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ANNUAL REPORT

CHAIR OF HYDROGEN STUDIES

Renewable hydrogen: *quo vadis?*

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CÁTEDRA DE ESTUDIOS SOBRE EL HIDRÓGENO

COMILLAS ICAI

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CONTENTS

ACRONYMS

AFIR	Alternative Fuel Infrastructure Regulation
ATJ	Alcohol to Jet
CBAM	Carbon Border Adjustment Mechanism
CE	European Comission
DRI	Direct Reduced Iron
EASA	Agency Wastewater Treatment Works
EDAR	Emission Trading Scheme *In spanish: Estación Depuradora de Aguas Residuales*
ETS	Emission Trading Scheme
FCEV	Fuel Cell Electric Vehicle
FFB	Fresh Fruit Bunch
FORSU	Organic Fraction of Municipal Solid Waste *In spanish: Fracción Orgánica de los Residuos Sólidos Urbanos*
FT	Fischer Tropsch
GNL	Liquefied Natural Gas *In spanish: Gas Natural Licuado*
HEFA	Renewable Aviation Diesel (Hydrotreated Esters and Fatty Acids) *In spanish: Diésel renovable para aviación*
HVO	Hydrotreated Vegetable Oil *In spanish: Hidrobiodiésel*

ACRONYMS

ICAO	International Commercial Aviation Organization
IPCEI	Important Proyect of Common European Interest
PERTE ERHA	Strategic Plan for Economic Recovery and Transformation *In spanish: Plan Estratégico para la Recuperación y Transformación Económica*
PNIEC	National Integrated Energy and Climate Plan *In spanish: Plan Nacional Integrado de Energía y Clima*
POME	Palm Oil Mill Effluent
PtL	Power to Liquid
RED	Renewable Energy Directive
RFNBO	Renewable Fuel of Non-Biological Origin
SAF	Sustainable Aviation Fuel
UCO	Used Cooking Oil

1. INTRODUCTION

1.1 The Chair in Hydrogen Studies

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

The decarbonisation of the economy is one of the great challenges currently facing our country. In this respect, renewable hydrogen is set to be a key vector in a decarbonised energy system, as it enables **decarbonisation of consumption that is difficult to electrify directly**, such as certain industrial processes or heavy or maritime transport. It can also play a role as a long-term energy storage solution **necessary to manage the variability of renewable electricity production**, and become a **new relevant commodity in the global energy market** due to its contribution to the transition towards a green economic model.

In this context, the Chair of Hydrogen Studies has set itself the objective of publishing an annual report analysing a series of relevant variables to take the pulse of the hydrogen sector in the European and national context.

With its activities, the Chair of Hydrogen Studies seeks to contribute to the debate by means of a multidisciplinary approach and by attending to the hydrogen value chain as a whole, including technical-economic, regulatory and financial aspects. The Chair's activity therefore seeks to contribute to the fulfilment of the European and Spanish green hydrogen strategy, as well as the objective of achieving climate neutrality by 2050 at the latest.

In order to achieve its objectives, the Chair has the participation of several sponsoring institutions present in different segments of the hydrogen value chain: Acerinox, Andersen, Carburos Metálicos, Moeve, Management Solutions and Redeia.

1.2. Objective and structure of the report

The importance of hydrogen for our future energy systems has become even more evident in the last years in the security of supply and that, in addition to decarbonisation, the energy autonomy and insdustry have been at the the centre of the European political debate. Proof of this is the increased ambition in the renewable hydrogen production and the use of targets included in the RePower EU plan presented by the European Commission in 2022, or the update of the Integrated National Energy and Climate Plan published in September 2024 by the Spanish government. However, the development of the renewable hydrogen sector is not without its challenges. The previous edition of this report highlighted the difficulties being encountered in reaching a final investment decision and discussed in detail some of the elements that could determine the future competitiveness of hydrogen. In addition, the report analysed the state of the hydrogen market and made an exercise to visualise a possible future development of the hydrogen market.

This edition of the report takes a further step in this direction by analysing, on the one hand, what the first hydrogen use cases could be, taking into account the regulations implemented in recent years and competition with other decarbonisation vectors such as direct electrification or biofuels. On the other hand, in addition to updating the analysis of the hydrogen market, possible business models are evaluated to make the first steps in the development of this sector viable.

In short, with this report we try to shed some light on the question of where hydrogen is going in Spain: *hydrogen, quo vadis?* Now that most of the European regulation has been deployed and is about to be transposed to the national level, and with a large volume of project aid already granted, it seems that we are at a turning point that will mark the future of this energy vector.

This report analyses the information gathered during the last 2023-2024 period by presenting an updated review of the status of electrolytic hydrogen production projects in Spain (section 2), regulatory developments and their implications (section 3), an analysis of the key drivers and use cases for hydrogen (section 4) and the medium and long term hydrogen trade outlook and business models (section 5).

2. STATUS OF RENEWABLE HYDROGEN PROJECTS IN SPAIN

The Chair periodically monitors the status of electrolytic hydrogen production projects in Spain based on the best available public information*(1):* information from different sources is monitored, analysed and filtered. The purpose of the publication of the data is purely informative and its content comes from external information sources referenced by means of the corresponding links. The chair is not responsible for the content of these links to other websites and therefore cannot guarantee the completeness, accuracy or suitability of these links for any particular use.

Below is a summary of the status of the projects as the end of January 2025 and their evolution over the last year.

Key figures for renewable hydrogen in Spain 2023-2024

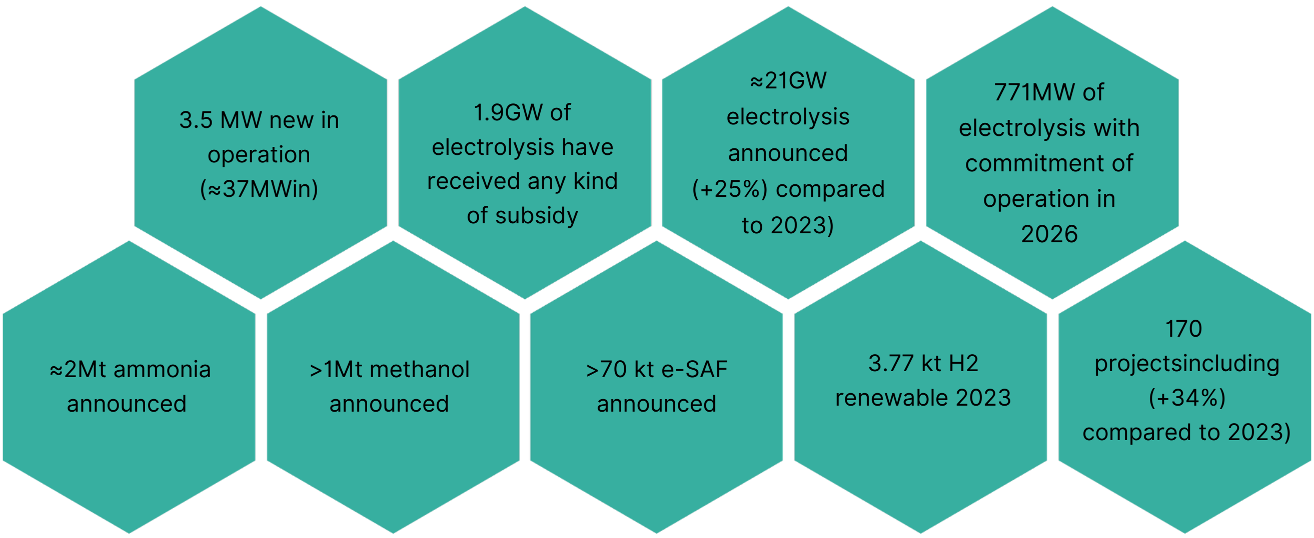

Figure 1: Summary of key figures on the evolution of renewable hydrogen in Spain

In 2024, there was a growth of 34% in relation to the number of projects collected in the Chair's Observatory, adding up to an electrolysis capacity of approximately 21 GW. The increase in number of projects is higher than the increase in electrolysis capacity, indicating that the new projects are smaller in size. If carried out, these projects would be sufficient for meeting the targets set out in the draft of the first update of the National Integrated Energy and Climate Plan (PNIEC),

[1] All the information can be found on the Chair's website: https://www.comillas.edu/catedras-de- investigacion/catedra-de-estudios-sobre-el-hidrogeno/mapa-de-proyectos-en-espana/

which foresees reaching 12 GW of electrolysis capacity by 2030. However, up to 2025, only around 37 MW of electrolysis capacity is in operation, with two new projects coming on stream in the last year.

Most of the projects are still in the early stages of development. However, around 40 have received some form of support, either at national or European level. Of these, a total of 771 MW of electrolysis capacity has been committed to come on stream by 2026.

An increasing number of projects are geared towards the production of hydrogen derivatives. The announced ammonia projects amount to more than 2 Mt per year, which would make it possible to decarbonise the use of domestic grey ammonia and to export to other countries. With regard to methanol, the announced production capacity also exceeds national demand. In addition, interest in e-SAF production has grown in the last year, with three existing projects that add up to more than 70 kt e-SAF of announced capacity. Finally, a first synthetic methane production plant has come on stream, albeit still with a token presence.

There has been a significant increase in the number of registered projects in 2024, although projects in advanced stages still represent a very small fraction.

As of the date of publication of this report, 170 hydrogen production projects have been registered at commercial level, compared to 112 projects registered in the report presented in 2023. Among these, the majority are projects that are still at a very early stage of development (feasibility study). This does not imply that these projects were conceived in 2024, but rather that they had not been identified beforehand by the Chair. The number of supported projects has increased slightly since the last report thanks to the resolution of the second call of the hydrogen pioneers programme approved in December 2023*(2)*.

In 2024, no new calls were resolved, although a new call was announced for Hydrogen Valleys which, at the date of publication of the report is still in, with list of projects admitted in the pre-evaluation phase having been published on 4 February 2025.

Finally, it should be noted that two new hydrogen projects came into operation in 2024. The first of these, located in the Parque Empresarial del Medio Ambiente (PEMA) in Soria, has a 2.5 MW electrolysis capacity that will enable the demonstration and replicability of this technology in Castilla y León.

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[2] The previous Chair's report was published in October 2023, so these projects had not yet been included in the database.

Its main uses will be the injection of natural gas into the grid, land transport and fenced industry. The second project is located in Miajadas, Cáceres, and has an electrolysis capacity of 1 MW. The hydrogen generated is combined with biogenic CO2 to produce e-methane, which is then injected into the grid for consumption by various off-takers.

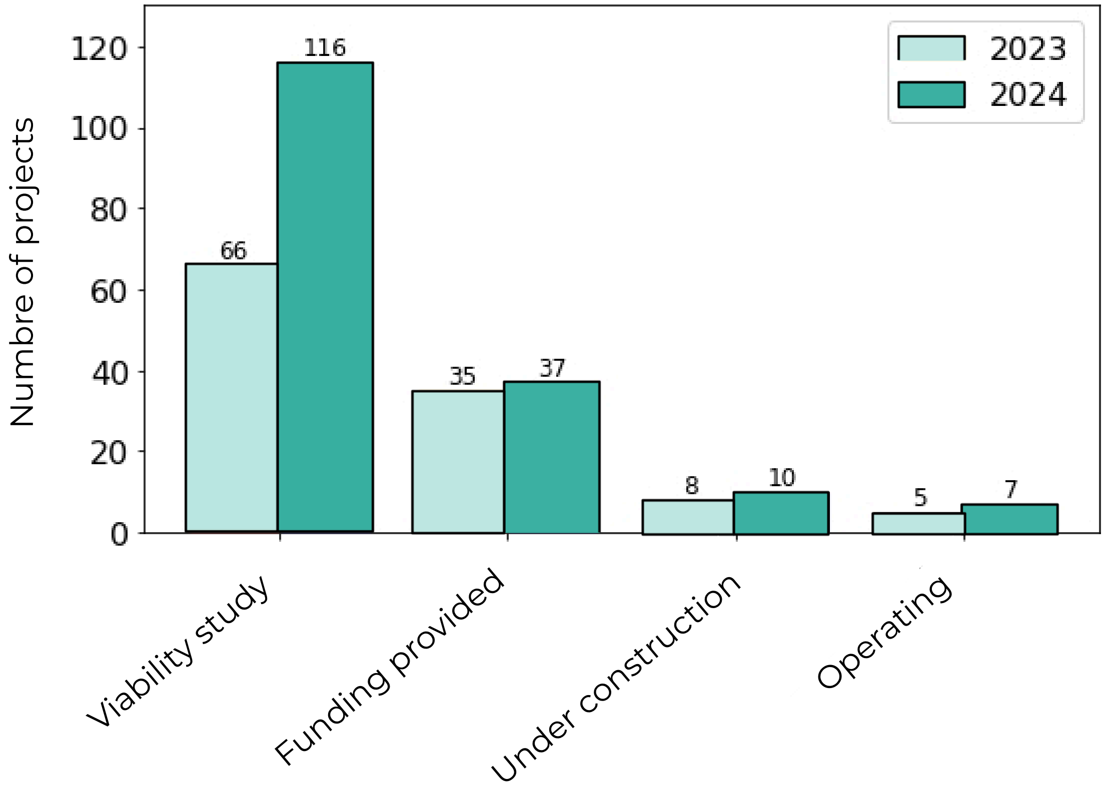

Figure 2: Status of hydrogen production in Spain by number of projects

More than 21.5 GW of projects have been announced, representing an increase of 7.5 GW over what was announced in the 2023 report.

Despite the large volume of announced project capacity, less than 1 % of the capacity is operational or under construction. Projects that have received some form of subsidy account for 17 % of the total announced capacity*(3)*, while the remaining 83 % are projects under feasibility study.

If realised, the projects that have been aid would represent more than 90% of the 4 GW electrolysis capacity target set in the 2020 Hydrogen Roadmap and 30% of the 12 GW target set by the PNIEC in 2024*(4)*.

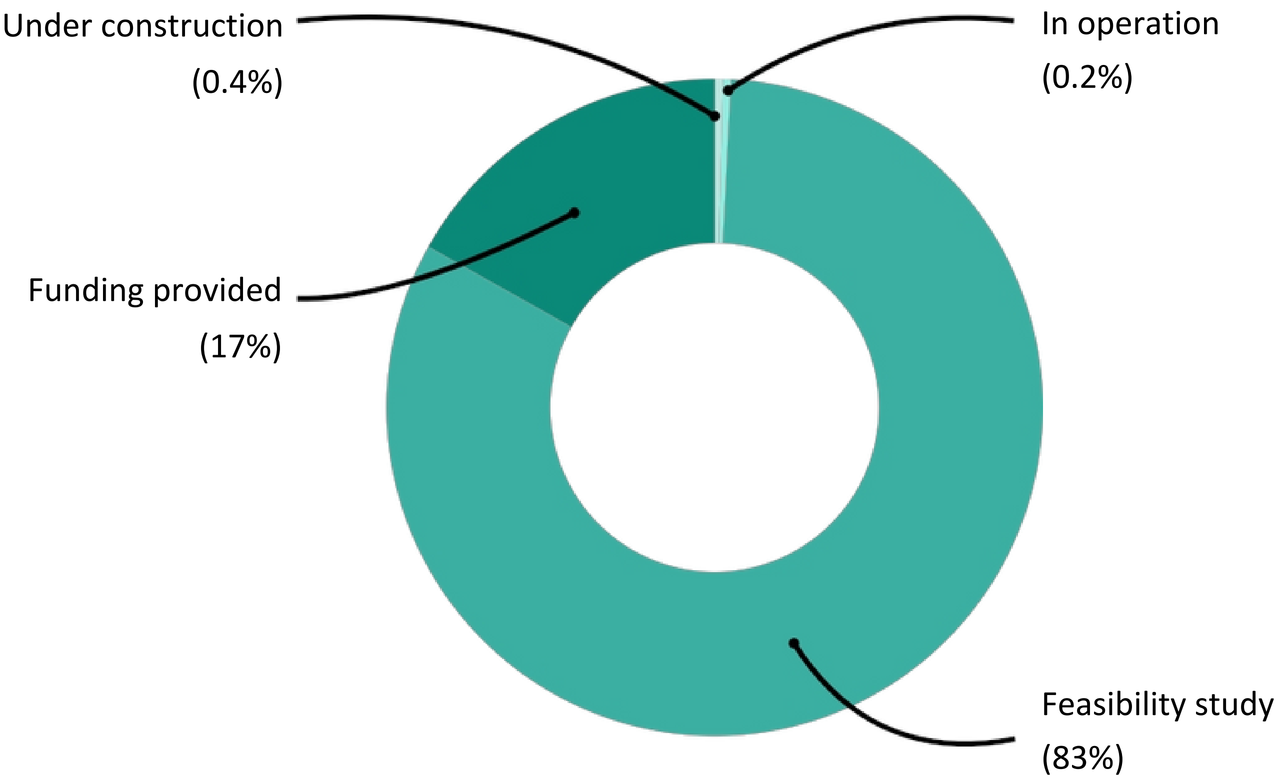

Figure 3: Status of hydrogen production in Spain by electrolysis capacity

Most of the new projects do not announce off-takers, increasing the number of projects aimed at the production of derivatives.

Regarding the uses of hydrogen, as shown in Figure 3, the largest increase in the number of projects is found in those that have not yet announced off-takers. Projects for land transport, blending or industrial heat are also increasing slightly. Regarding steel production, the HyDeal project remains the only active project, although the ambition has been moderated and the initial deadlines revised, as another announced project, Green Steel, does not seem to have progressed since 2021. Finally, the Hydnum Steel project located in Puertollano, which plans to install an integrated steel plant based on direct reduction of iron (DRI), has not announced an electrolysis capacity to be installed.

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3 Most of the projects are developed in several phases, so that in most cases the subsidised power is lower than the total power announced by the project.

4 Both targets are set for the year 2030.

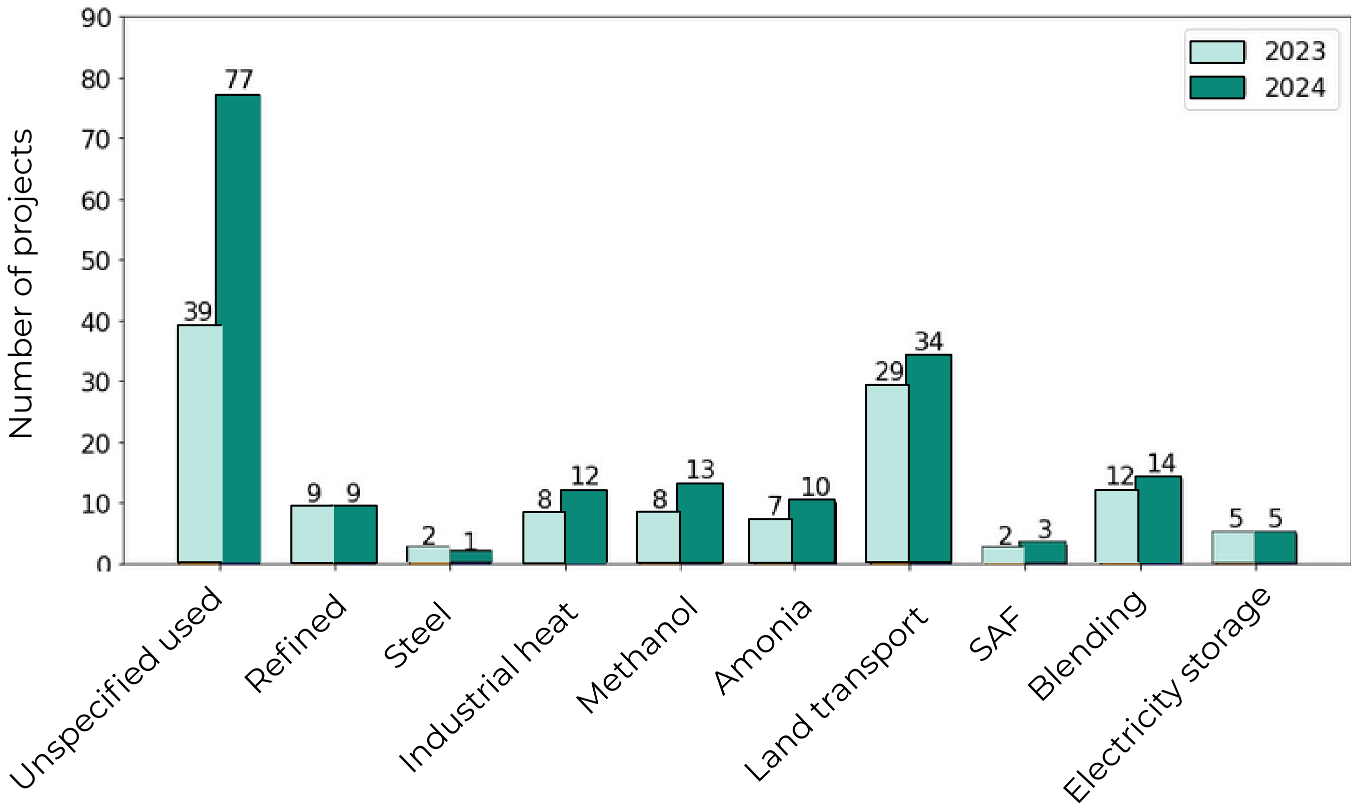

Figure 4: Hydrogen production projects by end-use(5)

Most of the projects do not clearly specify what their off-taker will be. Of the projects that do, a significant part of the production is aimed at replacing grey hydrogen in the refining sector or production of hydrogen derivatives, such as methanol and ammonia, which have applications in both industry and maritime transport. Also of note are the projects focused on the production of e-SAF or land transport, although the latter, although large in number, are small in size.

Figure 4 presents the announced hydrogen production potential in various sectors compared to the corresponding demand.

[5] The same project can have different end-uses, e.g. for methanol and ammonia.

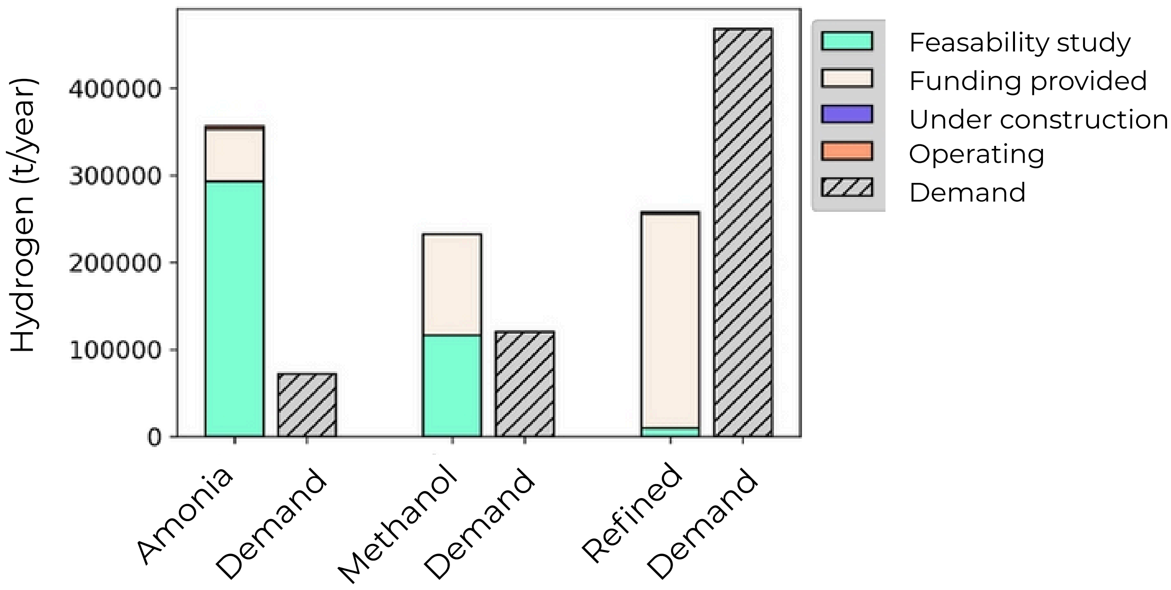

Figure 5. Announced production potential and hydrogen demand. The hydrogen production potential/year corresponds to the total potential of projects that have received some funding, this does not mean that 100% of the production potential is subsidised(6).

Eight refineries operate in Spain, which in 2023 consumed 467 kt tonnes of grey hydrogen [1]. Of this total, it is estimated that just over 50% could be decarbonised through the announced production. Of the nine projects under development, seven have received partial funding through national or European subsidies, one is under construction and one is under feasibility study.

In relation to ammonia, there are projects with a total production capacity of 2 Mt of ammonia, which would require approximately 354 kt of hydrogen per year. Of this amount, 3 kt tonnes of hydrogen come from projects already operational, such as Puertollano; another 60 kt correspond to projects with some aid granted, while the rest correspond to projects in the initial stages of development. In 2023, ammonia production in Spain consumed 72 kt tonnes of grey hydrogen [1], so the announced projects would make it possible to replace this consumption completely, reduce ammonia imports and promote both its export and its use in maritime transport*(7)*.

[6] Sources: The demand for hydrogen in the ammonia and refining sector corresponds to the existing demand 2023 based on data from the European Hydrogen Observatory [1]. On the other hand, for methanol, the potential demand for hydrogen to replace the estimated imports of methanol is presented [2].

[7] 2Mt of ammonia would replace approximately 10% of the total fuel supplied to maritime transport.

As for methanol, it is estimated that in Spain more 600 kt tonnes of grey methanol are consumed annually in the industrial sector [2], most of which are imported from outside the European Union. To replace these imports, it would be necessary to produce around 120 kt tonnes of hydrogen per year. The announced projects envisage a methanol production capacity of 1,150 kt/year, which would require approximately 230 kt tonnes of hydrogen. If realised, these projects would make it possible to decarbonise current methanol consumption, and would also open up opportunities for export to other European countries and for use in maritime transport*(8)*. Of this projected capacity, around 50 % corresponds to initiatives that have already received financial support, while the remainder is at the feasibility study stage.

[8] 1.15 Mt of methanol would replace approximately 6.5% of the total fuel supplied maritime transport.

3. REGULATORY DEVELOPMENTS AND THEIR IMPLICATIONS

3.1 Regulatory milestones at European level

Definition

Rules for determining renewable electricity for RFNBOs (Regulation (EU) 2023/1185)

Definition of low-emission H2 (Directive (EU) 2024/1788)

Rules for calculating RFNBO emissions (Delegated Regulation (EU) 2023/1185)

Rules for calculating low-emission H2 emissions (Delegated Regulation on Directive (EU) 2024/1788)

Demand

Revision of the Renewable Energy Directive (RED III) (Directive (EU) 2018/2001)

FuelEU Aviation (Regulation (EU) 2023/2405)

FuelEU Maritime (Regulation (EU) 2023/1805)

ETS Revision

Creation of ETS 2

Free allocations to renewable H2 producers

Mechanism Carbon Border Adjustment Agreement (CBAM)

CO2 emissions regulation for heavy-duty vehicles (Regulation (EU) 2019/1242)

Infrastructure/Distribution

Directive on the internal markets for renewable gas, natural gas and hydrogen (Directive (EU) 2024/1788) (AFIR, Regulation (EU) 2023/1804)

Incentives

European Hydrogen Bank

First auction

Second auction

Innovation funds

- 1st call
- 2nd call
- 3rd call
- 4th call

IPCEIs

- Hy2Tech
- Hy2Use
- HyInfra
- Hy2Move

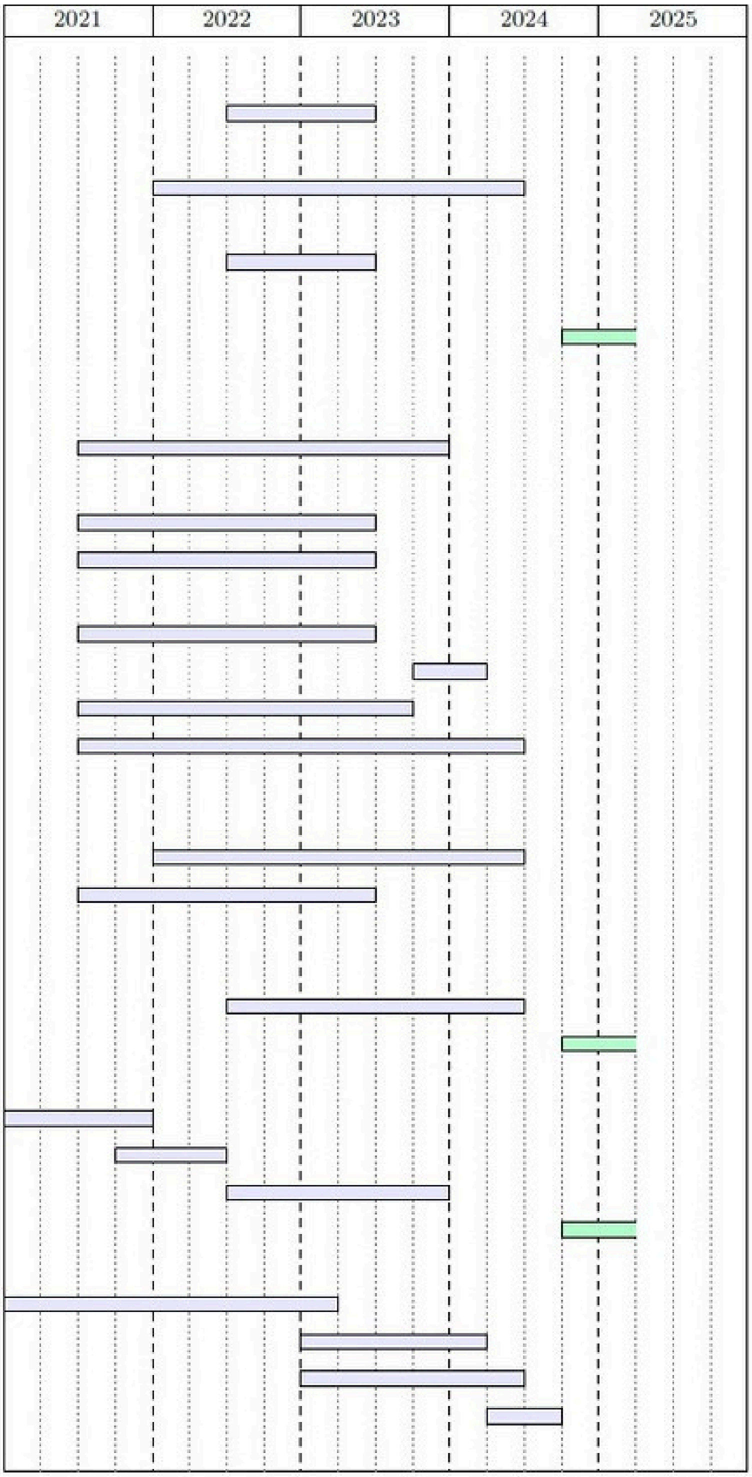

Figure 6. Regulatory actions at the European level - duration of the legislative process

The legal framework has been largely completed, but its overall impact on the market is still uncertain.

The EU's energy and climate policy of the previous years can be characterised by the announcements and agreements on more ambitious targets to achieve climate neutrality that resulted in the European Climate Legislation in June 2021, the agreement on the "fit-for-55" package to accelerate the transition towards 2030, and the marked increase in ambition, both in emission reductions and energy security, following 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. Figure 4 shows the most important hydrogen-related regulatory acts.

As it can be seen, the legal framework for the uptake of renewable hydrogen is largely complete. Below, we highlight the most important regulatory developments that took place before 2024, those that took place in 2024 and those that are yet to be defined.

3.1.1. Definitions

One of the main developments ahead of 2024 was related to the definition and determination of rules for renewable fuels of non-biological origin (RFNBO). An RFNBO is one that is derived from electrolytic hydrogen with renewable electricity and achieves a 70% reduction in emissions compared to a fossil benchmark. In this regard, two delegated acts were adopted in 2023: Delegated Act 2023/1184, which establishes the rules for determining that electricity used to produce hydrogen is renewable, and Delegated Act 2023/1185, which establishes the methodology for measuring CO2 equivalent emission reductions applicable to RFNBOs.

However, hydrogen from other technologies, but achieving emission savings (e.g. blue hydrogen), fell outside this definition.

For this reason, in 2024, with the publication of the Clean Gases Package, a new regulatory category was created for hydrogen and its derivatives: hydrogen or low-carbon fuels. This category includes all fuels of non-renewable, non-biological origin, but which achieve emissions reductions of up to 70%.

What has yet to be defined is precisely the methodology for certifying these emission reductions. In this sense, the Delegated Act concerning the methodology for measuring the reduction was launched for public consultation in September 2024 and it is expected to have a final text approved by 2025.

3.1.2. Demand

On the demand side, several important regulatory acts were approved in 2023 with regard to demand creation for renewable and low-emission hydrogen. These include the revision of the Renewable Energy Directive (RED III), the FuelEU Maritime and FuelEU aviation regulations and the creation of a new emissions trading market (ETS 2) for road transport and buildings.

In January 2024, the EC adopted the draft delegated act amending the ETS Regulation by expanding the allocation of the production of hydrogen from electricity. This means that zero-emission producers can sell their allowances for free and thus create a source of revenue for themselves.

Also in 2024, the revision of Regulation (EU) 2019/1942 related to CO_2 emission standards for new heavy duty vehicles was adopted. The new law sets the following CO2 reduction targets: (i)- 45 % by 2030, (ii) - 65 % by 2035, (iii) - 90 % by 2040*(9)*. These targets will oblige truck manufacturers to meet increasing average emission reduction thresholds by selling more zero-emission trucks and buses powered by batteries, fuel cells or hydrogen combustion engines.

3.1.3. Infrastructure

The rules for the development of hydrogen transport and distribution infrastructure were set out in the Clean Gases Package, which in addition to introducing the definition of low carbon fuels, aims to regulate elements such as planning (10-year EU-wide network development plan and national development plans), access to dedicated hydrogen infrastructure, separation of hydrogen production and transport activities and the setting of tariffs.

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9 Urban buses would have stricter emission limits, having to achieve an emission of at least 90% by 2030 and 100% from 2035 onwards.

Also related to establishing the necessary means for the development of hydrogen is the Alternative Fuels Infrastructure Regulation, AFIR, approved in July 2023. It establishes the minimum number of refuelling stations for the refuelling of alternative fuels such as electricity or hydrogen.

3.1.4. Incentives

Finally, there are also a number of subsidy mechanisms at European level to facilitate the uptake of renewable or low-emission hydrogen. These include the following:

The Innovation Fund is a subsidy programme for innovative industrial technologies and of renewable energies which is financed, in part, with the revenues from the EU ETS. Among the technologies benefiting from these funds is the production of hydrogen. It has been resolved into three calls for proposals, the last one distributing 4.8 euros. The EC launched a new call in December 2024.

The European Hydrogen Bank provides support for hydrogen production, which is distributed through an auction system financed by the Innovation Fund. This works as follows: renewable hydrogen producers can apply for support in an auction in the form of a fixed premium per kilogram of hydrogen produced. The results of the first auction were announced on the 30th of April 2024, and seven projects were selected with total of 720 million euros, of which three are Spanish and five are located on the Iberian Peninsula*(10)*. The second auction of the European Hydrogen Bank is expected in the last quarter of 2024 and will have a budget of €1.2 billion.

