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Optimising green hydrogen production across Europe: How renewable energy sources shape plant design and costs

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ABSTRACT

Green hydrogen is widely recognised as a key enabler for decarbonising heavy industry and long-haul transport. However, producing it cost-competitively from variable renewable energy sources presents design challenges. In this study, a mixed-integer linear programming (MILP) optimisation framework is developed to minimise the levelised cost of hydrogen (LCOH) from renewable-powered electrolysers. The analysis covers all European countries and explores how wind and solar resource availability influences the optimal sizing of renewable generators, electrolysers, hydrogen storage, and batteries under both current and future scenarios. Results show that renewable resource quality strongly affects system design and hydrogen costs. At present, solar-only systems yield LCOH values of 7.4–24.7 €/kg, whereas wind-only systems achieve lower costs (5.1–17.1 €/kg) due to higher capacity factors and reduced storage requirements. Hybrid systems, combining solar and wind, emerge as the most cost-effective solution, reducing average LCOH by 57 % compared to solar-only systems and 25 % compared to wind-only systems, effectively narrowing geographical cost disparities. In the future scenario, LCOH declines to 3–4 €/kg, confirming renewable hydrogen's potential to become economically competitive throughout Europe. A key contribution of this work is the derivation of design guidelines by correlating renewable resource quality with technical, energy and economic indicators.

1. Introduction

Hydrogen is currently gaining unprecedented momentum, marked by a rapid increase in the number of hydrogen-related policies and projects worldwide [1,2]. Presently, hydrogen serves various essential roles: as a feedstock for chemical production (such as ammonia and methanol), as a reducing agent in steelmaking, and for the purification and upgrading of heavy oil fractions in refineries. Moreover, it is expected to play a pivotal role in expediting the transition towards a carbon-neutral future. Indeed, in a decarbonised society, hydrogen and its derivatives will fulfil a wide range of applications, particularly in industrial sectors that already rely on fossil-based hydrogen, such as the chemical industry [3], steel production [4], and high-temperature heat generation [5]. Additionally, hydrogen represents a promising energy vector for heavy-duty transport [6], where long driving ranges and fast refuelling are essential. Due to its storability and versatility, hydrogen also plays a key role as a seasonal energy storage medium, both at grid scale [7,8] and in decentralised or off-grid contexts [9].

At the same time, widespread adoption of hydrogen faces several challenges, including high production costs, especially for renewable hydrogen, limited infrastructure, uncertainty on the future predicted demand and regulatory barriers. To address these issues and accelerate the development of the hydrogen economy, policies and investments are advancing rapidly. As of 2024, 58 countries, along with the European Union and the Economic Community of West African States, representing over 84 % of global energy-related CO_2 emissions, have published national hydrogen strategies. Additionally, announced projects indicate that global electrolysis capacity could reach nearly 520 GW by 2030 [10]. Despite these advancements, important gaps remain, particularly in investment stability, permitting procedures, and achieving cost competitiveness with fossil-based alternatives.

Water electrolysis is recognised as the most promising method for producing green hydrogen by using renewable energy [11]. However, because of the fluctuating behaviour of solar and wind energy, new challenges emerge in guaranteeing a reliable and cost-effective supply of green hydrogen [12]. A key component of any hydrogen production system is hydrogen storage, for which several technological options exist, including compressed gas, cryogenic liquid, and solid-state storage

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such as metal hydrides [13]. Among these, pressurised gaseous hydrogen storage is currently the most widely adopted in industrial-scale applications, particularly where space constraints are not critical. This preference is driven by its higher technological maturity, broader commercial availability, and lower investment and operational costs [14].

In this context, defining the cost-optimal design of the power-to-hydrogen (PtH) system, including renewable generators, electrolysers, battery and hydrogen storage, is essential to minimise hydrogen production costs while guaranteeing a reliable supply to meet end-user demand.

1.1. Literature review

Several studies have investigated the techno-economic feasibility of green hydrogen production via water electrolysis, with some methodologies focusing on optimal system design, particularly when integrating intermittent renewable energy sources (RES) such as solar and wind [15]. However, as detailed in the following literature review, most existing research focuses on case studies in specific geographical locations, which limits the extent to which their findings can be generalised and extrapolated to regions with different renewable resource profiles.

Atabay and Devrim [16] conducted a techno-economic analysis of a solar-based hydrogen refuelling station supposed to be built in Ankara (Türkiye). They analysed different sizes of photovoltaic (PV) systems and found a minimum levelised cost of hydrogen (LCOH) of approximately 8.5 €/kg. Ibáñez-Rioja et al. [17] explored the optimal design of an off-grid hydrogen production plant located in southeastern Finland, powered by both solar and wind energy, concluding that, at present, using a wind farm as the sole power source is the most cost-effective solution, and the use of batteries does not offer economic benefits. Similar considerations were drawn by Garud et al. [18], who reported that hydrogen storage is more economically favourable than batteries for providing flexibility in a PtH plant.

Other studies have examined the influence of system configuration and sizing strategies. Marocco et al. [19] developed an optimisation tool to determine the optimal sizing and operation of hydrogen production systems powered by both photovoltaic panels and the electrical grid, using Italy as a case study. The same country was selected to investigate the cost-optimal size ratio, namely the ratio between the sizes of the renewable generator and the electrolyser [20]. Specifically, several plant configurations were explored, demonstrating that the cost-optimal size ratio results from a trade-off between the utilisation factors of the electrolyser and the renewable generator, which follow opposite trends. Italy was also examined as a case study in a recent work by Ademollo et al. [21], who analysed a grid-connected, solar-based PtH system accounting for component ageing. The authors evaluated different regulatory frameworks for low-carbon hydrogen production and confirmed that supply-side flexibility is more economically viable when provided through hydrogen storage rather than battery storage. Similar conclusions were drawn in another study focusing on a wind-powered PtH system supplying hydrogen to the steel industry [22].

Lin et al. [23] analysed a complex hybrid system located in Cina, integrating both photovoltaic and wind turbines, and coupled with a dual electrolysis setup that combines proton exchange membrane (PEM) and alkaline technologies. Their study explored various size combinations of the two electrolyser types and their impact on the LCOH, showing that hybrid electrolysis configurations can reduce hydrogen production costs by 6–11 % compared to single-technology setups. China was also selected as the study location by Li et al. [24], who examined optimal size ratios for PV-wind hybrid systems in the context of a renewable energy plant where hydrogen acts as a buffer to comply with grid injection constraints. Similarly, El-Hamalawy et al. [25], investigated how the operating characteristics of electrolysers affect the cost-optimal design and the resulting LCOH. Maurer et al. [26] carried out a sensitivity analysis on the main component sizes (including PV panels, electrolyser and hydrogen storage) to assess their impact on the hydrogen production cost and identify the cost-optimal system configuration. Their analysis, applied to a location in Upper Austria with the goal of meeting the hydrogen demand for fuel cell buses, revealed that the optimal sizing is primarily influenced by the price of grid electricity. Dufo-López et al. [27] explored the optimal sizing of various PtH system configurations, including both PV and wind turbines (WTs), for a location near Zaragoza, Spain. They found that a constant efficiency for the electrolyser can lead to significant errors (ranging from 3.5 to 17.8 %) in estimating the LCOH compared to using a more accurate efficiency curve.

Some studies have also explored the impact of different climatic conditions on the performance of hydrogen production systems. Mazzeo et al. [28] conducted a global study across 28 locations, examining different configurations based on solar and wind energy. However, they considered fixed component sizes, without applying any design optimisation. Janssen et al. [29] assessed the cost of renewable hydrogen production through off-grid electricity systems, finding current costs in the range of 2.1–15 €/kg. Although their analysis covered a broad set of European countries, the same sizes for both the renewable generator and the electrolyser were assumed for all locations. Hofrichter et al. [30] investigated the optimal ratio of installed renewable power to electrolysis capacity across different geographical regions. They conducted the optimal design by performing a sensitivity analysis on the component sizes, without the use of optimisation algorithms. Moreover, only single-generator layouts (i.e. PV-only and WT-only layouts) were evaluated, without taking into account the benefits of hybridisation. Similarly, a recent report by IRENA [31] examined the cost-optimal capacities of the renewable generators and the electrolyser for different countries worldwide. The report used sensitivity analyses to determine the cost-optimal design point, which was presented solely for solar-only or wind-only PtH configurations.

In addition, some online tools have recently emerged to estimate the LCOH across different regions and scenarios. Notable examples include the calculators developed by the Clean Hydrogen Observatory [32] and the International Energy Agency [33]. While these tools provide useful high-level LCOH estimates, they do not include detailed optimisation of all components such as battery and/or hydrogen storage, nor do they account for hydrogen demand profiles.

1.2. Aim and novelty of the study

In this work, an optimisation framework is developed to address the cost-optimal design of hydrogen production systems powered by renewable energy sources. In contrast to much of the existing literature, which typically focuses on individual case studies, the analysis is extended to cover a large set of European countries. The objective is to evaluate how variations in wind and solar resource availability affects the optimal design of PtH systems and the associated hydrogen production costs. Optimal sizes for renewable generators, electrolysers, batteries and hydrogen storage systems are identified for 29 European countries, considering country-aggregated time series of solar and wind capacity factors. Additionally, to further generalise the results, a set of techno-economic indicators is proposed to provide practical design guidelines for hydrogen production systems based on geographical location.

The analysis compares various system configurations based on the type of renewable generator, which is rarely investigated in the literature: PV-only systems, WT-only systems and hybrid systems (combining PV and WT). This approach is essential for assessing the potential of single-generator solutions and quantifying the benefits of hybridising renewable power production.

To enhance the robustness of the study, a clustering procedure is employed to identify the most representative year for each European country, based on solar and wind resource profiles. Moreover, since electrolyser efficiency depends on its operating point, particular attention is given to accurately modelling the hydrogen production process by incorporating a performance map and operational constraints (e.g., modulation range) from actual electrolyser data. Such detailed representation is needed for reliably simulating electrolysers operating under variable renewable energy supply.

