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PAPER

Evaluating the levelized costs and life cycle greenhouse gas emissions of electricity generation from rooftop solar photovoltaics: a Swiss case study

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Abstract

The transition to renewable energy sources is pivotal in addressing global climate change challenges, with rooftop solar photovoltaic (PV) systems playing a crucial role. For informed decision-making in energy policy, it is important to have a comprehensive understanding of both the economic and environmental performance of rooftop solar PV. This study provides a high-resolution analysis of existing rooftop solar PV systems in Switzerland by assessing the robustness of the potential estimation to properly derive the amount of electricity generated by individual systems, and subsequently quantify the levelized cost of electricity and life cycle greenhouse gas (GHG) emissions of electricity generation from PV and compare them with those of grid electricity supplies. Our results indicate substantial geographical variations between potential estimations and real-world installations, with notable underestimations of approximately 1.3 Gigawatt-peak, primarily for systems around 10 kWp in size, mainly due to the quality of input data and conservative estimation. The study finds that in many regions and for most of the installed capacity, electricity generated from rooftop PV systems is more economical than the grid electricity supply, mainly driven by factors including high electricity prices, larger installations and abundant solar irradiance. The GHG emissions assessment further emphasizes the importance of methodological choice, with stark contrasts between electricity certificate-based approaches and others that are based on the consumption mix. This study suggests the need for more accurate geographical potential estimations, enhanced support for small-scale rooftop PV systems, and more incentives to maximize the potential of their roof area for PV deployment. As Switzerland progresses towards its renewable energy goals, our research underscores the importance of informed policymaking based on a retrospective analysis of existing installations, essential for maximizing the potential and benefits of rooftop solar PV systems.

1. Introduction

To address the challenges of climate change, a global shift towards renewable energy sources is occurring, and solar photovoltaics (PV) have emerged as a key technology. The past decade has witnessed a reduction of approximately 90% in the cost of solar PV, positioning it as a pivotal renewable technology for the global energy transition (IRENA 2022). Solar PV has not only become a cost-effective option but also a leading contributor to global electricity generation, with an annual production of approximately 1300 Terawatt-hour (TWh) and surpassing 1000 Gigawatt-peak (GWp) in cumulative installed capacity by 2022, making it the fastest-growing renewable energy source (IRENA 2022, IEA 2023).

Switzerland serves as an interesting case study in this context as well as a broader transition towards more sustainable energy systems due to its ambitious commitment to integrating renewable sources into its energy system. As delineated in its 2050 Energy Strategy, Switzerland aims to maintain its low greenhouse gas (GHG) emissions of electricity production, relying on a significant supply from solar PV to achieve this objective (Kemmler *et al* 2021). The country aims to produce 34 TWh annually from solar PV by 2050, which would satisfy more than half of its current electricity demand (SFOE 2023a). Additionally, the country's pivotal location in the European electricity network, acting as an essential channel for electricity transmission and exchange, renders its experience particularly relevant to other nations that encounter similar energy system challenges. Furthermore, the prevalent presence of residential buildings in the national building stock, notably single-family houses with limited rooftop space (FSO 2023), emphasizes the necessity for refined assessments of solar PV potential and bottom-up adoption considering both economic and environmental factors.

Large-scale ground-level PV systems have been subject to extensive discussions regarding their social acceptance (Späth 2018, Cousse 2021, Vuichard *et al* 2021) and have constrained potential when considering appropriate locations (Meyer *et al* 2023). In contrast, PV systems on building rooftops have emerged as preferred alternatives because of their greater social acceptance (Späth 2018) and lower costs (SFOE 2022b).

Previous research on rooftop solar PV in Switzerland has explored its spatial diffusion (Thormeyer *et al* 2020, Hirt *et al* 2021), model comparisons for short-term installation projections (Müller and Trutnevyte 2020, Wen *et al* 2023), and policy and social influences on adoption (Bach *et al* 2020, Petrovich *et al* 2021). However, there is a lack of combined understanding of the economic and environmental performances of rooftop solar PV systems on individual buildings. This could be particularly reflected by the levelized cost of electricity (LCOE) and life cycle GHG emissions (referred to as 'GHG emissions' hereafter) of electricity generation from rooftop solar PV. Understanding these aspects and comparing them with alternative grid electricity supplies would crucially affect the adoption of rooftop solar PV (Bach *et al* 2020). Additionally, there is a lack of studies exploring various methodologies and recent data for quantifying grid supply GHG emissions, which is essential for reliable comparisons with electricity from rooftop solar PV systems.

An improved understanding of these issues will guide policy decisions and investment in solar PV systems in Switzerland. Therefore, in light of these gaps, our study focuses on the following research questions:

(1) Considering the power capacity of existing systems, how robust and realistic are the potential estimates for rooftop PV systems in Switzerland?
(2) Given the current electricity tariffs, which existing rooftop PV systems are beneficial in terms of their LCOE compared to the grid supply tariff, and what are the driving factors?
(3) What are the differences in methodological approaches for calculating the GHG emissions of grid supply, and how do these impact the comparison of GHG emissions of PV-generated electricity versus grid supply?

To answer these questions, this study aims to conduct a national evaluation of rooftop PV systems in Switzerland at the individual building level. Our study focuses on both the LCOE and GHG emissions of electricity generated by rooftop PV systems. The paper is organized as follows. It begins with an extensive literature review, establishing the foundation for addressing the identified research gaps (section 2). The methods are explained in detail (section 3), starting with an assessment of the disparity between potential rooftop PV estimates and actual installations as a basis for quantifying LCOE and GHG emissions. This assessment allows us to select reliable data for calculating LCOE and GHG emissions, and further compare them with the costs and GHG emissions of grid supplies. Subsequently, the three methodologies applied to quantify the GHG emissions of grid supplies are explained, and their impact on our findings is examined. The outcomes highlight regions with favourable conditions for rooftop PV installations and areas needing more support in Switzerland. After presenting the results (section 4), the study proceeds to the discussion section (section 5), where the quality of key input data and the robustness of our approach are discussed in detail. While acknowledging the limitations of this study, it proposes future research directions. Finally, the study concludes by summarizing the key findings and discussing their implications for the expansion of rooftop PV systems in Switzerland (section 6), thereby contributing valuable insights to both the scientific community and policy-makers.

2. Literature review

Different solar PV technologies offer varying efficiency, costs, and environmental impacts. Crystalline Si-based solar cells dominate the market due to their balanced performance in terms of cost, efficiency and long-term stability (Heinrich *et al* 2020). Thin-film cells, while cost-effective with low material usage, generally have lower efficiency. Emerging technologies such as organic, dye-sensitized, and perovskite cells show promise. Perovskite cells, in particular, quickly achieve high efficiencies comparable to crystalline Si-based cells but are prone to moisture and oxygen degradation. For these various reasons, in Switzerland, crystalline Si-based PV systems are prevalent in rooftop installations, with monocrystalline cells presently favoured for their continuously improved efficiency in recent years (National Renewable Energy Laboratory 2024). The adoption and diffusion of rooftop solar PV technology in Switzerland have been extensively studied, with a focus on understanding the spatial distribution and drivers of adoption. Müller *et al* assessed the accuracy of regression models in projecting the spatial distributions of solar PV installations in Switzerland (Müller and Trutnevyte 2020). Hirt *et al* scrutinized the uneven diffusion of PV systems at a subnational level and explored the socio-technical regimes that foster solar PV adoption (Hirt *et al* 2021). Thormeyer *et al* emphasized the importance of accounting for real-world diffusion dynamics in creating spatially explicit models for renewable electricity (Thormeyer *et al* 2020). Wen *et al* evaluated statistical and optimization models projecting solar PV installations in Switzerland based on solar PV deployment from 2012 to 2020 at the district level. The authors concluded that the statistical regression model outperformed those based on extrapolation or optimization and stressed the importance of socio-demographic and techno-economic considerations (Wen *et al* 2023). Other studies explored the influence of energy policies on the dynamics of household adoption (Bach *et al* 2020), and investigated the policy-related risks and diversity for residential solar PV investments (Petrovich *et al* 2021, Schmidt *et al* 2023). In addition to spatial diffusion and policy influences, Hirt demonstrated a consistent and favourable depiction of solar PV in Swiss media and parliamentary discussions, emphasizing the solidification of techno-economic, technocratic, and reactive approaches in solar PV deployment (Hirt 2024). Another recent study by Lonergan *et al* highlighted the influence of distribution system operators on the uptake of solar PV in Switzerland, revealing that differences in solar PV adoption can be attributed to varying business models, despite a non-discriminatory connection policy (Lonergan and Sansavini 2022). In addition, the visibility of solar PV in urban planning and its role in enhancing social acceptability in urban environments have been discussed in Florio *et al* (2018).

In practice, the utilization of potential rooftop spaces for the installation of solar PV is primarily influenced by cost and construction-related factors (Remund and Albrecht 2019). Moreover, it is crucial to factor in the GHG emissions of PV systems to meet the public's desire for environmental sustainability (Koch and Christ 2018, Bach *et al* 2020). However, studies examining both the cost and GHG emissions of rooftop PV systems at a national scale for individual buildings are lacking. Bauer *et al* analyzed the costs and GHG emissions of rooftop solar PV systems on buildings in Switzerland for 2017, projecting trajectories for future costs up to 2050 (Bauer *et al* 2017). Han *et al* provided a techno-economic analysis of integrating rooftop PV systems with battery storage for various customer clusters in Switzerland from 2020 to 2050, demonstrating the economic viability of this combined system in some cases (2022). However, both these studies analyzed either the typical sizes of the system in terms of power capacity or representative customer groups given the median value of their characteristics (e.g. solar irradiance, roof size, etc) rather than individual buildings in the real world. Furthermore, comparing these values with grid supplies would provide insights into the specific benefits of rooftop PV systems, especially given the recent global geopolitical conflicts, which have led to significant changes in electricity prices and fuel shares in electricity generation (Ari *et al* 2022, Guan *et al* 2023). Regarding the GHG emissions of the grid supply, the literature lacks recent discussions on the implications of various methodological approaches, particularly in the Swiss context of evaluating rooftop PV systems. Contemporary analyses incorporating current data and different methodologies to assess GHG emissions of the grid supply are lacking.

Additionally, the estimation of both the cost and GHG emissions of electricity generated from PV systems requires the amount of electricity generated. Owing to the absence of detailed statistics on rooftop PV yields at the individual building level on a national scale, studies with potential estimations are referred to. Studies have estimated the physical, geographical, and technical potential of rooftop solar PV systems in Switzerland considering different factors. Assouline *et al* employed a Geographic Information System (GIS) and machine learning techniques to estimate this potential (*et al* 2017, 2018). Peronato *et al* developed a decision-support toolkit that incorporates the uncertainties from weather and vegetation and helps to prioritize locations based on the solar electricity generation potential (*et al* 2018). Walch *et al* improved upon these estimates by considering factors such as shading effects, sky view factor, and temperature influence, resulting in more realistic estimates of 24 ± 9 TWh of annual electricity generation (SFOE *et al* 2020, Walch *et al* 2020). A recent study that considered less productive roofs and an optimized east-west installation on flat roofs increased these estimates to approximately 41 TWh of annual generation (Walch and Rüdisüli 2023). Currently, approximately 4.7 GWp of PV systems are installed in Switzerland (SFOE 2023d). However, there is a lack of analysis comparing the potential estimates for these buildings on a national scale with the actual installed capacities to understand the robustness of the potential estimation.

Finally, factors such as solar irradiance, available area, and local grid supply that influence the cost and GHG emissions of electricity from rooftop PV systems have not been systematically analyzed. Identifying factors that render specific systems more attractive in terms of low GHG emissions and costs is a research avenue that remains unexplored. This study aims to fill these gaps by offering a comprehensive analysis of rooftop solar PV in Switzerland with a focus on the LCOE and GHG emissions of electricity generated by individual systems, thereby contributing to a more nuanced understanding of directions for potential policy and strategy development that further expands the adoption of rooftop PV systems in Switzerland.

