2022-2023 ANNUAL REPORT

From planning to execution: examining the success factors for the development of hydrogen in Spain

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COMILLAS ICAI

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CONTENT

1. INTRODUCTION

1.1. COMILLAS CENTRE OF HYDROGEN STUDIES

This Centre is a collaboration between the School of Engineering (Comillas ICAI) and the Faculty of Economics and Business Administration (Comillas ICADE), with the aim of contributing to the development of the renewable hydrogen sector in Spain through studies, data collection/analysis, dissemination, and informed debate.

The decarbonization of the economy is currently one of the greatest challenges facing our country. In this regard, hydrogen emerges as a key element in the transformation of our energy system. Due to its **ability to connect different sectors**, its suitability as a **means of long-term energy storage**, and its capacity to **decarbonize hard to abate sectors** such as certain heavy industrial processes, heavy road transport or maritime transport. In addition, hydrogen has the potential to become a **relevant new *commodity* in the global energy market** for its contribution to the transition to a green economic model.

The importance of hydrogen for our future energy systems has become even more evident in the last year. In the draft of the new National Integrated Energy and Climate Plan (PNIEC), published in June 2023, the Spanish government presents new targets that multiply the electrolyser capacity target set in the Hydrogen Roadmap by three (from 4 GW to 11 GW in 2030). In this context, the second call of funding for pioneering and unique renewable hydrogen projects (H2 Pioneers II), seems like a small step towards the expected hydrogen boom in our country.

However, for many projects and promoters the past year has also been a first reality check. As is often the case, the opportunities and challenges of a new technology only become apparent when it is examined in detail.

In the second year of its existence, the Centre of Hydrogen Studies has taken a closer look at various elements of the future hydrogen economy. The results we present in this report highlight the large potential for optimisation in order to achieve a competitive hydrogen economy. They also summarise the major uncertainties on the road to cross-border hydrogen trade.

Through its activities, the Centre of Hydrogen Studies seeks to provide an overview of the hydrogen economy with a multidisciplinary approach. It considers the hydrogen value chain as a whole, including technical-economic, regulatory and financial aspects. Therefore, the activities of the Centre will contribute to the achievement of the European and Spanish Green Hydrogen Strategy, as well as the objective of achieving climate neutrality by 2050 at the latest.

The Centre has the participation of sponsoring institutions present in different segments of the hydrogen value chain: Acerinox, Andersen, BBVA, Carburos Metálicos, Enagás, Cepsa Foundation, Management Solutions, Red Eléctrica de España and Toyota (2022-2023).

1.2. OBJECTIVE AND STRUCTURE OF THE REPORT

Given the almost continuous information flow and the frequent media coverage of new project , technological advances, regulatory developments or the global hydrogen trade; a certain contextualization is necessary for a debate and decision making. In this sense, the Centre of Hydrogen Studies has set the objective to publish an annual report, analysing a series of relevant variables to take the pulse of the hydrogen sector in the European and national context.

This report analyses the information gathered during the 2022-2023 term. It plans to contribute to the debate with an updated review on regulatory developments and their implications for project development today (section 2)[1], analysis of the most important regulatory milestones at a European and national level during the last year (section 3), the factors enabling a business case for hydrogen (section 4 and 5); and lastly, the drivers and prospects for hydrogen trade in the medium and long term (section 6 and 7). This report therefore provides a comprehensive overview of some key aspects of the successful transition to a hydrogen economy.

[1] The analysis of hydrogen production projects is carried out using a proprietary database, developed by the Centre. Such information is publicly available in an interactive format through the following link: https://www.comillas.edu/catedras-de-investigacion/catedra-de-estudios-sobre-el-hidrogeno/mapa-de-proyectos-en-espana/

2. CURRENT STATUS OF RENEWABLE HYDROGEN PRODUCTION IN SPAIN

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- **Production:** 30% growth in the number of projects related to hydrogen production, accounting for more than 16.5GW in total, 1 GW more than the capacity announced in 2022. The announced capacity increases only in 6% compared with 2022, due to the smaller size of new projects and the reduction in the ambitions of some existing projects.[2] . If finished, these projects would be sufficient to meet the targets set in the draft of the first update of the National Integrated Energy and Climate Plan (PNIEC), which foresees reaching an electrolysis capacity of 11 GW by 2030. However, as of 2023, only about 30 MW of electrolysis capacity is operational, and 91% of electrolysis capacity is in early stages of development. In 2022, Spain produced 2,810 tons of renewable hydrogen, which represents 0.46% of the total hydrogen consumed in that year [1].

- **Final applications:** Most of the announced electrolysis capacity is for large industrial projects. The number of projects related to land mobility plays a significant role, however, these projects are smaller. The largest growth in end-use applications takes place in maritime transport, where several large-scale projects have been announced in view of the imminent entry of the maritime sector into the European Union's Emissions Trading Scheme EU-ETS. Likewise, the International Maritime Organization (IMO) also proposes a global carbon tax system, although the decision is not yet firm and was not included in its plan to reduce greenhouse gas emissions published in July 2023 [1][3] .

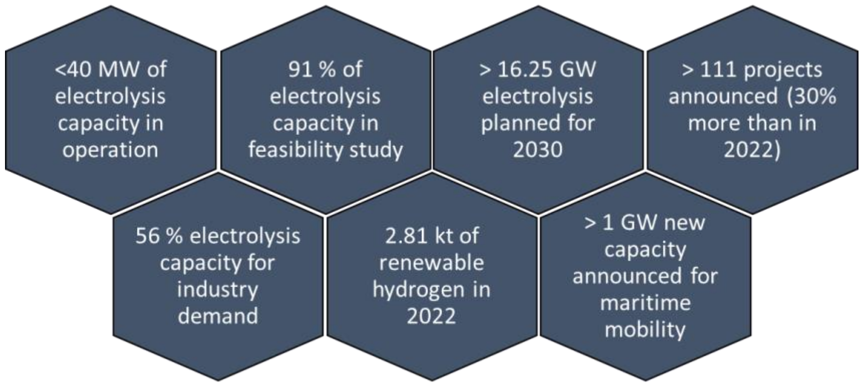

Figure 1. Key figures for renewable hydrogen in Spain. Source: own elaboration

[2] The most important of these is the Hydeal project, which planned to install 7.4 GW of power and has modified its plans, reducing the electrolysis capacity to be installed to 3.8 GW.

[3] If it enters into force, the European EU-ETS mechanism should be incorporated into this international system.

Compared to 2022, despite the increase in the total number of projects, only one new project was commissioned in 2023.

Only one new project came into operation in 2023: the electrolyser installed by Repsol at its Bilbao refinery with a capacity of 2.5 MW. Most of the projects are still in the feasibility analysis, a very early stage of development. The largest increase corresponds to projects that are in administrative procedures, going from six in 2022 to thirty-six in 2023. This increase is mainly due to the resolution of the PERTE hydrogen support schemes, as projects approved under these programmes must be implemented in less than 36 months from the date of positive notification[4] .

Project implementation may take longer than expected.

According to statements made by promoters, six projects were planned to come into operation during 2022; however, only four were materialized. By 2023, projections pointed to eight projects, a goal that seems difficult to meet, given that so far there are five projects in operation. These eight projects that were planned for 2023 would reach a capacity of 95 MW, but the current capacity stands at approximately 30 MW. This situation also occurs worldwide, according to the Hydrogen Council [2], in October 2021, the announced electrolysis capacity by the end of 2022 was 6 GW while as of January 2023, only 700 MW[5] of those 6 GW had come into operation. **It means that approximately 4% of the electrolysis capacity in operation worldwide is located in Spain**.

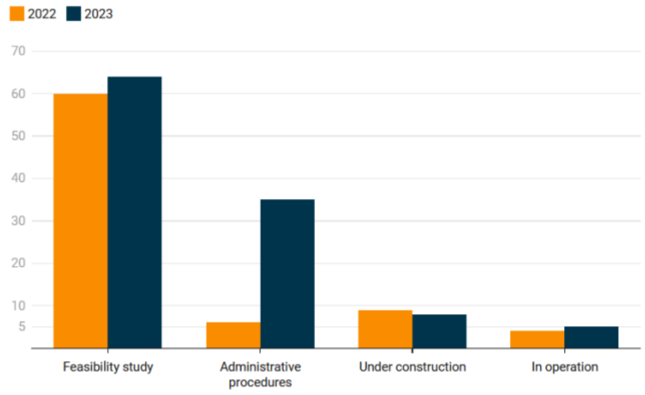

Figure 2. Status of hydrogen projects according to their degree of maturity. Source: own elaboration

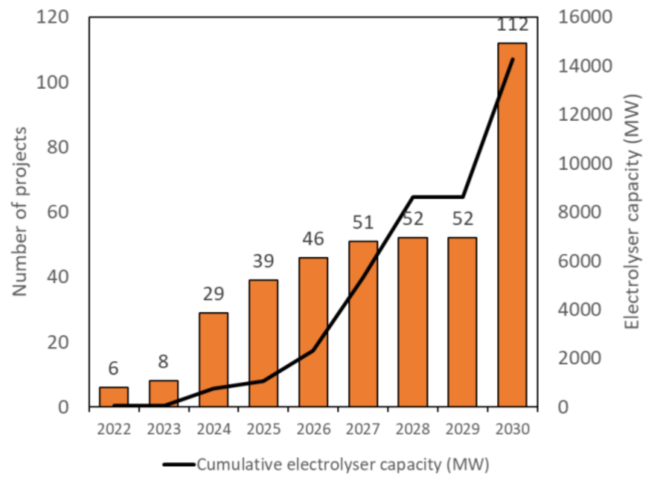

Figure 3. Number of projects and electrolysis capacity by date of entry into operation. Source: own elaboration

[4] See the terms and conditions of the hydrogen pioneers and value chain calls for proposals. https://www.boe.es/boe/dias/2021/12/24/pdfs/BOE-A-2021-21342.pdf

https://www.boe.es/boe/dias/2021/12/24/pdfs/BOE-A-2021-21341.pdf

More than 16.5 GW have been announced by 2030, representing an increase of approximately 300 times over the next seven years.

Despite the large volume of announced project capacity, only 1% of the capacity is operational or under construction, 8% is in administrative procedures, and 91% is under feasibility study. Globally, only 9% of the renewable or low-emission hydrogen production potential has reached the final investment decision (FID) [6] [2].

The industrial sector is the fastest growing in number of projects and there are still many projects with no declared off-taker.

Focusing on hydrogen applications, as shown in Figure 5, the greatest increase in the number of projects is found in those aimed to industry. Although, there is also a slight increase in projects aimed at both land and maritime mobility. Of the newly announced projects, only one has publicly announced hydrogen injection into the natural gas grid, with a total of 12 projects considering this use. This information contrasts with information published in a CNMC resolution regarding a grid connection conflict. In that resolution, reference is made to 250 requests for connection to the natural gas grid by green hydrogen production projects. Although the connection capacities requested by these 250 projects are not known, it is state that 27 of these projects total 326,732 kgH_2/year (415,000 Nm3/h), higher than the maximum hydrogen injection potential of 138,604 kgH_2/year (176,000 Nm3/h) to ensure a maximum 5% hydrogen mix in the natural gas network[7]. This 326 732 kgH_2/year represents 53% of current hydrogen demand, and the equivalent of 3.6 GW[8] of electrolysis for hydrogen blending alone.

The industry has begun the process of replacing gray hydrogen with renewable hydrogen.

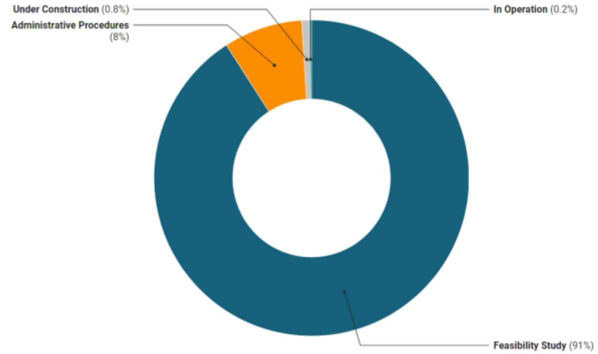

Figure 4. Electrolysis capacity according to project maturity level. Source: own elaboration

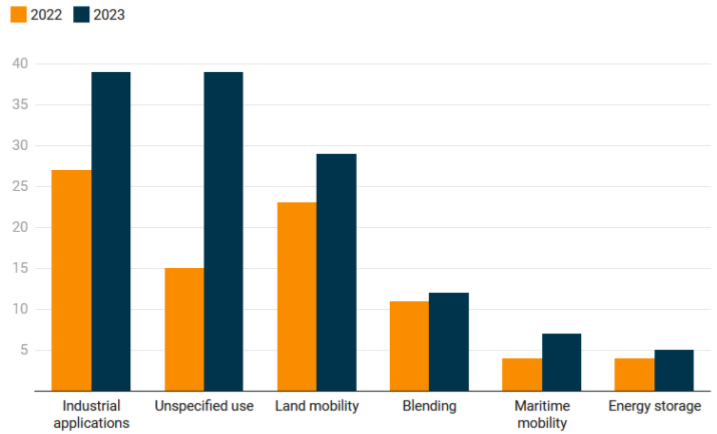

Figure 5. Number of hydrogen projects according to their final application. Source: own elaboration

Most of the industry-related projects are aimed at replacing grey hydrogen in the refining sector and in ammonia production. In Spain, there are eight refineries

[6] This comparison is only indicative, and it should be noted that the projects receiving assistance from PERTE ERHA are not necessarily in FiD, but they are at a more advanced stage than the rest of the projects announced.

[7] The large difference between the hydrogen projects announced by blending included in the observatory of the CNMC and the 250 referred to by the CNMC shows that there are many projects that have not been made public yet.

[8] Assuming an efficiency of 52 kWh/kgH2 and 4200 hours of operation

with a consumption of 478,900 tons of grey hydrogen in 2022; 34% of which could be decarbonized on the basis of the projects announced in 2023. This figure increases for ammonia, where up to 64% of the grey hydrogen currently consumed (66,290 tons) could be replaced[9] .

In relation to methanol, Spain consumes more than 600,000 tons of grey methanol[10] per year in the industrial sector; most of which comes from countries outside the EU [4]. The announced methanol production capacity is 403,300 tons per year although 104,000 of these will be exported to Germany[11]. This will result in the decarbonisation of around 50% of the methanol consumed in Spain, in addition to the emission savings associated with its transport and import.

The number of projects related to steel production remains the same since 2022, which is not surprising, given the high degree of concentration in this sector. There has been rapid growth in the use of hydrogen to produce industrial heat, mainly in the ceramics and glass industries. However, there are projects in other sectors such as paper production.

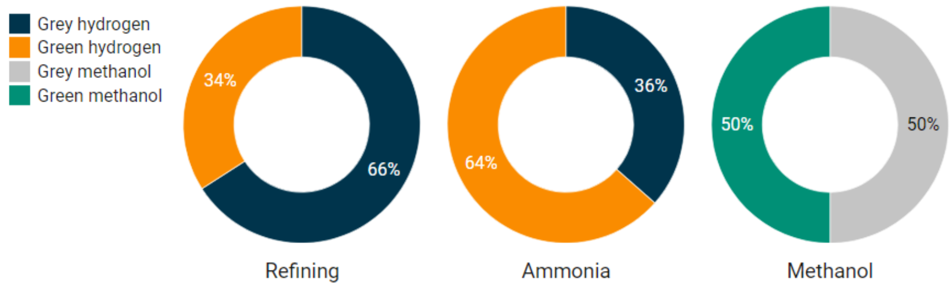

Figure 6. Percentage of green hydrogen, grey hydrogen, green methanol, and grey methanol according to announced projects.

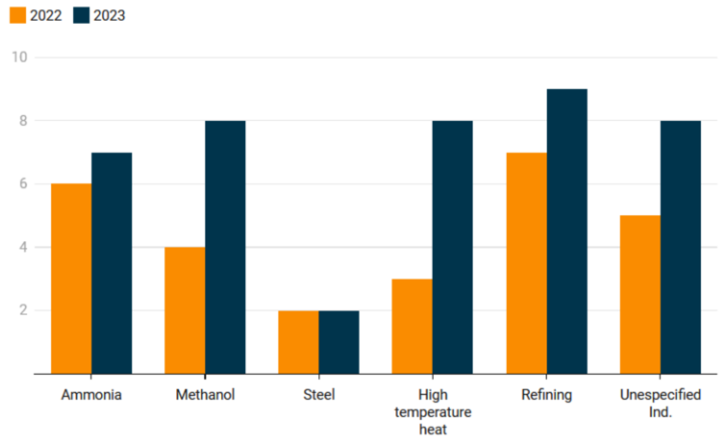

Figure 7. Number of hydrogen projects according to their industrial application. Source: own elaboration

[9] Source: Hydrogen Fuel Cell Observatory. Only projects at facilities that currently consume gray hydrogen are included; this leaves out projects that aim to create new ammonia production plants.

[10] Produced from natural gas

[11] https://www.juntadeandalucia.es/presidencia/portavoz/detalleAsuntoConsejo?asunto=247021

The maritime sector is gaining importance in comparison to the previous year, and it is becoming one of the focal points of the transition.

In terms of electrolysis capacity announced for different sectors, there is a notable increase in the production of hydrogen and its derivatives for maritime transport. This sector went from representing only 1.5% in 2022 to 12% of the total capacity announced in 2023.

Cepsa has announced the 'Hydrogen Valley' project in Andalusia, which will provide around 1GW of electrolysis capacity to produce ammonia and methanol as fuels for maritime transport. In addition, the Danish shipping company Maersk will invest €10 billion to produce 2 million tonnes of green methanol by 2030. These strategic initiatives highlight the growing importance of this sector in the development of hydrogen in Spain.

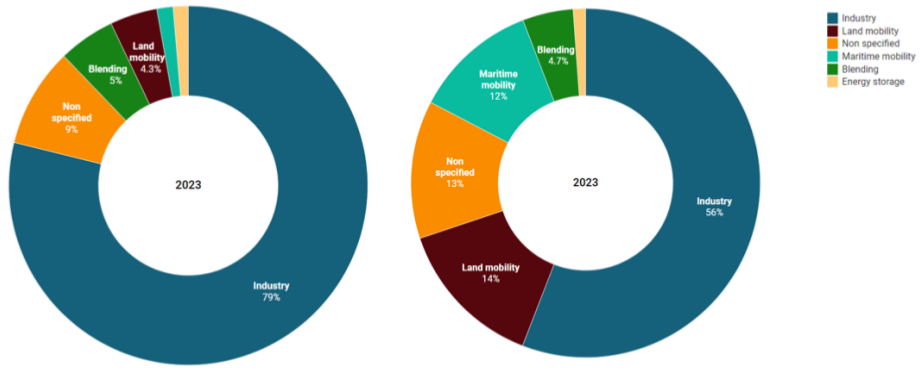

Figure 8. Distribution of announced hydrogen capacity according to final application. Source: own elaboration

The number of methanol and hydrogen tanker orders worldwide is increasing.

The interest in hydrogen production for the production of marine bunker fuels is supported by an increase in the number of orders for methanol and hydrogen ships. Figure 9 shows the number of alternative fuel ships in operation each year until 2028 and their distribution. In 2023, only 4.2% of the 719 ships using alternative fuels are using methanol as an energy source. This share will increase significantly in the following years, reaching 15% in 2028.

It is important to note that currently 99.41% of the worldwide fleet uses conventional fuels, and 83% of the orders are still using these fuels [5].

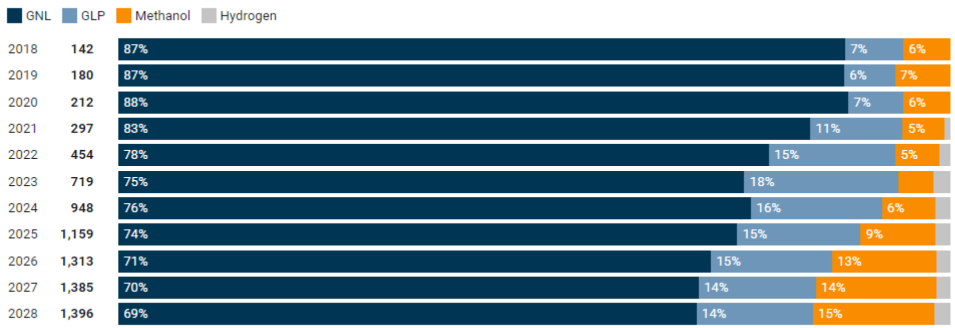

Figure 9. Growth of alternative fuels adoption by number of vessels. Source: [5]

3. REGULATORY DEVELOPMENTS AND THEIR IMPLICATIONS

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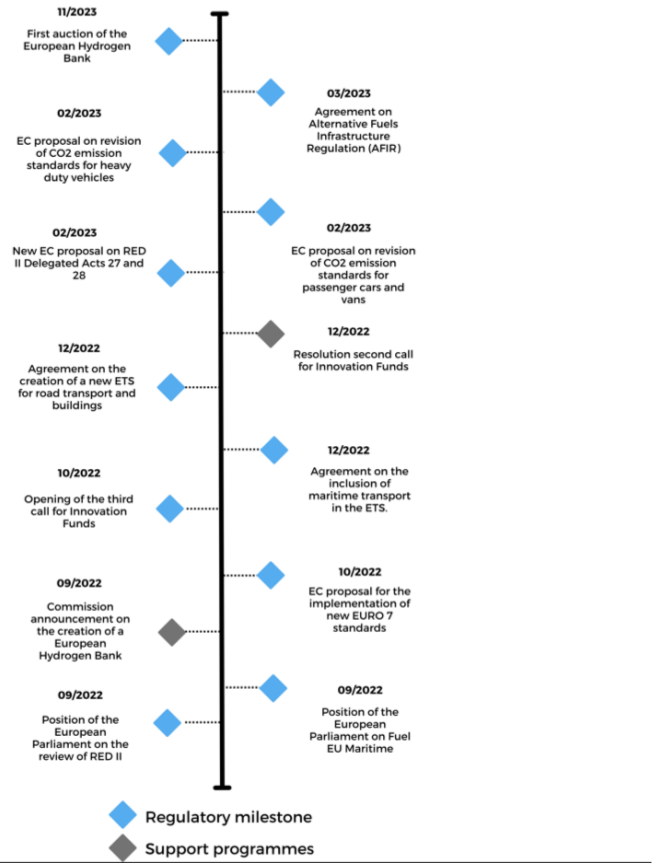

Figure 10. Main milestones of European legislation during the last period. Source: own elaboration

3.1. Milestones of European legislation

The European Union's energy and climate policy in recent years has been characterised by announcements and agreements on more ambitious targets to achieve climate neutrality. This led to the European Climate Change Act in 2021, the agreement on the 'fit-for-55' package to accelerate the transition to 2030, and the significant increase in ambition both in terms of emissions reductions and energy security. This was followed by the REPowerEU package presented in May 2022. Since then, a large number of legislative initiatives have been presented, detailed and agreed that clarify the role of hydrogen in the energy transition and aim to accelerate the development of a hydrogen economy at European and global level in the coming years. Below we have grouped the various legislative developments into different areas of activity, each with a different impact on hydrogen production, transport and demand in Europe.

