 VA, 5,500 VA, and 6,600 VA, respectively. HOMER simulates these size candidates and the fraction of electricity purchased from the grid. The optimisation will result in a system configuration with the least total NPC and other alternatives that exhibit higher total NPC.

The second scenario is called Half-PV-Capacity (HPVC). Under this scenario, simulations use up to half the maximum allowable PV capacity. For example, simulations for possible system configurations for a 2,200 VA household consider up to 1.1 kW peak capacity in 0.1 kW PV arrays. Other simulations for households with 3,500 VA, 5,500 VA, and 6,600 VA are carried out considering PV capacity of up to 1.75 kW peak, 2.75 kW peak, and 3.3 kW peak, respectively. This scenario is based on the low load during the day for all households, i.e., between 7 a.m. and 4 p.m. This study assesses the total NPC from both MPVC and HPVC scenarios for all household segments.

This study considers up to four cases for each household segment, i.e., 100%-MPVC, 100%-HPVC, 65%-MPVC, and 65%-HPVC. In this regard, either 100% or 65% refer to the applicable deduction factor according to the regulations mentioned earlier in Section 2. In other words, there are two cases for each scenario. The MPVC scenario consists of 100%-MPVC and 65%-MPVC, while the HPVC scenario consists of 100%-HPVC and 65%-HPVC.

4. Results and Discussion

Table 3 to Table 5 highlight the main results regarding important techno-economic aspects for all the cases considered in a 2,200 VA household. In the 100%-MPVC cases, the total NPC has reached USD 9,175 for 0% maximum unserved energy (no-unserved energy) and has declined to USD 7,987 or 13% for up to 11% simulated unserved energy. As for no-unserved energy, the total NPC has increased to USD 10,031, USD 10,371, and USD 10,661 for the 65%-MPVC, 100%-HPVC, and 65%-HPVC cases, respectively.

All the total NPC of 100%-MPVC is found to be the cheapest among other cases considering all unserved energy. From the simulations, it is revealed that the total NPC of 100%-MPVC with no-unserved energy is USD 9,175, cheaper than the total NPC of 65%-MPVC with 7% unserved energy and of HPVC cases with 11% unserved energy. The simulation results have implied potential benefits of rooftop PV installation up to the maximum permitted capacity and concerning a 100% billing deduction scheme for households

with 2,200 VA, considering different options regarding unserved energy, installed capacity, and percentage of billing deduction.

As shown in Table 3 to Table 6, renewable energy's contribution to electricity generation has reached 33-36% share in the cases of MPVC and 19-21% share in the cases of HPVC within the range of 11% unserved energy. As expected, reducing the installed capacity of PV modules to half the maximum allowable capacity will decrease PV penetration in the systems.

Table 3. Simulation results for 2,200 VA: 100%-MPVC

Maximum annual unserved energy (%)	PV (kW)	Converter (kW)	Grid (kW)	Initial Capital (USD)	Total NPC (USD)	COE (USD/kWh)	RE share (%)	Unserved energy (%)
0	2.2	1.5	1.8	1,900	9,175	0.081	33	0
5	2.2	1.5	1.4	1,900	8,796	0.081	34	4
10	2.2	1.5	1.3	1,900	8,446	0.080	35	7
15	2.2	1.5	1.2	1,900	7,987	0.079	36	11

Table 4. Simulation results for 2,200 VA: 65%-MPVC

Maximum annual unserved energy (%)	PV (kW)	Converter (kW)	Grid (kW)	Initial Capital (USD)	Total NPC (USD)	COE (USD/kWh)	RE share (%)	Unserved energy (%)
0	2.2	1.5	1.8	1,900	10,031	0.089	33	0
5	2.2	1.5	1.4	1,900	9,652	0.088	34	4
10	2.2	1.5	1.3	1,900	9,302	0.088	35	7
15	2.2	1.5	1.2	1,900	8,842	0.088	36	11

Table 5. Simulation results for 2,200 VA: 100%-HPVC

Maximum annual unserved energy (%)	PV (kW)	Converter (kW)	Grid (kW)	Initial Capital (USD)	Total NPC (USD)	COE (USD/kWh)	RE share (%)	Unserved energy (%)
0	1.1	1.0	1.8	1.150	10,371	0.092	19	0
5	1.1	1.0	1.4	1.150	9,987	0.092	20	4
10	1.1	1.0	1.3	1.150	9,636	0.091	21	7
15	1.1	1.0	1.2	1.150	9,177	0.091	21	11

Table 6. Simulation results for 2,200 VA: 65%-HPVC

Maximum annual unserved energy (%)	PV (kW)	Converter (kW)	Grid (kW)	Initial Capital (USD)	Total NPC (USD)	COE (USD/kWh)	RE share (%)	Unserved energy (%)
0	1.1	1.0	1.8	1,150	10,661	0.094	19	0
5	1.1	1.0	1.4	1,150	10,277	0.094	20	4
10	1.1	1.0	1.3	1,150	9,926	0.094	21	7
15	1.1	1.0	1.2	1,150	9,467	0.094	21	11

The optimisation results presented in Table 3 to Table 6 also provide customers with another insight into the potential role of the system cost components in shaping the cost-reliability trade-off. While the initial capital costs are of course found to be lower in HPVC cases compared to those in MPVC due to less PV array involved, i.e., USD 1,150 versus USD 1,900, it is found that the total NPC of MPVC cases are found to be cheaper than those of HPVC cases within the same unserved energy.

From the simulation results in 100%-MPVC cases, for example, it is found that 4% unserved energy is equal to 283 kWh/year of unmet electricity, while 7% and 11% unserved energies are equal to 542 kWh/year and 881 kWh/year, respectively. On the other hand, the total NPC of this particular case has shown a noticeable decrease of around USD 350 – USD 450 for every 3-4% additional unserved energy.

Table 7 to 10 shows the trade-offs between the total NPC, as expressed in annual total cost (USD/year), and unserved energy (kWh/year) of all simulations for a 2,200 VA household. The optimisation results show cheaper total annual costs as unserved energy increases. In addition, MPVC cases have shown more affordable yearly costs due to fewer energy charges (electricity bills) spent by the customers compared to those of HPVC.

It is of importance to observe the simulation results in terms of a range of shares of energy charge to the total (annual) cost of the systems. As presented in Table 7 to Table 10, all optimisation results in MPVC cases have shown lower shares of energy charge to the (annual) total cost compared to those in HPVC ones. It is found that the averaged shares of energy charge to the total cost are 70% and 74.6% for 100%-MPVC and 65%-MPVC, respectively, versus 83.9% and 84.3 for 100%-HPVC and 65%-HPVC, respectively.

As the finding compares MPVC and HPVC scenarios, it highlights the potential benefits of higher PV penetrations in reducing the energy charge component's share of the total annual cost within the same unserved energy range. In this regard, the lower applicable billing deduction factor indicates the smaller revenue that a customer can expect within the same scenario, which, of course, has an impact on the higher portion of energy charge in the total annual cost. While this paper highlights particular results for a 2,200 VA surveyed household, similar implications as obtained in Table 7 are also expected to occur for other households considered in this study, given the similarity of the households' daily load profiles.

Table 7. Trade-offs between annualised total cost and unmet energy for a 2,200 VA household

Scenario	Unserved energy (%)	Unmet energy (kWh/year)	Annual energy charge (USD/year)	Annualised total cost (USD/year)	Share of energy charge to total cost (%)	Averaged share of energy charge to total cost (%)
100%-MPVC	0	0	481	651	73.8	70
	4	283	454	624	72.8	
	7	542	429	599	71.6	
	11	881	396	567	69.8	
100%-HPVC	0	0	624	736	84.8	83.9
	4	287	597	709	84.2	
	7	546	572	684	83.6	
	11	886	539	651	82.8	
65%-MPVC	0	0	541	712	75.9	74.6
	4	283	515	685	75.2	
	7	542	490	660	74.2	
	11	881	457	627	72.9	
65%-HPVC	0	0	645	756	85.3	84.3
	4	287	617	729	84.6	
	7	546	592	704	84.1	
	11	886	560	672	83.3	

Figure 9 and Figure 10 depict the cost-reliability trade-offs in terms of total NPC versus unserved energy for all cases in 2,200 VA and 3,500 VA, as well as 5,500 VA and 6,600 VA households,

respectively. From the simulation results presented in Figure 9 and Figure 10, the total NPC of 100%-MPVC cases is the cheapest in every unserved energy. The finding indicates a comparative benefit of on-grid rooftop PV systems installing maximum PV capacity permitted combined with higher billing deduction factors (here is 100%) over other configurations. Moreover, there is a relatively large difference in total NPC between the 100%-MPVC cases and the 65%-MPVC cases concerning all unserved energies up to a 15% maximum annual unserved energy constraint, while insignificant differences of the total NPC are found between those in the 100%-HPVC cases and the 65%-HPVC cases, particularly in 3,500 VA and 6,600 VA households.

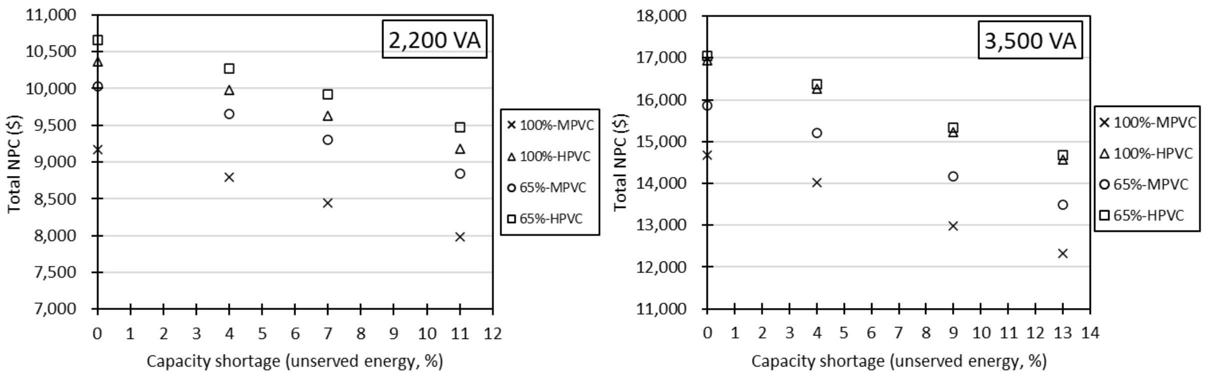

Figure 9. Total NPC versus unserved energy in all cases for 2,200 VA (left) and 3,500 VA (right)

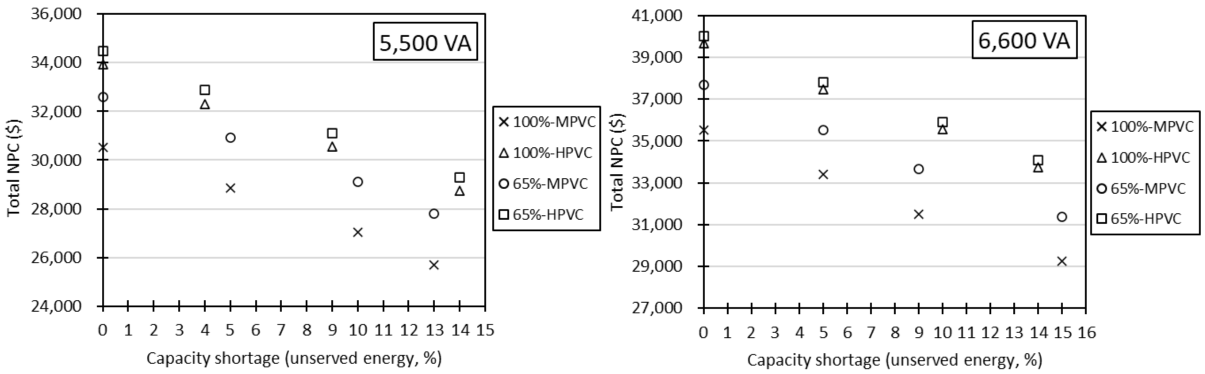

Figure 10. Total NPC versus unserved energy in all cases for 5,500 VA (left) and 6,600 VA (right)

Residential customers can further estimate one of the important indices for rooftop PV installation decision-making, i.e., the cost per MWh consumed (USD/MWh). Using 100%-MPVC cases in a 2,200 VA household as illustrations, and given the cost is the total NPC, as presented in Figure 9, the costs per MWh consumed during the project lifetime for 0%, 4%, 7%, and 11% unserved energies are USD 37.19/MWh, USD 36.70/MWh, USD 36.22/MWh, and USD 35.54/MWh, respectively, provided the total MWh consumed over the 25-year project lifetime are 246.68 MWh, 239,68 MWh, 233.20 MWh, and 224.73 MWh, respectively for the associated unserved energies.

From this particular analysis, it is found that, despite a considerably large difference in terms of total NPC between the system with no-unserved energy and that with the poorest reliability (USD 1,188 difference), the cost per MWh figures have shown a relatively small gap of cost difference during the project lifetime, i.e., USD 1.65/MWh, between no-unserved energy and 11% unserved energy.

In addition to merely exploring and comparing economic parameters such as total NPC, the share of energy charge to total annual cost, and COE, it is also of interest to assess the potential economic impact of the systems in terms of cost per watt of PV installed, i.e., through exploring which households exhibit the lowest cost per watt of PV installed capacity. The cost per watt of PV installed

can be used as one of the indicators for customers in deciding the capacity of PV to be installed while considering possible techno-economic scenarios, including the potential impact of applicable billing deduction factors and a range of different unserved energy.

The lowest cost per watt of PV installed capacity can be obtained for all scenarios by comparing the total system cost (total NPC) with the PV installed capacity. Table 8 presents variations in cost per watt of PV installed capacity for all the optimisation results of 100%-MPVC and 65%-MPVC, as well as 100%-HPVC and 65%-HPVC given no-unserved energy (0% maximum unserved energy), while Tables 9 to 11 present variations of the cost per watt of PV installed capacity considering 5%, 10%, and up to 15% maximum unserved energy, respectively.

Table 8. The cost per watt of PV installed capacity with 0% maximum unserved energy.

Household	The cost per watt of PV installed capacity ($/Watt)			
	100%-MPVC	65%-MPVC	100%-HPVC	65%-HPVC
2,200 VA	4.17	4.56	9.43	9.69
3,500 VA	4.20	4.53	9.68	9.74
5,500 VA	5.55	5.93	12.34	12.54
6,600 VA	5.39	5.71	12.02	12.12

Table 9. The cost per watt of PV installed capacity with 5% maximum unserved energy.

Household	The cost per watt of PV installed capacity (USD/Watt)			
	100%-MPVC	65%-MPVC	100%-HPVC	65%-HPVC
2,200 VA	3.99	4.39	9.08	9.34
3,500 VA	4.00	4.34	9.30	9.36
5,500 VA	5.24	5.62	11.75	11.95
6,600 VA	5.06	5.39	11.36	11.46

Table 10. The cost per watt of PV installed capacity with 10% maximum unserved energy.

Household	The cost per watt of PV installed capacity (USD/Watt)			
	100%-MPVC	65%-MPVC	100%-HPVC	65%-HPVC
2,200 VA	3.84	4.23	8.76	9.02
3,500 VA	3.71	4.05	8.71	8.77
5,500 VA	4.91	5.29	11.11	11.31
6,600 VA	4.78	5.10	10.78	10.88

Table 11. The cost per watt of PV installed capacity with 15% maximum unserved energy.

Household	The cost per watt of PV installed capacity (USD/Watt)			
	100%-MPVC	65%-MPVC	100%-HPVC	65%-HPVC
2,200 VA	3.63	4.02	8.34	8.61
3,500 VA	3.52	3.86	8.32	8.38
5,500 VA	4.68	5.06	10.45	10.65
6,600 VA	4.43	4.76	10.23	10.33

As shown in Table 8, the total NPC per watt of PV installed capacity, under 0% unserved energy, varied from USD 4.14/Watt to USD 12.54/Watt in all cases across all households. The results show similar costs in the MPVC cases concerning 2,200 VA and 3,500 VA households, slightly more than double in the HPVC cases, and similar for 5,500 VA and 6,600 VA households. It is also found that the results are not affected by the applicable billing deduction factors but simply by the PV capacity. Nevertheless, it should be noted that the results obtained in Tables 8 to 11 are largely influenced by the household's daily electricity load profile and other applied scenarios.

The simulation results in terms of possible system capacity, consisting of grid and PV capacity across all unserved energy in all cases of all households, are depicted in Figure 11 and Figure 12.