3. Method

This section outlines the methodological framework of our study, aimed at assessing rooftop solar PV systems in Switzerland as of August 2023, with a focus on their cost and GHG emissions. Figure 1 provides an overview of our analytical approach with various steps aligned with the corresponding subsections. Our initial step involves verifying the robustness of potential estimates by comparing the power capacity of the actual installed systems to their maximum capacity in the potential estimates (Step 1, section 3.1). This crucial step ensures the selection of proper input parameters for determining the electricity generation of each system (Step 2, section 3.2). Following this, each system's LCOE and GHG emissions were computed (Step 3, sections 3.3 and 3.4) and compared with those of alternative grid supplies (Step 4, section 3.5).

3.1. Robustness of potential estimation

3.1.1. Chosen potential estimation

The potential of rooftop solar PV systems in Switzerland has been quantified using various approaches in previous studies. These approaches encompass reviews (Biollaz *et al* 2021, Bucher 2022), simple calculations based on key assumptions (Bauer *et al* 2017, 2019, Remund and Albrecht 2019), analyses relying on national data (SFOE *et al* 2020), energy systems models (Kemmler *et al* 2021, Marcucci *et al* 2023), and considerations, such as potential grid expansion and storage (Gupta *et al* 2021). This study relies on the most recent PV potential estimation for Switzerland (Walch and Rüdisüli 2023), which builds upon the previous work of Walch *et al* (2020) based on methods involving high-resolution data of roof typologies, satellite images, and building registry statistics. Notably, this latest estimation adjusted the potential estimates for flat roofs (roofs with a tilt angle of less than 10°) to make them less conservative and more realistic by installing alternating east- and west-facing rows of panels with a tilt angle of 15°. In addition, it incorporates the stochasticity of solar radiation based on the lowest (in 2010) and highest (in 2011) solar irradiance in recent years. With these enhancements, the study concluded a maximum feasible potential of approximately 41 TWh of annual PV electricity generation if all building rooftops are exploited in Switzerland (Walch and Rüdisüli 2023).

3.1.2. Matching existing systems with potential estimation

Data on existing PV systems installed and registered in Switzerland until August 2023, including their address (number, street, municipality, and canton), geographical coordinates, initial and total installed capacity, and the start of operation, were obtained from the registered PV systems in the database of power generation plants in Switzerland (SFOE 2023b). To assess the robustness of electricity generation in the potential estimation, which is required for the quantification of LCOE and GHG emissions, the power capacities of these registered systems were compared with their estimated maximum power capacities in the potential estimates. Mapping registered systems to their corresponding potential estimates is achieved using the EGID (Eidgenössischer Gebäudeidentifikator) from the federal building and apartment registry (Eidgenóssisches Gebäude- und Wohnungsregister, GWR) (FSO 2022). The mapping follows a two-step process, which is described in detail in appendix A. The percentage of power capacity differences between the registered systems and the systems in the potential estimates was calculated for each system using equation (1),

$$\mathrm{Diff}_{\mathrm{PC}} = \left(\mathrm{PC}_{\mathrm{potential}} - \mathrm{PC}_{\mathrm{registered}}\right) / \mathrm{PC}_{\mathrm{registered}} \quad (1)$$

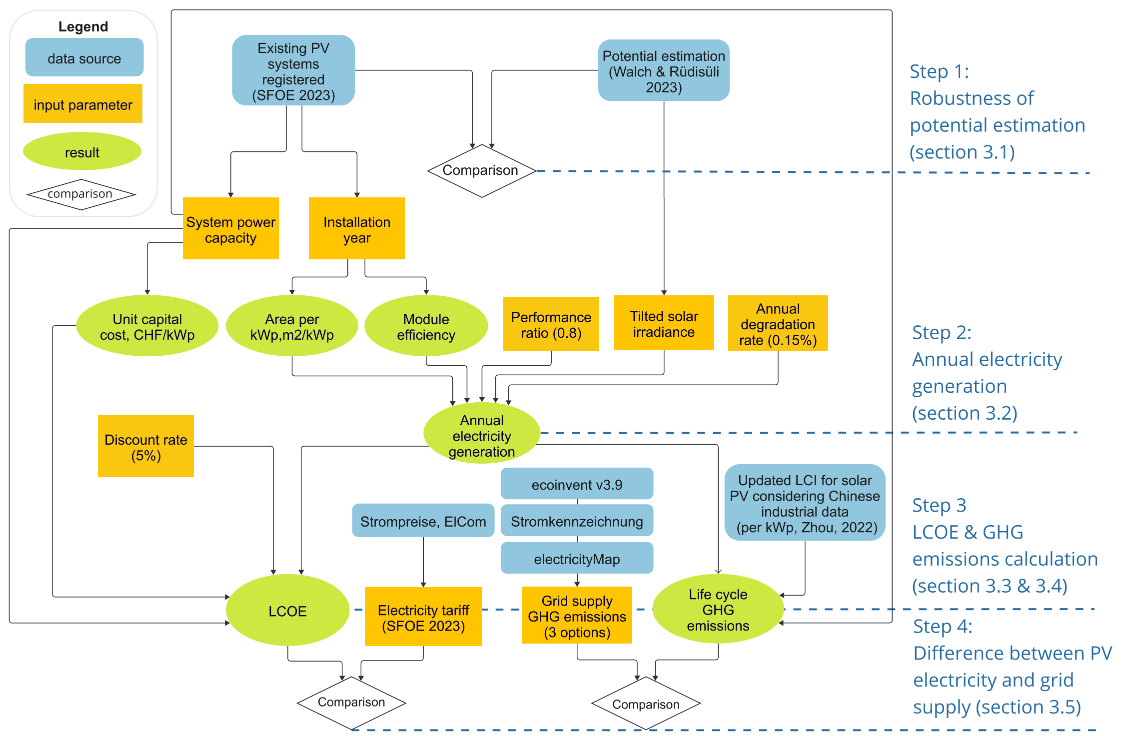

Figure 1. Overview of the analytical approach.

where Diff_{PC} is the power capacity difference in percentage, $\text{PC}_{\text{potential}}$ is the estimated power capacity of the registered system in the potential estimate in kWp, and $\text{PC}_{\text{registered}}$ is the actual installed power capacity of the registered system in kWp.

3.2. Annual electricity generation

The annual electricity generation for each system was estimated using equations (2) and (3), and was employed to calculate both the LCOE and GHG emissions of electricity generated by rooftop solar PV systems,

$$E_1 = \text{S} * \text{ApK} * \text{TSI} * \text{ME} * \text{PR} \tag{2}$$

where E_1 is the annual electricity generation in the first year of operation, in kWh yr^{-1}; S is the system size in kWp; ApK is the area per kWp in $\text{m}^2\,\text{kWp}^{-1}$; TSI is tilted solar irradiance in kWh m^{-2} obtained from Walch and Rüdisüli (2023); ME is the module efficiency based on system size; and PR is the average performance ratio of the system, assumed to be 0.8 in this study (Biollaz *et al* 2021),

$$E_{t,t\geqslant 2} = E_{t-1}\cdot(1-d)^{t-1} \tag{3}$$

where E_t is the annual electricity generation in year t from the second year, d is the system degradation rate, which is assumed to be constant at 0.15% per year during an average system lifetime of 30 years (Biollaz *et al* 2021).

3.3. LCOE

Building upon our assessment of the robustness of the potential estimation, data from both the registered systems database and the potential estimation were selected to quantify the LCOE and GHG emissions of PV-generated electricity for each system. Key parameters such as the size of each system in kWp and its year of installation, are sourced from the registered systems database, and determine the unit capital cost (appendix E), the required area per kilowatt peak power (kWp) of installed capacity, and module efficiency (appendix C, figure 1). This unit capital cost subsequently facilitates the computation of LCOE for each system. Our study opts for LCOE as a metric representing the cost of a solar PV system, given its capacity to encapsulate life cycle costs and distribute them over each kilowatt-hour of electricity produced. The methodology for deriving the LCOE for each system is obtained from Aldersey-Williams and Rubert (2019) following the UK Department for Business, Energy and Industrial Strategy in equation (4),

$$\mathrm{LCOE} = \sum_{t=1}^{n} (C + O\&M_t) / (1+r)^t \Big/ \left(\sum_{t=1}^{n} E_t / (1+r)^t \right) \quad (4)$$

where C represents the system's overnight capital investment in CHF, $O\&M_t$ is the operation and maintenance cost in year t in CHF/year, E_t is the annual generation in year t in kWh yr^{-1}, and r is the discount rate (dimensionless), assumed to be 5% for all systems (Bauer *et al* 2017, Biollaz *et al* 2021). The capital investment per kWp based on system size are calculated from offers submitted to 'Solar-Offerte-Check' of Energieschweiz from 2015 to 2022 (SFOE 2022a). Regression analysis is performed for the offer data for each year, and the capital investment for each system is determined based on its size (appendix E). Assumptions were made for operation and maintenance (O&M) costs: 2 Rp. kWh^{-1} of electricity generation is assumed for systems larger than 100 kWp, and 3 Rp. kWh^{-1} of electricity generation was assumed for systems equal to or less than 100 kWp (Toggweiler 2018). The total O&M cost per system was calculated by multiplying this by the electricity generated during the lifetime of the system. The end-of-life decommissioning labour cost is assumed to be equal to the system's residual value and is therefore not included in the LCOE calculation. For the grid electricity price, the 2023 electricity price published by ElCom was used (ElCom 2011). The electricity price provided by ElCom is at the municipal level. In some cases, one municipality has more than one utility provider. To obtain the electricity price applicable to each PV system given its geo-coordinates, geo-processing was performed at the utility provider level (appendix B).

3.4. GHG emissions

The GHG emissions per kWh of electricity from the PV systems and grid supplies were quantified. As China plays a dominant role in 80% of the supply chain stages for solar PV panels globally and has continually reduced the emission intensity of solar PV manufacturing since 2011 (IEA 2022), the life cycle inventory data in this study are for per kWp of PV system installation and incorporate the latest industrial data from monocrystalline solar PV panels manufactured in China (Zhou 2022). This data can be considered representative of both multi-crystalline and monocrystalline PV systems due to the negligible differences in life cycle GHG emissions between the two technologies (Frischknecht 2021). Crystalline-based technologies are chosen for this study because they hold the largest market share in global production (Fraunhofer Institute for Solar Energy Systems (ISE) 2023). The GHG emissions of the PV systems were calculated using equation (5),

$$\mathrm{GHG_{PV}} = \mathrm{S} * \mathrm{GHG_{perkWp}} \Big/ \sum_{t=1}^{n} E_t \quad (5)$$

where S is the system size in kWp, $\mathrm{GHG_{perkWp}}$ is the GHG emissions per kWp of PV system installation estimated based on the inventory data from Zhou (2022), and E_t is the annual generation in year t in kWh y^{-1}. Three methodological options are considered in this study for the GHG emissions of grid supplies:

(1) Static national value according to the ecoinvent LCA database version 3.9.1 (2022) (system model 'allocation, cut-off by classification') (Wernet *et al* 2016): this is the most straightforward among the three options. It is a static single annual value based on electricity certificates (also known as 'guarantees of origin') and is only available for the entire nation.
(2) Geographic-specific values by utility providers: this reflects the actual utility that provides grid supply to PV system owners and its supply mix based on electricity certificates. This is calculated based on the supply mix published by Pronovo for 2022 (Pronovo 2022) and power generation technology-specific GHG emissions according to the ecoinvent database version 3.9.1 (2022) (system model 'allocation, cut-off by classification') (Wernet *et al* 2016) (appendix D).
(3) National dynamic value based on the consumption mix considering electricity generation within the national territory and imported electricity at hourly resolution from Electricity Maps (ElectricitMap 2023). This method is detailed in Tranberg *et al* (2019), and its strength is its high temporal resolution. However, the value of GHG emissions of grid supply based on this method is only available for the entire nation without differentiation between specific utilities.

3.5. LCOE and GHG difference

The differences in cost and GHG emissions between electricity from PV systems and grid supplies were calculated based on equations (6) and (7),

$$\mathrm{Diff}_{\mathrm{cost}} = \mathrm{LCOE}_{\mathrm{PV}} - \mathrm{Electricityprice}_{\mathrm{grid}} \quad (6)$$

$$\mathrm{Diff}_{\mathrm{GHG}} = \mathrm{GHG}_{\mathrm{PV}} - \mathrm{GHG}_{\mathrm{grid}}. \quad (7)$$

All the variables in equation (6) are in CHF/kWh, and all the variables in equation (7) are in $\mathrm{gCO_2eq\,kWh^{-1}}$.

