

Research Paper

Techno-economic assessment of an air-source steam-generating heat pump with optimal PV–BESS integration

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ABSTRACT

This study evaluates the techno-economic performance of an air-source steam-generating heat pump supplied by a cost-optimized combination of grid electricity, on-site photovoltaics, and battery energy storage. A continuous baseload demand of 2 t/h of saturated steam at 15 bar is considered. The minimum levelized cost of heat and cost-optimal electricity-supply configurations are evaluated for electricity purchase prices from 20 to 200 €/MWh in Cagliari, Italy, and Berlin, Germany, selected as contrasting European cases with different solar-generation and ambient-temperature profiles. Hourly lifetime simulations account for component degradation and replacement.

The minimum levelized cost of heat ranges from 55 to 109 €/MWh in Cagliari and from 55 to 149 €/MWh in Berlin. As electricity prices increase, the optimal supply configuration shifts from grid-dependent operation to photovoltaic-supported hybrid systems and eventually to higher-autonomy configurations with daily-scale battery storage. These transitions occur earlier in Cagliari, where photovoltaic and storage investments become attractive at lower electricity prices. Photovoltaic deployment precedes battery adoption, reflecting the higher economic value of direct self-consumption. Cross-combined meteorological scenarios indicate that differences between the cases are mainly driven by their solar-generation profiles, while ambient temperature has a smaller effect. Broad near-optimal regions indicate limited sensitivity to photovoltaic and battery sizing. Overall, photovoltaic-battery integration can limit heat-production costs and reduce exposure to high grid-electricity prices, although its benefits remain location-specific. The economic performance of steam-generating heat pumps therefore depends not only on heat-pump performance but also on electricity-supply design, with more favourable meteorological profiles enabling earlier investment and greater cost-optimal energy autonomy.

1. Introduction

According to the International Energy Agency (IEA) [1], the industrial sector accounted for approximately 12.5 Gt of CO₂ emissions in 2023, representing about 36 % of global emissions and 30 % (130 EJ) of global final energy consumption. A significant fraction of this demand (70 %) is associated with low- and medium-temperature heat and steam processes, which contribute substantially to industrial direct emissions. These processes, widely present in sectors such as food and beverage, chemicals, textiles, paper, and wood products, are more suitable for near-term electrification than high-temperature industrial applications such as steel, cement, and glass production. Within this context, electrification of industrial heat can represent a key decarbonization pathway. The IEA [1] estimates that replacing fossil-based low-temperature heat and steam generation could reduce total EU greenhouse

gas emissions by approximately 8 %. Among available technologies, Industrial Heat Pumps (IHPs) are considered the most relevant option [2] due to their high efficiency. According to the IEA [3], systems operating below approximately 160 °C are already commercially available, while technologies in the 160–200 °C range are currently transitioning toward early commercialization. Systems operating in the 200–300 °C range remain at the edge of current development efforts and are still considered technically challenging. In the intermediate temperature range (160–200 °C), reported Coefficients of Performance (COP) typically vary between 2 and 4, depending mainly on the required temperature lift [4]. For low temperature lifts (20–40 °C), COP values close to 4 can be achieved, whereas for intermediate lifts (40–80 °C) COP typically ranges between 2.5 and 3.5, and for high lifts (80–120 °C) values close to 2 are commonly reported [3]. IHP operational lifetimes are on the order of 20 years [3,5,6].

From an economic perspective, IHPs exhibit strong case dependence,

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Nomenclature**Symbols**

C_G	Annual cost of electricity purchased from the grid (€ y^{-1})
c_G	Unit cost of electricity purchased from the grid (€ MWh^{-1})
C_{rate}	Battery C-rate (h^{-1})
E	Energy or energy capacity (kWh or MWh)
$\dot{E}$	Electric power (kW or MW)
I	Investment cash flow (€ y^{-1})
N	Project or component lifetime (y)
O	Operation and maintenance cash flow (€ y^{-1})
P	Power or installed capacity (kW or MW)
Q	Useful heat (MWh)
R_G	Annual revenue from electricity exported to the grid (€ y^{-1})
r_G	Feed-in remuneration for electricity exported to the grid (€ MWh^{-1})
RV	Residual value (€)
SOC	Battery state of charge (–)
SOH	Battery state of health (–)
x	Decision vector of the optimization problem (–)
β	Replacement cost coefficient relative to the initial investment (–)
δ	Degradation coefficient (y^{-1} , h^{-1} , or – depending on the specific parameter)
η	Efficiency (–)
π	PV-to-SGHP nominal power ratio, P_{PV}^0/P_{SGHP}^0 (–)
σ_{sd}	Battery self-discharge rate (h^{-1})
θ	Equivalent full-load storage duration, E_B^0/P_{SGHP}^0 (h)
Δt	Simulation time step (h)

Subscripts and superscripts

0	Initial, nominal, or design value
B	Battery energy storage system
G	Grid

HP	Heat pump
HTHP	High-temperature heat pump
k	System component index
L	Load
LTHP	Low-temperature heat pump
max	Maximum value
min	Minimum value
MTHP	Medium-temperature heat pump
PV	Photovoltaic system
R	Replacement
SGHP	Steam-generating heat pump
t	Time step index (–)
y	Year index (–)

Acronyms

BESS	Battery Energy Storage System
CAPEX	Capital Expenditure
COP	Coefficient of Performance
DR	Discount Rate
HTHP	High-Temperature Heat Pump
IEA	International Energy Agency
IHP	Industrial Heat Pump
IRENA	International Renewable Energy Agency
LCOE	Levelized Cost of Electricity
LCOH	Levelized Cost of Heat
LTHP	Low-Temperature Heat Pump
MTHP	Medium-Temperature Heat Pump
OPEX	Operating Expenditure
PV	Photovoltaic
SGHP	Steam-Generating Heat Pump
SOC	State of Charge
SOH	State of Health
SS	Self Sufficiency
WACC	Weighted Average Cost of Capital

with specific investment costs typically ranging between 300 and 2,000 €/kW [3] and annual operating costs generally reported between 1 % and 5 % of Capital expenditure (CAPEX) [7,8]. Their Levelized Cost of Heat (LCOH) is influenced by several factors, including investment cost, required sink temperature and temperature lift [9,10], COP [11], utilization hours [9,12] and local electricity prices [9], leading to a wide dispersion of reported values across the literature. For example, the IEA [1] reports LCOH values between 41 and 74 €/MWh for low-temperature applications (assuming COP = 3), while Faraldo et al. [12] report a range of 38–190 €/MWh for steam-related applications at around 120°C. Trevisan et al. [13], considering configurations including thermal storage and auxiliary electric heaters, report values between 70 and 110 €/MWh, while Norouzi et al. [14] estimate approximately 42 €/MWh for steam generation in industrial drying applications. However, these authors mainly agree that IHPs can be economically competitive with gas boilers, whose LCOH is reported in the range of 70–350 €/MWh [1,12,15]. Clearly, this competitiveness strongly depends on operating conditions and electricity-to-fuel price ratios, which remain key uncertainties in practical deployment.

Within industrial heat applications, a significant share of demand is associated with steam generation [16], making its decarbonization a priority pathway [17]. For this reason, Steam Generating Heat Pumps (SGHPs) have attracted increasing attention. The literature covers several SGHP configurations, including closed-loop systems, cascade architectures, and mechanical vapor recompression units, as well as open configurations based on flash tanks or direct steam generation [18]. However, according to Ma et al. [19], most existing studies assume

the presence of a waste heat source at the evaporator, which significantly improves thermodynamic performance [6,20,21]. By contrast, only a limited number of studies investigate configurations without waste heat availability. Yan et al. [22] and Ma et al. [19] analysed air-source SGHPs producing steam at temperatures up to 120 °C and 170 °C, respectively, reporting COP values within the range 1.4–2.1. However, these studies remain primarily focused on thermodynamic performance, with limited attention to economic aspects, leaving a gap in the literature regarding the actual costs of SGHPs under real operating conditions. Nevertheless, the IEA [3] generally considers IHPs a potentially significant contribution to 2030 decarbonization targets, provided two conditions are met: (i) sufficiently low-carbon electricity supply and (ii) low and stable electricity prices.

A solution compatible with these two conditions can be the integration of IHPs with dedicated renewable self-supply systems, such as photovoltaic (PV) systems combined with Battery Energy Storage Systems (BESS) [1]. Indeed, PV–BESS systems can support industrial decarbonization by increasing the share of locally generated renewable electricity, while also increasing energy autonomy and reducing reliance on grid electricity [23]. This opportunity is further reinforced by the ongoing global decline in PV and battery costs, which continues to improve the economic attractiveness of PV–BESS-powered configurations [24].

However, the economic viability of PV–BESS-powered systems remains highly dependent on local solar availability and electricity price levels, which ultimately determine the trade-off between high autonomy and grid dependence. Given the limited economic literature on SGHP

systems, studies on PV–BESS-powered SGHP systems are even scarcer.

Within the described context, three main gaps can be identified. First, air-source SGHP configurations remain underrepresented compared to waste-heat-driven systems, despite their broader applicability. Second, existing studies on air-source systems focus on thermodynamic performance, with limited techno-economic analysis. Third, the integrated design and optimization of PV–BESS-powered SGHP systems, across different electricity-price levels and solar variability, have not been addressed. In particular, the existing literature does not yet provide clear insights into how the optimal supply configuration of SGHP systems evolves with electricity prices and solar-resource availability, nor how these changes affect the resulting minimum LCOH.

This study addresses these gaps through a techno-economic analysis of an air-source steam-generating heat pump designed to continuously supply the baseload steam demand of an industrial facility and supplied by a cost-minimizing mix of grid electricity, on-site photovoltaic generation, and battery energy storage. The analysis reveals how the cost-optimal supply configuration evolves under different electricity-price levels and contrasting solar-resource conditions, and how these design transitions affect the resulting minimum LCOH.

The remainder of this paper is organised as follows: Section 2 describes the methods adopted to simulate and evaluate the techno-economic performance of the system and Section 3 discusses the results.

2. Methods

The considered system, illustrated in Fig. 1, is designed to continuously supply the baseload steam demand of an industrial facility by upgrading heat from ambient temperature through a cascade of three heat pumps (described in Section 2.1.2), supplied by a configuration including PV, BESS, and grid electricity. According to the numbering of Fig. 1, the system follows a fixed priority-based dispatch strategy. PV generation is first used to supply the SGHP load directly. Any surplus PV generation is then used to charge the BESS within its SOC and power limits, while the remaining surplus is exported to the grid. When PV generation is insufficient, the BESS is discharged to supply the residual SGHP demand, and the remaining load is supplied by the grid. Grid-to-BESS charging is not allowed. Accordingly, energy arbitrage is not considered.

The following sections detail the system's technical (Section 2.1) and economic (Section 2.2) modelling and the adopted optimization framework (Section 2.3). All models were implemented in MATLAB

R2026a [25] and simulated with an hourly temporal resolution ($\Delta t = 1h$) over the system lifetime.

2.1. Technical model

The system behaviour was simulated through a component-based modelling approach. Since the PV and BESS are introduced to decrease grid dependence by increasing the use of locally generated renewable electricity, the operational performance of the supply system was characterized through the self-sufficiency indicator (SS). This indicator quantifies the share of the SGHP electricity demand supplied by PV generation, either directly or after temporary storage in the BESS and is evaluated as:

$$SS^{y=N} = \frac{\sum_{t \in y} \dot{E}_{PV,SGHP}(t) \Delta t + \sum_{t \in y} \dot{E}_{B,SGHP}(t) \Delta t}{\sum_{t \in y} \dot{E}_{SGHP}(t) \Delta t} \quad (1)$$

where $\dot{E}_{PV,SGHP}(t)$ is the PV power directly supplied to the SGHP at time step t ; $\dot{E}_{B,SGHP}(t)$ is the power discharged from the BESS and supplied to the SGHP at time step t ; $\dot{E}_{SGHP}(t)$ is the total electrical power demand of the SGHP at time step t ; and Δt is the simulation time step.

