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Carbon abatement cost evolution in the forthcoming hydrogen valleys by following different hydrogen pathways

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ABSTRACT

The need to develop a forthcoming hydrogen economy emphasises the emerging concept of 'hydrogen valleys', where hydrogen production and consumption are being developed. This study assesses the Levelized Cost of Hydrogen (LCOH) and Carbon Abatement Cost (CAC) for various hydrogen end-use applications within the context of a hydrogen valley located in the southern Italy over different time horizons (Today 2023, Mid-Term 2030, Long-Term 2050). Examined applications include blending into the gas grid, reconversion into electricity for grid balancing by means of fuel cells, hydrogen refuelling stations for fuel cell electric vehicles (FCEVs), synthetic methane production, and electro-fuel synthesis. Employing a parametric approach, the study compares LCOH and decarbonisation costs across different pathways. Results indicate current LCOH production values of 3.66–4.90 €/kg_{H2}, projected to decrease to 1.41–1.94 €/kg_{H2} by 2050. Decarbonisation cost analysis identifies blending and FCEV scenarios as the most cost-effective, contrasting with Power-to-Power scenarios, particularly in the mid and long terms.

1. Introduction

The transition towards a more sustainable energy system is essential to reduce greenhouse gas emissions and mitigate climate change, representing the main transformation that societies will have to face in the coming decades [1]. This transition is not limited only to the substitution of fossil energy sources with renewable sources, but also requires a radical change in the structure and functioning of energy systems [2]. All energy-consuming sectors such as industry, transport, and buildings, have to contribute to accomplish those ambitious goals.

Achieving carbon neutrality by 2050 is a very challenging targets, especially for the energy-intensive industrial and the heavy transport sectors, i.e., the so-called hard-to-abate sectors, which annually are responsible for the emission in the atmosphere of about 10 Gton of CO_2, equal to 30% of total emissions [3].

The decarbonisation of hard-to-abate sectors can only be pursued by a diversified approach. Recognition of the imperative for the economy to progressively embrace new paradigms, namely, circular economy, energy efficiency, use of green fuels (i.e., hydrogen and biomethane), and electrification represent a set of solutions that can significantly reduce emissions in energy-intensive industrial sectors if implemented together [4].

Green hydrogen, i.e., the hydrogen produced from renewable sources, is essential on the path to a net-zero greenhouse gas emission future [5]. Specific actions are needed to satisfy the long-term hydrogen roadmap designed by the European Commission [6].

The Italian strategy, in line with the EU one, aims at increasing investments for the production and use of hydrogen, with a twofold horizon. In the short-term (2030), the goal is to make green hydrogen progressively competitive in specific industrial sectors, laying the foundations for a national ecosystem based on this energy vector. In the long-term (2050), on the other hand, the goal is to help the decarbonisation of hard-to-abate sectors by means of green hydrogen. The green hydrogen demand is expected to be approximately 0.7 Mt/year by 2030, requiring the installation of 5 GW of electrolysers by the end of the decade [7].

Green hydrogen plays a pivotal role in the energy system due to its adaptability and compatibility with renewable energy sources (RES) and other green technologies [8]. It enables the carbon abatement of energy-intensive sectors where electrification is not feasible, such as heavy industry, long-distance and heavy goods transport, non-electrified rail transport, and the residential sector as well [9]. By using hydrogen's flexibility along with competitive transport and storage capabilities, the decarbonisation process can be accelerated in those sectors [10].

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Table 1
LCOH value in several EU countries for 2023, 2030 and 2050.

Country	LCOH production range in EUR/kg H_2 – PEM electrolyser and RES power supply			Sources
	Today 2023	Mid Term 2030	Long Term 2050	
England	3.83–6.10	2.98–4.40	2.43–4.23	[45]
France	3.04–5.44	2.52–4.18	2.27–3.56	[46]
Germany	4.50–5.20	3.01–5.50	2.37–3.62	[46–48]
Italy	3.11–7.77	3.60–3.86	2.32–4.91	[2,44,46]
Netherland	2.61–6.10	2.17–4.73	1.95–4.05	[38,46]
Poland	6.37–13.48	2.33–4.30	1.23–2.03	[49]
Portugal	2.84–5.13	2.35–4.19	2.11–3.84	[50]
Spain	2.78–5.38	2.31–4.40	2.07–4.04	[33,46]

Additionally, hydrogen contributes to the stability and flexibility of the electrical energy system by power-to-gas (PtG) technologies [11]. By injecting the green hydrogen, originated from the renewable energy excess exploitation, into the natural gas (NG) pipelines, it contributes to mitigate the balancing issues and it supports the so called sector coupling between the NG and the electricity ones [12]. That enables the mutual connection of both production and demand sites over long distances, reducing supply costs and ensuring service reliability and continuity [13].

Hydrogen, as an energy carrier, facilitates the fossil fuels replacement with renewable energy sources in various sectors, including power generation, industry, transport, and heating [14]. Water electrolysis processes play a fundamental role in storing large amounts of energy for a long time, favouring the integration of intermittent RES, namely, solar photovoltaics (PV) and wind farms (WF), into the power generation system [15].

Moreover, hydrogen can be converted into other energy carriers, such as methane [16] by biological or thermochemical processes known as "Power-to-Methane" (PtM) technologies [17]. Both hydrogen and methane can be finally injected into existing natural gas pipelines.

Green hydrogen also offers a sustainable alternative to traditional fossil fuels in energy-intensive and hard-to-decarbonise sectors, including heavy transport (trucks, trains, ships) [18,19] and production processes (steel, glass, ceramic sectors) [20]. Its utilisation in those sectors helps to reduce emissions and mitigates the environmental impact associated with fossil fuel use.

Overall, green hydrogen provides significant benefits to the energy systems by lessening their environmental impact, enabling long-term energy storage, supporting renewable energy integration, and offering sustainable alternatives in challenging sectors [21].

The impacts of air pollution on health and living conditions in densely populated areas, ongoing natural disasters due to evident climate changes, inefficient waste management, and global pollution at large have transcended concern solely within scientific circles; those issues now preoccupy the entire world. Consequently, the stage is set for governments and investors to take action by increasing investments in green technologies. Currently, the forefront in hydrogen utilisation includes countries such as Japan, Germany, and the USA. Those nations were among the first to recognise the importance of addressing environmental concerns not only as a necessity but also as an economic opportunity [22].

However, several barriers still hinder green hydrogen potential in Italy [23]. Barriers such as: i) investment and operative costs, ii) hydrogen transport and distribution, iii) permit procedures, iv) safety and social concerns are complex to be managed by single companies.

As established by earlier studies, hydrogen technology has generally garnered a positive perception among the public. Nevertheless, the current findings indicate a notable decline in acceptance, particularly concerning large-scale infrastructure [24].

Therefore, the constitution of green hydrogen clusters, the so-called "Hydrogen Valleys", is crucial to stimulate in the early phase, synergies and collaboration of more actors involved in green hydrogen production and consumption, within a specific geographical area.

Hydrogen Valleys consist of integrated ecosystems, based on a combination of several hydrogen technologies covering the entire hydrogen value chain: production, storage, distribution, and final uses [25]. They represent the first step towards the development of a large-scale hydrogen economy.

The Hydrogen Valley concept was introduced only a few years ago. So, a small number of projects is ongoing, as reported by the Hydrogen Valley Platform, which is a freely accessible database that collects information and data regarding existing projects [26].

The optimal design of a hydrogen valley depends on the RES systems typology and the production profile, on the hydrogen final use, the end-users' needs, as well as on the selected objective function (minimum hydrogen production cost, maximum RES electricity use, etc.). Different solutions for green H_2 production systems are being studied and discussed in literature [27] and tested in different European countries [28]. Those integrated hydrogen-based ecosystems are therefore very interesting solutions to face the environmental problems associated to fossil fuels.

Finally, it is expected that in the next years, the hydrogen production costs will decrease reaching competitiveness, due to the development of more efficient generation technologies and the increasing availability of electric energy from RES.

The priority is to introduce an international hydrogen market. This market structure would facilitate the hydrogen production in all those countries or regions with favourable climate conditions for renewable electricity generation, thereby achieving the lowest production costs [29].

Hydrogen Valleys have the potential to be considered as an effective model for the large-scale deployment of hydrogen technologies to promote the transition towards a realistic hydrogen economy. It can be considered as a necessary step to support the energy transition and achieve a widespread integration across various energy sectors [30]. For the optimal development of those plants, technical and economic planning is strongly required.

One of the main parameters to assess the competitiveness of hydrogen-based scenarios is the Levelized Cost of Hydrogen (LCOH). It represents a measure of the average cost to produce one unit of hydrogen over the plant lifetime. It is calculated by considering the total project costs divided by the total amount of produced hydrogen.

It is a parameter widely used in the literature for various analysis. For instance, Khouya A. used that indicator as an optimisation parameter for the sizing process of hybrid systems producing hydrogen from renewables [31], while Di Micco et al. used it as one of the main parameters of technical-economic analysis for several Renewable Multi-Energy Systems (MESs) scenarios [32].

Otherwise Maestre et al. used the LCOH to compare different decarbonisation scenarios associated to the transport sector in Spain [33]; alternatively, it can also be used to compare the global costs related to the electrolysis-based hydrogen supply systems, either centralised, or decentralised for heavy road transportation [34]; finally, to check the technical economic viability of refuelling stations with on-site hydrogen production [35].

It can be an important parameter for analysing the costs of using hydrogen in scenarios such as power-to-gas [27]. For instance, Pastore et al. used it to analyse power-to-gas in Renewable Energy Communities (RECs) [36], while Gerloff N. analysed it for the German scenario [37]. It can be also applied as a meaningful parameter for the cost evaluation of an integrated ammonia production system from green hydrogen [38].

However, it is not an indicator exclusively related to hydrogen production phase, but it can also provide insight into additional aspects correlated to the supply chain, such as transport and storage.