Finally, there are the Important Projects of Common European Interest (IPCEIs). The main objective of the IPCEIs is to promote development and manufacturing along the entire hydrogen value chain, from electrolysers for hydrogen production to storage, transmission and distribution infrastructures, as well as its application. To date, the European Commission has approved state aid under four IPCEIs related to renewable hydrogen: Hy2Tech focused on the development of technologies of hydrogen, Hy2Use focused on applications industrial, Hy2Infra aimed at infrastructure deployment and Hy2Move aimed at mobility.

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10 One of these projects did not reach the signature of the Grant Agreement and was excluded from grant.

3.2 Regulatory milestones at European level

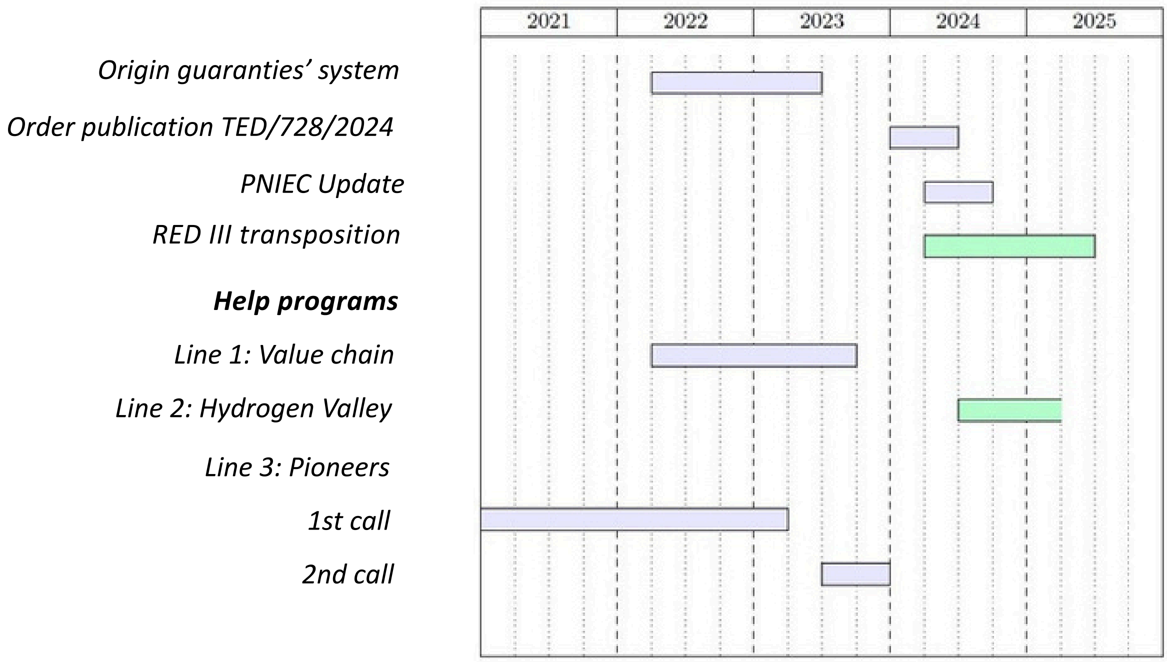

Figure 7: Regulatory actions at national level - duration of the legislative process

The hydrogen sector at national level has experienced significant movements over the last year, with some important developments from a legislative point of view. Important milestones had already been reached before 2024, such as the start-up of the Guarantees of Origin system managed by Enagás GTS, which has been operational since May 2023.

In 2024, guarantees of origin were issued for the first time to renewable hydrogen in Spain, all of them under *offgrid* logistics, with a total of 307, equivalent to approximately 9.2t of hydrogen.

One of the main new developments in 2024 is the publication of the updated National Integrated Energy and Climate Plan (PNIEC) 2023-2030, the first draft of which was presented in mid-2023. Although it is not a binding regulatory document, this document raises Spain's commitment to renewable hydrogen by setting a target of installing 12 GW of electrolysers by 2030*(11)*. The role of hydrogen in the PNIEC is discussed in more detail in section 4.1 of this report.

[11] It is important to remember that the Hydrogen Roadmap had a target of 4 GW of installed electrolysis capacity by 2030. Likewise, the draft presented in 2023 proposed to increase this target to 11 GW, 1 GW less than the target finally adopted.

However, the most important regulatory milestone in 2024 was the publication of order TED/728/2024 developing the mechanism for the promotion of biofuels and other renewable fuels for transport purposes.

This Order facilitates certification, introduces clear definitions and a specific framework for certifying and accounting for the use of biofuels and renewable fuels to meet European decarbonisation targets*(12)*. To this end, a certification system is established with six types of certificates depending on the feedstock used.

These targets refer to RED II, whose transposition in Spain took place in 2022 through RD 376/22. However, the new update of the Directive approved in 2024 (RED III) will increase the ambition of these targets and must be transposed in Spain by May 2025.

Finally, in relation to the hydrogen support programmes approved in December 2021 under the PERTE ERHA umbrella, 1.37 billion € have been committed to date to renewable hydrogen projects across the territory *(13)*

Initially, the PERTE had a budget of 1,555 M€, to which 1,600 M€ were added in a later addendum. In this sense, part of these new funds will be distributed in a new call aimed at "Hydrogen Valleys or Clusters", for which the deadline for submitting applications was 29 October 2024. On 21 February 2025, provisional decision on the granting of aid was published, in which 7 projects were approved out of a total of 16 applications admitted *(14)*

3.3. Projects located in Spain that have been awarded some type of support in European and/or national calls for proposals.

Together, the national initiatives add up to more than 771MW of electrolysis capacity, which should be operational between the second and third quarter of 2026.

[12] The latest update of RED III stipulates that Member States must guarantee a minimum share of 29 % renewable energy in transport by 2030, or a reduction of the greenhouse gas intensity of transport fuels by 14.5%.

[13] Post by the Ministry for Ecological Transition and the Demographic Challenge

[14] The list of approved projects is available on the website of the Instituto para la Diversificación y Ahorro de la Energía (IDAE).

In addition, the two projects benefiting from the European Hydrogen Bank should be operational in 2029*(15)*. It is worth noting that almost all the projects that have received some form of support have consolidated their acceptance, with the exception of three projects*(16)*.

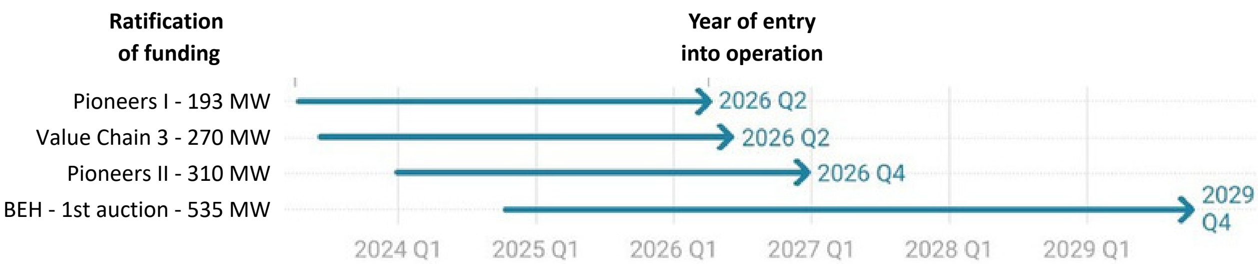

Figure 8: Timeline of aid programmes: granting of aid and deadline for entry into operation

Figure 9 shows the geographical distribution of renewable hydrogen projects awarded some form of national or European subsidy, as well as the intensity of the .

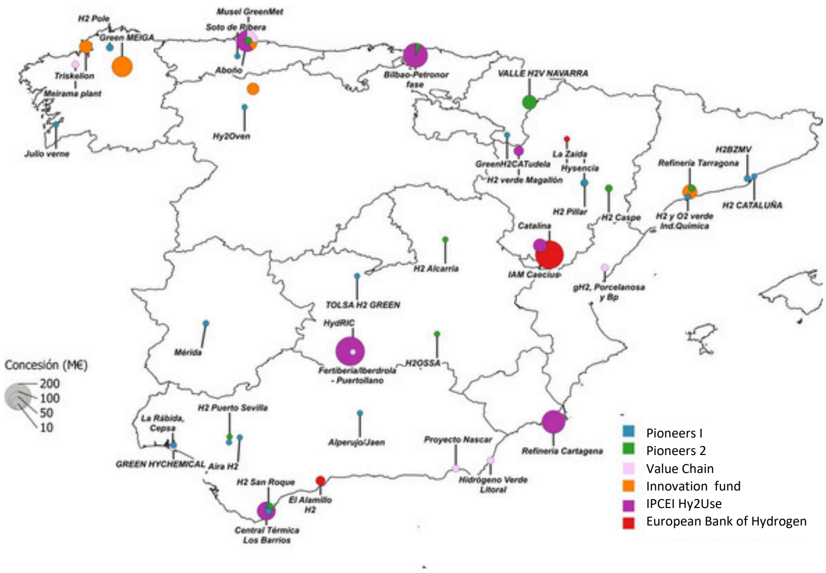

Figure 9: Map of hydrogen production projects with granted aid (17)

15 It is important to note that this time series does not include IPCEI Hy2Use or Innovation Fund projects, whose implementation period is determined for each specific project. In the case of projects that have received funding from the Innovation Fund (calls for large-scale projects) to date, they are scheduled to come into operation between 2026 and 2028.

16 The "La Zaida" and "H2-Jorge" projects did not ratify the grant under the Pioneers 2 call, while the "El Alamillo" project did not sign the ratification of the grant under the European Hydrogen Bank call either.

17 Note that this information does not include projects with grants awarded under the call for proposals of the Hydrogen Valleys Programme under the PERTE ERHA as the award decision published on 21 February 2025 is still provisional.

4. USE CASES FOR RENEWABLE HYDROGEN ACCORDING TO REGULATORY FRAMEWORK AND ENERGY POLICY

The data presented in section 2 of this report show that there is a strong interest in investments on the hydrogen and hydrogen derivatives production side. In addition, many of the regulatory measures described in section 3 are intended to serve as leverage to unlock hydrogen use in industry and transport.

This section attempts to identify and quantify, on the basis of the regulatory measures known to date, in which sectors and in what quantity it is foreseeable that demand for renewable hydrogen and its derivatives will start to develop in Spain. Naturally, this is an analysis heavily influenced by the assumptions made and subject to a high degree of uncertainty. Nevertheless, we believe that it can give an indication of what the playing field for hydrogen will be in the coming years.

4. 1. A possible scenario for hydrogen demand in Spain based on regulatory obligations

Within the European regulation, as mentioned in section 3.1, there are different objectives that aim to promote hydrogen demand in different sectors. These targets can be broadly differentiated into two: specific targets for renewable hydrogen or hydrogen derivatives, and more general targets where hydrogen competes with other renewable alternatives.

Figure 7 shows in simplified form the main general and specific objectives. These can be summarised follows:

- RED III: establishes a minimum share of RFNBOs of 1% of total energy consumption in transport in 2030, plus a combined share of RFNBOs, advanced biofuels and biogas of 5.5%. On the other hand, a 29% share of renewable energy transport is also set for the same year. In the case of Spain, the 29 % target would be reduced to 23.5 % *(18)*. This share can be met with different technologies such as renewable electricity, biofuels or RFNBOs.

  On the other hand, RED III also sets some targets for the uptake of renewable hydrogen in industry. In particular, it sets that by 2030, 42% of the hydrogen consumed in industry for non-energy uses should be RFNBO.

- ReFuelEU Aviation: sets a minimum increasing percentage of SAF and e-SAF in the aviation fuel offered from 2030 to 2050, as described below.

- FuelEU Maritime: establishes the option to set a quota of 2 % RFNBO per ship in energy content from January 2034, there is no development of these fuels before 2031. In addition, the regulation sets a decreasing limit on the emission intensity of energy used on board ships within the EU. This limit, among other alternatives, can be met by using methanol, ammonia or LNG.

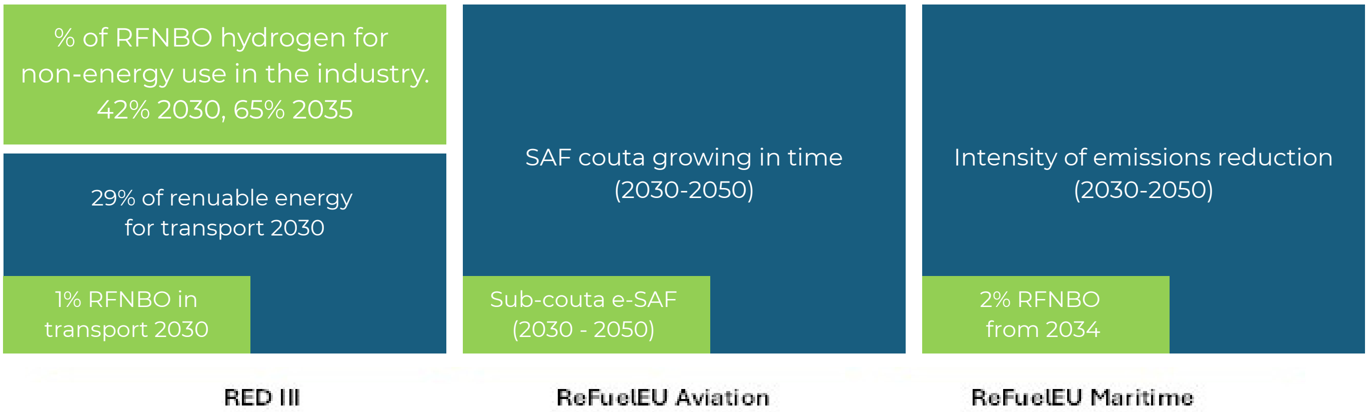

Figure 10: Obligations to use renewable fuels of non-biological origin by sector

We then delve into the implications and demand that the specific sub-targets for RFNBOs may have, followed by an analysis of the role that hydrogen can play in achieving the other general targets.

[18] This is because it imposes a limit on the contribution of biofuels from food and feed crops of 1.5%, which is more restrictive than the 7% of the Directive, and can reduce the overall target by a percentage equivalent to the difference (5.5%).

4. 1. 1. Specific objectives RFNBOs

4. 1. 1. 1. What does a 1 % RFNBO target for transport by 2030 entail?

Figure 8 shows energy consumption by mode of transport in 2023, totalling just over 530 TWh*(19)*. According to the RED III targets, at least 1% of this energy should be supplied by RFNBO. Under the assumption that energy consumption will remain constant until 2030*(20)*, this 1% corresponds to approximately 5.3 TWh/year.

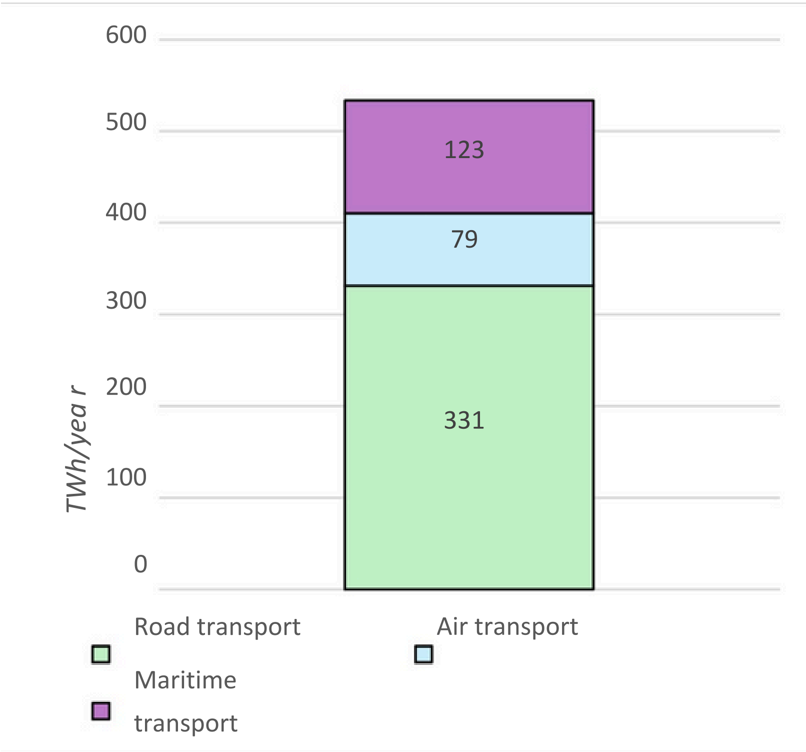

Figure 11. Energy consumption in transport by mode in 2023. Detailed values can be found in Annex I(a).

This minimum quota of RFNBOs in transport can be met by the direct use of hydrogen or its derivatives (methanol, ammonia or e-SAF). Measured in energy supplied to the transport, the necessary amount of hydrogen that needs to be produced may vary depending on the type of molecule.

19 Renewable electricity supplied to transport is not included.

20 Due to the increased efficiency of electric vehicles, total energy demand in the transport is likely to be partially reduced. However, given that the maximum target for renewable energy penetration in transport is 29%, the majority of transport energy will still be produced from fossil fuels in 2030.

Table 1 shows the amount of RFNBO hydrogen that would need to be produced for each MJ of final energy supplied in the form of ammonia, methanol or e-SAF. The differences observed are due to the different calorific value of each fuel and the amount of hydrogen required to produce each of them based on the chemical reaction involved. What these ratios show is that the amount of electrolytic hydrogen needed to meet the 1% sub-target will vary depending on the weight of each RFNBO in the supply to the final demand.

Vector	PCI MJ/kgX	Ratio kgH2/kgX	kgH2/MJ final	Ratio
Ammonia	18,9	0,177	0,009365	112 %
Methanol	20	0,187	0,009350	112 %
Hydrogen	120	1	0,008333	100 %
e-SAF	43	0,519-0,79	0,01207-0,018372	144-220%

Table 1: Hydrogen required to supply one unit of final energy depending on the type of RFNBO

Assuming that the 5.3 TWh/year needed to meet the RED III targets are met entirely by direct use of hydrogen, the most conservative scenario, 156 kt of hydrogen would need to be produced per year. However, according to Article 26 of RED III, the share of renewable fuels of non-biological origin shall be considered equivalent to twice their energy content. In other words, half of the RFNBO hydrogen (78kt/year) would be needed.

In an alternative scenario, where 80% of the energy is used for road transport in the form of hydrogen and 10% for the maritime and aviation sector through methanol and e-kerosene respectively, the required production would amount to 177 kt/year of hydrogen. However, applying the energy content , this figure would be reduced to 88 kt/year.

In this respect, it is important to note that, according to Article 25[2] of RED III, RFNBO hydrogen used as an intermediate product for the production of conventional fuels and biofuels in refining counts towards all transport sector targets, including the sub-target of 1% RFNBOs.

This percentage can therefore be achieved through direct supply of RFNBOs to vehicles, the use of RFNBO hydrogen at the refinery, or a combination of both.

As mentioned above, 470 kt of hydrogen is currently consumed in refining. The 78kt/year would represent approximately only one fifth of the hydrogen currently used by Spanish refineries. Moreover, the announced electrolysis projects associated with the refineries (2.5GW) would represent a production of more than 250 kt/year*(21)*. In other words, the target of 1% RFNBO in transport could be achieved if the existing refinery projects are implemented, without the need to directly supply hydrogen or its derivatives to final transport demand.

4. 1. 1. 2. What does the 42% target for renewable hydrogen in industry entail?

RED III also sets some targets for the uptake of renewable hydrogen in industry. In particular, it sets that by 2030, 42% of hydrogen consumed in industry should be RFNBO, excluding hydrogen for the production of conventional fuels and biofuels*(22)*. This means excluding most of the hydrogen used in the refining sector. As discussed in the previous section, this hydrogen would count towards meeting the target for the introduction of renewables in transport.

If refining is excluded, the existing hydrogen demand in industry is drastically reduced to 72kt/year from hydrogen for the production of ammonia and 16kt/year for the production of other chemical products. Methanol, which as mentioned above consumes up to 600 kt/year, is not produced in Spain. Its local production would require about 120 kt of extra hydrogen per year. In total, the potential hydrogen demand in indrustry, excluding refining, would reach 208kt/year, of which approximately 87 kt should be RFNBO. These 87 kt would translate into aproximately 870MW of electrolysis.

The target rises from42% in 2030 to 65% in 2035, which would translate into a hydrogen demand of 125kt H2 or 1.25GW of electrolysis.

To put these figures into context, the announced ammonia projects in Spain would require approximately 500kt of renewable hydrogen, while methanol projects would require approximately 200 kt/year*(23)* if the announced projects are realised, there would be sufficient capacity to meet the 42% RFNBO hydrogen requirement in industry.

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[21] Calculations based on an electrolyser running 5500 hours per year with an efficiency of 55 kWh/kgH2

[22] Also excluded are hydrogen that is produced through the decarbonisation of industrial waste gas and used to replace specific gas from which it is produced, and hydrogen produced as a by-product or derived from by-products in industrial installations.

In line with this sub-target, it is relevant to note that Article 22b of RED III opens the door to a 20% reduction in 2030, leaving the RFNBO target for hydrogen use in industry in 2030 at, provided that the share of hydrogen or derivatives produced from fossil fuels consumed does not exceed 23% in 2030*(24)*. This fossil contribution threshold is reduced to 20 % in order to be able to reduce the RFNBO share in 2035.

For the purposes of electrolytic hydrogen production, this condition is particularly relevant as it opens the door to the use of non-fossil low carbon hydrogen to reduce the amount of RFNBO hydrogen needed to meet the Article 22a quota. As shown in Figure 10, in 2030 this would bring the role of electrolytic hydrogen in industry, combining RFNBO and low carbon, from a minimum of 45% to a minimum of 77%, with at least 25% corresponding to RFNBO and up to 52% to low carbon. However, the demand for the latter could also be met by hydrogen from biogenic sources. In the case of 2035, assuming that fossil hydrogen for industry not exceed 20% of the total, the minimum share of RFNBO hydrogen could be reduced to 45%, leaving a margin of up to 35% for other low-emission hydrogen types.

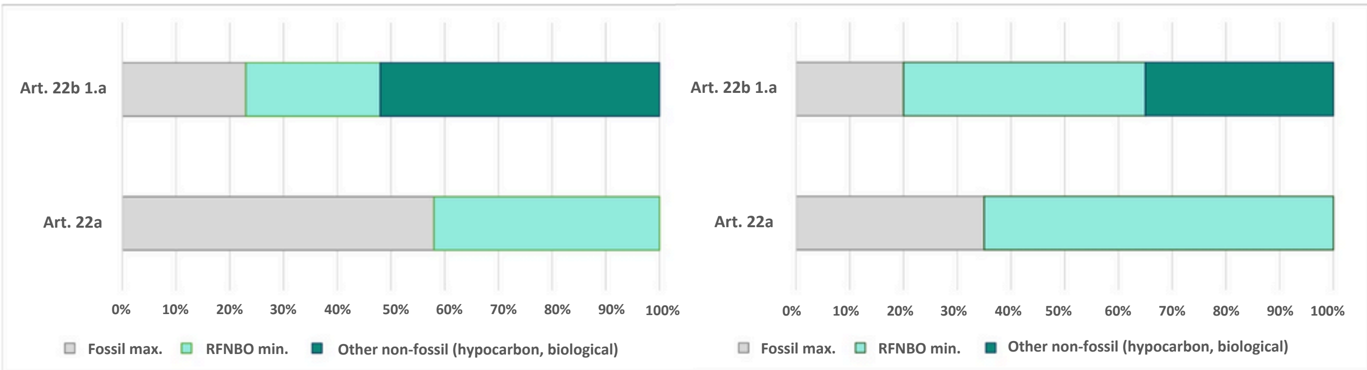

Figure 12: Scenarios for compliance with the RFNBO hydrogen quota to RED III industry in 2030 (left) and 2035 (right)

4. 1. 1. 3. What is the purpose of e-SAF in ReFuelEU Aviation?

ReFuelEU Aviation sets a minimum increasing percentage of SAF and e-SAF in the aviation fuel offered from 2030 to 2050. Figure 13 shows the e-SAF quotas for different years and the amount of e-SAF and hydrogen needed to meet them.

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[23] Many of the announced methanol and ammonia projects envisage exports to other countries, explains why the announced production capacities are higher than domestic demand.

[24] An equal reduction may be adopted when the Member State is in the process of reaching its contribution to the overall European decarbonisation target of 42.5% in 2030 set in the Directive itself.

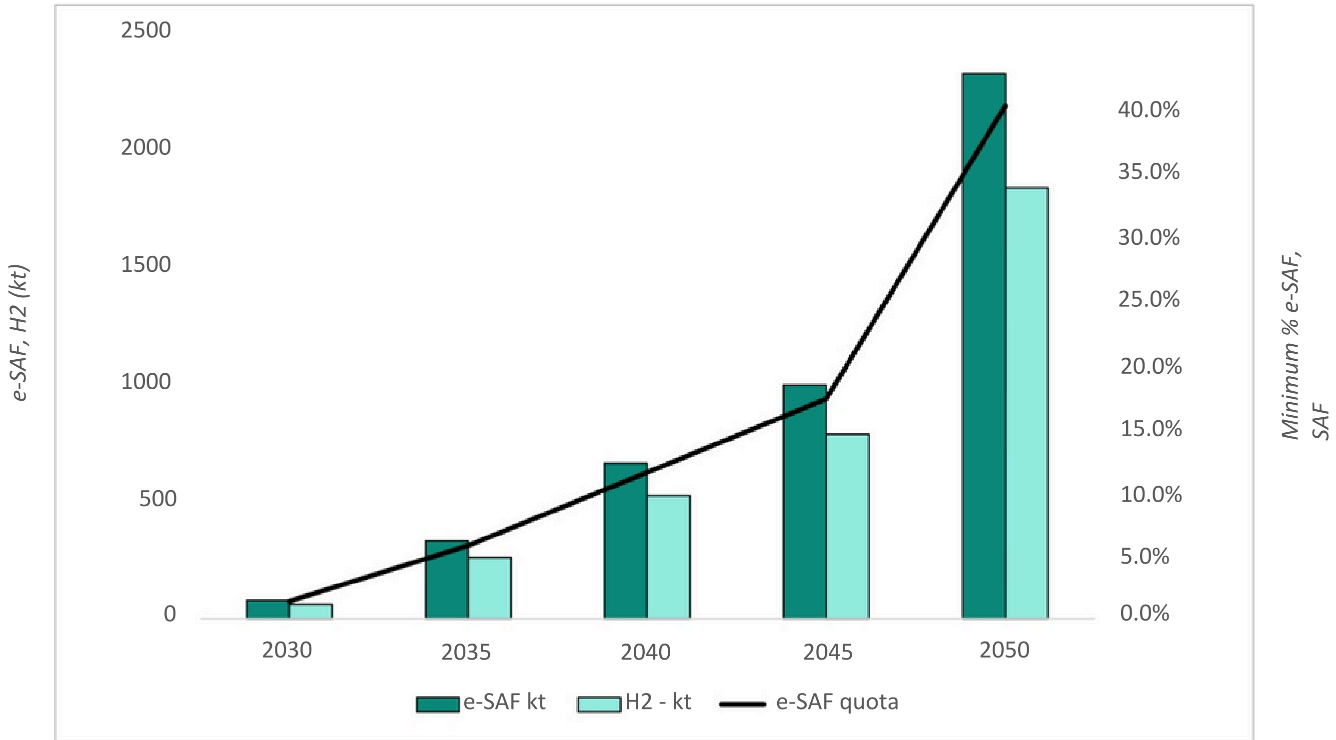

Figure 13. e-SAF quota (right axis) and demand for e-SAF and hydrogen needed for compliance (left axis). A selectivity of 100 % is assumed for SAF and a hydrogen consumption of 0.79 t H2/t e-SAF including upgrading [3].

By 2030, the share of e-SAF will represent only 1.2%(25), equivalent to an annual demand of 79 kt of e-SAF. However, this figure will increase significantly, reaching 332 kt/year in 2035 and 2300kt/year in 2050(26). In terms of electrolysis power, e-SAF production will require approximately 630 MW of renewable hydrogen in 2030, increasing to 23 GW in 2050.

As mentioned in section 2, there are three projects planned before 2023 with a combined capacity of 72 kt/year of e-SAF, which would be sufficient to meet more than 90% of the 2030 targets. However, these projects would be insufficient by 2035, as would only be able to meet 21% of the estimated demand by that date.

It is important to note that e-SAF quotas can also be met through the use of so-called low-carbon aviation fuels, i.e. fuels that come from non-fossil low carbon hydrogen*(27)* (which is not SAF per se). Low-carbon hydrogen is defined as hydrogen whose energy content comes from non-renewable sources and has an emissions intensity at least 70% lower than the reference fossil fuel. In practice, this type of hydrogen may correspond to blue hydrogen (fossil with CO2 capture) or to electrolytic hydrogen that does not comply with the RFNBOs rules but reduces emissions by at least 70%.

It is the latter type of hypo-carbon hydrogen that can be used in the production of e-SAF, as blue hydrogen is still of fossil origin. A plausible scenario is that the same electrolysis power is operated above the 5 500 equivalent hours assumed in previous calculations, with the production of these additional hours corresponding to hypocarbon hydrogen as the conditions of additionality and/or time correlation are not met.

4. 1. 1. 4. What does the RFNBO objective entail for FuelEU Maritime?

The FuelEU Maritime regulation provides for the option to set a quota of 2% RFNBO per ship in energy content from January 2034 in case the share of RFNBOs in 2031 is less than 1%. This sub-target would represent a demand for RFNBO hydrogen of approximately 82 kt/year(*28)*, or 820MW of electrolysis.

The regulation also establishes that this obligation can be met if it can be demonstrated that it has consumed an equivalent share of energy from advanced biofuels that achieve an equivalent reduction in emissions intensity. In short, the materialisation of this objective is yet to be confirmed, and it would only come into force as a tool to promote the use of RFNBOs in maritime transport if its development does not start before 2031 as expected.

4.1.1.5. What demand for hydrogen would emerge in Spain as a result of meeting the sectoral targets for RFNBOs defined in the European regulation?

Answering this question is not immediate because, as described for industry and aviation, the hydrogen consumption scenario will depend on the role of low-carbon hydrogen in these sectors. As a summary, Table 2 shows two possible scenarios for meeting the targets in the various sectors.

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[25] The regulation provides flexibility in meeting this target, setting an annual minimum of 0.7% for 2030 and 2031, provided that at least 1.2% is achieved as an annual average over this period. For simplicity this average value has been adopted.

[26] These values are always obtained assuming a constant final energy demand in aviation for 2023.

[27] Low carbon hydrogen is defined as hydrogen whose energy content comes from non-renewable sources and has an emission intensity at least 70% lower than the reference fossil fuel. In practice, this type of hydrogen can correspond to blue hydrogen (fossil with CO2 capture) or to electrolytic hydrogen that does not comply with RFNBOs rules but reduces emissions by at least 70%. The latter type of hydrogen hypocarbon is that it can be used in the production of e-SAF.

[28] Assuming the quota is met with methanol

- 100 % RFNBO scenario: the entire minimum RFNBO quota in industry and the e-SAF quota are covered exclusively by RFNBOs. In addition, the 2 % share of RFNBOs in maritime transport is met.

- Low-carbon scenario: Low-carbon hydrogen is used to reduce the need for H_2 RFNBO wherever possible. In this case, the 2 % share in shipping does not materialise. It is assumed that all low carbon hydrogen is sourced from electrolytic hydrogen that does not meet the RFNBO criteria.

	Time horizon	100% RFNBO scenario	Hypocarbon scenario
Industry	2030	42 % RFNBO	25 % RFNBO, 52 % hypocarbon
	2035	65 % RFNBO	45 % RFNBO, 35 % hypocarbon
Air transport	Increasing share 2030-2050	100 % quota via RFNBO	100 % quota through hypocarbon
Maritime transport	2034	2 % RFNBO	No obligation 1 %
Other modes of transport	2030	1 % RFNBO	RFNBO

Table 2: Summary of obligations to incorporate hydrogen and derivatives according to European legislation

Figure 14 (next page) shows the projected hydrogen demand in the 100% RFNBO scenario. In 2030, a total consumption of approximately 200 kt H_2 per year is expected, with 90 kt going to industry, 63 kt to e-SAF production and 51 kt to other transport modes. The inclusion of RFNBOs in the latter group is essential to meet the 1 % quota set for the transport sector.

Demand grows rapidly in 2035 as a result of the increase in e-SAF share, which rises from 63 to 260 kt. Also, the 65% target in industry raises demand to 135 kt/year, in addition to the introduction of the 2% share in maritime transport (80 kt). As a result, the total demand increases to 530 kt.

From 2035 onwards, hydrogen demand remains stable in all sectors except air transport, where it continues to increase until 2050, reaching a total demand of approximately 2 100 kt (21 GW).

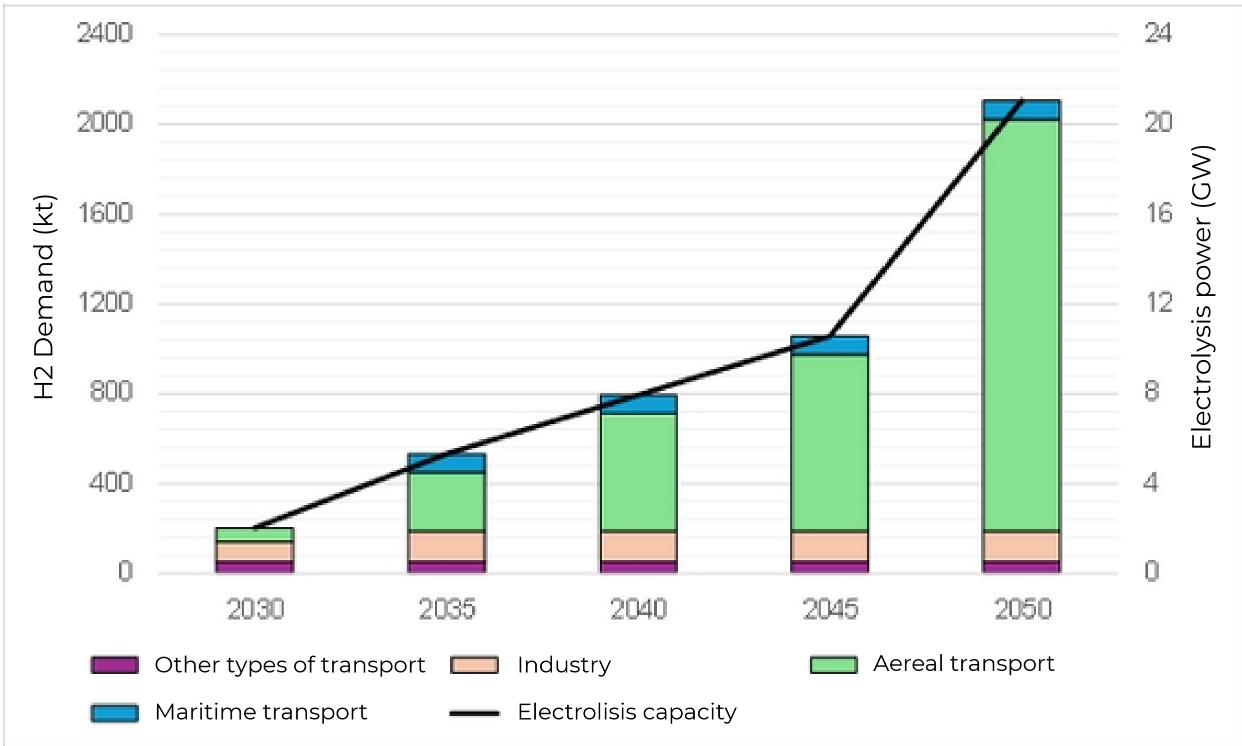

Figure 14. Expected H2 demand and electrolysis capacity in a 100 % RFNBO scenario

On the other hand, Figure 15 shows the low-carbon scenario, which introduces the use of low-carbon hydrogen as an alternative to reduce the demand for RFNBOs. In this scenario, hydrogen for industry increases significantly, reaching 77% in 2030 and 80% in 2035equivalent to 160 and 166 kt, respectively, in contrast to 90 and 135 kt in the 100% RFNBO scenario.

