INTERNATIONAL JOURNAL OF HYDROGEN ENERGY 48 (2023) 39514–39530

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Decarbonizing the Spanish transportation sector by 2050: Design and techno-economic assessment of the hydrogen generation and supply chain

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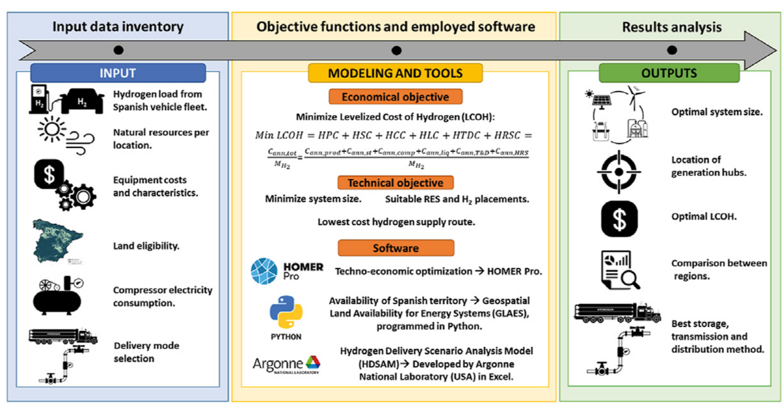
HIGHLIGHTS

- H_2 supply chain design to replace fossil fuels by H_2 in Spanish vehicles by 2050.
- RES and hydrogen infrastructure design for best delivery method and lowest LCOH.
- Six regions have been defined for RES deployment and centralized H_2 production.
- Gaseous hydrogen supply is, on average, 17% cheaper than liquid distribution.
- H_2 presents 33 and 38% lower prices than current ones for diesel and gasoline.

GRAPHICAL ABSTRACT



ARTICLE INFO

Article history:
Received 21 February 2023
Received in revised form
9 May 2023
Accepted 14 May 2023
Available online 2 June 2023

Keywords:
Spanish vehicle fleet
Renewable energy
Levelized cost of hydrogen
Supply chain
Techno-economic optimization
Delivery pathway comparison

ABSTRACT

The transport sector is difficult to decarbonize due to its high reliance on fossil fuels, accounting for 37% of global end-use sectors emissions in 2021. Therefore, this work proposes an energy model to replace the Spanish vehicle fleet by hydrogen-fueled vehicles by 2050. Thus, six regions are defined according to their proximity to regasification plants, where hydrogen generation hubs are implemented. Likewise, renewables deployment is subject to their land availability. Hydrogen is transported through an overhauled primary natural gas transport network, while two distribution methods are compared for levelized cost of hydrogen minimization: gaseous pipeline vs liquid hydrogen supply in trucks. Hence, a capacity of 443.1 GW of renewables, 214 GW of electrolyzers and 3.45 TWh of hydrogen storage is required nationwide. Additionally, gaseous hydrogen distribution is on average 17% cheaper than liquid hydrogen delivery. Finally, all the regions present lower prices per km traveled than gasoline or diesel.

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https://doi.org/10.1016/j.ijhydene.2023.05.154

Abbreviations

AOP	Spanish Association of Petroleum Product Operators
BEV	Battery Electric Vehicle
CAPEX	Capital Expenditures
CO_2	Carbon Dioxide
DOE	Department of Energy of the Unites States
FCEV	Fuel Cell Electric Vehicle
GHG	Greenhouse Gases
GLAES	Geospatial Land Availability for Energy Systems
H_2	Hydrogen
H2A	Hydrogen Analysis Project
HCC	Hydrogen Compression Costs
HDSAM	Hydrogen Delivery Supply Analysis Model
HLC	Hydrogen Liquefaction Costs
HOMER Pro	Hybrid Optimization of Multiple Energy Resources Pro
HPC	Hydrogen Production Costs
HRS	Hydrogen Refueling Station
HRSC	Hydrogen Refueling Station Costs
HSC	Hydrogen Storage Costs
HTDC	Hydrogen Transmission and Distribution Costs
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
LCOE	Levelized Cost of Energy
LCOH	Levelized Cost of Hydrogen
LOHC	Liquid Organic Hydrogen Carriers
NPC	Net Present Costs
NREL	National Renewable Energy Laboratory of the United States
OPEX	Operational Expenditures
OTLE	Spanish Observatory of Transport and Logistics
PEMEC	Proton Exchange Membrane Electrolyzer Cell
PV	Photovoltaic
RES	Renewable Energy Sources
WT	Wind Turbine

Introduction

The harmful impact of fossil fuels consumption on the environment due to their global warming potential has led to an unsustainable climate change situation. Thus, it is necessary to transit towards a broad deployment of renewable energy sources (RES) for mitigation of the effects of greenhouse gases (GHG) emission [1]. Transport has the highest reliance on fossil fuels of any sector. Besides, it accounted for 37% of CO_2 emissions from end-use sectors in 2021. While it was one of the sectors most affected by the Covid-19 pandemic, emissions resume rising as demands increase and the uptake of alternative fuels remains limited. Hence, this sector requires implementing a broad set of policies, to encourage modal shifts to the least carbon-intensive travel options, and operational and technical energy efficiency measures to reduce the carbon intensity of all transport modes [2].

On the other hand, there is a shortage of certain raw materials and minerals critical for the manufacture of batteries for electric mobility, such as lithium, nickel or cobalt [3]. This, together with the incompatibility of using batteries for heavy duty, maritime [4] or air freight applications, makes it necessary to look for new and low-carbon fuels or different ways of electrifying the transport sector. In this context, hydrogen appears as a competent and versatile energy vector capable of storing energy from intermittent renewable sources energies to power different mobility applications [5]. This makes hydrogen part of a more sustainable alternative, highly relevant in the process of transport decarbonization and positions it as an important element in the energy transition and reactivation of the economy [6].

Recent studies have modeled and sized hydrogen refueling stations (HRS) integrated with RES for hydrogen production and utilization as fuel for fuel cell electric vehicles (FCEV). Çiçek et al. [7] studied the optimal operation of an electric vehicle station with photovoltaic (PV) panels. The developed model includes battery charging, swapping and hydrogen refueling infrastructure in a specific location in Turkey, where the owner obtained a net profit of 33% at the end of the day. Likewise, Shoja et al. [8] integrated both electric charging and hydrogen refueling at the same building in Iran, reducing by 20.6% the wind generation and HRS demand forecast risk, and daily energy costs by 3.52% with an integrated demand response. Ayodele et al. [9] selected seven different cities of South Africa to optimize wind-powered HRS using HOMER Pro software, with a cost of hydrogen production ranging from 6.34 to 8.97 US$/kg. In China, Pang et al. [10] sized and modeled the scheduling of an off-grid hydrogen refueling station. This HRS is integrated in a building that is also powered by renewables and hydrogen, showing that capital and replacement costs of the PV panels are the major expenses during the lifetime of the HRS. Similarly, Xu et al. [11,12] proposed different off-grid configurations based on RES for hydrogen and electricity refueling in remote areas. Moreover, in the same electricity and hydrogen refueling station synthetic natural gas is produced for its delivery to gas-fueled vehicles. Thus, it has accomplished a refueling station capable of providing different fuels simultaneously. In this context, Wu et al. [13] integrated a renewable-powered HRS into a microgrid, achieving an optimal coordination between renewables and hydrogen refueling. Finally, multiple HRS for onsite green hydrogen use have been designed and optimized in Italy [14], Brazil [15], Japan [16], Turkey [17,18] and United Kingdom [19], reflecting hydrogen delivery costs between 7.53 and 13.55 US$/kg depending on the size and location of the refueling station.

