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Spatial strategies for siting variable renewable energy sources to ensure weather resilience in Switzerland

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ABSTRACT

Weather resilience of the electricity system with high shares of Variable Renewable Energy Sources (VRES) could potentially be increased by spatially siting these sources in a way that dims the impact of weather. Here, we use single-year high-resolution modeling to test the resilience of the Swiss electricity system in 2035 under four siting strategies for new solar PV, wind power plants, and heat pumps: expected siting (continuation of the current spatial trends), even siting that is proportional to the technical potential or population, and the minimum system cost approach from the system's perspective. Using weather data from 1995 to 2019, we calculate nine electricity system resilience indicators for each siting strategy, accounting for diversification, decentralization, import dependency, load shedding, and curtailment. We find that a Swiss system in 2035 running fully or almost fully on VRES is resilient to historical weather variations. The four siting strategies perform relatively similarly in terms of resilience, indicating that VRES locations are neither a major concern nor a promising solution to influence weather resilience in a small country, like Switzerland. Having said that, minimum system cost approach that sites technologies in a cost-optimal way from the system's perspective has consistent, albeit minor, advantages for resilience, especially for minimizing load shedding and curtailment.

1. Introduction

Energy systems worldwide seek to reach high shares of Variable Renewable Energy Sources (VRES) to limit global warming [1] and to address other environmental and supply security concerns [2]. In fact, latest evidence shows that it is technically and economically feasible to have very high shares or even 100 % of electricity supply met using VRES [3,4]. Yet, to ensure supply security, such systems need to be resilient to weather variability and to manage intermittency since both electricity demand and VRES supply depend on weather. As such, two types of research problems are typically investigated in terms of weather resilience of the electricity systems. First, electricity system models are used to design cost-efficient and technically-feasible systems of the future that are resilient to weather [5–7], including storage needs [8,9]. Second, predefined layouts of the electricity system today or in the future are tested against various weather conditions [10,11]. The latter type of studies is typically conducted at a large continental scale, e.g. Europe, and use several decades of historical weather data to investigate how intermittency can be managed through international trade. While there is at least one study that combines both approaches [12,13], the overall focus there still remains on Europe and the study has a relatively coarse spatial resolution. However, it is highly relevant to analyze the impact of weather patterns on the national electricity systems at higher, sub-national resolution because ensuring resilience of supply is, above all, a scope of national policy and a duty of system operators. Modelling weather-dependent electricity demand and VRES supply at sub-national resolution would also allow to capture the role of weather impacts on resilience more accurately.

Weather-resilience of the electricity system depends on both weather variability, locations of the VRES plants and weather-dependent electricity demand. Previous research analyzed VRES siting strategies from various perspectives, such as cost effectiveness [6], tradeoffs between cost effectiveness [14] and regional equity in terms of electricity generation [15,16], and environmental, economic [17,18] and health impacts [19]. Another strand of studies investigated how and why VRES plants are currently being built [20,21] and how this could be best

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represented in models for forward-looking planning [22,23]. Space and time variability of weather conditions makes the siting of VRES a crucial aspect of ensuring weather resilience of the system [6,24]. Indeed, wisely allocated PV and wind power installations across different regions can counterbalance weather patterns [25,26]. In a European study on wind power in particular, Grams et al. [27] observed that profound understanding of weather regimes and optimal siting of wind turbines can improve electricity system's resilience. On the demand side, allocating heat pumps and EV charging locations can also help increase system's flexibility and hence its resilience to respond to weather impacts [28,29]. However, while some studies came up with concrete proposals for Europe [6,30] or for specific countries [7] where to ideally build VRES, no study so far analyzed the broader siting rationales that could be transferred across regions, such as siting by cost efficiency, equity, or simply by allowing the continuation of current trends.

In this study, we address the mentioned research gaps using the case of Swiss electricity sector in the single year of 2035. Switzerland is an internationally interesting case study because in a referendum, the country recently adopted a new 2035 target of 35 TWh/year of new renewable electricity (solar PV, wind power, and biomass) [31]. In addition to around 35 to 40 TWh/year from existing hydropower plants, the achievement of this new target would make the country's electricity supply rely fully or nearly fully on VRES on an annual basis already in 2035 [32,33]. As a mountainous country, Switzerland has a combination of highly spatially uneven topology and hence spatially uneven VRES potential and electricity demand, in addition to an uneven actual growth in solar PV [22,34] and heat pumps [21]. This study therefore tests the resilience of the Swiss electricity system in 2035 against the conditions of 25 historical weather years (1995–2019), applying nine indicators to measure system's resilience from different perspectives. In particular, four broad strategies of siting solar PV, wind power plants, and heat pumps are assessed: (i) expected siting which assumes continuation of the current trends, (ii) even siting that is proportional to the technical potential or to (iii) population, and (iv) minimum system cost approach. The aims are to provide policy and planning insights for the implementation of this new target of 35 TWh/year of new renewable electricity in Switzerland in terms of weather resilience and to understand how these generalizable siting strategies perform in terms of weather resilience (Section 2.5) in systems that almost entirely depend on VRES.

2. Methods

2.1. Overall study design

The study uses the high-resolution cost-optimization electricity sector model EXPANSE (Section 2.2) for Switzerland to model capacity expansion and operation of electricity generation, storage, and transmission for meeting the required electricity demand in Switzerland and its four neighboring countries in 2035. To compare the four siting strategies (Section 2.3) on equal footing in terms of installed capacities, first, a reference electricity system's capacity layout in 2035 (Figure A.1 in the Supplementary Material) is calculated using cost optimization. In this reference scenario, we assume that nuclear power in Switzerland is completely phased out, that the target of at least 35 TWh/year from new renewable sources without hydropower is reached [33], that uptake of heat pumps evolves as currently expected [34], and that there are no additional electricity trade restrictions with the rest of Europe. The reference scenario has 21.5 GW of solar PV (of which, 8 GW are rooftop solar PV, 8 GW – rooftop PV coupled with residential batteries [32], 5.5 GW – on facades) and 1.7 GW of wind power. Reference values are taken from Renewable Energy Outlook for Switzerland [33] and the inclusion of residential batteries in the scenarios was suggested by a model inter-comparison study with other Swiss models [32]. The reference scenario also has 513.3 thousand buildings with heat pumps (based on the median projection from Ref. [34]). All other investments, such as generation capacities in neighboring countries and biomass, waste incineration, transmission, and storage capacities in Switzerland, are determined by optimization.

The installed capacities of solar PV, wind power, and the number of heat pumps from the reference scenario are then kept constant across scenarios at a national level, but spatially redistributed, using four different siting strategies (Section 2.3). Taking the weather conditions of the year 2015 (Section 2.4) [12,13], because the minimum total system cost in 2015 approached the average total system cost of 25 years, the capacities and operation of the rest of the electricity system in 2035 are then optimized when the quantities and locations of solar PV, wind power and heat pumps are enforced as defined by the four siting strategies (Figures A.1-A.2 in the Supplementary Material). Nevertheless, choosing another weather year, in place of 2015, would have led to a similar outcome as wind power capacities are low in Switzerland and it is wind power that has the highest variation from year to year. These new electricity scenarios, with capacities optimized for the average year 2015 for each of the siting strategies, are then tested against 25 years of historical weather patterns from 1995 to 2019, accounting for impacts on hydropower dams, run-of-river hydropower, solar PV, wind power, and electricity demand (Section 2.4). To measure weather resilience, nine indicators are then calculated for each of the siting strategies (Section 2.5) in addition to a more general analysis of the weather impacts on the technology mix.