For example, Lahnaoui et al. uses the LCOH for the cost-optimisation analysis of transporting H_2 via trucks/trailers [39]; Whilst Papadias et al. and Cui et al. analysed various transport scenarios via liquid H_2

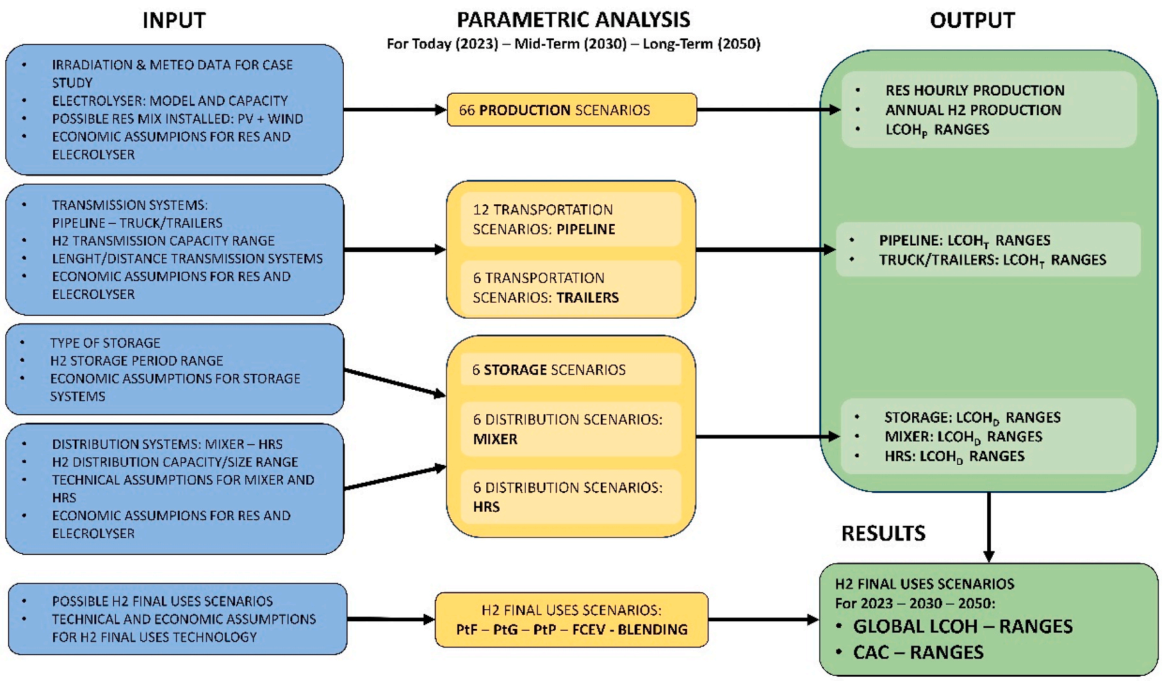

Fig. 1. Methodology workflow.

carriers such as methanol, ammonia and toluene [40,41]. Danebergs et al. used LCOH to evaluate if metal hydride hydrogen storage tanks are a competitive alternative for onboard hydrogen storage in the maritime sector compared to other solutions [42]. Salmachi et al. applied it as the main parameter in a technical-economic analysis for large-scale underground hydrogen storage in depleted gas reservoirs in Australia [43].

Therefore, it can be generally exploited to assess the optimisation of the whole hydrogen value chain [44].

In Table 1 a literature analysis of LCOH values in renewable production scenarios for several different regions and time periods has been reported.

1.1. Scope of the article

The purpose of this work is to evaluate the Levelized Cost of Hydrogen (LCOH) and the Carbon Abatement Cost (CAC) of different hydrogen end-use applications in the context of hydrogen valleys. This paper aims at estimating the LCOH in all of the different value-chain phases: production, transportation, distribution and end-uses in order to find the total hydrogen and decarbonisation cost. In order to complete this analysis, the following applications have been considered: power-to-fuel, power-to-gas, FCEV, power-to-power and blending into the gas grid.

Furthermore, the scenarios' simulation has been carried out referring to three different time horizons: Today (2023), Mid-Term (2030) and Long-Term (2050).

1.2. Outline

This paper is divided into three sections. In the first one, an updated literature survey and the general European framework have been reported and commented.

In the second section, the applied methodology and materials to perform the proposed analysis are outlined; specifically, the case study together with the technical and economic assumptions have been widely described. In the third one, the relevant findings are presented and discussed in detail. In the end, concluding remarks are provided to the readers, emphasizing the shifting correlation between the overall LCOH value and the nature of end uses, which leads to different considerations to be made by current and future policy makers.

2. Materials and method

To achieve the aim of this research project, the province of Taranto, in the Southern region of Italy, has been considered as a case study. By the meteorological data from that site, it has been possible to extrapolate a predictive profile of renewable energy production on which the parametric calculations, are based. A parametric approach has been used to subsequently carry out a comparative analysis between different pathways.

First, the green hydrogen capability analysis, using Renewable Energy Sources (RES), has been performed having considered a parameterised calculation based on a reference size of electrolysers (1 MW). Thus, different production scenarios have been investigated by varying capacities of installed PV and WIND power plants, proportional to the electrolysers reference size. From those calculations, the minimum and maximum LCOH values have been estimated for each reference period. As regards the transportation systems analysis, the H_2 delivery costs through pipelines and trucks/trailers have been evaluated by building up a parametric model considering different potential scenarios to obtain minimum and maximum LCOH values.

Referring to the storage phase, a cost analysis of a pressurised gaseous storage system (at 200 bar$_g$) has been carried out. For the H_2 distribution within the natural gas (NG) network, mixer units have been considered, while for distribution in the transport sector, different cost scenarios for HRS have been accounted for.

Finally, potential end uses of such green hydrogen have been identified, namely.

- Power-to-fuel: synthetic methanol (MeOH) production to replace gasoline as fuel for internal combustion engines -based vehicles (ICEV);
- Power-to-gas: synthetic methane production to replace methane from fossil fuels;
- FCEV: use as supply for fuel cell vehicles that would replace ICEV;

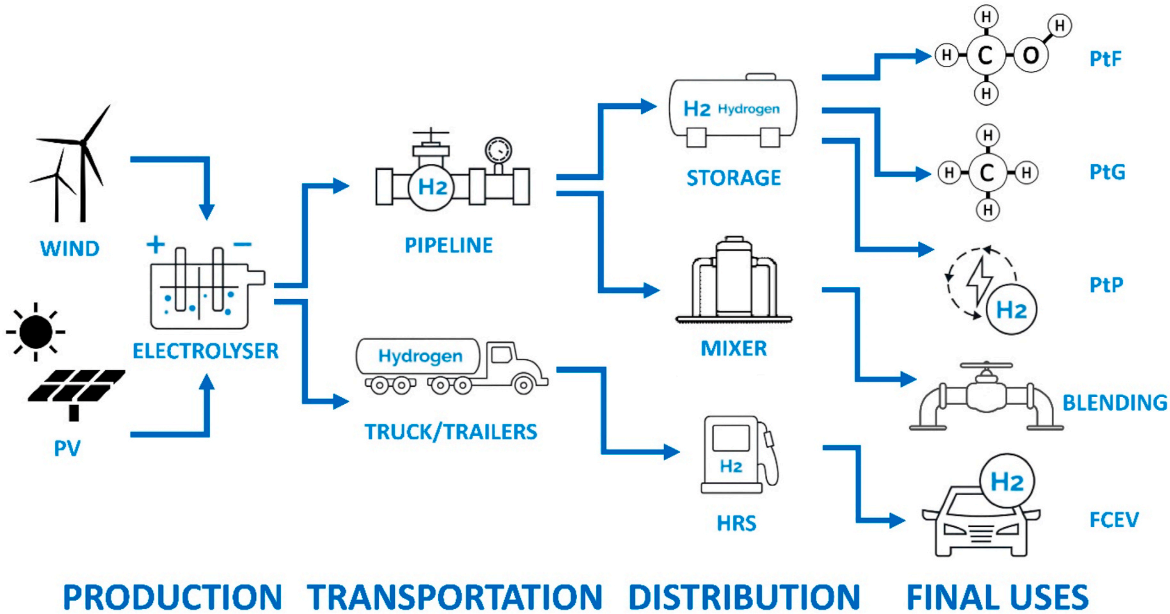

Fig. 2. Different hydrogen pathways considered for the final use scenarios.

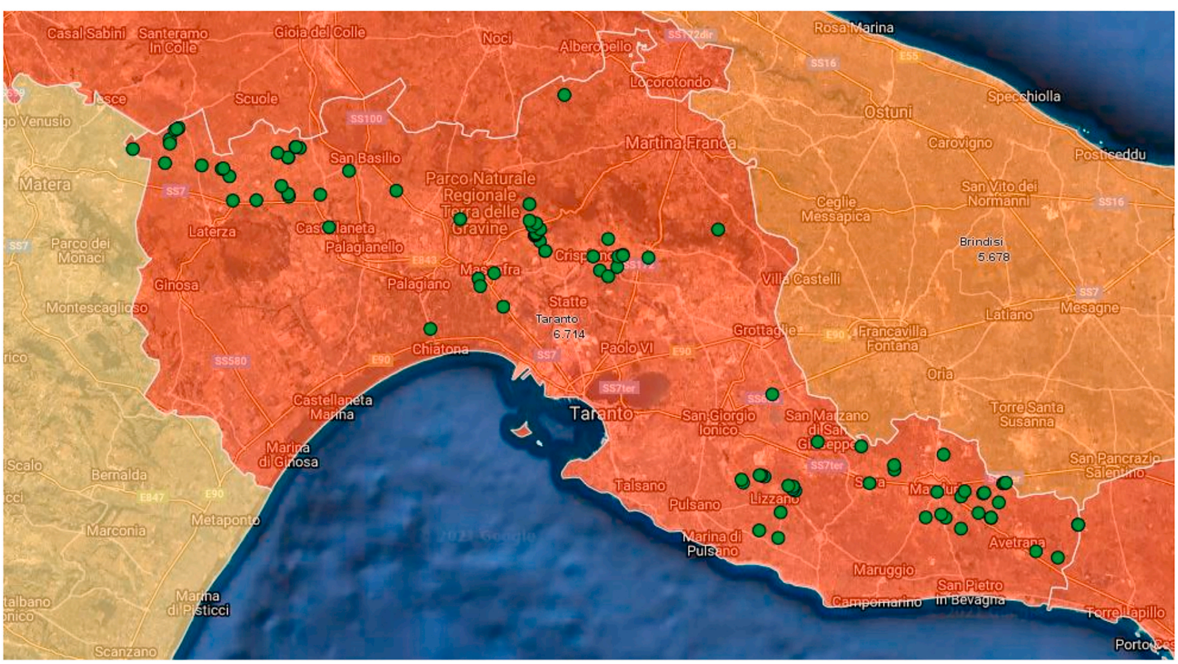

Fig. 3. Geographical location of onshore wind plants located in the territory of the province of Taranto. Source: Ref. [52].

- Power-to-power: H_2 conversion into electricity to be fed into the grid by the use of stationary fuel cells;
- Blending: direct injection into the national gas network according to a certain hydrogen percentage by volume.