In the case of air transport, demand remains constant at 100% low-carbon hydrogen. However, the lower uptake of RFNBOs in the aviation sector increases the amount required in other transport modes to meet the 1% energy share in 2030 from 50 kt/year in the 100% RFNBO scenario to 78 kt. As a result, in 2030 the total hydrogen demand increases from 200 kt to 278 kt in the low-carbon scenario.

From 2035 onwards, the increase in hydrogen demand in other modes of transport and industry is compensated by the elimination of the 2 % RFNBO share in maritime transport. The total demand for this year is 510 kt compared to 530 kt in the 100% RFNBO scenario. This difference is maintained until 2050, reaching 2080 kt/year by 2050, compared to 2 100 kt in the 100% RFNBO scenario.

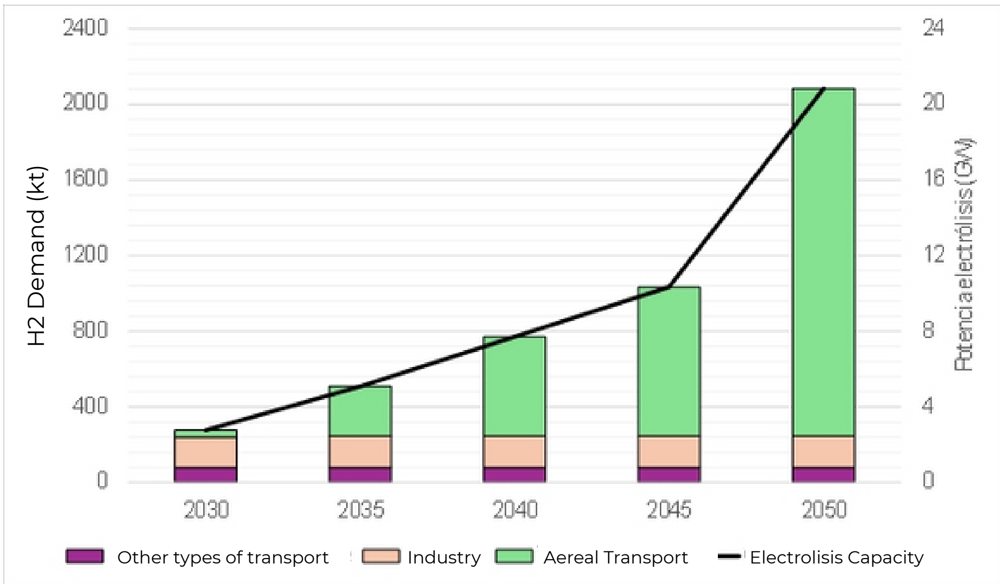

Figure 15. Expected H2 demand and electrolysis capacity in a RFNBO-hypercarbon scenario

Finally, it is important to note that these figures refer exclusively to the specific consumption targets of RFNBOs, without considering the hydrogen demand needed to meet broader targets, such as the emission intensity reduction set out in the FuelEU Maritime framework. In the following section, these aspects will be discussed in more detail.

4. 1. 2. General objectives

The adoption of hydrogen beyond the specific targets discussed above will depend on the availability of alternatives for the decarbonisation of the different sectors. Table 3 presents the different alternatives for meeting the overall targets by mode of transport.

Sector/Process	Main alternative
Maritime transport	Bio-GNL
Air transport	Bio-SAF
transport High	HVO, FAME, biomethane, electricity
temperature heat (>500 ºC)	Biomethane

Table 3: Main alternatives to hydrogen for decarbonisation of different sectors/processes

In the following, we take a closer look at each sector/process to analyse whether there is sufficient availability of alternative fuels to hydrogen in each sector/process.

4. 1. 2. 1. Maritime transport - FuelEU Maritime

As mentioned above, FuelEU Maritime sets a decreasing limit to the emission intensity of the energy used on board ships with respect to a fossil reference of 91.16gCO2eq/MJ (year 2020). Figure 16 shows the emission intensity limits from 2025 to 2050.

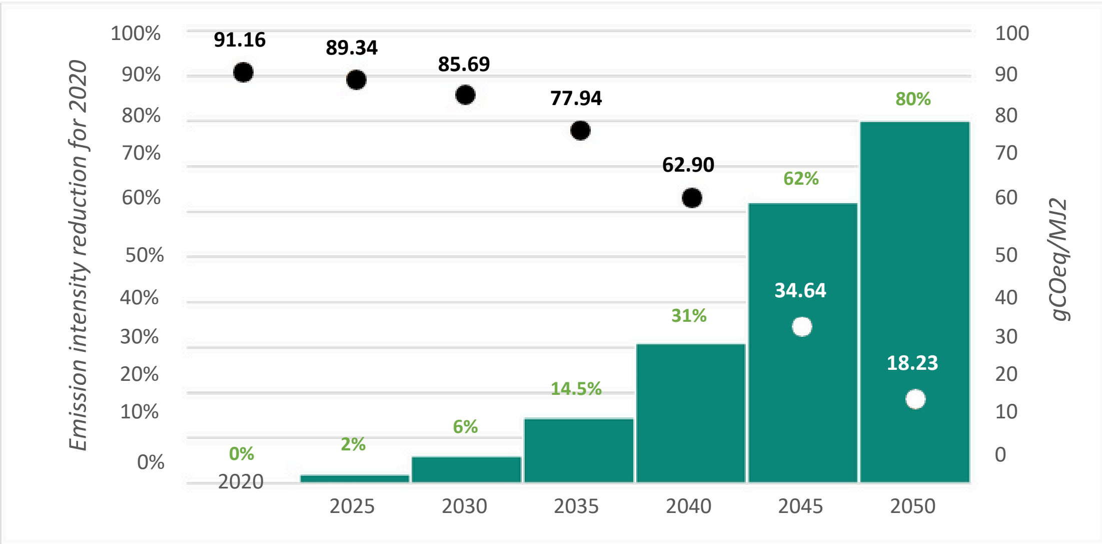

Figure 16. Emission intensity reduction target in FuelEU Maritime

As shown in Figure 17, up to 2035 the reduction in emissions intensity can be achieved with the use of LNG up to 100 %, in order to meet the targets from 2035 onwards, renewable fuels have to be incorporated, in case of incorporating bio-LNG*(29)*, a share of approximately 96% of bio-LNG would be needed to meet these targets in 2050.

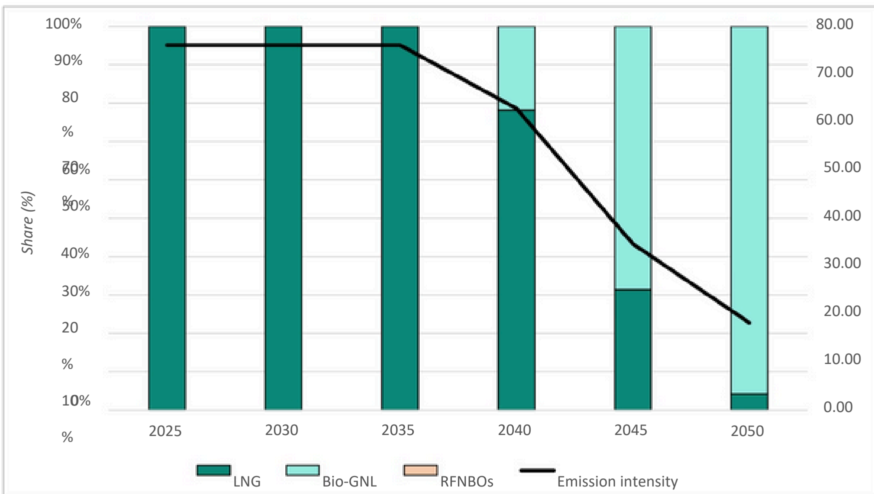

Figure 17. Share of LNG and bio-LNG needed to meet the FuelEU Maritime emissions reduction target

[29] A bio-LNG is used which reduces the emission intensity by about 85% compared to the use of LNG.
In practice, this value will depend mainly on the feedstock and the process used for the biomethane production.

As biomethane is also of great interest for the decarbonisation of other sectors such as industry, it is questionable whether sufficient biomethane will be available for maritime transport.

In the industrial sector, biomethane is mainly considered as substitute for natural gas for heat generation. Generally speaking, low and medium temperature applications (<400 °C) can be directly electrified, while that those that require high temperatures (>500 °C) will need biomethane or hydrogen to achieve decarbonisation. According to IDEA*(30)*, [1], the demand for heat and cooling in industry amounts to 172 TWh/year, of which 44 % is for applications above 500 °C*(31)*, equivalent to 74 TWh/year.

There are several estimates for the biomethane production potential in Spain. Sedigas estimates a potential of up to 160 TWh/year [5]. On the other hand, the EBA estimates a potential of 207 TWh/year by 2050 [6], while in 2018 the IDAE stated that the achievable potential in Spain was 20-34 TWh/year.

Using the potential provided by Sedigas, a study commonly used as a reference, 100 % of the high temperature thermal demand and up to 80 % of the LNG demand in shipping could be supplied*(32)*

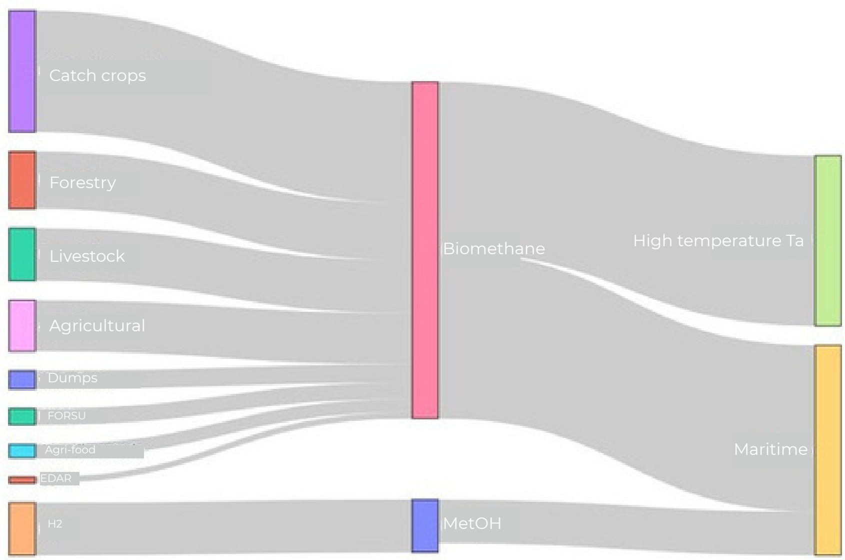

Figure 19. Comparison between the potential demand and estimated availability of biomethane. For more information information see Annex I b)

30 Source: IDAE Heat Map, https://mapadecalor.idae.es/

31 The heat quota above 500°C derived from the study [4], published in 2016, is applied.

32 Note that all calculations are made under the assumption of constant demand in the different sectors. This serves to illustrate by large numbers, but this demand will naturally evolve over time.

Considering that in order to meet the emission intensity reduction by 2050, approximately 100 % of the fuel needs to be covered bio-LNG, the bio-LNG potential would not be sufficient to supply both industrial and shipping demand. To supply the remaining 20 % would require approximately 764 kt of hydrogen, i.e. 7.6 GW of electrolysis.

It is also important to note that the scenario put forward by Sedigas can be considered very optimistic and it remains to be seen to what extent these values can be achieved. There are three main sources of biomethane that deserve to be discussed:

Forest biomass: The forest biomass potential represents 28 TWh biomethane/year. As this is woody waste, it cannot be used by anaerobic digestion, and the chosen route is thermal gasification. In this process, forest biomass is transformed into a synthesis gas, which is then reformed with steam to obtain biomethane. However, the synthesis gas already has a high added value and could be used for the production of other products such as bio-SAF.

Catch crops: they represent a potential of almost 60 TWh-biomethane/year (37.5% of the total). Catch crop is the use of a second crop before or after the harvest of the main food or feed crop. In theory, under the right conditions, this type of crop can be applied in a way that does not affect the yield of the main crop. However, this practice has only been applied in Italy, while in Spain it has not been widely implemented [6].

Agricultural biomass: In addition, agricultural biomass, while in part perfectly suitable for biomethane production, is one of the ICAO-approved routes for bio-SAF production.

If none of these feedstocks were used for biomethane production, the potential would decrease from 165 to 52 TWh/year. Figure 19 shows the availability and demand for biomethane and hydrogen required in this scenario. The supply of biomethane would be insufficient to cover the demand for high temperature heat or part of the demand for maritime transport.

Therefore, if intended for industrial applications, the bio-LNG quota set by ReFuelEU Maritime should be met by using methanol or ammonia *(33)*

[33] For more information on a possible hydrogen demand to cover the shortfall in bio-LNG availability see section 4.1.2.5.

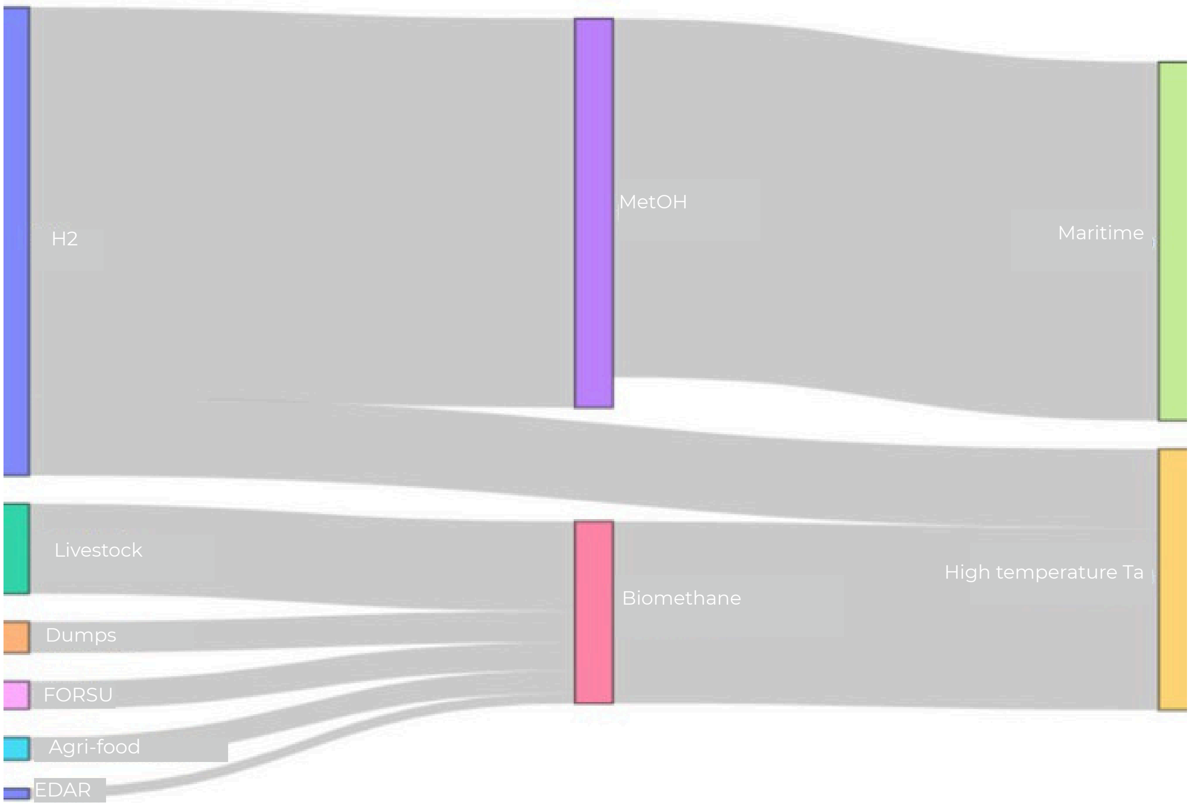

Figure 19. Comparison between potential demand and estimated availability of biomethane. For more information see Annex I b)

4. 1. 2. 2. Air transport

Figure 20 shows ReFuelEU aviation's target share of SAF for different years. This quota can be met through the consumption of bio-SAF, e-SAF or low-carbon aviation fuels.

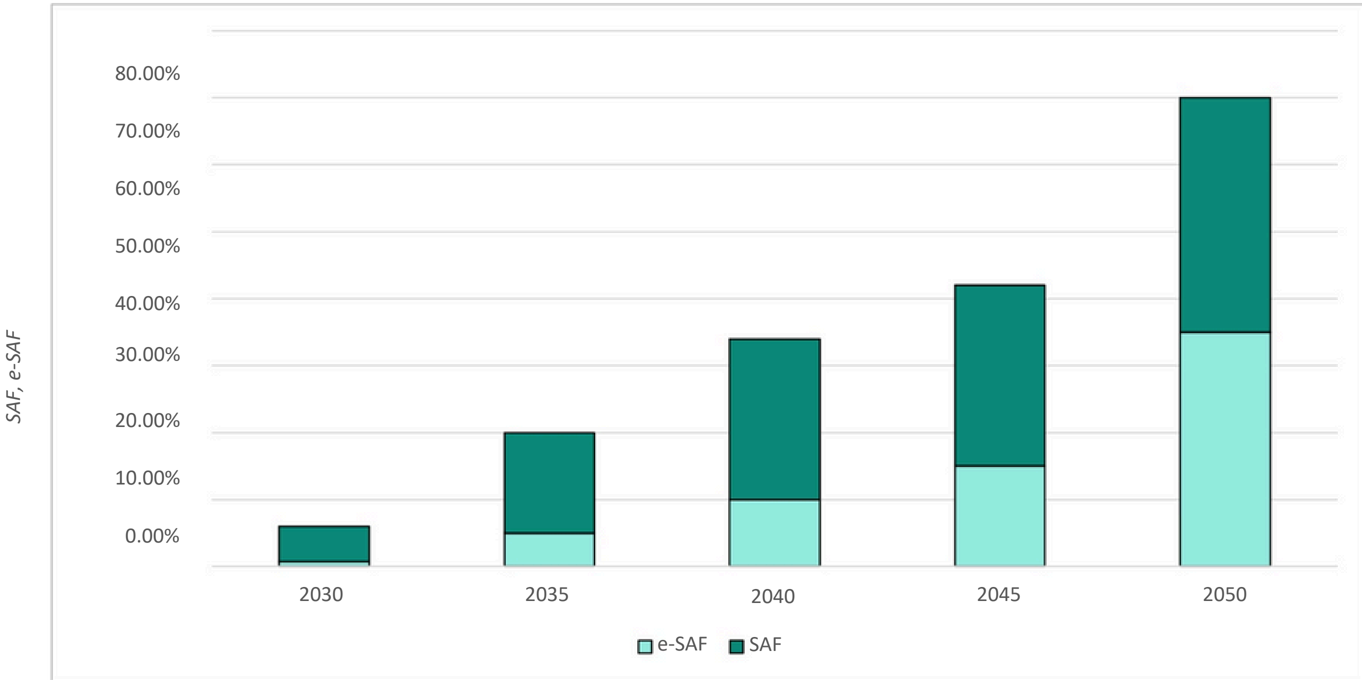

Figure 20. SAF quota in ReFuelEU Aviation

The availability of bio-based feedstock for the production of bio-SAF is assessed below. There are several routes available to produce International Civil Aviation Organisation (ICAO) approved PBS or e-SAF. *(34)*. The latest report of the European Aviation Safety Association (EASA) compiles the most important PFS production projects at European level, of which the vast majority opt for the Fischer Tropsch route, from bio-based feedstocks, co-processing in refineries, the HEFA route or the PtL route *(35)*. Another ICAO-approved pathway, Alcohol-to-Jet (ATJ), has only one planned facility in the whole of Europe, located in Sweden.

Therefore, the following considerations were taken into account to estimate the production capacity of PBS:

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[34] https://www.icao.int/environmental-protection/Pages/SAF_RULESOFTHUMB.aspx

[35] Electrolytic Hydrogen and CO2

- Two possible pathways for bio-SAF production were selected: HEFA, FT.
- ReFuelEU excludes the use of intermediate crops as potential feedstocks for the production of PBS, as well as palm oil derivatives such as POME.
- The HEFA pathway uses used cooking oil producing HVO as a co-product.
- RED III sets a limit of 1.7% on bio-based fuels generated from OUCO for total transport consumption, includes all distillate products from the production of PBS.
- The FT pathway is produced from synthesis gas. Bio-SAF production takes place by gasification of biomass to produce synthesis gas.
- The availability of feedstock as well as process and feedstock related PFS yields can be found in Annex I(c).

Figure 21 shows the percentage of current demand for PBS that could be met by bio-based feedstocks compared to the bio-PBS targets for different years*(36)*. As shown, the 2030 targets could be met by up to 3.5% with UF from UCO. The bio-FCS potential from OU is 3.55 TWh/year*(37)*. The 2045 targets could be met by using all forest and agricultural biomass for the generation of UF, while to meet the 2050 targets, 7% of UF (5.5 TWh/year) would need to be supplied. This 7% could be supplied by bio-SAF from other feedstocks such as MSW, by e-SAF or by aviation fuels. If supplied by e-SAF, it would require an additional hydrogen demand of 367 kt/year, equivalent to 3.67 GW of electrolysis.

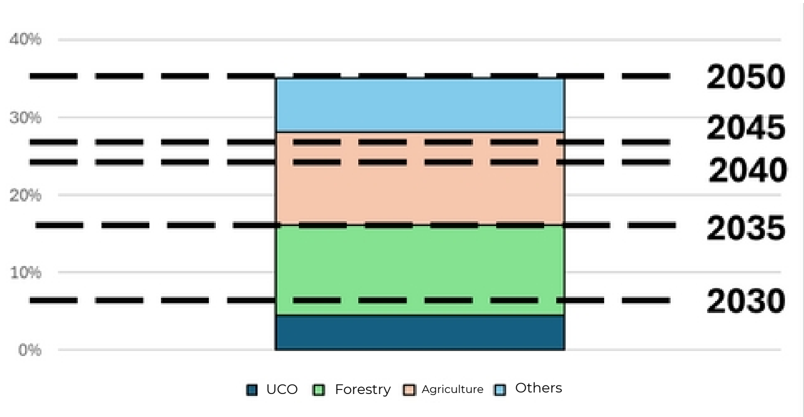

Figure 21. Potential bio-SAF production and share needed to reach ReFuelEU Aviation targets at different time horizons

[36] The target is calculated as the total SAF quota for the different years minus the mandatory e-SAF quota.

[37] It should be recalled that production of UF from UCO generates 40% UF, 50% HVO and 10% light hydrocarbons. Taking into account the fuel consumed in all transport segments, the limit of 1.7% corresponds to approximately 9 TWh/year including all distillate products from the production of SAF.

4. 1. 2. 3. Road transport

A large part of the decarbonisation of road transport could be achieved through the electrification of light-duty vehicles. However, the electrification of heavy goods vehicles or intercity buses is more uncertain. In this respect, hydrogen could contribute to meeting these objectives, although other fuels such as HVO (Hydrotreated Vegetable Oil)*(38)* are more attractive to hauliers as they can be used in conventional diesel vehicles.

HVO is a fuel that is produced from vegetable oils, used cooking oils or animal fats. In Spain, 52% of HVO comes from FFBs (fresh fruit branches), 21% from POME (waste generated in the extraction of palm oil from which oil can be extracted), 14% from UCO (used cooking oil) and the remaining 13% from other raw materials (animal fats, food waste, etc.).

According to RED III, FFBs cannot be used for HVO as they are feedstocks with a high risk of indirect land use change, so feedstock availability could be a constraint for the growth in HVO consumption. Most of the planned HVO plants consider the consumption of UCO, however, it has to be taken into account, as mentioned above, that RED III limits fuels from UCO to a 1.7% share of energy including all modes of transport.

Taking into account the fuel consumed in all segments, this 1,7 % corresponds to 9 TWh/year, or in other words 747 kt of HVO in case 100 % of the UCO will be used for HVO production *(39)*. However, as mentioned above, it is likely that a high fraction of UCO will also be used for the production of HEFA and HVO simultaneously. In this scenario, the availability of HVO from UCO would be reduced to around 370 kt HVO

On the other hand, the production of bio-SAF from agricultural or forestry residues could also increase the availability of HVO. Figure 22 shows the potential for HVO availability depending on the origin. In total, HVO has the potential to supply up to 19% of the current diesel demand in freight transport if 100% of UCO would be used for HVO production. This figure would otherwise be reduced to 13 %.

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[38] Fatty acid methyl ester (FAME) is another alternative for decarbonising road transport. However, it cannot replace diesel by 100 % as FAME contents higher than 20 % affect the quality of the fuel. For this reason, for simplicity, only HVO is considered as a potential alternative to hydrogen.

[39] It should be remembered that UCO is also receiving a lot of attention in air transport for HEFA production, which would reduce its availability for road transport.

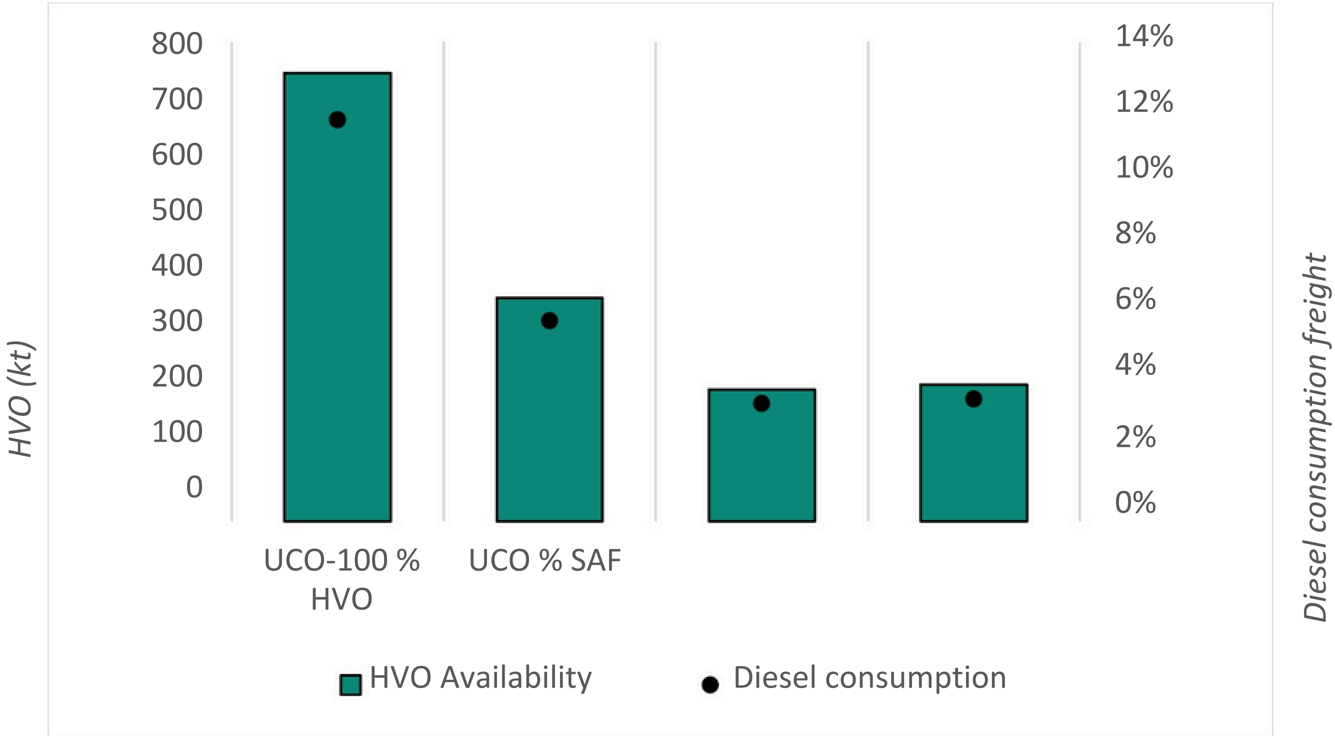

Figure 22. Potential availability of HVO relative to diesel consumpion in road freight transport in 2023.

In relation to the above, it is relevant to mention the regulation setting CO_2 emission standards for new heavy duty vehicles. This regulation sets targets for the progressive reduction of average CO_2 emissions for new heavy duty vehicles registered in the European Union between 2025 and 2050. These targets would fall on manufacturers who in turn would be exposed to possible penalties.

This regulation covers not only heavy goods vehicles, but also medium-sized trucks, city buses, coaches and trailers. The defined targets envisage a reduction of 15% by 2025, 30% by 2030, 65% by 2035 and finally 90% by 2040. In the legislation stipulates that 90% of new buses will have to be zero emission by 2030, and 100% fom 2035 onwards.

The only technologies considered zero emission technologies are battery electric, fuel cell electric and hydrogen combustion engine vehicles. Hydrogen will therefore play a key role in achieving these targets, especially from 2040 onwards, in all cases where electrification is not possible due to limited service requirements (range, recharging times, additional consumption due to unevenness or cooling, etc.) or restrictions on access to recharging infrastructure.

4. 1. 2. 4. Incorporation of renewable energies in industry

In addition to the share of renewable hydrogen in the total hydrogen used in industry (see section 4.2.1.2), Article 22a of RED III sets an indicative target of increasing the use of renewable energies in industry by at least 1.6 % on average per year during the periods 2021-2025 and 2026-2030. The Spanish PNIEC raises this target to 2.14% and 2.97% for the periods 2021-2025 and 2026-2030 respectively.

However, apart from being a target for the use of renewable energy in previous years and voluntary, RED III does not specify what kind of measures Member States have to take in order to achieve it, nor does it make any distinction by required temperature ranges. Therefore, it does not appear that associated obligation mechanisms will be put in place. Furthermore, the increase of this quota can be achieved, beyond the use of hydrogen, through direct electrification, use of waste heat, solar thermal energy or biomethane consumption. In view of the above, it has been decided to assume that the increase in hydrogen demand industry associated with this objective will not be relevant in the 2030 horizon.

4. 1. 2. 5. What demand for hydrogen would emerge in Spain as a result of the fulfilment of more general objectives defined European regulations?

In order to present an overall demand scenario, potential demands for the fulfilment of the RFNBOs sub-targets presented in Figure 23 (100% RFNBO scenario) and the hydrogen potentials derived from the limited biomass availability presented throughout this section are grouped together. The assumptions for development of this scenario are presented below:

- All agricultural and forestry biomass is used for the production e-SAF.
- The potential for the production of intermediate crops for biomethane is not considered. All available biomethane is destined for high-temperature heat generation in industry.
- The bioLNG default for compliance with the emission intensity quota in ReFuelEU Maritime is replaced by RFNBO*(40)* methanol.
- The share of bio-SAF that cannot be covered using UCO, forest biomass or agricultural biomass is supplied by e-SAF from RFNBO hydrogen.

[40] For RFNBO methanol, an emission reduction of 100 is assumed, compared to an emission of 83 % for bio-LNG. For this reason, the allowable LNG share increases compared to the use of bio-LNG. For more information see Annex d).

The resulting scenario is shown in Figure 23. For the years 2030 and 2035, no additional demand for hydrogen is foreseen, as the expected demand is limited to that needed to meet the minimum targets set by the RFNBO quotas. However, from 2040 onwards, it would be necessary to incorporate RFNBO methanol in shipping to meet the emission intensity reduction targets, which would generate a significant increase in hydrogen demand. This share would continue to increase progressively until 2050, becoming the main source of additional demand beyond the targets set by the RFNBO quotas.

As for e-SAF, no additional production is required until 2045, as demand can be fully met by bio-SAF. This situation changes in 2050, when a small additional demand for hydrogen for e-SAF production arises.

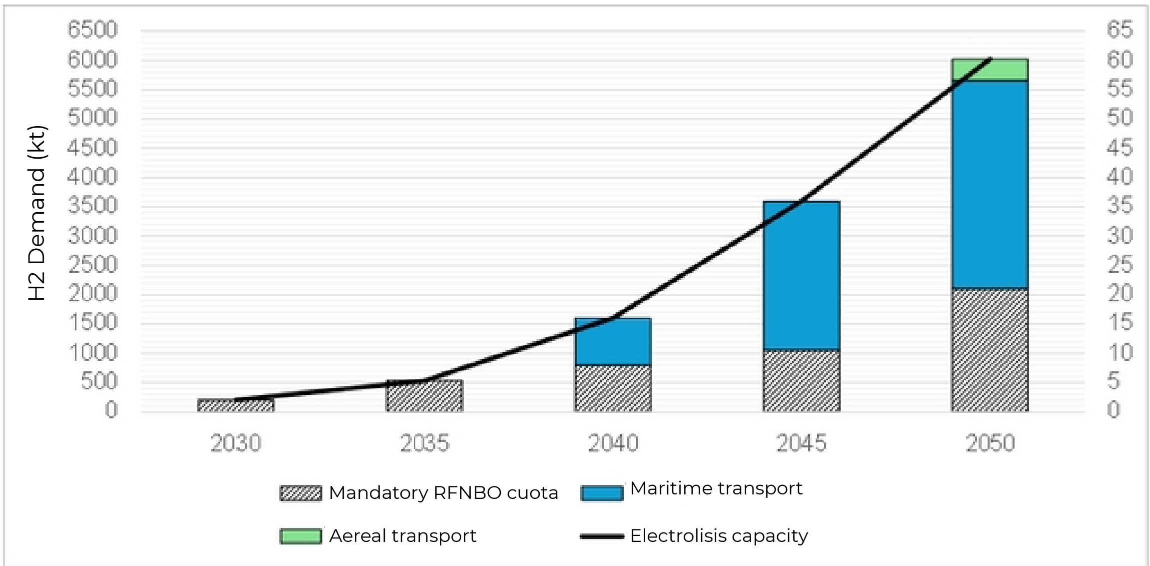

Figure 23. Expected H2 demand and electrolysis capacity derived from the fulfilment of more general objectives defined in the European regulation.

In this context, it is estimated that electrolysis capacity would reach 50GW by 2050. If the currently announced projects, totalling 22GW, are realised, it would be possible to cover most of the national hydrogen demand until 2045.