2.2. Photovoltaic and battery energy storage systems

The PV output was simulated at an hourly time step (t) using the Photovoltaic Geographical Information System (PVGIS) platform [26], relying on the ERA5-2023 solar radiation dataset. The analysis assumed crystalline silicon modules with tilt and azimuth angles automatically optimized by the software according to the geographical location under consideration. The PV degradation over the system lifetime was modelled using a conservative multi-stage approach to account for the typically higher degradation rate observed during the initial phase of operation [27]. This early-life loss is mainly associated with light-induced degradation (LID) and the possible manifestation of initial module defects, after which the degradation rate generally stabilizes. The yearly degradation was applied to the nominal design PV production (P_{PV}^0) as:

$$P_{PV}^y(t) = \begin{cases} P_{PV}^0(t)(1 - \delta_{PV,1}) & y = 1 \\ P_{PV}^0(t)(1 - \delta_{PV,1})(1 - \delta_{PV,2})^{(y-1)} & 1 < y \leq N_{PV} \end{cases} \quad (2)$$

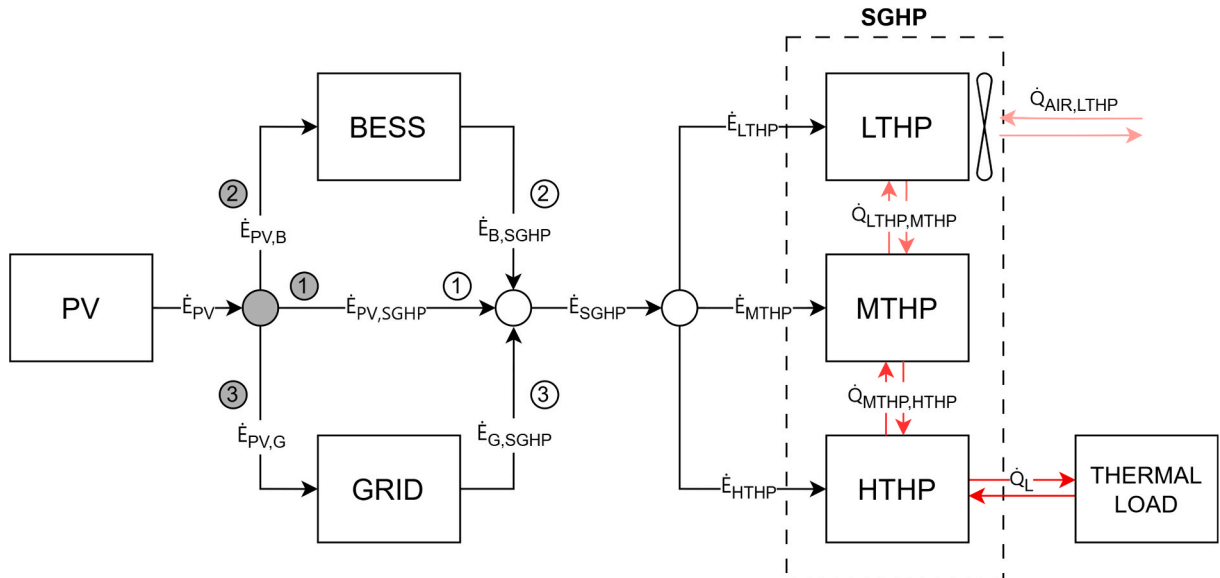


Fig. 1. Power flow diagram of the system, prioritized according to the numbering.

where N_{PV} is the PV lifetime and $\delta_{PV,1}$ and $\delta_{PV,2}$ are the first-year and mid-life degradation coefficients.

The BESS was modelled as a Lithium-ion battery, accounting for operational constraints, efficiency losses, degradation mechanisms, and replacement strategies over the system lifetime. Its State of Charge (SOC) was updated at each time step by accounting for charge and discharge processes, energy conversion losses, and self-discharge effects, as:

$$SOC^y(t+1) = SOC^y(t)(1 - \sigma_{sd} \Delta t) + \frac{\Delta t}{E_B^y} \left(\eta_B \dot{E}_{PV,B}^y(t) - \frac{\dot{E}_{B,SGHP}^y(t)}{\eta_B} \right) \quad (3)$$

where η_B is the charge and discharge efficiency and σ_{sd} is the self-discharge rate. The term E_B^y denotes the effective BESS capacity at year y , accounting for degradation effects (explained below).

Battery operation was constrained by SOC limits and maximum charge/discharge power:

$$SOC_{\min} \leq SOC(t) \leq SOC_{\max}, \quad 0 \leq \dot{E}_{PV,B}(t), \dot{E}_{B,SGHP}(t) \leq P_B^y \quad (4)$$

where P_B^y was determined as a function of the effective BESS capacity in year y through the C-rate:

$$P_B^y = C_{\text{rate}} \cdot E_B^y \quad (5)$$

The BESS state of charge was constrained to $SOC_{\min} = 0.1$ at the beginning and end of each annual simulation, ensuring cyclic consistency of the yearly operating profile.

The effective battery capacity in year y (E_B^y) was evaluated according to the Re-Twin Energy model [28], which is primarily based on the work of Schmalstieg et al. [29] and Keil et al. [30], as follows:

$$E_B^y = E_B^{y-1} - E_B^0 \left(\delta_{B,cal} + \delta_{B,cyc} \frac{E_{B,thr}^y}{2E_B^0} \right) \quad (6)$$

where $E_{B,thr}^y$ represents the total energy processed by the battery during year y , accounting for both charging and discharging contributions. The BESS degradation level was characterized by its State of Health (SOH), which was transferred between consecutive years:

$$SOH = \frac{E_B^y}{E_B^0} \quad (7)$$

The BESS was assumed to be replaced when its SOH reached the threshold value SOH_R . Following replacement, the SOH and effective battery capacity were restored to their nominal values, and the replacement unit was initialized at $SOC_{\min} = 0.10$.

The main specifications and modelling assumptions of the PV and BESS systems under nominal design conditions are reported in Table 1.

2.3. Steam generating heat pump

In the present study, 2 t/h of saturated steam at 15 bar, with condensate returned as saturated liquid at 1 bar, was selected as the baseload to be continuously supplied by the SGHP. These conditions, which are typical of industrial applications, define the nominal operating point of the system. The SGHP configuration adopted to provide this continuous steam output (Fig. 2) comprises three cascaded components coupled through intermediate water loops: a low-temperature air-to-water heat pump (LTHP), a medium-temperature water-to-water heat pump (MTHP) and an open-loop high-temperature heat pump (HTHP) based on mechanical vapor recompression, which is considered by the IEA to be the most mature technology for electrical steam generation above 160 °C [1]. The LTHP raises the temperature from the ambient-air level to the first intermediate water loop, while the MTHP supplies the second water loop. The HTHP then uses the heat delivered by this loop to generate and compress the water vapor to the required

Table 1

Main specifications and modelling assumptions of the PV and BESS systems under nominal design conditions.

Component	Parameter	Symbol	Value	Unit	Source
PV system	Nominal power (design space)	P_{PV}^0	0–12	MW	–
	Total system losses*	–	0.14	–	[26]
	First-year degradation coefficient	$\delta_{PV,1}$	15×10^{-3}	y ⁻¹	[27]
	Mid-life degradation coefficient	$\delta_{PV,2}$	5×10^{-3}	y ⁻¹	[27]
	Nominal capacity (design space)	E_B^0	0–24	MWh	–
BESS	Min/max state of charge	$SOC_{\min}/SOC_{\max}$	0.1/0.9	–	–
	C-rate	C_{rate}	0.25 ^a	h ⁻¹	[24]
	Charge/discharge efficiency	η_B	0.95	–	[31]
	Self-discharge rate	σ_{sd}	8.33×10^{-5}	h ⁻¹	[31]
	Cycling degradation coefficient	$\delta_{B,cyc}$	3×10^{-5}	–	[28]
	Calendar degradation coefficient	$\delta_{B,cal}$	1×10^{-2}	y ⁻¹	[28]
	SOH for replacement	SOH_R	0.8	–	[32,33]

* PVGIS input parameter.

^a According to IRENA, A C-rate of 0.25 was assumed to ensure maximum comparability of the results with the majority of studies in the literature [24].

delivery pressure.

As the SGHP is intended to meet a continuous steam demand, its components were modelled under steady-state operating conditions, using the data summarized in Table 2, which were selected with reference to commercially available units.

The component models were based on mass and energy balances, with thermophysical properties evaluated using CoolProp [37]. Compressors were modelled through their isentropic efficiencies, whereas expansion processes were assumed to be isoenthalpic. The HTHP section was represented as a multistage vapor compression system with inter-stage quench desuperheating. The number of compression stages was determined by imposing a maximum pressure ratio of 1.8 per stage. After each compression stage, direct-contact water injection was used to reduce the vapor temperature to a residual superheat of 5 °C above the corresponding saturation temperature. The injected water was withdrawn from the saturated liquid collected in the evaporator, and the resulting increase in vapor mass flow along the compressor train was included in the mass and energy balances. The component models were assessed at nominal conditions by comparing their predicted COPs with the corresponding manufacturer-reported values. The relative deviations are reported in the last row of Table 2.

Under full-year operating conditions, the MTHP and HTHP were assumed to operate continuously at their nominal COPs, consistently with the constant baseload demand and the stable thermal conditions maintained by the intermediate water loops. By contrast, since the LTHP is directly exposed to variations in ambient conditions, its COP_{LTHP} was calculated hourly by accounting for both the variation in temperature lift and the performance penalty associated with defrost operation. The effect of temperature lift was evaluated using the correlation proposed by the IEA [1] whose normalized trend is shown in Fig. 3. The defrost-related penalty was evaluated under evaporator frosting conditions by assuming a progressively increasing, temperature-dependent, COP reduction, reaching the 20 % penalty reported by Vocale et al. [38] at the lower operating limit of the heat pump.