Other works report different alternative routes for hydrogen supply. Chen et al. [20] compared the techno-economic performance of four different hydrogen supply alternatives for a refueling station in Shanghai: onsite hydrogen production vs detached hydrogen generation in a renewable energy rich area and delivery to the HRS via liquid hydrogen trucks. The study reports that the lowest cost of hydrogen is obtained for offsite H_2 production at a renewables-rich area with a grid-connected system and liquid hydrogen delivery to the HRS. De León et al. [21] developed a model for the supply chain of liquid hydrogen throughout Hungary for both transport and industry sectors. The work recommends sector-coupling as cost-effective measure with a smooth and gradual integration of both sectors, with hydrogen production costs between 3.95 and 6.33 US$/kg. Hurskainen et al. [22] evaluated the performance of liquid organic hydrogen carriers (LOHC) against gaseous hydrogen delivery for long distance road transport, with a significant improvement in the delivery costs when using LOHC compared to other alternatives for distances over 200 km. Likewise, Reuβ et al. [23,24] and Wulf et al. [25] studied the feasibility of LOHC for hydrogen distribution in Germany, showing that hydrogen storage in salt caverns and distribution through pipelines is the best option for higher penetration of fuel cell electric vehicles (FCEV), while Baufumé et al. [26] designed a pipeline network for hydrogen transmission, with a total length over 12,000 km. Furthermore, Reddi et al. [27] and Lahnaoui et al. [28] addressed the cost-competitiveness of compressed hydrogen transportation. Thus, Reddi et al. evaluated the configuration of tube trailers to lower delivery costs and reporting that the appropriate configuration may reduce by up to 16% the hydrogen delivery costs. In contrast, Lahnaoui et al. achieved transporting costs between 0.45 and 2.7 €/kg. Talebian et al. [29] conducted an optimization of the hydrogen supply chain selecting between different types of gaseous and liquid hydrogen trucks in Canada, with hydrogen obtained from steam methane reforming being the least costly hydrogen production technology even considering carbon taxes. Similarly, Parolin et al. [30] developed a multi-modality optimized hydrogen supply chain selecting among pipelines, gaseous and hydrogen trucks in Sicily (Italy), resulting in a cost of delivered hydrogen of 3.81 €/kg for an assumed demand of 1.1 million passenger cars. Vijayakumar et al. [31] accounted for demand uncertainties and electricity dispatch strategies when optimizing the hydrogen supply chain for the transport sector in California (USA), reporting that long-term investments, further incentivized grid-connected electrolyzers and demand certainty would overall reduce hydrogen costs. Forghani et al. [32] developed a multi-period model that extracts geospatial information from Google Maps for the design of the hydrogen supply chain in Oman. Likewise, Ibrahim et al. [33] proposed a model for the optimization of low-carbon hydrogen supply chain in industrial clusters of Qatar, reflecting that hydrogen transported as ammonia results in 19% reduction of costs compared to liquid hydrogen or LOHC. Eventually, Yang et al. [34] proposed a model for the planning and operation of a hydrogen supply chain based on off-grid wind energy and hydrogen production, achieving hydrogen production costs ranging between 3.073 and 3.155 US$/kg, while Tlili et al. [35] developed a geospatial model to identify the most convenient hydrogen supply pathway, with liquid hydrogen storage and distribution in trucks being the most competitive solution.

Under this framework, this manuscript performs a techno-economic analysis of a hydrogen generation and supply chain to contribute to the decarbonization of the Spanish transport sector by 2050. Thus, the substitution of the fossil fuel-based vehicle fleet (particularly cars, vans, trucks, buses and motorcycles) by hydrogen-powered vehicles is evaluated. In this sense, FCEV or internal combustion engines running on hydrogen have been considered, the latter representing an interesting alternative for the repurposing of fossil fuel-based vehicles [36,37]. To ensure the hydrogen supply to the overall vehicle fleet of Spain, the required green hydrogen infrastructure has been designed (RES hubs, electrolyzers, hydrogen storage, and auxiliary equipment). It should be noted that the existing transport natural gas grid is considered to be repurposed for hydrogen transmission and current gas stations replaced by hydrogen refueling stations (HRS). Thus, a favorable policy framework and commitment towards meeting GHG reduction targets is considered. This assumption implies that current natural gas consumption across the country will be substituted by hydrogen. Furthermore, geospatial evaluation is performed to allocate the different RES generation hubs dividing the peninsular territory into six different regions. In every region, a central hydrogen generation location has been defined coinciding with the regasification plants and refineries in Spain because they are connected to the natural gas transportation network. Besides, two different methods for hydrogen distribution are compared to assess the best alternative in every region: hydrogen distribution through pipelines and liquefied in trucks. As a result of the analysis, the configuration with the lowest levelized cost of hydrogen (LCOH) for end-users will be obtained, as well as the dimensions of the required infrastructure. Finally, the cost breakdown of hydrogen production, storage, compression, liquefaction (if any), transmission and hydrogen refueling costs in each of the six regions previously defined will be calculated. This analysis will be carried out using HOMER Pro, HDSAM and GLAES tools in the 2050 time horizon.

Methodology

This section outlines the energetic analysis performed in the manuscript, including the computational tools employed, the information of hydrogen demand of the Spanish vehicle fleet (excluding those of Balearic and Canary Islands, Ceuta and Melilla), the cost and characteristics of the main technologies considered for the optimization of the hydrogen supply routes and the land eligible for the deployment of RES generation hubs in the different defined regions. Thus, the present work aims at providing the most cost-effective green hydrogen supply infrastructure in Spain out of the simulated delivery methods to decarbonize light and heavy-duty transport applications by 2050, mainly passenger cars, motorcycles, trucks, vans and buses. In this regard, although green hydrogen is not foreseen in international and leading pledges to be employed for light mobility decarbonization, the complete Spanish vehicle stock is considered to be replaced by FCEVs, while current registered battery electric vehicles (BEVs) are out of the scope of this substitution process. The analysis of this ambitious scenario of 100% penetration of hydrogen-powered vehicles aims at evaluating the overall techno-economic feasibility of the hydrogen supply chain, assuming the investment required, the renewable capacity to be installed, and the location of the infrastructure. Moreover, a further evaluation will be made assuming a lower penetration of 50 and 75% to consider the effect of an insufficient infrastructure and/or other alternative mobility methods to hydrogen-powered vehicles. Hence, the ultimate goal of this study is the minimization of the levelized cost of hydrogen (LCOH), understanding it as the final price that end-users will pay at the nozzle of the hydrogen refueling station. This work has not considered the possibility of importing hydrogen from other locations rich in renewable energies such as Australia, Chile or United Arab Emirates (UAE), as they report overseas hydrogen import prices between 4.35 and 4.57 €/kg H_2 for the year 2030 (depending on whether the transport is in the form of liquid hydrogen, ammonia or LOHC); while local generation costs in Spain are estimated at 3.1 €/kg [38]. Concerning LCOH, it corresponds to the sum of hydrogen production costs (HPC), hydrogen storage costs (HSC), hydrogen compression costs (HCC), hydrogen liquefaction costs (HLC), hydrogen transmission and distribution costs (HTDC), and hydrogen refueling station costs (HRSC). Moreover, this research delves as well into the layout of RES in each region for centralized hydrogen production. Hence, Fig. 1 describes the overview of the methodology proposed for the development of the hydrogen supply model.

This methodology is separated into three different sections, namely 1) input data inventory, 2) objective functions and employed software, and 3) techno-economic assessment of the main outcomes arisen from the study. Firstly, the hydrogen demand of the Spanish vehicle stock is estimated. Moreover, the RES required to cover the hydrogen consumption, as well as the equipment costs and characteristics, the compressor consumption and the land eligible per location are considered. Hence, the hydrogen load profile varies depending on the number and type of vehicles registered per region according to the Spanish Observatory of Transport and Logistics (OTLE) [39]. Concerning land eligibility, constraining criteria have been selected for solar irradiation and average wind speeds to obtain the best locations for the deployment of photovoltaic (PV) panels and wind turbines (WT) using GLAES programming code. Apart from designing the required renewable and hydrogen production infrastructure by means of HOMER Pro software, the lowest-cost hydrogen transmission and distribution method is defined using HDSAM tool.

Modeling software

The computational tools HOMER Pro, GLAES and HDSAM employed for the techno-economic and geo-spatial simulation are explained hereafter.

HOMER Pro software

This tool developed by the National Renewable Energy Laboratory (NREL) of the United States stands for Hybrid Optimization of Multiple Energy Resources [40]. Despite it is often used to model different stationary applications [41] such as microgrids [42], remote areas [43], residential [44] or service buildings [45]; this software enables to optimize the dimensions of a hydrogen refueling station (HRS) [46] through the design of the required RES, electrolyzer and storage system [47]. Thus, this tool simulates multiple alternative configurations capable of meeting a certain load (either electric, thermal or hydrogen) and ranks them from the lowest to the highest net present costs (NPC) of the system.

Specifically, in this study HOMER Pro software has been applied to design the renewable energy capacity, the electrolyzer size and the hydrogen storage in each region aimed at decarbonizing the Spanish vehicle fleet by 2050. Firstly, hydrogen consumption introduced through and hourly distribution profile that differentiates between peak and off-peak refueling times. PV panels and wind turbines dimensions are calculated taking into account the electricity consumption of the electrolyzer and the auxiliary equipment such as compressors and liquefaction plants. Thus, the specific meteorological characteristics of each region (solar irradiation, average wind speed and temperature) are obtained from NASA databases. Subsequently, these components are defined by introducing their costs (CAPEX, OPEX, and replacement), and characteristics (lifetime, efficiency, temperature effects, and degradation). The main results of the simulations consist of the required capacities of the components to generate and store the amount of hydrogen specified, NPC, levelized cost of energy (LCOE), HPC, HSC, and the electricity mix composition. In this case, the most significant results for our analysis are those corresponding to HPC and HSC to finally get the hydrogen costs at the nozzle for end-users. Additionally, HOMER Pro provides an insightful report of every modeled equipment, evaluating several additional parameters such as hours of operation, maximum, minimum and average power delivered or consumed, hydrogen production, yearly storage evolution or hourly distribution of electricity generation. The *Supplementary Information Sheet* of Maestre et al. [48] can be consulted for more detailed information about the employment of HOMER Pro software.