4.2. Renewable hydrogen in the PNIEC target scenario

The role of renewable hydrogen in the target scenario proposed by the Integrated National Energy and Climate Plan is analysed, as this is an obligatory reference for any future energy scenario to be drawn up for Spain.

In relation to production, the main data provided by the PNIEC is the 11.98 GW of installed electrolysis power, which usually rounded up to 12GW. However, the PNIEC makes no explicit reference to the volume of hydrogen produced, which will depend on the assumptions made in relation to the specific consumption of the electrolyser and the operating hours of the upstream power.

In this respect, electricity consumption in energy transformation sector over the study horizon is provided (Table A.20 of the PNIEC). This sector includes refining for the production of fossil fuels and biofuels and the production of electrolytic renewable hydrogen. In this way, it is possible to estimate the electricity consumption of the installed electrolysis power.

For calculation purposes, this report derives the total electricity consumption for hydrogen production as the difference between the consumption in the energy transformation sector between 2030 (55 823 GWh) and 2020 (7 517 GWh). This implicitly assumes that in 2020 there is no production of electrolytic hydrogen and the entire electricity consumption in this sector corresponds to refining. It is also assumed that electricity consumption in the refinery in 2030 remains the same as in 2020.

Under these assumptions, in the PNIEC target scenario, 48 306 GWh of electricity would be used for hydrogen production which, considering a specific consumption of electrolysis of 55 kWh/kg-H2 (equivalent to an efficiency of about 60 %), would give a production of 878 kt.

In relation to the final uses of hydrogen and its derivatives in Spain in the 2030 horizon, the two most relevant data from the PNIEC are as follows:

- 74.46% share of RFNBOs over hydrogen used in industry for non-energy end uses (e.g. excluding production of conventional fuels and biofuels).
- 11.61% share of RFNBOs in the energy supplied to the transport sector and 3.56% contribution of RFNBOs to final energy consumption in transport. The difference between the two percentages lies in the fact that, while the latter is directly a quotient between RFNBOs energy and total energy in transport, the former percentage, to the rules defined in RED III, is affected by a number of multipliers *(41)* and additionally includes the possible use of RFNBOs in the production of fuels and biofuels.

[41] The contribution of RFNBOs shall be considered to be twice their energy content, when going to a mode of transport other than aviation or maritime, and 3 when going to either of these two sectors.

The plan does not explicitly translate these percentages into quantities of hydrogen demanded, nor are the calculation assumptions adopted provided (e.g. breakdown between transport sub-sectors, hydrogen demand in industry in 2030, amount of RFNBO used in refining, etc.). In order to be able to make an estimate in this report, a number of assumptions have therefore been made, as described below.

In the case of industry, the PNIEC does not provide the final hydrogen demand in industry for non-energy uses in 2030. For illustrative purposes, the assumption will be made that this remains the same as demand observed in 2023 according to data from the European Hydrogen Observatory*(42)*. Excluding refining, which demanded more than 80% of the total in 2023, this would leave a total of 103.5 kt of hydrogen in industry. Therefore, the PNIEC target of 74.46% would result in approximately 77.1 kt of renewable hydrogen in 2030.

On the other hand, for transport, the PNIEC does provide data on final demand in transport in the 2030 target scenario, which is estimated at 27397 ktoe. Multiplying the contribution of 3.56% by this final energy directly gives the final energy demand supplied in the form of RFNBOs to transport in 2030.

In order to translate this energy into electrolytic hydrogen mass, it would be necessary to know what percentage of each type of RFNBO has been considered. In order to estimate this conversion, for the sake of simplicity, it is assumed that the 1.2% contribution of synthetic PBS identified in ReFuelEU Aviation would be achieved by 2030, with the remainder going to the road *(43)*.

In section 4.1.1.3 it was quantified that reaching the ReFuelEU Aviation target in 2030 would require producing about 79 kt of e-SAF using approximately 62.7 kt of hydrogen. This would mean that 278 kt of hydrogen on the road would be needed to reach the 3.56% of final energy in transport. In total, this would amount to just over 340 kt of hydrogen used directly in transport.

Applying the multipliers for the energy supplied to the different transport modes calculated above would result in share of RFNBOs in transport of 7.8%. To reach the 11.61% defined in the PNIEC, and considering a multiplier of 2, it would be necessary to use about 183.4 kt of hydrogen for the production of transport fuels (approximately 39% of hydrogen consumption in refining in 2023).

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42 https://observatory.clean-hydrogen.europa.eu/hydrogen-landscape/end-use/hydrogen-demand

43 It has already been discussed earlier how by 2030 shipping will reduce the emission intensity of its fuels mainly through LNG.

Adding up all the above quantities and comparing this figure with estimated production, an excess of hydrogen of some 277 kt is observed. This difference may be due, on the one hand, to errors in the interpretation of the PNIEC or differences in the calculation assumptions, or on the other hand, to the fact that the PNIEC computes hydrogen use in sectors not considered in our calculations.

In the latter case, the sectors most likely to see the use of hydrogen would be the production of ammonia, urea or methanol, replacing imports of these, steel in the event that any of the direct reduction projects proposed finally materialise, or the refining sector itself for the production of fuels not destined for transport or non- energy products.

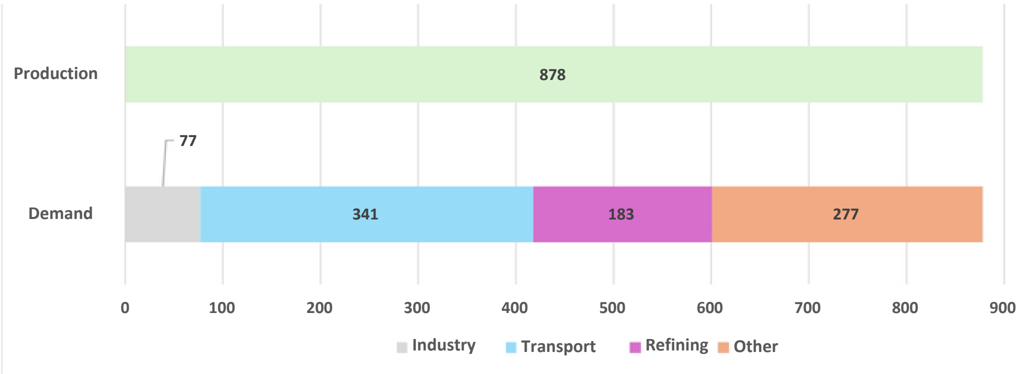

Figure 23: Estimated amount of renewable hydrogen produced and consumed in the PNIEC 2030 target scenario (kt H2)

The results of the above exercise are summarised in Figure 7, where several striking aspects can be noted. Firstly, there is the fact that hydrogen consumption in transport is very high and represents the majority of hydrogen end-use; in fact, the 11.61% share of RFNBOs in transport is much higher than the minimum share set by RED III for the year 2030 of 1% (see section 4.2.1). In fact, this 1% would be exceeded simply by the amount of hydrogen used in refining. Another relevant aspect is that the electrolysers would operate just over 4000 h at full load equivalent per year or, in other words, they would operate at a load level of only 46%.

4.3. Conclusions on the applications of renewable hydrogen in Spain

As shown in this section, hydrogen and hydrogen derivatives are key to achieving European decarbonisation targets. A distinction can be made between two types of targets: those specific to hydrogen or hydrogen derivatives consumption and those more general, where hydrogen competes with other technologies.

The specific targets for hydrogen in 2030 add up to a demand of approximately 200 kt/year, equivalent to 2 GW of electrolysis capacity. By 2050, this demand would increase to 2100 kt/year or 21 GW of electrolysis. It is important to note that most of the growth in regulatory demand for RFNBOs comes from the production of e- SAF, which could also be met by the use of non-fossil low-carbon fuels.

The 2030 scenario contrasts significantly with the projections of the PNIEC, which sets an electrolysis capacity of 12 GW for 2030. These differences are due to the ambition of the quotas set for RFNBOs in the transport and industry sectors.

In the case of transport, the RFNBO penetration target is 11.61*(44)*, well above the 1% established by European regulation. In the industrial sector, the penetration target is 73%, far exceeding the 42% set at European level. Furthermore, the PNIEC implicitly seems to assume a very low level of utilisation, lower than the hypothesis adopted in this report. It should not be forgotten that in addition to the specific targets for hydrogen consumption, there are other more general decarbonisation targets, where hydrogen can also play a key role. For this reason, the fulfilment of more general targets was also analysed to study the role of hydrogen.

First, the emission reduction targets set by FuelEU Maritime were analysed. The results indicate that, until 2035, the required emission intensity can be achieved through the exclusive use of LNG. From 2040 onwards, it will be necessary to incorporate a fraction of bio-LNG or other renewable fuels, reaching a 96% share of bio-LNG in 2050 (in case RFNBOs are not considered).

To assess the availability of bio-LNG for maritime transport, the biomethane potential in Spain was compared with the projected demand, which comes not only from maritime transport, but mainly from industry, where natural gas is used for high temperature heat generation. According to Sedigas estimates, the production potential amounts to 160 TWh/year, an amount sufficient to 100 % of the industrial high temperature heat demand and up to 80 % of the maritime transport demand.

In this scenario, no additional hydrogen fuels would need to be produced to meet regulatory targets. However, it is important to note that this estimate is particularly optimistic compared to other sources, such as those of the IDAE, which place the potential at between 20 and 24 TWh/year. In addition, there are biomass sources, such as those from intermediate crops, which have significant potential, but little developed in Spain, which generates great uncertainty.

[44] This figure includes multipliers and hydrogen used in refining. For more information, see 4.2.

On the other hand, potentials related to forest or agricultural biomass can also be harnessed in the production of PBS to meet the PBS targets set by ReFuelEU Aviation. The results indicate that, until 2040, it would be possible to meet these targets using used cooking oil, forest biomass and agricultural biomass. By 2050, the remaining fraction of AFS could be covered by e-SAF requiring approximately 3.67 GW of additional electrolysis. It is important to note that the use of forest and agricultural biomass to produce PBS would reduce the potential available for biomethane production, creating a shortfall that would then have to be compensated by hydrogen and its derivatives.

Finally, the availability of HVO for use in transport was analysed, concluding that the estimated production could cover between 13% and 19% of diesel demand in freight transport. Although there are currently no specific targets for the uptake of RFNBOs in this sector, the entry into force of the new ETS, together with the regulation setting a 45% reduction by 2030 and a 90% reduction by 2040 in emissions from newly purchased heavy duty vehicles (CO2 standard for heavy duty vehicles), puts increasing pressure on manufacturers and consumers to increase the use of zero emission vehicles, i.e. battery electric, fuel cell, or hydrogen combustion engine.

Overall, the lack of feedstock availability for biofuel production could generate an additional demand of around 39 GW by 2050. This demand, added to the 21 GW of electrolysis needed to meet mandatory RFNBO targets, would lead to an installed electrolysis capacity of up to 60 GW.

The demand scenarios analysed show the need to incorporate hydrogen, not only to meet specific targets, but also to make progress towards more general decarbonisation goals. The scaling up of hydrogen demand is expected to occur from 2040 onwards due to a combination of various factors such as more stringent synthetic PAS quotas, limited availability of certain feedstocks for biofuel production from waste, very restrictive emission standards for new heavy-duty road vehicles, emission intensity reduction targets for marine fuels, among others.

In the shorter term, these results highlight the discrepancy between the ambition of the PNIEC for 2030 (with an estimated demand of 800-900 kt/year) and the targets set in the European regulation (estimated at 200-300 kt/year).

5.MEDIUM AND LONG-TERM DEVELOPMENTS IN THE HYDROGEN ECONOMY.

5.1. The current state of hydrogen and hydrogen derivatives markets.

The European Hydrogen Strategy (COM/2020/31) states that achieving the EU's energy transition will require hydrogen production and consumption. This is not only a reality in Europe but a global objective. However, as highlighted in the annual report 2022-2023 of the Centre for Low Carbon Hydrogen Studies (ICAI-ICADE, Universidad Pontificia Comillas)*(45)*, recent data show that the costs of the first batch of hydrogen projects have been revised upwards and that subsidies have not yet yielded anything close to the required return*(46)*.

As can be seen in BloombergNEF's hydrogen strategy tracking map, there are currently 53 countries with a published hydrogen strategy, 30 countries with a strategy in preparation. 58 countries show no activity and 30 could not be assessed. This represents an increase in the number of available strategies by 26% over last year. The number of strategies in preparation has decreased by 16%. About 62% of the published strategies are in Europe, Middle East and Africa, 21% in the Americas region and 17% in Asia Pacific.

The same report notes that, although clean hydrogen production could triple by 2024 and increase 30-fold by 2030, growth is below what is needed to meet policy targets.

Indeed, in the context of the European Union, the European Court of Auditors in its report reviewing industrial policy in the field of renewable hydrogen*(47)*, points out that the targets of producing and importing 10 million tonnes of renewable hydrogen by 2030 are unlikely to be met on schedule.

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45 See Report Chair in Hydrogen Studies Comillas

46 See "Lex in depth: how the hydrogen hype fizzled out", Financial Times, May the 20th 2024

47 See Special Report 11/2024: The EU's renewable hydrogen industrial policy

Figure X: Hydrogen strategy map

Source: BNEF (2024)

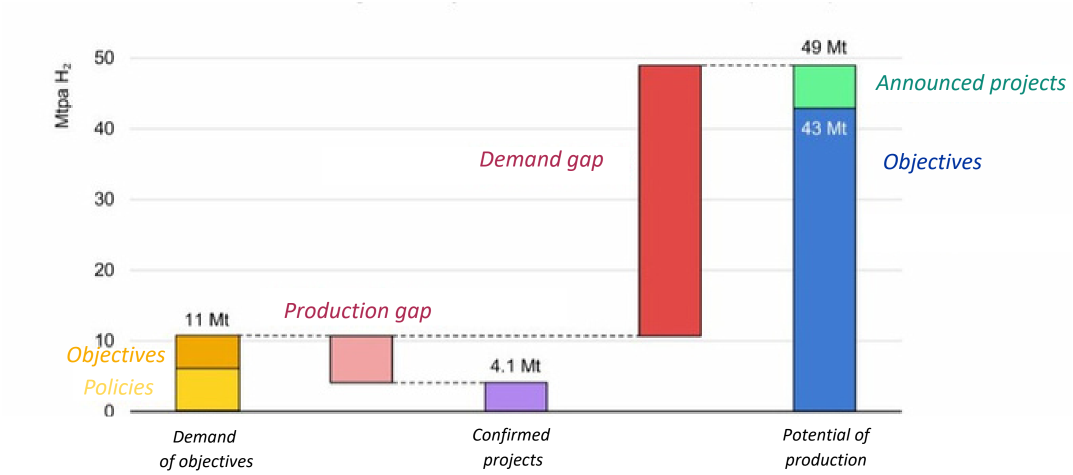
In the following sections we will analyse in detail the main challenges facing the nascent hydrogen market in achieving these goals, which can be summarised as the industry needs more demand incentives to grow at the necessary pace:

- Public policies are insufficient: most governments will not reach their hydrogen targets without tougher demands and better incentives.
- The development of demand with binding commitments is low: only 12% of planned capacity has buyers, and only 11% of contracts are binging.
- Firm investment is still very limited: Only on 7% of the announced capacity has reached a final investment decision.
- Supply is not the bottleneck: electrolyser manufacturing is in overcapacity, but demand remains low.
- Infraestructure is lagging behind: construction of storage and gas pipelines is progressing slowly, especially in Europe.

5.1.1. Public policies and objectives

Globally, there is a policy and target imbalance between future hydrogen supply and demand. Based on the compilation carried out by the International Energy Agency (IEA)*(48)*, the government policies and objectives established at global level for 2030 place low-emission hydrogen production*(49)* at 43 million tonnes per year (Mt/y), while those relating to demand only reach 11 Mt/y. This imbalance would be even greater if the announced production projects, which amount to 49 Mt/y by that date, are taken into account. These data show that public policies are putting more emphasis on production than on demand.

Figure X: Mismatch between global supply and demand targets for 2030



Source: IEA "Global Hydrogen Review" (2024)

In setting targets for low-emission hydrogen, it is essential to distinguish between supply-side and demand-side targets and policies:

- On the supply side, they focus on the quantities of hydrogen to be produced, usually measured in millions of tonnes. These targets drive investment in electrolysis capacity and the infrastructure needed for hydrogen production. They also facilitate the design of support such as investment grants, electricity tax exemptions, auctions and tariffs.
- On the demand side, they seek to promote hydrogen integration in key sectors. These targets support the design of policies such as quotas, penalties or contracts for carbon differences that facilitate the substitution of fossil fuels.

[48] IEA: "Global Hydrogen Review" (2024)

[49] Low-emission hydrogen includes renewable hydrogen from electrolysis and fossil fuels combined with carbon capture and storage (CCS).

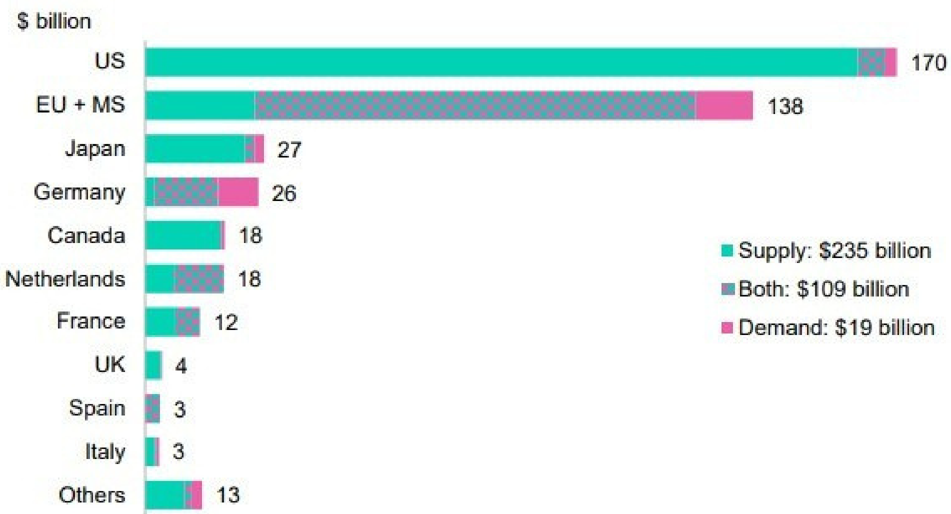
The main challenge currently facing the hydrogen economy is to stimulate demand sufficiently to balance supply, especially given the current concentration of hydrogen demand and the slow uptake in new uses. In parallel, if public initiatives dedicated to supply do not trigger a corresponding increase in demand, these initiatives face the risks of lack of real demand and commercialisation problems, making investment decisions difficult.

More than $360 billion is available for hydrogen, but very little goes to demand

- Government support: Until 30 April 2024, governments have allocated USD 362 billion for clean hydrogen. The US leads with 170 billion, followed by the EU and its member states with a combined total of 138 billion.
- Distribution of support: 65% of the money is earmarked for the supply of hydrogen, while only 5% goes to demand. The rest goes to infrastructure and a combination of supply and demand. This creates an imbalance, as most of the proposed projects lack buyers.
- Demand problem: Lack of support for demand means that many projects do not have secured customers. A recent example is the seven winners of the EU Hydrogen Bank auction, who must now look for buyers.

In summary, although there is strong financial support, the lack of demand-side incentives limits the growth of the clean hydrogen market.

Figure X: Government support by country and target area



Source: BNEF Hydrogen Subsidies Tracker (web | terminal). Note: EU + MS = European Union plus its member states. 'Both' also includes support for hydrogen midstream (storage and transport).

5.1.2. Developments in demand and binding contracts

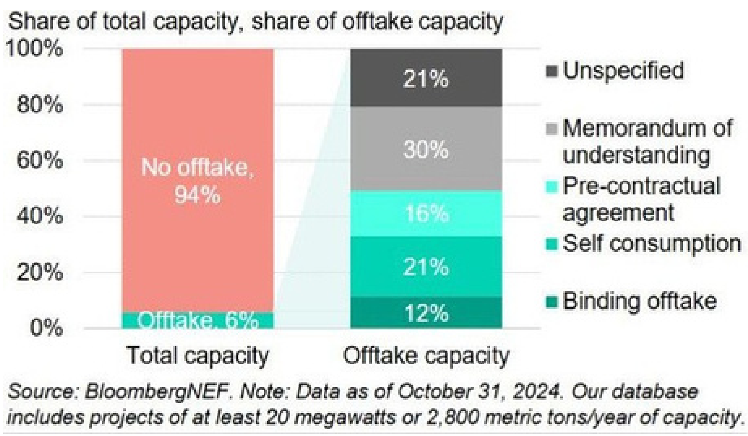
Binding purchase agreements are still very limited, representing 12% of the contracted volume.

Based on the Hydrogen Purchasing Agreements database, published in December 2024 by BloombergNEF, demand for clean hydrogen is growing, but remains low, according to this data.

This source has 269 purchase agreements for 13 million tonnes per year of clean hydrogen and its derivatives. This is increase of 17% compared to the data published between April and October 2024. The same source acknowledges that only 6% of the announced supply has a buyer, and only 12% of the entire contracted volume is binding, equivalent to 1.6 million metric tonnes of clean hydrogen per year. This has increased by 28% since April, thanks to five new binding contracts. About 2% of the contracted production volume was cancelled by developers since April 2024, all related to non-binding purchase contracts.

The same report states that clean hydrogen derivatives are more popular than hydrogen itself. Nearly 60% of the contracted volume is for ammonia (NH_3) or methanol (CH_3OH). Three of the five largest deals since April 2024 were for blue hydrogen and derivatives*(50)* India's green hydrogen is popular with importers in the EU and Japan, who have signed six purchase agreements with Indian projects since April.

Figure X: Hydrogen demand by type of contract

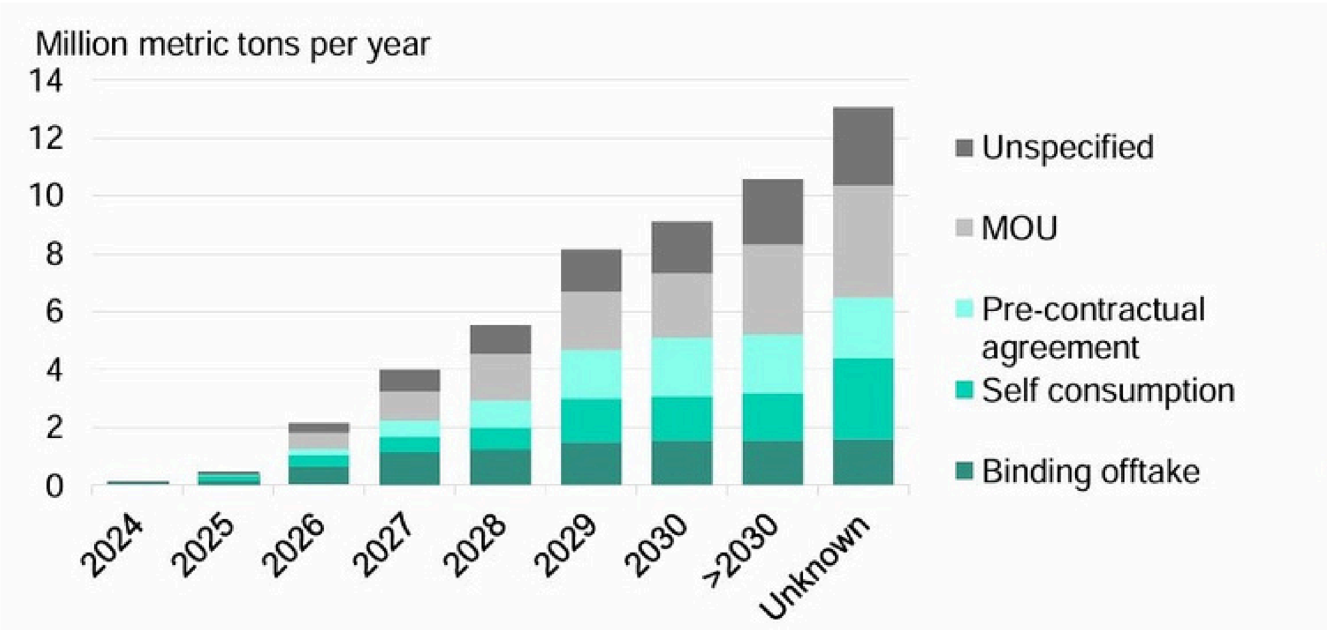


[50] A summary of this report is available at https://www.linkedin.com/posts/mtengler_hydrogen-offtake-h2-activity-7282801517403811843-bmA6/?utm_source=share&utm_medium=member_ios

Most of the binding contracts foresee deliveries starting 2026 and 2027. As hydrogen projects require two to three years to build after securing financing, those that are signing agreements now are likely to have planned start-up in 2026, with deliveries starting in 2027.

In addition, many of these self-consumption projects are targeting commissioning in 2028 and beyond. It is worth noting that more than 40% of the volume of these projects do not yet have a specific commissioning date.

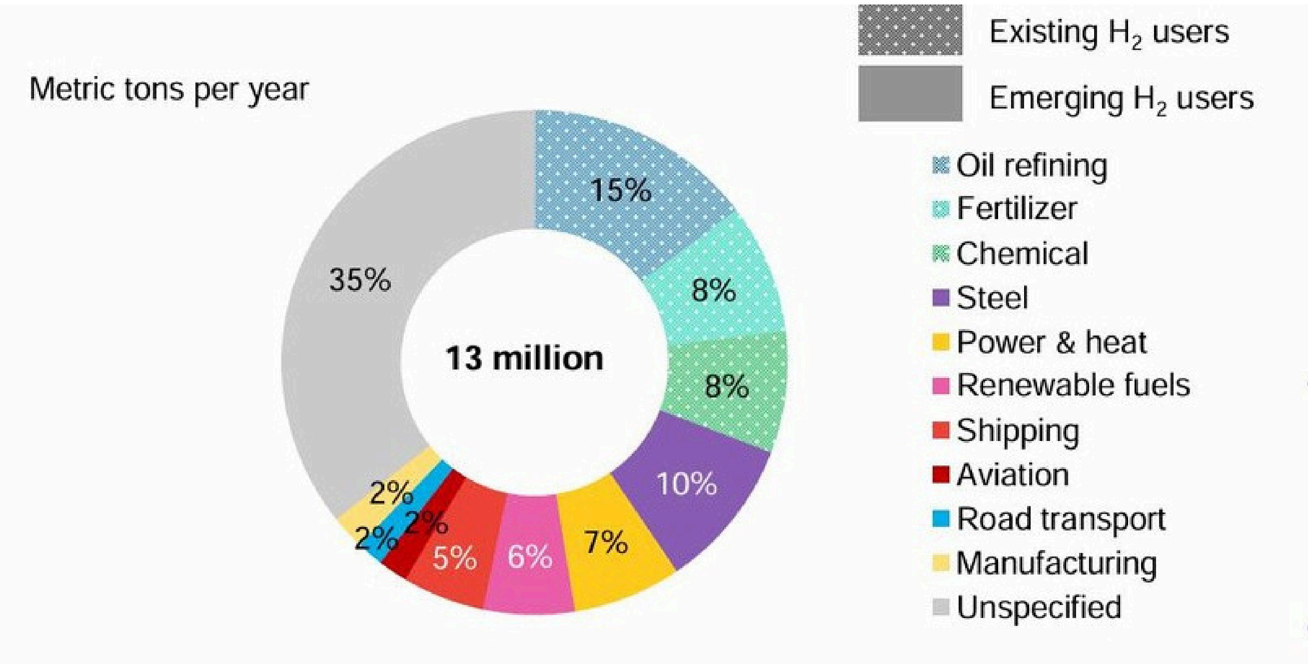
Figure X: Cumulative hydrogen demand by delivery date



Source: BloombergNEF. Note: Data as of October 31, 2024. BNEF's Hydrogen Offtake Agreement Database only includes projects of at least 20 megawatts or 2,800 metric tons/year of capacity. MOU is memorandum of understanding. Pre-contractual agreements include term sheets, letters of intent, and heads of agreements.

Analysing the sectors in which demand is concentrated, a relevant fact is that new sectors appear with 34% of the total volume, while traditional sectors represent 31%; the remaining 35% are not defined end consumer nor are destined for export. Among the sectors with new uses, the steel, electricity and heat generation sectors stand out, followed by renewable fuel producers and the maritime sector.

Figure X: Hydrogen demand by end-use



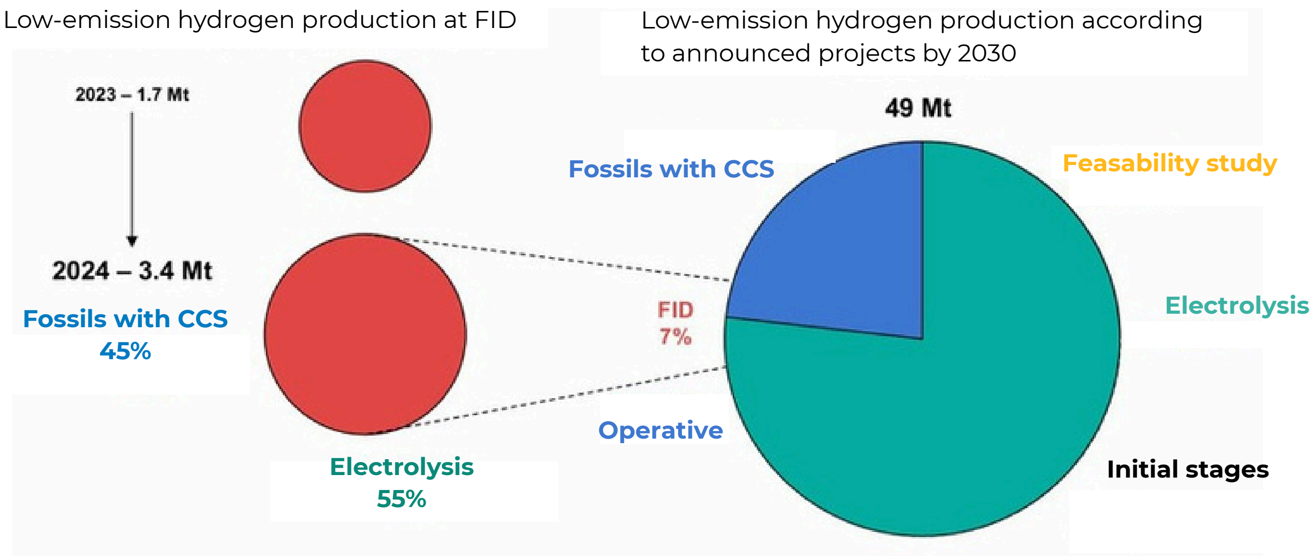
Source: BloombergNEF. Note: Data as of October 31, 2024. BNEF's Hydrogen Offtake Agreement Database only includes projects of at least 20 megawatts or 2,800 metric tons/year of capacity.

5.1.3. Investment decisions

Despite the increase in investment decisions in 2024, they account for only 7% of the projects announced for 2030 globally.

According to IEA data, the potential production of low-emission hydrogen in 2030, based on projects that have reached investment decisions (FIDs) by 2024, would increase by a factor of 2 compared to the previous year, reaching 3.4 million tonnes (Mt). Although the FID intake represents only 7% of the total 49 Mt of announced projects, they are 30% higher than in the previous year, split between electrolysis (55%) and fossil with CCS (45%). However, electrolysis projects would account for approximately 75% of the total projects announced by 2030; if we exclude those in very early stages and unlikely to be realised by that date, they would account for 66%.

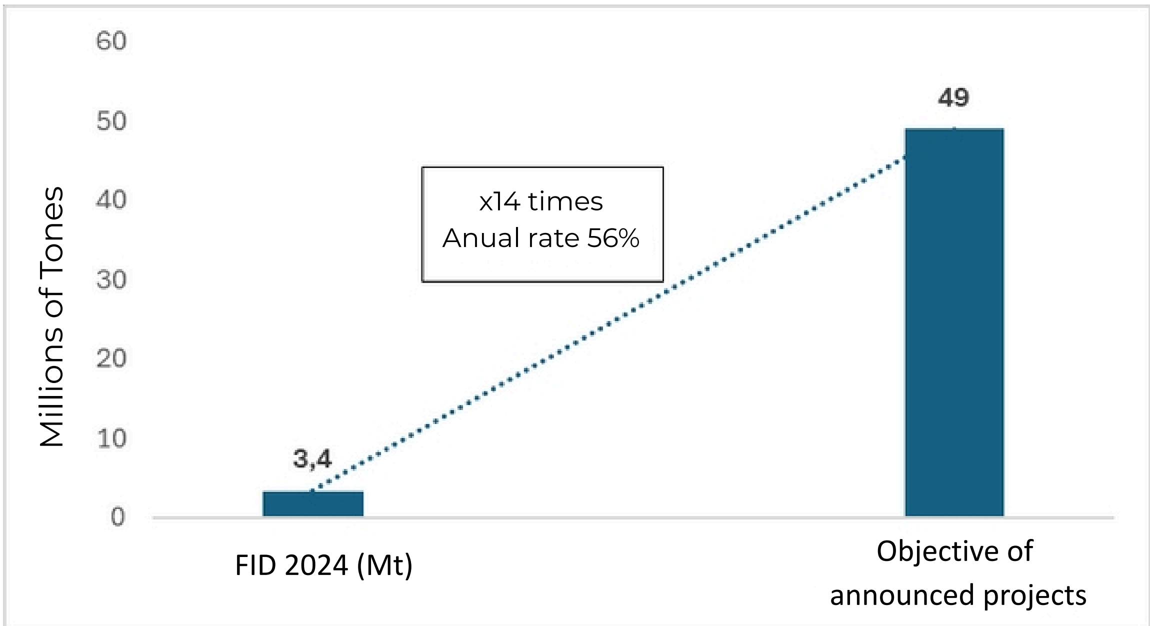
Figure X: Announced global targets for 2030 and investment decisions



Source: IEA "Global Hydrogen Review" (2024)

Despite the progress made this year, the IDF data is still far short of the global production targets for 2030, which in the period 2024-2030 would need to grow at a compound annual growth rate of 56% and multiply by a factor of 14.

Figure X: Evolution of FID needed to meet 2030 production targets



Source: Own elaboration

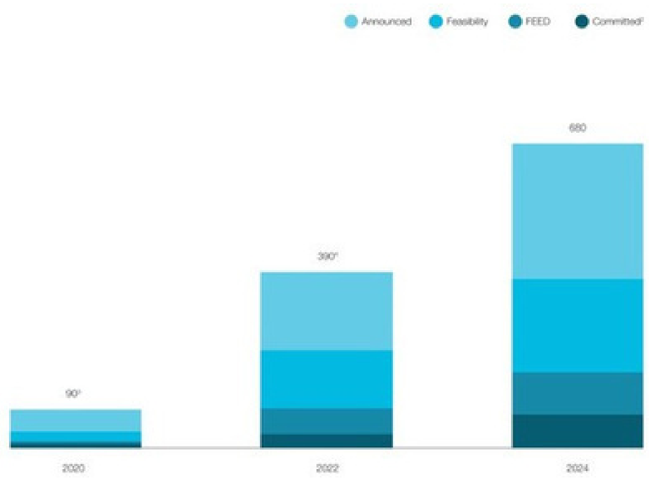
The overall volume of investments also demonstrates a greater focus on the supply side versus the demand side.