Consolidation of renewable targets for 2030

Recent legislative activity has been characterised by the development and translation into concrete policies of the 'fit-for-55' initiative. Its objective is an accelerated transition by 2030, to be endorsed by the European Council in June 2022. Achieving a 55% reduction in emissions by 2030 compared to 1990 levels will require greater penetration of renewable energy and a significant reduction in the use of fossil fuels. The following measures to consolidate the 2030 targets promote hydrogen as well as other renewable energy sources.

New targets for the use of renewable liquid and gaseous fuels of non-biological origin may stimulate the creation of hydrogen demand.

The revision of the **European Renewable Energy Directive (RED III)**, as *agreed following negotiations between the European Parliament and the Council on March 30th, 2023*; foresees reaching a renewable energy share of 42.5% of final energy consumption by 2030. It also targets for a minimum share of renewable liquid and gaseous fuels of non-biological origin (RFNBO) in various sectors. By 2030, RFNBOs and advanced biofuels must account for at least 5.5% of energy consumption in the transport sector, 1% of which, would be RFNBOs. These quotas will be implemented through a system of obligations on fuel suppliers. In addition, hydrogen used in industry must come from renewable fuels of non-biological origin in a proportion of 42% by 2030 and 60% by 2035.

Higher costs for industrial CO2 emissions and the extension of the EU ETS to more sectors will improve the business case for low-emission solutions.

An agreement was reached between the EC, the European Parliament and the European Council to reform the EU Emissions Trading System (EU ETS) in order to meet the 'fit-for-55' targets (see Figure 11). For phase IV of the existing system, it was agreed, inter alia, to accelerate the gradual reduction of free allowances in the EU ETS to 4.3-4.4% per year. The objective was to introduce a border adjustment mechanism (CBAM) for imports of hydrogen, steel, cement, aluminium, fertilisers and others, to strengthen the stability reserve (MSR) and to fully integrate the maritime and aviation sectors into the EU ETS by 2026. All these measures provide incentives for carbon prices to rise. The EU ETS II, a parallel emissions trading system, would come into force in 2027, covering emissions from road transport and buildings.

New regulations for land, air and sea transport favour alternative propulsion systems and the use of fuels based on renewable hydrogen.

In November 2022, **the Euro 7 regulation** was introduced, which aims to set more restrictive maximum limits for nitrogen oxide and ultrafine particulate emissions. For the first time, the targets for passenger cars, vans, buses, and trucks are brought together in one legal act. However, the position adopted by the Council in September 2023, involves no new limits compared to Euro 6 for light-duty vehicles. There are only minimal adjustments for buses and heavy-duty commercial vehicles. In addition, new CO_2 emission standards for passenger cars and light commercial vehicles were adopted in April 2023; in line with the **end of the sale of CO_2 emitting light cars in 2035**.

For the aviation (**ReFuelEU Aviation** in April 2023) and maritime (**FuelEU maritime iniative** in July 2023) sectors, agreements were reached on legislation introducing targets and incentives to significantly reduce emissions intensity. On the aviation's side, targets were set for the use of sustainable aviation fuels (SAF). A minimum percentage of 2% of SAF by 2025 and 5% of SAF by 2030, with a minimum percentage of 0.7% of synthetic fuels, was agreed upon. The use of RFNBO in the maritime sector will be incentivized with support schemes, but no targets are specified for the use of alternatives for fossil fuels.

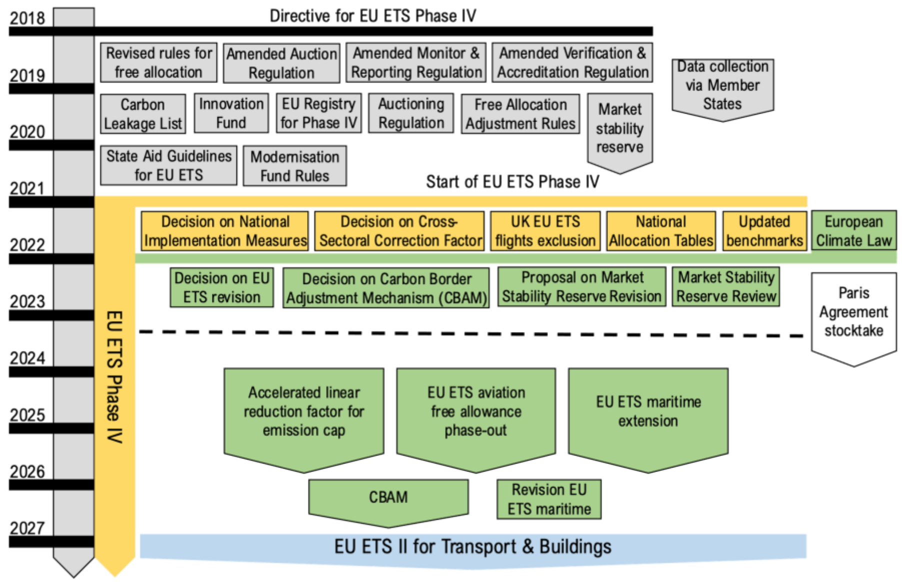

Figure 11 . Development of the main regulation impacting the functioning of the EU ETS. Source: Perspectives for industrial transformation towards a green economy (forthcoming). [3]

Support for the production and import of competitive renewable hydrogen

The EU is funding a large number of projects in member states; aimed at the transition to a hydrogen economy as part of the REPowerEU plan, the European response to the energy crisis caused by the war in Ukraine that was announced in March of 2022. The Commission has already approved at least two projects to be financed with REPowerEU funds in Spain: €220 million for the installation of 205 MW of electrolysers in Cartagena and Castellón, and €460 million to produce primary steel with hydrogen in Asturias. The use of European funds through PERTE at national level is discussed in more detail in the following section. During the past year, the most relevant direct aid at a European level has gone to the innovation fund and the new European hydrogen bank.

With each price increase in the EU ETS, the budget of the Innovation Fund and the availability of funds to finance the industrial transition increases.

The Innovation Fund is a direct subsidy program for innovative industrial and renewable energy technologies that is partially financed by EU ETS' revenues. With the increase in emission allowance prices over the last few years, a budget of approximately €40 billion is expected until 2030. So far, two calls for small-scale projects and two calls for large-scale projects have been resolved with several hydrogen projects funded in Spain (HyValue, Sun2Hy). In October of 2022, the third call for large-scale project was opened; and the third call for small-scale projects took place in March of 2023.

The European Hydrogen Bank plans to subsidize the cost of hydrogen production with part of the Innovation Fund budget.

In September of 2022, the creation of the **European Hydrogen Bank** was announced, aimed at promoting the creation of a hydrogen market and encouraging investment in technology and infrastructure. The bank's activities are oriented towards 4 pillars as detailed by the Commission in March 2023 (Figure 12). Part of the Innovation Fund's budget (800 M€) is dedicated to the implementation of a first auction of subsidies to support renewable hydrogen production at a domestic level, which is planned for November 23rd, 2023. The terms and conditions for this pilot auction were published on August 30th, 2023. The bank's role in subsidizing imports from third countries is yet to be defined.

Funding for the promotion of hydrogen demand

European incentives to encourage demand are compared to a few programs to support hydrogen production.

Figure 12. The four pillars of the activities related to the European Hydrogen Bank. Source: (COM (2023) 156 final)

In the coming years, demand for hydrogen will be concentrated in the industrial sector and, to a lesser extent, in the transport sector. The Green Deal Industrial Plan, published in February 2023, states that stimulating industrial demand is primarily a national responsibility, and proposes a stronger role for state aid in financing the transition. Carbon Contracts for Difference (CCfD) programmes can be one pillar of national funding, and the German government is expected to launch a first call for proposals before the end of the year, with a budget of tens of billions of euros.

Hydrogen is also a key element in transforming the inland transport sector and trans-European network development plans. Under the Connecting Europe Facility (CEF), the EU is funding projects such as the construction of hydrogen plants and refuelling stations on the main land transport corridors. In the last call for proposals in September 2023, €67 million was awarded to projects in Spain for the construction of 3,437 electric refuelling stations and two hydroelectric plants. In addition, several Member States are supporting the purchase of hydrogen vehicles with national and European funds, such as the MOVES III programme in Spain.

Development of regulations on the definition and sustainability criteria to be applied to renewable hydrogen

Delegated acts on the use of renewable energy and requirements to lower emissions provide clarity for investors, operators, and consumers.

The production and transportation of hydrogen as an energy vector and raw material imply the creation of a new sector. Therefore, a new regulatory framework is required to establish common standards for its certification and trade. The Commission published the following two delegated acts in February of 2023 which are part of the legislative initiatives towards a regulation on renewable hydrogen.

Delegated Act (EU) 2023/1184 establishes a common methodology defining detailed standards for the production of renewable liquid and gaseous fuels of non-biological origin. The fulfillment of several criteria should ensure the consumption of renewable energy for hydrogen production such as the temporal and geographical correlation between renewable energy production and its consumption for hydrogen production with the installation of renewable capacity that meets the additionality conditions.

Delegated Act (EU) 2023/1185 establishes a minimum threshold for the reduction of greenhouse gas emissions applicable to the use of recycled carbon fuels and RFNBOs. Greenhouse gas emissions from the production and use of renewable fuels will be calculated on the basis of direct and indirect emissions emitted in their production. In addition, the reduction from the use of RFNBOs, e.g. for the production of hydrogen-based synthetic fuels must be at least 70%.

Several legislative initiatives are underway to standardize and regulate access to an operation of the future hydrogen market.

The **European Clean Hydrogen Alliance (ECH)**, initiated by the Commission as a platform for cooperation with actors in the hydrogen economy value chain, published on March 2nd, 2023, the roadmap on the identification, prioritization, and implementation of a regulatory framework for hydrogen standardization.

EU institutions reach agreement on the **Alternative Fuels Infrastructure Regulation (AFIR)** which was adopted by the Council on July 25th, 2023. The revision of the 2014 directive on alternative fuels infrastructure (AFID) is converted into a regulation. This ensures the implementation of legally binding targets in all Member States regarding refueling infrastructure for alternative fuels such as electricity, hydrogen, and advanced biofuels.

In March of 2023, the Council reached an agreement on the **gas system package** that includes a new directive extending and expanding the legislation on gas networks to include hydrogen. In addition, the revision of the regulation on the functioning of gas markets to facilitate the incorporation of renewable gases, establish rules on the blending of hydrogen with natural gas and cross-border trade.

Improving the competitiveness of electrolyser manufacturing

During the first quarter of 2023, the Commission presented two communications highlighting how to accelerate the industrial transition to a green economy. Several of the Commission's proposed measures target the creation of renewable hydrogen production capacity. Final agreements with tangible implications for investors are pending.

The expansion of production capacity for electrolysers is key, but the relaxation of state aid rules risks a fair transition.

The **Green Deal Industrial Plan** was published in February of 2023 with the aim of creating a competitive and resilient industry to meet the challenges of the transition to emission neutrality. Several measures are proposed that should facilitate investment in component industries such as batteries, photovoltaic panels, fuel cells, and electrolysers. A simplified and predictable regulatory environment should support industrial investment such as the construction of community infrastructure. In addition, a revision of the state aid rules is proposed for a better and accelerated allocation of funds.

The proposed **zero net emissions industry regulation** of March 16th, 2023, aims to develop industrial capacities for the manufacturing of emission-neutral technologies until 2030 including electrolysers (100 GW). Several measures of the green pact's industrial plan are detailed; for example, with the appointment of competent authorities at national level for the permitting process of projects for the manufacturing of emission-neutral technologies, targets to accelerate the process and implementation of regulatory sandboxes by Member States to facilitate investments. In addition, mandatory requirements are introduced for public procurement in the Member States regarding the weight of sustainability criteria in the awarding of projects with/for emission-neutral technologies.

International cooperation to ensure security of supply

A very relevant pillar of the RePowerEU plan is the reinforcement of the security of energy supply that motivated the reorientation of foreign policy. A very important pillar of the plan is the supply of 10 Mt of imported hydrogen in 2030. The communication on EU energy engagement in a changing world by the Commission on May 18th, 2022, details several measures that were carried forward into various legislative initiatives during the last period; among them, the following:

The EU's bilateral agreements with technology development partners and potential exporters demonstrate the global nature of the transition.

Strategic Partnerships were established between the Commission and the governments of Egypt and Namibia during the 2022 United Nations Climate Change Conference (COP 27) in November. Both agreements are primarily aimed at developing an exportation industry for the production of green hydrogen and its derivatives in the partner countries. In December of 2022, the Commission agreed on a memorandum of cooperation with Japan aimed at the development of a global hydrogen market and innovation. In addition, cooperation with Ukraine on biomethane, hydrogen, and other synthetic gases was detailed in April of 2023.

The EU positions itself as a pioneer in the development of regulations for a global hydrogen market.

It is worth noting that the actions described on the previous page were intended to develop a regulation on the definition and sustainability criteria for renewable hydrogen. This could serve as a basis for the creation of **common standards for a global hydrogen market**, with competition being conditional on hydrogen imported into Europe meeting sustainability criteria equivalent to those required for domestic production.

National regulatory milestones

The country's high ambitions are not backed up by many concrete measures, and they fall far short on the subsidy schemes announced by other EU countries.

The hydrogen sector at national level in Spain has experienced important movements during the last year, although no major new developments have taken place from a legislative point of view. However, several previously announced measures have been implemented, such as the second call of the H2 Pioneers programme or the implementation of the guarantee of origin system for renewable gases. At the same time, public statements such as the Memorandum of Understanding (MoU) signed in February 2023 between the governments of

Spain and the Netherlands to promote the export of hydrogen are raising expectations. However, even the draft of the first update of the National Integrated Energy and Climate Plan (PNIEC), which significantly increases the ambition of the hydrogen production target, does not envisage new initiatives at national level in this area. The new national targets are discussed below and contrasted with the support schemes and regulatory framework for renewable hydrogen.

The New Role of Hydrogen in the PNIEC

The more ambitious emission reductions and the fulfilment of the "Fit-for-55" commitments for 2030 motivate a more important role for hydrogen in the draft PNIEC 2023-2030. Instead of 4GW of installed electrolysis capacity in 2030, according to the Hydrogen Roadmap published in 2020, the draft proposes 11GW. In addition, 74% of current industrial hydrogen consumption is expected to be replaced by RFNBOs. RFNBOs and biofuels are also expected to account for 11% of consumption in the transport sector by 2030. However, the main focus of the revised PNIEC is on incentivising hydrogen production. The plan presents 78 measures to ensure the fulfilment of its targets in a national context, 15 of which are (partly) aimed at promoting hydrogen. Its importance for the decarbonisation of road, sea and air transport, energy intensive industry and energy storage is highlighted. Reference is also made to the H2Med project, the gas pipeline corridor linking Portugal and Spain via France to the rest of Europe for the export of renewable hydrogen, agreed between the three countries in October 2022. The measures also include several training and innovation initiatives, such as the funding of jointly owned renewable energy research centres and an innovation pole at the City of Energy Foundation (CIUDEN). For the time being, however, the new initiatives that could speed up the transition are lacking in detail.

PERTEs for financial support

Strategic Projects for Economic Recovery and Transformation (PERTE) are public assistance programs funded by NextGenerationEU (2020) and REPowerEU (2022) funds in response to the COVID-19 pandemic and the energy crisis caused by Russia's invasion of Ukraine.

The Renewable Hydrogen Incentive Programme (PERTE ERHA) has a total budget of 1.5 billion euros, which will be distributed in several calls. So far, these calls have focused on financing investment costs (CAPEX) without providing support for hydrogen production. In contrast, other European countries such as France and Portugal have established more ambitious support programmes, many of which are designed to subsidise operating costs.

France, for example, plans to allocate €4 billion by auction over ten years, with a mechanism to compensate for the price difference with fossil fuels. On the other hand, Portugal plans to auction 120 GWh per year of renewable hydrogen, with a maximum price of 127 €/MWh for a period of ten years, corresponding to a maximum of 1,524 million € over this period.

Many of the current and future initiatives subsidized by a PERTE correspond to initiatives that have been implemented during previous years.

- The PERTE ERHA, for renewable energies, renewable hydrogen, and storage include several direct support measures for renewable hydrogen production. The application period for the **2nd call of the H2 Pioneers program was** between June 1st and July 31st of 2023. Projects for the generation and consumption of renewable hydrogen in sectors that are difficult to decarbonize such as industry or heavy transport are financed with €150 million.

  In June of 2023, the government published the addendum to the second phase of the Recovery, Transformation, and Resilience Plan (PRTR), which increases the funds allocated to PERTE ERHA until 2027. Specifically, the budget was increased from the initial €6.6 billion to €10.797 billion[12]. It remains to be seen how much of this new budget will go towards financing renewable hydrogen.

- The PERTE for industrial decarbonization was agreed on December 27th of 2022, and it finances a €450 million **aid to companies participating in the project of common European interest (IPCEI) on decarbonization of** primary **steel production** in Asturias using hydrogen as a raw material and energy source. In addition, a pilot project for **carbon contracts for difference (CCfDs)** will be financed with €100 M. Germany plans to use this type of contract to finance investments in the industrial transition while France wants to support large-scale hydrogen generation and consumption[13]. The new addendum to the PRTR increases the budget of this PERTE to €3.17 billion.

Other programs such as PERTE stand for the shipbuilding industry fund projects that explore the synergies of the port and maritime transition with the future hydrogen economy.

Guarantees of origin (GoO) system for renewable gases at the national level

The GoO legislation was established with Royal Decree 376/2022, dated May 17th of 2022, and the system is operational as of March of 2023. However, it is relevant to mention that the guarantees of origin, for the time being, do not serve as certification mechanisms for the sustainability and emission intensity criteria for renewable hydrogen set by the delegated acts on the production of renewable liquid and gaseous fuels of non-biological origin presented by the Commission in 2023 (see page 11).

[12]Source: https://www.lamoncloa.gob.es/lang/en/gobierno/news/Paginas/2023/20231002_recovery-plan-addendum.aspx

[13] In Germany, CCfDs cover the increase in operating costs for the use of new processes in the most energy intensive industries, for example, for the purchase of hydrogen instead of natural gas, with a budget of €2.2 billion in 2023, and a total costs of €50 billion for 15-year contracts. The French government has announced CCfDs for green hydrogen production with subsidies of €4 billion available to install 1 GW of electrolysers.

4. RELEVANT FACTORS TO HYDROGEN COMPETITIVENESS ALONG THE HYDROGEN SUPPLY CHAIN

4. RELEVANT FACTORS TO HYDROGEN COMPETITIVENESS ALONG THE HYDROGEN SUPPLY CHAIN

Section 1 highlighted the growing interest in developing industrial-scale renewable hydrogen projects. However, there are few actual projects in operation. This gap is not due to a lack of vision or commitment, but rather an underscore in the presence of numerous challenges associated with bringing such projects to fruition.

4.1 Hydrogen production

The production of renewable hydrogen at the announced scales requires complex decisions in the planning phase that can affect the viability of the project, and that are not only limited to the design of the plant, but also extend to the operation of the plant or logistical aspects related to transportation.

In this chapter, the most relevant factors affecting the business case for a renewable hydrogen project, from production to transportation and consumption of hydrogen, are presented.

The production of hydrogen by the electrolysis process has emerged as one of the pillars in the search for sustainable and clean solutions to meet current and future energy needs. However, this seemingly simple process of decomposing water to obtain hydrogen and oxygen hides a number of complexities that must be carefully evaluated. This section will delve into some of the variables that affect hydrogen production such as the connection scheme, economies of scale or the challenges in building large hydrogen production plants.

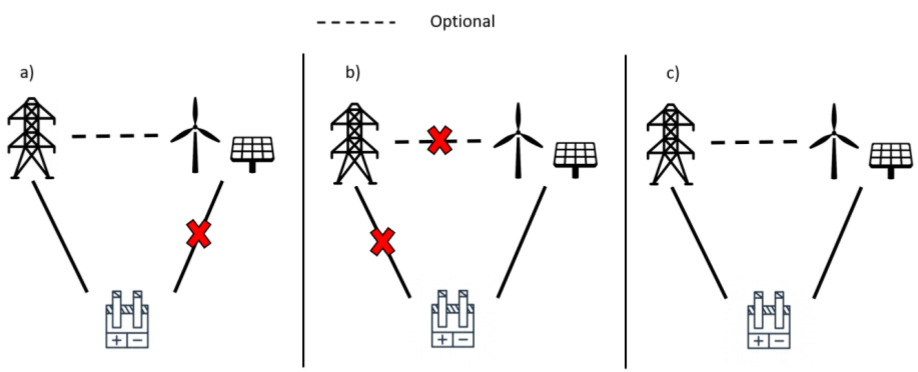

Figure 13. Operating modes of a hydrogen production plant according to the connection scheme. a) Grid connection, b) Island mode and c) Hybrid. Source: own elaboration

- **Grid connected**

It allows the number of hours that the electrolyser operates to be increased, but the intensity of emissions from the Spanish electricity grid does not allow the produced hydrogen to be certified as RFNBO.

