Hydrogen market penetration feasibility assessment: Mobility and natural gas markets in the US, Europe, China and Japan

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Abstract

Making it possible to bridge between different sectors thanks to its versatility, hydrogen is a promising enabler for a multi-sectorial decarbonisation. The remaining question is how feasible it is to substitute the current carbonized technologies already prevailing in the markets by new low-carbon hydrogen systems that can be more expensive today and by which timeframe hydrogen can reach the required competitiveness.

The market entry feasibility in the transport and natural gas sectors is assessed for USA, Europe, Japan, and China, and for different timeframes (up to 2040). According to the results, the most promising market in the four regions is hydrogen for mobility. This market even presents a potential room for taxation in the medium term. In contrast, blending with natural gas struggles to reach competitiveness. Both industrial and political efforts are required in the two markets in order to lower the costs and prepare a suitable market penetration environment.

Keywords

Hydrogen; Economy; Market penetration; Competitiveness; Multi-regional; Prospective

I- Introduction

1. Context

In order to mitigate climate change and fall in line with the decarbonisation targets expected worldwide, most energy mixes must undergo transformations with country-specific energy transition pathways. The universal Paris agreement, signed in December 2015, fixed a long-term goal of keeping the increase in global average temperature below 2°C above pre-industrial levels and pursuing efforts to limit it to 1.5°C [1]. This implies that, for each country, specific measures must be considered in order to reduce greenhouse gas (GHG) emissions. The challenge remains on identifying the optimal ways to reduce these emissions, while preserving growth, competitiveness and security of supply.

Nowadays, the energy sector is responsible for 32.2 Gt of global CO_2 emissions, with a high share caused by the power sector (42%). Electric power is a core issue: significant decarbonisation of the energy system will be driven by both enhancing the role of electricity and decarbonizing the power sector.

This second driver has led to the wide spread of renewable energies. However, their integration into the power system may trigger some challenges. In fact, they engender higher risk of power system imbalances, thus jeopardizing the grid stability. This situation is a new challenge for system operators which are responsible for maintaining the balance of the electric system by procuring reserve power and by dealing with the system imbalances in real time.

Besides, in order to reach the 2° or further, the 1.5° goal, thinking beyond the electric system is required. Other sectors like transport which accounts for nearly 22.7% of total energy-related CO_2 emissions [1] will need to be considered in the decarbonisation strategy. Transportation is challenging, being so far highly dependent on fossil fuel combustion engines. The European Union (EU) has set CO_2 reduction targets for transport activity aiming to reach a 95 g $_{CO2}$/km cap by 2020. These targets are more demanding than the ones expected in the United States (US), China and Japan (121, 117 and 105 g_{CO2}/km respectively) [2].

In order to preserve the security of supply while reducing carbon emissions, rethinking the way the energy system is managed may be crucial. Coupling the power system with other energy sectors (via power-to-heat and power-to-mobility for example, either directly with electricity, or synthetic gas as final energy) could be a promising solution to contribute to both flexibility provision (hence easing the penetration of renewable energies) and a multi-sectorial decarbonisation at the same time [3]–[5].

In this perspective, hydrogen systems can be key enablers to promote promising synergies between sectors. Provided that hydrogen (H_2) is produced via low-carbon technologies such as electrolysis coupled with a decarbonized power mix, it offers a new approach to flexibility provision, and makes it possible to link the different energy sectors together, thanks to the hydrogen versatility [6]. The produced hydrogen can be used for both chemical purposes and energy applications.

In 2015, the global hydrogen production reached 61Mt per year [7], 96% of which were produced from fossil sources [8], through natural or refinery gas reforming (48%), chemical processing (30%) or coal gasification (18%). Only about 4% of the global hydrogen production came from electrolysis [9].
Three main types of electrolysers have been developed. The most commercialized one is the alkaline technology which is mature. Proton exchange membrane (PEM) is in its early commercial phase (especially for high-capacity electrolysers) but its high flexibility and simple design makes it the most adapted for grid services, being able to withstand variable loads. Last but not least, high-temperature steam electrolysis (SOEC) is still under research and development [9], [10]. Its process offers interesting perspectives through reversible operation, and co-electrolysis of water and carbon dioxide to generate syngas. In addition to intentionally produced hydrogen, large volumes of by-product hydrogen are generated from a variety of production processes. One of the most important sources of by-product hydrogen is catalytic reforming processes in refineries. This hydrogen is typically recovered and used captively in other refinery operations [3], [7].

Today, hydrogen is mainly used as a chemical product with 80% of its global consumption attributed to refineries and ammonia production [3]. Industrial uses are expected to grow. Indeed, beyond the current use for nitrogen fertilisers production and refining activities, hydrogen or hydrogen-rich chemicals can be used as process agents (e.g. for low-carbon emissions steelmaking) [11]. In addition, hydrogen may also be used to decarbonize industry fuel needs, as well as in other end-use sectors such as buildings and transport. Thus, in the future, an increasing use of hydrogen as an energy carrier is expected [12], [13]. So far, only small amounts of hydrogen are used in energy applications. Hydrogen can be injected into natural gas networks, or used for transport, heating or power supply purposes.

Hydrogen can thus contribute to decarbonize a variety of sectors, including the most challenging ones like transport, but how far is from being able to penetrate these markets?

The development of these diverse markets will be related to the regional contexts, namely the energy-related policies that may ensure or hinder the large deployment. A multi-regional assessment of hydrogen market penetration feasibility is conducted in this paper in view of the latest announced policies and targets. The considered regions are the United States, Europe, China and Japan, presenting different energy contexts and allowing challenging hydrogen under different circumstances. The evaluated markets in this paper are the mobility sector via fuel cell electric vehicles (FCEV, for passenger light duty vehicles) and the direct injection of hydrogen into natural gas networks.

Studies tackling a multi-regional future potential for hydrogen, taking into account more than one hydrogen application are scarce in the literature. The few multi-regional publications addressing this issue [10], [14], [15] generally consider either a normative scenario with stringent CO_2 emission constraints and strong policy or industry incentives for hydrogen deployment or an evaluation of (only) the hydrogen prospective costs without comparing them to the targets that should be reached in order to penetrate the market.

The aim of this paper is to propose a different approach characterizing the market penetration feasibility based on an assessment of both the hydrogen costs through different pathways and the market entry costs. The economic assessment is conducted in the context of the latest governmental announcements and energy policies, in order to evaluate whether the current policies are sufficient or not to trigger the hydrogen development.

The first part of the study is a prospective analysis carried out to identify the future market entry costs for the two applications. This market entry cost represents the benchmark that should not be exceeded in order to reach competitiveness with other reference options and is then based on the competitor cost. In the second part of the paper, the current and prospective hydrogen costs (starting from production and adding up other cost components to the pump, considering different pathways) are evaluated and compared to the target costs, in order to assess the market penetration feasibility based on the gap between the two evaluated costs. The larger the gap is, the harder the market penetration will be.

2. Objective of the study

As mentioned in the introduction, the aim of this paper is to examine whether the current and near-term energy policy environment is suitable for hydrogen penetration, to assess the deployment feasibility of hydrogen in the considered markets. To do so, the economic penetration feasibility of hydrogen systems into the new markets is evaluated considering the latest governmental energy policies and orientations in four different regions of the world: the United States (USA), Europe (EU), Japan and China. For each of these regions, the hydrogen integration feasibility is assessed for different timeframes up to 2040. This variety of geographies and target dates impacts the energy prices considered in the calculations. The future electricity, oil, natural gas and carbon prices are exogenous parameters in this study. They are taken from the World Energy Outlook (WEO) accordingly with the New Policies Scenario [1]. These values are hence in harmony with the Governments' views on their future energy systems. They take into account the policies already communicated (but not necessarily put in place) that will shape the future energy systems in each of the regions considered in this study. Hence, in other terms, the approach of this paper consists in evaluating the consequences of the governmental targets and pledges on the penetration feasibility of hydrogen into the energy system.

The energy and carbon prices adopted in this paper are presented in Table 1.

Table 1: Energy prices according to the New Policies Scenario [1]

	New Policies Scenario		
	2015	2030	2040
Oil prices - $/boe			
World	**51**	**111**	**124**
Gas prices - $/boe			
USA	**15**	**31**	**40**
EU	**41**	**60**	**67**
Japan	**60**	**69**	**72**
China	**56**	**67**	**70**
CO2 prices - $/tCO2			
USA	-	-	-
EU	-	**37**	**50**
Japan	-	-	-
China	-	**23**	**35**

Generally, according to the latest energy strategies and pledges, the overall prices are expected to grow by 2040. A sensitivity analysis is conducted in order to investigate other scenarios for the carbon price (450 ppm scenario carbon prices), since some of the regions that are considered in this study do not show yet an explicit carbon pricing scheme. The evolution of the oil and gas prices may be subject of discussion. Indeed, the so called "Green Paradox" predicts that switching to a greener energy system will result in a drastic reduction in oil and gas consumption following the GHG mitigation targets. The latter can lead to a drop in oil and gas prices due to the low demand falling below the supply potentials [16].

The energy-related markets that are considered in this study are: 1) mobility applications via fuel cell vehicles for the passenger light duty sector 2) and direct injection of hydrogen into natural gas networks (methanation is not considered due to its high costs compared to the direct injection of hydrogen into the grid [17]).

The energy-related markets represent new markets for hydrogen, hence the interest of investigating the feasibility of entry into these markets. The already existing ones (the industrial/chemical applications of hydrogen) are not included. Previous work tackled the future market size potential of these markets as well as their contribution in decarbonizing the industrial sector [13]. Besides, in these markets, hydrogen is already present but mainly produced via SMR. Therefore, the competition will rather be between the carbonised and the low carbon hydrogen production. A recent study in the literature [11] evaluated the potential of green hydrogen in the industrial sector. The outcomes of this study show that hydrogen production via electrolysis could compete with the SMR method in regions where renewable sources (for electricity production) are abundant. In such regions, hydrogen production cost via electrolysis can be lower than 2$/kg of H_2 which is the result of a combination of a decreasing renewable cost and a profitable load factor.

In order to assess the competitiveness of hydrogen in each of the considered market segments, two different approaches are coupled. A top-down approach considers the evaluation of the market entry cost depending on the competing technology. This view is completed with a bottom-up approach evaluating the existent and expected future costs of hydrogen throughout its supply chain. To do so, the hydrogen production cost is evaluated for different production technologies and for different scenarios of electricity prices and load factors. Then, depending on whether centralized or decentralized the production systems are, the delivery costs are added in order to obtain the hydrogen cost at the pump/end-use. The gap between this hydrogen cost and the targeted cost is then assessed in order to quantify the industrial efforts that need to be done in order to lower the hydrogen costs throughout the whole supply chain. This gap is also an evaluation of the need for governmental incentives or subsidies that are required to ease the first stage penetration of hydrogen technologies into the markets. The evolution of this gap over the years also gives an idea on the timeframe of the competitiveness achievement.

The specific assumptions regarding the market entry costs in each of the mentioned market segments, as well as the hydrogen production and delivery costs, are detailed below.

II- Top-down approach

In this section the general methodology of the paper is explained as well as the assumptions considered in order to conduct the study for the different market segments.

1. Top-down approach: Evaluation of market penetration costs methodology

In order to penetrate the different markets, hydrogen will have to compete with the historically preponderant technologies already prevailing on the market. Hence, the penetration feasibility is represented in this study by the target cost that should not be exceeded in order to be able to compete with the other options on the market. The aim behind this top-down logic is to evaluate the capability of hydrogen systems to provide same services for the client with similar or lower costs in the future. This approach was also used in the past back in the nineties where natural gas wells were discovered in the north of Europe (in Groningen specifically). At that time, Exxon knew that in order to sell gas to Germany, France, Belgium, and eventually even to Italy that already had a local gas production, the natural gas must be priced to sell in competition with and by reference to the alternative fuels already present in the market. This approach was referred to as the "Market Value" method [18], which was used to set long term natural gas contracts, linking the gas price with the oil one [19], [20].

Similarly, the hydrogen market entry costs also depend on the competitors which vary from one market segment to another and from one region to another as well. The competitor definition is detailed in the next subsections for the considered market segments.