From the perspective of the overall volume of investments across the value chain, Hydrogen Council data*(51)* show that investments in low-emission hydrogen projects have also seen a significant increase in recent years, from USD 90 billion in 2020 to USD 680 billion in 2024, reflecting an exponential growth of the industry.

A maturing of projects is also observed, with a decrease in the proportion of projects at the announcement stage and an increase in those at more advanced stages, such as the committed stage (including all those in operation, under construction or FID), indicating concrete progress towards the materialisation of projects.

In particular, investments in the committed phase have doubled since 2022, from USD 30 billion (8% of total investments) to USD 75 billion (11%) in 2024. It is worth noting that in the previous year's report, this figure represented 9%. In relation to the average investment size for projects in the committed stage it has increased from USD 5 million in 2020 to USD 25 million in 2024, which clearly shows that projects are growing.

Figure X: Distribution of investments according to project development stages (billions of dollars)



Source: Hydrogen Council, "Hydrogen Insights" (2024). Data referring to December 2020, May 2022 and May 2024.

[51] Hydrogen Council & McKinsey Project & Investment Tracker data, referring to December 2020, May 2022 and May 2024.

The latest available data show that total announced investments up to 2030 for low-emission hydrogen have increased by approximately 20% in the period October 2023 to May 2024, from USD 572 billion to USD 678 billion, uneven growth across project stages and destinations within the value chain.

The highest growth of 90% is observed in the committed capital stage, followed by 30% in the engineering of design (FEED), 15% in announced projects and 2% feasibility stage projects, indicating an overall maturing of projects.

Now, 11% of low-emission hydrogen investments are committed (up from 7% previously) and 14% are in the FEED stage (up from 12% previously). Of the 90% growth in the committed stage, 60% is due to end-use investments ($21bn), infrastructure investments grow by about 40% ($20bn) and production and supply investments grow by 15% ($70bn), although growth in production and supply is also high in both the announced ($25bn) and FEED ($22bn) stages.

In summary, investments in production and supply account for 75% of the total, with the same trend as the previous year. This is followed by end-use investments with 15% and 10% in infrastructure, which also shows a greater focus on the supply side versus the demand side.

Figure X: Destination of investments according to project development stages until 2030 (billions of dollars)

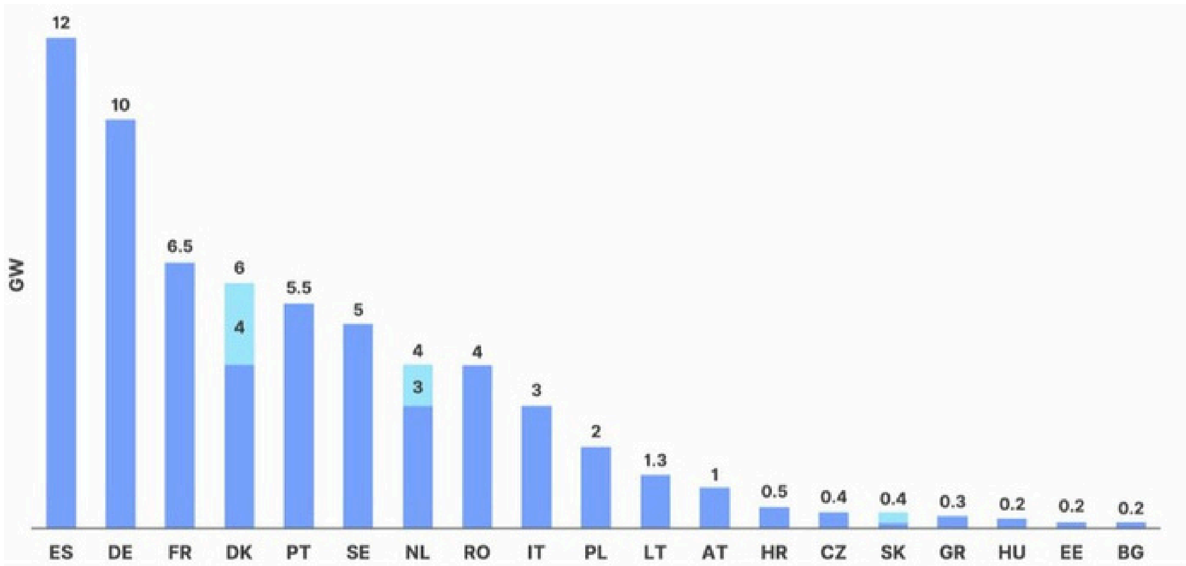
Source: Hydrogen Council, Project & Investment tracker. "Hydrogen Insights (2024)

In the European Union, renewable hydrogen projects installed or with FID are also insufficient with respect to the 2030 targets.

The EU hydrogen strategy prioritises renewable hydrogen produced by electrolysis as the most compatible with climate policy, but also recognises that hydrogen from other low-carbon sources will be needed in the short to medium term to enable the sector to develop.

The Agency for the Cooperation of Energy Regulators in the European Union (ACER) recognises that a total of 19 EU Member States have defined specific targets for the planned electrolysis capacity in 2030, reaching between 59 and 62 GW across the EU. Spain and Germany top the list with the most ambitious targets of 12 GW and 10 GW respectively. This is followed by France (6.5 GW), Denmark (4-6 GW), Portugal (5.5 GW) and Sweden (5 GW), with significant contributions to the total*(52)* It should be noted that these figures exceed the aggregate EU target of 40 GW by 2030.

Figure X: Electrolysis capacity targets for 2030 according to National Plans and Strategies



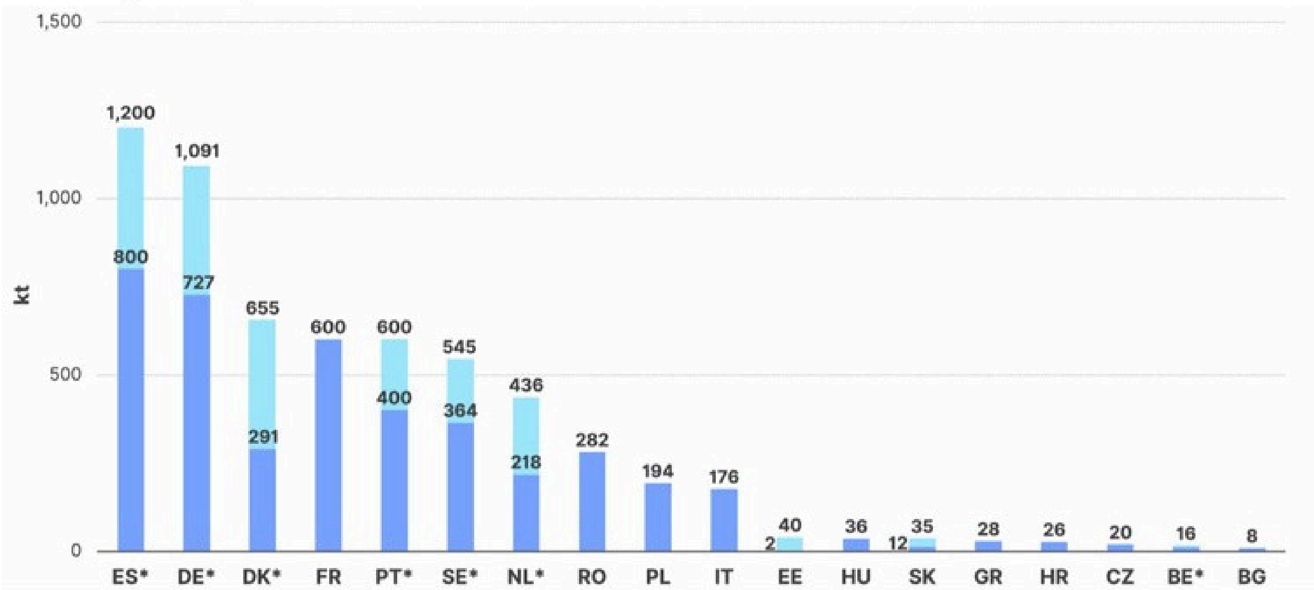
Source: ACER. "European hydrogen markets: 2024 Market Monitoring Report".

52 ACER: "European hydrogen markets: 2024 Market Monitoring Report".

Only a few EU Member States include concrete references on their renewable hydrogen production targets. Taking into account national strategies and certain estimates derived from the projected electrolysis capacity for 2030*(53)*, Spain and Germany again lead the list of countries, with 1.2 Mt/a and 1.1Mt/a, respectively.

A relevant fact is that the total estimated production for all countries amounts to between 4.4 Mt and 6.2 Mt while the target for EU as a whole represents 10 Mt, which indicates that the target for installed capacity in the EU should be revised well above 40 GW, since the high capacity range of 62 GW indicated in the National Plans and Strategies would not achieve the 10 Mt by 2030 either.

Figure X: Estimates of 2030 production targets based on National Plans and Strategies



Source: ACER . "European hydrogen markets: 2024 Market Monitoring Report".

In terms of hydrogen demand, Germany leads with the highest target, estimated at between 3 and 3.9 million tonnes per year (Mt/y), well above the second country, France, with 0.77 Mt/y. This German target is almost equivalent to the combined total of the other countries and, if the upper limit is taken (3.9 Mt/y), it far exceeds it.

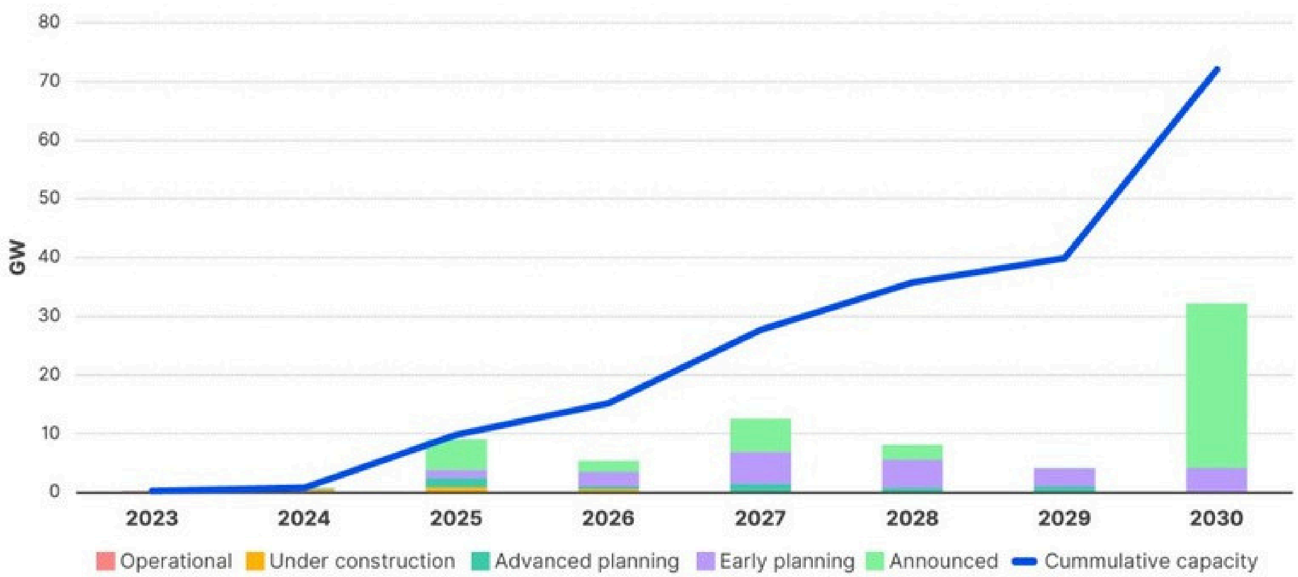
53 Estimates based on the electrolysers operating at an efficiency of 61% (55 kWh / kg H2) and a factorload between 4,000 and 6,000 hours/year (46%-68%)

Current hydrogen demand in the EU amounts to 7.2 Mt/year and is mainly concentrated in refining, ammonia consumption and other chemical products, which are produced 99.7% fossil fuels.

By the end of 2024, the EU produces only around 0.02 Mt/year by electrolysis, with a total installed capacity of around 311 MW, according to data from the European Hydrogen Observatory (EHO)*(54).* These are 96 projects, and if we add the 67 projects that are in operation and under construction, with a production capacity of 2.5 GW, the total capacity amounts to 2.8 GW, most of them thanks to their own buyer or industry.

Compiling data from ACER, the EHO and S&P Global Commodity Insights, they estimate that by 2030, approximately 70 GW of additional capacity could be in operation, although only 0.5 GW has taken FID and 6 GW is at an advanced stage.

Figure X: Electrolysis projects in the EU, by stage of completion and estimated date of operation



Source: ACER, European Hydrogen Observatory and S&P Global Commodity Insights (2024).

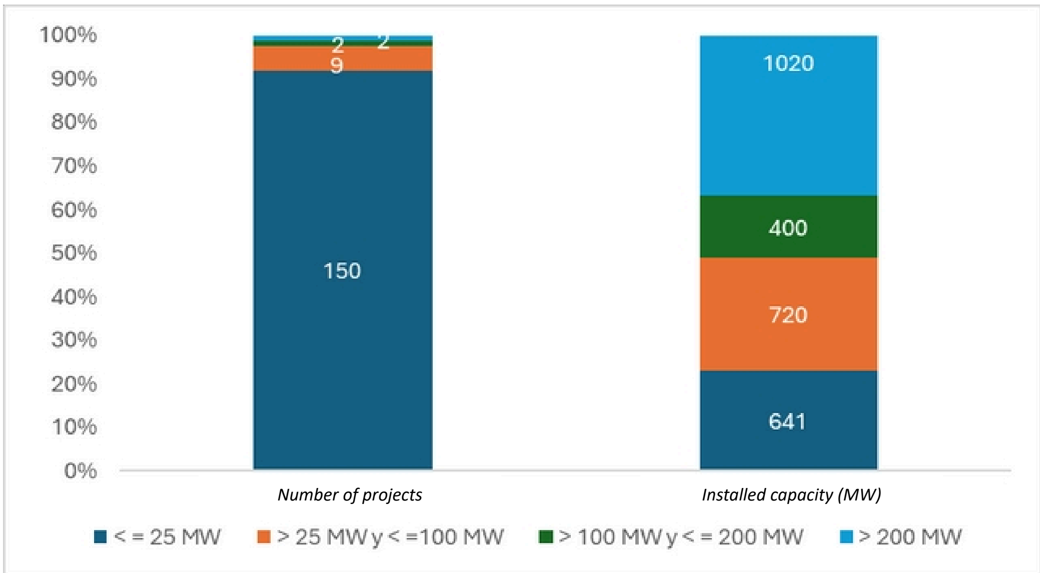
[54] See EHO in Hydrogen Production and Consumption Projects| European Hydrogen Observatory

These data show that also in the EU a significant boost in FID is needed to reach the 2030 production targets, as it has not been sufficient to reach the intermediate target of installing at least 6 GW of electrolyser capacity by 2024, capable of producing approximately 1 Mt of renewable hydrogen.

Most of the projects installed and under construction in the European Union are less than 25MW.

Analysing the data in detail, most of the projects installed and under construction by the end of 2024 are relatively small in size: of the total 163 projects with a production capacity of 2.8 GW, 92% are smaller than 25 MW in size and represent an installed production capacity of 23% of the total. On the other hand, at the extreme end, the 2 projects (1%) that have a production capacity of more than 200 MW, "H2 Green Steel (H2GS) - Phase I with 740 MW and Clean Hydrogen Coastline - EWE East Friesland with 280 MW, in Sweden and Germany, respectively, account for 37% of the total capacity.

Figure X: Distribution of installed and under construction electrolysis projects in the EU



Production capacity	No. of projects	Capacity installed (MW)
Less than or equal to 25 MW	150	641
More than 25 MW and less than or equal to 100 MW	9	720
More than 100 MW and less than or equal to 200 MW	2	400
More than 200 MW	2	1020
TOTAL	**163**	**2781**

Source: Own elaboration. EHO database

These figures indicate that most projects are at a stage where investors and developers want to position themselves and gain experience, but are cautious about scaling the size before proving the technology and its economic viability.

Challenges that are slowing down global investment decisions

Choosing the right time to make investment decisions on hydrogen projects is a balancing act. Acting too late or too early has important consequences that can affect their competitiveness and thus their success. Fundamentally, this balancing act consists of responding to three key challenges: the availability and duration of rules related to public incentives and policies, the evolution of technology, and the changing costs associated with the development of the hydrogen economy.

As pointed out by different studies and expert surveys*(55),* for hydrogen projects to reach the FID stage, it is crucial that certain fundamental requirements are met:

- **Firm purchase agreements:** currently represent the most relevant uncertainty. Purchase contracts must be secured that guarantee the demand for the hydrogen produced, clearly specifying the volume, price and duration of supply. This would provide certainty for investors and facilitate the economic viability of the project.

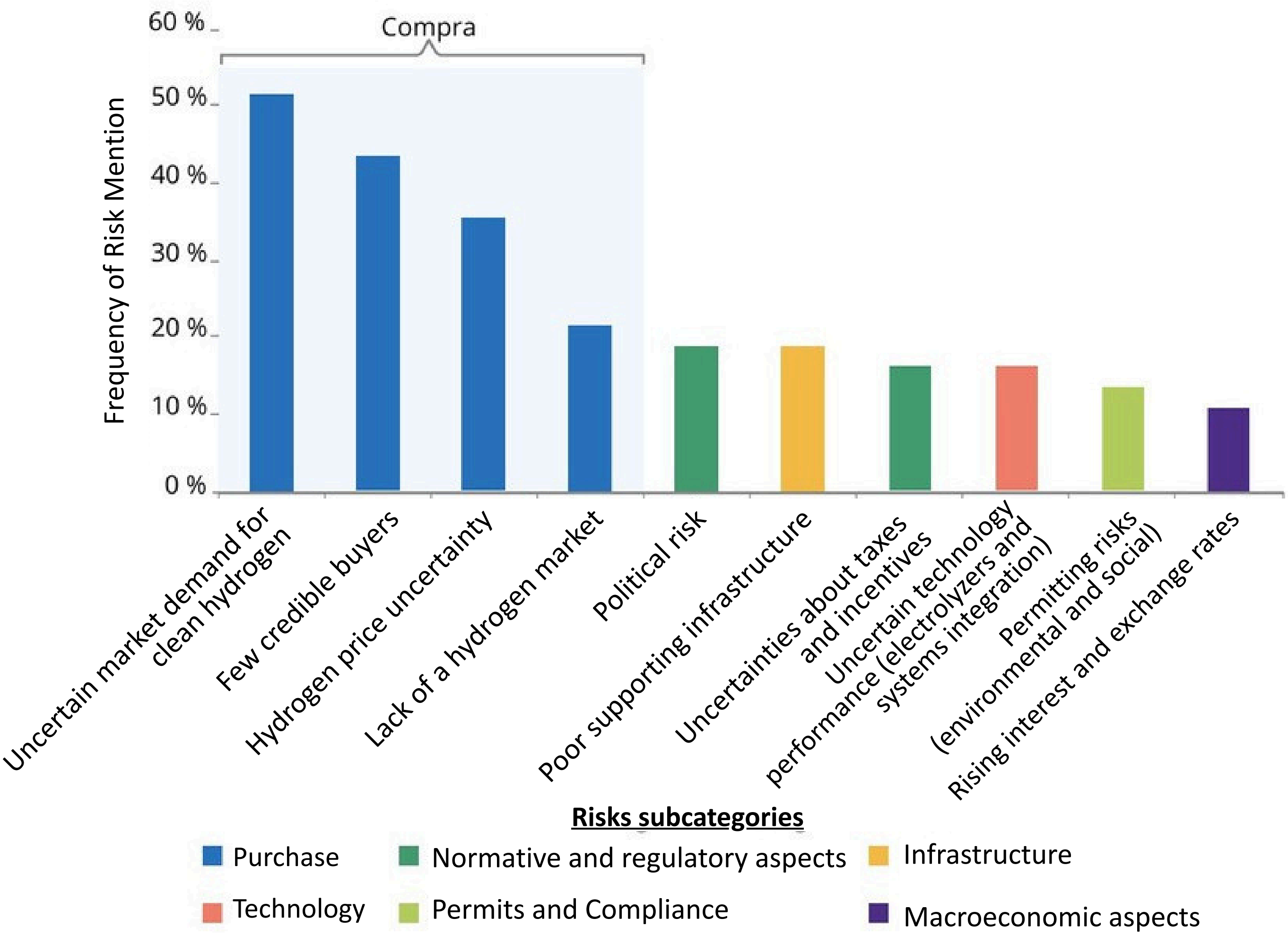
- **Regulatory certainty, incentives, permitting and taxation:** The hydrogen obtained must meet regulatory requirements and have economic incentives. Compliance with established standards and certification systems ensures that hydrogen is produced using renewable energy sources and low-emission processes, which is essential for its acceptance on the market and its contribution to decarbonisation.

- **Adequate infrastructure:** a well-developed infrastructure is essential for the efficient management of hydrogen, the water, electricity, carbon dioxide and hydrogen derivates generated during production. This ranges from production and storage to transport and distribution networks.

55 ESMAP, OECD : "Scaling Hydrogen Financing for Development" (2023)

- **Foreseeable technology evolution:** projections on the reduction of the cost of the electrolysers remain uncertain, as well as the costs of renewable electricity, which depend mainly on effeciency and operating hours. Innovation, economies of scale and the learning curve are essential to identify the right time.

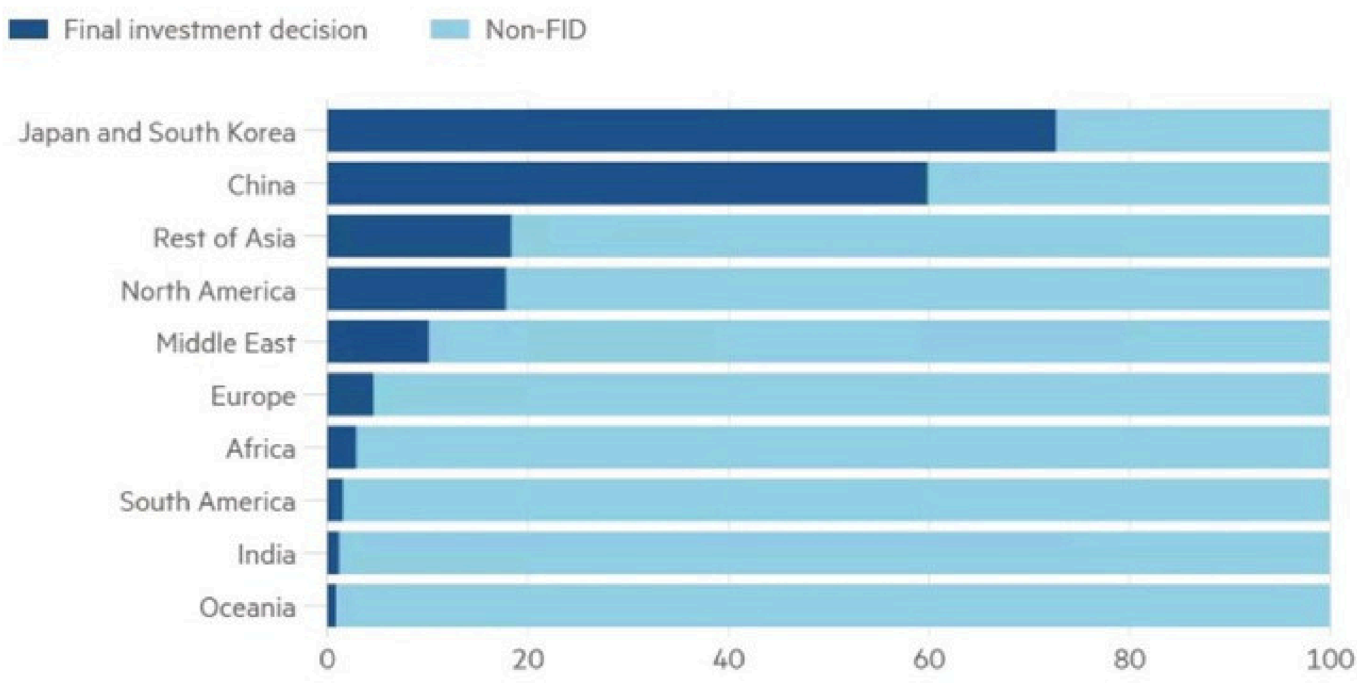
Figure X: Expert survey: main uncertainties of hydrogen projects



Source: ESMAP, "Scaling Hydrogen Financing for Development" (2023).

Some regions are finding it easier and are leading investment decisions. Although the set of challenges can be considered global, we find that some regions are finding some of these uncertainties easier or clearer than others.

Figure X: Leading regions in investment decision making

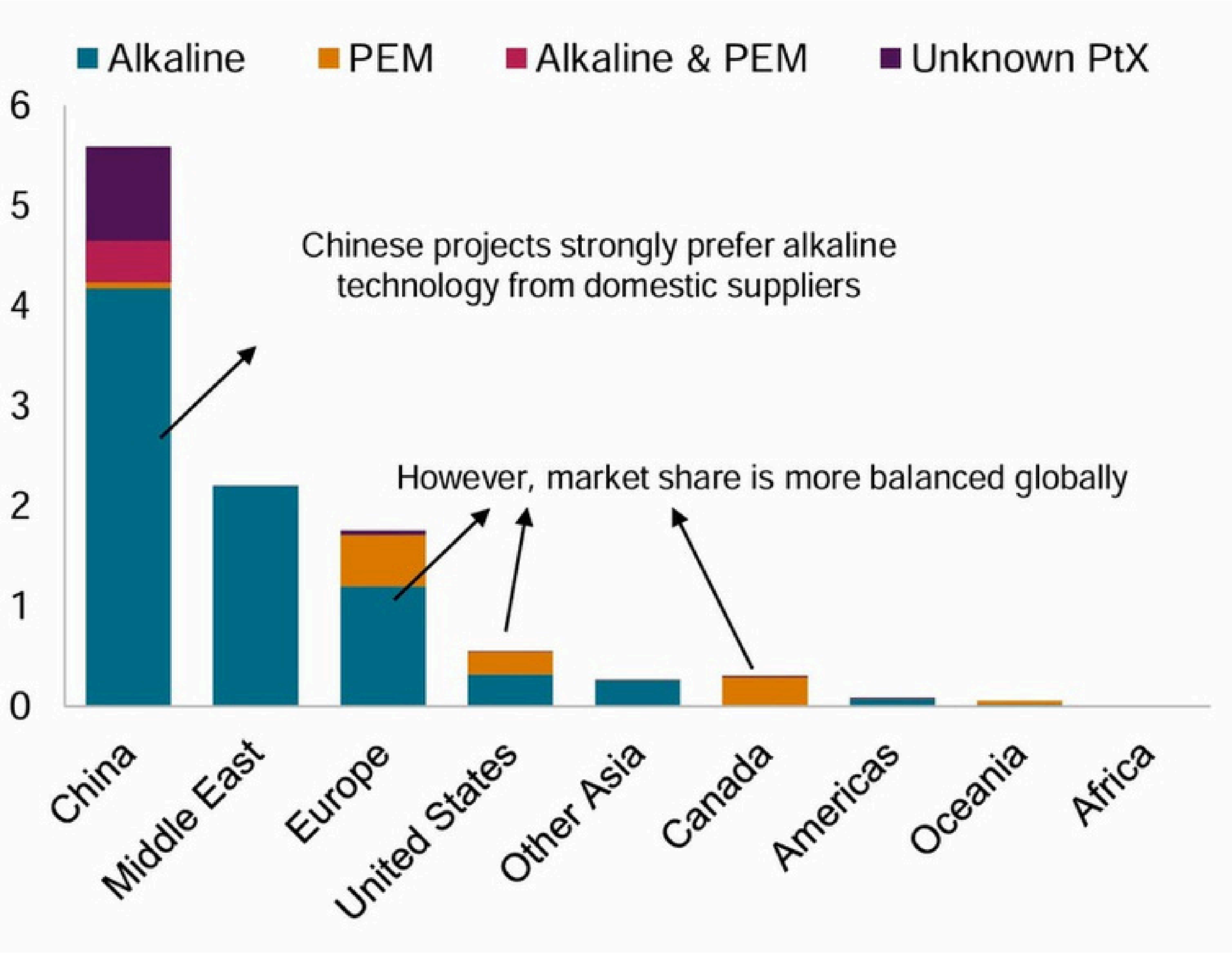


Source: Financial Times, October 2024, based on McKinsey and Hydrogen Council.

Of all the countries analysed, Japan, South Korea and China lead in terms of FIDs, with a percentage of between 60% and 80%, while North America and Europe lag far behind, with percentages of 20% of all projects.

This global data, however, requires further analysis to incorporate the different stages of development of these projects and the technology applied. Data provided by S&P Global Commodity Insights on electrolysis projects under construction in the third quarter of 2024 show China and the Middle East leading in the use of alkaline technology, followed by Europe, the United States and Canada with a similar combined share of alkaline and PEM.

Figure X: Leading regions in the construction of electrolysis projects and technology used (in GW)

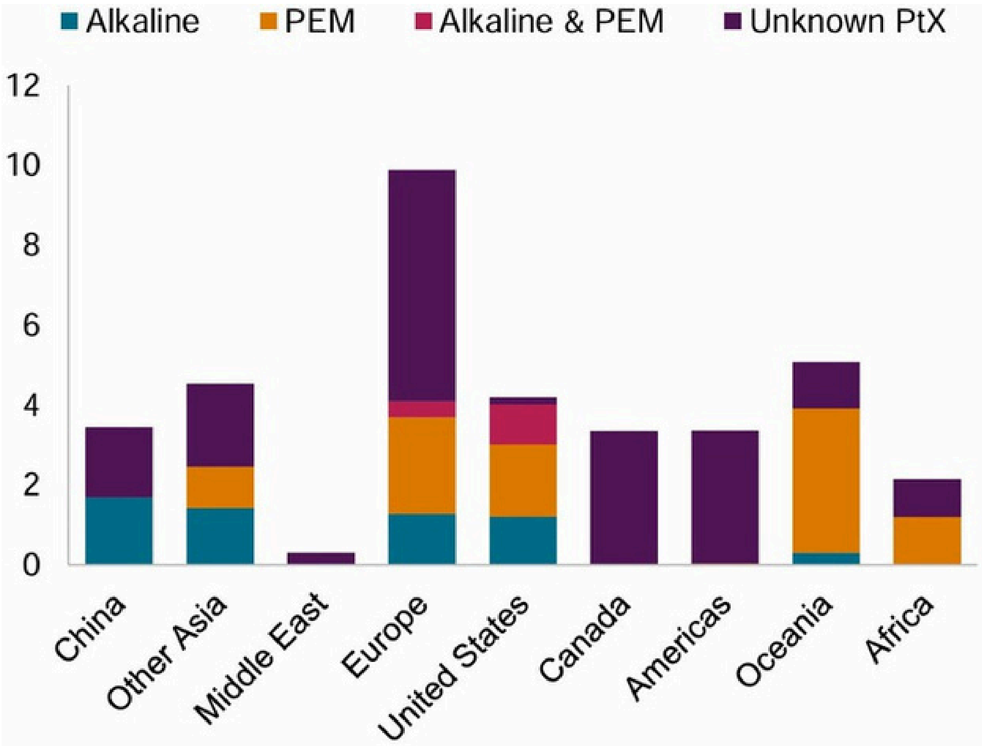


Source: S&P Global Commodity Insights, "Hydrogen Market Monitor Q3 2024".

However, if we look at projects at an advanced stage of development (with a feasibility study and are moving forward with FEED, applying for permits, issuing equipment purchase orders or taking FIDs), the situation is different.

In this case, Europe leads the way, followed by Oceania, the United States and other Asian countries with the use of PEM technology, although there is also a very significant proportion of projects at this stage where the technology does not materialise. This context leads us to raise again the uncertainty in the market.

Figure X: Leading regions of advanced stage electrolysis projects and technology employed (in GW)



Source: S&P Global Commodity Insights, "Hydrogen Market Monitor Q3 2024".

Listed hydrogen companies face a fragile financial situation.

While investments in hydrogen projects have increased and are reaching more advanced stages, the companies that depend on the success of this technology are not yet in sound financial health. Many of these companies are investing heavily in new facilities and projects in order to meet the growing demand for equipment; however, costs, rates of return and expectations of project delays have negatively affected these companies.

An analysis of 45 listed companies in the hydrogen sector the IEA*(56)* reveals that their medium-term performance more closely resembles the S&P Cleantech index of cleantech companies than the NASDAQ index, which is dominated by technology companies with less capital-intensive business models.

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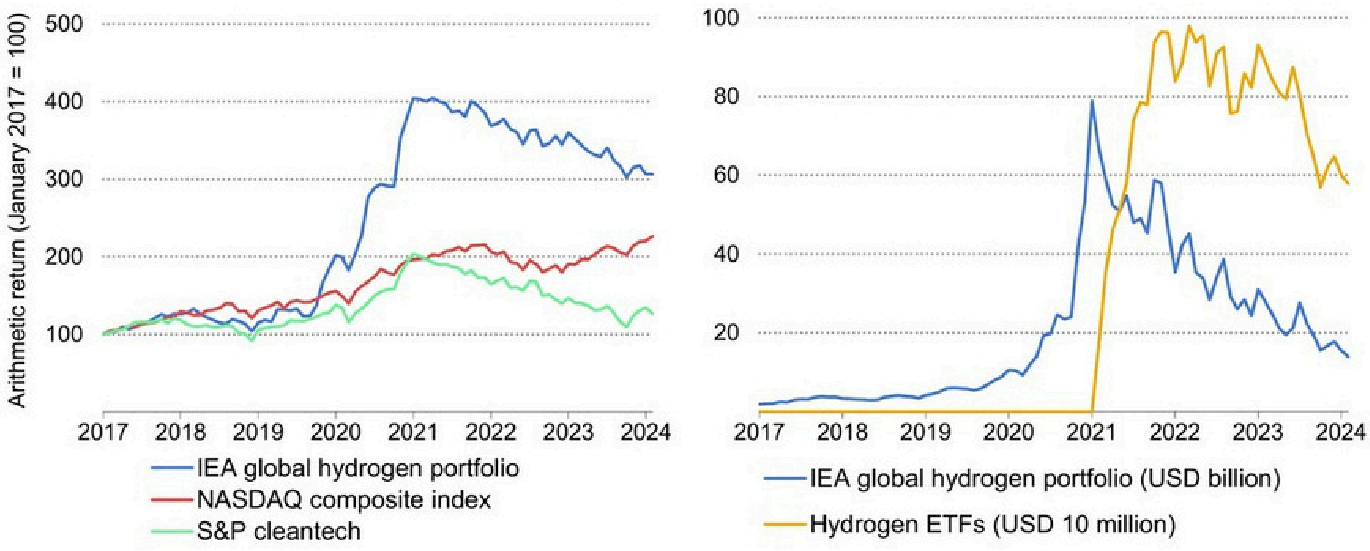
[56] IEA, "Global Hydrogen Review 2024".