In addition, a future scenario is introduced to complement the present-day analysis and provide long-term insights. This scenario accounts for projected reductions in the capital costs of renewable technologies, batteries and electrolysers, alongside improved electrolyser performance. Including this future outlook allows for an assessment of how technological advances may influence system design and hydrogen production costs over the coming decades, offering a more complete picture of future competitiveness across Europe.

The structure of the paper is as follows: Section 2 outlines the cost-optimal design methodology and the necessary techno-economic input data; Section 3 presents and discusses the main sizing results for different PtH configurations across various European countries; finally key conclusions are drawn in Section 4.

2. Optimal design methodology

Fig. 1 illustrates the layout of the PtH system analysed in this work. The electricity used to power the electrolyser is generated on-site by a photovoltaic and/or wind system. Various configurations have been assessed based on the renewable generation technology: PV-only, WT-only and hybrid systems (with the latter incorporating both PV and WT). Battery storage can be integrated within the electricity supply system if deemed economically advantageous by the optimisation framework. The system layout also includes a hydrogen storage system to provide flexibility and reliably meet the end-user's hydrogen demand. In this work, the hydrogen demand is assumed to remain steady over time, reflecting the operational characteristics of hard-to-abate industrial sectors where hydrogen is already widely used or expected to play a key role in the near future [10,34]. These sectors are characterised by a continuous hydrogen demand and limited process flexibility, making constant demand a representative and realistic assumption for techno-economic modelling [22,35].

As displayed in Fig. 1, this analysis focuses on electrolytic hydrogen production relying on local renewable energy sources. The need for low-carbon electricity (from renewable energy sources with constraints on additionality and temporal/geographical correlation) to power the production of synthetic fuels, as testified by the updated Renewable Energy Directive (RED III) [36], is leading to a progressive decentralisation of the production plants, with consequent challenges to cope with the fluctuating nature of variable RES.

2.1. MILP-based optimisation framework

An optimisation framework – based on the mixed integer linear programming (MILP) technique – was developed to determine the optimal design of renewable-based hydrogen production systems. The levelised cost of hydrogen (LCOH) was used as the objective function for the optimisation. The goal is to meet the end-user's hydrogen demand at each time step (t) over the time horizon (T), while minimising the LCOH. The simulation was conducted over a year-long time horizon with hourly resolution.

As shown in Fig. 2, the primary inputs to the MILP-based optimisation process are as follows:

1. Techno-economic data (e.g. investment costs, operation & maintenance costs, modulation range, and efficiency curve) for all components of the PtH system.
2. The hydrogen demand profile $\forall\, t \in T$.
3. Meteorological data, in terms of capacity factor (CF), for the photovoltaic and wind systems $\forall\, t \in T$.

The following decision variables are provided:

1. The optimal sizes of all components of the PtH system, i.e. photovoltaic (PV), wind turbine (WT), battery storage (BS), electrolyser (EL) and hydrogen storage (HS).
2. The electrical power supplied to the electrolyser (input) and the hydrogen power generated by the electrolyser (output) $\forall\, t \in T$.
3. The surplus renewable power not directed to the electrolyser $\forall\, t \in T$.
4. The charging and discharging power of the battery and hydrogen storage systems $\forall\, t \in T$.
5. The quantity of energy stored in the battery and hydrogen storage systems $\forall\, t \in T$.

2.1.1. Design variables

The sizes of the PtH components were treated as continuous variables, constrained between a minimum and maximum value as outlined below (with j = PV, WT, EL, HS):

$$0 \le S_j \le S_{j,max} \tag{1}$$

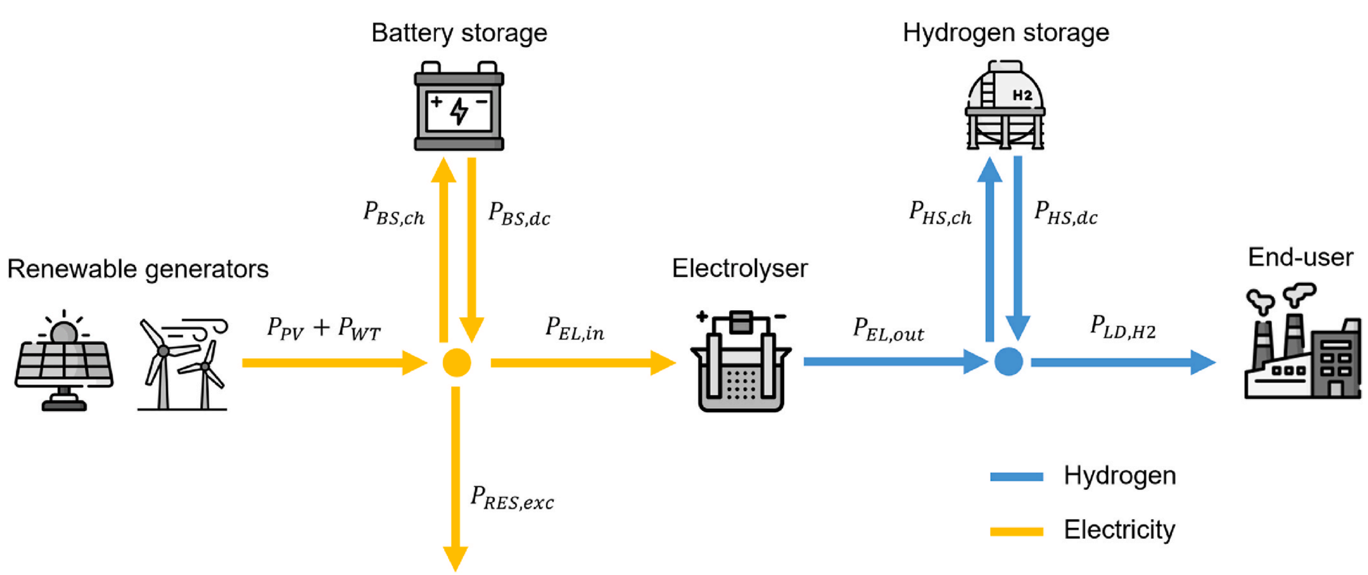

Fig. 1. Layout of the investigated hydrogen production system (adapted from Ref. [19]).

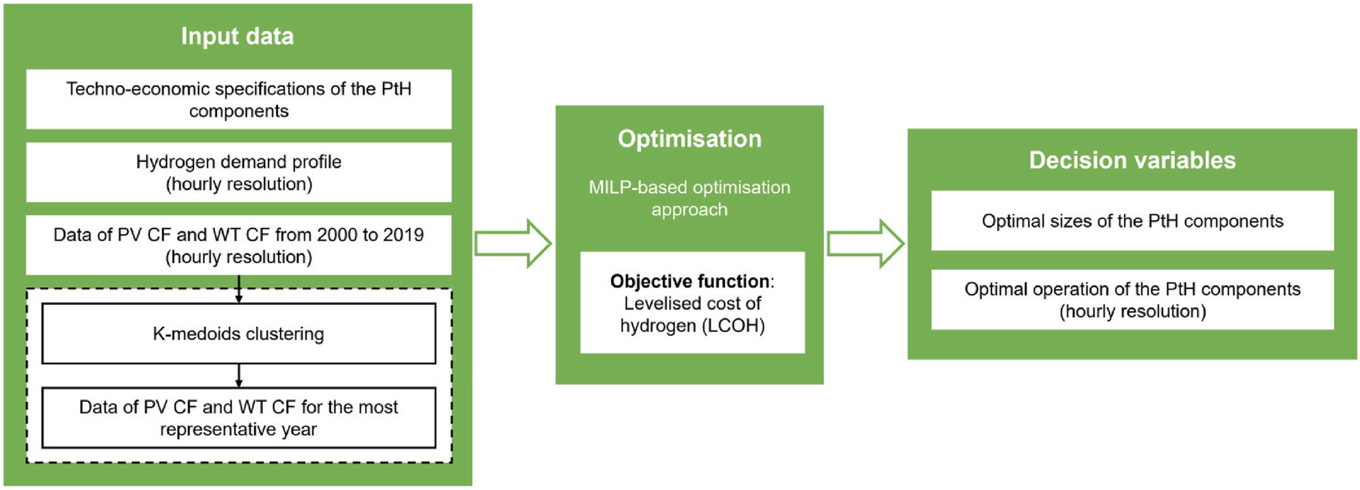

Fig. 2. Schematic representation of the methodology used in this study for the optimal design of hydrogen production systems (extended from Ref. [19]).

where S_j is the size of the j-th component. For the photovoltaic system, the wind system and the electrolyser, it corresponds to the rated power (in kW), while for the battery storage and hydrogen storage, it refers to the rated energy (in kWh). Specifically, for the electrolyser, S_j denotes the rated input electrical power.

The $S_{j,max}$ value was chosen to ensure it does not act as a constraint in optimising the size of the j-th component. In specific cases, such as WT-only scenarios, $S_{j,max}$ for the PV system was set to 0, and similarly, $S_{j,max}$ for the WT system was set to 0 in PV-only scenarios.