For each of these scenarios, the hydrogen value chain has been reconstructed, as reported in Fig. 2, and the overall LCOH has been determined (see Fig. 1). In the end, an analysis has been carried out to assess the decarbonisation cost, in terms of cost associated to CO_2 emissions avoided, by using hydrogen in these sectors instead of fossil fuels. This final analysis has been also performed using a parametric model over three different time horizons, namely in the short, in the medium and long term.

2.1. Case study

As it is well known, hydrogen does not exist naturally on Earth and must be extracted from other compounds through processes such as methane steam reforming (SMR), water electrolysis, coal gasification, and thermochemical water splitting [51]. For this analysis the province of Taranto has been assumed as a case study. Thereafter, various scenarios consisting of green hydrogen local production by using electrolysers renewable-powered by wind (WIND) and photovoltaic (PV) plants have been investigated. The capacities of the dedicated RES plants have been identified in accordance with the reference electrolyser size of 1 MW. For RES power supply systems, 22 potential scenarios have been simulated, studying different energy mixes of PV and WIND. Scenarios

Fig. 4. Identification of the 14 characteristic coordinates used for calculating the local wind power potential.

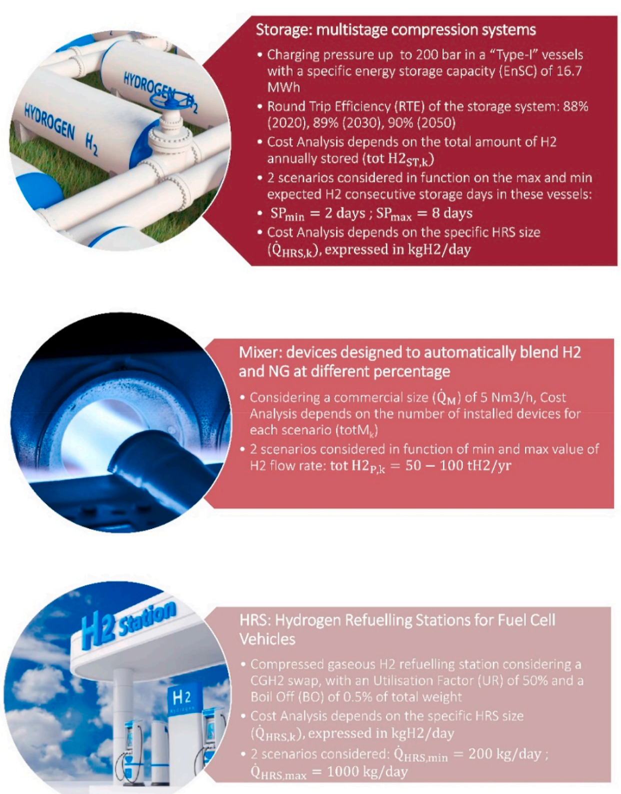

Fig. 5. Storage and distribution assumptions.

characterised by installed WIND or PV power ratio, with respect to the installed electrolysers capacity, ranging from 0 to 2, have been taken into account; the variable power ratio step has been fixed equal to 0.5, but considering only those scenarios in which the total RES capacity is at least equal to the electrolyser's power.

To calculate the hourly production curve of PV, the PVGIS software has been used by entering the coordinates for Taranto, assuming a tilt angle of 35° and a southward orientation. The considered panels are made of crystalline silicon with a peak power of 1 kW_p. The production curves of five years have been then extrapolated and averaged to obtain a single curve for subsequent calculations. To derive the WIND production curve, an investigation has been carried out on existing real plants (Fig. 3) using information provided by the Atlaimpianti portal, managed by GSE [52] (see Fig. 5).

The plants feasibility analysis has been carried out using the wind data extracted from the PVGIS software, evaluating the overall production.

Taking into account 14 characteristic coordinates, the PVGIS wind speed data, referred to a height of 10 m above the ground level, has been converted using the logarithmic Prandtl model to make them representative of different hub heights.

$$v_z = v_0 \bullet \frac{\ln\left(\frac{z}{m}\right)}{\ln\left(\frac{z_0}{m}\right)} \tag{1}$$

where.

- v_0 is the wind speed value 10 m above the ground level, expressed in m/s
- $z_0 = 10$ m
- z is the considered height values that vary from 25 m to 40 m, depending, site by site, on the actual hub height of the installed turbines in that area.
- m is the roughness coefficient. For this analysis a value of 0.03 has been used, which is representative of open agricultural areas without fences or hedges, with widely spaced buildings, and gentle sloping hills.

Taking into account 14 characteristic coordinates, an average value has been deduced from the production curves of these real plants, to

Table 2
Fuel and energy prices trend in Italy.

Fuel and electricity prices in Italy	Today 2023	Mid Term 2030	Long Term 2050	Sources
C_{ElEn} (EUR/MWh)	98	114	123	[58]
C_{NG} (EUR/Nm3)	0.80	0.88	0.91	[68,69]
C_D (EUR/l)	1.487	1.629	1.679	[68,70]
C_B (EUR/kg)	1.626	1.781	1.836	[68,70]

determine the unit production curve (1 kW_p); thus, those coordinates have been entered as input into PVGIS, to reproduce the actual distribution of those plants in the territory (Fig. 4).

Those unit curves of PV and wind have proven to be fundamental in analysing renewable energy production scenarios, which will be described below.

The present analysis aims at providing an indicative value of the potential energy capacity associated to the Taranto province area, not specifying precise locations for photovoltaic plants and wind farms installations. However, the potential land footprint impacts of those plants have been examined. For photovoltaics, considering a fixed-axis plant and local latitudes, a space requirements of about 1.15 hectares per MW_p has been assumed from literature [53]. As regards wind farms, the installation of 200 kW onshore turbines, characterised by a rotor diameter of 30 m, has been considered. In order to minimise wake effect losses caused by the dense turbine arrangement, a spacing of 5D between columns and 5D between rows has been proposed, where D denotes the rotor diameter [54]. Those considerations lead to a power density of approximately 1 hectare per MWp for wind farms. Once the desired power has been fixed, the next step is to precisely identify suitable areas in the province of Taranto for renewable plants, accounting for location characteristics and proximity to the existing NG mains. However, it is worth of noticing how this analysis is out of scope of the present paper and it will be addressed in the future as further development of this research activity.

Therefore, as far as the case study is concerned, no geo-localisation survey has been conducted to optimise the geographical distances between renewable energy production, hydrogen production and hydrogen end-users. Since the topic of this project is to estimate weaknesess and strengths of a foreseeable demo Hydrogen Valley, the fundamental assumption is to consider ideal users as close as possible to the H_2 production plant. Consequently, transportable distance ranges have been identified in line with a province-wide spatial range. Anyway, it has been discusse more in detail in the following chapters.

2.2. H_2 production

Water electrolysis technologies can be generally classified according to the operating temperature, i.e. low-temperature (alkaline and polymer electrolyte membrane) and high-temperature (solid oxide electrolysers) electrolysers. Among those, the alkaline electrolysers are the most established typology, but they show limitations at partial load with fluctuating renewable energies [55]. Conversely, the polymer electrolyte membrane electrolysers (PEM-E) are able to operate at higher currents and pressures, and under a wide range of power input, making them well suited with the intermittent nature of renewables [56].

For those reasons, PEM electrolyser characteristics have been considered as a reference in the calculation.

From the unit production curves, the electrolysers equivalent full load hours value has been computed for each scenario. From that value, for each *k-th* scenario, it is possible to calculate the annual H_2 production by the Equation (2):

$$\text{tot } H2_{P,k} = \frac{h_{eq,P,k} \bullet P_{EL}}{\frac{LHV_{H2}}{\eta_{LHV,P}}} \tag{2}$$

where:

tot $H2_{P,k}$ is the amount of annually produced hydrogen in k scenario, expressed in t_{H2}/yr; $h_{eq,P,k}$ are the electrolysers full load hours in the *k-th* scenario, expressed in h/yr; P_{EL} is the electrolysers installed capacity assumed equal to 1 MW; LHV_{H2} is the H_2 Lower Heating Value, expressed in kWh/kg_{H2}, and $\eta_{LHV,P}$ is the electrolyser First Law efficiency, based on the hydrogen's LHV

Once the hydrogen annual capability for each year is known it is possible to determine the LCOH value for each scenario.

2.3. Transportation and distribution

The following solutions have been considered for delivering the produced hydrogen: pipelines and road transport by truck/trailer.

The first case concerns the use of a pipeline that can transport hydrogen under pressure. For the LCOH calculation, four different scenarios have been considered, depending on the hydrogen flow rate within the pipelines and their length. Two reference flow rates have been assumed, chosen in accordance with the annual quantity of produced hydrogen. The two values of minimum and maximum pipes length have been chosen taking into account that the case study refers to a Hydrogen Valley and, therefore, the distances between H_2 production and any users will be contained.

The CAPEX value of these scenarios was a function of pipeline diameter D and length L [57], in accordance with Equation (3) and Equation (4):

$$D_k = \sqrt{\frac{4 \bullet \text{tot } H2_{P,k}}{\pi \bullet \rho \bullet v}} \tag{3}$$

$$CAPEX_{PL,k} = \left(3,400,000 \bullet D_k^{\,2} + 598,600 \bullet D_k + 329,000\right) \bullet L_{PL,k} \tag{4}$$

here.

- D_k is the pipeline diameter, expressed in m
- ρ is the hydrogen density, expressed in kg_{H2}/m^3
- v is the average velocity of hydrogen inside the pipeline, expressed in m/s
- $CAPEX_{PL,k}$ is the pipeline capital expenditure expressed in EUR
- $L_{PL,k}$ is the pipeline length, expressed in km.

As a second option, road transport by truck in special pressurised hydrogen gas containers, called trailers, has been considered. The LCOH for this system is considered proportional to the travelled distance d_k, in *k-th* scenario, by the truck to transport the hydrogen, expressed in km [58].

As a maximum distance range to run, the provincial territory has been assumed.

In the equations used to calculate the LCOH related to the two transport options, the associated costs of compressing hydrogen up to the required pressure by the transport system are also implicitly incorporated.

Thereafter, the following distribution systems have been implemented in the model: Storage, Mixers and HRS.

In the LCOH assessment, the overall H_2 storage costs are associated with a multistage compression system, to pressurise hydrogen up to 200 bar_g, and to vessels of Type-I.

Two different scenarios have been considered for the calculation. Those scenarios depend on the maximum and minimum expected value of H_2 storage days in those tanks. Consequently, the total annually stored H_2 reads as follows:

$$\text{tot } H2_{ST,k} = \frac{EnSC \bullet RTE}{\frac{SP_k}{365}} \tag{5}$$

where.