SGHP ageing in year y was accounted for through an annual decrease

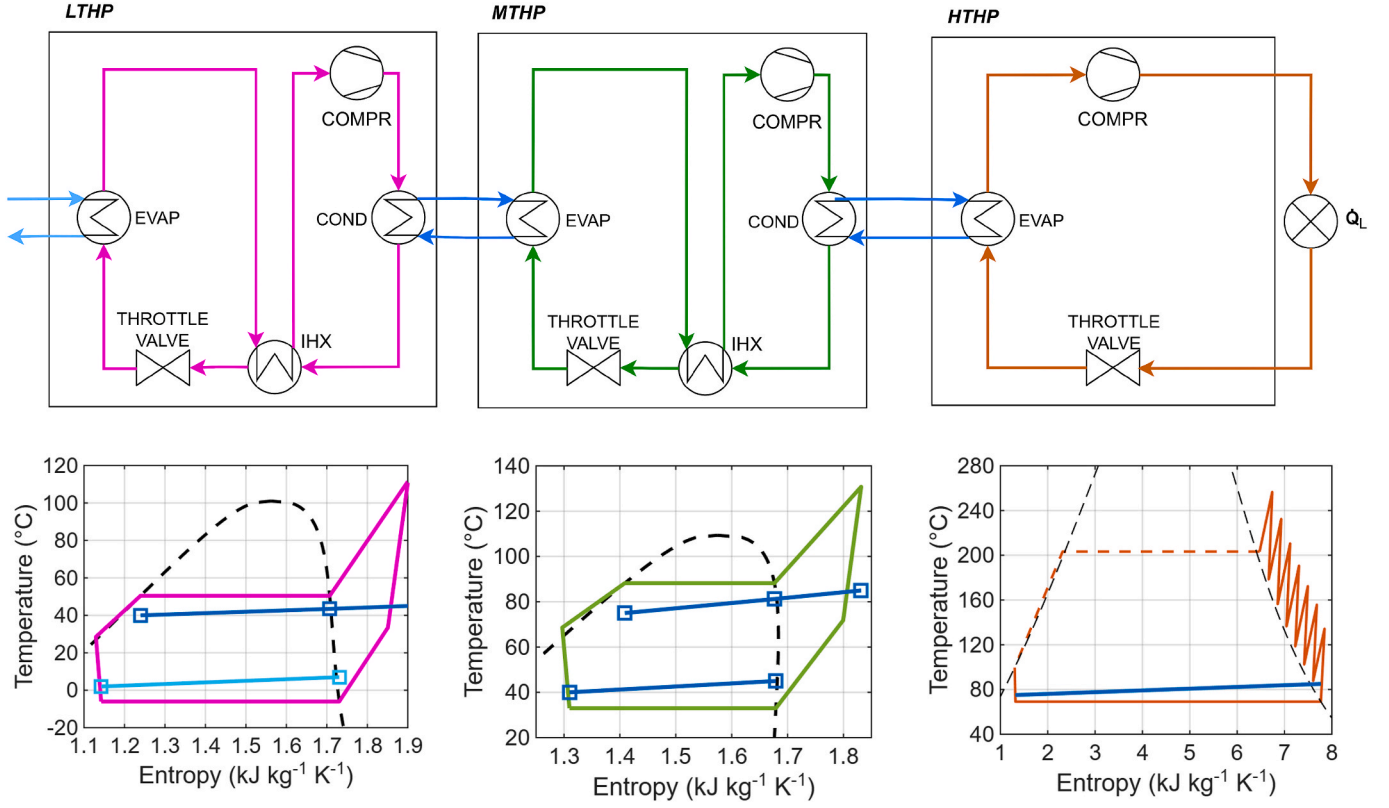


Fig. 2. SGHP schematic layout and thermodynamic cycles under nominal design conditions for saturated steam production at 15 bar, with condensate returned as saturated liquid at 1 bar.

Table 2

Key specifications and modelling parameters of the LTHP, MTHP, and HTHP under nominal design conditions for a continuous production of 2 t/h of saturated steam at 15 bar, with condensate returned as saturated liquid at 1 bar.

	LTHP	MTHP	HTHP
Refrigerant/process fluid	R134a	R1234ze(E)	Water
Compression technology	Variable-speed screw compressor	Fixed-speed screw compressor	Centrifugal compressor
Isentropic efficiency	0.70 [34]	0.70 [34]	0.85 [35]
Electromechanical efficiency	0.95	0.95	0.95
Heat source conditions	Ambient air at 7 °C ΔT_{PINCH} : 8 °C	Water at 45/40 °C ΔT_{PINCH} : 7 °C	Water at 85/75 °C ΔT_{PINCH} : 5 °C
Heat sink conditions	Water at 45/40 °C ΔT_{PINCH} : 5 °C	Water at 85/75 °C ΔT_{PINCH} : 7 °C	Saturated steam at 15 bar, with condensate returned as saturated liquid at 1 bar
IHX Effectiveness	0.70 [36]	0.70 [34]	Not applicable
Heating capacity ($\dot{Q}_{HP}^0$)	573 kW	788 kW	1319 kW
Power input (P_{HP}^0)	172 kW	228 kW	501 kW
Predicted COP (COP_{HP}^0)	3.34	3.46	2.63
Manufacturer COP	3.18	3.44	2.80
Relative COP deviation	+5.0 %	+0.6 %	-6.1 %

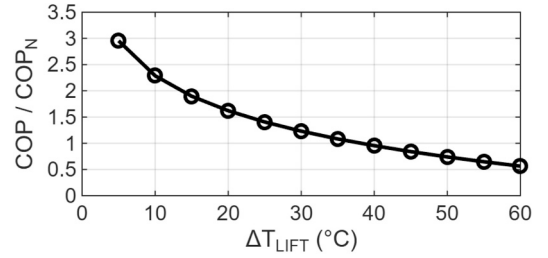


Fig. 3. Normalized COP_{LTHP} as a function of ΔT_{LIFT} .

2.4. Economic model

The economic model was formulated through a component-wise representation of all cost streams, including capital expenditures, operational expenditures, replacement costs, electricity-related cash flows, and residual values. The initial investments were evaluated at the beginning of the project, whereas operating costs, replacement costs, electricity-related cash flows, and residual values were evaluated on an annual basis and discounted over the project lifetime. The capital expenditures for each subsystem k were expressed as:

$$I_k^y = \begin{cases} I_k^0 & y = 0 \\ \beta_k \cdot I_k^0 & y \in \mathcal{R}_k \\ 0 & \text{otherwise} \end{cases} \quad (9)$$

where I_k^0 represents the initial investment cost of component k , calculated by multiplying the specific CAPEX of component k by its installed capacity, while β_k is a coefficient accounting for cost variations associated with replacement events, expressed as a fraction of the initial investment. The set $\mathcal{R}_k$ identifies the years in which component k is

in COP, calculated according to Lee et al. [39] as follows:

$$COP_{SGHP}^y = COP_{SGHP}^0 (1 - \delta_{SGHP})^{(y-1)} \quad (8)$$

where δ_{SGHP} is the yearly degradation coefficient (0.0025 y^{-1}).

replaced over the system lifetime.

Annual electricity-related cash flows were computed as:

$$C_G^y = E_{G,SGHP}^y \cdot C_G \quad (10)$$

$$R_G^y = E_{PV,G}^y \cdot r_G \quad (11)$$

where C_G is the unit cost of electricity purchased from the grid and r_G is the remuneration associated with electricity fed into the grid. Given the current value decline of PV due to overgeneration [40,41], the feed-in remuneration was assumed to be very low, corresponding to the current (2025) minimum levelized cost of electricity (LCOE) for PV in Europe¹ [24].

Residual value (RV_k^y) represents the remaining economic value of system component k at the end of its lifetime. In the present study, according to the International Renewable Energy Agency [24], the lifetimes of both the PV and SGHP systems were assumed to be equal to 20 years and, therefore, coincident with the project duration. For this reason, no residual value was assigned to these components. In contrast, the BESS residual value (RV_B^y) was evaluated considering the potential reuse of the battery in second-life applications. Indeed, batteries in this type of application are typically assumed to be replaced when reaching a $SOH_R = 0.80$ [32,33], while second-life utilisation is considered viable down to a SOH_{SL} around 0.50 [42]. Accordingly, the BESS residual value² was estimated as a function of the battery SOH following the methodology proposed by Layedra et al. [42] as:

$$RV_B^y = 0.75 \cdot E_{B,R}^y \cdot \frac{SOH^y - SOH_{SL}}{1 - SOH_{SL}} \quad (12)$$

Finally, the Levelized Cost of Heat (LCOH) was evaluated as:

$$LCOH = \frac{\sum_k I_k^0 + \sum_{y=1}^N \frac{\sum_k (P_k^y + O_k^y - RV_k^y) + C_G^y - R_G^y}{(1+DR)^y}}{\sum_{y=1}^N \frac{Q_k^y}{(1+DR)^y}} \quad (13)$$

where I_k^0 is the initial investment associated with component k , P_k^y and O_k^y are the investment and operation and maintenance cash flows, respectively, associated with component k in year y and DR is the discount rate. Annual operation and maintenance costs (OPEX) were modelled as a fraction of the corresponding component investment cost. The main economic parameters and assumptions are reported in Table 3.

2.5. Optimization framework

The optimized supply system configuration was determined by solving a cost-minimization problem in which the Levelized Cost of Heat defined in Eq.(13) was adopted as the objective function:

$$\min_x LCOH(x) \quad (14)$$

where the decision vector is given by $\mathbf{x} = \{P_{PV}^0, E_B^0\}$, representing the installed PV and BESS capacities.

The optimal supply configuration was identified by direct evaluation of the objective function over a discretized design space. P_{PV}^0 was varied from 0 to 12 MW in increments of 0.25 MW, while E_B^0 was varied from 0 to 24 MWh in increments of 0.25 MWh. Electricity purchase costs were evaluated from 20 to 200 €/MWh in increments of 5 €/MWh. Accordingly, 4,753 PV-BESS configurations were evaluated for each electricity-price scenario. A grid-convergence analysis was also performed by reducing the PV and BESS capacity increments from 0.250 MW and

0.250 MWh to 0.125 MW and 0.125 MWh, respectively. Across the two locations, this refinement resulted in a maximum deviation of only 0.02 % in the minimum LCOH, confirming the numerical convergence of the adopted discretization.

3. Results and discussion

This section discusses the optimal supply configurations for the air-source SGHP under electricity purchase costs ranging from 20 to 200 €/MWh and two contrasting meteorological conditions: Cagliari, Italy (39.217° N, 9.113° E), characterized by Mediterranean conditions, and Berlin, Germany (52.517° N, 13.395° E), characterized by Central European conditions. Their main geographical and annual meteorological characteristics are summarized in Table 4 and complemented by Fig. 4, which shows the corresponding monthly distributions of global in-plane irradiation³ (Fig. 4a) and ambient temperature (Fig. 4b).

Clearly, the two cases represent contrasting combinations of solar availability and ambient temperature. To distinguish their respective contributions to the optimized system performance, additional controlled scenarios were evaluated by cross-combining the solar-generation and ambient-temperature profiles of the two locations, as discussed in Section 3.2.

The results are organized into five complementary parts. Section 3.1 analyses the evolution of the optimal supply configurations for the Cagliari and Berlin cases as a function of electricity price, together with the corresponding design transitions and their interpretation. Section 3.2 separates the effects of solar availability and ambient temperature through cross-combined meteorological scenarios. Sections 3.3 and 3.4 examine the associated economic and operational trade-offs and the LCOH cost breakdown, respectively. Section 3.5 presents a sensitivity analysis to assess the robustness of the main findings with respect to key technical and economic assumptions.

3.1. Optimal supply configuration and design transitions

Fig. 5 shows the evolution of the optimal sizes of PV (blue) and BESS (red) (a,b), together with the corresponding minimum LCOH (black) and self-sufficiency (green) (c,d), as a function of the electricity purchase cost C_G , for both locations. For context only, the grey area in the bottom panels indicates the typical LCOH range for coal and natural gas boilers in Europe [1,12,15]. This reference is included solely as an indicative benchmark, as the study is not intended to provide a comparative assessment with fossil-fuel technologies.

To facilitate the interpretation of the results, the PV and BESS configurations are described not only in terms of their absolute sizes (kW and kWh), but also relative to the SGHP nominal power input. PV capacity is normalized as a power ratio ($\pi = P_{PV}^0 / P_{SGHP}^0$), while BESS size is expressed in terms of equivalent full-load storage duration ($\theta = E_B^0 / P_{SGHP}^0$, in hours).

In both Cagliari and Berlin, increasing electricity prices drive a transition of the optimal supply configuration through three main design categories: ① grid-dependent, ② hybrid, and ③ high-autonomy. These categories are identified in Fig. 5, with the transition thresholds marked by vertical grey dashed lines.

In Cagliari (Fig. 5, left), the optimal supply configuration remains fully grid-dependent ① at electricity prices below approximately 40 €/MWh, with LCOH values ranging from 55 to 70 €/MWh. In this design condition, the system is strongly competitive with conventional fossil-fuel boilers, as its LCOH lies near the lower bound of the reported fossil-fuel range. For electricity prices between 40 and 90 €/MWh, the

¹ the feed-in remuneration was also varied as part of the sensitivity analysis presented in Section 3.3 ($r_G \pm 100\%$).

² accounted for both at replacement events and at the end of the project lifetime.