2.1.2. Electrical and hydrogen power balances

At any time step (t), the sum of the PV power (P_{PV}, in kW), the wind power (P_{WT}, in kW) and the battery discharging power ($P_{BS,dc}$, in kW) is equal to the sum of the battery charging power ($P_{BS,dc}$, in kW), the electrical power supplied to the electrolyser ($P_{EL,in}$, in kW) and the excess renewable electricity ($P_{RES,exc}$, in kW). Specifically, the electrical power balance can be expressed as follows:

$$P_{PV}(t) + P_{WT}(t) + P_{BS,dc}(t) = P_{BS,ch}(t) + P_{EL,in}(t) + P_{RES,exc}(t) \tag{2}$$

At any time step (t), the hydrogen produced by the electrolyser ($P_{EL,out}$, in kW) must meet the hydrogen demand ($P_{LD,h2}$, in kW). Any excess hydrogen beyond the demand is stored ($P_{HS,ch}$, in kW), while in case of a deficit, the fraction of hydrogen demand not directly satisfied by the electrolyser is drawn from the storage ($P_{HS,dc}$, in kW). This can be expressed by the following linear relationship [19]:

$$P_{EL,out}(t) + P_{HS,dc}(t) = P_{HS,ch}(t) + P_{LD,H2}(t) \tag{3}$$

It should be noted that the power values of Eq. (3) are expressed on a lower heating value (LHV) basis.

2.1.3. Renewable power production

The renewable power (P_{PV} and P_{WT}) from PV and WT during each time step t, can be computed based on the solar and wind capacity factors, as expressed through Eq. (4) for each time step (t) over the 1-year time horizon (with j = PV, WT) [20]:

$$CF_j(t) = \frac{P_j(t) \cdot \Delta t}{S_j \cdot \Delta t} \tag{4}$$

where P_j (in kW) and CF_j are, respectively, the electrical power produced and the capacity factor of the j-th renewable generator for a given time step (t), S_j (in kW) is the rated power (size) of the j-th renewable generator, and Δt (in h) is the duration of the time step.

To improve the robustness of the renewable electricity generation estimates, the most representative year of solar and wind resource profiles was identified for each country. As illustrated in Fig. 2, this was achieved by applying the k-medoids clustering technique [37] to the country-aggregated time series of PV and WT capacity factors (with hourly resolution), available from 2000 to 2019 [38]. The PV and WT profiles corresponding to the medoid (i.e., the most representative year) were then used as input to the optimisation framework. This procedure was carried out for 29 European countries (EU-27 excluding Malta due to lack of wind data, plus United Kingdom, Switzerland, and Norway), with the ultimate goal of evaluating the optimal LCOH as solar and wind energy availability varies.

In Section 3, the annual average capacity factor of the various European countries was often employed for comparing and discussing the sizing results. For each country, it can be defined as (with j = PV, WT):

$$CF_{j,avg} = \frac{\sum_{t=1}^{T} (P_j(t) \cdot \Delta t)}{\sum_{t=1}^{T} (S_j \cdot \Delta t)} \tag{5}$$

where T is the number of time steps in the selected time horizon (1 year in this analysis).

2.1.4. Electrolyser modelling

An efficiency curve was considered to relate the output hydrogen power ($P_{EL,out}$, in kW) to the inlet electrical power ($P_{EL,in}$, in kW) of the electrolyser. Piecewise affine (PWA) approximation was employed to integrate this curve into the MILP-based framework. The PWA method involves approximating the nonlinear efficiency curve using a series of linear segments. The optimal locations of the n breakpoints along the curve were determined by applying the nonlinear optimisation problem detailed in Ref. [39]. Following this, for each i-th segment of the PWA approximation, the expression below was utilised to define the relationship between $P_{EL,out}$ and $P_{EL,in}$ at any given time step (t) of the simulation [19]:

$$P_{EL,out}(t) \le \alpha_i \cdot P_{EL,in}(t) + \beta_i \cdot S_{EL,aux}(t) \tag{6}$$

where α_i and β_i are the coefficients of the i-th affine segment (the adopted values for these coefficients are provided in the Supplementary Material). $S_{EL,aux}$ (in kW) is an auxiliary variable that must be introduced to formulate – as a linear constraint – the product between a continuous variable (S_{EL}) and a binary variable (δ_{EL}), as described in Ref. [19]:

$$S_{EL,aux}(t) = S_{EL} \cdot \delta_{EL}(t) \tag{7}$$

where S_{EL} (in kW) is the rated electrical power (size) of the electrolyser, and δ_{EL} is a binary variable that is equal to 1 if the electrolyser is on and

0 if the electrolyser is off.

During operation, the electrolyser is modulated between a minimum and maximum power value, as recommended by manufacturers to ensure safety and efficiency. The constraints for establishing the lower ($y_{EL,min}$) and upper ($y_{EL,max}$) bounds of the modulation range were set through Eq. (8). In particular, the parameters $y_{EL,min}$ and $y_{EL,max}$ were defined as a percentage of the electrolyser rated power.

$$y_{EL,min} \cdot S_{EL,aux}(t) \leq P_{EL,in}(t) \leq y_{EL,max} \cdot S_{EL,aux}(t) \tag{8}$$

2.1.5. Storage modelling

Regarding the hydrogen storage, the amount of energy in the storage (E_{HS}, in kWh) can be determined by considering the energy stored in the previous time step, along with the hydrogen charging power ($P_{HS,ch}$, in kW) and the hydrogen discharging power ($P_{HS,dc}$, in kW):

$$E_{HS}(t+1) = E_{HS}(t) + P_{HS,ch}(t) \cdot \Delta t - P_{HS,dc}(t) \cdot \Delta t \tag{9}$$

Similarly, the battery storage behaviour can be expressed as follows:

$$E_{BS}(t+1) = (1-\sigma_{BS}) \cdot E_{BS}(t) + \eta_{BS,ch} \cdot P_{BS,ch}(t) \cdot \Delta t - \frac{P_{BS,dc}(t) \cdot \Delta t}{\eta_{BS,dc}} \tag{10}$$

where E_{BS} (in kWh) is the stored energy, $P_{BS,ch}$ (in kW) is the battery charging power, $P_{BS,dc}$ (in kW) is the battery discharging power, $\eta_{BS,ch}$ is the charging efficiency, $\eta_{BS,dc}$ is the discharging efficiency, and σ_{BS} is the self-discharge coefficient of the battery storage. The latter is defined as the energy losses expressed as a percentage of the stored energy for each time step.

The following constraint was also added to ensure that the stored energy complies with the size constraints (with j = BS, HS):

$$y_{min,j} \cdot S_j \leq E_j(t) \leq y_{max,j} \cdot S_j \tag{11}$$

where $y_{min,j}$ and $y_{max,j}$ represent the minimum and maximum state-of-charge (SOC) of the j-th storage system, respectively.

2.1.6. Objective function

The levelised cost of hydrogen (LCOH) of the PtH system was chosen as objective function of the optimisation problem. It was assessed as follows [19]:

$$c_{H2} = \frac{C_{NPC,tot}}{\sum_{n=1}^{N} \left(M_{H2,n} \cdot (1+d)^{-n}\right)} \tag{12}$$

where c_{H2} (in €/kg) is the LCOH, $C_{NPC,tot}$ (in €) is the net present cost (NPC) of the overall PtH system, $M_{H2,n}$ (in kg) is the hydrogen production during the n-th year, N (in years) is the project lifetime, and d is the discount rate.

The NPC ($C_{NPC,tot}$, in €) was computed according to the following expression (with j = PV, WT, BS, EL, HS) [19]:

$$C_{NPC,tot} = \sum_j \left(C_{capex,j} + \sum_{n=1}^{N} \frac{C_{opex,tot,j,n}}{(1+d)^n} \right) \tag{13}$$

where $C_{capex,j}$ is the investment cost of component j and $C_{opex,tot,j,n}$ is the total operating cost of component j during year n. For each component, $C_{opex,tot,j,n}$ includes both operating and replacement costs, the latter determined based on the component's lifetime.

2.2. Evaluation metrics and input data

Several indicators were introduced to offer general guidelines for designing renewable-based PtH system and assessing its techno-economic performance. These indicators can be grouped into three categories: design, energy and economic. A summary and description of all indicators is provided in Table 1. Additionally, a detailed description and mathematical expressions for their computation are included in the Supplementary Material for clarity.

The average annual capacity factors of PV and onshore WT are shown in Fig. 3. For each European country, they refer to the most representative year, which was computed according to a clustering procedure of country-aggregated CF time series from 2000 to 2019 [38, 40]. Specifically, based on the available data, all EU-27 member states, as well as Norway, the UK and Switzerland were considered in this analysis. The average PV capacity factor spans from 10 % (Finland) to 19 % (Cyprus); whereas a broader range is found for onshore wind farms, from 7 % (Slovenia) to 30 % (Finland).

For the current scenario, the main techno-economic assumptions – including CAPEX, OPEX and technical specifications for all components – were drawn from a previous work by the authors [20]. A future scenario, referring to the year 2050, was also examined, incorporating CAPEX projections and improved electrolyser efficiency. All techno-economic input data are detailed in the Supplementary Material.

Concerning hydrogen production, a 30-bar PEM electrolyser was selected given its high performance and good compatibility with variable renewable energy sources (in terms of dynamic operation). The electrolyser parameters used in this study refer to commercial industrial-scale systems in the MW-range. To accurately simulate the partial-load behaviour of the electrolyser under variable renewable supply, a real efficiency curve – see blue line in Fig. 4 – was considered to relate the hydrogen production to the inlet electrical power as a function of the operating point [20]. For the future scenario, the efficiency curve (green line in Fig. 4) was derived from the current one by assuming a 10 % efficiency improvement across the entire modulation range [41].

At the system level (including both the stack and auxiliaries), the

Table 1
Design, energy and economic indicators employed in the research study. Detailed definitions and equations for each indicator are provided in the Supplementary Material.

Parameter	Description
Design indicators	
PV ratio[a]	Ratio of the PV rated power to the electrolyser rated power.
WT ratio[a]	Ratio of the WT rated power to the electrolyser rated power.
EL ratio	Ratio of the hydrogen production under rated conditions to the average hydrogen demand.
BS autonomy (hours)	Period during which the battery storage can meet the electricity demand of the electrolyser under rated conditions.
HS autonomy (hours)	Period during which the hydrogen storage can meet the average hydrogen demand.
Energy indicators	
RES utilisation (%)	Fraction of RES energy that is used by the electrolyser for hydrogen production (over 1-year time horizon).
EL utilisation (%)	Ratio of actual electrical energy used by the electrolyser to the maximum amount it could utilise (over 1-year time horizon).
Economic indicators	
LCOE (€/MWh)	Net present cost of the electricity production system over its lifetime divided by the discounted total electricity production during the same period.
LCOH (€/kg)	Net present cost of the PtH system over its lifetime divided by the discounted total hydrogen production during the same period.

