Techno-economic assessment of hydrogen offloading systems for offshore wind farms

Brais Armiño Franco

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Supervisors: Dr. Rui Pedro de Costa Neto

Dr. Patrícia de Carvalho Baptista

Examination Committee

Chairperson: Prof. Susana Isabel Carvalho Relvas

Supervisor: Dr. Rui Pedro da Costa Neto

Member of the Committee: Dr. Ana Filipa da Silva Ferreira

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The development of this thesis, that results in the MSc completion, started much sooner than 2 years ago. At home I learned the ethics of hard work, of responsibility and how holistic is our existence, where our actions have great repercussion in others. My grandpa taught me to love the nature and I understood that it is necessary to preserve what you love. This results in the choice of a career focused on sustainability in order to secure well-being for the society and environment.

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RESUMO

A produção de hidrogénio a partir de energia eólica *offshore* é um tema que está sendo explorado atualmente, oferecendo bons fatores de capacidade e energia elétrica de baixo custo. Este trabalho estuda a competitividade das diferentes vias de produção e exportação de H_2 produzido *offshore*, realizando uma avaliação técnico-económica desses casos, incluindo custos de produção de H_2, NPV do projeto e a sua eficiência energética, com foco especial nas opções de exportação de H_2 para o seu uso final. Entre as vias estudadas, a utilização de gasoduto para transportar H_2 parece ser a melhor solução, proporcionando um custo do hidrogénio de 5,35 €/kgH_2 para o caso de referência, embora tenha o potencial de ser tão baixo quanto 2,17 €/kgH_2 se o apoio da UE à implantação do H_2 for bem-sucedido e atingisse os seus objetivos. O uso de energia para essa via é de 0,46 MWh/MWhH_2, sendo um dos métodos menos intensivos em energia, devido a menos etapas de conversão. Outra percepção importante deste trabalho é que considerar o valor de mercado do O_2 pode melhorar muito a economia e a viabilidade do projeto. Além disso, uma análise de sensibilidade é realizada para as variáveis mais influentes, mostrando que o LCOH é muito dependente dos custos de eletricidade e eletrolisador. O H_2 tem potencial para reduzir o seu preço a um ponto em que a sua aplicação possa ser competitiva em diversos mercados, atingindo uma procura de H_2 global de 666 Mt por ano, 950% mais que a produção dedicada atual.

Palavras-chave: *Produção de hidrogénio; produção de eletricidade eólica offshore; métodos de descarregamento; análise energética e económica*

ABSTRACT

Offshore wind with H_2 production is an interesting topic being currently explored, offering good capacity factors and low-price electricity for cheap H_2 production. This work studies the competitiveness of different pathways of producing and exporting offshore H_2, by performing a techno-economic assessment of these cases, including H_2 production costs, NPV of the project and their energy efficiency, with special focus on the offloading options to export H_2 for its final use. Among the studied pathways, the use of pipelines to transport H_2 seems to be the best solution, providing a LCOH of 5,35 €/kgH_2 for the baseline case, whereas it has the potential of being as low as 2,17 €/kgH_2 if the EU support to H_2 deployment is successful and achieves its targets. The energy requirement for this pathway is 0,46 MWh/MWhH_2, being one of the less energy intensive methods, due to less conversion steps. Another key insight of this work is that considering the market value of O_2 can improve greatly the economics and viability of the project. Also, a sensitivity analysis is performed to the more influential variables, showing that LCOH is very dependent on the costs of electricity and electrolyzer costs. H_2 has the potential to cut its price to a point in which its application can be competitive in several markets, reaching a worldwide H_2 demand of 666 Mt per year, 950% more than the current dedicated production.

Keywords: *Hydrogen production; offshore wind electricity production; offloading methods; energy and economic analysis*

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Nomenclature

ASU	Air Separation Unit
CCUS	Carbon Capture Utilization and Sequestration
CH_2	Compressed Hydrogen
DBT	Dibenzyltoluene
DRI-EAF	Direct Reduced Iron Electric Arc Furnace
EU	European Union
FCEV	Fuel Cell Electric Vehicles
HER	Hydrogen Evolution Reaction
HHV	Higher Heating Value
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
LCOE	Levelized Cost of Electricity
LCOH	Levelized Cost of Hydrogen
LH_2	Liquefied Hydrogen
LHV	Lower Heating Value
LOHC	Liquid Organic Hydrogen Carriers
Mt	Million Tons
NG	Natural Gas
NH_3	Ammonia
NPV	Net Present Value
OER	Oxygen Evolution Reaction
PEM	Polymer Exchange Membrane
PSA	Pressure Swing Adsorption
RES	Renewable Energy Sources
SOEC	Solid Oxide Electrolyzer Cell
TCO	Total Cost of Ownership
TPD	Tons Per Day
TSO	Transmission System Operator

1. Introduction

1.1 Motivation

In 2018, IPCC published in its "Global Warming of 1.5ºC" report that in order to limit the global increment in temperatures to 1,5 ºC compared to pre-industrial levels, CO_2 emissions should be cut down to zero by 2050 [1]. This report was induced by the Paris Agreement, signed by almost every nation in the world and which aims to limit the temperature increase up to 2 ºC above pre-industrial levels while pursuing efforts to limit it even further to 1,5 ºC.

There is a clear goal to be "Net zero" by this time, overall, in advanced economies. This fact is supported by the commitment of more than 20 countries which already mentioned their targets of reaching carbon neutrality before 2050 [2] and more are expected to announce it soon, such as the EU [3].

In order to achieve such goals, not only energy systems (including electricity or fuels) must be fully decarbonized, but also feedstocks for chemical industries or metallurgic processes which consume fossil fuels need to be produced by clean pathways. Here is where the importance of green hydrogen (H_2) as a future energy vector lies on. This H_2 is the one produced from renewable energy sources (RES) and has no direct CO_2 emissions associated, as opposed to the one produced from fossil fuels (Grey H_2) or the one produced from fossil fuels but with the use of carbon capture, sequestration and utilization (CCUS) (Blue H_2).

H_2 versatility allows its use as an energy storage medium, enabling a better integration of RES in the energy systems. Moreover, it can be a fuel for transportation of all kinds, both in its pure form or as a synthetic fuel. It can generate electricity (both by combustion and by the use of fuel cells), it can be used to produce heat for industry and buildings, it can be used for the iron reduction in order to produce steel and, finally, it has several uses as feedstock for the chemical industry (Ammonia, methanol, plastics…) [4]. Furthermore, by using green H_2, all these applications can be free of CO_2 emissions.

The growing interest on H_2 production has emerged worldwide since it is seen as a necessary element of the energy system in order to guarantee energy storage over long time and also to decarbonize sectors that are very challenging or impossible to address with electricity [5]. This attention received by H_2 is also supported by several factors, like the increasing prices of oil and gas, the increasing deployment of RES with its underlying flexibility need and intermittency and the concerns over the security of energy supply for countries that depend on imports of fossil fuels.

Several nations worldwide have already recognized H_2 as a relevant pillar in order to build their future energy systems. Starting by the EU, which on the 8th of July 2020 announced its Hydrogen Strategy, which aims to cover up to 13-14 % of its final demand of energy with green H_2 [6] by 2050. Other countries, such as Australia, Portugal or Germany have also published their H_2 roadmaps, placing this energy vector at the core of their energy systems [7] [8] [9].

H_2 could support the integration of intermittent renewables by avoiding power curtailments, electricity grid congestions and by improving the system reliability in remote areas [10]. In addition, it offers possibilities for the exploitation of RES in areas where transmission lines do not exist, or in places where the grid is already saturated [11]. This fact is especially relevant in the case of offshore wind, where, as seen in Figure 1, most of the best resources are in areas where there is no population. This translates into the nonexistence of power grids or consumption areas close to the production point. Thus, either this energy potential is converted into H_2 to be transported, untapping this vast potential, or it will not be used [11].

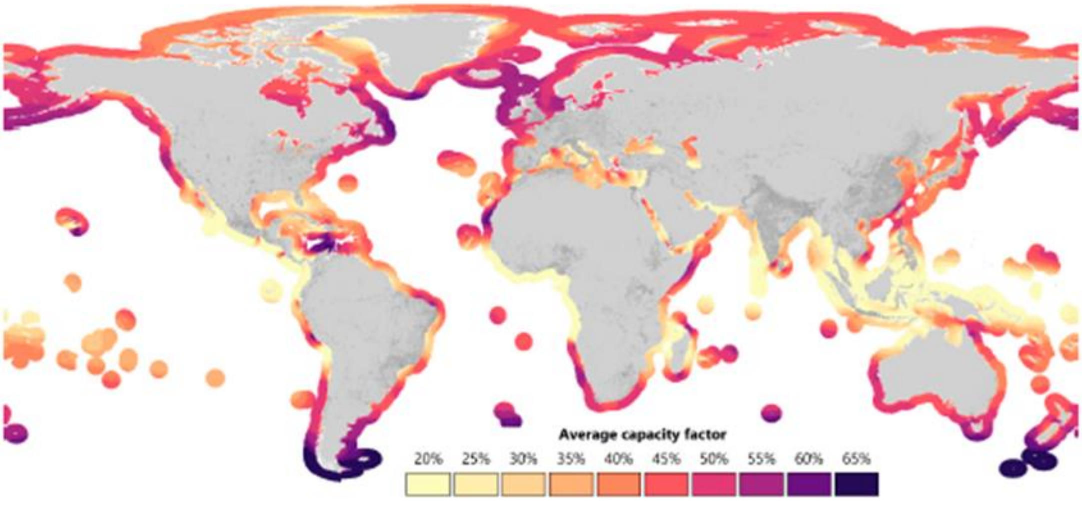

Figure 1 Average capacity factor for offshore wind [11]

Offshore wind energy is one of the most important RES that offer synergies with H_2. This technology will be the second fastest growing industry in the energy sector after PV for the next two decades [11]. Its increase in installed capacity from 2010 to 2018 was of 30 % per year [11], achieving a worldwide installed capacity of 28,3 GW in 2019 [12]. Under the current investment and policies announced, its development during the next ten years is expected to be of 13 % annually, reaching to 20 GW of installed capacity every year [11]. Therefore, global wind energy is expected to increase 15-fold in the next two decades. However, in order to achieve the climate goals, it is necessary to add an additional yearly capacity of 40 GW compared to the current scenario [11].

Consequently, it looks clear than offshore wind energy will be a key enabler for a clean energy transition. The resource is vast and achievable with current technology. Worldwide offshore wind´s technical potential for installations less than 60 meters deep and less than 60 km from shore is 36.000 TWh, 156 % more than the current electricity demand [11]. Besides, technological developments such as floating wind structures can take this technology to areas where the total resource is as high as eleven times the current electricity demand [11].

This high potential of energy provided by offshore wind, overpassing the electricity demand leads to a new paradigm. Offshore itself could produce energy at very competitive prices, nevertheless the excess electricity may not be absorbed by the grids. Also, many of the places that provide a good source for offshore wind are in remote areas where no transmission lines or demand exist. A clear example is Greenland, which could offer up to 14.000 TWh of offshore wind electricity production compared to

50.000 TWh in all Europe [11]. The use of H_2 could enable the transportation of this energy potential to other economies.

H_2 and offshore wind present synergies that can leverage the growth of both sectors. In one side, H_2 deployment depends significantly on economies of scale, it has been estimated than 90% of the cost reduction in non-transport applications depends just on the massive deployment of H_2 value chains [4]. The same reason can also bring down the costs of electrolyzers by 60-80 % in the next ten years [4]. Moreover, most of the Levelized Cost of H_2 (LCOH) comes from the prices of electricity (60 - 90 % of the total cost) [13], making it clear than cheap electricity is required in order to produce cost-competitive $H_{2,}$ This low-cost could be provided by offshore wind farms, which are expected to achieve LCOE of 50 €/MWh by 2040, or around 25 €/MWh excluding the transmission assets cost [11].

The dedicated production of H_2 from offshore wind could also reduce costs and losses by enhancing technology integration, for example avoiding additional AC-DC and DC-AC conversion costs plus losses and due. Moreover, the reduction of transaction, permitting costs and taxes could be also very significative [14]. However, offshore production of H_2 requires its transportation to land, requiring of an offloading method that can export pure H_2 both in compressed gas (CH_2) or liquefied form (LH_2), or combine it with larger molecules to form more stable compounds that are easier to transport, such as ammonia (NH_3) or liquid organic H_2 carriers (LOHC).

Hence, as these two new technologies with huge potential to help to fully decarbonize most of the sectors in society are starting to accelerate their growth, synergies, challenges and potential of their integration need to be assessed.

1.2 Objective

In a context where H_2 presents increasing potential as an alternative energy source, this work aims at analyzing the energy and economic competitiveness of offshore H_2 offloading systems. For that purpose, the following tasks are proposed:

- Explore the state-of-art of different green H_2 production technologies, summarizing their working principles and characteristics (Costs, efficiencies, working temperatures, etc.);
- Explore the state-of-art of different H_2 offloading methods such as NH_3 or LOHC for the exportation of H_2 produced from offshore wind;
- Estimate a LCOH from an offshore wind farm, evaluating the different elements in the supply chain, as well as their costs (CAPEX & OPEX), and their final share in the cost of H_2;
- Evaluate the market potential for the produced green H_2 and its competitiveness. Propose a market "appetite" for the H_2 offloading concepts;
- Assess how different variables would affect the LCOH and the viability of the project.

1.3 Thesis outline

This thesis analyzes the competitiveness of dedicated green H_2 production from offshore wind farms by exploring its production and transportation to shore through different H_2 offloading methods.

Section 1 introduces to the current reality of our energy systems, which decarbonization is recognized as paramount and gains more relevance as 2050 is the year where several nations aim to reach zero emissions targets. In order to do so, improvements in efficiency, in renewable electricity share and shifts to electrification at the consumption points are the main steps to follow. However, in our society it is difficult to electrify several sectors, both from a technical and/or economical point of view. At this point, the importance of H_2 as the only energy vector with the potential to decarbonize the hard-to-abate sectors of our society arises. This is recognized by the recent EU announcements where it states that 14 % of the final energy demand by 2050 will be covered by H_2.

In **Section 2** the state-of-the-art of the different H_2 production and offloading methods is covered. Providing an overall approach to these and to the combination with an emerging technology, such as offshore wind. This combination brings enormous benefits to both technologies, overall, the access to areas with vast potentials that do not have access to electricity grids. H_2 production from offshore wind brings the possibility of doing it onshore or offshore, studying in the second case different offloading methods. These methods consider the transportation of the produced H_2 in its pure form (compressed or liquefied) but also loaded into larger molecules, such as ammonia (NH_3) or Liquid Organic Hydrogen Carriers (LOHC). Transportation of the compounds by pipeline or vessels is also assessed. Moreover, a market study of the competitivity of this green H_2 in different applications

The different pathways and scenarios elaborated in order to study the competitiveness of the different offloading methods are defined in **Section 3**. Here, the different pathways are described and the values used for the economic analysis are stated for every case. In addition, the modelling approach and the used values for the calculations are shown. Also, the way results will be presented is explained. Two scenarios are explored, the first one considers an evolution based on the technology learning curve that H_2 is expected to follow, according to different studies. The second scenario follows the EU Commission intentions of increasing the pace of H_2 deployment, both by improving economies of scales but also by boosting innovation.

Section 4 presents the results of the work. The results show that low H_2 production costs can be achieved, allowing the decarbonization of many applications in an economically competitive way. In the economic aspect, a levelized cost of hydrogen (LCOH) is provided in order to see the potential markets that every pathway could address. Moreover, the importance of selling the oxygen that is generated as a by-product is presented, by indicating its effect in Net Present Value (NPV) terms. Here, the NPV, becomes positive due to the revenues generated by the commercialization of this gas. Important cost reductions can be achieved in both of the presented scenarios. Specially for Scenario 2 (EU H_2 Strategy), the achieve LCOH becomes competitive to a point where there is a market size of 666 Mt for green H_2.

In **Section 5** the main conclusions are stated. The introduction of novel concepts, taking the H_2 production offshore offers great opportunities such as cost reductions or much more spots to exploit. However, challenges are big and H_2 handling difficulty poses several questions in terms of transportation and storage methods. Among the studied pathways, the use of pipelines to transport H_2 seems to be the best solution in economic terms, providing a LCOH of 5,35 €/kgH_2 for the baseline case, whereas it has the potential of being as low as 2,17 €/kgH_2 if the EU support is successful and achieves its targets. However, careful assessment of distance and sea depth needs to be considered along the development of the project since it has great impact on the cost but overall, in the technical complexity.

Vessel transportation of liquid H_2, ammonia or LOHC does not outcompete the pipelines use in LCOH terms, while it can be better in order to reduce the technical complexity of the project.

A key insight of this work is that what could seem a waste product such as O_2 can improve greatly the economics and viability of the project, increasing the NPV by more than 150 M€ without major complexities in the infrastructure.

2. State-of-the-art

2.1 Current situation and projects

Green H_2 production is a topic which acquires more and more relevance as the concerns about CO_2 emissions grow. The number of announced projects has increased drastically in the last years, as it did with their size. If in 2015 the average announced Polymer or Proton Exchange Electrolysis (PEM) electrolyzer project was around 1 MW [15], in 2020 its capacity multiplies up to 20 MW [15] and for the next years projects up to 4 GW have already been announced [16].

The importance of H_2 for the coupling of RES is of great importance since the energy systems are advancing towards sustainable energy generation in the long term, as already stated in the policies of some of the major institutions worldwide, such as the EU, which has clear objectives to cut its emissions to 0 by 2050 [17]. It is estimated that by 2030, at costs of 1,62 €/kgH_2, 15% of the total energy demand could be covered by clean H_2 in a competitive way [4].