Table 3
Economic assumption.

Type of Plant	CAPEX			UoM	O&M	UoM	TL (yr)	Source
	Today 2023	Mid Term 2030	Long Term 2050					
Wind Plant	1473	1075	825	EUR/kW	2%	%CAPEX	25	[71,72]
PV Plant	995	587	323	EUR/kW	1%	%CAPEX	25	[71,73]
Electrolysers	900	700	450	EUR/kW	1.5%	%CAPEX	20	[58]
H_2 Storage System	57	45	21	EUR/kWh	2.5%	%CAPEX	30	[74]
HRS - size 200 kg/day	900	700	560	kEUR	5%	%CAPEX	30	[58,75]
HRS - size 1000 kg/day	1800	1500	1200	kEUR	5%	%CAPEX	30	[58,75]
Power-to-fuel	321.61	242.22	154.70	EUR/t_{CH3OH}	1.5%	%CAPEX	25	[58,76]
Power-to-gas	845	735	565	EUR/kW	4%	%CAPEX	30	[58]
Power-to-power	5.80	1.70	1.30	kEUR/kW	5%	%CAPEX	12	[77]
FCEV – car	60.0	46.7	33.4	kEUR	0.03	EUR/km	10	[78,79]
ICEV – car	21.9	21.6	21.2	kEUR	0.04	EUR/km	10	[79,80]
FCEV – truck	391.8	219.7	157.1	kEUR	1.5%	%CAPEX	10	[81,82]
ICEV – truck	105.5	115.3	115.3	kEUR	1.5%	%CAPEX	10	[82]

Table 4
Technical assumptions for H_2 value chain scenarios.

	Parameter	Today 2023	Mid Term 2030	Long Term 2050	UoM	Sources
Production	P_{EL}	1			MW	
	η_{LHV}	64%	69%	74%	%	[58]
Pipeline	$totH2_{min}$	50			t_{H2}/yr	
	$totH2_{max}$	100			t_{H2}/yr	
	L_{min}	0.5			km	
	L_{max}	3			km	
	ρ	0.55			kg/Nm3	[57,58]
	v	15			m/s	[57,58]
	O&M	5%			%CAPEX	[84]
	TL	40			yr	[84]
Truck/ Trailers	d_{max}	200			km	
Storage	SP_{min}	2			days	[85]
	SP_{max}	8			days	[85]
	EnSC	16.7			MWh	[74]
	RTE	88%	89%	90%	%	[74]
Mixer	$totH2_{min}$	50			t_{H2}/yr	
	$totH2_{max}$	100			t_{H2}/yr	
	$h_{eq,min}$	1366				
	$h_{eq,max}$	5334				
HRS	EID	1.7	1.6	1.5	kWh/ kg_{H2}	[58]
	BO	0.5%			%	[58]
	UF	50%			%	[58]

- tot $H2_{ST,k}$ is the amount of hydrogen annually stored in *k-th* scenario, expressed in kg_{H2}/yr
- EnSC stands for the specific energy storage capacity for one tank, expressed in kWh
- RTE denotes the round-trip efficiency, expressed in %
- SP_k represents the period of consecutive storage days for the *k-th* scenario that have been assumed, expressed in days.

The second H_2 distribution system concerns the use of mixers, which are devices designed to automatically blend hydrogen and natural gas at different percentages. To determine the LCOH associated to this case, four scenarios have been analysed, considering two different H_2 flow rates that should be managed by those appliances along with two different values of electrolysers' full load hours. These minimum and maximum values of the two parameters hail from H_2 production calculations. Therefore, it is possible to deduce the total flow rate handled by mixers and, by considering their commercial size, to find the total devices number to be used for a given scenario. Based on the reference size and the total number of mixers, the following analytical function is applied to assess the CAPEX value.

Table 5
Technical assumptions for H_2 end-uses scenarios.

	Parameter	Today 2023	Mid Term 2030	Long Term 2050	UoM	Sources
Power-to-Fuel	$\dot{Q}_{H2}$	104			kg_{H2}/h	[76]
	$\dot{Q}_{MeOH}$	500			kg_{MeOH}/h	[76]
	EC	2971			MWh/yr	[76]
	h_{eq}	7884			h/yr	[76]
Power-to-Gas	η_{LHV}	77%			%	
	EC	0.72			MWh/ Nm^3NG	
	h_{eq}	7884			h/yr	
Power-to-Power	P_{FC}	100			kW	[58]
	η_{HHV}	43%	56%	56%	%	[58]
	h_{eq}	5256	6395	6395	h/yr	[16,76]
FCEV - Car	MC_{FCEV}	0.55	0.46	0.45	kg_{H2}/100 km	[79]
	MC_{ICEV}	7.35	6.53	6.53	l_D/100 km	[79]
	D	15,000			km/yr	[58]
FCEV - Truck	MC_{FCEV}	7.50	6.32	6.12	kg_{H2}/100 km	[81]
	MC_{ICEV}	35.00	31.11	31.11	l_D/100 km	[86]
	D	100,000			km/yr	[58]

$$CAPEX_{M,k} = \left(13,302.378 \bullet \dot{Q}_M{}^{-0.613}\right) \bullet totM_k \tag{6}$$

where.

- $CAPEX_{M,k}$ is the mixer capital expenditure expressed in EUR
- $\dot{Q}_M$ is the mixer commercial size, expressed in Nm^3/h
- $totM_k$ represents the total number of mixers in *k-th* scenario.

The last distribution system concerns hydrogen refuelling stations for fuel cell vehicles. The HRS typology used for simulations consists of compressed gaseous hydrogen filling station considering a compressed

Table 6
Fuel and electricity emission factors.

Emission Factor fem	Today 2023	Mid Term 2030	Long Term 2050	UoM	Sources
Electric Energy	0.34	0.17	0.07	t_{CO2}/ MWh	[58,88, 89]
Natural Gas	1.972			kg_{CO2}/ m^3_{NG}	[90]
Gasoline	3.14			kg_{CO2}/kg_B	[90]
Diesel	3.16			kg_{CO2}/kg_D	[90]

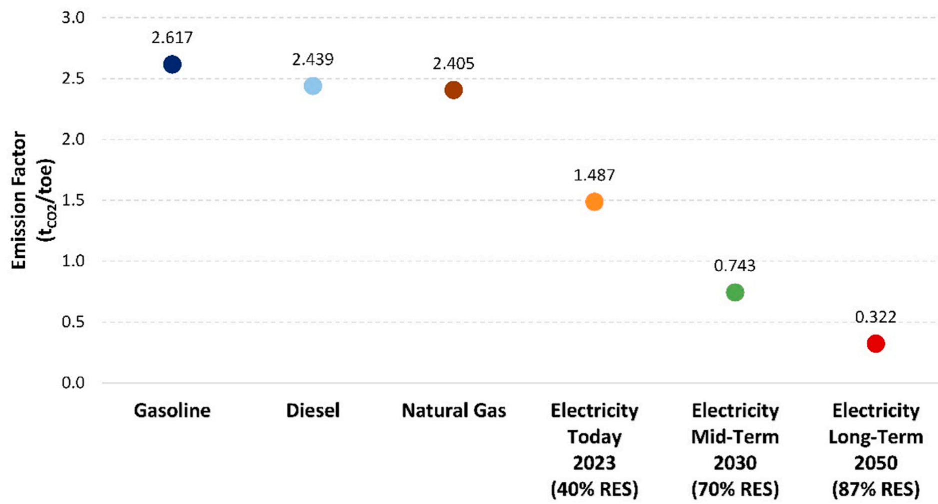

Fig. 6. Graphical comparison between the emission factors.

gaseous hydrogen trailer swap delivery (CGH_2 swap) [59]. To find the LCOH value that refers to the costs of this type of distribution system, two scenarios have been hypothesised according to two HRS reference sizes.

The total annual H_2 distributed by HRS in the scenario ($totH2_{RS,k}$ expressed in kg_{H2}/yr) can be calculated by Equation (7):

$$tot\ H2_{HRS,k} = \dot{Q}_{HRS,k} \bullet (UF_{HRS} - BO_{HRS}) \bullet 365 \tag{7}$$

here.

- $\dot{Q}_{RS,k}$ represents the HRS size, i.e. how much hydrogen can be daily distributed, expressed in kg_{H2}/day;
- UF_{HRS} is the HRS utilisation factor, expressed in %;
- BO_{HRS} is the Boil Off, expressed in % of total weight.

The annual O&M operating costs, expressed in EUR/yr read as:

$$O\&M_{HRS,k} = O\&M_{\%,k} + C_{EnEl,k} \bullet ElD_{HRS,k} \tag{8}$$

where.

- $O\&M_{\%,k}$ is the generic operation and maintenance cost, expressed in % of CAPEX
- $C_{EnEl,k}$ is the electricity price, expressed in EUR/kWh
- $ElD_{HRS,k}$ is the HRS electricity demand, expressed in kWh/kg_{H2}

Technical assumptions for storage and distribution systems have been summarised in the following figure.

2.4. Hydrogen end-uses

Different end-use scenarios associated to the green H_2 production have been investigated considering the context of the Hydrogen Valley. For each of those scenarios, it is possible to calculate the global LCOH by adding the relative LCOH value referred to each subsystem, namely to production, to transportation system and distribution system, respectively, as also applied by Correa et al. in his methodology [44]. A final minimum and maximum value range for the LCOH will be presented for today (2023), mid-term (2030) and long-term (2050). However, it is important to note that all of the technologies are characterised by different Technology Readiness Levels (TRLs), which may fluctuate in the near future depending on their level of development. For this reason, the investigation has been focused on finding not specific values, but minimum and maximum cost ranges.

The selected scenarios are.

1. The synthetic methanol production that is used in the transport sector by replacing gasoline in thermal engines (power-to-fuel);
2. The synthetic natural gas production to be used instead of that of fossil origin (power-to-gas);
3. Used in the transport sector as a fuel for both light and heavy fuel cell vehicles (FCEVs)
4. Reconvert the H_2 produced into electricity to be fed into the grid through stationary fuel cells (power-to-power);
5. The direct H_2 injection into the natural gas network (blending).

Finally, for each scenario, the decarbonisation cost has been calculated in terms of carbon abatement cost (CAC), i.e. the cost of each ton of avoided CO_2 by using H_2 instead of fossil fuels.

2.4.1. Power-to-fuel

One of the H_2 end-use scenarios is the synthetic methanol production.

