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Geospatial modelling of the hydrogen infrastructure in France in order to identify the most suited supply chains

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Abstract

One major issue that is source of uncertainty holding back the hydrogen deployment, is the infrastructure development needs and costs. Different studies in the literature tackled this issue in France but partially, assessing either one part of the hydrogen supply chain or the whole supply chain but for one possible delivery pathway. This paper compares five hydrogen pathways, going from the production step up to the fuelling station and tackling pipeline and truck options. In order to capture the time evolution aspect of the infrastructure deployment needs, three demand scenarios are investigated, going from 1% of market penetration up to 15%. Additionally, two scenarios are taken into account when it comes to the location of the hydrogen production sites vis-à-vis the demand centres. According to the results, economies of scale that can be driven by higher market penetration rates have significant impact on lowering the hydrogen cost.

Keywords

Hydrogen; Infrastructure; France; Cost; Geographic distribution

1. Introduction

The transport sector caused 29% of the total French energy-related CO₂ emissions in 2015 [1] due to its high dependency on fossil fuels for road transport and specifically for passenger light duty vehicles (PLDV) [2]. The latest discussions about diesel in Europe [3] may lead to a progressive phase out of this fuel in the years to come. Meanwhile, a more serious shift towards zero emission mobility has to be achieved in order to ensure the required reductions in CO₂ emissions by 2050. In the short term, France set a pledge during the COP 21 to reduce the emissions in the transport sector by 29% until 2028 [4].

As mentioned already, hydrogen (H₂) systems present a promising potential for multi-sectorial decarbonisation (including the transport sector via the fuel cell electric vehicles (FCEV)) while contributing to the provision of flexibility services to the grid, as long as hydrogen is produced via low carbon technologies such as electrolysis coupled with a decarbonized power mix [5], [6].

Hydrogen development in France have been going through different periods with ups and downs that are strongly dependent on the role of the Government in the guidance of public research [7]–[9]. Belot and Picard (2014) [7] detailed the trends of hydrogen concern in France from a historical perspective, citing the main events and the role of actors (policy makers, industrials, researchers) from 1960 to 2010. Three major phases were identified. The first one starting in the sixties raising the awareness regarding hydrogen potential and strongly pushed by governmental involvement and “the weight of geopolitical considerations in defining national research orientations”. The second phase is characterised by a withdrawal in the hydrogen interest wave, which is due to the absence of real industrial application prospects and the weakening of the Government’s strategic role. However, in the late nineties till 2005, marked by a rise in the oil prices, more environmental awareness and the investigation of new energy sources in the field of transport, research in fuel cells and hydrogen systems rose dramatically. Nevertheless, reluctance towards hydrogen potential remained in France. In August 2014, the French roadmap left little room for hydrogen development in the proposed energy strategy [9], [10]. Later in 2015, a report that was commissioned by the Ministry of Environment [11] detailed the technical and economic obstacles to the development of hydrogen systems in France. The different production options and market prospects were investigated leading to a set of twenty recommendations that did not result in regulatory actions at that time. However recently, following the energy transition debates and the PPE (Programmation Pluriannuelle de l’Energie - Multiannual Energy Program), the interest in hydrogen rose again but this time along with governmental involvement and a clear deployment strategy. The Government will dedicate 100 M€ starting from 2019 to the deployment of hydrogen projects. “The Hydrogen Plan” presented by Nicolas Hulot, Minister of Ecological Transition and Solidarity until August 2018, aims at supporting the first industrial deployments of low-carbon hydrogen, with a target to make it a pillar of the energy transition in the medium term. The French hydrogen roadmap aims at:

“- Introducing 10% decarbonised hydrogen into the industrial hydrogen markets by 2023 (approximately 100,000 t p.a.) and 20 to 40% by 2028.

- Deploying territorial ecosystems of hydrogen mobility, based in particular on fleets of commercial transport, with the introduction of around 5,000 light commercial vehicles and 200 heavy vehicles (buses, trucks, regional trains, ships) and the construction of 100 hydrogen fuelling stations with on-site hydrogen production by 2023. By 2028, the target is to reach from 20,000 to 50,000 light duty commercial vehicles, 800 to 2,000 heavy duty vehicles and 400 to 1000 stations.”

Up to now, Paris counts four refuelling stations deployed in the framework of the “Hype project” that aims at reaching 600 hydrogen taxis in Paris by 2020 [12].

However, the remaining question is how to deploy the adequate infrastructure to meet this potential demand.

The aim of this paper is to analyse a potential future hydrogen supply infrastructure and assess the cost of hydrogen at the pump for different possible pathways of delivery. The deployment of the infrastructure is based on spatially resolved modelling framework that allows the analysis of the distribution of the infrastructure.

Only a few studies in the literature tackled the hydrogen infrastructure issues in France.

On the production and storage parts of the hydrogen supply chain, Menanteau et al. (2011) [13] investigated the economic viability of producing hydrogen from wind electricity for use in transport

applications considering onsite storage in tube trailers in gaseous form. The study is conducted in the framework of the HyFrance3 Project [14]. The results showed considerable variations in hydrogen production costs depending on the demand profiles concerned. Keeping the use of storage systems to the minimum proved to lead to the most favourable configurations, economically speaking.

Later in 2017, continuing the HyFrance 3 analysis, Le Duigou et al. (2017) [15] investigated the underground storage in salt caverns relevance for large scale hydrogen deployment in France. Potential storage sites are identified and the hourly operation of the selected cavern is modelled. The hydrogen production is assumed to occur via electrolysis sourced from wind farms and the electricity grid. The hydrogen market segments that are considered are mobility, industry and “Power-to-gas” here referring to the injection of hydrogen into natural gas networks. The study shows that the need for high storage capacity appears when the renewable penetration rate reaches 50%. As for the levelized hydrogen production cost (LCOH), it varies between 4.5€/kg_{H2} and 6.6€/kg_{H2} depending on the scenario of the electricity source (percentage of the wind penetration rate). Regardless of the scenario, the cost of the underground hydrogen storage always represents less than 5% of the overall cost.

As for the hydrogen delivery infrastructure, André et al. (2013) [16] suggested a new optimal design approach for hydrogen transmission pipeline networks based on a method adjusting pipeline diameters by section in order to reduce the costs (called the Delta Change method) instead of looking for the minimal length network topology. The method is then tested on the French case to respond to a hydrogen demand assuming 100% market share for hydrogen as a fuel for passenger cars for a timeframe beyond 2050. Two scenarios are considered for the production sites: a centralized one with a single production plant (with two sub-scenarios for its location vis-à-vis the consumption areas), and a distributed one considering regional hydrogen production plants. According to the results, the total infrastructure investment decreased by 18% when adopting the “Delta Change” approach. The plant location has also a significant impact on the final cost for the centralized case study. Considering a regional distribution of hydrogen production allows reducing the investment costs by 30% compared to the centralized case study.

Later in 2014, André et al. (2014) [17] considered the time deployment of the pipeline network taking into account the competitiveness of the pipelines as a hydrogen transmission option compared to other alternate ones, in particular the transportation via trucks in liquid or compressed gas form. The study is then applied to the deployment of a new transmission network for the North of France for two hydrogen demand scenarios (high and low) for the mobility sector (passenger cars). The results show that for low market shares, trucks are the most economical options. On the other hand, the pipeline option becomes economically attractive when the hydrogen market share (mobility) reaches 10%. The transport distance of hydrogen has an important impact as well on the attractiveness of the transmission options. Indeed, compressed gas trucks are competitive for short distances while cryogenic trucks require a minimal distance of 300 km to be economically justified.

D. Almaraz et al. (2015) [18] suggested a potential infrastructure layout for hydrogen deployment based on a multi-objective optimisation in order to minimize, for the French case, the total daily cost of hydrogen at the pump, its environmental impact and its safety risk. The aim is to meet a potential hydrogen demand for the mobility sector (passenger cars, light duty vehicles and buses). The different components of the supply chain are considered (production, storage, delivery in liquid form and refuelling station) for different timeframes going up to 2050. A spatial based approach is used to present the geographic and demographic data of France allowing to have a snapshot on the geographic deployment of the infrastructure and its feasibility. A sensitivity analysis to the geographic scale is conducted to test the differences between the regional and national scales. According to the results, considering the national scale presents better economic trade-off than the regional case study. This

latter presenting an important issue for the flow rate of liquid hydrogen because the demand on the district scale is lower than the tanker truck capacity, resulting in low usage rate and high costs especially in the first time periods.

J. Brunet and J.-P. Ponssard (2017) [19] considered the EasHyMob project in the Normandy region in France. The project builds on the substitution of diesel Kangoo vehicles by electric Kangoo ZE with a fuel cell range extender considering public fleets. The whole value chain is analysed, from the production step up to the final use (in this case including the vehicle manufacturing and the running cost using the hydrogen Kangoo). Two demand scenarios are investigated. The first one considers a low hydrogen demand, with a centralized production of hydrogen and transportation via tube trailers, while in the second, a more voluntarist deployment of the infrastructure takes place taking into account an on-site production. The results show that the higher the consumption level, the lower the cost of the hydrogen refuelling and transportation. The required governmental support is also tackled showing that in the first stages of market penetration there is a high need for public funds.

None of the literature studies regarding hydrogen infrastructure in France tackled all of the components of the supply chain while considering different options for the hydrogen storage, transmission and distribution pathways. All of the studies either focus on one part of the supply chain or consider the whole supply chain but with only one option for the transport/distribution.

Detailed studies on hydrogen infrastructure modelling are available for the German case [20], [21]. We adopted for the first time in France similar approaches to address the hydrogen deployment issue for the French case study.

Hydrogen infrastructure studies are available for several regions around the world: in California [22]–[25], the UK [26], [27], Korea [28], etc. However, none of them (according to our review) have tackled all of the different hydrogen supply chains, from the production to the refuelling station, considering a high spatial resolution.

In this paper, the whole supply chain starting from the production from electrolysis up to the deployment of the refuelling stations for passenger light duty vehicles is investigated, taking into account different options for hydrogen storage and different options for transport and distribution (pipelines and trailer trucks), including transporting hydrogen in gaseous and liquid forms.

The aim of this paper is to identify optimal supply chains depending on different hydrogen market penetration rates (with a focus on passenger cars) and the electrolyser placements.