[a] The term RES ratio is used when referring generally to either the PV ratio or the WT ratio.

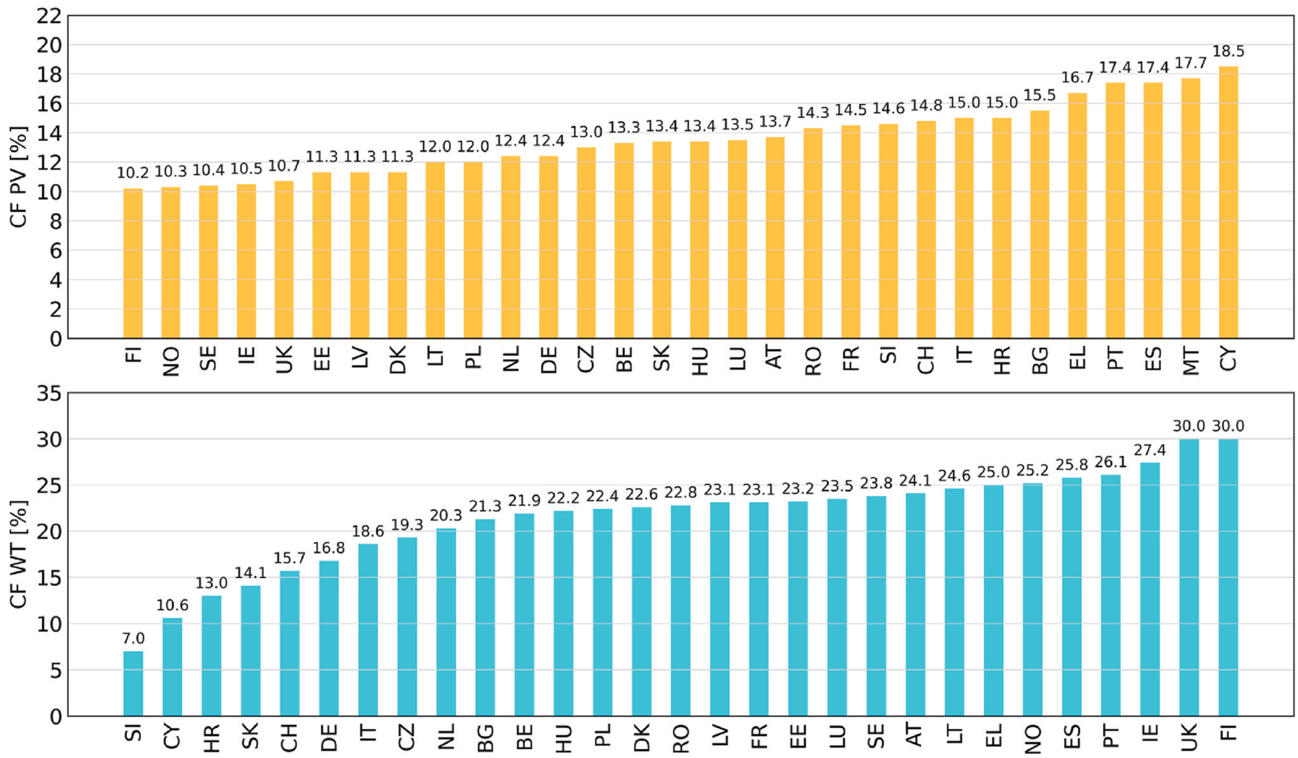

Fig. 3. Average annual capacity factors of PV (orange bars) and onshore WT (light-blue) across different European countries. The average annual capacity factors refer to the most representative year, which was computed according to a clustering procedure of country-aggregated CF time series from 2000 to 2019 (representative year for each country is available in the Supplementary Material).

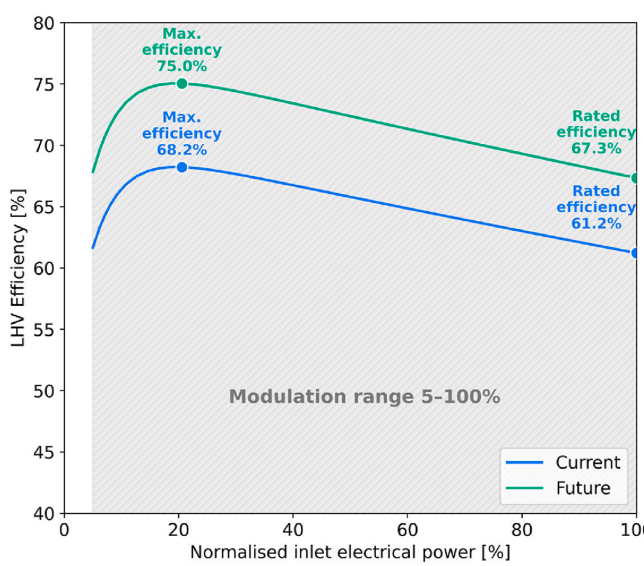

Fig. 4. System-level efficiency of the PEM electrolyser (LHV basis) as a function of normalised input electrical power for the current and future scenarios. Derived from Refs. [20,41].

current efficiency at rated power is 61.2 %, while the maximum efficiency of 68.2 % is achieved at 20 % of the rated power (efficiency values are based on the lower heating value, LHV). In the future scenario, the projected efficiency at rated power increases to 67.3 %, with a peak efficiency of approximately 75.0 %. These curves were incorporated into the MILP-based optimisation framework using the PWA approximation method described in Section 2.1.4. Specifically, both curves were approximated using five breakpoints (resulting in four linear segments), which proved sufficient to achieve a high level of accuracy, with the relative error consistently remaining below 1.5 %.

Finally, as shown in Fig. 4, a minimum modulation threshold was also imposed to prevent operation at very low loads, which could compromise safety and performance.

3. Results and discussion

Based on the identified hourly profiles of PV and WT capacity factors, the optimal design of the power-to-hydrogen system was conducted for 29 European countries, considering a steady hydrogen demand profile over the year. Single-generator configurations (i.e. PV-only and WT-only) are initially examined in Section 3.1, while the potential benefits of hybridising power generation are presented and discussed in Section 3.2. Finally, Section 3.3 provides an analysis of the LCOE and its correlation with the LCOH. While Sections 3.1 to 3.3 focus on the current scenario, Section 3.4 presents an outlook on a long-term scenario, highlighting how future improvements in technology costs and performance may impact the PtH system design and the hydrogen cost.

3.1. Single generator configurations

Fig. 5 presents the main evaluation metrics for PV-only and WT-only configurations as a function of solar and wind capacity factors, respectively.

The RES ratio (Fig. 5a), which indicates the degree of oversizing of the renewable generator relative to the electrolyser, is found to be highly sensitive to the availability of renewable resources, ranging from about 2 to 6 for both PV-only and WT-only systems (with an average value across Europe close to 4).

To meet a given hydrogen demand, a larger electrolyser is generally needed for solar-based configurations compared to wind-based ones. This is reflected in the EL ratio parameter (Fig. 5b), which is in the range of 3.2–4.5 for PV-only systems and drops to 1.5 to 3.0 when considering wind energy. Since the RES ratio is similar for PV-only and WT-only

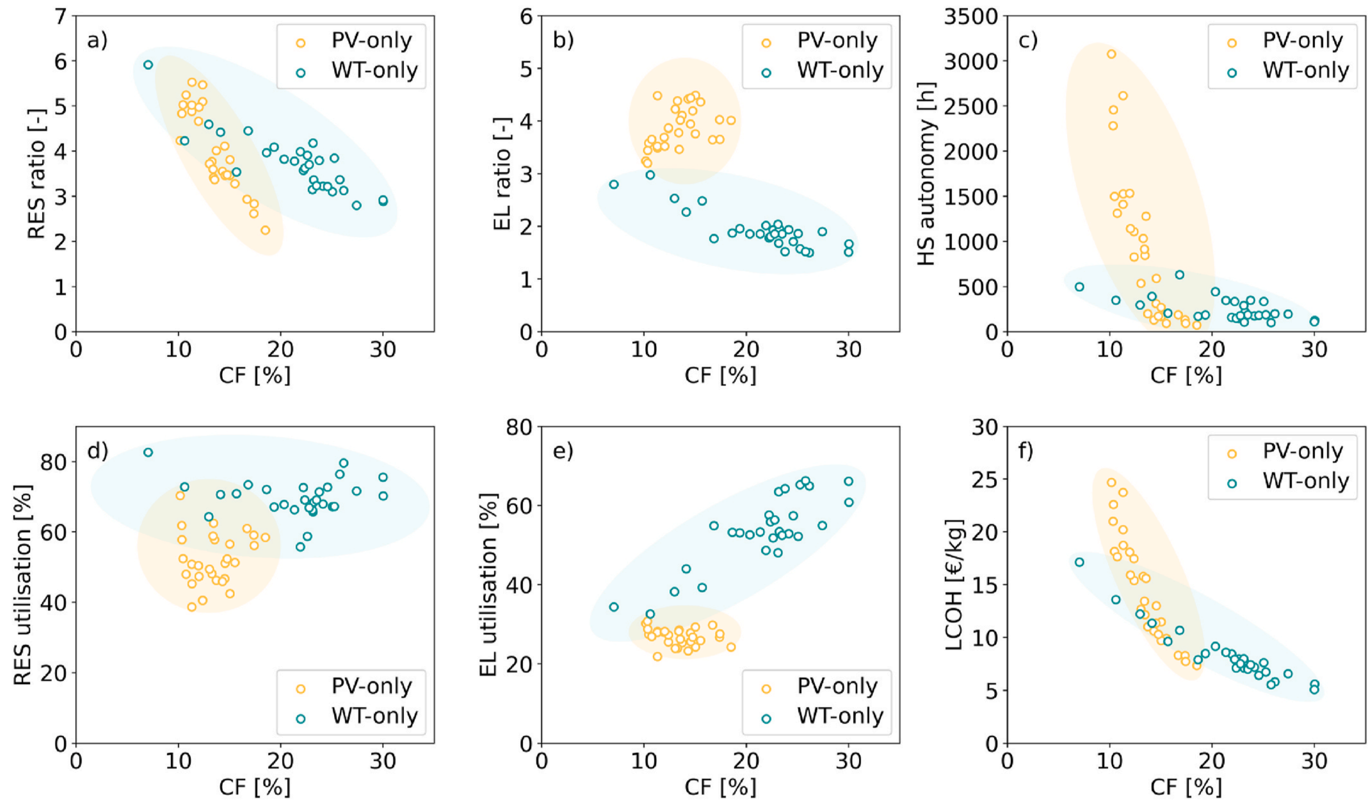

Fig. 5. PV-only and WT-only configurations: Design, energy and economic indicators across different European countries for the current scenario. The indicators are expressed as a function of the average annual PV and WT capacity factors.