Land eligibility

The deployment of renewable energies highly depends on the optimal climate resources for a given location. However, these optimal locations might be occupied by other facilities, different infrastructure or even belong to protected natural parks. Hence, the land eligibility in the different regions is analyzed to evaluate the deployment feasibility of the RES obtained in HOMER Pro simulations. The evaluation of the geo-spatial allocation is carried out within a program

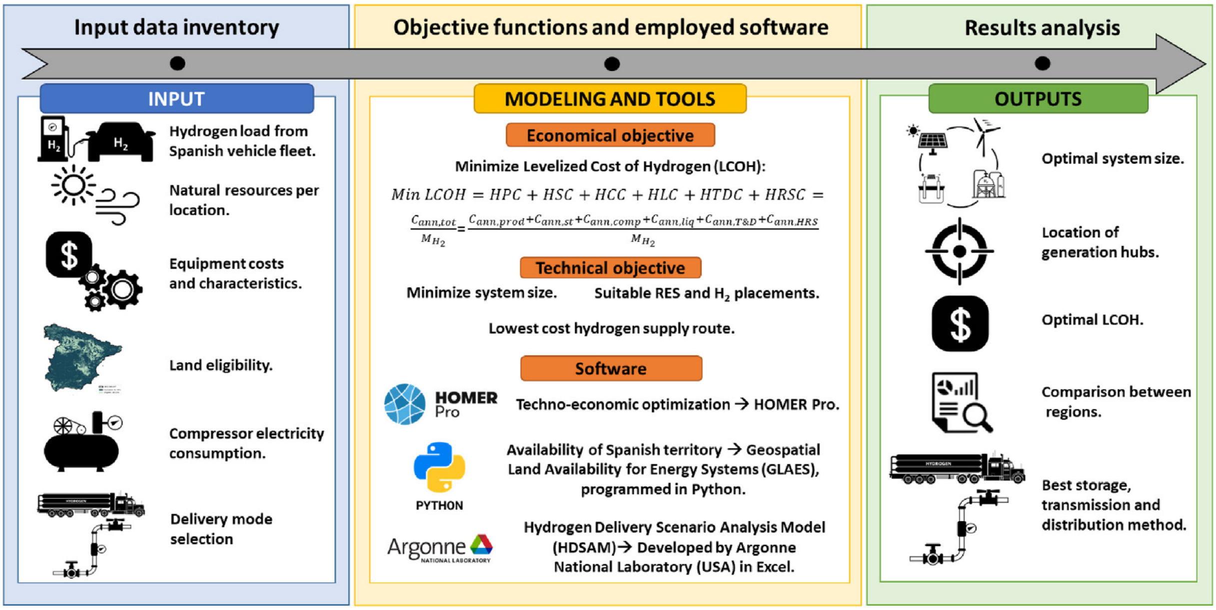

Fig. 1 – Overview of the methodology proposed for the hydrogen supply model.

developed in the Python programming language named GLAES (acronym of Geospatial Land Availability for Energy Systems) which has been developed by Forschungszentrum Jülich GmbH. This programming code can be found on GitHub as open source [49]. This tool restricts the available surface area of a region according to its proximity to different infrastructures, protected areas, or geological formations. In this way, more or less restrictive values can be defined for different exclusion criteria depending on how demanding they are with respect to the constraints of each location [50,51]. Apart from those eligibility standards, the places that do not secure a certain solar irradiation or wind speed at different heights are excluded [52]. As the complete substitution of fossil fuel-based vehicle fleet by FCEVs and hydrogen-based heavy-duty vehicles requires an ambitious economic and policy framework, minimum values for exclusion have been defined except from solar irradiation and wind speed criteria, which are more demanding to obtain the better locations [48]. The criteria for land eligibility is included in the *Supplementary information sheet*.

HDSAM model

The Hydrogen Delivery Scenario Analysis Model (HDSAM) is an Excel-based model developed by the Argonne National Laboratory for the Department of Energy of the United States (DOE) within the framework of the Hydrogen Analysis Project (H2A). This tool aims at estimating the cost of delivering hydrogen from the production facility to the FCEV [53]. It enables to model different hydrogen supply routes and different delivery methods such as liquid or compressed hydrogen, and even pipeline delivery. Users may also include relevant parameters such as the penetration of hydrogen-fueled vehicles in the market, the HRS capacity, if the infrastructure is designed for an urban or rural area, etc. [54]. In this work, HDSAM is employed to assess the most cost-competitive hydrogen delivery scenario per region, where natural gas transmission infrastructure is overhauled and repurposed for hydrogen transport. Finally, two different distribution methods are evaluated: gaseous hydrogen through dedicated pipeline network or liquid hydrogen distributed in trucks to hydrogen refueling stations. To this end, the daily hydrogen consumption per region is introduced, as well as the number of vehicles per region, and the dispensing rate of every HRS. Finally, a cost breakdown is obtained according to their origin, these being hydrogen compression costs (HCC), hydrogen liquefaction costs (HLC, in the case of liquid hydrogen distribution in trucks), hydrogen transmission and distribution costs (HTDC) and hydrogen refueling station costs (HRSC), which are added to hydrogen production costs (HPC) and hydrogen storage costs (HSC) obtained with HOMER Pro software [55]. All these equation are defined in *Supplementary information sheet*.

Hydrogen demand

According to the Spanish Ministry for the Ecological Transition and the Demographic Challenge, the transport sector in Spain is responsible for 43% of the final energy consumption and 27% of CO_2eq emissions [56]. In addition, 92% of emissions associated with passenger mobility are linked to road transport, rising to 96% in the case of freight transport [57]. Therefore, the decarbonization of this hard-to-abate sector would lead to a dramatic decrease of GHG emissions and, thus, it would foster the mitigation of climate change in Spain.

Within this scope, the following section addresses both the total and the regional estimation of the hydrogen consumed by the Spanish vehicle stock (excluding Balearic and Canary Islands, Ceuta and Melilla) for its complete decarbonization by 2050.

Estimation of Spanish vehicle stock consumption

As per 2021, the Spanish vehicle fleet (excluding the aforementioned regions) amounted to 32.2 million between cars, motorcycles, trucks, buses, vans and other heavy-duty vehicles [39]. Due to the demographic characteristics of Spain and the expected compensation of the vehicle market growth by future alternative ways of mobility such as car sharing or public transport, it is assumed that the vehicle stock will not increase by 2050 compared to 2021 [58]. Concerning hydrogen demand, different consumption rates have been estimated depending on the type of vehicle. Furthermore, it has been distributed between regions taking into account the vehicle share in each one. Thus, passenger cars (71% of the vehicle stock) predominate over trucks and vans (14%), motorcycles (11%), and other vehicles (including buses, industrial tractors, etc., 4%). Finally, considering the fuel consumption rate and mileage per year for each vehicle it has been estimated a total demand for the Spanish vehicle stock of 22.25 million tonnes of H_2 per year. More details are given in the *Supplementary information sheet*.

Distribution of hydrogen demand

Here, both the hourly consumption and the geographical consumption distribution are discussed. With regard to the hourly demand profile of hydrogen in the different HRS in every region, the work developed by Chen et al. [20] has been employed as reference. Furthermore, real traffic data obtained from OTLE [57] database have been included to consider the variability throughout the year between different days and months. The peak demand occurs from 15:00 to 18:00 when most of the workers are leaving their jobs. On the contrary, the off-peak periods correspond to the early morning hours when most people are sleeping. The shape of the consumption profile is displayed in Fig. 2.

Spain has seven different regasification plants for liquid natural gas imported overseas (one of them has started its operation in January 2023) spread over the country in different coastal areas. All these plants have a total natural gas storage capacity of 3.6 million Nm^3. In addition, the primary natural gas transportation network in Spain is connected to different underground storage facilities that have a useful storage capacity of 3.4 billion Nm^3 (excluding cushion gas) [59]. These regasification plants have been considered to allocate the required amount of electrolyzers. Thus, different regions have been defined according to their proximity to them. These regions are represented in Fig. 3. In the case of Region 5 (Community of Madrid and Castile-La Mancha), the refinery of Puertollano is considered as the center of hydrogen generation [60]. Moreover, their estimated hydrogen consumption according to the vehicle share in each region [61] are summarized in Table 1.