Moreover, policy support is starting to grow, as policymakers accept this energy vector as a key enabler in order to achieve the climate targets. H_2 is already in the energy roadmaps of numerous countries worldwide [15], and some recent moves, as the foundation of the Clean H_2 Alliance by the EU, with the clear goal of bringing investors together with governmental, institutional and industrial partners in order to identify technology needs, investment opportunities and regulatory barriers and enablers [18]. Also, private stakeholders show commitment to the development of H_2, this is seen in the growing members that groups such as H_2 Europe or H_2 Council [19] are acquiring.

This strong momentum H_2 is experiencing is supported by the great projections regarding its use in many different applications in the medium to long term, being expected to provide a clean and cost competitive alternative for well-established applications such as fuel for transportation or industry and feedstock for the chemical industry or new applications such as seasonal energy storage [15]. Conversely, in order to achieve cost competitiveness with fossil fuel alternatives or to be able to be used as energy carrier for energy storage and transportation.

Nevertheless, H_2 must overcome several challenges to allow its widespread adoption and cost reduction [4]. Some of the most significant obstacles H_2 supply chain is facing are the lack of infrastructure for transportation, storage and delivery. Also, the lack of an established value chain for the production of the necessary equipment to produce, handle and deliver H_2 is causing that equipment prices remain higher than what is needed in order to bring down the H_2 production costs. Eventually, there are issues with the absence of international regulation, which creates uncertainty for all the different stakeholders, specially investors [15].

On the other side, offshore wind is a technology with clear goals and support from a regulatory framework. This promising outlook is underpinned by policy support in an increasing number of regions. As mentioned in the previous section, 20 GW of offshore wind energy are expected to be installed worldwide annually over the next two decades, being possible that this number expands to 40 GW in order to achieve the Paris Agreement targets [15], contrasting with the current 28,3 GW existing capacity at the end of 2019. This fact indicates the existence of a fast growing and developing market. For the upcoming offshore projects, most of the already announced are in a range of less than 100 km to shore, and less than 40 m deep [11]. However, floating wind technology is developing fast and despite its higher upfront investments, it could offer significant cost reductions since it is still at a demonstration stage [11]. Floating wind turbines could reach areas with better wind resources that couldn´t be exploited otherwise.

The rollout of floating wind turbines will act as catalyst for the deployment of offshore wind farms, and its scaling up will rapidly decrease production costs. Some of the recent announced offshore projects concerning floating wind turbines are:

- Hywind Tampen, led by Equinor and other partners, which will bring 88 of offshore power to the North Sea [11]. This same company plans to start operations to build 200 MW of floating wind turbines in the Canary Islands before 2024 [20].
- Macquarie Group has teamed with Gyeongbuk Floating Offshore Wind Power to jointly develop a 1 gigawatt (GW) floating wind project in Korea [11] .
- KFWind, led by Aker Solutions, aims to build 500 MW of floating wind turbines in Korea [21].

One of the questions to answer during the deployment of floating structures is if large offshore substations internal equipment is capable to withstand movements from the sea waves and its impact on the additional costs [11]. Another is if distance from shore would be technically feasible in terms of electric transmission. This would open an opportunity, for example, to produce green H_2 in offshore platforms and export it by vessels or loaded into other molecules [11]. H_2 bonding to other materials is a solution that is being explored in deep. The objective of these processes is to create more stable molecules that are easier to handle, taking advantage in many cases of already existing infrastructure. The most common H_2 carriers under research are currently methane, methanol, NH_3 and liquid H_2 organic carriers [22].

Due to these potential benefits that H_2 and offshore wind technologies could offer to each other, numerous companies have developed pilot projects and announced plans for the expansion into this business for the next ten years. These aforementioned projects are ambitious, their capacities and logistics overpass by far the characteristics of what has been done so far. This fact proves the trust that the stakeholders, from companies to governments or financial institutions, have in H_2 and offshore wind together. The most significant projects announced to date in Europe are:

- Dolphyn project, led by ERM, which will study the H_2 production in bulk from offshore floating wind in deep water locations by including an electrolyzer in the foundation structure of the wind turbine. The idea is to take advantage of the good resource in the UK seas in order to produce cheap and green H_2. This project was recently awarded by the UK government and will test a 2 MW pilot [23].
- Gigastack project, led by ITM Power and Orsted, which will produce low-cost and zero-carbon H_2 through ITM (PEM) electrolyzers, manufactured in the UK. Offshore electricity will power

these electrolyzers, based inland. The project high electrolysis power demand (100 MW) will allow ITM to build the first PEM production line at large scale, producing up to 300 MW/year [24].

- Tractebel, this ENGIE-derived company is developing an all-in-one platform that will allow the centralized production of offshore H_2. The size of the installation would go up to 400 MW and transport the H_2 by pipeline to the shore [25].
- PosHYdon, led by Neptune Energy, plans to install a 1 MW electrolyzer within a sea container on Neptune's Q13a platform, located near the Dutch coast, 13 km from shore. The H_2 produced by the electrolyzer on the Q13a platform will be used to generate electricity. For now, this is a project that aims to increase the knowledge on offshore H_2 production and the re-utilization of oil & gas platforms to produce H_2 [26].
- Deep Purple, leaded by TechnipFMC and HYON. This project plans to convert power from offshore wind to H_2 and store it on the seabed. Fuel cells would then re-electrify the H_2 to provide a clean source of power for offshore oil and gas platforms, with shipping and seafood among other potential target markets for green electricity produced [27].
- NortH2, led by Shell, Gasunie and Groningen Seaports. The project envisages a wind farm that would grow from a capacity of 3-4 GW in 2030 to possibly 10 GW by 2040. Currently under feasibility study, the intention is to power electrolyzers placed inland, producing up to 800.000 tons of H_2 per year [28].

In terms of costs, offshore wind energy current capital costs including transmission assets are in the order of 3.750 €/kW, while the projections estimate than it could drop to 1.710 €/kW by 2040 [11]. Excluding transmission costs, current prices of 2.970 €/kW would drop to 900 €/kW by 2040, since transmission assets are supposed expected to represent around 50 % of the CAPEX by this time [11].

The global LCOE provided by offshore wind farms today is on average 126 €/MWh [11]. Offshore wind farms are multi-million investments and, therefore, companies need to ask for financial support to institutions. This incurs into credits with high interests due to the uncertainty of this new technology and the high amount of money required. These interests are currently representing half of the final LCOE from the offshore wind farm [11]. This fact underpins the necessity of reducing CAPEX, since it has a higher proportion of reduction of the final cost of energy [11]. With expected cost reductions in the upfront investment and higher expertise in the technology, this cost of capital will also be lower, expecting to halve from 8 % to 4 % [11]. This reduction will have significant impacts on the LCOE, causing that by 2040 the global average LCOE will be less than 40,5 €/MWh [11].

The combination of both H_2 and dedicated offshore wind energy would erase or reduce drastically the costs of transmission, which as mentioned, are expected to account for 50% of the total capital cost by 2040. Thus, by 2030, in Europe, H_2 could be benefiting of LCOE as low as 27 to 45 €/MWh instead of 36-63 €/MWh with transmission assets. Some projects in specific locations are already being awarded costs of 50 €/MWh without the electricity transmission assets, like the Dunkirk project in France [29].

This is even more significant when compared to the average EU retail industry electricity prices projected to be around 117 €/MWh, offshore wind could offer 60-80% savings on the costs of electricity input [11]. This fact is very significant, since more than 50% of the H_2 cost comes from the electricity price [15].

The responsibility for designing, installing and maintaining offshore transmission assets is defined by regulation, and can rest with the transmission system operator (TSO), government or project developer. Furthermore, regulation is country dependent [11]. In most of the projects built until now in Europe, the wind farm developer is in charge of building the transmission systems and transfers it to the TSO after completion [30].

2.2 Hydrogen production

Demand for H_2 in its pure form rounds 70 million tons (Mt) per year [15]. Currently, 76 % is produced via Steam Methane Reforming (SMR), from natural gas, and 23 % comes from coal [15]. The associated emissions of the total H_2 production are in the order of 830 $MtCO_2$/year, which equals the emissions of UK and Indonesia combined [15]. In contrast, growing climate concerns and cleaner energy needs pinpoint the need of more environmentally friendly H_2 production. Using RES, H_2 can be obtained by electrolysis process, providing an eco-friendly and high purity H_2 [31].

Currently green H_2 produced by electrolysis is not competitive with fossil fuels applications in most parts of the world, due to the high capital costs, its low efficiency, its low capacity factors and high electricity prices [31]. However, rapid decline in costs of RES and the expected reduction of H_2 value chain cost are expected to make it competitive with all the clean alternatives to fossil fuels in several applications that could cover 15 % of the total energy demand by 2030 [4]. Thus, electrolysis is expected to be the H_2 source of the future [15].

2.2.1 Electrolysis

Water electrolysis is an electrochemical process that breaks the water molecules into H_2 and O_2, using electricity in order to induce this process [15]. Currently, less than 0,1 % of the dedicated H_2 production worldwide is obtained by electrolysis powered by RES. Nevertheless, declining costs in electricity production using RES, and the sustainable environmental targets in different countries are opening a window of opportunity for this technology, which can provide clean H_2 at a competitive price [15].

In order to split the water molecule into H_2 and O_2, the reaction has to be induced, which means that energy is required. The theoretical energy needed in order to produce 1 kg of H_2 is 39,36 kWh or 142,1 MJ [32]. However, the inefficiencies of the used systems increase this value to ranges between 55-65 kWh/kgH_2 depending on the electrolyzer system efficiency. The reaction is as follows:

$$2H_2O\ (l) \rightarrow 2H_2\ (g) + O_2\ (g)\ (Overall\ reaction) \tag{1}$$

Around 9 liters of water are needed to produce 1 kg of H_2, producing 8 kg of O_2 as a by-product [15]. Different electrolytic technologies are available to produce H_2, which will be explained in detail next.

2.2.1.1 Alkaline Electrolysis

Alkaline electrolysis is a very well-known and bankable technology and, currently, the one with more installed capacity (MW) for commercial applications worldwide [31]. Alkaline electrolyzers are formed by an anode and a cathode, which operate in a liquid electrolyte solution (KOH/NaOH) with 25-30% concentration. Anode and cathode are separated by a diaphragm or membrane. This ion-conducting membrane is used in electrolyzers for the dual purpose of carrying electric charge between electrodes and separating the products formed at each electrode [33] which allows the flow of hydroxyl ions (OH^-) formed in the cathode to the anode [34]. The membrane must have high chemical and physical stability with a high ionic conductivity [13].

Alkaline electrolysis for H_2 and O_2 production in industry uses 'zero gap' configuration, which means that the electrodes are pressed into the membrane or diaphragm, in order to reduce the distance between cathode and anode. This happens because the transport of electric charges in an electrolyte follows Ohm's law, and larger distances between the two electrodes mean larger losses, bringing down the cell efficiency [33]. The working process starts at the cathode when water is pumped into it. Here, two water molecules are reduced to molecular H_2 and OH^-. The H_2 is then removed from the electrolyzer, while the OH^- flows through the electrolyte and diaphragm due to the influence of the potential difference induced by the connected circuit to the anode where it is oxidized, producing molecular O_2 and water [33]. H_2 and O_2 gas bubbles, produced at cathode and anode, respectively, increase the cell resistance by reducing the contact between the electrodes and electrolyte. As a consequence, overall efficiency is reduced. The reaction inside the cell is shown in the equations (2) and (3):

$$2H_2O\ (l) + 2e^- \rightarrow H_2(g) + 2OH^-(g)\ (Cathode) \tag{2}$$

$$2OH^-(g) \rightarrow \frac{1}{2}O_2(g) + H_2O(l) + 2e^-\ (Anode) \tag{3}$$

The electrodes typically consist of perforated plates, foams, expanded metals or meshes proposed. In industry, porous nickel electrodes are the most used as catalyst for the H_2 evolution reaction (HER) and the O_2 evolution reaction (OER) because of its high activity and its low cost [35]. The working process of the alkaline stack can be seen in Figure 2, while the weight of every component in the total cost is summarized in Figure 3.

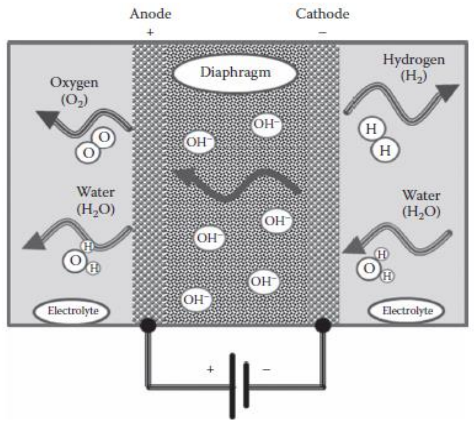

Figure 2 Alkaline electrolysis process illustration [13]

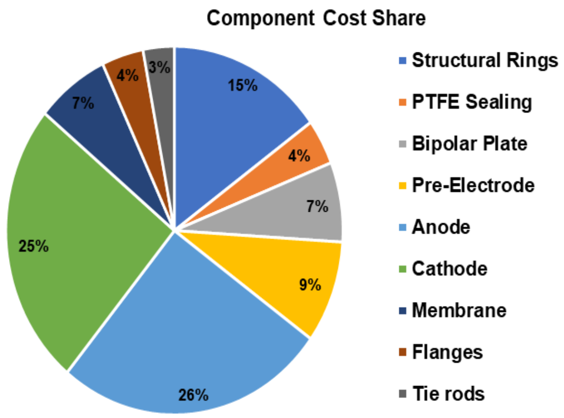

Figure 3 Alkaline cost share by component [13]

The main drawbacks related to alkaline technology are the corrosive environment inside the stack, the low current density (0,2-0,4 A/cm^2) [13] and the limited load flexibility of 10%–110% which makes it challenging to work with RES [15]. Currently, alkaline electrolyzers costs vary, depending on the size of the system and its characteristics. These are in the range of 450 to 1.260 €/kWe (Power input in the electrolyzer), nevertheless, the costs could be cut by more than 50% in the long term [15], due to larger scale of the manufacturing processes and optimization of these. The current and future operating conditions and costs of this technology are summarized in Table 1.

Table 1 Alkaline electrolysis characteristics

Alkaline electrolysis			
	Today	**2030**	**Long term**
Electrical efficiency (%, LHV) [36] [15]	63–70	65–71	70–80
Current density (A/cm^2) [36]	0,2-0,4	-	-
H_2 purity [36] [13]	>99,3	-	-
Operating pressure (bar) [13] [15] [36]	1–30	-	-
Operating temperature (°C) [36] [13] [15]	60-80	-	-
Stack lifetime (thousand hours)	60-90 [36] [15]	90-100 [15]	100-150 [15]
Load range (% of nominal load) [15]	10–110	-	-
Plant footprint (m^2/kWe) [15]	0,095	-	-
System response [36]	Seconds	-	-
Maturity [36] [15] [13]	Mature	-	-
CAPEX (€/kW$_e$) [36] [15]	450-1.260	360-765	180-630
OPEX (% of CAPEX) [37]	3	3	3

2.2.1.2 Solid Oxide Electrolysis (SOE)

Solid oxide electrolyzer (SOE) is the least developed electrolysis technology. It is mostly under research stage, with no commercial or pilot projects running yet [15]. This limits the understanding of its performance to a single stack laboratory level, lacking a whole system performing knowledge. Solid oxide electrolyzer cells (SOECs) do not have any liquid component. The key elements of a SOEC are a dense ionic conducting electrolyte (typically a ceramic electrolyte) and two porous electrodes (anode and cathode). These types of electrolyzers work under high temperatures (650-1000ºC), which offers better electrical efficiency in the H_2 generation, since as long as the temperature of the water (steam) increases, so does the kinetics of the reaction. The required energy for water to split into H_2 and O_2 is expressed by the following equation:

$$\Delta H = \Delta G + T\Delta S \tag{4}$$

Where ΔH stands for the total energy demand, ΔG for the electric energy demand (free Gibson energy change) and TΔS for the heat demand (kJ/molH_2). As seen in Figure 4, an increment in temperature barely modifies the total energy demand, while it decreases the need of electricity. This unlocks the possibility for the use of residual or cheap heat in these applications [38].

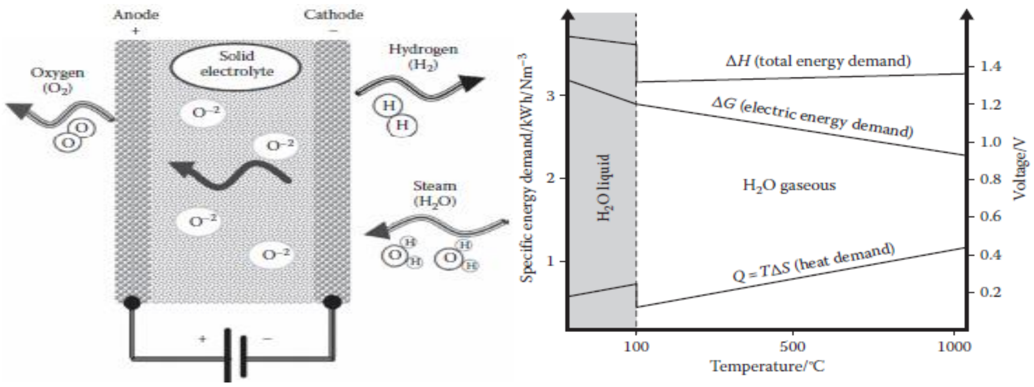

Figure 4 SOEC process illustration and operation principles [13]

When the required electric potential is applied to the SOEC, water molecules diffuse to the reaction sites and are dissociated to form H_2 gas and O_2 ions at the cathode–electrolyte interface. The H_2 gas produced diffuses to the cathode surface and it is driven out of the cell, while oxygen ions (O^{-2}) flow across the electrolyte to the anode. Here, the oxygen ions are oxidized to O_2 gas and transported through the pores of the anode to the anode surface, leaving the cell [38].