Synthetic methanol is a fuel originated from green H_2 produced by RES that is combined with carbon dioxide to yield CH_3OH. This can be used as fuel in all those vehicles equipped with traditional internal combustion engines (ICEVs) [60]; however, some adjustments must be set to the engine and fuel system to allow adequate combustion and to achieve performance like the gasoline ones. This is due to the fact that methanol has a lower octane index than gasoline, therefore it has a greater tendency to detonate during combustion together with a lower energy density.

It has been assumed that the H_2 value chain for this scenario is composed of:

PRODUCTION + PIPELINE + STORAGE.

CAC has been calculated on two scenarios, min and max, determined by the min and max value of the total LCOH:

$$LCOH_{PtF,min/max} = LCOH_{P,min/max} + LCOH_{PL,min/max} + LCOH_{S,min/max} \tag{9}$$

The cost and emission contributions of the required CO_2 for synthetising methanol are considered negligible.

The hydrogen annually consumed by that process ($totH2_{PtF}$), expressed in kg_{H2}/yr, the electricity annually required by the process ($totElEn_{PtF}$), expressed in MWh/yr, and the total gasoline potentially substitutable per year with the synthetic methanol ($totB_{eq}$), expressed in kg_B/yr, normalised by the annual production of CH_3OH, have been evaluated by Equations (10)–(12), respectively:

$$totH2_{PtF} = \frac{\dot{Q}_{H2}}{\dot{Q}_{MeOH}} \bullet h_{eq,PtF} \tag{10}$$

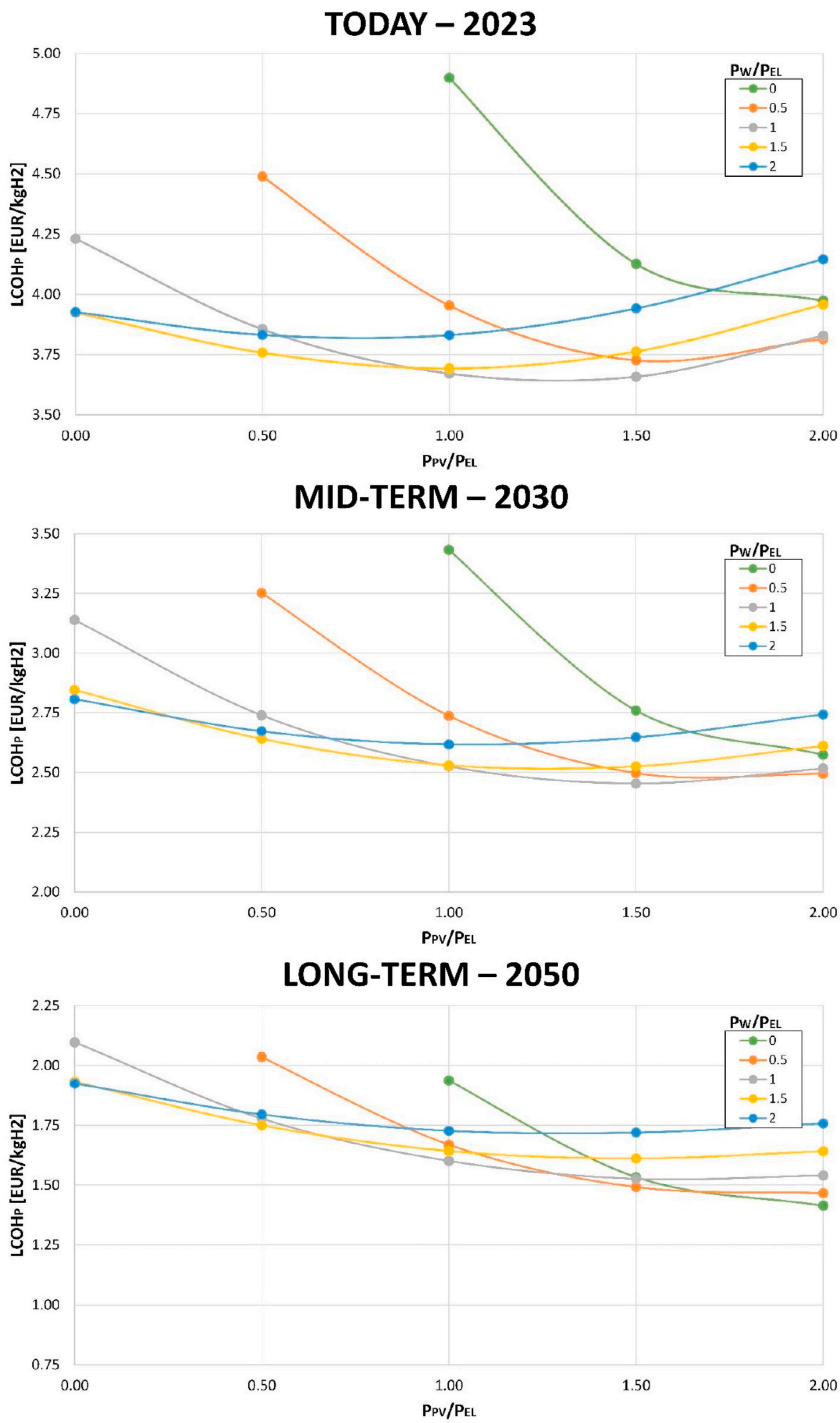

Fig. 7. LCOH vs PV to electrolyser power ratio with changes in Wind penetration based on various mix of RES supply in different time horizons.

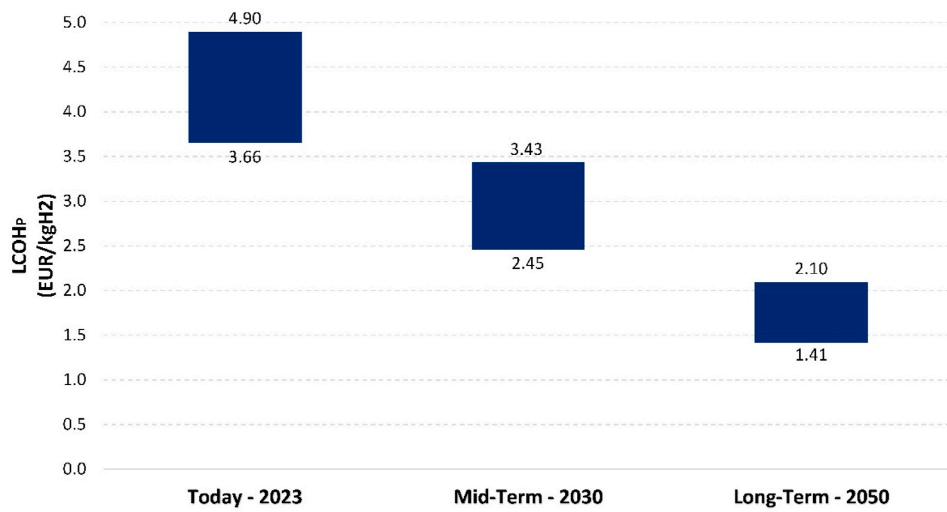

Fig. 8. LCOH production trend.

$$totElEn_{PtF} = \frac{EC_{PtF}}{\dot{Q}_{MeOH}} \bullet h_{eq,PtF} \quad (11)$$

$$totB_{eq} = \frac{LHV_{MeOH}}{LHV_B} \bullet h_{eq,PtF} \quad (12)$$

Here.

- $\dot{Q}_{H2}$ is the hourly flow rate of H_2 required by the process, expressed in kg_{H2}/h
- $\dot{Q}_{MeOH}$ is the hourly flow rate of methanol produced by the process, expressed in kg_{MeOH}/h
- $h_{eq,PtF}$ represents the equivalent operating hours of the methanol production process, expressed in h/yr
- EC_{PtF} represents the electricity consumption that the process requires, expressed in MWh/yr
- LHV_{MeOH} represents the lower heating value of methanol, expressed in kWh/kg_{MeOH}
- LHV_B represents the lower heating value of gasoline, expressed in kWh/kg_B

2.4.2. Power-to-gas

Another H_2 end-uses scenario concerns the synthetic natural gas production which can be used instead of the fossil one.

The Power-to-Gas (PtG) process is a synthetic gas production technology from green H_2 produced by RES. The methanation process consists of combining this hydrogen with CO_2 to produce CH_4 by a catalytic chemical reaction. CO_2 can be obtained from renewable sources such as biogas, landfills or captured from the atmosphere. Synthetic methane originated from PtG process can be either used as fuel in natural gas vehicles (CNG), or as a fuel for stationary electricity production, or it can be injected into the national gas grid, thus contributing to the greenhouse gas emissions reduction.

It has been considered that the hydrogen value chain for this scenario is made up of: PRODUCTION + PIPELINE + STORAGE.

For the CAC value, 2 scenarios are used, min and max, determined by the min and max value of the total LCOH:

$$LCOH_{PtG,min/max} = LCOH_{P,min/max} + LCOH_{PL,min/max} + LCOH_{S,min/max}. \quad (13)$$

As in the previous case, costs and emissions contribution related to the required CO_2 are negligible.

The hydrogen annually consumed by this process ($totH2_{PtG}$), expressed in kg_{H2}/yr, the annually required electricity by the process ($totElEn_{PtG}$) expressed in MWh/yr, normalised by the annual CH_4 production, can be calculated as follows:

$$totH2_{PtG} = \eta_{LHV,PtG} \bullet h_{eq,PtG} \bullet \frac{LHV_{NG}}{LHV_{H2}} \quad (14)$$

$$totEnEl_{PtG} = EC_{PtG} \bullet h_{eq,PtG} \bullet LHV_{NG} \quad (15)$$

where.

- $\eta_{LHV,PtG}$ is the efficiency, as a LHV function of the PtG process;
- $h_{eq,PtG}$ represents the equivalent operating hours of the PtG process, expressed in h/yr;
- LHV_{NG} is the natural gas lower calorific value, expressed in kWh/Nm^3_{NG}.

2.4.3. FCEV

H_2 end-uses scenario consists of exploiting the green hydrogen in the transport sector for driving fuel cell vehicles (FCEVs).

FCEVs are basically electric vehicle that uses fuel cells to produce electricity on board, without emitting harmful exhaust gases. Fuel cells use hydrogen as fuel and oxygen in the air to produce electricity by chemical reaction, producing water as the only by-product. The electrical energy produced is then used to power an electric motor that propels the vehicle. Polymeric Electrolyte Membrane (PEM) fuel cells are widely adopted in the transport sector due to their quick start-up and low weight compared to other fuel cell technologies. Those cells use a solid polymer as the electrolyte and porous carbon electrodes with a platinum or alloy catalyst, making them more expensive. Operating with hydrogen, oxygen and water, they are typically fuelled with hydrogen from storage tanks characterised by a high purity degree [61]. Moreover, running at relatively low temperatures, PEMs offer high power density, mitigating wear on system components, but showing a low carbon monoxide (CO) tolerance [62].