Definition of hydrogen supply pathways

The supply of hydrogen to decarbonize the Spanish vehicle stock can be executed through different configurations that are shown in Fig. 4. Hence, this work considers the repurposing of the Spanish natural gas transmission grid to transport the produced hydrogen. This transmission network has more than 13,000 km [59] of pipelines whose design pressure is mostly between 70 and 80 bar (although there are stretches of up to 220 bar for offshore natural gas transmission) [62]. Therefore, the outlet hydrogen stream from the electrolyzers with a pressure of 70 bar [63] is compatible with the existing natural gas grid and it has been chosen for hydrogen transmission. Furthermore, this network is well distributed throughout the Spanish territory, and it includes strong interconnections with neighboring countries like France and Portugal. The hydrogen generated and transmitted is then compressed up to 250 bar and stored prior to the distribution phase, aligned with different recent works conducted for the design and analysis of hydrogen supply chain [23,24,30,32]. In this regard, two different alternative distribution methods have been compared to assess their cost-competitiveness, which are either pipeline or liquid hydrogen distribution in tanker trucks. In the case of gaseous distribution, the distribution network has been considered to supply hydrogen to the refueling station at 70 bar. To ensure this pressure at the outlet (entry of the hydrogen refueling station), the inlet pressure at the distribution pipeline is 100 bar to avoid pressure losses, with this value being 100 bar. Then, hydrogen is compressed to 875 bar in the HRS to secure that 700 bar are provided during dispensing. On the contrary, the distribution of liquid hydrogen requires three additional stages prior the final compression and dispensing in HRS, being those the transformation of gaseous hydrogen into liquid hydrogen in a liquefaction plant, then its distribution by trucks and the final evaporation in a vaporizer to obtain gaseous hydrogen again [64]. This method has been selected instead of gaseous delivery in trucks due to the bulk hydrogen quantities to be dispensed. In this sense, using liquid hydrogen for distribution increases the amount of hydrogen transported per truck. At 1 bar, liquid hydrogen has a density of 71 kg/m^3 while gaseous hydrogen density is 0.0899 kg/m^3 under ambient conditions [65]. Nevertheless, liquid hydrogen conditioning results in higher CAPEX and OPEX than compression, being gaseous hydrogen delivery in trucks the optimal choice in the case of low hydrogen demand. Finally, current gas stations are considered to be substituted by hydrogen refueling stations.

Description of system components

The feasibility of the complete substitution of the Spanish vehicle fleet by hydrogen-powered vehicles highly depends on the levelized cost of the obtained hydrogen. Thus, prospective costs and characteristics of the main technologies for 2050 are considered. Therefore, Table 2 gathers the forecasted range of capital expenditures (CAPEX), operational expenditures (OPEX), and replacement costs of the equipment along with the main characteristics considered in the simulation of the energy system. These values have been obtained from different projections made by international organisms such as IEA [66–69], IRENA [63,70], DOE [71–73], or Clean Hydrogen Partnership [74]. In this regard, the lowest limit of capital investment ranges has been chosen for the calculation of the resulting costs as a favorable policy framework and an advanced development of these technologies is considered.

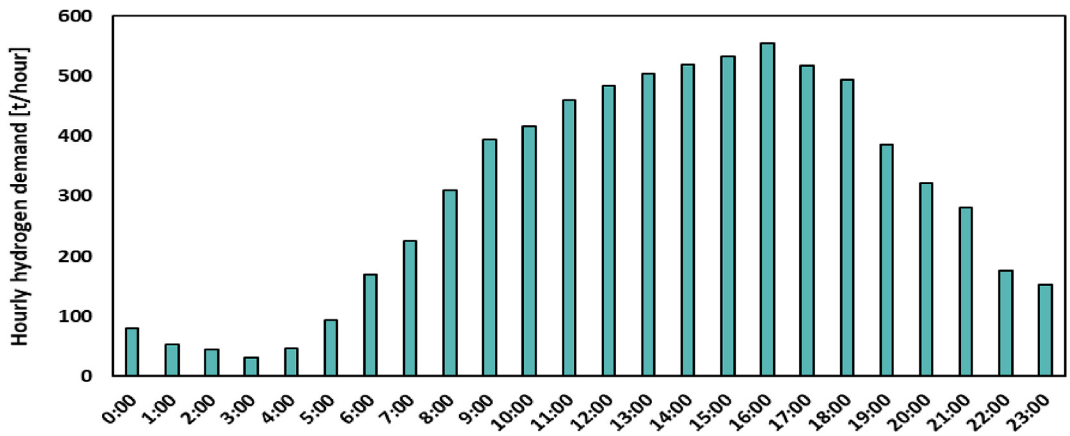

Fig. 2 – Hourly hydrogen demand profile shape.

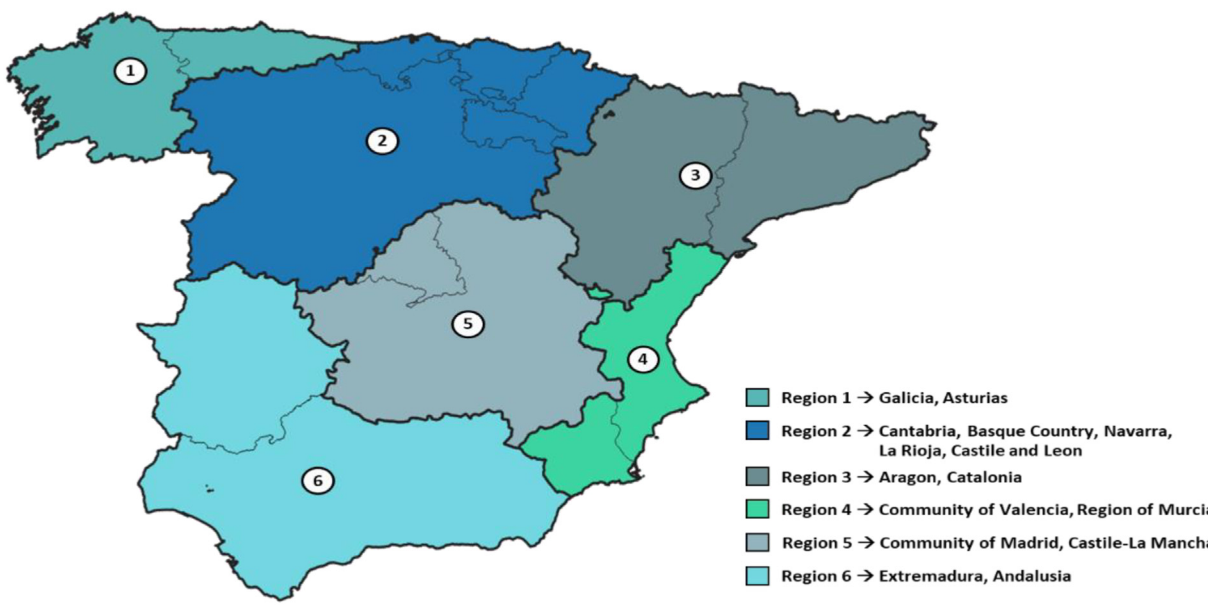

Fig. 3 – Different regions of analysis.

Table 1 – Population and hydrogen demand per region.

Region	Hydrogen demand (millions tonnes H_2/year)	Daily hydrogen demand (tonnes H_2/day)	Registered vehicles (millions)
1	1.96	5366	2.8
2	3.06	8382	4.4
3	4.40	12,050	6.3
4	3.33	9127	4.8
5	4.69	12,842	6.9
6	4.81	13,189	7
Total	22.25	60,956	32.2

The energy infrastructures are sized to meet the hydrogen load previously depicted per region through the deployment of new capacities of PV panels and wind turbines. This renewable energy is employed to power the electrolyzers for hydrogen generation and the ancillary equipment such as compressors and liquefaction plants. Steel vessels have been selected for intermediate hydrogen storage, while the required power conversion is introduced to adapt RES generation to the electric requirements of the electrolyzer stack and auxiliary devices. These components modeled in HOMER Pro software as well as the equations to calculate the hydrogen compressor capacity have been taken from Maestre et al. [48].

On the other hand, hydrogen transmission and distribution costs depend on the method selected. In this case, major

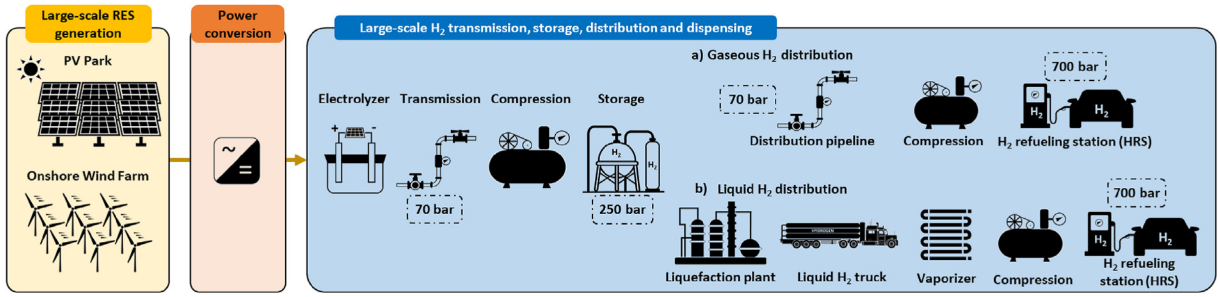

Fig. 4 – Different hydrogen supply pathways.