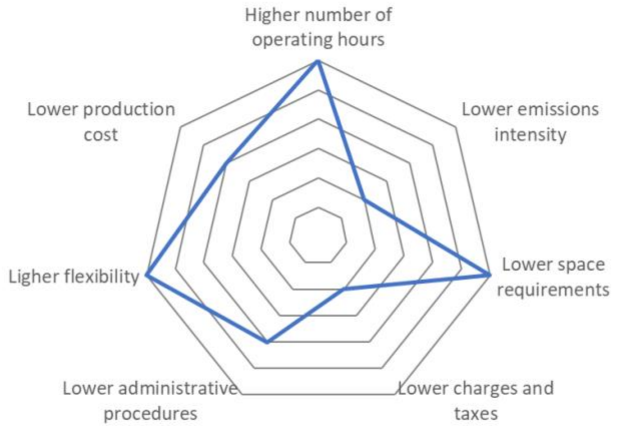

Figure 14. Evaluation of mode of operation according to different criteria. Source: own elaboration

The electrolyser can operate connected to the grid in three different ways: by signing one or more PPA contracts, buying electricity on the day-ahead market or by a combination of both.

In the first case, hydrogen production will be limited by the number of hours for which the PPA has been signed to. In addition, if the hydrogen is to be certified as renewable, it must comply with the hourly time correlation criteria of Delegated Act (EU) 2023/1184 (this case would be equivalent to case b) island connection.

In the second case, there is no limitation on the number of hours the electrolyser can operate. However, as the number of hours of operation of the electrolyser increases, the need to operate it during hours of high electrical demand increases which implies the purchase of electricity at higher prices. This results in an increase in operating costs (OPEX). Restricting the operating time to a few hours per day (as in the case of 1000 hours per year) considerably raises the CAPEX impact on the final cost of hydrogen (see Figure 15).

In economic terms, there are the costs associated with grid connection such as charges and tolls which increase the price of hydrogen. There can also be administrative complications in obtaining the necessary permits, especially for large projects. However, a benefit of this connection scheme is that it requires less space as there is no need for additional infrastructure for renewable energy generation while reducing the need for storage.

Another advantage of this connection scheme is that it allows the electrolyser to participate in the market to provide frequency support ancillary services, providing a promising additional revenue stream.

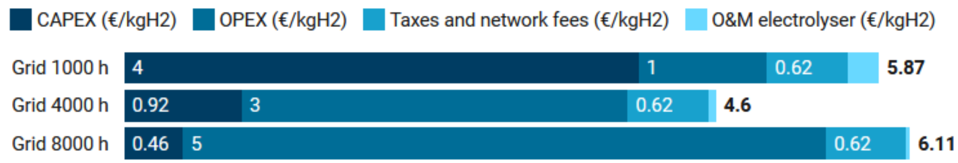

Figure 15. Cost of hydrogen production taking electricity from the grid for three scenarios: 1000, 4000, and 8000 hours of operation taking electricity prices for the year 2021[14,15]. For more information see methodological notes (section 8.1).

[14] No data was taken for 2022 due to the strong increase in costs as a consequence of the energy crisis, considering 2021 a better representative year. For the calculations of these scenarios, tax costs were taken into account according to Eurostat data [6].

[15] According to order TED/1312/2022, hydrogen production in Spain is exempt from the payment of charges, but not from network tolls.

In terms of emissions intensity, operating a grid-connected electrolyser without any PPA will have a carbon footprint that may prevent the hydrogen produced from being considered RFNBO. According to the criteria set by Delegated Act (EU) 2023/1185, the produced hydrogen must reduce emissions by 70% compared to the fossil benchmark to be considered RFNBO. This benchmark is 94 gCO2eq/MJ equivalent to 3.37 kgCO2/kgH2.

Figure 16 shows the emissions intensity that hydrogen produced by taking electricity from the grid. A reference of the emissions intensity of the electricity generated in 2022 in the peninsular territory is used. As shown below, this criterion is very restrictive when applied to the Spanish electricity grid. The number of hours in which emissions are below the established limit by the delegated act is quite small, approximately 200 hours per year.

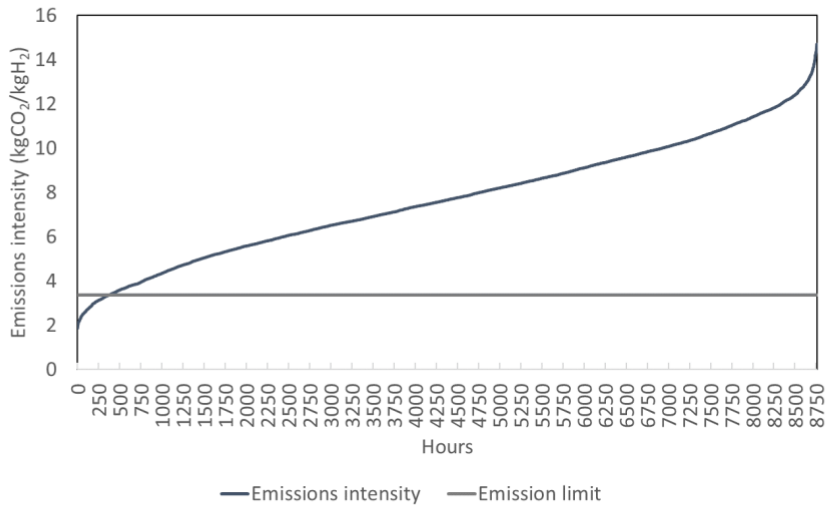

Figure 16. Emissions intensity of hydrogen produced by taking electricity from the grid in Spain. Electricity grid intensity factors taken for 2022[1] . Source: own elaboration. For more information see methodological notes (section 8.2).

- **Island operation**

The number of operating hours is limited by the availability of renewable energy.

In this connection scheme, the electrolyser is directly connected to a renewable energy source, which limits the hours during which the electrolyser can operate. This limitation can be challenging for industries that require an uninterrupted supply of hydrogen. However, a clear advantage is the ease with which the hydrogen can be certified as renewable, given that the renewable generation plant is new and meets the additionality criteria of the delegated acts.

From the economic point of view, this scheme does not incur charges and tolls for connection to the electricity grid. Although the limited number of hours that the electrolyser can operate[16], increases the impact of CAPEX on the final cost, being the connection scheme with higher production costs. In addition, since the electrolyser is not connected to the grid, it cannot participate in the electricity market to provide flexible services which can reduce profit margins.

On the other hand, this scheme significantly reduces administrative procedures as it does not require connection to the electricity grid of any kind. However, building a new renewable generation plant may entail additional procedures, particularly those related to environmental impact assessments.

Space is a critical, as a large area of land is needed to house both the renewable plant and the electrolyser. Ideal locations would be those where both can coexist: close to industrial areas, but with sufficient space for the renewable plant. In addition, hydrogen storage systems and/or batteries are essential to manage fluctuations in hydrogen production.

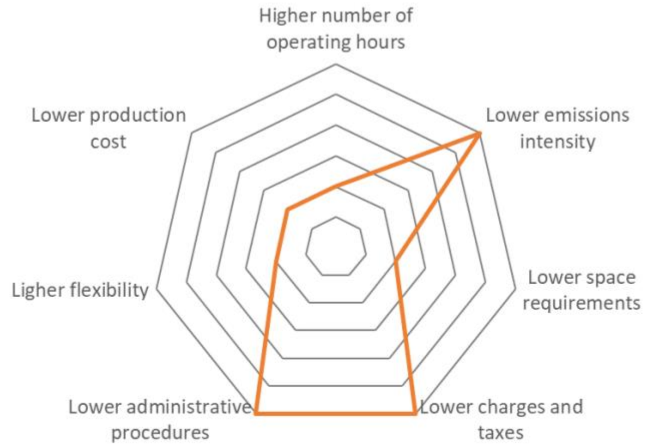

Figure 17. Evaluation of mode of operation according to different criteria. Source: own elaboration

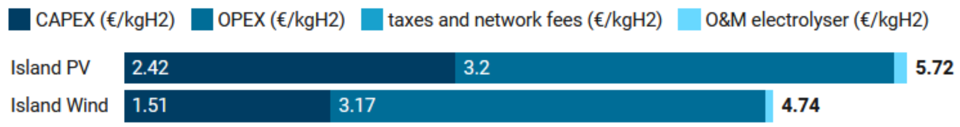

Figure 18. Cost of hydrogen production with island operation for solar and wind energy in Spain. Source: own elaboration. For more information see methodological notes (section 8.1).

[16] 1,515 and 2,426 hours on average in Spain, using solar energy and wind energy, respectively

- **Hybrid operation**

To generate profits from the operation of an electrolyser, it is important to consider as many different revenue sources and operation modes as possible.

In a hybrid scheme, the electrolyser is connected to both a renewable energy source and the grid which brings combined advantages and challenges of both models.

The hybrid plant can operate without being completely limited by the availability of renewable energy. This makes it possible to increase the number of operating hours by reducing the weight of CAPEX in the cost of hydrogen production with respect to the island case (see Figure 20).

Another source of income in the case of such connection scheme mode is participation in electricity markets, being able to provide flexibility services and sell electricity to the grid when there are surpluses of renewable electricity.

In relation to emissions intensity, hydrogen generated with grid electricity will not be recognized as RFNBO if it does not meet certain emission requirements. Although it is possible to use PPA contracts, these may limit the number of operating hours due to the time correlation criteria of Delegated Act (EU) 2023/1184.

On an administrative level, there are costs and administrative procedures associated with grid connection. This applies to both the electrolyser and the renewable energy plant, which may be required to feed excess production into the grid. Project implementation may be delayed by these processes.

In relation to space, a high availability of land is required for the renewable plant. However, in this case, by being connected to the electricity grid, the storage needs can be reduced by increasing the number of operating hours of the electrolyser and, therefore, the hydrogen production.

This case is a combination of the two previous cases, the electrolyser is connected both to a renewable generation plant and to the grid.

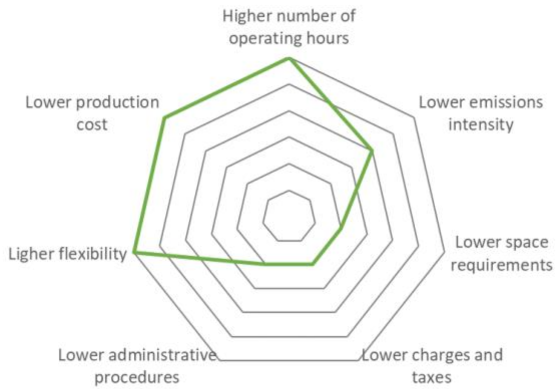

Figure 19. Evaluation of operation modes according to different criteria. Source: own elaboration

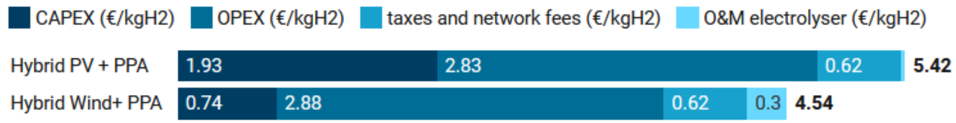

Figure 20. Hydrogen production cost with hybrid operation assuming a power purchase agreement (PPA) of 2500 hours and 50 €/MWh. Source: own elaboration. For more information see methodological notes (section 8.1).

PRODUCTION: ECONOMIES OF SCALE

The balance of plant components is the most likely to benefit from economies of scale.

The heart of a hydrogen production plant is the electrolyser stack, but technical limitations prevent it from being significantly larger, which limits its economies of scale. Therefore, to increase the production capacity of a plant, it is necessary to adopt a modular approach using several stacks in parallel rather than increasing the capacity of a single stack [7].

However, the ancillary elements required to operate the plant - balance of plant, compressors, control systems or piping - account for a large proportion of the cost of hydrogen production. Unlike the stack, these elements can have strong economies of scale. For example, a 10 MW compressor does not cost ten times as much as a 1 MW compressor, but about four times as much [8].

Significant cost reduction up to 10 MW due to economies of scale. Above this capacity, the reduction is more moderate.

Figure 21 shows the cost reduction trend for the two commercially available electrolysis technologies. Based on the calculations in Figure 22, the cost reduction trend for the two commercially available electrolysis technologies is shown in Figure 21. Figure 22 shows that when moving from a 500 kW to a 10 MW production plant, the CAPEX savings for hydrogen production is around 1 €/kgH2. When comparing a 10 MW electrolyser with a 100 MW electrolyser, the difference is 0.5 €/kgH2. If a 500-kW electrolyser is compared to a 100 MW electrolyser, the difference can be up to 1.4 €/kgH2. This difference is significant and illustrates the trade-off between small distributed demands with higher production costs or centralised plants with lower production costs but higher associated transport costs.

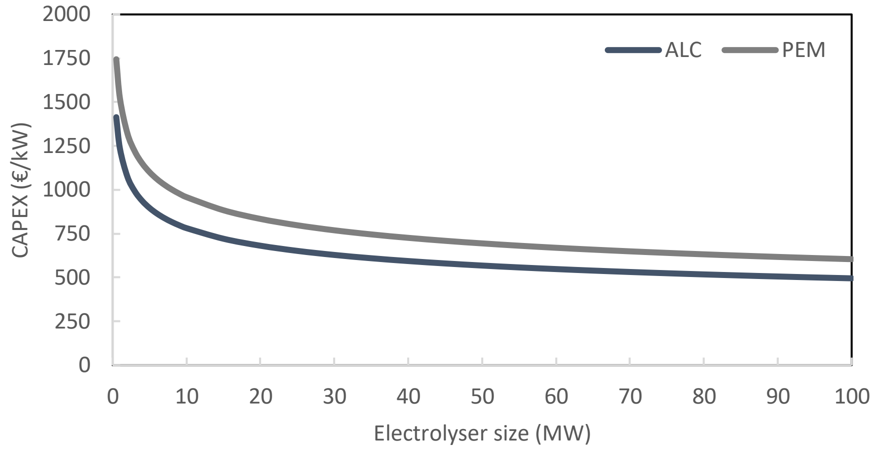

Figure 21. Investment costs of electrolysers according to power and type of technology. Source: Hyjack [9][17]. For more information see methodological notes (section 8.3).

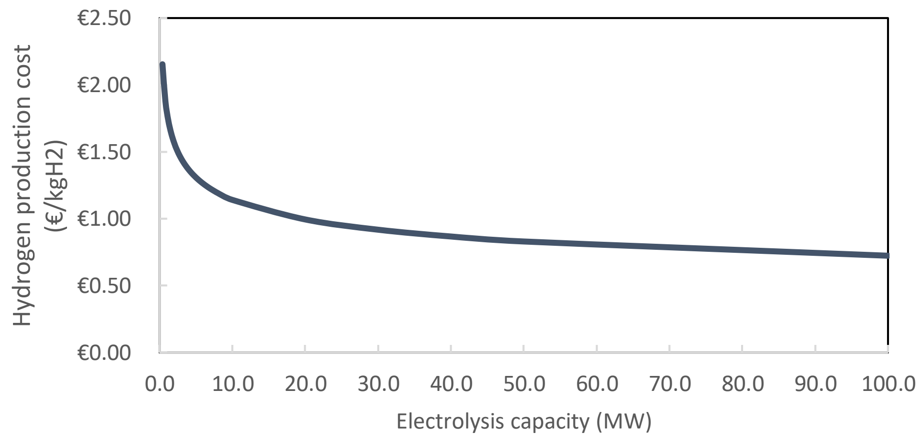

Figure 22. Effect of investment costs (CAPEX) on the final cost of hydrogen production according to power for an alkaline electrolyser. Source: Hyjack [9]. For more information see methodological notes (section 8.3).

PRODUCTION: LARGE-SCALE ELECTROLYSIS

A large hydrogen production plant consists of several modules which are made up of several stacks and auxiliary elements.

A hydrogen production plant consists of several stacks working in parallel which require proper management. Currently, a PEM electrolyser stack has a capacity of 1 MW. Although, it is expected that it can be increased in size up to 5 or even 10 MW in the future [8]. Currently, an alkaline has a capacity of between 1-5 MW [10] with prospects of increasing to 10 MW [8]. Therefore, a 1000 MW plant could have approximately 100 stacks.

As proposed by [11] stacks are grouped into modules where each module has its own balance of plant; thus, increasing flexibility, future expansion possibilities, favoring standardization, and reducing costs.

Each module is composed of elements such as transformers, rectifiers, compressors, and separators among others. It is necessary to optimize the design of all the components of the module shown in Figure 23. Figure 23 is an example of this distribution, using a 20 MW transformer for every 10 PEM electrolysers of 2 MW, a separator per module and a compressor for every 2 modules.

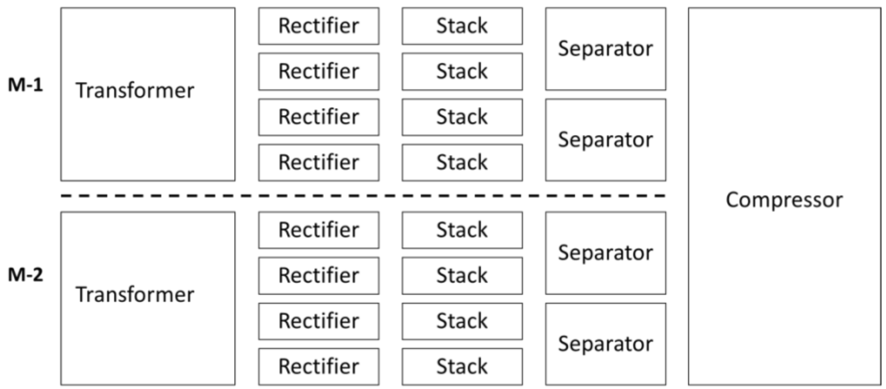

Figure 23. Example of distribution of a plant with two modules and four stacks per module. Source: own elaboration

The management of the different modules is key to adapting hydrogen production to fluctuations in input (renewable electricity) and output (possible fluctuations in demand).

Proper management of hydrogen production and storage is key to ensure optimal plant operation and to certify compliance with delegated acts so that the hydrogen produced can be considered RFNBO.

Hydrogen production is managed by modifying the degree of charge of each stack (between 10-100 %) and choosing the state in which each one is on at a given time. Each electrolyser can adopt three states: ON, OFF, and SB. Normal operation takes place in the ON state where the electrolyser is producing hydrogen at the optimum temperature and pressure. In the OFF state the electrolyser shuts down, reducing its temperature and pressure as its start-up requires energy and time to reach operating conditions again, this is known as cold start. The SB state allows short interruptions, maintaining temperature and pressure but without producing hydrogen, allowing a quick restart. Start-up from SB mode, for both PEMs and modern AELs, usually occurs within a few seconds [1,11], and it is known as hot start. An example of planning for the operation of a hydrogen production plant can be seen in Figure 24 whereas the state of each stack at different time periods is depicted in Figure 25 where the degree of loading of the stacks is represented.

Finally, due to the changing nature of renewable generation, planning in the operation of a hydrogen production plant has to be done using forecasting tools which allow the optimizing of the real-time management of the plant considering the expected future production in order to optimize the management of storage and production.

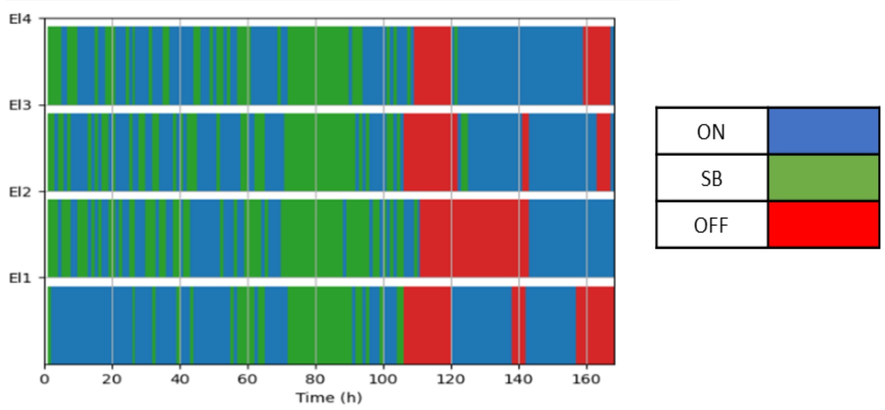

Figure 24. Optimal planning for a single module production plant with four stacks during one week of operation. Source: own elaboration

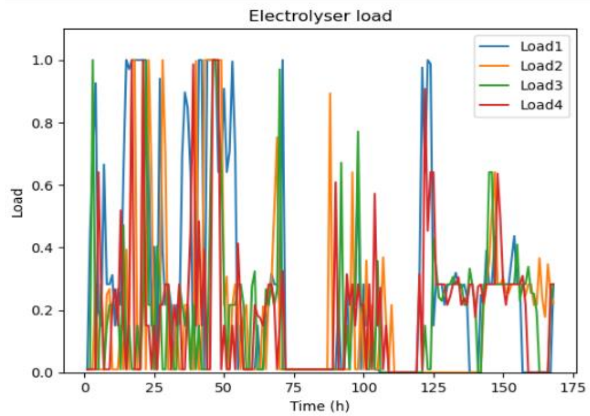

Figure 25. Optimal loading degree of each stack for a single module production plant with four stacks during one week of operation. Source: own elaboration

4.2 Hydrogen transportation and distribution

It is not always possible to produce hydrogen where it is needed due to the lack of space or for economic reasons. Therefore, it is essential to understand how hydrogen is transported and distributed to end consumers.

There are two levels of hydrogen distribution: local and long distance.