Currently, Hydrogen FCEVs encounter big challenges that hinder their competitiveness in the market. One of the challenges is the issue of overall efficiency. With the current state of the art, this lags behind that of battery electric vehicles (BEVs) due to significant energy losses [63]. However, FCEVs offer several advantages over gasoline or diesel vehicles, including greater energy efficiency, reduced greenhouse gas emissions, longer range than BEVs and the ability to quickly refuel.

The hydrogen value chain for this scenario comprises:

PRODUCTION + TRUCK/TRAILERS + HRS.

For the CAC values, four total scenarios are hypothesised: two of them are referred to the minimum and maximum values, considering small fuel cell vehicles (e.g. segment B–C cars) while the others are

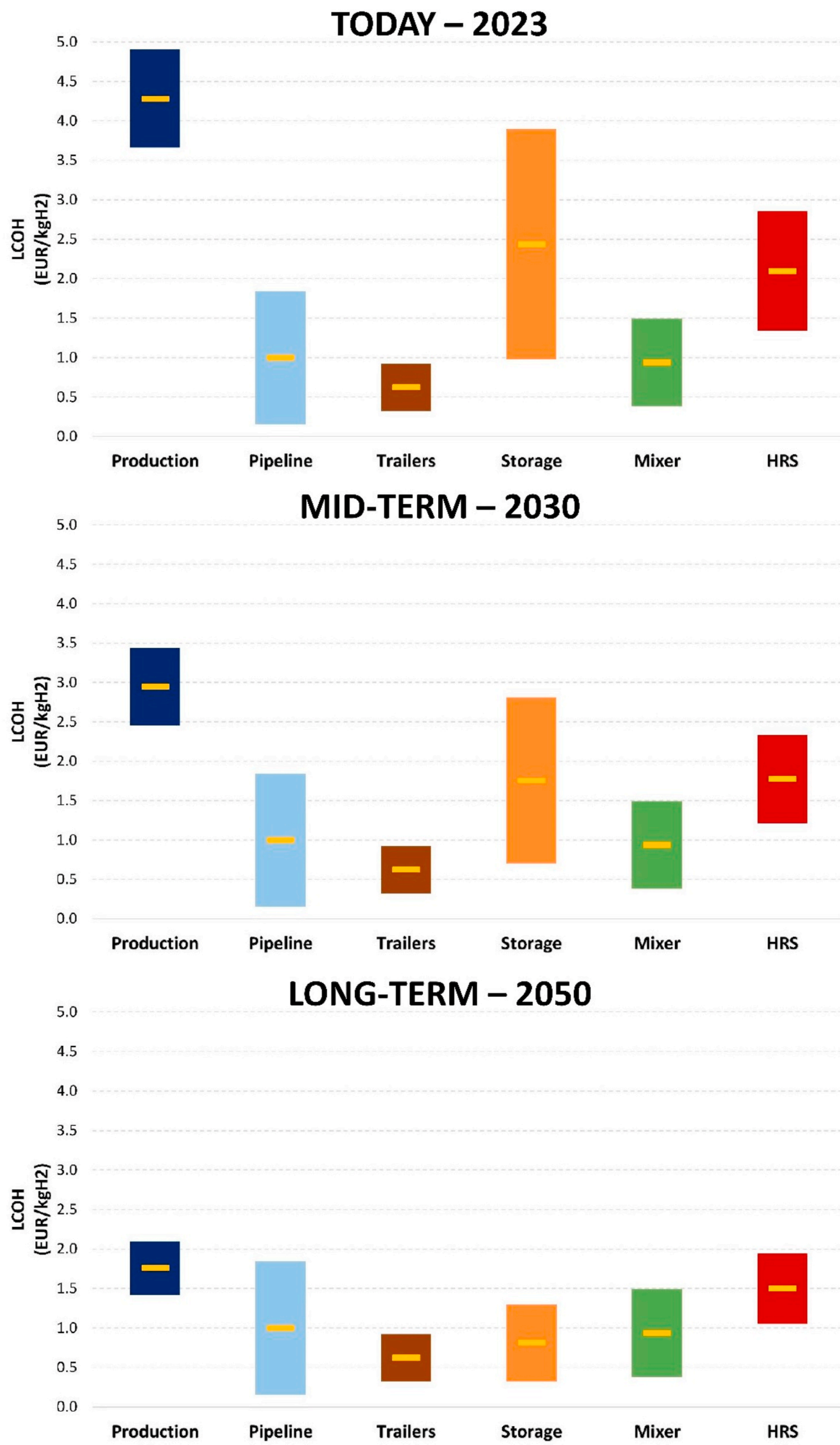

Fig. 9. H_2 value-chain levelized cost range for 2023, Mid-Term and Long-Term.

referred to the min and max values in case of fuel cell trucks. The minimum and maximum scenarios are determined by the total LCOH min and max values:

$$LCOH_{FCEV,min/max} = LCOH_{P,min/max} + LCOH_{T,min/max} + LCOH_{RS,min/max} \quad (16)$$

The emissions contribution of the green H_2 are considered negligible and a comparison with internal combustion vehicles (ICEVs) fuelled with diesel has been made.

The hydrogen potentially consumed over the year by FCEVs ($totH2_{FCEV}$), expressed in kg_{H2}/yr and the total diesel consumed

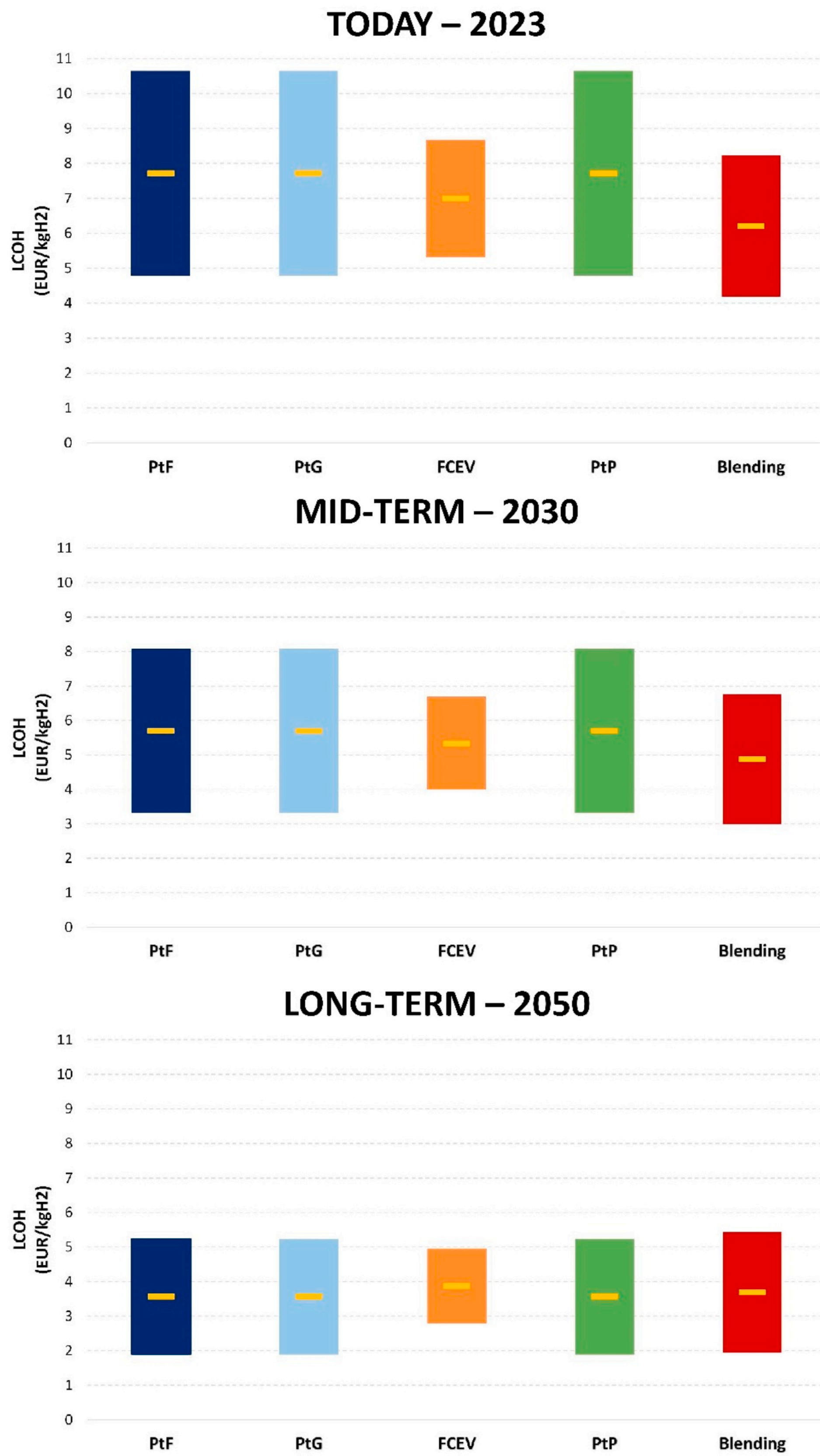

Fig. 10. Global LCOH for different H_2 final use scenarios for 2023, Mid-Term and Long-Term.