One of the most interesting features of the SOEC technology is the possibility of synthetizing syngas if CO_2 is pumped into the cathode with the water [15]. Also, its possibility of being used for grid balancing services, since it can operate in reverse mode, as a fuel cell, generating electricity from the stored H_2 in peak-hours. Nevertheless, significant challenges still need to be overcome, like the degradation of the materials of the cell and the whole system at such high temperatures [15]. Despite many features are still unknown due to its early stage development. Some of the most relevant details of the SOEC are represented in Table 2.

Table 2 SOEC electrolysis characteristics

SOEC electrolysis			
	Today	**2030**	**Long**
Electrical efficiency (%,LHV) [36] [15]	74–81	77–84	77–90
Current density (A/cm²) [36]	0,3-2	-	-
H_2 **purity** [36] [13]	99,99	-	-
Operating pressure (bar) [36] [15]	1-25	-	-
Operating temperature (°C) [36] [15]	650-1.000	-	-
Stack lifetime (thousand hours)	10-30 [36] [15]	40-60 [15]	75-100 [15]
Load range (% of nominal load) [15]	20–100	-	-
Plant footprint (m²/kWe)	-	-	-
System response [36]	Seconds	-	-
Maturity [36] [15]	Demonstration	-	-
CAPEX (€/kWe)	2.520-5.040 [36] [15]	720-2.520 [15]	550-900 [15]
OPEX (% of CAPEX)	-	-	-

The used components are most commonly yttria-stabilized zirconia (YSZ) for the electrolyte, porous cermet of YSZ and nickel for the cathode and lanthanum, strontium or manganite for the anode. These are not expensive materials, but still respond to the requirements of operation under high heat conditions, or the porosity enough to allow the H_2 and O_2 transportation outside the cell once these gases are formed. These materials are relatively cheap, and even if the cost calculation of the whole system is difficult to determine due to the lack of pilot projects, it is higher due to the high temperatures that the auxiliary systems are required to withstand [36].

2.2.1.3 Polymer Membrane Electrolysis (PEM)

Polymer or proton exchange electrolysis (PEM) is a technology that is already at a commercial level, while its bankability is still to be proven. This technology is expected to cope with the biggest share of new installations due to its good performance under variable input of RES and the cost reduction possibilities [36].

PEM water electrolyzers use a polymer electrolyte membrane (or proton exchange membrane), an acid membrane that consists of a thin, solid ion-conducting membrane instead of the aqueous solution used in the alkaline electrolyzers. The membrane not only transfers the H^+ ion (i.e., proton) from the anode to the cathode side, but also separates the H_2 and O_2 gases. The most used membrane material worldwide is Nafion® from DuPont [13].

The working principle of this sort of electrolyzers consists of the ionization of water (oxidation) in the anode, splitting it into O_2 and H^+, creating two electrons on the process. O_2 is transported through the gas diffusion layer in the electrode outside the cell, while the H_2 protons (H^+) are carried through the membrane to the cathode where they are reduced and H_2 is formed. The reactions in each side of the cell are as follows:

$$2H^+(g) + 2e^- \rightarrow H_2(g) \ \ (Cathode) \tag{5}$$

$$H_2O(l) \rightarrow \frac{1}{2}O_2(g) + 2H^-\,(g) + 2e^-\,(Anode) \tag{6}$$

PEM electrolyzers are divided in two areas, anode and cathode, divided by the proton exchange membrane. Most commonly, the electrocatalysts or electrodes are deposited in both sides of the membrane, creating the membrane electrode assembly (MEA). The electrocatalysts are different depending on the reaction to be activated. In the anode, iridium or ruthenium are used in order to lower the activation energy of the O_2 evolution reaction (OER), while in the cathode, platinum or palladium supported in carbon black are the electrocatalysts used for the H_2 evolution reaction (HER).

Another key component of this technology are the bipolar plates, which are the structure that encase the two half cells (anode and cathode) and also provides the contact point with the external power source. These plates work under high pressure and corrosive environments; hence, its composition plays a significant role in order to avoid failure. Most of the bipolar plates are titanium based, what makes it account for around 50% of the cell cost [13]. Together with the bipolar plates, current collectors carry the electric power towards the electrodes. Also, these collectors provide a distributed supply of reactant water and facilitate the evacuation of the recently formed gases (O_2 and H_2). An illustration of the PEM stack shows the mentioned components in Figure 5.

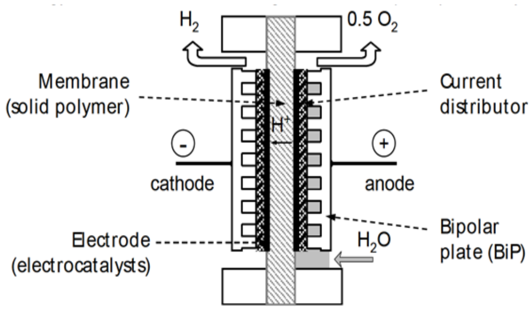

Figure 5 PEM Electrolyzer process illustration [39]

Compared to alkaline systems, PEM electrolyzer systems show a wider operational range (0% to 160%) and higher H_2 purity [36]. Apart from higher operational ranges, PEM systems have less inertia in the response time. These two conditions ease the integration with RES, since they allow a continuous stop and go operation, while accepting lower quantity of energy input. Also, the working principles of these technologies mean that the pre-conditioning of the power input and the post-conditioning of the generated gas will have a different importance in the overall system. This can be seen in Figure 6.

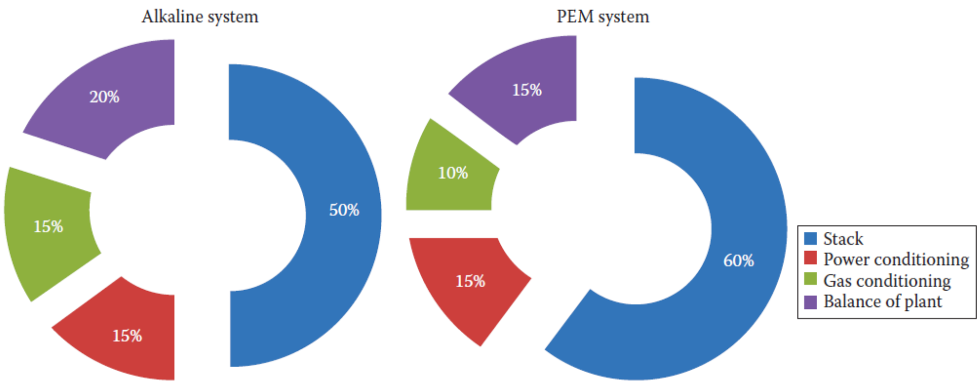

Figure 6 Total plant cost influence AE and PEM technologies [13]

This difference in the total cost of the system is due to the requirements that each technology has, and also depending on the quality of the H_2 produced. In Table 3 the features of a PEM system are summarized:

Table 3 PEM electrolysis characteristics

PEM electrolysis			
	Today	**2030**	**Long**
Electrical efficiency (%, LHV) [15] [31]	56–60	63–68	67–74
Current density (A/cm$_2$) [13] [31]	1-3	10-20	-
H_2 purity [31] [36]	99,99	-	-
Operating pressure (bar) [15] [13] [31]	30–80	-	-
Operating temperature (°C) [15] [13] [36]	50–80	-	-
Stack lifetime (thousand hours)	20-90 [15] [36]	60-90 [15]	100-150 [15]
Load range (% of nominal load) [15] [36]	0–160	-	-
Plant footprint (m^2/kWe) [15]	0,048	-	-
System response [36]	Milliseconds	-	-
Maturity [36] [15]	Commercial	Mature	Mature
CAPEX (€/kWe) [15]	990-1.620	585-1.350	180-810
OPEX (% of CAPEX) [40]	1,5 %	1,5 %	1,5 %

A general comparison of the different electrolysis technologies, covering the most relevant variables for the scope of this project is shown in Table 4:

Table 4 Overview of the main parameters of electrolysis technologies

	Alkaline electrolyzer			**PEM electrolyzer**			**SOEC electrolyzer**		
	Today	**2030**	**Long**	**Today**	**2030**	**Long**	**Today**	**2030**	**Long**
Electrical efficiency (%, LHV)	63 – 70	65 – 71	70 – 80	56 – 60	63 – 68	67 – 74	74 – 81	77 – 84	77 – 90
Operating pressure (bar)	1–30			30–80			1		
Operating temperature (°C)	60-80			50–80			650-1.000		
Stack lifetime (thousand operating hours)	60 - 90	90 - 100	100 - 150	30 - 90	60 - 90	100 - 150	10 - 30	40 - 60	75 - 100
Load range (%, relative to nominal load)	10–110			0–160			20–100		
CAPEX (€/kW$_e$)	450 - 1.260	360 - 765	180 - 630	990 - 1.620	585 - 1.350	180 - 810	2.520 - 5.040	720 - 2.520	450 - 900
OPEX (% of CAPEX)	3			1,5			-		

Novel concepts and the possibility of coupling H_2 production with offshore wind are creating the opportunity to produce H_2 offshore. Here, the production of H_2 is not the only concern, in addition, several challenges arise in the H_2 supply chain. These challenges go from the harshness of a corrosive environment such as the ocean to the added complexity of routines such as O&M and interventions.

H_2´s low density, high diffusivity, high self-ignition range and small size make it very difficult to store and to transport [15], it requires high volumes of space for little amounts of energy due to its low energy density in normal conditions. This is the reason why different offloading methods are on the scope in order to promote and facilitate the widespread use of H_2. These methods are diverse, going from the compression or liquefaction of H_2 to its conversion to other compounds that can act as H_2 carriers or be used as fuels or feedstocks in several applications. The goal of the different processes is to increase the energy density by volume, so that transporting or storing H_2 is less energy or cost intensive. Also, to make H_2 handling easier to avoid risk and expensive infrastructure. The combination of offshore wind farms and H_2 make the production and transportation even more challenging, since producing and transporting H_2 from far away from the coast is an unknown process that can be complex and costly, but also can bring several benefits as already explained. Therefore, two main pathways are available. The first is the onshore production of H_2 powered by offshore wind turbines, the second one is the offshore production of H_2 and its posterior transportation as pure H_2 (liquid and compressed forms) or in H_2 carriers such as NH_3 or LOHC.

2.2.1.4 Oxygen as a by-product

H_2 is the sought product from the electrolysis process. However, splitting water also generates O_2 as a by-product. The proportion is 8 kg of O_2 per each kg of H_2 obtained.

O_2 is a valuable product that can be used in several applications along industry, health or recreational sectors. Some of the O_2 uses include production of steel, polymers and textiles, welding and cutting of steels and other metals, rocket propellant, O_2 therapy, and life support systems in aircraft, submarines, spaceflight and diving.

Oxygen is typically produced by an air separation unit (ASU) through liquefaction of atmospheric air and separation of the O_2 by continuous cryogenic distillation [41]. It can be transported either in liquid form or in gas cylinders. The base containers for liquid O_2 are available in various quantities varying from 31 to 41 liters, with pressures typically up to 200 bar [42].

Oxygen market is expected to grow at a compounded annual growth (CAGR) of roughly 3,9% over the next five years, and is expected to reach 43.920 M€ in 2023, from 34.920 M€ in 2017, according to the literature [43].Therefore, there is already a well-established growing market. Selling prices of O_2 vary according to literature, depending on purity and final uses. The price range is between 0,1-0,28 €/kgO_2 [44] [45].

In spite of the fact that O_2 is not the intended outcome of the electrolysis process, it can be however used to improve the economics of the system, by not wasting it.

2.2.2 Onshore production

Onshore H_2 production consists in a more traditional approach, of having offshore wind farms connected through electricity transmission assets to the coast, where the H_2 production facility is placed. Some of the previously explained projects, such as NorthH_2, consider this pathway, which benefits from less uncertainty and easier operations. These upsides need to be weighed against some drawbacks such as high costs for transmission assets or land requirements.

The electric connection to grid is the current method to transport the energy produced from wind farms. This electric system comprises several steps that allow the transportation of electricity from the nacelle to the inland grid. The main components in offshore plants transmission systems are the substations, one onshore and usually one offshore (also called collector system), and the cable connection. Today, the longest offshore cable is in Germany and spans 160 km, while the largest capacity of an offshore cable supports 916 MW (5).

As conducting medium, cables are installed. There are two kind of cables in an offshore wind farm, inner array cables, which collect power from the wind turbines and deliver it to the offshore substation and the export cable that connects the windmills to shore, and is divided into offshore export cable and onshore export cable [46]. Cables have as main goal to minimize the losses, which can incur into high economic impact in the whole life span of the wind park. Export cables can operate in HVDC (High voltage direct current) or HVAC (High voltage alternate current). The advantage of the first is that the losses are minimum due to a significative reduction in the dielectric losses, offering better features for the transmission of high power over long distances [47]. In addition, the HVDC system reduces cable quantities or constraints on supply due to single-core wires needed, compared to HVAC that generally uses three-core wires which mean more expensive investment and complexity [46]. On the contrary, costs of the substation electric equipment for HVDC are higher than for HVAC, and also the technology is less mature [47]. The cables are generally buried.

The offshore substation is an element that may or may not exist, depending on the distance to shore and the total capacity of the wind park. Wind farm substations gather the power generated from wind turbines and submarine power transmission systems in order to transfer the electricity generated from offshore to onshore grids. These can be AC or DC, while for now AC output is the most common type [48], conversely, as explained above, DC offers better characteristics for the upcoming windfarms, which will be situated at longer distances and handling more capacity. In addition, DC substations occupy less space for the same rated power [48]. Array cables generally provide the electricity in AC [48].

Offshore substations or collector systems are generally needed when the installed power of the wind farm is larger than 100 MW and/or when the farm is situated more than 15 km from shore [49]. Their function is to collect the electricity coming from different windmills and to convert the voltage, typically at 20 or 33 kV (although 66 kV is projected to be used due to a reduction in losses), into high voltage for its transmission, 132 kV in most of the cases [50]. Higher voltages have been announced for the upcoming projects, especially in the HVDC case [51]. The equipment of these substations is mainly a transformer that raises the voltage, gas insulated switchgears and backup diesel generators [49]. Both transformers and switchgears are gas insulated type due to the better security against possible fires, which would be devastating in an offshore platform [49]. For HVDC substations, converters need to be also installed in the platform [49]. Efficiencies for HVDC substations are very high, only 0,7 % of the total power is lost during the process, although transmission losses should be added too, which are estimated to be 3 %/1.000km [52], this value is 40-50 % lower than that for HVAC, since in direct current transmission losses are just line-resistive losses [53]. Two main components of an offshore converter platform are the topside and the foundation support structure [48].

HVDC breaks-even with distances over 50 km from shore compared to HVAC [46]. However, in this project HVDC will be the only considered technology because of the synergies it offers for the integration with electrolyzers, which need of DC for the to work minimizing, thus the equipment costs and reducing the size of the H_2 producing station. In traditional wind farms, onshore plants are also installed. In this work the onshore plant is already included in the H_2 production facilities calculations [15].

Substations usually have a maximum power capacity of 500 MW, from this power upwards is recommended to have more than one transforming structure, in order to improve the security of supply to the onshore grid [49]. These platforms are generally 25-30 m above sea level and have an area of 800-1.200 m^2 [49]. However, know-how in these kinds of infrastructure can be imported from oil & gas industry where, much bigger platforms are found [54].

The costs of offshore wind power structures depend on many factors, such as the sea conditions it must withstand, water depth, and distance from the coast, as well as technology maturity and availability of the different used structures [55]. Some studies find a regression model which specifies a correlation in the cost of windfarms with depth or distance to shore, it indicates that a 10 % increase in either water depth or distance to shore will imply a 1 % increase in specific investment costs [56]. Other sources state different factors which should be multiplied by the inland construction costs, these factors are stated in Table 5:

Table 5 Values to adjust offshore wind farm costs to distance and depth [57]

Water depth(m)	**Distance from shore (km)**							
	0-10	**10-20**	**20-30**	**30-40**	**40-50**	**50-100**	**100-200**	**>200**
10-20	1	1,02	1,04	1,07	1,09	1,18	1,41	1,6
20-30	1,07	1,09	1,11	1,14	1,16	1,26	1,5	1,71
30-40	1,24	1,26	1,29	1,32	1,34	1,46	1,74	1,98
40-50	1,4	1,43	1,46	1,49	1,52	1,65	1,97	2,23

It is important to keep in mind that in offshore projects, the above mentioned factors can incur into a significative increment in costs, since just the installation of the wind farm represents up to 20 % of the LCOE from the farm [58].

CAPEX for the different elements of the transmission system are as follows:

- Substations initial investment vary from 115.510 €/MW [30] to 185.000 €/MW [59] or 175.150 €/MW [58]. These costs already include the installation as well as the materials costs. In the first and the third case, distances to shore and water depths are 12 km - 15 m and 60 km - 30 m respectively, which, as shown below explain the difference in prices. These costs are provided for HVAC substations, in the case of HVDC transmission, the substation cost multiplies by 3,5 [60], being the final expense 390.286 €/MW [30], 613.025 €/MW [59] and 647.500 €/MW [58] for the previously reported values.

- The array cables cost is reported to be between 39.550 €/MW [58] and 43.000 €/MW [59], while the installation costs are as high as 117.000 €/MW [58].

- Regarding the export cables, a value based on their distance to shore is more adequate than simply power. The given values for offshore cables are 2.448 €/MW/km, while their installation represents up to 4.143 €/MW/km [58]. The installation of DC cables is easier than for of AC cables, leading to a lower installation cost. This is due to the better flexibility of the cables and the simpler (and thinner) cable insulation [52]. These values agree with the total cost of installation plus cable cost provided by Catapult of 6.251 €/MW/km [59].

Regarding the O&M costs of transmission systems, it is important to specify that these do not incur into a big share of the total maintenance costs. However, these need to be considered, as well as the decommissioning costs. OPEX of the substations are in the order of 230 €/MW/year [61]. Decommissioning cost are stated to be of 73.450 €/MW for the substation and 86.580 €/MW for the array cables [58]. In the case of the export cables, costs round 2.683 €/MW/km, although if these are buried, their decommissioning is not necessary.