In order to evaluate the role of environmental policies, the impact of the CO_2 price on the market entry cost, and consequently, on the hydrogen penetration feasibility is assessed in section IV-, by using the carbon prices from the 450 ppm scenario as a variant. According to the International Energy Agency (IEA), not all of the regions around the world will be able to establish the carbon market pricing nationally. In the USA for example only regional carbon prices may arise like in California for example but no federal target has been announced so far [21]. The carbon pricing is still an ambiguous issue in Japan. Hence, in the central case, future carbon prices are considered only for Europe and China [1].

Table 2 displays the CO_2 emissions related to the combustion of the hydrogen competing fuels. These values are considered in the calculation of the carbon tax included when assessing the market entry costs.

Table 2: Combustion CO_2 emissions by fuel

	g_{CO2}/MJ
Diesel [22]	66.6
Gasoline [22]	58.3
NG [23]	50.3

The next sections detail the assumptions behind the target costs calculation for each of the market segments.

1.1. Mobility markets

Regarding mobility applications, hydrogen is considered in this study as a direct fuel via fuel cell vehicles. Few studies in the literature tackled the competitiveness of hydrogen as a feedstock product for advanced biofuels; it seems that hydrogen still has a long way to go to be able to enter this market segment economically speaking [24], despite the fact that, technically, advanced biofuels do not require major modifications in the car engine [3]. Besides, the regulatory framework for identifying hydrogen-based fuels as advanced fuels is not sufficiently defined, making it difficult today to characterize the hydrogen to be produced for these fuels [25]. This market segment is then not included in the study.
In order to assess market entry costs for mobility use as a direct fuel in FCEV, only particular light duty vehicles are considered. Today, road transport represents more than 70% of the global transport energy consumption, of which 71% is PLDV-related [26], [27]. However, other transport segments such as trains and maritime transport may emerge in the short term, driven by environmental standards [28]–[30].

The reference alternative to FCEV is the use of fossil fuels in internal combustion engine (ICE) vehicles. The most used fossil fuel is considered the first competitor. Gasoline is the major fuel in almost all the regions except for Europe, where diesel is rather the first fossil competitor [31]. Note that the recent controversies about the diesel use in Europe may become a game changer [32]. Lately, several cities across Europe have also decided to ban the circulation of diesel vehicles [32]. This decision was initiated by the German Court enabling the cities in Germany to ban the most heavily polluting diesel cars from their streets. Stuttgart, Düsseldorf and Hamburg were the first ones to respond to this call. Paris and Copenhagen are also planning to join this decision [32].
For long term competitiveness assessment, hydrogen vehicles will also compete with electric vehicles (EV), which are expected to largely expand in the years to come. This competition may take place sooner than expected. Comparing FCEV to EV is beyond the scope of this study. A proper comparison would require a detailed competitiveness assessment based on not only the fuel cost but also the infrastructure cost. A recent study compared the investment amounts required for both types of mobility in Germany, according to the number of vehicles. Higher costs for hydrogen at small penetration rates are amortized when the fleet develops [33]. Furthermore, one could argue that FCEV are electric vehicles and that FCEV and EV should not be opposed. On the contrary, synergies can be found, either technically with the implementation of range extenders [26], [27], or from the market standpoint by positioning the most appropriate technology on each market segment, overall contributing to decarbonize the transport sector [14].

The market entry cost of hydrogen in this study is assessed based on the cost to travel one km. For hydrogen as a fuel, in order to enter this market segment, its selling price must be at the most equal to the oil product price that a consumer pays at a refueling station to cover the same distance. In order to be

competitive with the other fuels, hydrogen must provide the same service for the same price or less. This criterion is important to the consumer preference [24]. The total cost of ownership (TCO) is also an important factor to take into consideration in order to assess in more details the competitiveness of different mobility options [26], [27], [34]–[36]. The evaluation of the TCO of hydrogen vehicles compared to the main competitors will be the aim of future works. Here, we consider as it is projected by [2], that the price of the FCEV compares to the ICE one by approximately 2025 as a timeframe.
In accordance with the durability criteria defined by the European Union, hydrogen fuel should be competitive in the long term, without subsidies, with alternative fuels [24], [37]. All fuels were thus considered to be subjected to the same amount of taxes except for the “TDCPP” (Tax on Domestic Consumption of Petroleum Products) which represents the tax on the petroleum products. The amount of this tax depends on the nature of the product (gasoline or diesel for example), but also the type of consumption (use as fuel or for heating). In France, it has integrated a carbon component since 2014 indexed on a carbon reference price [38], [39]. In order to assess the impact of higher carbon prices on this tax, a specific carbon tax is included in the paper as discussed in section II-2.3.
The TDCPP tax is then not considered when assuming a clean hydrogen production as in this paper. However, this can be challenged by future policies , since the revenues of this tax are used to finance local authorities and the projects involving energy transition targets and transport infrastructure deployment [39].
The equation below defines the costs to travel one kilometer using gasoline or diesel.

$$Travel\ cost\ (\frac{\$}{km}) = \frac{Oil\ price\ \left(\frac{\$}{l}\right) + Refining\ and\ distribution\ costs\ \left(\frac{\$}{l}\right) + TDCPP\ \left(\frac{\$}{l}\right)}{Energy\ to\ travel\ 1\ km\ \left(\frac{l}{km}\right)} * (1 + VAT\ (\%))$$

The oil prices are detailed in Table 1, they evolve according to the New Policies scenario up to 2040 [1]. Refining and distribution costs are assumed to be the same in the four regions and for the different timeframes considered in this study (see Table 3). Regarding the TDCPP, it varies depending on the region. Table 3 shows the tax amount by region. The tax on the added value (VAT) is then considered to assess the final cost [40]–[43].

Table 3: Fuel cost assumptions [$/l] (adapted from [24], [44], [45])

	Gasoline	Diesel	
Refining cost	*0,12*	*0,16*	*$/litre*
Distribution cost	*0,10*	*0,11*	*$/litre*
Fuel Tax - US	*0,13*	*0,14*	*$$_{2016}$/litre*
EU	*0,83*	*0,59*	*$$_{2016}$/litre (French Tax ~ mean in EU)*
Japan	*0,71*	*0,43*	*$$_{2016}$/litre*
China	*0,17*	*0,13*	*$$_{2016}$/litre*

For fossil-fueled engines, a consumption of 7.4 l/100km and 6.3 l/100km are considered for gasoline and diesel vehicles respectively [2], [46], [47]. These values correspond to real-world fuel consumption on the

road. Progress in motorization performance is also taken into account. Energy efficiency is assumed to reach 18% in 2030 and remain constant until 2040 (average from [2], [47]–[49]).
Once the travel cost is assessed, the targeted hydrogen cost at the pump (market entry cost) is evaluated. It represents the ratio of the cost to travel one km by the hydrogen consumption (amount of hydrogen needed to travel the same distance).

$$Hydrogen\ target\ cost\ at\ the\ pump\ \left(\frac{\$}{kg}\right) = \frac{Travel\ cost\ (\frac{\$}{km})}{Hydrogen\ consumption\ by\ km\ \left(\frac{kg}{km}\right)}$$

The hydrogen consumption is detailed in the table below assuming efficiency evolution by 2030 to the theoretical consumption value announced for the Mirai model [50].

Table 4: Hydrogen consumption per km

H2 consumption (kg/km)	Current	2030	2040
	0.008	0.0076	0.007

Based on the hydrogen target cost at the pump, the segmentation of the supply chain is conducted in order to evaluate a targeted hydrogen production cost. In section IV-, the top-down approach is confronted with the bottom-up approach in order to evaluate the penetration feasibility of hydrogen into this market.

1.2. Natural gas markets

The hydrogen penetration potential into the natural gas market is based on the cost of the thermal energy consumed, in \$/MWh. Indeed, to be competitive, hydrogen mixture should provide the same energy for the same price (or less) as natural gas. A mixture of 10%$_{vol.}$ hydrogen and 90%vol. natural gas is considered. According to the literature, this composition does not require major modifications of the existing installations and equipments currently functioning on natural gas [51], [52]. Natural gas prices are detailed in Table 1.

2. Results

As detailed in the methodology section, market entry costs are assessed according to the competitor cost in the market. The higher the cost is, the easier it will be to reach, and hence be able to penetrate the market.
Firstly, results are given without considering carbon taxation. Then, the impact of environmental policies will be analysed through the consideration of prospective CO_2 prices.
The results are detailed for each of the considered market segments in the following sections.

2.1. Mobility market segment

In order to be cost competitive, hydrogen will have to provide the same service (here mobility) for same or better costs. Hence, competing with diesel and gasoline, the cost to travel one km with hydrogen should at maximum be equal to the travel cost using the competing fuels. In Figure 1, the maximum allowed costs to travel one kilometre are displayed. Since Europe is the only region where diesel is the first prevailing fuel, it has different cost values than the other regions where gasoline is adopted as a first used fuel for transportation. However, diesel dominance in the European mobility sector is expected to decrease in the years to come.

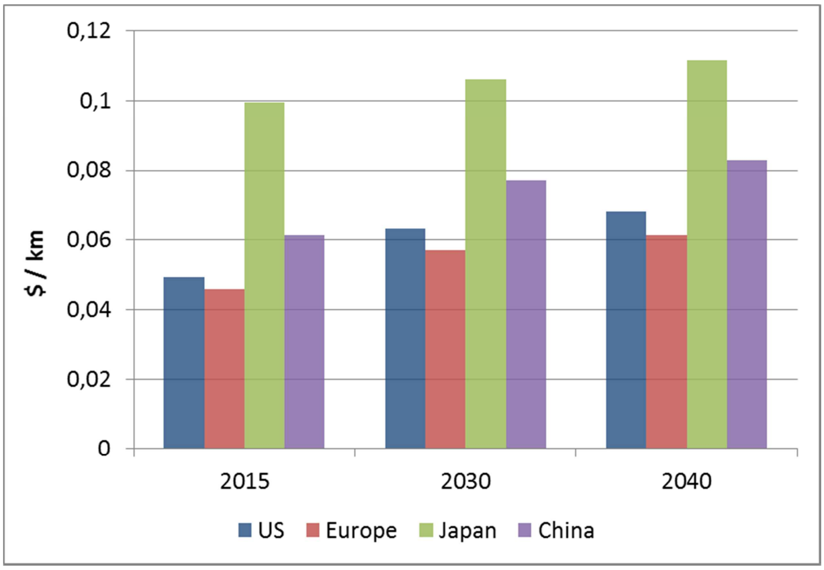

Figure 1: Cost to travel one km using diesel (Europe) and gasoline (the rest of the regions)

Maximum allowed values for travel cost by km are lower in Europe, hence reflecting a harder competitiveness in this region. This is due to the energy efficiency of diesel compared to gasoline. In terms of energy consumption, diesel cars consume less energy than the gasoline ones to travel the same distance, which means that less fuel is burnt so lower costs will occur. In the US, China and Japan gasoline is the most common fuel used for transportation. Consequently, fuel consumption is considered to be the same in these regions. However, beyond the type of the fuel itself, other factors may impact the fuel consumption, like the size of the car, the driving patterns (e.g. speed, driver behaviour), the average number of people by car and the driving conditions in general (state of the roads, weather, etc.) [27]. These factors may vary from one region to another. For example, American cars tend to have bigger engines than the average vehicles. Hence, even with the same fuel, we can have different travel cost values for each region. To take into account these differences, social aspects should be included in the calculation which is beyond the scope of this paper. In this study, it is rather the tax amounts varying from one region to another that impact the fuel cost. Japan presents the highest tax levels compared to the other considered regions. This leaded to much higher fuel costs by km easing the competitiveness in this region. Europe presents the second highest tax rates (Table 3), nevertheless the energy efficiency of diesel outweighs the tax effect on the travel cost.

The slight increase of the travel costs between 2015 and 2040 is mainly related to the increase of the oil prices in the scenario as shown in Table 1.

Based on these fuel costs by km, the market entry costs are evaluated for the different regions. Figure 2 shows the target costs of hydrogen at the pump. These costs should not be exceeded in order to keep hydrogen in the competitiveness area.