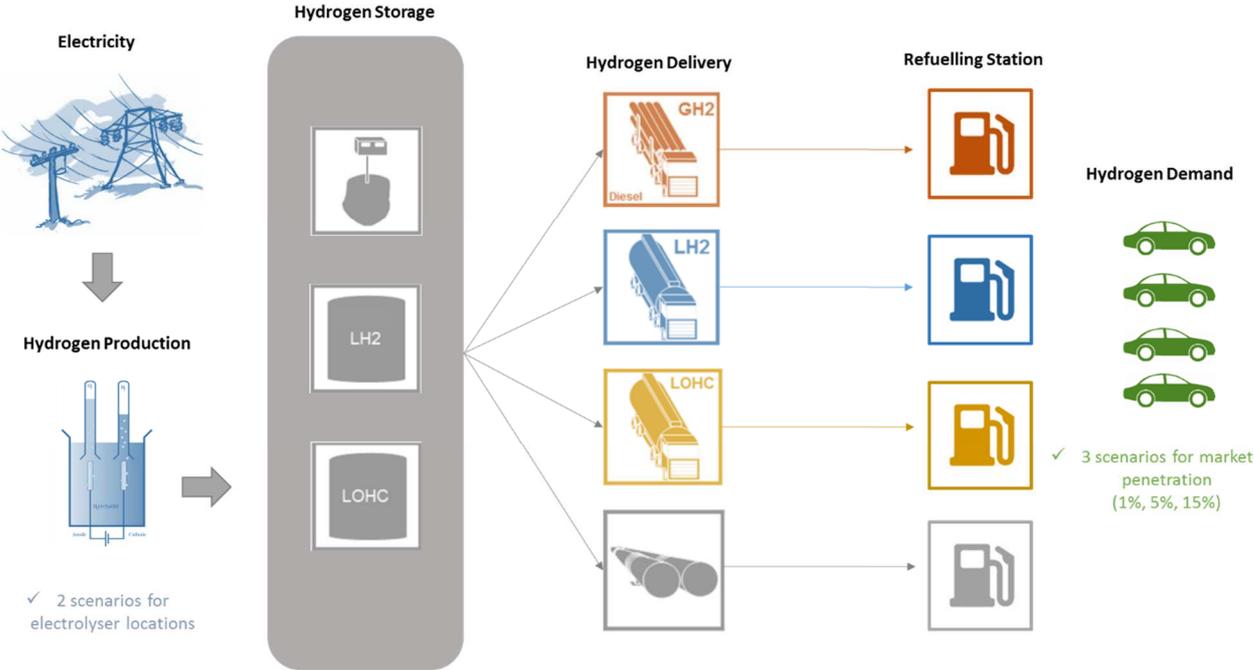
The structure of the paper is as follows. Section 2 details the methodology adopted to assess the cost of each step of the supply chain. Different scenarios are considered presenting the potential time and geographic deployment of the hydrogen infrastructure. Next, in section 3, the geographical representation of the infrastructure is presented based on a spatially resolved model and the costs of the different delivery pathways are compared.

2. Method and Data

The different delivery pathways are assessed and compared based on the total levelized cost of hydrogen delivered at the pump.

In this section, the methodology as well as the assumptions taken into account to assess the hydrogen cost at the pump are presented. The different stages of the supply chain are taken into account. The

targeted market in this study is the transport sector considering fuel cell electric vehicles for the passenger cars. Different scenarios for the demand in terms of market penetration are considered and will be detailed in section 0. In order to meet this demand, different hydrogen delivery pathways are considered as presented in Figure 1. The aim is to identify the least cost option for each market penetration value which gives an idea on deployment time of the required infrastructure. In the next sub-sections the different assumptions regarding the calculation of the hydrogen cost at each step of the supply chain are detailed.



*GH2: Gaseous hydrogen - LH2: Liquid hydrogen - LOHC: liquid organic hydrogen carrier

Figure 1: Representation of the considered hydrogen supply chains

2.1. Hydrogen supply chain modelling and global assumptions

The general methodology for assessing the hydrogen supply chain is based on Reuß et al. [21], who developed a supply chain model for analysing hydrogen production, storage, transport and fuelling of passenger cars. Between the different steps of each pathway a connector is taken into account ensuring the adequacy of the hydrogen state and pressure level. For each step, the specific hydrogen costs (total expenditures – TOTEX) are calculated with regards to capital expenditures (CAPEX), fixed operation and maintenance costs (fixOPEX) and variable operational costs (varOPEX). To do so, technological details like investments, energy consumption and losses have to be taken into account for each step. However, the cost calculation in each step is similar. The TOTEX of each step is the sum of all occurring costs:

$$\text{Eq. (1)} \quad \text{TOTEX} = \text{CAPEX} + \text{fixOPEX} + \text{varOPEX}$$

Further details regarding the equation variables are available in the annex.

The supply chain model finally adds up all parts of a predefined pathway and calculates the overall costs with a setup as shown in Figure 2. The electrolyzers are operated when the electricity price is under a certain threshold. An optimisation is carried out in order to set the optimal threshold that ensures a minimal production cost. To address this, storage of hydrogen is necessary before transportation. In this study, the transport is divided into transmission and distribution for the case of locating the electrolysis next to the nuclear power plant. If the electrolysis is located next to the demand, no additional transmission is necessary. The storage capacity as well as the share of hydrogen that can be bypassed is calculated in advance. We consider a flexible production of the electrolysis and Connector 1 and 2. After the storage module, all technologies are considered to operate continuously 24/7. The hydrogen is finally just used for fuelling 700 bar fuel cell cars. The general supply chain setup is in accordance with Reuß et al.[20].

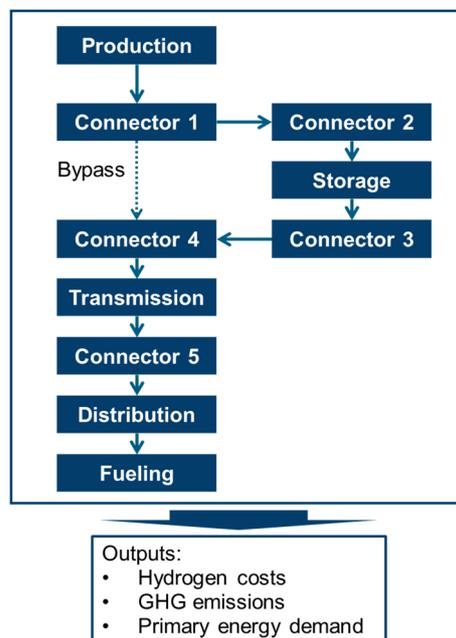


Figure 2: Supply chain setup used in this study

The different assumptions taken into account in this study regarding each step of the hydrogen supply chain are further detailed in the next sections.

2.2. Hydrogen production

The hydrogen production modelling is carried out following two major steps. First, the geographic locations of the electrolyzers are identified following two scenarios. In the first scenario, the electrolyzers are located next to the nuclear power plants. These latter present a centralized low carbon electricity source that can be available at low cost especially in the context of high renewable penetration [29]. No direct coupling with the nuclear power plant is considered though. The connection would be done at the transmission grid nodes, close to the nuclear power plants. A second scenario investigates locating the production of hydrogen next to the demand using a clustering

method to minimize the travelled distance between the production site and the refuelling stations (for hydrogen delivery). These two scenarios allow having strategic insights on where to locate the electrolyzers in a manner that ensures low costs of the supply chain.

A prospective electrolyser investment cost (C_I) going down to 500€/kW is assumed for the considered timeframe (2035) which is in line with what is expected in the years to come in terms of cost reductions according to the literature [30]. As for the annual maintenance costs, they are assumed to represent 3% of the investment costs. The depreciation time (referred to by n) is set at 10 years.

E_p being the electricity price threshold and LF is the resulting load factor that corresponds to the number of hours throughout the year where the electricity price is equal to or below E_p . This means that a fixed electricity price (the threshold) is paid during the period that is defined by the load factor, even when the electricity price is under the threshold. In this way, the over-estimation of the production cost (that may be implied by the non-consideration of the electrolyser operation impact on the electricity price time series) can, in part, be avoided. To do so, time series of electricity cost throughout the year are adopted based on a previous work [29] assuming a 50% share of renewables in the electricity generation mix and a reduction of nuclear capacities from 63 GW in 2017 to 48.5 GW by 2035, in accordance with a scenario designed by the French Transmission System Operator RTE. The electricity price time series are presented in Figure 3.

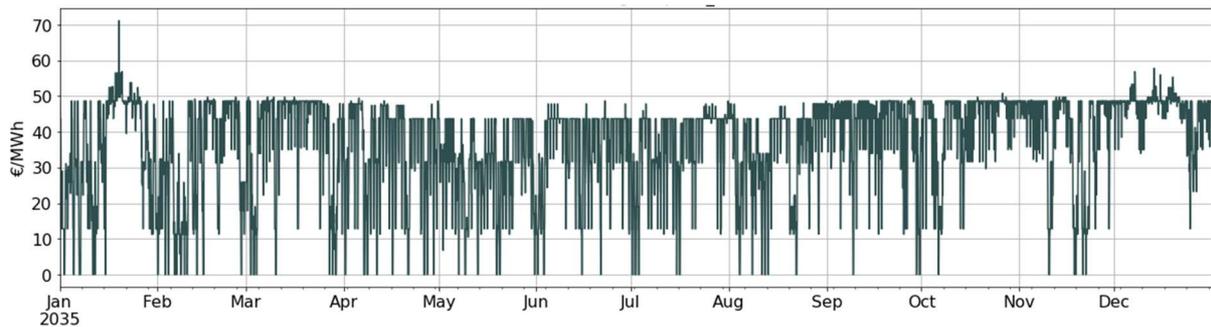


Figure 3: The adopted electricity price time series throughout the year

Added to the electricity generation cost, the grid fees are also included when the electrolyser location is near the demand hubs. and are taken from Eurostat [31] for the French case.

Hence, an electricity grid fee exemption is assumed for the case where the electrolyzers are located next to the power plants in transmission grid nodes.

Electricity taxes are not included in the cost.

Finally, the evaluation of the hydrogen production is carried out as follows, per kW of installed electrolysis capacity:

$$\text{Eq. (7)} \quad P_{H_2} = \frac{LF}{C_{EL}}$$

C_{EL} is the electrolyser electricity consumption that is assumed to be improved to 47.6 kWh/kg by 2035 knowing that nowadays it is approximately 50 kWh/kg [30], [32].

Accordingly, minimizing the *LCOH* (or *TOTEX* of the production step) is a function of the electricity price that is taken as a threshold (E_p) and the resulting number of hours of operation (*LF*).

More techno economic assumptions regarding the hydrogen production are presented in the annex.

Next section addresses the assumptions of the hydrogen storage step.

2.3. Hydrogen storage

The hydrogen storage role is twofold. On the one hand, it allows ensuring a seasonal storage in order to cope with the variability of renewable energy resources. On the other hand, hydrogen storage is a key component of the hydrogen supply chain allowing to bridge between discontinuous production and demand, exhibiting non-matching profiles. This will be further detailed in section 3.2 (see Figure 6).

Since hydrogen is the lightest element, the storage and handling remains a challenge. The energy volumetric density is low at normal conditions (0.003 kWh/l) compared to conventional fuels such as gasoline (10 kWh/l) [6], [33]. High energy densities are important to decrease specific costs for hydrogen transport and long-term storage. Therefore, the energy density of hydrogen requires further adjustments [21] and different storage options are considered in this study.

The most common way to achieve higher hydrogen storage densities is via compression in gaseous form [21]. Stationary tube systems normally have pressures of between 200 and 350 bar [33]. Gaseous hydrogen at 700 bar is generally regarded as the most viable storage system for on-board hydrogen storage in automotive applications [6]. However, high-pressure gas vessels have high investment costs and special requirements for the vessel material. Storing hydrogen in salt caverns can also be a viable option especially for large hydrogen volumes [6]. In this case, the hydrogen is stored on geological conditions up to 150 bar [21]. However, salt rocks for the construction of caverns are not available everywhere in France. This will be further discussed in section 3.3.

Liquid hydrogen offers the possibility of increasing the density up to 71 kg/m³ (2.4 kWh/l) by cooling the hydrogen below 21 K. Liquid hydrogen can be stored in cryogenic tanks with a robust insulation at low pressure (<10 bar), which allows the use of large bulk storage systems with high energy densities. On the other hand, the liquefaction process is energy intensive presenting electricity consumption needs that can reach 36 to 45% of the overall hydrogen energy content today, as discussed in Reuß et al. [21].