transport from the centralized hydrogen generation hubs to the intermediate storage points is done through the reconditioned primary natural gas grid. Thus, capital costs (CAPEX) of transmission pipes are reduced by 16–19% compared to the installation of new ones for hydrogen transport [78]. In this case, 16% value is selected as a favorable framework and an advanced technology development has been considered in the simulations. This increase in the costs is mainly related with the substitution of joints, gauges, and valves, and thus, all the primary pipeline network is harnessed for the transportation of hydrogen with a replacement of these devices. CAPEX, replacement costs (referred to the complete substitution of the pipeline) and operational costs (OPEX) are defined in Eqs. (1)–(3) [20,53] as function of the diameter of the pipeline and its length. These equations have been obtained from Hydrogen Delivery Scenario Analysis Model (HDSAM):

$$CAPEX\,(US\$) = 0.209\cdot\left[\left(303.13\cdot(2.54\cdot D)^2 + 12{,}908\cdot(2.54\cdot D) + 164{,}241\right]\cdot 1.60934\cdot L + 1.1\cdot 63{,}027\cdot e^{(0.177038\cdot D)}\cdot 1.60934\cdot L \right. \tag{1}$$

$$Replacement\ costs\,(US\$) = 1.1\cdot 63{,}027\cdot e^{(0.177038\cdot D)}\cdot 1.60934\cdot L \tag{2}$$

$$OPEX\,(US\$) = 1.1\cdot\left[\left(-51.393\cdot(2.54\cdot D)^2 + 43{,}523\cdot(2.54\cdot D) + 16{,}171\right]\cdot 1.60934\cdot L\right. \tag{3}$$

Furthermore, in the case of distribution pipeline, replacement costs and OPEX are the same, while CAPEX, given in Eq. (4), considers a new dedicated hydrogen infrastructure:

$$CAPEX\,(US\$) = 1.1\cdot\left[\left(303.13\cdot(2.54\cdot D)^2 + 12{,}908\cdot(2.54\cdot D) + 164{,}241\right]\cdot 1.60934\cdot L + 1.1\cdot 63{,}027\cdot e^{(0.177038\cdot D)}\cdot 1.60934\cdot L\right. \tag{4}$$

In all equations D is the diameter of the pipeline in centimeters and L the length of the pipeline in kilometers.

Finally, liquid hydrogen production is an energy intensive process, requiring an energy amount between 8 and 12 kWh/kg of hydrogen [25]. These energetic needs are modeled in HDSAM through Eq. (5), while CAPEX and OPEX are given in Eqs. (6) and (7) [54,55]:

$$Liquefaction\ power\ plant\,(kWh/kg) = 13.382\cdot(Plant\ capacity)^{-0.1} \tag{5}$$

$$CAPEX\,(US\$) = 5{,}600{,}000\cdot(tons\ of\ H_2/day)^{0.8} \tag{6}$$

$$OPEX\,(US\$) = 17{,}520\cdot\left(\frac{M_{H_2}}{100{,}000}\right)^{0.25} \tag{7}$$

Where the base liquefaction plant capacity is assumed to be 200 metric tonnes per day, and M_{H_2} the average liquid demand of hydrogen in kg/day.

Results and discussion

The results obtained through the application of the previously described methodology are presented and evaluated. Thus, in this section sizing and location of PV panels and wind turbines in every region and sizing of electrolyzers and hydrogen storage capacities are assessed. Moreover, the comparison of different delivery options and hydrogen supply routes is made, with the final analysis of the cost-breakdown of all the expenses involved in the final levelized cost of hydrogen in every region for end-users.

Large scale RES generation, hydrogen production and storage

Fig. 5 depicts the land eligibility in Spain for both PV panels and wind turbine deployment along with their corresponding installed capacities and those required for hydrogen generation and storage. The land eligibility per region together with the maximum installable capacity of PV panels and wind turbines is gathered in the *Supplementary information sheet*. Fig. 6 represents the installed capacity of the main RES technologies, electrolyzers and hydrogen storage per region. Furthermore, compression and liquefaction requirements per zone are also reflected along with the energy consumed by these auxiliary equipment.

The eligibility of the territory reflects a clear division in Spain between north and south. The regions with more wind energy potential are in the north of Spain, while large-scale deployment of PV panels is neither cost-effective nor feasible due to the lack of solar irradiance in these provinces, the rugged relief of these areas and the large number of natural parks and protected areas. Likewise, coastal zones of Catalonia, Community of Valencia and Region of Murcia are not eligible due to their high population density. For instance, PV panels are not eligible in region 1 where only wind turbines can be deployed to provide cheap and efficient energy to the electrolyzers. Thus, a low penetration of PV panels is obtained in regions 2 and 3 (except in some areas of Castile and Leon or Aragon) representing around 20% of their total installed renewable capacity.

On the contrary, the mid-south of Spain is rich in solar resources where large PV parks are more efficient and cost-competitive. Besides, certain zones of Andalusia or Castile-La Mancha present great possibilities for the implementation of wind turbines. Therefore, the RES capacities installed in regions 4, 5 and 6 present a more balanced mix, with a slight predominance of PV panels (51% of total installed capacity in these regions) over wind turbines (49%). It should be noted that PV panels stand over wind turbines in region 4 due to the limited area available for their installation. As for the comparison between regions, region 6 represents almost 25% (102.9 GW) of the total installed capacity (443.1 GW) and together with regions 4 and 5 account for almost two thirds of the renewable capacity in Spain. In total, the resulting installed renewable capacity in Spain necessary for the decarbonization of the transport sector in 2050 is 266.4 GW of wind generators and 176.7 GW of solar photovoltaic panels. This predominance of wind energy as the main renewable energy source is aligned with the perspective of the Integrated Energy and Climate Strategy carried out by the Spanish Government [79].

Table 2 – Equipment costs and main characteristics of components for the year 2050.

Component	Technology	Costs			Equipment characteristics	Ref.
		CAPEX (US$/kW)	Replacement (US$/kW)	OPEX (US$/kW)	Description	
PV	Large scale	400–600	50% CAPEX	4% CAPEX	Lifetime: 25 years. Derating factor: 90%	[66,67,70,71]
Wind turbine	On-shore	900–1100	75% CAPEX	2% CAPEX	Lifetime: 25 years. Rated capacity: 7.58 MW (Enercon E–126). Hub height: 135 m. Rotor diameter: 127 m.	[70,72]
Electrolyzer	PEMEC	200–600	30% CAPEX	2% CAPEX	Lifetime: 25 years. Efficiency: 43.8 kWh/kg. Outlet pressure: 70 bar	[63,68,74,75]
Hydrogen storage (US$/kg)	Steel vessel	120–150	85% CAPEX	1% CAPEX	Lifetime: 25 years. Storage pressure: 250 bar	[74,76]
Compressor	Mechanical	600–800	85% CAPEX	5% CAPEX	Lifetime: 22 years. Isentropic efficiency: 88%.	[73,74]
Power conversion		400–600	85% CAPEX	5% CAPEX	Lifetime: 25 years. Efficiency: 95%	[77]

Concerning hydrogen generation and storage, a total capacity of 214 GW of proton exchange membrane electrolyzers (PEMEC) and a storage capacity of 3.45 TWh are required. Hence, an installed capacity of 10 GW of electrolyzers is required on average to produce a million ton of H_2 every year. All the regions reflect an installed electrolyzer capacity proportional to their hydrogen demand. However, there are slight differences between regions with similar hydrogen consumption. For instance, regions 5 and 6 have a consumption of around 13 tonnes of H_2 per day, being the demand in region 6 the highest one. Nevertheless, the installed electrolyzer capacity is 1 GW less in this region despite the higher consumption due to the higher primary renewable energy available that leads to a higher capacity ratio (defined as the ratio between the average power consumed by the electrolyzer and its installed capacity) and more operating hours at full load, resulting in more hydrogen generated at region 6 with a lower installed capacity. On the other hand, regions 3 and 4 present the highest storage capacities. In the case of region 3 (Catalonia and Aragon), with a similar hydrogen consumption to region 5 (Community of Madrid and Castile-La Mancha) there is a difference of 4 GW less of PEMEC and 284 GWh more of storage capacity that is related with the lower average solar irradiance and wind speed available in region 3 compared to region 5. These differences in climate resources have an impact from an economic perspective, making hydrogen produced in region 3 more competitive in a