3.6. Software and tool

The analysis was carried out through Python scripts in Jupyter notebooks, employing various Python packages for specific tasks: Geopandas and Shapely were used for GIS-related analysis, while Plotly was applied for result visualization. For other data processing and cleaning, Pandas and NumPy were utilized. Additionally, SQLite3 was employed to access the GWR database.

4. Results

4.1. Robustness of potential estimation

Figure 2 compares the actual installed capacity of rooftop PV systems with their maximum power capacity estimated in the potential estimation by Walch and Rüdisüli (2023). This comparison is essential to evaluate the robustness of the potential estimation, which is closely related to the electricity generation of each system and subsequently influences both the LCOE and GHG emissions of the electricity generated by PV systems. In the potential estimation, a power capacity difference percentage below zero (as defined in equation (1)) suggests an underestimation, where the estimated maximum capacity is lower than the installed capacity. Specifically, a −100% indicates the complete omission of the actual installed system in the potential estimate. Conversely, a positive percentage indicates potential underutilization of the available roof space.

The top section of figure 2 reveals a pronounced underestimation, primarily marked at -100%, suggesting that the existing systems were not accounted for in the potential estimate. The cumulative power capacity graph, depicted in the lower part of the figure, indicates these completely omitted systems correspond to an overall underestimation of approximately 0.9 GWp across approximately 30 000 systems. This underestimation is significant when compared with Switzerland's total installed capacity of approximately 4.7 GWp in 2022, as reported by the Swiss Federal Office of Energy (SFOE 2023d). Moreover, the discrepancy is considered significant given the cumulative power capacity underestimation of 1.3 GWp. Potential reasons for this underestimation are discussed in detail in section 5.1. The discrepancy between the power capacity of the installed systems and the maximum power capacity is also illustrated in the bottom section of figure 2, together with the cumulative power capacity of all the systems on the y-axis. It shows that the underestimation of installed capacity is gradually counterbalanced by the real-world under-utilization of rooftop spaces, which eventually leads to the cumulative power capacity of the potential estimate surpassing the actual installed capacity. This observation suggests that, while the potential estimate may be justifiable on a national scale when considered as an aggregate figure, as it surpasses the current installed power capacity, there remains a clear need to improve the potential estimate spatially. In other words, the present acceptable national potential estimate is achieved by completely omitting many actual installations and underutilizing numerous roof areas. To enhance accuracy, an improved spatial analysis is required to investigate these discrepancies and better reflect the true potential on a localized scale.

Because the power capacity difference falls primarily between −100% and 300%, figure 3 provides a closer examination by restricting the power capacity difference to this range, segmented by various system size ranges and pinpointing the predominant system sizes where underestimation is most prevalent. The top figure shows the relationship between the power capacity difference in percentage (x-axis), size of the system (y-axis), and the distribution of the number of systems (colour scale).

The results illustrate that complete omissions (represented by a power capacity difference of −100%) predominantly occur in small-scale systems, specifically those approximately 10 kWp in size. When considering roof under-utilization (indicated by power capacity difference exceeding 0%), the majority of systems have a power capacity difference of less than 100%. The aggregated power capacity (figure at the bottom), when analyzed with the distribution of system size and power capacity difference, follows a similar trend. However, systems around 30 kWp exhibit a more pronounced impact in both under-estimation and under-utilization. This pattern may be attributed to past incentive programs that provided elevated feed-in

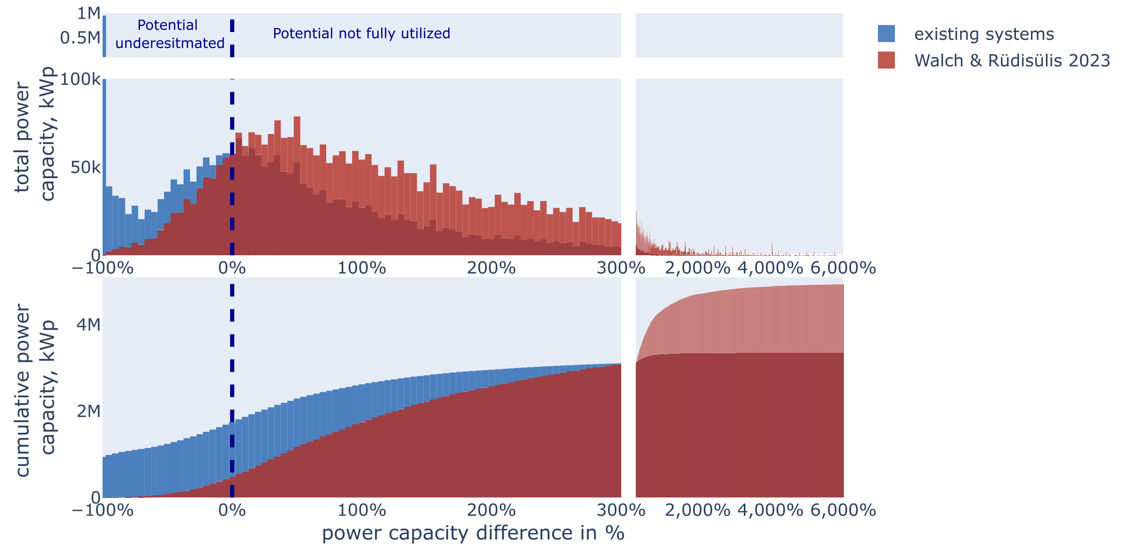

Figure 2. Distribution of power capacity difference in percentage compared with installed capacity with the potential estimation, with the total power capacity for each bin of power capacity difference (top) and cumulative power capacity (bottom). The color legends for both existing systems and potential estimation from Walch and Rüdisüli (2023) are set to be semi-transparent to show the overlapped area.

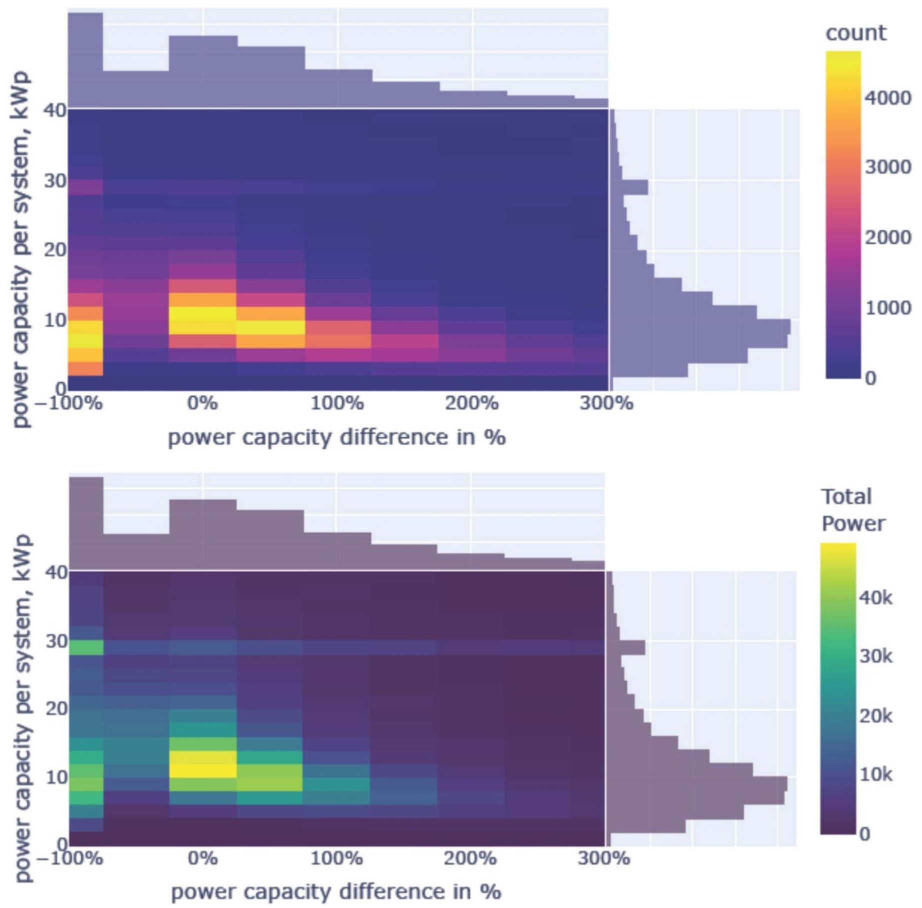

Figure 3. Distribution of power capacity difference in percentage (x-axis), grouped by individual system size (y-axis): the top section illustrates the distribution in terms of the count of systems and the bottom section illustrates the distribution in terms of the total power capacity of the systems (both indicated by colour).

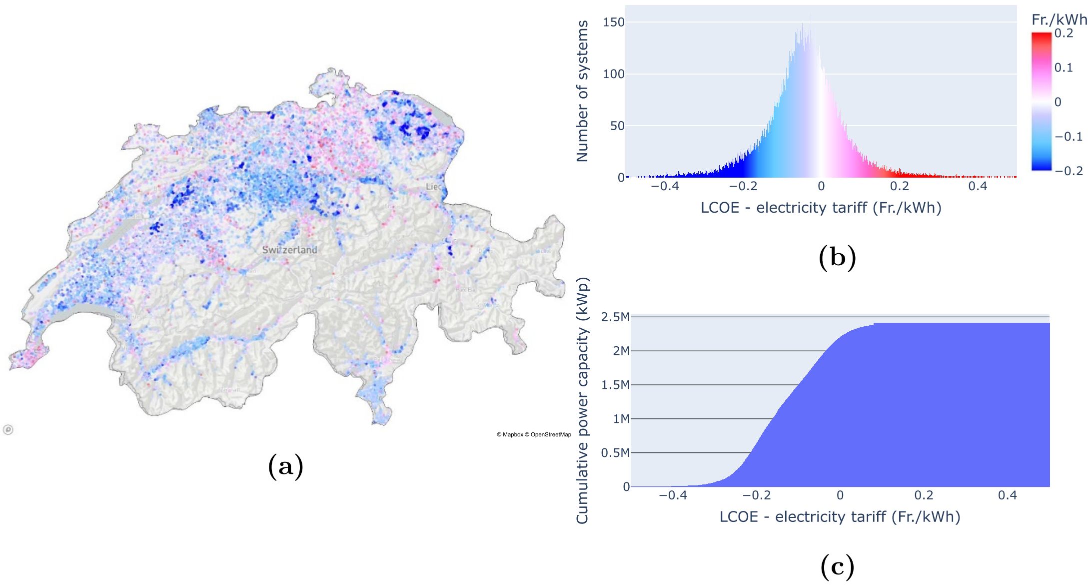

Figure 4. (a) Difference between LCOE of electricity generated from PV and electricity price (b) distribution of the difference between LCOE of electricity generated from PV and electricity price in terms of the number of systems (c) distribution of the difference between LCOE of electricity generated from PV and electricity price in terms of the cumulated power capacity .

prices for systems exceeding 10 kWp but not surpassing 30 kWp, as mentioned by Bauer *et al* (2017), which results in many systems installed in reality with a size of just or slightly below 30 kWp.

Both figures 2 and 3 show that using electricity generation from the potential estimation in calculations of LCOE and GHG emissions for PV-generated electricity is unsuitable because of considerable omissions of systems or under-utilization of roofs in reality. This leads to our own estimation of electricity generation for each system by employing only the tilted solar irradiance from the potential estimate (section 3.2).

4.2. LCOE of electricity generation from PV vs. Grid electricity price

Delving into the difference between LCOE and electricity prices for each system across Switzerland (figure 4), our results also show that electricity generated by rooftop PV systems is already more economical than grid supplies for the majority of installed capacities. As shown in equation (5), a negative difference implies that the electricity produced from PV systems is less expensive than that purchased from the grid. Conversely, a positive difference indicates that the grid electricity is more affordable than that generated by a PV system.