Aside from the compressed and liquid storage options, the liquid organic hydrogen carriers (LOHC) are considered in this study. The LOHC are based on capturing hydrogen in the middle of molecules of "refillable" organic liquids such as naphthalene or benzene. To do so, these liquids are hydrogenated at higher temperature (< 300°C) leading to obtain two new stable molecules (cyclohexane and decalin), which are then conditioned at low temperature to be easily stored, transported and used. Hydrogen can afterwards be extracted via a dehydrogenation reaction (endothermic reaction) [34]. The main advantage of the LOHC technology is that it enables hydrogen storage in a chemically bound form under ambient conditions without the necessity for high-pressure

or super insulated tank. The technology can use the existing infrastructure for fossil fuel like tanker ships, rail trucks, road tankers and tank farms [21].

The operational costs are annual maintenance costs (OM), assessed by a percentage of the investment.

The techno-economic assumptions taken into account in the calculation of the storage cost are derived from a previous work applied to the German case study [21] as detailed in the annex (Table 2).

2.4. Hydrogen transmission and distribution

The link between the hydrogen production and storage sites and the demand locations is investigated considering five possible pathways, combining the different options for storage and transmission/distribution.

2.4.1. Technical and techno-economic details

The techno-economic assumptions considered in the calculation of the transport and distribution costs are presented in the annex (table 3).

In the case of hydrogen transport via pipelines, the investment cost corresponds to the total length of the deployed pipelines multiplied with the specific investment costs caused by the necessary diameter. The specific investment cost are evaluated as follows [21]:

$$\text{Eq. (8)} \quad C_{I_pipeline} \left[\frac{\text{€}}{\text{m}} \right] = \text{Invest}_A \times d^2 + \text{Invest}_B \times d + \text{Invest}_C$$

With d as diameter in mm, Invest A, Invest B and Invest C as polynomial coefficient of second order according to Baufumé et al. [35].

The variable operation costs include the fuel costs and the driver cost in the case of trucks. Regarding the fuel cost, it corresponds to diesel or hydrogen consumption cost in the case of the trucks and to the electricity consumption cost in the case of pipelines. As for the driver cost, it is assumed that only one driver is allocated to each truck with a wage of 35€/h [36]. The truck costs are calculated in accordance to Teichmann et al. [36] and Yang and Ogden [22] by calculating the TOTEX of the roundtrip of each trailer.

2.4.2. Spatial methodology for elaborating transmission and distribution length

To assess the travelled distances for trucks as well as the design of transmission and distribution pipeline grids, georeferenced methods for designing hydrogen transport are used, according to the methodology presented in Reuß et al. [20].

To examine the travelled distance of trucks, a truck routing model is applied. The street grid from OpenStreetMap [37] is used as a basic graph separated into highways and remaining roads. The truck speed is set to 60 km/h on motorways and 30 km/h on all remaining roads. Each fuelling station, hub or transmission grid node connected to the nuclear power plant is connected by a beeline to the closest street node. For each edge, the travelled distance and time is calculated. Based on this information, a linear flow optimization is conducted, minimizing the used time.

The pipeline system design is separated into three steps, similar to Reuß et al. [20] without applying pressure drops. First, a candidate grid is derived from the work of Baufumé et al. [35]. For Euclidian distances a detour factor of 1.4 is added. Second, the topology selection is then performed by applying

a minimum spanning tree algorithm [38]. Last, on the resulting tree, a linear flow optimization similar to the truck routing is conducted to get the resulting flow, the necessary diameters, and respective the investment costs for each pipe. Similar to Baufume et al. [35] the gas velocity was set to 15 m/s and the hydrogen density was assumed to be 5.7 kg/m³.

The street grid as well as the existing natural gas pipeline routes that are used for the georeferenced transportation design are shown in Figure 4.

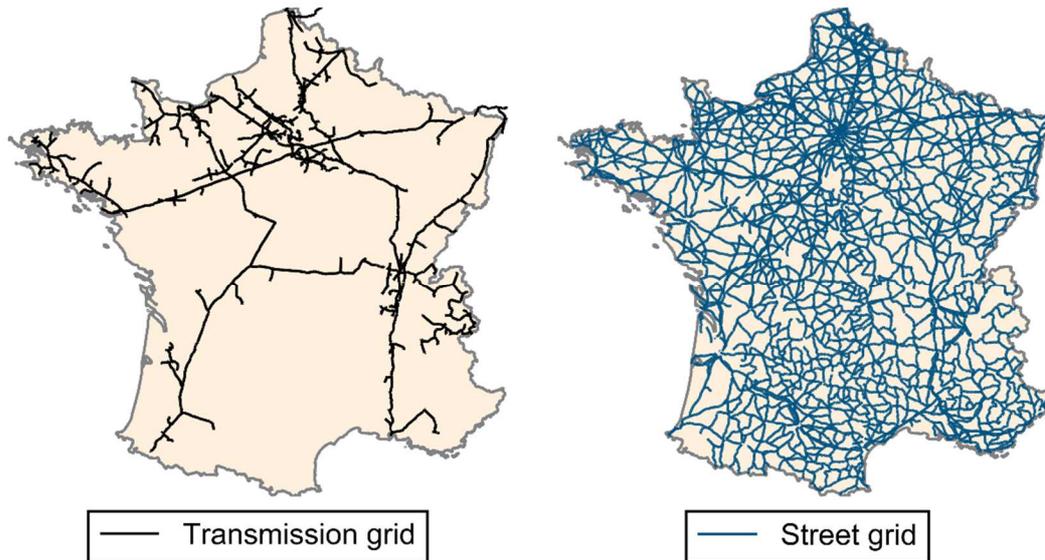


Figure 4: Input data for the candidate pipeline grid (left) and the French street network (primary and secondary routes) extracted from OpenStreetMap [37]

2.5. Refuelling stations

The fuelling station is the last step in the supply chain, supplying GH₂ at 700 bar to a stock of FCEV.

2.5.1. Technical and techno-economic background

In Germany, H2MOBILITY [39] developed three different fuelling station concepts: small (212 kg/day), medium (420 kg/day) and large (1000 kg/day). For the timeframe of 2035, we assume a medium sized fuelling station to be the average station type.

The characteristics of the fuelling stations are varying with each supply mode and can have a major impact on the final costs. Reuß et al. [20] estimate fuelling station investment costs on the basis of previous estimations from Robinius et al. [40] and results from the HRSAM [41], as well as own considerations. However, Melaina and Penev [42] claim that, as with other technologies, fuelling stations are subjected to learning and scaling effects. Comparing the today's low number of four hydrogen fuelling stations in Paris with the numbers of large stations of more than 1000 necessary for supplying a meaningful stock of FCEVs in future, the learning and scaling effects could have a significant impact on fuelling station costs. Therefore, Reuß et al. [20] conducted a bottom-up analysis of hydrogen fuelling station investment costs

based on the approach of the HRSAM [41] for GH₂, LH₂, and LOHC fuelling station types in order to determine the scaling effects, as well as base investment costs for all supply types. Reuß et al. [20] suggests for the investment costs of different supply modes the following equation:

$$\text{Eq. (9) Station Investment} = 1,3 * 600.000 \text{ EUR} * \gamma * \left(\frac{\text{station capacity}}{212 \frac{\text{kg}}{\text{day}}} \right)^\alpha,$$

with γ as the base investment of each supply mode compared to the reference station and α as the scaling factor compared to a small sized fueling station. The scaling and base investment costs compared to a reference station design are given in the annex (table 4) together with other techno-economic assumptions that are considered in the calculation.

The electricity demand of fuelling stations consists of compression/pump energy and precooling with the assumptions based on the DOE values [43]. To supply the heat demand required for the LOHC station, natural gas is assumed as an energy source in accordance to Reuß et al. [20].

2.5.2. Spatial methodology and distribution of hydrogen demand

In order to assess the potential demand of hydrogen in the mobility sector, the total number of passenger light duty vehicles is appraised on a district level based on 2016 Eurostat values [44]. Then, different scenarios for market penetration are considered, 1%, 5% and 15% for the timeframe of 2035. In order to evaluate the hydrogen consumption corresponding to these scenarios, the following assumptions are considered: an average annual travelled distance by car equal to 13 000 km [45] and a hydrogen consumption of 0.7 kg_{H2}/100 km.

In order to evaluate the hydrogen demand profile throughout the year, a seasonal, a weekly and an hourly distribution of the demand are assumed based on data for a Chevron refuelling station operation profile [46], that is representative of a typical refuelling station.

According to [46], the fuel demand is 10% higher during summer time and 10% lower during winter. As for the weekly distribution, a peak is noticed for the station operation by the end of the week (Thursday, Friday). During the day, the fuel demand reaches its highest levels between 2pm and 6pm.

Based on the regional distribution of the hydrogen demand, the total number of required fuelling stations in each county is evaluated. As stated above, a medium sized fuelling station with 420 kg/day is selected for the analysis. A maximal utilisation of 70% is assumed for each station with respect to a varying number of cars refuelling per day and during the year in accordance to H2MOBILITY [39] expectations. Once the number of required fuelling stations is identified, their geographic locations are selected. We assumed in this study that the current locations of fuelling stations for diesel and gasoline are very likely to be used for hydrogen fuelling in future. Therefore, the locations of current fuelling stations which are extracted from OpenStreetMap [37] are used as candidate locations for future fuelling stations. The penetration order is based on the following territorialities: metropolitan area (>1million inhabitants), urban area (<1 million inhabitants) and rural area based on the GRUMP model [47], which offers a population density on global scale. Metropolitan fuelling stations are selected first, rural stations last. If there are not enough fuelling stations available, an additional fuelling station at an existing location will be selected.

As discussed in Reuß et al. [20], the placement of the hub is important, because it defines the ratio between the pipeline lengths of transmission to the distribution. The allocation of hubs to separate between transmission and distribution is carried out by a predefined number of fuelling stations, which are clustered to one cluster centre by a k-means cluster algorithm from scikit-learn [48], which is a tool for data mining and data analysis in python. The number of fuelling stations that are clustered is set to 250.

2.6. Connectors

Different storage methods necessitate conversion technologies to change between GH₂, LH₂ and LOHCs. Five technological capabilities are considered, namely: Compression, liquefaction, evaporation, hydrogenation and dehydrogenation. Detailed information are given in Reuß et al. [21], Teichmann et al. [36], [49], the Nexant Report [46] and Aasadnia and Mehrpooya [50]. All techno-economic assumptions for conversion technologies employed in this study are provided in the annex (table 5).

2.7. Scenario Framework and analysed supply chain

In order to route the hydrogen up to the refuelling station, three major delivery pathways can be identified:

- Transmission and distribution via trucks (GH2, LH2 and LOHC),
- Transmission and distribution via pipelines,
- Transmission via pipelines and distribution via trucks (GH2).

These combinations allow having an extensive representation of the different hydrogen delivery possibilities. For each of the identified pathways, the model deploys the selected infrastructure linking between the production sites and the demand locations while minimizing the required delivery distance across France.

3. Results

The aim behind the extensive representation of the supply chain is to identify which pathway is most suited for which situation, in terms of geography and time scale, based on the assessment of the levelized hydrogen cost at the pump. The progressive demand scenarios (1%, 5% and 15% of vehicle fleet) allow representing the potential time development of the required infrastructure, while the electrolyser location scenarios (detailed in section 2.2) allow comparing two different possible situations: producing hydrogen next to the available power sources or next to the hydrogen demand hubs. Other case studies can also be considered such as placing the electrolysers next to point sinks of hydrogen (e.g. refineries). This approach can contribute to the decision making regarding the integration of the hydrogen transmission and distribution installations.