Figure A.3 in the Supplementary Material provides the schematic drawing of the study design.

2.2. EXPANSE electricity system model

EXPANSE is a bottom-up, technology-rich model that in its basic version applied here generates technically-feasible cost-optimal scenarios of electricity generation, storage, and transmission [14,17,18]. The model stands out among the Swiss electricity models for its technology diversity and high spatial and temporal resolution [32,33] as well as for its testing by retrospective modeling [23]. The model outlines electricity supply-demand dispatch in a single year (2035) with a temporal resolution of 3 h as a trade-off between computational requirements and capturing time variability of weather in detail [11,35]. The model has a spatial resolution of 2′136 Swiss municipalities, while the modeling of supply-demand balance, transmission and storage is conducted at an aggregated level of 15 grid nodes. This spatial resolution captures the combination of spatial heterogeneity of renewable electricity sources and potential grid bottlenecks. High-voltage transmission lines are explicitly modelled in EXPANSE (Figure A.18 in the Supplementary Material), using power flow constraints and losses, while the distribution grid is modelled in a simplified way by accounting for losses only. Four neighboring countries of Switzerland (Austria, France, Germany, and Italy) are also represented as additional technology-rich single nodes at hourly resolution, just not disaggregated into subnational regions. Their electricity generation, transmission, and storage capacities and operation are co-optimized with those of Switzerland to adequately represent electricity trade and transit. The list of electricity generation technologies include non-renewable technologies (gas plants in Switzerland and nuclear, coal, lignite, oil, and gas plants elsewhere), renewable technologies (solar PV on rooftops and facades, onshore wind power, hydropower dams, run-of-river hydropower, biogas, woody biomass, and waste incineration in Switzerland and additionally open-field PV and offshore wind power elsewhere), storage units (pumped hydropower storage, grid-scale batteries, power-to-hydrogen, and in the case of Switzerland also decentralized batteries combined with rooftop solar PV installations). The electricity demand in the reference scenarios is assumed to be 68.1 TWh/year in Switzerland (assuming an increase of population and partial electrification of heating and mobility [32]), 88.0 TWh/year in Austria, 520.1 TWh/year in France, 605.0 TWh/year in Germany, and 313.3 TWh/year in Italy, in line with ENTSO-E TYNDP 2022 "National trends" scenario, and hence it already includes certain deployment of heat pumps and electric vehicles [36]. In addition to the Swiss policy assumptions (Section 2.1), the model requires the neighboring countries to meet country-specific CO_2 emissions reductions (maximum 108.7 Mt/year of CO_2 emissions in Germany, 19.5 Mt/year in France, 38.3 Mt/year in Italy, 4 Mt/year in Austria) and renewable electricity targets of 65 % in Germany, 40 % in France, 55 % in Italy, and 100 % in Austria, based on the European Commission's National Energy and Climate Plans [30,37].

Running EXPANSE with historical weather data for testing resilience, including extreme weather situations, increases the likelihood of finding infeasible scenarios, mainly due to nodal power balance constraint. For this reason, in this study, EXPANSE is extended with the functionality of load shedding. Load shedding is represented as an electricity generator at a nodal level, including in the neighboring countries, with zero investment cost and operational cost of 10 thousand EUR/MWh, and with an installed capacity equal to the maximum demand load (in MW) of each grid node [38,39]. Preliminary runs of the model showed that the operational cost of load shedding is sufficiently high to activate load shedding only in extreme cases in which the supply-demand balance or other constraints would otherwise prevent finding feasible solutions. The level of load shedding is then included as one of the resilience criteria (Section 2.5) too to indicate how often the historical weather conditions push the model to this extreme state.

2.3. Siting strategies to be compared

In this study, different spatial strategies (c.f. [14]) are tested for allocating solar PV, wind power, and heat pumps in Switzerland. The overall installed capacity and number of buildings with heat pumps are set constant across scenarios as described in Section 2.1 and these installations are only distributed differently across the municipalities (see Figures A.1-A.2 in the Supplementary Material for maps).

- *Expected siting, based on the continuation of the current spatial trends:* Multiple previous studies showed that the actual growth of solar PV [20,22,23], heat pumps [21] and other energy technologies more broadly [40,41] do not follow a straightforward logic. For future distribution of solar PV and heat pumps, Zielonka et al. [34,42] provide probabilistic spatial projections until 2050 in Switzerland in the case of continuation of current trends and socio-political context. We use the spatial patterns of the median projection for the year 2035. For wind power, there are currently only 12 wind power plants in operation in Switzerland and hence an in-depth analysis of current trends and their continuation is not meaningful. We assume then that in this siting strategy wind power plants will be installed in the municipalities where such plants already exist as well as in the surrounding municipalities, assuming a spillover effect [20].
- *Even siting that is proportional to the technical potential*: following the equity principle in terms of evenly allocating generation and its environmental [18] and other impacts [14,15], here we assume that solar PV and wind power would be allocated throughout Switzerland based on their technical potential that is used in the EXPANSE model [43,44]. For wind power, the technical potential already accounts for available land area as well as constraints where no wind power could be built. For solar PV, the technical potential only accounts for PV on rooftops and facades and not for open-field PV which is not permitted in Switzerland except for specific cases. The technical potential for heat pumps is assumed to be proportional to the total number of buildings per municipality.
- *Even siting that is proportional to the population:* following a similar equity rationale as before, solar PV, wind power, and heat pumps are allocated here proportionally to the population [14,15]. In Switzerland, allocation by population is similar to the allocation by electricity demand, but it is more transparent and precise [14].
- *Minimum system cost approach:* solar PV and wind power plants in this case are allocated on the basis of cost efficiency from the electricity system's perspective [14,15], using the cost optimization function of EXPANSE. For this, the model is run another time with the constraint that the total PV and wind power capacities at a country level should be as defined in Section 2.1. As EXPANSE exogenously assumes electricity demand as input and hence cannot optimize the locations of heat pumps, the siting strategy that is even by technical potential is adopted here, as described before.

2.4. Historical weather patterns

For this study, we enlarge the EXPANSE model with an extended dataset of 25 historical weather years (1995–2019) for estimating hourly capacity factors of solar PV, wind power, run-of-river hydropower, and hydropower dams, as well as for estimating hourly electricity demand for heating with heat pumps [7]. The weather impacts are modelled at municipal level in Switzerland (except for hydropower inflows that are modelled at nodal level) and at a national level in the four neighboring countries. Data on solar PV and wind power generation are synthetized using renewables.ninja [35,45] and Calliope datasets [26]. Run-of-river hydropower data are extended from an earlier SCCER-JASM dataset by the dataset's author [46]. The inflow data for hydropower dams is generated using an existing time series from the year 2016 from Calliope model [26] and afore-mentioned run-of-river data as training data for a linear regression model [7]. Figures A.16 and A.17 in the Supplementary Material show the variation of the average capacity factors in Switzerland across weather years and across regions. For the neighboring countries, data on inflow for hydropower dams and run-of-river hydropower is taken from Calliope model for the year 2016 [26] and then linearly scaled for the other years using the IEA Hydropower data explorer [47], considering historical trends of both installed capacity and generation.

