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A Cost-Effective and Transferable Methodology for Rooftop PV Potential Assessment in Developing Countries

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Abstract: The efficient uptake of decentralized solar rooftop photovoltaics (PV) is in some cases hindered by ineffective energy and political framework conditions. These may be based on inaccurate and uncertain potential assessments in the early development stage of the solar market. This paper develops a more accurate, cost-effective, and robust potential assessment for emerging and developing economies. Adjusting the module efficiency corresponding to regional and household conditions improves the output accuracy. The rooftop PV market changes are simulated regarding different input changes and policy designs, including changing the Feed-In Tariff (FIT), grid tariff, and technology development. In the case study, the market potential in Vietnam is estimated at 260–280 TWh/a and is clustered into six groups in priority order, in which Hanoi and Ho Chi Minh need the most policy focus. Changing the FIT from 8.83 to 9 Euro cent/kWh and using different regional FITs can activate an additional 16% of the market and lead to a possible 28 million Euro benefit. Increasing the grid tariff to 8.7 cents/kWh could activate the self-consumption model, and the self-sufficient market can be guaranteed in the case of CAPEX and OPEX being lower than 650 Euro/kWp. Future developments of the method should focus on combining this top-down method with detailed bottom-up approaches.

Keywords: rooftop PV; resource assessment; renewable support policies; self-consumption; developing countries

1. Introduction

Renewable energy technologies have gained momentum in cost competition with conventional thermal electricity generation and have become significant in the global electricity transition. They had a share of 14% in global electricity generation by 2018, with around 53% of all renewable energy investments in developing and emerging economies [1]. In the countries concerned, distributed solar PV systems not only play a prominent role in spreading energy access to households in remote areas [1] but also promise an effective alternative to serving the highly increased urban electricity demand [2–4].

Many sub-national governments have become leaders of solar development by setting even more ambitious targets than their national counterparts [1]. However, national and local governments in the countries are dependent on generic rooftop PV assessments. These assessments often have a rather low accuracy, which could direct investors into suboptimal locations and configurations [5,6]. As a result, the diffusion of PV power projects is spatially heterogeneous between the different regions in a country [7–9]. If the development goes in one direction only, this could have a far-reaching impact on both grid and market congestion [9–12]. To avoid this, policymakers urgently need a superior method

to provide their market with transparent targets and stable policies so that the market will continue growing without threatening the stability of national electricity systems.

Previous studies focus on investigating rooftop areas for solar PV with many different methodologies such as GIS [13–17], 3D models [18–20], and LIDAR technology [16,19,21–23]. The 3D model is the most advanced and accurate method that allows the digitization of features, followed by simulations of insolation and shading of buildings [5,18–21]. However, it is challenging to employ this approach at the national level in developing countries because their data conditions and financial budgets will take years to reach the sufficiency for 3D model estimation.

In this context, this paper proposes an accurate, cost-effective, and transferable potential assessment method with a geostatistical approach across cities to assist policymakers in assessing their local and national rooftop PV potential. The proposed method is suitable for application in a country with unfavorable data conditions and a meager investment budget for conducting a high-resolution assessment. To improve the accuracy of the technical assessment, this paper adjusts solar irradiation and corrects the module efficiency of the PV system corresponding to the geographic and climate conditions, as well as dwelling design. A novel approach to control model accuracy is introduced by identifying and classifying the impact level of the uncertain parameters used in this paper. Considering the findings, we build different scenarios to observe market reactions as a result of various technological, investment, and policy changes. The paper comprehensively presents a three-step model, which is instantly applicable to different levels of detail of rooftop PV potential assessment and policy design, such as sub-regional, regional, and national scales. This model is used for deploying the rooftop PV potential strategically, and for preventing aggressive local development and structure-inherent rooftop PV conflicts between different regions. The results provide a more realistic picture of the medium-term growth and the interaction of various impacts, e.g., technology and policy changes, on the rooftop PV market in the considered country.

The paper is structured into six sections. Section 2 provides a succinct comparison between different levels of spatial resolution techniques and points out the advantages of our methodology. The detailed method is described in Section 3, including the methodology flow chart, methods for geographical, technical, and economic potential assessments as well as the case study. Section 4 reports the study results, and Section 5 contains the discussion and suggestions for policymakers based on shifting and bending market distribution under different possible framework conditions. The final section is the conclusion and outlook.

2. Literature Review of Potential Assessments for Rooftop PV

The studies of photovoltaic energy potential assessment can be categorized into three groups: low-, medium-, and high-level spatial resolution techniques [24,25]. Low-level assessment is usually based on statistical data, which are supposed to be homogeneous throughout the investigated area [24,26]. It can be employed on a large scale, e.g., many cities all around the world, based on the correlation between solar insolation and population density. However, due to the uneven distribution of population and buildings between different areas, this type of assessment provides poor quality and inaccurate results due to the general assumptions.

The existing medium-resolution assessment is claimed to be inaccurate for tailored policy designs [24]. Because they are faced with the uncertainty caused by using many assumptions due to data deficiency [27], their outputs tend to vary widely from 16% to 207% when compared with other resolution assessments over the same geographies [5,6]. To conquer the uncertain and applicable issues, studies in this field usually focus on developing high-level assessments on a small scale, e.g., for buildings [18,21,22] or district(s) [5], to avoid inaccurate results. When studying a larger scale, e.g., at city-level or multi-cities level, researchers are limited to estimating only geographic potential based on different assumptions such as roof area available [15,26,28,29], land use data [8,26], and type of building [26]. Some studies investigate the technical potential [14,16,30], but detailed uncertainty analyses to measure the error are not covered.

To calculate a high-resolution PV potential, previous studies have used advanced and accurate technologies such as 3-D models to calculate geometry, insolation, and shading of buildings [5,18–21]. Even though the methods are more precise, the main barrier to employing them at national and international scales is the associated challenge of an exponentially increasing number of uncertain parameters with an increase in the sample size or studied space. This leads to computationally intensive models and expensive data collection [25], especially for 3D models [18–20] or solar detective models [31]. Therefore, these methods are not currently economically viable for developing countries [24,27].

This paper provides a less costly and more accurate solution that is able to cover a large scale by estimating rooftop PV potential for each region corresponding to its climatic, geographic, and demographic conditions. The available roof for installing solar PV and the expected electricity production are calculated based on housing characteristics such as the type of roof, the azimuth of the building, and the roof. Statistical data and previous research results are used to determine housing architecture. Uncertainty in the data coming from the natural variability of the data generating, measuring, and sampling processes is then simulated by using an iterative process. The results of the simulation are the output distributions (Section 5.3). The details of the method are presented in Section 3.

3. Methodology for Rooftop PV Potential Assessment

Figure 1 describes the method of PV potential assessment proposed in this paper. The outputs of each step are highlighted in blue, and the dark blue arrows show the direction of the mathematical flow. Input data are collected from (*) national/international statistical sources, (**) the assumptions based on previous studies, and/or (***) a collection from manufacturers’ catalogues. The iterative process to create datasets are represented by orange arrows. There are in total four different loops numbered in Figure 1.

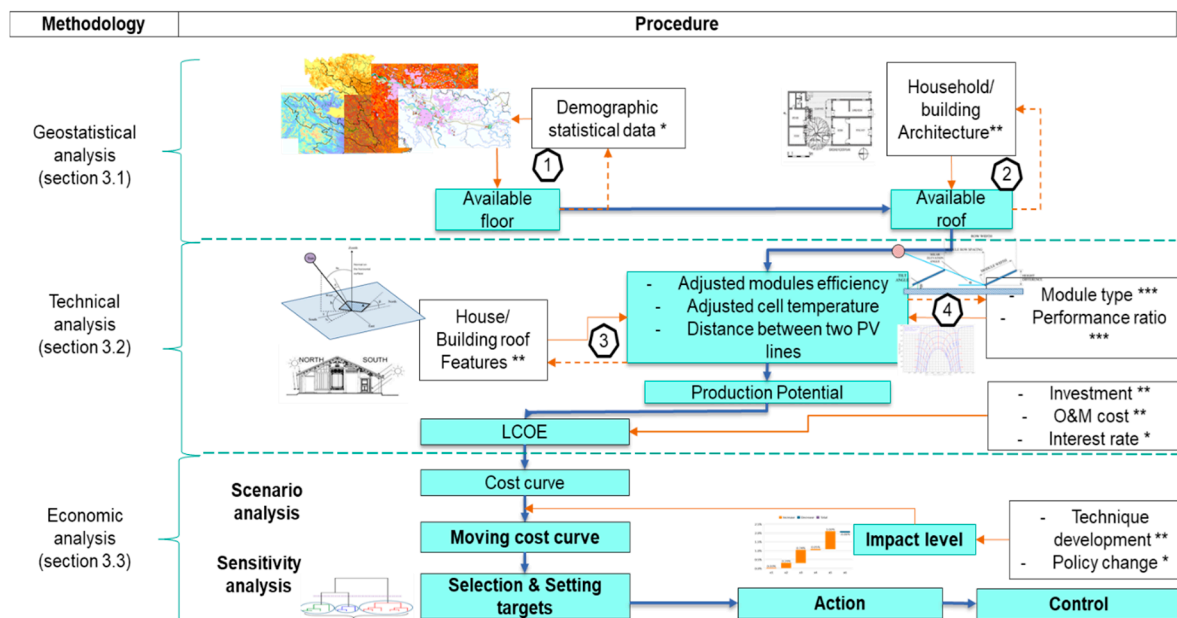


Figure 1. Methodology flow chart of the proposed potential assessment model for rooftop PV. Pictures are own illustrations, based on sources for Figures 2–5 and reference [32].

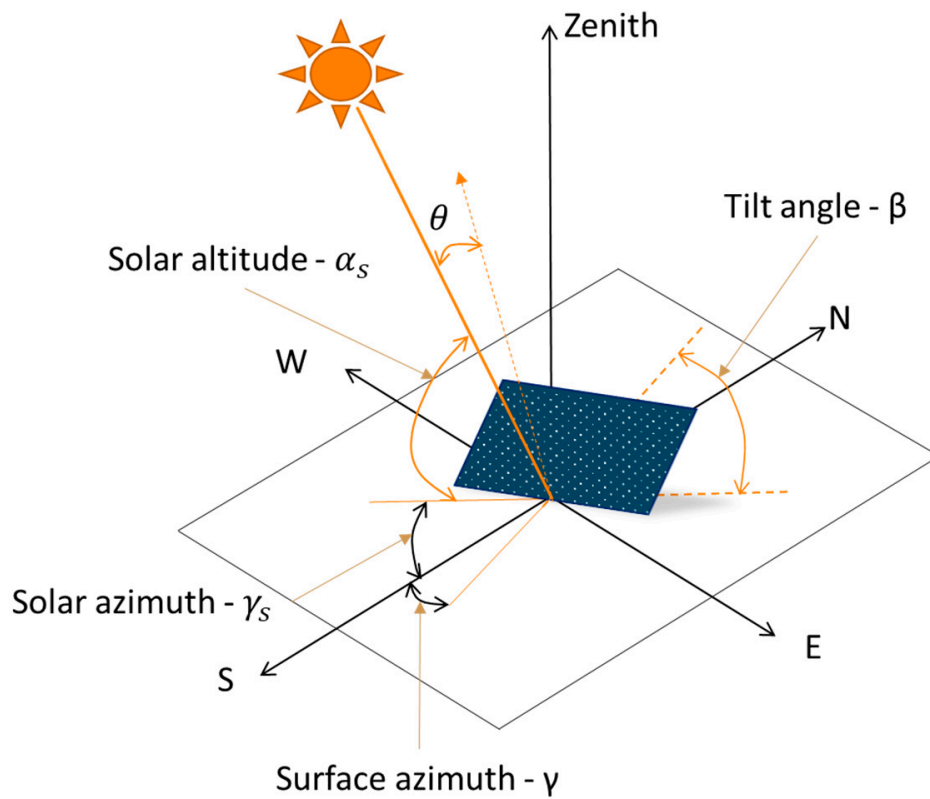


Figure 2. Solar and PV module characteristic angles. Reproduced with permission from the authors of “Submerged and Floating Photovoltaic Systems”, Copyright Elsevier Science Publishing Co Inc., 2018 [33].

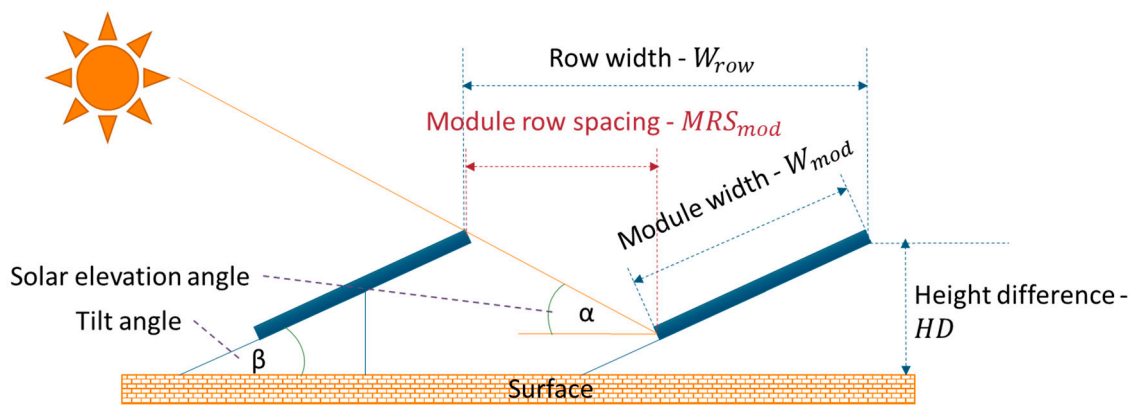


Figure 3. Schematic of two simulated photovoltaic rows at solar noon. Reproduced with permission from the authors of “Submerged and Floating Photovoltaic Systems”, Copyright Elsevier Science Publishing Co Inc., 2018 [33].

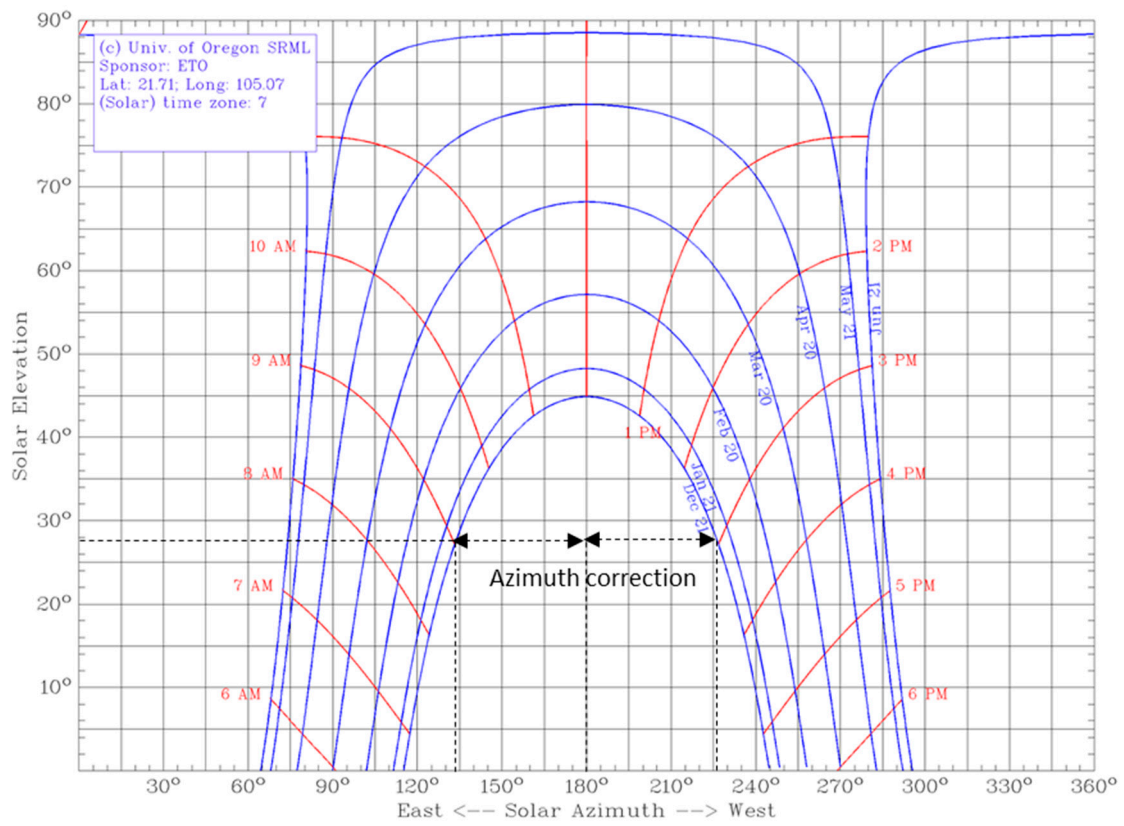


Figure 4. Example of the Cartesian plot of the sun path chart for North Vietnam. Adapted with permission from the Solar Radiation Monitoring Laboratory, University of Oregon, 2015. <http://solardat.uoregon.edu/SunChartProgram.html>.