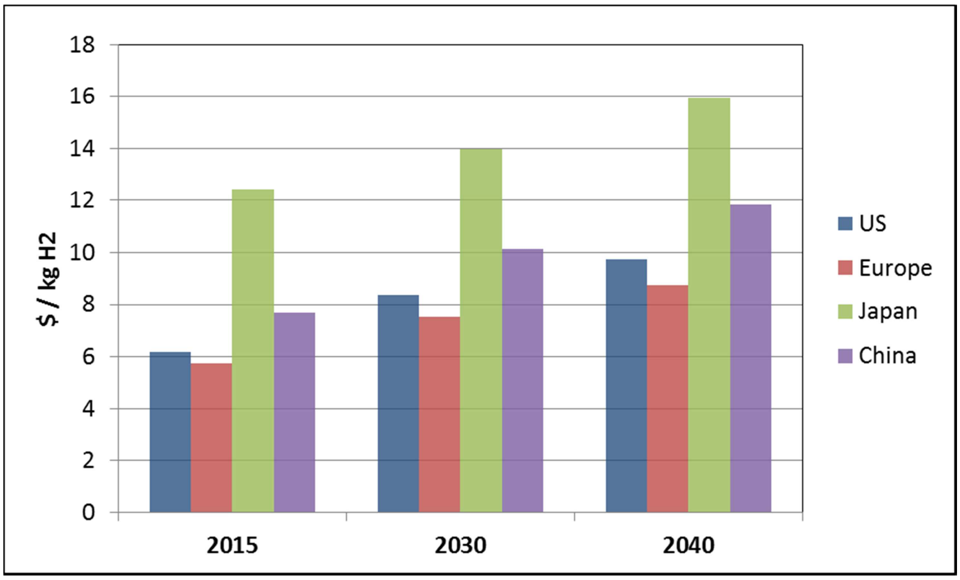

Figure 2: Hydrogen target costs at the pump in the mobility market segment by region

Values for 2040 show that hydrogen can be sold at the pump at a price varying between approximately 9$/kg$_{H2}$ and 16$/kg$_{H2,}$ depending on the region. This price represents the threshold of hydrogen total cost at the pump including the taxes.

The decrease of hydrogen costs at the pump will depend on the deployment and penetration rate of hydrogen technologies. In the years to come, the competitiveness gets easier according to the results. The market entry cost increases, meaning that hydrogen can be sold at higher prices. This increase in the market entry cost is related to both the increase of oil prices and the decrease of hydrogen consumption by kilometre assumed in the scenario. Together, these factors overcome the improvement of the fuel efficiency of the thermal internal engines assumed in the scenario (section 1.1).

2.2. Natural gas market segment:

In this section, the competitiveness with natural gas usage is assessed on an energy basis, meaning that, in order to be competitive, hydrogen must provide the same service (in terms of energy content in this case) for the same or lower costs.

Results show that, despite the high potential in terms of market size that was identified in previous work [13], the hydrogen market penetration costs for the natural gas market segment turn out to be harder to reach compared to the mobility case (Figure 2). Figure 3 summarizes the results for the different regions considered in the study.

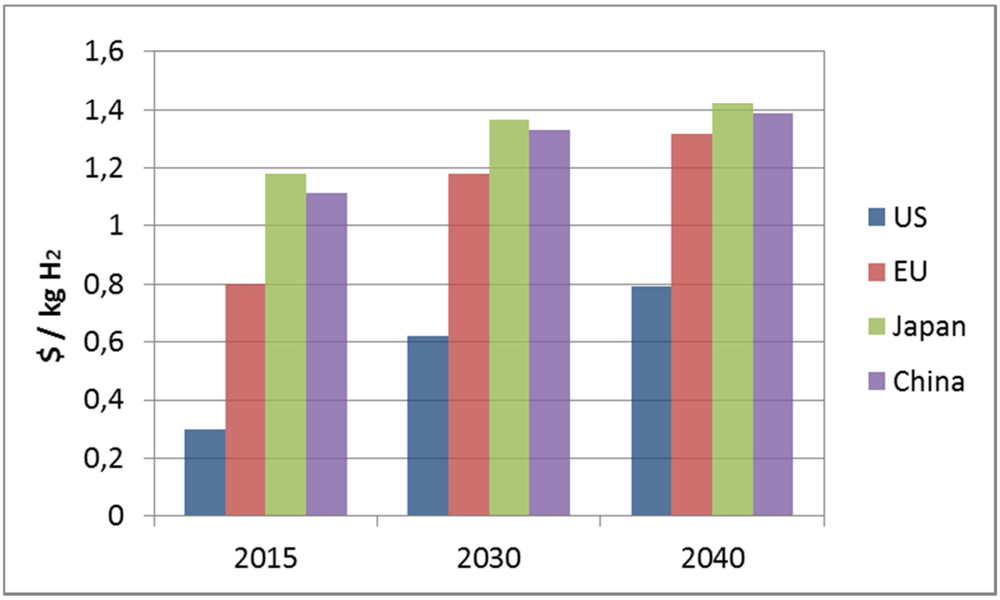

Figure 3: Natural Gas blending market penetration costs by region and timeframe

Overall, market penetration costs are slightly increasing in all of the regions when moving from the short to the mid, and to long term. The difference between 2015 and 2040 values varies between 0.2 and 0.5 $/kg which is quite low. In the USA, competitiveness is hard to achieve. The exploitation of shale gas led to a sharp decrease of natural gas prices, hence becoming hard to compete with. Japan represents the highest market penetration cost followed by China. However, the most promising region for hydrogen injection into gas networks is Europe which combines a comparatively high gas price [1] and the most developed gas networks (2,030,058 km [53]), easing the hydrogen penetration into this market segment. Germany is now leading the European R&D activity [51]. This interest for power-to-gas is directly linked to its decarbonisation targets set in the Energiewende and to the higher shares of renewable electricity production that are expected in the years to come and that do not necessarily match the evolution of the demand. The localization of the electric demand which is often situated far from the production centres is also problematic requiring energy routing solutions. Hence hydrogen is needed as an energy carrier [51].

Nonetheless, the potential of this market segment highly depends on the governmental incentives that will ease the market penetration, not only financially but by also fixing the allowed volume proportions of hydrogen to be injected in order to trigger its development.

In the next section, the environmental policies are evaluated through the CO_2 price impact on the results.

2.3. Impact of environmental policies (carbon pricing)

Environmental policies are crucial in order to ease the development of new “clean” technologies. The aim of this section is to evaluate whether CO_2 pricing as a supporting scheme is sufficient in order to trigger the different market segments.

As detailed in section I- paragraph 2, we use the carbon price assumptions from the IEA New Policies scenario which takes into account the latest national policies and pledges (a variant will be studied in section IV-, following the 450ppm scenario). Only Europe and China have set CO_2 price targets for the years to come [1]. In the USA, there is no federal carbon price. However, several States, mainly California, do have a carbon trading system with a current CO_2 price of 15\$/t_{CO2} [54]. Data for Japan is lacking. A current price of 3\$/t CO_2 in mentioned in [54] but no future targets have been set so far for carbon pricing.

In Figure 4, the CO_2 tax impact on the market penetration costs is presented for the mobility market segment considering the two different competitors (diesel and gasoline).

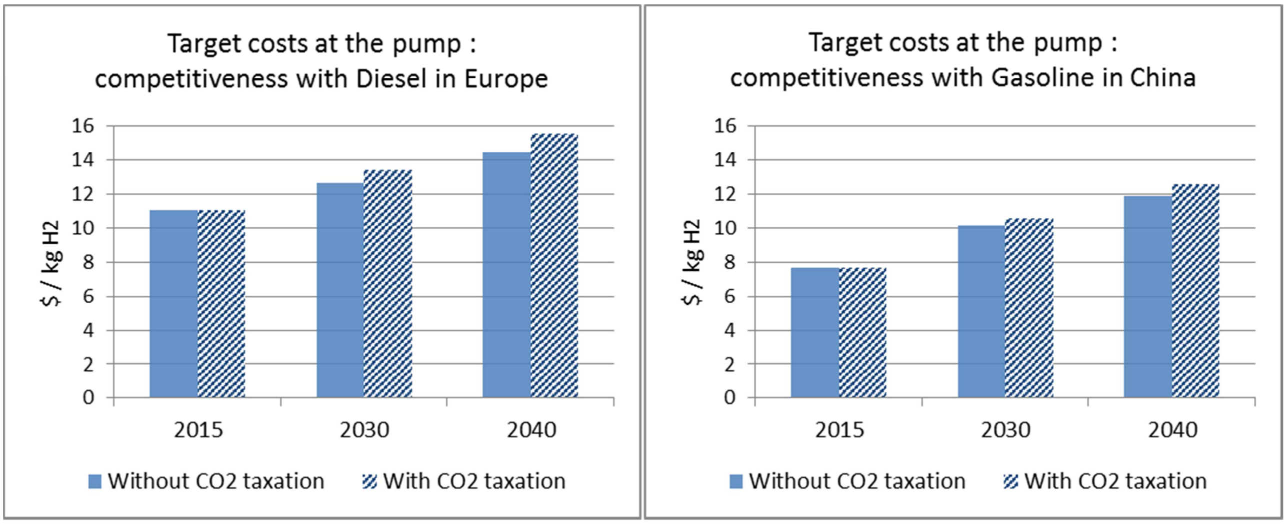

Figure 4: Target Costs at the pump considering carbon taxation

As shown in the figure and as expected, considering a CO_2 price penalizes the fossil fuels. Target costs are likely to increase by approximately 10% in Europe and 5% in China by 2040 if CO_2 taxation is considered. This will ease the competitiveness since it allows hydrogen to be sold at higher prices at the pump. In other terms, carbon taxation eases reaching the break-even threshold.

The injection into natural gas networks is likely to be harder to achieve, even if carbon taxation is implemented (at the expected levels). Figure 5 shows the impact of carbon taxation on the natural gas market entry cost.

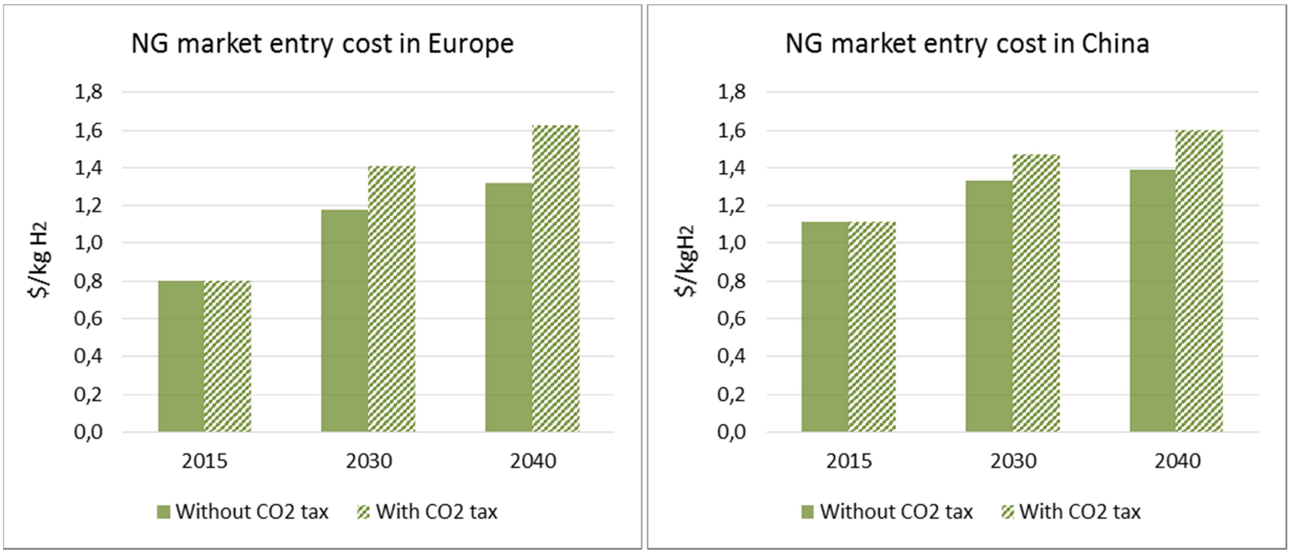

Figure 5: Natural Gas blending market penetration costs considering CO_2 taxation

The carbon price consideration by 2040 increases the market entry cost by around 23% in Europe and 14% in China. However, this increase is not sufficient and the target cost values remain very low.