Local or regional demand for hydrogen can be met by trucks transporting compressed or liquid hydrogen or by hydrogen pipeline. The choice of the best way to transport hydrogen is not immediate and will depend on two factors: the amount of hydrogen to be transported and the distance between the production and demand points (see Figure 26). For example, existing studies indicate that for demands above 1 tonne H2 /day, transport as liquid hydrogen would start to become competitive. For lower demands, compressed hydrogen is the preferred option, while for much higher demands, a hydrogen pipeline may be the more attractive [12].

To transport hydrogen in large quantities and over **long distances**, transporting hydrogen by truck would no longer be economically viable. In this case, a choice has to be made between pipeline and ship transport. Pipelines are more attractive than ships for moderate distances whenever possible, but for very long distances, such as between continents, shipping is often the only option.

Another question arises, which is in what form to transport hydrogen would be the best option: as liquid hydrogen, ammonia or using a liquid hydrogen carrier (LOHC). In case of transforming hydrogen to one of its carriers, two processes must be added: one of conversion and one of reconversion to hydrogen. The last step may not be necessary when the hydrogen carrier can be used directly (e.g. ammonia in industry).

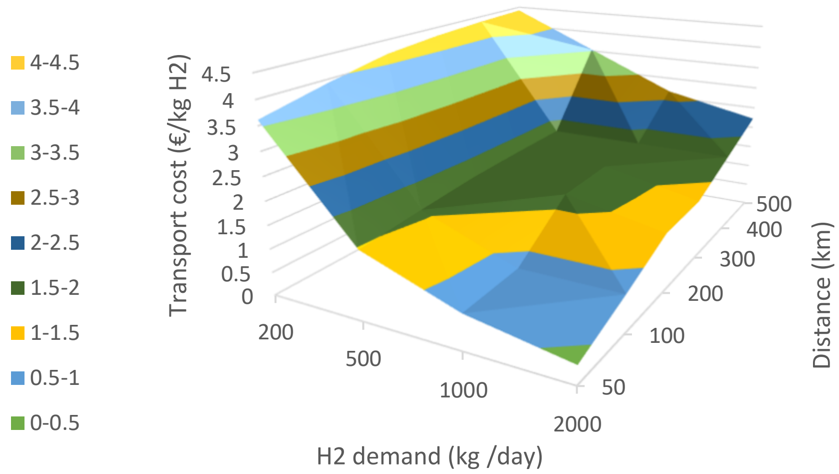

Figure 26. Cost of transporting compressed hydrogen in tube trailer as a function of distance and hydrogen demand. Source: own elaboration. For more information see methodological notes (section 8.4).

Transport costs often receive less attention than production costs, and can sometimes be as high as production costs.

Transporting hydrogen over long distances by ship or pipeline will be a key factor in determining the success of hydrogen as an international commodity as many countries, driven by their low hydrogen production costs, hope to become major exporters. Transportation costs are often overlooked or given less importance than they have when they may be of equal magnitude to production costs.

As shown in

Figure 27, the best way to transport hydrogen over distances of up to 10 000 km by 2030 is by pipeline whenever possible. Otherwise, transportation in the form of ammonia by ship is the best option, with a cost of around €2/kgH2 which is very close to the expected hydrogen production cost in many exporting regions by 2030.

As with production costs, transportation costs are also expected to be reduced in the long term due to economies of scale and learning curves

Transportation costs are expected to be significantly reduced by 2050 due to innovation which will minimize energy consumption in hydrogen liquefaction and conversion to ammonia and LOHC as well as economies of scale which will achieve a reduction of up to 80% in the investment costs of these technologies. These innovations mean that hydrogen transportation by ship will become more competitive, being a better option for transporting hydrogen through pipelines over 4,000 km.

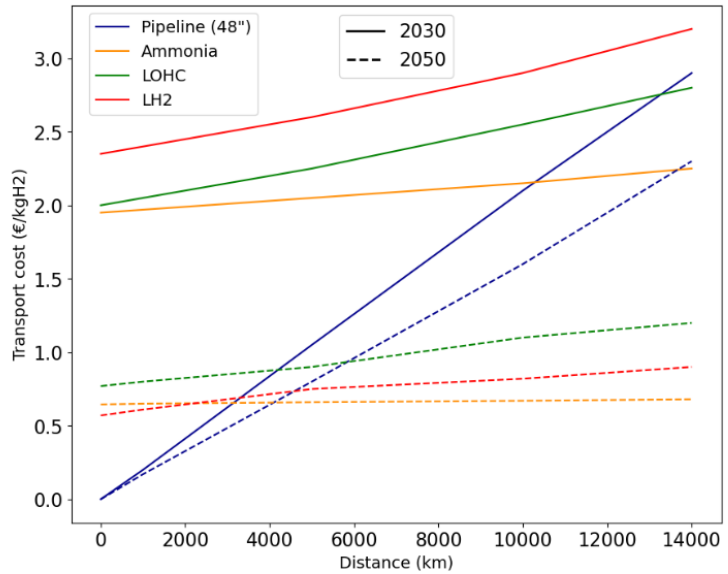

Figure 27. Hydrogen transportation cost by distance and mode for 2030 and 2050. Sources: Own elaboration based on [13] (2030) and [14] (2050).

CASE STUDY: TRANSPORTING HYDROGEN OVER LONG DISTANCES

In November 2022, a Memorandum of Understanding was signed between the EU and Namibia, agreeing to develop a secure and sustainable supply of feedstock, refined materials and renewable hydrogen. In line with this agreement, the largest green hydrogen production project in sub-Saharan Africa was announced in May 2023, with an investment of €10 billion. It seeks to produce renewable hydrogen using the country's excellent solar resources and export it to European ports in the form of ammonia. However, some experts question this approach due to the inefficiencies and costs associated with transporting hydrogen to ammonia, arguing that pipeline transport could be more economical [12].

In order to analyse each of these options, it is necessary to calculate the production and transport costs in each case. It is assumed that hydrogen is produced in the Netherlands using wind energy and in Spain and Namibia using solar energy. Two scenarios are analysed: 2030 and 2050, considering the reduction in production and transport costs.

The aim of this case study is to analyse different scenarios for the supply of hydrogen to the port area of Rotterdam:

- Imports from Barcelona with the construction of a new hydro product.
- Imports from the port of Algeciras by ship in the form of ammonia.
- Imports from Namibia by ship in the form of ammonia.

Figure 28. Different transportation options to Rotterdam in the case study.

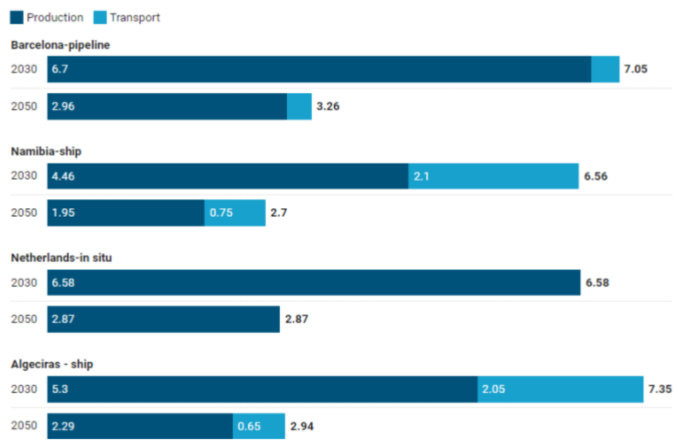

Figure 29. Cost of hydrogen supply in the port of Rotterdam according to the different supply options. Source: own elaboration[18] . For more information see methodological notes (section 8.5).

[18] Ammonia transportation costs include conversion and reconversion costs.

Results in Figure 29, show the narrow margin between local production and hydrogen imports from other countries. For both 2030 and 2050, the difference between local production and imports from Barcelona or Namibia is less than 0.5 €/KgH2. The worst alternative being transportation from Algeciras by ship. This small margin relative to hydrogen costs raises questions about the need to import hydrogen from other regions into Europe. However, the limits to local hydrogen production are not only due to the cost of hydrogen production, but also to other factors such as land use restrictions. Therefore, despite the small margin in total cost, importing hydrogen could still be attractive.

Depending on the fuel used, the greenhouse gas emissions associated with the transport of hydrogen by ship may be relevant to the certification of the ship as an RFNBO.

An often overlooked aspect that needs to be taken into account when considering long-distance hydrogen transport is the fuel used by the transport vessels themselves. According to DNV, 99.43% of current ships use conventional fuels. Of the ships ordered up to 2028, 83.8% use conventional fuels, while 16.2% use alternative fuels, most of which are LNG and LPG ships (12%) [5]. Therefore, the existence of ships using zero emission fuels by 2030 is uncertain and it is possible that much of the ammonia transported from Namibia to Europe will use these fuels.

The emissions associated with transport are important in the context of the certification of hydrogen as RFNBO according to the emission reduction criteria of the delegated act. According to the delegated act, for hydrogen to be certified as RFNBO, there must be an emission reduction of at least 70% compared to the fossil benchmark (94 kgCO2eq/MJ). For example, the lifecycle emissions intensity of renewable hydrogen shall not exceed 3.37 kgCO2/kgH2.

Figure 30 In the most restrictive case, where heavy fuel oil is used, the emissions intensity can be up to 25% of the total allowable emissions for hydrogen certification; thus, narrowing the scope for emissions from other processes even more so if this hydrogen has to be transported internally to other parts of Europe.

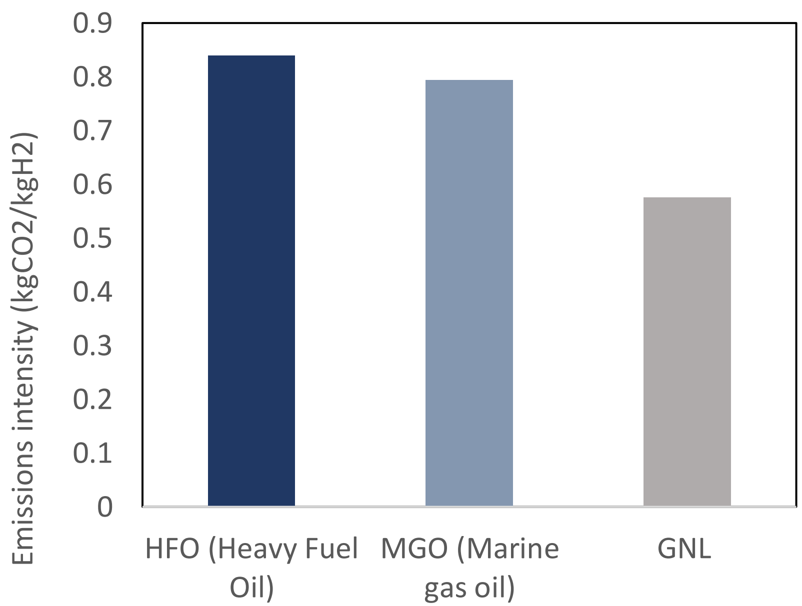

Figure 30. Emission intensity associated with ammonia transportation (kgCO2/kgH2). Source: own elaboration. For more information see methodological notes (section 8.5).

4.3 Hydrogen demand: Hydrogen Fueling Station

Hydrogen refueling stations (HRS) are key elements in achieving the hydrogen penetration targets in the transportation sector. There are two types of stations: HRS with and without in-situ hydrogen production.[19].

In HRSs, hydrogen is stored in tanks, and before being supplied, it must be compressed at high pressure. There are two standards for hydrogen compression: 350 and 700 bar. Higher pressure translates into a greater amount of hydrogen stored in the vehicle and therefore greater autonomy.

There are strong economies of scale in a hydrogen refueling station; the higher the demand for hydrogen, the lower the cost per kilogram supplied.

The compressor is the component that has the greatest weight in the final cost of the station and largely determines its economic viability. This and other components have strong economies of scale, meaning that the larger the hydrogen station, the lower the cost of the hydrogen supplied. Figure 31 shows the cost of supplying hydrogen to a hydrogen station for different demands and utilisation factors. As can be seen, there is a significant reduction in the cost of hydrogen supply for the same utilisation rate. This difference can be up to 2.2 €/kgH2 in the most extreme case (100 kgH2 /day vs. 2000 kgH2 /day).

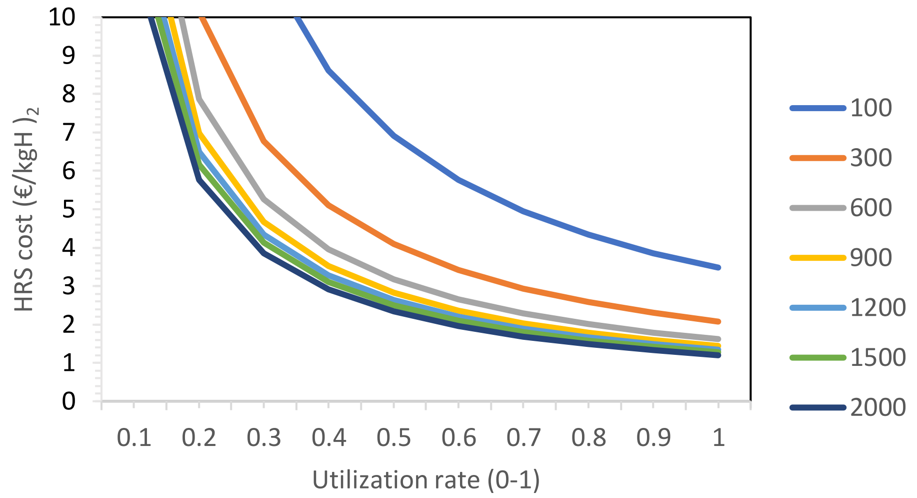

Figure 31Estimate of the cost of a hydrogen plant according to the degree of utilization and daily hydrogen demand. Source: Prepared by the authors. For more information see methodological notes (section 8.6).

The utilisation rate has a large impact on the final cost of the hydrogen supplied, although there is some scope for oversizing the hydrogen plant.

The higher the utilisation rate of the station, the lower the cost of the hydrogen supplied. However, the difference between 70-100% utilisation is not significant and may justify oversizing the hydrogen plant to prepare for future hydrogen demand. For example, there are two options for supplying a demand of 900 kg/day of hydrogen: a 900 kgH2/day hydrogen plant with 100% utilisation and a 1200 kg/day hydrogen plant with 75% utilisation. The difference in supply price between the two options is about 0.3 €/kgH2 (see Figure 32).

[19] In this report, for simplicity, the term hydrogenerators will be used to refer to both station times indistinctly, specifying when there is in-situ production.

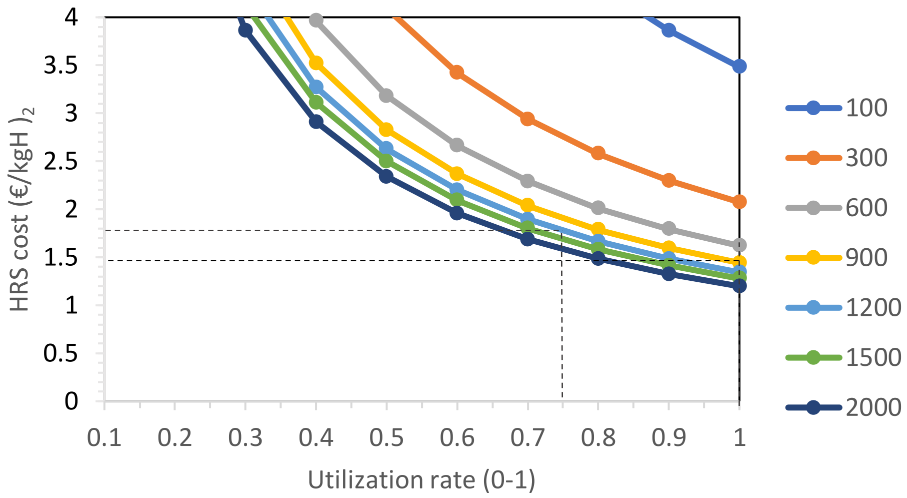

Figure 32. Examples of costs according to degree of utilization for demands of 900 and 1200 kg/day. Source: own elaboration

The deployment of a network of hydrogen plants requires public-private collaboration to take advantage of scale economies and reduce the cost of hydrogen supply.

The deployment of a hydrogen network faces a chicken-and-egg challenge: there are no refuelling stations because there are not enough hydrogen vehicles, and at the same time there are not enough hydrogen vehicles because there are no refuelling stations. In this situation, collaboration between different fleets and relevant players in the hydrogen sector is essential to maximise economies of scale. As an example, consider the hypothetical case of a logistics hub where several companies join forces to build one large refuelling station instead of several smaller ones. Similarly, a public bus fleet could expand its refuelling capacity to serve a larger number of hydrogen vehicles in the future.

CASE STUDY: CENTRALIZED VS. ON-SITE PRODUCTION

The cost of supplying hydrogen to a hydrogen station is determined by the cost of production, the cost of transport and the cost of the hydrogen station itself. The first question to be answered when designing a refuelling station is how the hydrogen will be produced: on-site (decentralised) production or centralised production. On-site production eliminates the cost of transporting and distributing hydrogen. Centralised production, on the other hand, can take advantage of economies of scale and reduce production costs. However, transport costs can be high due to the distance between production and consumption sites. The assumptions of the two scenarios to be analysed are described below:

Centralized production: this scenario represents a large production plant (30-100 MW) that produces hydrogen by drawing electricity from the grid. Compressed hydrogen is delivered using tube trailers to nearby HRS (100-500 km from the production plant). It is assumed that the combined demand of all HRS is greater than 1000 kgH_2/day. According to Figure 26, the transportation cost for these demands and distances is around 1 €/kgH2.

Decentralized production: this scenario is represented by HRSs with on-site production using electricity from the grid. In this case, the electrolyser operates for 14 hours (the time the HRS is open), and its size is given by the demand of the hydrogenerator, and there is no cost associated with transportation.

The results of Figure 33 show that for HRS with hydrogen demands below 500 kg H2/day, centralized production can be a better option, reducing the cost by up to 0.8 €/kgH2 in the most extreme case (100 MW and 100kg/day demand). For very low demands, the electrolyser is very small, and it cannot take advantage economies of scale. For example, for 100 kg/h of hydrogen, the electrolyser is 400 kW, for 500 kg/h, it is 1.8 MW, and for 1000 kg/day, it is 3.5 MW. From 700 kg/day, under the hypotheses considered, on-site production and centralized production have practically the same cost. Centralized production being the most appropriate for demands of more than 1 ton H2/day.

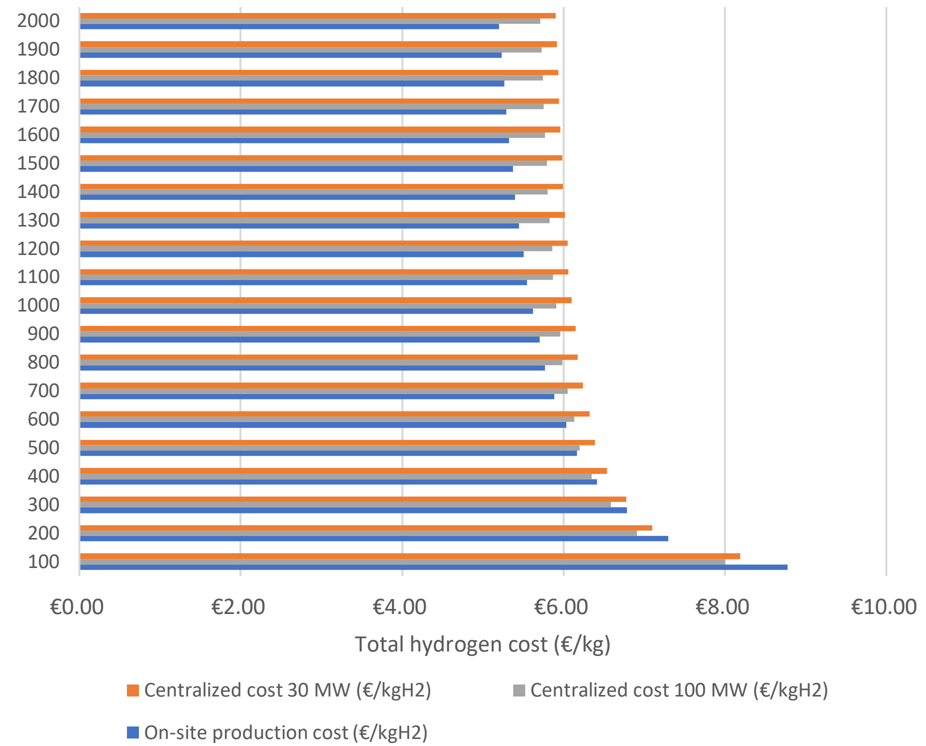

Figure 33. Hydrogen supply cost including production, transportation, and hydrogen supply for the different case studies. Source: Prepared by the authors. For more information see methodological notes (section 8.7).

When considering the deployment of the hydrogen refueling station network, all these factors must be considered to determine the best configuration: several small hydrogen plants with truck transportation or a network of larger and more distributed refueling stations where on-site production can be more attractive.

5. LOCATION FACTORS FOR PRODUCTION AND DEMAND

5. LOCATION FACTORS FOR PRODUCTION AND DEMAND

As seen in previous sections, hydrogen transportation can have a significant weight in the final cost of hydrogen. It is logical to think that to reduce this cost it is sufficient to bring production closer to demand (or vice versa). However, this situation is not always possible due to low land availability and low availability of renewable resources among other reasons. The factors affecting the location of hydrogen demand and production are evaluated below.

5.1. Demand location factors

- **Location of industrial hydrogen demand**

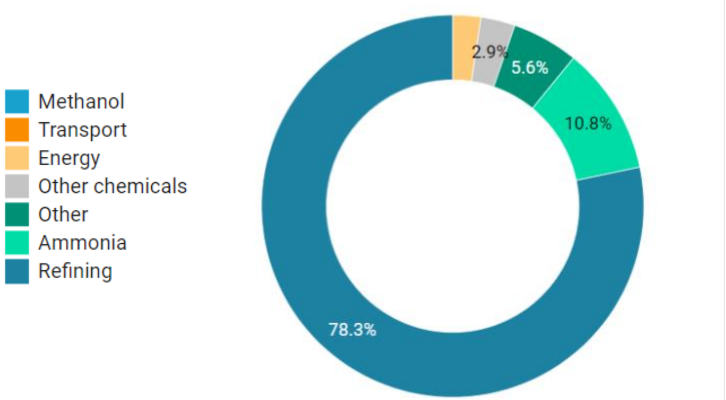

Figure 34. Distribution of current hydrogen demand in Spain. Source: Fuel cells and hydrogen observatory [15].