³ The global in-plane irradiation was evaluated by PVGIS [26] using location-specific optimized plane orientations. The resulting tilt and azimuth angles were 35° and 3° for Cagliari and 37° and -1° for Berlin, respectively.

Table 3
Economic parameters and assumptions.

Component	Parameter	Symbol	Value*	Unit	Notes	Source
System	Discount rate	DR	0.05	–	Real weighted average cost of capital (WACC) for OECD countries	[24]
	Electricity purchase cost	c_G	20–200	€/MWh	Range for the analysis	
	Feed-in remuneration	r_G	28	€/MWh	Minimum LCOE for PV in Europe, 2025	[24]
	Lifetime	N	20	years	–	–
PV	Capital Expenditure	$CAPEX_{PV}$	585	€/kW	valid for Europe, 2025	[24]
	Operating Expenditure	$OPEX_{PV}$	12	€/kW.y	2 % of $CAPEX_{PV}$ per year	[24]
	Lifetime	N_{PV}	20	y	–	[24]
	Capital Expenditure	$CAPEX_B$	102	€/kW	Utility-scale four-hour Lithium-ion BESS co-located with PV. Valid for Europe, 2025	[24]
BESS	Operating Expenditure	$OPEX_B$	2.6	€/kW.y	2.5 % of $CAPEX_B$ per year	[24]
	Capital Expenditure at replacement	$CAPEX_{B,R}$	60	€/kW	Utility-scale four-hour Lithium-ion BESS co-located with PV. Valid for Europe, 2035	[24]
	Minimum SOH for second-life	SOH_{SL}	0.5	–	Minimum SOH for second-life applications	[42]
	Capital Expenditure	$CAPEX_{LTHP}$	450	€/kW	–	[43]
SGHP		$CAPEX_{MTHP}$	1,000	€/kW	conservatively assumed as the upper limit	[3]
		$CAPEX_{HTHP}$	2,000	€/kW	conservatively assumed as the upper limit	[3]
	Operating Expenditure	$OPEX_{SGHP}$	173	€/kW.y	5 % of $CAPEX_{SGHP}$ per year	[6,8]
	Lifetime	N_{SGHP}	20	y	–	[3,6,44]

* Values expressed in USD were converted into EUR using an exchange rate of 1 USD = 0.85 EUR.

Table 4
Geographical and annual meteorological characteristics of the considered locations.

Location	Coordinates	Annual global in-plane irradiation	Annual mean ambient temperature
Cagliari	39.217° N, 9.113° E	2,090 kWh/m ²	18.5°C
Berlin	52.517° N, 13.395° E	1,303 kWh/m ²	11.3°C

optimal solution enters the hybrid design condition ②, characterized by the introduction of PV generation and, at higher electricity prices, short-duration battery storage. Within this range, the optimal capacities remain limited to about $P_{PV}^0 = 2.5$ MW ($\pi = 2.8$) and $E_B^0 = 0.5$ MWh ($\theta = 0.55$ h), yielding a self-sufficiency of approximately 0.33 at an LCOH of about 93 €/MWh. At higher electricity prices, the optimal supply solution enters the high-autonomy design condition ③. This design transition is characterized by a substantial increase in both PV and BESS capacities, with the storage system shifting from short-duration buffering to daily-scale operation. Indeed, at $c_G = 200$ €/MWh, the optimal configuration reaches approximately $P_{PV}^0 = 10.5$ MW ($\pi = 11.7$) and $E_B^0 = 17.5$ MWh ($\theta = 19.4$ h), resulting in a SS of approximately 0.91 and an LCOH of about 109 €/MWh. It is worth noting that, based on the results

of Bolinger et al. [45], a 10.5 MW fixed-tilt PV system would require an overall site area of approximately 12 ha, whose availability may represent a site-specific constraint on the physical feasibility of the considered configuration.

A markedly different behaviour emerges when the same analysis is performed for Berlin (Fig. 5, right), although some structural similarities can still be observed. In both locations, LCOH increases monotonically with c_G , and the system progressively shifts toward higher PV and BESS capacities. However, both the transition thresholds and the extent of these changes differ significantly. Indeed, the first design transition (from grid-dependent ① to hybrid ②), that for Cagliari was around $c_G = 40$ €/MWh, is delayed to approximately $c_G = 70$ €/MWh for Berlin, while the second transition (from hybrid ② to high-autonomy ③), around $c_G = 90$ €/MWh for Cagliari, occurs for Berlin around $c_G = 130$ €/MWh. Therefore, transitions toward increasingly autonomous supply configurations occur at substantially higher electricity prices under Berlin meteorological conditions. Moreover, even at $c_G = 200$ €/MWh, the optimal supply configuration ($P_{PV}^0 = 8$ MW, $\pi = 8.9$; $E_B^0 = 14.5$ MWh, $\theta = 16.1$ h) yields a self-sufficiency below 0.6, well below the 0.9 achieved in Cagliari and at a higher LCOH (149 €/MWh).

Overall, while both systems exhibit a transition from grid reliance to hybrid (short-duration storage) and from the latter to high-autonomy (daily-scale storage) as c_G increases, the economic threshold at which these transitions become optimal is significantly higher in Berlin, and

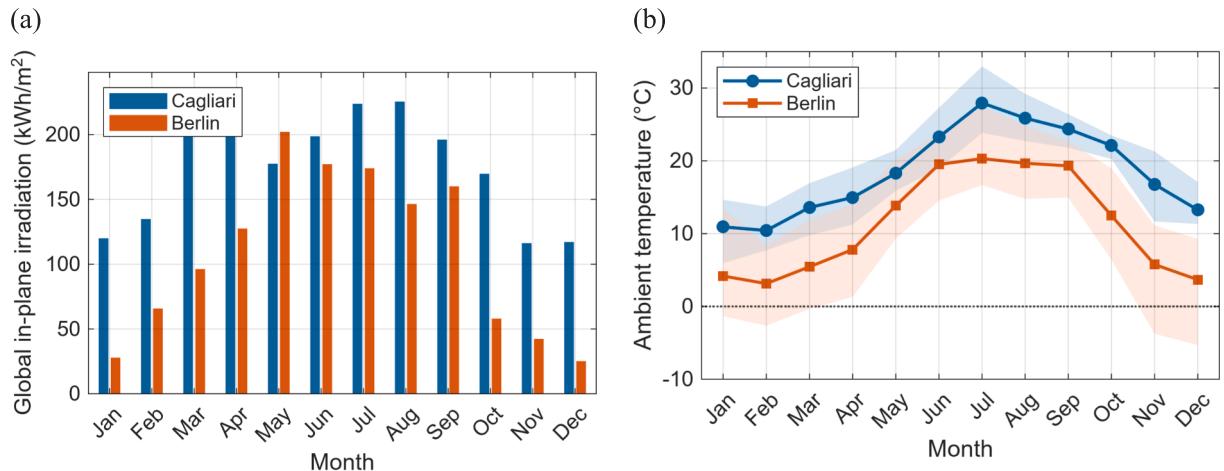


Fig. 4. Monthly comparison between Cagliari and Berlin of: (a) global in-plane irradiation on the PVGIS-optimized plane; and (b) average ambient temperature, with shaded areas indicating the range between the minimum and maximum daily mean temperatures within each month.

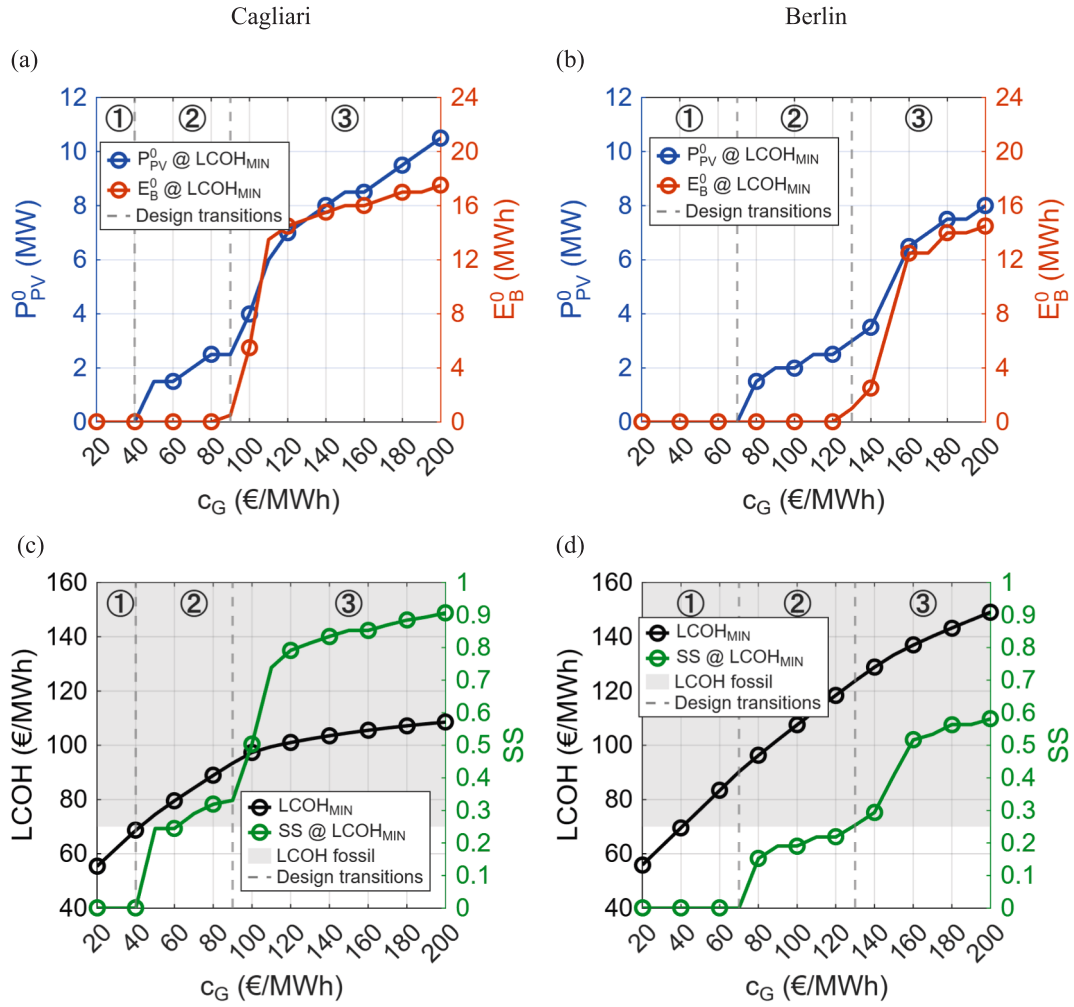


Fig. 5. PV and BESS sizes (top) achieving the minimum LCOH and the corresponding self-sufficiency (bottom) as a function of the electricity purchase cost. Labels ①, ②, and ③ identify the grid-dependent, hybrid, and high-autonomy design categories, respectively, while the vertical grey dashed lines mark the design transitions. The grey area indicates the LCOH range of fossil-fuel boilers. Results are shown for Cagliari, Italy (left), and Berlin, Germany (right).

the resulting benefits are more limited. Consequently, while Cagliari system evolves toward near self-sufficiency, the Berlin system remains considerably more dependent on grid electricity, indicating that even daily-scale storage cannot fully compensate for limited solar-resource availability.

Focusing on the current European context (2026), where electricity prices for large industrial customers are around 100 €/MWh [46], it is interesting to observe that hybrid to high-autonomy supply solutions may be already preferable to grid-dominated configurations.