Introducing a carbon price eases the penetration of hydrogen technologies into the different market segments that are considered. However, it may not be sufficient. While the mobility have higher market entry costs, the injection into natural gas networks seems to present some challenges although it has, as detailed in previous work [13], the highest CO_2 mitigation potential compared to any of its other market segments (both industrial and energy related). This potential is 60% higher when considering the impact of methane leakages [13] that are avoided by hydrogen blending and that have much higher global warming potential than the carbon dioxide [55], [56]. Accordingly, since the injection of low-carbon hydrogen into the grid allows decreasing the carbon footprint of natural gas, it should be eligible for a feed-in tariff or a premium supporting its market penetration, during the transition phase. Further potential governmental support schemes are discussed in section V-.
In order to be able to conclude regarding the feasibility of market penetration, the market entry costs will be compared to the actual costs of hydrogen detailed in the next section.

III- Bottom-up approach: Evaluation of hydrogen current costs

1. Methodology

The bottom-up approach consists in assessing the hydrogen current and expected future costs throughout the supply chain. The final total cost is then compared with the targeted one previously established (section II-), in order to evaluate the market penetration feasibility.

1.1. Production cost evaluation

The production costs are evaluated in the different regions for 2030 and 2040 considering two electrolysis options: PEM and alkaline technologies. To do so, the levelised cost of hydrogen (LCOH) is assessed according to the following equation.

$$LCOH = \frac{\sum_{t=0}^{n} \frac{C_I + C_R + C_M + C_E}{(1+r)^t}}{\sum_{t=0}^{n} \frac{P_{H_2}}{(1+r)^t}}$$

C_I: investment cost, C_R: replacement cost, C_M: maintenance cost, C_E: electricity consumption cost, P_{H2}: Hydrogen production, r: discount rate, n: project lifetime

For the calculation of the LCOH ($/kg), a duration (*n*) of 30 years is adopted for the project lifetime with a discount rate (*r*) of 8%.

C_I and C_R correspond respectively to the investment and replacement costs, assuming that the replacement occurs in the middle of the project lifetime. The investment costs depend on the type of the electrolysis. The adopted costs for the electrolysers are displayed in Table 5.

Table 5: Electrolyser costs for PEM and Alkaline technologies (adapted from [10], [57]–[59])

$/kWe	2015	2030	2040
Alkaline	867	615	447
PEM	1749	750	459

A drop in the cost of the production technology is expected in the years to come [30], [57]. The data for the alkaline technology correspond to the investment cost assumptions made in the ETP (Energy Technology Perspectives [31]) hydrogen supply-side analysis [57]. The cost of the PEM technology is assumed to converge with the alkaline one by 2040 [58].

Regarding the maintenance costs (C_M), they are assumed to be 2% of the total investment cost per year and remain constant during the project period.

As for the electricity consumption costs (C_E), a value of 50 kWh/kg H_2 [3] is adopted in the calculation. The electricity prices are displayed in Table 6. They correspond to the industrial sector prices of the IEA scenarios, consistent with the energy prices considered elsewhere [1].

Table 6: Electricity prices (including taxes) adopted in the calculation of the H2 production cost [1]

$/MWh	2015	2030	2040
USA	70	74	77
EU	132	150	150
Japan	161	140	130
China	125	146	145

The electricity price is mainly affected by the wholesale price. The latter highly depends on the fuel cost and the electricity mix in general. Hence, the low electricity prices in the United States can be explained by the fact that most of the electricity is generated through coal, natural gas and nuclear [60]. Coal and natural gas, being locally produced, are very cheap in the US while nuclear, as capital intensive as it is, presents very low operational costs. Coupling these different factors with low tax levels compared to the other regions [1], the US exhibits the lowest electricity price in this study. On the other hand, Europe struggles to decrease its electricity price, being driven by the pledges in terms of renewable energy investments and the simultaneous phase-out of the conventional thermal power production [61]. However, several countries within Europe are an exception and do not have the same electricity values, like France for example which benefits from much lower electricity prices [62], [63] due to its high share of low cost nuclear power generation. The prices in China are expected to rise by 2040 according to [1], as carbon prices become more widespread. As for Japan, the high electricity prices are related to the phase-out of nuclear generation after the Fukushima accident (but there is an intention to restart a portion of its nuclear fleet) and the switch to natural gas power plants with high natural gas import costs [1], [64].

Thus, the electrolysis plant is assumed to be supplied with power at a given price (which does not only include the power production cost but all the cost factors, including taxation), whatever the load profile. However, other strategies could be considered, namely by taking advantage of low power prices on the market, and avoiding peak ones. Also, as previously mentioned, some specific contexts, more favourable, could be identified. A sensitivity analysis is then conducted in order to investigate the impact of the electricity price on the final production cost of hydrogen.

Based on the previous assumptions, the hydrogen production cost is assessed for different load factors that have a specific impact on the depreciation of the electrolyzer. In order to give orders of magnitude, the current costs of hydrogen production via SMR are provided being the benchmark process, assuming a natural gas price of 35.7 $/MWh and considering two case studies: with and without carbon taxation (100$/t CO_2). Two scenarios are then compared (centralized and decentralized production) impacting the costs of the transport and distribution infrastructure in the calculation.

1.2. Delivery cost evaluation

The hydrogen infrastructure costs are exogenous parameters in this study. The delivery cost evaluation requires a geographically detailed model for each of the considered regions. Values for the transport, storage, distribution and refuelling costs are taken from [3], [65]. These values are provided by the JRC-EU-TIMES modelling framework and the Schlumberger SBC Energy Institute which present the most detailed hydrogen cost data found in the literature. The selected values are detailed in the sections below (Figure 6, Table **7** and Table 8).

- Mobility markets

The delivery steps considered in the mobility market segment consist in the compression of hydrogen, its transport and distribution via the different pathways detailed in the previous paragraph, and finally the refueling to the station (gas to gas).

Three pathways are considered for hydrogen transportation and distribution:

- Transport in gaseous state at 180 bar via tube trailer trucks,
- Transport in liquid form in cryogenic tanks,
- And transport via pipelines.

In order to compare the three pathways on the same basis, the travelled distance and the total hydrogen throughput chosen in this study are the same for the three options (50 km and 1MW_{H2} throughput). Varying these parameters changes the order of the pathways in terms of costs. Figure 6 shows the impact of the transport distance (50 km and 200 km) and the hydrogen throughput (1 MW and 50 MW) on the pathway cost.

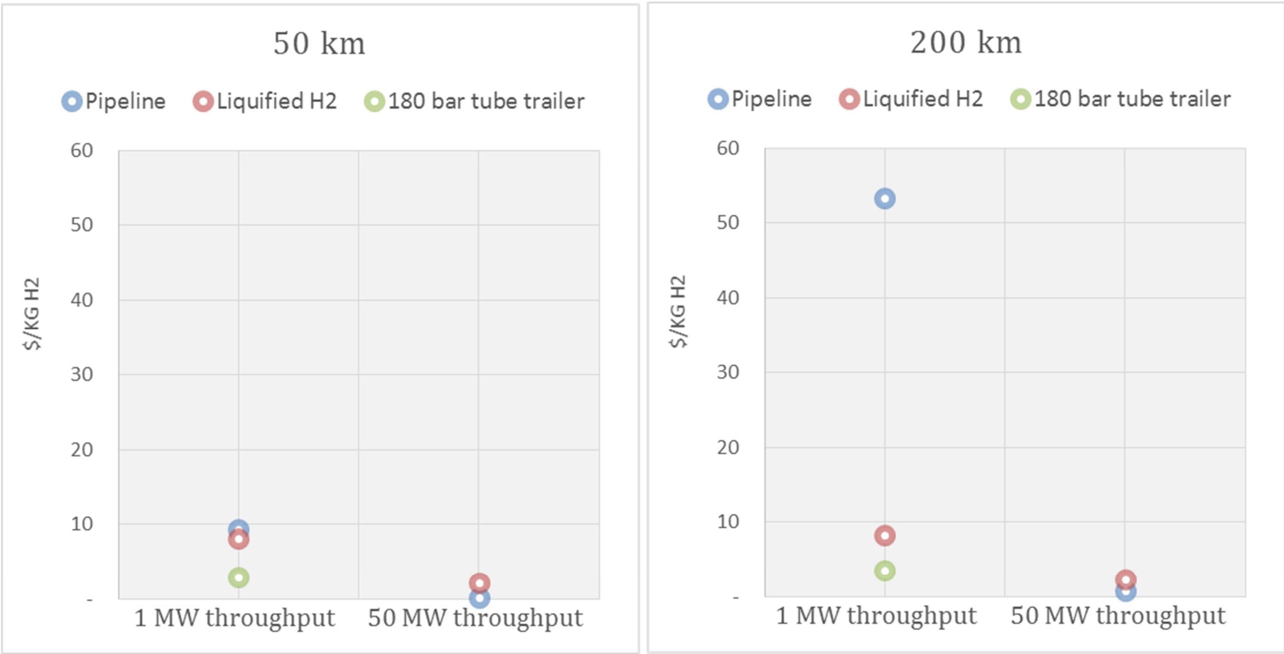

Figure 6: Hydrogen transport pathways comparison (adapted from [3])

The gaseous transport pathway via tube trailers is the cheapest option regardless of the travelled distance when 1 MW throughput capacity is considered. However, this option completely disappears from the graph (the cost becomes extremely high) when it comes to high throughput capacity transportation. This is due to the low transport capacity by truck especially considering the poor energy density by volume of gaseous hydrogen which leads to a need for multiple trucks or multiple travels to transport the same quantity as the other pathways. The transport distance have little impact on the liquid hydrogen pathway, yet with higher hydrogen throughput, the costs can be divided by four approximately (drop from around 8$/kg$_{H2}$ to around 2.3$/kg$_{H2}$) when going from 1MW to 50 MW. As for the pipeline option, as shown in Figure 6, this pathway is clearly not the most economical option for low throughput capacities especially if long travel distances are required. This is due to the high initial investment cost that requires high throughput in order to have profitable payback time. When considering 50MW of throughput capacity, the pipeline transport cost drops from 53$/kg$_{H2}$ to 0.8$/kg$_{H2}$ making it the most economically attractive option.

The refueling costs are assumed to be the same in all of the regions as presented in Table 7.

Table 7: Hydrogen refueling costs for the mobility market segment $/kgH2 (data adapted from [65]**)**

2015	2030	2040
1.52	1.24	1.01

Data is available only up to the 2030 timeframe, hence a continuity in the trend is assumed to generate the cost values for 2040. A sensitivity analysis is carried out to test the impact of the scenario choice (in terms of delivery pathway and cost) on the final results.

- Injection into natural gas network

The injection into natural gas networks includes, as upstream stages, the compression of hydrogen, the storage in centralized underground caverns, the transmission via pipelines and the blending into the natural gas network. The associated costs are displayed in Table 8.

Table 8: Hydrogen delivery costs for the natural gas market segment $/kgH2 (data adapted from [65])

2015	2030	2040
0.19	0.17	0.15

As in the mobility market segment, the delivery costs for 2040 are based on a continuity of the trend.

2. Results:

As detailed in section III- paragraph 1, the bottom-up approach aims at assessing the different costs throughout the hydrogen supply chain or pathway up to the refuelling station or the injection into the natural gas network step. The final cost is then compared to the market entry cost in order to evaluate the feasibility of market penetration.
In the next subsections, the hydrogen production and delivery costs are appraised for different pathways.

2.1. Production costs

This section is dedicated to the evaluation of the hydrogen production cost. This cost varies from one region to another depending on the specific context (here specifically, the electricity price). In this paper, the hydrogen production technologies that are considered are the SMR with CCS and the alkaline and PEM electrolysers. Nevertheless, there are other options for hydrogen production (high-temperature steam electrolysis, photoelectrolysis, etc.). These options are not mature enough or still under research and development and further work is required to lower the costs, enhance the efficiency or improve the lifetime of the corresponding materials [3], [66]–[68].