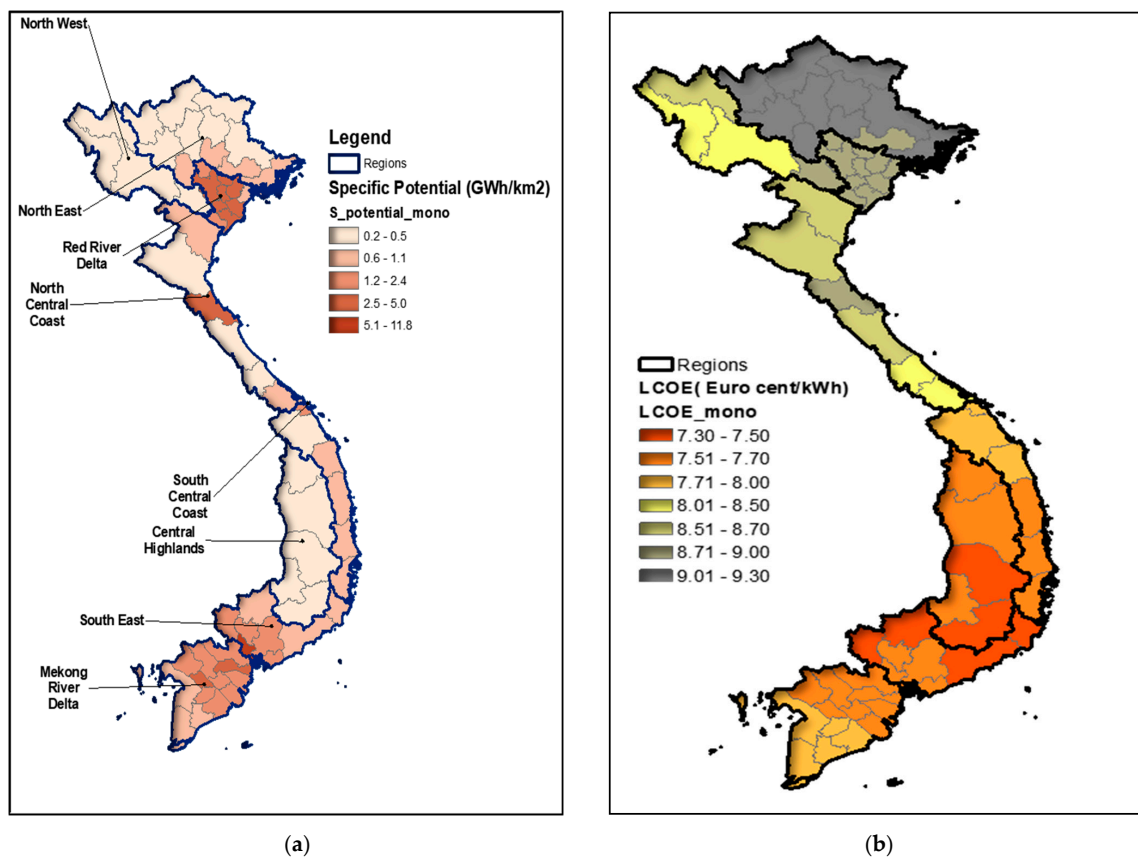


Figure 5. Maps of distributed electricity potential (a) and average LCOE (b) of rooftop PV by regions. Please refer to the online version of the article for references to color in this figure. Detailed region and province can be found in Figure A2. Detailed maps are extracted from the library of The University of Texas at Austin. <http://legacy.lib.utexas.edu/maps/topo/vietnam/>. Latest access on 20.05.2019.

The method proposed in the paper consists of three steps. The first step is determining the geographical potential using ArcGis and geostatistical analysis (Section 3.1), which is proposed in previous studies [25]. The second step is identifying the technical potential (Section 3.2), in which the authors improve the assessment accuracy by determining the electricity output of the solar cell regarding the expected operating temperature of the PV module and the corresponding solar cell efficiency for the specific considered region. The last step is the economic and sensitivity analyses (Section 3.3). Section 4 presents data, assumptions and results for our case study, which is used to illustrate the methodology proposed.

3.1. Geographical Potential

In the case of unavailable high-resolution street maps, household data from government statistical offices can be used to calculate the available roof area for PV installation A_{roof} (m²) for detached houses and apartment buildings. Equation (1) is suggested based on previous studies [25].

$$\begin{aligned}
 A_{roof} &= S_{roof} \times \mu \times \frac{1}{\cos(\nu)} \\
 &= \begin{cases} \text{Detached house} : S_F \times (1 - b_1) \times \mu \times \frac{1}{\cos(\nu)} \\ \text{Apartment building} : \left(S_F \times \frac{n_A}{F} \right) \times (1 - b_1 + b_2) \times \mu \times \frac{1}{\cos(\nu)} \end{cases} \quad (1)
 \end{aligned}$$

The total roof area, S_{roof} (m²), is calculated by subtracting the exterior area, b_1 (percent of total roof area), such as garden, back yard, etc., and adding the interior area, b_2 (percent of total roof area),

such as stairway, corridors, etc. for an apartment building, to the ground area of a household S_F (m^2). For apartment buildings, $\frac{n_A}{F}$ is the average number of apartments, n_A , in a building on one floor, F .

The available roof for installing rooftop PV, A_{roof} (m^2), is determined by multiplying the total roof area, S_{roof} (m^2), with the utilization factor, μ (%), which is a percentage of the roof area that can be used for PV installations. The factor μ excludes the utilized area of antennas, chimneys, HVAC systems, and unusable area such as shades from the total roof area, S_{roof} (m^2). It can be identified based on national statistical data of household architecture or based on previous studies [25]. ν is the average house/building roof slope (degrees).

Figure 2 demonstrates the two angles related to the sun position, which are the solar altitude angle α_s , and the solar azimuth angle γ_s , the angles β and γ that define the PV module position. β is the tilt angle, and γ is the surface azimuth angle. Further, the angle θ between the normal to the PV surface and the incident beam radiation is indicated [33,34].

The solar irradiation at different azimuths, inclination angles, and horizontal positions regarding different locations is calculated as in Equation (2), in which SI_{dir} and SI_{diff} are the direct and diffuse solar irradiations, respectively.

$$SI = f(SI_{dir}, \beta, \theta) = SI_{dir} \times \cos \theta + SI_{diff} \times \cos\left(\frac{\beta}{2}\right) \quad (2)$$

The geographical potential is determined by using ArcGis to match available roof area, A_{roof} , and relative solar irradiation with data of the topographic, population distribution, and cadastral maps.

The raster maps [17,35] only provide the solar irradiation at 90° to the horizontal. However, the irradiation changes depending on the solar position and its relation to an oriented panel. To improve the accuracy of the geographical potential, this paper calculates relative solar irradiations corresponding to the northern, central, and southern horizontal surface in different azimuth and inclination angles.

The geographical potential is determined by using ArcGis to match available roof area, A_{roof} , and relative solar irradiation with data of the topographic, population distribution, and cadastral maps.

3.2. Technical Potential

A PV module will typically be rated at standard test conditions (STC), which indicates a condition of a cell temperature of 25°C and an irradiance of 1000 W/m^2 with an air mass 1.5 (AM1.5) spectrum [36], ensuring a relatively independent comparison and output evaluation of different modules. However, when operating in the field, they typically operate at higher temperatures and at somewhat lower insolation conditions. To improve the accuracy of technical potential assessments, the paper determines the power output of the solar cell regarding the expected operating temperature of the PV module and the corresponding solar cell efficiency.

First, the paper identifies the operating cell temperature T_{mod} ($^\circ\text{C}$) based on nominal operating cell temperature (NOCT $^\circ\text{C}$) Equation (3).

$$T_{mod} = T_{air} + (\text{NOCT} - 20) \times \frac{G_{mod}}{G_{\text{NOCT}}} \quad (3)$$

NOCT is defined as the temperature reached by open-circuited cells in a module under the conditions of the maximum irradiance, $G_{\text{NOCT}} = 800 \text{ W/m}^2$, air temperature is 20°C , wind velocity is 1 m/s , and an open rear surface mounting. NOCT can be calculated from the NOCT model [37] or taken from the information given by the module specification. The equation is a literature model [38] that gives a reasonable estimate of the operating temperature of the module as a function of the ambient temperature (T_{air} $^\circ\text{C}$) and the irradiance at the instant G_{mod} (W/m^2) when the ambient temperature is T_{air} ($^\circ\text{C}$). T_{air} ($^\circ\text{C}$) can be obtained from Raster data or extracted manually from the climate map [39]. As can be seen in Equation (3), because the irradiance and temperature changes over a calendar year,

we would see an effect of both irradiance and temperature on the electricity output of a solar cell across the seasons.

Another factor that affects the electricity output is the solar cell efficiency. Because the efficiency depends on the spectrum and intensity of the incident sunlight and the temperature of the solar cell [40], the paper calculates the corrected energy conversion efficiency (η_{cor}) of a solar cell corresponding to the operating temperature T_{mod} , which is reflected in the latitude and climate of the considered region. The corrected temperature factor η_{TC} and the corrected efficiency of the module cell η_{cor} are determined via Equation (4). A constant value (CT) can be extracted from the module datasheet (%/K). T_{STC} and η_{STC} are the temperature and efficiency at STC conditions.

$$\eta_{cor} = f(T_{mod}) = \eta_{CT} \times \eta_{STC} = \left[1 + \frac{CT}{100} \times (T_{mod} - T_{STC}) \right] \times \eta_{STC} \quad (4)$$

Moreover, to be more precise in assessing technical potential, this paper identifies the least space distance between PV modules to minimize shading effects. To calculate the module row spacing between two lines of modules, the first step is to calculate the height difference, HD (m), from the back edge of the module to the surface [34]. Equation (5) is used for this purpose. β (degrees) is the tilt angle and W_{mod} (m) is the module width.

$$HD = \sin(\beta) \times W_{mod} \quad (5)$$

The module row spacing (MRS_{mod}) is determined by using the Sun Elevation Angle. The row width, W_{row} , which is the distance from the trailing edge of one row to the trailing edge of the subsequent row, is calculated as in Equation (6), in which α is the solar elevation angle (degrees) (Figure 3) and κ is the azimuth correction angle (degrees) (Figure 4). The shadow between rows falls perpendicular to a south-facing array only when the sun is located at true south in the sky. At solar noon, the length of the shadow cast between rows would be equal to the minimum row spacing (MRS_{mod}). In this paper, MRS_{mod} is calculated in the worst case from 9 AM to 3 PM of the winter solstice, therefore an azimuth angle correction is required (Figure 4).

$$W_{row} = MRS_{mod} \times \cos \beta \times W_{mod} = \frac{HD}{\tan(\alpha)} \times \cos \kappa \times \cos \beta \times W_{mod} \quad (6)$$

The number of PV modules, n_{mod} , on a rooftop for each raster map unit corresponding to the available roof area for PV, A_{roof} , is obtained from Equation (7), in which L_{mod} is the length of the PV module (m).

$$n_{mod} = f(A_{roof}, A_{mod}, HD) = \frac{A_{roof}}{L_{mod} \times W_{row}} = \frac{A_{roof}}{A_{mod} \times \frac{HD}{\tan(\alpha)} \times \cos \kappa \times \cos \beta} \quad (7)$$

The electricity output of the solar system, M_{el} , is obtained from Equation (8), in which PR is performance ratio of the module, SI is the adjusted solar irradiation (kWh/m²) and A_{mod} is the module area (m²)

$$\begin{aligned} M_{el} &= PR \times A_{mod} \times f(T_{mod}) \times f(A_{roof}, A_{mod}, HD) \times f(SI_{dir}, \beta, \theta) \\ &= PR \times A_{mod} \times \eta_{cor} \times n_{mod} \times SI \end{aligned} \quad (8)$$

3.3. Levelized Cost of Electricity (LCOE)

The Levelized Cost of Electricity (LCOE) is a measure of the average net present cost of electricity generation for a generating plant over its lifetime, which is assumed to be 20 years in this study [41]. The LCOE depends on costs (i.e., the initial capital investment, maintenance, and operational costs), local condition (load profile), and financial condition (i.e., the discount rate).

The LCOE is calculated as in Equation (9) [42]

$$\text{LCOE} = f(I_0, A_t, M_{el}) = \frac{I_0 + \sum_{t=1}^{n_s} \frac{A_t}{(1+i)^t}}{\sum_{t=1}^{n_s} \frac{M_{el}}{(1+i)^t}} \quad (9)$$

where I_0 (Euro) stands for the total initial investment, which is the product of module size (in kW) and specific investment i_0 as the investment cost per installed kW (€/kW); A_t (Euro) is the yearly operating cost; i (%) is the discount rate; n_s (year) is the life span; and M_{el} (kWh) is the annual electricity production.

3.4. Sensitivity Analysis

The proposed model is computationally intensive and highly parameterized with model input uncertainty, which can reduce the accuracy of the model outputs. To provide a robust assessment at medium resolution, this paper suggests a solution to estimate the impact and significance of uncertain parameters in the model by using variance-based sensitivity analysis. A variance-based method is a probabilistic approach, which quantifies the input and output uncertainties as probability distributions and decomposes the output variance into parts attributable to input variables and combinations of variables.

The sensitivity of the output to an input variable is therefore measured by the amount of variance in the output caused by that input.

Considering our model in Equation (10):

$$\begin{cases} M_{el} = PR \times A_{mod} \times f(T_{mod}) \times f(A_{roof}, A_{mod}, HD) \times f(SI_{dir}, \beta, \theta) \\ LCOE = f(I_0, A_t, M_{el}) \end{cases} \quad (10)$$

As $Y = f(X)$ for $X = \{X_1, X_2, \dots, X_k\}$, a measure of the sensitivity of the i th variable X_i is given as $\text{Var}(E_{X_{-i}}(Y|X_i))$, where “Var” and “E” denote the variance and expected value operators, respectively, and X_{-i} denotes the set of all input variables except X_i . This expression essentially measures the contribution of X_i alone to the uncertainty (variance) in Y (averaged over variations in other variables) and is known as the first-order sensitivity index or main effect index, S_i , which is determined as in Equation (11). Importantly, it does not measure the uncertainty caused by interactions with other variables.

$$S_i = \frac{\text{Var}_{X_i}(E_{X_{-i}}(Y|X_i))}{\text{Var}(Y)} \quad (11)$$

This method allows exploration of the input space, accounting for linear and nonlinear responses. As demonstrated in Figure 1, four loops, represented by orange arrows, repeatedly run to generate the final outputs until all the possibilities of the inputs are covered. The first input set is built based on the available data and assumptions from previous studies.

Subsequently, this paper fits a linear and/or nonlinear regression to the model response and the standardized regression coefficients are used to measure the level of impact of each uncertain parameter on the output. The relationship between the uncertain parameters and the output is presented as in Equation (12), for example.

$$\Delta y_j = a_1 \Delta x_i^2 + a_2 \Delta x_i + b \quad (12)$$

This paper uses hierarchical clustering in the manner of the Pareto principle to generate the ranking of the uncertainty factors x_i according to their relative contribution to the output variability. The influencers are categorized into different groups, including “strong influencer”, “moderate influencer”, and “negligible influencer”. The goals of the analysis are to provide different references for policymakers and stakeholders to choose an appropriate interaction with the current rooftop PV

market status. One goal focuses on quantifying the uncertainty in the output of the model, thus it is used as a control tool for modelers and policymakers in order to ensure the accuracy of the output. The other goal focuses on apportioning output uncertainty to the different sources of uncertainty inputs and will be used for designing policy and for supporting the decision-making of investors in the rooftop PV market.

4. Case Study and Results

4.1. Data and Assumptions

Vietnam is taken as a case study for demonstrating our method and findings. It is one of the 65 emerging countries in the world with typical features and struggles to develop solar PV [2–4]. The Vietnamese population is 94 million people, with annual GDP growth of around 7%, the total electricity demand of 227,421 GWh, total supply capacity of 48.57 GW [43], and power demand surging at an average rate of 12% per year since 2010 and expected to continue growing by 8%/year until 2030 (Vietnam energy outlook 2018). Residential demand for electricity accounts for almost a third of the total electricity demand [43], with the average retail tariff of 9.3 Euro cents/kWh (Appendix A Table A1). However, during the period 2016–2030, the original estimation of the additional capacity is estimated to be decreased by 16% (~15.2 GW) because of the delay of some natural gas projects. This would be likely to increase the power shortage in the south, especially from 2022 onwards (EVN June 2019).