As for the Swiss electricity demand, only demand for heat pumps is modelled as weather dependent, while the demand for electric vehicles and other uses is assumed constant in 2035 under different weather conditions. Electricity demand time profile for heat pumps is estimated bottom up as a sum of weather-independent hot water demand and weather-dependent space heating demand in each municipality [48]. Hot water demand is assumed to be equal to the product between the number of people living in a building with a heat pump and the Swiss average demand for hot water per capita [49], and then constant in time. Hourly demand for space heating is estimated as the product between a specific heat coefficient representing the average consumption per heating degree hour and per heat pump, the assumed number of heat pumps in use in each municipality (Section 2.3) and the yearly timeseries of heating degree hours. Hourly values of heating degree hours are calculated as the absolute value of the difference between the outdoor temperature at 2 m height in 2000–2019 [50] and a threshold temperature of 12 °C [51], above which the value of heating degree hour is zero. We use hourly values instead of daily averages to allow testing of more extreme conditions of heat pump use at low outside temperatures, even if in this way we underestimate the inertia in the heating system. Due to lack of temperature data availability and the desire to nonetheless conduct the analysis from 1995 at least for renewable technologies, we assume the years 1995–1999 had the same temperature as the year 2000, and we also conduct additional analysis just for the years 2000–2019. The heating demand is then translated into electricity demand assuming a coefficient of performance of 3.5 without accounting for the dependency of the coefficient of performance (COP) on temperature. For neighboring countries, electricity demand values and timeseries are taken from ENTSO-E dataset (TYNDP 2022 "National trends" scenario) [36], which cover projections based on historical weather years, including the range of 1995–2019 of our interest.

2.5. Electricity system resilience indicators

As a multi-faceted concept, the weather resilience of the scenarios is quantified using nine indicators from the SWEET SURE project framework [52,53], defined by desk research and a stakeholder workshop, as shown in Table 1. As a whole, these indicators measure various aspects of the electricity system resilience: diversification and decentralization, reliance on import or renewable electricity sources, and the need for load shedding and curtailment.

3. Results

3.1. Electricity supply under conditions of historical weather

Overall, all four siting strategies to locate 21.5 GW of solar PV, 1.7 GW of wind power, and 513.3 thousand buildings with heat pumps (Figures A.1-A.2 in the Supplementary Material) lead to technically operational system designs under the conditions of all 25 historical weather years. Load shedding is required only from time to time, often for less than 3 h per year. As shown in Fig. 1, despite the complex Swiss topology, solar PV (rooftop PV, rooftop PV with batteries, and facade PV) is the VRES that is, in terms of coefficient of variation, the most robust to different weather years at an annual level, supplying an average of 17.6 TWh/year with a standard deviation of only 0.5 TWh/year. Wind power production is also robust across the years with an average production of 2.3 TWh/year and a standard deviation of 0.2 TWh/year. Electricity demand from heat pumps ranges from 7.5 TWh/year to 10.1 TWh/year: while this range is substantial as it originates in outdoor temperature variations, it is still relatively small if compared to the average value of total electricity demand of 61.3 TWh/year. In contrast, the ranges and standard deviations obtained for run-of-river hydropower and hydropower dams are higher, indicating much higher sensitivity to weather. A similar weather sensitivity is observed for net import, whose values range from about +6.6 TWh/year to −5.9 TWh/year (negative values indicate net export). Generation from gas, biogas and woody biomass together in Figure A.4 also indicates wide variation of 0.98 TWh/year for gas and 0.7 TWh/year for biogas and woody biomass, at least when compared to their average generation of 0.9 TWh/year and 1.9 TW/year respectively. When compared to the least flexible thermal power generation in Switzerland, i.e., waste incineration, these results indicate that thermal generation together with import have a role in ensuring system's flexibility, including the responsiveness to different weather conditions, even if marginal in the bigger picture. It is assumed that they at least work at 20 % annual capacity factor to ensure economic viability (Table A.2 in the Supplementary Material). As for batteries and pumped hydropower storage, the results also show a moderate dependency on weather conditions, while the installed capacity of power-to-hydrogen is negligible in all cases.

Electricity generation levels differ for the four siting strategies for solar PV and especially wind power (Fig. 1), but not for the other technologies. The two siting strategies that concentrate all wind power turbines in fewer locations (*Minimum system cost approach* and *Expected siting*) are more productive than the strategies with spatially more even siting. For solar PV, the *Minimum system cost approach* deviates from the other three strategies, resulting in a lower PV production on average. As *Minimum system cost approach* has the highest wind power production, lower PV generation is sufficient for the system to run in a cost optimal way. Additionally, there is a lower uptake of decentralized batteries as solar PV is operated more cost efficiently. A small deviation is observed for the case of *Minimum system cost approach* for run-of-river hydropower, indicating a lower curtailment and more efficient use of this resource. As for net import, heat pumps, hydropower dams, gas plants and waste incineration, no substantial difference across different siting strategies is observed. The outdoor temperature dependency affects the demand from heat pumps in a more pronounced way than the siting strategies of these heat pumps.

Investigating the weather years leading to extreme values for each

Table 1
Resilience indicators used in the study.

Concept	Resilience indicator	Definition	Unit of measure	Justification
Diversification and decentralization	Diversification of electricity supply	Shannon index $\sum_{i=1}^{n} p_i \cdot \ln(p_i)$, where p is the share of domestic electricity production of each technology i and n is the total number of technologies considered. Biomass and waste are, for this indicator specifically, considered as one technology.	Unitless	This indicator measures diversification as a means of electricity supply not to overrely on one or several energy sources [54,55]
	Decentralization index	Ratio of the electricity generated by decentralized renewable sources (solar PV, wind power, biogas, waste incineration, and woody biomass) to total domestic electricity generation	Unitless	This indicator measures the reliance of the system on decentralized sources [14,52]
Import vs. domestic supply	Import dependency	Ratio of net electricity import to total domestic electricity generation. Negative values indicate net export of electricity.	Unitless	This indicator reflects the reliance on the imported rather than domestically produced electricity [26,52]
	Self-sufficiency of electricity supply	Number of hours per year in which domestic supply is equal or higher than the electricity demand	Hours	This indicators complements the indicator on import dependency by enhancing the temporal dimension [52]
	Total generation from renewable sources	Electricity generation from solar PV, biomass and waste, wind power, run-of-river hydropower, and hydro dams	TWh	This indicator measures the system's reliance on domestic electricity sources [3,52]. Switzerland has no domestic fossil fuel extraction
Load shedding	Hours of load shedding above 1 % load	Number of hours per year in which more than 1 % of the demand load is not supplied	Hours	This indicator measures the activation of load shedding to estimate the frequency of insufficient electricity supply [13,52]
	Hours of load shedding above 5 % load	Number of hours per year in which more than 5 % of the demand load is not supplied	Hours	To complement the previous indicator, this indicator additionally measures the frequency of more severe insufficiency of electricity supply [13,52]
Curtailment	Equivalent availability factor for solar PV	Ratio of electricity produced by solar PV and a sum of produced and curtailed electricity	Unitless	This indicator measures the need for solar PV curtailment [52,56]. Curtailment leads to economically sub-optimal operation of the installations
	Equivalent availability factor for wind power	Ratio of electricity produced by wind power and a sum of produced and curtailed electricity	Unitless	This indicator measures the need for wind power curtailment [52,56]. Curtailment leads to economically sub-optimal operation of the installations.