Geographical representation reveals that in many areas, generating electricity using PV systems is already more cost-efficient than procuring electricity from the grid, given the electricity prices in 2023. This cost advantage is particularly pronounced in parts of German-speaking regions of Switzerland. However, the underlying factors (input parameters that are not constant, visualized by light orange rectangular boxes in figure 1) for this favourable LCOE vary across regions. Generally, abundant solar irradiance, relatively large system size, high grid electricity price, or a combination of these factors are the main factors that result in a favourable LCOE:

- In north-eastern Switzerland, this is caused by a combination of high electricity prices and the larger scale of the systems: the electricity prices are more diverse than in other regions and reach to around 0.4 CHF/kWh, and the PV systems installed are generally larger than in other areas (appendix H).
- On the west side of central Switzerland, the favourable LCOE primarily results from the higher solar irradiance (appendix I).
- Central Switzerland features numerous PV systems with a power capacity ranging from 10 to 30 kWp, generally surpassing the typical capacities seen elsewhere, which are often under 10 kWp (appendix J).

In contrast, on the northern side of central Switzerland, there are more than half of the systems in which the grid supply is more cost-effective than the PV-generated electricity (appendix K). This can be attributed to the combination of modest grid electricity prices and in general, the smaller scale of PV installations. Intriguingly, although this is the case for many systems, over 80% of the total power capacity in this area demonstrates a lower LCOE than the grid electricity price. This suggests the presence of a limited number of

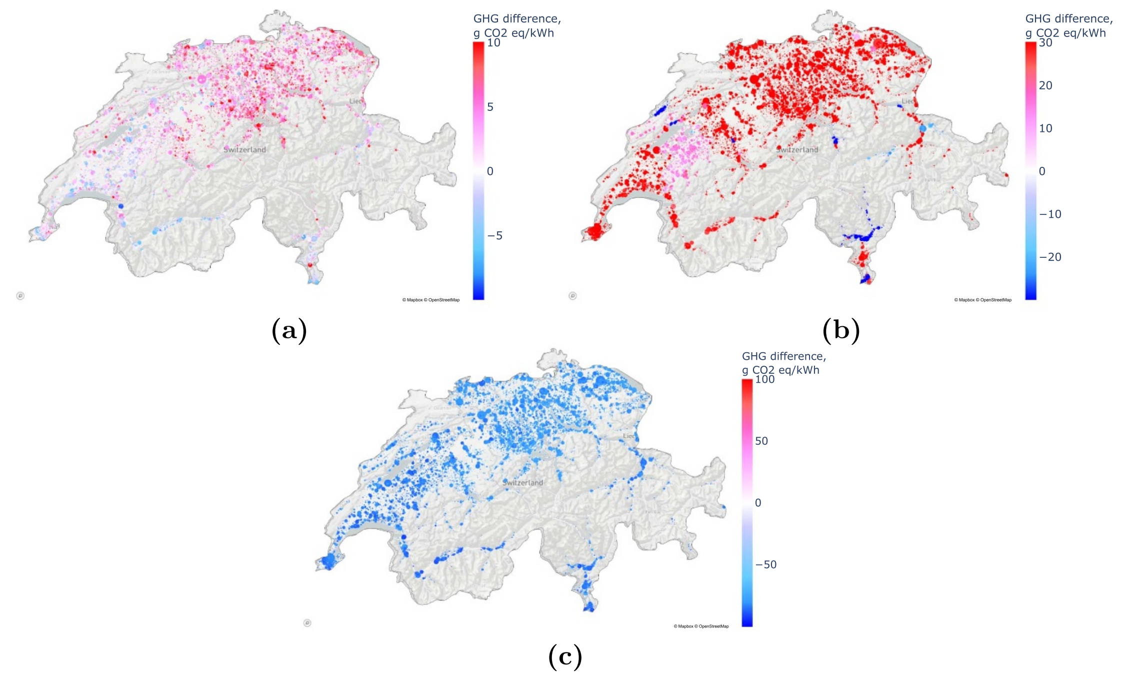

Figure 5. Difference between GHG emissions of electricity from PV and GHG emissions of grid supply using methodological (a) Option 1 based on a single national static value, (b) Option 2 based on electricity certificates by utility providers, and (c) Option 3 based on consumption mix (production + import) from Electricity Maps (ElectricitMap 2023). Note that the scales in the subfigures differ, with each adjusted to highlight areas of negative (blue) or positive (red) differences. Therefore, color intensities (shades of red or blue) should not be compared across subfigures. © Mapbox (www.mapbox.com/about/maps), © OpenStreetMap (www.openstreetmap.org/copyright).

large-scale PV systems that achieve an LCOE that is more competitive than the relatively low grid electricity prices.

In addition, the detailed results of specific regions (appendices H–K) suggest that while earlier PV installations generally incur higher costs (except for 2022, where costs might exceed those of 2021 for certain system sizes because of supply chain disruptions from COVID-19, recent geopolitical conflicts, and inflation), the installation year appears to have a minimal impact on making rooftop PV systems economically more attractive. In other words, investing in larger rooftop PV systems is more economically beneficial, especially in regions with higher electricity prices or abundant solar irradiance resources, compared with the relatively smaller advantages due to earlier installations. Furthermore, the data indicates that even regions with less ideal conditions, such as lower solar irradiance or competitive grid electricity prices, could still be economically viable for rooftop solar PV systems. This viability improves particularly when the system size is increased to reduce capital costs. As shown in appendix E, this cost reduction is more significant for small-scale systems, where a slight increase in installed capacity can lead to substantial savings in specific capital investments. On the other hand, in regions with relatively low grid electricity prices, additional incentives are needed to enhance the appeal of small-scale PV systems to prospective investors.

4.3. Life cycle GHG emissions of electricity generation from PV vs. Grid electricity supply

Our study explored the difference in GHG emissions between PV systems and grid supplies in a similar vein, taking into account three methodology options for estimating grid supply GHG emissions. Our findings underscore the critical influence of the chosen method in determining the GHG emissions of the grid supplies. Specifically, the methodology that incorporates the physical consumption mix, which accounts for both national electricity production and imported power from neighbouring countries, results in higher GHG emissions of grid supply than the generation from rooftop solar PV systems.

Figure 5 illustrates the difference between the GHG emissions of PV systems and those of grid supplies, for which the latter was estimated using three methodological options. As defined in equation (7), a positive difference (indicated by the red color gradient) signifies that the GHG emissions of PV generation are greater than those from grid supply, and vice versa for a negative difference. Both options 1 and 2 derive their estimates from electricity certificates (also known as the market-based approach in Holzapfel *et al* 2023). However, they differ in their geographical resolution: Option 1 employs a static national grid supply GHG emission factor of 40 $gCO_2eq\,kWh^{-1}$ (Wernet *et al* 2016), while Option 2 offers a more granular approach, differentiating the GHG emissions of grid supplies according to the electricity certificates disclosed by utilities in 2022. Option 3 adopts a different strategy, estimating GHG emissions from the hourly consumption mix of the Swiss national grid supply considering both electricity generation within the national territory and imported electricity (also known as the location-based approach in Holzapfel *et al* 2023), as sourced from the Electricity Maps between 2018 and 2022. This results in an average GHG emissions of 124 $gCO_2eq\,kWh^{-1}$ of grid supply.

The findings reveal a stark contrast between the outcomes of the electricity certificate-based and the consumption-mix-based approaches. Specifically, while the consumption mix-based approach generally indicates that all PV systems generate electricity with lower GHG emissions than grid supplies, certificate-based approaches suggest nearly the opposite. When compared with Option 1, Option 2's differentiation by utility providers shows more extreme results: PV systems in certain areas (e.g. the French-speaking part of Switzerland, shown as pink area in subfigure (b)) have higher GHG emissions than the corresponding grid supplies, and a few areas (e.g. Neuchatel and Ticino, shown as blue area in subfigure (b)) emerge as even more advantageous for PV systems. This variation can be attributed to the fact that a significant proportion of electricity certificates acquired by utility providers are associated with low-emission sources such as hydropower and nuclear power, with GHG emissions often below 10 $gCO_2eq\,kWh^{-1}$, and conversely, only a few utility providers possess certificates for high-emission power produced from fossil fuels, which range from 650 to over 1000 $gCO_2eq\,kWh^{-1}$ (Wernet *et al* 2016) (see GHG emissions of grid supplies by utility providers in appendix N), significantly elevating the GHG emissions of their grid supplies. When utility providers are aggregated at the national level, as in Option 1, the high GHG emissions linked to a small portion of electricity certificates become less noticeable, leading to a less pronounced difference in GHG emissions between the generated electricity from PV systems and the grid supply. Although Option 2 offers a more detailed geographic resolution for GHG emissions associated with grid supplies by utility providers, it is important to recognize that, similar to Option 1, reliance on electricity certificates for GHG emissions estimation carries a high risk of double-counting renewable electricity (Böck 2023a, 2023b), and misrepresents the grid supply as more renewable than it physicallyis. Despite awareness of this issue since the inception of electricity certificates (Verwimp *et al* 2020), the absence of standardized accounting rules for the GHG emissions of grid electricity supplies continues to create challenges in decision-making processes that rely on these calculations (Holzapfel *et al* 2023).

5. Discussion

In this section, we critically discuss our findings, starting with a quality evaluation of the key input data and followed by an assessment of the robustness of our approach. The robustness assessment involves validating a key geoprocessing step of our method and contextualizing our results within the existing literature. Finally, we conclude by acknowledging the limitations and suggesting directions for future research.

5.1. Data quality

The quality of data is critical for reliable potential estimation. In our analysis, two primary causes for the underestimation of power capacity (figure 2) were identified: either the complete omission of systems or the potential estimate's maximum power capacity being lower than that of actual installed systems.

The former accounts for 70% of the total underestimation. Upon further investigation, it becomes evident that this significant discrepancy is largely attributed to reliance on outdated data. Specifically, the data employed by Walch and Rüdisüli (2023), originating from Walch *et al* (2020), is not the most recent data available on Sonnendach (SFOE 2023c), which undergoes annual updates. In addition, the data currently available on Sonnendach are not as current as those in GWR, which is updated daily. This discrepancy likely leads to the exclusion of some considerable systems installed in recent years.

For instances where the potential estimate's maximum power capacity falls short of the actual installed systems, the explanation is twofold. First, the discrepancy could arise from the registered address of the installed system not encompassing all building rooftops where the actual systems are mounted. For example, the registered address might correspond to the administrative building of a factory, yet the entire factory's rooftops are equipped with solar PV. Second, the potential estimate model used in Walch and Rüdisüli (2023)is conservative, particularly for smaller-scale systems under 10 kWp.

Addressing these issues to improve potential estimation is beyond the scope of this study. However, specific recommendations are proposed: for inaccuracies of potential estimation caused by data, both updated building registry data and more accurate installed system registration data, which correctly reflect the actual or complete set of buildings with installed PV systems, are crucial for ensuring more accurate future potential estimates. Regarding the conservative methodology employed by Walch and Rüdisüli (2023) for small-scale systems, the integration of satellite image detection techniques into future methodologies could yield a more precise estimation of potential.

5.2. Methodological robustness

When assessing the installed capacity against potential estimates, the PV systems were indexed with EGIDs to match with specific buildings and corresponding potential estimates. To validate this step and ensure that the geo-processing is appropriate, the study calculated the ratio of the area occupied by the PV system to the total available roof area. It was hypothesized that a correctly mapped system would result in a ratio of less than 1. This is because a well-aligned system should not occupy more than the available roof area. Conversely, if a PV system is mistakenly mapped to a building where it is not actually installed, the ratio may exceed 1. This would occur if the roof area of the incorrectly mapped building is smaller than the required area of the PV system. This reveals that for over 98% of the roofs, the proportion of the area occupied by PV systems relative to the total available roof area is below 1, suggesting that the geo-processing applied in this study is generally reliable.

Of these roofs, 80% have a ratio less than 50% (appendix O). This supports the previous potential analysis by SFOE, which considered 70% as the usable proportion of the roof area for PV systems (SFOE 2023c). However, relying on this ratio as an assumption is optimistic when estimating the realistic potential of rooftop PV systems. Furthermore, this also indicates that the available roof area does not appear to be a limiting factor for the PV systems installed to date. Instead, other factors such as cost and electricity demand may be more constraining. From a policy standpoint, this suggests that there is a need for more incentives and initiatives to enable PV owners to maximize the utilization of their rooftop areas for PV.