The modelling results are detailed in the next subsections.

3.1. Hydrogen demand

Based on the total number of vehicles by region and the assumptions detailed in section 2.5, the hydrogen demand by region is appraised. The total amounts of hydrogen that are required to fuel the FCEV fleet in each scenario are presented in Table 1.

Table 1: Resulting hydrogen demand by scenario, 2035

	Percentage of the total PLDV fleet		
	1%	5%	15%
FCEV fleet size	320 000	1 600 000	4 800 000
Hydrogen demand [kt/a]	29	146	437

Figure 5 shows the distribution of the demand across France for the scenario of 5% market penetration. The distribution (between the regions) remains the same for the other scenarios but with higher/lower demand values depending on the penetration rate.

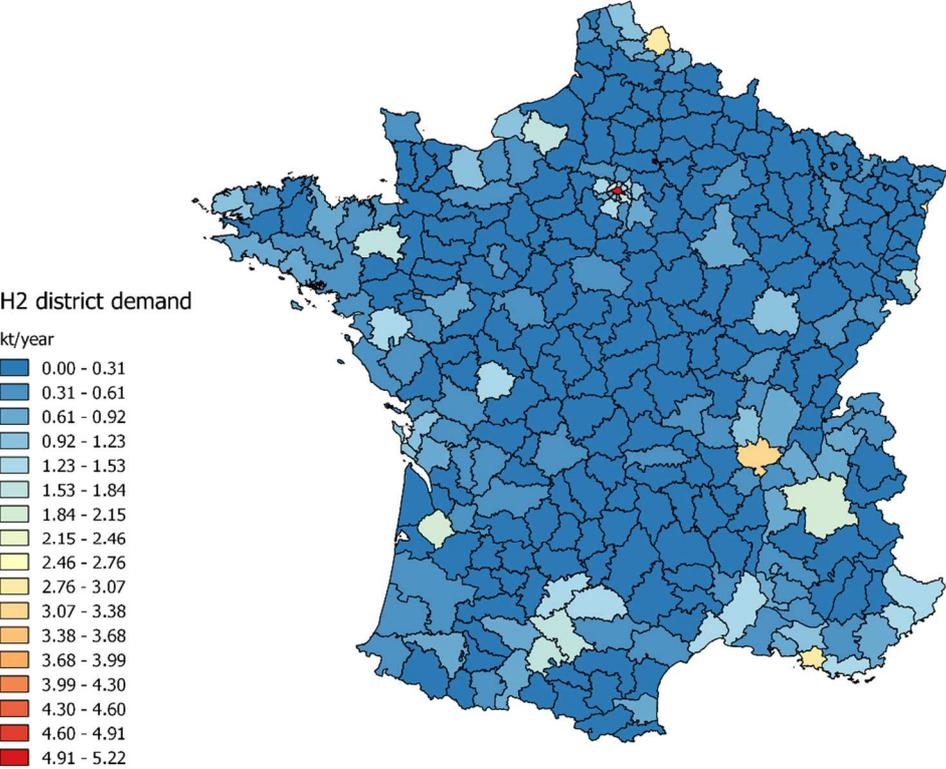


Figure 5: Distribution of hydrogen demand for mobility use for the scenario of 5% market penetration

The demand is concentrated in few areas of the map which are the big cities and the most urbanized areas (Paris, Lyon, Lille, Marseille, Toulouse, etc.). The highest demand is identified in Paris having the highest concentration of cars. Nowadays, the Parisian region attracts hydrogen vehicle penetration projects. For instance, the “Hype project” aims at deploying hydrogen taxis in the Parisian region.

A methodological limit that can be mentioned here is the fact that the same penetration rate is adopted for all of the regions in each scenario. However, in the real world, the distribution of the demand may rather depend on the emergence of hydrogen projects by region and the willingness of each region to deploy the hydrogen required infrastructure, which can be both an industrial and a governmental effort on a regional scale. Several projects are emerging in different regions across France (Auvergne Rhône Alpes [51], [52], Toulouse [53], Dunkirk [54], etc.).

As detailed in section 2.5, the hydrogen demand tackled in this paper corresponds to the passenger light duty vehicle fleet. However, an interesting perspective that can be evaluated is to include the other types of transportation (buses, trains, trucks, etc.). This can be more complicated to implement, since once the long distance transportation is tackled, it can be tricky to identify the demand distribution knowing (especially for trucks) that the refuelling may occur anywhere between the starting location and the final destination of the vehicle. On the other hand, including the long distance vehicle fleets may present a game changer in lowering the final cost of hydrogen since the demand

requirements can be higher than the ones driven by the passenger light duty vehicles. And this can lead to the required economies of scale that allow enhancing the utilization rates of the production and delivery infrastructure.

Following the assumptions detailed in section 2.5, the demand profile is constructed. The constructed hourly profile of the hydrogen demand is presented in Figure 6 for the example of 5% market penetration on a national level (similar approach is adopted for all the scenarios).

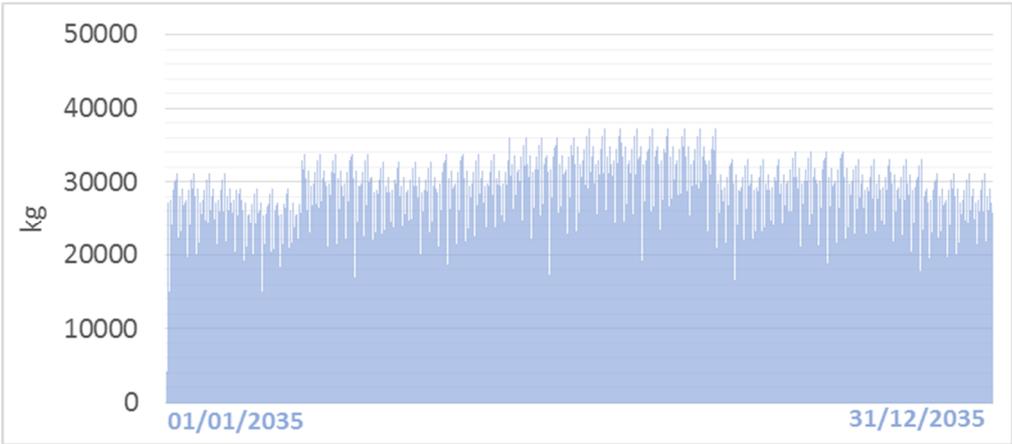


Figure 6: Hourly profile of hydrogen demand throughout the year – example scenario 5% market penetration

The demand is expected to be higher during summer time driven by the travelling for vacation, as for the weekly distribution, an increase in the demand is noticed by the end of the week, which can be explained by the refuelling of the vehicles in preparation for the weekends and the beginning of the following week. These aspects are highly dependent on consumer preferences that can vary from one region to another. Accordingly, a quite strong assumption consists in applying the same profile variations for all of the refuelling stations across France, which, in the real world, can be different.

In the next section, the hydrogen production profile is assessed which allows, once coupled with the demand profile, to evaluate the storage capacity needs.

3.2. Levelling hydrogen production and storage

In order to meet the hydrogen demand that is presented in the previous section, several hydrogen production plants are deployed across the country. The evaluated total capacity needs for hydrogen production are presented in Table 2 for each demand scenario.

Table 2: Total electrolyser capacities by penetration scenario

	Percentage of the total PLDV fleet		
	1%	5%	15%
FCEV fleet size	320,000	1,600,000	4,800,000

Electrolyser total capacity [GW]	0.23	1.15	3.5
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As detailed in the methodology section, in this study, the electrolysers are operated when the electricity price is under a certain threshold that is defined in a way that minimizes the production cost (depending on the total number of operation hours).

Figure 7 shows the evolution of the hydrogen production cost (LCOH or production step “Totex”, red line, right axis) and the total number of operation hours (blue line, left axis), as functions of the electricity price (€/MWh).

The LCOH is the production cost taking into account the electricity price, the load factor and the investment cost of the electrolyser. It does not include the storage costs.

The number of operation hours corresponds to the number of hours for which the electricity price is below the selected electricity price in the x axis. Accordingly, the total number of hours for which the electricity price is under 10€/MWh for example is very low. –It does not exceed 500 hours- which leads to a very high production cost of nearly 20€/kg, due to insufficient CAPEX amortization. The higher the threshold is, the higher operation hours are reached.

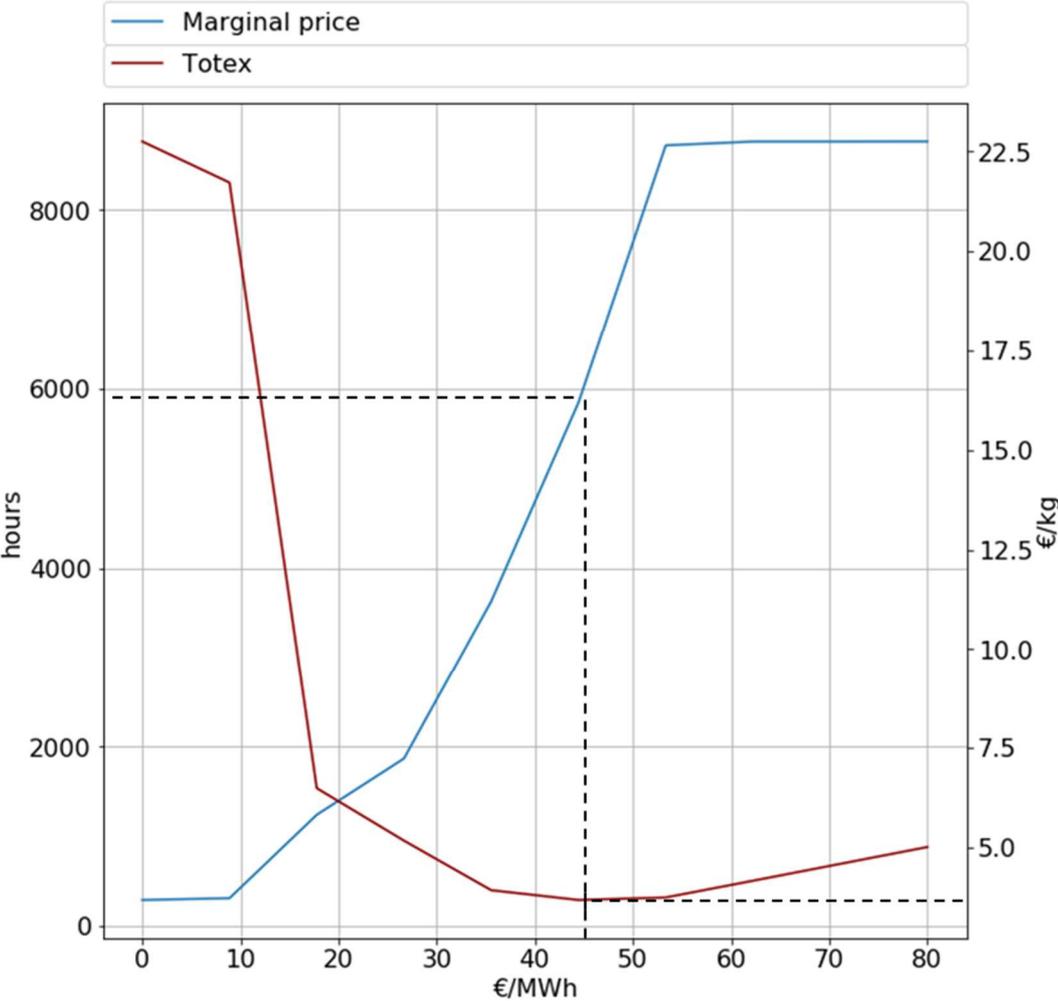


Figure 7: Hydrogen production cost evolution (LCOH, or production step TOTEX) and the total number of operation hours depending on the electricity price

As a result, there is a trade-off to make between CAPEX amortization (the higher the load factor, the better) and the cost of electricity consumption (the higher the load factor, the higher due to more expensive power). As shown in Figure 7, the electricity price threshold that ensures a minimal hydrogen production cost is 45€/MWh, with a load factor of 6000h. The grid fees [31] are included for

the case study in which electrolyzers are located close to the demand hubs, resulting in an optimal production cost of 3.7 €/kg. These results do not depend on the market penetration scenario, since no scaling effect was assumed for the electrolyser investment in the present study.