A general assessment of the hydrogen production cost via electrolysis is conducted in order to evaluate the impact of the different cost components on the final cost, before connecting the production costs to the regional context. Varying the electricity price, the annual load factor and the investment cost (cost of the electrolyser), Figure 7 presents the cost results as a function of the different variables. The evolution of the electrolyser cost between 2015 and 2040 is detailed in the methodology section (section III-1.1).

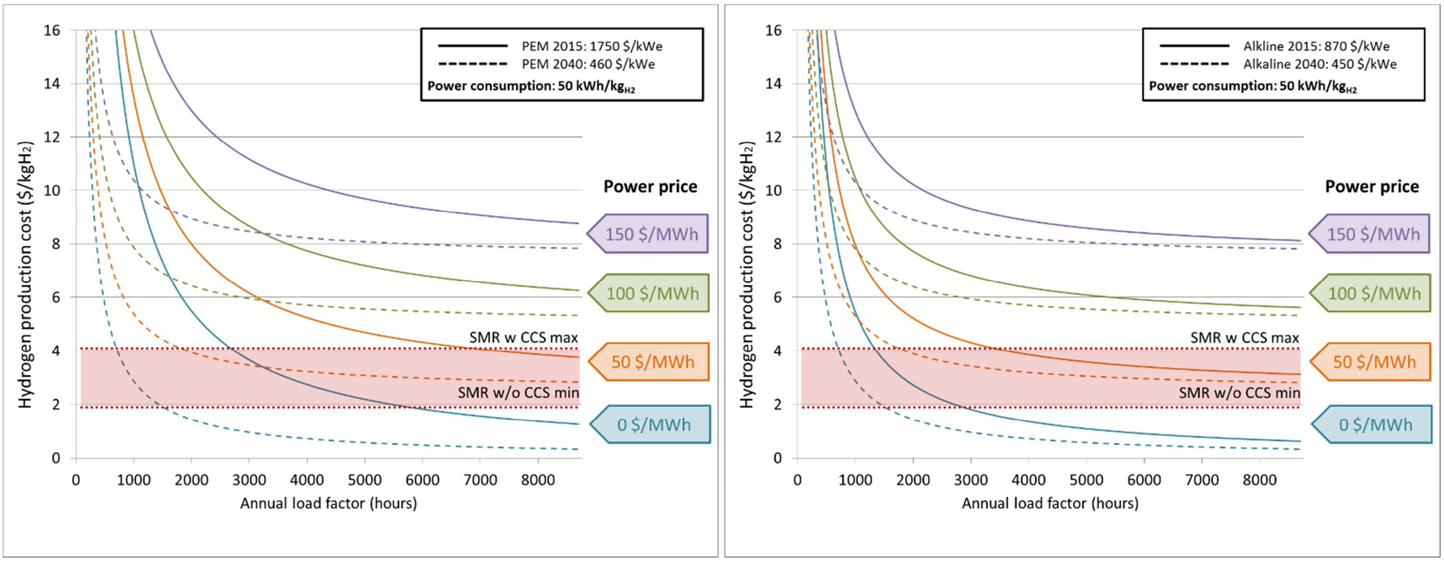

Figure 7: Hydrogen production cost assessment

Globally, in 2015, the alkaline technology led to lower production costs regardless of the electricity price or the load factor. This is related to the investment cost itself, where alkaline electrolysers present cheaper alternatives since the technology was the most mature one then available on the market [3], [9]. However; the higher the load factor is, the lower the impact of the investment cost on the production cost gets. In the future, the capital cost of the PEM electrolysers is expected to drop and converge with the alkaline cost values.

The load factor is a key variable impacting the production cost. Even with no electricity fees (0$/MWh), if the load factor is not high enough to cover the capital costs, hydrogen production will not be economically acceptable. The higher the load factor is, the lower cost we get. However, the results show that, starting from a certain threshold of load factor, around 5,000 hours, the production cost almost stabilizes.

Electricity prices have high influence on the production cost. They impact linearly the LCOH. The current production costs via SMR can be reached with an electricity price of a maximum of 50$/MWh for the PEM technology assuming a high load factor, and it is possible to go up to 75$/MWh for the alkaline technology.

With lower electricity prices, cost parity can be reached for lower load factors. For instance, at 50$/MWh, the break-even point can be reached at 7,000h as load factor for the PEM technology while it does not exceed 4,000h for the alkaline technology.

Figure 8 presents the evolution of the hydrogen production costs in the four considered regions from 2015 to 2040 considering the electrolysis and the SMR (with and without CCS) options for the production. The cost parity timeframe and conditions are searched for. To do so, a sensitivity analysis regarding the electricity price, the gas price and the carbon price is conducted.

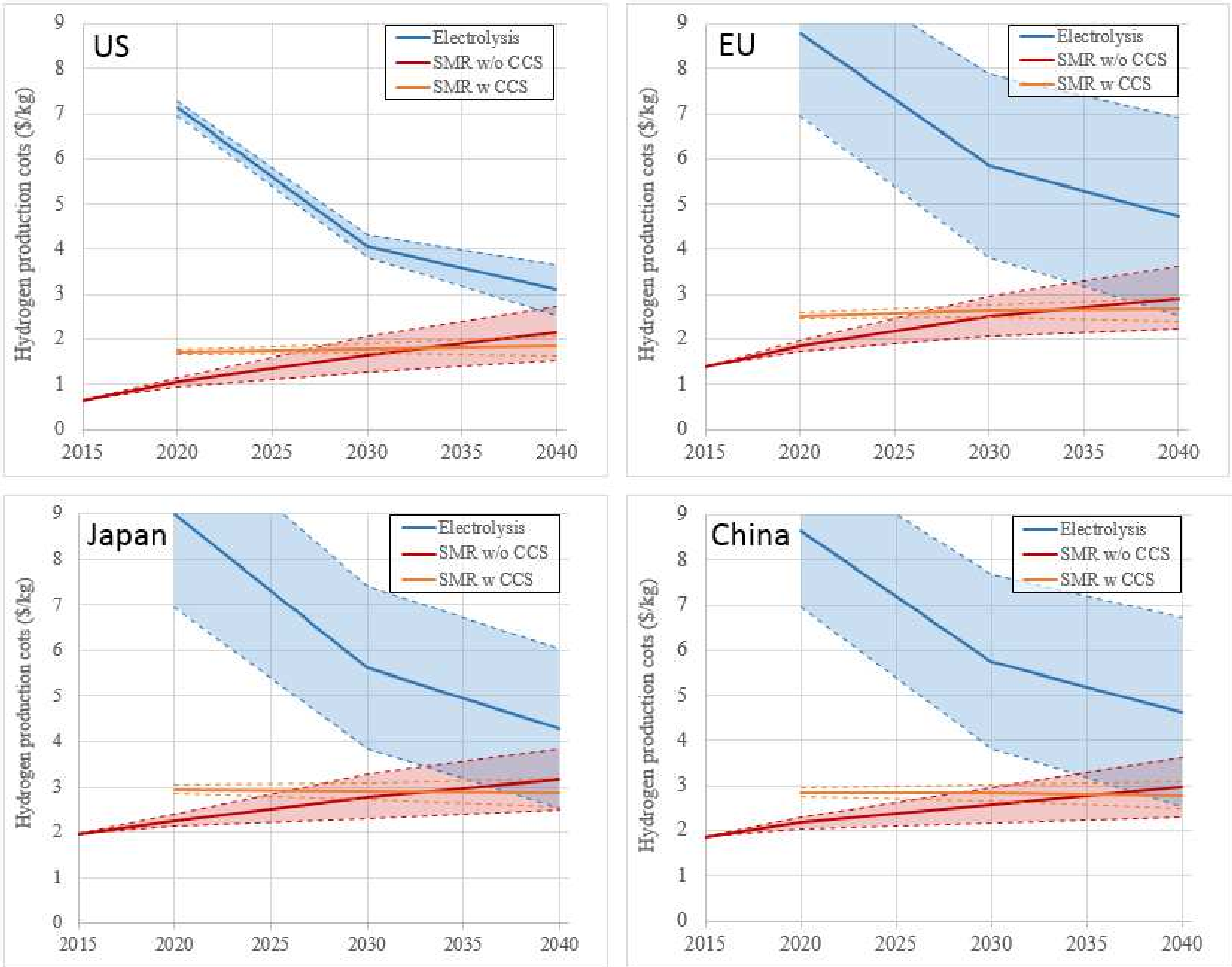

Figure 8: Hydrogen production cost evolution in the considered regions

Regarding the electrolysis curves, the electricity prices that are considered as a maximum value correspond to the electricity tariffs of the industrial sector. A minimum going from 65$/MWh in 2020 to 50$/MWh in 2040 (which would correspond to favourable energy policy, e.g. via tax exemption) is then considered allowing to establish a cost sensitivity area, presented in the graph in blue colour.

As shown in Figure 8, considering the industrial sector tariffs for the electricity prices leads to high production costs even in the long term. In this case, despite the drop of the electrolyser cost and regardless of the load factor, the electrolysis cannot compete with the SMR presented in red (and orange for the SMR with CCS) colour in the graph. Accordingly, the switch from SMR to electrolysis is unlikely to come naturally. Specific support mechanisms like tax exemption or grid fee exemption need to be set in order to lower the operational costs by acting on the electricity prices. As presented in Figure 8, lowering the electricity prices down to 50$/MWh by 2040 allows to reach the cost parity especially if a carbon cost is taken into account penalizing the SMR costs. The cost parity can be reached by different timeframes that depend on the regional context. The American case study is quite special, although the electricity prices are the lowest compared to the other regions, the break-even point is not likely to be reached any time before 2040. In this case, lowering the electricity price down to 50$/MWh is not enough to compete with the very low gas prices that lead to low hydrogen production costs via SMR, even if a high carbon tax (going up to 140$/t) is applied. Nevertheless, the results show that Europe, Japan and China can reach the hydrogen cost parity by 2033-2035 if a carbon tax going up to 140$/t is considered. Otherwise, it can be reached around 2037. The maximum carbon tax considered in this study is far from representing the required tax that should be applied in order to reach the 1.5°C target. According to [69], the carbon price could reach 400$/t CO_2 by 2040 if we commit to the 1.5°C target. Hence higher values for the carbon cost could favour the electrolysis as a hydrogen production means.

In order to further lower the hydrogen production cost via electrolysis, further decrease in the capital costs is desirable. Besides, the electrolysis option has the advantage of being highly flexible especially if the PEM technology is considered [3], [9], [10]. PEM electrolysers can reach full load in less than 10 seconds from cold start. Their easy start-and-stop operation, without the need for preheating or purging inert gases makes them a perfect match with the grid flexibility needs [10]. This means that they can provide the grid with services such as frequency regulation and reserve control which are highly required in a context of future high shares of renewables in the electricity mix [3]. Taking advantage of the remuneration for these services provided by the grid operator can help improve the electrolysis profitability.

Considering SMR plus CCS can be an attractive option. It presents lower costs than the electrolysis in the short to medium term (but this may change if the previously discussed factors are taken into account) and reaches cost parity with SMR between 2032 and 2035 (and between 2025 and 2030 when assuming higher carbon prices penalizing the SMR option) depending on the region. It can hence be considered as a transitional hydrogen production pathway allowing decreasing its carbon footprint. However, further issues regarding the availability and the geography of carbon storage locations need to be considered more carefully. Another option that is not included in the paper and that should be considered more carefully is the hydrogen supply via imports which can be the case in Japan for example [70] planning to import hydrogen from Australia, the latter having recently presented a promising hydrogen roadmap [71].

Added to the production costs, the storage and delivery costs are required to assess the total costs at the pump. The next section details the impact of different hydrogen transport and distribution pathways on the final cost and assesses the market penetration feasibility.

2.2. Hydrogen cost at the pump

As detailed in the methodology section, the hydrogen final cost at the pump is appraised taking into account two major scenarios: centralized and decentralized production.

- Mobility market segment:

For the mobility market segment, the final cost at the pump corresponds to the cost at the refuelling station.

Figure 9 compares, for the centralized case, the final costs of hydrogen at the pump considering three pathways for hydrogen transportation and distribution (three lines in the figure):

- Transport in gaseous state at 180 bar via trucks (tube trailers) (first line graphs in Figure 9),
- Transport in liquid for in cryogenic tanks (second line graphs),
- And transport via pipelines (third line graphs).