Eighty-nine per cent of the current hydrogen demand in Spain comes from refining and ammonia

According to data from the observatory "fuel cells and hydrogen", 611.840 tons of hydrogen were consumed in Spain in 2022, 89.1 % of which went to the refining industry and ammonia production. The use of hydrogen in the manufacture of other chemical compounds was 2.9%. Other uses of hydrogen in the food or glass sector accounted for 5.6%. The application of hydrogen to generate heat accounted for 2.4%. In contrast, the relevance of hydrogen in the field of transportation and methanol production was practically negligible, accounting for less than 0.5% of total demand.

New industrial applications for hydrogen are expected to emerge in the coming years, diversifying its use beyond traditional applications.

Some of these new applications can be seen in Figure 35 where the different industrial uses of hydrogen are ranked according to their expected level of adoption.

The first sectors to consume renewable hydrogen will be those that currently consume grey hydrogen such as ammonia and refining. In addition, there are other processes that have the potential to use hydrogen as a feedstock, but those will require adjustments to their production methods. For example, in methanol production which is currently based on natural gas, and it will be produced from H_2 and CO2 in the future. Similarly, in the steel industry, hydrogen can be used as a reduction agent in the production of steel. Traditionally, this process relies on coking coal.

The use of hydrogen for high-temperature industrial heat generation is also being explored where no other low-emission alternative is available. Low and medium temperature applications (<400°C) can be efficiently electrified with existing technology. However, sectors related to the production of non-metallic minerals such as cement, ceramics or glass, metal production, and petrochemicals, predominantly rely on process temperatures above 400°C.

The use of hydrogen for high-temperature heat generation could generate a demand of up to 990,000 tons of hydrogen per year.

Despite this scenario, hydrogen is not the only option for decarbonising high-temperature heat production, as biomethane can be used for this purpose, as well as new technologies using electricity that are currently under investigation. Biomethane has the advantage of an existing infrastructure and does not require any changes to the production process. However, it is unlikely that all high-temperature industrial heat can be decarbonised with biomethane alone. The current biomethane production capacity in Spain is 0.268 TWh/year and the forecast for 2025 is 3.7 TWh/year, while the latest draft of the PNIEC sets a target of 20 TWh for biogas production in 2030 [20] [16].

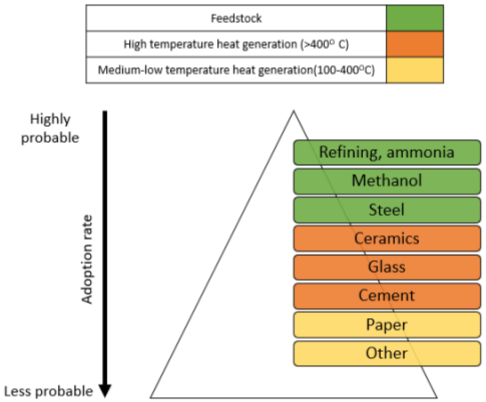

Figure 35. Level of adoption of renewable hydrogen in different industrial sectors: own elaboration. Source: own elaboration

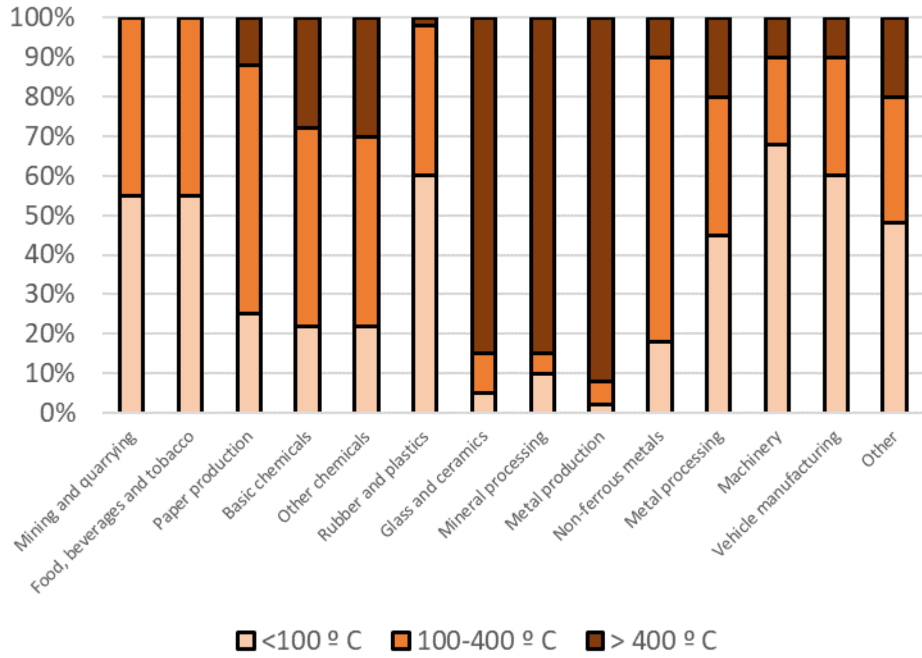

Figure 36. Process heat consumption in EU industries by temperature band. Source: [17]

Some industrial activities are more centralized than others, and transportation costs may be relevant.

The location and density of demand is very relevant. Sectors such as refining, fertilizer or steel production are characterized by being activities with a high degree of centralization where hydrogen production is likely to be on-site. On the other hand, sectors such as ceramics, glass or the chemical industry are more distributed activities, and transportation costs may be relevant. The map in Figure 36 shows the geographical distribution of the different industries in the national territory.

[20] It is unclear what proportion of these biogas plants will upgrade to biomethane.

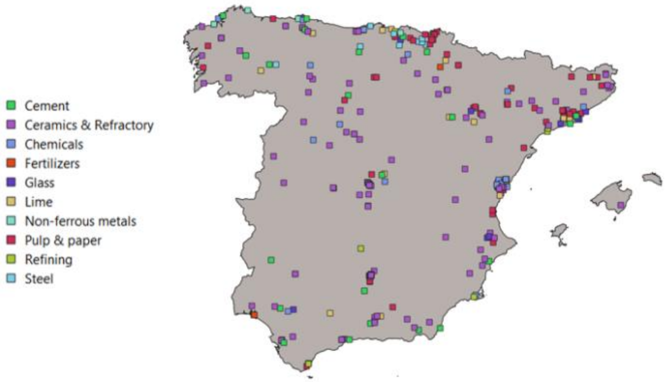

Figure 37. Distribution of energy intensive industry in Spain.

- **Localization of hydrogen demand in the transportation sector**

According to the requirements set by AFIR, Spain must have at least 78 HRS plants by 2030 with a demand of up to 24,000 tons per year, the equivalent of 4,190 trucks.

The location of hydrogen demand in road transport is very difficult to forecast, and it will depend on the adoption of hydrogen by the different vehicle segments. However, a first approximation of the location of this demand can be made on the basis of the recently approved regulation on the deployment of alternative fuels infrastructure (AFIR). This regulation sets by 2030, the obligation to have at least one HRS every 200 km within the Ten-T Core network. In addition, it also imposes the obligation to have one HRS in each urban node of the Ten-T Core network[21]. These HRS must be publicly accessible, dispense hydrogen at 700 bar, be accessible to light and heavy vehicles, and have a capacity to supply 1-ton H2/day.

According to calculations by Hydrogen Europe[22], there should be at least 78 HRS in Spain by 2030 to meet AFIR requirements. This is 71 more HRS than those existing today. Depending on the utilisation rate of these hydrogen plants, the estimated demand in the transportation sector for 2030 could reach up to 24,000 tons of hydrogen per year or the equivalent of 4,190 hydrogen fuel cell trucks.

Figure 38. Corridors and urban centres of the Ten-T Core network in Spain.

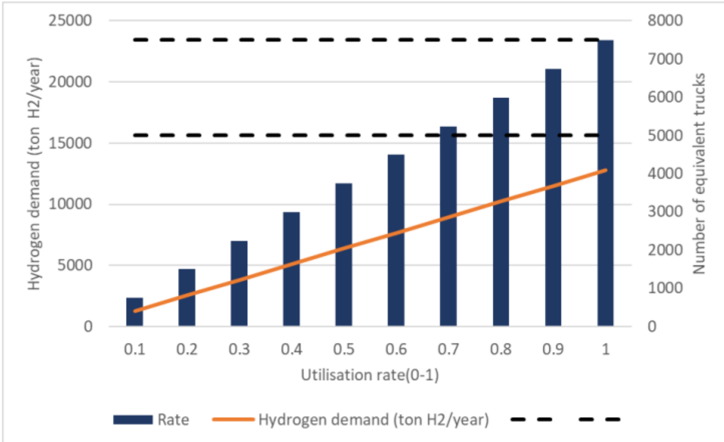

Figure 39. Expected demand for hydrogen in mobility based on AFIR and number of equivalent trucks[23,24]. Source: own elaboration

[21] In Spain, there are 49 Ten-T urban nodes according to the definition of urban node in Regulation (EU) No. 1315/2013 of the European Parliament and of the Council.

[22] https://h2me.eu/wp-content/uploads/2023/06/2023-0508_G25-Hoffmann-HRS-AFIR-Hydrogen-Mobility-Europe-Conference_2023-0510_viewer.pdf

[23] Calculations based on a consumption of 4.91 kgH2/100 km and on the assumption that a truck travels an average of 388 km per day (for more details see methodological annex 8.8) [18].

[24] The hydrogen roadmap targets mention between 5000-7500 heavy and light goods vehicles, not including only trucks.

5.2. Production location factors

- **Environmental impact**

Renewable hydrogen production should avoid competing with agricultural land and look for low environmental impact areas with favourable orographic conditions.

A hydrogen production plant involves significant land use, especially when linked with a renewable generation plant. The Environmental Sensitivity Index (published by MITECO) is a tool that can be used to help decide where to locate renewable energy farms. It classifies land into five classes according to the environmental impact of placing a renewable energy project in that location: maximum - not recommended, very high, high, moderate and low.

Moreover, in addition to the environmental impact, land use must also be taken into account. The Copernicus program and its monitoring tools can play an essential role in this process by providing accurate data on land cover and vegetation condition in a given region.

Another factor to consider is the slope and elevation of the terrain which may bring technical limitations for the installation of electrolysers, solar panels or wind turbines.

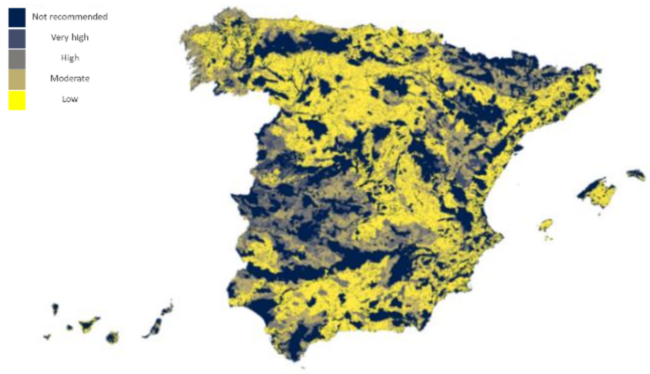

Figure 40. Environmental sensitivity index solar energy

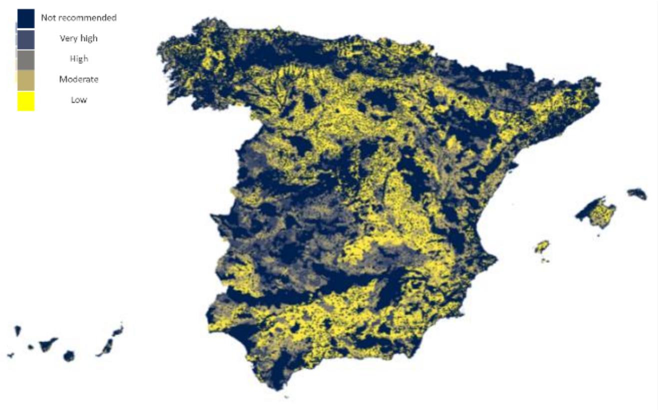

Figure 41. Environmental sensitivity index wind energy

- **Availability of renewable resources**

The availability of renewable resources is a critical factor that directly influences the economics of hydrogen production. The more renewable energy available, the more hours per day and days per year the electrolyser can operate. For this reason, it is essential to identify these locations as well as potential locations that can benefit from the use of both resources (solar and wind energy).

Wind energy has higher capacity factors, but is much more concentrated at specific points, usually far from industrial centres.

The average capacity factor for wind energy in Spain is 0.24; however, there are large differences between one location and another. The highest capacity factors are found in the north of the peninsula and in mountainous areas, usually far from the industrial centres where hydrogen is required.

Solar energy has lower capacity factors, but is much more consistent across Spain

Average solar capacity in Spain is 0.17, being higher in the middle and southern areas of the peninsula. Its distribution is much more uniform than that of wind energy. Also, it is more predictable, and the limitations on land use are lower. This may explain why, despite having a lower average capacity factor, most projects opt for this type of energy.

Figure 43 and 43. Capacity factors for solar energy and wind energy. Source: [4] y [5]

Figure 42. Distribution of capacity factors for wind energy and solar energy in Spain with a grid size of 25x25 m.

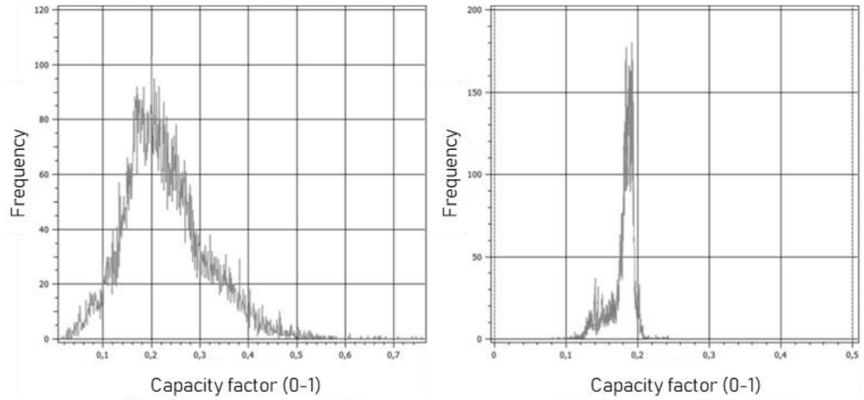

Figure 44. Distribution of capacity factors in the Iberian Peninsula for wind energy (left) and solar energy (right). The histograms correspond to a 25x25 m grid size.

- **Existing infrastructure: natural gas network**

Proximity to the existing natural gas network is an important strategic consideration. It is possible to use the route of the existing gas pipeline network to build a new national hydrogen product network or to adapt the existing gas network to transport hydrogen, at least in the less used sections. This strategy would reduce administrative procedures and construction times. In this line, Enagás, the TSO of the Spanish gas system, proposes the creation of a dedicated hydrogen transport infrastructure by 2030, capable of transporting up to 2Mt of hydrogen.

Another factor that may be relevant to near-term projects is the possibility of injecting hydrogen into the natural gas grid (blending). Although there is great uncertainty about the technical limits of blending, many projects are already applying for permits to connect to the gas grid for hydrogen injection. In August of 2022, Enagás published the optimal hydrogen injection zones in the different sections, and they classified the different sections according to their hydrogen injection potential (see section 1). The CNMC resolution mentions a blending limit of 5%[25] while the Enagás report mentions a more restrictive amount of 3%. This translates into a reduction of injection capacity from 4.62 TWh/year to 3.5 TWh/year.

Figure 45. Proposal for basic hydrogen infrastructure proposed by Enagás for Spain in 2030 and 2040. Source: Enagás

[25] See section 1

- **Other factors affecting the location of a hydrogen project**

Power grid

The siting of renewable hydrogen projects is closely tied to the availability of existing electrical infrastructure. It is common practice to oversize the renewable generation plant relative to the electrolyser to increase operating hours. However, this can result in surplus electricity that must be fed into the grid, so it is essential to have a nearby electrical substation with grid feed-in capacity. On the other hand, connecting the electrolyser to the grid may also increase the hours of operation by requiring permits to be obtained. This can be a technical challenge if the power of the electrolyser is significantly high.

Social criteria: aspects such as the generation of employment, the unemployment rate or the degree of population of a territory may influence the decision on the location of a project.

Water availability: it is necessary to find a location with proximity to a water source that ensures a constant supply of hydrogen without interfering with other end uses. These sources can be surface such as lakes, rivers, the sea or derived from wastewater treatment plants (WWTP) or directly from the water network.

Land use: in addition to assessing the environmental impact on the land, land uses that do not conflict with other activities such as agriculture should be prioritized.

Proximity to roads: this is another crucial aspect both for the construction phase and for transporting hydrogen in trucks.

6. TRADE IN THE MEDIUM AND LONG TERM

6. TRADE IN THE MEDIUM AND LONG TERM

6.1. The current state of H2 markets and its derivatives

Hydrogen will account for 12-22% of the final energy demand forecast for 2050.

The outlook of the main international agencies and analysts indicates that hydrogen will be a relevant energy source for the decarbonization of the economy by 2050. These studies, as reflected in Figure 45, estimate that the current demand for gray hydrogen could multiply in the range of 5 to 8 times by 2050 in the form of green and blue hydrogen. This would represent a weight between 12% and 22% of the final energy demand forecast for that date.

Only 9% of the USD 320 billion of investment capital announced for renewable hydrogen represents committed capital.

With a closer perspective in time, if we globally analyse hydrogen projects announced for 2030, we observe that the pace of firm investment decisions is very low. Only 9% of the 320 USD billion of announced investments up to that year are actually committed capital.

Some of the barriers faced by developers have been discussed in previous sections. Here, we are going to refer to those related to their transformation to reach a real market and those related to their financing.

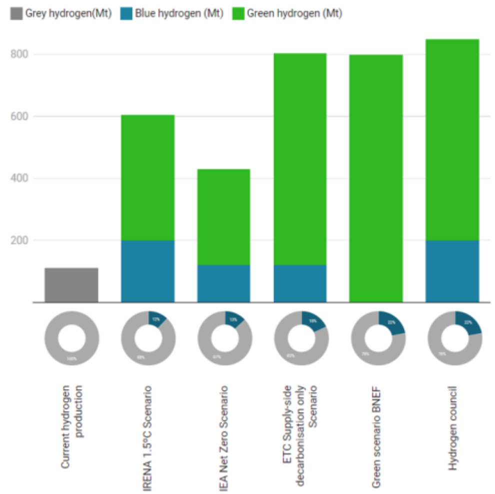

Figure 46. Hydrogen: global demand and 2050 outlook. Source: IRENA (2022), Geopolitics of the Energy Transformation: The Hydrogen Factor.

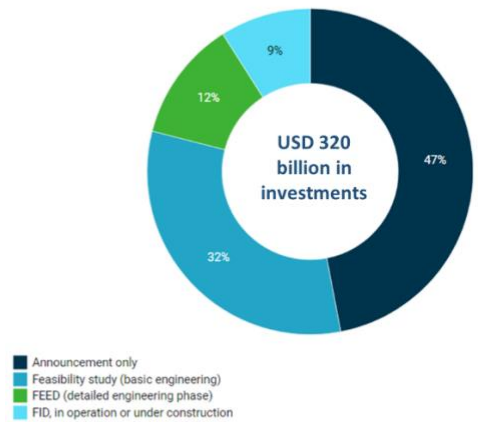

Figure 47. Status of worldwide hydrogen projects announced through 2030. Source: Hydrogen Insights 2023, Hydrogen Council, and McKinsey & Company

6.2. Development of the hydrogen trading market

Renewable hydrogen trading can be equated to the state supply chain with very capital-intensive investments that are also affected by technological changes and scale economies.

Despite the worldwide drive to develop hydrogen projects, it is not yet possible to speak of the existence of a market as such. For the time being, we are at an earlier stage, which could be called a new energy supply chain. As shown in Figure 48, the development of low-carbon hydrogen still fits into this characterization of a supply chain with bilateral contracts and long-term relationships or low transparency among others.

Latin America, especially Chile, will be the main hydrogen exporters by 2030 although Spain is also in a privileged position.

The expected increasing expansion of hydrogen worldwide foresees a significant change in the geography of global energy investment and trade with new countries becoming either importers or exporters.

An analysis of hydrogen production projects and their levelized cost, shows Latin America and especially Chile, as the main exporter of green hydrogen in 2030 [26(1)]. According to projections by the International Renewable Energy Agency (IRENA), it is anticipated that in the long term, by 2050, China will overtake Chile as the main producer of green hydrogen with the lowest levelized cost.

In this context, the Iberian Peninsula, particularly Spain, is also in a privileged position with an exportation potential in 2030 of 2.45 million tons. This will mainly be through the connection of the planned Mediterranean hydro-product (H2MedBarMar) between Barcelona and Marseille.