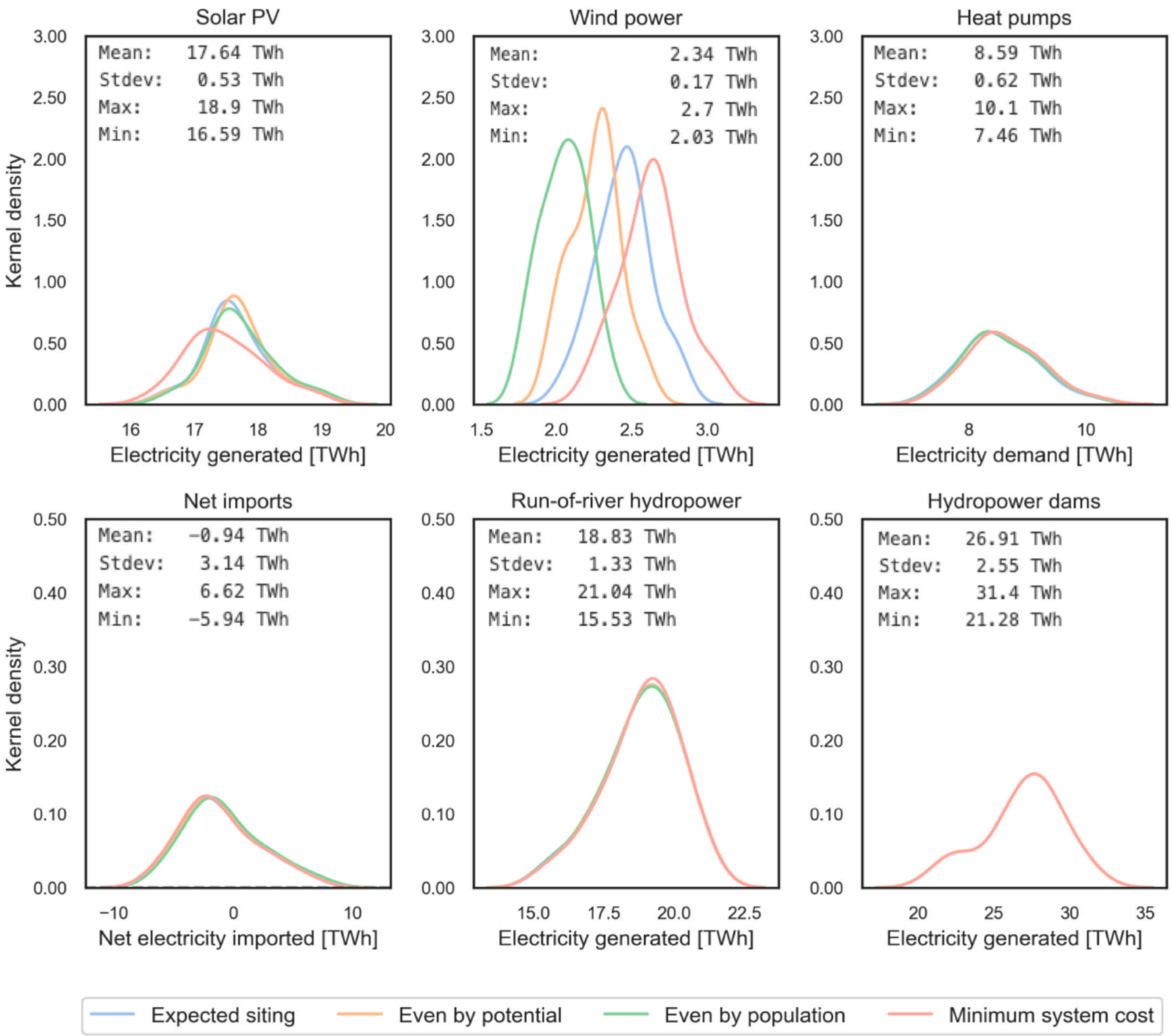

Fig. 1. Kernel distribution densities for each siting strategy across 25 weather years for selected technologies in Switzerland (other technologies are shown in Figure A.4). The densities on the vertical axis show the smoothed frequency of the distributions of the data. The smoothing factor is calculated using Scott's rule. The values of mean, standard deviation, maximum and minimum values are calculated for all siting strategies and all weather years together.

technology in the generation mix (Table A.1 in the Supplementary Material), we observe that net electricity import is at its maximum for the same weather year 2005 where production from hydropower dams is the lowest, and conversely for the weather year 2001. In fact, hydropower dams represent the highest share in the electricity mix and, in the case of unfavorable weather conditions, the system reacts with import rather than other domestic generation. The maximum electricity production from solar PV is observed during the weather conditions of 2011, which coincides with the lowest run-of-river hydropower production. This result indicates how a diversified portfolio of VRES can effectively complement and balance each other. Concerning wind power, the weather conditions that induced the highest and the lowest electricity production are found to be 2007 and 1996, respectively. As for the case of gas, biomass, waste incineration and storage technologies, the weather year 2017 requires the highest production from all the mentioned technologies and the highest use of grid-scale batteries, indicating a particularly high need of flexibility for this type of weather year. As shown in Section 3.2, this weather-year corresponds to the year with the highest diversification of electricity supply, one of the highest levels of decentralization, and one of the lowest years of renewable electricity production due to low hydropower production. The highest electricity demand for heat pumps occurs for the weather year 2010, which was a particularly cold year [57], and the lowest – for the year 2014. The yearly electricity generation per technology for all the 25 weather years analyzed is shown in Figure A.21 in the Supplementary Material.