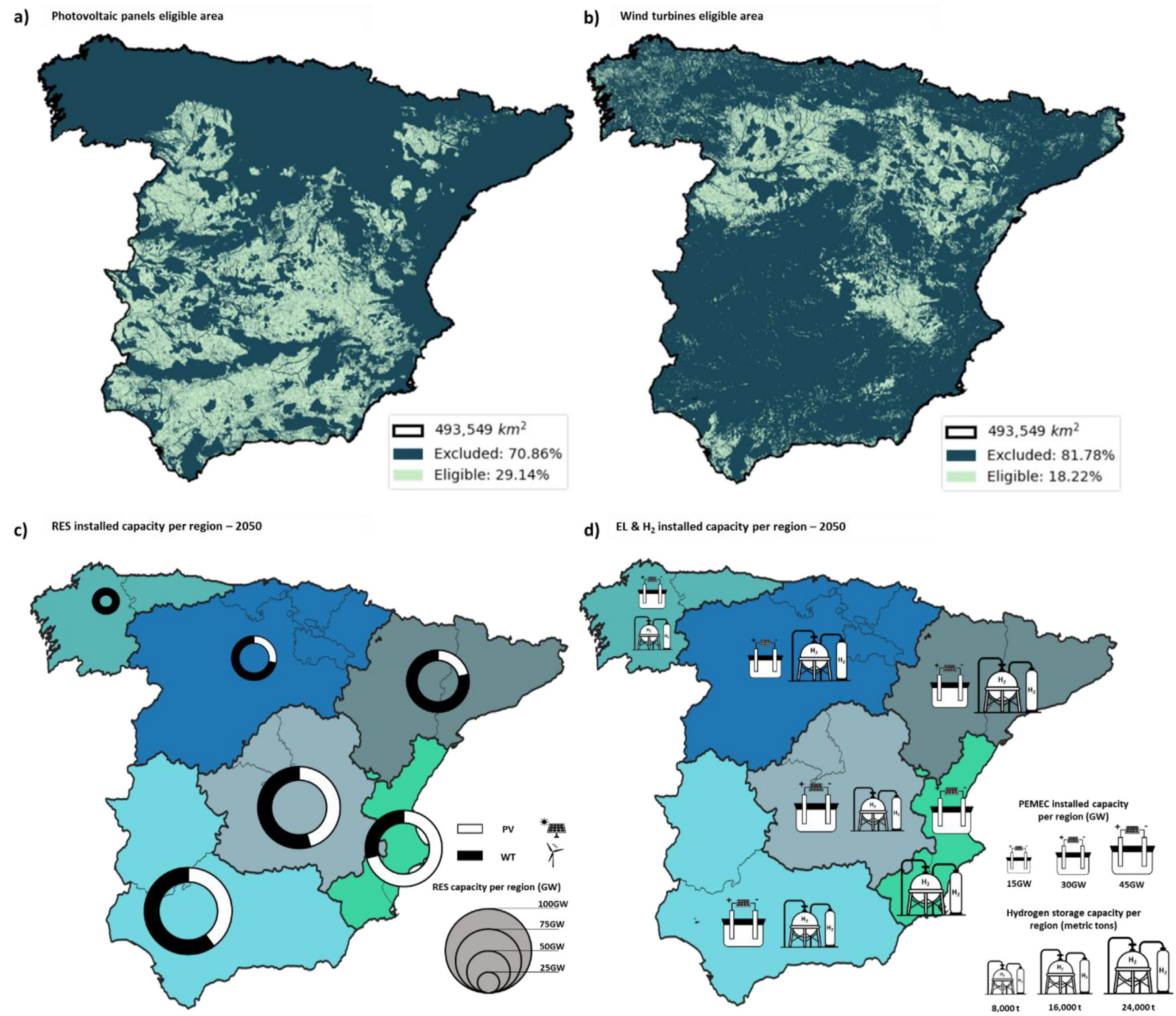

Fig. 5 – Land eligibility for PV farms (a) and wind turbines (b), RES deployment (c), required electrolyzers and hydrogen storage capacities (d) per region.

configuration where storage is increased versus direct hydrogen generation and consumption.

Fig. 6b shows both the installed capacities of compressor and liquefaction plants and their energy consumptions per regions. Compression installed capacities include two different stages: the first stage increases hydrogen pressure from 70 bar to 250 bar for storage, and the second stage from 70 to 875 bar for hydrogen refilling in the HRSs at 700 bar. In contrast, in the case of liquid distribution, hydrogen is converted into its liquid from in the liquefaction plant that is made right after the storage. Thus, hydrogen enters the liquefaction facility after the first compression stage. Then, it is transported in liquid form at atmospheric pressure to the hydrogen refueling station, where it is firstly stored in a liquid hydrogen vessel, then pumped and evaporated in a vaporizer to convert it back to its gaseous form. Finally, hydrogen is compressed for its storage in pressurized hydrogen tanks for its dispensing at 700 bar [64]. For the selected liquefaction plant capacity of 200 tonnes of H_2 per day, an average consumption of 8 kWh/kg of hydrogen is obtained [25], while the energy requirements for hydrogen compression from ambient temperature and 20–700 bar are between 2.9 and 3.2 kWh/kg [80]. In this sense, liquid hydrogen distribution in trucks almost triples the energy consumption for hydrogen gas delivery. Finally, the surplus renewable energy generated to supply the electrolyzer is sufficient to meet the energetic requirements of compression and liquefaction processes.

Analysis of levelized cost of hydrogen (LCOH)

This section evaluates all the costs involved in the final levelized cost of hydrogen (LCOH) obtained per region and distribution method. This cost-breakdown is reflected in Fig. 7. Besides, Fig. 8 collects the topology of the repurposed transmission network, the distribution pipeline length as well as the number of liquid tanker trucks required and the number of

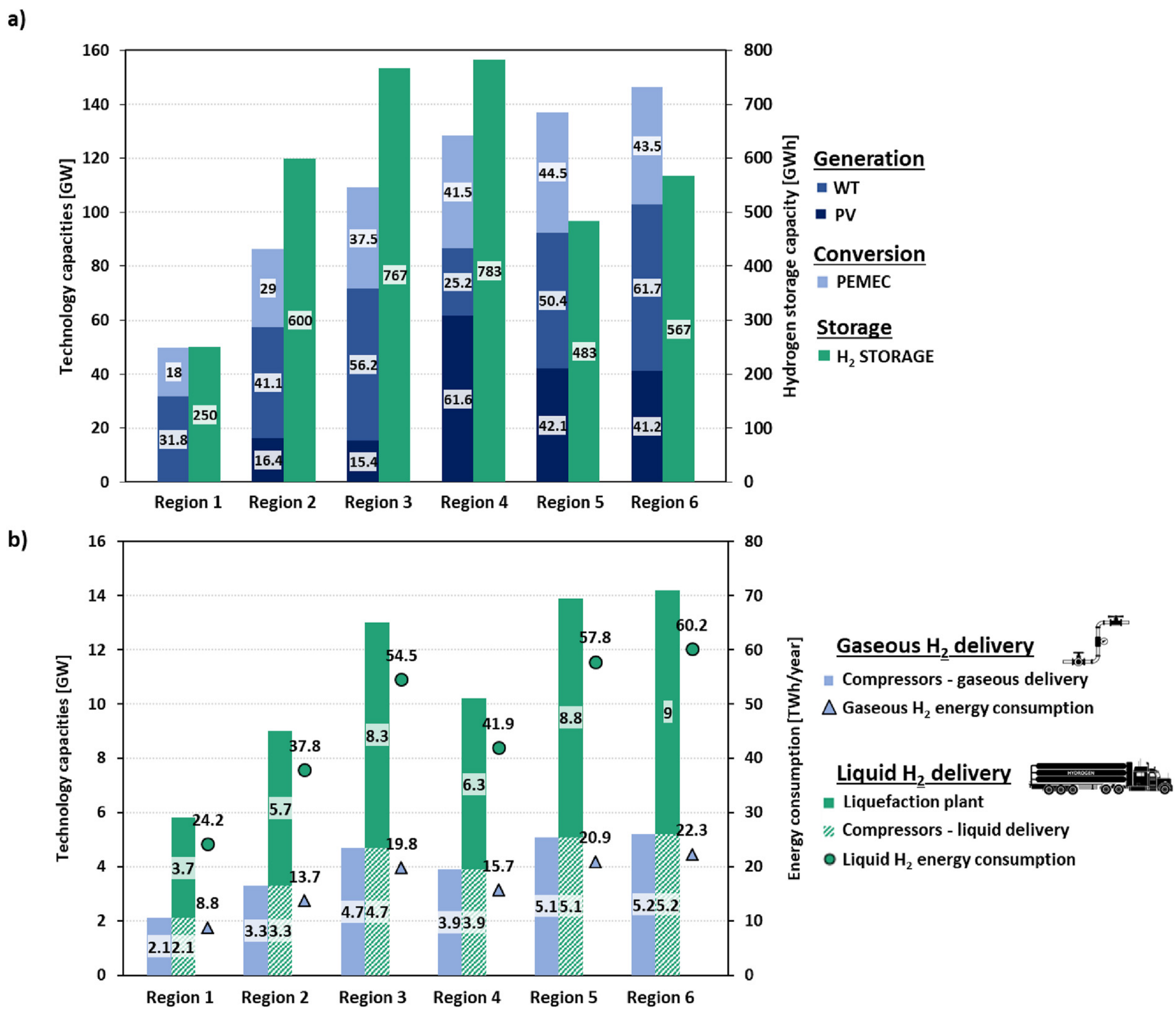

Fig. 6 – a) Generation, conversion (GW), and storage capacities (GWh) per region; b) installed capacities (GW) and energy consumption (TWh/year) of gaseous and liquid hydrogen delivery pathways in each region. The capacities in GW refer to electrical capacity.

hydrogen refueling stations per region. It should be noted that in Fig. 8 the distribution pipeline length refers to the gaseous delivery scenario, while the number of tanker trucks relates to liquid hydrogen distribution. More details of the different costs involved in the final LCOH and other parameters are included in the *Supplementary Information Sheet*.

As previously stated, the energetic infrastructure is the same for both supply methods, so hydrogen production costs (HPC) vary from 1.43 US$/kg for region 1 to 1.75 US$/kg in region 4 for hydrogen gas distribution and liquid delivery. Moreover, regions 3 and 6 present HPCs of 1.45 and 1.47 US$/kg. In this regard, regions 1, 3 and 4 result in these lowest values as they present the most cost-effective hydrogen production: the lowest levelized cost of energy (LCOE) from renewables to power the electrolyzers and the highest capacity factor of the latter. Fig. 7 reflects that hydrogen storage costs (HSC) represent a small fraction of the LCOH. All these costs have been obtained through the optimization of RES, electrolyzers and hydrogen storage capacities in HOMER Pro software. Besides, these costs are common for both supply methods.