The two columns in the figure correspond to the two case studies that are considered for the throughput capacity (1 MW and 50 MW). Indeed, as shown in Figure 9, the liquid and the pipeline options are investigated considering two capacities of throughput (1 MW and 50 MW). On the other hand, the gas tube trailers are considered for only 1 MW throughput capacity, since for high capacities, they would require large volumes that can be solved by rather multiple trailers or multiple travels, leading to an excessively high cost. The transport distance value taken into account is 50 km.

Since the focus in this section is put on the delivery costs, only one value by region and timeframe is adopted for the production cost as an example. Therefore, the production costs in this graph correspond to the PEM technology and a load factor of 6000h.

The choice of the technology does not impact the final cost in a significant way compared to the transport and refuelling costs detailed hereafter. Switching to the alkaline alternative impacts the final cost by, at maximum 0.92 \$/kgH_2 in 2015 and 0.01\$/kgH_2 in 2040. Besides, the regional context only influences the production cost contribution.

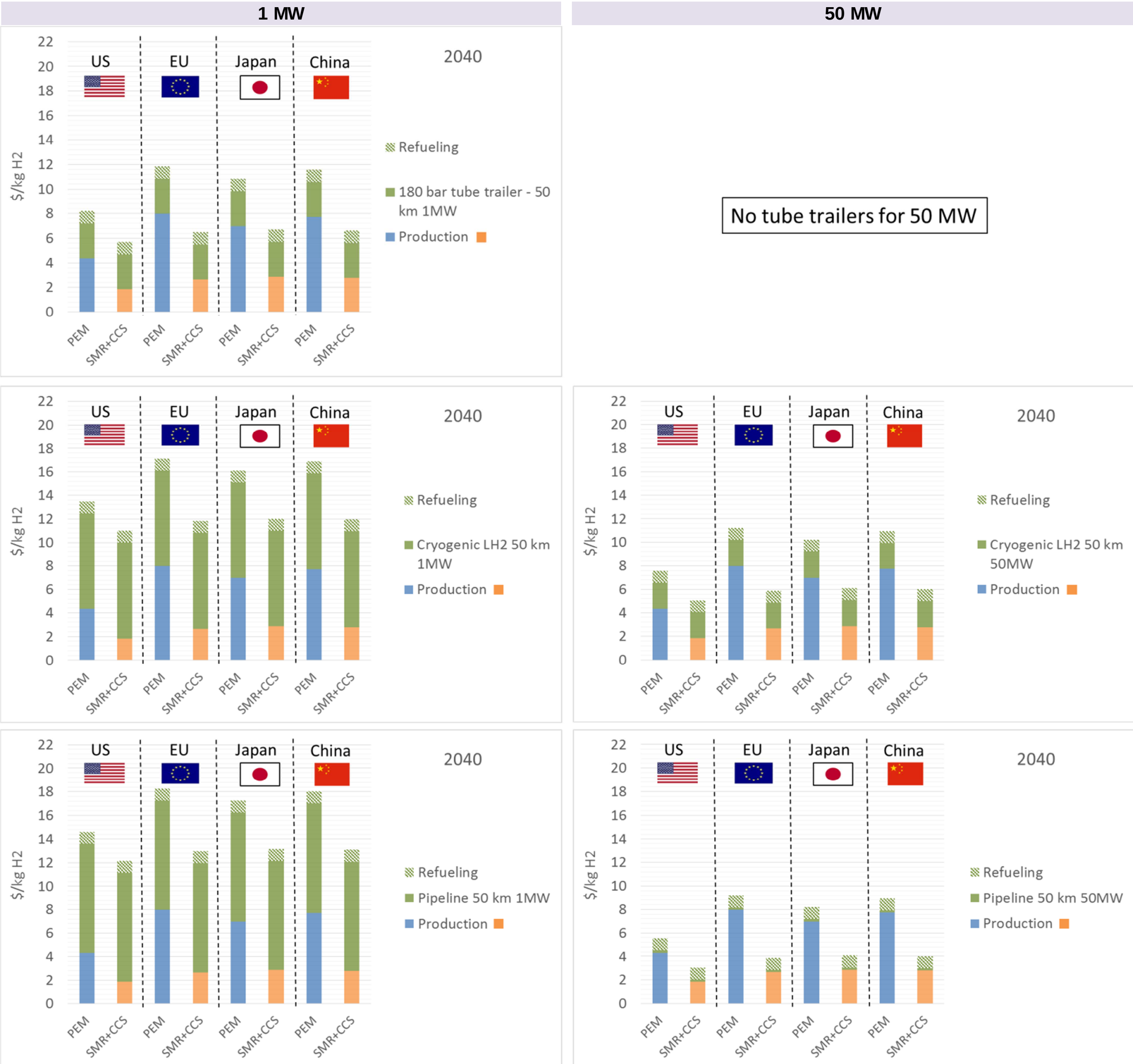

Figure 9: Hydrogen cost at the pump for the centralized case study in 2040 (left column 1 MW, right column 50 MW of throughput capacity, each line corresponds to a delivery pathway)

As shown in Figure 9, the throughput capacity of the hydrogen transport and distribution pathway has an important impact on the final cost. The higher the throughput capacity is, the lower the hydrogen transport cost gets. This means that going from early market penetration to full deployment allows decreasing the costs at the pump. For high throughput capacities (50 MW), the pipeline option is the most economical hydrogen transport pathway. On the other hand, the compressed gas tube trailers cannot be considered for such important volumes. Enhancing the transport capacity also helps decrease the liquid hydrogen pathway cost by 73% making it an attractive option for hydrogen transportation.

The delivery costs are exogenous in this study, they are assumed to be the same for the different regions. However, in reality, they are tightly related to the geographical context and the amount of hydrogen to be transported by region. More detailed information about production and demand localization is required to assess the infrastructure costs. Other transport and distribution pathways can also be considered (liquid organic hydrogen carrier for example, etc.) yet they are not included in this study due to lack of data. As for the potential hydrogen demand amounts by region, a previous work tackled this issue elaborating a scenario for future demand based on the latest governmental policies [13].

A drop in the refuelling station cost is expected in the years to come. Nowadays, the deployed hydrogen station costs between $2 million to $3 million per station. According to [72], the mean cost is expected to drop in the years to come to approximately $1 million per station and even lower (hence a sharper decrease than what is assumed in this study). This drop in the costs can be explained by the rising penetration of the hydrogen fuel cell vehicles into the fleet, leading to more investments in station deployment (hence creating an economy of scale effect) and higher utilisation of the recharging stations. Globally, as of July 2017, the number of fuel cell electric vehicles reached 4,500 cumulative vehicles. California accounts for approximately 48% of the FCEV sales, followed by Japan for about 35%, Europe 14%, and 3% in South Korea [72]. An increase of the size of the hydrogen vehicle fleet is expected in the years to come, according to Toyota announcements planning to sell 30,000 fuel cell vehicles per year by 2020 [72]. Several governmental targets have been set around the world for hydrogen penetration into the PLDV sector (800,000 FCEV in Japan and 1 million in China by 2030) [73], [74].

Overall for the centralised case study and considering the electrolytic hydrogen, the cost at the pump may range between approximately 6 $/kg and 18 $/kg by 2040, depending on the region, the throughput capacity and the selected transport and distribution pattern. On the other hand, considering the SMR plus CCS allows reaching lower costs at the pump that may range between 3$/kg and 13$/kg, but the availability of carbon storage locations nearby should be investigated. As presented in section III- 2.1, the electrolysis costs can be decreased if lower electricity prices or tax exemptions are considered. Taking into consideration the services to the grid that can be procured by the electrolyser flexibility may also result in more advantageous costs for the electrolytic hydrogen.

A second scenario considers decentralized production. This means that the electrolyser is located next to the recharging station. Figure 10 compares the hydrogen cost at the pump for the different regions in 2040 for this scenario. The transport and distribution costs are avoided. However, a local storage bulk on site can be required. The gap with the centralized case is about 8 $/kgH$_2$ by 2040 when compared with the pipeline or liquid transport case for 1 MW throughput (and 2.25 $/kgH$_2$ with the tube trailer gaseous transport case). If storage is not included, the gap would represent the cost of the transport and distribution.

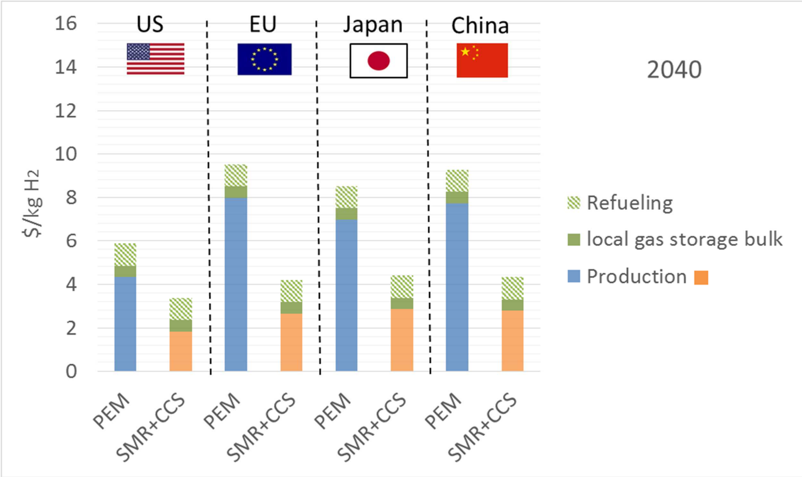

Figure 10: Hydrogen cost at the pump for the decentralized case study

To sum up, the hydrogen cost at the pump for the decentralized case by 2040 ranges from nearly 6$/kg to 9.5$/kg depending on the region. As for the SMR plus CCS case study, the costs range between 3 and 4$/kg approximately. However, having lower costs at the pump for the decentralized case study does not guarantee the competitiveness of hydrogen since generally decentralized production would imply lower capacities which often mean higher CAPEX per installed capacity.

- Injection into natural gas network

Similarly to the mobility case study, the infrastructure costs are exogenously added to the production costs analysed in section 2.1.

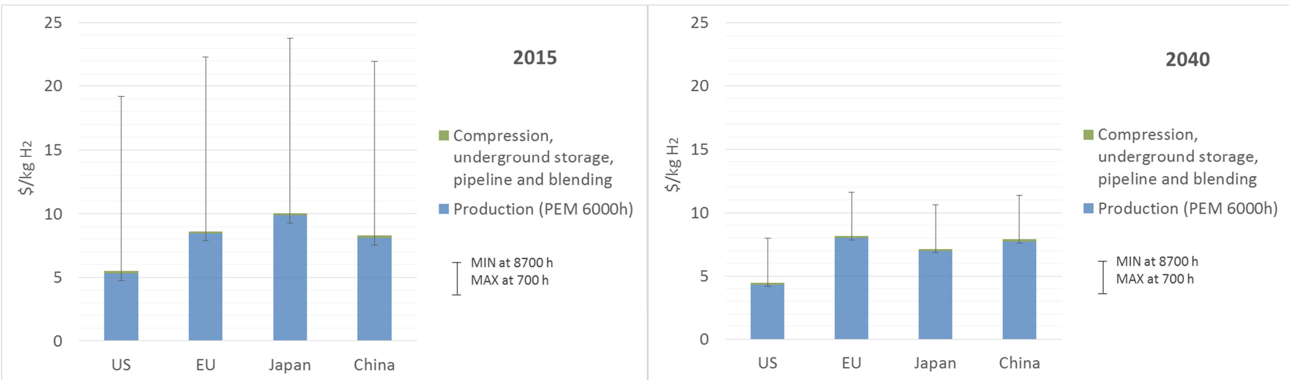

Figure 11: Hydrogen cost after blending

As shown in Figure 11, the infrastructure costs are negligible compared to the production costs when it comes to the injection of hydrogen into natural gas networks. Accordingly, this market segment is one of the least capital-intensive ones, since it does not require heavy infrastructure investments like the mobility case for example. Technically speaking, as detailed in the methodology section, hydrogen injection into natural gas networks is feasible up to 10% of injection rate (in terms of volume), however some concerns about the variation of the composition of the transported gas in the pipeline have been expressed by the industries. No clear regulation has been set so far to fix the allowable rate in order to trigger this market segment.