Under these circumstances, solar and wind power are expected to play significant roles as alternative resources and turn Vietnam into a hot spot for energy investors. Renewable energy supply, including small hydro, wind, solar, and biomass power plants, currently covers 7.16% of total national supply [43]. However, given a local overload, transmission losses, and uneven infrastructure between different regions, the Vietnamese government has been provoking significant investment in power infrastructure with net metering. As a result, by June 2019, the country has shown a surge of centralized solar capacity connected to the national grid of 4.46 GW. This accounts for 8.28% of the Vietnamese electricity supply mix, which is far more than the 1000 MW target set for 2020 (EVN report, June 2019), while PV rooftop projects only grow at a very modest level. Moreover, because of lacking integrating policy, management, and compensation mechanisms to support rooftop PV development in the whole country, it has developed rapidly solely in Ninh Thuan. This region accounts for 90% of the total national solar capacity, which has caused significant grid congestion and reduced the spread of the development.

To solve the issue of the lacking integrating policy and mechanisms to support rooftop PV development, this paper focuses on assessing rooftop PV potentials in 63 provinces in Vietnam and proposes different suggestions for the government to unleash their PV potentials.

This paper uses a previous study of house design in Vietnam [32], in which the average number of apartments on one floor of the building, $\frac{n_A}{F}$, is 5, the exterior area, b_1 , is 0.2, and the interior area, b_2 , is 0.1 to calculate the available roof area for installing rooftop PV. The roof of the apartment buildings is considered flat, so ν for them is 0. For single-detached houses, ν is presented in Table 1. A sensitivity analysis for these assumptions is conducted in this paper.

Table 1. Average of relative solar irradiation in accordance with different roof slopes in Vietnam.

Region	Detached House Roof Slope— ν (degrees)	Average of Relative Solar Irradiation— SI
North Vietnam	25	0.95
	32	0.93
Central Vietnam	25	0.95
	26	0.95
South Vietnam	34	0.90
	24	0.93

The utilization factor of the flat roof is estimated to be 50% based on previous studies [5,9,14,44], which concluded that 35% to 65% of residential flat roofs are available for PV because 5% of the roof is covered by HVAC equipment or other building components, which would shade over 35% of the entire rooftop, and trees and other construction would shelter from 0% to 30% of the rest. The utilization factor of a slanted roof is assumed to be 58%, which considers that a north-facing roof also has the potential for installing PV systems [25].

Based on Equation (2), the relative solar irradiation for different roof types in three different parts of Vietnam is calculated. The results are presented in Table 1.

In this paper, two main models of PV modules, i.e., monocrystalline and polycrystalline, are considered. The characteristics of these two models, extracted from the catalogue, are given in Table 2. The performance ratio is considered as 0.85 [25].

Table 2. Specifications of the PV modules.

Module	Type	Watt Price— I (Euros/W)	Maximum Power— E (W)	Efficiency of Module— STC (%)	Performance Coefficient— CT (%K)	Length— L_{mod} (mm)	Width— W_{mod} (mm)
Monocrystalline [45]	NeMo	0.59	275	16.4	−0.4	1670	1006
Polycrystalline [46]	NeMo	0.53	260	16	−0.42	1640	991

To assess the effect of uncertainty parameters on the outputs, this paper alters the assumptions and the values of input variables, which have been referenced from other studies but for which sensitivity analyses have not been performed in previous studies. The used values of these inputs and the considered variation range are presented in Table 4.

4.2. Results of the Potential Analysis

Section 4.2.1, firstly, presents the spatial potential distribution of rooftop PV with detailed potential for 63 provinces as well as the cumulative potential for eight classified territories of the country: Northern Midlands (NML), Northern Mountains (NM), Red River Delta (RRD), North-Central Coast (NCC), South-Central Coast (SCC), Central Highlands (CH), Southeast (SE), and Mekong River Delta (MRD). Section 4.2.2 then presents the results of the sensitivity analysis for two purposes: (1) to control the accuracy of the output; and (2) to measure the output variability regarding possible input changes in order to support policy decision making.

4.2.1. Spatial Potential Distribution of Rooftop PV

This paper breaks down the estimated theoretical potential of solar with a total of around 120 thousand TWh per year (TWh/a) from the solar irradiation raster map [17,34,49] to geographical and technical potentials of rooftop PV with 1407.2 km² available rooftop and 278 TWh/a, respectively. The technical potential is calculated with the results of roof-mounted solar cells in the whole country being 228.3 and 215.8 GWp or 278.1 and 262.7 TWh/a with monocrystalline and polycrystalline solar cells, respectively (detailed results for each region are given in Table A3).

Comparing different regions in Vietnam, 58% of the total national rooftop PV potential is concentrated in three territories, including the two river deltas and the southeast with an almost equally divided potential of around 20%, equivalent to an average installable capacity of 43.9 GWp. The remaining potential is divided among the coastal areas and the midlands at approximately 10% or 22 GWp, and the mountains and highlands have the lowest potential with about 5% or 11 GWp in each territory.

Taking economic factors into account, the cost per kWh of rooftop PV varies greatly depending on the region and the prevailing economic conditions, in particular regarding different capital costs and discount rates. This paper determines the LCOE (Euro/kWh) of rooftop PV for each province in order to assess the economic attractiveness of the rooftop PV assumed at the current discount rate of 8%.

The distributed PV potentials, including the specific production potential per total area (GWh/km²) and the LCOE (Euro/kWh) in Vietnam, are shown in Figures 5 and 6. The potential density is significantly high in the two river delta regions, which are Red River Delta (RRD) and Mekong River Delta (MRD) in Vietnam, especially in the two largest cities of the country, Hanoi (in the RRD) and Ho Chi Minh (in the MRD), with the most enormous potential of electricity production of about 12 and 5 GWh/km² (Figure 6) or around 24.8 and 15.2 TWh/a or 18 and 15.1 GWp, respectively. These cities are the largest metropolitans and most populous cities with an estimated population of 7.7 million and 8.4 million, corresponding to 8.6% and 9.3% of the national population, respectively, and they also have the largest household area in Vietnam (Government statistical reports, 2018). Hanoi has 407 km² of housing land, of which around 93.9 km² rooftop available to install solar cells, while Ho Chi Minh City has about 282 km² housing land but can provide an estimated 110 km² roof for installing solar. Moreover, since Ho Chi Minh City is in the southern part of Vietnam, it could potentially generate in total 24.8 or 23.4 TWh/a with monocrystalline or polycrystalline solar cells, respectively, which is nearly 60% more than the electricity production potential from solar in Hanoi. This gives Ho Chi Minh City the most significant potential for solar power throughout the country, while Hanoi is ranked second. Currently, Ho Chi Minh City has only installed around 44.56 MWp of its 18 GWp total potential [50].

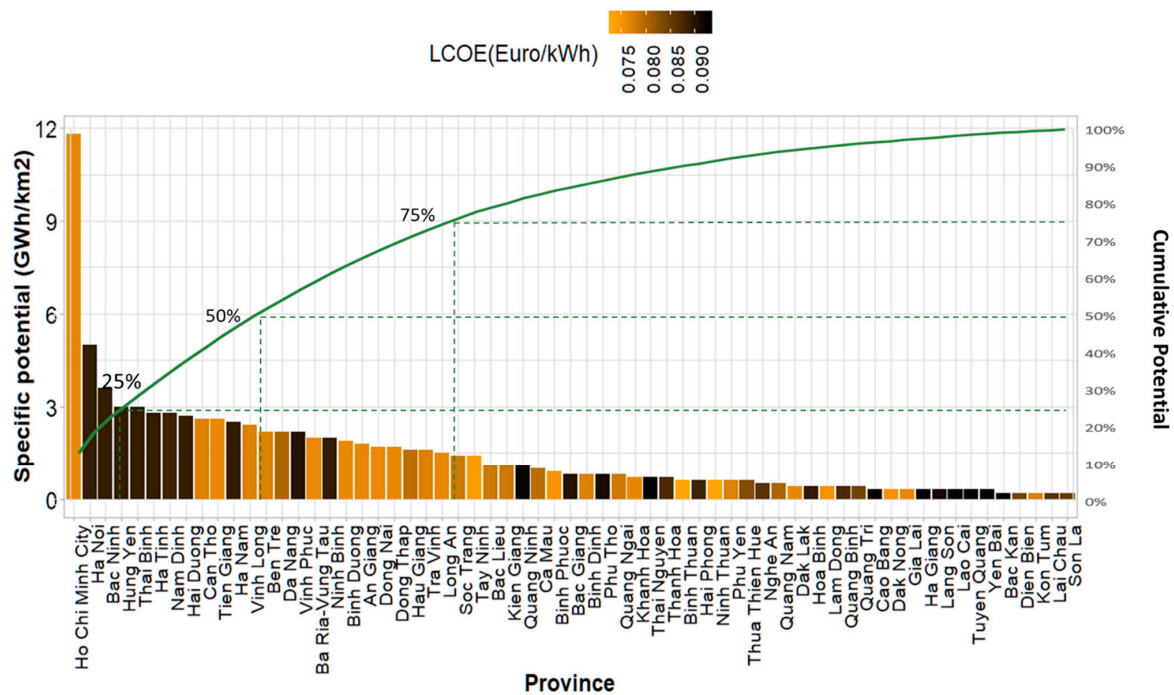


Figure 6. The electricity production potential (TWh/a) and average LCOE (Euro/kWh) at the discount rate 8% in 63 regions in descending order.

The LCOE ranges from 7.5 to 9.2 Euro cents/kWh at a discount rate of 8% across 63 provinces in Vietnam (Figure 5). In the regions with a vigorous radiation intensity such as Central Highland, Mekong River Delta, South Central Coast, and Southeast (see Figure 5 for regions), rooftop PV is more economical than in other areas with the LCOE being around 0.075 Euro/kWh. Among the eleven cities, which account for 50% of the total specific potential (GWh/km²) in the whole country, there are only four cities, namely Ho Chi Minh City, Can Tho, Tien Giang, and Vinh Long, with the average LCOE being less than 0.076 Euro/kWh (Figure 6). Despite having a sizeable available roof area, Hanoi and the rest do not have a convincing economic potential due to their low radiation intensity, which leads to a relatively high LCOE of around 0.085–0.089 Euro/kWh. The other quarter of potentials consists of 12 provinces that are relatively promising for investment with high potentials of approximately 2–3 GWh/km² and a low LCOE of about 0.075–0.080 Euro/kWh, except for Vinh Phuc and Ninh Binh.

However, Ninh Thuan and Binh Thuan, which are the best places for investing in rooftop PV with the lowest LCOE in Vietnam at around 0.073 Euro/kWh, have relatively small solar resources at about only 0.6 GWh/km².

Figure 7 illustrates the cost–potential curves for monocrystalline solar deployment in Vietnam at different discount rates ranging from 5% to 11%. With varying rates of discount, the cost curve for solar PV in Vietnam shifts vertically. The total electricity potential in the case of considering monocrystalline and polycrystalline cells adds up to around 278 and 262 TWh/a, respectively. The total electricity demand in 2018 in Vietnam is 192.36 TWh, which implies that the total solar rooftop could cover the current demand of the country. However, Vietnam has only exploited about 0.1% of its potential [43].

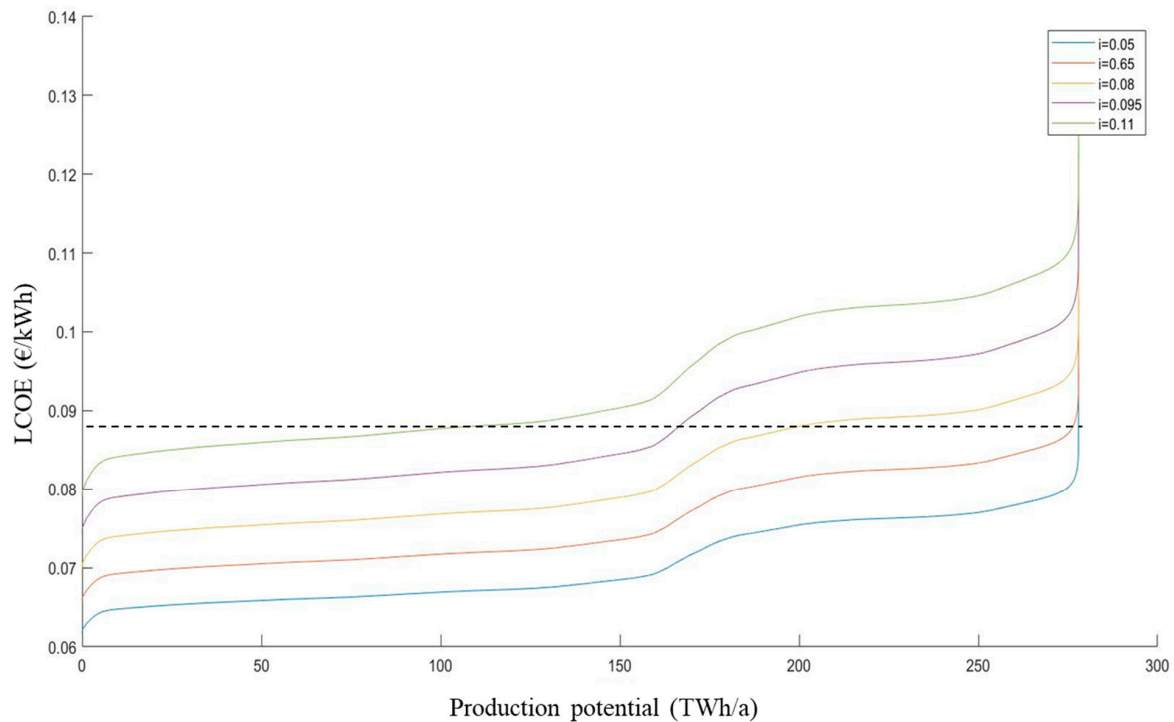


Figure 7. The cost–potential curves for electricity generation from monocrystalline solar cells at different discount rates and the average FIT 2.0 of 0.088 Euro/kWh as a dashed line.

The step in the curve (see Figure 7) results from the LCOE jumping from high irradiation in the southern part to low radiation to the northern part of Vietnam. It reveals the significant difference in solar irradiation along with the country, which causes a drastic increase in LCOE from south to north. Referring the LCOE results to FIT [51] reveals a favorable condition for the rooftop solar development because the FIT can cover the LCOE cost. Details of the relation between LCOE and FIT are discussed in Section 5.2.

Finally, we analyze the results of the present paper in the context of additional studies relating to rooftop PV in Vietnam. As compared to other studies in Vietnam, this method poses its advantages of providing a reasonably accurate result at low-cost (Table 3), even though it deals with insufficient data and meager budget. When normalizing for the area covered to 80% of the cities' area, this paper determines the potentials for rooftop PV in HCM and DN with a relative error of 4% and 6% compared with the field study, respectively.

Table 3. Comparison of the results of the suggested model and the field study in Ho Chi Minh (HCM) and Da Nang (DN).

Subject	This Paper	Field Study [52]
Coverage	Whole country	Only urban areas of HCM and DN
Method to identify technical potential	Geostatistical analysis, GIS, Monte Carlo Simulation	Deep learning, Photogrammetry, GIS, Image processing, Digital surface, and elevation models
Production potential for the specific cities (TWh/a)	HCM: 23.4 (100% of the city area) DN: 2.7 (100% of the city area)	HCM: 18 (80% of the city area) DN: 2.3 (80% of the city area)

4.2.2. Sensitivity Analyses

Similar to many other developing countries, Vietnam has deficient and inadequate data conditions even to estimate rooftop PV potential at medium spatial resolution. It is worth mentioning that conducting such an assessment for countries with similar unfavorable data condition requires significant manual processing of inputs and maps, for example matching geographic and population distributions and building densities with 11,050 clusters of the topographic map in the case of Vietnam.

This section assesses the effect of each mentioned input or assumption on technical and economic potentials and identifies an acceptable confidence interval of every particular variable required to achieve specific confidence in the result. The results are demonstrated in Figures 8 and 9.