systems (Fig. 5a), the higher EL ratio in PV-based layouts also implies a greater need for installed renewable power capacity compared to wind-based systems.

The greater oversizing of solar-powered hydrogen production systems is further evident when analysing the energy indicators, namely RES utilisation (Fig. 5d) and EL utilisation (Fig. 5e). The RES utilisation for solar-based systems ranges from 39 % to 70 % (with an average value of 52 %), whereas for wind-based systems, it increases to 56 %–83 % (with an average value of 70 %). This indicates that wind energy is more effectively exploited, resulting in a lower amount of unconverted surplus electricity. The EL utilisation is also generally higher for WT-only systems, reaching up to 66 %, while PV-based systems exhibit values ranging from only 22 %–31 %. The higher utilisation rate of the electrolyser for WT-only systems is primarily attributed to the lower oversizing of this component (i.e. lower EL ratio).

Moreover, hydrogen storage is also a crucial component for providing flexibility to the system, ensuring the reliability of the hydrogen supply throughout the year. As shown in Fig. 5c, the hydrogen storage autonomy for WT-only systems is always below approximately 630 h. In contrast, the storage capacity increases significantly for solar-based configurations when the PV capacity factor drops below about 13 %, even reaching excessively high values (2500–3000 h) in countries with limited solar resource availability, such as in Finland, Norway and Sweden.

Fig. 5 also shows the resulting LCOH values, which range from 7.4 to 24.7 €/kg for PV-only systems and from 5.1 to 17.1 €/kg for WT-only systems. Overall, the higher capacity factors achievable with wind resources lead to lower hydrogen production costs compared to relying solely on solar resources.

Although battery storage is not excluded from the cost-optimal configurations, its contribution is consistently limited across all countries and scenarios. The battery autonomy remains significantly lower than hydrogen storage autonomy, and always below 20 min (see Supplementary Material for the optimal battery sizes in all countries). This indicates that, in PtH systems, it is more effective to manage the mismatch between intermittent renewable generation and hydrogen demand through chemical storage rather than electrochemical storage. The marginal contribution of batteries to overall system flexibility also results in a negligible impact on the NPC, often falling within the optimisation tolerance of the objective function.

Nevertheless, a consistent trend emerges: configurations based on photovoltaic generation tend to exhibit slightly higher battery autonomy than wind-based ones – typically in the range of 3–16 min for PV-only systems versus 0–11 min for WT-only systems – due to the more unstable day-night production profile of solar irradiance compared to wind availability. This confirms that batteries, while not economically pivotal in this context, may offer limited short-term buffering benefits, particularly in solar-powered systems. This finding aligns with previous studies in the literature, which suggest that the current specific CAPEX of batteries renders them economically unviable – compared to hydrogen storage – for providing flexibility to PtH systems [18,19]. It is also important to highlight that the current economic drawback of batteries is primarily associated with power-to-hydrogen systems, where hydrogen constitutes the main load to be covered. In contrast, batteries, owing to their high round-trip efficiency, play a crucial role in renewable energy systems primarily designed to meet electrical loads [42].

The spatial distribution of the average annual PV capacity factor across Europe is shown in Fig. 6, along with the corresponding LCOH for PV-only systems. It is evident that, as latitude increases, the PV capacity factor decreases, reaching values close to 10 % in Northern Europe. As the solar resource becomes more limited, the cost of hydrogen production rises sharply, exceeding 21 €/kg in Finland, Norway and Sweden. Conversely, in Southern Europe, where the PV capacity factor approaches 18 %, the LCOH drops to around 8 €/kg, as observed in Spain, Portugal and Greece.

Similarly, results for WT-only configurations are displayed in Fig. 7.

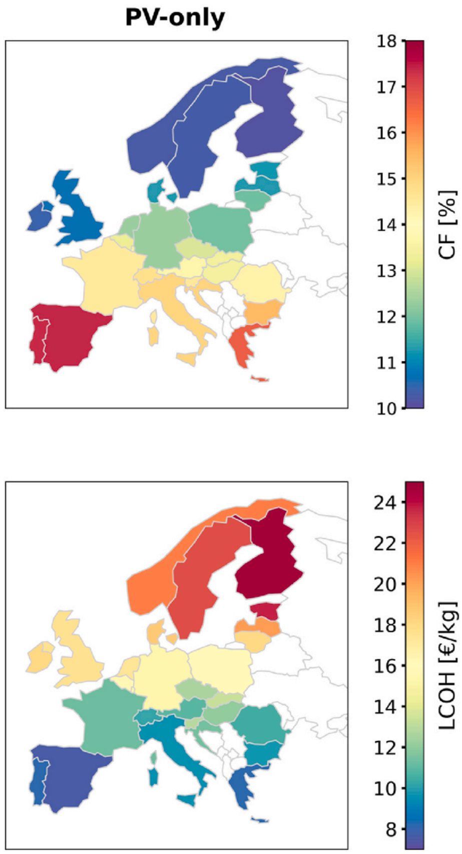

Fig. 6. PV-only configurations: average annual capacity factor (CF) and levelised cost of hydrogen (LCOH) for the current scenario.

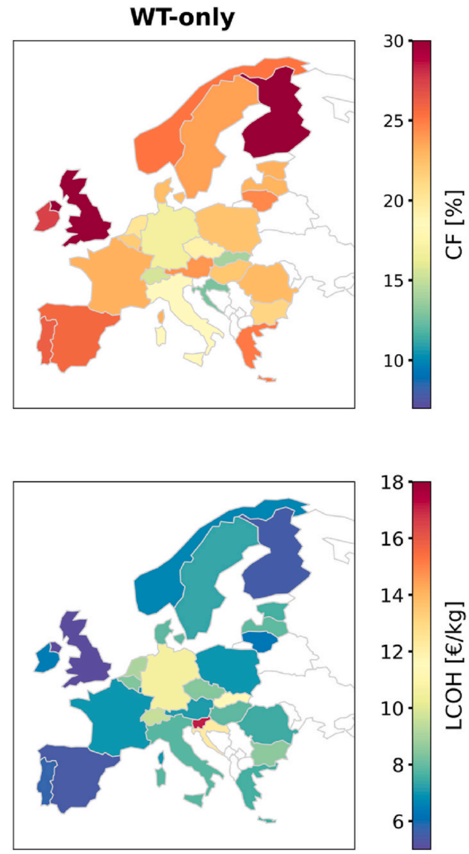

Fig. 7. WT-only configurations: average annual capacity factor (CF) and levelised cost of hydrogen (LCOH) for the current scenario.

Looking at the WT capacity factors, it can be noted that there is no longer a marked dependence on latitude as observed in the PV case; instead, the wind resource is distributed more uniformly across Europe. The average annual WT capacity factor is up to 30 % in Finland and United Kingdom, where LCOH values close to approximately 5 €/kg can be achieved. In general, as for PV-only systems, a good correlation exists between the average annual CF and the resulting cost of hydrogen production, as also previously displayed in Fig. 5f.

3.2. Hybrid configuration

The impact of hybridising the power production is shown in Fig. 8, where design and energy indicators are reported for the hybrid configurations and compared with results of single-generator layouts. Specifically, results are displayed at European level in the form of box-and-whisker plots, also including mean values and eventual outliers. It can be observed that the PV ratio decreases significantly when moving from PV-only to hybrid solutions, with the mean value that drops from approximately 4.0 to 1.6 (Fig. 8a). Analogously, as illustrated in Fig. 8b, the average WT ratio reduces from 3.7 to 2.2.

It is worth noting that the integration of wind turbines in power-to-hydrogen systems (both WT-only and hybrid scenarios) is highly effective in keeping low the oversizing of the electrolyser (see Fig. 8c): the average EL ratio is 3.9 for PV-only systems and drops to 1.9 for WT-only systems and 1.8 for hybrid systems. Relying on wind power is also crucial to significantly reduce the autonomy required for hydrogen storage. Indeed, the average HS autonomy reduces by almost 4 times when shifting from PV-only to WT-only configurations and by more than 6 times when considering a hybrid solar-wind layout.

Hybrid configurations also lead to a better exploitation of the local renewable resources, as shown in Fig. 8e, where the average RES utilisation increases from 52 % for systems relying solely on PV to 70 % for systems powered exclusively by wind energy, reaching up to 83 % for hybrid systems. Finally, the use of wind turbines positively impacts the EL utilisation indicator, which approximately doubles when moving from a PV-only configuration to a WT-only configuration. Only minor improvements in the EL utilisation (+6 % based on average values) are observed in hybrid layouts with respects to WT-only systems.