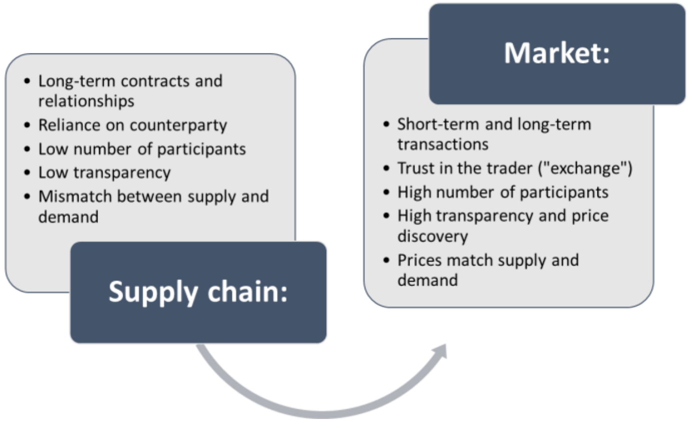

Figure 48. Evolution from a supply chain to a market. Source: own elaboration

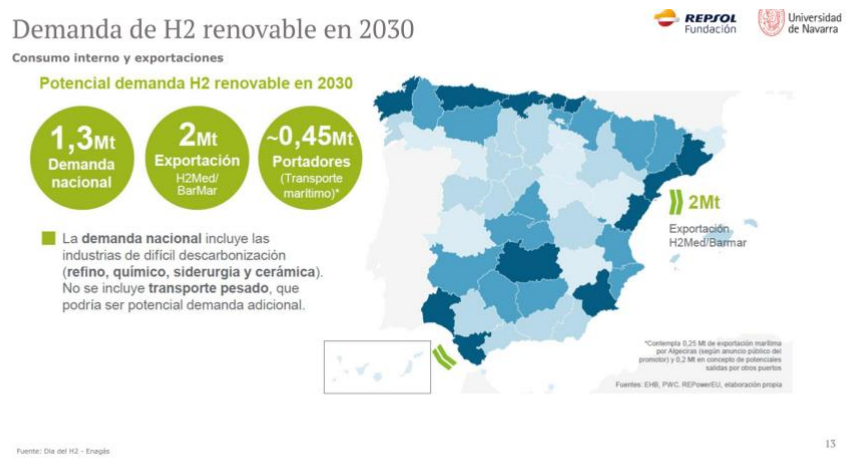

Figure 49. Domestic consumption and exportation of hydrogen in 2030. Source: Hydrogen Day Enagás (2023).

[26] Source: Hydrogen Exportation Markets (2023). World Hydrogen Leaders.

The development of a hydrogen market is key for investment decisions to be made jointly.

The foreseen map of renewable hydrogen trade relations suggests a transformation towards a future regional or global market depending on the means and cost of transportation. As indicated in previous sections, renewable hydrogen or its carriers (methanol, ammonia or liquid organic hydrogen -LOHC-) may be transported by truck, adapted pipelines, hydro products or by ship, and the determining factors for their choice will be the volume to be transported and their cost. This will imply the creation of regional hubs where renewable hydrogen is produced and exported. This will serve as a reference for determining prices not only at the regional level, but also at the global level adjusting supply and demand.

However, we are still far from this scenario. Currently, price signals for renewable hydrogen such as those used by Platts Global S&P, are based on assessments of capital and operating costs depending on the projects and their location[27]. In fact, one of the key elements in ensuring the success of such capital-intensive investment projects is that investment and financing decisions are made in tandem.

Green hydrogen production costs will still be higher than those of blue hydrogen and the price of natural gas by 2040[28].

One of the most important aspects for obtaining financing for renewable hydrogen projects is the stability and predictability of their cash flow. In the current environment, where renewable hydrogen is more expensive to produce than gray hydrogen, formulas must be found to ensure its long-term competitiveness and thus its financing.

S&P Global Commodity Insights forecasts anticipate that this trend will continue until 2040 at least. Although the production costs of green hydrogen will decrease, they will still be higher than the price of natural gas and even the cost of blue hydrogen.

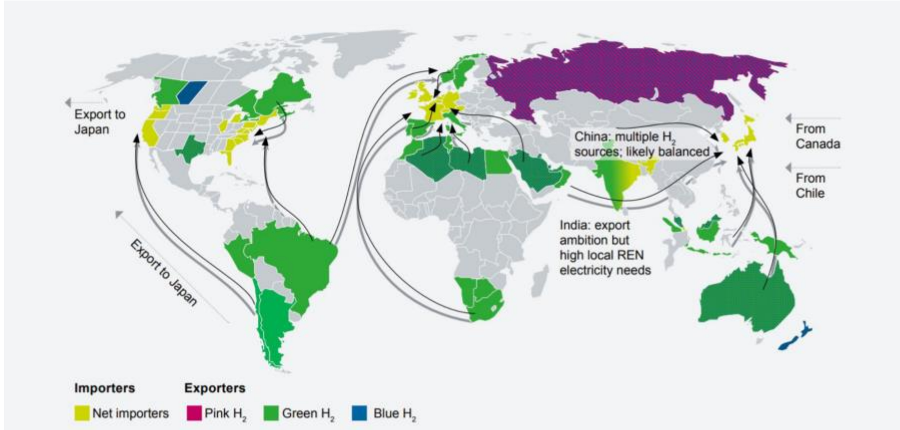

Figure 50. Hydrogen importers and exporters in 2030. Source: Hydrogen Exportation Markets (2023). World Hydrogen Leaders.

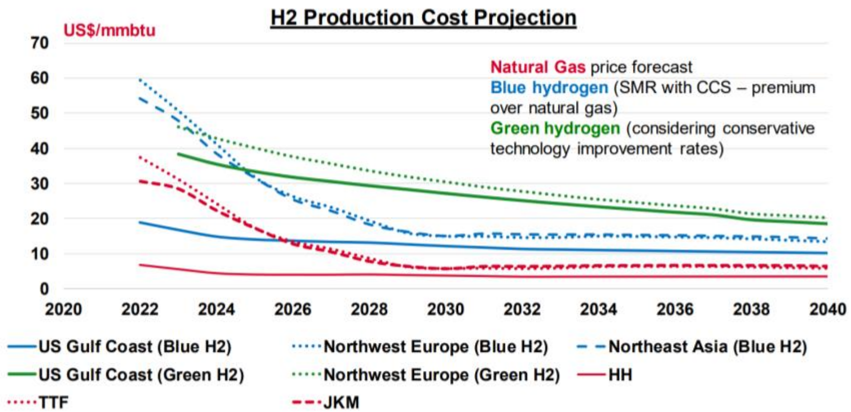

Figure 51. Predicted evolution of hydrogen production costs. Source: S&P Global

[27] More details on the function of these prices can be found in the following section 6.3.

[28] In energy content

To close this "gap" in the competitiveness of renewable hydrogen, institutional and regulatory support is essential through incentives to supply and demand. It can be materialized through different instruments, some of which have already been mentioned in previous sections:

- Progressive extension of carbon taxes (e.g., reduction of activities and volumes exempted in the ETS mechanism).
- Investment subsidies (e.g., PERTES).
- Compensation mechanisms on revenues or operating expenses (e.g., contracts for difference, **European Hydrogen Bank price auctions**).
- Tax credits (e.g., Inflation Reduction Act in the USA).

While these incentives are necessary conditions, they are not sufficient, as they require private initiative to mobilize the capital to facilitate the volume of investment envisaged for the hydrogen economy. One of the biggest uncertainties in investment relates to the cost of electrolysers which is affected by advances in technology, feedstock costs, scale economies, and the learning curve.

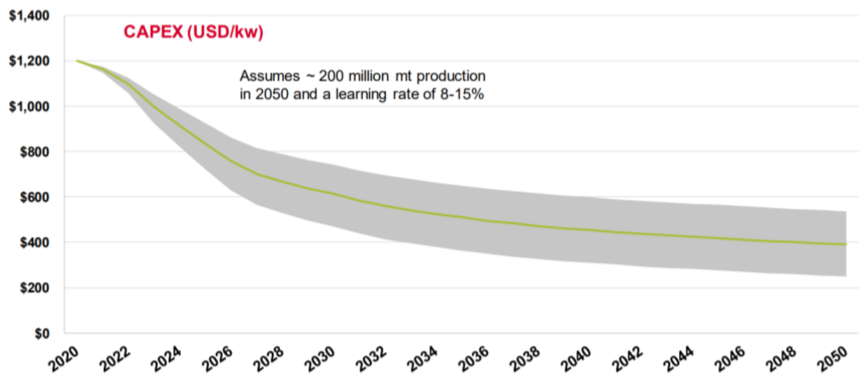

Figure 52. Expected cost evolution of investment in electrolysers. Source: S&P Global

The LNG market can be taken as a model for forecasting the future development of the hydrogen supply chain.

In order to interpret some keys for the present and future development of hydrogen projects, the Liquefied Natural Gas (LNG) business can be considered as a close precedent in time. It can offer valuable information for its evolution as a supply chain and for the instrumentation of its financing.

LNG origins are characterized precisely by being a supply chain with very capital-intensive investments that are also affected by technological changes and scale economies. This chain ranges from the exploration and development of gas reserves through the liquefaction process and transportation by ship to the destination countries where it is regasified for final consumption.

The investment and financing risks of the LNG chain were very similar to those now faced by hydrogen which require diversification and guarantee mechanisms such as those described below:

1- LNG investment is made with heterogeneous partners: those who provide the gas reserves, those who provide the technology, those who facilitate commercialization, etc. In the case of hydrogen, it could be those who provide renewable energy production, electrolyser technology, consumers, etc.

2- In LNG, long-term bilateral purchase and sale contracts are signed for more than 20 years with key clauses where cash flow is guaranteed:

- Gas purchase security: "take or pay".
- Safety in the liquefaction process: "process or pay".
- LNG sales security: "deliver or pay".
- Transportation security: "ship or pay".
- Destination fixation which prevents the buyer from reselling the LNG to a third party.

Similarly, hydrogen supply chain contracts could follow this warranty scheme.

3- For the determination of the price of LNG, a replacement value is established where the price is not based on the cost of production plus transportation, profit margin, etc., but it is linked to the price of certain competing fuels (e.g., on the price of oil to which premiums or discounts are applied). In the case of renewable hydrogen, there are also competitors such as natural gas, gray hydrogen, ammonia or methanol obtained from fossil fuels which have their own market characteristics and therefore transparent pricing. Pricing formulas for renewable hydrogen or its carriers could be articulated, incorporating differentials over these competing products.

4- The financing of the LNG chain is obtained thanks to the project guarantees mentioned above, limiting the recourse to its shareholders who contribute a percentage between 30%-40% of the total investment.

With similar diversification mechanisms and guarantees, hydrogen could be a natural candidate to successfully obtain financing structures. Similar to those of LNG at that time as the objectives and barriers to the development of renewable hydrogen projects are very alike to those faced by LNG.

Currently, LNG supply has reached all the characteristics of a developed market with multiple counterparties traded in organized chambers with regional character in the form of "hubs". This serves as a price reference at a global level and allows the adjustment of supply and demand in a transparent manner.

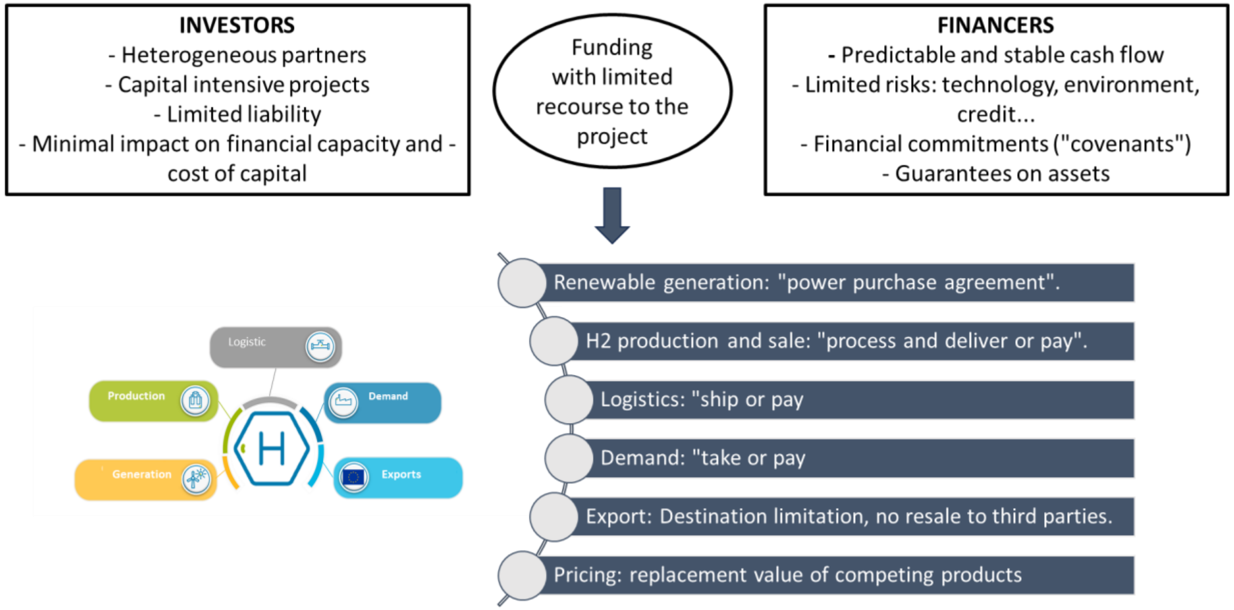

Figure 53. Financing of hydrogen projects. Source: own elaboration

6.3. Signals and price formation in the renewable hydrogen market

There are price signals for renewable hydrogen. However, they are closely linked to the electricity price and therefore to the reference gas price.

To make hydrogen a competitive vector, it is essential that economies of scale are achieved in its production processes. This will require the creation of a hydrogen market with appropriate price signals. Current hydrogen trading is opaque and lacks *price discovery* or quoted prices that reflect supply and demand conditions. Currently the most historic hydrogen price benchmark is provided by S&P Global.

The hydrogen price valuations provided by S&P Global Platts "Carbon Neutral hydrogen" (CNH) point to the use of information from market participants on completed transactions. There is no information on transactions in Europe in practice, and there is only very limited activity in the USA. In the absence of a spot market, assessments of the cost of hydrogen production are used where emissions have been: a) avoided using renewable energy in its production b) eliminated through the use of carbon capture and storage c) offset by the use of carbon credits. The analysis from the centre has been carried out for the type of hydrogen specified on point “a”. This *benchmark* is referred to by the same source as "*Carbon Neutral Hydrogen*" (CNH), and it is available in the database under its *ex-work* metric (excluding financing cost and transportation cost). These metrics exist for the following geographical areas: I) California, II) United States of America (USA) Gulf Coast with delivery in Texas or Louisiana, III) Northwest Europe reflecting the price for delivery in the Netherlands, IV) Middle East with CNH benchmark for Saudi Arabia, V) Far East Asia, with CNH delivery in Japan, and VI) Australia CNH benchmark in Western Australia.

The centre has focused on the behavior study of the renewable hydrogen series in Europe (Northwest benchmark), and in the United States (Gulf Coast benchmark) which are available daily since December of 2021. In this analysis, we compare these series with the gas benchmark trading contract (The Henry Hub future for US, and the Title Transfer Facility TTF future for Europe). Figure 54 and Figure 55 show the daily evolution of CNH and gas quotations for a period from December of 2021 to September of 2023. The CNH series are measured for Europe (EU) and the United States (US) in €/mmbt and $/mmbt while the gas series are quoted in €/MWh and $/mmbt respectively. Note that the gas and CNH series for US CNH looks more competitive, this is because the ex-work measure is being considered (cost or transaction estimates without taking into account future taxes and transportation or financing cost)[29]. Both graphs suggest that the gas and renewable hydrogen benchmarks are closely linked and reached peaks in August of 2022 at the time when the flow of Russian gas to Europe through the North Stream 1 channel was definitely cut off[30]. This is because one of the variable costs in hydrogen production is the cost of electricity which is strongly linked to the price of gas. Other influencing factors are the cost of the electrolyser and the hours of use, identified through CAPEX and OPEX respectively (see Lefranc et al. 2023)[31]. In August of 2022, gas supply constraints due to supply disruptions

[29] The ex-works measure includes the value of all materials used and other costs in the production process less taxes that will be paid when the product is sourced or imported. According to CNH analysts at S&P Global, the ex-works measure does not include construction work and the financing required for it. This is important as new hydrogen capacity is currently under construction and under feasibility studies.

[30] See details on Russia's disruptions of gas flows to Europe during the energy crisis, it can be found in BBC news "Nord Stream 1: Russia shuts major gas pipeline to Europe" September 1, 2022 (https://www.bbc.com/news/world-europe-62249015), "Nord Stream 1: How Russia is cutting gas supplies to Europe" September 22, 2022.

[31] To see the value-added composition of each component in the renewable hydrogen production value chain, the reader can see the report "Green hydrogen in Germany a

via the North Stream 1 pipeline led to price peaks in gas prices and the gas-CNH price differential narrows for both the USA and Europe with a further narrowing of the differential for the latter. Gas returned to competitive levels with respect to CNH from autumn of 2022 onwards. Other important increases took place during the month of July when North Stream gas flows were partially suspended. It is important to note that gas prices in Europe and the USA, as well as those of the electricity market futures represented by the electricity price futures on the German European Energy Exchange (EEX) and the electricity futures on the Chicago Mercantile Exchange (CME), began to rise in spring of 2021 when Gazpron announced that it would reduce gas flows to Europe[32].

Therefore, the price formation of renewable hydrogen has similarities with LNG: a replacement value is established which implies that the price is not based on the cost of production plus transportation, profit margin, etc., but it is linked to the price of certain competing fuels (e.g. LNG over the price of oil to which premiums or discounts were applied). Current quotations reflect both the replacement cost and the prevailing cost in the production process.

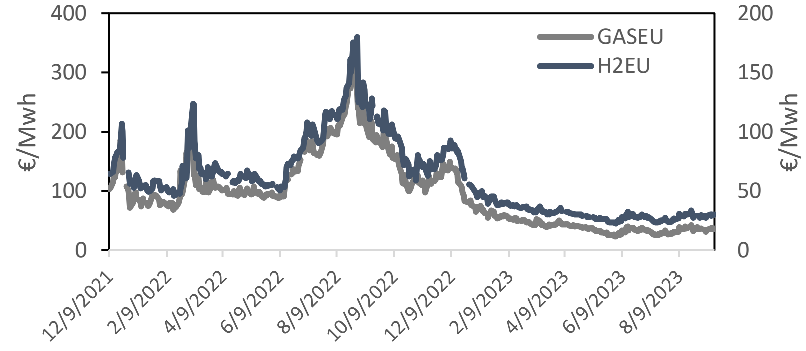

Figure 54. Evolution of the futures price (front Month) TTF (GASEU left axis) and the Low Carbon H2 S&P Global price assessment Ex Works Northwest Europe (H2EU right axis).

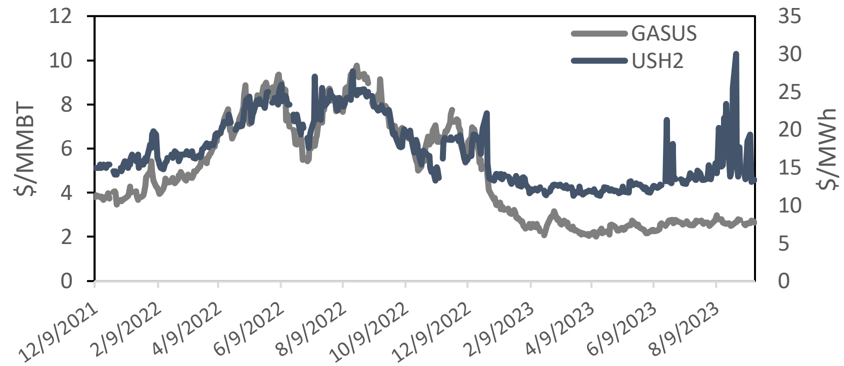

Figure 55. Evolution of the Henry Hub (GASUS left axis) and Low Carbon H2 S&P Global price assessment Ex Works US west Coast (H2US right axis) futures price (front Month).

long-term bet." October 2021 (accessible at: https://www.icex.es/content/dam/es/icex/documentos/el-exportador/mercado/alemania/PdfAlemania.pdf).

[32] According to the European Commission's quarterly report on gas markets (issue 2 Q2 2021) there was a significant increase in quoted gas prices from €10/MWh at the beginning of April to reach €35/MWh in June and €48/MWh in mid-August. The same report states that Gazprom reserved less capacity than expected, mainly for the Ukrainian and Yamal pipelines.

Although the rise in the price of fossil fuels such as gas seems beneficial in making renewable hydrogen more competitive, such an increase in fossil fuel prices contributes to a rise in inflation that may trigger future rate hikes. Given that hydrogen investment requires significant CAPEX, we believe that excessive fossil fuel price increases are not a desirable scenario.

CNH production in some regions of the USA is much more competitive than in Northern Europe.

Figure 56 shows the price of CNH (in USA and EU) is measured in €/kg to make comparisons of competitiveness in the two geographic areas. An analysis of the evolution of both benchmarks over time shows that CNH in the US is quoted at more competitive values than the European benchmark. This is mainly due to the existence of a more competitive gas price in the US than in the EU. It can also be inferred that the US Gulf Coast benefits from a high installed renewable power capacity with limited demand in all those months when there are no extreme temperatures caused by heat waves.

Another important point to note is that CNH assessments do not currently constitute a reference for the price of current transactions. They are largely determined by the production cost calculation according to the definitions established by S&P Global which are highly dependent on the cost of electricity (and therefore on the price of gas). Only in the case of the US, there are production cost estimates checked against spot market transaction prices.

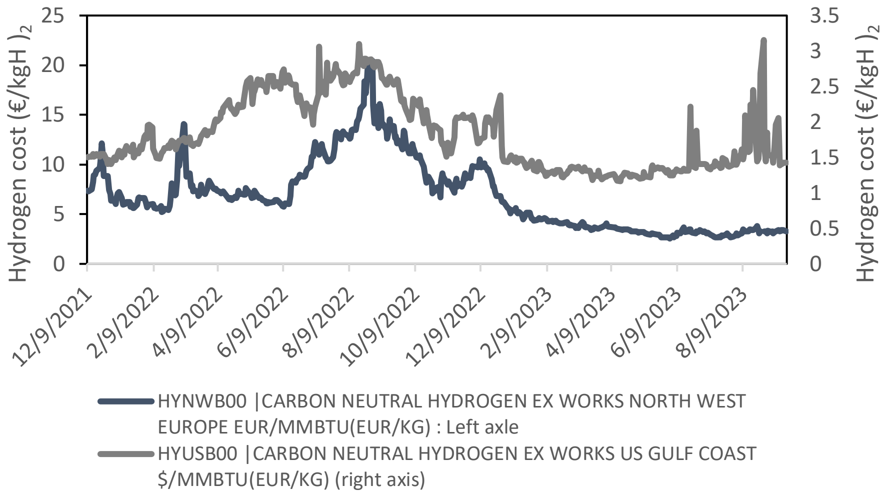

Figure 56. Evolution of low carbon hydrogen reference prices in Europe and the United States (€/kg).