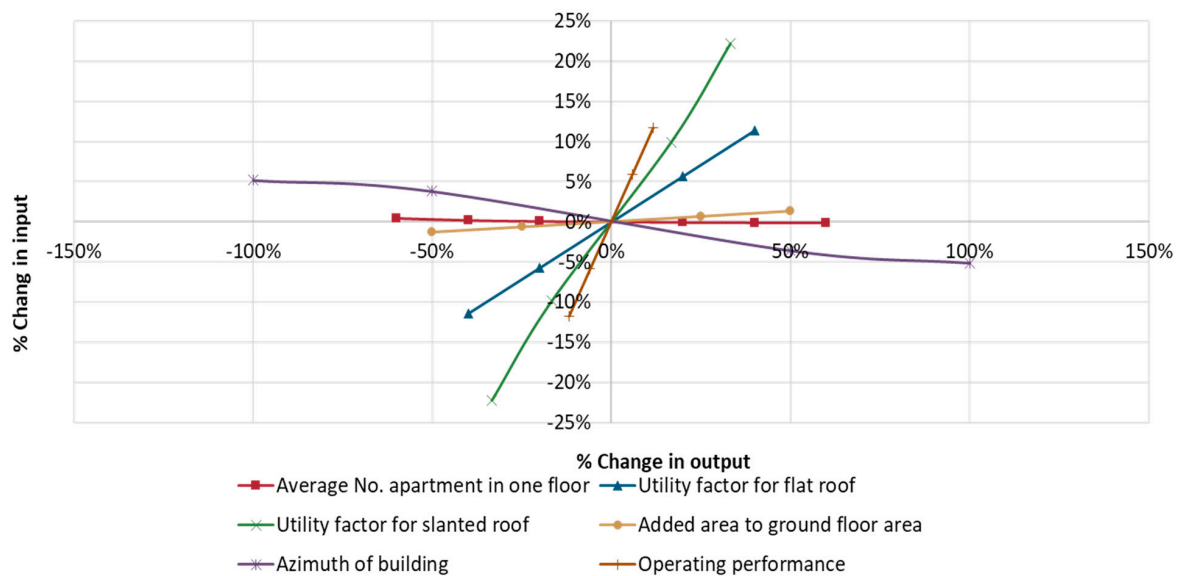


Figure 8. Sensitivity analysis of input variation effect on technical potential output.

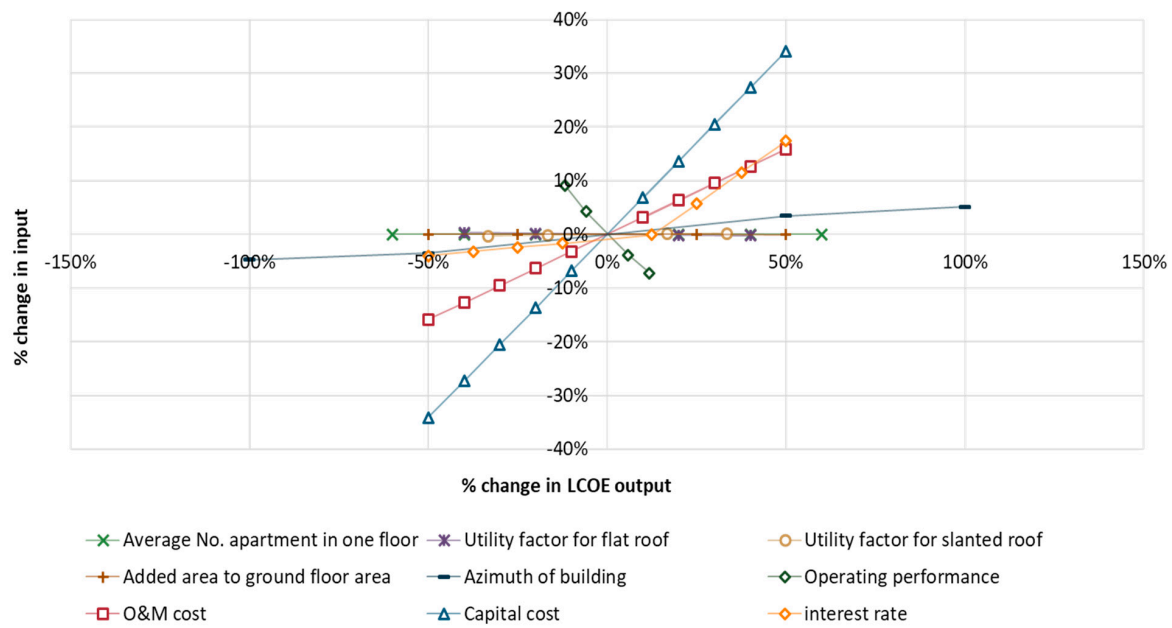


Figure 9. Sensitivity analysis of input variation effect on LCOE output.

The results show that, among the uncertain parameters that are used to calculate the geographical and technical potentials, the utilization factors for flat and slanted roofs and the efficiency or performance ratio of a considered PV system are the most critical parameters influencing the accuracy of the technical potential output (Figure 8). Considering the economic potential, all the uncertain geographical inputs, such as the average number of apartments on one floor in a building, area added to the ground floor area, and utilization factors for different roofs, are irrelevant to the LCOE output. However, technical inputs, especially the efficiency of the PV module, show significant effects on the LCOEs. Lastly, the economic data, such as costs and interest, have the most significant impact on the LCOE output, especially the capital cost (Figure 9).

To verify the correlation of the variation of these variables with the output, we use regression techniques, including curve fitting and linear fitting, to specify the model that provides the best explanation of the relationships between the uncertain parameters and outputs. The considered outputs are the technical potential (y_1) and the LCOE (y_2). The uncertain parameters are indicated below:

- | | | | |
|----|-------------------------------------------|----|---------------------|
| x1 | Area added to a ground floor area | x6 | Azimuth of building |
| x2 | Utilization factor for flat roof | x7 | Capital cost |
| x3 | Utilization factor for slanted roof | x8 | O&M cost |
| x4 | Average number of apartments on one floor | x9 | Discount rate |
| x5 | Performance ratio | | |

Figure 10 shows the strong influence of the uncertain parameters on the outputs in descending order. Using the Pareto principle [53,54] indicating that roughly 80% of the effects come from 20% of the causes, this paper divides them into three groups. The first group is called “strong influencer”, which consists of x_3 , x_5 , x_5 , and x_7 that are responsible for more than 80% of the impact on the technical and economic outputs, respectively. The second one is the “moderate influencer”, which includes x_2 for technical output and x_8 for economic output, and accounts for the next 15% of the impact on the outputs. The other factors belong to the “negligible influencer” group. By selecting impacts based on their strength, we can measure the change of the outputs based on the different possible alterations of the uncertain parameters, as in Equations (13) and (14).

$$y_1 = 0.2851 x_2 + 0.7401 x_3 + x_5 + 0.025 \tag{13}$$

$$y_2 = -0.6908 x_5 + 0.6827 x_7 + 0.3173 x_8 + 0.3128x_9^2 + 0.1965x_9 + 0.364 \tag{14}$$

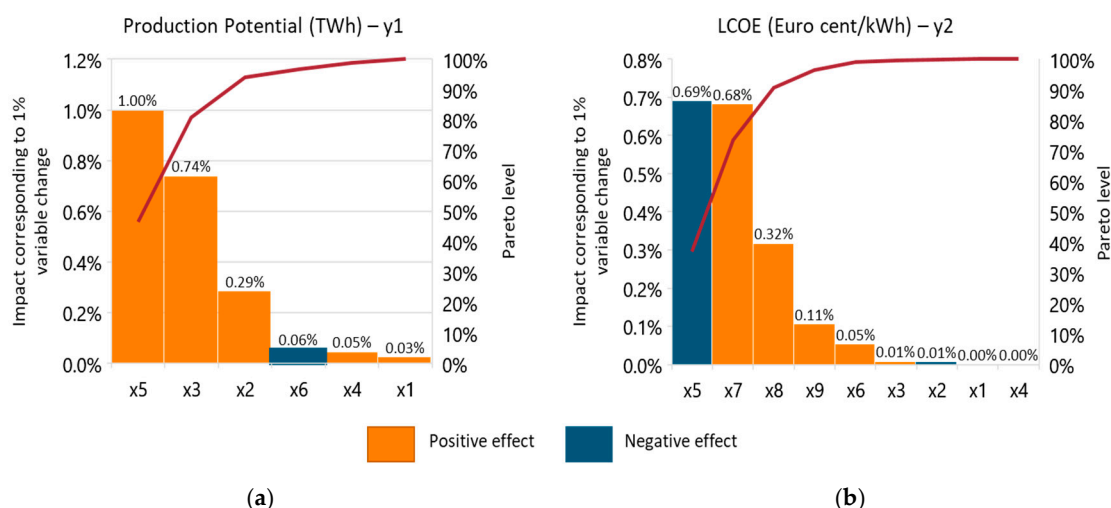


Figure 10. Comparing the influence of the considered parameters on the technical potential (a) and LCOE (b). Columns in orange, positive value; columns in blue, negative value; red lines, Pareto lines.

The results show how dependent the output is on a particular input value. The performance ratio - x_5 has the most significant impact on both outputs of the model, which are the electricity potential - y_1 , and the LCOE - y_2 . While the electricity potential is also changed considerably when the utilization factors change, the LCOE is not be affected by these two variables. It alters when the costs and discount rates vary.

These results can be used to assist policymakers for decision making by predicting the outcome of a decision in case they intend to change inputs using policy incentive/subsidy. It helps in assessing the riskiness of a strategy and in making informed and appropriate decisions. A detailed discussion of and examples for this argument are presented in Section 5.

5. Deriving Policy Implications from the Potential Assessment Results

Based on the results from the sensitivity analysis, we identified that factors including the performance ratio of the PV system, capital and O&M costs, and the discount rate are the variables with the most significant impact on the results of LCOE. To design a practical and transferable tool for policymakers in planning rooftop PV and a reference for stakeholders, this paper explores changes in each area when these variables change. First, we identify target groups based on their PV potential and demographic characteristics (Section 5.1). Then, we build the market distribution curves based on the techno-economic results and then observe the possibilities of shifting and bending distribution curves under different possible impact changes (Sections 5.2 and 5.3). This paper compares different desirable policies to help policymakers select effective strategies to promote their desire for the rooftop PV market.

5.1. Defining Target Groups

From the results in Section 4.2.1, national and regional governments can choose the most economic provinces directly from the potential ranking in Figure 6. However, the main drivers for solar development in developing countries are urbanization and GDP [2,55]. This means the chance of higher-income people investing in rooftop solar PV is higher in urban than in rural areas.

Figure 11 shows the available rooftop PV distribution corresponding to the level of urbanization (left) and the GDP per capita in 2018 (right) distributions in 63 regions in Vietnam. The distributions highlighted in red, which consist of 14 provinces, indicate the minimal potential area, with less than 5 km² of roof area, 15% of urbanization, and 1000 Euro/a income. The green distributions illustrate the outstanding potential area, including nine provinces with more than 35 km² of the available roof,

60% of urbanization, and 2000 Euro/a income. Details of potential assessment results and demographic indicators can be found in Tables A2 and A3.

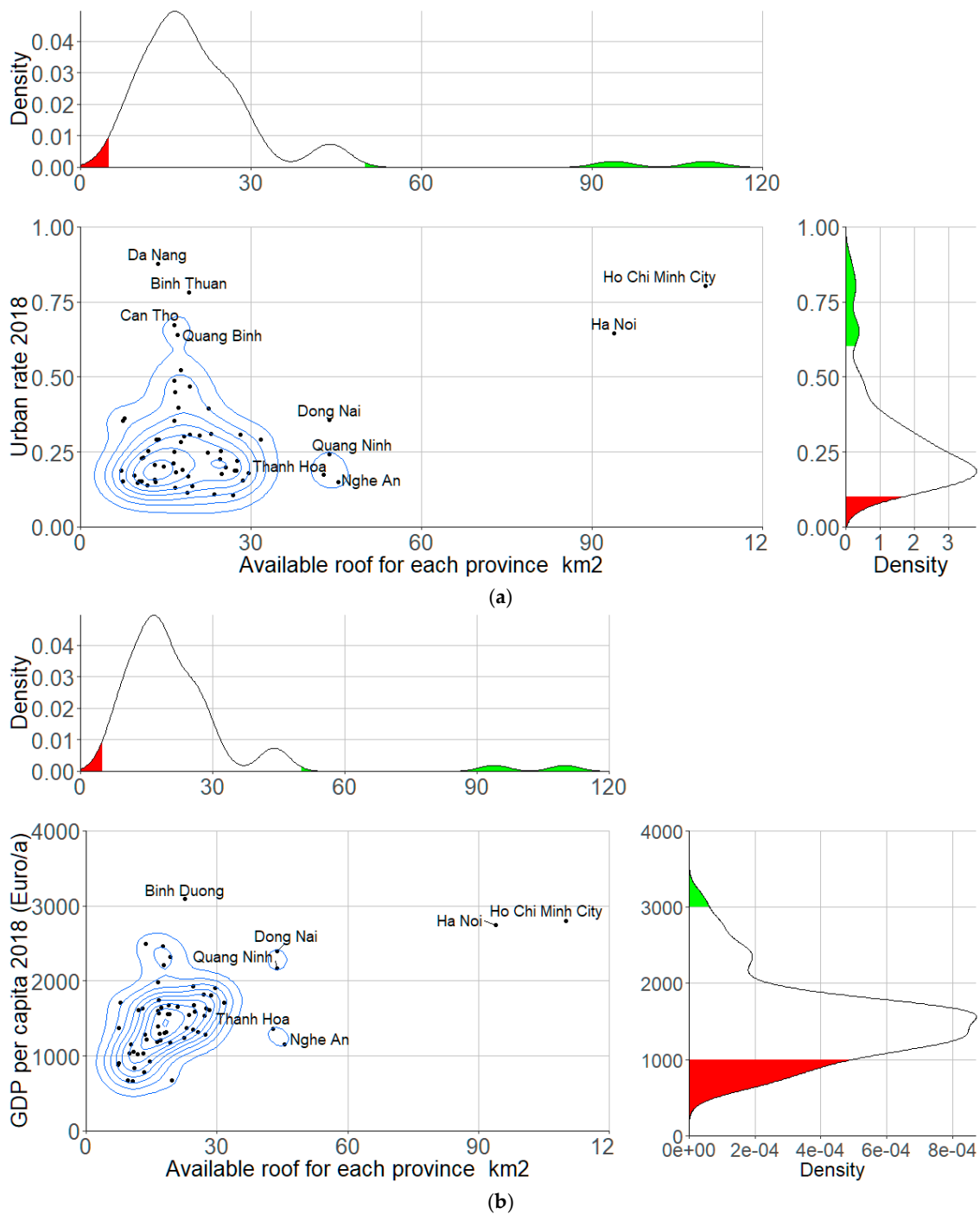


Figure 11. Rooftop PV potential distribution corresponding to the level of urbanization (a) and income per capita (b) [46] in 63 provinces in Vietnam.

Table 4. Employed values of the uncertain parameters and their considered variation range in this study.

Uncertain Parameter	Variable	Symbol	Used Value (unit) [ref]	Variation Range
Geographical input	Utilization factor for flat roof	M	50 (%) [16]	±40%
	Utilization factor for slanted roof	M	58 (%) [25]	±33%
	The average number of apartments on one floor of the building	$\frac{n_A}{F}$	10 (-) [47]	±60%
	Added area to the ground floor area	<i>b</i>	10 (%) [47]	±50%
Technological input	The azimuth of the slanted roof	γ	90 (degrees) [32]	±100%
	Performance ratio	PR	85 (%) [25]	±10%
Economic input	O&M cost	A_t	0.036 (Euro/kWh) [48]	±50%
	Capital cost	I_0	0.59 (Euro/W) [48]	±50%
	Discount rate	<i>i</i>	8 (%) [47]	±50%

Because most of the provinces have a relatively low (15–60%) urban rate and humble economic (1000–2000 Euro/a income) development, the success of the first adopters plays a crucial role in the new market due to their potential impacts on followers. To improve rooftop solar development, the role of local and government authorities is equally essential. However, in practice, sub-national or local governments are constrained by limited resources, weak institutional capacity, inadequate mechanisms, and limited availability of information [3,7,26,29]. These circumstances, as well as the complication of land ownership and attractiveness, constitute a narrow space for the policymakers to encourage rooftop PV development at the local level without significant support from the government. This means that there is an obvious need for selecting target groups that is unified from national to local levels.

Based on the market characteristics, this paper suggests determining target groups based on k-means clustering of the development dynamics of 63 provinces in Vietnam with the criteria, i.e., their techno-economic potentials including the available roof (km²), the production potential (TWh/a), LCOE (Euro cent/kWh), the level of urbanization (%) [47], and GDP (Euro/a) [47] (See Table A2 for detailed information). The results are shown in Table 5, Figure 12, and Figure A1. Because there are more than two dimensions (variables), Table 5 shows the principal component analysis and plots the data points according to the first two principal components (Dim1 and Dim2) that explain the majority of the variance and shows an illustration of the clusters. Figure A1 shows the clusters corresponding to their geographic position in the country.

Table 5. Priority groups and their specific characteristics.