When opting for a lower electricity threshold, higher electrolyser capacity is needed to meet the same demand since the total number of operation hours drops raising the hydrogen production cost due to degraded amortization.

On the other hand, when operating the electrolyzers at higher electricity prices, the hydrogen production carbon footprint is likely to increase due to the activation of polluting power plants during peak hours [55].

In order to accurately assess the hydrogen production cost, including hydrogen as a flexible demand seems crucial, especially when considering the high FCEV penetration rates for which the required electrolyser capacities reach the GW scale, which can impact the electricity prices. Hence, the “price taker” strategy reaches its limits for hydrogen penetration rates higher than 1%. On the other hand, considering that the electrolyser is always paying the electricity price at the threshold value even when the real price is under the threshold, allows to partially avoid the underestimation of the hydrogen production cost.

Coupling the production with the demand profile allows to construct the state of charge of a generic storage and to identify the storage capacity needs as presented in Figure 8.

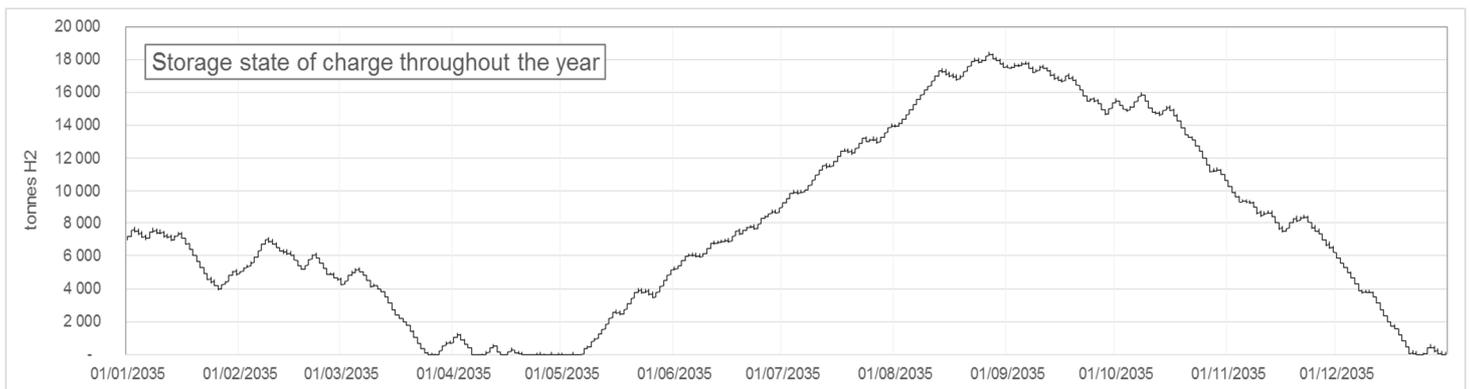


Figure 8: Hydrogen storage needs for the 5% penetration rate scenario

Figure 8 highlights the seasonal energy storage role ensured by hydrogen. Indeed, linking the hydrogen production to the electricity prices allows reflecting the seasonal variability of the renewables based on a previous work analysis [56]. Accordingly, this highlights the multi-sectorial decarbonisation potential of hydrogen, easing the penetration of renewable energies into the system while contributing to the decarbonisation of the transport sector.

3.3. Delivery pathways comparison

In order to link the hydrogen production sites to the refuelling stations, several pathways are considered as detailed in section 0.

Special focus is put on the geographical representation of the hydrogen infrastructure deployment. This deployment is mapped for the different scenarios of electrolyser locations as well as the various pathways that are considered in this study. Figure 9 presents the mapping of the infrastructure for the example of a 5% penetration rate.

The fuelling stations are presented in coloured circles. The colours are graduated from blue to red depending on the demand that is satisfied by the refuelling stations. The red colour represents the highest demand levels (also highest operation rates). As shown in the figure, the most utilized refuelling stations correspond to the metropolitan and urban areas where demand levels and vehicle concentrations are higher, while the further we get from the big cities, the lower the utilisation rates are, which impacts the profitability of the stations. However this may change when considering long distance transportation like trucks for example that would increase the utilisation rates of the refuelling stations outside the urban areas, on the highways for instance. Furthermore, in order to reduce the risks, deploying smaller refuelling stations with lower capacities can be envisaged for the rural areas, which is not the case in this paper (only one size was assumed).

The hydrogen production sites are represented by green squares on the maps, with different sizes representing the capacity of each production site.

As presented in section 2.2, two scenarios are adopted for the electrolyser locations. In the first scenario, the electrolysers are located next to strong transmission grid nodes (connected to the nuclear power plants) avoiding electricity grid fees while in the second scenario, the hydrogen production is rather located next to the demand hub. Accordingly, two different distributions of the hydrogen production capacities by region are obtained. For example, in the first scenario, the hydrogen production is directly linked to the presence of a nuclear power plant, hence not all of regions present a hydrogen production capacity. However in the second scenario, each region is supplied via an internal hydrogen production capacity.

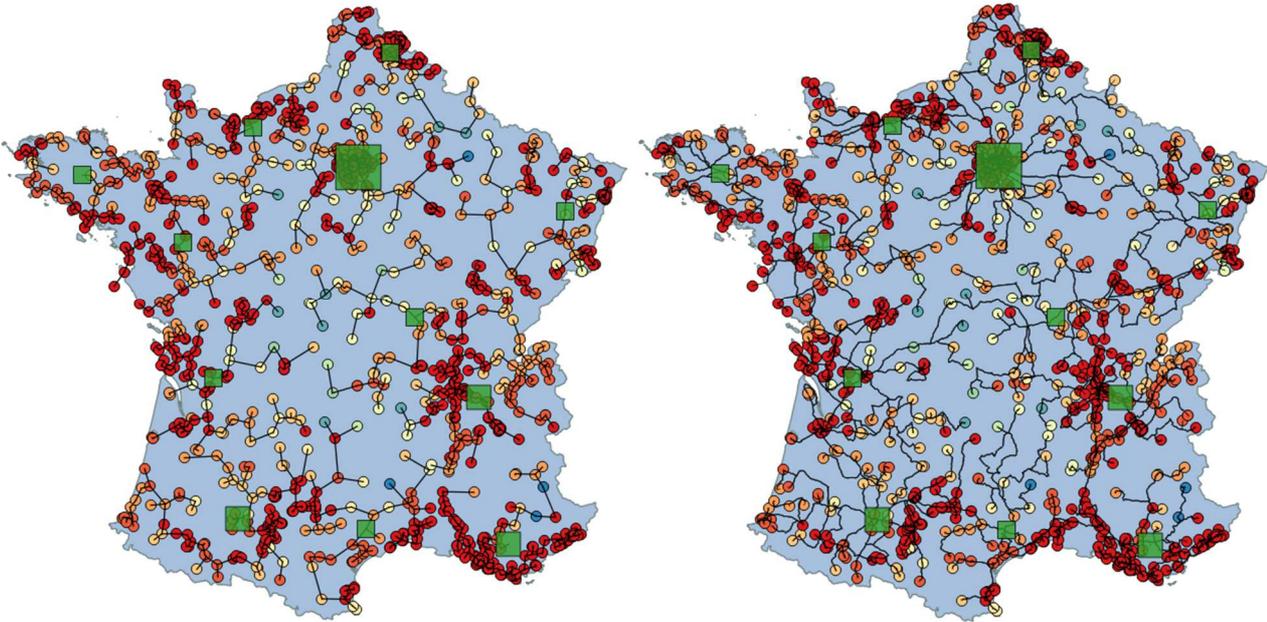
As shown in **Figure 9**, more electrolyser facilities are deployed in the first scenario (next to nuclear power plants) accounting for 19 potential locations while in the second scenario, only 12 electrolyser facilities are installed. However, locating the electrolysers next to the demand hubs leads to a more homogenous distribution of the capacities. In this scenario, almost each region presents an internal hydrogen production capacity (except for Centre Val de Loire and Pays de la Loire), limiting the need for trades between the regions. However, in the first scenario, it is tricky to reach certain locations that are remote from the nuclear power plants (for example the south of the Bretagne region and the south of the Occitanie region for example). What is more, adjusting to the nuclear power plant locations leads to locate electrolysers in regions where the demand is particularly low. A visible example is the Centre Val de Loire region that, as shown in Figure 5, presents low demand values, but the model allocates four electrolyser locations there. This distribution can have a significant impact on the final cost of hydrogen at the pump, since it affects the deployment of the required infrastructure. Trade-offs may be observed there, depending on the demand levels. On the other hand, locating the electrolysers next to the nuclear power plants allows avoiding the electricity grid fees that correspond to the cost of transporting electricity. These fees are though included in the electricity price when considering a decentralized distribution of the electrolysers.

In order to route the hydrogen up to the refuelling station, three major delivery pathway representations can be identified:

- Transmission and distribution via trucks (GH2, LH2 and LOHC),
- Transmission and distribution via pipelines,

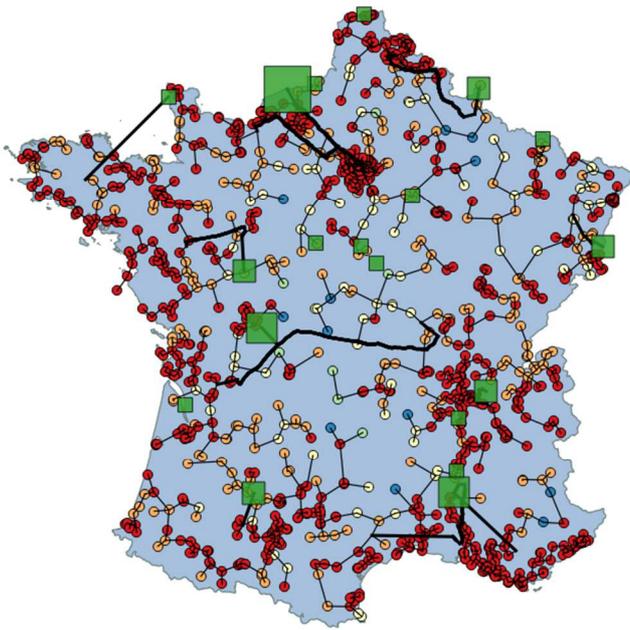
- Transmission via pipelines and distribution via trucks (GH2).