The above-mentioned technical benefits of hybrid layouts also reflect in lower hydrogen production costs. The LCOH for PV-only systems spans over a wide range, with an average European value of 14.6 €/kg. Lower LCOH values are observed for wind-only systems, where the average cost drops to approximately 8.3 €/kg. The lowest costs are found in solutions that leverage both wind and solar resources, with an average LCOH of 6.2 €/kg.

Fig. 9 shows the LCOH breakdown among its main cost components: renewable generators, electrolyser, hydrogen storage and battery storage. The results are presented for the three PtH configurations under analysis (PV-only, WT-only and hybrid) and across the various European countries. In the PV-only scenario, it is noteworthy that, as the analysis shifts to countries with lower solar resource availability, the hydrogen production cost increases sharply, primarily driven by a significant rise in the contribution associated with the hydrogen storage system. Specifically, in regions where the average PV capacity factor falls below approximately 13 %, large-scale hydrogen storage systems (providing approximately 500–3000 h of autonomy) become necessary. This not only substantially raises the final cost of hydrogen but also presents considerable technical challenges. For instance, in areas with limited availability of solar resource – such as Norway, Sweden, Estonia and Finland – over half of the LCOH of PV-only systems would be attributed to the hydrogen storage component.

Despite the higher specific cost of wind turbines (1120 €/kW)

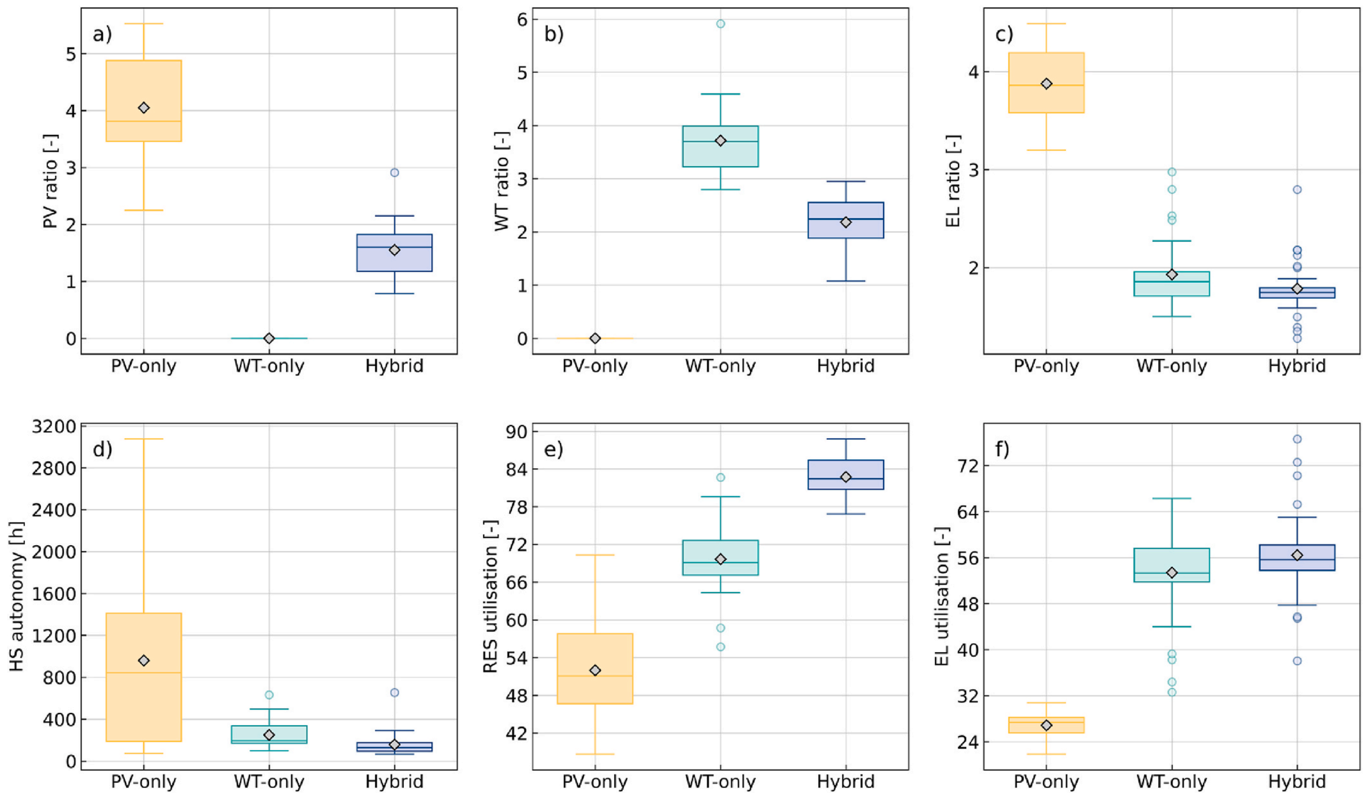

Fig. 8. Comparative assessment of design and energy indicators for the three plant configurations (PV-only, WT-only and hybrid) across different European countries, for the current scenario. Grey diamond markers indicate average European values.

compared to PV (650 €/kW), the LCOH for WT-only systems is lower than that of PV-only systems (expect in Croatia, Cyprus, Slovenia). This is because WT-only configurations generally require less oversizing of renewable generators, electrolysers and hydrogen storage, while also enabling more efficient utilisation of local renewable resources. As evident in Fig. 9, this mainly results in a reduced cost contribution from the electrolyser (green area) and, most notably, from hydrogen storage (pink area). The latter, in particular, remains relatively low across all the countries analysed. Although a life cycle assessment (LCA) is beyond the scope of this work, it is worth noting that wind power, in addition to delivering lower LCOH than solar-based PtH systems, is also associated with lower life-cycle CO_2-equivalent emissions compared to photovoltaic systems. Specifically, wind turbines exhibit emissions in the range of approximately 7–38 g CO_2-eq/kWh, while PV systems, depending on factors such as silicon processing and energy mix, range between 28 and 100 gCO_2-eq/kWh [43].

Finally, hybridising renewable production proves to be highly effective in further limiting oversizing and enhancing the utilisation of local renewable energy sources. Moreover, it significantly reduces hydrogen production costs and smoothens geographical disparities. On average, the hybrid solution reduces the LCOH by 57 % compared to the PV-only configuration and by 25 % compared to the WT-only configuration. Notably, the variability in LCOH across European countries is substantial for PV-only systems, ranging from 7.4 €/kg (Cyprus) to 24.7 €/kg (Finland). This variability is partially reduced in WT-only systems, where the LCOH spans from 5.1 €/kg (United Kingdom) to 17.1 €/kg (Slovenia). Hybrid solutions achieve the lowest variability, with LCOH values ranging from 4.7 €/kg (United Kingdom) to 11.8 €/kg (Slovenia). Even in countries with limited solar or wind resources, optimally designed hybrid systems thus enable more stable and affordable hydrogen production costs across Europe.

In summary, a hybrid PV-wind layout is the optimal choice for green hydrogen production throughout European countries. Where hybrid systems are not feasible, wind-only systems emerge as the next best option, except in Croatia, Cyprus and Slovenia. Solar-only systems are typically the most expensive solution. However, in Bulgaria, Greece, Slovakia and Switzerland, the cost difference between wind-only and solar-only systems is relatively modest, at less than 15 %.

Fig. 10 illustrates the LCOH for the hybrid PtH scenario across various European countries, plotted against the PV capacity factor (horizontal axis) and the WT capacity factor (vertical axis). Larger bubbles, coloured closer to yellow, represent higher LCOH values. It is interesting to note that all the smaller bubbles (i.e. countries with the lowest LCOH values) are positioned in the upper section of the graph, regardless of the PV capacity factor. This suggests that wind resource availability has a greater impact on the optimal sizing of hydrogen production systems than solar resource availability. In particular, the lowest LCOH values are observed in locations where the wind capacity factor exceeds approximately 22 %, regardless on the solar capacity factor.

3.3. Electricity and hydrogen price correlation

The analysis of the relationship between the cost of hydrogen production (LCOH) and the cost of electricity generation (LCOE) is essential for evaluating alternative renewable energy system layouts for hydrogen production. Fig. 11 illustrates this correlation for the three investigated configurations (PV-only, WT-only, and hybrid systems). The scatter plot