The market capitalisation of these companies has been on a downward trend since 2021, reflecting the difficulty of balancing investment in research and development, facilities and projects with still insufficient revenues and rising capital costs in private markets.

Figure X: Monthly returns (Base 100= 2017) and market capitalisation of the hydrogen sector



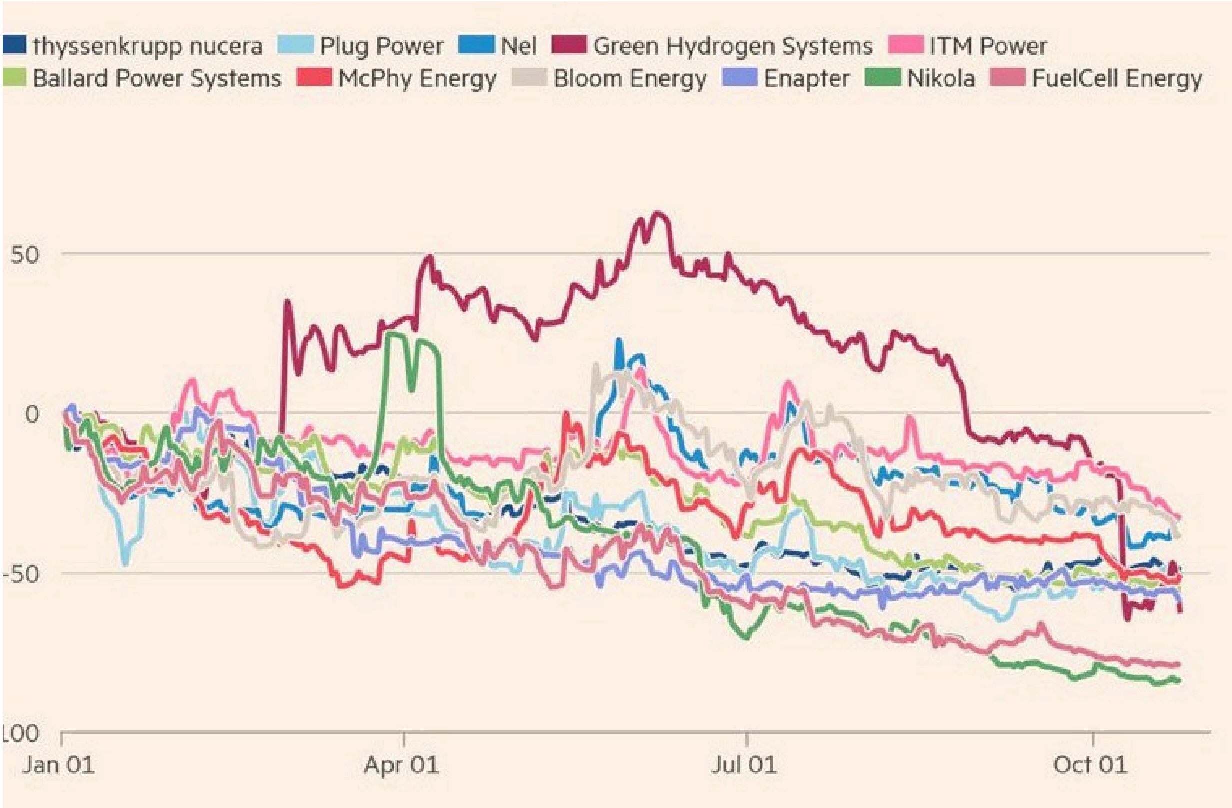
Source: IEA, "Global Hydrogen Review 2024".

A detailed overview by the Financial Timesof companies such as Plug Power*(57)*, Ballard Power Systems and Green Hydrogen Systems shows their share prices falling by more than 50% by 2024, while others such as Nel, Bloom Energy and ITM Power have seen declines of 33%.

Share prices of hydrogen companies in the US and Europe have collapsed, mainly due to project delays due to lower than expected demand, regulatory uncertainties and growing investor scepticism.

[57] See Financial Times, 27 October 2024: US and European hydrogen stock prices collapse as prospects deflate

Figure X: Share price of companies in the hydrogen sector: % change January - October 2024



Source: Financial Times, October 2024

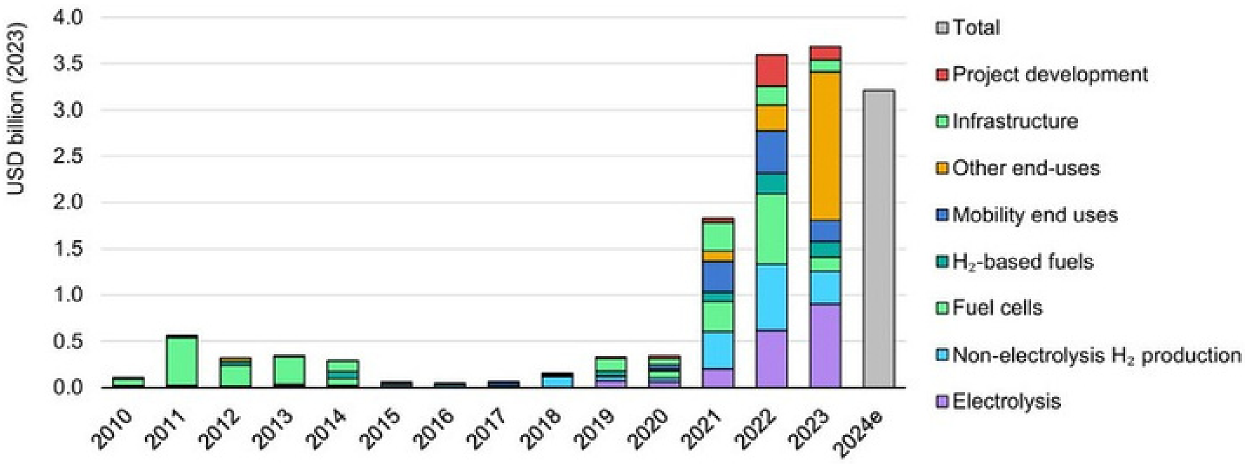
Although hydrogen venture capital funds are growing more than in other energy sectors, this trend is slowing down.

Investor caution towards the hydrogen sector is evidenced by the lack of significant new IPOs and the underperformance of hydrogen investment funds.

The evolution of hydrogen venture capital (VC) investment reached a record USD 3.7 billion in 2023, according to IEA data*(58)*. Hydrogen-related VC investment remained stronger than overall energy-related VC investment. However, although definitive data for 2024 is not yet available, due to the circumstances described above this trend is expected to come to a halt.

[58] IEA, "Global Hydrogen Review 2024".

Figure X: Venture capital investments in hydrogen startups by destination



Source: IEA, "Global Hydrogen Review 2024".

Among the concerns raised by investors are the high valuations of some hydrogen companies, which make it difficult for them to exit viably at a later stage, and the difficulty of de-risking a completely new business for scalability, with inherent technological uncertainties and often non-existent supply chains, all operating in a climate of limited demand.

VC investment in new companies to develop electrolysis technologies increased by almost 50% in 2023 compared to the previous year, while investment in other hydrogen-related sectors, such as mobility and the development of supply projects, decreased, the most relevant being the 80% drop in funds raised by startups focused hydrogen fuel cells.

To ensure the viability of the business model, investment and financing decisions must be taken at the same time.

Many of the uncertainties outlined above require in-depth analysis and risk management measures before investors and promoters of hydrogen projects can reach FID.

Due to the high volume of investment and the associated risks, risk diversification becomes an objective shared by all actors in the value chain.

Some companies are adopting "asset-light" business models to spread risk and attract new sources of capital. An example of this model is to co-develop projects and sell them to co-owners once operational. At the extreme, large multinationals with different business lines, not exclusively focused on hydrogen, have more options to integrate them into their value chain and to finance these projects within their capital structure.

However, the most widespread model is the one we outlined in last year's report, which has many similarities with the one developed for liquefied natural gas (LNG) projects, where investment and financing decisions have to be taken at the same time. This model means that decisions have to be made in two areas:

- On the corporate capital structure, where possible alliances between different partners are defined, although with common objectives that pursue the economic viability of the project and therefore expect a minimum profitability.
- How to obtain the necessary sources of finance, in which the financial institutions assume the project risks and hardly require any guarantees from the partners (project finance model), so that they do not compromise their future financial capacity.

To achieve this, we believe it is essential to develop a network of partnerships with the potential stakeholders involved in each project. This ranges from renewable generation companies (including potential PPA suppliers), to electrolyser manufacturers, power utilities, energy companies, and other stakeholders. From logistics companies, operation maintenance companies and potential end-buyers.

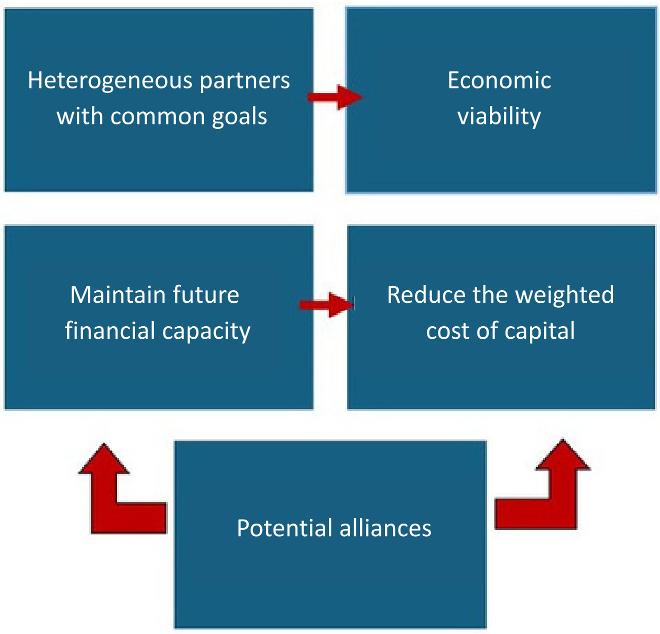


Figure X: Schematic of the investment and financing decision model

Source: Own elaboration

5.1.4. The evolution of storage and transport infrastructures

One of the essential factors for the efficient development of the hydrogen market is the creation of an adequate infrastructure connecting production and consumption centres. Renewable hydrogen production is concentrated in areas with high renewable energy potential, while demand is located in industrial and urban centres, which do not necessarily coincide in the same place. An infrastructure network is therefore essential to transport hydrogen efficiently over long distances.

At the same time, an interconnected network ensures security of supply, avoiding dependence on a single point of production, diversifying hydrogen sources, mitigating potential disruptions and creating a competitive, liquid and transparent market with common reference prices and standards.

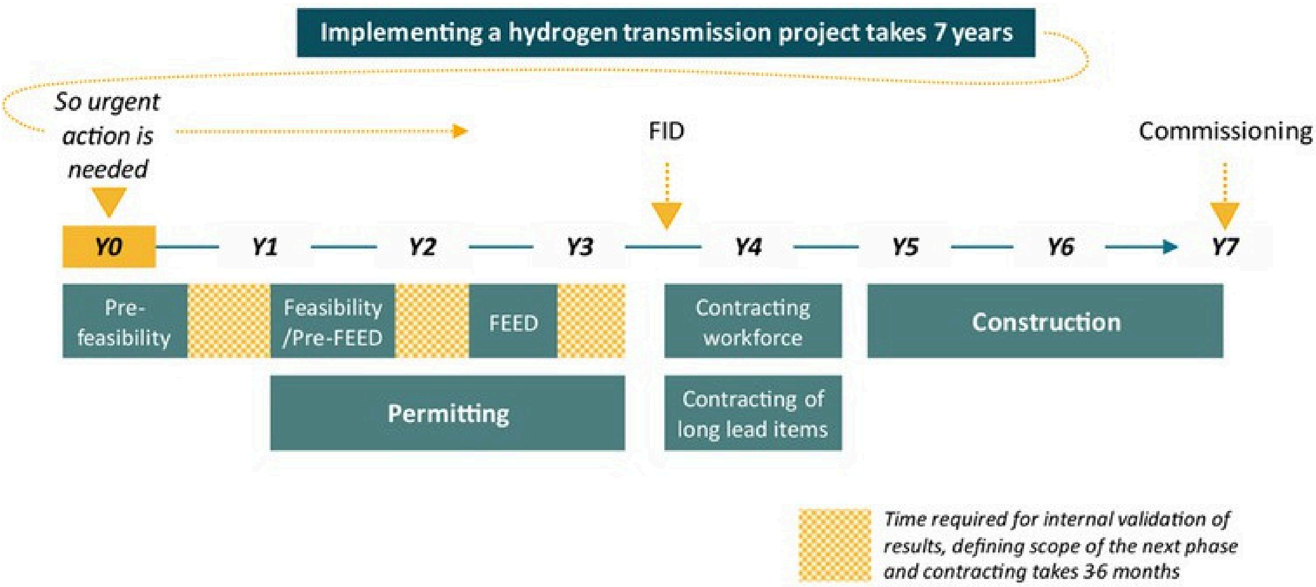
In the EU context, the European Hydrogen Backbone (EHB) alliance of 33 European energy infrastructure operators aims to bring together this shared vision to develop the hydrogen market. The collaboration between EHB members results in recommendations and proposals for EU public policy making, such as the one on grid integration instead of relying solely on the concept of regional hydrogen valleys, connecting the main pan-European production and consumption centres, which would save EUR 330*(59)*.

Figure X: Promoter companies and EHB alliance recommendations. Source: EHB (2023)

Despite regulatory momentum in Europe, the construction of storage and pipelines is proceeding slowly.   .

As highlighted by the EHB alliance, support for infrastructure development is crucial and urgent*(60)*. On average, hydrogen pipeline infrastructure projects take around seven years to develop, but most projects have already passed the pre-feasibility phase. Speeding up the permitting process (e.g. through general recognition of existing rights of way for all gases) would help reduce overall duration of projects. By reducing permitting times and lowering investment risks, investment decisions can be made more quickly and hydrogen infrastructure can arrive on time at an affordable cost.

Figure X: Estimated start-up times for hydrogen pipelines



Source: EHB (2024)

[59] https://gasforclimate2050.eu/wpcontent/uploads/2023/12/GfC_PanEU_230320_received_230323_published_final.pdf

[60] Ver 1732103116_EHB-Boosting-EU-Resilience-and-Competitiveness-20-11-VF.pdf

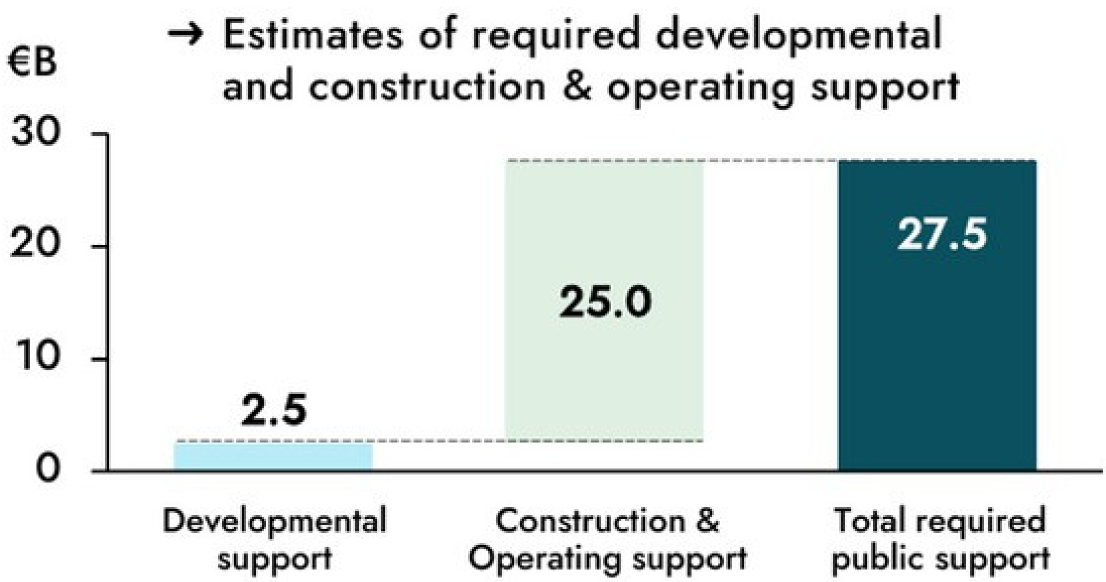
To speed up the process, the EHB recommends two forms of public support:

a) **During the development stage:** Allocating support at this early stage provides policy makers with key information on the construction of the network and, in turn, allows the developers of these projects to access the capital market by creating projects where risks are duced and allow to obtain financial conditions acceptable.

b) **During the construction and operation phase:** Align incentives and overcome the temporary imbalance of revenues and costs that occurs during the first five to ten years of network operation. Policy makers should avoid penalising early adopters of the hydrogen network with high tariffs and pioneering network developers with the full cost of market development risk.

27.5 billion in public support (2.5 billion in the first stage and 25 billion in the second stage) is estimated to be needed to enable the delivery of 14 million tonnes (490 TWh) of hydrogen through approximately 31,000 km of hydrogen pipelines by 2030, an amount significantly higher than what is currently available EU funding.

Figure X: Estimated pubic support needs



Source: EHB (2024)

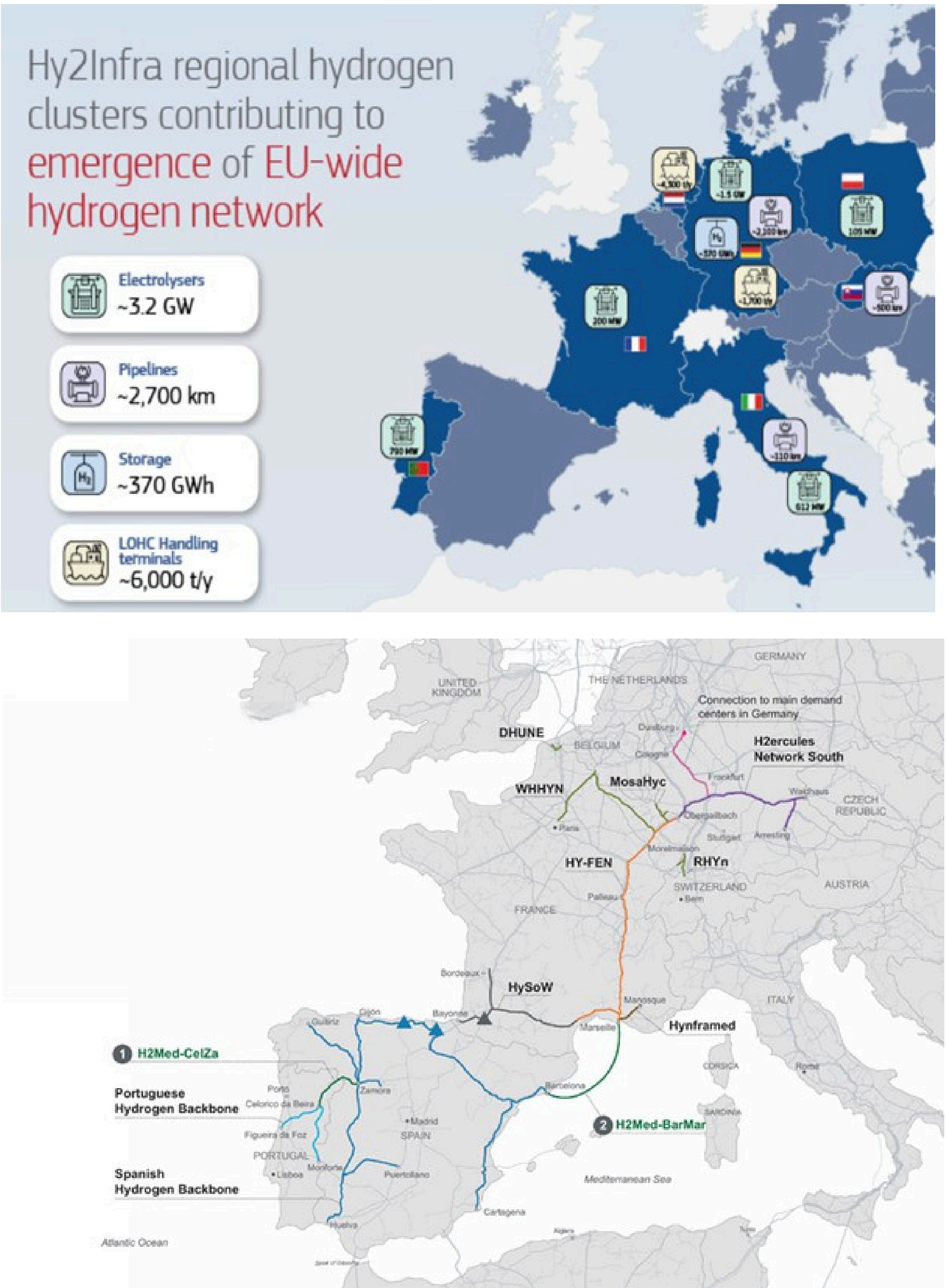
These recommendations have been reflected in different regulatory initiatives, including the one approved by the European Commission in February 2024 with the Important Projects of Common European Interest (IPCEI) to support hydrogen infrastructure. These projects, called in aggregate "IPCEI Hy2Infra", were jointly prepared and notified by seven Member States: France, Germany, Italy, the Netherlands, Poland, Portugal and Slovakia, which will provide up to €6.9 billion in state aid, expected to unlock €5.4 billion in additional private investments.

The Hy2Infra IPCEI will cover a broad part of the hydrogen value chain, supporting the deployment of large-scale electrolysers (3.2 GW capacity), new hydrogen transmission and distribution pipelines (2,700 km), large-scale storage facilities (370 GWh) and hydrogen handling terminals (6,000 tonnes/year). Several projects are expected to be implemented in the near future, with electrolysers operational between 2026 and 2028, and pipelines between 2027 and 2029, depending on the geographical area. Full completion of the projects is scheduled for 2029.

Subsequently, in April 2024, Delegated Regulation (EU) 2024/1041 updated the final list of infrastructure IPCEIs, including the first axes of the Spanish Hydrogen Backbone Network and the Interconnection Project from the Iberian Peninsula to North-West Europe. The latter project, known as H2Med, promoted by the governments of Spain, Portugal, France and Germany, with the support of the European Commission, is being promoted by the national transmission system operators (TSOs): REN, Enagás, Teréga, GRTgaz and OGE. The H2Med project consists of two interconnections: CelZa between Portugal and Spain, and BarMar, an undersea gas pipeline between Spain and France. A combined investment of 2.5 billion euros is estimated for these two interconnections, with an estimated commercial operation date of 2030.

In turn, key projects to connect the Iberian Peninsula with Northwest Europe include the Portuguese Hydrogen Backbone Network and the Spanish Hydrogen Backbone Network. In France, three pipelines are planned: HySoW, HYnframed and Hy-FEN, which will connect to the H2ercules Network in southern Germany.

Figure X: IPCEI Hy2Infra infrastructure map, including H2Med



Source: European Commission and Enagás

The Spanish trunk network approved as an IPCEI consists of 2,600 km and 2 underground storage facilities which, based on the results of the expressions of interest obtained by Enagás, will be extended by a proposal for new sections submitted in November 2024 to a second list of IPCEIs. The new routes would link the axes shown in the map below:

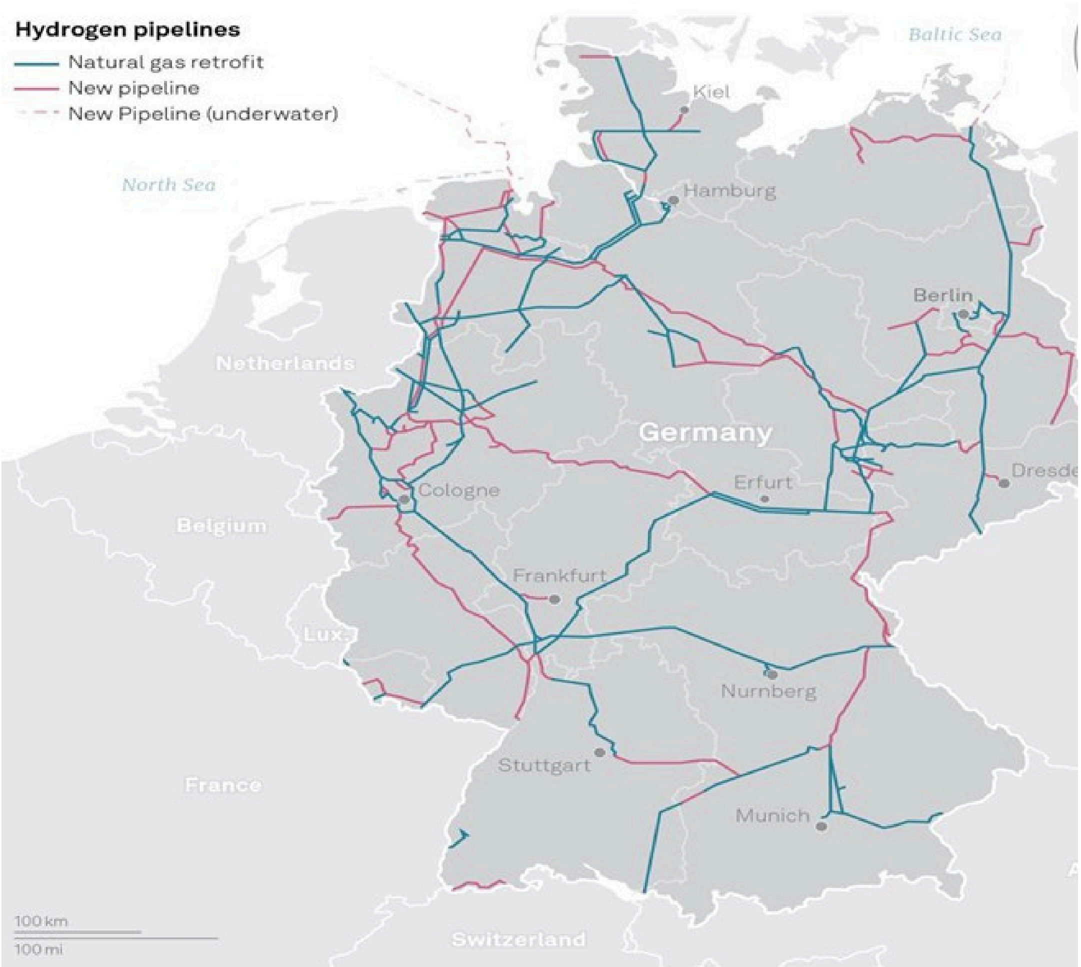
Figure X: Map of the proposed extension of the Spanish backbone network

Source: Enagas (2024)

Meanwhile, in Germany, the Bundesnetzagentur has announced the Hydrogen Core Network, in which the German government has committed €3.2 billion to unlock up to €20 billion in private investment. Sixty per cent of the planned 9,000 km network is reused natural gas pipelines, with the first conversion expected to start in 2025.

The network is expected to be fully operational by 2032, transporting at full capacity 278 TWh per year (approximately 8 million metric tonnes of hydrogen per year). Importantly, the network around the industrial hubs in Düsseldorf and Cologne (H2ercules) has been granted IPCEI status by the EU.

Figure X: Proposed hydrogen network infrastructure in Germany



Source: S&P Global Commodity Insights, November 2024

Regarding new marine terminal infrastructure along the northern coast in Europe, most projects are still in the early stages of development, according to S&P Global Commodity Insights data:

- **In Rotterdam:** The Port Authority has carried out a feasibility study for the import of 1 million tonnes of hydrogen.
- **In Antwerp:** Air Liquide is working in partnership with KBR and Fluxys/Advario are collaborating on an open ammonia terminal.
- **In Hamburg:** Import infrastructure under expansion Mabanaft and a 30,000 tonne per floating hydrogen cracker.
- **In Wilhelmshaven:** Uniper is developing and electrolysis project and an ammonia import terminal and BP is developing an ammonia crackers with a capacity of 130,000 tonnes per year.

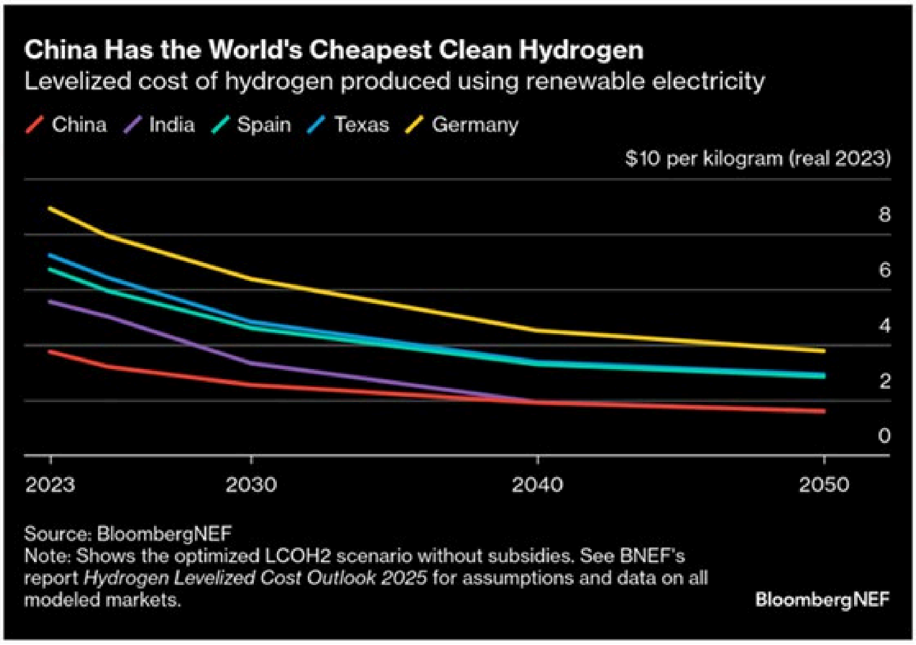
Figure X: Major hydrogen terminals in Northern Europe

Source: Own elaboration. Data from S&P Commodity Insights

By way of summary, it should be noted that, according to Enagás estimates, based on publicly available information, there are 48 infrastructure projects recognised as hydrogen IPCEI in the EU Member States as a whole, representing around 21,000 km of pipeline and a total investment volume of around 60 billion euros*(61)*.

5.2.The development of the hydrogen trading market

The analysis of the LCHO at level global shows that Spain remains more competitive than Germany in the long run.



61 See https://www.enagas.es/content/dam/enagas/es/ficheros/sala-de-comunicacion/actualidad/eventos/avances-de-hydr%C3%B3gen-infrastructure-in-spain%C3%B1a-and-europe.pdf

However, India and China maintain their competitive advantage over Spain. The levelised cost of hydrogen produced from off-grid renewables will remain higher for longer. Renewable hydrogen only becomes competitive with grey hydrogen in a handful of markets, and only after 2030. This will affect the attractiveness of renewable hydrogen as a decarbonisation strategy, unless there is a breakthrough in the cost of electrolysers.

Signals and price formation in the renewable hydrogen market: the European hydrogen bank auctions.

Spain and Portugal are the main beneficiaries of the first auction in which 719 million euros in subsidies were awarded.

Following the establishment of the European Hydrogen Bank in September 2022, with part of the Innovation Fund budget, the results of the first auction were announced on 30 April 2024, in which 719 million euros were awarded to 7 renewable hydrogen projects. This was the first milestone in achieving the objective of supporting the domestic hydrogen production market and connecting renewable hydrogen supply with demand. The subsidy scheme consisted of a fixed premium in €/kg of hydrogen produced from renewable fuels of non-biological origin (RFNBO).

Figure X: Results of the first auction of the European Hydrogen Bank

Project acronym	Project Coordinator	Project location	Bid price (EUR/kg)	Bid volume (kt H_2/10years)	Bid capacity (MWe)	Expected GHG abatement ($ktCO_2$/10years) *	Total requested funding (EUR) **
eNRG Lahti	Nordic Ren-Gas Oy	Finland	0.37	122	90	836	€ 45,228,375
El Alamillo H2	Benbros Energy S.L.	Spain	0.38	65	60	443	€ 24,605,819
Grey2Green-II	Petrogal S.A.	Portugal	0.39	216	200	1477	€ 84,227,910
HYSENCIA	Angus	Spain	0.48	17	35	115	€ 8,104,918
SKIGA	Skiga	Norway	0.48	169	117	1159	€ 81,317,443
Catalina	Renato Ptx Holdco	Spain	0.48	480	500	3284	€ 230,463,819
MP2X	Madoquapower 2x	Portugal	0.48	511	500	3494	€ 245,178,772
			Ø 0.44 €	Σ 1580 kt_H2	Σ 1502 MWe	Σ 10 808 kt_CO2	Σ 719,127,056 €

* Calculated vs. the 2021-2025 ETS benchmark of 6.84 t_CO2e/t_H_2. Not taking into account additional carbon abatement due substitution effects in the H_2 end use application (i.e. conservative estimate).
** Remaining budget will accrue back to the Innovation Fund.

Source: European Hydrogen Bank (2024)

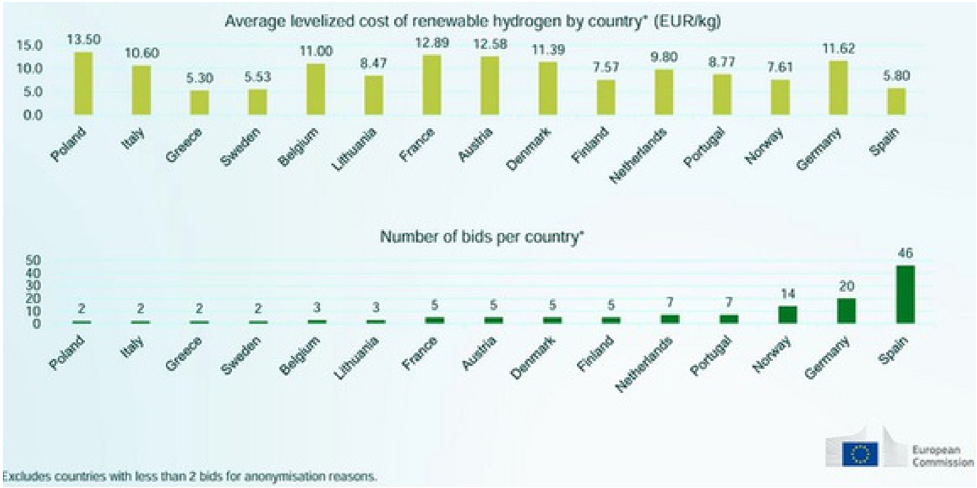
With this award, subsidies have been approved for the installation of 1.502 MW of capacity of electrolysis, which will allow the production of 158,000 tonnes of renewable hydrogen per year for 10 years. This first hydrogen auction has used a "pay-as-bid" system with no minimum price, meaning that producers indicate the minimum remuneration they need to make their projects viable. The results show that projects will receive subsidies of between €0.37 of hydrogen, an amount well below the maximum threshold of €4.5/kg set in the auction conditions, which will allow them to cover the price between their production costs and the market price of hydrogen, which is currently determined by non-renewable production. The selected projects will have to start production within a maximum of 5 years after the signature of the subsidy agreement.