Figure 9 presents in black lines the roads that are taken by the trucks for the delivery as well as the transmission and distribution pipelines. Transmission pipelines are needed only for the scenario where the electrolyzers are located next to the nuclear power plants, since some of the latter are far from the demand centres. On the other hand, considering the scenario where the electrolyzers are rather located near the demand, only distribution pipelines are needed since the delivery distances are shorter.

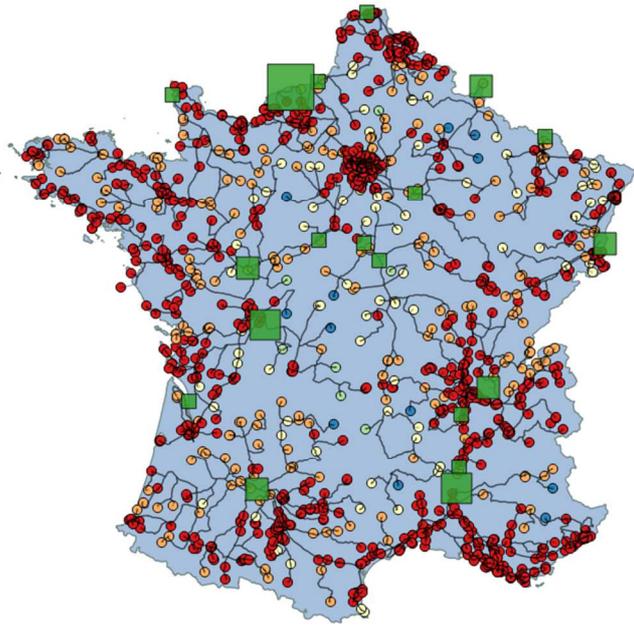


a) TR: Pipeline – Distr: Pipeline
electrolyser next to the demand

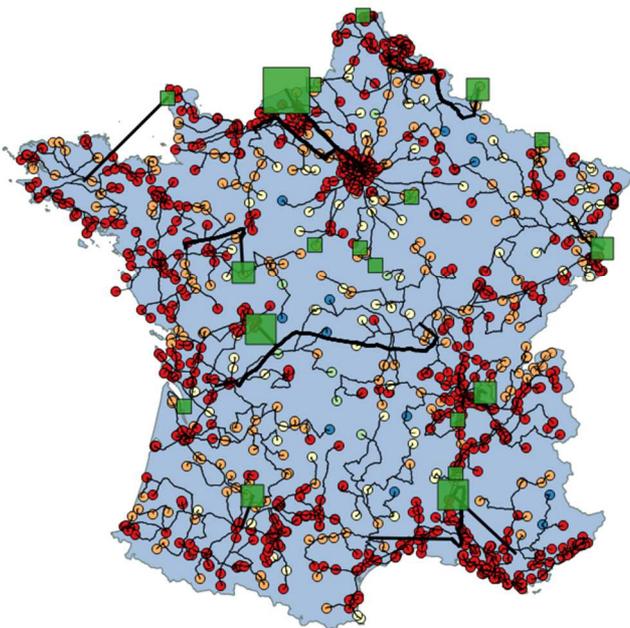
b) TR: Trucks – Distr: Trucks
electrolyser next to the demand



c) TR: Pipeline – Distr: Pipeline
 electrolyser next to the nuclear power plants



d) TR: Trucks – Distr: Trucks
 electrolyser next to the nuclear power plants



e) TR: Pipeline – Distr: Trucks
 electrolyser next to the nuclear power plants

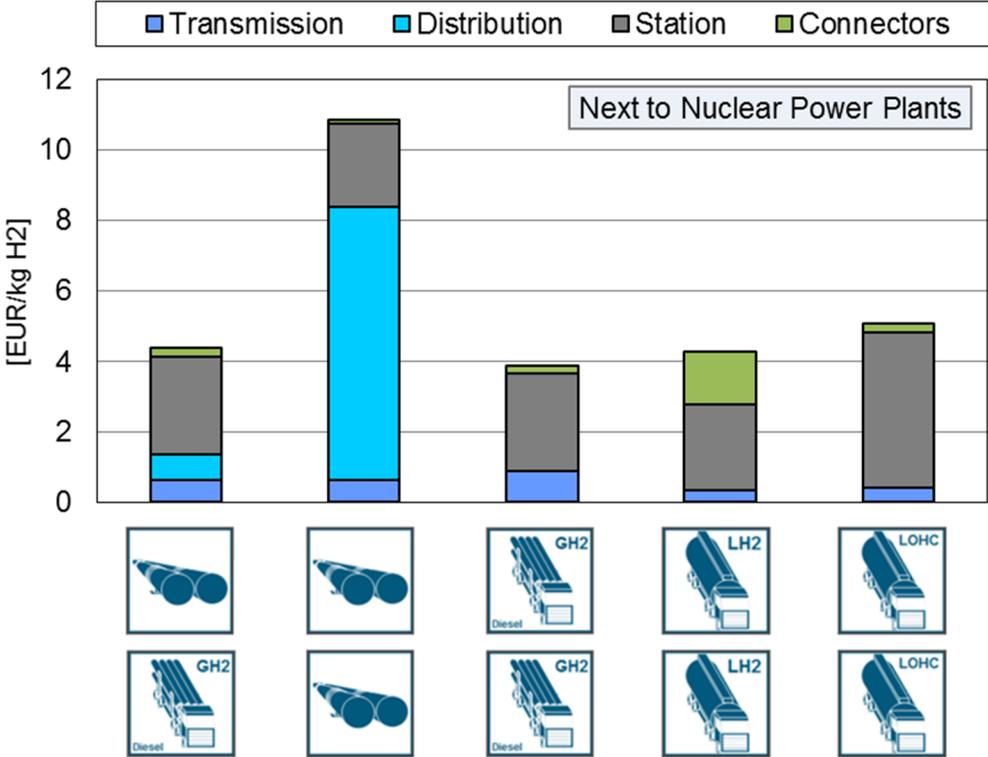
Legend

- Hydrogen Production [kt/year]
- 0.0 - 7.1
 - 7.1 - 14.3
 - 14.3 - 21.4
 - 21.4 - 28.6
 - 28.6 - 35.7
- PipeTransmission
- PipeDistribution
- TrucksRoutingTransmission
- TrucksRoutingDistribution
- Fueling Station [kt/y]
- 0.02 - 0.04
 - 0.04 - 0.05
 - 0.05 - 0.07
 - 0.07 - 0.09
 - 0.09 - 0.11

Figure 9: Geographic representation of the hydrogen infrastructure deployment (pipelines and trucks for 5% penetration rate) considering the two scenarios (a,b: electrolyser next to the demand – c,d and e: electrolyser next to the nuclear power plants)

In this study, the deployment of the pipelines is based on a point to point delivery consideration. Further work is needed in order to take into consideration the constraints that may impact the installation of a pipeline and modify its path. These constraints can also significantly impact the cost of pipeline installation. A visible example in Figure 9 (compare c and e) is the transmission pipeline crossing the ocean from the Normandie region to Bretagne. Such configuration may be too expensive to be considered.

In Figure 10, the cost of hydrogen delivery is compared for the five pathways, considering the example of 5% market penetration. The top graph corresponds to the scenario where the electrolyzers are located next to the nuclear power plants, while in the bottom graph, their location is optimized to be near the refuelling stations.



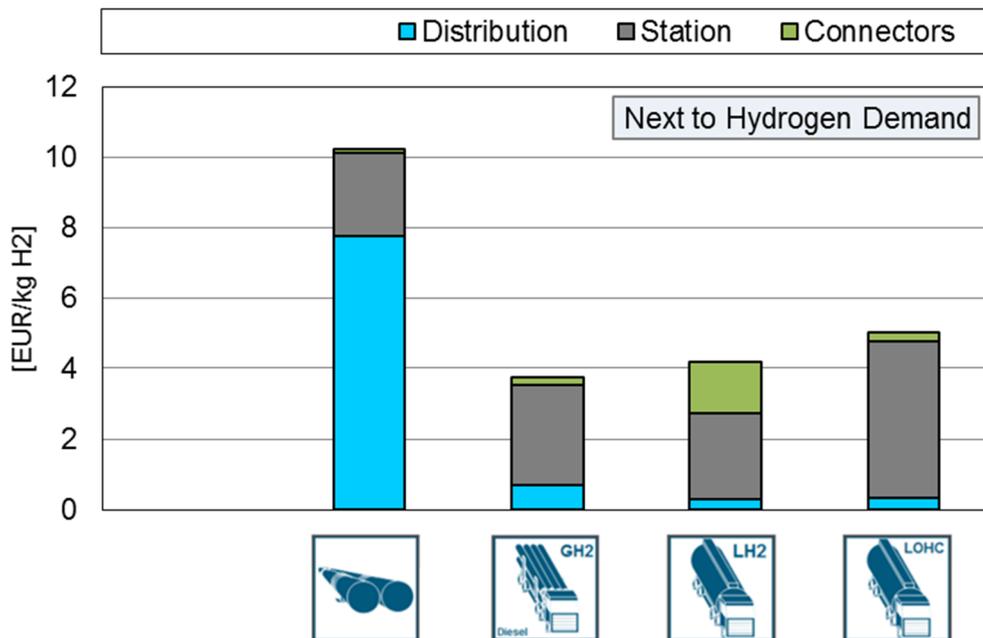


Figure 10: Hydrogen delivery cost (scenario 5% market penetration)

Amongst the five pathways that are considered in Figure 10, the pipeline transmission option is not applicable to the second scenario (electrolysers next to the demand), since in the latter the production sites are located in an optimal way to minimize the distance to the refuelling stations using a clustering method, which leads to the unnecessary of deploying heavy transmission pipeline. Additionally, in this scenario, the resulting transported quantities (from the production site to the refuelling station) are not high enough to trigger transmission pipeline investments. However, distribution pipelines can be deployed. On the other hand, in the first location scenario, considering the truck pathways (GH2, LH2 and LOHC), the trucks are used for both transmission and distribution of hydrogen.

As shown in Figure 10, for each selected pathway, the final delivery costs of hydrogen at the pump for both electrolyser location scenarios are very close. Hence at the end, both electrolyser location scenarios present similar cost values considering the 5% penetration rate. However, this may change when taking into account different market penetration rates as detailed in the next paragraphs.

Starting with the 5% penetration scenario, most of the pathways present a cost of hydrogen delivery that is in the range between 3.7€/kg and 5€/kg, the latter cost value corresponding to the LOHC supply chain. Only one specific pathway can be distinguished, clearly leading to higher costs, which is the second pathway presenting high costs of hydrogen distribution via pipelines. The delivery cost of hydrogen at the dispenser reaches 10.9€/kg in this case. Indeed, on the distribution level, the hydrogen throughput is reduced to respond to the demand at the station level, which makes investments in pipelines a non-viable option for both scenarios.

Regarding the delivery pathways via trucks, the gaseous option seems to present the most attractive alternative (third bar on the graph) when it comes to the 5% penetration rate scenario, as presented in Figure 10. The connectors between the supply chain steps (and within the refuelling station as for the

LOHC case), in the gaseous hydrogen pathway, mainly consist in compressing hydrogen from a pressure level to the required one for the next step, which is less energy-intensive than the liquefaction/evaporation and the hydrogenation/dehydrogenation that are required for LH2 and LOHC. On the other hand, the cost fraction related to the transmission alone (without considering the connectors) is more attractive in the LH2 and LOHC cases compared to the GH2 one, which can be explained by the higher capacities of the LH2 and LOHC trailers allowed by the higher hydrogen volumetric densities.