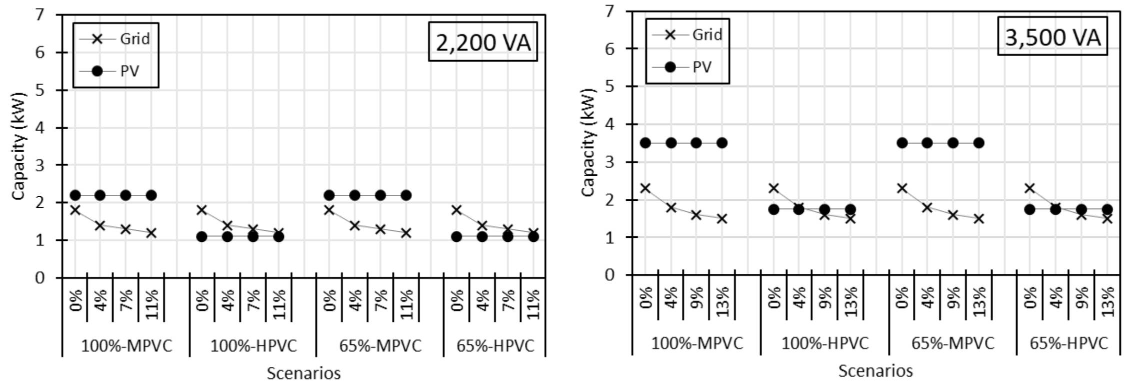

Figure 11. System capacity across all unserved energies for 2,200 VA (left) and 3,500 VA (right)

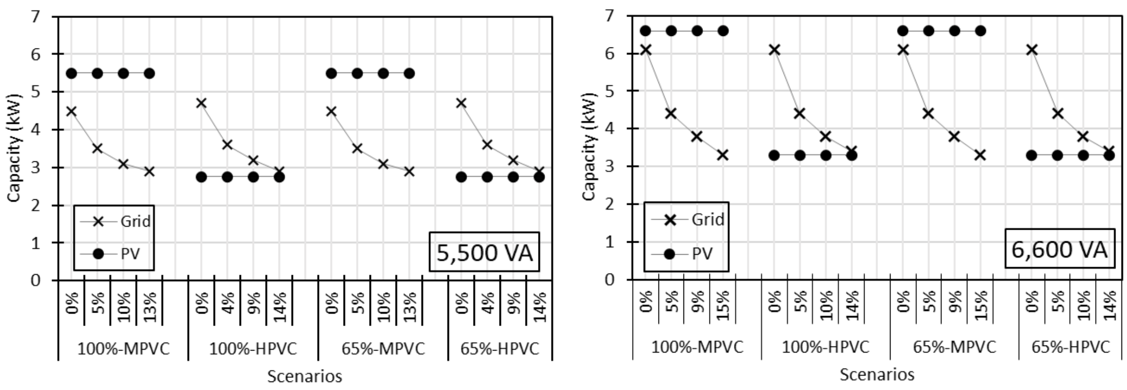

Figure 12. System capacity across all unserved energies for 5,500 VA (left) and 6,600 VA (right)

As seen in Figures 11 and 12, higher unserved energy has resulted in lower grid capacity required by the system to meet the demand according to the system's maximum unserved energy constraint, and the PV capacities are maximised across all unserved energies in different scenarios. Moreover, it is interesting to note that the PV capacities across all MPVC cases are always higher than the grid ones. On the other hand, the grid capacities are mostly higher than those of PV in most HPVC cases, except in 3,500 VA for 9% unserved energy and beyond. In all cases, the grid capacities have similarly decreased within the unserved energy range. For example, in 2,200 VA (see Figure 11 left), the grid capacities are found at 1.8 kW, 1.4 kW, 1.3 kW, and 1.2 kW for 0%, 4%, 7%, and 11% unserved energy, respectively, and similarly in other households.

A sensitivity analysis of the techno-economic factors influencing system performance would benefit stakeholders, particularly residential customers. While focusing on system reliability, this study uses only a 5% annual interest rate and fixed electricity rates associated with household segments. As a result, the sensitivity variable used in HOMER is maximum annual unserved energy.

Taking a 2,200 VA household with 100%-MPVC as an example, a graphical sensitivity result depicting possible trade-offs on total NPC versus unserved energy fraction and a sensitivity result of net grid purchases (electricity purchased from the grid minus electricity sold to the grid) versus maximum annual unserved energy are presented in Figure 13 and Figure 14, respectively. Meanwhile, a sensitivity result of total NPC versus total electricity production is shown in Figure 15.

Maximum annual unserved energy constraints have varying effects on total NPC, total electricity production, and nett grid purchases. As shown in Figure 13, total NPC cannot be less than USD 8,500

when unserved energy is kept at or below 6%. According to Figure 15, a 10% unserved energy would result in approximately 9,700 kWh/year of electricity production, which would equal approximately USD 8,500 in total NPC.

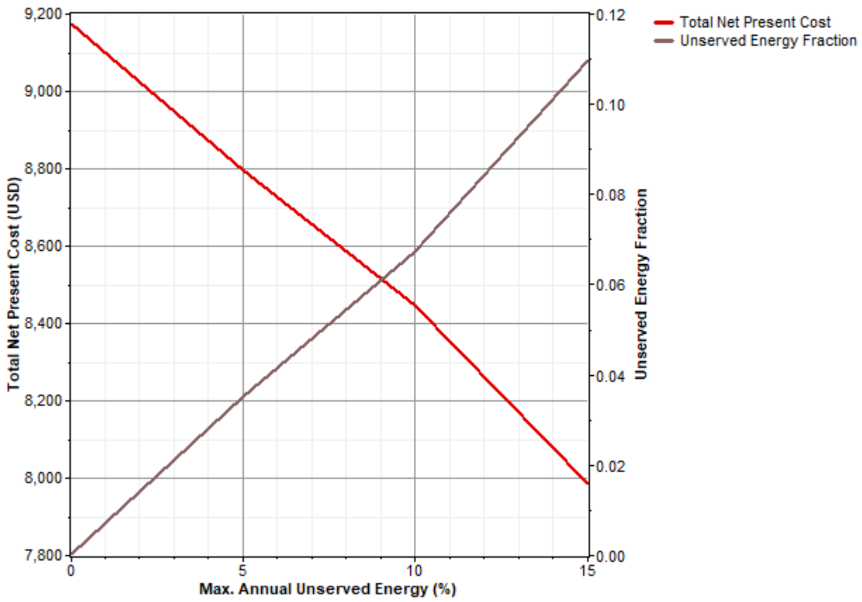

Figure 13. Sensitivity result of total NPC versus unserved energy fraction in a 2,200 VA household with 100%-MPVC.

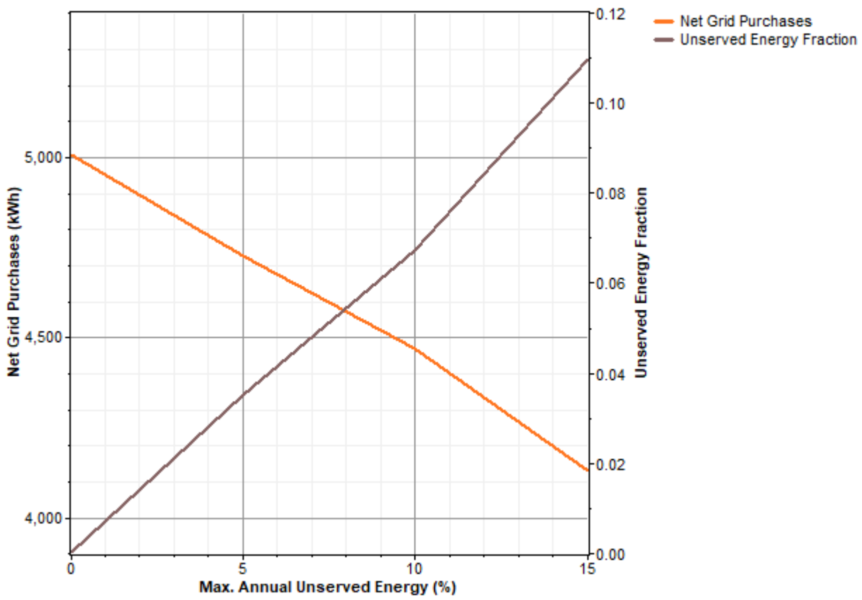

Figure 14. Sensitivity result of net grid purchases versus maximum annual unserved energy in a 2,200 VA household with 100%-MPVC.

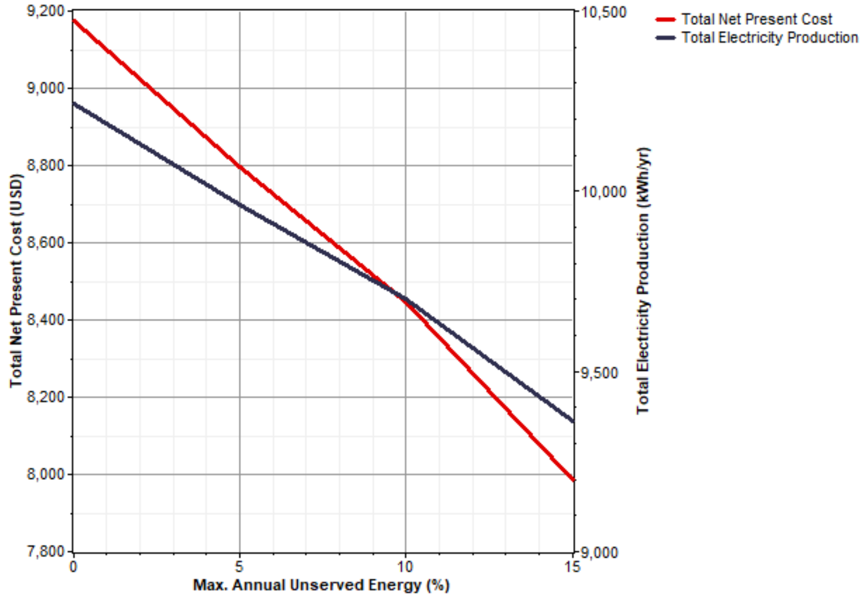

Figure 15. Sensitivity result of total NPC versus total electricity production in a 2,200 VA household with 100%-MPVC.

Despite possible variations and differences in households' daily loading profiles along with other affecting factors, which, of course, may provide different results and interpretations, this study has sought to explore possible cost-reliability trade-offs in Indonesia's urban residential grid-connected rooftop PV due to three key factors, namely potential unserved energy, PV capacity, and possible billing deduction scheme. The significance of these factors has been shown in the analysis considering different residential household segments, and therefore, should be considered not only by customers who are willing to apply on-grid rooftop PV but also by stakeholders such as government and utility companies according to their role in supporting more grid-connected rooftop PV capacity.

5. Conclusions

This paper explores the potential of grid-connected rooftop PV systems in terms of how they can be better planned and utilised by understanding the possible trade-offs between system reliability and cost while recognising challenges related to electricity supply security in the context of emerging economies. The effects of various unserved energy limits, PV capacities, and billing deduction factors (modelled in HOMER using different sell-back rates) on the systems' techno-economic parameters have been investigated in order to better understand possible cost-reliability trade-offs for total NPC and unserved energy. The analyses are carried out with the help of HOMER, with four different residential household segments in Surabaya, Indonesia, serving as a case study.

In all four cases of each household segment, i.e., 100%-MPVC, 65%-MPVC, 100%-HPVC, and 65%-HPVC, the optimisation results show reliability-cost trade-offs between the total NPC and all unserved energies. Furthermore, the role of cost components in the trade-offs between HPVC and MPVC cases in terms of initial capital costs and total NPC was highlighted in the analyses. The findings revealed a relatively large difference in total NPC for all households between 100%-MPVC cases and 65%-MPVC cases for all unserved energies, while differences between those in 100%-HPVC cases and 65%-HPVC cases are insignificant. The simulation results implied potential benefits of rooftop PV installation up to the maximum permitted capacity and a 100% billing deduction scheme for households with 2,200 VA, taking into account different options for unserved energy, installed capacity, and billing deduction percentage.

Among the significant results of this study that highlight the benefits of grid-connected rooftop PV are the following: 1) higher renewable energy penetration for MPVC systems compared to HPVC systems regardless of the billing deduction factors; 2) cheaper total NPC are shown by MPVC cases than those of HPVC cases within the same unserved energy; 3) lower shares of energy charge to the annual total cost in MPVC cases compared to those in HPVC ones; and 4) Over the project lifetime, the cost per kWh consumed (USD/MWh consumed) showed only a slight variance between the system with no-unserved energy and the system with the poorest reliability, given 100%-MPVC cases in 2,200 VA as an example; 5) All households with a 15% maximum limit on unserved energy have the lowest costs per watt of installed PV capacity, and these costs are unaffected by billing deduction factors; 6) based on the system's maximum unserved energy limits, higher unserved energy has led to a decrease in the amount of grid capacity needed by the system to meet demand, and the PV capacities are maximised across all unserved energies in various scenarios; and 7) Sensitivity analyses have revealed a range of impacts of maximum annual unserved energy constraints on various parameters, including total NPC, total electricity production, and net grid purchases.

When it comes to grid-connected rooftop PV, residential customers must be thoughtful, as there are potential trade-offs between cost and reliability. At the same time, attention must be paid to changing regulations that may have an impact on overall profitability. This study's analyses provided important findings and insights not only to the residential customers but also to stakeholders involved in the planning and implementation of rooftop PV policies.

Finally, there is no doubt about the grid-connected rooftop PV's techno-economic potential for accelerating distributed renewable energy penetration. Nonetheless, because rooftop PV deployment appears to be modest, especially in Indonesia, changes to the existing set of regulations are required. More encouraging, innovative policies should be introduced to address the barriers and challenges that customers and the industry face in moving rooftop PV deployment forward.

Acknowledgement

The author would like to thank the reviewers for their time and effort in reviewing the manuscript. All valuable comments and suggestions for improving the manuscript's quality are greatly appreciated.

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Response to editor's and reviewers' comments and review report:

Ref. No.: EGY-D-23-04810

Title:
Cost-reliability trade-offs for grid-connected rooftop PV in emerging economies: a case of Indonesia's urban residential households

I thank the editor and reviewers for their thoughtful criticisms and helpful suggestions on how to improve the paper. I have addressed these with extensive revisions to the paper, as outlined below, and believe the work has been greatly strengthened as a result. I hope that it is now suitable for publication in ENERGY.

Editor #:
Please make sure that your paper is clear in the description of the scientific novelty in comparison to what have previously been published in ENERGY within the same topic. Introduction and literature review should be revised by looking at recent papers published in this field within the scope of Energy Journal.

Author's response: Thank you for this suggestion. I have improved the introduction section (Section 1) and updated the literature review up to Section 2. The revised paper now has 15 references from ENERGY journal (marked up with yellow in the references section of the revised paper), and this includes 6 additional papers on the topic from ENERGY as detailed below:

[22] K. Mohammadi, M. Naderi, M. Saghafifar. Economic feasibility of developing grid-connected photovoltaic plants in the southern coast of Iran. Energy, 156 (2018), pp. 17-31.
[24] Á. X. C. de Jesus, D. P. Neto, E. G. Domingues. Computational tool for technical-economic analysis of photovoltaic microgeneration in Brazil. Energy, 271 (2023), 126962.
[30] Z. Xin-gang, X. Yi-min. The economic performance of industrial and commercial rooftop photovoltaic in China. Energy, 187 (2019), 115961.
[31] A. Orioli, A.D. Gangi. Six-years-long effects of the Italian policies for photovoltaics on the pay-back period of grid-connected PV systems installed in urban contexts. Energy, 122 (2017), pp. 458-470.
[33] G.G. Pillai, G.A. Putrus, T.Georgitsioti, N.M. Pearsall. Near-term economic benefits from grid-connected residential PV (photovoltaic) systems. Energy, 68 (2014), pp. 832-843.
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In addition to references previously included in Section 1 and Section 2 of the submitted draft, I have added additional literature from sources other than the ENERGY journal, marked up with grey, as follows:

[3] PVPS: Snapshot of Global PV Markets 2023. Available: https://iea-pvps.org/snapshot-reports/snapshot-2023/ [Accessed 1 September 2023].
[15] HOMER software. Available: https://www.homerenergy.com/ [Accessed 29 August 2023].
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[19] Photovoltaic Geographical Information System (PVGIS). Available: https://joint-research-centre.ec.europa.eu/photovoltaic-geographical-information-system-pvgis_en [Accessed 2 September 2023].
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[23] RETScreen software. Available: https://natural-resources.canada.ca/maps-tools-and-publications/tools/modelling-tools/retscreen/7465 [Accessed 15 September 2023].
[29] PVsyst Photovoltaic Software. Available: https://www.pvsyst.com/ [Accessed 7 September 2023].
[35] Regulatory Support: Key to Unlock Indonesia's Solar Potential. Available: https://iesr.or.id/en/regulatory-support-key-to-unlock-indonesias-solar-potential [Accessed 2 September 2023].
[36] Technical issue is not the main barriers to the renewable energy transition; financial and regulatory issues are. Available: https://iesr.or.id/road-to-energy-transition [Accessed 9 September 2023].
[37] Indonesia's Solar Policies Designed to Fail? Available: https://ieefa.org/wp-content/uploads/2019/02/Indonesias-Solar-Policies_February-2019.pdf [Accessed 3 September 2023].
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[47] Flexible Thermal Power Plant: An Analysis of Operating Coal-Fired Power Plants Flexibly to Enable the High-Level Variable Renewables in Indonesia's Power System. Available: https://iesr.or.id/wp-content/uploads/2022/06/IESR-Flexible-Thermal-Power-Plant-2022.pdf [Accessed 29 August 2023].
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[50] Not Yet Extinct, PLN Adds 13,819 MW Coal Power Plants Until 2030 (in Bahasa Indonesia). Available: https://www.cnbcindonesia.com/news/20211005154444-4-281622/belum-punah-pln-tambah-13819-mw-pltu-batu-bara-hingga-2030 [Accessed 5 September 2023].

New references included in Section 3 of the revised paper are as follows.

[52] Page, J. (2012). The Role of Solar-Radiation Climatology in the Design of Photovoltaic Systems. Practical Handbook of Photovoltaics, 573–643.
[53] NSRDB: National Solar Radiation Database. Available: https://nsrdb.nrel.gov/data-viewer [Accessed 31 August 2023].
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I have also presented a clearer description of the scientific novelty and new perspectives provided by the study in comparison to this existing work, as follows.