To further support and interpret these results, Fig. 6 presents the contour maps of LCOH as a function of PV and BESS sizing (P_{PV}^0, E_B^0) for four different electricity price levels (50, 100, 150, 200 €/MWh). These figures complement the previous analysis by explicitly showing the shape of the LCOH landscape around the optimal supply configuration, rather than only the trajectory of $LCOH_{MIN}$ as a function of c_G . In particular, the green marker identifies the $LCOH_{MIN}$ configuration already shown in Fig. 5, while the green dashed contour highlights the near-optimal region, here considered as the set of configurations whose LCOH is no more than 5 €/MWh higher than $LCOH_{MIN}$.

From a physical standpoint, the contour evolution across different c_G levels provides further insight into the transitions identified above. At low electricity prices, the cost landscape is relatively flat and skewed toward grid-dependent solutions, confirming that neither PV nor storage is economically justified. As c_G increases, the minimum LCOH progressively moves toward higher PV and BESS sizes, and the contour lines

become more curved and structured, highlighting the emergence of a well-defined optimum driven by self-sufficiency. In particular, at high c_G , the contours become elongated along directions corresponding to combinations of large PV and long-duration storage, consistent with the transition toward the high-autonomy design condition. Focusing on the near-optimal region (green dashed contour), it is interesting to note that in most cases a relatively wide range of PV and BESS combinations yields comparable performance, suggesting the robustness of the optimal supply design.

3.2. Separate effects of solar availability and ambient temperature

The location-specific results discussed in Section 3.1 reflect the combined influence of solar availability and ambient temperature. To separate their respective effects, two additional controlled scenarios were evaluated by cross-combining the solar-generation and ambient-temperature profiles of Cagliari and Berlin. Together with the two location-specific cases, this resulted in four combinations: Cagliari solar and temperature profiles (base case), Cagliari solar and Berlin temperature profiles, Berlin solar and Cagliari temperature profiles, and Berlin solar and temperature profiles (base case). Comparing scenarios with the same solar profile isolates the effect of ambient temperature, whereas comparing scenarios with the same temperature profile isolates the effect of solar availability. The optimization was repeated for each combination over the complete electricity-price range.

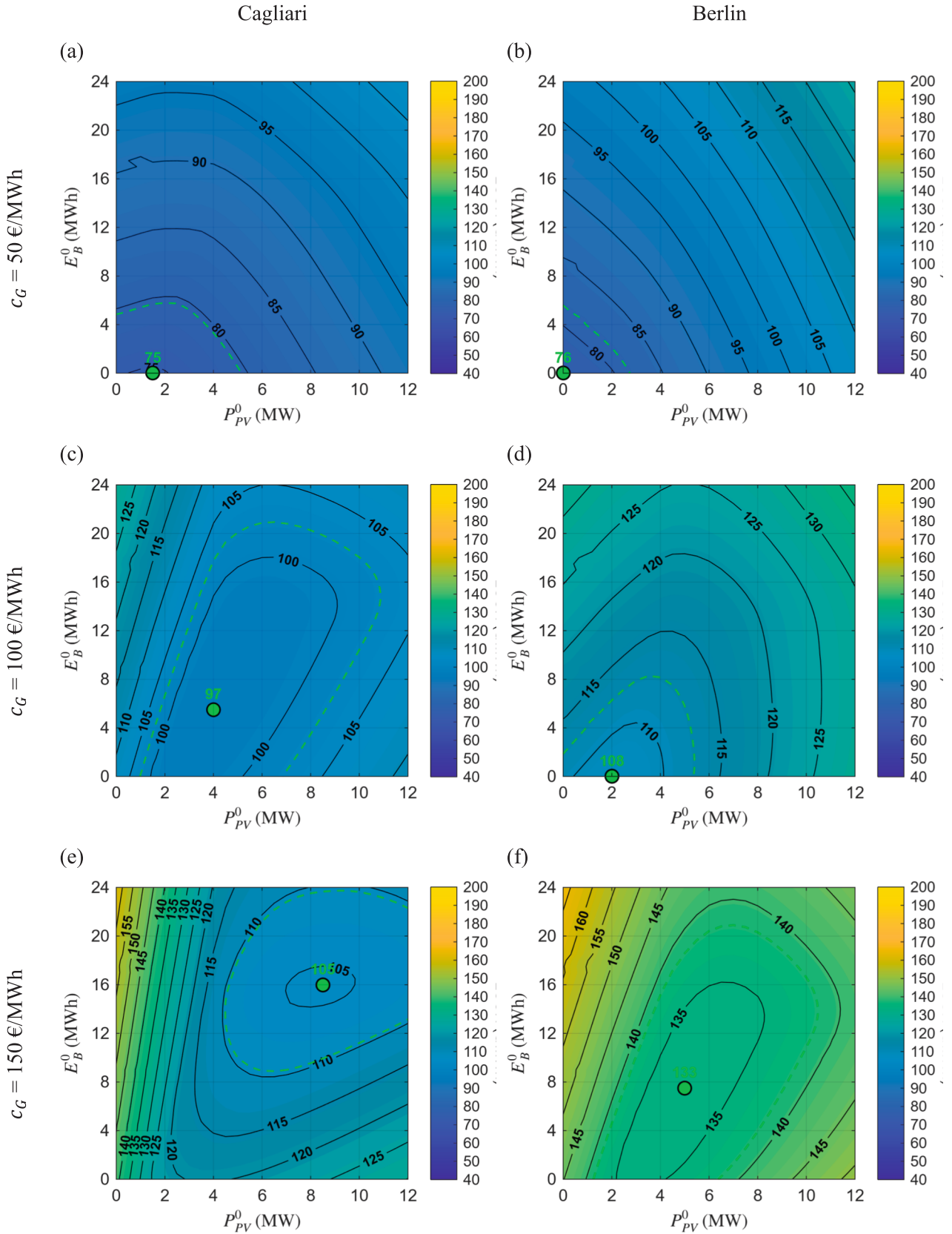


Fig. 6. LCOH as a function of PV and BESS sizes at different electricity purchase costs. The green marker identifies the configuration achieving $LCOH_{\min}$. The green dashed line indicates $LCOH_{\min} + 5$ €/MWh. Results are shown for Cagliari, Italy (left), and Berlin, Germany (right).

Fig. 7 shows the $LCOH_{\min}$ obtained for the four meteorological combinations. The solid curves represent the two location-specific base

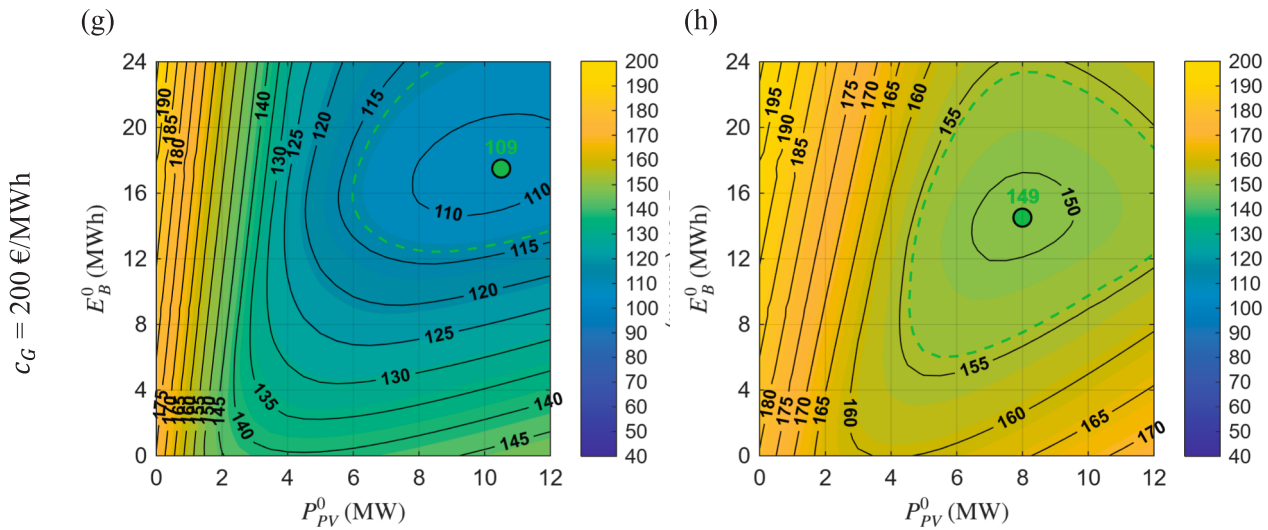


Fig. 6. (continued).

cases, while the dashed curves represent the cross-combined scenarios. Circular markers identify the scenarios based on the Cagliari solar profile, whereas square markers identify those based on the Berlin solar profile.

The ambient-temperature effect can be isolated by comparing curves with the same solar profile. Replacing the Cagliari temperature profile with the Berlin profile while retaining the Cagliari solar profile increases $LCOH_{MIN}$, as indicated by the separation between the solid and dashed curves with circular markers. Similarly, the corresponding effect under the Berlin solar profile is identified by comparing the dashed and solid curves with square markers. The ambient-temperature effect increases gradually with the electricity purchase cost but remains limited, reaching approximately 2.8 % under the Cagliari solar profile and 2.9 % under the Berlin solar profile at 200 €/MWh. This increase results from the greater electricity consumption of the air-source LTHP under the less favourable temperature conditions associated with Berlin.

The solar-profile effect can instead be isolated by comparing curves associated with the same temperature profile. Under the Cagliari temperature profile, the effect is represented by the separation between the

solid curve with circular markers and the dashed curve with square markers. Under the Berlin temperature profile, it is represented by the separation between the dashed curve with circular markers and the solid curve with square markers. The solar-profile effect is considerably larger than the temperature effect and becomes increasingly pronounced as the electricity purchase cost rises. At low electricity prices, the differences among the four scenarios are limited because the optimal configurations remain predominantly grid supplied. As electricity becomes more expensive and PV-BESS integration becomes economically advantageous, the effect of the lower solar availability in Berlin on $LCOH_{MIN}$ becomes progressively larger. At 200 €/MWh, replacing the Cagliari solar profile with the Berlin profile increases $LCOH_{MIN}$ by approximately 33.5 % under the Cagliari temperature profile and 33.7 % under the Berlin temperature profile.

Overall, the controlled scenarios suggest that the differences between the Cagliari and Berlin cases are mainly driven by solar availability, while ambient temperature provides a smaller contribution.

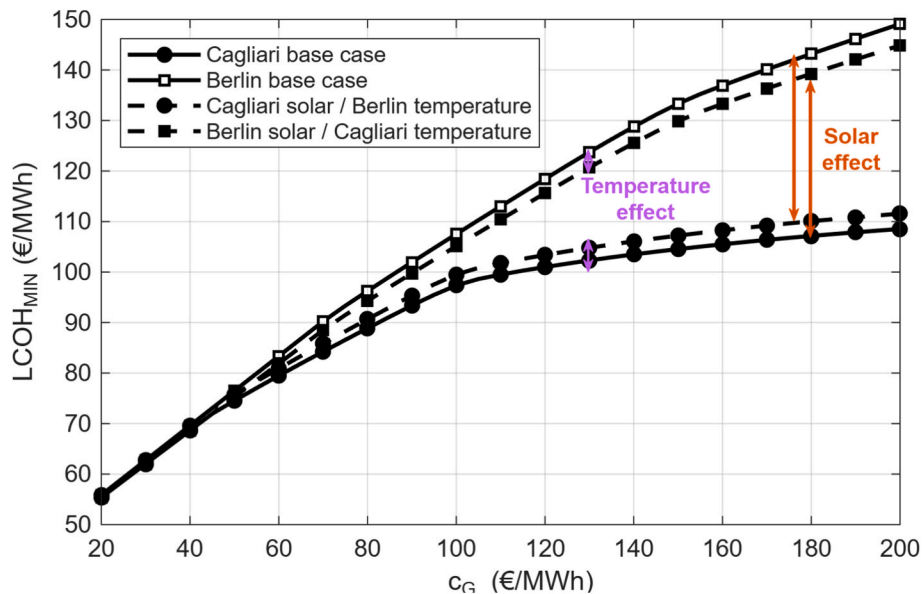


Fig. 7. $LCOH_{MIN}$ as a function of electricity purchase cost for the four combinations of Cagliari and Berlin solar-generation and ambient-temperature profiles. Solid curves represent the location-specific base cases, while dashed curves represent the cross-combined scenarios.