2.2.3 Offshore production

This disruptive way of producing H_2 is a new concept that as previously shown in the projects under development is seriously consider as a key enabler for the clean energy transition. Millions of euros are being invested into pilot projects and feasibility studies announced in 2019 [25] [26] [23], what supports the belief than more will be announced soon.

This pathway consists of the production of H_2 in offshore platforms, that could be placed in centralized stations or in the wind turbine structures. Then, this H_2 would be exported by pipeline or vessel to where the demand is located. This is a very innovative process and the associated logistics, technologies and costs are still very uncertain and challenging. However, its adoption would take offshore wind energy to places where the wind potential is vast, producing large amounts of cheap clean H_2 that could power nations worldwide. For the offshore H_2 production, water desalination has to be included in the system compared to the inland case. The most common method for purifying the sea water is to use reverse osmosis demanding 3–4 kWh/m^3 of water (0,027-0,036 kWh/kgH_2) and having costs around 0,63–2,25 €/m^3 of water. This has only a minor impact on the total costs H_2 production which increase by 0,009–0,018 €/kgH_2 [15].

2.2.3.1 Offshore H_2 transportation to land

H_2 could be offloaded from offshore platforms in two different manners, one option could be to transport it as a pure substance, by pipelines (gaseous) or vessels (liquefied). The second option would be to load the H_2 molecules into H_2 carriers, such as NH_3 and LOHC, which could use both pipelines and vessels to be transported to the demand points.

2.2.3.1.1 Pure H_2

2.2.3.1.1.1 Pipelines

H_2 can be transported via pipelines to the destination point. The installation of offshore pipelines is a complex process, nevertheless, it has been done with oil and gas for more than 60 years and it is a very mature business [62].

Pipelines use for the transportation of H_2 is a very well-known process at a distribution level, but not so much at a transmission one [15]. Materials selection is key in order to ensure good performance and durability of the H_2 pipelines, due to the aforementioned characteristics of this gas, since it is able to cause embrittlement, leakages or fires [63]. The study of the materials used for the pipelines is important not only for new projects dedicated only to H_2, but also for the repurposing of the natural gas infrastructure, where most of the existing pipelines can be adapted to H_2 without major changes, being the complementary systems (e.g. compressors, sensors and other devices) the main bottlenecks for the repurposing [15].

In Europe, two significant projects can provide an approximation to the costs of offshore pipelines installation. Firstly, Nord Stream I, a Gazprom project which provides gas to Europe via two sub-sea pipelines through the Baltic sea. It is operated at pressures up to 220 bar, with diameters of 1,4 m and depths which vary between 30-210 m [64]. The annual capacity of each pipeline is 27,5 bcm (Billion cubic meters) and the total cost amounts for 8,8 billion €, which equals is 3,57 M€/km [65] or 31,025 €/cm/km (being cm the diameter), which is a better magnitude in order to adapt the project costs to the diameter of the pipeline. Secondly, there is the Norway-UK connection with Langeled Pipeline, a 1.200 km project which transports 25,5 bcm of natural gas every year to the UK. The operating pressures are about 155 bar, a diameter of 1,1 m and maximum depths between 800-1,100 m. The total cost of the project amounted for 3,35 billion € adjusted to inflation in 2020 (1,7 billion £ in 2003) [66], representing costs of 2,79 M€/km or 25.378 €/cm/km, being cm the diameter. Up to 20 Gulf of Mexico projects from 1995 to 2012 have been studied with reported average costs of 28.170 €/cm/km adjusted to 2020 values [67]. Pipeline cost are the sum of material, installation, engineering, and inspection expenses. Cost-breakdown is specific of each project, but materials and installation costs are always the biggest share of the total CAPEX [67].

OPEX in these systems is very low, overall if it is possible to avoid the introduction of compressors, as in the case of Nord Stream project, which operates more than 1.200 km without the need of compressing the NG [64], as H_2 is a lighter gas, the need of compression should be even lower. OPEX for offshore oil & gas pipelines is in the range of 3.450-115.000 €/km [68], depending on the used materials, the corrosivity of the transported element and several other factors. Lifetime of new pipelines is above 40 years [15].

In addition, there is the possibility of taking advantage of already existing infrastructure for H_2 transportation. This scenario is very interesting for players in the oil and gas sector, which can provide a second life to the platforms and pipelines, by combining them with RES and by adding big savings to the new projects. Every pipe would require an assessment but it is common than natural gas pipes are usable for H_2 transportation [63], conversely, oil and water systems are not usually reusable [69].

Decommissioning of gas pipelines has been studied for 28 projects in the Gulf of Mexico, costs of pipeline removal are related to the total length, more than the diameter, and are estimated to be 180.866 €/km adjusted to 2020 values [70].

As of 2017, the dedicated H_2 pipelines built in the world were about 5.000 km, most of them dedicated to distribution and divided mainly into the United States with 2.600 km, Belgium with 600 km and Germany with just under 400 km [15]. This fact proves that there is already experience with this infrastructure, although the scale of the new projects would represent a massive deployment regarding the current situation, especially for the offshore projects.

The use of pipelines to transport H_2 requires a previous compression of the gas (CH_2). Nowadays, H_2 compression is required for NH_3 production and hydro-cracking of heavy-petroleum, however, new horizons are opening for H_2 as an energy vector, and its new uses will require it to be packaged, transported by surface vehicles or pipelines, stored and transferred to the end user [71]. All these steps of the supply chain require some level of H_2 compression, so the optimization of this step will play an important role in the overall efficiency of the H_2 value chain. H_2 compression can be done in different ways:

Mechanical compression: Mechanical compressors are the most widespread type of compressors used nowadays and are based on the direct conversion of mechanical energy into gas energy [72].

- **Reciprocating piston compressor:** The piston compressor is an electro-hydraulically driven, non-lubricated, liquid cooled, single-stage unit mechanism [71]. It is specially used in applications where the output pressure is higher than 30 bar [72]. Pressures up to 850 bar have been demonstrated, with capacities around 430 kg/h. It lowers its efficiency as the flow rate increases. In general, these compressors are not a good option for high quantities of H_2, its complexity and low performance increase the costs and lower the efficiency [72].

- **Metal diaphragm compressor:** Is a variant of the previous configuration where in this case are moving metal diaphragms that move in order to compress the gas [71]. Diaphragm compressors reach very high efficiency levels. Even if piston compressors are still the most common worldwide, metal diaphragm ones are being deployed at a higher pace, with output pressures up to 517 bar and flow rates up to 280 Nm^3/h [72].

- **Linear compressor:** These compressors are specially used in cryogenic applications. They offer lower costs due to the simplicity of the system, which has fewer rotating components than the cases mentioned above. Although these compressors offer promising possibilities for H_2 compression, their use has still not been reported at an industrial scale. Nevertheless, some studies reported efficiencies of around 73 % for pressure change from 2 to 860-950 bar and flows higher than 112 Nm^3.

- **Liquid compressors:** They are devices which use liquid instead of a solid piston to compress the H_2, providing several advantages as better heat dissipation and no need of lubrication [72]. They are widely recognized as achieving inexpensive compression because they ensure a quasi-isothermal process. In general, efficiency values are higher than 83 % [72].
    - **Liquid piston compressors:** H_2 confined in a closed space is directly compressed by a moving piston and in these devices, it is liquid that compresses the gas. This technology is already working in compressed air energy storage applications, with outlet pressures of 200-300 bar [72].
    - **Liquid rotary compressor:** Are particularly used to compress a gas with a high liquid content. Their low efficiency of about 50% discard them for any industrial application [72]**.**
    - **Ionic liquid pistons**: These compressors have been specially developed for H_2 applications. The used compression elements are molten salts which are ionic liquids, this is very favorable at the time of compressing, since the H_2 solubility in them is negligible, allowing for higher compression ratios [72]. Reported efficiencies are in the range of 83-93 % [73], while the capacities and outlet pressures increase compared to the previous technologies to 90-340 Nm^3/h and 450-900 bar [72].

Electrochemical compression: It consists in the compression of H_2 through electrochemical reactions, in a process similar than the one happening in PEM electrolyzers but using H_2 only as an input in the cell [74]. Electrochemical compression can simultaneously compress and purify the H_2 due to the Nafion® membrane that permits almost only the permeation of protons through. Despite its good perspectives, electrochemical compression is still a novel technology out of the laboratories, and much research and testing for larger applications needs to be carried out. Maximum efficiencies are in order of 79% [73].

Metal Hydrides (MH): It consists of reversible heat-driven interactions of hydride-forming metals with H_2, MH compression offers simplicity in design and operation, with compact systems that avoid moving parts, reducing costs and noise. Also, their working principle allow to use waste heat, opening possibilities for their use in industrial applications [75]. Is not commercially available yet, lab projects probed the compression up to 220 bar, and 350 bar metal hydrides compressors are being tested [75].

Ionic liquid piston compressors seem to be the most promising technology for the near future of H_2 compression with high efficiencies, flow rates and an acceptable background. Its input requirements match perfectly with the use of PEM electrolyzers, which typically produce H_2 at 30-70 bar. The costs of an ionic liquid compressor handling 340 Nm^3/h are not public yet, due to the initial stages of this technology. Therefore, costs from US DOE Technical Targets for H_2 Delivery for 2020, specified for 200 daily tons and 100 bar have been used, being the CAPEX of this technology 16.200 €/tH_2/day while OPEX is expected to be 4 % of the total initial expenditure [76].

2.2.3.1.1.2 Vessels

Currently, despite several projects mentioning the possibility of using seaborne transportation of H_2, as of July 2020, only one liquefied H_2 carrier exists. The “Suiso Frontier” is the first ship dedicated to the H_2 trade, and has been built to supply Japan with H_2 produced in Australia, being able to carry 1.250 m^3 of liquid H_2 in a single tank [77]. The tank is constructed to keep 75 tons of H_2 at -253 ºC for three weeks without use of external cooling [78]. Nevertheless, this is a pilot model that will enable the development of larger ships, which size will be needed if countries like Japan want to achieve their national H_2 targets [77]. This pilot project is planned to expand into two large liquid H_2 carriers with a tank capacity of 160.000 m^3 by 2030 [78].

The proposed size of the tanks by 2030 matches with the IEA estimations for the medium-term vessels size, which is 11.000 tons of H_2 per ship with a CAPEX of 412 M€ and an OPEX of 4% of the total initial expense. The ship velocity is expected to be 30 km/h (versus 25 km/h proposed by Kawasaki in the Australia-Japan project) with a fuel consumption of 1.487 MJ/km and a boil-off rate of 0,2 %/day [40]. A vessel like this could cover up to 720 km/day, consuming 0,08% of the initial energy content per day.

The transportation by ship would require liquefied H_2 (LH_2) in order to optimize economics. H_2 is liquefied in normal conditions at -253 ºC. Liquefiers with a capacity of up to about 35 tpd (tons per day) of H_2 are in operation today [22]. Nevertheless, typical liquefaction plants installed nowadays have a capacity of 5-10 tpd. The specific energy consumption for state-of-the-art 5 tpd plant is currently between 10-13 kWh/kgH_2 [79] [80]. H_2 liquefaction tends to be more efficient when the plant increases in size [81], having the largest existing units energy consumptions of around 10 kWh/kgH_2 [22]. Studies show that the energy consumption can be reduced up to 40% by scaling up the size of the liquefier systems from 5 to 40 tons of liquified H_2 per day, being needed in the last configuration around 6 kWh to liquefy one kg of H_2 [40] [82].

The consumed energy to reach liquefaction is very high with current plants, representing between 25-30% of the energy content of H_2, against the 5-10 % for the compression [15] [81]. However, getting to a specific energy consumption of 6 kWh/kg, only 15% of the HHV of the H_2 would be used in the process [83], overcoming one of the big challenges of liquefied H_2 transportation.

This cryogenic H_2 is kept in vessels with efficient insulation, covered with an external protective jacket and an inner pressure tank. Cryo-compressed storage (-253 ºC and at least 300 bar) can be applied in order to reduce the boil-off rate of H_2 [81], which can be a problem for long term storage, representing around 0,1% of H_2 contained in a vessel loss [22]. However, some sources do not consider this as a main issue, since this H_2 is assumed to be powering the auxiliary systems [40].

Conventional industrial H_2 liquefaction systems typically consist of two refrigeration steps for different temperature ranges. H_2 is first cooled with liquid nitrogen down to -193 ºC, secondly it goes through a cryogenic refrigeration cycle, that can be either a helium Brayton cycle or a H_2 Claude cycle [82]. Being Claude cycle the most used technology for liquefaction of large amounts of H_2 (>5 tpd) in the existing plants. A typical liquefaction plant layout is shown in Figure 7.

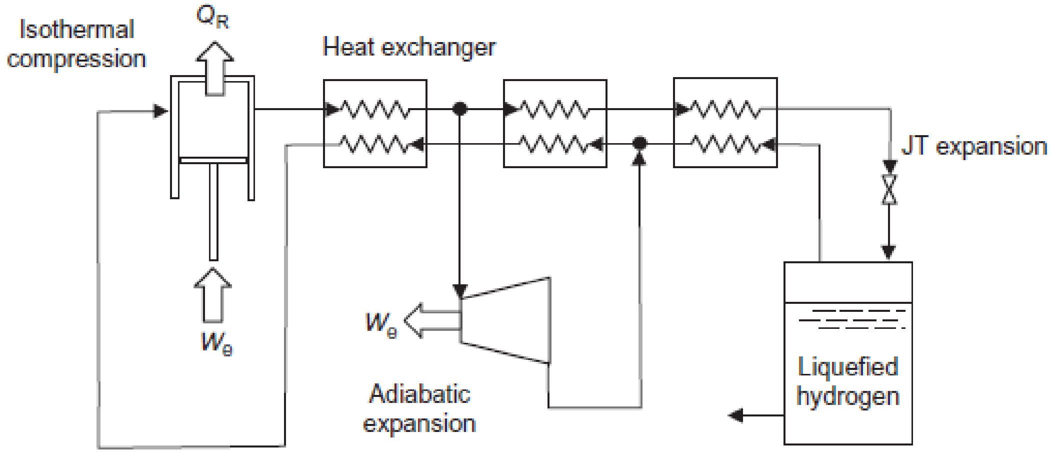

Figure 7 H_2 liquefaction process layout [84]

Nevertheless, in 2013, a consortium of companies led by Shell and Linde, and funded by the EU developed the "IDEALHY" project, which intended to achieve improvements in the efficiency and cost of liquefaction plants. The results of this project were very promising, since it proved the possibility of bringing down the costs and the energy consumption of liquefaction plants, being needed around 6 kWh/kgH_2 in order to liquefy H_2 with the designed process and a plant with a liquefaction capacity of 50 tpd [83].

This technology would be very promising for the implementation with renewables and for the use of H_2 in large scale, since it needs of large quantities of H_2 (more than 40 tpd). Also, it has a working range that would adapt to the intermittency of renewables (25-100% load range) without major losses (10 kWh/kgH_2) working at 25% capacity [83].

In spite of the good efficiency improvements, liquefaction costs are significant and represent a share of around 50 % of the total cost that the liquefaction process adds up to H_2 [22]. Regarding to the CAPEX and OPEX of these technologies, the lack of projects and its public data make it difficult to approximate to one figure. USA Department of Energy indicates costs that go from 3,85 M€/tpd for 27 tpd plants to 2,66 M€/tpd for 150 tpd plants [80]. IEA assumes that in the medium term, costs of 1,76 M€/tpd could exist if the production scales up to 712 tpd [15]. NCE Maritime Cleantech, from Norway also provides costs of around 2,5 M€ in the short to medium term. In 2019, Air Liquide, started the construction of a liquefaction plant for 30 tpd, being the cost 140 M€, equal to 4,55 M€/tpd [79]. The latest announced project, as of April 2020, was signed by Linde for a third party in South Korea, investing this country 226

M€ for a plant that will liquefy 35,61 tpd, equal to 6,35 M€/tpd [85]. IDEALHY project states that a plant of 50 tpd would have an approximate cost of 100 M€, including costs for one week of storage [83].

In terms of OPEX, IEA assumes 4% of the CAPEX [40], which seems a fair value when comparing with the effect on the H_2 cost that other sources attribute to OPEX, around 40-45% of the LCOH. The total effect of liquefaction can be below 1 €/kg with large scale liquefiers [82] in the near term.

It is important to remark than the current H_2 liquefaction capacity would have to multiply several times in order to meet the potential demand. As an example, a 100 MW wind park with 0,50 as capacity factor would be producing around 20,42 tpd of H_2, while the capacity of the largest liquefaction plant ever built was 55 tpd, while it is no longer in operation.

2.2.3.1.2 H_2 carriers

Liquefaction and compression of H_2 allow to increase H_2 energy density significantly. However, its transportation as pure substance offers still several disadvantages, one of them is that its energy density is still low compared to other fuels or H_2 transportation alternatives. Moreover, the development of a new infrastructure can be very costly. On the contrary, the use of H_2 carriers, this is, molecules that can combine with H_2 in order to form larger and more stable compounds can benefit from already existing infrastructure for transportation and storage. Besides, as explained below, the storage of H_2 carriers is much simpler in terms of volume requirements and energy consumption than for CH_2 or LH_2.

Among the most common H_2 carriers, NH_3, methane (CH_4), methanol (CH_3OH) and liquid organic H_2 carriers (LOHC) standout [22]. However, the production of methanol or methane requires CO_2 addition and, therefore, this gas needs to be supplied [15]. The nature of this project is not site specific, and these processes require to have a CO_2 source providing continuous supply to the production facility. Hence, these two offloading methods are not considered for this project.

Every H_2 offloading method has complex processes and infrastructure behind it. Some processes have been known for more than 100 years, like the NH_3 case, while others are still under development, i.e. liquid organic H_2 carriers. Nevertheless, and despite the different possibilities that every method offers, a detailed explanation needs to be provided in order to assess properly the best offloading possibility.