In order to address the penetration feasibility, the top-down and bottom-up approaches are confronted to each other. The market penetration feasibility into the different markets is assessed in the next section.

IV- Market penetration feasibility assessment

- Mobility market

Once the final cost at the pump is assessed, the aim of this section is to evaluate the market penetration feasibility by comparing the costs at the pump with the market entry costs, evaluated in sections II- and III-. Figure 12 shows the evolution of the two costs between 2015 and 2040 for the mobility case study. The hydrogen cost at the pump is presented for three pathways: i) centralized with tube trailer gaseous transport, ii) centralized with pipeline transport, and iii) decentralized with storage facility. The costs at the pump (for the different pathways assuming a hydrogen production via PEM electrolysis and considering 6,000 hours as load factor) shown in the graph include the value added tax (VAT) since, as detailed in the methodology section, hydrogen will have to prove its long-term competitiveness without any subsidies or tax exemptions.

A sensitivity analysis is conducted on the market penetration cost. In Figure 12, the impact of the CO_2 taxation is presented via the interval area in light blue. The carbon price is varied between zero and the required price to reach the climate targets mentioned in the 450 ppm scenario of the IEA [1] (i.e.: 140€/tCO_2 for USA, EU and Japan, and 125€/tCO_2 for China).

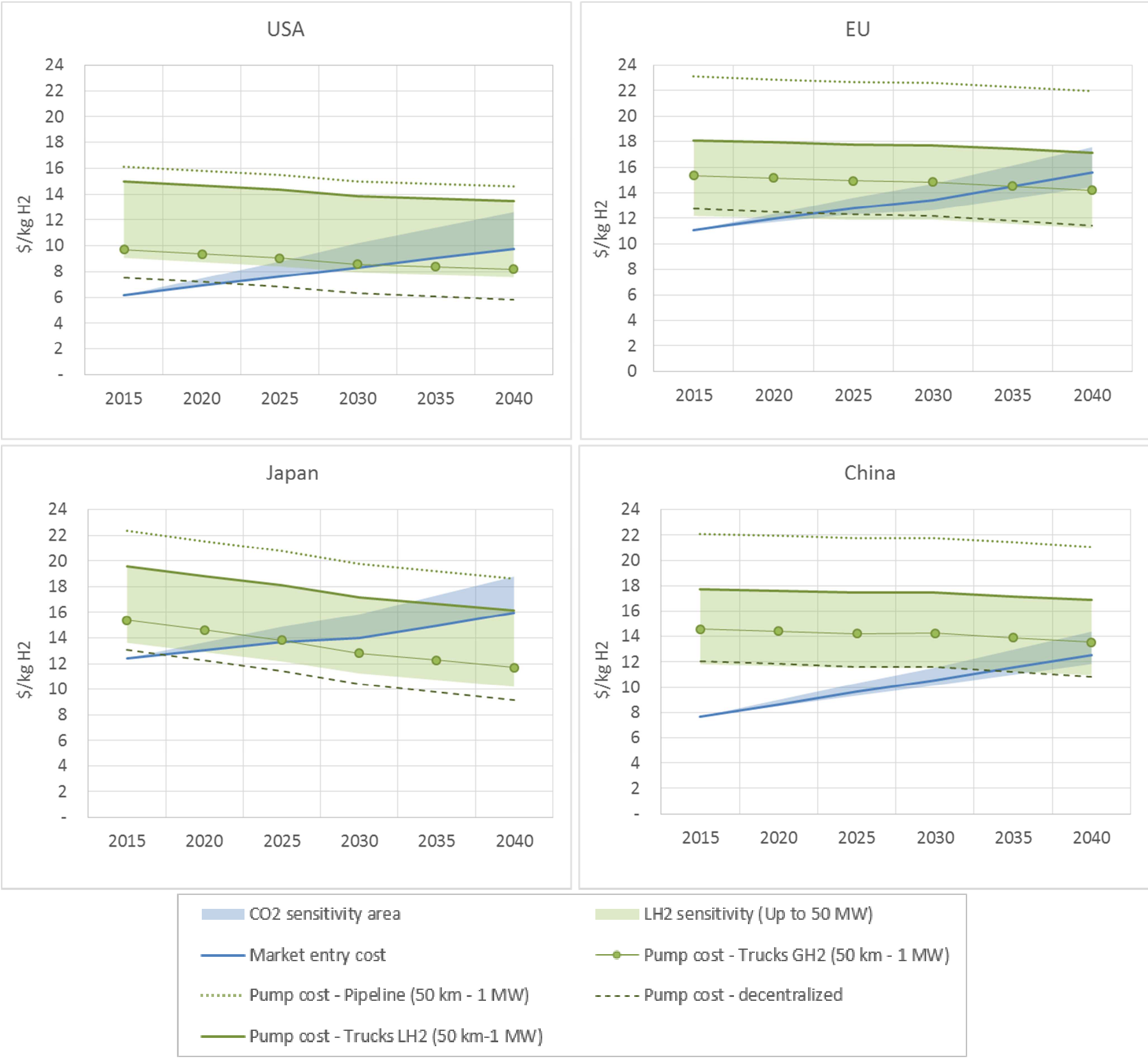

Figure 12: Mobility market penetration feasibility in the considered regions

The market penetration feasibility is marked by the intersection of the two curves (cost at the pump and market entry cost). At the break-even point, the hydrogen cost equals the competitor fuel price at the pump. However, going lower in terms of cost may be needed in order to take into account profit margins and additional taxes. By 2040, considering the compressed gas tube trailer pathway, almost all of the considered regions show feasible market penetration, where hydrogen can easily compete with the fossil fuels with no specific need for subsidies. The cost reductions achieved by 2040 give enough room for hydrogen taxation and even profits except for the Chinese case where the break-even point cannot be reached by 2040 without higher carbon prices (for the centralized case). Considering higher carbon taxes on the fossil fuels (up to 140\$/tCO_2 in the US, Europe and Japan, and 125\$/tCO_2 in China according to the 450ppm scenario of the IEA) helps accelerate the market penetration feasibility and advances the break-even point by approximately five years.

Hydrogen transport via pipelines is more expensive than the compressed gas tube trailer option in this case study (50 km travel distance and 1 MW throughput), which leads to a significant delay of the market penetration feasibility. However, as detailed in the methodology section, this depends on different factors like the transport distance and the hydrogen demand volumes. Hence in the short term, with low volumes of hydrogen to be transported, pipelines are not the first pathway to be deployed. A more detailed study on infrastructure cost is required in order to capture the impact of the delivery pathway on the market penetration feasibility. Transporting hydrogen in liquid form is more advantageous than the pipeline pathway when considering low and medium throughput capacities, it thus can serve as a transitional pathway between early market penetration and advanced hydrogen deployment.

The results show that Japan is the first to achieve hydrogen competitiveness. The break-even point is already reached by 2025 for the tube trailers pathway even without carbon taxation on the fossil fuels. This can be explained by the fact that Japan presents the highest tax rates on gasoline compared to the other regions [45] which eases the competitiveness of hydrogen. Many programs are already launched in Japan to trigger hydrogen development [74], [75], which may lead to an even earlier market penetration.

The US is the second most promising region for hydrogen penetration. Although it presents low tax rates on gasoline as a fuel, it shows the lowest electricity prices compared to the other regions for the years to come (according to the IEA [1]), thus leading to low hydrogen production costs and low costs at the pump.

The European case is quite special since the competitor is different. In Europe hydrogen is competing with diesel which, according to the results, is hard to compete with, compared to the gasoline. Nevertheless, seeing the latest controversies about diesel in the last few years, gasoline may become the first competitor which would ease the competitiveness, but further cost reductions on the hydrogen production side are still needed to ensure earlier market penetration. The electricity prices in Europe are high, hence the need to consider a specific market design where hydrogen can benefit from lower power prices and/or participate to the reserve market. Otherwise, the market penetration is hard to achieve before 2030 even with a carbon price of 140€/t CO_2, unless decentralized production is considered.

China seems to struggle compared to the other regions when it comes to hydrogen penetration. It combines both high electricity prices leading to high hydrogen costs and low fuel taxes not penalizing enough the competitor. Consequently, higher carbon prices (up to 125$/$t_{CO2}$) are required to reach the break-even point by 2040.

Considering the decentralized production with a storage facility helps achieve the market penetration feasibility significantly earlier. The cost profiles for the decentralized case study cross the market entry cost curves approximately 10 years before the tube trailer pathway break-even point.

- Injection into natural gas networks

Despite the fact that the penetration in the natural gas market segment does not require heavy initial investments, hydrogen competitiveness with natural gas does not seem to be easily achievable. Figure 13 compares the injected hydrogen costs after the blending step and the market entry costs in the different regions. The impacts of the tax (VAT) and the electricity price on the costs of the injected hydrogen are also presented in the graph. The light green area represents the interval of hydrogen cost assessed after injection considering lower electricity prices, down to 0$/MWh.

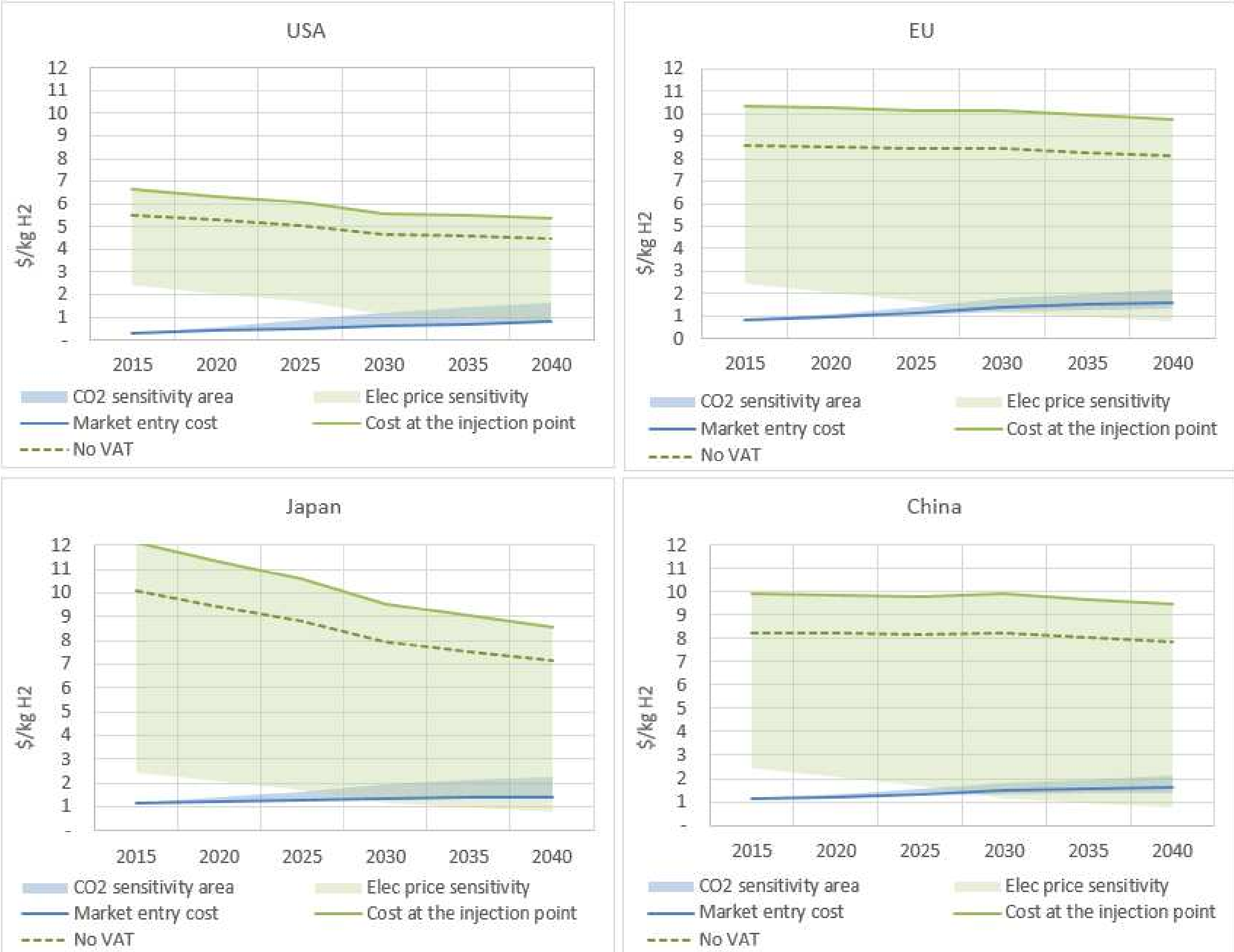

Figure 13: Natural gas market penetration feasibility in the considered regions

According to the results, even with tax exemptions, hydrogen is not able to compete with natural gas. Since natural gas is a relatively cheap energy carrier, it seems to be hard to achieve in the short to mid-term. Dramatic cost reductions on the hydrogen side need to be achieved in order to facilitate the market penetration. These reductions concern mainly the hydrogen production costs since in this case, and as shown in section III-2.2, the delivery costs are negligible compared to the production ones. This can be achieved either through a technology-push approach lowering the costs of the production technologies (further electrolysis cost reductions) or via a market-pull approach involving governmental incentives to ease the market penetration. The sensitivity analysis shows that the carbon taxation of natural gas is not sufficient to ease the hydrogen competitiveness. However, with much lower electricity prices, hydrogen market integration can be feasible. This would require a governmental support allowing hydrogen production to benefit from lower electricity prices. A clear regulation regarding the participation of the electrolysers in the provision of ancillary services can be a game changer in this case study, since it will allow hydrogen production to exploit its flexibility potential and gain profits on the electricity market which is proved to often help achieve lower production costs through better load factors [76], [77], and higher revenues than systems engaging in only hydrogen markets [9], [78].