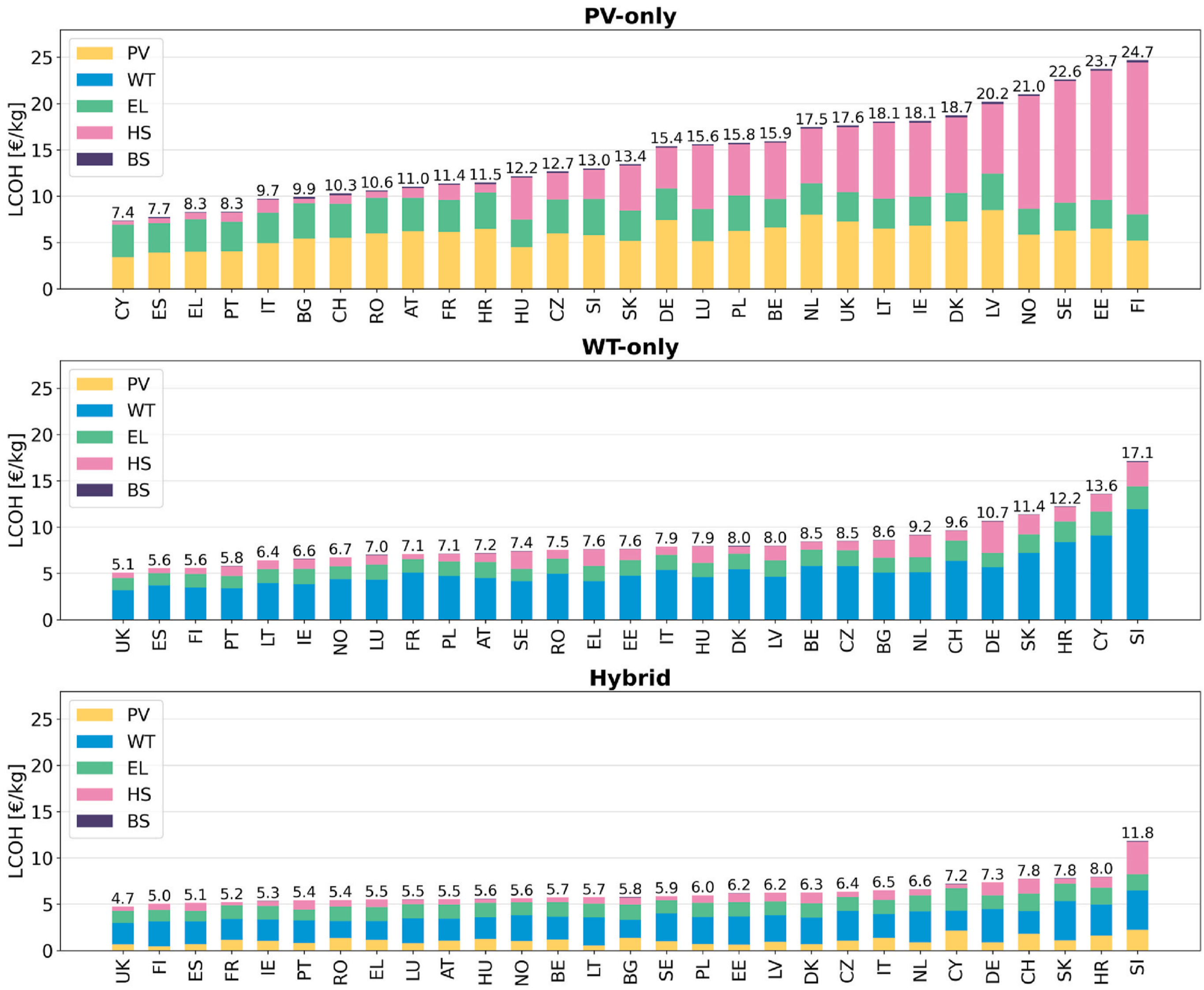

Fig. 9. Breakdown of the levelised cost of hydrogen (LCOH) by plant component (PV, WT, EL, HS and BS). The breakdown is presented for the three plant configurations under analysis (PV-only, WT-only and hybrid) across different European countries, for the current scenario.

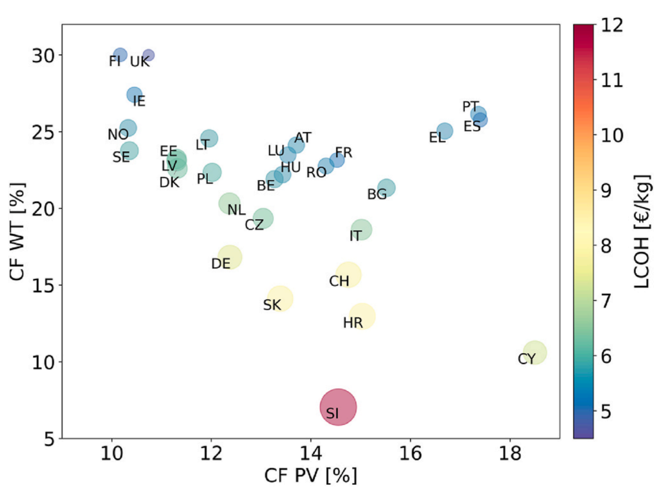

Fig. 10. Levelised cost of hydrogen (LCOH) as a function of the average annual PV and WT capacity factors in the hybrid configuration across different European countries, for the current scenario.

focuses on the LCOE range of 30–100 €/MWh, while higher values (observed in WT-only scenarios, e.g. Cyprus, Croatia, and Slovenia) are excluded to centre the analysis on the primary trends. These outliers, however, are included into the trendlines calculation for accuracy.

The graph reveals that a lower LCOE does not always correspond to a lower LCOH. For instance, PV-only systems, despite having a relatively low LCOE (ranging from 38 to 68 €/MWh range, with an average of 53 €/MWh), yield the highest LCOH. This is due to the low PV capacity factor and the necessity to oversize the PtH system to reliably meet the hydrogen demand. In contrast, WT-only systems show the highest LCOE values (ranging from 44 to 188 €/MWh range, with an average of 68 €/MWh) but result in a lower LCOH because of the higher wind capacity factor and reduced oversizing requirements. Hybrid systems exhibit an LCOE in the range of 46–94 €/MWh (59 €/MWh average value) and the lowest LCOH among the three configurations. These findings underscore the influence of renewable resource availability (capacity factors) and system sizing on the interplay between LCOE and LCOH.

The trendlines in Fig. 11 further highlight the linear relationship between LCOH and LCOE, with their slopes reflecting the sensitivity of hydrogen production costs to electricity prices. Solar-only systems display the steepest trendline and the highest LCOH, demonstrating their greater dependence on electricity costs. Conversely, wind-only and

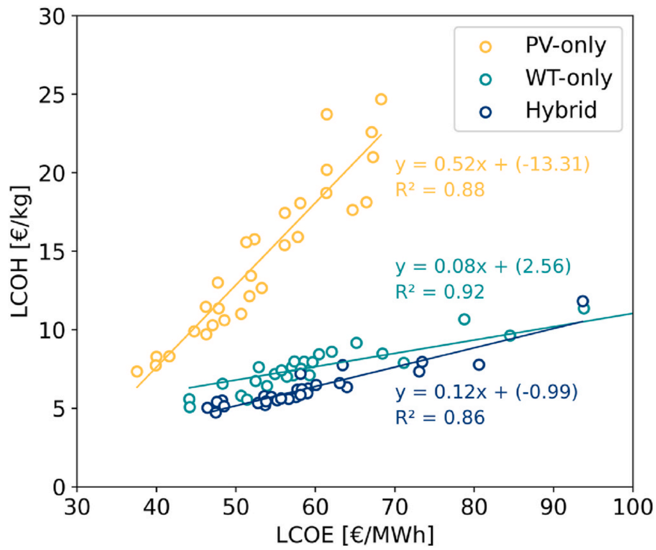

Fig. 11. Relationship between the levelised cost of hydrogen (LCOH) and the levelised cost of electricity (LCOE) for the three plant configurations (PV-only, WT-only, and hybrid) across different European countries, for the current scenario.

hybrid systems show lower and more stable LCOH values, emphasizing their advantage in minimising cost variability and ensuring reliable hydrogen production. The trendlines provide a practical tool for estimating the LCOH for specific LCOE values across the three plant layouts, facilitating decision-making in hydrogen system design.

3.4. Future scenario

To provide insights into the long-term potential of renewable-based hydrogen production systems, a future scenario is considered (Fig. 12). This scenario assumes a reduction in the capital costs of key components (PV, WT, battery and electrolysers), and an improved system-level electrolyser efficiency (see Section 2.2 and Supplementary Material). These assumptions are based on expected technology learning curves and international projections.

Fig. 12 illustrates the resulting LCOH values across Europe for all three PtH configurations under both current and future scenarios (technical and energy indicators for the future scenario are reported in the Supplementary Material). The future scenario results in a significant reduction in hydrogen production costs, ranging from 31 % to 48 % depending on the configuration.

In particular, PV-only systems benefit the most, with LCOH decreasing by 48 % on average across Europe (from 14.6 to 7.6 €/kg), primarily due to the projected decline in the specific CAPEX of PV (from 650 to 350 €/kW) and electrolyser systems (from 1188 to 314 €/kW). Notably, the expected drop in electrolyser CAPEX allows for greater oversizing, with the EL ratio increasing on average from 3.9 to 5.0. The average PV ratio remains relatively stable at around 4.0, implying that the absolute installed PV capacity is increased relative to the current scenario, to match the higher electrolyser size. This combined oversizing of both the renewable generator and the electrolyser leads to a substantial decrease in hydrogen storage requirements, with average HS autonomy reduced from 959 to 414 h. However, as a consequence of this oversizing, the average utilisation rates of both the electrolyser and the PV system decrease by approximately 20 %.

The results differ for the WT-only configurations. According to literature projections, the anticipated cost reduction for wind turbines is less pronounced compared to PV systems (with specific CAPEX decreasing from 1120 to 960 €/kW). This limited cost variation translates into smaller changes in the associated design, energy and economic indicators. Similar to the PV scenario, lower specific costs for the electrolyser lead to a higher degree of electrolyser oversizing, with the average EL ratio increasing from 1.9 to 2.2. The average WT ratio experiences a decrease of approximately 20 % on average, accompanied by a slight reduction in the average hydrogen storage autonomy (−12 %). Consequently, the resulting average LCOH across Europe declines by 31 % relative to the current scenario (from 8.3 to 5.8 €/kg), remaining lower and thus more competitive compared to the PV-only configuration.

Finally, the hybrid configuration continues to offer the most cost-effective solution for hydrogen production, also in the future scenario. Hybridising renewable energy supply remains the economically optimal choice, although the average RES ratio shifts slightly from 1.6 to 1.7 (PV ratio) and from 2.2 to 1.3 (WT ratio) when moving from the current to the future scenario. This variation is primarily due to the more significant projected CAPEX decrease for photovoltaic systems compared to wind turbines. Moreover, electrolyser oversizing is confirmed also in this configuration, with the EL ratio rising on average from 1.8 in the current scenario to 2.4 in the future scenario (consequently resulting in lower electrolyser utilisation). Hydrogen storage autonomy also decreases (by an average of 37 %). Overall, the average LCOH in the hybrid future scenarios decreases by 43 %, dropping from 6.2 to 3.6 €/kg. Specifically, the LCOH values for hybrid configurations in the future scenario span from below 3 €/kg (in Cyprus, France, Greece, Portugal, Romania, Spain and UK) to slightly above 5 €/kg (only in Slovenia). This narrower range demonstrates that, due to hybridisation and projected cost reductions, nearly all European countries will be capable of producing renewable hydrogen at costs below 5 €/kg, with many achieving values even below 3–4 €/kg.