On the contrary, hydrogen compression costs (HCC), hydrogen transmission and distribution costs (HTDC), and hydrogen refueling station costs (HRSC) have been calculated via HDSAM tool. Regarding HCC for gaseous delivery, compression stages from 70 to 250 bar and from 250 to 700 bar are considered. Thus, regions 6 and 2 reflect the lowest and highest prices, which are 1.72 and 1.98 US$/kg respectively. This low variation is linked with the number of refueling stations to be supplied and the extension of the region considered.

Besides, gaseous distribution in pipelines results in hydrogen transmission and distribution costs (HTDC) from 0.68 US$/kg in region 4 (Community of Valencia and Region of Murcia) to 1.54 US$/kg (Cantabria, Basque Country, Navarra, La Rioja and Castile and Leon). This wide range of prices is related to the length of the distribution pipeline required. Therefore, the largest regions present the highest HTDC. In

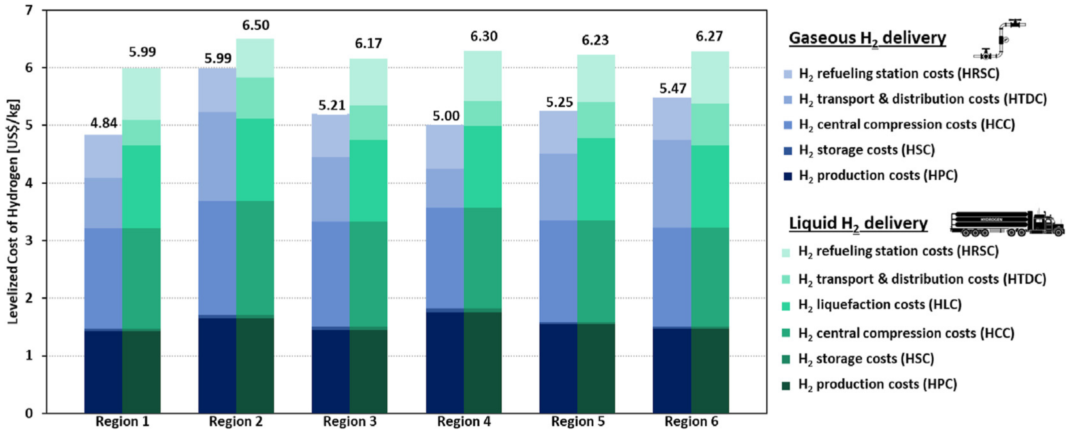

Fig. 7 – Levelized Cost of Hydrogen (LCOH) breakdown for gaseous and liquid hydrogen delivery pathways.

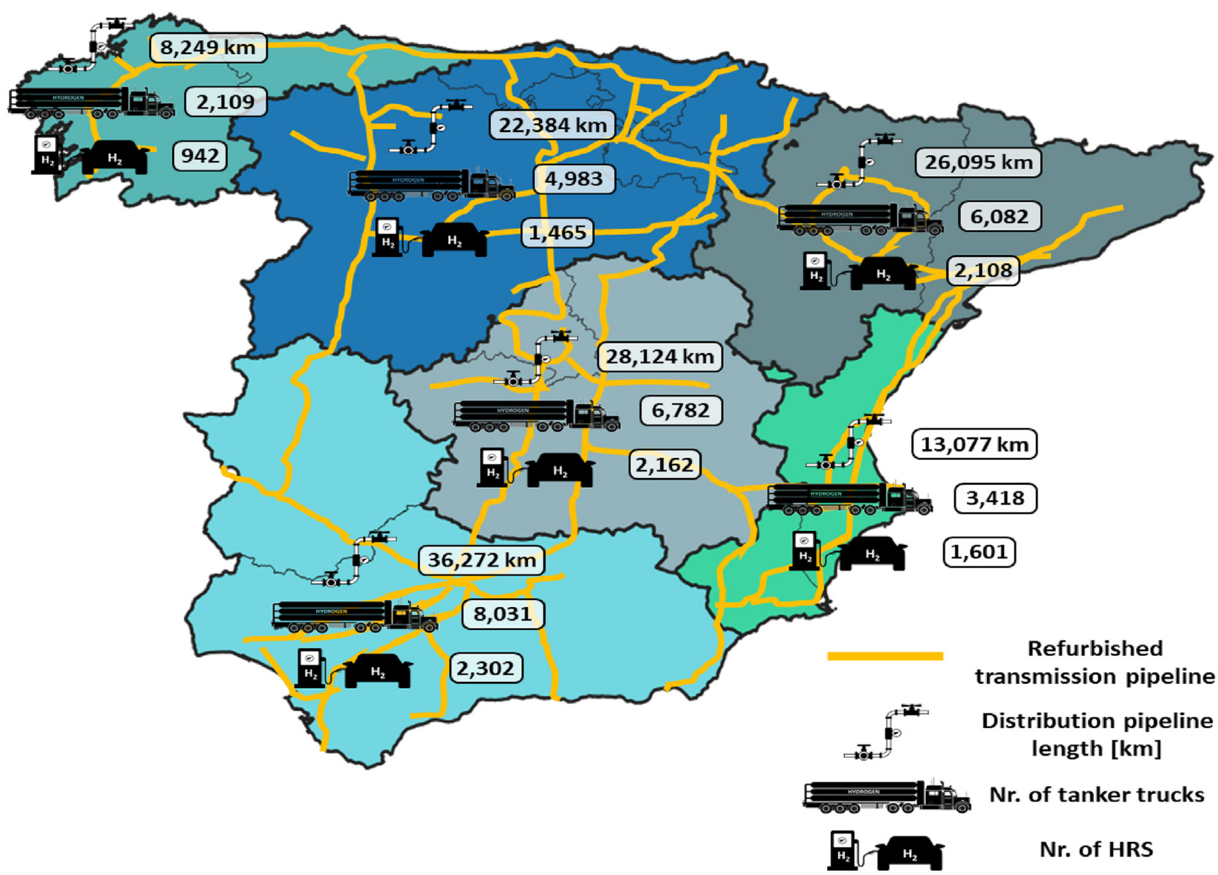

Fig. 8 – Topology of refurbished transmission pipeline, distribution pipeline length, number of tanker trucks and hydrogen refueling stations per region.

total, gaseous distribution requires a length of 134,200 km of dedicated hydrogen distribution network, which together with the more than 13,000 km of repurposed natural gas transmission grid makes a total length of transmission and distribution pipelines throughout Spain over 147,000 km. Finally, hydrogen refueling station costs (HRSC) shows values ranging between 0.63 and 0.65 US$/kg. The total number of hydrogen refueling stations required is 10,580, coincident with the number of gas stations reported by the Spanish Association of Petroleum Product Operators (AOP) in the regions subject of analysis [60].

Concerning the distribution of liquid hydrogen, hydrogen compression costs (HCC) remain constant from one delivery method to the other as pressure levels are not changed, while the liquefaction plant costs (HLC) increase to total LCOH in 1.42–1.43 US$/kg. Hydrogen transmission and distribution costs (HTDC) are lower for liquid hydrogen distribution in tanker trucks (0.43–0.75 US$/kg) than hydrogen distribution through pipelines. The variation of these costs between regions are related with the area and the hydrogen demand. Hence, regions 2 and 6 reflect the highest HTDC, being the largest regions. Every truck can deliver up to 3610 kg/day of hydrogen, which leads to a total tanker trucks fleet of 31,405 vehicles for liquid hydrogen delivery. Andalusia and Extremadura (region 6) represent more than 25% of this additional fleet (8031 trucks).

Finally, the costs of hydrogen refueling stations (HRSC) in the case of liquid hydrogen supply are higher compared to gaseous pipeline delivery due to the complexity of the refueling station, thus incrementing HRSC on average from 0.75 to 0.83 US/kg. The commissioning of liquid hydrogen is a demanding process in terms of security and ancillary equipment. These stations require a liquid hydrogen tank, a liquid pump and a vaporizer apart from the compressor and storage of gaseous hydrogen prior the delivery. Moreover, overheating and boil-off of liquid hydrogen has to be avoided, so all the equipment have great insulation requirements [64]. Thus, HRSC varies between 2.60 and 2.65 US$/kg, which are approximately 1.90 US$/kg more than gaseous hydrogen refueling costs.