3.3. Economic and operational trade-offs

To provide a complementary perspective to the previous analysis by explicitly showing the trade-off between levelized heat cost and self-sufficiency across all feasible system configurations, Fig. 8 reports the Pareto fronts for two representative electricity purchase costs, $c_G = 80$ €/MWh and $c_G = 160$ €/MWh. These values were selected to compare a supply condition within the hybrid with a condition within the high-autonomy design condition. The shape and position of the fronts reveal how the trade-off between economic performance and grid independence changes with both electricity price and solar-resource availability.

At $c_G = 80$ €/MWh and for Cagliari (a), the Pareto front is long and initially rather flat, extending from about $SS=0.30$ to nearly full self-sufficiency. This means that a large increase in SS can be achieved with only a moderate LCOH increase over a wide interval. The front becomes steep only at very high SS values, indicating that the last portion of grid independence is the most expensive. Conversely, in Berlin (b), the front is shifted upward and more continuously increasing. It reaches only about $SS=0.70$, and LCOH increases more sharply as self-sufficiency is increased. Therefore, while the Cagliari case shows a wide

economically accessible self-sufficiency range, the Berlin case exhibits a more constrained and costly transition toward local supply.

At $c_G = 160$ €/MWh, both fronts are located at higher SS values, but their shapes remain markedly different. In Cagliari (c), the Pareto front is concentrated in the high-self-sufficiency region and shows a clear minimum around $SS=0.85-0.90$. Low-SS configurations are strongly penalized by high grid electricity costs, while near-self-sufficient solutions become economically favourable. The front is relatively flat around the optimum, suggesting that several high-SS configurations provide similar LCOH values. However, the final increase toward full self-sufficiency remains steeper, confirming diminishing returns. In Berlin (d), the front is instead much narrower and shifted to higher LCOH values. Unlike the Cagliari case, the Pareto front does not approach full self-sufficiency, remaining approximately within $SS = 0.55-0.75$. Its U-shaped tendency is also less pronounced: the economic optimum occurs at intermediate SS, but further increases in self-sufficiency rapidly increase LCOH. This indicates that even when grid electricity is expensive, the lower solar yield limits the effectiveness of PV-BESS oversizing, preventing the system from reaching near-autonomous operation.

Overall, the four Pareto fronts show two key effects. Increasing c_G

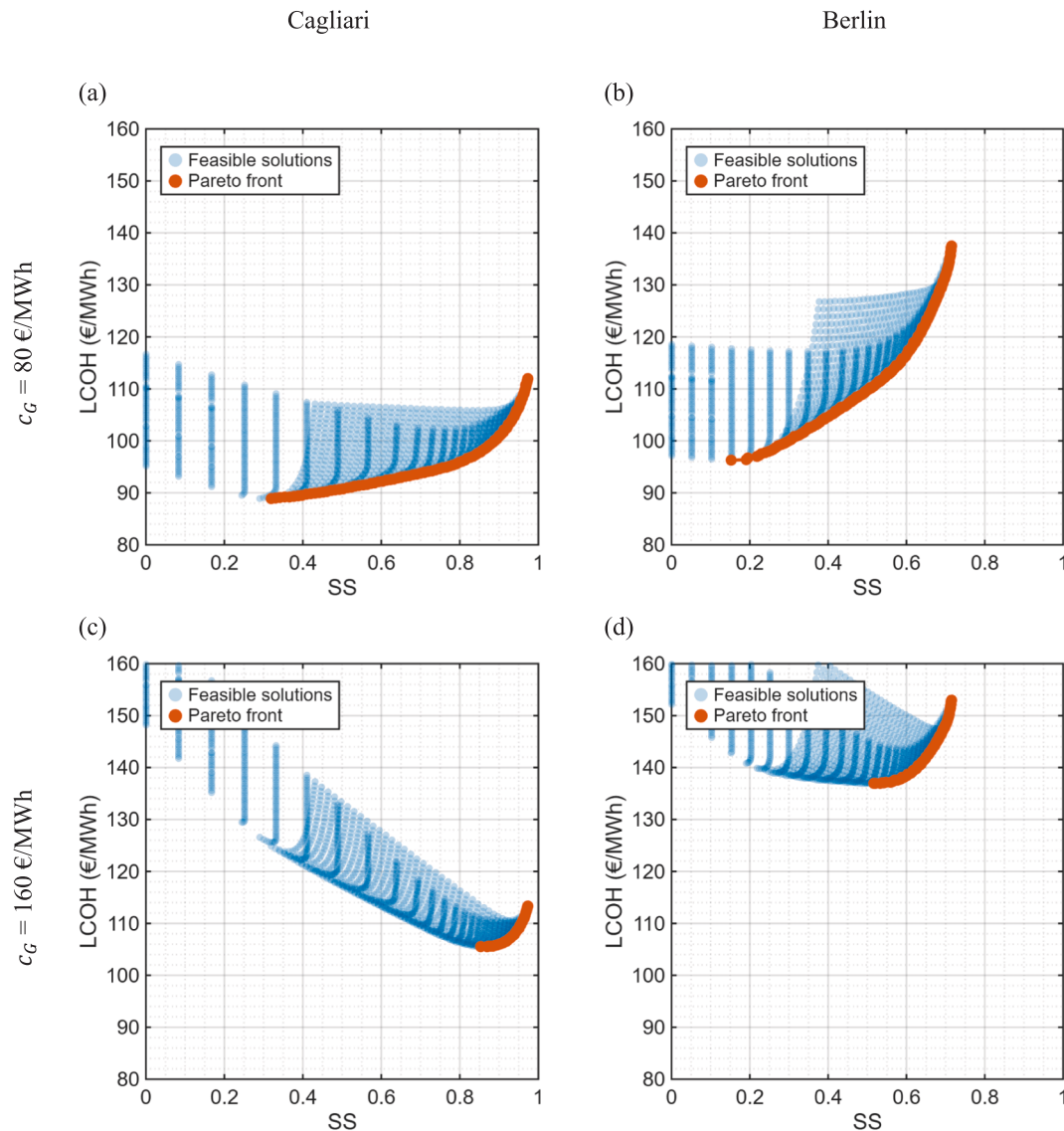


Fig. 8. Pareto fronts of LCOH versus SS at different electricity purchase costs. Red markers identify the Pareto-optimal solutions. Results are shown for Cagliari, Italy (left), and Berlin, Germany (right).

shifts the optimal region toward higher self-sufficiency, because reducing grid purchases becomes more valuable. However, meteorological conditions determine the achievable extent and cost of this shift. In the Cagliari case, the fronts allow high SS with relatively moderate penalties. In the Berlin case, the fronts are steeper and shifted upward, showing that higher self-sufficiency is both technically more limited and economically more expensive.

Fig. 9 illustrates the design trajectory of the optimal supply configurations as a function of c_G reported in the PV-BESS design space for the Cagliari (a) and Berlin (b) cases. The colour map (self-sufficiency) provides a physical interpretation of how the optimal supply configurations move across the design space as electricity prices increase.

In Cagliari (a), the trajectory initially lies along the bottom edge of the design space, where BESS capacity is zero and PV remains limited. The corresponding region is characterized by low SS values (blue–green shades), confirming that the early optimal supply configurations are grid-dominated configurations. As c_G increases toward 90 €/MWh, the trajectory begins to move upward and to the right, entering regions with slightly higher SS. This shift corresponds to the first PV expansion and appearance of storage, although still within a hybrid design condition. A key feature clearly visible in the plot is the sharp diagonal transition occurring between approximately 90 and 110 €/MWh. In this region, the trajectory rapidly moves into the upper-right portion of the design space (high-autonomy), where both PV and BESS capacities increase simultaneously. The colour gradient confirms that this shift is associated with a strong increase in SS. The slope of the trajectory in this region highlights the strong coupling between PV oversizing and storage duration: increasing one without the other would move the system away from the minimum-LCOH region. At higher values of c_G , the trajectory progressively flattens, approaching a region where further increases in PV and BESS produce only marginal gains in SS (yellow plateau). This confirms the presence of diminishing returns, already observed in Fig. 5, where SS saturates around 0.9. From a geometric perspective, the trajectory tends to align with the upper boundary of the feasible region, corresponding to near-daily storage operation and large PV oversizing.

In contrast, the Berlin case (b) exhibits a markedly different trajectory. At low and intermediate electricity prices, the optimal supply configurations remain clustered near the origin, with negligible PV and no storage, and thus lie entirely within the low-SS region (blue tones). The trajectory remains almost horizontal and confined to very low BESS

values for a wide range of c_G , confirming that local generation is not economically attractive under limited solar resource availability. Only beyond approximately 130 €/MWh does the trajectory begin to move decisively toward higher PV and BESS values (high-autonomy region). However, even in this case, the path followed is more gradual and less steep than in the Cagliari case. The transition toward daily-scale storage is visible as an upward bend of the trajectory, but it occurs later and requires significantly higher electricity prices to be triggered. Moreover, the trajectory remains largely confined to intermediate SS regions (green shades), never reaching the high SS plateau observed in the Cagliari case.

An additional insight provided by the Berlin case plot is the reduced effectiveness of storage, which is evident from the spacing of SS contours. Even large increases in BESS capacity (vertical movement in the plot) correspond to relatively modest improvements in SS, reflecting the limited availability of excess PV generation. As a result, the optimal trajectory does not extend into the top-right corner of the design space, but instead stabilizes in a region characterized by moderate PV oversizing and long, but underutilized, storage durations.

3.4. LCOH cost breakdown

Fig. 10 reports the LCOH breakdown of the minimum-cost configurations, for both locations, as a function of the electricity purchase cost (c_G), separating the contributions associated with the PV system (I_{PV} , O_{PV} and RV_{PV}), BESS (I_B , O_B and RV_B), SGHP (I_{SGHP} , O_{SGHP} and RV_{SGHP}), electricity purchases (C_G) and revenues from feed-ins (R_G). This analysis complements the previous results by clarifying the economic mechanisms behind the described design transitions. The SGHP contribution, including both capital and O&M costs, remains constant across all scenarios, since its size is fixed by the industrial steam demand and does not depend on the electricity price.

In Cagliari (Fig. 10a), the cost structure changes markedly as the electricity purchase cost increases. At low electricity prices, the LCOH is dominated by the SGHP-related costs and grid electricity purchases. In this region, the optimal configuration includes no, or limited, PV capacity and no storage, meaning that the system mostly behaves as an electrified steam generator supplied by the grid. Consequently, the grid electricity cost contribution increases almost linearly with c_G , while PV-related costs remain marginal and BESS-related costs are absent.