Introduction – paragraph 9:

While studies focussing on single household analysis or involving multiple sites have provided useful insights for stakeholders regarding the potential techno-economic impacts of grid-connected rooftop PV and its deployment opportunity, less explored, however, has been the impacts of different capacity shortages (unserved energy targets), PV capacity, and billing deduction factors. In particular, there has been little attention of the potential trade-offs between system reliability and costs.

Introduction – paragraph 11:

This paper offers a new perspective on the ongoing rooftop PV studies from a techno-economic standpoint. It introduces the concept of reliability-cost trade-offs that may arise due to different energy targets and the resulting variations in PV system sizes. These trade-offs are particularly relevant in emerging economies given the level of reliability and associated costs can vary significantly. The paper models unserved energy targets by accounting for potential capacity shortages on the supply side.

Reviewer #1:

The manuscript cannot be published in this presentation, it needs to be improved. Here are my recommendations:

1. It should be defined how decimals are going to be separated, in some cases they use comma as decimal separator and in others they do not, please check well the text.

   Response: Thank you for this constructive feedback. In the revised paper, the separator between the decimals is a dot (point), and the thousands separator is a comma. I double-checked that this arrangement is applied consistently.

2. Present a table with the solar irradiance data obtained by NASA, frequency of registration.

   Response: Thank you for this comment. I should have been clearer on this issue. The solar irradiance data presented in the paper, i.e., the GHI and / or Clearness Index, were obtained from NASA database through HOMER. I have now added some discussions in the revised paper regarding the two options that users can choose in entering the solar irradiation data into HOMER software. In summary, the data can be either downloading from HOMER or from the NREL National Solar Radiation Database (NSRDB) data viewer website. The complete descriptions are provided in Section 3.1 paragraph 2 (including the steps to access the data in NSRDB website), paragraph 3 (including description about time interval of the data), and paragraph 4, as follows.

Section 3.1 – paragraph 2:

HOMER allows users to enter GHI and/or Clearness Index values using one of the two possible approaches, i.e., by downloading GHI and/or Clearness Index values from HOMER or by obtaining the NASA/MERRA2 hourly-based datasets of GHI and/or Clearness Index from the NREL National Solar Radiation Database (NSRDB) viewer [53]. While the first approach allows users to directly obtain 'ready to use' monthly average values of GHI and/or Clearness Index by specifying the location's latitude and longitude, the second approach lets users explore the data using the following steps: (1) entering the location's latitude and longitude; (2) selecting available datasets; (3) selecting appropriate attributes; (4) selecting year(s); (5) selecting time interval of the data; (6) selecting data formatting options; (7) typing an email for receiving the data; and (8) submitting the request.

Section 3.1 – paragraph 3:

While obtaining the GHI and/or Clearness Index data from the NREL NSRDB data viewer website may provide users with flexibility and options of getting the preferred data granularity (10-minute, 30-minute, or 60-minute time intervals for Asia, Australia, and Pacific regions during 2016 – 2020), HOMER detects the time step of the imported data file based on the number of lines. If, for example, the imported data file contains 8,760 lines, HOMER assumes it contains hourly data. Subsequently, HOMER will convert the data into monthly averages, i.e., a single value for each month. Users, however, should first convert the GHI from hourly-based W/m^2 into daily-based kW/m^2 for a particular year before importing the data into HOMER. In addition, if the year selected on the NREL data viewer website is more than one specific year, users must produce an average value for each time step within all considered years.

Section 3.1 – paragraph 4:

This study applies the first approach, i.e., downloading the 'ready to use' GHI and Clearness Index data for a location having a South Latitude of 7°19' and an East longitude of 112°47'. While the considered latitude in this study is slightly different from that in [51], the location provides an average daily GHI of 5.26 kWh/m^2, similar to that in [51]. Table 2 presents numerical values of the monthly average GHI, and Clearness Index obtained for this study, while Figure 3 shows how HOMER depicts the values graphically.

In addition, a table regarding the GHI and Clearness Index used in the study has been included in the revised paper, as follows.

Table 2. Monthly average GHI and clearness index for the specified location

Month	Clearness index	Global Horizontal Index (kWh/m^2/day)
January	0.45	4.84
February	0.46	4.97
March	0.48	5.05
April	0.52	5.09
May	0.56	5.00
June	0.57	4.82
July	0.59	5.10
August	0.60	5.62
September	0.61	6.21
October	0.56	5.96
November	0.50	5.34
December	0.48	5.13

Average	0.53	5.26

3. Demonstrate how the data were calibrated for use in HOMER.

   Response: Thank you for this valuable comment. In case of utilising the data from NSRDB data viewer website, the data needs to be converted from its original temporal into HOMER's hourly-based temporal data. Users should first adjust the unit of GHI from Wh/m^2 into kWh/m^2 once it is converted into hourly-based temporal data. The complete discussion is presented as follows.

   Section 3.1 – paragraph 3:
   While obtaining the GHI and/or Clearness Index data from the NREL NSRDB data viewer website may provide users with flexibility and options of getting the preferred data granularity (10-minute, 30-minute, or 60-minute time intervals for Asia, Australia, and Pacific regions during 2016 – 2020), HOMER detects the time step of the imported data file based on the number of lines. If, for example, the imported data file contains 8,760 lines, HOMER assumes it contains hourly data. Subsequently, HOMER will convert the data into monthly averages, i.e., a single value for each month. Users, however, should first convert the GHI from hourly-based W/m^2 into daily-based kW/m^2 for a particular year before importing the data into HOMER. In addition, if the year selected on the NREL data viewer website is more than one specific year, users must produce an average value for each time step within all considered years.

4. Figure 2 should be improved; the legend is not distinguishable.

   Response: Thank you for this comment and suggestion. Figure 2 has been enhanced by displaying the entire country of Indonesia in the upper portion and zooming out Java in the lower portion, where Surabaya is situated. I used arrows to indicate both Surabaya location and the associated daily long-term average GHI of 5.3 kWh/m^2. The figure is presented as follows.

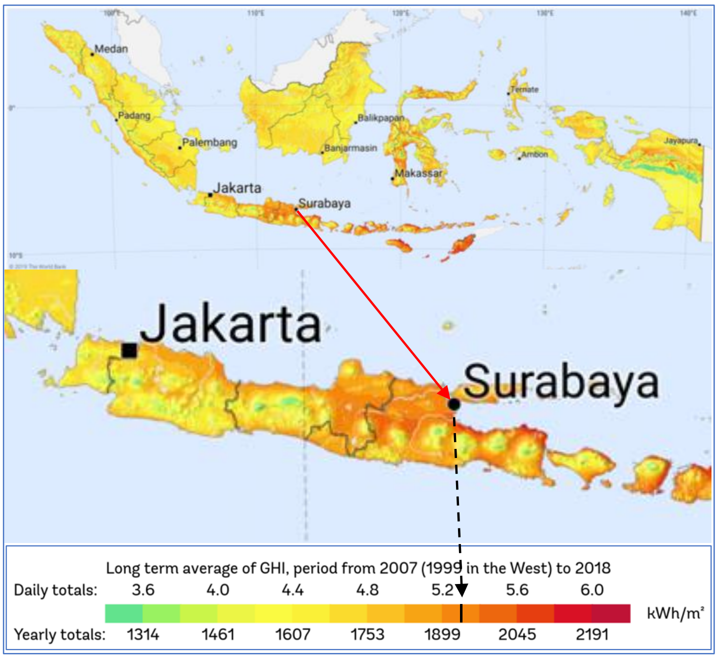

Figure 2. A map showing daily and yearly long-term average GHI (kWh/m^2) in Indonesia and Surabaya [51].

5. Describe what the clearness index is.

Response: Thank you for this comment. I should have been clearer on this term. Description of the Clearness Index has been included in the 2nd paragraph of Section 3.1 (Solar resource data) as follows.

Section 3.1 – paragraph 2:
HOMER uses either the average daily GHI or the average Clearness Index for each month to calculate PV power for each hour of the year. The Clearness Index, a dimensionless number between 0 to 1, is obtained by dividing the horizontal surface global radiation by the extraterrestrial horizontal radiation for the same period [52]. HOMER divides GHI by the extraterrestrial horizontal radiation to find the clearness index. A low value of the clearness index, for example, 0.25, indicates a very cloudy month, while 0.85 indicates a very sunny month.

6. Present the equations for calculating the Solar PV array and converter section.

Response: Thank you for this important suggestion. In addition to the equation for calculating the power output generated by the solar PV array, the equations for calculating the Solar PV array and converter section have been added in the revised paper, particularly in Section 3.3 under the specific section of Solar PV array and converter, as follows.

Section 3.3 >> Solar PV array and converter:
In HOMER, the rated capacity of the PV array Y_{PV} is specified by users as one of the input variables to Eq. 1. Users can either enter at least one size of solar PV module and the capital cost associated with that particular size, for example, 2 kW, or in fractions, for example, 0.1 kW PV. If the second option were selected, the user must enter several PV module capacities in multiples of 0.1 kW to 2 kW or up to the maximum capacity considered. HOMER simulates possible supply configurations to meet hourly-based energy demand and displays the system's Y_{PV} in the simulation results. Therefore, if users enter Y_{PV} as fractions, the number of solar PV arrays N_{PV} can be obtained using the following equation.

$$N_{PV} = \frac{calc\_Y_{PV}}{frac\_Y_{PV}} \quad (2)$$

where cal_Y_{PV} is the calculated system's rated capacity of the PV array (kW), and $frac\_Y_{PV}$ is the fraction of the rated capacity of the PV entered by users (kW).

HOMER models a converter, commonly known as an inverter, to convert DC electricity generated by solar PV arrays to AC electricity by considering the user-specified efficiency η of the inverter side. HOMER calculates the performance of a converter on an annual basis according to the following equation.

$$\eta = \frac{kWh/year_{in}}{kWh/year_{out}} \quad (3)$$

where $kWh/year_{in}$ is the DC electricity generated by PV arrays (kWh/year), and $kWh/year_{out}$ is the AC electricity produced by inverter (kWh/year).

7. Present the source of the data in the System economic section.

Response: Thank you for this comment. The source of the data for system's economic, such as electricity rates, capital and replacement costs for converter, capital and replacement costs for PV modules, system capital cost and the fixed O&M cost for the context of Indonesia market have been added in the revised paper, as follows.

Section 3.3 – paragraph 5:

………………… The electricity rate for households with a 2,200 VA power contract (R1) is IDR 1,444.70 per kWh, while households with power of 3,500 VA or above (R2/R3) are charged IDR 1,699.53 per kWh [[54], [55]]. Assuming the exchange rate is IDR 15,000 per USD 1, this gives us USD 0.096 per kWh for 2,200 VA customers and USD 0.113 per kWh for 3,500-6,600 VA ones. The simulation, therefore, applies different electricity rates between 2,200 VA and higher segments.

Section 3.3 >> Solar PV array and converter:

…………. Capital and replacement costs of the 1 kW converter are assumed to be USD 400 (IDR 6,000,000) [56] and USD 380 (IDR 5,700,000), respectively, without annual O&M costs. ………..

This study assumes capital and replacement costs for the 0.1 kW peak PV module in Indonesia to be USD 50 each (equal to around IDR 750,000) [57], and no annual Operating and Maintenance (O&M) costs for the PV arrays. ……………………

Section 3.3 >> System economic:

………………… Considering the current total installed cost of solar PV for the Indonesian residential sector, i.e., USD 1,000/kW peak (IDR 15,000,000/kW peak) [[58], [59]], and the cost of solar PV modules and converters, the system fixed capital cost and the fixed O&M cost are set at USD 200 (IDR 3,000,000) [60] and USD 20/year (IDR 300,000/year), respectively.

All sources for system's economic have been included in the revised paper's references, as follows.

[54] Tarif Adjustment (in Bahasa Indonesia). Available: https://web.pln.co.id/pelanggan/tarif-tenaga-listrik/tariff-adjustment [Accessed 24 February 2023]

[55] Good News! Electricity Tariffs for The Next 3 Months Don't Increase. Available: https://voi.id/en/economy/241919 [Accessed 24 February 2023].

[56] Solar PV Inverter DC to AC 1000-Watt price in Indonesia. Available: https://www.tokopedia.com/baterailab/thinkpower-grid-tie-ongrid-inverter-1-6k-sseries-with-limiter-wifi-1000w?extParam=ivf%3Dfalse&src=topads [Accessed 10 September 2023].

[57] Solar PV panel 100-Watt peak price in Indonesia. Available: https://www.tokopedia.com/asia-teknindo/solar-panel-surya-solar-cell-100-wp-100-wattpolycrytalline-maysun [Accessed 9 September 2023].

[58] How much does it cost to install a solar PV roof at home? (in Bahasa Indonesia). Available: https://www.kompas.com/properti/read/2022/06/04/080000221/berapa-biaya-pemasangan-plts-atap-di-rumah-simak-penghitungannya?page=all [Accessed 21 February 2023].

[59] Should I install solar panels at home? Available: https://www.thejakartapost.com/business/2022/02/04/should-i-install-solar-panels-at-home.html [Accessed 20 February 2023].

[60] Rooftop PV system fixed capital and maintenance cost in Indonesia (in Bahasa Indonesia). Available: https://www.kompas.com/properti/read/2022/06/04/080000221/berapa-biaya-pemasangan-plts-atap-di-rumah-simak penghitungannya?page=all#:~:text=Adapun%20total%20biaya%20pemasangan%20PLTS%20sebesar%20Rp%2033.703.900%2C%20rinciannya,Beton)%3A%20Rp%203.060.000 [Accessed 11 September 2023].

Additional comment from Reviewer #1:
The authors present a study with two scenarios using the HOMER software, much of the method is done through this software, it is recommended to the authors to add a model, or more scientific method, to use HOMER and enrich it with the proposal of a model that improves it.

Response:
Thank you for this thoughtful comment and suggestion. Additional explanations and discussions on the model and specific method to improve HOMER utilisation have been added in the revised paper, as follows.

Introduction – paragraph 10:
………………… In particular, this study suggests a method for applying billing deduction factors in HOMER optimisation while taking into account the implications of setting and regulation through different unserved energy targets, PV capacity, and billing deduction factors on the assessment of cost-reliability trade-offs.

Section 3.3 – paragraph 1:
This study assesses the grid-connected rooftop PV systems for residential households by using HOMER software to model system configurations for four residential household segments with their associated load profiles in the urban area of Surabaya, Indonesia, as a case study. The complete model consists of an electricity grid, the household's loading pattern, and the main components consist of PV array and converter. While much of the simulations are performed in HOMER, this study takes into account the implications of setting and regulation through different unserved energy targets, PV capacity, and billing deduction factors on the assessment of cost-reliability trade-offs.

Section 3.3 – paragraph 2:
In particular, this study suggests a method for incorporating billing deduction factors in HOMER optimisation since the software does not account for billing deduction cases in in its direct calculations. In HOMER, varying sell-back rates for energy sold to the grid can be used to account for various billing deduction factors. To simulate a billing deduction factor of 65%, for instance, the model multiplies the amount of electricity sold to the grid by 65% of the electricity full rate for customers.

Reviewer #2:

Thank you for the submission of the paper. The paper can be considered for publication after a major revision.

Main comment:

1. Before resubmitting the revised version, a thorough language check has to be done.

Response: Thank you for this comment. The revised paper has been checked in terms of its language and thoroughly.

2. Section 2: When describing the current situation, it is of importance to describe the development of the massive oversupply of coal fired power stations from 2015 on. In addition, it should be mentioned that PLN is very reluctant to modify its plans for additional coal fired power stations, which are not yet build. A quantification of the oversupply in the different Indonesian regions as well as the still planed capacity additions should be show to explain the situation. In this context it would be of interest to add a more detailed description of the actual barriers for PV implementation and how this could eventually be solved.

   Response: Thank you for this constructive feedback. The revised paper has now included more comprehensive description (as written in Section 2, paragraph 3 – 5) on the challenges to the slow deployment of residential rooftop PV in Indonesia, especially regarding the actual barriers due to PLN's unchanging plan for ongoing development of coal-fired power plants, financial implication of electricity oversupply, and updated status of regulatory approach, as follows.

   Section 2 – paragraph 3:
   Through the Ministry of Energy and Mineral Resources (MEMR), the Indonesian government has made efforts to encourage the implementation of rooftop solar PV. This includes the issuance of Ministerial Regulation No. 49/2018, revised by Ministerial Regulation No. 26/2021 [48]. These regulations aim to achieve a rooftop PV capacity of 3.6 GW. Although the revised regulation is seen as a positive step, especially regarding the recognition of 100% export of electricity back to the PLN grid, implementation has been challenging.

   Section 2 – paragraph 4:
   As the grid operator, PLN is hesitant to approve applications for rooftop PV installations up to the maximum allowable capacity quota per customer due to oversupply and financial issues, mainly caused by the ongoing take-or-pay scheme derived from the Power Purchase Agreement (PPA) of large quantities of coal-based electricity from Independent Power Producers (IPP). To address the situation, MEMR has consulted with stakeholders to discuss various options, focusing on revising Ministerial Regulation No. 26/2021. Due to the current oversupply situation, rooftop PV users will most likely not be allowed to export electricity to the PLN grid, according to the newly revised regulation that has yet to be published [49].

   Section 2 – paragraph 5:
   Despite the positive efforts on the regulatory framework, the ongoing 35 GW coal power plant mega-project started in 2015 has become a problem for Indonesia's energy transition. The unchanging plans for additional coal power plants, which are not yet built, are arguably seen as one of the main barriers that hinder the massive development of PV, including rooftop systems – that require a comprehensive solution. While the share of coal in electricity generation is expected to decrease from around 56 GW to 40 GW, the capacity of coal-fired power plants is proposed to increase by 13 GW in the RUPTL 2021-2030. It has come to light that there are still plans to construct coal power plants in 2027, as per the 2015-2019 PPA [50].