Contextualizing with existing literature, this study is the first in Switzerland to quantify the LCOE of rooftop PV electricity generation at such a high geographical resolution. However, a direct comparison with existing literature on the LCOE of rooftop solar PV systems in Switzerland is not feasible (Bauer *et al* 2017, 2019, Han *et al* 2022). This limitation arises from the varying assumptions and methodologies used in previous studies, such as differences in data sources for electricity generation, considerations of subsidies, and inclusion of electricity generation discounting in LCOE calculations. On the other hand, there is abundant literature focused on quantifying the GHG emissions from electricity generated by PV systems and their comparison with grid supplies.

Our study adopted a life-cycle-based approach to quantify the GHG emissions. This methodology is one of the several possible options. An alternative method could allocate the embodied GHG emissions of rooftop PV systems upfront, treating onsite PV generation as zero-emission during its operation. This approach hinges on whether the embodied GHG emissions of PV systems can be offset during their operational lifespan by reducing the grid-supplied GHG emissions. The International Energy Agency (IEA) conducted a related study in 2022 (IEA 2022), which assumed the domestic production and operation of PV modules. The IEA study concluded that, for most countries, the embodied GHG emissions of PV can be recuperated within a year. However, this conclusion has certain limitations. First, the scenario where manufacturing and operation of the PV systems occur within the same country is primarily applicable to a few countries, such as China, with significant involvement in the global PV supply chain. For countries such as Switzerland, where PV systems are predominantly imported, the generation-based grid emission intensity of the manufacturing location could be substantially higher, potentially exceeding 10 to 20 times that of domestic production scenarios. Second, the IEA's analysis focused solely on the embodied GHG emissions of solar PV modules, excluding other crucial components that make up the balance of the system. A more inclusive calculation encompassing the entire PV system, as mentioned in the study itself, could potentially double or triple the GHG emissions estimated in the IEA study. Moreover, when assessing the generation-based GHG emissions of grid supplies, multiple methodologies exist, in particular, whether and how to handle marginal power supply (Braeuer *et al* 2020), further complicating this issue. These factors collectively cast doubt on the conclusion that the embodied GHG emissions of PV systems can be easily compensated for during their operational lifetime, thereby justifying the relevance of the approach adopted in our study for decision-making.

Moreover, Electricity Maps was selected as the primary data source for determining the GHG emissions of grid supplies based on the physical consumption mix in our study. This choice was motivated by its expansive geographical coverage and free accessibility for academic purposes, thereby broadening the potential application of our methodology to other regions and countries in the future. Alternatively, other life-cycle-based dynamic grid emission factors specific to Switzerland can be considered, which also include life cycle GHG emissions unique to the power generation technology in Switzerland (Lédëe *et al* 2023, Romano *et al* 2023, University of Geneva 2023). Despite the presence of alternative sources, our analysis conclusively shows that the GHG emissions from PV electricity generation are significantly lower than those from Switzerland's grid electricity based on the consumption mix. Specifically, annual GHG emissions from alternative sources in Switzerland have been reported to range from 98 to 124 $gCO_2eq\,kWh^{-1}$ over the past five years (Lédëe *et al* 2023, Romano *et al* 2023, University of Geneva 2023), while in contrast, the emissions associated with PV electricity generation, as estimated in this study, range from 30 to 60 $gCO_2eq\,kWh^{-1}$.

To estimate the GHG emissions of PV electricity generation, this study applied specific Life Cycle Inventory data considering recent and average industrial manufacturing data from China. However, it is also acknowledged that variations in these values are possible, influenced by the chosen PV panel manufacturing process, its supply chain, manufacturing location, and the type of solar PV technology employed (e.g. monocrystalline, polycrystalline, cadmium telluride, copper indium gallium selenide, etc). Galimshina *et al* (2023) conducted a comprehensive analysis of various PV technologies, including emerging third-generation PV panels, with a user-friendly tool, enabling users to tailor their PV systems by selecting specific system components, such as the frame, glass type, cell type, and encapsulant. For precise GHG emission estimation, particularly for specific systems, adopting such tools can provide a more comprehensive estimation of GHG emissions associated with PV systems.

5.3. Limitations and future research

Although the study offers enhanced insights into the potential estimation, LCOE, and GHG emissions of rooftop solar PV systems in Switzerland at the individual building level, it is also acknowledged that there are certain limitations to our approach. First, while comparing PV supply with electricity grid supply offers insights for PV owners, it is essential to recognize the intermittent nature of PV supply versus the on-demand availability of grid electricity. A fairer comparison would need to consider local electricity storage, such as building- or community-scale batteries (Gupta *et al* 2021, Han *et al* 2022), as part of the PV supply. Given the lack of high-resolution data on storage and the high computational demands for simulating the sizing and operation of local storage, this aspect was excluded from the scope of our study. Nevertheless, this remains a vital area of future research. Second, each PV system registration typically corresponds to a geographical centroid of the system. In reality, a single registration might encompass multiple systems on adjacent buildings, for example, connected semi-detached houses. To accurately link the installed systems with potential estimates, building EGIDs were used as connecting attributes. This method works well for connected buildings with a single EGID in GWR. However, challenges arise when connected buildings have unique EGIDs but share a central coordinate for one system registration. Our approach might inadvertently link this central coordinate to only the nearest EGIDs, leading to potential mismatches. For future data collection by Swiss authorities (SFOE 2023b), PV systems installed on separate buildings or roofs but owned by the same individual or entity should be reported as distinct registrations. This distinction will facilitate future evaluations of the potential estimation robustness, similar to the analysis conducted in this study. Furthermore, the registration should include the EGID of the building where the PV system is physically installed, rather than the main building on which the actual system is not installed (e.g. the administrative building or a factory's main structure, which is the case for some buildings). This ensures the accurate identification of a specific building equipped with a PV system. Lastly, while our PV capital investment analysis incorporates historical capital costs based on (SFOE 2022a), our GHG emissions estimation for PV systems does not account for the historical supply chain and the development of PV system manufacturing processes throughout the years. This oversight might lead to an underestimation of the GHG emissions of the installed PV systems. However, given that most systems were installed post-2020 (SFOE 2023b), variations in the supply chain and manufacturing processes in recent years are likely minimal.

For further research, it is crucial to extend the existing framework to include storage, such as PV-battery systems. This extension necessitates a detailed consideration of the operation of individual PV-storage combined systems, as well as the factoring of temporal electricity demand, which may pose challenges in terms of data requirements and computational costs. Moreover, the current analysis relies on the installed capacity of existing systems, thus not utilizing potential estimates for future systems. Therefore, follow-up research should investigate the detailed causes of observed underestimation and under-utilization of roof areas to achieve more robust potential estimates for future installations. With improved geographical potential estimation, future trends can be anticipated by considering the time-dependent diffusion of systems, and the cost evolution of PV systems. Supply chains and manufacturing processes can be integrated into GHG emissions calculations, and for the cost side of the analysis, future scenarios should account for developments in prices and the supply mix of grid supplies. Lastly, since the analytical framework applied in this analysis is generic, its application should be explored for other countries, provided the data requirements outlined in figure 1(i.e. input parameters) are met. The framework can be applied to both existing systems and future installations. Primarily, the application requires high-resolution geographical data, including solar irradiance, roof geometry, and statistics on rooftop solar PV system investment costs as a function of system capacity. This may pose challenges regarding data availability in some countries. However, the remaining input parameters can be adjusted to align with the specific data conditions of the applicable country.

6. Conclusions

This study provides a detailed analysis of existing rooftop solar PV systems in Switzerland, examining actual installations up to August 2023. In combination with potential estimations, our study derives the annual electricity generation. This allowed us to calculate the LCOE and GHG emissions for each system at the individual building level. While the national potential estimate offers a reliable reference, our findings highlight significant geographical variations between potential estimations and real-world installations. Notably, there is an underestimation of approximately 1.3 GWp, predominantly for systems close to 10 kWp in size. This is partially due to the outdated data used for potential estimation, and partly due to the conservative estimation by the potential estimation model. However, this gap is counterbalanced by the under-utilization of available rooftop spaces at the national level.

In comparing the LCOE to the 2023 grid electricity price, it was found that a substantial portion of the installed capacity has a more competitive LCOE than the prevailing grid electricity price. However, this advantage is not uniformly distributed, with some regions benefiting more from factors such as elevated grid electricity prices, larger system installations, or higher solar irradiance. These factors are found to be more influential than other factors, such as installation year, in contributing to the more attractive LCOE of rooftop PV systems and deserve more attention in the design of future renewable energy subsidies and policies. Interestingly, the benefits in terms of power capacity do not always correspond to a large number of systems (e.g. onn the northern side of central Switzerland). Moreover, small-scale system owners often require policy support to realize the economic benefits of their installations. This is particularly true when storage costs are incorporated into the analysis. Additionally, there is a need for enhanced incentives and initiatives to empower PV system owners to fully utilize their rooftop space for PV deployment.

Our assessment of GHG emissions using three methodological options, revealed stark contrasts in the outcomes based on the chosen method. Specifically, methodologies based on electricity certificates produced markedly less favourable results for PV systems than those using a consumption-mix-based approach that reflects the physical flows of electricity, emphasizing the critical role of method choice for the GHG evaluation of grid supplies in such a decision-making context.

While our study offers valuable insights, there are also known limitations, particularly regarding the lack of consideration of the cost and GHG emissions associated with the integration of renewable electricity (e.g. via storage) and data alignment. For the latter, our study recommends specific improvements in the data collection process for PV system registration, and suggests directions for future research. In conclusion, our research emphasizes the need for more accurate potential estimations geographically, a call for policy support for small-scale rooftop PV systems, and the promotion of better utilization of suitable roof areas. As Switzerland pursues its renewable energy objectives, informed policymaking grounded in a retrospective analysis of existing installations, will be pivotal in maximizing the potential and benefits of rooftop solar PV systems.

Data availability statement

The data cannot be made publicly available upon publication due to legal restrictions preventing unrestricted public distribution. The data that support the findings of this study are available upon reasonable request from the authors.

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Authors contributions

Xiaojin Zhang: Conceptualization, Data curation, Methodology, Software, Formal analysis, Visualization, Writing—Original Draft, Validation, Writing—Review & Editing, Funding acquisition. **Alina Walch**: Methodology, Data curation, Validation, Writing—Review & Editing. **Martin Rüdisüli**: Data curation, Writing—Review & Editing. **Christian Bauer**: Methodology, Writing—Review & Editing. **Peter Burgherr**: Methodology, Writing—Review & Editing, Funding acquisition, Project administration. **Russell McKenna**: Methodology, Writing—Review & Editing. **Guillaume Habert**: Methodology, Writing—Review & Editing, Supervision

Conflict of interest

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.

Appendix A. Two-step geo-mapping of registered PV systems with EGIDs

A two-step geo-mapping is followed to map registered PV systems installed in Switzerland until August 2023 using the EGID index from the Swiss Federal Registry of Buildings:

(1) In the first step, the exact geographical coordinates of the registered systems were matched with the system coordinates in the federal building and apartment registry. This step successfully matched 32% of the registered power capacity with the corresponding EGIDs.
(2) In the second step, a spatial join was performed for the coordinates of the registered systems and the system coordinates in the federal building and apartment registry with a proximity of 2 meters.

This two-step process matches 97% of the registered systems with their corresponding EGIDs, allowing the mapping of registered systems with potential estimates based on their EGIDs.

Appendix B. Geo-mapping of electricity price: from municipality level to utility provider level

Given that these electricity price data are geographically specified by Swiss municipalities, and that some municipalities have multiple utility providers, the analysis assigns each system to a specific utility provider and grid electricity price. This is achieved through the compilation of geo-definitions by utility providers for these special municipalities, using collected geodata of net coverage (known as 'Netzgebiete' in German) from cantons. Any mismatches between names from ElCom and cantonal geodata were identified and corrected (see mapping in the research data). Both the cost and annual generation were discounted in the calculation of the PV LCOE.

Appendix C. System installation year, module efficiency, and area required per kWp of system installation

Table C1. System installation year, module efficiency and the area required per kWp of system installation.