3.2. Resilience implications

Fig. 2 depicts the spread of the resilience indicators across the weather years for each siting strategy. In terms of the diversification of electricity supply, the Shannon index ranges from 1.53 (lowest diversification) to 1.65 (highest diversification) as compared to the theoretical maximum of 1.95 which would be achieved if all technologies

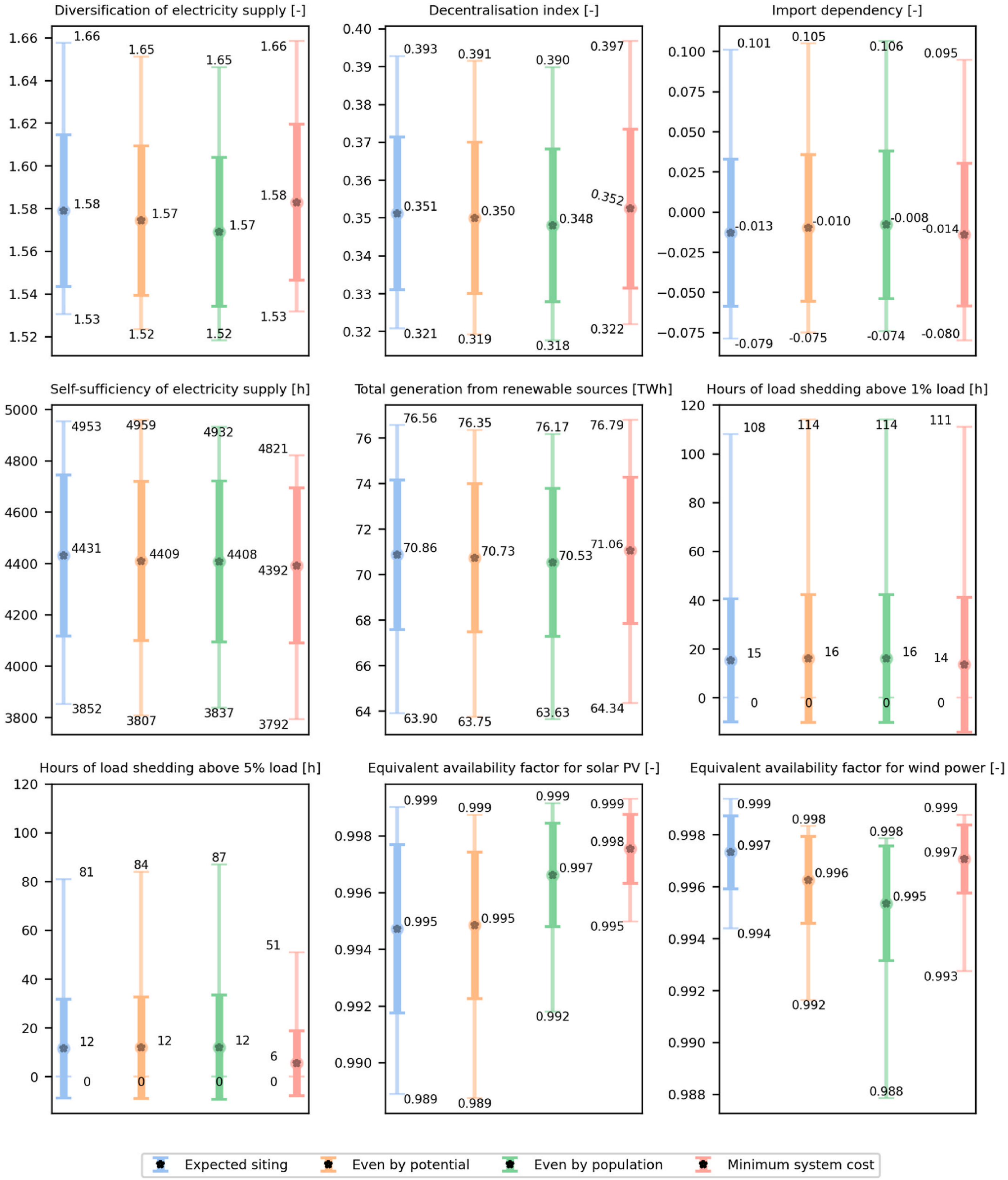

Fig. 2. Resilience indicators for the four siting strategies under the conditions of 25 historical weather years. Each error bar represents range, standard deviation, and mean of the indicators' values. The kernel distribution densities of these results and the normalized values for individual years are shown in Figures A.5 and A.6-A.9, respectively.

contributed 14 % to the generation mix. High contributions of Swiss hydropower as well as solar PV thus limit the diversification potential in Switzerland. Minor technologies, whose contribution varies across weather years, such as biomass and gas, are the ones that influence the diversification of electricity supply the most. For example, the weather year 2017 has the highest generation from biomass and gas as well as the highest Shannon index. By contrast, Shannon index is much more robust to the variation in PV generation across the years because this variation is small as compared to the overall contribution of solar PV to the supply mix. In terms of decentralization, decentralized sources represent about 35 % of the domestic generation on average. The remaining share of domestic generation is mostly supplied by hydropower and, in much smaller quantities, by natural gas. The spread across weather years is due to different weather impacts on solar PV and wind power generation, ranging from 32 % decentralization in the case of weather year 2013 to 39 % in 2005. The *Minimum system cost approach* and, to a lesser extent, *Expected siting* perform better than the other two strategies on both indicators, although the difference is small.

Import dependency is on average at −1.1 %, with negative value indicating that Switzerland would be a net exporter of electricity. However, in some weather years like 2005 and 2017, import dependency would reach +10.2 % and +7.6 %, respectively. The self-sufficiency indicator provides additional insights into the temporal perspective, showing that, on average, Switzerland has sufficient domestic electricity supply to cover its own demand for around half of the year. *Even siting by population* and *by potential* perform well on both indicators and, additionally, *Expected siting* scores best on the self-sufficiency of electricity supply, although the difference is relatively small. The outcomes of the two indicators in different weather years mainly depend on the need for importing electricity when domestic supply is limited and on the need for frequent hourly electricity exchange with neighboring countries. Total generation from renewable sources represents, except for a little share of gas generation, the entire domestic supply and varies from 63.9 TWh/year to about 76.5 TWh/year. *Minimum system cost approach* and *Expected siting* are the siting strategies that perform best on this indicator.

The use of load shedding, on average, remains very low, for 14–16 h per year, of which most are already for shedding 5 % rather than 1 % of the national load. Load shedding is not needed for more than 3 h per year for around half of the weather years analyzed, whereas some rare weather conditions (2009, 2010, 2012) can lead up to 20–110 h of load shedding above 1 % of the demand and to 20–80 h above 5 % of demand, which is substantial. For example, the weather year 2010 required load shedding likely due to its high electricity demand from heat pumps and low production from solar PV (Table A.1), while hydropower production was similar to that of a typical year. Years 2009 and 2012, together with 2010, are among the five years that exhibit the highest heating degree hours between 1st January and 28th February. Within the year 2012 the maximum peak of load shedding is recorded (23.5 % of the national load). In these weather years, load shedding happens in the neighboring countries as well (Figure A.19), during winter, and in Germany especially. *Minimum system cost approach* exhibits an advantage over other strategies for reducing the need for load shedding and especially its sensitivity to weather. In terms of equivalent availability factors for both solar PV and wind power, the values are higher than 99 % for all siting strategies, indicating an efficient use of the generable VRES electricity and robustness to different weather conditions globally. *Minimum system cost approach* performs best in terms of solar PV availability factor and still performs well for wind power, but *Expected siting* overtakes it in terms of the equivalent availability factor of wind power. *Even siting by population* and *by potential* have lower equivalent availability factors on average, but the difference again is not so large across the strategies, while *Even siting by population* leads to narrower spread of availability factors for solar PV.