3. Currencies should always be written in ISO code, eg. IDR, USD.

Response: Thank you for this valuable comment. The revised paper has now adopted ISO 4217 for currency codes. I have double-checked that all monetary values have applied IDR for Indonesian Rupiah and USD for United States Dollar.

4. CAPEX and OPEX should be given in IRD to make it comparable with kWh prices.

   Response: Thank you for this comment. I have now added the monetary values in IDR for economic variables of the system in the revised paper. Those can be found in Sub-Section 3.3 System modelling, economic parameters, and assumptions, particularly in the following parts.

   - Solar PV array and converter:

     .... Capital and replacement costs of the 1 kW converter are assumed to be USD 400 (IDR 6,000,000) [56] and USD 380 (IDR 5,700,000), respectively, without annual O&M costs. Capital and replacement costs are assumed to increase linearly concerning size.

     This study assumes capital and replacement costs for the 0.1 kW peak PV module in Indonesia to be USD 50 each (equal to around IDR 750,000) [57], ...

   - System economic:
     .... Considering the current total installed cost of solar PV for the Indonesian residential sector, i.e., USD 1,000/kW peak (IDR 15,000,000/kW peak) [[58], [59]], and the cost of solar PV modules and converters, the system fixed capital cost and the fixed O&M cost are set at USD 200 (IDR 3,000,000) [60] and USD 20/year (IDR 300,000/year), respectively.

5. All abbreviation should be spelled out at the first use in the text.

   Response: Thank you for this comment. I have double-checked that all abbreviations are spelled out the first time they are use in the text of the revised paper.

Detailed comments:

6. Ref 1, 2: Here the IEA PVPS Snapshots could be added: https://iea-pvps.org/snapshot-reports/snapshot-2023/

   Response: Thank you for this valuable suggestion. I agreed with the reviewer and have added the suggested reference (Ref. [3]) to support the first sentence – along with the other two references – as follows.

   [3] PVPS: Snapshot of Global PV Markets 2023. Available: https://iea-pvps.org/snapshot-reports/snapshot-2023/ [Accessed 1 September 2023].

   Emphasising on the recent global PV capacity growth, the first sentence of the revised paper now becomes:

   The utilisation of solar photovoltaic (PV) systems has increased significantly in recent years, with global capacity growth reaching 1.2 TW by 2022 [[1], [2], [3]].

7. Page 1, line 46-49: The uptake of PV rooftop systems due to rising electricity prices is a worldwide phenomena, not only in emerging economies. Eg. Australia, Netherlands and many others.

   Response: I agreed with this thoughtful comment and could have been clearer with this issue. The uptake of rooftop PV systems due to rising electricity prices in many countries, including the developed ones, has been included in the revised paper, now at the 2nd paragraph, as follows.

   Introduction – paragraph 2:
   Rising electricity prices in developed countries like Australia, the Netherlands, Germany, and many others have fuelled the adoption of residential rooftop PV systems along with the growth in capacity. However, it is worth noting that rooftop PV development in emerging economies has been influenced by both economic and technical factors. Increasing electricity rates and challenges utilities face in providing a reliable power supply, particularly in urban distribution networks, have contributed to the rise of rooftop PV in these countries.

8. Page 2, line 11 and 15: reference to the respective software programmes, e.g., where to find it, is missing.

   Response: Thank you for this feedback. I have now added the ref. number for all software used by previous studies in the revised paper (now are mentioned in paragraph 5 and paragraph 6) and included them in the references as follows.

   Introduction – paragraph 5 and 6:

   HOMER: [15] HOMER software. Available: https://www.homerenergy.com/ [Accessed 29 August 2023].

   PV*SOL: [18] PV*SOL software. Available: https://pvsol.software/en/ [Accessed 30 August 2023].

   PVGIS: [19] Photovoltaic Geographical Information System (PVGIS). Available: https://joint-research-centre.ec.europa.eu/photovoltaic-geographical-information-system-pvgis_en [Accessed 2 September 2023].

   SolarGIS: [20] SOLARGIS PV planner. Available: https://solargis.info/pvplanner/#tl=Google:hybrid&bm=satellite [Accessed 2 September 2023].

   SISIFO: [21] SISIFO. Available: https://www.sisifo.info/es/default [Accessed 1 September 2023].

   RETScreen: [23] RETScreen software. Available: https://natural-resources.canada.ca/maps-tools-and-publications/tools/modelling-tools/retscreen/7465 [Accessed 15 September 2023].

   SolarEnergy: [24] Á. X. C. de Jesus, D. P. Neto, E. G. Domingues. Computational tool for technical-economic analysis of photovoltaic microgeneration in Brazil. Energy, 271 (2023), 126962.

9. Page 3, line 5: Various publications and organisations like ISER mention: missing permits, administrative barriers, perception of high costs

   Response: Thank you for this constructive comment. I agreed with the reviewer and have now added a reference by IESR (ref. [38]) to complement the 'on customer side's barrier' as follows.

Introduction – Paragraph 12:

On the customer side, on the other hand, the decision regarding whether to implement grid-connected rooftop PV or rely solely on electricity from the utility grid, in many cases, has not been supported by sufficient knowledge of techno-economic aspects, particularly on reliability and cost implications due to different system settings and regulations. In addition, lack of product knowledge, complicated permit requirements, and perception of expensive systems were identified as the main barriers to adopting rooftop PV for households [38].

10. Page 3, line 45 -50: Here some of the arguments a contradicting each other, eg. if an oversupply in the form of coal exists, no additional flexibility reserve is needed.

    Response: Thank you for this critical comment. While the paragraph has been improved grammatically as well as its readability and delivery of the sentences, a sentence has been added into the last part of the paragraph to critically comment the PLN's contradicting arguments by presenting the opportunity for coal-fired power plants in providing the grid with required flexibility, as follows.

    Section 2 – paragraph 2:

    There are challenges to the slow deployment of residential rooftop PV in Indonesia that are currently affecting all PLN customers. Some of these challenges have been acknowledged in the PLN Electricity Supply Business Plan (RUPTL) 2021-2030 [43]. These include: 1) several PLN electricity networks are currently not prepared to handle distributed renewable energy-based generation due to oversupply conditions caused by decreased demand; 2) there will be a need for PLN to add more generation plants to increase system flexibility if there is a relatively massive penetration of rooftop PV; and 3) there will be additional investment costs in generation control and forecasting, dispatch system, and grid code enforcement [[44], [45]]. While the challenges may delay large-scale PV deployment, oversupply of system capacity, including from coal-fired power plants, can present an opportunity to provide the grid with increased flexibility [[46], [47]].

11. Figs 5 to 8: These are actually tables. Please avoid the term operating costs, because you are effectively describing the costs for the PV generated and grid bought electricity.

    Response: Thank you for this valuable comment and suggestion. In the revised paper, Figures 5 to 8 have been modified into Tables 3 to 6 and have been placed after the 3rd paragraph of Section 4 (Results and Discussion). A screenshot of Table 3 is presented below.

Table 3. Simulation results for 2,200 VA: 100%-MPVC

Maximum annual unserved energy (%)	PV (kW)	Converter (kW)	Grid (kW)	Initial Capital (USD)	Total NPC (USD)	COE (USD/kWh)	RE share (%)	Unserved energy (%)
0	2.2	1.5	1.8	1,900	9,175	0.081	33	0
5	2.2	1.5	1.4	1,900	8,796	0.081	34	4
10	2.2	1.5	1.3	1,900	8,446	0.080	35	7
15	2.2	1.5	1.2	1,900	7,987	0.079	36	11

I have replaced the term 'maximum capacity shortage' with 'maximum annual unserved energy' to better represent the system reliability constraints and capacity shortage' with 'unserved energy' for the reliability results of the optimised configurations.

As suggested, the term 'operating costs' has now been avoided in Tables 3 to 6, also in the revised paper. To exclude the term 'operating costs' in the analysis, the text has been modified as follows.

Section 3.3 >> System economic **(*****last sentence*****)**

…………………. While the term operating costs is useful in providing the user with some insights into the contribution of these types of costs on the total NPC and typically decreases at higher unserved energy, this study rules out the term operating costs in the analysis due to the focus of this study on analysing the possible trade-off between the system cost, which is already well represented by the total NPC, and unserved energy.

12. A sensitivity analysis of the economic variable would be helpful.

Response: Thank you for this suggestion. The revised paper has now included sensitivity analyses described at paragraphs 16, 17, and 18. The study has used 'maximum annual unserved energy' as the sensitivity variable. The descriptions are accompanied by sensitivity results presented in Figures 13, 14, and 15. These include: 1) possible trade-offs on total NPC versus unserved energy fraction; 2) net grid purchases (electricity purchased from the grid minus electricity sold to the grid) versus maximum annual unserved energy; and 3) total NPC versus total electricity production. Overall, the sensitivity analysis parts are as follows.

Results and Discussion – paragraph 13:

A sensitivity analysis of the techno-economic factors influencing system performance would benefit stakeholders, particularly residential customers. While focusing on system reliability, this study uses only a 5% annual interest rate and fixed electricity rates associated with household segments. As a result, the sensitivity variable used in HOMER is maximum annual unserved energy.

Results and Discussion – paragraph 14:

Taking a 2,200 VA household with 100%-MPVC as an example, a graphical sensitivity result depicting possible trade-offs on total NPC versus unserved energy fraction and a sensitivity result of net grid purchases (electricity purchased from the grid minus electricity sold to the grid) versus maximum annual unserved energy are presented in Figure 13 and Figure 14, respectively. Meanwhile, a sensitivity result of total NPC versus total electricity production is shown in Figure 15.

Results and Discussion – paragraph 15:

Maximum annual unserved energy constraints have varying effects on total NPC, total electricity production, and nett grid purchases. As shown in Figure 13, total NPC cannot be less than USD 8,500 when unserved energy is kept at or below 6%. According to Figure 15, a 10% unserved energy would result in approximately 9,700 kWh/year of electricity production, which would equal approximately USD 8,500 in total NPC.

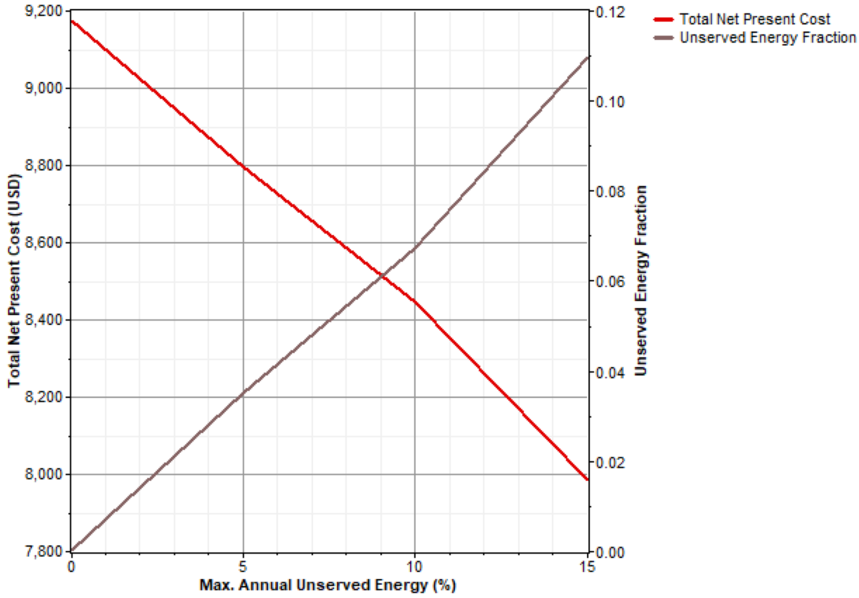

Figure 13. Sensitivity result of total NPC versus unserved energy fraction in a 2,200 VA household with 100%-MPVC.

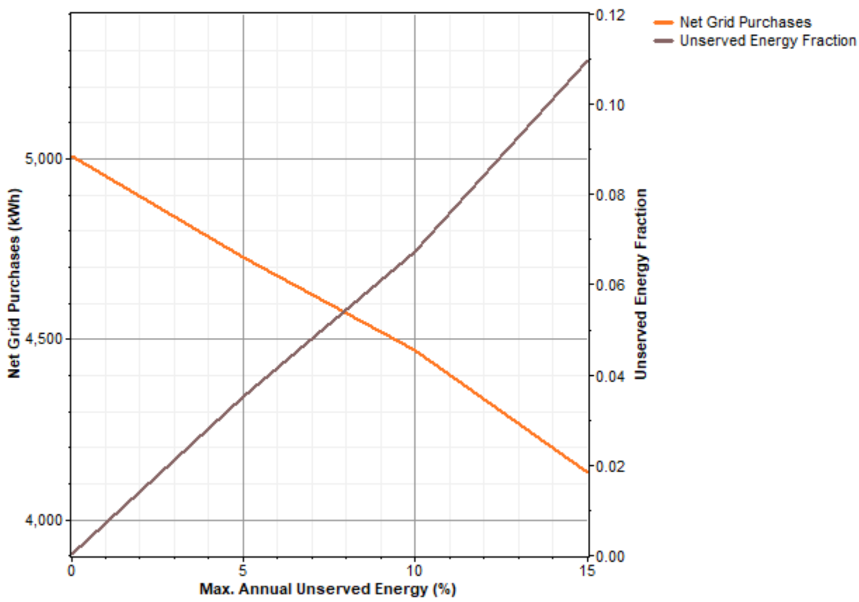

Figure 14. Sensitivity result of net grid purchases versus maximum annual unserved energy in a 2,200 VA household with 100%-MPVC.

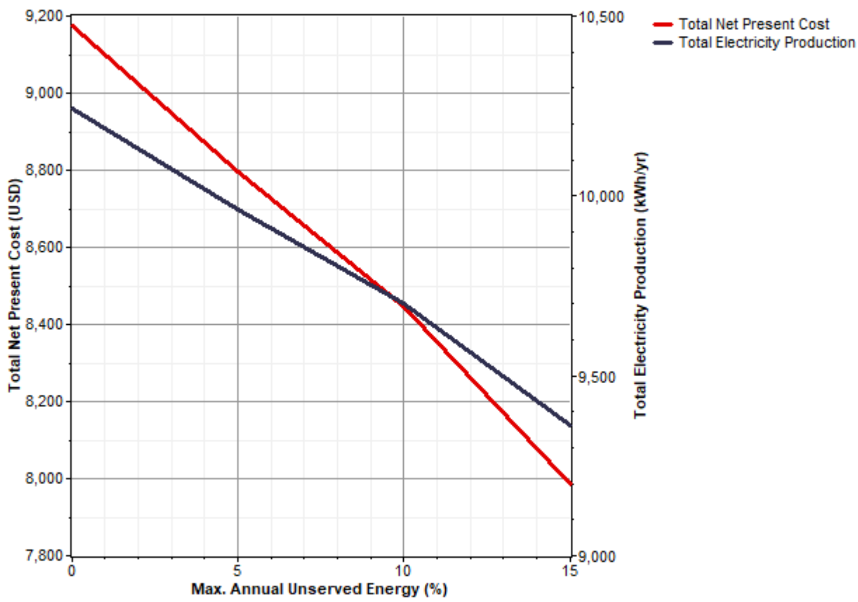

Figure 15. Sensitivity result of total NPC versus total electricity production in a 2,200 VA household with 100%-MPVC.

Additional comment from Reviewer #2:

- The conclusion should put more emphasis on the benefits of rooftop PV supported by the findings of the paper.

  Response: Thank you for this valuable suggestion. I could have been clearer in this part. In the revised paper, I have modified sentences in paragraph 2 and added a specific paragraph (paragraph 3) to put more emphasis on the benefits of grid-connected rooftop PV by highlighting important findings from the case study as follows.

  Conclusions – paragraph 2:

  In all four cases of each household segment, i.e., 100%-MPVC, 65%-MPVC, 100%-HPVC, and 65%-HPVC, the optimisation results show reliability-cost trade-offs between the total NPC and all unserved energies. Furthermore, the role of cost components in the trade-offs between HPVC and MPVC cases in terms of initial capital costs and total NPC was highlighted in the analyses. The findings revealed a relatively large difference in total NPC for all households between 100%-MPVC cases and 65%-MPVC cases for all unserved energies, while differences between those in 100%-HPVC cases and 65%-HPVC cases are insignificant. The simulation results implied potential benefits of rooftop PV installation up to the maximum permitted capacity and a 100% billing deduction scheme for households with 2,200 VA, taking into account different options for unserved energy, installed capacity, and billing deduction percentage.

  Conclusions – paragraph 3:

  Among the significant results of this study that highlight the benefits of grid-connected rooftop PV are the following: 1) higher renewable energy penetration for MPVC systems compared to HPVC systems regardless of the billing deduction factors; 2) cheaper total NPC are shown by MPVC cases than those of HPVC cases within the same unserved energy; 3) lower shares of energy charge to the annual total cost in MPVC cases compared to those in HPVC ones; and 4) Over the project lifetime, the cost per kWh consumed (USD/MWh consumed) showed only a slight variance between the system with no-unserved energy and the system with the poorest reliability, given 100%-MPVC cases in 2,200 VA as an example;

5) All households with a 15% maximum limit on unserved energy have the lowest costs per watt of installed PV capacity, and these costs are unaffected by billing deduction factors; 6) based on the system's maximum unserved energy limits, higher unserved energy has led to a decrease in the amount of grid capacity needed by the system to meet demand, and the PV capacities are maximised across all unserved energies in various scenarios; and 7) Sensitivity analyses have revealed a range of impacts of maximum annual unserved energy constraints on various parameters, including total NPC, total electricity production, and net grid purchases.