System installation year	Module efficiency	Area per kWp (m^2)
2013	13%	8.0
2014	14%	7.8
2015	15%	7.5
2016	16%	6.5
2017	17%	6.0
2018	18%	5.5
2019	19%	5.3
2020	19.5%	5.1
2021	20%	5.0
2022	20.8%	4.9
2023	21%	4.8

Appendix D. GHG emissions per kWh of electricity generation by power generation technology

Table D1. GHG emissions per kWh of electricity generation by power generation technology, based on allocation, cut-off by classification, ecoinvent database version 3.9.1 (2022) (Wernet *et al* 2016).

Power generation technology	IPCC 2021 GWP100 ($gCO_2eq\,kWh^{-1}$)
Hydro	6
Wind	2.4
Solar PV	34
Biomass	95
Geothermal	20
Nuclear	6
Oil	825
Natural gas	657
Coal	1143
Waste incineration	4
Subsidized electricity	40.5[a]

[a] Subsidized electricity comprises 47.5% hydropower, 16.4% solar PV, 3.1% wind, and 33% biomass in 2022.

Appendix E. Unit capital cost based on size and installation year, based on data collected from solar PV offer checks, SFOE/energieschweiz (SFOE 2022a)

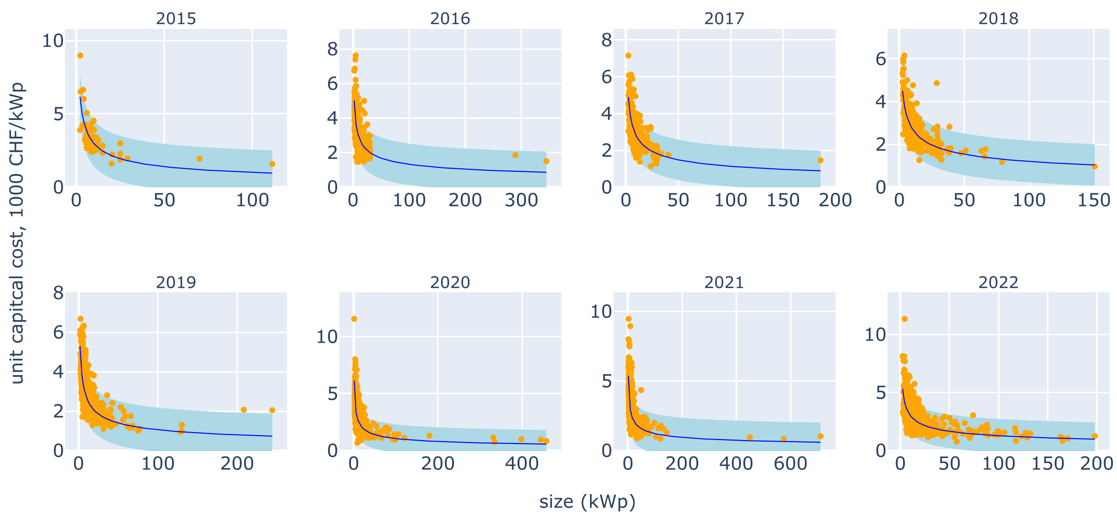

Figure E1. Unit capital cost based on size and installation year.

Appendix F. Distribution of power capacity, existing PV systems installed in Switzerland until August 2023

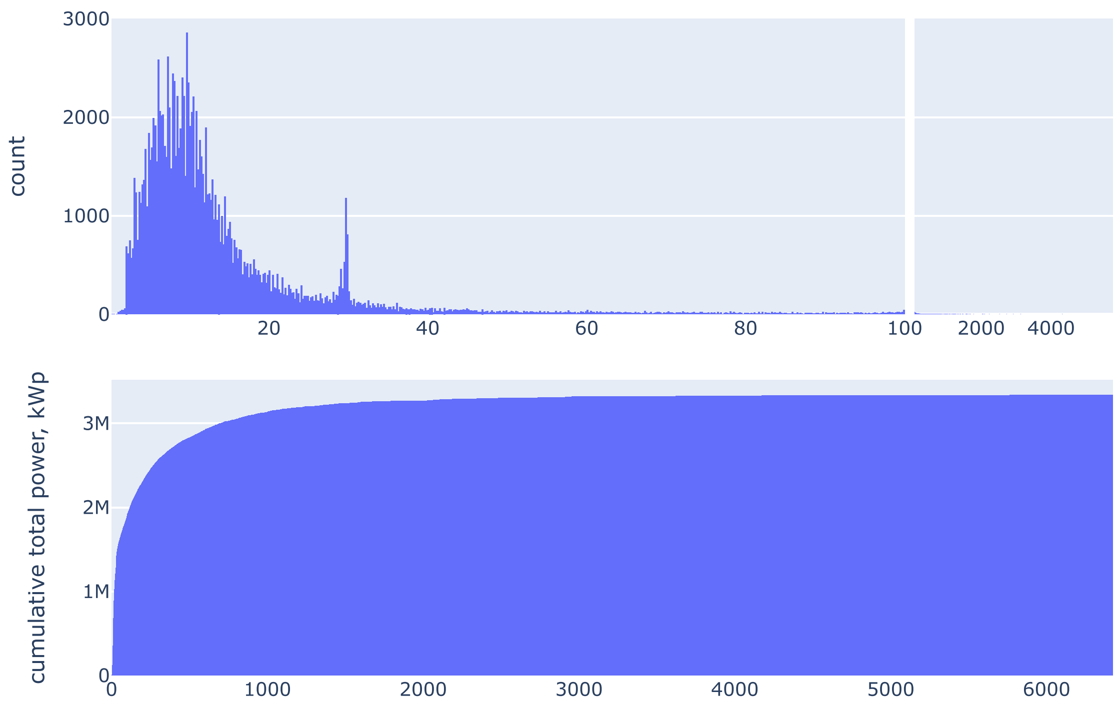

Figure F1. Distribution of power capacity, in terms of the number of systems (top) and cumulative power capacity (bottom), for existing PV systems installed in Switzerland until August 2023 (SFOE 2023b).

Appendix G. LCOE of existing systems installed in Switzerland until August 2023, in CHF/kWh

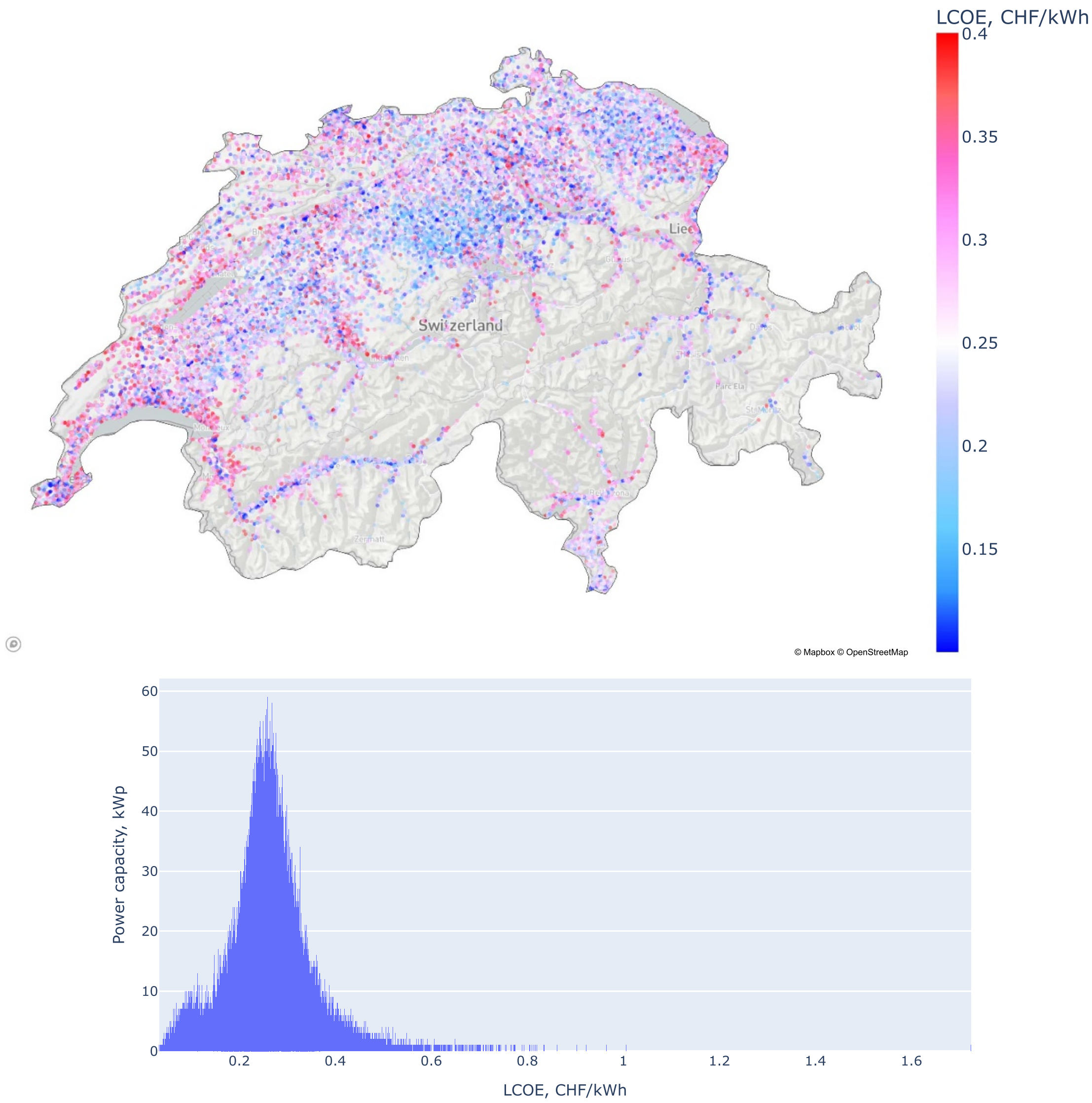

Figure G1. LCOE of existing systems installed in Switzerland until August 2023, in CHF/kWh, map (top) and distribution (bottom). © Mapbox (www.mapbox.com/about/maps), © OpenStreetMap (www.openstreetmap.org/copyright).

Appendix H. Cost difference for the systems in the north-eastern side of Switzerland (Thurgau and St. Gallen)