The future evolution of renewable hydrogen prices is subject to a high degree of uncertainty. The "European Electricity Long term forecast" report published by S&P Global in September of 2021 indicates that in 2050 a renewable hydrogen price of €1.5/kg will be sufficient to incentivize its substitution by CCGT gas assuming an EUA price of €120/tCO2e[33]. As shown in Figure 56, in Europe, we are far from this target.

[33] This estimate requires significant assumptions about the price of electricity, storage, and transportation assumptions.

6.3.1. Valuation of future CNH PPAs

Preliminary PPA prices on CNH show Spain's competitive advantage over other European countries such as Germany and the Netherlands.

Regulatory developments reflected in the introduction of RED III and the delegated act have enabled the S&P Global rating agency to consider the valuation of renewable hydrogen PPAs based on country-level wind and solar power generation capacity based on S&P Global's own capacity data and Eurostat's wind and solar generation data. This allows the creation of a monthly wind versus solar capacity factor and its 5-year average. This ratio is applied to the calculation formula to obtain PPA prices at the country level. The table below shows the preliminary price evolution according to the S&P Global source. It can be seen that higher competitiveness is predicted for the benchmark Spanish PPP H_2 than for the German and Dutch analogues. This is largely due to the wide access to low-cost renewable sources in Spain. As the International Energy Agency points out, Spain is the European country with the greatest potential for renewable energies and already occupies a benchmark position in terms of installed capacity.

The Chair welcomes the new methodology developed by S&P Global to value H2 PPAs, considering that it is the most appropriate to promote the creation of the renewable hydrogen market.

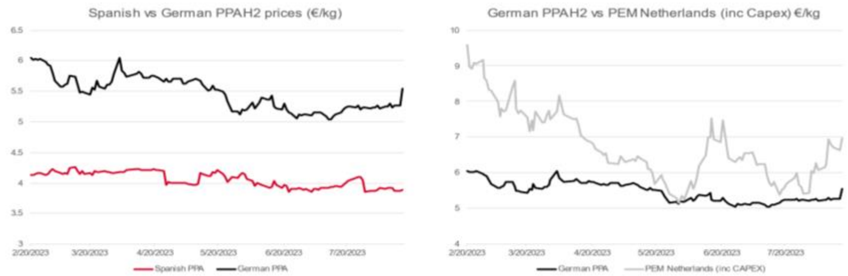

Figure 57. Preliminary PPA costs for renewable hydrogen production. Source: S&P Global

6.3.2. Creation of green hydrogen index

The hydrix renewable hydrogen index shows that the green fuel remains very uncompetitive with gas.

Last June, the European Energy Exchange announced the creation of the **Hydrix** index , the first hydrogen index in the market with the objective of representing information on traded prices of renewable hydrogen, reflecting supply and demand conditions. The objective of this index is to create a benchmark price that can be used for investment and financing decisions plus a subsequent optimal allocation of resources.

According to information provided by the EEX market, the Hydrix index data aggregates buyer and seller transaction information in the German market.[34] They are updated on a weekly basis and new quotes are published in euros per megawatt (€/MWh) on Wednesdays. All agents contributing to the formation of the quotation calculate a single bid and ask price representing the average price in accordance with the requirements of the *Underlying Data and Suitability* document published by the EEX market itself. This ensures that the price signals are clear. Currently the Hydrix value cannot be considered as a stock price or *Over the Counter*. However, it is expected that the value of this index will be a benchmark for bilateral trading. It is also unclear to what extent the index has been designed in line with the EU guideline established under the new RED III regulation and the delegated act.

According to Refinitiv's data, see Figure 58the index was quoted in September at 236.45 €/Mwh. This is equivalent to approximately €9.3/kg, indicating that prices are still far from the €1/kg target set for 2050. On the other hand, the average

[34] Source: https://www.eex-transparency.com/hydrogen

quotation of the Hydrix index since its introduction has been €233.8/Mwh while the average quotation of the reference natural gas in Europe (front month TTF) during the same period is €32.4/Mwh. Therefore, the benchmark renewable hydrogen in Germany is still quoted 7 times more expensive on average than its fossil fuel substitute. If we use weekly data for the period from May to September 2023 and calculate the volatility of the price changes of the two raw materials, we can say that the volatility in the gas market has been twice as high as the volatility in the renewable hydrogen market (98% versus 41%). However, this figure may simply indicate the low frequency of transactions in the renewable hydrogen market compared to the benchmark gas market in Europe.

Despite its incipient introduction, we believe that the hydrix renewable hydrogen index is an important resource for creating price signals to optimize renewable hydrogen-related investments through the following mechanisms:

- Introduction of direct signals and not indirect or derived from the price of the renewable hydrogen substitute such as natural gas.
- Unit of quotation in €/MWh, which allows a direct comparison of renewable hydrogen prices in €/MWh with gas and electricity prices.
- Price Transparency and Price Discovery with global visibility

These characteristics will facilitate the development of renewable hydrogen as a new commodity.

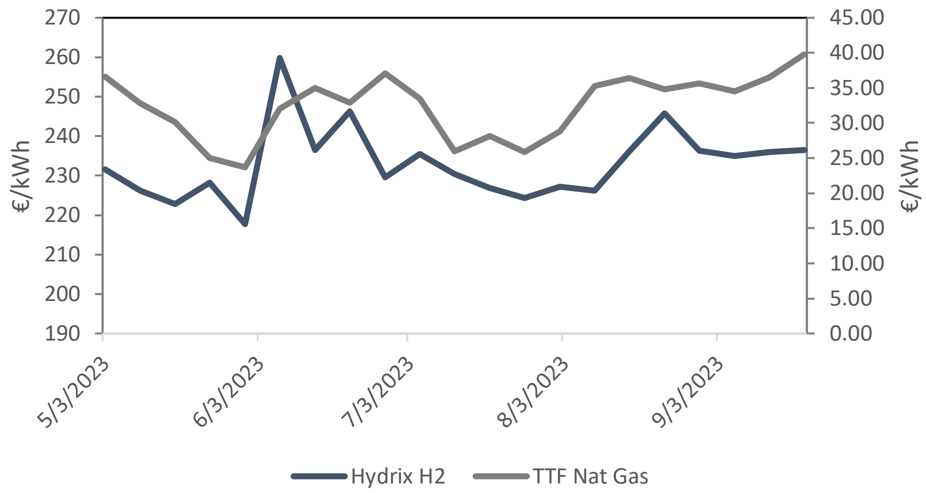

Figure 58. Evolution of the price of hydrix renewable hydrogen index (left axis) and future TTF gas (right axis) both in euros/Kwh.

6.3.3. European Hydrogen Auction

Another development that will facilitate the development of the hydrogen market and the market price disclosure process is the introduction of auctions in Europe. As mentioned above, on August 30, 2023, the European Commission published details on the operation of the first renewable hydrogen auction in Europe. The initiative will be financed by the Innovation Fund under the umbrella of the European Hydrogen Bank. The first pilot test is scheduled for November 23. The aim is to start with the official auction during the first quarter of 2024. The European Union has earmarked up to 800 million euros for renewable hydrogen producers and consumers under this program.

The aid will consist of guaranteeing a premium denominated in €/kg for hydrogen produced with ten years of operation, closing the gap between the cost of production and the price the consumer is able or willing to pay. According to the note published by the European Commission on August 30, the auction has the following objectives: [35]

i) Encourage the *price discovery* process in the renewable hydrogen market. Competitive auctions with simple and transparent operation provide information on the cost of production, creating a valid price signal for the start of market creation.

ii) They encourage efficient production and reduce the gap between renewable hydrogen and alternative fossil fuels in the EU as quickly and efficiently as possible through a combination of public subsidies that allow competition between different producers. The aim is to replicate the model that was designed for renewables, which was successful in increasing competitiveness and mobilizing capital.

iii) Reducing risk in the hydrogen market by encouraging investment. The objective is to stimulate the balance between hydrogen supply and demand by lowering the cost of capital and absorbing private capital. The Innovation Fund will therefore act as seed capital to stimulate increased private investment.

iv) Reduction of administrative costs thanks to the introduction of a Platform that centralizes and aggregates information and procedures.

The new auction mechanism will provide support for project development through public-private financing instruments. This is expected to increase the innovative technologies required for the transition in hard-to-abate sectors.

The Innovation Fund is one of the largest financing programs for the development of innovative net-zero technologies. It is a key part of the Green Industrial Plan funded by revenues from the trading of regulated carbon allowances under the *EU Emissions Trading Systems* (ETS). The Hydrogen Bank is being introduced in May 2023 to stimulate investment in renewable hydrogen. Its operation is organized on the basis of the following pillars:

- Coordination in the creation and development of domestic renewable hydrogen markets
- Promoting transparency in the design of investment and financing instruments
- Supporting infrastructure for renewable hydrogen imports

[35] See details at https://climate.ec.europa.eu/news-your-voice/news/upcoming-eu-hydrogen-bank-pilot-auction-european-commission-publishes-terms-conditions-2023-08-30_en

6.3.4. Market creation in Northern Europe through renewable hydrogen import agreements

The introduction of the h2Global platform has traded the first forward contracts in Germany, signaling the first signs of the creation of a forward market.

Agreements for future renewable hydrogen imports are also proliferating in Germany, where the first three-year contract is expected this fall under an initial €900 million in support of the creation of the first renewable hydrogen derivatives. Domestic auctions to import green hydrogen are set to begin activity in 2024 with deliveries projected in 2025. Procurement will be done through the H2Global platform, which has already been used for green ammonia trading. Through this platform, long-term contracts for green hydrogen or its derivatives will be purchased abroad and resold in Germany in annual auctions. Funds from the German Ministry of Economics will be used to make up the difference between the purchase price of hydrogen derivatives and the domestic selling price for some time.[36]

The Figure 59 shows the evolution of gas markets according to their maturity. If we assume that renewable hydrogen will follow a similar process, we can conclude that the creation of its market is in the second phase of the 6 possible phases.

The Dutch government also hopes to use the same platform to centralize the import of renewable hydrogen. Specifically, the government intends to issue €300 million for the first auctions. From Spain, the Ministry of Economy has supported the initiative to build a green hydrogen market on this newly created platform by some of the main German industrial groups such as Siemens Energy, Linde, Nordex or ThyssenKrupp. [37]

Other important developments in the field of renewable hydrogen market creation include the signing by the Netherlands of a *memorandum of understanding* with Saudi Arabia on energy security that lays the groundwork for the two nations to cooperate in the field of renewable hydrogen, transport technologies, certification and development of internal supply chains. The Netherlands is thus positioning itself as a hub for imports from Saudi Arabia. [38]

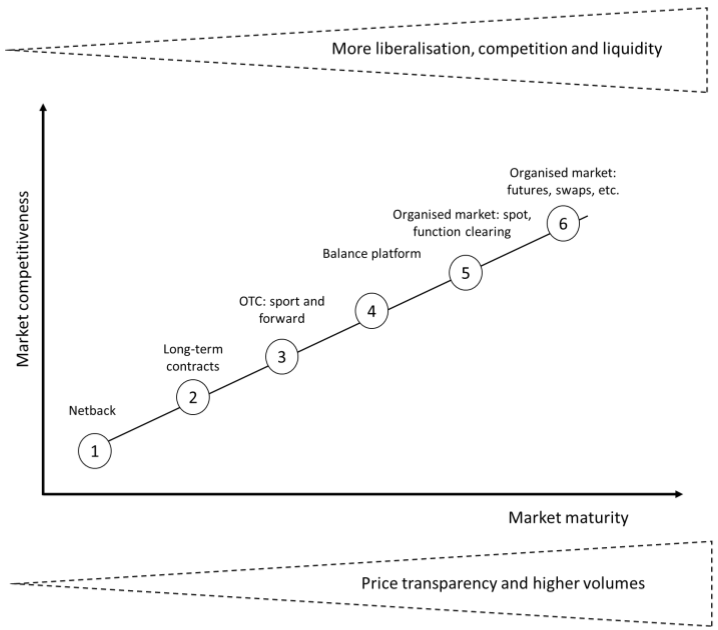

Figure 59. Temporal evolution of gas markets according to their maturity. Source: MIBGAS presentation, Energy crisis and the proposal of renewable hydrogen as a new commodity.

[36] See details at: https://www.icex.es/es/quienes-somos/donde-estamos/red-exterior-de-comercio/de/documentos-y-estadisticas/estudios-e-informes/hidrogeno-verde-en-alemania--una-apuesta-a-largo-plazo.html

[37] See details at https://www.icex.es/es/quienes-somos/donde-estamos/red-exterior-de-comercio/de/documentos-y-estadisticas/estudios-e-informes/hidrogeno-verde-en-alemania--una-apuesta-a-largo-plazo.html

[38] Source: Hydrogen Market Monitor, S&PGlobal, 30th June, 2023

6.3.5. H2 trading platforms

As noted above, trading platforms are essential to facilitate the evolution of the hydrogen chain towards a developed market. In the case of hydrogen, they would help create a transparent market, with standardized quality assurance and certification processes that will promote confidence in its procurement.

Similar to the functioning of other existing European hubs for the gas market, where operator neutrality is guaranteed (as in the case of the TTF in the Netherlands, the NBP in the UK or MIBGAS in the Iberian Peninsula), the creation of hubs for renewable hydrogen would facilitate transparency and price discovery to match supply and demand.

In particular, the implementation of a renewable hydrogen hub on the Iberian Peninsula would be a significant milestone in the creation of the hydrogen market for the European Union, as its production potential far exceeds national demand. This would allow regional price signals to be transferred to southern Europe and serve as a reference for the European market as a whole.

7. TRANSITION’S GEOPOLITICAL DIMENSION

7. THE GEOPOLITICAL DIMENSION OF THE TRANSITION

7.1. Critical materials

The transition towards a more decarbonized economy, in which hydrogen will play a relevant role, will also entail significant changes in commercial and geopolitical relations for acquiring the resources essential for its development. Concern for security of supply and the search for energy self-sufficiency will change the relationship between energy importing and exporting countries, adding greater competition for the so-called critical materials needed to drive these new technologies.

Globally, we foresee an increasing dependence on new critical materials both in their production and in their transformation process. Renewable energy technologies, and their associated equipment and infrastructure, demand a large amount of minerals such as copper, lithium, cobalt, nickel, graphite and rare earths. According to the International Energy Agency, over the next two decades, the demand for these critical minerals for these technologies will increase four to six times, which will generate significant competition for their acquisition [19].

As can be seen in **Error! Reference source not found.** As can be seen in Figure 60, the extraction of lithium, cobalt and nickel is significantly concentrated. This may complicate the dependence on countries that control most of the mines, such as Chile in the case of copper, Australia with lithium, the Democratic Republic of Congo with cobalt and Indonesia with nickel; however, there is no single country that dominates the reserves and production of the different critical materials.

This increased demand for critical materials, on the other hand, will come up against the fact that their processing and refining is highly concentrated in certain countries, mainly China, which will generate a new map of geopolitical interdependencies.

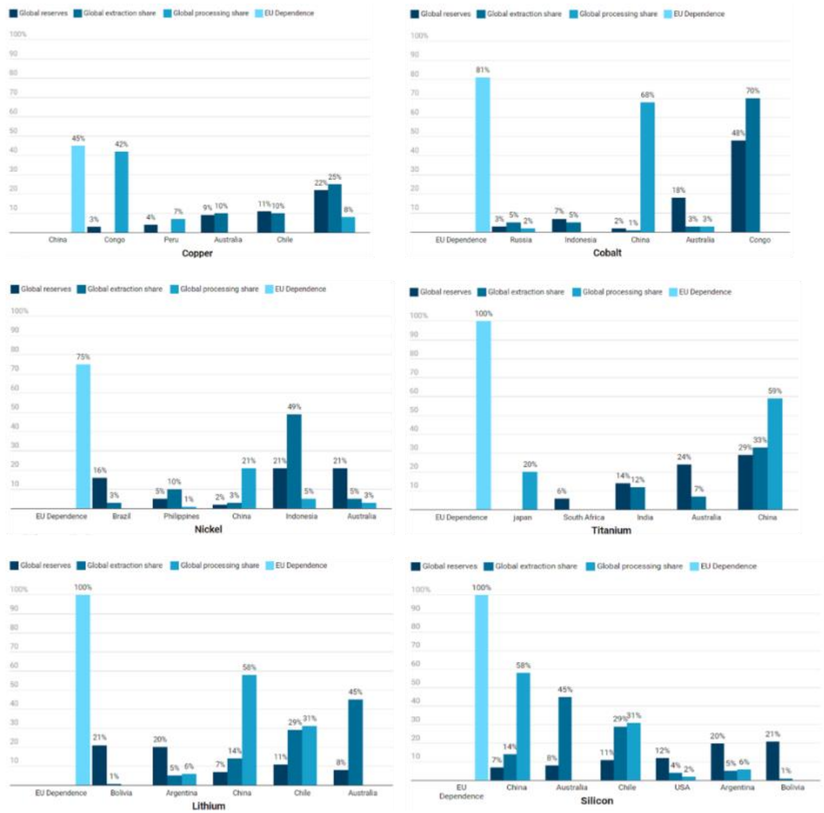

Figure 60. Major suppliers of critical materials needed for the energy transition and EU import dependence. Source:

The above shows how the energy transition will involve the entry of new players and generate new patterns in international energy trade. In Figure 61 Figure 61 Figure 17shows the change in dependence on fossil energy commodities (oil and gas) versus renewable hydrogen. Unlike what happens with gas and oil, Europe plays an important role in the midstream stage (manufacturing of electrolysers), having the largest manufacturing capacity; however, China is the leader in their export since they are also much cheaper than the European ones. According to the

BloombergNEF report, China can produce standard alkaline electrolysers for USD 300 / kW, 75% cheaper than Western ones of the same type [39] .

According to IRENA, to counter this trend, many Western companies are devoting resources to research and development of more advanced technologies.

7.2. Creation of the hydrogen economy

The hydrogen economy is in its early stages. The analysis of the current state in section 1 demonstrates how, as of today, sustainable hydrogen markets are an aspiration rather than a reality, and the discourse is dominating for their possible operation under the assumption that all elements of the future hydrogen economy, such as access to critical materials for the production of electrolysers, will be available. However, this discourse on the hydrogen economy and its implications already allows identifying certain trends at the global level with

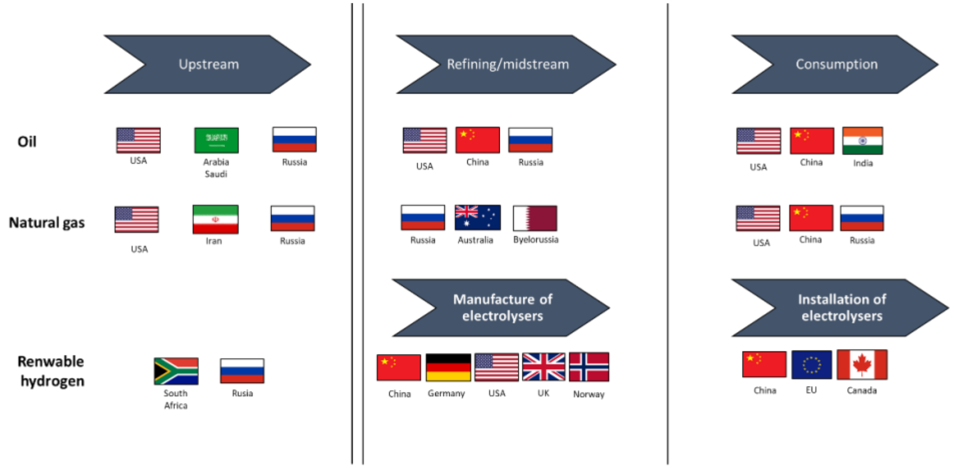

Figure 61. Oil, gas and renewable hydrogen supply chains. Source: IRENA (2022), Geopolitics of the Energy Transformation: The Hydrogen Factor.

possible relevant consequences for the commercial and political relationship between different regions, countries and continents.

The following is a summary of the analysis conducted by members of the Chair in various studies, articles and reports[40] highlighting short, medium and long-term geopolitical trends.

Short term: plans and proposals for a hydrogen economy

The European Union recognizes the need to import hydrogen in the future, signing the first partnership agreements with countries outside the EU.

[39] BloombergNEF (2021), 2H 2021 Hydrogen Market Outlook: China Drives a Gigawatt, Bloomberg New Energy Finance, London.

[40] T. Gerres, R. Cossent. Is the European Union's green hydrogen strategy in Africa coherent with sustainable development? Funded by the European Parliament. Oct/2023. // T. Gerres, R. Cossent. The complex reality behind the simplest element. Foreign Policy. Vol. XXXVII, no. 213, pp. 106 - 114, June 2023. // S. Serna, T. Gerres, R. Cossent. National hydrogen strategies: common design elements and lessons learned. Papeles de Economia Española. No. 174, pp. 52 - 71, December 2022.

Many national governments are currently taking a stand on the transition to a hydrogen economy. The role of the new energy carrier and its contribution to meet the commitments of the Paris climate summit and limit global warming to 1.5-2 °C is studied. In addition, the potential national benefits of producing, commercializing and consuming renewable hydrogen are assessed. For the most part, national governments present strategies to support research and technology development, measures to encourage hydrogen production and consumption at the national level, and a vision for the long-term role of hydrogen.