Author's additional response to the revised paper:

- All revisions in terms of language and/or additional sentences in the revised paper are marked up in yellow. Grammatical errors have been corrected and additional sentences have been added throughout the text's body, either by rewriting existing paragraphs or adding new ones, to improve readability and manuscript delivery.

- In addition to presenting all of the corrected sections in response to the reviewers' comments, Section 4 (Results and discussion) has undergone significant improvement. This is done expanding the analyses and discussions pertaining to the grid-connected rooftop PV model in the case study, including: the potential role of the system cost components on the cost-reliability trade-offs, the trade-offs between annualised total cost and unserved energy, the cost per MWh energy consumed during the project lifetime, the cost per watt of PV installed for all unserved energies, sensitivity analysis of the techno-economic factors due to different maximum annual unserved energy. All additional analyses and discussions in Section 4 of the revised paper have been marked up with yellow as well.

4. Email received: Submission accepted (16 October 2023 – Indonesia time) and notification of production for typesetting (16 October 2023 – Indonesia time)

UNIVERSITAS KRISTEN PETRA

Yusak Tanoto <tanyusak@petra.ac.id>

Your Submission

2 messages

Energy <em@editorialmanager.com> Mon, Oct 16, 2023 at 12:30 PM
Reply-To: Energy <support@elsevier.com>
To: Yusak Tanoto <tanyusak@petra.ac.id>

Ms. Ref. No.: EGY-D-23-04810R1
Title: Cost-reliability trade-offs for grid-connected rooftop PV in emerging economies: a case of Indonesia’s urban residential households
Energy

Dear Dr. Tanoto,

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Sincerely,

Henrik Lund
Editor-in-Chief
Energy

Comments to Authors:

Reviewer #1: The authors followed all my suggestions, my recommendation is to accept the manuscript.

Reviewer #2: The author responded properly to the comments. the paper can now be published.
manuscript is accepted, your Data in Brief submission will automatically be transferred to Data in Brief for editorial review and publication.

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Energy <em@editorialmanager.com> Mon, Oct 16, 2023 at 12:30 PM
Reply-To: Energy <support@elsevier.com>
To: Yusak Tanoto <tanyusak@petra.ac.id>

Ms. Ref. No.: EGY-D-23-04810R1
Title: Cost-reliability trade-offs for grid-connected rooftop PV in emerging economies: a case of Indonesia's urban residential households
Energy

Dear Dr. Tanoto,

I am pleased to confirm that your accepted manuscript has now been sent to production for typesetting.

Your accepted manuscript will now be transferred to our production department and work will begin on creation of the proof. If we need any additional information to create the proof, we will let you know. If not, you will be contacted again in the next few days with a request to approve the proof and to complete a number of online forms that are required for publication.

We appreciate and value your contribution to Energy. We regularly invite authors of recently published manuscript to participate in the peer review process. If you were not already part of the journal's reviewer pool, you have now been added to it. We look forward to your continued participation in our journal, and we hope you will consider us again for future submissions.

Kind regards,

Energy

Comments from the Editors and Reviewers:

%COMMENTS_TO_AUTHOR%
[Quoted text hidden]

5. Email received: Production begun (17 October 2023 – Indonesia time)

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Yusak Tanoto <tanyusak@petra.ac.id>

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Our reference: EGY 129388
Article reference: EGY_EGY-D-23-04810
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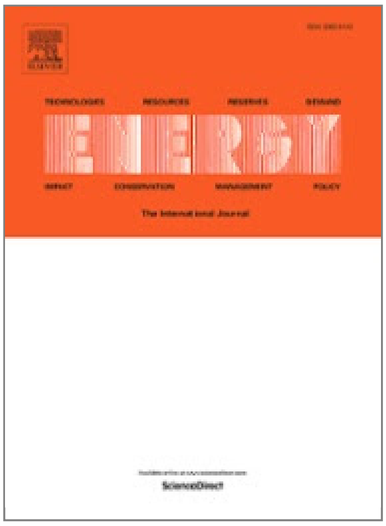

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Table 3 to **Table 6** highlight the main results regarding important techno-economic aspects for all the cases considered in a 2,200 VA
household. In the 100%-MPVC cases **(see Table 3)**, the total NPC has reached USD 9,175 for 0 % maximum unserved energy (no-unserved energy) and has declined to USD 7,987 or 13 % for up to 11 % simulated unserved energy. As for no-unserved energy, the total NPC has increased to USD 10,031, USD 10,371, and USD 10,661 for the 65%-MPVC **(see Table 4)**, 100%-HPVC **(see Table 5)**, and 65%-HPVC cases **(see Table 6)**, respectively.

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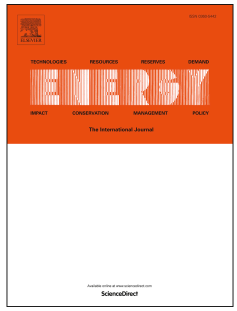

Cost-reliability trade-offs for grid-connected rooftop PV in emerging economies: A case of Indonesia's urban residential households

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PII: S0360-5442(23)02782-2

DOI: https://doi.org/10.1016/j.energy.2023.129388

Reference: EGY 129388

To appear in: *Energy*

Received Date: 29 April 2023

Revised Date: 21 September 2023

Accepted Date: 16 October 2023

CRediT author statement

Yusak Tanoto: Conceptualisation, Methodology, Data preparation, Simulation, Analysis, Visualisation, Writing – Original draft preparation, Review and Editing.

Cost-reliability trade-offs for grid-connected rooftop PV in emerging economies: a case of Indonesia’s urban residential households

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Abstract

This study explores the potential of grid-connected rooftop photovoltaic (PV) systems in terms of how they can be better planned and utilised by understanding possible trade-offs between cost and reliability while acknowledging challenges to utility supply security in the context of emerging economies. The study particularly examines the implications of unserved energy targets, PV capacity, and billing deduction factors on grid-connected rooftop PV’s trade-offs in terms of total net present cost and unserved energy. This study considers four residential household segments in Indonesia’s urban area as a case study, with four cases applied in each segment representing scenarios on PV capacities and billing deduction factors. Using HOMER software, the analyses highlight the role of cost components in trade-offs involving potential PV capacity cases. Systems with maximum PV capacity exhibit cheaper total net present costs than those of half PV capacity within the same unserved energy. While the optimisations pushed PV capacity up to the maximum size across all unserved energies, higher unserved energy resulted in lower grid capacity required to meet demand associated with the system’s maximum unserved energy limit. This study provides residential customers and stakeholders with insights to better plan and implement grid-connected rooftop PV systems and policies.

Keywords: on-grid, rooftop PV, emerging economies, reliability-cost, trade-offs.

1. Introduction

The utilisation of solar photovoltaic (PV) systems has increased significantly in recent years, with global capacity growth reaching 1.2 TW by 2022 [[1], [2], [3]]. In several emerging economies and jurisdictions, the installation of rooftop solar PV has witnessed significant growth [[4], [5], [6], [7], [8]]. Grid-connected rooftop PV is a feasible option for providing electricity in residential households in many urban areas [9]. Installing grid-connected rooftop PV is simpler, cheaper, and requires almost no maintenance compared to hybrid systems [10]. Adopting low-cost, green technologies like PV can reduce CO_2 emissions and support sustainable energy transition [[11], [12]]. However, when choosing grid-connected rooftop PV, customers consider various factors, including the system’s performance expectations, socio-environmental beliefs, and price-value beliefs, among others [13].

Rising electricity prices in developed countries like Australia, the Netherlands, Germany, and many others have fuelled the adoption of residential rooftop PV systems along with the growth in capacity. However, it is worth noting that rooftop PV development in emerging economies has been influenced by both economic and technical factors. Increasing electricity rates and challenges utilities face in providing a reliable power supply, particularly in urban distribution networks, have contributed to the rise of rooftop PV in these countries.

It is of importance to pay special attention to the low reliability of urban distribution networks [14]. This is particularly essential for households choosing the appropriate size of rooftop PV components. A grid-connected system without any capacity shortage, representing excellent reliability, would require a larger supply capacity to meet high peak loads during a short period. This, of course, would come at a

higher cost. On the other hand, a smaller and less expensive system may meet a reasonable portion of the load while allowing for some capacity shortage.

Many studies have investigated different aspects of the techno-economic feasibility of rooftop solar PV systems in the context of emerging economies and developing countries. These studies have primarily focused on grid-connected residential applications and have used various techniques and tools. Some studies have concentrated on system planning through simulations, while others have evaluated the performance of installed systems, either at a single location or across several sites.

Gabr et al. [10] assessed the techno-economic feasibility of a grid-connected rooftop PV system in Egypt, considering the ongoing electricity retail prices and net-metering policy applied to three types of housing rates with different demand levels. They used HOMER (Hybrid Optimization of Multiple Energy Resources) software [15] to measure the net present value of energy cost, payback period, and bill savings. Laib et al. [16] evaluated the performance of a grid-connected solar PV system and its energy balance in Algeria. The authors developed a Matlab-Simulink model to optimise, rationalise, and implement energy-saving approaches to evaluate the system's energy performance and balance.

Dondariya et al. [17] predicted the performance of grid-connected rooftop PV systems in Ujjain, India. The authors compared PV*SOL [18], PVGIS [19], SolarGIS [20], and SISIFO [21] to analyse system performance in terms of energy generation, performance ratio, and solar fraction. Mohammadi et al. [22] analysed the impact of different tracking options on the potential of grid-connected PV development in Iran using RETScreen software [23]. Jesus et al. [24] proposed SolarEnergy, a new optimisation tool for the techno-economic analysis of PV microgeneration. The authors conducted a techno-economic analysis of grid-connected PV systems in Brazil, providing decision-making indicators such as net present value, modified internal rate of return, discounted payback period, and sensitivity analysis of key techno-economic parameters. In another study, Al Garni et al. [25] assessed the optimal design of grid-connected PV by considering various PV tracking systems applied in Makkah, Saudi Arabia. The authors used HOMER to examine the horizontal axis, vertical axis, and a two-axis tracking system. Earlier study by Lau et al. [26] analysed the pricing mechanism for grid-connected PV projects in the residential sector of Malaysia by evaluating the impact of component costs, feed-in tariffs, and carbon taxes using HOMER.

Duman and Güler [27] assessed the economic feasibility of 5 kW grid-connected solar PV in nine provinces of Turkey. Using HOMER, the study evaluated the discounted payback period, internal rate of return, and profitability index, and found that the system would not be feasible in two provinces under the practiced feed-in tariff. Bakhshi and Sadeh [28] examined the economic feasibility of grid-connected rooftop PV systems in Iran. They used PVsyst software [29] to estimate the annual energy generation of a 5-kW peak system in different cities. Their analysis included Net Present Value (NPV), Internal Rate of Return (IRR), payback period (PP), and Levelised Cost of Energy (LCOE), and employed a dynamic feed-in tariff strategy. Similar indicators, i.e., NPV, LCOE, IRR, and static PP and dynamic PP, were used by Xin-gang and Yi-min [30] in building a cost-benefit model to evaluate the economic performance of China's rooftop PV industry. Meanwhile, Orioli and Gangi [31] considered the effects of time variation on the PP assessment of grid-connected rooftop PV systems in Italy.

Li et al. [9] conducted a study to evaluate and compare the techno-economic performance of grid-connected rooftop PV systems and other alternatives in five climate zones in China using HOMER. The study found that grid/PV systems were the most cost-effective option among all the studied systems, and Kunming is the most economical among other regions. Tomar and Tiwari [32] discussed the feasibility of grid-connected rooftop PV for three residential households. The authors used HOMER to simulate the impact of feed-in tariffs/net metering along with a tariff-of-day policy in New Delhi, India. They concluded that systems without energy storage are technically and economically viable for

decentralised households. An earlier study by Pillai et al. [33] developed an economic evaluation methodology to assess the near-term benefits of grid-connected residential PV systems in the United Kingdom and India. The authors developed a metric called 'Prosumer Electricity Unit Cost' (PEUC) and used it to examine the effects of solar input, financial mechanisms, and demand profiles in the near-term time frame of the project.

While studies focussing on single household analysis or involving multiple sites have provided useful insights for stakeholders regarding the potential techno-economic impacts of grid-connected rooftop PV and its deployment opportunity, less explored, however, has been the impacts of setting and regulation through different unserved energy targets, PV capacity, and billing deduction factors. In particular, there has been little attention of the potential trade-offs between system reliability and costs.

This paper aims to explore the potential benefits of grid-connected rooftop PV in terms of how the systems can be better planned and utilised through understanding possible trade-offs between system reliability and cost while also recognising the challenges to utility supply security in the context of emerging economies. While system reliability and efficiency of residential rooftop PV can be enhanced by incorporating other technologies such as wind or diesel, gas, and energy storage [34], this paper focuses on the grid-connected PV systems in urban households in emerging economies. In particular, this study suggests a method for incorporating billing deduction factors in HOMER optimisation while taking into account the implications of setting and regulation through different unserved energy targets, PV capacity, and billing deduction factors on the assessment of cost-reliability trade-offs. The city of Surabaya, Indonesia, is considered a case study.

Despite high-level supportive legislation, rooftop PV has only seen modest deployment in Indonesia mainly due to non-technical barriers and challenges, such as missing permits, lack of regulatory certainty, lack of alignment and synchronisation of implementing regulations, project bankability issues, and cost burden for PLN (Perusahaan Listrik Negara, i.e., Indonesia's state-owned electricity company that is solely responsible for electricity generation, transmission, and distribution) as the sole off-taker, among others [[35], [36], [37]].

On the customer side, on the other hand, the decision regarding whether to implement grid-connected rooftop PV or rely solely on electricity from the utility grid, in many cases, has not been supported by sufficient knowledge of techno-economic aspects, particularly on reliability and cost implications due to different system settings and regulations. In addition, lack of product knowledge, complicated permit requirements, and perception of expensive systems were identified as the main barriers to adopting rooftop PV for households [38].

This paper offers a new perspective on the ongoing rooftop PV studies from a techno-economic standpoint. It introduces the concept of reliability-cost trade-offs that may arise due to different energy targets and the resulting variations in PV system sizes. These trade-offs are particularly relevant in emerging economies given the level of reliability and associated costs can vary significantly. The paper models unserved energy targets by accounting for potential capacity shortages on the supply side.

The paper is organised as follows. Section 2 provides a brief overview of the current status of solar PV deployment, with a focus on rooftop solar PV systems in Indonesia. Section 3 explains methods used in this study, including an overview of the simulations, input data, and modelling assumptions. Results and discussions are presented in Section 4. Finally, the conclusion of the paper is presented in Section 5.

2. Brief Status of Rooftop Solar PV Deployment for Residential Households in Indonesia

The potential for rooftop solar PV systems in Indonesia is immense due to the country's vast solar irradiation coverage and large market [39]. Despite this, the development of residential rooftop PV systems has been slow. As of October 2022, 75% of the 6,261 PLN customers who installed rooftop PV were residential customers with mostly on-grid systems [40]. The residential sector has installed rooftop PV with a total capacity of 15.2 MW, representing approximately 22% of the total rooftop capacity for all PLN customers [41]. The Java-Bali area has the largest share of the national rooftop PV capacity, accounting for around 80% in 2021 [42].

There are challenges to the slow deployment of residential rooftop PV in Indonesia that are currently affecting all PLN customers. Some of these challenges have been acknowledged in the PLN Electricity Supply Business Plan (RUPTL) 2021-2030 [43]. These include: 1) several PLN electricity networks are currently not prepared to handle distributed renewable energy-based generation due to oversupply conditions caused by decreased demand; 2) there will be a need for PLN to add more generation plants to increase system flexibility if there is a relatively massive penetration of rooftop PV; and 3) there will be additional investment costs in generation control and forecasting, dispatch system, and grid code enforcement [[44], [45]]. While the challenges may delay large-scale PV deployment, oversupply of system capacity, including from coal-fired power plants, can present an opportunity to provide the grid with increased flexibility [[46], [47]].

Through the Ministry of Energy and Mineral Resources (MEMR), the Indonesian government has made efforts to encourage the implementation of rooftop solar PV. This includes the issuance of Ministerial Regulation No. 49/2018, revised by Ministerial Regulation No. 26/2021 [48]. These regulations aim to achieve a rooftop PV capacity of 3.6 GW. Although the revised regulation is seen as a positive step, especially regarding the recognition of 100% export of electricity back to the PLN grid, implementation has been challenging.

As the grid operator, PLN is hesitant to approve applications for rooftop PV installations up to the maximum allowable capacity quota per customer due to oversupply and financial issues, mainly caused by the ongoing take-or-pay scheme derived from the Power Purchase Agreement (PPA) of large quantities of coal-based electricity from Independent Power Producers (IPP). To address the situation, MEMR has consulted with stakeholders to discuss various options, focusing on revising Ministerial Regulation No. 26/2021. Due to the current oversupply situation, rooftop PV users will most likely not be allowed to export electricity to the PLN grid, according to the newly revised regulation that has yet to be published [49].

Despite the positive efforts on the regulatory framework, the ongoing 35 GW coal power plant mega-project started in 2015 has become a problem for Indonesia's energy transition. The unchanging plans for additional coal power plants, which are not yet built, are arguably seen as one of the main barriers that hinder the massive development of PV, including rooftop systems – that require a comprehensive solution. While the share of coal in electricity generation is expected to decrease from around 56 GW to 40 GW, the capacity of coal-fired power plants is proposed to increase by 13 GW in the RUPTL 2021-2030. It has come to light that there are still plans to construct coal power plants in 2027, as per the 2015-2019 PPA [50].