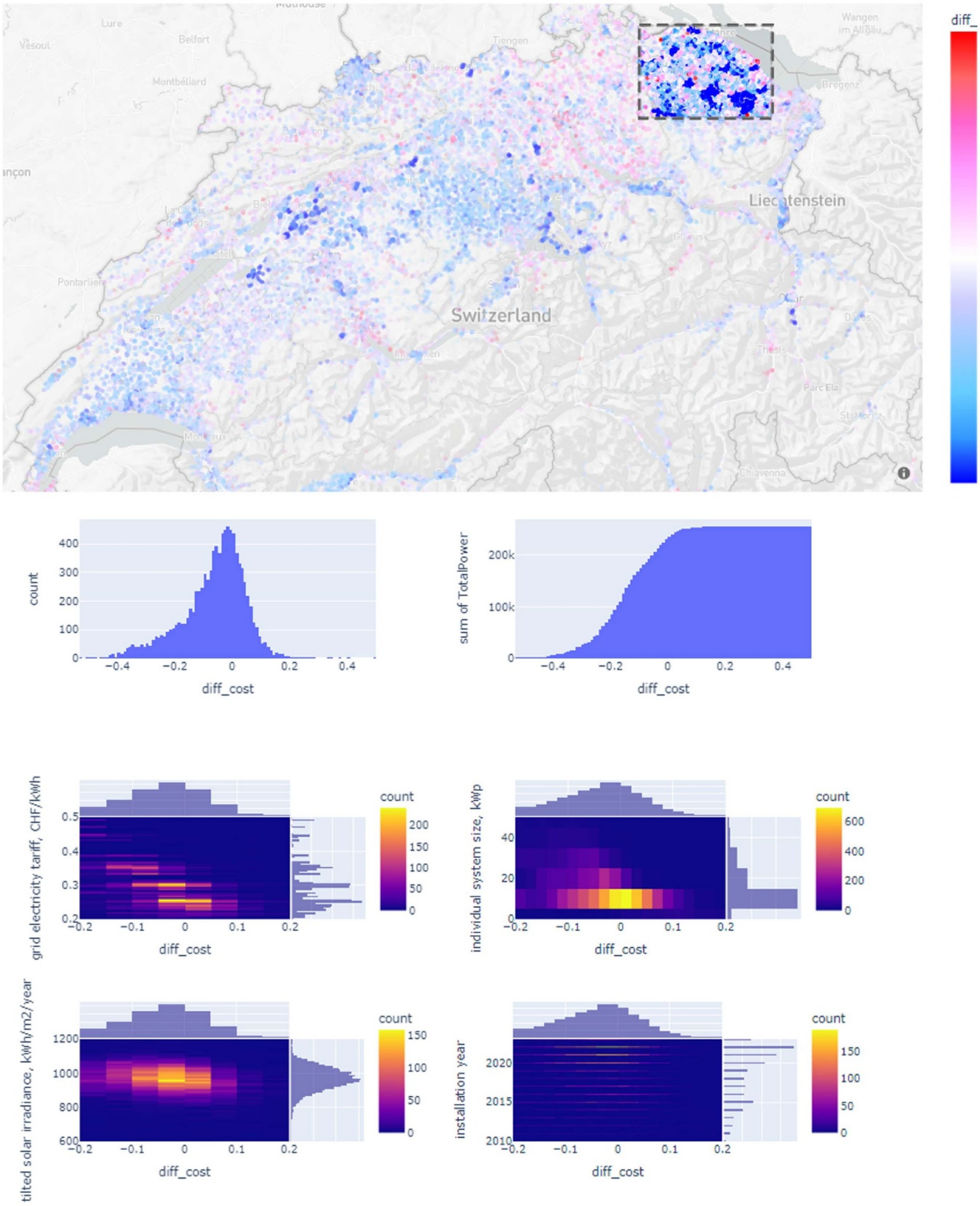

Figure H1. Cost difference for the systems in the north-eastern side of Switzerland (Thurgau and St. Gallen): geographical distribution of cost difference (map on top), by count of system (2nd row, left), by sum of power capacity (2nd row, right), by grid electricity tariff (third row, left), by individual system size (third row, right), by tilted solar irradiance (fourth row, left) and by installation year, (fourth row, right). The color in all heatmap figures indicates the count of the systems.

Appendix I. Cost difference for the systems in the west side of central Switzerland (Bern)

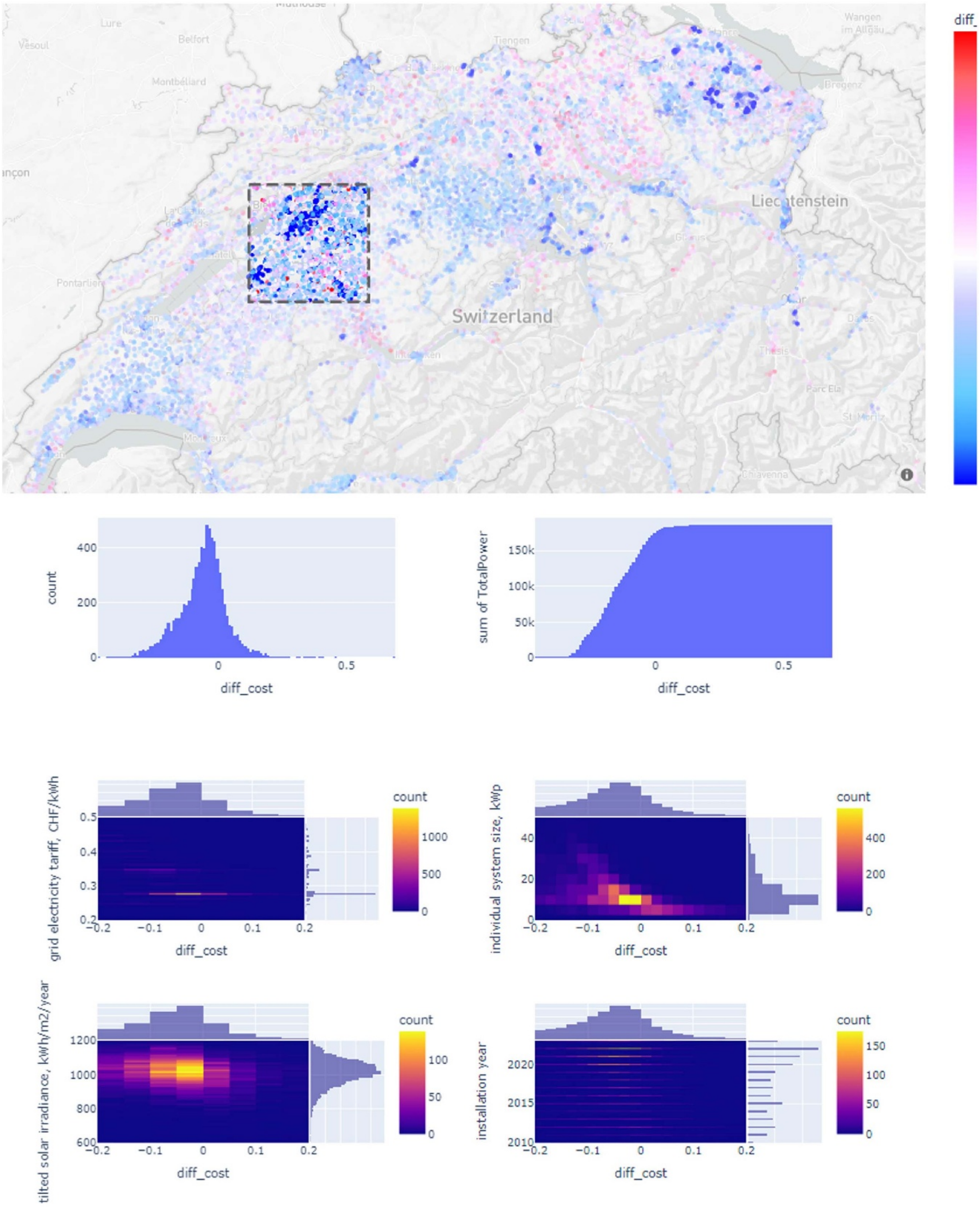

Figure I1. Cost difference for the systems in the west side of central Switzerland (Bern): geographical distribution of cost difference (map on top), by count of system (2nd row, left), by sum of power capacity (2nd row, right), by grid electricity tariff (third row, left), by individual system size (third row, right), by tilted solar irradiance (fourth row, left) and by installation year, (fourth row, right). The color in all heatmap figures indicates the count of the systems.

Appendix J. Cost difference for the systems in the area of central Switzerland (Lucerne)

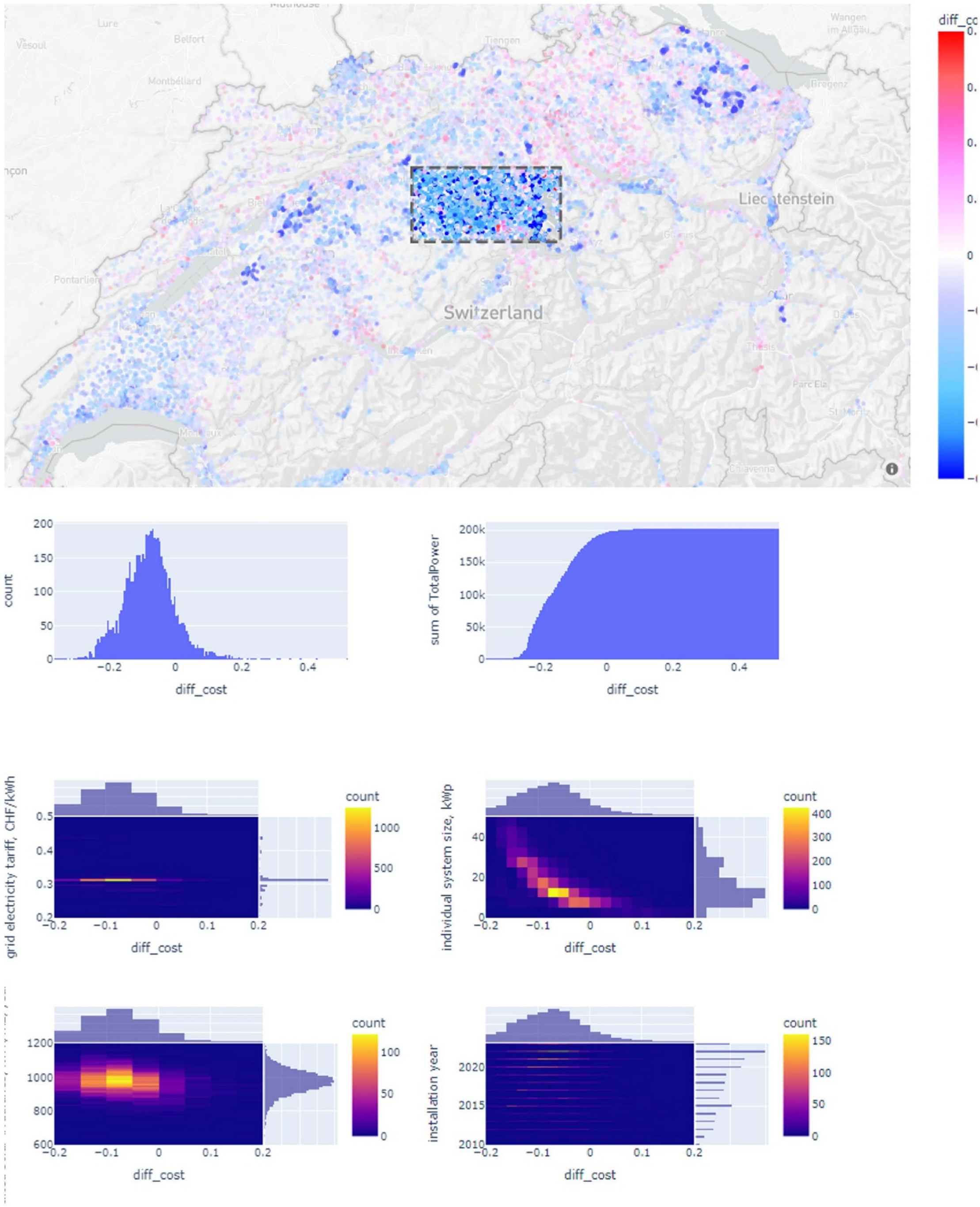

Figure J1. Cost difference for the systems in the area of central Switzerland (Lucerne): geographical distribution of cost difference (map on top), by count of system (2nd row, left), by sum of power capacity (2nd row, right), by grid electricity tariff (third row, left), by individual system size (third row, right), by tilted solar irradiance (fourth row, left) and by installation year, (fourth row, right). The color in all heatmap figures indicates the count of the systems.