Looking at the resilience indicators for each weather year individually (Figures A.5-A.9), total generation from renewable sources is the highest for the weather year 2001, corresponding to the year with the highest production from hydropower dams (cf. Table A.1). The same happens for the weather year 2005, where both the hydropower dams and total renewable electricity production are the lowest. The share of hydropower dams in the mix (30–45 %) is so high in Switzerland that the effects of low or high PV and wind power generation are concealed. Under the weather conditions of 2005 and 2017, the two indicators of diversification of electricity supply and decentralization index, simultaneously perform either at their best or second best, and import dependency performs at its worst or second worst. In these weather years, total generation from renewable sources is comparatively low and thus the import and the generation from biomass are increased. In these weather years, the equivalent availability factors of solar PV and wind power also perform rather low, indicating overproduction from time to time and the need for more flexibility in the system. On the other hand, looking for example at the weather years 2001 and 2014, where the system's performance on diversification and decentralization is very low and import dependency high, lower curtailment is used for solar PV and wind power, and the overall generation from renewable sources is higher. The weather years that require load shedding for the highest number of hours are 2004, 2009, 2010 and 2012, but no other indicators are simultaneously pushed to their extreme in these years. For example, both the total generation from renewable sources, import dependency and even self-sufficiency of electricity supply that adopts a temporally disaggregated perspective are not far from their average value across the weather years. This result points to supply constraints in neighboring countries as well as reduced capacity to export electricity out of Switzerland. Given the approximation in the temperature data for the years 1995–1999, Figures A.23 and A.24 in the Supplementary Material show that similar results would have been obtained if the analysis was restricted to the years 2000–2019 of complete data only.

3.3. Spatially- and temporally-explicit analysis

Seven resilience indicators (Table 1), excluding import dependency and self-sufficiency of electricity supply that analyze country-level trade with neighboring countries, can be investigated in a spatially-explicit way at a level of 15 EXPANSE nodes (see Fig. 3 for weather year 2010 that required load shedding, and Figures A.10-A.12 for other weather years of interest). Northern and western Switzerland particularly contribute to the diversification and decentralization of electricity supply as they complement the ubiquitous large hydropower dams in the mountainous south of the country. When all renewable technologies are summed together, the total renewable electricity generation by node is rather uniform throughout the country, except for higher shares in the mountainous southwest. While for the previous indicators all siting strategies perform spatially similarly in all weather years, *Minimum system cost approach* achieves higher renewable generation in the central north due to higher installed capacities of solar PV. If activated, load shedding is localized in the northern node between Basel and Olten and, to a lesser extent, in the southwestern node around Geneva without much variation across spatial siting strategies. Both regions border neighboring countries and do not have hydropower dams and pumped hydropower storage capacity. Lower equivalent availability factors (or curtailment) of solar PV are spatially localized in two regions in the south and in one region in the northeast, with minor differences among the siting strategies only. Wind power curtailment is also distributed similarly in space for the *Minimum system cost approach* and *Even siting by population*, whereas the remaining two strategies involve even more regions. The regions with lower equivalent availability factors of solar PV and wind power and the regions of load shedding taken together indicate the more problematic areas in terms of supply-demand balancing.

The aforementioned properties are similar across weather years, especially for the indicators of diversification, decentralization and generation from renewable sources. For the other indicators, only some

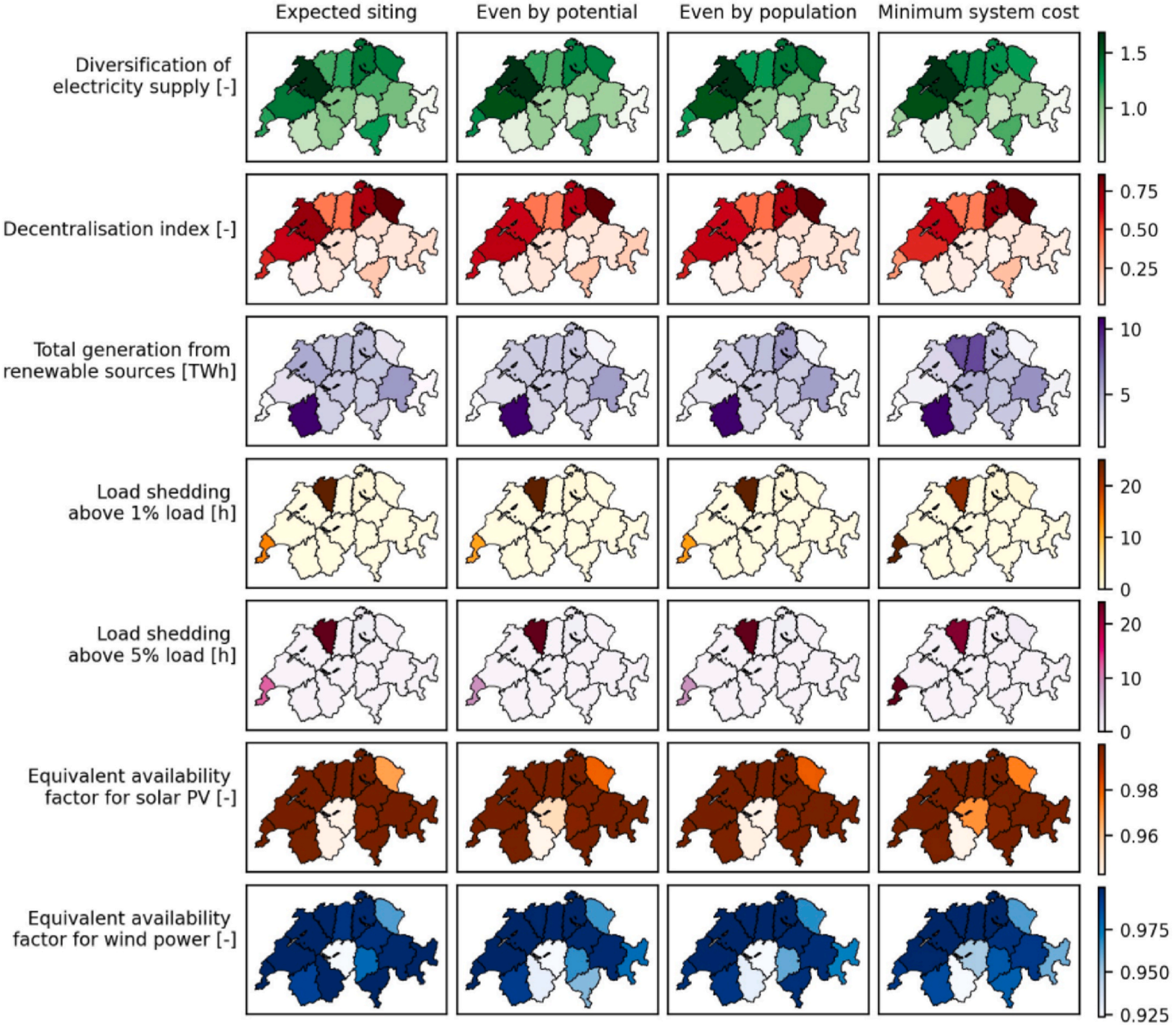

Fig. 3. Selected resilience indicators for the four siting strategies at a spatial level of grid nodes for the weather year 2010. Results for the other weather years are given in Figures A.10-A.12.

minor differences are noticeable: in the year 2017 (Figure A.12), load shedding is concentrated in another region, which is also a border region, but has hydropower and pumped hydropower capacity. In the same year 2017, solar PV is curtailed solely in the two regions in the south. A more pronounced dependency on the specific weather year is observed for the equivalent availability factor of wind power indicator.