In the case of the European Union, a major objective of these strategies is to position the European industry as a technology supplier.[41] Given the predominant role of China in the entire manufacturing process of photovoltaic modules and batteries, from raw materials to the final product, the aim is to establish a prominent EU presence in the local production of electrolysers and to ensure access to key resources. A similar positioning can be observed in the United States with the "Made in America" strategy that is clearly reflected in the hydrogen support systems under the "Inflation Reduction Act" (IRA), which implies a certain confrontation between the large blocks of industrialized countries in Asia, Europe and the Americas.

At the same time, the European Union recognizes that the renewable resources available in its territory will not be sufficient to produce the total amount of green hydrogen required to meet projected demand in member countries. The RePowerEU plan foresees imports of 10 Mt of hydrogen per year in 2030, corresponding to 50% of the expected demand. The EU has therefore begun to position itself with an external energy policy that encourages the production of renewable hydrogen in countries such as Namibia and Egypt for export to Europe through partnership agreements.[42]

Many emerging and developing countries offer excellent conditions for photovoltaic and wind power installations that would allow hydrogen to be produced more economically than in Europe, Japan, China, South Korea and some parts of the United States. Aware of this, the governments of countries such as Chile, Colombia, South Africa, Namibia, Morocco, Egypt and the Gulf States are positioning themselves as exporters of renewable hydrogen. Some countries are making great efforts to accelerate the development of an export economy and are supporting pioneering hydrogen production projects with their own sovereign wealth funds, for example in Namibia and Egypt.

At first glance, the recent partnerships between the European Union and the countries of the South, with the aim of cooperating and establishing close relations, look like "peer-to-peer" collaborations. In these collaborations, potential exporting countries work with EU member countries, which anticipate the need for imports to meet their demand for hydrogen and to establish themselves as technology suppliers.

Medium term: the role of European public support in the global context

Accelerated investments in hydrogen production by exporting countries are not without risks, and only a strong commitment including shared legal and financial responsibilities on the part of the EU can help reduce these risks in the long term.

Many characteristics of the future hydrogen economy will be decided by how and when hydrogen production, transportation and demand develop. Historically, energy generation and demand, as well as natural resource exploitation and processing, were established on the basis of geographic proximity. Long-distance logistics are established whenever reduced transportation costs eliminate the benefits of geographic proximity between production and consumption. The hydrogen economy will develop under strong public support to make its

[41] See RePowerEU (COM(2022)230) of May 18, 2022.

[42] "EU-Namibia strategic partnership agreement MoU" signed in Sharm El-Sheikh on November 8, 2022 // "EU-Egypt strategic partnership agreement on renewable hydrogen MoU" signed in Sharm El-Sheikh on November 16, 2022.

production and consumption competitive with the use of conventional hydrocarbons over the next decade. Therefore, the role of public support in reducing transportation costs is key to the establishment of global supply chains in the medium term.

To realize the 10 Mt of hydrogen imported into the EU by 2030, incentives are required to reduce the cost and financial risk of transporting hydrogen and its derivatives, mostly by ship, from exporting countries to Europe. In addition, investments are required in the infrastructure needed to link the ports of entry with the major centers of industrial consumption.

The success of future supply chains between hydrogen exporting countries and Member States depends very much on the willingness and ability of the EU and national governments to reduce these logistical barriers and to commit economically to imports (e.g. through long-term contracts), in particular because other import markets are likely to exist in the medium term. [43]

Otherwise, exporting countries may find themselves in a situation where they will have to subsidize the export of renewable hydrogen for lack of domestic demand in their own low energy-intensive economies. Moreover, this may not be sufficient if there is a lack of economically viable options for supplying hydrogen from ports of entry to inland consumption centers.

At the same time, exporting countries face great uncertainty regarding European legislation, to be more precise, the rules and standards defining the functioning of the common market for hydrogen and the sustainability criteria. As a consequence, in the medium term, exporting countries that invest in novel facilities with the aim of exporting hydrogen to Europe are implicitly betting on the ability of the EU and member states to establish an environment that is favorable for hydrogen imports and meeting the REPowerEU plan targets of 10 Mt of imported hydrogen in 2030.

Only a strong commitment with shared legal and financial responsibilities on the part of the EU can mitigate the risks for exporting countries in the medium term.

Long term: three axes of global trade

In its report on the geopolitics of hydrogen in the energy transition published in 2022[44] the international renewable energy agency (IRENA) characterized the future hydrogen market by its high degree of competition between a multitude of exporting and importing countries. In relation to transport, IRENA differentiates mainly between the mode of transport, by ship and pipeline, and the transported good, (hydrogen, hydrogen derivatives such as ammonia or synthetic fuels). Based on this classification, they differentiate between three possible axes of global hydrogen market development, each with the potential to dominate future global hydrogen trade in the long term:

A global hydrogen trade is mainly characterized by the purchasing capacity of regions with a deficit of local production and multiple available suppliers.

Global trade is based on liquefied hydrogen or through carriers (such as ammonia): this scenario implies that the cost of transporting by ship and retrofitting hydrogen carriers is reduced in such a way that it can be competitive with local production or pipeline imports. Hydrogen markets would resemble current natural gas markets, but with much less market power for producing and exporting countries. At present, few players control the most relevant natural gas reserves, and large market power translates into geopolitical power. In the case of hydrogen, the barriers to entry in a future global market are more limited

[43] The Japanese government's new hydrogen strategy published in June 2023 envisages a rise in hydrogen imports and harmony from 2 Mt (conventional harmony) to 3 Mt in 2030, while other potential importing countries such as China and South Korea did not specify medium-term targets.

[44] IRENA, 2022. Geopolitics of the Energy Transformation: The Hydrogen Factor.

because many regions in Latin America, Africa, the Middle East and Australia offer excellent conditions for producing renewable hydrogen at low cost.

Interregional markets would result in greater energy autonomy for the European Union.

A global hydrogen trade with low transport costs can be further characterized by the purchasing power of regions with a local production deficit vis-à-vis many suppliers.

Interregional markets connected by pipeline could dominate the hydrogen trade if ship transport and conversion of hydrogen carriers proves more costly than expected. It should be kept in mind that neither the port infrastructure nor commercial ships exist for hydrogen transport today and, because of the low volumetric density of hydrogen, transporting it by ship would be much more expensive than, for example, liquefied natural gas. In contrast, pipeline transportation has a high technological maturity and the capacity of converted pipelines corresponds to 80% of the energy capacity of natural gas transportation.[45] In Europe, these interregional markets would connect the major consumption centers in Central Europe with Scandinavia, the Iberian Peninsula and neighboring regions such as Ukraine or North Africa with surplus renewable energy. According to studies for the German government, almost all of the country's hydrogen demand in 2050 could be met by imports from Scandinavia and the Iberian Peninsula, leaving a marginal role for imports via the sea route.[46] In the case of Europe, hydrogen supply by hydrogen products could result in shifting power balances by creating new dependencies between producing and consuming countries.

Interregional markets would result in greater energy autonomy for the European Union.

While pipeline-connected interregional markets seem feasible in the European context, they do not present themselves as realistic alternatives for countries such as Japan and South Korea. Their insular nature and lack of neighboring exporting countries means that they should maximize hydrogen production domestically, for example, by means of pink hydrogen from nuclear power plants, and beware of import costs that are much higher than in other regions with high degrees of industrialization.

In a scenario dominated by markets for hydrogen-fueled goods, Spain can benefit from its low production costs compared to other European regions and offer high supply chain security to European customers compared to global competitors.

Global markets for hydrogen **goods** may emerge due to the high transportation costs of both hydrogen and hydrogen carriers**.** Energy-intensive industries that use hydrogen as a feedstock or energy source will be a key consumer in the future. Their products have in common that they are commodities that are much easier to transport in ships than hydrogen and its carriers. Because of this, and given the high costs of transporting hydrogen by ship and the limitations of pipeline transport, the hydrogen economy could evolve around global markets for related products and goods. These include reduced iron (DRI), a by-product of steel production that can be manufactured using hydrogen instead of fossil coal, ammonia, used in fertilizer production and as a fuel, and other hydrocarbons and basic hydrogen-derived chemicals. Hydrogen exporting countries could benefit from this situation thanks to the increased value-added contribution and diversification of their revenues. In the case of iron, countries with significant mineral deposits and privileged access to renewable energy resources such as Australia, Sweden, Brazil, Peru, South Africa or Mauritania could be transformed from mineral exporters to DRI exporters. The implications of this axis of global

[45] ACER, 2021. Transporting Pure Hydrogen by Repurposing Existing Gas Infrastructure: Overview of existing studies and reflections on the conditions for repurposing.

[46] See the T45 (2045) scenarios of the Frauhofer ISI for the German Federal Ministry of Economics and Climate Protection: www.langfristszenarien.de

hydrogen trade are industrial relocation and partial deindustrialization of certain European regions with few natural resources to produce hydrogen in situ.

In a scenario dominated by markets for hydrogen-fueled goods, Spain can benefit from its low production costs compared to other European regions and offer high supply chain security to European customers compared to global competitors.

As of today, it is not known which will be the dominant axis of the future global hydrogen market, and the coexistence and competition of different options for connecting demand and consumption is likely. All three axes offer great opportunities for producing and exporting countries to enhance their economic and geopolitical influence, and to position themselves as a powerful counterpart to more developed economies. However, if these exporting countries were to bet on a single axis of the future hydrogen market through the accelerated formation of an export-driven industry, this would also carry great risks of failure and geopolitical dependence on the consuming and financing countries.

The good news for consuming countries is the wide variety of possible import routes that would allow them to secure their supply with energy and renewable materials.

At the same time, high long-distance transportation costs may result in macroeconomic trends that accelerate the decline of the energy-intensive industry and increase its dependence on imported raw and processed materials.

The good news for consuming countries is the wide variety of possible import routes that would allow them to secure their supply with energy and renewable materials.

8. METHODOLOGICAL NOTES

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8.1. Electrolyser operating modes: production costs

Table 1. Electrolyzer parameters, and renewable generation plants for the calculation of hydrogen production costs.

Parameter	Value	Source
Life time (years)	20	Own criteria
Efficiency (kWh/kgH2)	52	[20]
CAPEX electrolyser (€/kW)	1000	[20]
Electrolyser maintenance costs (%/CAPEX)	4 %	[21]
CAPEX PV (€/kW/year)	667	[21]
PV maintenance costs	10	[21]
Wind CAPEX (€/kW/year)	995	[21]
Wind energy maintenance costs	31	[21]
Interest rate (WACC)	10 %	Own criteria

8.2. Methodology for calculating the emissions intensity of electricity generation.

To calculate the emissions associated with electricity generation in Spain, data were taken from the generation measured in combined cycle, cogeneration with natural gas and coal plants from 01/01/2022 to 12/31/2022 in the peninsular territory[47] . These three technologies accounted for more than 95% of the emissions associated with generation this year (see Figure 62). Figure 62).

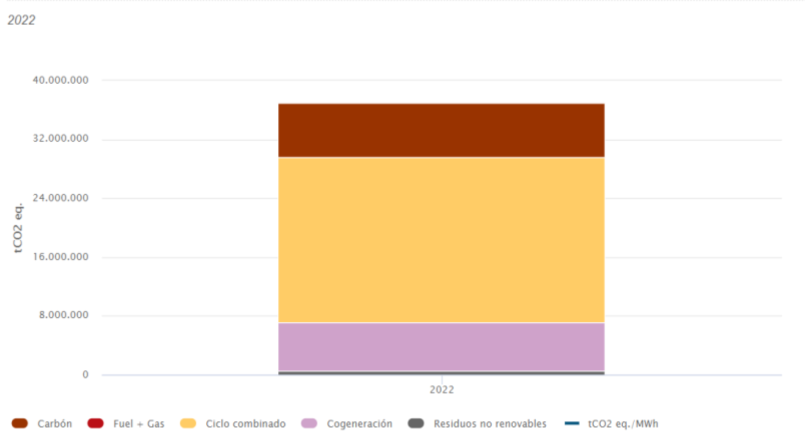

Figure 62. CO emissions$_2$ -eq from electricity generation in the Iberian Peninsula in 2022. Source: ESIOS

The emission factors for these technologies can be found in the report published by Red Eléctrica [22], and are summarized in the following table. Table 2.

[47] Obtained using the public data website e-sios belonging to Red Eléctrica. Total metered generation data with breakdown by technology (link).

Table 2. CO2-eq emissions associated with different technologies in electricity generation in the peninsular system.

	CO Emissions$_2$ -eq (tCo$_2$ -eq/MWh)
Combined cycle thermal power plant (natural gas)	0,37
Cogeneration	0,38
Coal-fired power plant	0,95

Using the information on power generation and its level of emissions, it is possible to calculate the amount of carbon dioxide equivalent (CO2-eq) emitted by each technology during each time period, which is measured in 1-hour intervals. By dividing this figure by the total amount of electricity generated in that same period[48] , it is possible to determine the emissions intensity of electricity generation, expressed in terms of tCO2-eq/MWh.

8.3. Prospects on the operation: economies of scale

Table 3. Electrolyser parameters for the calculation of hydrogen production costs considering only investment costs.

Parameter	Value	Source
Length of life (years)	20	Own criteria
Hours of operation per year	4200	Own criteria
CAPEX PEM electrolyser (€/kW)	6046*Power(kW$)^{-0.2}$	[20]
CAPEX electrolyser Alc (€/kW)	4841*Power(kW)$^{-0.198}$	[20]
Electrolyser maintenance costs (%/CAPEX)	4 %	[21]
Interest rate (WACC)	10 %	Own criteria

[48] Obtained using the public data website e-sios belonging to Red Eléctrica. Total metered generation data with breakdown by technology (link).

8.4. Hydrogen transport and distribution by tube trailer

Premises for calculating the cost of transporting compressed hydrogen by tube trailer can be found in Table 4. Table 4.

Table 4. Parameters for the calculation of tube-trailer compressed hydrogen transport costs. Source: [23]

Parameter	Value	
Average speed	50	km/h
Charging time	1,5	N/A
Discharge time	1,5	N/A
Hydrogen transport capacity (kg)	670	kg H2
Fuel consumption (diesel) (L/km)	0,39	L Diesel/km
Diesel cost (€/L)	1,1	€/L
Labor costs	23	20 €/h
CAPEX trailer	650000	€
CAPEX for cryo triler	1000000	€
CAPEX tractor tractor unit	100000	€
Maintenance costs	0,047	€/km
Lifetime of tractor unit	5	years
Lifetime trailer	20	years

The extended calculation methodology can be found in [23].

Compression costs

$$P^C = \frac{RT_{in}}{2(\gamma-1)\eta_c}\left(\left(\frac{P_{out}}{P_{in}}\right)^{\frac{\gamma-1}{\gamma}} - 1\right)\dot{m}_t$$

Equation 1

The compressor is modeled as an adiabatic compressor where:

- P^C is the compressor power (kw)
- R is the universal ideal gas constant (8.314 J/mol k)
- T_{in} is the inlet temperature of hydrogen (298 k).
- γ is the diatomic constant (1.4 for hydrogen)
- P_{out} y P_{in} are the compressor inlet and outlet pressure (bar).
- η_c is the mechanical efficiency of the compressor (0.7)
- $\dot{m}_t$ is the mass flow rate (kg/s).

The cost of the compressor is given by:

$$CAPEX_{compresion}(€) = 2\ 417 * P(kW)$$

While operating costs are given by:

$$OPEX_{compresion} = \frac{0{,}85 * 8760 * Precio\_el(\frac{€}{MWh})}{Eff\ térmica} * P(€)$$

With an electricity cost of 50 €/MWh in 2010 and a thermal efficiency of 90%.

8.5. Case study: transporting hydrogen over long distances

The hydrogen production costs were calculated based on the parameters in Table 5. Table 5 and transportation costs were calculated based on

Figure 27.

Table 5. Electrolyser parameters, and renewable generation plants for the calculation of hydrogen production costs for 2030 and 2050.

Parameter	2030	SOURCE	2050	SOURCE
Life time (years)	20	independent judgment	30	independent judgment
EFFICIENCY (kwh/kgh2)	52	[20]	45	[20]
Capex electrolyser (€/kw)	1000	[20]	200	[20]
Electrolyser maintenance costs (%/capex)	4 %	[21]	4 %	[20]
Capex pv (€/kw/year)	667	[21]	473	[26]
Maintenance costs pv	15	[27]	10	[26]
Wind Capex (€/kw/year)	995	[28]	803	[28]
Wind energy maintenance costs	31	[27]	15	[28]
Interest rate (wacc)	10 %	independent judgment	10 %	independent judgment

For the calculation of emissions associated with transport by ship, the transport of ammonia using three different fuels was considered: Heavy Fuel Oil (HFO), Marine Gas Oil (MGO) and liquefied natural gas (LNG). The parameters used for the calculation as well as the sources are shown in Table 6. Table 6 and the emission factors for each fuel in Table 7. Table 7 .

Table 6. Parameters for the calculation of emissions associated with the transport of ammonia by ship.

		Source
Transport capacity (t NH3)	53 000	[6]
Fuel use (MJ/km)	1487	[6]
Speed (km/h)	30	[6]
Recovery rate in reconversion (%)	99	[6]
Recovery rate in purification (%)	85	[6]
Combustion engine efficiency (%)	40	[7]
LNG engine efficiency (%)	42	[7]

Table 7. Hull-to-wake combustion emission factors by fuel (g/MJ fuel).

	HFO (gCO2/MJ)	Source
HFO (Heavy Fuel Oil)	81.1	[7]
MGO (Marine gas oil)	76.7	[7]
LNG	58.4	[7]

8.6. Calculation of hydrogen refueling station costs

According to [24] a HRS can be divided into several modules: compressor, low-pressure storage, high-pressure storage, dispenser and refrigeration unit (see Figure 50).

- **Storage tanks:** There are several configurations, although the simplest is to use a low-pressure tank and a high pressure tank. The low-pressure tank is used as a hydrogen supply to ensure a constant flow of inlet gas to the compressor. The high-pressure storage, on the other hand, ensures the supply of hydrogen at times of high demand.

- **Compressor:** This module is essential for increasing the hydrogen pressure from the low pressure storage to the high pressure storage required for the filling process.

- **Dispenser:** Through the dispenser, vehicles or equipment that use hydrogen as fuel can be refueled. It works similarly to a gasoline pump at a gas station.

- **Cooling unit:** Since hydrogen expands rapidly when heated, it is essential to keep it at low temperatures, especially during the refueling process. The refrigeration unit is used to ensure that the hydrogen is kept at a constant and safe temperature to avoid any risk.

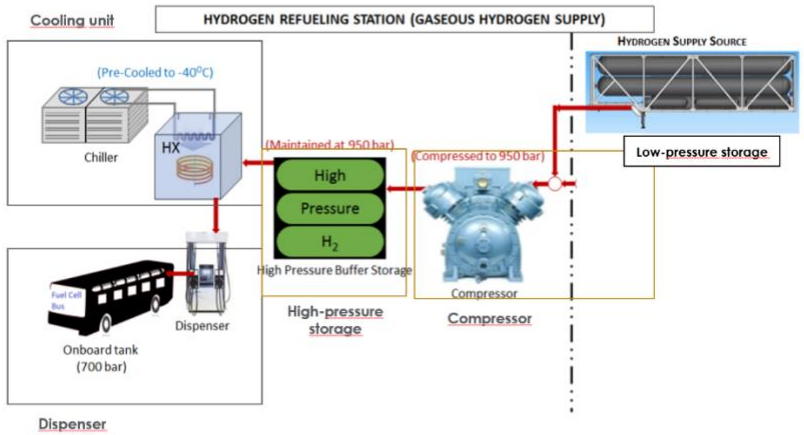

Figure 63. Representation of a typical hydrogen plant. Source: [24]

The **investment costs** correspond to the costs of each of the station's components, which are shown in Table 8. Table 8.

Table 8. Investment costs of the components of a hydrogen plant.

	CAPEX	Units
Refrigeration unit	140000	€/hose
Compressor	$40035*P^{0.6038}$	€
High pressure storage	1800	€/kgH2
Low pressure storage	1050	€/Kg H2
Dispenser cost	100000	€

*Assumes a life time of 20 years for all components.

Station **operating costs** are derived from compression costs (which can be calculated on the basis of compressor power (Equation 1) assuming an electrical efficiency of 0.8 and an electricity cost of €50/MWh. On the other hand, cooling costs can be assumed to be 0.18 kWh/kgH2 [25].

8.7. Case study HRS plants: centralized vs. on-site production

The final cost of hydrogen is given by the costs of production, transportation and the cost of the hydrogen plant itself. The methodology used to calculate each of these costs is explained below.

- **Production costs**

Parameter	Value	Source
Length of life (years)	20	Own criteria
Hours of operation per year	4200	Own criteria
CAPEX Alkaline electrolyser (€/kW)	$4841*Power(kW)^{-0.198}$	[20]
Electrolyser maintenance costs (%/CAPEX)	4 %	[21]
Interest rate (WACC)	10 %	Own criteria
Cost of electricity (€/MWh)	50	Own criteria

- **Transportation costs**

For on-site production there are no transport costs and for the centralized case transport costs of €1/kgH2 are assumed on the basis of the Figure 26calculated on the basis of the methodology described in section 8.4.

- **Hydrogen costs**

The values of the Figure 31 calculated using the methodology described in section 8.6, assuming a utilization rate of 100%.

8.8. Expected demand for hydrogen in mobility

According to, the annual distance and market share of the different types of trucks can be found in Table 9. Table 9 [18].

Table 9. Annual distance traveled and market share of the different categories of heavy vehicles in Europe.

Category	Annual distance traveled (miles)	European market share
0	40000	10.30%
1	62000	0.40%
2	62000	1.80%
3	62000	1.50%
4-UD	60000	0.04%
4-RD	78000	4.20%
4-LH	98000	3.00%
5-RD	78000	0.50%
5-LH	116000	60.90%
9-RD	73000	4.10%
9-LH	108000	10.00%
10-RD	68000	0.01%
10-LH	107000	3.00%
11	75000	0.09%
12	105000	0.06%
16	60000	0.20%

The number of kilometers per year, considering the share of the different types of trucks, is 100,948 km/year, or 388.26 km/day.

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