Another market-pull support scheme is the possibility to benefit from feed-in tariffs which is already the case for the biomethane injection into the grid. A study conducted by Tractebel and Hinicio and funded by the FCH-JU (Fuel Cell and Hydrogen Joint Undertaking) [79] evaluated the amount of feed-in tariffs that are required for hydrogen penetration into the gas market segment. An interesting outcome of the study is that, besides the fact that the feed-in tariffs are needed to trigger the market penetration, coupling the natural gas blending market with the mobility market (in other terms considering a system producing hydrogen for both markets) allows to lower the feed-in tariff needs by 10 to 20% and enhances the hydrogen system profitability. Hydrogen versatility should be taken advantage of, to leverage the most profitable markets so as to open the other ones.

But together with the financial support, the allowed hydrogen concentration into the natural gas networks is also a key factor in the development of this market. Hence a clear standard needs to be set in order to trigger this market, which can be a huge contribution to decarbonize the energy system.

V- Discussions

Compared to the current and prospective hydrogen costs, the market penetration for the mobility segment seems to reach more easily the targets. As discussed in the methodology section, the market penetration cost in this case study is based on the fuel cost only, while the total cost of ownership may reflect, in a better way, the choice of the final consumer. The TCO includes the car purchase price, the maintenance costs, the insurance and also the decommissioning costs. According to the literature [26], [34]–[36], the current TCO of a hydrogen vehicle is higher than the conventional mobility one although fuel cell cars require less maintenance than the diesel engines. However in the future, the total cost of a hydrogen vehicle is expected to drop and be equal to the diesel car one. This will mainly depend on the development of hydrogen mobility in the future creating an economy of scale effect. According to [34], the TCO break even between diesel and hydrogen mobility is reached when at least 50,000 units of fuel cell vehicles are manufactured by year.

Another important factor to take into account is the external costs [68], [80]–[82], in terms of social and environmental costs, that are not directly paid by the final costumer, but represent a non-negligible spending at the national scale. These costs reflect the environmental damages and adverse effects on human health caused by the emissions of CO_2 and other greenhouse gases [81]. Substituting the carbonized transport means by clean hydrogen ones helps cities gain direct and indirect benefits that can outweigh short-term costs [82].

However, the expansion of electric mobility may be faster than expected, following recent announcements of total phase out of internal combustion engine vehicle sales by 2040 in several countries, like France and China [32]. This new competition, if it proves to be one, since we could also witness technology cooperation (see for instance the hydrogen range-extender technology for electric vehicles that relies on a small fuel cell to extend the autonomy of a battery electric vehicle), should be further analyzed. Indeed, comparing fuel cell vehicles to the battery electric ones should not only be based on “fuel cost” but also include specific aspects. For instance, it is true that the electric vehicles consume less electricity than the fuel cell ones to travel one km (from a well-to-wheel analysis viewpoint), however the autonomy of the vehicle as well as the required refueling time are also key issues to take into consideration, especially when tackling the consumer behavior and preference. As a matter of fact, the annual mean travelled distance by vehicle that may reflect the need for autonomy varies according to the driving patterns that are diverse when considering different regions. Another aspect that needs to be further investigated is the segmentation of mobility by type. When it comes to heavy duty transport (freight trucks, buses, etc.), autonomy and refueling time are key aspects to take into account. New customer practices may also emerge like car-sharing that allows enhancing the usage of a given vehicle as a potential way to reduce the total number of vehicles, and thus contribute to CO_2 mitigation. Such new usage of vehicles, and more generally all the intensive use (e.g. taxi fleets) could require longer autonomies and quicker refueling of the vehicle, making hydrogen the preferred option. Beyond the vehicle itself and the consumer preference, switching to a fully decarbonized vehicle fleet would require an in-depth analysis of the infrastructure requirements. Indeed, fuel cell vehicle deployment is dependent on the infrastructure availability. The latter would also depend not only on industrial investments but also governmental efforts to reduce the risks for the companies. Such governmental support has been observed in the recent years to trigger the electric charging station deployment. In addition, regarding the infrastructure required for the electric mobility, apart from the recharging station installation, advanced electric mobility adoption may also require a reinforcement of the electricity distribution network and maybe also transmission network. Hence, a detailed comparison of the cost of infrastructure deployment for both means of low carbon mobility (FCEV and EV) should be conducted. Studies can be found in the literature tackling this issue for different countries. For instance, a recent study investigating the German case was elaborated in the framework of H2Mobility project [33]. It inspects the expenses that are required for infrastructure deployment for both EV and FCEV considering different levels of market penetration. The results show that for early market integration phases and up to around 50% of the vehicle fleet, the electric mobility deployment shows economic advantages when it comes to infrastructure requirements. However, for higher market penetration levels, hydrogen infrastructure deployment may become more economical reducing the costs due to the scaling effect. Nonetheless, as introduced before, complementarities can be searched for between FCEV and EV: in technology terms such as the "range-extender vehicles, or in economic terms, by bringing the most appropriate solutions to the diverse market segments. Overall, the decarbonization of the transport sector can be reached through different pathways not necessarily competing with one another.

As for the injection into the natural gas network it seems to still have a long way to go to reach competitiveness. The needed support is not only financial, e.g. via tax or electricity fees exemption or a subsidy such as the feed-in tariff scheme discussed before; it is also required to set a clear target for the maximum concentration of hydrogen into the gas grid. This concentration currently highly varies from one region to another. It can reach 10% (of the volume) like in Germany for example while it does not exceed 6% in France and 0.1% in the UK [30], [83]. In Japan it is not allowed at all. A harmonization of the standards at the European level (but not only) is crucial to prepare a more suitable market penetration environment.

Despite the disparity of the cost ranges, both markets would need support schemes in order to be triggered, hence the importance of governmental involvement through encouraging regulations and policies.

Finally, the results discussed in this paper may be challenged once the carbon impact of the electricity generation is taken into account when considering electrolysis. As a matter of fact, sourcing hydrogen production with electricity from the grid may not be the best environmentally-efficient way to make hydrogen a low carbon energy carrier. Indeed, as shown in Table 9 the carbon footprint of hydrogen production from electrolysis can be higher than the SMR one (i.e. approximately 10 kg CO_2/kgH_2) when considering the electricity from the grid. A carbon taxation is already taken into account in the electricity prices considered in the NP scenario [1], the impact of considering higher carbon taxes on electrolytic hydrogen cost is not discussed in this paper.

Table 9: Carbon footprint of hydrogen generation considering the regional electricity mix as stated in NP scenario [1]

kg CO_2/kg H_2	2014	2030	2040
US	24.4	17.4	14.8
EU	17.9	10.9	7.7
Japan	27.6	17	14.7
Chine	38.4	25.9	21.6

Accordingly, producing hydrogen from low carbon electricity should be further investigated. Two potential options can be considered. On the one hand, renewable energies allow reaching low carbon intensities at low electricity cost but induce low load factors leading to a high hydrogen production cost as presented in Figure 7. Some exceptions to this fact can take place in regions where renewables are abundant such as in Australia where according to the analysis made in [84] "The cost of electricity in these locations in 2040 would be less than \$47/MWh with the hybrid systems operating at capacity factors of between 30% and 40% (depending on the optimal combination of solar PV and wind). This 100 Mtoe of hydrogen could be manufactured at less than \$3/kg H2". Another option that can also be considered is the available nuclear energy that is not dispatched due to higher renewable production, for the regions where nuclear is installed. This effect is discussed in more details for the French case in [85]. Overall, the electric sourcing for electrolysis needs to be adequate, to make hydrogen low-carbon. This can be done by direct sourcing from low-carbon power generation plants, or by sourcing from the grid, provided that the power mix is low carbon enough, by avoiding peak hours where fossil power plants are the peaking units.

VI- Conclusion

The aim of this paper is to evaluate the hydrogen penetration feasibility into the energy-related markets. The focus is put on the mobility sector via FCEV and the injection of hydrogen into the natural gas networks considering four regions (USA, Europe, Japan and China). Although the focus was put on specific regions in this study, other geographies recently emerged in terms of hydrogen deployment potential. For instance, South Korea has recently developed a hydrogen roadmap aiming at integrating hydrogen as a pillar for energy security [86]. By 2040, the government seeks to "increase the cumulative total of fuel cell vehicles to 6.2 million, raise the number of hydrogen refuelling stations to 1,200 (from only 14 today) and also boost the supply of power-generating fuel cells" [87]. Hydrogen deployment plans are also emerging in Australia with a view not to only enhance domestic hydrogen use, but also position the region as a large exporter of hydrogen in the years to come [71].

Top-down and bottom-up approaches were compared in order to assess the timeframe of hydrogen competitiveness. The results show that the most promising market among the ones examined here is hydrogen as a direct fuel for mobility in fuel cell vehicles, from an economic standpoint. This market is easier to penetrate in all the considered regions, it even presents a potential room for taxation in the medium to long term. However investments still need to be triggered by a clear political positioning, in order to hinder the uncertainties and the risk perception. The mobility market is more favourable in Japan, due to the coupling of interesting patterns penalizing the competitor (high taxes on gasoline) and support schemes for hydrogen (a clear roadmap for hydrogen penetration). On the other hand, the injection into natural gas networks exhibits much lower market entry costs, then harder to achieve. They do not exceed 2.3\$/kg of H_2, even when a carbon taxation going up to 140 \$/t_{CO2} is considered. Thus, the current policies are still insufficient to trigger this market segment and stronger governmental support is required in order to ease the market penetration. A potential support scheme that can be envisaged is the possibility to benefit from feed-in tariffs which are already implemented for biomethane blending. Another uncertainty hindering the development of this market segment is the uncertainty regarding the allowed concentration of hydrogen. Different standards are applied in different countries even within the same region (for example among the European countries [51], [88]). Harmonizing the regulations is key.

Regarding hydrogen production, the governmental role is crucial in order to decrease the electrolysis costs and further improve the profitability of hydrogen systems. Implementing a multi-sectorial approach seems essential to benefit from the versatility of hydrogen as a chemical component and an energy carrier, thus enhancing the margins and gain in profitability. Hydrogen production via electrolysis can also participate to the provision of flexibility to the electricity grid. This would help hydrogen systems further increase their revenues than systems engaging in only hydrogen markets. Tax exemptions can also be part of the solution to lower the costs and ease the early market penetration.

Overall, different options can be considered in order to surpass the economic barriers: both industrial and political efforts need to be achieved to lower the costs and prepare a suitable market penetration environment.

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