Priority	Cluster Name	Available Roof km ²	Average LCOE (euro cent/kWh)	Production Potential (TWh/a)	GDP per Capita (Euro)	Urban Rate	No. Province
1	6	101.95	8.25	20.20	2260.53	65%	2
2	2	17.11	8.06	3.51	1558.96	51%	7
3	1	29.04	7.59	6.59	1431.55	29%	9
4	3	26.12	8.92	4.42	1307.08	22%	13
5	5	17.03	7.69	3.74	1143.27	26%	18
6	4	12.57	8.96	2.07	794.10	19%	14

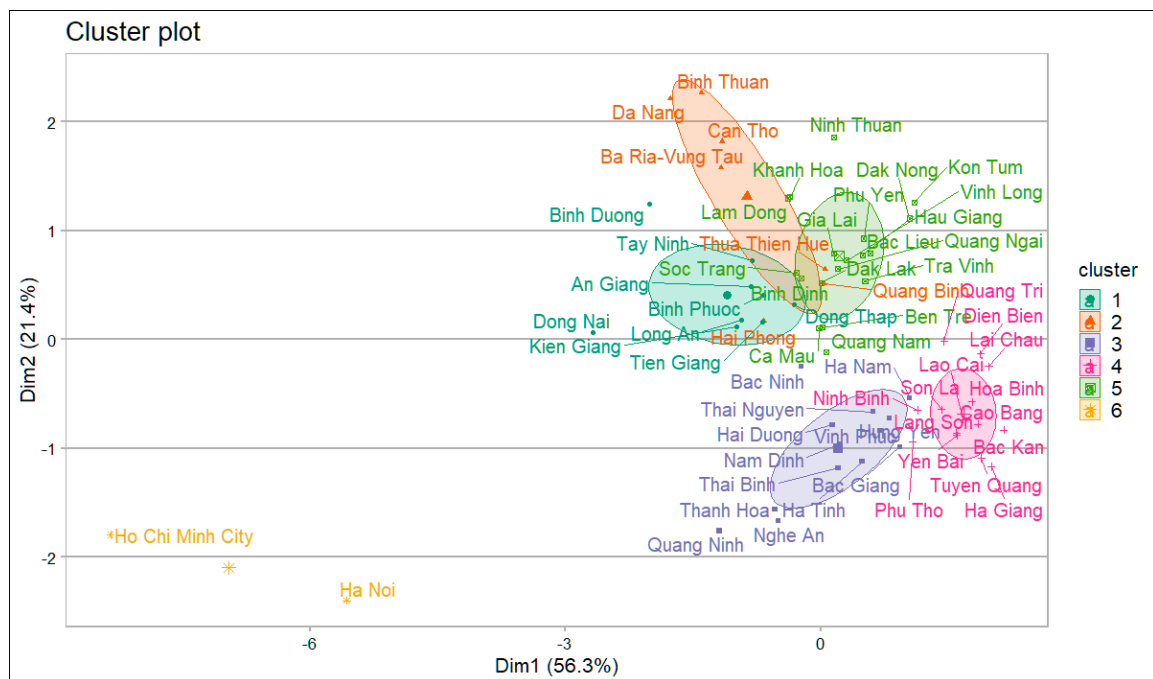


Figure 12. The results of clustering provinces based on their potentials and characteristics.

Ranked in order of priority for rooftop PV policies, Hanoi and Ho Chi Minh are classified as Priority 1, which requires the most policy focus due to their most favorable condition for rooftop PV development, followed by Ba Ria Vung Tau, Binh Duong, Can Tho, and Da Nang. Detailed clustering and priority ranking results for each region can be found in Table A4.

The results do not only recommend policy priority but also support national policymakers to redirect and balance the PV development between different regions. For example, the government can provide a favorable policy to the higher LCOE but potentially fast-uptake regions, e.g., cities and provinces of Priorities 1 and 2.

5.2. Assessing the Market Attractiveness and FIT

Rather than just analyzing the sensitivity of the output analysis to changes in the variable assumptions, as above, this section also looks at the probability distribution of the outcome in order to make decisions or take actions accordingly. Scenario analysis is designed to analyze the change of output regarding the different sets of inputs and then based on the various possible outcomes. In this paper, we use competitive prices to compare the potential benefit of installing rooftop PV between different scenarios. The competitive prices are the differences between the FIT and LCOE and between LCOE and the grid tariff (T_G) (Equation (15)).

$$\begin{cases} \Delta_1 = \text{FIT} - \text{LCOE} \\ \Delta_2 = T_G - \text{LCOE} \end{cases} \quad (15)$$

Table 6 summarizes the different possibilities of different metering models concerning LCOEs and grid tariffs. The business model indicates that residential customers can sell generated electricity on the grid to the system operator. The self-consumption model indicates that consumption of PV electricity takes place directly at the house/building—either immediately or delayed through the use of storage systems.

Table 6. Competitive prices and corresponding metering models in the rooftop PV market (“x”, beneficial; “-”, not beneficial).

Competitive Price		Metering Model	
Δ_1	Δ_2	Business	Self-Consumption
>0	>0	x	x
>0	<0	x	-
<0	>0	-	x
<0	<0	-	-

The results support policymakers in making decisions and testing the robustness of an effect. By understanding the relationships between input and output variables, policymakers can encourage rooftop PV market development in certain areas by keeping the risk of investors at a comfortable level. With each specific decision, policymakers can measure the effect coverage, as well as the cost and benefit of their choice, and can compare and therefore decide which action should be taken.

Vietnam has an attractive solar market. However, it is undergoing a period of intense transformation. In 2017, the Vietnamese Ministry of Industry and Trade (MOIT) introduced the first FIT, called FIT 1.0, of 8.83 Euro cent/kWh for all solar projects under Decision No. 11. It officially laid the primary foundation for solar power development. To promote market development, in February 2019, MOIT released the draft Decision with new FITs, called FIT 2.0, of an average of 9 Euro cents/kWh for rooftop solar [56] to replace Decision No. 11. FIT 2.0 proposed FITs ranging from 7.45 to 10.26 Euro cents/kWh depending on the four classified irradiation regions of Vietnam. However, in December 2019, a final draft submission letter from MOIT (with a signature but no stamp) for another FIT, called FIT 2.1, has been internally circulated. The FIT 2.1 for rooftop PV projects would be set at 7.91 Euro cents/kWh (Currency exchange rate (Nov 2019): 1 Euro = 1.06 Dollar US), which is around 1 Euro cent/kWh less than the first proposal.

This paper compares the effect of the three FITs on the fledgling market (Figure 13). FIT 1.0, set at 8.83 Euro cent/kWh, generated significant interest in the whole market, especially in the southern regions of Vietnam, which have the highest levels of irradiation. If this price was maintained, the Vietnamese rooftop market would continue to flourish. The expected total return per kWh of the whole market for rooftop PV would be 0.56 Euro cents (blue line). However, 24% of areas would remain unattractive.

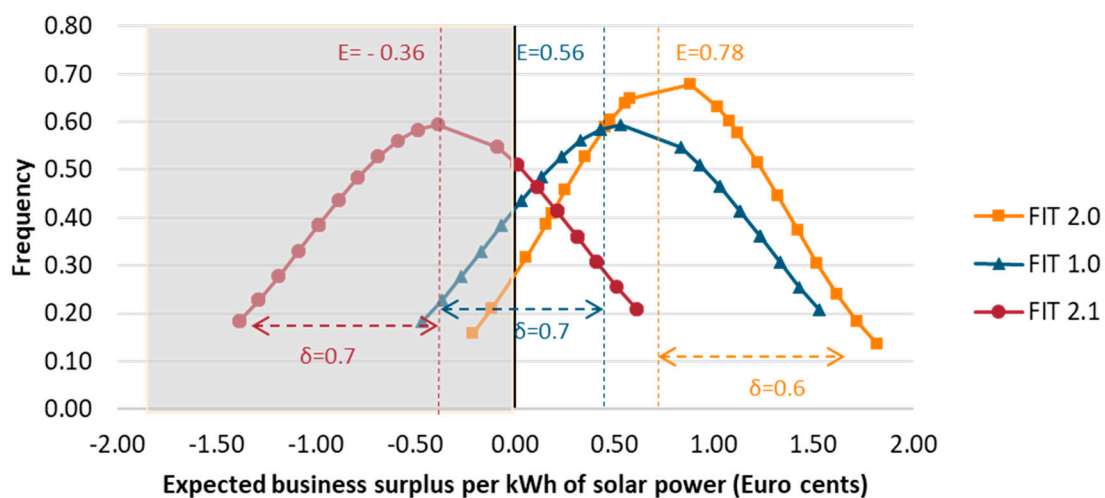


Figure 13. Analyzing the market attractiveness corresponding to the three different FITs.

If the FIT 2.0 was approved, it would create a momentum pushing the entire market moving up and to the right of the coordinate axes. This means the expected profit per kWh would increase by

0.12 cents in all localities (orange line). By increasing 0.07 cents/kWh of the average FIT and specified regional price, FIT 2.0 would increase the possible activated market from 76% to 92% and create an additional exploitable 56 TWh potential, equivalent to a possible of 28 million Euro of profits. More than 30 provinces could show their aggressive competition of more than 1 Euro cent profit per kWh.

While the FIT 2.0 promises a bright future for rooftop PV, only some areas may qualify for the FIT 2.1 if the Prime Minister agrees with this approach. More than 60% of the market would be pushed into a difficult situation (red line), causing damage of 900 million Euro in the whole market (Table A5). The possibility of suppressing development or even market recession due to this FIT 2.1 needs to be borne in mind [57].

5.3. The Role of Grid Tariffs and PV Module Costs in Self-Sufficiency Developments

According to Vietnam EVN reports, the country's retail electricity price is projected to gradually increase by around 6.12% per year so that the electricity supply units, including EVNs, can offset costs. This paper analyzes the grid tariff changes reflecting on the self-consumption rooftop PV market by ranging it from 7.2 Euro cent/kWh in 2018 to a projected tariff of 8.7 Euro cent/kWh in 2025 (Figure 14). The left chart displays the current market with the grid tariff of 7.2 Euro cent/kWh with different discount rates of 4% and 12%. The right one presents the market when the grid tariff increases to 8.7 Euro cent/kWh. Increasing the grid tariff undeniably creates a favorable condition for the self-consumption business by increasing the expected benefit to -0.5 and 1.2 Euro cent/kWh at a 12% and 4% discount rate, respectively. Detail results for each region can be found in Table A6. As the grid tariff increases, the chance for self-consumption will also increase. However, it should be noted that, even though the policy seems to be effective in encouraging rooftop PV development, it faces many mixed reactions from the public. While researchers and banks complain that electricity price policy in Vietnam is inappropriate for investment because of its relative low grid tariff compared with the grid tariff in neighbor countries [58,59], the increasing grid tariff has led to an increase in the price of finished products, making it particularly tricky for domestic manufacturing enterprises and public consumers.

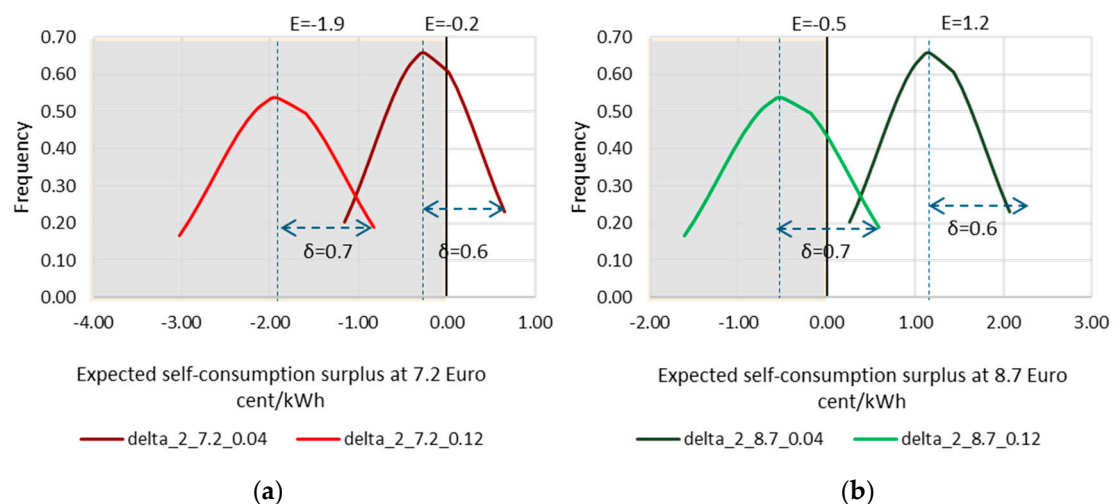


Figure 14. Competitive prices change in accordance with the projected grid tariff increases from (a) 7.2 to (b) 8.7 Euro cent/kWh.

In this paper, we observe the effect of the reduction in specific investment for rooftop PV in Vietnam by adjusting the capital expenditure (CAPEX) of the small rooftop PV systems (1–15 kWp), which will also affect O&M costs (OPEX). The current total costs (CAPEX + OPEX) range from 635 to 1038 Euros/kWp in Vietnam. At a discount rate of 8% and under the FIT 1.0 or FIT 2.0, the business project can expect an average benefit ranging from -1.7 to 3.3 Euro cent/kWh and the self-consumption

project can expect from -3.5 to 1.5 Euro cent return per kWh (Figure 15). If the total cost is lower than 650 Euros/kWp, it is feasible to invest in either of the metering models. However, the projects, whose total cost is higher than 836 Euros/kWp, are not recommended in Vietnam.

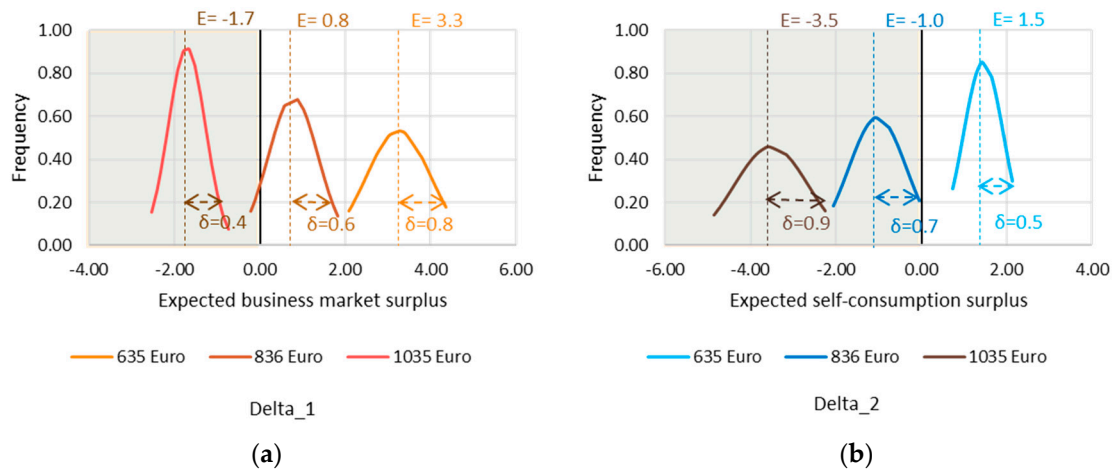


Figure 15. Expected business market (a) and expected self-consumption (b) surplus change in accordance with investment costs increase from 635 to 1038 Euros/kWp.

Rooftop PV technology is becoming more efficient and cost-competitive compared to other traditional energies. A dramatic decrease in the average wholesale price for crystalline modules is reported in China with a reduction from about 530 to 400 Euros/kWp in less than two years from 2016 to the first quarter of 2018 [60]. Moreover, while in 2005 solar modules constituted almost 75% of the system costs, this share amounts to around 50% today, even for rooftop PV systems [60]. In light of the reduced prices for crystalline modules in the global market [60,61], if the total cost for a rooftop PV system is lower than 650 Euros/kWp, it will provide a significant impetus to self-sufficient developments for the rooftop PV market in Vietnam.

5.4. Critical Discussion

A cost-effective and transferable methodology for rooftop PV potential assessment in developing countries has been developed. The accuracy of the proposed method has been improved. However, challenges related to the data input still exist. The paper uses digital maps, which are prepared by using satellite imagery, combined with a manual spatial data collection method to conduct geospatial analysis. For example, the final map of Vietnam requires matching geographic and population distributions and building densities within 11,050 clusters of the topographic map in the case of Vietnam. The uncertainty issue arises when different maps often exhibit different accuracy levels depending on their application and spatial extent. The final map incorporates the mistakes of all component maps. The geo-referencing errors, the tilt angle of the sensor, the spatial resolution of the digital data, etc. affect the accuracy of the final map. The performance of the raster map of Vietnam in monthly means compared to measurements at 11 ground stations results in a mean bias error of $-0.05 \text{ kWh m}^{-2} \text{ day}^{-1}$ (which represents -1.2% in relative mean bias error) and a root mean square error of $0.32 \text{ kWh m}^{-2} \text{ day}^{-1}$ (8.3% in relative root mean square error) [49]. The data collecting methods and the limitations/errors associated with those methods disturb the spatial accuracy. For example, different classification and interpolation methods were used in preparing the population distribution map for data presented with different errors of around 2–5% in the final map [47]. This paper conducts a sensitivity analysis to assess the effect of these uncertainties on the final results.