3. Methods

In this study, HOMER software is used to model grid-connected rooftop solar PV systems. Possible system sizes with various load profiles are simulated, as are their economic parameters, such as total Net Present Cost (NPC) and Cost of Energy (COE). Four different daily load profiles for residential households with electricity contracts of 2,200 Volt-Ampere (VA), 3,500 VA, 5,500 VA, as well as 6,600 VA have been created. Figure 1 depicts these load profiles.

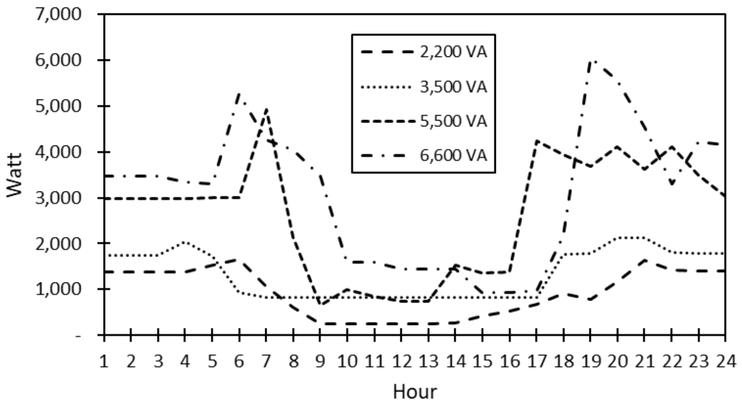

Figure 1. Surveyed hourly based daily load profile for four residential households.

While a preliminary survey has been carried out to obtain the load profiles (as shown in Figure 1) owned by different households in different locations in Surabaya – to represent different residential customer segments – this study considers only one location to allow the same solar irradiation data to be used in all simulations. It should be noted that all load profiles surveyed, as shown in Figure 1, are for weekdays. Nevertheless, weekend patterns for most residential segments show similar base load values to weekdays but have slightly higher peak load, over a short period, than weekdays. One thing to note is that the surveyed load profiles have ruled out the impact of the Covid-19 pandemic which has recently subsided, where people spent more time at home due to restrictions on outdoor activities or working from home.

Meanwhile, Table 1 shows several loading parameters for all residential segments, including the base load, maximum (peak) load, demand factor, and load factor. The demand factor is defined as the maximum demand divided by the connected load. The load factor is the ratio of average to maximum load for a 24-hour period.

Table 1. Loading parameters for all surveyed residential households

Parameter	Residential household segments			
	2,200 VA	3,500 VA	5,500 VA	6,600 VA
Base load	240 Watt	820 Watt	657 Watt	935 Watt
Maximum load	1,655 Watt	2,127 Watt	4,915 Watt	6,056 Watt
Demand factor	0.53	0.32	0.48	0.43
Load factor	0.56	0.63	0.53	0.51

As shown in Table 1, the surveyed households have a fairly low to medium range of demand factors and relatively low load factors, i.e., around 0.5 – 0.6. This, however, is a typical household situation in many Indonesian urban areas, including Surabaya. Between 7 a.m. and 4 p.m., demand for electricity falls because most people spend their days outside their homes studying or working. Furthermore, with the exception of refrigerators, electricity has not been used for kitchen appliances. While gas is commonly used in stoves and ovens, microwaves are uncommon in Indonesia.

3.1. Solar resource data

Surabaya has huge untapped potential for rooftop PV. Located on the east coast of the Java Sea, Surabaya is Indonesia's second-largest urban area of around 300 km^2 and has relatively high solar resources. According to a World Bank report that selected a geographical site of -7.32° (7°19') South Latitude and 112.68° (112°40') East Longitude, the long-term average daily Global Horizontal Irradiation (GHI) in Surabaya has reached 5.29 kWh/m^2 [29], higher than Indonesia's average daily GHI

of 4.8 kWh/m^2. Figure 2 presents the map of daily and yearly long-term averages of GHI values in Indonesia, including Surabaya, from 1999-2018 [51].

HOMER allows users to enter GHI and/or Clearness Index values using one of the two possible approaches, i.e., by downloading GHI and/or Clearness Index values from HOMER or by obtaining the NASA/MERRA2 hourly-based datasets of GHI and/or Clearness Index from the NREL National Solar Radiation Database (NSRDB) viewer [53]. While the first approach allows users to directly obtain 'ready to use' monthly average values of GHI and/or Clearness Index by specifying the location's latitude and longitude, the second approach lets users explore the data using the following steps: (1) entering the location's latitude and longitude; (2) selecting available datasets; (3) selecting appropriate attributes; (4) selecting year(s); (5) selecting time interval of the data; (6) selecting data formatting options; (7) typing an email for receiving the data; and (8) submitting the request.

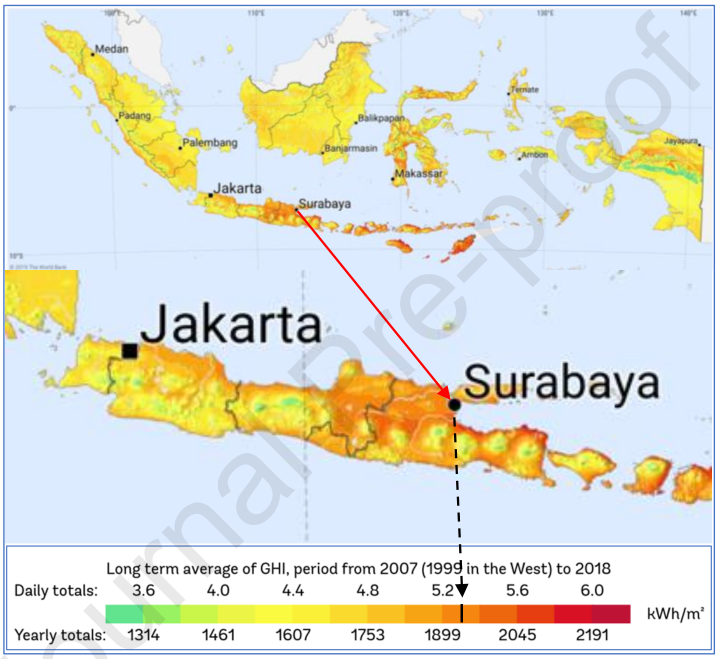

Figure 2. A map showing daily and yearly long-term average GHI (kWh/m^2) in Indonesia and Surabaya [51].

While obtaining the GHI and/or Clearness Index data from the NREL NSRDB data viewer website may provide users with flexibility and options of getting the preferred data granularity (10-minute, 30-minute, or 60-minute time intervals for Asia, Australia, and Pacific regions during 2016 – 2020), HOMER detects the time step of the imported data file based on the number of lines. If, for example, the imported data file contains 8,760 lines, HOMER assumes it contains hourly data. Subsequently, HOMER will convert the data into monthly averages, i.e., a single value for each month. Users, however, should first convert the GHI from hourly-based W/m^2 into daily-based kW/m^2 for a particular year before importing the data into HOMER. In addition, if the year selected on the NREL data viewer website is more than one specific year, users must produce an average value for each time step within all considered years.

This study applies the first approach, i.e., downloading the 'ready to use' GHI and Clearness Index data for a location having a South Latitude of 7°19' and an East longitude of 112°47'. While the considered latitude in this study is slightly different from that in [51], the location provides an average daily GHI of 5.26 kWh/m^2, similar to that in [51]. Table 2 presents numerical values of the monthly average GHI, and Clearness Index obtained for this study, while Figure 3 shows how HOMER depicts the values graphically.

Table 2. Monthly average GHI and clearness index for the specified location

Month	Clearness index	Global Horizontal Index ($kWh/m^2/day$)
January	0.45	4.84
February	0.46	4.97
March	0.48	5.05
April	0.52	5.09
May	0.56	5.00
June	0.57	4.82
July	0.59	5.10
August	0.60	5.62
September	0.61	6.21
October	0.56	5.96
November	0.50	5.34
December	0.48	5.13
Average	0.53	5.26

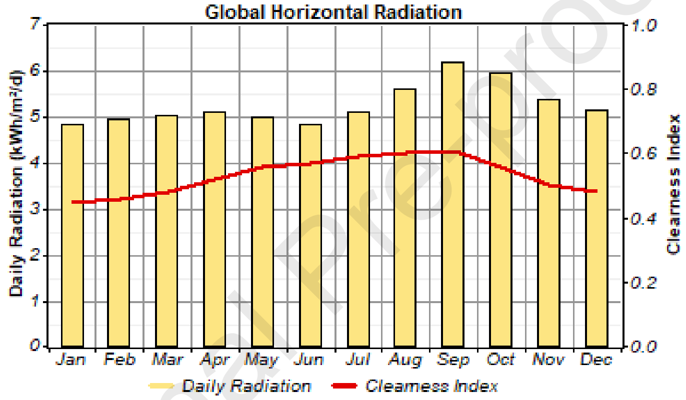

Figure 3. HOMER visualisation of monthly average GHI and Clearness Index for the specified location.

3.2. Reliability-cost trade-offs

The cost-reliability trade-offs in the context of residential grid-connected rooftop PV analysis should demonstrate to customers the importance of understanding the options available and their possible two-sided impacts. This impact may be caused by different PV sizes that customers may consider due to budget or other constraints, such as daytime power requirements and supply reliability. In contrast to the load profiles of commercial buildings in general, which have relatively flat loads during the day, the load profiles for all surveyed households, as shown in Figure 1, can provide more options to all customers, particularly considering the shape of a deep valley from 7 a.m. – 4 p.m. However, there are different consequences for installing any PV size that suits their needs and limitations, not just only maximising the size allowed by regulations up to the contracted amount of power.

The cost-reliability trade-off analysis in this study is based on the maximum annual capacity shortage values assigned to the simulation. HOMER uses the term 'maximum annual capacity shortage' to express the system's reliability constraint. It defines the total capacity shortage as the total amount of capacity shortage throughout a year, expressed in kWh/year. The value is used to calculate the capacity shortage fraction. This fraction is a ratio between total capacity shortage and total electric load, expressed in kWh/year. The simulated systems may end up with a situation where there is an unmet load or unserved energy when the electrical load exceeds the supply. Therefore, the total unmet load and the unmet load fraction can be calculated accordingly. This study applies 0%, 5%, 10%, and 15% of the maximum annual capacity shortage (or maximum unserved energy). Hereafter, the

paper uses the term 'maximum unserved energy' as the system reliability constraint and 'unserved energy' as the result of system reliability.

3.3. System modelling, economic parameters, and assumptions

This study assesses the grid-connected rooftop PV systems for residential households by using HOMER software to model system configurations for four residential household segments with their associated load profiles in the urban area of Surabaya, Indonesia, as a case study. The complete model consists of an electricity grid, the household's loading pattern, and the main components consist of PV array and converter. While much of the simulations are performed in HOMER, this study takes into account the implications of setting and regulation through different unserved energy targets, PV capacity, and billing deduction factors on the assessment of cost-reliability trade-offs.

In particular, this study suggests a method for incorporating billing deduction factors in HOMER optimisation since the software does not account for billing deduction cases in its direct calculations. In HOMER, varying sell-back rates for energy sold to the grid can be used to account for various billing deduction factors. To simulate a billing deduction factor of 65%, for instance, the model multiplies the amount of electricity sold to the grid by 65% of the electricity full rate for customers.

This study examined four load profiles corresponding to the four residential customer segments. Simulations are performed for each load profile, considering the electricity export deduction factor. The applicable kWh export deduction factor determines the proportion of kWh exported to the grid that can be used as a factor for reducing electricity bills. This study uses two different billing deduction factors, i.e., a 65% deduction factor according to Ministerial Regulation No. 49/2018 and a 100% deduction factor according to Ministerial Regulation No. 26/2021. The first deduction factor shows that only 65% of the kWh exported to the grid is permissible for customers to reduce electricity bills. The second factor indicates that the customer can use all kWh exported to the grid to reduce the amount of kWh purchased from the grid.

In HOMER, these two conditions can be treated differently. HOMER calculates the total energy charge without net metering, i.e., using the 65% deduction factor, by multiplying the total energy purchased from the grid by the electricity rate applicable to that household segment minus the amount of electricity sold to the grid times the applicable sell-back rate. Using a 100% deduction factor (net metering), HOMER calculates the total energy charge by multiplying the amount of net kWh purchased from the grid by the electricity rate that applies to the household segment.

No Time-of-Use (TOU) rate and demand charge is applied to Indonesian residential sector customers. The electricity rate for households with a 2,200 VA power contract (R1) is IDR 1,444.70 per kWh, while households with power of 3,500 VA or above (R2/R3) are charged IDR 1,699.53 per kWh [[54], [55]]. Assuming the exchange rate is IDR 15,000 per USD 1, this gives us USD 0.096 per kWh for 2,200 VA customers and USD 0.113 per kWh for 3,500-6,600 VA ones. The simulation, therefore, applies different electricity rates between 2,200 VA and higher segments.

The simulation also accounts for demand uncertainty by allowing for up to 5% day-to-day variability, i.e., the standard deviation in the sequence of daily averages, and up to 5% time-step-to-time-step variability, i.e., the standard deviation in the difference between the hourly data and the average daily profile, depending on the contract. This configuration results in a higher peak load than the surveyed households have. For example, a 2,200 VA household with 22 kWh/day and a peak load of 1.65 kW is simulated to have a peak load of 2.1 kW due to the 5% day-to-day and time-step-to-time-step variability. Aside from that, electricity demand is assumed to remain constant over the PV's lifetime. The complete system configuration models for all households in HOMER is illustrated in Figure 4.

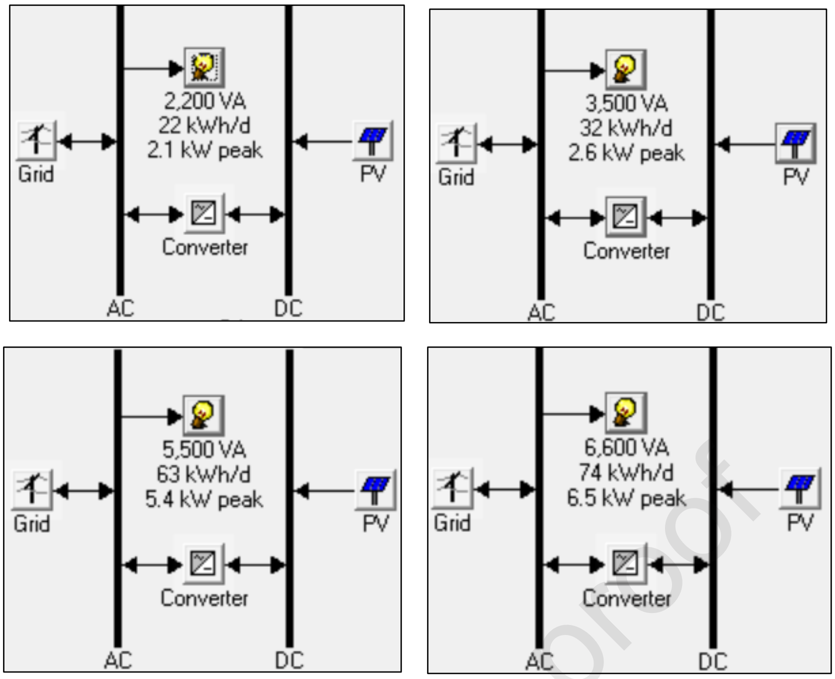

Figure 4. HOMER system configurations for residential households with 2,200 VA and 3,500 VA (top left to right), households with 5,500 VA and 6,600 VA (down left to right) electricity contracts.

Solar PV array and converter

Since the effect of temperature on the PV array is not considered, HOMER calculates the power output generated by the solar PV array P_{PV} according to the following equation.

$$P_{PV} = Y_{PV} \times f_{PV} \left(\frac{G_T}{G_{T,STC}}\right) \tag{1}$$

where Y_{PV} is the rated capacity of the PV array (kW), f_{PV} is the derating factor (%), G_T is the solar radiation incident on the PV array in the current time step (kW/m^2), and $G_{T,STC}$ is the incident radiation at standard test condition (1 kW/m^2).

In HOMER, the rated capacity of the PV array Y_{PV} is specified by users as one of the input variables to Eq. 1. Users can either enter at least one size of solar PV module and the capital cost associated with that particular size, for example, 2 kW, or in fractions, for example, 0.1 kW PV. If the second option were selected, the user must enter several PV module capacities in multiples of 0.1 kW to 2 kW or up to the maximum capacity considered. HOMER simulates possible supply configurations to meet hourly-based energy demand and displays the system's Y_{PV} in the simulation results. Therefore, if users enter Y_{PV} as fractions, the number of solar PV arrays N_{PV} can be obtained using the following equation.

$$N_{PV} = \frac{calc\_Y_{PV}}{frac\_Y_{PV}} \tag{2}$$

where cal_Y_{PV} is the calculated system's rated capacity of the PV array (kW), and $frac\_Y_{PV}$ is the fraction of the rated capacity of the PV entered by users (kW).

HOMER models a converter, or better known as an inverter, to convert DC electricity generated by solar PV arrays to AC electricity by considering the user-specified efficiency η of the inverter side.

HOMER calculates the performance of a converter on an annual basis according to the following equation.

$$\eta = \frac{kWh/year_{in}}{kWh/year_{out}} \quad (3)$$

where $kWh/year_{in}$ is the DC electricity generated by PV arrays (kWh/year), and $kWh/year_{out}$ is the AC electricity produced by inverter (kWh/year).