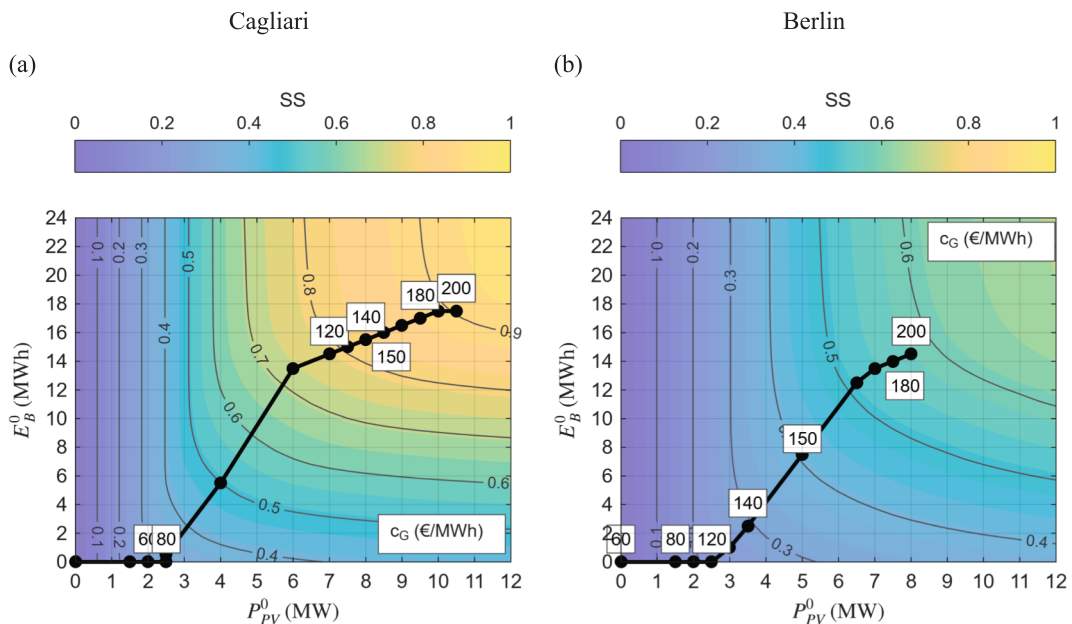


Fig. 9. Design trajectory of minimum-LCOH configurations as the electricity purchase cost varies (values in boxes). Colours represent self-sufficiency over the PV-BESS design space. Results are shown for Cagliari, Italy (left), and Berlin, Germany (right).

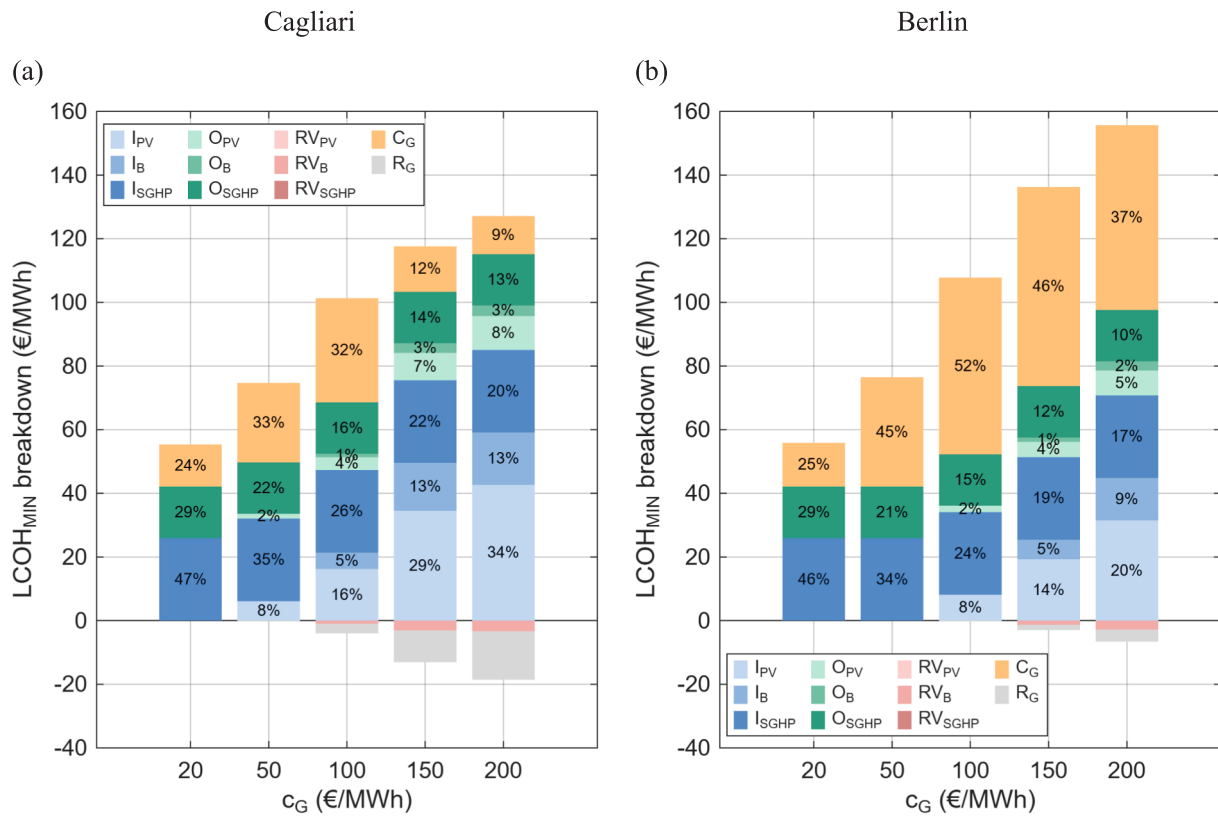


Fig. 10. LCOH breakdown of the minimum-cost configurations as a function of the electricity purchase cost for Cagliari, Italy (left), and Berlin, Germany (right). Positive contributions indicate cost components, while negative contributions represent revenues. Percentages indicate the share of total positive costs.

As c_G approaches the high-autonomy transition region identified previously, the breakdown shows a progressive substitution of grid electricity costs with PV and BESS investment costs. This is the economic counterpart of the design shift toward high-autonomy: increasing PV capacity reduces electricity imports, while the introduction of storage allows a larger fraction of PV generation to be used internally. In this range, the increase in PV and BESS annualized costs is compensated by the avoided grid electricity expenditure, resulting in a relatively limited increase in total LCOH despite the higher electricity price. The BESS installation becomes convenient only when the value of additional self-consumption exceeds the combined cost of storage capacity, efficiency losses, degradation, and replacement.

At highest electricity prices, grid electricity purchases become a much smaller fraction of the total LCOH, while PV and BESS costs become structurally important components. In particular, PV investment and maintenance represent the main additional cost required to reduce exposure to the electricity cost, whereas the BESS contribution reflects the cost of shifting daytime PV generation toward evening and night demand. The relatively slow increase of total LCOH at high c_G is therefore explained by the strong reduction in grid dependence: once the system reaches high self-sufficiency, further increases in electricity price affect only the residual fraction of demand still supplied by the grid.

The negative contributions associated with feed-in revenues and residual values remain limited. This was expected because the optimization prioritizes self-consumption rather than electricity export, and the assumed feed-in remuneration is low. Therefore, PV oversizing is economically justified mainly by avoided grid purchases rather than by revenues from surplus electricity. Similarly, the BESS residual value only partially offsets storage-related investment and replacement costs and does not alter the overall cost hierarchy.

In the Berlin case (Fig. 10b), the same qualitative trend is observed, but the magnitude and effectiveness of the substitution are substantially different. At low and intermediate electricity prices, the LCOH remains

dominated by SGHP costs and grid electricity purchases, while PV and BESS contributions remain negligible or limited. Compared with Cagliari, the grid electricity contribution is larger for the same electricity price because the lower PV productivity reduces the amount of useful self-generation. As a result, the economic incentive to install PV and storage appears only at higher values of c_G . When the electricity price increases beyond the transition thresholds, the breakdown shows an increase in PV and BESS costs, consistently with the design trajectory already discussed. However, unlike the Cagliari case, these additional investments do not lead to an equally strong decrease in grid electricity costs. The lower annual irradiation limits both the amount of PV electricity produced and the availability of surplus energy to charge the battery. Consequently, the BESS is less effectively utilized, and storage costs become more difficult to recover through avoided grid purchases. This explains why the optimal configurations in the Berlin case remain less autonomous than in the Cagliari.

At highest electricity prices, the LCOH breakdown shows that grid electricity purchases still represent a significant contribution to the total heat cost, even after PV and BESS deployment. This residual dependence on the grid is the main reason why the minimum LCOH continues to increase steeply with c_G , as observed in Fig. 5. In other words, while PV and BESS reduce electricity-cost exposure, they cannot provide the same hedging effect achieved in the Cagliari case. The system therefore faces a double cost penalty: higher local generation and storage costs are added, but grid electricity costs remain substantial because self-sufficiency is technically and economically limited.

Overall, the LCOH breakdown highlights a fundamental economic difference: in the Cagliari case, increasing electricity prices trigger a clear shift from variable to fixed costs, effectively transforming the system from a price-dependent to a predictable and price-insulated one. In the Berlin case, this transition is only partial: despite increasing investments, grid purchases remain a major cost component. As a consequence, the two systems exhibit different levels of economic resilience.

In Cagliari meteorological conditions, the dominance of capital costs reduces exposure to market prices and enables more predictable energy costs. In Berlin conditions, persistent grid dependence implies continued exposure to electricity prices and a limited ability to stabilize long-term costs.

3.5. Sensitivity analysis

To assess the robustness of the optimal supply configurations identified in the previous sections, a sensitivity analysis was performed around the base-case assumptions. The investigated parameters include the discount rate (DR), the feed-in remuneration (r_G), and the CAPEX and associated OPEX of the SGHP, PV system, and BESS. The discount rate and technology costs were varied by $\pm 20\%$, while the feed-in remuneration was either set to zero or doubled. For each perturbed case, the optimization was repeated over the same design space, and the resulting LCOH_{MIN} was compared with the corresponding base-case value, $\text{LCOH}_{\text{MIN},0}$, at the same electricity purchase cost. Fig. 11 reports the resulting percentage variations for selected electricity purchase costs. Additional sensitivity checks were performed on the BESS C-rate, as well as on the calendar and cycling degradation assumptions. Since these parameters produced negligible variations in LCOH_{MIN} , their detailed results are not reported in Fig. 11.

The discount rate produces a moderate and approximately symmetric effect in both locations. In the Cagliari case, reducing DR by 20 % decreases LCOH_{MIN} by 3.5–6.2 %, whereas an equivalent increase in DR raises it by 3.6–6.2 %. The effect generally becomes more pronounced as the electricity purchase cost increases because the optimal configurations progressively incorporate larger PV and BESS capacities, increasing the importance of upfront investments. In Berlin, the

corresponding variations are smaller, ranging from approximately -2.8% to -3.8% for the lower discount rate and from $+2.7\%$ to $+3.8\%$ for the higher discount rate. This lower sensitivity is consistent with the more limited contribution of capital-intensive PV-BESS configurations to the optimal electricity supply in Berlin.

Feed-in remuneration has a strongly location-dependent influence. In Cagliari, setting r_G to zero has no effect at 50 €/MWh but progressively increases LCOH_{MIN} , reaching $+7.8\%$ at 200 €/MWh. Conversely, doubling r_G reduces LCOH_{MIN} by approximately 19–21 % over the investigated electricity-price range. This pronounced response results from the favourable solar profile, which enables substantial PV generation and makes the revenues associated with surplus electricity exports economically relevant. The response is also asymmetric because changes in r_G affect not only export revenues but also the optimal PV-BESS sizing. In Berlin, the influence of r_G is markedly smaller: zero remuneration increases LCOH_{MIN} by no more than 2.1 %, while doubling it produces a maximum reduction of 4.7 %. At 50 €/MWh, neither variation affects the optimum because the corresponding configuration remains grid-based. The doubled-remuneration case should nevertheless be interpreted as an exploratory scenario, since high export remuneration may promote PV oversizing and shift the optimal configuration toward greater electricity exports.