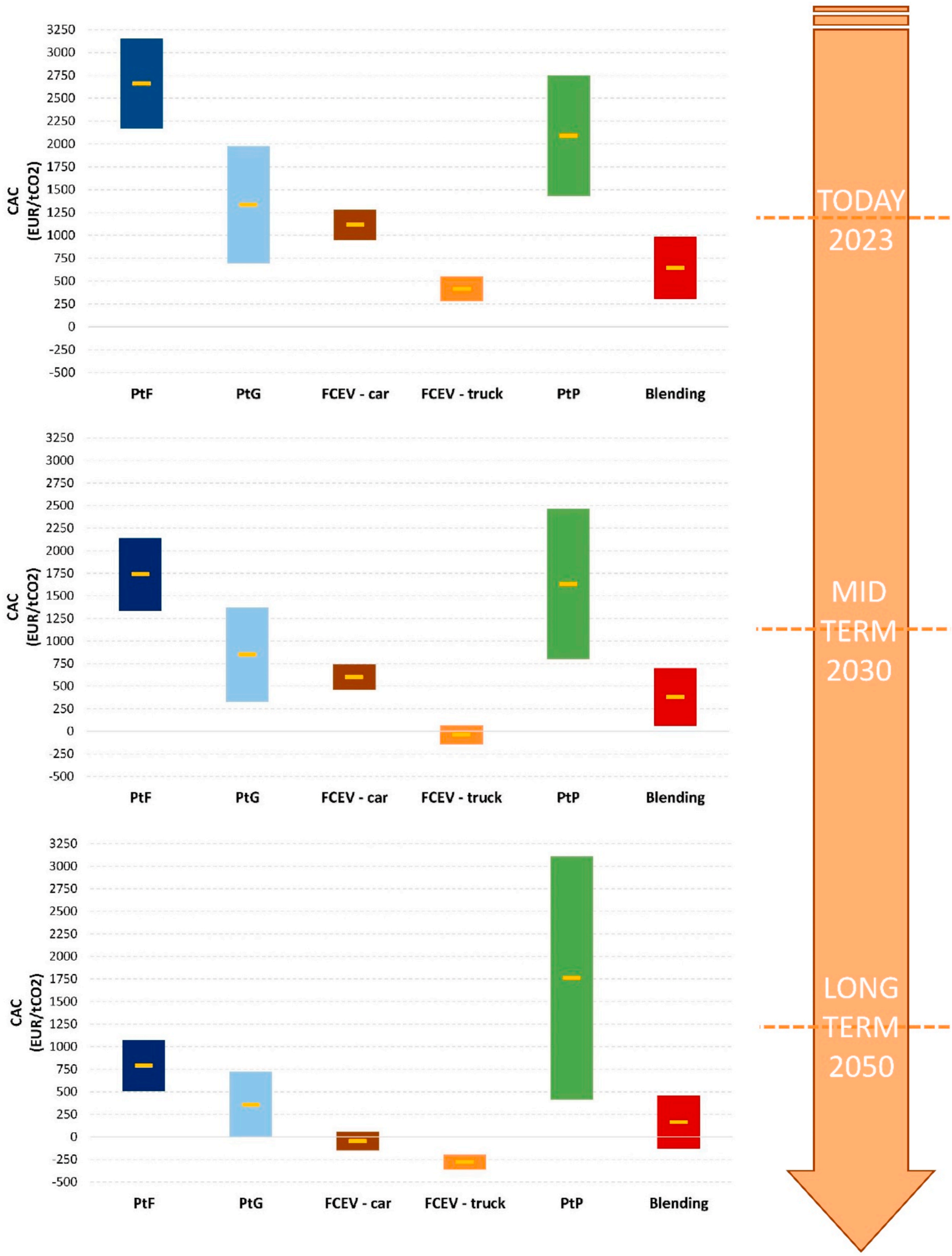

Fig. 11. Global CAC for different H_2 final use scenarios for 2023, mid-term and long-term.

annually by ICEV vehicles and potentially avoidable ($totD_{eq}$), expressed in lD/yr, have been evaluated as follows:

$$totH2_{FCEV,k} = MC_{FCEV,k} \bullet D_k \tag{17}$$

$$totD_{eq} = MC_{ICEV,k} \bullet D_k \tag{18}$$

here.

- $totH2_{FCEV,k}$ is the annual amount of hydrogen consumed by an FCEV, expressed in kg_{H2}/yr;
- $totD_{eq}$ is the annual amount of diesel consumed by an ICEV, expressed in l_D/yr;
- $MC_{FCEV/ICEV,k}$ is the average vehicle consumption, expressed in kg_{H2}/100 km and l_D/100 km, respectively;
- D_k is the annual distance travelled by vehicle, expressed in km/yr.

It is important to highlight how the present analysis exclusively focuses on the direct environmental impact caused by the hydrogen use as a fuel in vehicles, comparing it to traditional fossil fuels combustion. It is remarkable that an assessment over of the whole life cycle of such vehicles reveals how the upstream processes involved in the FCEVs construction generate considerable emissions [64]. Indeed it makes those vehicles significantly more environmentally impactful than ICEVs [65]. This environmental drawback can be only offset in all those regions where electricity is extremely clean (less than 200 $gCO_{2,eq}$/kWh); beneath that threshold value green hydrogen-powered FCEVs offer an overall climatic advantages over ICEVs [66].

2.4.4. Power-to-power

In this scenario H_2 is used to be converted into electricity, in order to release energy into the electric grid, by applying stationary fuel cells.

Fuel cells convert hydrogen into electricity and water, thus producing a clean energy source that can be used to mitigate the effects associated to the renewable capacity firming over the national grid or to supply power to specific loads.

The hydrogen value chain for this scenario involves the following subsystems:

PRODUCTION + PIPELINE + STORAGE.

CAC has been calculated on two scenarios, min and max, determined by the min and max value of the total LCOH:

$$LCOH_{PtP,min/max} = LCOH_{P,min/max} + LCOH_{PL,min/max} + LCOH_{S,min/max} \tag{19}$$

The hydrogen amount converted by fuel cell ($totH2_{PtP}$), over one year period, expressed in kg_{H2}/yr, the annual electricity generation which is potentially released into the grid ($totElEn_{PtP}$), expressed in MWh/yr, have been evaluated in accordance with Equation (20) and Equation (21), respectively:

$$totH2_{PtP,k} = \frac{totElEn_{PtP,k}}{\eta_{LHV,PtP} \bullet HHV_{H2}} \tag{20}$$

$$totElEn_{PtP,k} = h_{eq,PtP,k} \bullet P_{PtP} \tag{21}$$

In which.

- $\eta_{HHV,PtP}$ is the efficiency of the PtP process based on HHV;
- HHV_{H2} is the hydrogen Higher Heating Value, expressed in kWh/kg_{H2};
- $h_{eq,PtP,k}$ represents the plant full load hours, expressed in h/yr;
- P_{PtP} indicates the reference nominal power of the fuel cell, considered to be equal to 100 kW.

2.4.5. Blending

The last end-uses scenario is the direct injection of the green H_2 within the natural gas network, replacing a certain amount of natural gas fossil-based in order to provide the same energy.

Direct use of hydrogen can have disadvantages. For instance, flame instabilities as well as flashback can occur within burners or ducts. A more promising approach in today's context, on the other hand, is the introduction of hydrogen into the existing natural gas pipelines. This is in line with the wider objectives of efficient energy distribution and use, as well as addressing potential flame-related issues [67].

Blending is a process that consists of mixing green hydrogen with natural gas, so as to create an environmentally friendly fuel.

This blending process can take place at different points in the supply chain, from production to distribution, generating mixtures characterised by different hydrogen volumetric fractions depending on technical constraints and regulatory requirements.

The hydrogen value chain considered in this scenario is:

PRODUCTION + PIPELINE + MIXER.

CAC value is based on two maximum and minimum scenarios determined by the LCOH min and max values.

$$LCOH_{B,min/max} = LCOH_{P,min/max} + LCOH_{PL,min/max} + LCOH_{M,min/max} \tag{22}$$

Investment values for specific plants has been not accounted for, nonetheless only the costs related to the injected hydrogen and savings for unused natural gas have been considered. The amount of H_2 has been found by calculating the ratio between the low heating values of gaseous fuels so as to provide the same energy amount released by burning NG.

2.5. LCOH

The analytical correlation used to calculate the levelized cost of hydrogen for the various production, transportation, and distribution scenarios ($LCOH_{prod/trans/distr}$), expressed in EUR/kg_{H2}, reads as follows:

$$LCOH_{prod/trasm/distr} = \frac{\sum_k (CAPEX_k \bullet crf_k + O\&M_k)}{totH2_{prod/trans/distr}} \tag{23}$$

where.

- $CAPEX_k$ is the capital expenditure related to the various technologies required for the production/transportation/distribution phase, expressed in EUR;
- $O\&M_k$ are the operating and maintenance costs for the various technologies required for the production/transportation/distribution phase, expressed in EUR/yr
- $totH2_{prod/trans/distr}$ indicates either the total hydrogen annually produced or transported or distributed, expressed in kg_{H2}/yr, according to the scenario;
- crf_k is the capital recovery factor related to the selected technology, which can be computed as follows:

$$crf_k = \frac{DR \bullet (1+i)^{TL_k}}{\left((1+DR)^{TL_k} - 1\right)} \tag{24}$$

here.

- DR is the discount rate, expressed in %
- TL is the Technical Lifetime, expressed in yr

The total LCOH of the end-uses scenarios, expressed in kg_{H2}/yr, is calculated as the sum of the LCOHs of the three value chain phases for that *k-th* scenario:

$$LCOH_{tot,k} = LCOH_{prod} + LCOH_{trans,k} + LCOH_{distr,k} \tag{25}$$

2.6. Carbon abatement cost

The applied model for calculating the decarbonisation cost in terms of CAC, expressed in EUR/tCO_2, reads as follows:

$$CAC_k = \frac{\left(COST_k - COST_{F,k}\right) + LCOH_{tot,k} \bullet totH2_k + \sum_j \left(C_{G,j} \bullet totG_j\right)_k - C_{F,k} \bullet totF_k}{fem_F \bullet totF_k} \tag{26}$$

The meaning of all terms in Equation (26) is listed here below.

- $COST_k = (CAPEX_k \bullet crf_k + O\&M_k)$, expressed in EUR/yr, referred to the plant costs for the use of H_2 in *k-th* scenario;
- $COST_{F,k} = (CAPEX_{F,k} \bullet crf_{F,k} + O\&M_{F,k})$, expressed in EUR/yr, referred to the traditional plants costs which use fossil fuels and that will be replaced by new H_2-based plants;
- $tot\,H2_k$ is the total hydrogen annually used in *k-th* scenario, expressed in kg_{H2}/yr;
- $\sum_j (C_{G,j} \bullet totG_j)_k$ is the sum of all generic costs related to the H_2 end-use scenario, expressed in EUR/yr
- $C_{F,k} \bullet totF_k$ represents the cost of using the traditional fossil source in *k-th* scenario, to be replaced by hydrogen, expressed in EUR/yr;
- $fem_F \bullet totF_k$ rarepresents the total amount of annual emissions avoided by using H_2 in *k-th* scenario, expressed in tCO_2/yr.

2.7. Technical and economic assumptions

All parametric calculations described above are based on assumptions or values that are given below in this Section.

2.7.1. General economic assumptions

All costs are presented in Euro (EUR) using an exchange rate of 1092 USD/EUR and that the discount rate (DR) assumed is 3% per year. The fuel and energy prices in Italy have been summarised in Table 2, starting from the current recorded values and then scaled to 2030 and 2050. Thereafter, assumptions underlying the employed economic model are reported in Table 3.