The expected converter life is 15 years, with 90% efficiency on the inverter side and 85% efficiency on the rectifier side. The converter-rated capacity candidates can be slightly higher than the solar PV capacity specified in the simulation search space, as HOMER does not consider the power factor of the load. Capital and replacement costs of the 1 kW converter are assumed to be USD 400 (IDR 6,000,000) [56] and USD 380 (IDR 5,700,000), respectively, without annual O&M costs. Capital and replacement costs are assumed to increase linearly concerning size.

This study assumes capital and replacement costs for the 0.1 kW peak PV module in Indonesia to be USD 50 each (equal to around IDR 750,000) [57], and no annual Operating and Maintenance (O&M) costs for the PV arrays. The cost of additional or replacement modules is assumed to increase linearly. The derating factor is considered 80%, and the ground reflectance is supposed to be 20%. Given an expected lifetime of 25 years, the PV arrays are installed without tracking. The slope is specified in the same degree as the location's latitude, 7.3°, while the azimuth is set at 180° (due North).

System economic

This study considers a project lifetime of 25 years and assumes an annual interest rate of 5%. Other important assumptions include system fixed capital cost and system fixed O&M cost. Considering the current total installed cost of solar PV for the Indonesian residential sector, i.e., USD 1,000/kW peak (IDR 15,000,000/kW peak) [[58], [59]], and the cost of solar PV modules and converters, the system fixed capital cost and the fixed O&M cost are set at USD 200 (IDR 3,000,000) [60] and USD 20/year (IDR 300,000/year), respectively.

In HOMER, the economic feasibility of the systems can be assessed by using total Net Present Cost (total NPC), Cost of Energy (COE), and operating costs. The total NPC, expressed in USD, is used in economic analysis to show the system's life cycle cost. It is calculated as follows.

$$C_{NPC} = \frac{C_{ann,tot}}{CRF(i, R_{proj})} \quad (4)$$

$$CRF(i, N) = \frac{i(1+1)^N}{(1+i)^N - 1} \quad (5)$$

where $C_{ann,tot}$ is total annualised cost (USD/year), CRF is capital recovery factor, i is interest rate (%), and R_{proj} is project lifetime (year).

HOMER defines COE as the average cost per kWh produced by the system. It is calculated by dividing the total annualised cost by the total electricity produced including total grid sales as follows.

$$COE = \frac{C_{ann,tot}}{E_{prim,AC} + E_{grid,sales}} \quad (6)$$

where $E_{prim,AC}$ the total electricity produced by all components of the system in a year, and $E_{grid,sales}$ is the total grid sales (electricity sold to the grid).

Operating costs, expressed in USD/year, are the sum of the annual O&M costs, and annualised replacement cost minus annualised salvage value. For grid-connected systems, it includes the annualised cost of electricity purchased from the grid minus electricity sold to the grid. While the term operating costs is useful in providing the user with some insights into the contribution of these types of costs on the total NPC and typically decreases at higher unserved energy, this study rules out the term operating costs in the analysis due to the focus of this study on analysing the possible trade-off between the system cost, which is already well represented by the total NPC, and unserved energy.

Scenarios and cases

This study considers two main scenarios in the simulation regarding the selection of solar PV-size candidates. The first scenario is called Maximum-PV-Capacity (MPVC). This basically refers to the maximum PV capacity a customer can install, i.e., up to the power (VA) contracted by a household, as per Ministerial Regulation No. 26/2021. For example, a household with 2,200 VA contracted power can install PV panels up to 2.2 kW peak capacity. In this case, the simulation considers up to 2.2 kW peak PV capacity in 0.1 kW PV arrays. This scenario considers PV sizes of up to 3.5 kW peak, 5.5 kW peak, and 6.6 kW peak for households with 3,500 VA, 5,500 VA, and 6,600 VA, respectively. HOMER simulates these size candidates and the fraction of electricity purchased from the grid. The optimisation will result in a system configuration with the least total NPC and other alternatives that exhibit higher total NPC.

The second scenario is called Half-PV-Capacity (HPVC). Under this scenario, simulations use up to half the maximum allowable PV capacity. For example, simulations for possible system configurations for a 2,200 VA household consider up to 1.1 kW peak capacity in 0.1 kW PV arrays. Other simulations for households with 3,500 VA, 5,500 VA, and 6,600 VA are carried out considering PV capacity of up to 1.75 kW peak, 2.75 kW peak, and 3.3 kW peak, respectively. This scenario is based on the low load during the day for all households, i.e., between 7 a.m. and 4 p.m. This study assesses the total NPC from both MPVC and HPVC scenarios for all household segments.

This study considers up to four cases for each household segment, i.e., 100%-MPVC, 100%-HPVC, 65%-MPVC, and 65%-HPVC. In this regard, either 100% or 65% refer to the applicable deduction factor according to the regulations mentioned earlier in Section 2. In other words, there are two cases for each scenario. The MPVC scenario consists of 100%-MPVC and 65%-MPVC, while the HPVC scenario consists of 100%-HPVC and 65%-HPVC.

4. Results and Discussion

Table 3 to Table 5 highlight the main results regarding important techno-economic aspects for all the cases considered in a 2,200 VA household. In the 100%-MPVC cases, the total NPC has reached USD 9,175 for 0% maximum unserved energy (no-unserved energy) and has declined to USD 7,987 or 13% for up to 11% simulated unserved energy. As for no-unserved energy, the total NPC has increased to USD 10,031, USD 10,371, and USD 10,661 for the 65%-MPVC, 100%-HPVC, and 65%-HPVC cases, respectively.

All the total NPC of 100%-MPVC is found to be the cheapest among other cases considering all unserved energy. From the simulations, it is revealed that the total NPC of 100%-MPVC with no-unserved energy is USD 9,175, cheaper than the total NPC of 65%-MPVC with 7% unserved energy and of HPVC cases with 11% unserved energy. The simulation results have implied potential benefits of rooftop PV installation up to the maximum permitted capacity and concerning a 100% billing deduction scheme for households

with 2,200 VA, considering different options regarding unserved energy, installed capacity, and percentage of billing deduction.

As shown in Table 3 to Table 6, renewable energy's contribution to electricity generation has reached 33-36% share in the cases of MPVC and 19-21% share in the cases of HPVC within the range of 11% unserved energy. As expected, reducing the installed capacity of PV modules to half the maximum allowable capacity will decrease PV penetration in the systems.

Table 3. Simulation results for 2,200 VA: 100%-MPVC

Maximum annual unserved energy (%)	PV (kW)	Converter (kW)	Grid (kW)	Initial Capital (USD)	Total NPC (USD)	COE (USD/kWh)	RE share (%)	Unserved energy (%)
0	2.2	1.5	1.8	1,900	9,175	0.081	33	0
5	2.2	1.5	1.4	1,900	8,796	0.081	34	4
10	2.2	1.5	1.3	1,900	8,446	0.080	35	7
15	2.2	1.5	1.2	1,900	7,987	0.079	36	11

Table 4. Simulation results for 2,200 VA: 65%-MPVC

Maximum annual unserved energy (%)	PV (kW)	Converter (kW)	Grid (kW)	Initial Capital (USD)	Total NPC (USD)	COE (USD/kWh)	RE share (%)	Unserved energy (%)
0	2.2	1.5	1.8	1,900	10,031	0.089	33	0
5	2.2	1.5	1.4	1,900	9,652	0.088	34	4
10	2.2	1.5	1.3	1,900	9,302	0.088	35	7
15	2.2	1.5	1.2	1,900	8,842	0.088	36	11

Table 5. Simulation results for 2,200 VA: 100%-HPVC

Maximum annual unserved energy (%)	PV (kW)	Converter (kW)	Grid (kW)	Initial Capital (USD)	Total NPC (USD)	COE (USD/kWh)	RE share (%)	Unserved energy (%)
0	1.1	1.0	1.8	1.150	10,371	0.092	19	0
5	1.1	1.0	1.4	1.150	9,987	0.092	20	4
10	1.1	1.0	1.3	1.150	9,636	0.091	21	7
15	1.1	1.0	1.2	1.150	9,177	0.091	21	11

Table 6. Simulation results for 2,200 VA: 65%-HPVC

Maximum annual unserved energy (%)	PV (kW)	Converter (kW)	Grid (kW)	Initial Capital (USD)	Total NPC (USD)	COE (USD/kWh)	RE share (%)	Unserved energy (%)
0	1.1	1.0	1.8	1,150	10,661	0.094	19	0
5	1.1	1.0	1.4	1,150	10,277	0.094	20	4
10	1.1	1.0	1.3	1,150	9,926	0.094	21	7
15	1.1	1.0	1.2	1,150	9,467	0.094	21	11

The optimisation results presented in Table 3 to Table 6 also provide customers with another insight into the potential role of the system cost components in shaping the cost-reliability trade-off. While the initial capital costs are of course found to be lower in HPVC cases compared to those in MPVC due to less PV array involved, i.e., USD 1,150 versus USD 1,900, it is found that the total NPC of MPVC cases are found to be cheaper than those of HPVC cases within the same unserved energy.

From the simulation results in 100%-MPVC cases, for example, it is found that 4% unserved energy is equal to 283 kWh/year of unmet electricity, while 7% and 11% unserved energies are equal to 542 kWh/year and 881 kWh/year, respectively. On the other hand, the total NPC of this particular case has shown a noticeable decrease of around USD 350 – USD 450 for every 3-4% additional unserved energy.

Table 7 to 10 shows the trade-offs between the total NPC, as expressed in annual total cost (USD/year), and unserved energy (kWh/year) of all simulations for a 2,200 VA household. The optimisation results show cheaper total annual costs as unserved energy increases. In addition, MPVC cases have shown more affordable yearly costs due to fewer energy charges (electricity bills) spent by the customers compared to those of HPVC.

It is of importance to observe the simulation results in terms of a range of shares of energy charge to the total (annual) cost of the systems. As presented in Table 7 to Table 10, all optimisation results in MPVC cases have shown lower shares of energy charge to the (annual) total cost compared to those in HPVC ones. It is found that the averaged shares of energy charge to the total cost are 70% and 74.6% for 100%-MPVC and 65%-MPVC, respectively, versus 83.9% and 84.3 for 100%-HPVC and 65%-HPVC, respectively.

As the finding compares MPVC and HPVC scenarios, it highlights the potential benefits of higher PV penetrations in reducing the energy charge component's share of the total annual cost within the same unserved energy range. In this regard, the lower applicable billing deduction factor indicates the smaller revenue that a customer can expect within the same scenario, which, of course, has an impact on the higher portion of energy charge in the total annual cost. While this paper highlights particular results for a 2,200 VA surveyed household, similar implications as obtained in Table 7 are also expected to occur for other households considered in this study, given the similarity of the households' daily load profiles.

Table 7. Trade-offs between annualised total cost and unmet energy for a 2,200 VA household

Scenario	Unserved energy (%)	Unmet energy (kWh/year)	Annual energy charge (USD/year)	Annualised total cost (USD/year)	Share of energy charge to total cost (%)	Averaged share of energy charge to total cost (%)
100%-MPVC	0	0	481	651	73.8	70
	4	283	454	624	72.8	
	7	542	429	599	71.6	
	11	881	396	567	69.8	
100%-HPVC	0	0	624	736	84.8	83.9
	4	287	597	709	84.2	
	7	546	572	684	83.6	
	11	886	539	651	82.8	
65%-MPVC	0	0	541	712	75.9	74.6
	4	283	515	685	75.2	
	7	542	490	660	74.2	
	11	881	457	627	72.9	
65%-HPVC	0	0	645	756	85.3	84.3
	4	287	617	729	84.6	
	7	546	592	704	84.1	
	11	886	560	672	83.3	

Figure 9 and Figure 10 depict the cost-reliability trade-offs in terms of total NPC versus unserved energy for all cases in 2,200 VA and 3,500 VA, as well as 5,500 VA and 6,600 VA households,

respectively. From the simulation results presented in Figure 9 and Figure 10, the total NPC of 100%-MPVC cases is the cheapest in every unserved energy. The finding indicates a comparative benefit of on-grid rooftop PV systems installing maximum PV capacity permitted combined with higher billing deduction factors (here is 100%) over other configurations. Moreover, there is a relatively large difference in total NPC between the 100%-MPVC cases and the 65%-MPVC cases concerning all unserved energies up to a 15% maximum annual unserved energy constraint, while insignificant differences of the total NPC are found between those in the 100%-HPVC cases and the 65%-HPVC cases, particularly in 3,500 VA and 6,600 VA households.

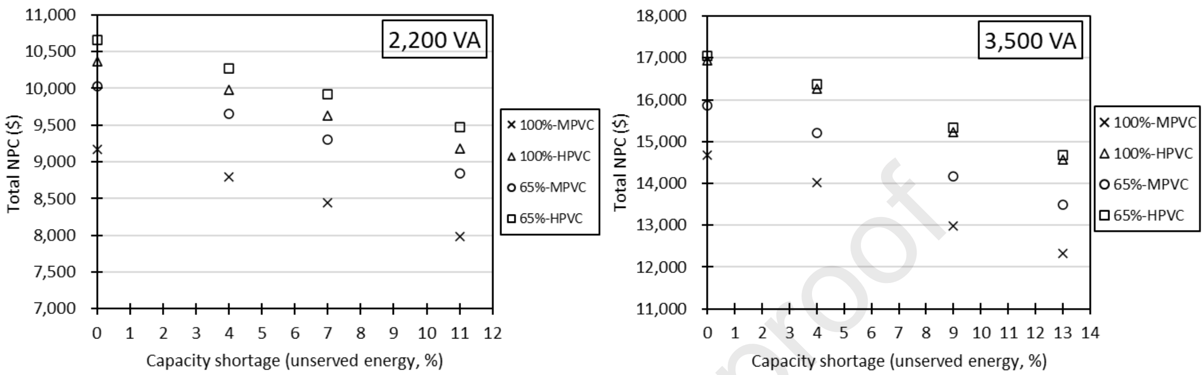

Figure 9. Total NPC versus unserved energy in all cases for 2,200 VA (left) and 3,500 VA (right)

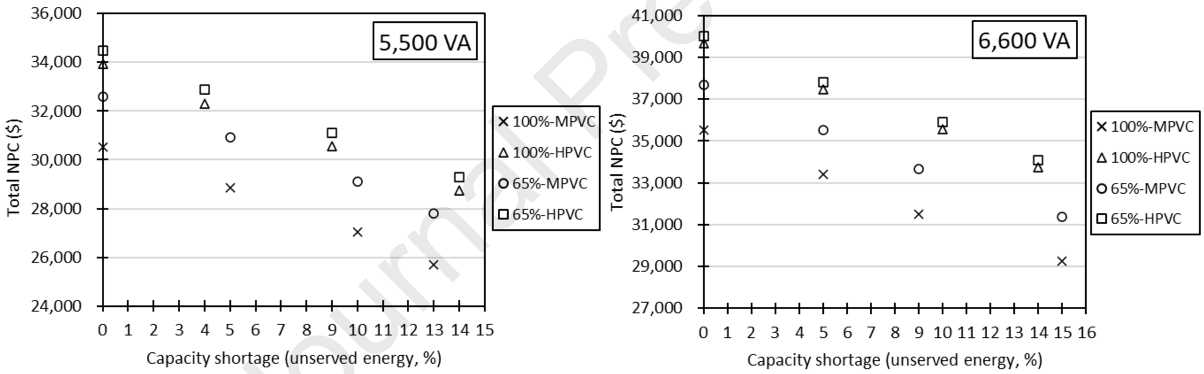

Figure 10. Total NPC versus unserved energy in all cases for 5,500 VA (left) and 6,600 VA (right)

Residential customers can further estimate one of the important indices for rooftop PV installation decision-making, i.e., the cost per MWh consumed (USD/MWh). Using 100%-MPVC cases in a 2,200 VA household as illustrations, and given the cost is the total NPC, as presented in Figure 9, the costs per MWh consumed during the project lifetime for 0%, 4%, 7%, and 11% unserved energies are USD 37.19/MWh, USD 36.70/MWh, USD 36.22/MWh, and USD 35.54/MWh, respectively, provided the total MWh consumed over the 25-year project lifetime are 246.68 MWh, 239,68 MWh, 233.20 MWh, and 224.73 MWh, respectively for the associated unserved energies.

From this particular analysis, it is found that, despite a considerably large difference in terms of total NPC between the system with no-unserved energy and that with the poorest reliability (USD 1,188 difference), the cost per MWh figures have shown a relatively small gap of cost difference during the project lifetime, i.e., USD 1.65/MWh, between no-unserved energy and 11% unserved energy.

In addition to merely exploring and comparing economic parameters such as total NPC, the share of energy charge to total annual cost, and COE, it is also of interest to assess the potential economic impact of the systems in terms of cost per watt of PV installed, i.e., through exploring which households exhibit the lowest cost per watt of PV installed capacity. The cost per watt of PV installed

can be used as one of the indicators for customers in deciding the capacity of PV to be installed while considering possible techno-economic scenarios, including the potential impact of applicable billing deduction factors and a range of different unserved energy.

The lowest cost per watt of PV installed capacity can be obtained for all scenarios by comparing the total system cost (total NPC) with the PV installed capacity. Table 8 presents variations in cost per watt of PV installed capacity for all the optimisation results of 100%-MPVC and 65%-MPVC, as well as 100%-HPVC and 65%-HPVC given no-unserved energy (0% maximum unserved energy), while Tables 9 to 11 present variations of the cost per watt of PV installed capacity considering 5%, 10%, and up to 15% maximum unserved energy, respectively.