2.2.3.1.2.1 Ammonia (NH_3)

Ammonia (NH_3) is a compound formed by H_2 and nitrogen (N_2), therefore, its use does not incur into CO_2 emissions, hence, only those concerning the production of H_2 are considered in order to determine the CO_2 intensity of this carrier. The interest of producing this compound is twofold, in one side, NH_3 is already used worldwide in the chemical industry, at a big scale, since it is the main feedstock used for the production of fertilizers, NH_3 is the second largest synthetic inorganic commodity produced worldwide, with 80% of the production used by the fertilizer industry [86] which requires up to 31 Mt of H_2 per year [15]. Direct use of renewable NH_3 as a chemical feedstock is a very promising possibility due to its competitiveness with the current prices and the large scale of infrastructure needed, which would lower the costs of H_2 technologies [15]. Secondly, NH_3 (17,65 %wtH_2) is a better H_2 carrier than

H_2 itself, it offers better possibilities for the transportation of H_2 due to its high energy density at liquid state (50% more than liquid H_2), the easiness of liquifying it compared to pure H_2 (NH_3 is liquid at -33ºC or 10 bar) and a smaller risk due to self-ignition or leakages due to a larger molecule size [15]. Also, although NH_3 is mainly used for fertilizer applications nowadays, it can also be a fuel in energy applications, either being combusted or used in fuel cells to generate electricity directly [15]. Being very promising its use for example to power ships, which is currently receiving a lot of attention from boat manufacturers [87].

NH_3 is a very well-known technology, there are pipelines, vessels and trucks that have been transporting this compound for years. Also, big scale production plants have been in operation for decades, which gives more reliability to this technology [15]. Current H_2 production for NH_3 elaboration represents 0,93% of total greenhouse gases emissions [86]. Transportation of NH_3 is generally performed at liquid state, since it offers a more efficient process due to its increase in energy density (17,30 to 15.342,75 MJ/m^3), 883 times more compact, and its significant reduction in volume (0,769 to 681,9 kg/m^3), 682 times reduction in volume [88].

NH_3 synthesis from power involves several steps, which lowers the overall efficiency of the process. However, some studies suggest that in a scenario with broad presence of RES, renewable NH_3 costs would be equal to current NH_3 produced from fossil fuels [86]. The production of NH_3 from RES follows the configuration explained in Figure 8:

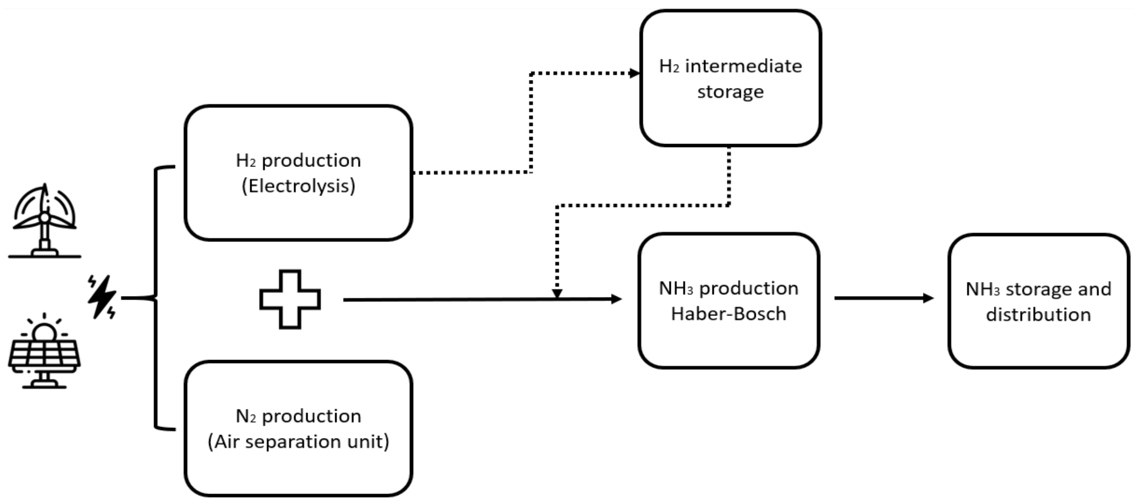

Figure 8 Layout of NH_3 production from RES

Electrolytic H_2 production for green NH_3 from electrolysis could follow any of the mentioned pathways explained in section 2.2. N_2 production is a key process in order to produce NH_3 in combination with electrolytic H_2. As a first stage, N_2 must be separated from the air. Air separation units (ASUs) are the systems used for this purpose. This is a very mature technology that couples very well with the power-to-ammonia concept due to its large power consumption and the possibility of operating during surplus electricity hours [89].

Cryogenic distillation of air is the only commercially available technology for large-scale and high purity industrial applications [90] [86]. Cryogenic air separation units are formed by compressors, heat exchangers, expanders and distillation columns which function is to cool down the air to a temperature were its compounds (mainly O_2 and N_2) liquefy [90]. A typical ASU layout is as indicated in Figure 9, which belongs to Linde, one of the most relevant companies in this issue.

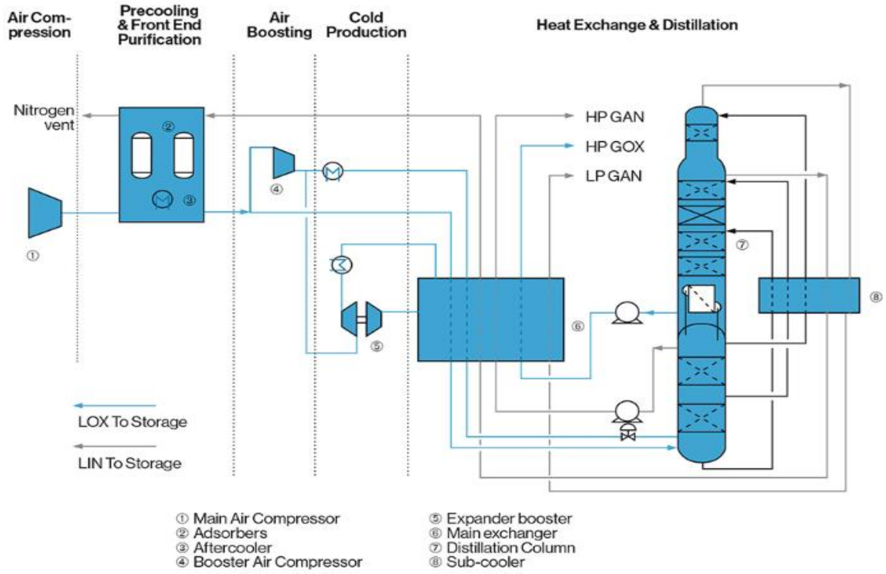

Figure 9 Air Separation Unit layout [91]

Firstly, air is compressed and cleaned. In the first compression stage the pressure increases to approx. 6 bar and this raises the temperature of the process stream to around 185°C. Gas temperatures can be lowered by reducing pressure in exactly the opposite way to the temperature increase that occurs under compression, and this is the basis of the refrigeration process employed to reach the cryogenic temperatures needed for air separation. This absorbs mechanical energy from the stream as it expands to lower pressure, causing the gas temperature to lower rapidly. Energy recovered by the expander is typically used to drive a process compressor, looking for taking advantage of energy waste since energy is the major cost of operating an ASU and plants are designed to optimize efficiency.

At the core of the air distillation process a series of columns are found housed inside an insulated chamber called the cold box; here the super-cooled air is condensed into liquid and the component gases separated. Partially condensed air flows into the lower end of the cold box, while cold gas bubbles up through liquid air that has collected in the perforated trays attached to the columns.

This interaction accumulates liquid O_2 at the bottom of the distillation column, as its higher boiling point (-183°C) allows it to condense more readily. While nitrogen with its lower boiling point (-196°C) concentrates in the gas phase at the top of the column, nitrogen exits from the top of each distillation column and O_2 exits at the bottom [92].

Despite new processes being tested, commercial NH_3 is synthetized by the Haber-Bosch process. This process combines elemental N_2 and H_2 under high temperature (400-650°C) and pressure (100-250 bar) [93]. Waste heat is generated during this process, which is equal to 8% of the total energy input in the power-to-NH_3 conversion, or 0,7 MWh/tNH_3. However, this waste heat can be coupled with other processes of the system, like for example the SOEC electrolysis process, which usually at high temperatures (650ºC), being able to supply 98% of the energy required for this process. This enhances the possibilities of using green H_2 in the NH_3 production if co-located.

The reaction that takes place in this process follows the chemical equation:

$$\frac{1}{2}N_2(g) + \frac{3}{2}H_2(g) \leftrightarrow NH_3(g)\ ;\ \Delta H_{298K} = -45.7\ kJ/mol \qquad (7)$$

This is a reversible and exothermic reaction, with 2,6 MJ of heat released per kg of NH_3 [86].The reaction is accompanied by decrease in volume because there is a decrease in the number of moles of gas from 2 to 1 in the final product. The NH_3 production process is sketched in Figure 10**.**

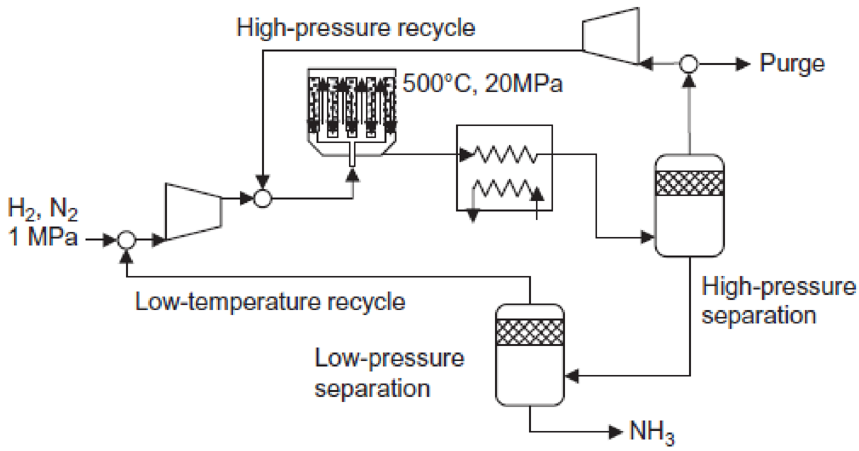

Figure 10 Conventional layout of the Haber-Bosch process for NH_3 production [84]

The NH_3 extraction of the system is done from the equilibrium mixture of gases leaving the reaction vessel. The hot gases are cooled enough, whilst maintaining a high pressure, for the NH_3 to condense and be removed as liquid. Unreacted H_2 and nitrogen gases are then returned to the reaction vessel to undergo further reaction [87].

The energy consumption of the process, including the compression and the air separation unit mentioned before, varies depending on the literature between 0,64 – 0,75 MWh/tNH_3 [86] [94]. Regarding to costs, the Haber-Bosch synthesis CAPEX is estimated to be 125 k€/tNH_3/day [86]. While for the ASU, the initial expenditure approximates 49,75 k€/tNH_3/day [86]. All the sources agree that OPEX in these systems is no more than 2 % of the initial cost [87] [86] [40]. These numbers are in concordance with the data provided by the IEA, which suggests a total cost of the all-electric NH_3 system (including the electrolysis, with a cost of 810 €/kWe and 64 % LHV efficiency) of 310,43 k€/tNH_3/day [40]. Some announced projects for all-electric 54,79 tpd of NH_3 plants report costs of 4.100 k€/tpd [95]. Nevertheless, this is a small capacity plant, being therefore less efficient and assuming higher costs for the electrolysis system. The electrolysis system can represent up to 65% of the CAPEX of such installations [96], and therefore it can have a huge impact on the final cost of NH_3.

NH_3 synthesis from renewables faces several challenges, the main one is the intermittency of the power, which goes against the nature of the Haber-Bosch process, designed for continuous operation [97]. New studies reported successful operation of these plants with loads varying between 20-100%. Nevertheless, below this range the operation is impossible, since the process of stopping and cold-starting again takes more than 24 hours [87] while damaging the equipment and therefore reducing its lifetime [97]. Also, other measures to mitigate these challenges are to have several reactors, with a smaller size than just one that produces all the NH_3. This solution is explored in several projects, but the increase in cost and the required energy to keep these sub-plants in an idling process only allows to divide the plant into two in some cases [98]. Other possibility is to include a big H_2 storage buffer, which would need to have some days of feedstock storage, depending on the characteristics of the location. This should also be complemented with excellent meteorology forecasts that allow to plan the production with more than 48 hours in advance, something that looks feasible with current models and technology [87]

NH_3 in large quantities is stored refrigerated to -33ºC in cylindrical double-walled storage tanks [86]. Costs of NH_3 storage (between 0,9-1,41 €/kg [40] [86]) are much lower than those for H_2, due to less expensive materials, less energy requirements and more maturity of the technology. CAPEX of 1,41 €/kg [96] is considered in this project. OPEX of 1% of the initial investment is considered.

The seaborne transportation of NH_3 is much cheaper than that of H_2. The cost of a ship which carries 53 kt of NH_3 rounds 76,5 M€, meaning 1.443 €/tNH_3 [40]. OPEX is estimated to represent 4 % of total costs, while the fuel consumption of a fully loaded vessel is 2500 MJ/km.

As there is no real data of NH_3 sub-sea pipelines, the same costs as those for the H_2 pipelines were considered. Ammonia pipelines operate at pressures close to 17 bar, transporting it in liquid state [99], while the pressure output of the Haber Bosch reactor could be between 100-250 bar, releasing already liquid NH_3 and at pressures that do not need compression for its transportation. Hence, no energy expenditure is considered along the pipeline.

Despite the possibility of using ammonia directly as a feedstock or fuel, the scope of this project is to provide a H_2 output cost at the import terminal, therefore it is necessary to reverse the reaction induced during the Haber-Bosch process. Reconversion of NH_3 into H_2 is carried out in dedicated reactors, named ammonia crackers. Here, under temperatures of (850-950ºC) thermolysis takes place, and the molecules split into H_2 and N_2 again, under the presence of nickel as catalyst [100]. This separation process is the most challenging when it comes to use NH_3 at large scale as an H_2 storage medium, since it has not been commercially demonstrated yet [22]. Costs for this unit are estimated to be 100,74 €/kgNH_3/day and requires up to 6,3 kWh/kgH_2 of heat in order to break down the NH_3 into H_2 and N_2 [22], being also used for this process 1,5 kWh/kgH_2 of electricity for the posterior H_2 purification unit, the pressure swing adsorption process (PSA) in order to achieve pure H_2 [40].

2.2.3.1.2.2 Liquid Organic Hydrogen Carriers (LOHC)

LOHC consists of a series of molecules that combine with H_2, forming compounds that act as H_2 carriers. These are liquids or low-melting solids which offer the possibility of being hydrogenated or dehydrogenated in order to store and transport H_2 in a safe and convenient way [101]. The combination of H_2 and LOHC and its posterior separation are carried out under the influence of catalysts and high temperatures. These molecules can be re-used since its chemical structure remains the same after H_2 is released [101].

The main interest of using LOHC is that the H_2 carrier would be so similar to oil that its logistics could take advantage of existing infrastructure for this fossil fuel. For example, oil product tankers could be used for shipping H_2 overseas, or pipelines and trucks for its transportation inland [15]. Also, its great stability would allow the storage of H_2 for long periods without losses and in standard conditions [15]. Also, it is remarkable than the quality of H_2 after dehydrogenation is very high, due to the high selectivity of the process and the absence of impurities in the chemicals [101] [15].

Several molecules are under consideration for its use as LOHC, for now, the most widely known are toluene and benzene, which would form methylcyclohexane (MCH) and cyclohexane [101]. Nevertheless, both products are toxic and flammable, requiring careful handling [15] [101]. Toluene, for example is already having an annual production of 22 Mt currently, this could carry with 1,4 MtH_2 [15]. Toluene costs vary between 360-810 €/t [15] depending on the location and time. Another LOHC which is gaining a lot of popularity in the recent publications due to its better safety and lesser environmental hazard is dibenzyltoluene (DBT), which forms perhydrodibenzyltoluene once it is loaded with H_2 [15]. Its current costs round 4.000 €/t, although it is assumed that its widespread use would reduce it significantly [102].

The process of hydrogenation is an exothermic process, releasing up to 9,05 kWh/kgH_2 for DBT and 9,48 kWh/kgH_2 for the toluene case. Nevertheless, this released heat is usually wasted since there is not direct use of it in the hydrogenation location (48). It involves high pressures and temperatures. Toluene has been hydrogenated at 50–150 °C and 10–50 bar [101], in the dibenzyltoluene case higher temperatures are needed, reaching up to 320ºC and 30 bar [103]. Hydrogenation is commonly performed in a fixed-bed catalytic reactor at elevated temperature and pressure to increase the density of the H_2 and increase the rate of reaction. Catalysts composed by platinum and aluminum oxide are used in order to improve the reaction kinetics [102]. On the contrary, dehydrogenation process is endothermic, requiring high energy input of around 9,5 kWh/kgH_2 for the DBT and 10 kwh/kgH_2 for the toluene in the best cases, due to its higher standard reaction enthalpy [102]. Nevertheless, the commercial activities that are current in the market show lower efficiencies, requiring up to 12 kWh/kgH_2 in the case of DBT [104] or 13,6 kWh/kgH_2 for the MCH. This is around 36 % of the of the H_2 LHV just for the dehydrogenation process. However, as this energy input is almost entirely heat, possibilities for coupling with other waste heat generating processes occur. A disadvantage related to this method is that, after dehydrogenation, not all the H_2 contained in the LOHC is discharged, having generally a recovery rate of 90-95 % [40] while the obtained H_2 needs to be purified in a PSA unit, generally with high purification rates of 98 %. This last process involves an energy use of 1,5 kWh/kgH_2 [15].