In general, the decrease in technology costs and performance improvement in the future scenario also leads to a clear reduction in the variability of LCOH across Europe, as illustrated by the narrower interquartile range and shorter whiskers in the boxplot of Fig. 12. The reduced variability is also visually confirmed by the more uniform colour distribution in the hybrid future scenario map.

Despite a reduction in the specific CAPEX of battery storage from 306 €/kWh to 131 €/kWh, it remains consistently marginal in the future scenario for all the three configurations (PV-only, WT-only and hybrid). Batteries continue to exhibit limited storage autonomy (always below 20 min) and negligible economic impact, always within the optimisation tolerance (MIP gap) of the objective function. Therefore, conclusions drawn regarding battery storage in the current scenario remain valid in the long-term perspective for power-to-hydrogen applications.

4. Conclusions

This study investigates the impact of renewable energy sources on the optimal design of hydrogen production systems under both current and future scenarios. The analysis focused on a generic PtH system consisting of renewable generators, a battery, an electrolyser and hydrogen storage. The system was designed to meet a steady hydrogen demand over time, representative of typical industrial applications – such as refineries, the chemical industry, and steelmaking – where hydrogen is already widely used or is expected to play a key role in the near future. Different power-to-hydrogen systems were explored by varying the type of renewable generators: PV-only, WT-only and hybrid (combining both PV and WT).

An optimisation framework was developed to determine the cost-optimal configuration of PtH systems for 29 European countries, based on local solar and wind availability. To ensure robust and representative results for each European country, a clustering procedure was implemented to identify the most representative year from a multi-year time series. The sizes of the components and their operation over time were treated as decision variables, with the goal of minimising the hydrogen production cost (LCOH). Additionally, to generalise the findings beyond specific applications, a set of performance metrics was introduced. The

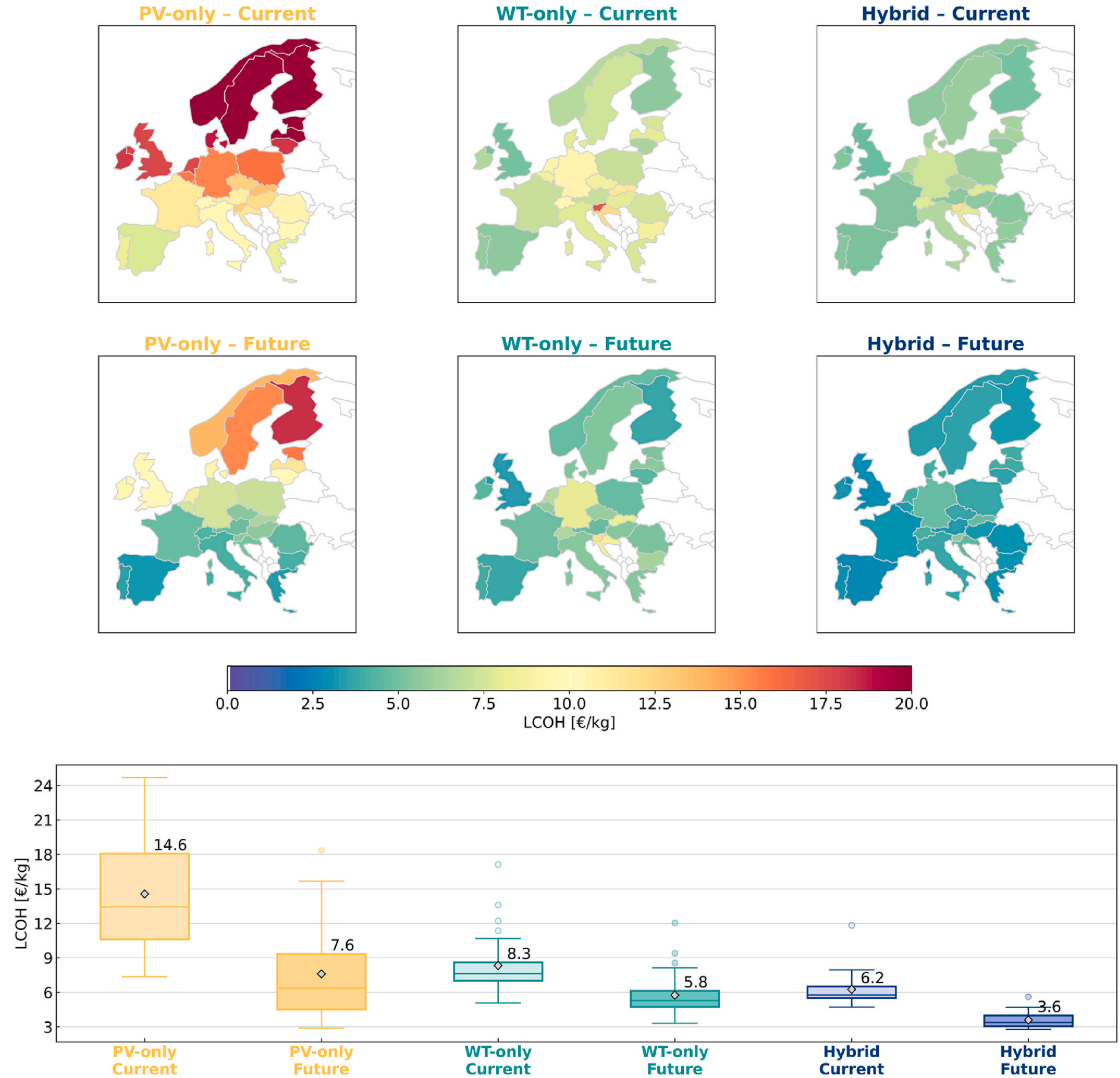

Fig. 12. Levelised cost of hydrogen (LCOH) for the three plant configurations (PV-only, WT-only and hybrid) across different European countries, for the current and future scenarios. Grey diamond markers in the box plots indicate average European values.

metrics provide a framework to understand the optimal design, energy use, and economic performance of PtH systems, making results accessible and broadly applicable.

The results of the current scenario show that the LCOH varies significantly across Europe and depends heavily on the system configuration. In solar-only systems (7.4–24.7 €/kg), hydrogen storage emerges as a significant cost contributor (exceeding 30 % and up to 67 % of the LCOH) when the average annual PV capacity factor falls below approximately 13 % (as observed in about half of the European countries). The optimal configuration for such systems requires substantial oversizing of the electrolyser, with a rated hydrogen output 3.2 to 4.5 times the hydrogen demand, and storage autonomy of up to 3000 h. In contrast, wind-only layouts typically require less oversizing of the renewable generators, electrolyser and especially hydrogen storage, leading to lower LCOH values (5.1–17.1 €/kg). The electrolyser ratio is reduced to between 1.5 and 3, and hydrogen storage autonomy stays below 650 h. Hybrid configurations, relaying on both solar and wind energy, prove to be the most cost-effective solution for producing green hydrogen across Europe, with LCOH ranging from 4.7 to 11.8 €/kg. On average, hybrid solutions reduce the LCOH by 57 % compared to the solar-only configuration and by 25 % compared to the wind-only configuration, smoothing out differences in LCOH across various geographical areas.

The assessment also establishes correlations between the LCOE and the LCOH, revealing that a lower LCOE (as observed in solar-only systems) does not necessarily translate in a lower LCOH. This is due to the variability in renewable resource availability (i.e. capacity factor), which may necessitate significant system oversizing to meet the hydrogen demand, thereby driving up hydrogen production costs.

Finally, to assess long-term perspectives, a future scenario was introduced based on projected reductions in capital expenditures for the system components and improvements in electrolyser performance. The results show that average LCOH can be further reduced by 31–48 % (compared to the current scenario) depending on the configuration, with average costs falling to 7.6 €/kg for PV-only, 5.8 €/kg for WT-only, and as low as 3.6 €/kg for hybrid systems. Importantly, the future scenario also leads to a significant reduction in the variability of LCOH across Europe, making hydrogen production more competitive and geographically balanced. In particular, hybrid configurations enable nearly all countries to reach LCOH values below 5 €/kg, and many below 4 or even 3 €/kg.

Future works will extend the analysis in the following directions: (i) investigating various hydrogen demand profiles representative of different end-use sectors, including potential long-term applications beyond industry; (ii) including additional power-to-X pathways, such as synthetic fuels (e.g., ammonia and methanol); and (iii) evaluating environmental impacts through life-cycle assessment indicators.

CRediT authorship contribution statement

Paolo Marocco: Writing – review & editing, Writing – original draft, Visualization, Validation, Software, Resources, Project administration, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **Marta Gandiglio:** Writing – review & editing, Visualization, Validation, Resources, Project administration, Investigation, Formal analysis, Conceptualization. **Massimo Santarelli:** Writing – review & editing, Funding acquisition.

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.

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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.2025.124542.

Acronyms

BOP	Balance of plant
BS	Battery storage
CAPEX	Capital expenditure
CF	Capacity factor
EL	Electrolyser
EU	European Union
HS	Hydrogen storage
LCOE	Levelised cost of electricity
LCOH	Levelised cost of hydrogen
LHV	Lower heating value
MILP	Mixed integer linear programming
NPC	Net present cost
OPEX	Operational expenditure
PEM	Proton exchange membrane
PtH	Power-to-Hydrogen
PV	Photovoltaic
PWA	Piecewise affine
RES	Renewable energy sources
SOC	State-of-charge
WT	Wind turbine

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