Upstream, the cost of hydrogen production and hydrogen storage is assessed for the different supply chains. Production costs amount to 3.7 €/kg approximately. Slightly lower hydrogen production costs are reached in the first scenario (putting the electrolyzers next to the nuclear power plants) due to the electricity grid fee exemptions. In this case, the production cost reaches 3.2 €/kg.

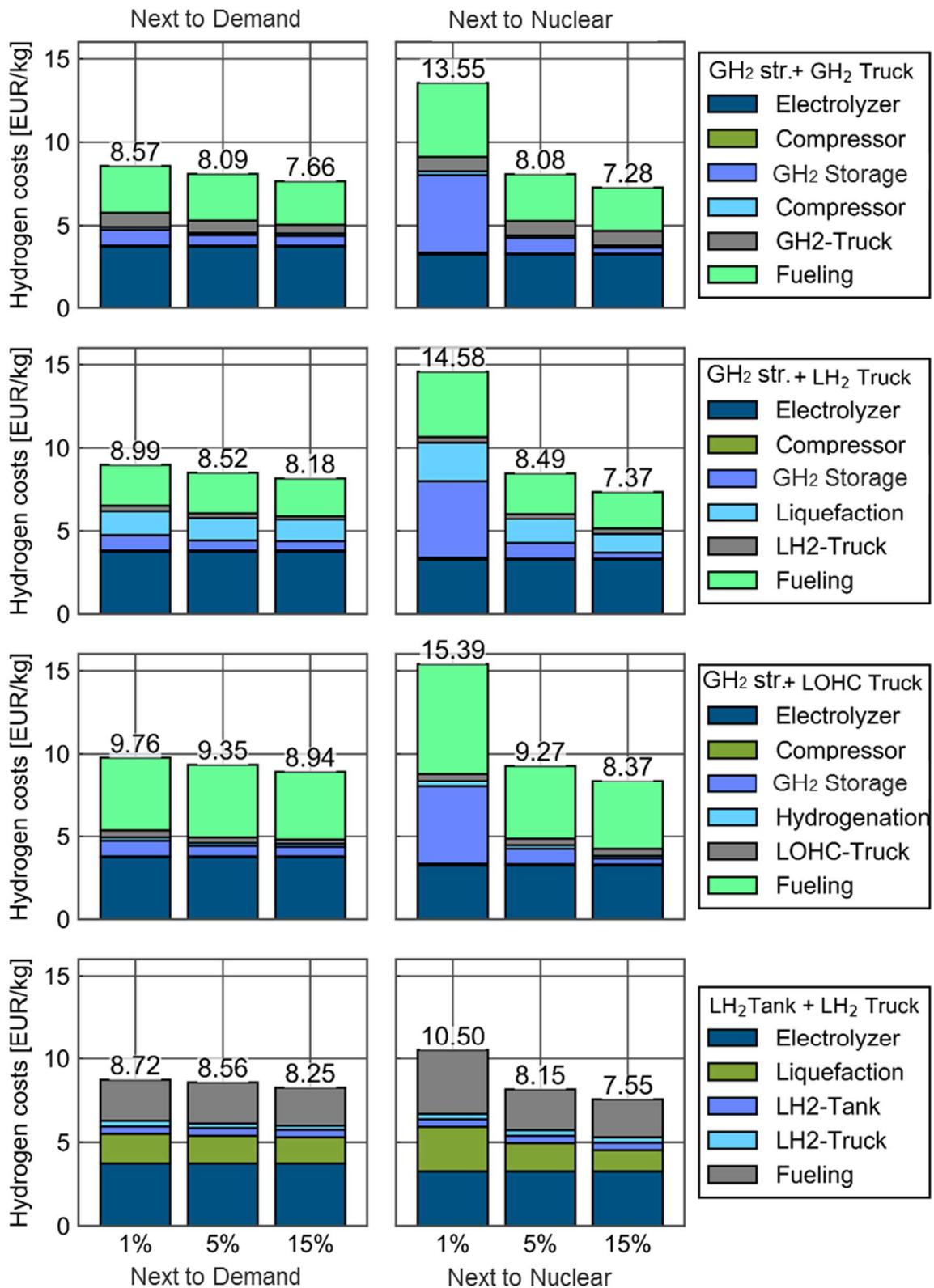
However, this gain is compensated by a higher cost of hydrogen storage in this scenario that is due to the inadequacy of the electrolyser locations compared to the demand centres. Considering a representative hydrogen storage facility characterized with cost similar to underground cavern to be installed next to the production sites, the storage cost amounts to 0.93€/kgH₂ in the first location scenario (next to nuclear power plants) and 0.62€/kgH₂ in the second one. Nonetheless, regarding underground storage, this would clearly be an under-estimation of the cost since it depends on the possibility to build storage facilities in salt caverns next to every hydrogen production site (which is not the case in France, this will be further detailed hereafter, see **Figure 13**, which implies that the cost of transporting hydrogen up to the available storage sites and then to the demand hubs needs to be added. The liquid and LOHC storage options are more realistic in this case, presenting a flexibility of location; the corresponding costs vary between 0.4€/kgH₂ and 0.7€/kgH₂ for the 5% penetration scenario, comparable to gaseous storage cost estimate. Overall, the storage cost range is not large: the storage cost component varies between 0.4€/kgH₂ and 0.9€/kgH₂ for the 5% penetration scenario depending on the considered pathway (gaseous, liquid or LOHC storage) and the electrolyser location scenario. Storage is not the first cost contribution, whatever the selected option.

Based on the analysis made above, four main pathways are selected for further investigation, taking into account the impact of the scenario (the location of the electrolyser and the FCEV penetration rate) on the final cost at the pump in order to investigate if a cost gap between location scenarios is created when moving from one penetration rate to the other. The selected pathways are applicable to all of the scenarios (hence the transmission via pipeline option is excluded).

Accordingly, the following delivery pathways are investigated:

- Gaseous storage, GH2 trailer trucks;
- Gaseous storage, LH2 trailer trucks;
- Liquid storage in tanks, LH2 trailer trucks;
- And gaseous storage with LOHC trailer trucks.

For each pathway, six scenarios are compared as presented in Figure 11: two scenarios for the location of the electrolyser facilities and for each one of them, three case studies are suggested for the market penetration (1%, 5% and 15%). The selection of different market penetration scenarios for the fuel cell electric vehicle deployment allows having an idea on the potential dynamic development of the required infrastructure and the evolution of the “most suitable” delivery option depending on the FCEV penetration rate.



*GH2: Gaseous Hydrogen - LH2: Liquid Hydrogen - LOHC: Liquid Organic Hydrogen Carrier

Figure 11: Impact of the scenario on the final cost at the dispenser

As shown in Figure 11, for all of the four selected pathways, the higher the market penetration, the lower the cost at the pump, highlighting the benefit of creating economies of scale. The nuclear scenario (placing the electrolysers next to the nuclear power plants) is more sensitive to the scale effect. This is significantly visible when it comes to the cost fraction related to the gaseous storage. In this case, during the early hydrogen market penetration phase presented here by the 1% penetration rate scenario, massive gaseous hydrogen storage seems to present a non-viable option. This is balanced out with higher penetration rates allowing higher hydrogen throughput and better load factors.

It is interesting to notice the trade-off between the two location scenarios. As a matter of fact, the results show that during the early market penetration phases, placing the electrolysers near the demand is more economically attractive than placing them next to the nuclear power plants. The latter scenario implying higher investments require high throughput to be amortized. Indeed, when increasing the market penetration rate up to around 5%, the two location scenarios seem to converge in terms of economic attractiveness.

Figure 12 allows following the impact of the hydrogen market penetration on the cost break-even point between the two location scenarios.

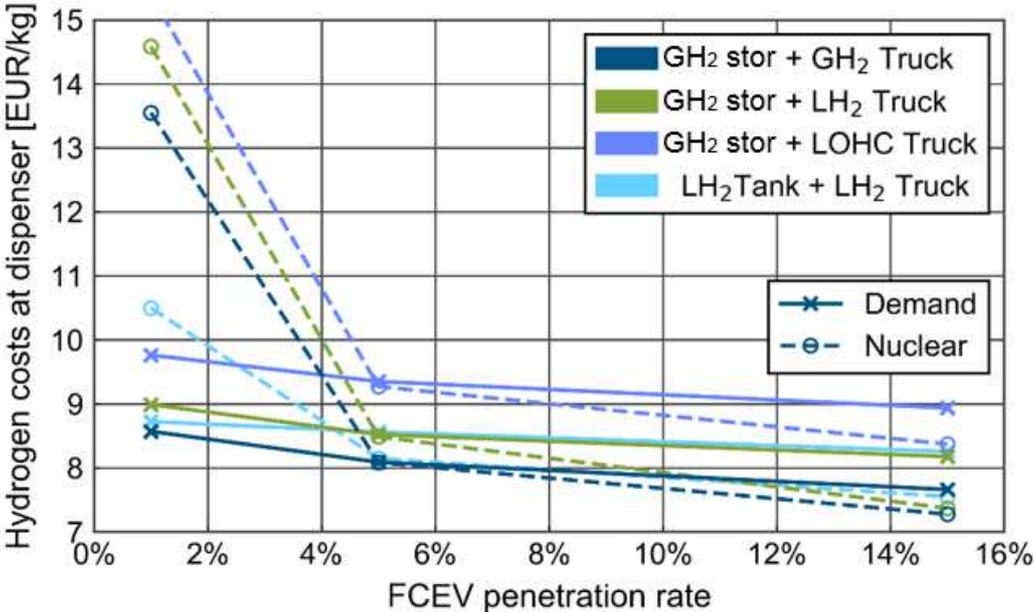


Figure 12: Comparison of total hydrogen costs at the dispenser for the placement next to nuclear power plants and next to the demand for supply pathways

Indeed, in almost all of the considered pathways, the break-even point is reached at around 5% market penetration rate except for the “all-liquid” pathway where the intersection occurs at around 3%. Starting from which, the first option (placing the electrolysers next to the nuclear power plants) becomes more economically attractive than the second one. At this stage, the hydrogen demand levels allow to amortize the infrastructure costs, besides, placing the electrolysers next to the nuclear power plants allows to reach cheaper hydrogen production costs thanks to electricity grid fee exemption as considered in the study and to the scale effect.

In other terms, this also allows to partially analyse the economic attractiveness of both energy vectors (electricity and hydrogen) when it comes to transporting energy. Indeed, in the second case study, when the electrolyzers are placed near the demand, energy is routed from the power plants up to the hydrogen demand centres in the form of electricity using the existing power grid. On the other hand, when placing the electrolyzers next to the power plants, the electricity transmission up to the hydrogen demand hubs is replaced with hydrogen delivery pathways.

Although it seems not fair to compare investing in new hydrogen infrastructure to using the already installed electric grid to route the required energy, the results show that starting from a 5% market penetration rate, it can be considered that hydrogen presents economic advantages when it comes to transporting energy compared to electricity. Conducting a cost analysis of the infrastructure investments comparing the potential upgrade of the power grid and the deployment of hydrogen infrastructure can give further insights regarding the energy vector comparison [57].