Appendix K. Cost difference for the systems in the northern side of central Switzerland (Zurich)

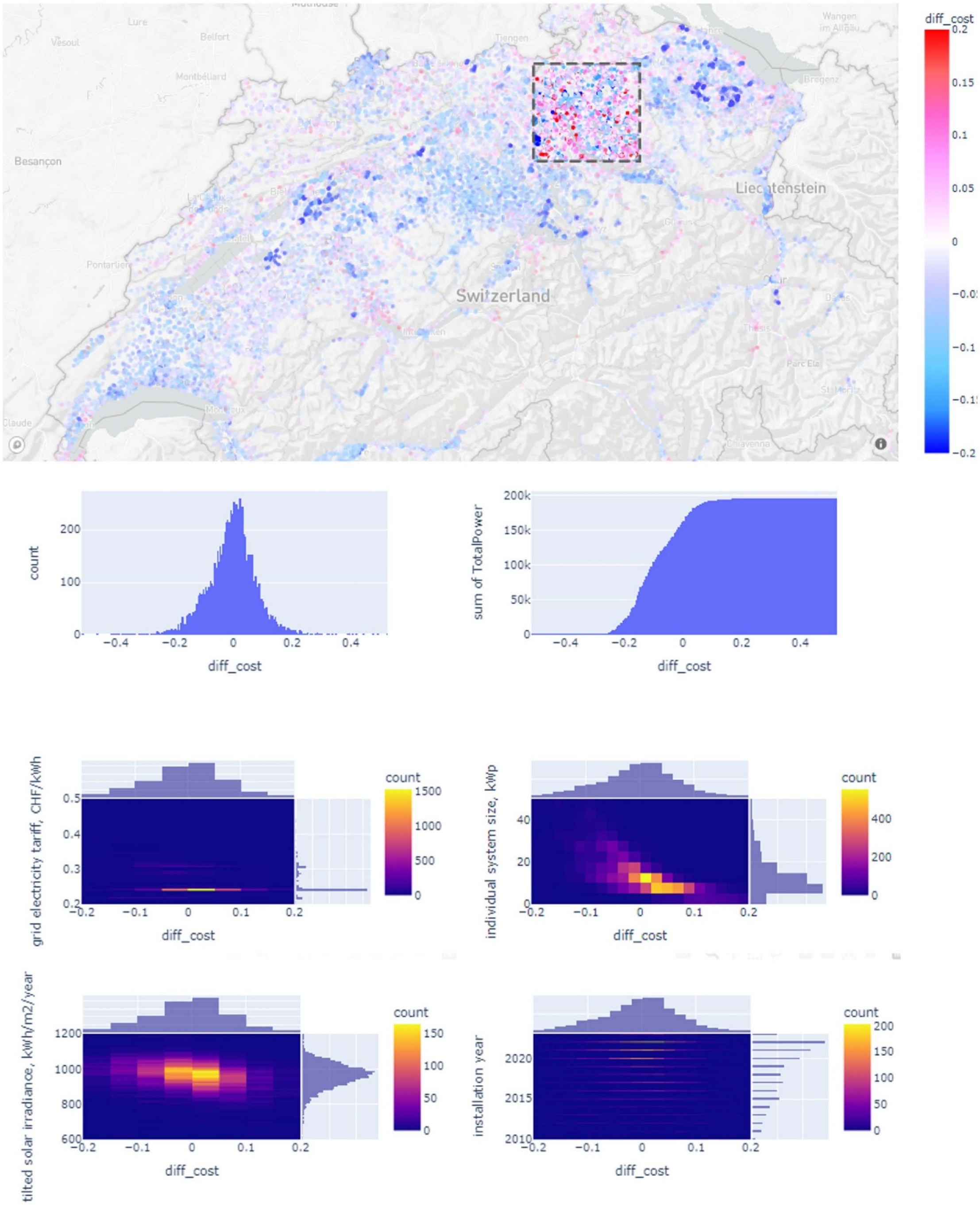

Figure K1. Cost difference for the systems in the northern side of central Switzerland (Zurich): geographical distribution of cost difference (map on top), by count of system (2nd row, left), by sum of power capacity (2nd row, right), by grid electricity tariff (third row, left), by individual system size (third row, right), by tilted solar irradiance (fourth row, left) and by installation year, (fourth row, right). The colour in all heatmap figures indicates the count of the systems.

Appendix L. GHG emissions of electricity generated from existing rooftop PV systems

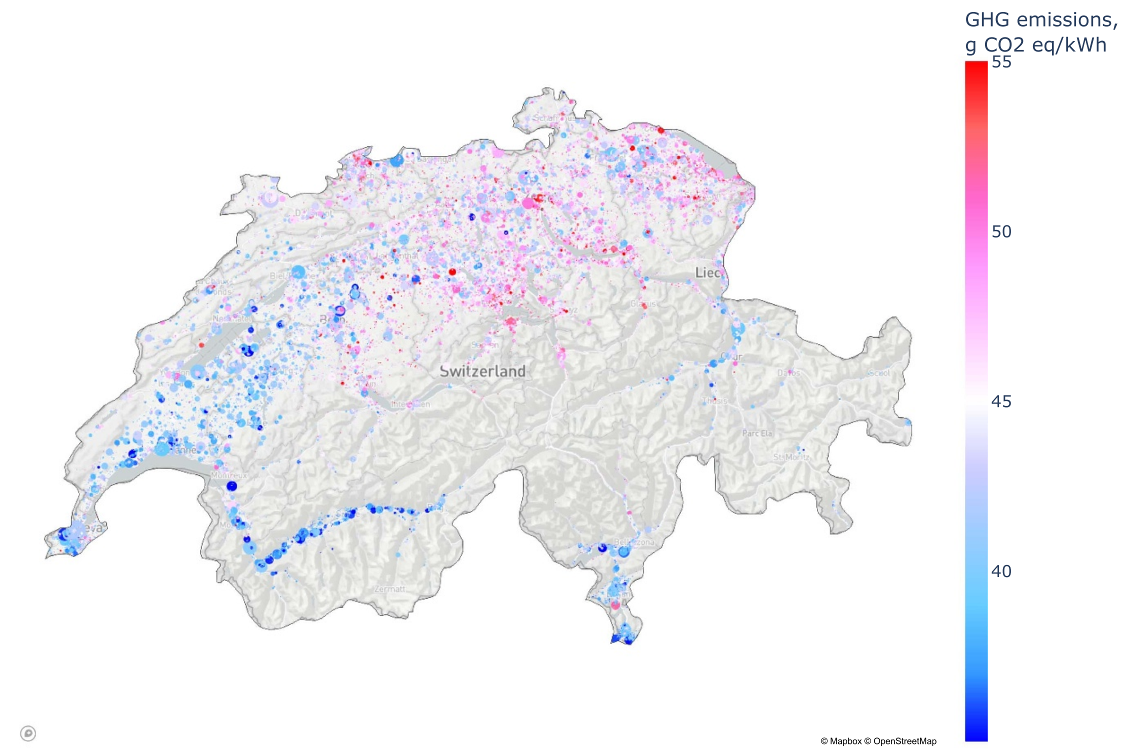

Figure L1. GHG emissions of electricity generated from existing rooftop PV systems. © Mapbox (www.mapbox.com/about/maps), © OpenStreetMap (www.openstreetmap.org/copyright).

Appendix M. Dynamic GHG emissions of swiss grid based on consumption mix, electricity Maps

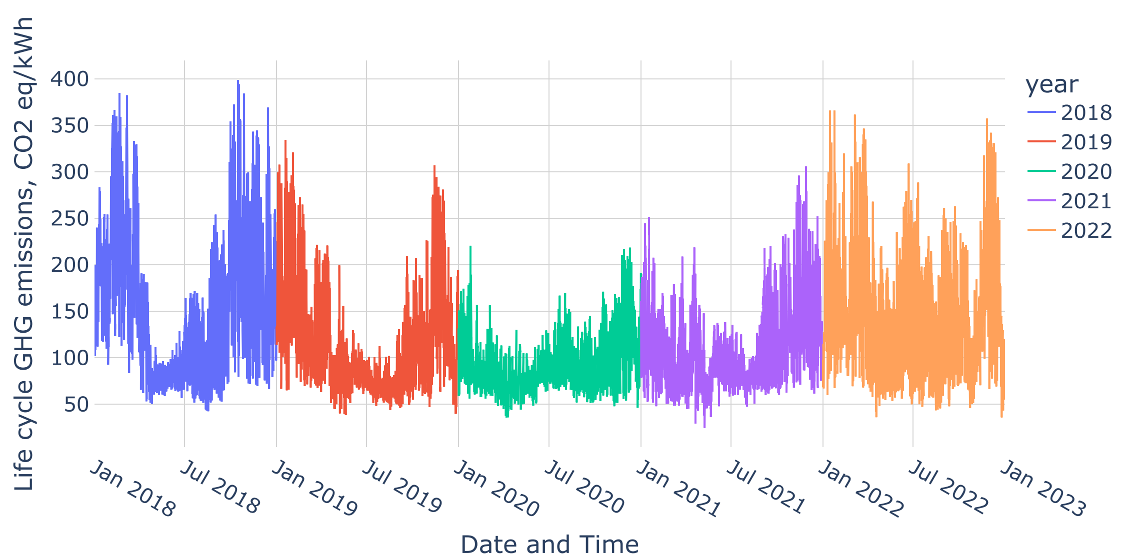

Figure M1. Dynamic GHG emissions of grid supply based on consumption mix and data from Electricity Maps 2018–2022 (ElectricitMap 2023).

Appendix N. GHG emissions by utility providers in 2021 based on electricity certificates

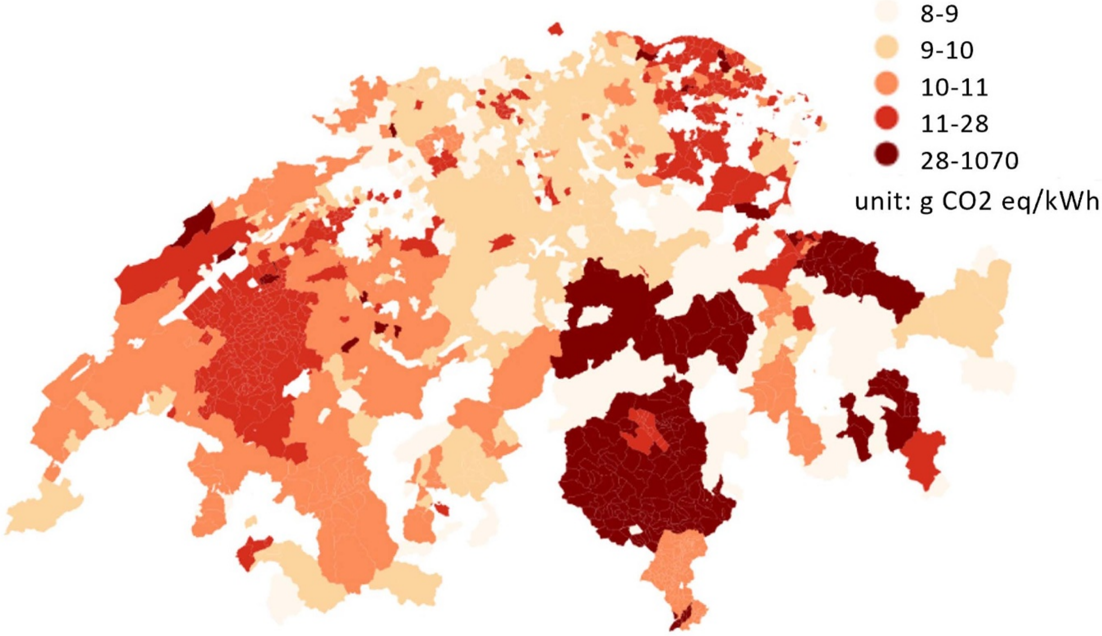

Figure N1. GHG emissions by utility providers in 2021 based on electricity certificates.

Appendix O. Distribution of the ratio of PV occupied area and total available roof area

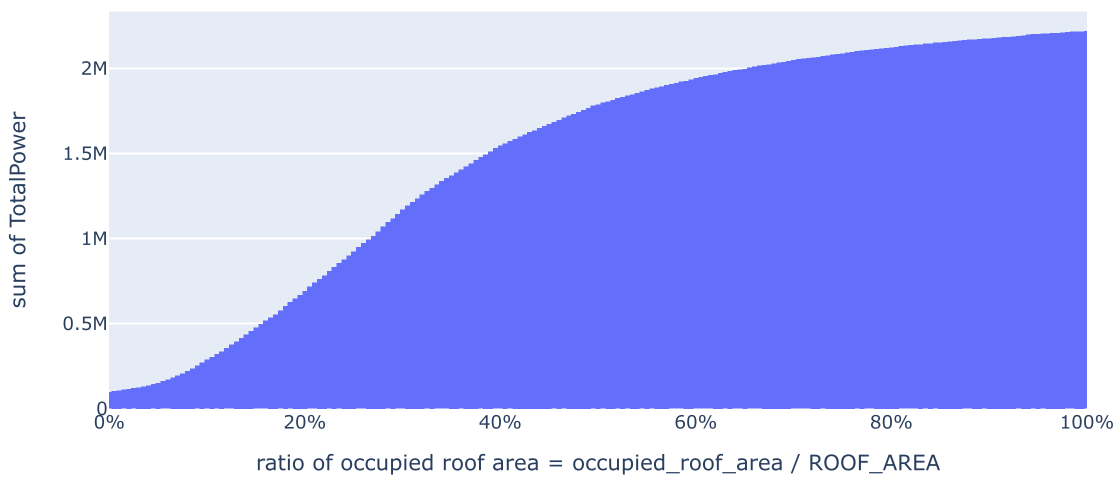

Figure O1. Ratio of area occupied by solar PV system and total available roof area, distribution of cumulative power capacity.

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