The information about the costs associated to the hydrogenation and dehydrogenation plants is scarce and diverse. Some authors [102] state costs of 38 and 110 k€/tpd of H_2 for the hydrogenation and dehydrogenation plants respectively. Others [105] present costs of 110 and 133 k€/tpd of H_2 for hydrogenation and dehydrogenation plants. IEA assumes higher costs, which are 290 k€/tpdH_2 for the hydrogenation plant CAPEX and 845 k€/tpdH_2 for the dehydrogenation plant. IEA reliability and clarity on the included factors in the analysis, such as conditioning power plant for the dehydrogenation or the H_2 purification units (PSAs) favor the election of its data for this study. OPEX is 4% of the initial expenditure [40].

The LOHC systems based on DBT and toluene have a H_2 loading capacity of 6,2 %wt (62 kgH_2/m^3 and 7,4 MJ/kg). This is higher than the US DOE target of 5,5 %wt for 2020, and higher than the practical H_2 storage capacity of compressed or liquefied H_2 today when the whole system weight is considered [101]. However, its dehydrogenation efficiency maximum limit is 95 %, which will be considered in this project. Therefore, the H_2 loading capacity is 5,9 %wt. In terms of infrastructure costs, the storage of these carriers, could be done with conventional oil tanks. Their investment costs are around 192 €/m^3 [105] for stationary applications.

Its transportation can be carried out both by pipelines and vessels. The similarity of these compounds with oil, allow the use of oil tankers and pipelines. Hence, costs for ship transportation are estimated to be 0,62 k€/$t_{toluene}$, with an estimated consumption of 8,33 kWh/$t_{toluene}$/1.000km [40]. In the case of using pipelines, the fluid velocity is expected to be 6,5 km/h [99]. A similar approach than liquid NH_3 is done here, hydrogenation output has already high pressures and high temperatures as shown above, hence, it is in good conditions for the transportation, not incurring into higher energy inputs for its compression.

Another factor to take into account when studying the possibility of using LOHC is that these molecules are not generated or consumed in the H_2 production or use areas. Therefore, once the H_2 is released at the end-use point, it is necessary to take back the carriers to the H_2 production point. This implies that either return pipelines, trucks or ships need to be considered in the economics and logistics [15].

Table 6 Comparison of different characteristics for the mentioned H_2 offloading methods

Offloading method	CH2 (200bar)	LH_2	LOHC	LNH_3
Volumetric energy density (kWh/l) [106] [103]	0,43	2,36	9,83	3,58
Gravimetric energy density (kWh/kg) [106] [103]	33,36	33,36	11,18	5,25
Storage time (Stability) [101]	Medium	Low	High	High
Infrastructure compatibility [101]	Low	Low	High	Medium
Maturity [101]	Medium	Medium	Low	High
Dynamic operability [104] [86] [83]	High	Medium (25-100 %)	Low (50-100 %)	Medium (20-100 %)

A visual approach to the H_2 loading capacity of each method is shown in Figure 11. Here, the gravimetric density of the different methods takes into consideration the weight of the containers needed to store the H_2.

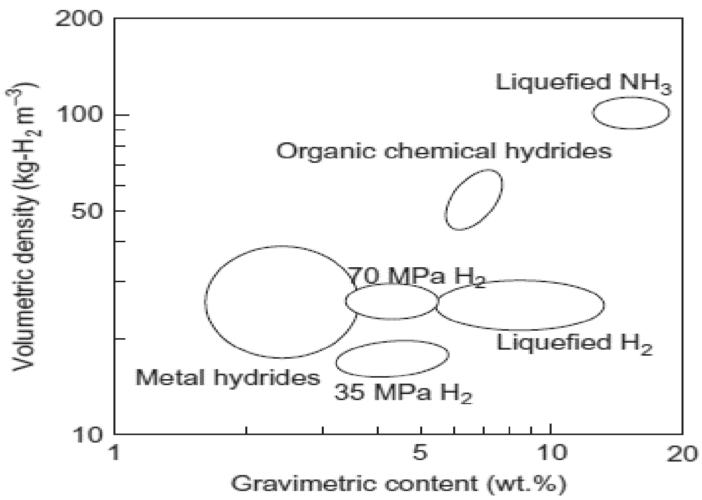

Figure 11 Volumetric density and gravimetric content (wt %) for different H_2 offloading methods [106]

2.3 Potential markets

H_2 future development is highly dependent on the cost competitiveness it can offer to the market. When analyzing its potential is key to bear in mind that savvy steps along its deployment can have great impact on its future acceptance, cost and adoption. The more applications H_2 is cost-competitive in, the more cost reduction it offers, creating a loop that retrofits itself, being able to bring down the price of H_2 and therefore, being able to address more sectors with this technology. Hence, a proper market assessment is of great relevance in order to find current niche markets which can pave the road for a mass scale adoption in the short to medium term.

In terms of price, green H_2 is very prone to lose in the comparison against fossil fuels for most of its applications. However, two facts support its introduction in the markets. Firstly, the need of decarbonizing our economy, which has been already explained. Secondly, the increasing cost of CO_2 could act as a catalyzer for the green H_2 introduction.

An intermediate option between fossil fuels and green H_2 would be the use of the so-called Blue Hydrogen, which is obtained from natural gas reforming with carbon capture, reducing greatly the CO_2 emissions associated to the process.

H_2 production costs vary greatly between different countries due to different availability of their resources (both renewable and fossil) and the H_2 production method. For example, in Europe, H_2 produced from natural gas would cost between 1,75 - 2,3 €/kgH_2 depending on whether CCUS is used or not, while in the US these costs would drop to 1-1,5 €/kgH_2 [15].

Nevertheless, blue H_2 is considered to be more a “bridge fuel” between the current situation and a future where green H_2 plays a major role than a definitive solution for the energy sector, since it still has CO_2

footprint and it is not sustainable in the long term [107]. CCUS is a technology currently under development and it could offer better efficiencies and costs in the years to come. Current costs of CO_2 capture range 450 €/tCO_2 when it is extracted from air (DAC) or 50 €/tCO_2 when a high purity stream is used, typically from power plants, steam reformers or cement facilities [108].

Blue H_2 is prone to be more an enabler than a competitor in the long term for green one. The increase of cheap low carbon H_2 in the market will foster the investment along the whole value chain, clearing the path for electrolytic H_2 which will take more time to reach to those cost levels. Also, it is necessary to remark that the CCUS will be only possible in places with reservoirs to store the CO_2, high demand industries or good logistics to transport it.

Figure 12 summarizes an analysis that assesses in what markets H_2 would be the best solution for decarbonization by 2030 [4]:

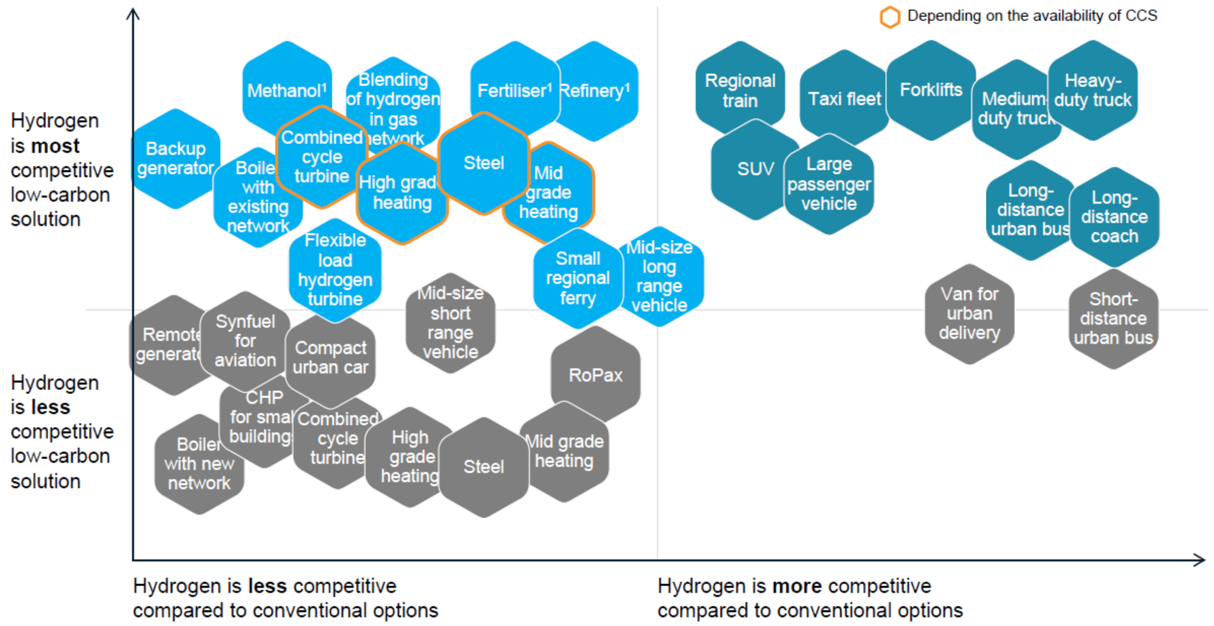

Figure 12 H_2 applications competitiveness against conventional and clean alternatives [4]

As aforementioned, H_2 dedicated production nowadays goes up to 70 Mt every year. The top four single uses of H_2 today (in both pure and mixed forms) are: oil refining (33 %), ammonia production (27 %), methanol production (11 %) and steel production via the direct reduction of iron ore (3 %). However, oil refining generally uses by-product H_2 as source, covering up to one third of their total H_2 demand [15].

These already existing markets are set to grow in the upcoming years due to several reasons. Some of the future forecasts for the different sectors are:

- **Oil refining**: H_2 is used nowadays in the oil refining sector for the hydrotreatment and hydrocracking processes. Demand of pure H_2 is set to grow by 7 % over the next 10 years due to increasing standards in fuels quality, achieving 41 Mt per year. In the longer term (2030-2050) demand for oil is expected to flatten, but still will be a major source of demand for H_2. However, this does not look as a big opportunity for the green H_2 production pathways, since H_2 production is already well integrated in the oil refining plants. Carbon Capture Utilization and Sequestration (CCUS) techniques are more likely to be successful in this field [15] due to an easier integration in existing refineries and lower costs.

- **Chemicals production**: NH_3 and methanol production are expected to require 40,6 Mt of H_2 per year by 2030, with an increase of 52 % over the current demand of dedicated H_2 production [15]. NH_3 is mainly used for the manufacturing of fertilizers, and this application will offer 1,7 % growth rate over the next ten years. Methanol is forecasted to grow significantly faster, at 3,6 % [15], spurred by the development of methanol to high-value-chemicals (HVC). Greater growth could happen if these chemicals were used as H_2 carriers.

  In areas where natural gas prices are higher, such as Europe, where these are expected to be in the order of 6,3 €/MMBtu, break-even cost of H_2 to be competitive with fossil fuel options for NH_3 production is 1,6 €/kgH_2 assuming a CO_2 price of 45 €/t. At these costs, NH_3 can be produced at 333 €/t, the forecasted price for 2030 [4]. High CO_2 consumption of this process makes it highly sensitive to CO_2 variations, raising the NH_3 price to 621 €/t if CO_2 prices were up to 180 €/t. This would make green H_2 cost competitive at 2,7 €/kgH_2. For the methanol case, costs of 1,53 €/kgH_2 break-even in areas where natural gas prices are higher, such as Europe, and assuming 45 €/tCO_2, in the methanol case, CO_2 price sensitiveness is smaller since emissions are lower.

- **Iron and steel production**: Requiring nowadays 4 Mt of dedicated H_2 per year. Dedicated H_2 production is used for the direct reduction of iron-electric arc furnace (DRI-EAF), which accounts for 7 % of current steel production nowadays. This method of producing steel is expected to double the H_2 requirements by 2030. Paris Agreement compatible pathways for iron industry would imply a larger renewable H_2 consumption, reaching up to 67 Mt of H_2 per year if 100 % of steel would be produced through DRI-EAF. Costs at which green H_2 could compete with grey options is 1,62 €/kgH_2 with CO_2 prices of 45 €/t.

The applications mentioned above, cover the biggest share of H_2 production currently. However, RES irruption in the energy systems and concerns about sustainability are creating new opportunities for H_2 in order to expand into markets where it doesn´t have presence. Some of these applications where H_2 could offer value and expand its demand are:

- **Transportation**: Transportation is responsible for 24 % of the total CO_2 emissions caused by direct combustion worldwide [109]. Three quarters of these emissions come from road transportation, while maritime and airborne transportation account for the rest [15].

  The different realities faced in order to decarbonize this sector underpin the important role H_2 has as an energy carrier of the future thanks to its versatility. Passenger cars, commercial vehicles or long-haul vessels have different requirements and H_2 can fulfil these needs by being used as a fuel for fuel cells, generating thus electricity, or being converted to synthetic fuels that adapt better to the logistics of the sort of transportation method.

The presence of vehicles running on H_2 or H_2 derived fuels is almost negligible currently, with around 12.500 Fuel Cell Electric Vehicles (FCEV) running worldwide and some pilot projects for buses, trucks and train fleets. Conversely, forklifts powered by H_2 are already in a commercial stage, with more than 25.000 units operating worldwide and offering good advantages compared to electric ones, due to less charging times and optimized logistics [15]. Potential for FCEVs adoption is large, but H_2 costs need to offer competitiveness with current state. As an example, and in order to compare with other markets, if all the current vehicles on the road were running on H_2, the demand for H_2 would increase up to 300 Mt per year, more than 4 times as it is now [15].

For **road transportation**, despite a full switch to 100% H_2 fleet is unlikely to happen, due to competition with other green alternatives such as biofuels and Battery Electric Vehicles (BEV). For vehicles, Total Cost of Ownership (TCO) is the fairest way of comparing different technologies. TCO is relevant in order to address which could be a better option for H_2 introduction in the transportation market. FCEV vehicles are sensitively more expensive than internal combustion ones, having a significant impact on the TCO of the fleets [4]. This fact is partly offset by vehicles with longer mileage over their entire life, for these, the cost of fuel gains more weight in the final TCO. Therefore, it is easily appreciable that commercial fleets (trucks, vans, taxis or buses) will be a better option for the early adoption of H_2 as fuel in the transportation sector than passenger cars, where BEV offer a better alternative in the short to medium term for most of the users [15].

It is important to mention that most of the cost projections for H_2 to be competitive with fossil fuels or other alternative fuels, also include other assumptions such as a scale up in the manufacturing of H_2 technologies, like the case of fuel cells, storage tanks or refueling stations. For example, fuel cells costs are expected to drop from €178/kWe to €50/kWe (>3 times) when the annual production of vehicles with fuel cells reaches 20.000 units per year [110].

However, this report focuses on the H_2 costs, and these will be assessed, assuming that the other needed variables will be developed by the mentioned times.

In the case of fuel cell trucks, buses and even taxis, cost parity is expected to be reached even before 2030, with H_2 costs of 3,6-4,5 €/kgH_2 at the pump or 2,6-3,5 €/kgH_2 production costs. Higher utilization of refueling stations for this sort of vehicles could even give more margin to the production costs. 100% adoption in this market would require around 200 Mt of H_2 by 2030 [111]. For passenger vehicles, short mileage of these produces that H_2 should offer costs of 2,7 €/kgH_2 at the pump, or 1,7 €/kgH_2 production costs to be competitive with BEVs or diesel cars [4].

For the case of **maritime applications**, special opportunities arise due to the synergies that H_2 and ports offer, concentrating many players in the H_2 sector around a specific location, increasing thus the use of infrastructure and reducing transportation distances, turning out into a cost reduction. The reasoning behind competitiveness of H_2 in the maritime sector is similar to that for road transportation. The more use of the assets, the better TCO results for the H_2 case. Being specially interesting the use of H_2 in vessels use for trading goods.

Being expected that maritime transportation will threefold by 2050, a big market is opening ahead for clean fuels to step on. However, some issues arise with inclusion of these kind of fuels, such as the need of redesign of the vessels or more frequent stops to refuel due to less energy density of compounds such as NH_3 or liquid H_2 (LH_2) [15]. For the maritime industry, fuel cell or NH_3 ships are expected to be competitive by 2030. Satisfying shipping demand in the long term would require 500 Mt of NH_3 and 88 Mt of H_2 [15]. Costs of H_2 should be rounding 1,8 €/kg in order to outcompete diesel engines with the use of fuel cell boats [15]. In the case of ammonia, prices could be higher due to cheaper equipment in the boat and less required space for storage [4].

Another interesting sector for the introduction of H_2 would be **railway transportation**, where fuel cell powered trains seem to be an option for lines where an expansion on the electric grid is needed. This option would save costs and complexity while providing more range to the trains. However, sizing the market for this sector is difficult. In the case of railway transportation, specific environments will favor the incorporation of H_2 powered trains. In order to overcome other solutions such as diesel or electric trains, the H_2 fuel cell train is best suited for longer, relatively low-frequency routes, with short downtimes and limited time for battery charging, and routes that are not electrified yet. For these routes, at current costs of H_2, it already beats the electric alternative option, while it will reach parity with diesel trains when fuel costs go as down as 4-5 €/kg at the pump [4]. Market size for this segment is difficult to determine due to the particularity of the lines in which H_2 would be competitive.

Aviation is the last considered transportation market for $H_{2,}$ Accounting for almost 3 % of the total CO_2 emissions worldwide, and being expected to double its activity by 2050, necessity for decarbonization of the sector is clear. Here, use of pure H_2 does not look promising due to technical difficulties and slow pace in plane replacements. However synthetic fuels could provide clean energy using the same infrastructure. These fuels are, yet 4 to 6 times more expensive than jet fuel, requiring further drop in prices [15]. Current costs of kerosene are in the order of 0,45 €/liter, while biofuels round 1,20-1,50 €/liter and hydrogen-based synfuel costs 1,8-2,07 €/liter, depending on the carbon source. To outcompete biofuels, H_2 should reach costs of 2,43 €/kgH_2, reaching cost parity by 2030 [4]. Direct competition with kerosene is very difficult to happen, requiring CO_2 costs that would vary from 103,5-540 €/tCO_2 [15].