Of the total 132 bids from 17 countries, only 7 projects were the winners. Spain was the leading country, with 46 proposals totalling nearly 3,000 MW of electrolysis capacity. Another remarkable fact is that Spain and Portugal were the countries with the highest number of winning projects. In particular, 3 of the 7 selected projects are Spanish: El Alamillo H2 by Benbros Energy, Hysencia by DH2 Energy and Catalina by a holding company composed of Copenhagen Infrastructure Partners (CIP), Enagás Renovable and Fertiberia. All of them represent a total of 595 MW of electrolysis capacity and obtain 263 million euros, i.e. 36.6% of the total awarded. Portugal, with 2 winning projects with a total of 700 MW electrolyser capacity, obtained 329 million euros, in which one of them, Madoqua Power2X, received 245 million euros, in which CIP also participates together with the Dutch company Power2X and the Portuguese company Madoqua. The other project is Grey2Green II, Galp's second hydrogen project in Portugal, which receives 84 million euros.

In addition to the projects in Spain and Portugal, there is one in Finland and another in Norway, with an electrolysis capacity of 90 MW and 117 MW, respectively, obtaining a total of 127 million euros. Giving visibility to renewable hydrogen prices is another of the auction's objectives, as they provide price signals for the market as a whole. The result of the bids submitted, grouped on average by country, shows a wide dispersion, with LCOH prices ranging from 5.3 to 13.5 €/kg.

It should be noted that Spain is in third position with 5.8, only behind Sweden and Greece with 5.53 and 5.3, respectively.

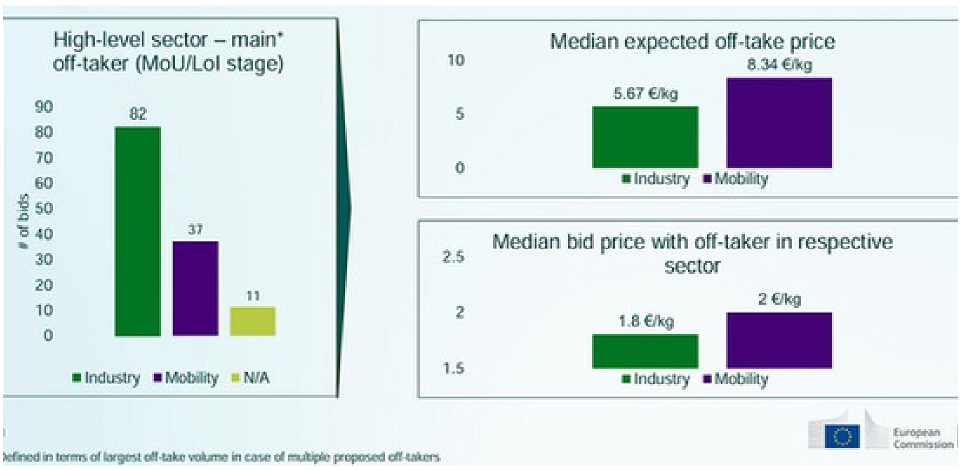
Figure X: Average LCOH of submitted bids



Source: European Hydrogen Bank (2024)

Among the conditions of the auction, the European Hydrogen Bank required a 60% purchase commitment with the final consumer through a Memorandum of Understanding or Letter of Interest (MoU or LoI). Of the 82 MoUs or LoIs received, 82 were in the industrial sector, covering methanol, fertilisers, refineries, natural gas grid injection, steel, chemicals, ammonia, glass, heat or power generation and industrial gases, with an average purchase price of €5.67/kg. For the mobility sector, 37 proposals were submitted with an average purchase price of €8.34/kg, showing a significantly higher willingness to pay.

Figure X: Average purchase price by final consumer



Source: European Hydrogen Bank (2024)

In addition to the described auction mechanism of the European Hydrogen Bank, Member States can use a new "auction as a service" mechanism, which allows them to benefit from the EU auction platform and grant additional funding to national projects, which counts as state aid, with the approval of the European Commission. On this occasion, Germany was the only country to use this mechanism, earmarking €350 million to fund top-ranked projects in its country, which do not qualify for EU-level subsidy, but meet the eligibility criteria.

In the second auction scheduled for September-November 2025, 1.2 billion euros in subsidies will be allocated.

Based on the high oversubscription of the first auction, the European Commission has prepared a second auction to support domestic hydrogen producers with a budget of 1.2 billion euros:

- 1.000 million of euros regardless of the sector in which it is consumed.
- 200 million specifically for consumption in the maritime sector.

Figure X: Planned timetable for the second auction

Key Events	Planned Schedule
Call for Proposals Opens	December 3, 2024
Application Deadline	February 20, 2025
Evaluation Results	May-June 2025
Grant Awarding	September-November 2025

Source: Own elaboration. Data from the European Commission

Although the subsidy will take the same form of a fixed premium payment in €/kgper verified and certified RFNBO hydrogen production for a maximum of 10 years, with the experience of the first auction, a number of requirements have been incorporated or modified:

- The maximum price of the fixed premium is reduced from 4.5 €/kg in the first auction to 4 €/kg in the second auction.
- More comprehensive reporting on the procurement of electrolysers and the hydrogen value chain is required, ensuring greater transparency and control over the projects submitted.
- Sourcing from Chinese suppliers is limited to a maximum of 25% of electrolyser capacity in order to strengthen European supply chains.
- The performance guarantee is increased from 4% to 8% of the total grant requested and there is a new requirement for projects to reach closure of funding within 2.5 years of the grant agreement and to be operational within 5 years is intended to reinforce the commitment of the participants to the successful implementation of the projects.
- Flexibility is introduced to combine European Hydrogen Bank grants with other funds, facilitating access to increased funding for selected projects.

On this occasion, Spain, Austria and Lithuania have announced their participation in the complementary "auction as a service" mechanism with national funds to support renewable hydrogen production projects located in their respective countries. Initial estimates are that Spain would contribute between €280 and €400 million, Austria €400 million and Lithuania around €36 million.

THE DEVELOPMENT OF COMPETITIVE AUCTIONS IN SPAIN

In order to facilitate the connection between hydrogen supply and demand, first steps were taken in Spain in November 2024 to make the interests of producers and consumers visible. This first initiative arose from the Iberian gas futures market operator MIBGAS Derivatives and the developer and producer DH2 Energy to carry out a competitive tender or request for quotation (RFQ) process for the sale of renewable hydrogen production from the Hysencia project, one of the winning projects in the first auction of the European Hydrogen Bank.

The announced RFQ process follows a procedure similar to a closed auction and is open to all companies interested in purchasing renewable hydrogen, both nationally and internationally, with no restrictions on its application. Different lots will be offered based on the volume of supply and the duration of the contract, with a base price for delivery "ex works", with transportation at the purchaser's expense.

The process starts with a pre-qualification phase, followed by a qualification phase. Subsequently, only qualified companies will be allowed to submit bids in a competitive phase. The companies submitting the best bids will be selected to negotiate final agreements with DH2 Energy, which could result in the signing of purchase contracts.

Participants will be able to bid for the renewable hydrogen produced by DH2 Energy's Hysencia plant in Aragon, which is due to start construction in mid-2025 and come on stream in the first half of 2027 and has a 5 tonne storage capacity, mainly to modulate production.

5.3.Towards a hydrogen price reference in Spain

Achieving economies of scale in the hydrogen market will enable hydrogen production at low costs. This requires the creation of a hydrogen market with appropriate fundamental price signals. However, although there have been significant developments in recent months, the current hydrogen market remains opaque and has limited transparency in price formation.

To contribute to market transparency, different price indices have been developed in Europe. Although there is no hydrogen trading either on the over-the-counter market or on stock exchanges, there are already price indications from bilateral supply contracts. The following are the different benchmarks.

5.3.1. S&P global price signals

As noted in last year's report, the hydrogen price valuations provided by S&P Global Platts "Carbon Neutral hydrogen" (CNH) point to the use of information from market participants on transactions. In practice there is no information on transactions in Europe and 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 through the use of 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 chair has been carried out for the type of hydrogen specified under (a). This benchmark is called "Carbon Neutral Hydrogen" (CNH) by the same source and is available in the database under its ex- work measure. According to S&P Global's CNH analysts, the ex-work measure includes the value of all materials used and other costs in the production process minus the taxes that will be paid when the product is sourced or imported. This measure also does not include financing costs.

This is important since, as noted in previous sections, new hydrogen capacity is currently under construction and under feasibility studies in terms of financing and transport costs. These metrics exist for several geographic areas globally. In this report, we continue to monitor the performance of the renewable hydrogen series in Europe (Northwest reference) and in the United States (Gulf Coast reference) which are available on a daily basis from December 2021. They are therefore the price signals with the longest history. We compare the evolution of these series with the gas benchmark trading contract (the Henry Hub future for the US, and the Title Transfer Facility TTF future for Europe).

Figures X and XI show the daily evolution of CNH and gas prices for the period December 2021-February 2025. The CNH series are measured for Europe (EU) and the United States (USA) in €/mmbt and $/mmbt respectively while the gas series are quoted in €/MWh and $/mmbt respectively $/mmbt. The CNH measure for Europe has been transformed to MW/h to be directly comparable with the units of the future gas TTF*(62)* Note that the measure being taken for H2 is exwork defined as cost or transaction estimates without taking into account future taxes and transport or financing cost.

As discussed in the previous report, both graphs suggest that the gas and renewable hydrogen benchmarks are closely linked and that they peaked in August 2022 at the moment when the flow of Russian gas to Europe through the North Stream channel was definitively cut off. 1.31 This is because one of the variable costs in hydrogen is the cost of electricity which is strongly linked to the price of gas. While in the case of Europe the correlation between EUH2 and TTF gas is 0.96 during the period December 2021-December 2022, this correlation remains at 0.95 during the period January 2023-February 2025, suggesting that the high dependence (on price levels) is not conditioned by state of nature*(63)*.

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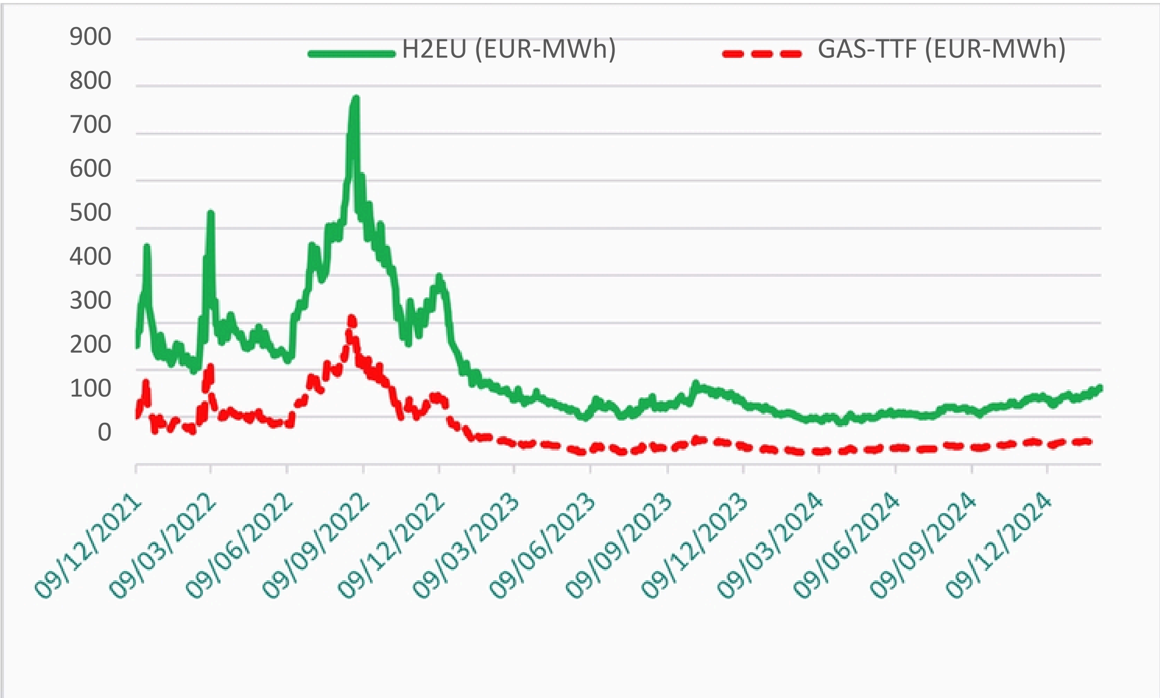
62 Converted from MMBTU to EUR/kg by dividing by 7.729 following the S&P Global conversion factor. We converted from EUR/kg to MWh by multiplying by 30 assuming a calorific value of 33.33.

63 For an analysis of the link between gas and electricity prices during the energy crisis see Segarra Atasanova and Figuerola-Ferretti (2024).

Academic literature suggests that the correlation between gas and electricity becomes more acute in times of crisis (see Chulia et al. 2024, Segarra, Atasanova Figuerola-Ferretti 2024)(64).

If we take the correlation between the changes we see that while it was at levels of 0.06 during the first sample, the same metric increases to 0.06 during the second sample 0.70 in the post-crisis sample. It is clear that the link between the two price signals remains (or even increases) over time. According to the hydrogen levelised cost calculator provided by Agora Energiewende*(65)*, the cost of electricity is 67% of the cost hydrogen production so what these calculations show is that the CNH price signal for low countries mainly measures the cost of electricity, which is strongly linked to the evolution of TTF gas price*(66)*.

Fig X: Evolution of CNH Netherlands (H2EU) and future TTF gas prices (Daily Data December 2021-February 2025)

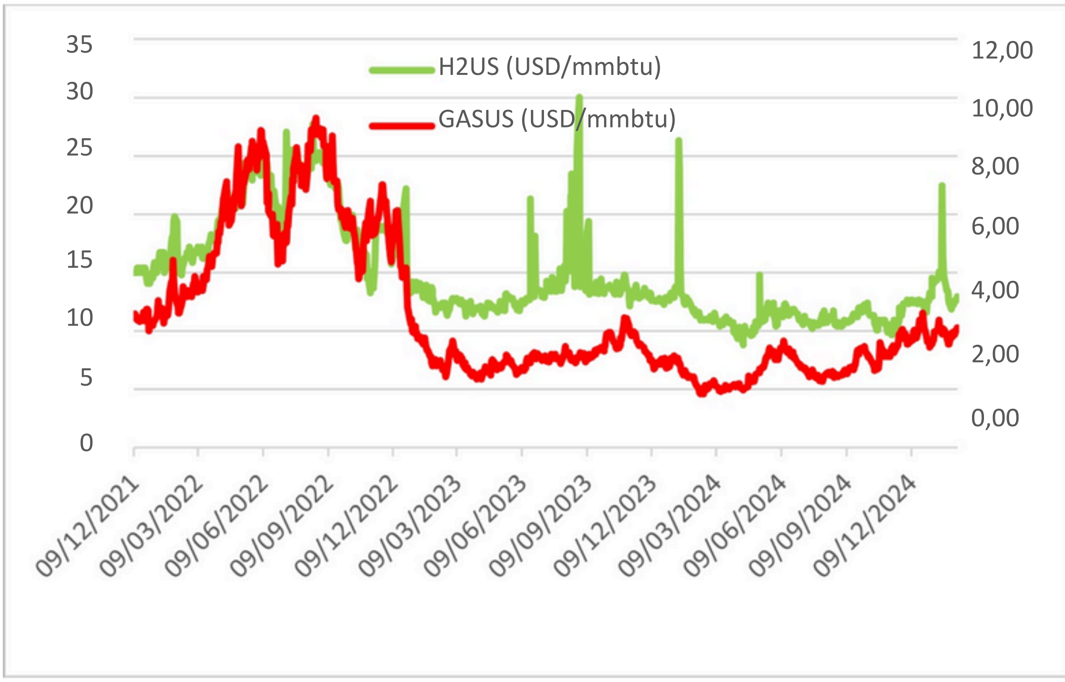


64 Chulia, H., Klein, T., Mendoza, J.A.M., Uribe, J.M., 2024. Vulnerability of european electricity markets: A quantile connectedness approach. Energy Policy 184, 113862. Segarra, I., Atanasova, C., Figuerola-Ferretti, I., 2024. Electricity markets regulations: The financial impact of the global energy crisis. Journal of International Financial Markets, Institutions and Money 93, 102008. doi:https://doi.org/10.1016/j.intfin.2024.102008

65 See details at https://www.agora-energiewende.org/data-tools/levelised-cost-of-hydrogen-calculator

66 According to Agora's source other components of LCOH are cost of capital (13.7%), OPEX (8.7%), CAPEX depreciation (9.7%).

Fig XI: Evolution of CHN West Coast US future Henry Hub gas prices (Daily Data December 2021-February 2022)



When we compare the CNH price signal for the US with the Henrry Hub gas futures price we see a similar, albeit less pronounced, behaviour. While in the first sample the correlation between the two benchmarks is 0.48 in the post-crisis period (January 2023- February 2025) this correlation between the price levels increases to 0.66, confirming that the CNH benchmark is linked to the Henrry Hub Gas price.

The strong link between the CNH price signals for Europe and the US and their fossil fuel analogue suggests that it is necessary to introduce prices that are consistent with the energy transition. Another limitation of the CNH price metric for Europe is that it is not designed to comply with the Delegated Act.

5.3.1.1. S&P Platts ratings compliant with European Regulation

In response to these constraints, S&P Global has designed hydrogen Power Purchase Agreements (PPAs) for Europe for this purpose that comply with regulatory standards.

Platts' hydrogen assessments aligned with European regulation reflect the market value of hydrogen that meets the European Union's definition of Renewable Fuels of Non-Biological Origin (RFNBO), in accordance with EU Delegated Act C/2023/1087. As noted in section XX above, the scope of RFNBO includes hydrogen produced by electrolysis from renewable electricity, its derivatives and other energy carriers

In the absence of market-based information, Platts uses a production cost plus premium model to reflect the market value of firm hydrogen supply, hence these price signals are supply price signals referred to as the "ask" price. This model takes into account the role of hydrogen in storing electricity and the possibility of arbitrage. When available, market information such as bids, offers, transactions and indications will take precedence in the assessments.

To model the cost of production, it is assumed that the renewable hydrogen purchases renewable electricity in the form of a "Pay as Produced" Power Purchase Agreement (PPA). The size of the alkaline electrolyser is 100MW and operates under "minimum load". Platts assesses hydrogen prices in compliance with European regulation in four countries:

- Spain (Alkaline Renewable Hydrogen PPA)
- France (Alkaline Renewable Hydrogen PPA)
- Germany (Alkaline Renewable Hydrogen PPA)
- Netherlands (Alkaline Renewable Hydrogen PPA)

The series are measured in EUR-kg hydrogen and are available from the 18th of March 2024.

Fig XII shows the evolution of S&P PPAH2 prices from the start of their available sample, 18th of March 2024 until 10th of Feb 2025 for Spain and Germany. We illustrate these signals together with the GAS TTF time series and see a slight upward evolution.

A simple visual inspection of these prices shows i) the PPAH2 for Spain is quoted at a lower price than the corresponding price for Germany showing Spain's competitive advantage due to its access to low cost renewable energy, and ii) the price series for Germany and Spain are linked to the TTF gas price.

It is important to mention at this point that TTF gas rose to its highest since May 2023 at the end of January 2025. Quotes are therefore at a two-year high of 58 (MWh), roughly three their pre-invasion level, although well below the 2022 record 311 euros per MWh.

According to Reuters, the rise in TTF gas prices is partly due to gas storage in Europe being at 49% of capacity on 10 February, down from 67% last year and the 10-year average of 51% for the same period. The same report documents that seasonal withdrawal has been higher than in the previous two winters due to colder weather, lower wind speeds and the termination of imports through the last major pipeline connecting Europe to Russia earlier this year.(67) Low storage levels, coupled with higher gas demand in Europe, have pushed the TTF price well US benchmark prices during January 2025, as Europe sought flexible LNG cargoes.

Fig XII Evolution of PPAH2 (S&P Platts) allied to European regulation - Signals for Spain Germany along with TTF gas.

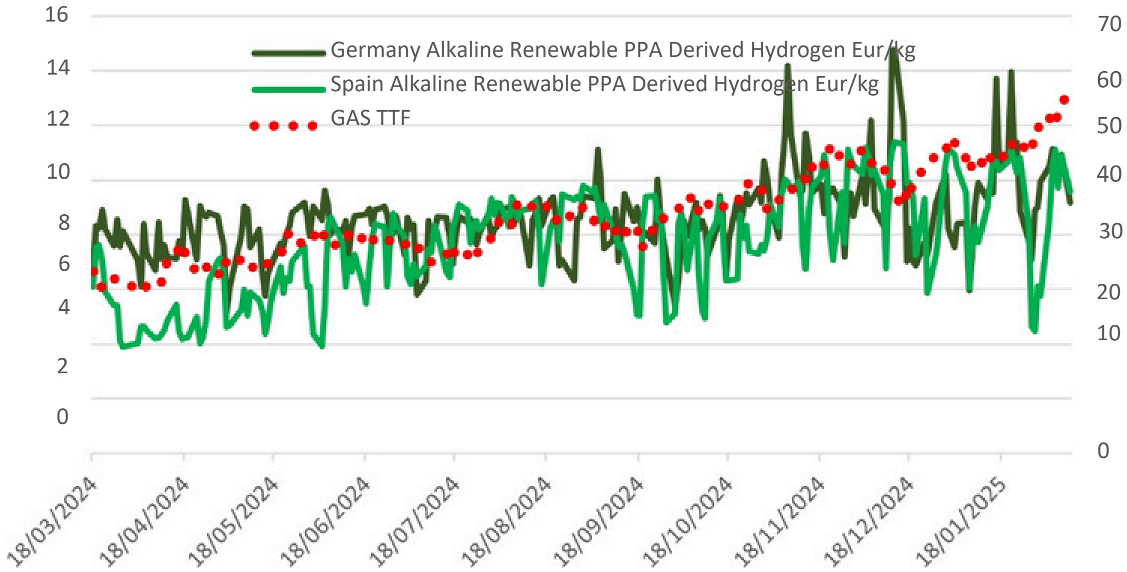


Fig XIII Evolution of PPAH2s aligned with European regulation

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67 See Reuters article "EU rules risk overheating a red-hot gas market," 11 February 2025

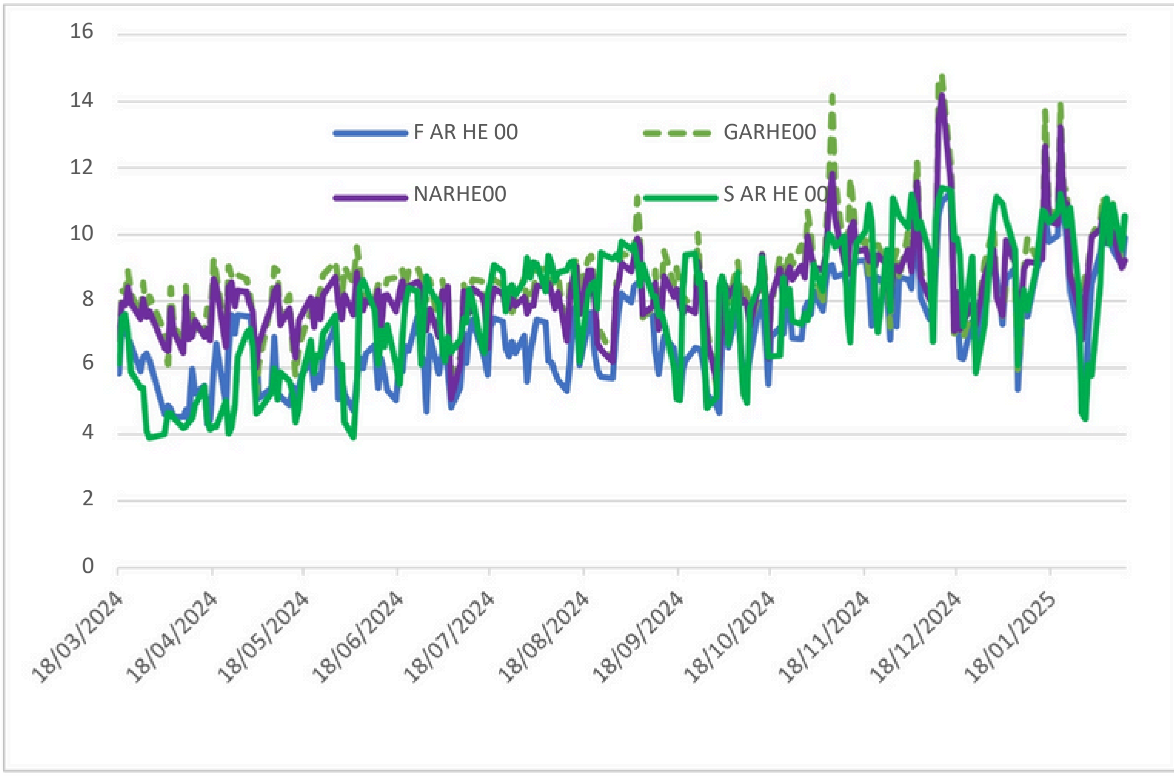


Fig XIII illustrates the evolution of the 4 European PPAH2 benchmarks showing that prices are closely linked. Correlation analysis for these prices and TTF gas (see table XI) shows a correlation of 0.65, 044, 0.52 and 0.62 for the prices of France, Germany, the Netherlands and Spain respectively. The volatilities of these prices are calculated as 230%, 232%, 199%, 275% for France, Germany, the Netherlands and Spain. However, the calculated volatility for TTF gas over the same period is 46%. This suggests that the PPAH2 price signals are incorporating additional volatility probably linked to the premium reflecting the firm supply value of hydrogen. This last observation will be considered further in section 3.

Table XI correlation analysis RRAH2 and GAS TTF

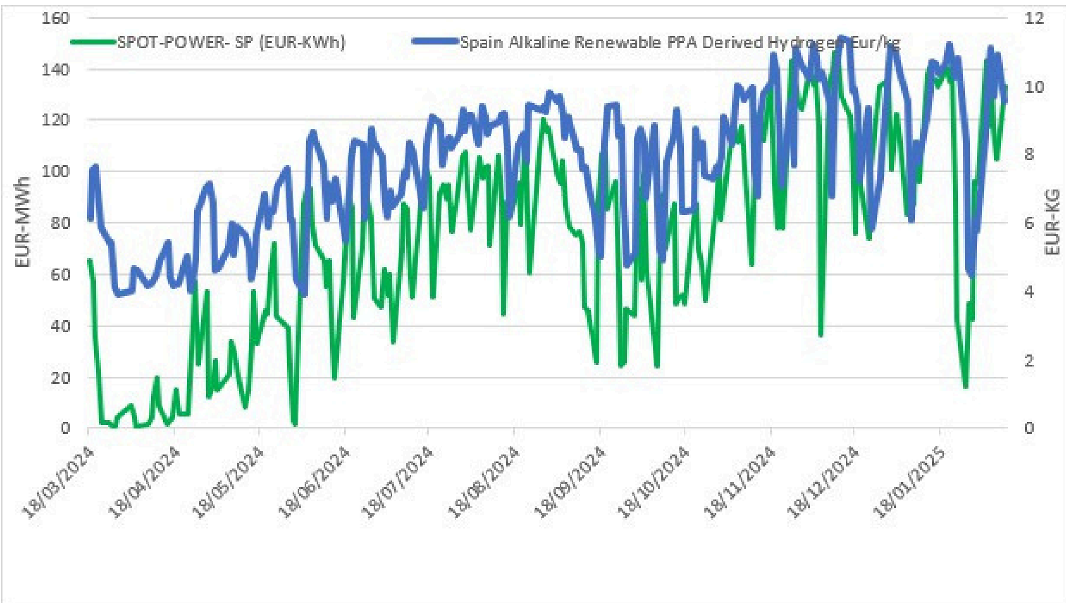
	FRANCE PPAH2	GER PPAH2	NETHER PPAH2	SPAIN PPAH2	GAS TTF	POWER SP
Volatility	230%	232%	199%	275%	46%	330%
Correlation with GAS TTF	0.65	0.44	0.52	0.62		
Correlation POWER-SP	0.64	0.48	0.53	**0.72**	0.69	

This table presents annualized volatilities for the 4 PPAH2 benchmarks, TTF gas and the spot electricity price in Spain during the period March 2024 to February 2025. Daily series source S&P Global (PPAH2) and Bloomberg (TTF gas and POWER SP)

It is important to note that PPAH2 Germany shows a lower correlation with TTF gas than its analogue for Spain. The high volatility of PPAH2 prices suggests that these prices are linked to the spot price of electricity traded in the associated geographical area. We analyse this hypothesis for the case of Spain. Fig XIIIa illustrates the evolution over time of PPAH2 prices for Spain with the daily average electricity price in the spot market quoted on OMEL, labelled SPOT- POWER-SP and measured in EUR-MWh units for the sample between March 2024 and February 2025*(68)* The figure suggests a clear common evolution between both series which as confirmed by a correlation coefficient of 0.72, which is reported in the last row of table XI (column 4) is from 0.72. The same table shows that there is a big relationship between the Spanish spot electricity price and the PPAH2 measures for other geographical areas and especially for France. Again this can be explained by the high dependence of the electricity price on the TTF gas price.

It is important to note at this point that the association of hydrogen price signals with other commodities will allow us to link the future reference price of hydrogen to the prices of these raw materials, which is a step forward for the creation of a renewable hydrogen market.

Fig XIIIa: Evolution of the PPA benchmark for Spain and the spot day-ahead electricity price for Spain quoted on OMEL



68 The Bloomberg code for this series is OMLPDAHD index, and it covers hourly electricity consumption, taking marginal prices in the day ahead market and total electricity sales.

5.3.2. Theindex HYDRIX, signal of prices renewable hydrogen in Germany

This index was launched in May 2023 by the German trading exchange European Energy Exchange (EEX), recognised for its centralised trading of electricity and gas market futures in Germany. This benchmark has introduced renewable hydrogen trading with the aim of creating a price benchmark based on market transactions.

EEX calculates the HYDRIX on a weekly basis, as an average value of the bid and offer, whenever there are transactions. The HYDRIX is published every Wednesday. Fig XIII shows the evolution of the index since its inception using Bloomberg data. Its evolution is illustrated together with TTF gas futures prices. As noted in the PPAH2 price analysis, we can observe a gradual price increase since March 2024 following the evolution of TTF gas. Specifically, Hydrix index value quotes 200 MWh at the beginning of February 2024 and reaches 278 MWh one year later exhibiting an increase of 28%. During the same period the TTF gas future increased from 29 MWh to 55.9 MWh representing a 90% increase. This implies that the German renewable hydrogen benchmark is not only increasing in price and trading at a multiple of 5 with respect TTF gas, but is currently trading at an equivalent value of 9.3 €/kg. This is in line with the reported quotes for HAPH2, indicating that the available price series is still far away from the €1/kg target for 2050(69). The good news is that the price difference Hydrix and its fossil fuel substitute has decreased. Whereas the difference in January 2024 was a multiple of 7.9, the difference during January 2025 was a multiple of 5.45. Despite the fact that the rate of renewable hydrogen is 5.45 times more expensive than its fossil fuel substitute.

If we use weekly data for the period from May 2023 to February 2025 and calculate the volatility of the price changes of the two commodities, we can say that the volatility in the gas market has been almost twice as high as in the renewable hydrogen market (72% versus 38%).

[69] It is important to note that in last year's report we reported a price of 9.3 €/kg as equivalent to 233 KWh, using a conversion factor greater than 33.33/1000.

As we noted last year, we point out that this data may simply reflect a less close link to electricity prices than that observed in the S&P PPAH2 analysis. We discuss this issue further below. Fig XV shows the evolution of the HYDRIX index together with the TTF and the European benchmark electricity price (Power EXAA) corresponding to the EXAA Day Ahead Baseload Electricity Spot Price for Germany*(70)*. Also illustrated is the track record of European emission allowance futures (EUA futures) traded on the International Commodity Exchange (ICE) Endex, whose price is measured in EUR per metric tonne. The data source is Bloomberg. When we analyse price signals on the supply side (ask prices) we can see that the higher the value of these EUA futures, the higher the cost of producing fossil fuels.

Therefore an increase in the price of emission allowances will increase the price of TTF gas and electricity as long as it remains linked to the marginal producer *(71)*. The graph shows a positive correlation between all variables which is confirmed in table II, which reports correlations between the Hydrix index, the TTF, the benchmark Northern European reference electricity price (power EXAA) and the ETS future. The table shows that the Hydrix index has a correlation of 0.655 with the TTF and 0.47 with the power EXAA. The correlation is 0.15 with the EUA future, confirming that an increase in the price of emission allowances increases the cost of gas, the electricity price and the price of renewable hydrogen as measured by the Hydrix series. This analysis is consistent with that of the previous section developed for PPAH2 and TTF gas prices, which showed a correlation of 0.44 for TTF gas and German PPAH2.

Table II: correlations between tiers, German H2 HYDRIX index, TTF gas, Power EXAA, EU ETS

	Hydrix (EUR/MWh)	TTF (EUR/MWh)	powerEXAA(EUR/MWh)	EU ETS (EUR/MT)
Hydrix (EUR/MWh)	1.000	0.655	0.470	0.150
TTF (EUR/MWh)	0.655	1.000	0.146	0.257
powerEXAA(EUR/MWh)	0.470	0.129	1.000	0.269
EUA (EUR/MT)	0.150	0.257	0.269	1.000

70 EXAA's supply areas are the three Austrian trading areas (APG, TIWAG and VKW) as well as two control areas in Germany, the E.ON area and the RWE area.

71 Note that if we analyse the bid price, the effect of the price of emission rights will have a negative effect on the benchmark renewable hydrogen (H2) bid price. The higher the penalty of producing with fossil fuels, the lower the renewable hydrogen (H2) bid price will be.

Fig XV shows the evolution of the Hydrix H2 benchmark together with TTF gas and one-month futures on emission allowances (EUA futures) and the EEX spot baseload price (power EXAA). The visual analysis shows that TTF gas and EUA futures have evolved in the same direction while the Hydrix index does not show a significant correlation with any of the variables analysed. This is confirmed by the correlation analysis presented table 1.

The Hydrix index is an important resource for the creation of price signals in the renewable hydrogen market. Its introduction has encouraged the design of alternative benchmarks in Europe which we will discuss in this paper. However, it has two important limitations. A) although ideally the price benchmark should use market transactions it is not clear that trade transaction data is available on a weekly basis B) The index is not designed in line with the RED III regulation and the delegated act.