This paper considers the temperature and solar radiation, which have significant effects on the performance of photovoltaic (PV) systems; PV cell temperature, which is related to the ambient temperature; and the solar radiation incident on the PV surface, which depends on the slope and

azimuth of the PV panels. Another factor that affects the solar radiation incident on the PV surface and hence influences its performance is the ground reflectance (albedo). This paper does not consider this factor due to the renowned complicated vertical distribution of cloud and aerosol layers of Vietnam [62]. Moreover, based on the literature, the albedo effect seems to be relatively small in Vietnam. Vietnam has a diffuse broadband solar irradiance (310–2100 nm) with the normalized solar wavelength of 532 nm [62]. The corresponding albedo spectrum and the effective albedo value, thus, range from around 5% to 15% and 0.1 to 0.35, depending on the rooftop materials such as brick, red shingle, ceramic tiles, and green paint, respectively [63]. The effective albedo can lead to errors of less than 1.6% and 6.7% for the module tilt angles from horizontal of 40° and 90° [64]. Further studies, especially field studies on a small scale, can use this effective albedo value to optimize PV system design and take advantage of the reflected albedo resource.

This study improves the accuracy of technical potential output by calculating the corrected temperature based on the NOCT model. As mentioned in Section 3, NOCT is obtained under predetermined environmental conditions, while STC is the test condition used to rate the performance of a PV panel. STC is the idealized condition, which can overpredict PV performance [65,66]. Since the NOCT is based on realistic data, it is simple and easy to apply. Manufacturers usually include NOCT in the module characteristic data. However, NOCT can overpredict the PV cell temperature by around 10% [67], and can also vary around 2–5 °C, depending on the module materials [68]. Thus, it can underpredict the PV performance [36]. Another option for calculating the expected PV system yield for specific provinces or even buildings is the free online tool PVGIS, provided by the European Commission [69]. The tool uses the real measured values of solar radiation at specific location and provides an overview information about PV system performance. However, while PVGIS is certainly more accurate for a specific building, it would not be feasible to perform a national analysis with this tool.

When calculating the cost for decentralized PV generation technologies, this paper uses LCOE, which is the most widely used metric for a cost comparison between different generation technologies. However, since the renewable energy share in total electricity supply increases, it poses a difficulty for LCOE to make comparisons between different categories of supply, e.g., residual load, load following, and variable load. Another concern regarding LCOE is that it is becoming more difficult to justify applying the same weighted average cost of capital to technologies with very different climate policy risks. To deal with these drawbacks, the new measure, called the Value-Adjusted Levelized Cost of Electricity (VALCOE), is now recommended by the IEA [70], which includes three adjustments to LCOE: energy, value, and flexibility. Although the VALCOE may be a better measure of cost for grid managers, the IEA needs to provide the data for the added factors from their World Energy Model (WEM) regional hourly dispatch models. Once these data are available and the flexibility value, outside of the WEM model, in the VALCOE equation, are well defined, future studies can replace LCOE by this new measurement.

6. Conclusions and Policy Implications

Rooftop PV is driving the decentralization of electricity production, which is a cornerstone of the sustainable development concept, whereby households become more independent of the electricity grid due to a thorough integration of renewable energy sources. However, it is still often seen as a novelty, and legally, local authorities have difficulties enforcing this specific technology in their detailed development plans partly because of the lack of expertise and capital. Therefore, it is relevant to address decentralized PV potentials as early as possible when the state and local governments start planning for the type of energy source. Since different regions have different climatic, geographic, and demographic profiles, this paper provides an affordable, robust and high-resolution potential assessment for rooftop PV and suggests target groups alongside policy solutions with clear national and local goals, based on the findings. The proposed method considers construction and design constraints, obstacles on the rooftop, and the proper orientation on the roof, including shading effects

and the slum areas (informal settlements). The paper considers Vietnam as an example for other emerging countries to apply the method. The results can provide an overview plan as well as an integrated strategy for developing rooftop PV between different administrative levels.

The physical potential in the raster maps, which encompasses the maximum amount of solar energy received in a particular area, is broken down into the geographic potential of in total 1407 km² available rooftop by gradually excluding the zones reserved for other uses and restricting the locations where solar energy can be gathered. The technical potential is calculated with the results of roof-mounted solar cells in the whole country being about 228 and 216 GWp or about 278 and 263 TWh/a with monocrystalline and polycrystalline solar cells, respectively. The LCOE is also calculated, ranging from about 7.6 to 9.2 Euro cents/kWh at a discount rate of 8% in 63 provinces in Vietnam. However, since the techno-economic potential of PV is associated with a certain degree of uncertainty, we measure the error regarding the uncertainty of data assumptions and inputs and the inherently unknowable reaction of the market. Overcoming the unfavorable data conditions, this paper provides a practical and useful tool for policy-making processes. We suggest dividing the market by target group and priority level based on their PV potentials, demographics, and economic status. Hanoi and Ho Chi Minh City should be classified as the highest priority cities for policy focus based on their high potential and robust internal economic and demographic conditions.

This paper also provides systematic guidance to help policymakers design political strategies to support market development. For example, only projects with total costs (CAPEX + OPEX) and discount rates lower than 850 Euros/kWp and 8% respectively, can be beneficial in the current market. With total costs of around 650–850 Euros/kWp, the only attractive investment option is the business model, which is selling generated PV electricity directly on the state grid, while total costs lower than 650 Euros/kWp make a choice between the business and the self-consumption models possible for their rooftop PV projects. For self-consumption, there is no clear strategy, but the situation improves due to increasing grid tariffs. Consumers must, however, wait until around 2025 when their grid tariff should rise to at least about 8.7 cents/kWh and self-consumption will become attractive, but this date could be sooner if costs for solar technology continue to decrease. By simulating the rooftop PV market in different projected FITs, we recommend that the government consider their tariff strategies carefully. In the case of changing the average FIT from 8.83 to 9 Euro cents/kWh and establishing regional FITs, they can activate an additional 16% of the total market, equivalent to around 56 TWh and approximately 28 million Euro of profit. However, if they were to reduce the FIT to 7.79 Euro cents/kWh, it would deactivate about 60% of the rooftop PV market and would reduce total market benefits of approximately 900 million Euro (Table A5).

This paper presents a methodology to carry out resource assessments for rooftop PV in developing countries, as applied to Vietnam. The method is a top-down method that can be employed where detailed, accurate data on buildings, their outlines, and associated infrastructure are lacking. It represents an improvement beyond state of the art and has an absolute error of about 5% compared to detailed bottom-up city models, which is very low for a method at this spatial scale and resolution. Uncertainties relating to the input data are significant but are considered in the sensitivity analysis, which should be borne in mind when interpreting the results. Especially the accuracy of the assumptions relating to the building location, size, orientation, and shading impacts are country-specific and require further research to be employed elsewhere. One promising avenue in this context is the combination of open mapping data with satellite images to automatically identify suitable geometries for rooftop PV [31]. By further validating the top-down results from this study with bottom-up results from 3D models (e.g., Effigis Geo-Solutions 2018), the method could be improved and applied to other contexts. Finally, this and related studies have tended to focus on the supply side for rooftop PV, but there is a need for future research to analyze the demand side, especially public opinion and willingness to pay for PV systems.

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Nomenclature

PV	Photovoltaics
LIDAR	Light detection and ranging
HVAC	Heating, Ventilation and Air Conditioning
STC	Standard test conditions
AM	Air mass
NOCT	Nominal operating cell temperature
CT	Constant value
HD	Height difference
MRS	Module row spacing
PR	Performance ratio
LCOE	Levelized Cost of Electricity
GDP	Gross domestic product
Dim	Dimension
FIT	Feed-in tariff
MOIT	Vietnamese Ministry of Industry and Trade
EVN	Vietnam Electricity Enterprise
CAPEX	Capital expenditure
OPEX	Operational and maintenance expenditure

Appendix A

Table A1. Retail electricity tariff for household customers (published 20/03/2019).

	Customer Group	Rate (VND/kWh)	Rate (Euro cents/kWh)
1	<i>Retail price for household electricity</i>		
	Rate 1: For 0–50 kWh	1678	6.33
	Rate 2: For 51–100 kWh	1734	6.54
	Rate 3: For 101–200 kWh	2014	7.60
	Rate 4: For 201–300 kWh	2536	9.57
	Rate 5: For 301–400 kWh	2834	10.69
	Rate 6: For 401 kWh onwards	2927	11.05
2	<i>Retail price for household electricity via prepaid card meter</i>	2461	9.29

Table A2. Provinces in Vietnam and their demographic characteristics.

ID	Province	Region	Total Area (km ²)	Household Area (km ²)	% of Household Area	Population	Urban Rate 2018 (%)	Gdp/a/person 2018 (Euro/a)
1	An Giang	Mekong river delta	3536	135	3.8%	2164.2	30.8%	1612.1
2	Ba Ria-Vung Tau	Southeast	1979	71	3.6%	1112.9	52.4%	2210.3
3	Bac Giang	Northern midlands	3895	185	4.7%	897.0	11.5%	1562.3
4	Bac Kan	Northern midlands	4860	26	0.5%	327.9	18.8%	880.8
5	Bac Lieu	Mekong river delta	2668	49	1.8%	1691.8	29.1%	1222.2
6	Bac Ninh	Red river delta	822	104	12.7%	1247.5	28.3%	2466.1
7	Ben Tre	Mekong river delta	2395	81	3.4%	1268.2	10.8%	1543.7
8	Binh Dinh	South central coast	6066	94	1.5%	2163.6	31.0%	1369.4
9	Binh Duong	Southeast	2696	136	5.0%	1534.8	39.4%	3089.7
10	Binh Phuoc	Southeast	6878	65	0.9%	979.6	22.0%	1632.0
11	Binh Thuan	South central coast	7946	89	1.1%	1239.2	78.2%	1560.0
12	Ca Mau	Mekong river delta	5221	65	1.2%	1229.6	22.7%	1352.2
13	Can Tho	Mekong river delta	1439	82	5.7%	540.4	67.3%	1979.3
14	Cao Bang	Northern midlands	6701	56	0.8%	1282.3	23.2%	840.5
15	Da Nang	South central coast	1286	75	5.8%	1080.7	87.8%	2493.3
16	Dak Lak	Central highlands	13030	150	1.2%	1919.2	24.7%	1244.4
17	Dak Nong	Central highlands	6513	55	0.8%	645.4	15.3%	1372.1
18	Dien Bien	Northern Mountains	9542	50	0.5%	3086.1	15.1%	668.8
19	Dong Nai	Southeast	5863	177	3.0%	1693.3	35.6%	2400.0
20	Dong Thap	Mekong river delta	3383	146	4.3%	576.7	17.8%	1584.9
21	Gia Lai	Central highlands	15511	183	1.2%	1458.5	30.9%	1171.0

Table A2. Cont.

ID	Province	Region	Total Area (km ²)	Household Area (km ²)	% of Household Area	Population	Urban Rate 2018 (%)	Gdp/a/person 2018 (Euro/a)
22	Ha Giang	Northern midlands	7929	71	0.9%	846.5	15.1%	781.1
23	Ha Nam	Red river delta	859	63	7.3%	808.2	15.9%	1633.8
24	Ha Noi	Red river delta	3360	407	12.1%	7520.7	64.6%	2741.4
25	Ha Tinh	North central coast	5990	121	2.0%	1277.5	18.7%	1287.8
26	Hai Duong	Red river delta	1666	167	10.0%	1807.5	25.3%	1672.3
27	Hai Phong	Red river delta	1561	145	9.3%	2013.8	46.8%	2316.7
28	Hau Giang	Southeast	1622	45	2.8%	776.7	25.4%	1606.6
29	Ho Chi Minh City	Mekong river delta	2062	282	13.7%	8598.7	80.5%	2797.1
30	Hoa Binh	Northern Mountains	4591	140	3.0%	846.1	14.8%	1039.2
31	Hung Yen	Red river delta	929	96	10.3%	3558.2	13.0%	1740.2
32	Khanh Hoa	South central coast	5139	67	1.3%	1188.9	45.0%	1564.5
33	Kien Giang	Mekong river delta	6348	137	2.2%	1232.4	29.2%	1711.2
34	Kon Tum	Central highlands	9675	84	0.9%	1810.5	35.5%	908.8
35	Lai Chau	Northern Mountains	9069	29	0.3%	535.0	17.3%	676.1
36	Lam Dong	Central highlands	9780	125	1.3%	790.5	39.8%	1648.8
37	Lang Son	Northern midlands	8310	81	1.0%	1312.9	20.3%	926.9
38	Lao Cai	Northern Mountains	6366	52	0.8%	456.3	22.9%	1052.4
39	Long An	Mekong river delta	4496	266	5.9%	705.6	18.0%	1908.7
40	Nam Dinh	Red river delta	1669	112	6.7%	1503.1	18.7%	1532.4
41	Nghe An	North central coast	16482	256	1.6%	1854.4	15.1%	1151.5
42	Ninh Binh	Red river delta	1385	68	4.9%	3157.1	21.1%	1191.4

Table A2. Cont.

ID	Province	Region	Total Area (km ²)	Household Area (km ²)	% of Household Area	Population	Urban Rate 2018 (%)	Gdp/a/person 2018 (Euro/a)
43	Ninh Thuan	South central coast	3354	49	1.5%	973.3	36.2%	1710.8
44	Phu Tho	Northern midlands	3535	106	3.0%	611.8	19.1%	1309.6
45	Phu Yen	South central coast	5022	54	1.1%	1404.2	29.1%	1284.7
46	Quang Binh	North central coast	7999	63	0.8%	909.5	63.9%	1207.2
47	Quang Nam	South central coast	10574	204	1.9%	887.6	19.8%	1315.9
48	Quang Ngai	South central coast	5157	116	2.2%	1501.1	30.3%	1313.2
49	Quang Ninh	Northern midlands	6179	82	1.3%	1272.8	24.3%	2163.2
50	Quang Tri	North central coast	4623	43	0.9%	1266.5	15.2%	1151.5
51	Soc Trang	Mekong river delta	3314	57	1.7%	630.6	30.6%	1654.2
52	Son La	Northern Mountains	14124	86	0.6%	1315.9	13.7%	671.5
53	Tay Ninh	Southeast	4042	92	2.3%	1242.7	22.6%	1928.2
54	Thai Binh	Red river delta	1588	136	8.6%	1133.4	10.5%	1818.1
55	Thai Nguyen	Northern midlands	3526	123	3.5%	1793.2	35.3%	1606.2
56	Thanh Hoa	North central coast	11116	552	5.0%	1268.3	17.3%	1365.3
57	Thua Thien Hue	North central coast	4901	95	1.9%	1163.6	48.9%	1396.5
58	Tien Giang	Mekong river delta	2512	100	4.0%	1762.3	15.5%	1804.1
59	Tra Vinh	Mekong river delta	2356	49	2.1%	1049.8	18.3%	1299.2
60	Tuyen Quang	Northern midlands	5868	61	1.0%	780.1	13.9%	1024.3
61	Vinh Long	Mekong river delta	1524	60	3.9%	1051.8	25.0%	1398.8
62	Vinh Phuc	Red river delta	1237	79	6.4%	1092.4	17.0%	1675.0
63	Yen Bai	Northern Mountains	6887	54	0.8%	815.6	20.7%	1037.0

Table A3. Results of potential assessment.