In spite of difficulty to compete directly with kerosene, opportunities arise for H_2 in the aviation industry. Sector´s commitment of halving its emissions by 2050 compared to its 2005 levels [112], presents an scenario at which 10 % of the aviation fuel demand by 2030 will be based on biofuels, while it will raise to 20 % by 2040 [112]. The centralized nature of aviation fueling, where less than 5% of all airports handle 90% of international flights, will lower the additional costs of H_2 due to a high use of the infrastructure [112]. This demand would increase the H_2 demand on approximately 10 Mt by 2030 and 20 Mt of H_2 by 2040 [112].

- **Buildings**: The global energy sector accounts nowadays for 30 % of global final energy use, being ¾ of it used for heating [113]. While 1/2 of this energy is directly produced is from fossil fuels, many sustainable options exist to partially address many of the challenges related to decarbonize this sector. However, there is a wide range of circumstances that determine the decision of what option to choose, such as location, electricity and fuel prices, heating requirements, etc. H_2 can have an opportunity in the task of overcoming these challenges, both as pure H_2 or as a blended element in natural gas [15]. Prices of H_2 delivered to consumers would likely need to be in the range of 1,35–2,7 €/kgH_2 in many major heating markets for H_2 to compete with natural gas boilers and electric heat pumps [15]. Higher final prices in the range of 2,7–3,6 €/kgH2 might still be competitive with natural gas prices in some countries or for some building types (and eventual CO_2 pricing would narrow that spread), while in other countries with low gas prices, such as Canada, prices would probably need to be below 0,9 €/kgH_2, By 2030, 12–20 Mt of H_2 in the principal markets shown in Table 7 if the boilers that will be replaced in this time will be H_2 ready [15]. Combining this with low-concentration H_2 blends in the wider natural gas grid gives an upper bound of 14–24 Mt of global H_2 demand in 2030 [15].

Table 7 H_2 competitiveness with natural gas in buildings heating for major markets [15]

Region	Natural gas demand (Mtoe)	Competitive price range for H_2 (€/kgH_2)	Indicative H_2 demand (MtH_2)
Canada	21	0,72-1,10	0,7-1,1
United States	147	1,10-1,35	5,1-7,7
Western Europe	80	1,80-2,70	0,5-0,7
Japan	14	1,80-3,15	0,4-0,6
Korea	11	0,80-1,70	2,8-4,2
Russia	43	1,35-1,60	1,5-2,2
China	51	1,10-1,30	1,8-2,7

Opportunities also arise in the already existing buildings against clean alternatives. H_2 outcompetes heat pumps for refurbished residences when hydrogen's cost falls to 4,9 €/kgH_2, and it can beat biomethane and heat pumps for newly built houses as H_2 costs drop to approximately 2,7 €/ kgH_2 [4]. However, to compete against natural gas, costs are much more dependent on fossil fuel prices, and should drop as explained above.

- **Industry heat**: H_2 could play a role in providing heat above 100ºC in industry. Especially for applications that require intermittent heat production, where electricity is not a proper choice. In this case, costs of H_2 would represent up to 90 % of the total costs over the lifetime of the systems. Therefore, this sector is very price sensitive. Hence, in order to compete with natural gas or coal, assuming CO_2 prices of 45 €/kgH_2, it should reach costs of 1 €/kgH_2 that would increase up to 1,35 €/kgH_2 in the case that CO_2 rises up to 90 €/tCO_2 [4].

- **Power sector**: By-product H_2 is used in industrial processes to produce electricity nowadays, accounting for 0,2 % of the worldwide electricity generation [15]. In the future, H_2 will likely contribute to the power sector in two ways, firstly as energy storage medium, offering the possibility to store energy over long periods and thus balancing the system. Secondly, as a power generator, where it could be fired both in its pure form or as ammonia or methane. NH_3 co-firing in coal plants has already been demonstrated, and it is though that blends up to 20 % NH_3 in total energy content are feasible to implement without major challenges [15]. Implementing this solution by 2030 in the coal power plants that will still have 20 or more years of life remaining, would boost the H_2 requirements by adding the demand of 120 Mt of H_2 per year.

  Most of the gas turbines can already tolerate 5 % share of H_2 in the natural gas, while some can run properly even with mixtures of 30 % H_2 [11]. For the clean power production in the peak power plants, H_2 competes with alternatives such as natural gas turbines equipped with CCUS or running on biogas. These alternatives represent higher capital costs than the case of H_2, this higher initial investment is especially important in plants where the load factor is low. Currently, at a capacity factor of 15 %, green H_2 would become competitive with electricity generation from natural gas with CCUS at H_2 prices of 2,25 €/kgH_2 if the gas price is 6,3 €/MMBtu as the case for Europe [15].

  In order for H_2 to be competitive with natural gas without CCUS systems, CO_2 prices above 90 €/tCO_2 would be needed and H_2 prices would have to drop to 1,35 €/kgH_2. Despite the difficult competitivity of H_2 over the current situation in this sector, the large amounts of energy generated here, would significantly boost the demand of H_2. As an example, a single plant of 500 MW would have the annual demand of 455.000 fuel cell cars, around 20 thousand tons of H_2 per year. At prices of 1,8 €/kgH_2, a H_2 turbine would be generating electricity at a cost of 162-180 €/MWh. Being competitive in some peak power applications where load factors are below 25 % (See Figure 13) [4].

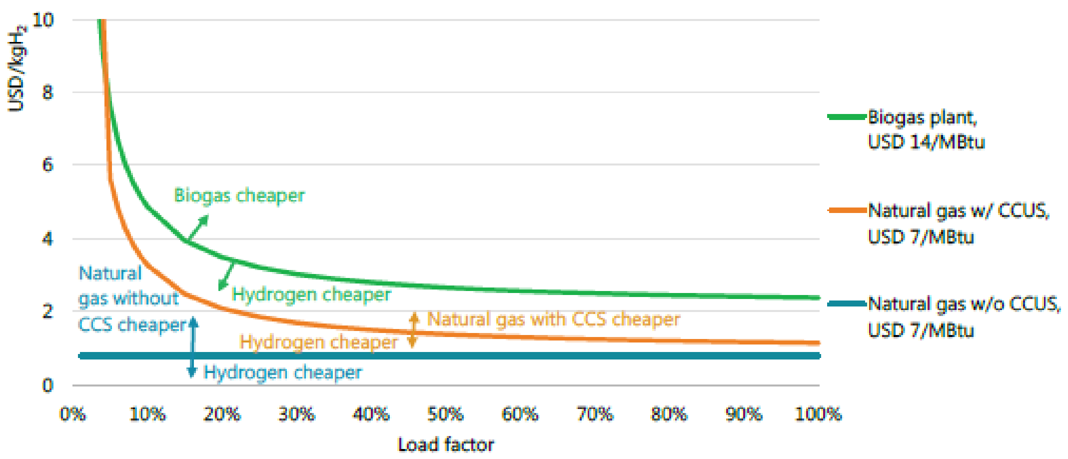

Figure 13 Influence of load factor and gas prices in H_2 competitiveness [15]

As a summary of the section, and bearing in mind that final H_2 costs are very dependent on different steps along the value chain and not only on the production costs, the estimated cost projections provided by the Hydrogen Council are presented next [4].

Table 8 H_2 production cost projections [4]

H_2 production costs			
	2020	**2030**	**2050**
LCOE (€/MWh)	50	30	20
Electrolyzer (€/kW$_e$)	900	500	250
Capacity Factor (%)	40	40	40
LCOH (€/kg)	5,4	2,25	1,44

These values can be used in order to trace a timeline that shows when H_2 is expected to be cost competitive with low-carbon options, this is shown in Figure 14.

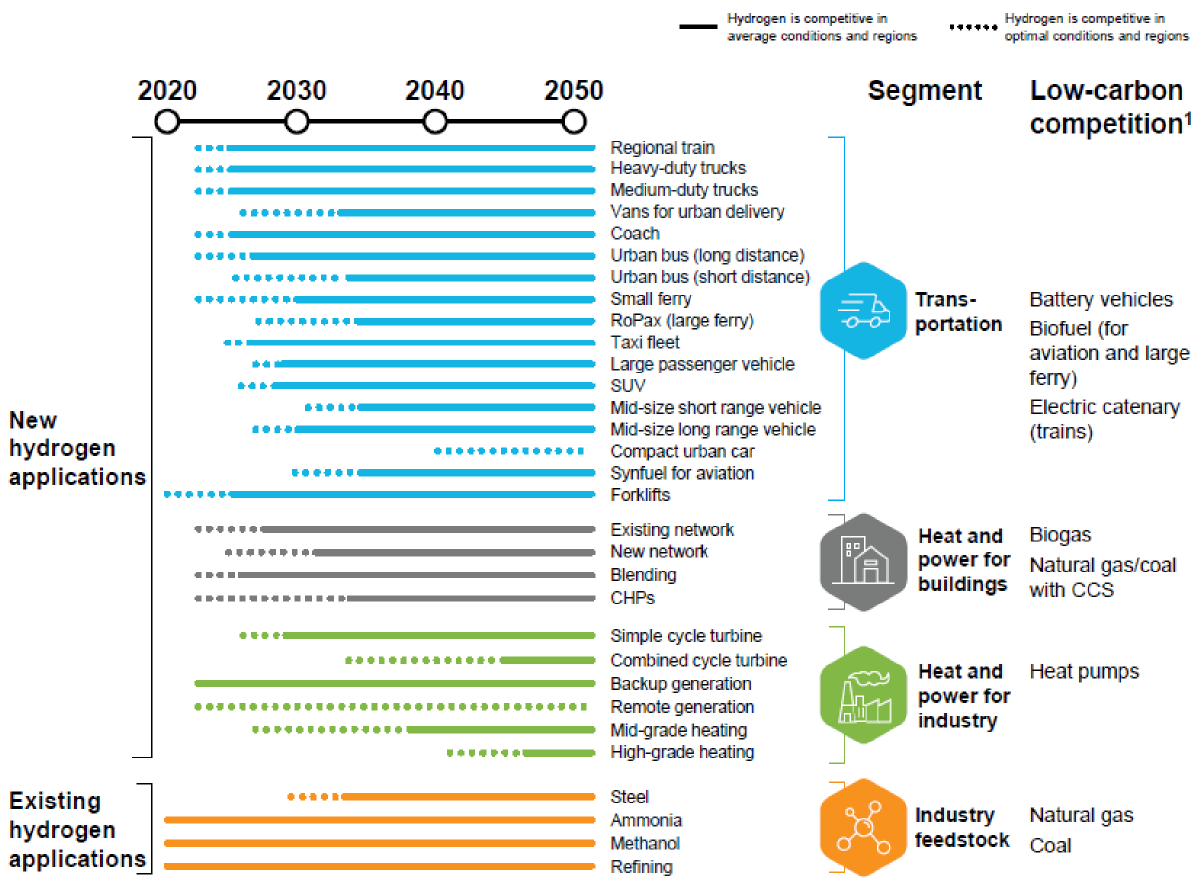

Figure 14 H_2 competitiveness in the next 30 years [4]

This timeline is complemented by Figure 15 , which provides an energy quantification of all the demand that these sectors would incur in if H_2 played a role by decarbonizing them. It shows at which price H_2 would reach cost parity with other low carbon solutions, and the market potential it would mean in terms of energy. Note that the Y axis provides costs in USD/kgH_2. Therefore, to convert it into €, a multiplier of 0,9 needs to be applied.

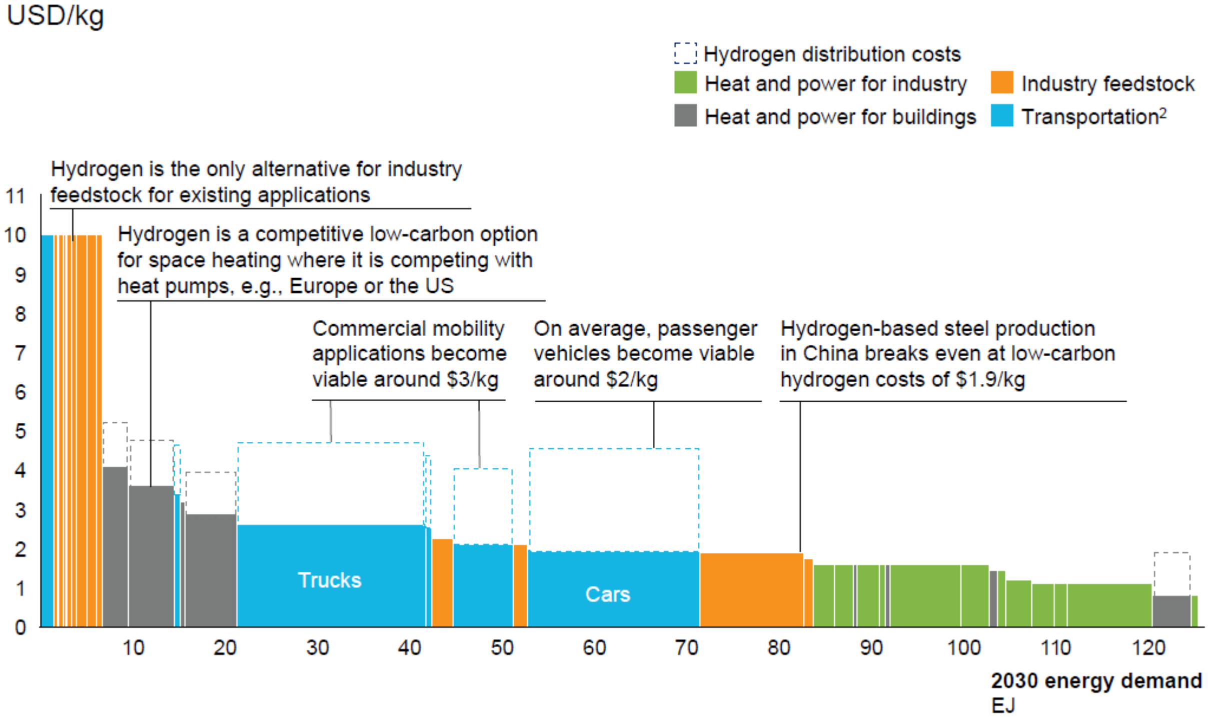

Figure 15 Production cost at which H_2 reaches parity with other low carbon options [4]

The image considers distribution costs for transportation and buildings, while for large, centralized consumers such as industry it is negligible. These distribution costs are between 0,9-1,8 €/kgH_2. For simplification reasons, it is only considered that H_2 could cover all the demand of a segment when it addresses competitively 100 % of the segment i.e. trucks demand would be satisfied at a H_2 cost of 2,5 USD/kgH_2.

According to this chart, the market size and value for low carbon H_2 (Both blue or green) depending on its production costs are summarized in Table 9.

Table 9 Market size for green H_2

H_2 price (USD/kg)	H_2 price (€/kg)	Energy demand (EJ)	H_2 amount (Mt)	Market value (billion €)
1	0,9	120	999	899
2	1,8	80	666	1.199
2,5	2,25	40	333	749
3	2,7	20	167	449
4	3,6	10	83	299
10	9	8	67	600

Noticing that it would be specially interesting to reach to the point where H_2 can be sold at 1,8 €/kgH_2, since it is the price at which the market opportunity is bigger.

The abovementioned information refers to production costs, however, it is important to bear in mind that distribution to final users adds up additional expenditures. Figure 16 offers some numbers on the surplus costs that distributing H_2 in different forms would have.

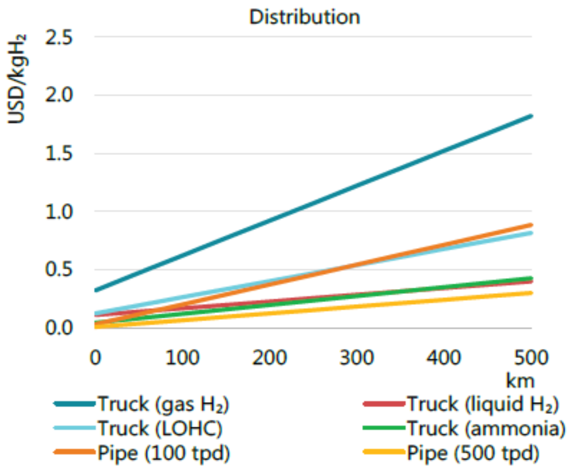

Figure 16 H_2 distribution costs depending on the conversion method [15]

2.4 Sustainability assessment of offshore H_2 production and offloading

Offshore H_2 production is a novel concept and that is visible in the few studies that have been performed to date. In the literature, only three documents are found that provide results for a similar analysis to what is carried out in this project. These are explained next.

Van Nguyen Dinh et al. assessed the state-of-the-art of current H_2 offshore production studies [114], realizing that there are no integrated analysis considering all the elements that affect the viability assessment of these projects. Also, in some cases, the costs of the different elements were taken at different times. This study considers time-varying wind speed in order to determine the installed wind power output, electrolysis plant size, and total H_2 production, optimizing the results. The case study is focused on Ireland, the site is 15 km off the shore of the town of Arklow, County Wicklow, with water depth between 30 and 40 m below the mean sea level. The used electrolyzers are PEM and the considered storage is at geological formations. The project does not determine a LCOH, but it considers a selling price of 5 €/kgH_2, which is suggested in the Hydrogen Roadmap for Irish Transport. With these considerations, the results of the study show positive NPV for different configurations dependent on the storage days of the H_2 in the caverns. This project does not include in its scope the costs of transportation or storage at the import terminal. It finishes once the H_2 is offloaded from the underground storage location. Shane McDonagh et al. explored different configurations on how inland H_2 production powered by offshore wind farms could offer the best economic results [115]. It finds that for an LCOE of 38,1 €/MWh, the LCOH is 3,77 €/kgH_2. Aurélien Babarit et al. posed an innovative solution for harvesting offshore energy, using wind energy converters attached to H_2 production facilities [116]. Assuming an on-board electricity cost of 40 €/MWh, the cost estimates could be reduced to 3,5-5,7 €/kgH_2.