Fig XIV

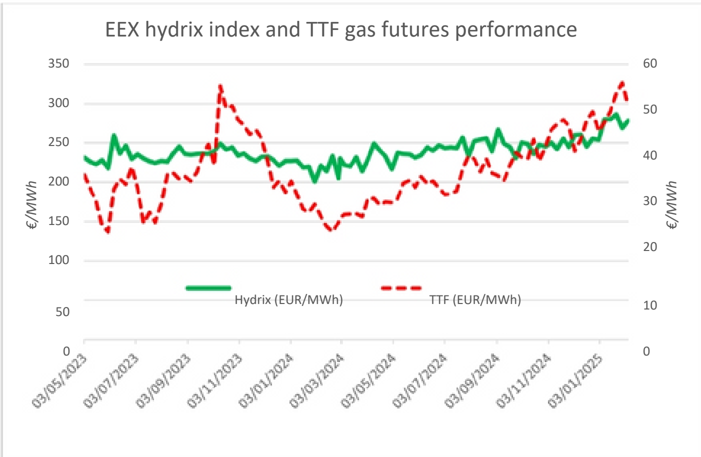
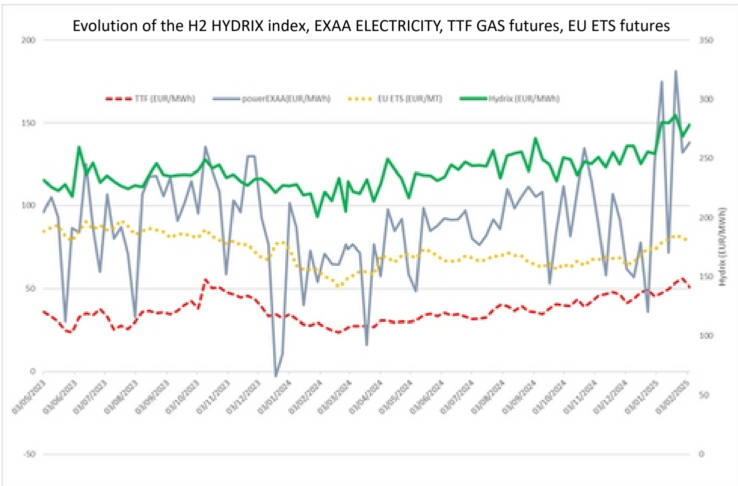


Fig XV



Next, we describe the indices benchmark at Europe whichcare consistent with RED III and the delegated act.

5.3.3. The Austrian CEGH Index

To support this transition from long-term purchase contracts to market-based trading, CEGH publishes several green hydrogen price indices, representing reservation price levels (ask prices) for hydrogen, i.e. the minimum prices at which green hydrogen suppliers are willing to offer hydrogen volumes on the market.

In this way, these CEGH GreenHydrogen Price indices help project developers and potential buyers to understand the level and drivers of hydrogen cost value, as well as to assess the price differences between different forms of green hydrogen production ("shades of green hydrogen").

The "CEGH GreenHydrogen Indices" are, for the time being, based solely on a "cost plus margin" logic, reflecting the expected production costs of green hydrogen at a "representative" electrolysis site. That is, project developers or potential buyers may need to make adjustments to capture project-specific differences (e.g. in terms of Capex levels, applied energy supply strategy, industrial applications).

Depending on the approach used to structure the energy supply to the electrolyser, "CEGH GreenHydrogen" indices will differentiate between different "grades" of green hydrogen*(72)* In this paper we focus on describing the CEGH green hydrogen index.

Based on a 100% supply power purchase agreement (PPA) in accordance with the Delegated Act, RED II(73) Once the purchase of electricity from the grid complies with the requirements of the RED II (or in the future RED III) Delegated Act, the index could become RED II (RED III) compliant.

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[72] The different degrees allow for ways to standardise the contract. In practice, there may be even more variations in the energy supply strategies applied by different hydrogen projects (e.g. the use of battery storage or H_2 storage to structure energy supply or H_2 production. These complexities are not considered in the construction of the CEGH H_2 indices to achieve a transparent index design.

[73] Art. 4 of the RED II Delegated Act (Delegated Regulation (EU) 2023/1184 of 10 February 2023 supplementing Directive (EU) 2018/2001 of 11 December 2018 on the promotion of the use of energy from renewable sources of the European Parliament and of the Council).

Fig XVI

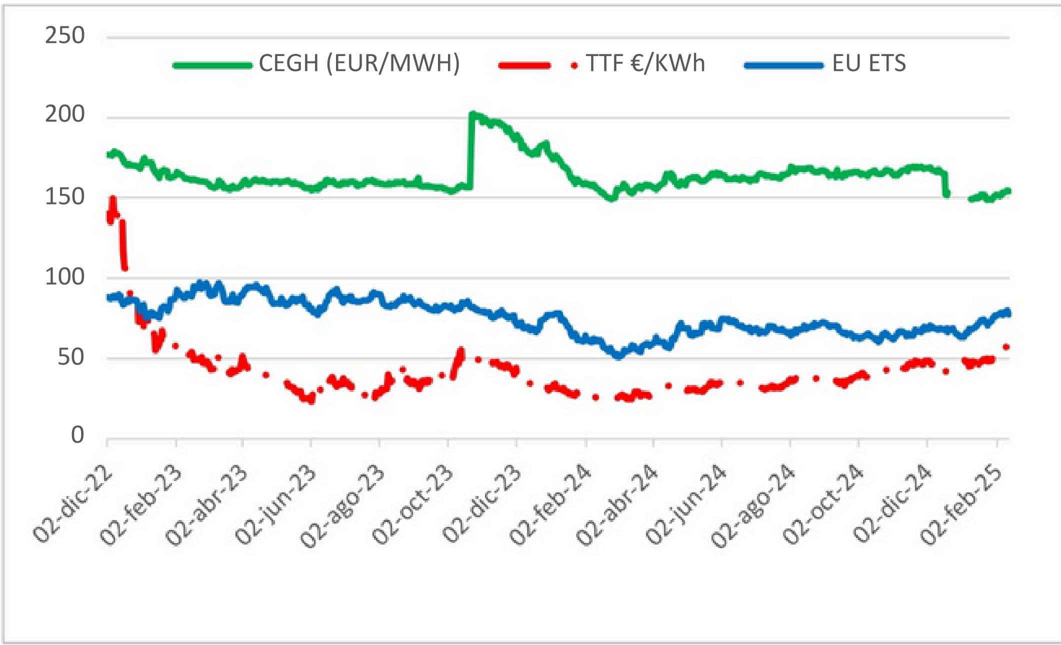
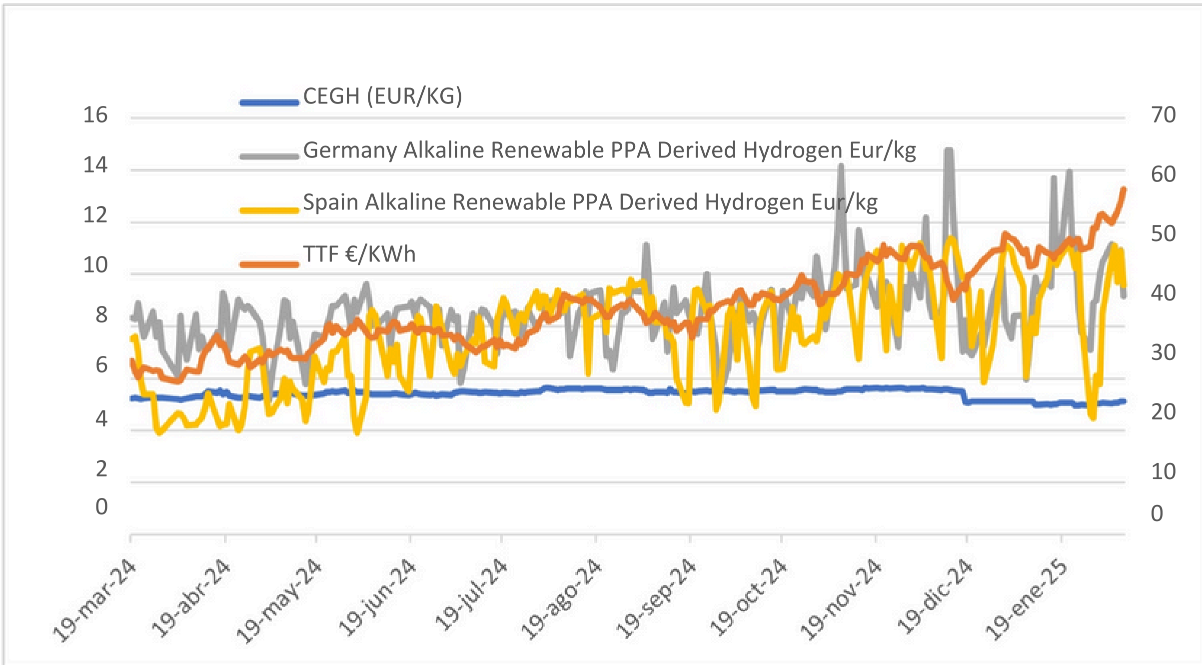


Fig XVI illustrates the evolution over time of the CEGH index together with the fossil fuel analogue during the period for which the CEGH RED III index is available (2nd of december 2022) on a daily frequency. It is interesting to note that while the gas price increased by 90% in the last year and the value of the Hydrix index increased by 35%, the CEGH benchmark decreased by 0.06%, showing a higher degree of stability than its competitors.

Fig XVII (next page) shows the evolution of the CEGH in EUR/KG H2 and its German and Spanish analogue PPAH2. TTF gas is also shown with its units on the secondary axis. The graph clearly shows that the CEGH index is trading below the PPAH2 prices for Spain and Germany. Fig XVII Evolution of CEGH index, TTF gas and PPAh2 S&P prices for Spain and Germany. March 2024-February 2025.



The correlation analysis shown in table III confirms the disparity between the PPAH2 indices and the CEHG index.

	CEGH (EUR/MWH)	TTF €/KWh	EUA Futures	EXAA	France H2PPA	Germany A H2PPA	NetherH2PPA	SPAIN H2PPA
CEGH (EUR/MWH)	1	-0.213	-0.181	-0.130	-0.134	-0.014	-0.061	0.075
TTF €/KWh		1.000	0.398	-0.205	0.650	0.440	0.521	0.615
EUA Futures			1.000	-0.125	0.287	0.256	0.271	0.305
EXAA				1.000	-0.146	-0.158	-0.148	-0.238
France H2PPA					1.000	0.758	0.843	0.741
Germany H2PPA						1.000	0.960	0.505
Netherlands H2PPA							1.000	0.567
Spain H2 PPA								1.000

5.4. Construction of signs from price of renewable hydrogen.

A common feature of the metrics discussed is that they are essentially Levelised Cost of Hydrogen (LCOH) measures. Currently, most hydrogen users either produce and consume hydrogen on-site as part of their production process or procure it from producers through dedicated distribution routes and bilateral agreements. The details of such bilateral agreements, in particular those related to the supply price, are normally not disclosed. In the absence of liquid markets for hydrogen, policy makers and investors currently rely mostly on Levelised Cost of Hydrogen (LCOH) estimates.

These metrics use cost-based models considering the various factors that determine production costs (in terms of investment and operating costs). Where possible, this data is verified with information from individual projects, contracts or transactions (e.g. hydrogen purchase agreements or PPAs). Another limitation of these price signals is that their design is not always aligned with the delegated act. Only the CEGH index and the S&P Platts hydrogen PPA are consistent with the delegated acts for obtaining RFNBOs.

5.4.1. Renewable hydrogen price signal at IBERIA

The IBHYX Index according to the criteria set out in the delegated acts for obtaining RFNBO (Renewable Fuel of Non-Biological Origin) reflects the levelised cost of renewable hydrogen production from a business model that guarantees profitability to the developer.

As previously discussed, ideally, the price benchmark should be constructed on the basis of actual market transactions reported by the actors. However, the renewable hydrogen market is still immature and lacks sufficient liquidity to allow such approach. Therefore, this index has been derived by a transition from a production cost-based approach to an assessment of the expected return, derived from the anticipated future returns of equity investors, thus estimating the possible hydrogen price.

One implication of the lack of market maturity is that production costs and expected returns may be above the price that end-users would be willing to pay for this hydrogen, i.e. there is a gap between the supply price and the demand price.

This index indicates the minimum selling price that the producer must set to achieve the expected profitability, or, in other words, it represents the bid price signal (ask) for renewable hydrogen produced in the Iberian Peninsula, in a standard electrolysis plant.

The MIBGAS green hydrogen offer price is derived from a proprietary model used to calculate the reference offer price renewable hydrogen in the Iberian Peninsula. Due to the lack of transactions for this energy vector, the proposed index is calculated using Discounted Cash Flow (DCF) valuation, which considers the intrinsic value of an asset as the present value of its expected future cash flows. Specifically, the algorithm uses the Free Cash Flow to Shareholder (FCFE), defined as the free cash flows available for distribution to shareholders. The price of hydrogen is set as the sale price that makes the Net Present Value (NPV) to the shareholder, defined as the FCFE discounted at the cost of equity minus the initial shareholder investment, equal to zero. This method is a shift from the traditional cost-based approach to an index based on the "expected return" of equity investors.

This requires modelling the equilibrium hydrogen price for an electrolysis plant that obtains its electricity from both a dedicated renewable generation plant and electricity drawn from the grid through a Renewable Power Purchase Agreement (PPA) that complies with the requirements for the production of renewable fuels of non-biological origin, as defined in the Renewable Energy Directive and its Delegated Regulations (Article 4 of Delegated Regulation (EU) 2023/1184 of 10 February 2023, supplementing Directive (EU) 2018/2001 of December 2018 on the promotion of the use of energy from renewable sources of the European Parliament and the Council).

The cost of electricity consumed by the electrolyser is therefore determined as a combination of the Levelised Cost of Electricity (LCOE) of the dedicated renewable plant and the price of a renewable PPA. Both the dedicated plant and the PPA combine solar photovoltaic (PV) and wind energy.

To estimate the LCOE of the dedicated plant, the model also follows the "expected return" method, where the electricity price is the selling price that makes the Net Present Value (NPV) for the shareholder, defined as the FCFE discounted at the cost of equity minus the initial shareholder investment, equal to zero. The proposed framework constitutes a "cascade model" that takes the LCOE as an input for the calculation of the hydrogen production price.

The assumptions on the parameter values have been agreed by the hydrogen pricing working group, which has been involved in developing the methodology for calculating a reference price for renewable hydrogen that reflects a reliable, transparent and representative cost signal. This group has conducted several sessions in which a representative plant model of a renewable hydrogen production project in the Iberian Peninsula has been defined, including all its parameters and the cost-based methodology. The model is designed to provide the necessary revenues to guarantee a given return on investment in the defined model plant. Therefore, the framework sets the price of the proposed green hydrogen index based on the expected return of equity investors within a project finance based version designed for the Iberian case.

The calculation model used by MIBGAS to determine the Levelised Cost of Hydrogen (LCOH) is therefore more advanced than traditional models. It considers all financial variables associated with the reference hydrogen production plant, as well as the costs associated with the production of renewable electricity, both from a dedicated plant and from grid-sourced electricity. These factors are essential to accurately calculate the cost of renewable electricity and hydrogen. In the following, we describe the move from the LCOH model to the Project Finance model.

5.4.1.1. Renewable hydrogen price signal at IBERIA

The offer price is obtained as the Levelised Cost of Hydrogen (LCOH) for the reference plant, i.e. the average break-even price of hydrogen over the lifetime of the plant. The traditional LCOH calculates the fixed price at which green hydrogen would be sold for the investment to break even, which implies that the investment recovers its costs and the target Internal Rate of Return (IRR) is achieved. It can also be defined as the minimum selling price at which the Net Present Value (NPV) of costs equals the NPV of revenues, i.e. the break-even price.

$$\boldsymbol{NPV(Costs) = NPV(Revenues)}$$

$$\boldsymbol{I_0 + \sum_{t=1}^{n} \frac{C_t}{(1+IRR)^t} = \sum_{t=1}^{n} \frac{I_t}{(1+IRR)^t}}$$

Where revenue is defined as the quantity produced times its price, i.e.: $I_t = M_t \cdot P_t$ defined as the LCOH and is calculated using the following formula:

$$\boldsymbol{LCOH = \frac{I_0 + \sum_{t=1}^{n} \frac{C_t}{(1+IRR)^t}}{\sum_{t=1}^{n} \frac{M_t}{(1+IRR)^t}}}$$

Where IRR is the Internal Rate of Return and usually captures the average cost of debt as the investor's expected average return on equity (the weighted average cost of capital or WACC).

The price based on this formulation is provided as a reference in the offer price calculator.

The bid price calculator used by Mibgas departs from this conventional LCOH formulation towards an evaluation method based on a Project Finance approach or Project Finance model. The model takes into account the capital structure and stitching and calculates taxes, allowing tax credits to be incorporated if the project incurs losses. The free cash flow to the investor (FCFE) is obtained after debt service and taxes, and is calculated by discounting the cash flows at the rate of return required by the investor, less the initial investment. The Project Finance method develops the calculation of renewable hydrogen price benchmark as shown below:

$$NPV_{Equity} = \sum_{t=1}^{n} \frac{FCFE_t}{(1 + IRR)^t} - Initial\ Investment$$

NPV_{Equity} :Net Present Value of Equity Cashflows
FCFE :Free Cashflow available to equity investor (Free Cashflow to Equity) in period t
IRR: D iscounted rate or cost of equity
t:time period (in years)
n:total number of periods Initial Investment: Value of the initial shareholder contribution

FCFE-based valuation takes the revenue from the sale of given quantity of hydrogen at an equilibrium price that makes the FCFE-based project's Internal Rate of Return (IRR) equal to the cost of equity.

This approach considers the capital structure (debt and equity), depreciation and after-tax profits. FCFE is defined as:

FFCE= EBITDA - Debt Service - Taxes+ Residual Value

Where EBITDA is Earnings before interest, taxes and depreciation:

EBITDA=Revenues-Operating Expenses (excluding depreciation and amortisation)

The use of the FCFE method aims to closely follow the analysis used by a developer (or investor) of renewable hydrogen projects. It allows capturing the impact of taxes and depreciation. The cost of equity capital becomes an important parameter, does the capital structure and the cost of debt service or interest rates.

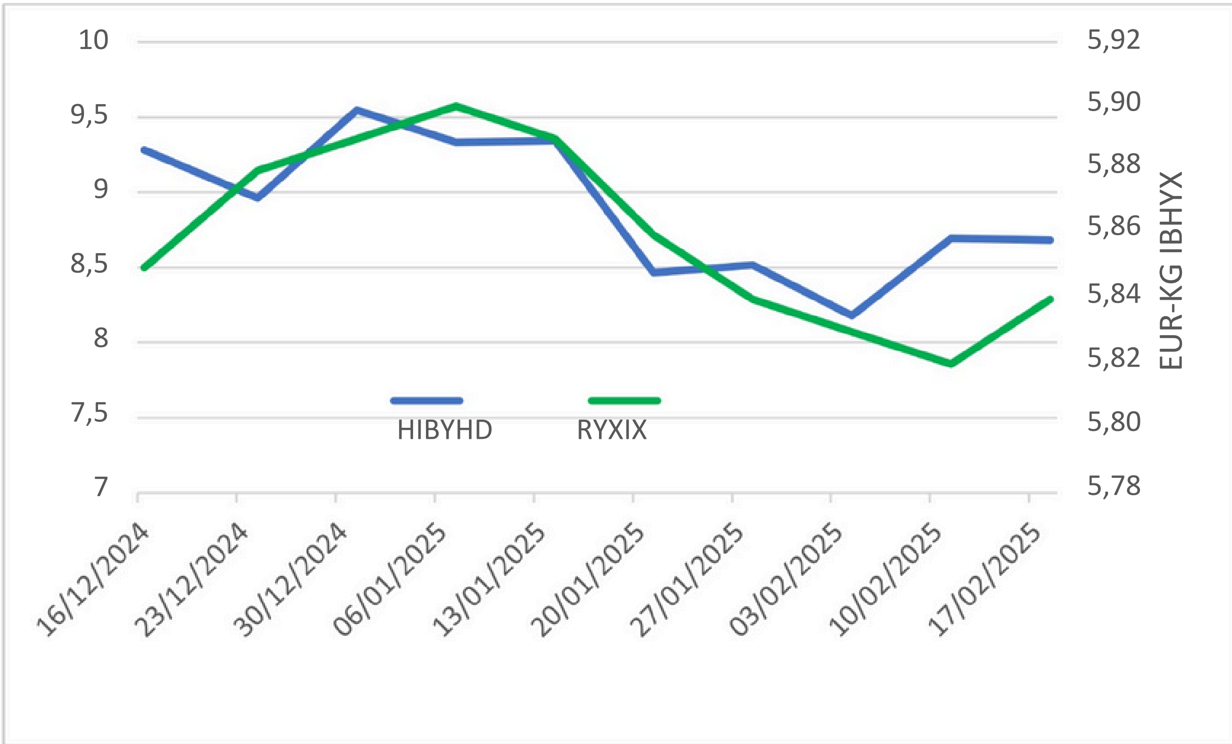
The **LCOE** (Levelised Cost of Electricity) for the electrolyser is calculated from the price of energy generated by solar and wind plants, as well as renewable PPA contracts. The cost of debt service is determined by considering the interest rate and the years of project life, with a flat annual debt amortisation.

The model also calculates taxes, allowing tax credits to be incorporated if the project incurs losses. The free cash flow to the investor (FCFE) is obtained after debt service and taxes, and is calculated by discounting the cash flows at the rate of return required by the investor, minus the initial investment.

Some of these variables are updated periodically, allowing the estimated hydrogen price to change on a weekly basis.

The Project Finance model uses a spreadsheet solver to iterate the value of the LCOH until the FCFE (free cash flow to the investor) is zero. This ensures that the investor's investments are offset by returns, meeting the required profitability. In addition, the DSCR (Debt Service Coverage Ratio), which assesses the project's ability to cover debt service, is calculated annually. This ratio must be higher than 1.35 each year. If it is not met, the financial leverage must be reduced, reducing the weight of the debt.

Chart XVIII shows the evolution of the IBHYX index from its introduction on 16 December until February 2025 together with the Hydrix index. The Iberian benchmark is trading at lower levels but follows a similar evolution to its German analogue.



5.4.1.2. Dedicated renewable generation and electrolysis plant: integrated vs. cascade model.

As mentioned above, a dedicated hybrid renewable generation plant is an essential component of the reference plant model. There are two main approaches to incorporate it into the overall Levelised Cost of Hydrogen (LCOH) financial model:

a. Cascade model. In this approach, the dedicated renewable plant is treated separately from the electrolysis plant, as if they were two independent investment projects. First, the Levelised Cost of Electricity (LCOE) of the renewable plant is calculated, and then this value is used as input to calculate the LCOH, considering it as an operating expense (OPEX) from the perspective of the electrolysis plant.

b. Integrated model. In this alternative, the investment and operation and maintenance (O&M) costs of the renewable plant are combined with those of the electrolyte in a single project, with a common financial structure. As a result, the LCOE is not explicitly calculated.

The integrated model is generally more accurate in representing a case where a hydrogen producer operates an integrated project without considering the possibility of injecting self-generated electricity into the grid or selling it to third parties. This is the case assumed by the chosen reference plant. However, both models give the same result in terms of LCOH, provided the same input data are used.

The adopted model follows the cascade approach (see Figure 2), which means that it calculates the LCOE of the renewable plant and the LCOH separately, for two main reasons:

i.Increased flexibility: This approach allows for more flexibility. No changes to the structure of the model would be needed in the future if different capital structures, debt costs or required returns are deemed necessary for renewable hydrogen and electricity production.

ii.Transparency: As the LCOE is explicitly calculated, the cascade model improves the transparency of the process. This is important because, as the technology improves and other costs (such as the CAPEX of electrolysers, the costs of insurance, etc) decrease, the LCOE will accoutn for a higher proportion of total hydrgen costs.

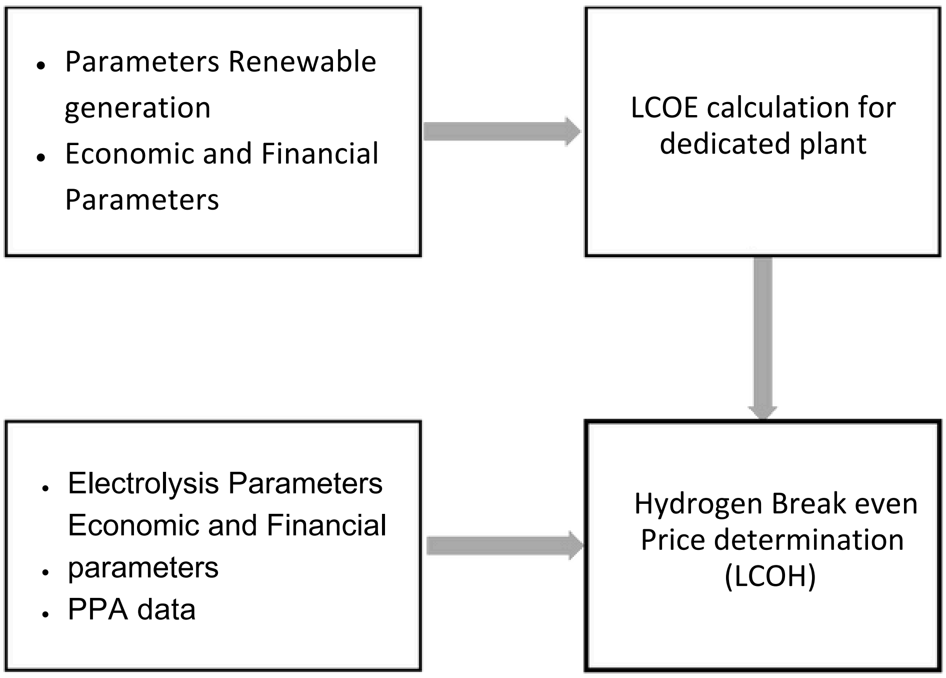


Figure 2: Waterfall model to calculate the LCOE of the dedicated renewable plant and the LCOH

5.4.1.3. Design of electricity generation plant

As noted in the information provided by the marketplace Mibgas*(74)*, the electrolysis plant includes a 50 MW electrolyser with an integrated stack design, which incorporates all ancillary services necessary for its operation. A size is chosen which is feasible according to the current state of the art and offers competitive advantages in terms of economy of scale. No specific technology has been selected (PEM or Alkaline), as the model does not require a detailed choice, seeking to represent real current and future projects.

The total investment cost is set at €1,600/kW, covering water treatment equipment, stack, balance of plant, power supply, and engineering and construction (EPC), but does not include land and licenses. The plant's lifetime is estimated at 25 years, with 4,500 hours of operation per year at full load.

The plant will be supplied with electricity from nearby dedicated renewable plants (photovoltaic and wind), and will be supplemented with grid power through PPA contracts. The electricity production from these plants will be used exclusively for the electrolysis process, with no surplus being fed into the grid.

Operating costs are considered as a percentage of the annual CAPEX (2.5%), with additional expenses for insurance (1.5%). Plant efficiency is set at 60%, with a conversion factor of 55.5 kWh/kg. Efficiency will gradually decrease due to equipment degradation, with a replacement of the stack at 80,000 operating hours, which will be included as an investment of 15% of the initial CAPEX.

This detailed approach allows the calculation of the levelised cost of renewable hydrogen produced, taking into account all associated costs and project parameters.

[74] Consult for detailed information MIBGAS - Green Energy

5.4.1.4. Design of electricity generation plant

The design of the power generation plants for the project includes a combination of photovoltaic and wind power plants, with a total of 4,500 operating hours per year for the electrolyser. Of these, 3,500 hours will come from own plants (2,500) hours of PV and 1,000 hours of wind), and the remaining 1,000 hours will be covered by solar and wind PPAs. The generation plants will be located in the centre of the Iberian Peninsula, taking advantage of local solar and wind conditions. The photovoltaic plant will have a capacity of 58 MWp, while the wind plant will have a capacity of 23 MW. The CAPEX and OPEX costs of these plants are used to calculate the LCOE of the dedicated plants.

To complete the necessary hours, solar and wind PPAs will be contracted for a duration of 10 years. These PPAs will be strategically located in the south-east and north-east of the peninsula, respectively, and their cost will be adjusted to the production profile of the dedicated plants. The LCOE is calculated from the costs of these plants and PPAs, using the MIBGAS Project Finance model. The total LCOE, once calculated, is used as a parameter to calculate the LCOH (levelised cost of hydrogen) in the project's economic model. This final cost reflects the price of renewable hydrogen produced and is reported as the MIBGAS IBHYX Index.

5.4.2. Conclusions

The hydrogen market needs the commitment of credible off-takers. To this end, the creation of reference price signals is essential. In the case of Europe such a benchmark must be compatible with the delegated act.

As defined by their own providers the Austrian CEGH index and the S&P PPAH2 are aligned with the delegated act. While the former does not correlate with the TTF gas, the PPAH2 does move in the same direction as the fossil fuel analogue. PPAH2 prices for Spain show a high correlation with spot prices in the Spanish electricity market, which explains the high volatility recorded.

The Hydrix index is not consistent with the delegated act and its evolution is highly correlated with the TTF gas and the European electricity price.

The futures on emission allowances exhibit positive correlations with the PPAH2 price, and with the Hydrix index, suggesting that a higher cost emission allowances raises the price of TTF GAS and thus of hydrogen price signals.

The price signals introduced in the market so far are measures of offer prices or "ask" prices. While the increase in price signals for renewable hydrogen is good news, it is important to standardise price metrics to facilitate comparison between different benchmarks.

The benchmark design for IBERIA IBHYX is innovative in that it focuses on finding the price of H2 that guarantees the expected return for the developer. This framework allows the design of an electricity price model that integrates with the cascading electrolyser plant model adding transparency and flexibility to the valuation process.

ANNEX I: DEMAND SCENARIO METHODOLOGY

a) Total fuel consumption in transport 2023

CORES	Year	kt	TWh/y	Source
Automotive diesel	2023	21642	256,02486	CORES
Automotive gasoline	2023	6064	71,5552	CORES
Natural gas vehicles	2023	-	3,6	Enagás
Conventional maritime transport	2023	10000	113,9	Cero 2050
LNG maritime transport	2023	-	1,92	Enagás

b) Comparative availability and potential demand for biomethane

Origin	Target	Value	Units
Forestry	Biomethane	27.66	TWh/year
Intermediate crops	Biomethane	58.8	TWh/year
Agri-food	Biomethane	6.42	TWh/year
WWTP	Biomethane	2.99	TWh/year
FORSU	Biomethane	7.92	TWh/year
Livestock	Biomethane	25.48	TWh/year
Agriculture	Biomethane	24.77	TWh/year
Landfills	Biomethane	8.81	TWh/year
Biomethane	High Temperature Heat	74.07	TWh/year
Biomethane	Maritime	80.55	TWh/year
MetOH	Maritime	21.14	TWh/year
H2	MetOH	22.94	TWh/year

* Biomethane to useful heat conversion efficiency of 90 % is assumed (69).

62 https://thermalprocessing.com/efficient-gas-heating-of-industrial-furnaces/

c) Availability of raw materials for the production of bia-SAF

For the production of bio-SAF, forest biomass, agricultural biomass and used cooking oil were considered as potential feedstocks.

The availability of used cooking oil was made based on the maximum limit of 1.7% as detailed in section 4.2.2.2. For the availability of forest and agricultural biomass, the biomethane potential estimated by Sedigas in tonnes of feedstock was transformed using the yields provided in the report of the European Biogas Association [6].

	Biomethan e powerL (TWh)	**biomethane (Mm3)**	**Performance**	**Raw material (kt-dry)**
Agriculture	24,77	2309,83	0,18 m3 metano/kg-seco	12832,42
Forestry	27,66	2579,33	0,42 m3 metano/kg-seco	6097,71

Based on the feedstock availability and the yield and consumption of different technologies for e-SAF/ bio-SAF production in Table 4, the PBS production potential was calculated.

Table 4. Performance and selectivity made SAF for different routes and feedstocks

Technology	Raw materials	Yield (t distillate/ t raw material)	Product distribution
FT	FORSU	0,31	70 % SAF, 20 % HVO, 10 % light weight
FT	Forest Biomass	0,18	70 % SAF, 20 % HVO, 10 % light weight
FT	Agricultural Biomass	0,14	70 % SAF, 20 % HVO, 10 % light weight
HEFA	UCO Biomass	0,83	40 % SAF, 50 % HVO, 10 % light weight

Source: ICAO (70)

62 https://www.icao.int/environmental-protection/Pages/SAF_RULESOFTHUMB.aspx

(s) Calculation of LNG/CNG quota needed to meet FuelEU Maritime targets

Well-to-Wheel emissions for LNG and bio-LNG gas.

Fuel	WtW emissions (gCO2-eq/MJ)	Source
Dual LNG-diesel low speed engine	76,13	Sustainable Ships 71
Dual bio LNG-diesel low speed engine	15,68 *	Own estimation
Dual bio methanol-diesel low speed engine	0	Own estimation

* 83 % reduction vs. fossil benchmark, 94 gCO2-eq/MJ

LNG and bio-LNG quota for ReFuelEU Maritime compliance using LNG and bio-LNG

	GNL	Bio-GNL	LNG-TWh/y	Bio-GNL- TWh/year	Intensity emissions
2025	1,00	0,00	113,90	0,00	76,08
2030	1,00	0,00	113,90	0,00	76,08
2035	1,00	0,00	113,90	0,00	76,08
2040	0,78	0,22	89,04	24,86	62,90
2045	0,31	0,69	35,75	78,15	34,64
2050	0,04	0,96	4,80	109,10	18,23

LNG and bio-LNG quota for compliance with ReFuelEU Maritime using LNG and methanol RFNBO

	LNG	MetOH RFNBO	LNG-TWh/y	MetOH RFNBO - TWh/year	Emissions intensity
2025	1.00	0.00	113.90	0.00	76.08
2030	1.00	0.00	113.90	0.00	76.08
2035	1.00	0.00	113.90	0.00	76.08
2040	0.80	0.20	91.18	22.72	62.90
2045	0.37	0.63	42.47	71.43	34.64
2050	0.12	0.88	14.19	99.71	18.23

[1]"Hydrogen Demand | European Hydrogen Observatory." Accessed: Feb. 21, 2025. [Online]. Available: https://observatory.cleanhydrogen.europa.eu/hydrogen- landscape/end-use/hydrogen-demand.

[2]I.CORPORATIVA, "Iberdrola and Foresa advance in their alliance to lead the production of green methanol in Spain," Iberdrola. Accessed: Feb. 21, 2025. [Online]. Available: https://www.iberdrola.com/salacomunicacion/noticias/detalle/iberdrola-yforesa-avanzan-en-su-alianza-para-liderar-produccion-metanol-verdeespana

[3]EASA, "State of the EU SAF market in 2023," 2024. Accessed: Jan. 20, 2025. [Online]. Available: https://www.easa.europa.eu/en/document-library/general-publications/state-eu-saf-market-2023 [4]M. Rehfeldt, C. Rohde, T. Fleiter, F. Toro, and F. Reitze, "A bottom-up estimation of heating and cooling demand in the European industry".

[5]"sedigas-informe-potencial-biometano-2023.pdf." Accessed: Feb. 07, 2025. [Online]. Available:https://estudio-biometano.sedigas.es/wp-content/uploads/2023/03/sedigas-informe-potencial-biometano-2023.pdf.

[6]"GfC_national-biomethane-potentials_070722.pdf." Accessed: Feb. 07, 2025. [Online]. Available: https://www.europeanbiogas.eu/wp-content/uploads/2022/07/GfC_national-biomethane-potentials_070722.pdf.

[7]V. Doedee, "Sustainable Ships," vol. 2024.

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CHAIR OF HYDROGEN STUDIES

Renewable hydrogen: quo vadis?