Analyzing all the costs involved, the LCOH achieved by gaseous hydrogen transmission and distribution to the refueling station presents a higher cost-competitiveness compared with liquid hydrogen distribution in trucks. In this regard, the results line up with the strategy of the Spanish Government to create a hydrogen pipeline infrastructure to cover domestic demand and export low-cost green hydrogen to other European countries [81,82]. Thus, pipeline supply results in LCOH in the range of 4.84–5.99 US$/kg, while liquid hydrogen distribution costs are between 5.99 and 6.50 US$/kg depending on the region. Particularly, region 1 reflects the lowest LCOH (4.84 US$/kg) as it is the smallest region in terms of area and leads to minimal hydrogen transport and distribution costs (HTDC). This LCOH is around 68% less than the dispensing price in Germany in February 2023, with costs of 13.85 €/kg (around 15 US$/kg) [83]. It should be noted that this difference is related to the forecasted evolution on equipment costs and characteristics. Furthermore, the current refueled hydrogen is obtained through steam methane reforming of natural gas, whose price has exponentially increased during 2022. Region 2 presents the lowest difference between supply methods due to the large distribution pipeline required for a relatively low hydrogen demand.

The implementation of this ambitious scenario to achieve hydrogen-based road transport in Spain by 2050 requires a great commitment from the government, as it is necessary to mobilize a large investment capacity. In this sense, the total CAPEX per Mt of hydrogen produced over 25 years amounts to 25 billion US$/Mt of H_2. Besides, OPEX and replacement costs add up to an additional 13 billion US$/year in the case of hydrogen distribution through pipelines. In contrast, these values increase to 27 billion US$/Mt of H_2 and 14 billion US$/year respectively for liquid transport in trucks. Overall, these investments are in the range of the ones provided by the Spanish Government in the framework of the Recovery, Transformation and Resilience funds received from Europe and planned for the Spanish transition towards a sustainable energy system. Moreover, recently published works reported by Parolin et al. [30] for the case study of Sicily (Italy) or Vijayakumar et al. [31] in California (USA) reflect similar investments around 26 billion US$/Mt of H_2. However, the large renewable surplus can be used by other economic sectors or for international exports that can result in revenues up to 5 billion US$, taking forward prices into account provided by the Iberian Electricity Market Operator for prospect prices (OMIP) [84]. Detailed information on costs per region can be found in the *Supplementary Information Sheet*.

Given the implications of creating such infrastructure and the required capital mobilization, the impact that a reduction in hydrogen demand may have on LCOH and on the necessary investment must be considered. This reduction may occur either because the infrastructure size is not sufficient or because it coexists with other modes of transport. Thus, two additional preliminary scenarios have been proposed in which hydrogen demand is 50% and 75% of the original estimate respectively. This evaluation has been carried out for the regions presenting the lowest and highest LCOH to assess the range of variation on hydrogen dispensing prices and dimensions. Particularly, region 1 (Galicia and Asturias) that presents the lowest LCOH reduces the installed wind energy capacity from 31.8 GW to 16.2 GW (49% decrease) when the penetration of hydrogen-powered vehicles is halved, and to 27 GW (15% reduction) for a hydrogen demand corresponding to 75% of the original demand. Regarding the hydrogen value chain, the electrolysis capacity is reduced in 50% and 25% proportion when the hydrogen demand is the half and three-quarters of the base scenario, with the storage capacity being reduced in 47% and 27% respectively. Conversely, region 2 (composed by Cantabria, Basque Country, Navarra, La Rioja, and Castile and Leon) with the highest LCOH, the total RES capacity is reduced from 57.5 GW to 24.5 GW (57% less) in the case of 50% with a special impact on PV capacity that is reduced almost four-fold from 16.4 GW to 4.4 GW. Likewise, for a penetration of 75%, renewables capacity diminish to 44.1 GW (23%). PEMEC capacity decreases from 29 GW to 17 GW (41%) and hydrogen storage capacity from 600 GWh to 283 GWh (53%) when halving the demand. This reflects a higher direct consumption of hydrogen compared to the 100% decarbonization scenario. If the penetration of hydrogen-powered vehicles corresponds to 7% of the original values, electrolyzers are reduced to 21.5 GW and (26%) and the storage capacity to 467 GWh (23%). Concerning LCOH, its range increases for pipeline distribution from 4.84 to 5.99 US$/kg in the case of 100% substitution, to 6.85–8.1 US$/kg and 5.83–6.89 US$/kg for 50% and 75% of replaced vehicles respectively. Likewise, for liquid distribution the base scenario varies between 5.99 and 6.50 US$/kg, while 50% shows values of 9.48–10.40 US$/kg and 75% scenario ranges between 7.78 and 8.76 US$/kg. Concerning CAPEX and OPEX, these are reduced a 45% when the hydrogen demand is halved, while in the case of 75% these costs are reduced around 21%.

Additionally, both gas and liquid hydrogen delivery routes are more cost-competitive than diesel and gas. Assuming an average forecasted consumption of a fuel cell passenger car of 0.7 kgH_2/100 km and taking into account the average prices of 5.30 and 6.25 US$/kg for gaseous and liquid hydrogen distribution obtained in this work, it results in 3.71 and 4.4 US$/100 km respectively. While supposing a standard consumption of 6 L/100 km for a gas-powered car and a current gas price in Spain of around 1.75 US$/L, 5 L/100 km for a diesel-fueled vehicle and a diesel cost of 1.80 US$/L (after taxes, Spain, 2023 [85]), the resulting costs are 10.5 and 9 US$/100 km. Besides, diesel and gasoline present taxes of 38% and 43% respectively [86]. Therefore, the potential implementation of these large-scale infrastructures for hydrogen delivery results in a cost reduction of between 33 and 38% for the gaseous hydrogen supply route prior taxes (accounting for 2023 gasoline and diesel prices in Spain).

Conclusions

This study delves into the assessment of a future hydrogen supply chain alternative to enable the decarbonization of the Spanish vehicle fleet by 2050 thanks to a hydrogen-powered transport sector. Thus, this energy model proposes different hydrogen delivery methods to minimize the hydrogen dispensing costs for end-users. Moreover, the territory has been divided into 6 different regions for the distribution of different RES and hydrogen generation hubs, evaluating the energetic mix composition and the resulting LCOH per region. In this regard, the ultimate objective of the conducted analysis is the dimensioning of the most economic hydrogen infrastructure and the definition of the least-cost distribution scenario among the evaluated case studies.

Under this scenario, the most remarkable conclusions drawn from the work are.

- The geospatial analysis reflects a clear predominance of wind energy in the north of Spain, while solar energy prevails over wind in the mid-south. Overall, wind energy installed capacity totals 266.4 GW and PV panels 176.7 GW, with southern areas (regions 4, 5 and 6) absorbing almost two thirds of the total RES installed output related to the number of vehicles to be supplied. Concerning hydrogen generation, PEMEC capacity results in 214 GW installed in the current liquid natural gas regasification terminals spread over the country. Moreover, 3.45 TWh of hydrogen storage capacity are required to meet the demand of the transportation sector.
- Hydrogen transmission and distribution to refueling stations through pipelines result in a most cost-competitive option than liquid hydrogen delivery, resulting in 33% reduction on the energy consumption of auxiliary equipment (compressors and liquefaction plants) compared to liquid distribution in tankers. Hence, this configuration offers the best trade-off between LCOH and complexity. The evaluation of the LCOH cost-breakdown reflects promising and competitive results for the use of green hydrogen as fuel in Spain. These prices range from 4.84 to 5.99 US$/kg for compressed hydrogen gas supply and from 5.99 to 6.50 US$/kg in the case of liquid hydrogen supply. On average, these costs are 5.30 and 6.25 US$/kg respectively for all the country, with compression being the main cost driver for gaseous hydrogen. Thus, all hydrogen supply pathways report competitive prices with gasoline and diesel, hydrogen being 33–38% cheaper per km traveled than these fossil fuels. Furthermore, reducing the hydrogen demand to 50% and 75% results in an increase of 2 and 1 US$/kg of dispensed hydrogen as the infrastructure is employed more efficiently as the penetration increases, although it helps to diminish the necessary investment by 45% and 22%, respectively.
- Decarbonizing the Spanish transport sector is critical to achieve the emissions targets by 2050. Thus, the complete substitution of the fossil fuel-based vehicle stock by hydrogen-powered mobility would help to cut down almost 96 Mt of CO_2eq emissions per year. The conducted work provides a robust methodology that can be applied in other regions or countries. Hence, given these results, the economic feasibility of the proposed supply chain for hydrogen gas distribution is an interesting alternative to fossil fuels. Besides, it has been proven that the economy of scale and the efficient utilization of the infrastructure play a major role in reducing the LCOH. However, further studies are required to assess other potential supply methods and the temporal evolution of both the infrastructure required and the LCOH.

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.

Acknowledgements

This research is being supported by the Project ENERGY PUSH SOE3/P3/E0865, which is co-financed by the European Regional Development Fund (ERPF) in the framework of the INTERREG SUDOE program, as well as the project, "HYLANTIC"-EAPA_204/2016 within the framework of the INTERREG ATLANTIC program. The Spanish Ministry of Science and Innovation is also supporting this investigation through the projects PID2021-123120OB-I00, TED2021-129951B-C21, and "Complementary Plan for Energy and Renewable Hydrogen" additionally financed by European Union Next GenerationEU/RTRP. Furthermore, authors also acknowledge the funds received within the project PLEC2021-007718 financed by MCIN/AEI/10.13039/501100011033 and European Union Next GenerationEU/RTRP.

Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.ijhydene.2023.05.154.

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