The SGHP CAPEX and associated OPEX are the most influential technology-cost parameters at low electricity purchase costs. At 50 €/MWh, a $\pm 20\%$ variation produces an approximately symmetric change of $\pm 11.3\%$ in Cagliari and $\pm 11.0\%$ in Berlin. Their relative influence decreases as the electricity purchase cost rises, reaching $\pm 7.8\%$ in Cagliari and $\pm 5.6\%$ in Berlin at 200 €/MWh. This trend reflects the declining relative contribution of SGHP investment and operating costs to the total LCOH as electricity-supply costs and investments in PV and

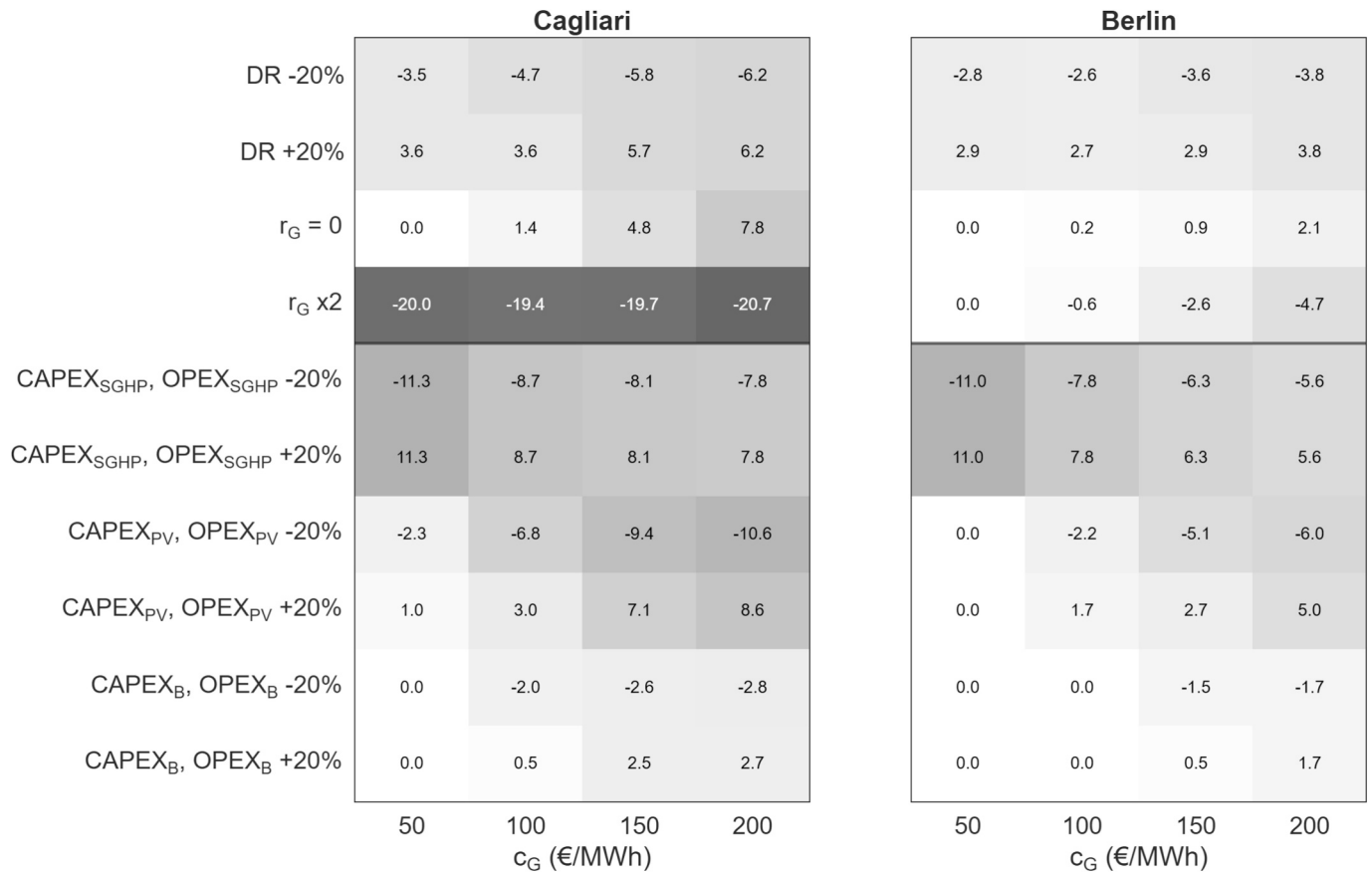


Fig. 11. Sensitivity of LCOH_{MIN} to the discount rate (DR), feed-in remuneration (r_G), and the CAPEX and associated OPEX of the SGHP, PV system, and BESS for the Cagliari (left) and Berlin (right) cases. Values represent the percentage variation relative to the corresponding base-case $\text{LCOH}_{\text{MIN},0}$ at the same electricity purchase cost. Negative and positive values indicate reductions and increases in LCOH_{MIN} , respectively.

BESS become progressively more important.

The opposite trend is observed for the PV CAPEX and associated OPEX. Their influence increases substantially with the electricity purchase cost as PV becomes progressively integrated into the optimal electricity-supply configuration. In Cagliari, reducing PV costs by 20 % decreases $LCOH_{MIN}$ by 2.3 % at 50 €/MWh and by 10.6 % at 200 €/MWh, while a 20 % cost increase raises it by 1.0 % and 8.6 %, respectively. In Berlin, PV-cost variations have no effect at 50 €/MWh because PV is not included in the corresponding optimal configuration. Their influence subsequently increases, reaching −6.0 % and +5.0 % at 200 €/MWh for the low- and high-cost assumptions, respectively. The greater sensitivity observed in Cagliari is consistent with its more favourable solar profile and the resulting higher PV capacities. The asymmetric effects of equivalent cost increases and decreases arise from the reoptimization of the PV–BESS configuration in each perturbed case.

The BESS CAPEX and associated OPEX have a comparatively limited effect. In Cagliari, the sensitivity is negligible at 50 €/MWh and increases to approximately −2.8 % and +2.7 % at 200 €/MWh for the low- and high-cost assumptions, respectively. In Berlin, no effect is observed at 50 and 100 €/MWh, while the maximum variation reaches approximately ± 1.7 % at 200 €/MWh. These results indicate that BESS cost becomes relevant only when sufficiently high electricity purchase costs make storage part of the optimal configuration. Even under these conditions, its influence remains substantially smaller than that of the SGHP and PV costs.

Additional analyses showed that variations in the BESS calendar and cycling degradation assumptions produce negligible changes in $LCOH_{MIN}$. This limited influence is consistent with the comparatively small contribution of BESS costs to the overall economic sensitivity. Similarly, increasing the battery C-rate from the base-case value of 0.25 h^{-1} to 0.50 and 1.00 h^{-1} produced virtually no change in $LCOH_{MIN}$, indicating that the baseline power capability is already sufficient for the charge and discharge profiles of the optimal configurations.

Overall, the disaggregated sensitivity analysis indicates that the relative importance of the economic parameters changes with both electricity purchase cost and location. The SGHP cost is the dominant technology-cost factor when electricity is inexpensive, whereas the influence of PV and, to a lesser extent, BESS costs increases as the optimal configuration becomes more reliant on local renewable generation and storage. Feed-in remuneration produces the largest overall variation in Cagliari but has a much smaller influence in Berlin because the lower solar availability limits surplus PV generation. The discount rate has a secondary but systematic effect, which is more pronounced in Cagliari owing to the greater capital intensity of its optimal configurations. These results confirm that the economic sensitivity of the system depends on the composition of the optimal electricity supply rather than on a uniform response to aggregate technology-cost variations.

4. Conclusions

This study assessed the techno-economic performance of an air-source steam-generating heat pump supplied by a cost-optimized combination of grid electricity, on-site photovoltaic generation, and battery energy storage. A continuous baseload demand of 2 t/h of saturated steam at 15 bar was considered as case study.

The analysis investigated the leveled cost of heat of this system as well as the optimal electricity supply configuration, across electricity purchase price levels ranging from 20 to 200 €/MWh and under the meteorological conditions of Cagliari, Italy and Berlin, Germany.

For the considered case-study, the minimum LCOH varied between approximately 55 and 109 €/MWh in the Cagliari case and between 55 and 149 €/MWh in the Berlin case. As electricity prices increase, the cost-optimal supply configuration progressively shifts from a grid-dominated solution to a PV–BESS supported hybrid design with buffer storage and, eventually, to configurations characterized by a higher degree of energy autonomy supported by daily-scale storage. These

transitions occur at lower electricity-price levels in the Cagliari case, at approximately 40 and 90 €/MWh, than in the Berlin case, at approximately 70 and 130 €/MWh, respectively. Higher electricity-price thresholds are therefore required to justify investments in PV and storage under Berlin meteorological conditions. The transition toward hybrid supply is not simultaneous for PV and storage: PV deployment becomes cost-effective first, whereas BESS capacity is introduced only when the value of additional self-consumption exceeds storage-related costs, losses, degradation, and replacement effects. Notably, electricity-price levels commonly observed today in Europe already fall within the range where hybrid supply solutions can become economically attractive compared to grid-dominated configurations.

The controlled simulations based on cross-combined solar-generation and ambient-temperature profiles allowed the respective meteorological effects to be separated. The results show that the difference between the Cagliari and Berlin cases is primarily driven by solar availability, while ambient temperature has a smaller, although non-negligible, influence on SGHP electricity consumption. The relative importance of solar availability increases with the electricity-price level because PV–BESS integration becomes progressively more relevant to the optimal configuration.

The minimum-LCOH solutions are surrounded by relatively large near-optimal regions. This indicates that the economic performance of the system is not highly sensitive to the exact sizing of PV and battery capacity and suggests that the identified design solutions are robust, with moderate deviations from the exact optimum resulting in only limited economic penalties.

From an economic perspective, PV–BESS integration can provide a cost-reduction opportunity and limit exposure to high grid-electricity price levels by reducing grid dependence, but its effectiveness remains highly site-dependent. In Cagliari, increasing electricity prices progressively shift the cost structure from grid-electricity expenditures towards fixed PV and BESS costs, thereby reducing the sensitivity of the LCOH to electricity-price. In Berlin, this shift remains only partial, and a significant dependence on grid electricity persists.

The sensitivity analysis confirms the robustness of the main trends. SGHP CAPEX and associated OPEX are the dominant technology-cost parameters at low electricity-price levels, whereas the influence of PV costs increases as PV becomes a larger component of the cost-optimal electricity supply. BESS costs have a smaller effect and become relevant only when storage is included in the optimal configuration. Feed-in remuneration is relevant mainly under Cagliari conditions, where PV oversizing can generate significant surplus electricity. The discount rate has a moderate but non-negligible effect, while variations in BESS C-rate, calendar and cycling degradation assumptions produce negligible changes in the minimum LCOH.

These conclusions should be interpreted within the modelling assumptions adopted in this study, including the assignment of the SGHP to a continuous steam baseload, fixed electricity purchase prices, no electricity arbitrage, two different meteorological conditions, the absence of site-area constraints, and a specific air-source SGHP configuration. However, while the specific transition thresholds and optimal system configurations are case-study dependent, the overall trend towards increased PV and BESS deployment with rising electricity prices proved robust across all analysed scenarios.

Future work should extend the analysis to a broader geographical domain, investigate time-varying electricity-price profiles, assess process-specific operating hours, load factors, and steam-demand profiles, including their effects on optimal PV–BESS sizing and LCOH, and compare alternative SGHP technologies.

Overall, the results suggest that the economic viability of air-source SGHPs depends not only on the performance of the heat pump itself, but also on the design of the electricity supply system. For the two cases examined, the more favourable meteorological conditions of Cagliari enable lower heat-production costs and facilitates the deployment of configurations with higher levels of energy autonomy. Under Berlin

conditions, the economic value of PV and storage is more limited, and significant dependence on grid electricity remains.

CRedit authorship contribution statement

Luca Migliari: Writing – review & editing, Writing – original draft, Visualization, Validation, Software, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **Daniele Cocco:** Writing – review & editing, Supervision, Project administration, Methodology, Conceptualization.

Declaration of competing 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.

Data availability

Data will be made available on request.

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