During PEM electrolysers lifetime, the replacement of the stack, primarily consisting of bipolar plates and the membrane. These replacement interventions are encompassed in the considered CAPEX costs and constitute a significant percentage of the investment cost.

- Stack Lifetime: 10 yr;
- Stack Replacement Cost: 40% of capital cost [83].

2.7.2. Hydrogen value-chain assumptions

Parameters and assumptions used for the hydrogen value-chain scenarios are reported in the Table 4.

2.7.3. Hydrogen end-uses assumptions

Parameters and assumptions used for the hydrogen end-uses scenarios are reported in the Table 5.

Emission factors of fossil-based fuels considered in the various H_2 end-uses scenarios are shown in Table 6. It also reports the electricity *fem* of the Italian national electricity system. It depends on the percentage of energy produced annually in Italy from fossil sources compared to the total. To assess the emission values, forecasting values of national electricity production scenarios by 2030 and by 2050 have been extrapolated from literature [87]. Starting from the current RES percentage of about 40%, an increase of up to 70% has been assumed for the medium term (2030) and up to 87% for the long term (2050).

The following is a graphical representation of the emission factors all reported as a function of tonne of oil equivalent (toe) (see Fig. 6).

3. Results and discussion

In this section the outcomes of this parametric analysis are widely presented and discussed.

All of data associated to 22 hydrogen production scenarios analysis within a Hydrogen Valley in the province of Taranto, for each time horizon are depicted in Fig. 7.

The LCOH varies according to the renewable energy mix assumed for the specific scenario. It is noteworthy how it is not so much effective to drive electrolysers by photovoltaic energy only for 2023 and mid-term scenarios, whilst it is better to use the wind energy. This is owing to the difference in the production curves associated to the two different technologies. It entails that wind power is able to keep more constant the average production level with fewer hourly peaks, allowing electrolysers to reach higher values of full load hours. The optimal scenario, in terms of cost, is characterised by a PV installed capacity equal to 1.5 times higher than the electrolysers one and a wind power capacity equating this latter. By implementing this scenario, it is possible to get to electrolysers full load hours equal to 3936 h/yr nowadays and until 2030.

The scenario accomplishing higher values of this parameter is composed by PV and wind power plants, where both the renewable sources are characterised by an installed capacity doubling the electrolysers one (i.e. four times totally), allowing to attain about 5300 h/yr. However, this scenario involves much higher investment costs, therefore it is not cost-effective in terms of LCOH. In long-term, the optimal mix scenario changes due to the strong decrease of PV purchase costs, much higher respect the cost reduction of wind plants. In this temporal scenario, it becomes more convenient a renewable mix characterised by a double PV installed capacity compared to the electrolysers one and no wind plant installed. Although this scenario is not the best in terms of H_2 production and full load hours (2563 h/yr), it turns out to be the one with the lowest LCOH.

Fig. 8 shows that the cost range of H_2 production decreases in the medium term and even more in the long term. This is certainly due to the strong reduction in the investment costs, both for electrolysers and for renewables, which is expected in the coming years. In addition, an expected increase in the efficiency of these devices will lead to an increase in annual production, thus lowering the LCOH close to the 50% off.

The comparison between the costs referred to the various phases of the hydrogen value-chain is outlined in Fig. 9. From data it emerges how the production phase is the one with the highest LCOH, but it is also the one that contains the highest investment costs. While, among the H_2 transport systems, it results that LCOH varies greatly depending on the transport distance. Indeed, for short distances, the pipeline as a solution is more convenient, but the higher the distance value, the lower the convenience of that solution is, in favour of road transport.

The costs related to refuelling stations depend both on the station size and on the amount of hydrogen they can distribute annually. Over time, as the investment costs of this technology fall down and the hydrogen demand is expected in the transport sector increases, the LCOH range for HRS will decrease with values ranging between 1.05 and 1.95 EUR/kg_{H2}. Compared to other hydrogen transportation and distribution scenarios, storage is the one with the highest costs. This is mainly due to the high investment costs, not so much for purchasing vessels, but for the multistage compression system to pressurise the H_2 coming from a pipeline up to the storage pressure of 200 bar_g. In addition, the cost range is strongly influenced by the hydrogen storage period in those tanks: fewer storage days lead to a lower LCOH.

Finally, the outcomes related to the various H_2 end-uses scenarios within the Hydrogen Valley of Taranto have been presented.

The Fig. 10 shows the LCOH values for the various current, mid-term and long-term scenarios, respectively. While Fig. 11 shows the decarbonisation cost ranges of the same scenarios in the various periods.

From the comparisons it emerges that Blending is the most cost-effective solution in terms of LCOH and one of the best in terms of CAC, especially in the short and medium term. This is due to the fact that these costs are greatly influenced by the costs of the technologies for the hydrogen use. Blending, on the other hand, among all the solutions, is the one that requires less investment and infrastructure costs; it becomes particularly convenient especially nowadays and until 2030, or in all those periods in which the technologies related to the hydrogen use will still have high prices.

In the medium term the levelized cost bands are tightened and shift down. Notwithstanding, also in this case the blending option still remains the most competitive.

Only in the long term the depreciation of these technologies will allow the other scenarios to be competitive with the blending scenario: levelized cost bands shift down more and become practically flattened. As a consequence, in the next future the hydrogen cost over the supply chain will be almost independent of its pathways for the end uses.

Another excellent scenario was the use of hydrogen via FCEV. This scenario appears to have one of the most advantageous LCOH in all time bands and in terms of decarbonisation cost turns out to be the best, along with blending, especially when considering the replacement of heavy vehicles. Already in the medium and then also in the long term the CAC can reach negative values evidencing the effective convenience from the scenario. This is mainly due to the total reduction of emissions of the replaced vehicles that exploit very polluting fuels. The greater convenience of the scenario with heavy means is to attribute to the great number of kilometers crossed annually from these vehicles. Furthermore, it is known that they have better performance compared to small-sized fuel cell cars when compared to their respective internal combustion engine category [91].

The PtG and PtF scenarios are intermediate scenarios in terms of convenience for the CAC. This is due to the high cost for the industrial plants necessary for conversion. On the other hand, those scenarios are not totally disadvantageous. This is due to the possibility of using these synthetic fuels in sectors where the demand is already substantial, such as transport. Therefore, by associating a H_2 storage systems to the conversion plants, it will be possible to obtain a considerable amount of final product owing to the high capacity factor of these plants, which is about 0.9. In addition, they are particularly convenient also due to the high emission factor of traditional fossil fuels. The alternative use of synthetic fuels derived from green hydrogen makes it possible to totally abate the amount of greenhouse gases that would otherwise be emitted into the atmosphere. The decarbonisation cost of both scenarios will continue to fall from year to year.

Finally, the power-to-power solution results highly inconvenient. Indeed, this scenario has a high initial investment cost related to the fuel cells. While today the cost, however high, is comparable with the cost ranges of other hydrogen technologies, in the medium and long term PtP turns out to be one of the worst scenarios, in terms of economic, accounting for both the LCOH and the cost of decarbonisation. This is due to the lower depreciation of fuel cells compared to other hydrogen-related technologies of the other scenarios, but mainly to the emission factor of electricity from the national electricity grid. This factor strongly depends on the renewables share that contribute to national electricity production. This fraction is expected to increase strongly in the medium and long term; Therefore, the positive contribution in terms of emission reduction that could potentially be obtained from the reconversion of green hydrogen into electricity does not provide significant advantages compared to the other analysed scenarios in 2030 and 2050.

4. Conclusion

In this paper a parametric analysis to identify the hydrogen production cost evolution by 2050, within a potential Hydrogen Valley in Italy, has been proposed. In detail, an estimation of the LCOH over all the different phases of the value-chain, such as production, transportation, distribution and end-uses, has been presented in order to understand also the decarbonisation cost. To do so, several applications have been assessed: power-to-fuel, power-to-gas, FCEV, power-to-power and blending into the gas grid, by simulating 22 different scenarios for three different time horizons. Additionally, this investigation provides as a useful information the required renewable capacity to be installed for producing completely green hydrogen over a restricted territory represented by a hydrogen valley. The main findings of this research project outlined that the optimal scenario, in terms of cost, is characterised by a PV/Electrolyser ratio equal to 1.5 and a wind power equal to 1 from now to 2030 and total PV with a power ratio of 2 for 2050. By implementing the first scenario, it is possible to get to electrolysers' full load hours equal to 3936 h/yr, whilst with the second scenario it is possible to get 2563 h/yr. Other scenarios are able to increase the electrolysers full load hours at the expense of the LCOH resulting in less cost-effectiveness. Outcomes reveal that starting from a current maximum LCOH value close to 5 EUR/kg, it is expected that the potential production cost reduction will be equal to 50% lower by 2050.

Moreover, it appears that over the supply chain, after the production phase, storing hydrogen represents the most expensive solution due to the high costs related to the compression phase. As regards hydrogen pipelines, they are competitive when the distribution distances are short, otherwise road transport by truck/trailers is favoured.

While, with regard to the hydrogen end use, Blending is the most cost-effective solution both in terms of LCOH and one of the best in terms of CAC, especially in the short term. FCEV is the best solution in terms of CAC over all the time horizons.

It emerges that only in the long term the depreciation of the other hydrogen technologies will allow the other scenarios, such as PtF and PtG, to be competitive with the blending and FCEV scenarios. Indeed, by 2050 the LCOH ranges for each option are very similar, namely 2.3 EUR/kg up to 5.5 EUR/kg;

In the end it is possible to state that the decarbonisation process by the hydrogen deployment can follow different pathways. Depending on the technologies price evolution over the next decades, the LCOH associated to the different use widely varies.

From this analysis it has been possible to derive the overall levelized cost of the whole hydrogen value chain for several potential end uses. It turns out that currently the costs vary substantially between one scenario and the other, while in the next future the hydrogen cost over the supply chain will be almost independent of its pathways for the end uses.

From that data results comes out that, especially for a long-period analysis, another evaluation will be necessary to effectively identify a set of best options. For this reason, the Carbon Avoidance Cost analysis is required.

It is not easy to identify a unique optimal and universally valid solution over the time horizon.

Notwithstanding, it is crucial to start right now to promote several initiatives dealing with the hydrogen exploitation. By clustering all the activities related to the hydrogen supply chain it is possible to get to a critical mass to address such massive investments. Hence, hydrogen valleys could represent the first step of a bridge to a cleaner future, overcoming the current barriers to the wide spreading of the concept "hydrogen for all".

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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