ID	Province	Available Roof (km ²)	LCOE Mono (Euro cents/kWh)	LCOE Poly (Euro cents/kWh)	Production Potentials Mono (TWh/a)	Production Potentials Poly (TWh/a)	Installable Potentials Mono (GWP)	Installable Potentials Poly (GWP)	Specific Potential Mono (GWh/km ²)	Specific Potential Poly (GWh/km ²)
1	An Giang	28.2	7.6	7.2	6.3	6	4.6	4.4	1.8	1.7
2	Ba Ria-Vung Tau	17.7	7.6	7.2	4	3.8	2.9	2.7	2	1.9
3	Bac Giang	18.8	9	8.5	3.1	2.9	3	2.8	0.8	0.8
4	Bac Kan	7.2	9.3	8.7	1.1	1.1	1.2	1.1	0.2	0.2
5	Bac Lieu	13.8	7.8	7.4	3	2.8	2.3	2.1	1.1	1.1
6	Bac Ninh	17.6	8.9	8.4	2.9	2.8	2.8	2.7	3.6	3.4
7	Ben Tre	23.5	7.7	7.2	5.3	5	3.9	3.6	2.2	2.1
8	Binh Dinh	23	7.7	7.3	5.1	4.8	3.8	3.6	0.8	0.8
9	Binh Duong	22.6	7.6	7.2	5.2	4.9	3.7	3.5	1.9	1.8
10	Binh Phuoc	27.5	7.5	7.1	6.4	6	4.5	4.2	0.9	0.9
11	Binh Thuan	19.1	7.3	6.9	4.6	4.4	3.1	2.9	0.6	0.6
12	Ca Mau	24.5	7.9	7.5	5.2	4.9	4	3.8	1	0.9
13	Can Tho	16.5	7.7	7.3	3.6	3.4	2.7	2.6	2.6	2.4
14	Cao Bang	11	9.2	8.7	1.7	1.6	1.7	1.7	0.3	0.2
15	Da Nang	13.7	8	7.6	2.8	2.7	2.2	2.1	2.2	2.1
16	Dak Lak	22.4	7.6	7.2	5.1	4.8	3.6	3.4	0.4	0.4
17	Dak Nong	7.5	7.5	7.1	1.7	1.6	1.2	1.1	0.3	0.2
18	Dien Bien	10.7	8.4	7.9	1.9	1.8	1.7	1.6	0.2	0.2
19	Dong Nai	43.8	7.6	7.2	9.9	9.4	7.1	6.8	1.7	1.6
20	Dong Thap	24.9	7.6	7.2	5.7	5.3	4.1	3.8	1.7	1.6
21	Gia Lai	19.3	7.6	7.2	4.3	4.1	3.1	2.9	0.3	0.3

Table A3. Cont.

ID	Province	Available Roof (km ²)	LCOE Mono (Euro cents/kWh)	LCOE Poly (Euro cents/kWh)	Production Potentials Mono (TWh/a)	Production Potentials Poly (TWh/a)	Installable Potentials Mono (GWP)	Installable Potentials Poly (GWP)	Specific Potential Mono (GWh/km ²)	Specific Potential Poly (GWh/km ²)
22	Ha Giang	13.2	9.3	8.7	2	1.9	2.1	2	0.3	0.2
23	Ha Nam	13	8.9	8.4	2.2	2.1	2.1	2	2.5	2.4
24	Ha Noi	93.9	8.9	8.4	15.6	14.8	15.1	14.3	5	4.7
25	Ha Tinh	27.4	8.9	8.4	4.6	4.3	4.4	4.2	2.8	2.6
26	Hai Duong	24.7	8.9	8.3	4.2	3.9	4	3.8	2.7	2.6
27	Hai Phong	19.2	8.8	8.3	3.4	3.2	3.2	3	0.6	0.5
28	Hau Giang	11.9	7.9	7.4	2.5	2.4	2	1.8	1.6	1.5
29	Ho Chi Minh City	110	7.6	7.2	24.8	23.4	18	17	11.8	11.2
30	Hoa Binh	10	8.9	8.4	1.7	1.6	1.6	1.5	0.4	0.3
31	Hung Yen	16.6	8.9	8.4	2.8	2.6	2.7	2.5	3	2.9
32	Khanh Hoa	16.7	7.6	7.2	3.8	3.6	2.7	2.6	0.7	0.7
33	Kien Giang	31.7	7.8	7.4	6.8	6.5	5.2	4.9	1.1	1
34	Kon Tum	7.5	7.7	7.3	1.6	1.5	1.2	1.1	0.2	0.2
35	Lai Chau	9.5	8.6	8.1	1.6	1.6	1.5	1.4	0.2	0.2
36	Lam Dong	17.2	7.5	7.1	3.9	3.7	2.8	2.6	0.4	0.4
37	Lang Son	14.6	9.1	8.6	2.3	2.2	2.3	2.2	0.3	0.3
38	Lao Cai	10.8	9.2	8.7	1.7	1.6	1.7	1.6	0.3	0.3
39	Long An	29.6	7.6	7.2	6.8	6.4	4.8	4.6	1.5	1.4
40	Nam Dinh	27.1	8.8	8.3	4.7	4.4	4.4	4.1	2.8	2.7
41	Nghe An	45.4	8.6	8.1	8.1	7.7	7.4	7	0.5	0.5
42	Ninh Binh	16.3	8.9	8.3	2.8	2.6	2.6	2.5	2	1.9

Table A3. Cont.

ID	Province	Available Roof (km ²)	LCOE Mono (Euro cents/kWh)	LCOE Poly (Euro cents/kWh)	Production Potentials Mono (TWh/a)	Production Potentials Poly (TWh/a)	Installable Potentials Mono (GWP)	Installable Potentials Poly (GWP)	Specific Potential Mono (GWh/km ²)	Specific Potential Poly (GWh/km ²)
43	Ninh Thuan	7.8	7.3	6.9	1.9	1.8	1.3	1.2	0.6	0.5
44	Phu Tho	17.9	9.1	8.6	2.9	2.7	2.9	2.7	0.8	0.8
45	Phu Yen	13.4	7.7	7.3	3	2.8	2.2	2.1	0.6	0.6
46	Quang Binh	17.1	8.7	8.2	3	2.9	2.8	2.7	0.4	0.4
47	Quang Nam	25.6	8	7.6	5.3	5	4.2	4	0.5	0.5
48	Quang Ngai	18.3	7.8	7.4	3.9	3.7	3	2.8	0.8	0.7
49	Quang Ninh	43.8	9.2	8.6	7	6.6	7	6.6	1.1	1.1
50	Quang Tri	10.3	8.4	7.9	1.9	1.8	1.7	1.6	0.4	0.4
51	Soc Trang	20.9	7.8	7.4	4.5	4.3	3.4	3.2	1.4	1.3
52	Son La	19.7	8.5	8	3.5	3.3	3.1	3	0.2	0.2
53	Tay Ninh	24.5	7.4	7.1	5.8	5.4	4	3.8	1.4	1.3
54	Thai Binh	26.9	8.9	8.3	4.6	4.3	4.3	4.1	3	2.8
55	Thai Nguyen	16.5	9.3	8.7	2.6	2.4	2.7	2.5	0.7	0.7
56	Thanh Hoa	42.8	8.7	8.2	7.5	7.1	6.9	6.6	0.7	0.6
57	Thua Thien Hue	16.5	8.3	7.8	3.2	3	2.7	2.5	0.6	0.6
58	Tien Giang	28.6	7.6	7.2	6.4	6.1	4.7	4.4	2.6	2.4
59	Tra Vinh	16.8	7.7	7.3	3.7	3.5	2.7	2.6	1.6	1.5
60	Tuyen Quang	11.7	9.3	8.7	1.8	1.7	1.9	1.8	0.3	0.3
61	Vinh Long	16.5	7.7	7.3	3.6	3.4	2.7	2.6	2.4	2.3
62	Vinh Phuc	18.9	9	8.5	3.1	2.9	3	2.9	2.2	2.1
63	Yen Bai	13.1	9.2	8.7	2.1	1.9	2.1	2	0.3	0.3

Table A4. Results of clustering.

ID	Province	Available Roof (km ²)	LCOE Mono (Euro cents/kWh)	Production Potentials Mono (TWh/a)	Urban Rate 2018 (%)	gdp/a/Person 2018 (Euro/a)	Clustering Result	Priority
1	An Giang	28.2	7.6	6.3	30.8%	1612.1	1	5
2	Ba Ria-Vung Tau	17.7	7.6	4.0	52.4%	2210.3	2	3
3	Bac Giang	18.8	9.0	3.1	11.5%	1562.3	3	4
4	Bac Kan	7.2	9.3	1.1	18.8%	880.8	4	6
5	Bac Lieu	13.8	7.8	3.0	29.1%	1222.2	5	2
6	Bac Ninh	17.6	8.9	2.9	28.3%	2466.1	3	4
7	Ben Tre	23.5	7.7	5.3	10.8%	1543.7	5	2
8	Binh Dinh	23.0	7.7	5.1	31.0%	1369.4	5	2
9	Binh Duong	22.6	7.6	5.2	39.4%	3089.7	1	5
10	Binh Phuoc	27.5	7.5	6.4	22.0%	1632.0	1	5
11	Binh Thuan	19.1	7.3	4.6	78.2%	1560.0	2	3
12	Ca Mau	24.5	7.9	5.2	22.7%	1352.2	5	2
13	Can Tho	16.5	7.7	3.6	67.3%	1979.3	2	3
14	Cao Bang	11.0	9.2	1.7	23.2%	840.5	4	6
15	Da Nang	13.7	8.0	2.8	87.8%	2493.3	2	3
16	Dak Lak	22.4	7.6	5.1	24.7%	1244.4	5	2
17	Dak Nong	7.5	7.5	1.7	15.3%	1372.1	5	2
18	Dien Bien	10.7	8.4	1.9	15.1%	668.8	4	6
19	Dong Nai	43.8	7.6	9.9	35.6%	2400.0	1	5
20	Dong Thap	24.9	7.6	5.7	17.8%	1584.9	1	5
21	Gia Lai	19.3	7.6	4.3	30.9%	1171.0	5	2

Table A4. Cont.

ID	Province	Available Roof (km ²)	LCOE Mono (Euro cents/kWh)	Production Potentials Mono (TWh/a)	Urban Rate 2018 (%)	gdp/a/Person 2018 (Euro/a)	Clustering Result	Priority
22	Ha Giang	13.2	9.3	2.0	15.1%	781.1	4	6
23	Ha Nam	13.0	8.9	2.2	15.9%	1633.8	3	4
24	Ha Noi	93.9	8.9	15.6	64.6%	2741.4	6	1
25	Ha Tinh	27.4	8.9	4.6	18.7%	1287.8	3	4
26	Hai Duong	24.7	8.9	4.2	25.3%	1672.3	3	4
27	Hai Phong	19.2	8.8	3.4	46.8%	2316.7	2	3
28	Hau Giang	11.9	7.9	2.5	25.4%	1606.6	5	2
29	Ho Chi Minh City	110.0	7.6	24.8	80.5%	2797.1	6	1
30	Hoa Binh	10.0	8.9	1.7	14.8%	1039.2	4	6
31	Hung Yen	16.6	8.9	2.8	13.0%	1740.2	3	4
32	Khanh Hoa	16.7	7.6	3.8	45.0%	1564.5	5	2
33	Kien Giang	31.7	7.8	6.8	29.2%	1711.2	1	5
34	Kon Tum	7.5	7.7	1.6	35.5%	908.8	5	2
35	Lai Chau	9.5	8.6	1.6	17.3%	676.1	4	6
36	Lam Dong	17.2	7.5	3.9	39.8%	1648.8	5	2
37	Lang Son	14.6	9.1	2.3	20.3%	926.9	4	6
38	Lao Cai	10.8	9.2	1.7	22.9%	1052.4	4	6
39	Long An	29.6	7.6	6.8	18.0%	1908.7	1	5
40	Nam Dinh	27.1	8.8	4.7	18.7%	1532.4	3	4
41	Nghe An	45.4	8.6	8.1	15.1%	1151.5	3	4
42	Ninh Binh	16.3	8.9	2.8	21.1%	1191.4	4	6

Table A4. Cont.

ID	Province	Available Roof (km ²)	LCOE Mono (Euro cents/kWh)	Production Potentials Mono (TWh/a)	Urban Rate 2018 (%)	gdp/a/Person 2018 (Euro/a)	Clustering Result	Priority
43	Ninh Thuan	7.8	7.3	1.9	36.2%	1710.8	5	2
44	Phu Tho	17.9	9.1	2.9	19.1%	1309.6	4	6
45	Phu Yen	13.4	7.7	3.0	29.1%	1284.7	5	2
46	Quang Binh	17.1	8.7	3.0	63.9%	1207.2	2	3
47	Quang Nam	25.6	8.0	5.3	19.8%	1315.9	5	2
48	Quang Ngai	18.3	7.8	3.9	30.3%	1313.2	5	2
49	Quang Ninh	43.8	9.2	7.0	24.3%	2163.2	3	4
50	Quang Tri	10.3	8.4	1.9	15.2%	1151.5	4	6
51	Soc Trang	20.9	7.8	4.5	30.6%	1654.2	5	2
52	Son La	19.7	8.5	3.5	13.7%	671.5	4	6
53	Tay Ninh	24.5	7.4	5.8	22.6%	1928.2	1	5
54	Thai Binh	26.9	8.9	4.6	10.5%	1818.1	3	4
55	Thai Nguyen	16.5	9.3	2.6	35.3%	1606.2	3	4
56	Thanh Hoa	42.8	8.7	7.5	17.3%	1365.3	3	4
57	Thua Thien Hue	16.5	8.3	3.2	48.9%	1396.5	2	3
58	Tien Giang	28.6	7.6	6.4	15.5%	1804.1	1	5
59	Tra Vinh	16.8	7.7	3.7	18.3%	1299.2	5	2
60	Tuyen Quang	11.7	9.3	1.8	13.9%	1024.3	4	6
61	Vinh Long	16.5	7.7	3.6	25.0%	1398.8	5	2
62	Vinh Phuc	18.9	9.0	3.1	17.0%	1675.0	3	4
63	Yen Bai	13.1	9.2	2.1	20.7%	1037.0	4	6

Table A5. Market benefit changes according to different FIT strategies.

ID	Province	FIT_2.0 (Euro cents/kWh)	Delta_1_1.0 (Euro cents/kWh)	Delta_1_2.0 (Euro cents/kWh)	Delta_1_2.1 (Euro cents/kWh)	Benefit_1.0 (10 ⁶ Euro)	Benefit_2.0 (10 ⁶ Euro)	Benefit_2.1 (10 ⁶ Euro)
1	An Giang	7.95	1.23	0.35	0.31	77.49	22.25	19.53
2	Ba Ria-Vung Tau	7.95	1.23	0.35	0.31	49.20	14.13	12.40
3	Bac Giang	10.32	-0.17	1.32	-1.09	-5.27	40.90	-33.79
4	Bac Kan	10.32	-0.47	1.02	-1.39	-5.17	11.21	-15.29
5	Bac Lieu	7.95	1.03	0.15	0.11	30.90	4.60	3.30
6	Bac Ninh	10.32	-0.07	1.42	-0.99	-2.03	41.16	-28.71
7	Ben Tre	7.95	1.13	0.25	0.21	59.89	13.42	11.13
8	Binh Dinh	7.95	1.13	0.25	0.21	57.63	12.91	10.71
9	Binh Duong	7.95	1.23	0.35	0.31	63.96	18.37	16.12
10	Binh Phuoc	7.95	1.33	0.45	0.41	85.12	29.01	26.24
11	Binh Thuan	7.48	1.53	0.18	0.61	70.38	8.47	28.06
12	Ca Mau	7.95	0.93	0.05	0.01	48.36	2.77	0.52
13	Can Tho	7.95	1.13	0.25	0.21	40.68	9.12	7.56
14	Cao Bang	10.32	-0.37	1.12	-1.29	-6.29	19.03	-21.93
15	Da Nang	8.88	0.83	0.88	-0.09	23.24	24.61	-2.52
16	Dak Lak	7.48	1.23	-0.12	0.31	62.73	-5.91	15.81
17	Dak Nong	7.95	1.33	0.45	0.41	22.61	7.70	6.97
18	Dien Bien	8.88	0.43	0.48	-0.49	8.17	9.10	-9.31
19	Dong Nai	7.95	1.23	0.35	0.31	121.77	34.97	30.69
20	Dong Thap	7.95	1.23	0.35	0.31	70.11	20.13	17.67
21	Gia Lai	7.48	1.23	-0.12	0.31	52.89	-4.98	13.33

Table A5. Cont.

ID	Province	FIT_2.0 (Euro cents/kWh)	Delta_1_1.0 (Euro cents/kWh)	Delta_1_2.0 (Euro cents/kWh)	Delta_1_2.1 (Euro cents/kWh)	Benefit_1.0 (10 ⁶ Euro)	Benefit_2.0 (10 ⁶ Euro)	Benefit_2.1 (10 ⁶ Euro)
22	Ha Giang	10.32	−0.47	1.02	−1.39	−9.40	20.38	−27.80
23	Ha Nam	10.32	−0.07	1.42	−0.99	−1.54	31.22	−21.78
24	Ha Noi	10.32	−0.07	1.42	−0.99	−10.92	221.40	−154.44
25	Ha Tinh	10.32	−0.07	1.42	−0.99	−3.22	65.29	−45.54
26	Hai Duong	10.32	−0.07	1.42	−0.99	−2.94	59.61	−41.58
27	Hai Phong	10.32	0.03	1.52	−0.89	1.02	51.65	−30.26
28	Hau Giang	7.95	0.93	0.05	0.01	23.25	1.33	0.25
29	Ho Chi Minh City	7.95	1.23	0.35	0.31	305.04	87.60	76.88
30	Hoa Binh	10.32	−0.07	1.42	−0.99	−1.19	24.13	−16.83
31	Hung Yen	10.32	−0.07	1.42	−0.99	−1.96	39.74	−27.72
32	Khanh Hoa	7.48	1.23	−0.12	0.31	46.74	−4.40	11.78
33	Kien Giang	7.95	1.03	0.15	0.11	70.04	10.42	7.48
34	Kon Tum	7.95	1.13	0.25	0.21	18.08	4.05	3.36
35	Lai Chau	10.32	0.23	1.72	−0.69	3.68	27.51	−11.04
36	Lam Dong	7.95	1.33	0.45	0.41	51.87	17.68	15.99
37	Lang Son	10.32	−0.27	1.22	−1.19	−6.21	28.04	−27.37
38	Lao Cai	10.32	−0.37	1.12	−1.29	−6.29	19.03	−21.93
39	Long An	7.95	1.23	0.35	0.31	83.64	24.02	21.08
40	Nam Dinh	10.32	0.03	1.52	−0.89	1.41	71.40	−41.83
41	Nghe An	10.32	0.23	1.72	−0.69	18.63	139.26	−55.89
42	Ninh Binh	10.32	−0.07	1.42	−0.99	−1.96	39.74	−27.72

Table A5. Cont.