Indicators of diversification, import dependency, decentralization, total generation from renewable sources, load shedding and availability factors can also be investigated from the temporal perspective within a year (Fig. 4 for the year 2010 and Figures A.13-A.15 for the other years). Renewable electricity generation peaks during summer due to higher solar PV and hydropower (both run of river and hydropower dams, as shown in Figure A.20) generation and, more moderately, during winter due to wind power and to hydropower dams. This temporal pattern, together with the higher electricity demand in winter, explains why import dependency and load shedding increase during the winter. Depending on the specific weather year and time window observed, load shedding events can either be isolated or repeat in consecutive sequences. These features are apparent in all siting strategies, while for the case of import dependency, both the time span and the number of times in which the symbolical threshold of 100 is surpassed varies across siting strategies. From the decentralization index it is possible to observe how charge and discharge of solar PV with decentralized batteries peaks during the winter, likely to adapt to import availability to cover the domestic electricity load. Solar PV and wind power electricity generation is also mostly, but not exclusively, curtailed during the summer period. The *Minimum system cost approach* for siting solar PV shows the highest peak curtailment, likely due to the higher concentration of solar PV in fewer locations.

The overarching pattern of seasonal variations between summer and winter is consistently observed across all weather years, albeit with some minor annual discrepancies. Taking the year 2017 (Figure A.15) as an example, the curtailment of both solar PV and wind power is less pronounced during the summer months and the peak of renewable electricity generation shifts towards September. This shift is attributable to an increased reliance on thermal generation sources, such as biomass

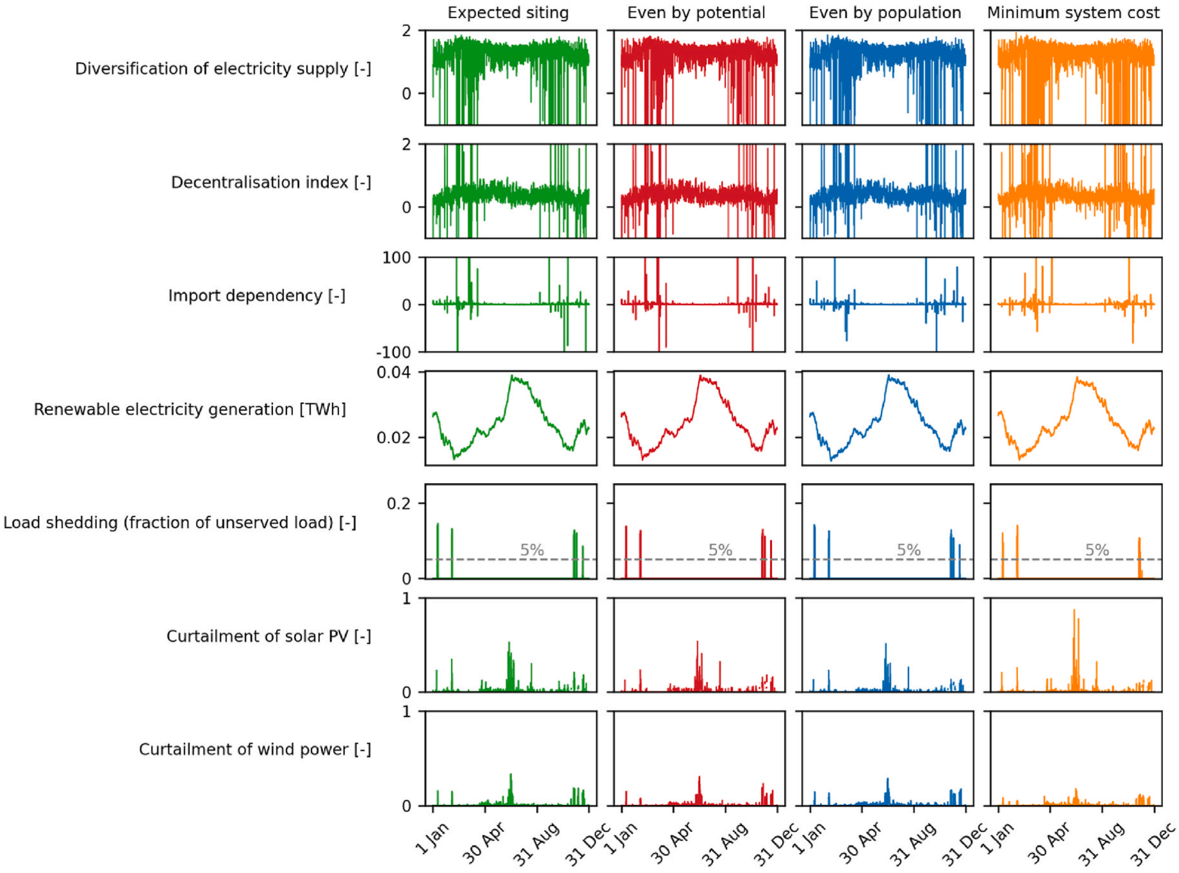

Fig. 4. Temporal analysis of selected resilience indicators for the four siting strategies and for the weather year 2010. The high frequency variations in renewable electricity generation have been smoothened out using the moving average method. The import dependency values that surpass ±100, as well as the decentralization index and import dependency values lower than −1, have been cut off. Curtailment of solar PV and wind power is expressed as (1 – equivalent availability factor). Results for other representative weather years are given in Figures A.13-A.15.

and gas. Conversely, in the years 2001 and 2005 (Figures A.13-A.14), curtailment predominantly occurs during the summer period.

The number of hours in which import dependency surpasses the value of 100 and the timespan in which this situation is achieved, depends on the weather year. A similar dependency across weather years is observed for the spikes in the decentralization index. Load shedding increase during winter is verified for all the weather years, but the exact time windows within the winter period in which load shedding is activated depend on the specific year. Electricity generation from hydropower dams and run-of-river hydropower and their yearly states of charge (Figures A.20 and A.22 in the Supplementary Material) are consistent across different weather years in the monthly-seasonal timescale, with differences found mostly in the daily-weekly timescale, mainly to balance different weather effects.

4. Discussion

Overall, this study shows that the Swiss electricity system in 2035 with very high shares of VRES is operational and in principle resilient, given its acceptable performance on all resilience indicators investigated, including none or very low use of load shedding for around half of the weather conditions in 1995–2019. Hydropower generation and electricity demand for heat pumps are the two elements that make the Swiss system most sensitive to weather. Variation in electricity supply and its resilience across the weather years supersedes the variation that can be achieved by changing siting strategies. In other words, due to a complex Swiss topology and associated factors, such as large fleet of existing hydropower, spatial constraints on VRES potential, and small geographic scale, specific spatial strategies to locate VRES can have only a minor impact on increasing the resilience of the Swiss system. The results also indicate that hydropower, solar PV, and wind power together work effectively. Having said that, *Minimum system cost approach* tends to have advantages, albeit small ones, over other siting strategies on multiple resilience indicators. For example, considering the weather years 2009, 2010, and 2012 that are the most challenging in terms of load shedding needs, *Minimum system cost approach* to site solar PV, wind power, and heat pumps manages to avoid load shedding the most as compared to the other strategies. Cost-efficient siting of solar PV and wind power leads to optimal conditions from the system's perspective to avoid the costly load shedding, and this type of siting deviates from the *Expected siting* or spatially *Even siting*. Solar PV has lower productivity in the case of *Minimum system cost approach* and a rather similar behavior for the other three strategies. When wind turbines are concentrated in fewer sites (like in *Minimum system cost approach* or *Expected siting* strategy), they produce more electricity due to lower curtailment and better wind conditions rather than in siting strategies in which the same capacity of turbines is sparsely spread in the Swiss territory. Wind power production is also advantageous for domestic electricity in winter. This similarity in the performance of the siting strategies might not be the case in all countries though [58,59], where hydropower does not have such a large share in the electricity mix and where solar PV is not the principle technology to deliver transition to high shares of VRES [22].