Amongst the four considered hydrogen pathways, the “all gaseous option” always presents the lowest cost, no matter what the scenario is, except for the 1% case study in the nuclear location case where the “all-liquid pathway” (liquid storage and LH2 trailer truck) seems to present the most suitable supply chain for hydrogen early market penetration. This is mainly related to the hydrogen storage cost for such low throughput and such geographic configuration. Hence the liquid hydrogen storage option is more attractive when it comes to low market penetration rates and long delivery distances.

When higher market penetration rates are reached, new hydrogen delivery options may emerge such as the LOHC option. The latter presents big advantage in terms of delivery costs (compared to both gaseous and liquid options) which is related to its high energy density. However, reducing the refuelling station costs seems to be a challenge even at high penetration rates. This can be related to the energy-intensive dehydrogenation step that is required to extract hydrogen from the carrier.

The needed storage capacities are compared for the penetration rate scenarios. The results are presented in Table 3.

Table 3: Storage capacity needs

		Storage capacity needs		
FCEV penetration rate	1%	3.5	kt	115
	5%	17.5		577
	15%	52.5		1,732
				GWh

Although the geographic location of the salt caverns is not taken into account in this paper, their capacity adequacy to the storage needs as assessed in this paper is investigated.

Table 4 presents the salt caverns capacity in France.

Table 4: Salt cavern capacities in France (adapted from [58])

	Etrez	Manosque	Tersanne	Hauterives	
Salt cavern capacity	1,117	496	262	200	million m ³
	Total: 2,075				million m ³
	Total: 200 *				kt

*Hydrogen density = 0.08988 kg/m³

*Methane density = 0.656 kg/m³

It is interesting to notice that, as shown in Table 3 and Table 4, the salt cavern capacities are sufficient to cope with the storage needs that are assessed in this paper. Nevertheless, many questions are still remaining regarding the real availability of these caverns for hydrogen storage, knowing that they are already operated today for natural gas storage [58]. The latter will still be needed in future and therefore a reconversion to hydrogen stays in competition with the gas storage market.

There are a number of regions across France that are suitable for underground hydrogen storage (see **Figure 13**). These geographic locations are characterized by the presence of geological salt formation. New caverns may be built, provided that the soil nature is appropriate.

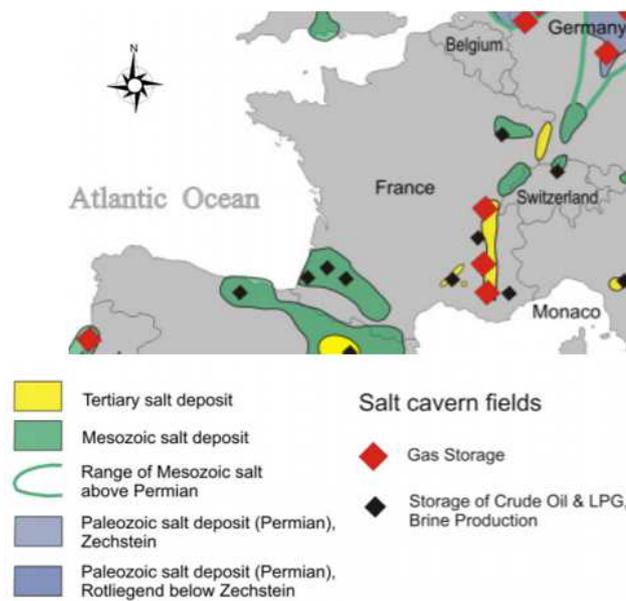


Figure 13: Salt cavern locations across France (adapted from [59])

However, in the present study, when considering the storage in the calculation, the model assumes that the geographic availability is given.

In order to overcome cavern geographic availability issue, considering liquid storage can be an economically viable option as presented in Figure 11, with costs amounting to 0.45\$/kg_{H₂}. If the underground storage were to be replaced by compressed gas storage, the resulting costs are expected to be higher. According to Tzimas et al. [60], the compressed gas storage cost can vary from approximately 0.9\$/kg_{H₂} to nearly 5\$/kg_{H₂} depending on the storage capacity.

To sum up, there is no one best option for hydrogen delivery in France according to the results. It depends on the adopted scenario defining the market deployment phase. At low market penetration rates, placing the electrolyzers near the demand allows avoiding over-scaled infrastructure and hence presents lower costs than the first scenario (electrolyzers next to the nuclear power plants). At more advanced deployment phases (starting from 5% penetration rate), placing the electrolyzers next to the nuclear power plants becomes more economically attractive having the advantage of lower production costs due to electricity grid fee exemption.

Nevertheless, regardless of the electrolyser location, some pathways present relatively low costs compared to other ones considered in this study. For instance, as a general trend, the all-gas pathway coupled with an underground storage seems to be the most economically attractive option in most of the scenarios, once the early market penetration step is achieved.

This result is tightly dependent in the real world on the availability of the underground storage next to the production sites, which can be considered as a strong assumption in this study. Resorting to higher hydrogen volumetric density via the all-liquid hydrogen pathway can be an alternative option, followed by the LOHC pathway.

4. Summary and discussion

Different studies in the literature tackled the hydrogen infrastructure deployment issue in France but partially, assessing either one part of the hydrogen supply chain or the whole supply chain but for one possible delivery pathway.

This paper compares five different hydrogen pathways, going from the production step up to the fuelling station. Different storage and delivery options are investigated for both gaseous and liquid hydrogen. In order to capture the time evolution aspect of the infrastructure deployment needs, three demand scenarios are investigated, going from 1% of market penetration up to 15%. Additionally, two scenarios are taken into account when it comes to the location of the hydrogen production sites vis-à-vis the demand centres.

One interesting outcome of the study is the order of hydrogen pathway adoption preferences depending on the situation. According to the results, during the very first market penetration phases (1% scenario), it is more interesting to store and transport hydrogen in liquid form, which allows to benefit from the high volumetric density of this option while avoiding to resort to gaseous storage and delivery that proved to be expensive at this stage. Beyond the results of this paper, similar results regarding liquid hydrogen are reached for the shipping supply chain (for imports/exports for example) [61].

However, when the hydrogen market penetration gets higher, the gaseous pathway proves to be the most economically attractive option. However, the real geographic availability of the salt caverns in France for hydrogen storage needs to be taken into account, since otherwise, the delivery costs are under-estimated neglecting the cost of transporting hydrogen to the storage cavern and then to the demand.

Higher penetration rates also give room for the new technologies like LOHC to emerge allowing to create the economies of scale. However, the carbon impact of the LOHC supply chain is far from being attractive as far as the natural gas is still the energy source for heating during the dehydrogenation step.

Overall, regardless of the selected supply chain option or the scenario, the production cost represents a high share of the final cost of hydrogen at the pump, varying between 10% and 50% depending on the scenario and the pathway. Further studies should be conducted in order to assess the potential of reducing the hydrogen production cost by benefiting from the electrolyser flexibility and the possibility to participate to the reserve market or to act as a flexible demand, thanks to which the electrolyser operator can be remunerated. Such studies were carried out in [55], [62]–[66], but special

attention should be dedicated to “cannibalisation” effects that may appear when more flexibility providers compete to participate to this market which reduces the income share of each.

Finally, the approach adopted in this paper is deterministic, assuming the same hydrogen penetration rate everywhere across France and deploying each time one possible supply chain. Nevertheless, in the real world, hydrogen demand can be heterogeneous across the country, which may be in part lead by regional and local, governmental and industrial incentives. Presenting a mixed infrastructure deployment depending on the regional demand can be a perspective to this paper. Examples of such studies can be found in the literature for the German case (Reuß et al. [20]).

In addition, considering the other hydrogen markets, whether they are related to the mobility sector (buses, trucks, trains, etc.) or the industry and natural gas sectors can be of major impact. The geographic distribution of these demands can highly impact the infrastructure development needs. The case of public fleets is studied in [19] for the Normandy region, showing that during the early stages of market penetration, the infrastructure costs are high calling for a strong need for governmental support. In Z. Lin et al. (2008) [23] the authors consider the industrial hydrogen, added to the hydrogen generation means (SMR, electrolysis, coal gasification, etc.) for the case study of Southern California. Indeed, the results show that industrial hydrogen could be a critical pathway for early stages because it delays massive capital investment and therefore lower cost and risk.

Other aspects can be envisaged as a perspective to this paper, including the coordination that can take place between the different stakeholders (car manufacturers and infrastructure providers for instance) in order to avoid underused infrastructure or running vehicles without appropriate refuelling facilities, or the so called “chicken-egg” dilemma. This is very important from a strategic point of view since it allows lowering the investment risk. The French Hydrogen Plan considers a strategy going in this direction suggesting to start with captive fleets allocating the infrastructure needs (refuelling stations and delivery) to a specified demand. On the other hand, Germany adopted a different strategy starting with the deployment of the hydrogen infrastructure and aiming to attract the demand once the refuelling infrastructure is made available. This may lead to an under-utilisation of the refuelling stations at the first steps of the hydrogen mobility deployment. Our paper takes the coordination between stakeholders as given on a national level, which is a limit of this study. Further work is needed in order to locate the regional collaboration incentives. Several projects can already be identified in France in the Normandy region [19], Ile de France [12] and Auvergnés Rhône Alpes [51], [52], for the mobility use but not only. For instance, projects for injection of hydrogen into natural gas networks are identified in Marseille [67] and Dunkirk [54]. The stakeholder collaborations can occur on the different steps of the hydrogen supply chain, from the production step up to the final use. Popov et Baldynov (2018) [68] address this aspect for the Japanese case study identifying some important corporations involved in the hydrogen infrastructure development in Japan.

The limits of not considering such initiatives and interactions between stakeholders can be reduced via a sensitivity analysis in order to appraise the uncertainty of the demand and the impact of the latter on the results. Several studies in the literature tackle this issue. Almansoori et Shah (2012) [69] addressed the hydrogen supply chain cost for a case study in Great Britain. The authors considered the demand uncertainty via a scenario-based approach using a stochastic model for different steps of the hydrogen deployment and different supply chain configurations. The results show that the consideration of uncertainty can lead to significant changes in the final costs and even the structure of the optimal supply chain. Later, Nunes et al. (2015) [70] elaborated the same case study using a two stage stochastic model and a sample average approximation method showing that in order to reach reasonably good solutions, the analysis of up to 15 scenarios is required.

5. Conclusion

Hydrogen is a promising solution for a multi-sectorial decarbonisation. It also allows to link between the electricity system (provided that it is produced via electrolysis) and the other energy sectors (industry, transport, natural gas system). This paper focuses on the transport sector and specifically the use of hydrogen in fuel cell electric vehicles for light duty passenger mobility. One major issue that is source of uncertainty holding back the hydrogen deployment there is the infrastructure development needs and costs.

According to the results, economies of scale that can be driven by higher market penetration rates have significant impact on lowering the hydrogen cost at the pump. This impact is more visible in the first stages of hydrogen deployment (going from 1% to 5% market penetration results in a cost drop of around 2€/kg), highlighting the necessity of growing in size in order to reach the targeted cost reductions. This step can be fostered by governmental incentives to help industries overcome the “death-valley”.

Placing the electrolyzers next to the demand helps reduce the infrastructure needs. This would allow lowering the costs of hydrogen delivery which is crucial especially during the first market penetration phases. When higher penetration rates are reached, placing the electrolyzers next to the electricity source proved to be more economically attractive.

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