Table 8. The cost per watt of PV installed capacity with 0% maximum unserved energy.

Household	The cost per watt of PV installed capacity ($/Watt)			
	100%-MPVC	65%-MPVC	100%-HPVC	65%-HPVC
2,200 VA	4.17	4.56	9.43	9.69
3,500 VA	4.20	4.53	9.68	9.74
5,500 VA	5.55	5.93	12.34	12.54
6,600 VA	5.39	5.71	12.02	12.12

Table 9. The cost per watt of PV installed capacity with 5% maximum unserved energy.

Household	The cost per watt of PV installed capacity (USD/Watt)			
	100%-MPVC	65%-MPVC	100%-HPVC	65%-HPVC
2,200 VA	3.99	4.39	9.08	9.34
3,500 VA	4.00	4.34	9.30	9.36
5,500 VA	5.24	5.62	11.75	11.95
6,600 VA	5.06	5.39	11.36	11.46

Table 10. The cost per watt of PV installed capacity with 10% maximum unserved energy.

Household	The cost per watt of PV installed capacity (USD/Watt)			
	100%-MPVC	65%-MPVC	100%-HPVC	65%-HPVC
2,200 VA	3.84	4.23	8.76	9.02
3,500 VA	3.71	4.05	8.71	8.77
5,500 VA	4.91	5.29	11.11	11.31
6,600 VA	4.78	5.10	10.78	10.88

Table 11. The cost per watt of PV installed capacity with 15% maximum unserved energy.

Household	The cost per watt of PV installed capacity (USD/Watt)			
	100%-MPVC	65%-MPVC	100%-HPVC	65%-HPVC
2,200 VA	3.63	4.02	8.34	8.61
3,500 VA	3.52	3.86	8.32	8.38
5,500 VA	4.68	5.06	10.45	10.65
6,600 VA	4.43	4.76	10.23	10.33

As shown in Table 8, the total NPC per watt of PV installed capacity, under 0% unserved energy, varied from USD 4.14/Watt to USD 12.54/Watt in all cases across all households. The results show similar costs in the MPVC cases concerning 2,200 VA and 3,500 VA households, slightly more than double in the HPVC cases, and similar for 5,500 VA and 6,600 VA households. It is also found that the results are not affected by the applicable billing deduction factors but simply by the PV capacity. Nevertheless, it should be noted that the results obtained in Tables 8 to 11 are largely influenced by the household's daily electricity load profile and other applied scenarios.

The simulation results in terms of possible system capacity, consisting of grid and PV capacity across all unserved energy in all cases of all households, are depicted in Figure 11 and Figure 12.

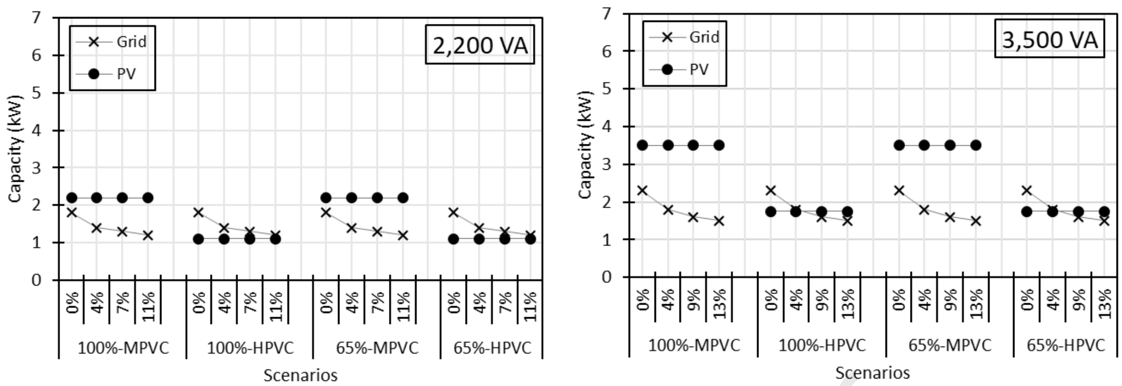

Figure 11. System capacity across all unserved energies for 2,200 VA (left) and 3,500 VA (right)

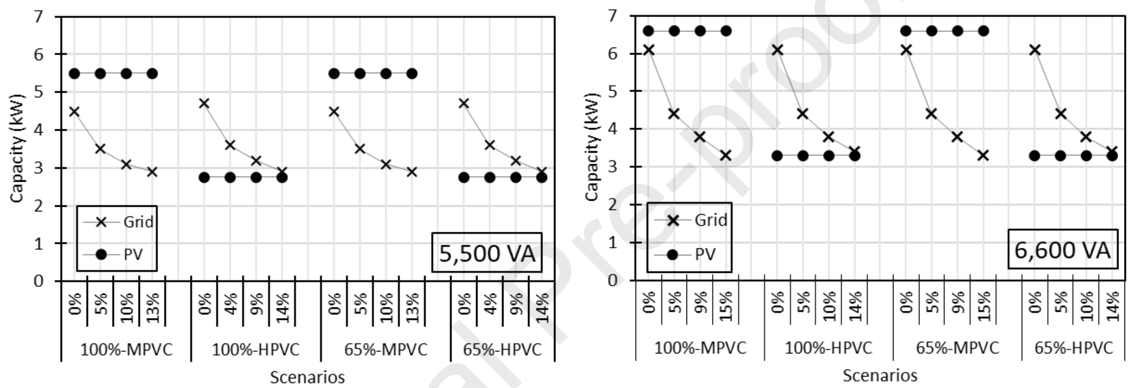

Figure 12. System capacity across all unserved energies for 5,500 VA (left) and 6,600 VA (right)

As seen in Figures 11 and 12, higher unserved energy has resulted in lower grid capacity required by the system to meet the demand according to the system's maximum unserved energy constraint, and the PV capacities are maximised across all unserved energies in different scenarios. Moreover, it is interesting to note that the PV capacities across all MPVC cases are always higher than the grid ones. On the other hand, the grid capacities are mostly higher than those of PV in most HPVC cases, except in 3,500 VA for 9% unserved energy and beyond. In all cases, the grid capacities have similarly decreased within the unserved energy range. For example, in 2,200 VA (see Figure 11 left), the grid capacities are found at 1.8 kW, 1.4 kW, 1.3 kW, and 1.2 kW for 0%, 4%, 7%, and 11% unserved energy, respectively, and similarly in other households.

A sensitivity analysis of the techno-economic factors influencing system performance would benefit stakeholders, particularly residential customers. While focusing on system reliability, this study uses only a 5% annual interest rate and fixed electricity rates associated with household segments. As a result, the sensitivity variable used in HOMER is maximum annual unserved energy.

Taking a 2,200 VA household with 100%-MPVC as an example, a graphical sensitivity result depicting possible trade-offs on total NPC versus unserved energy fraction and a sensitivity result of net grid purchases (electricity purchased from the grid minus electricity sold to the grid) versus maximum annual unserved energy are presented in Figure 13 and Figure 14, respectively. Meanwhile, a sensitivity result of total NPC versus total electricity production is shown in Figure 15.

Maximum annual unserved energy constraints have varying effects on total NPC, total electricity production, and nett grid purchases. As shown in Figure 13, total NPC cannot be less than USD 8,500

when unserved energy is kept at or below 6%. According to Figure 15, a 10% unserved energy would result in approximately 9,700 kWh/year of electricity production, which would equal approximately USD 8,500 in total NPC.

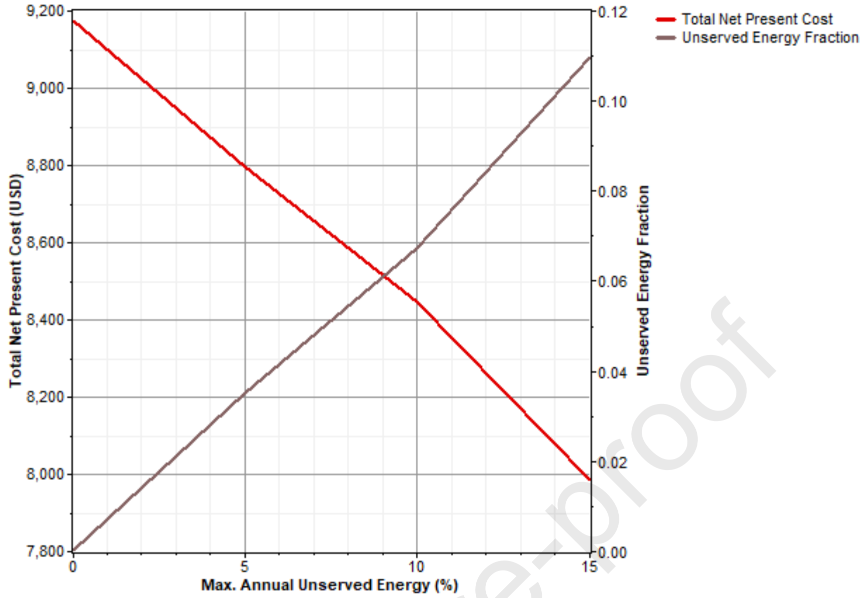

Figure 13. Sensitivity result of total NPC versus unserved energy fraction in a 2,200 VA household with 100%-MPVC.

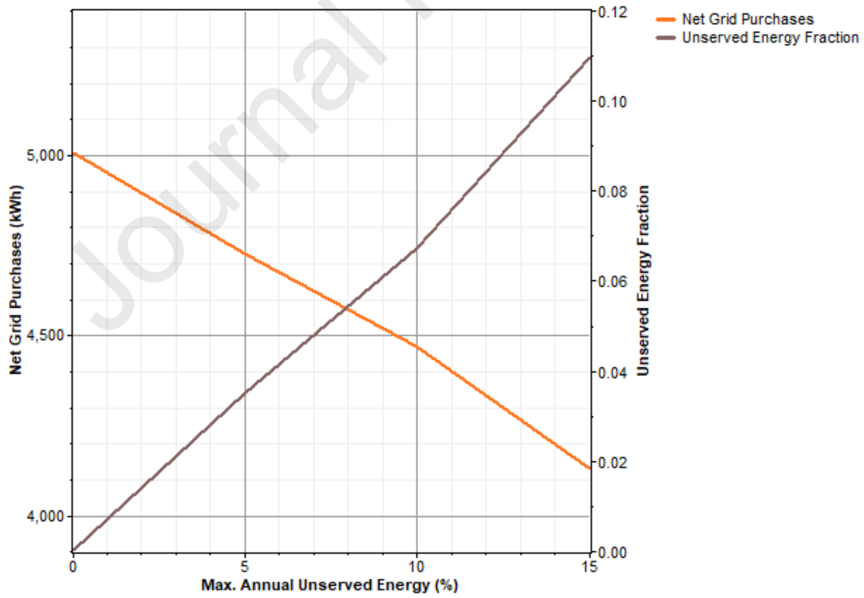

Figure 14. Sensitivity result of net grid purchases versus maximum annual unserved energy in a 2,200 VA household with 100%-MPVC.

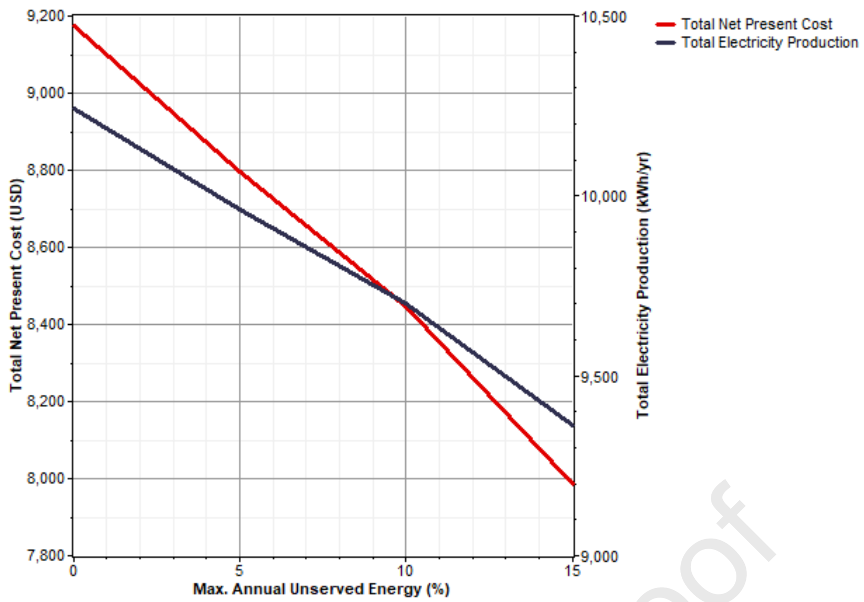

Figure 15. Sensitivity result of total NPC versus total electricity production in a 2,200 VA household with 100%-MPVC.

Despite possible variations and differences in households' daily loading profiles along with other affecting factors, which, of course, may provide different results and interpretations, this study has sought to explore possible cost-reliability trade-offs in Indonesia's urban residential grid-connected rooftop PV due to three key factors, namely potential unserved energy, PV capacity, and possible billing deduction scheme. The significance of these factors has been shown in the analysis considering different residential household segments, and therefore, should be considered not only by customers who are willing to apply on-grid rooftop PV but also by stakeholders such as government and utility companies according to their role in supporting more grid-connected rooftop PV capacity.

5. Conclusions

This paper explores the potential of grid-connected rooftop PV systems in terms of how they can be better planned and utilised by understanding the possible trade-offs between system reliability and cost while recognising challenges related to electricity supply security in the context of emerging economies. The effects of various unserved energy limits, PV capacities, and billing deduction factors (modelled in HOMER using different sell-back rates) on the systems' techno-economic parameters have been investigated in order to better understand possible cost-reliability trade-offs for total NPC and unserved energy. The analyses are carried out with the help of HOMER, with four different residential household segments in Surabaya, Indonesia, serving as a case study.

In all four cases of each household segment, i.e., 100%-MPVC, 65%-MPVC, 100%-HPVC, and 65%-HPVC, the optimisation results show reliability-cost trade-offs between the total NPC and all unserved energies. Furthermore, the role of cost components in the trade-offs between HPVC and MPVC cases in terms of initial capital costs and total NPC was highlighted in the analyses. The findings revealed a relatively large difference in total NPC for all households between 100%-MPVC cases and 65%-MPVC cases for all unserved energies, while differences between those in 100%-HPVC cases and 65%-HPVC cases are insignificant. The simulation results implied potential benefits of rooftop PV installation up to the maximum permitted capacity and a 100% billing deduction scheme for households with 2,200 VA, taking into account different options for unserved energy, installed capacity, and billing deduction percentage.

Among the significant results of this study that highlight the benefits of grid-connected rooftop PV are the following: 1) higher renewable energy penetration for MPVC systems compared to HPVC systems regardless of the billing deduction factors; 2) cheaper total NPC are shown by MPVC cases than those of HPVC cases within the same unserved energy; 3) lower shares of energy charge to the annual total cost in MPVC cases compared to those in HPVC ones; and 4) Over the project lifetime, the cost per kWh consumed (USD/MWh consumed) showed only a slight variance between the system with no-unserved energy and the system with the poorest reliability, given 100%-MPVC cases in 2,200 VA as an example; 5) All households with a 15% maximum limit on unserved energy have the lowest costs per watt of installed PV capacity, and these costs are unaffected by billing deduction factors; 6) based on the system's maximum unserved energy limits, higher unserved energy has led to a decrease in the amount of grid capacity needed by the system to meet demand, and the PV capacities are maximised across all unserved energies in various scenarios; and 7) Sensitivity analyses have revealed a range of impacts of maximum annual unserved energy constraints on various parameters, including total NPC, total electricity production, and net grid purchases.

When it comes to grid-connected rooftop PV, residential customers must be thoughtful, as there are potential trade-offs between cost and reliability. At the same time, attention must be paid to changing regulations that may have an impact on overall profitability. This study's analyses provided important findings and insights not only to the residential customers but also to stakeholders involved in the planning and implementation of rooftop PV policies.

Finally, there is no doubt about the grid-connected rooftop PV's techno-economic potential for accelerating distributed renewable energy penetration. Nonetheless, because rooftop PV deployment appears to be modest, especially in Indonesia, changes to the existing set of regulations are required. More encouraging, innovative policies should be introduced to address the barriers and challenges that customers and the industry face in moving rooftop PV deployment forward.

Acknowledgement

The author would like to thank the reviewers for their time and effort in reviewing the manuscript. All valuable comments and suggestions for improving the manuscript's quality are greatly appreciated.

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Highlights:

- Cost-reliability trade-offs are assessed for grid-connected rooftop PV models.
- Reliability is expressed in HOMER optimisation by capping annual unserved energy.
- Impacts of unserved energy targets, PV capacity, and sell-back rates are examined.
- Cheaper net present costs are achieved by systems with maximum PV capacity.
- Higher unserved energies lowered the costs per watt of PV installed capacity.

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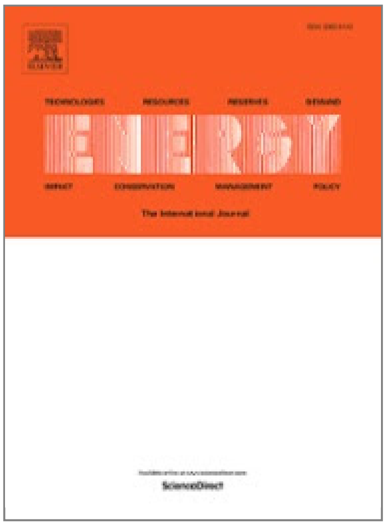

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