Weather variations in the case of a high penetration of VRES in Switzerland also significantly affect net import. The responsiveness of electricity import to accommodate weather variations complements previous insights in literature that import is the primary tool to adapt to the future uncertainty in electricity demand [37]. While hydropower, solar PV, wind power, and the electricity demand for heat pumps have always been considered as variable, weather-dependent generation, the operation of systems with high shares of VRES requires import and also gas and biomass plants to operate flexibly in a weather-dependent way, following the needs of the whole electricity system. As a consequence of this dependency of each generation technology on weather variations directly or indirectly, the diversification and decentralization of electricity supply and total generation from renewable sources, as resilience indicators, also significantly depend on the weather conditions. If the Swiss electricity system was designed and run in a cost-optimal way, as in *Minimum system cost approach*, the system would achieve the highest resilience in terms of import vs. domestic generation and in terms of most other aspects that we measured. Having said that, even if the system develops following current trends (*Expected siting*) or in a more spatially even way, not much of the resilience will need to be sacrificed. If other strategies to site VRES have other economic, environmental [14, 18] or social advantages [19], electricity supply resilience is not an argument to forego these strategies.

Investigating at increased spatial and temporal resolution, we showed that the curtailment of solar PV and wind power would need to happen in 2035 in the same subnational regions, with some deviations observed across siting strategies for the case of wind power. This finding is in line with our other observations, where wind power is affected by different siting strategies more than solar PV. The presence of regions common to the curtailment of both technologies shows that lack availability of hydropower and storage as well as limits on transmission and trade in these regions pose challenges for the VRES-dominated system. Similarly, load shedding, for those weather years and siting strategies where it is used, is also spatially concentrated and mostly occurs in regions where there is no presence of hydropower dams and pumped hydropower storage. Concerning the temporal dimension, load shedding and import dependency peak during the winter period when electricity demand increases, also due to heat pumps, and when the hydropower output is low. The model used here is decoupled from non-electricity sectors, but the regions with load shedding needs are the same regions where EXPANSE version coupled to hydrogen infrastructures and hydrogen demand would install most fuel cells [60], which convert stored hydrogen into electricity during winter. Curtailment of solar PV and wind power occurs all year around and slightly more often in summer due to lower electricity demand. Hence, a system that is based fully or almost fully on VRES can be resilient to weather variations in the case of Switzerland and other countries with a substantial amount of hydropower, pumped storage, and possibility of importing and exporting electricity.

In terms of limitations and future research needs, this study, first of all, used historical weather conditions and electricity consumption habits as well as currently most promising technologies to estimate the electricity system's resilience in 2035. Future research could potentially account for the impacts of climate change [61], including effects on hydropower generation [62], potential evolution of behaviors related to electricity consumption and demand-side flexibility [63] (comprising heat pump demand profiles adjusted to heating degree days), use of new technologies like alpine PV [32,64], emergence of new electricity demands, such as hydrogen production at scale [60,65], or dependence of COP on outside temperature. Second, we used a single weather year 2015 to determine the system's reference capacity layout to be then tested against several weather years, while future research could use as many design years as weather years available for the analysis [7,13]. Previous research shows that 2010 could be of particular interest [6,14]. Third, Switzerland would in principle have a larger potential for wind power [32,33], which was limited in this study considering acceptance issues and legal hurdles that wind power currently faces in Switzerland. If higher shares of wind power are modelled in the future, the insights on the impacts of weather on resilience could be more pronounced. Fourth, modelling over multiple years simultaneously might be of interest for assessing weather variability over the whole life time of VRES. Fifth, Modeling to Generate Alternatives could be further used to extend this study for identifying system designs that are cost-optimal or near-optimal, but offer supply security advantages in terms of varying weather, e.g. Refs. [5,7]. Finally, our insights for Switzerland are to some extent particular since Switzerland has a small geographic scale, high hydropower availability and grid connection with neighboring countries that not all countries necessarily present. Similar studies at high spatial and temporal resolution [12,13] and following our methodological approach could be hence conducted in other larger countries or even at continental scale to verify the performance of the four siting strategies and potentially even taking other types of strategies into consideration [66,67].

5. Conclusions

This study investigated electricity supply resilience of the Swiss electricity system in the single year of 2035 with very high shares of VRES to historical weather patterns from 1995 to 2019, using high resolution spatial and temporal modeling. In particular, four strategies for spatially siting solar PV, wind power, and heat pumps were assessed: siting by *Minimum system cost approach*, *Expected siting* trends, and spatially *Even siting by technical potential* or *by population*. Inter-annual weather variations were found to particularly affect electricity demand for heat pumps and availability of hydropower in Switzerland, indirectly additionally influencing electricity import and export as well as the use of biomass and gas generation. Nonetheless, the key policy finding is that the Swiss system that fully or almost fully runs on VRES was found to be techno-economically operational and resilient to weather variations, when applying a multi-dimensional definition of resilience that covers diversification, decentralization, import dependency, renewable generation, load shedding and curtailment. The four strategies for siting solar PV, wind power, and heat pumps generally perform very similarly in terms of resilience, indicating for policy makers that the location of VRES is not a major issue for weather resilience, but also that there is limited possibility to further increase resilience by modifying technology siting in Switzerland. Technology siting decision should thus be guided by other technical, economic and environmental arguments than resilience. Having said that, *Minimum system cost approach* that sites technologies in cost-optimal locations from the whole electricity system's perspective has consistent, albeit minor, advantages for resilience, especially related to minimizing load shedding and curtailment of solar PV and wind power.

CRediT authorship contribution statement

Giacomo Rubino: Writing – review & editing, Writing – original draft, Visualization, Software, Investigation, Data curation, Conceptualization. **Collin Killenberger:** Software, Data curation. **Jan-Philipp Sasse:** Software, Data curation. **Zongfei Wang:** Software. **Xin Wen:** Software. **Nik Zielonka:** Conceptualization. **Evelina Trutnevyte:** Supervision, Funding acquisition, Conceptualization.

Declaration of competing interest

The authors declare the following financial interests/personal relationships which may be considered as potential competing interests: Giacomo Rubino, Evelina Trutnevyte reports financial support was provided by Swiss Federal Office of Energy. Nik Zielonka, Jan-Philipp Sasse, Evelina Trutnevyte reports financial support was provided by Industrial Services of Geneva. If there are other authors, they declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.renene.2025.123237.

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