ID	Province	FIT_2.0 (Euro cents/kWh)	Delta_1_1.0 (Euro cents/kWh)	Delta_1_2.0 (Euro cents/kWh)	Delta_1_2.1 (Euro cents/kWh)	Benefit_1.0 (10 ⁶ Euro)	Benefit_2.0 (10 ⁶ Euro)	Benefit_2.1 (10 ⁶ Euro)
43	Ninh Thuan	7.48	1.53	0.18	0.61	29.07	3.50	11.59
44	Phu Tho	10.32	-0.27	1.22	-1.19	-7.83	35.36	-34.51
45	Phu Yen	7.48	1.13	-0.22	0.21	33.90	-6.48	6.30
46	Quang Binh	10.32	0.13	1.62	-0.79	3.90	48.58	-23.70
47	Quang Nam	8.88	0.83	0.88	-0.09	43.99	46.58	-4.77
48	Quang Ngai	8.88	1.03	1.08	0.11	40.17	42.08	4.29
49	Quang Ninh	10.32	-0.37	1.12	-1.29	-25.90	78.35	-90.30
50	Quang Tri	8.88	0.43	0.48	-0.49	8.17	9.10	-9.31
51	Soc Trang	7.95	1.03	0.15	0.11	46.35	6.89	4.95
52	Son La	10.32	0.33	1.82	-0.59	11.55	63.67	-20.65
53	Tay Ninh	7.95	1.43	0.55	0.51	82.94	32.09	29.58
54	Thai Binh	10.32	-0.07	1.42	-0.99	-3.22	65.29	-45.54
55	Thai Nguyen	10.32	-0.47	1.02	-1.39	-12.22	26.50	-36.14
56	Thanh Hoa	10.32	0.13	1.62	-0.79	9.75	121.44	-59.25
57	Thua Thien Hue	8.88	0.53	0.58	-0.39	16.96	18.52	-12.48
58	Tien Giang	7.95	1.23	0.35	0.31	78.72	22.61	19.84
59	Tra Vinh	7.95	1.13	0.25	0.21	41.81	9.37	7.77
60	Tuyen Quang	10.32	-0.47	1.02	-1.39	-8.46	18.35	-25.02
61	Vinh Long	7.95	1.13	0.25	0.21	40.68	9.12	7.56
62	Vinh Phuc	10.32	-0.17	1.32	-1.09	-5.27	40.90	-33.79
63	Yen Bai	10.32	-0.37	1.12	-1.29	-7.77	23.50	-27.09

Note: FIT 1.0 = 8.83 Euro cents/kWh & FIT 2.1 = 7.91 (Euro cents/kWh) are applied for all regions.

Table A6. Market benefit changes according to different grid tariff strategies.

ID	Province	Delta_2_2019 (Euro cents/kWh)	Delta_2_2025 (Euro cents/kWh)	Benefit_2019 (10 ⁶ Euro)	Benefit_2025 (10 ⁶ Euro)
1	An Giang	−0.40	1.10	−25.20	69.30
2	Ba Ria–Vung Tau	−0.40	1.10	−16.00	44.00
3	Bac Giang	−1.80	−0.30	−55.80	−9.30
4	Bac Kan	−2.10	−0.60	−23.10	−6.60
5	Bac Lieu	−0.60	0.90	−18.00	27.00
6	Bac Ninh	−1.70	−0.20	−49.30	−5.80
7	Ben Tre	−0.50	1.00	−26.50	53.00
8	Binh Dinh	−0.50	1.00	−25.50	51.00
9	Binh Duong	−0.40	1.10	−20.80	57.20
10	Binh Phuoc	−0.30	1.20	−19.20	76.80
11	Binh Thuan	−0.10	1.40	−4.60	64.40
12	Ca Mau	−0.70	0.80	−36.40	41.60
13	Can Tho	−0.50	1.00	−18.00	36.00
14	Cao Bang	−2.00	−0.50	−34.00	−8.50
15	Da Nang	−0.80	0.70	−22.40	19.60
16	Dak Lak	−0.40	1.10	−20.40	56.10
17	Dak Nong	−0.30	1.20	−5.10	20.40
18	Dien Bien	−1.20	0.30	−22.80	5.70
19	Dong Nai	−0.40	1.10	−39.60	108.90
20	Dong Thap	−0.40	1.10	−22.80	62.70
21	Gia Lai	−0.40	1.10	−17.20	47.30

Table A6. Cont.

ID	Province	Delta_2_2019 (Euro cents/kWh)	Delta_2_2025 (Euro cents/kWh)	Benefit_2019 (10 ⁶ Euro)	Benefit_2025 (10 ⁶ Euro)
22	Ha Giang	-2.10	-0.60	-42.00	-12.00
23	Ha Nam	-1.70	-0.20	-37.40	-4.40
24	Ha Noi	-1.70	-0.20	-265.20	-31.20
25	Ha Tinh	-1.70	-0.20	-78.20	-9.20
26	Hai Duong	-1.70	-0.20	-71.40	-8.40
27	Hai Phong	-1.60	-0.10	-54.40	-3.40
28	Hau Giang	-0.70	0.80	-17.50	20.00
29	Ho Chi Minh City	-0.40	1.10	-99.20	272.80
30	Hoa Binh	-1.70	-0.20	-28.90	-3.40
31	Hung Yen	-1.70	-0.20	-47.60	-5.60
32	Khanh Hoa	-0.40	1.10	-15.20	41.80
33	Kien Giang	-0.60	0.90	-40.80	61.20
34	Kon Tum	-0.50	1.00	-8.00	16.00
35	Lai Chau	-1.40	0.10	-22.40	1.60
36	Lam Dong	-0.30	1.20	-11.70	46.80
37	Lang Son	-1.90	-0.40	-43.70	-9.20
38	Lao Cai	-2.00	-0.50	-34.00	-8.50
39	Long An	-0.40	1.10	-27.20	74.80
40	Nam Dinh	-1.60	-0.10	-75.20	-4.70
41	Nghe An	-1.40	0.10	-113.40	8.10
42	Ninh Binh	-1.70	-0.20	-47.60	-5.60

Table A6. Cont.

ID	Province	Delta_2_2019 (Euro cents/kWh)	Delta_2_2025 (Euro cents/kWh)	Benefit_2019 (10 ⁶ Euro)	Benefit_2025 (10 ⁶ Euro)
43	Ninh Thuan	−0.10	1.40	−1.90	26.60
44	Phu Tho	−1.90	−0.40	−55.10	−11.60
45	Phu Yen	−0.50	1.00	−15.00	30.00
46	Quang Binh	−1.50	0.00	−45.00	0.00
47	Quang Nam	−0.80	0.70	−42.40	37.10
48	Quang Ngai	−0.60	0.90	−23.40	35.10
49	Quang Ninh	−2.00	−0.50	−140.00	−35.00
50	Quang Tri	−1.20	0.30	−22.80	5.70
51	Soc Trang	−0.60	0.90	−27.00	40.50
52	Son La	−1.30	0.20	−45.50	7.00
53	Tay Ninh	−0.20	1.30	−11.60	75.40
54	Thai Binh	−1.70	−0.20	−78.20	−9.20
55	Thai Nguyen	−2.10	−0.60	−54.60	−15.60
56	Thanh Hoa	−1.50	0.00	−112.50	0.00
57	Thua Thien Hue	−1.10	0.40	−35.20	12.80
58	Tien Giang	−0.40	1.10	−25.60	70.40
59	Tra Vinh	−0.50	1.00	−18.50	37.00
60	Tuyen Quang	−2.10	−0.60	−37.80	−10.80
61	Vinh Long	−0.50	1.00	−18.00	36.00
62	Vinh Phuc	−1.80	−0.30	−55.80	−9.30
63	Yen Bai	−2.00	−0.50	−42.00	−10.50

Note: Grid tariff in 2019 = 7.2 Euro cents/kWh & Grid tariff in 2025 = 8.7 (Euro cents/kWh) are applied for all regions.

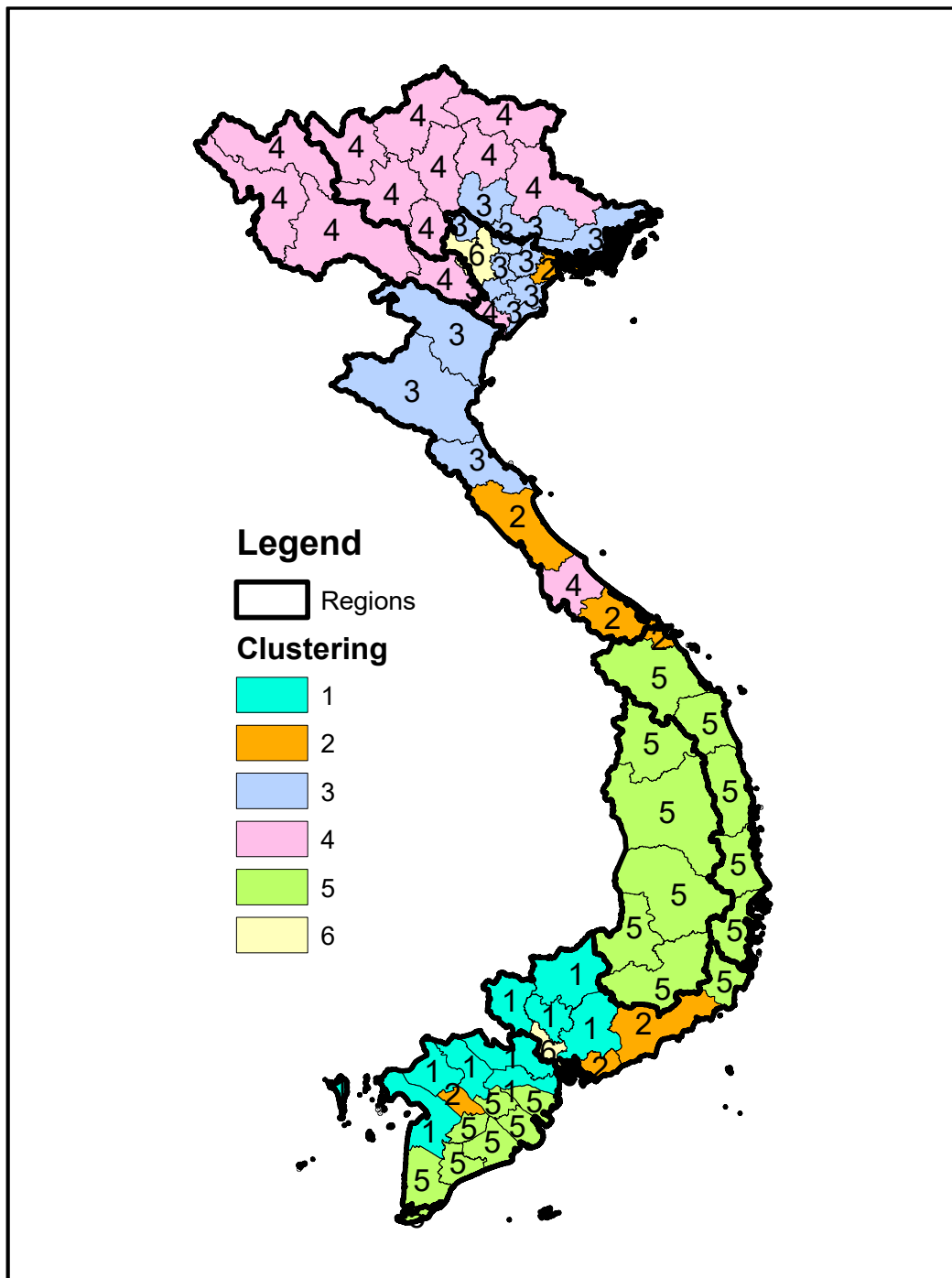
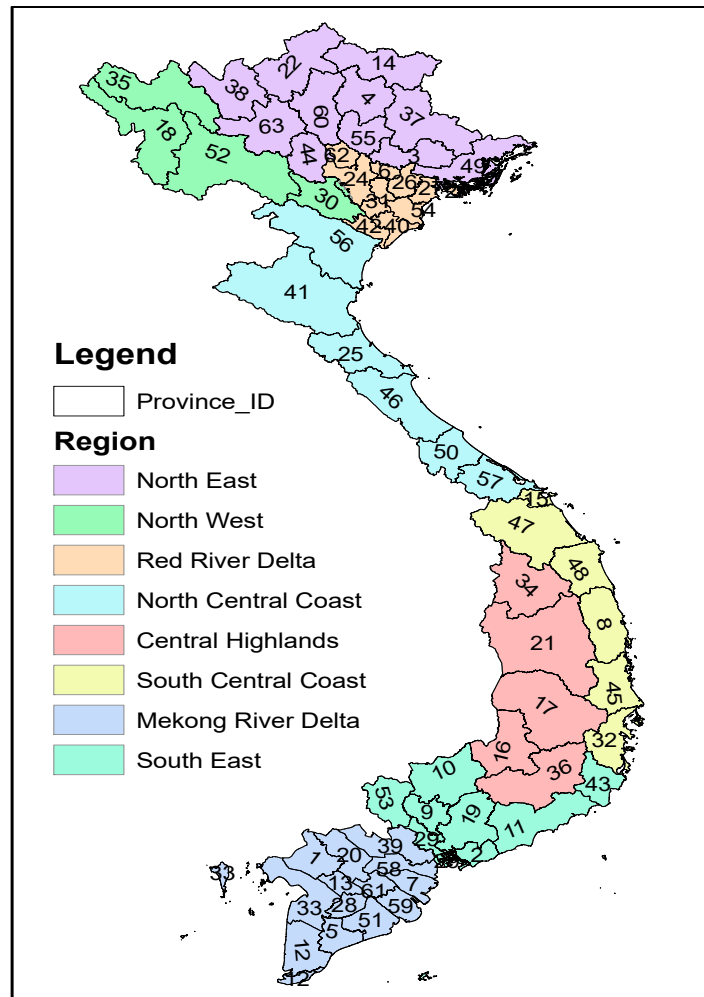


Figure A1. The clustering distribution on map.



ID	Province	ID	Province	ID	Province
1	An Giang	22	Ha Giang	43	Ninh Thuan
2	Ba Ria-Vung Tau	23	Ha Nam	44	Phu Tho
3	Bac Giang	24	Ha Noi	45	Phu Yen
4	Bac Kan	25	Ha Tinh	46	Quang Binh
5	Bac Lieu	26	Hai Duong	47	Quang Nam
6	Bac Ninh	27	Hai Phong	48	Quang Ngai
7	Ben Tre	28	Hau Giang	49	Quang Ninh
8	Binh Dinh	29	Ho Chi Minh City	50	Quang Tri
9	Binh Duong	30	Hoa Binh	51	Soc Trang
10	Binh Phuoc	31	Hung Yen	52	Son La
11	Binh Thuan	32	Khanh Hoa	53	Tay Ninh
12	Ca Mau	33	Kien Giang	54	Thai Binh
13	Can Tho	34	Kon Tum	55	Thai Nguyen
14	Cao Bang	35	Lai Chau	56	Thanh Hoa
15	Da Nang	36	Lam Dong	57	Thua Thien Hue
16	Dak Lak	37	Lang Son	58	Tien Giang
17	Dak Nong	38	Lao Cai	59	Tra Vinh
18	Dien Bien	39	Long An	60	Tuyen Quang
19	Dong Nai	40	Nam Dinh	61	Vinh Long
20	Dong Thap	41	Nghe An	62	Vinh Phuc
21	Gia Lai	42	Ninh Binh	63	Yen Bai

Figure A2. Administration map of Vietnam: Regions and Name & ID of Provinces.

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