3. Data and methods

3.1 Modelling approach

The methodology used for the modelling of the project is based on a techno-economic analysis of the different alternatives considered for the H_2 production, conversion and transportation from an offshore wind farm. Therefore, the bibliographic research of efficiencies of the processes, energy requirements and economic values is the key first step in order to assess the feasibility of the different options.

Once the values are known and the most logical pathways are described, a mathematical tool is developed in order to determine the LCOH in function of the previously stated values. This tool is also helpful to screen the large quantities of data and determine the variables which offer higher potential for LCOH reduction. NPV is used in order to know the profitability of the project and determine the most viable option. Oxygen sales are included in the NPV.

Temporal resolution in order to determine the optimal capacity of the H_2 production systems has not been performed. Despite it may offers some extra optimization, the general approach of this project and the H_2 dedicated production influenced the decision of sizing the systems to take advantage of all the electricity generated in the wind farm.

3.2 Definition of assessment model

The main goal of this study is to provide an assessment on the different pathways that exist in order to export H_2 from an offshore wind farm to the import terminal onshore. Therefore, the focus is in the H_2 production and transportation. This production can be either onshore or offshore, and the transportation is evaluated in the H_2 offshore production cases and covers the conversion to different H_2 carriers and its transportation by pipeline or shipment to the import terminal. In order to make a fair comparison among the different studied pathways, the system boundaries in the production phase start at the array cables of the wind farm, considering the electricity costs of the wind farm as an external input (see Figure 17). The study finishes at the exit of the import terminal, where posterior costs such as refueling stations or transportation to other consumers are not accounted.

Regarding oxygen, it is assumed that it is sold to an industrial gas provider, which would provide the storage cylinders. Therefore, additional costs due to O_2 needed infrastructure are found in the need of compressors in order to raise the pressure to 200 bar, and the transportation methods from offshore platforms (additional pipelines or vessel).

Figure 17 represents the system including physical boundaries and the main scheme of H_2 production and transportation logistics.

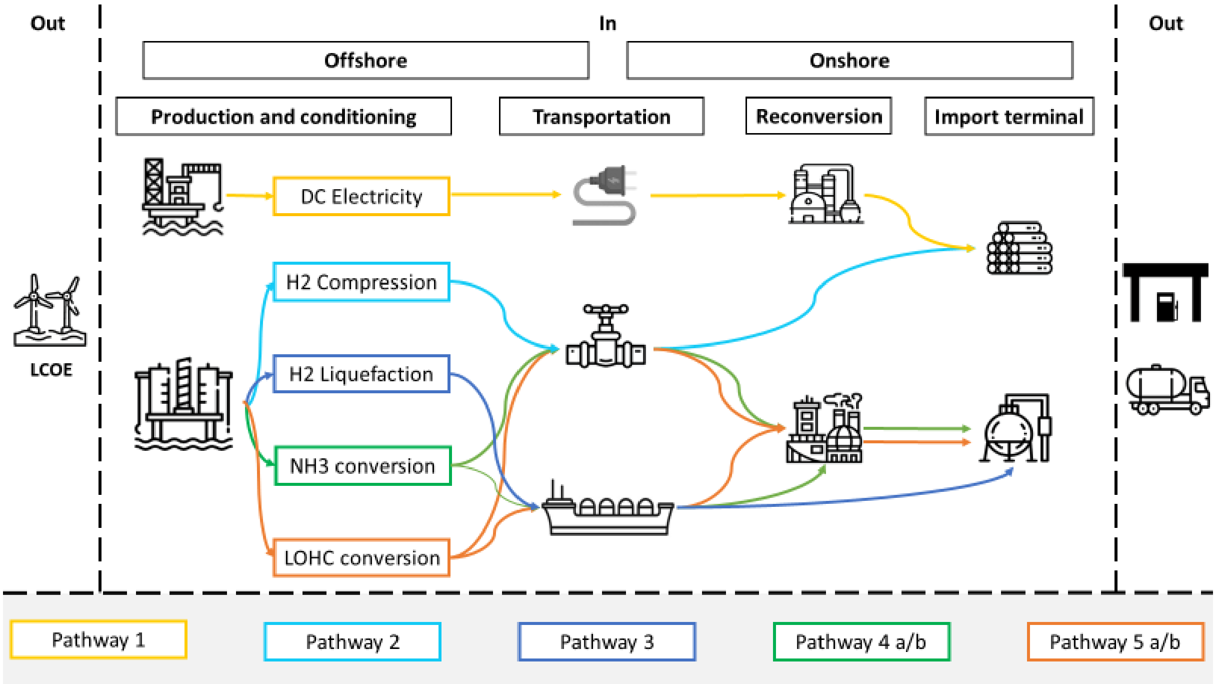

*Figure 17 Explored pathways scheme. Included elements in the analysis shown within the "In" area, between the dashed lines. *Pathway 1 reconversion stands for inland H_2 production. Pathways 4a and 5a explore the transportation by pipeline, while Pathways 4b and 5b assess the vessel exportation.*

Five possible pathways are analyzed in the scope of the project:

1. **Pathway 1**: Inland H_2 production, explained in Section 3.3.1, explores a case in which electricity is transported to shore to produce H_2 through a dedicated production plant. As seen in yellow in Figure 17, this scenario starts with the electricity conditioning in an offshore substation, where electricity is converted into HVDC for its transportation through cables towards the H_2 production plant. This plant is assumed to be placed in the ports, where H_2 is stored in gas form for its use. Oxygen produced inland is also compressed at 200 bar and stored in gas cylinders.

2. **Pathway 2**: Explained in Section 3.3.2, this pathway explores the offshore production of H_2 and its posterior transportation via pipeline as a compressed gas. As seen in light blue in Figure 17, this case exports pure H_2 in a gas form towards mainland. The offshore platform includes all the electrolyzer system needed equipment, such as power conditioning, cooling system, firefighting, electrolyzers and gas conditioning systems. Once produced, H_2 is exported towards the import terminal through pipes. Once in the import terminal H_2 is stored as a compressed gas in cylinders. O_2 would be transported by pipeline from the offshore platform to the import terminal, where it is compressed to 200 bar and stored in the provided cylinders.

3. **Pathway 3**: Described in Section 3.3.3, this pathway produces H_2 offshore and liquefies it in order to be exported by boat. It is represented by the dark blue line shown in Figure 17. Here, as in the previous case, H_2 is produced in an offshore platform, however, it is not directly transported via pipeline, but liquefied in a dedicated facility placed in the offshore platform and shipped to the import terminal placed inland. Here, H_2 in liquefied form is stored for its posterior

use. O_2 in this case would be compressed in the offshore platform and consequently transported in the vessel, which is required to have a slot for the gas cylinders, to the import terminal.

4. **Pathway 4**: Explained in Section 3.3.4, and represented in green color in Figure 17. It explores the benefits of converting H_2 into NH_3 for an easier and cheaper transportation and storage. This pathway includes the H_2 generation offshore and its posterior conversion into NH_3 in the platform. For this, the platform includes an air separation unit (ASU) and a Haber-Bosch reactor. Subsequently, NH_3 transportation towards mainland is explored both by pipeline (**Pathway 4a**) and boat (**Pathway 4b**), being liquid NH_3 in both cases. Once the NH_3 reaches the import terminal, it is stored and reconverted to H_2 via NH_3 cracking in the reconversion plant. Pathway 4a considers an additional pipeline for the produced O_2, which is later compressed at the import terminal, while Pathway 4b includes additional space in the vessel that transports the NH_3 which is compressed beforehand in the offshore platform.

5. **Pathway 5**: Covered in Section 3.3.5, and represented in orange color in Figure 17. It explores the benefits of loading H_2 into LOHC for an easier and cheaper transportation and storage. This pathway includes the H_2 generation offshore and its posterior loading into LOHCs in the platform. For this, the platform includes a hydrogenation unit. Subsequently, LOHC transportation towards mainland is explored both by pipeline (**Pathway 5a**) and boat (**Pathway 5b**). Once the LOHC reaches the import terminal, it is stored and reconverted to H_2 through the dehydrogenation process in the reconversion plant. Pathway 5a considers an additional pipeline for the produced O_2, which is later compressed at the import terminal, while Pathway 5b includes additional space in the vessel that transports the LOHC which is compressed beforehand in the offshore platform.

The baseline scenario is projected to be an offshore wind farm placed 50 km from shore, with a nominal capacity of 100 MW and a capacity factor of 0,5, the distance to shore is selected in between the ranges for newly announced offshore wind projects [11]. In the capacity case, even if the value is low if compared to the recently approved projects, it is assumed that the electrolyzer systems low maturity limits the size of the system. The selected capacity factor is the average for the new offshore wind projects announced in Europe for the next years [11]. H_2 production technology is always considered to be **PEM** due to its better features for offshore applications (more compact) and variable electricity inputs. The selected **efficiency** is **60 %** according to literature for current projects [15].

In economic aspects, all the considered currencies were adjusted to 2019 € values. The lifetime of the project is considered to be **25 years**, according to the typical lifetime of offshore wind farms. Annual € inflation is 1,7 %, which is the forecasted inflation by the European Central Bank [117]. This provides a cumulative inflation of 152 % over the lifetime of the project. The cumulative inflation is relevant in order to account for the decommissioning costs. These are included in the economic study by provisioning a share of the adjusted final decommissioning cost in every period, which is added to the financial expenses for every year as a part of the cash out.

Straight line depreciation method is followed to discount for the assets value loss. This means the depreciation is considered to be equal over every period of the lifetime of the project. No salvage value is considered. The depreciation rate is relevant to calculate the net income per period, since it acts as a tax shield, in order to reduce the amount of income tax paid every year. Depreciation rate is not an expense, since it has been paid for it at the beginning of the project, however it accounts as a loss when considering the income tax.

Discount rate for the project is **7%**, which is a common value for renewable energy projects. No financial costs (WACC) due to credit interests or equity raising are considered in the analysis**. Income tax** is **20%** in the baseline scenario, which is the average value for the EU countries [118].

The determination of LCOH is key in order to know the approximate cost of H_2 production and have an insight of in which markets H_2 could be competitive. The determination of this value, is performed following the equation (8):

$$LCOH = \frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}} \tag{8}$$

Where I_t stands for the expenditures in year t, M_t accounts for the OPEX and the adjusted share of the decommissioning costs in year t. F_t refers to the expense relative to the electricity costs, while E_t is the total H_2 production in year t. Finally, r and n stand for the discount rate and the lifetime of the project respectively.

LCOH is not a definitive value for the H_2 sale price, since it has certain limitations that would affect the viability of the project, making it a bad investment in economic terms. For example, it does not include the income tax rate of different countries, or the inflation of the currency.

Once LCOH provides the approximate cost of fuel, another economic indicator is studied, in this case the NPV of the project is analyzed in order to determine if it makes sense financially. NPV can offer a good insight of whether the project will payoff or not, however, it offers some disadvantages such as the necessity of knowing the real cost of the project, something very difficult in innovative solutions such as the ones being discussed in this work.

The equation (9) is used for the NPV is as follows:

$$NPV = \sum_{t=1}^{n} \frac{Net\ income_t}{(1+r)^t} \tag{9}$$

This equation allows to account for variables such as the income tax and the depreciation rate. These are subtracted from the operating cash flow (Gross revenue – Expenses = Operating cash flow), providing the net income input in the NPV equation.

3.3 Case study definition and assumptions

Offshore H_2 offloading is a challenge itself. The intrinsic difficulty of handling this element is reinforced by the fact that every conversion step to increase its energy density for a better transportation comes with important energy losses attached. Once the different possibilities were covered in the introductory sections, now the studied pathways are stated. Five different configurations have been chosen according to the most logical solution for the transportation of H_2 towards land. Also, the scenario constraints of this project limit an overall assessment, which would provide an absolute best solution depending on the final market. This means that the optimum solution for every certain case would depend on the end-use of the H_2, in its pure form or as a carrier. Nevertheless, the scope of the project and the given indicators are given at the exit of the import terminal, putting little attention in the next steps to the demand center.

In the cases where assets such as H_2, NH_3 or LOHC production plants are placed offshore no extra costs regarding the offshore nature of this H_2 plant have been considered, not incurring into higher installation expenses, since its considered that all the equipment is assembled inland and then transported, having similar logistics than the electric substation case. OPEX is not considered to increase compared to the state-of-the-art inland.

As mentioned above, wind turbines and therefore LCOE are out of the influence of the project, thus, it is an external input. This work considers that the decommissioning must happen at the end of the lifetime of the asset and it only applies to the array cables and offshore substation.

Also, the way decommissioning is accounted is in a yearly provision basis, where every year, a share of the final removal costs is provisioned. This means that decommissioning is accounted as an expense that will affect the cash flows of the system. These decommissioning costs are adjusted to inflation.

Five different case studies are explored as presented in Figure 17. The values, configurations and assumptions related to each pathway are explained in the next sections.

3.3.1 Pathway 1 - Inland H_2 production

In this first case, H_2 is produced inland, meaning that there is a state-of-the-art transmission system to bring the electricity to the H_2 production facility. The electricity transmission assets deliver the power produced exclusively to the H_2 production plant placed inland.

The included elements in this analysis are the transmission system assets, including array cables, offshore substation, export cables and the H_2 production facility. The used costs have already been introduced in section 2 and are the current costs. Future cost reductions will be included in the sensitivity analysis.

Table 10, summarizes the main numbers used in the analysis of this pathway. It includes CAPEX, OPEX and decommissioning costs, which are mandatory for offshore projects.

Table 10 Economic values for Pathway 1

CAPEX			
Array cables	Installation [58]	117.000	€/MW
	Cable [58]	43.000	€/MW
Offshore substation	Structure [58]	67.800	€/MW
	HVDC equipment [58]	177.975	€/MW
	Installation [58]	39.550	€/MW
	Facilities [58]	22.600	€/MW
Export Cables	Installation [58]	4.143	€/MW/km
	Cable (HVDC) [11]	3.645	€/MW/km
Desalination	Equipment + Installation [15]	4.300	€/MW
Hydrogen production inland	H_2 plant [40]	990.000	€/MW
Compression of H_2	Compression to 200 bar [76]	16.200	€/tH_2/day
Compression of O_2	Compression to 200 bar [119]	7.348	€/tO_2/day
Storage	Storage related costs [86]	423.000	€/tH_2
Decommissioning			
Array cables [58]		86.580	€/MW
Offshore substation [58]		74.450	€/MW
Export Cables [58]		Not included	
OPEX			
Array cables [61]		0,50 %	Of CAPEX/year
Offshore substation [61]		0,08 %	Of CAPEX/year
Export Cables [61]		0,10 %	Of CAPEX/year
Desalination [15]		1,00 %	Of CAPEX/year
Hydrogen plant [15]		1,50 %	Of CAPEX/year
Stack Replacement [120]		27,00 %	Of CAPEX
Compression of H_2 [72]		4,00 %	Of CAPEX/year
Compression of O_2		4,00 %	Of CAPEX/year
Storage [15]		4,00 %	Of CAPEX/year

In terms of CAPEX, distance to shore has not been considered for the array cables or the substation in the baseline scenario. The provided values are extracted from the cost projection for an offshore farm placed 60 km from shore and 30 m deep [58]. However, distance is a key parameter for the export cables cost, since it doesn´t only mean more material costs but also more working days for installation services, which have significant rates.

Decommissioning costs have been considered just for offshore assets. Some sources mention the possibility of not having to remove the cables if, for example they are buried and could disturb the wildlife [121]. This last possibility is assumed in this project, where neither cable or pipelines in the next sections will be included as a part of the decommissioning costs.

Regarding to OPEX, electric transmission offshore assets represent reduced economic impact due to O&M, being the array cables those that imply higher effort due to movements of the cable, exposure by tides or sediment flows that can damage or break them. OPEX for the O_2 compressor is assumed to be the same as for H_2 one. The assumed values are presented in Table 10.

In relation with the energy spent along this process, it can be divided in the electricity transmission assets and the H_2 production plant, which represents the biggest share. Array cables energy loss are only relative to the power of the wind farm, and they are not considered to depend on the distance but on the size of the wind farm. Export cables, on the contrary, are influenced by the distance and, therefore, they have to be included in the calculations. Regarding to the offshore substation, HVDC converters are sensitively more expensive than HVAC transforming stations, but as seen in Table 11, efficiencies are very high. Regarding H_2 production, the energy expenditure includes the balancing of the plant, both from the electricity input (power electronics, transforming systems…) and the H_2 output (conditioning of the gas), following the IEA values [40].

Table 11 Energy expenditure for Pathway 1

Energy expenditure				
	Specific energy expenditure		Overall energy expenditure	
Array cables (33kV) [122]	1,10	MWh/MWh	0,0187	MWh/MWhH_2
Offshore substation [123]	0,70	MWh/MWh	0,0119	MWh/MWhH_2
Export Cables [124]	3,30 %	MWh/MWh/1000 km	0,0028	MWh/MWhH_2
Desalination [15]	0,04	MWh/tH_2	0,0011	MWh/MWhH_2
Hydrogen production inland [15]	13,34	MWh/tH_2	0,4001	MWh/MWhH_2
Compressor of H_2 [106]	0,98	MWh/tH_2	0,0298	MWh/MWhH_2
Compressor of O_2 (116)	2,08	MWh/tH_2	0,0624	MWh/MWhH_2
Storage [15]	0,20	MWh/tH_2	0,0006	MWh/MWhH_2

3.3.2 Pathway 2 - Offshore H_2 production with pipeline transportation of CH_2

This configuration explores the H_2 production away from shore. The novel concept of H_2 production offshore, includes platforms, similar to the electric substations, where the electrolyzers, H_2 compressors, water desalinization systems, power electronics equipment and facilities for the use of maintenance personal are co-located. These platforms transport the H_2 via pipeline to an import terminal placed onshore. The pathway follows the configuration shown in section 3.2.

Concerning the economic values included in the analysis and shown in Table 12, array cables are already explained in the previous section. In this case, the offshore platform does not only have a HVDC converter, but also a H_2 production facility with PEM electrolyzers. The used sources already include the grid balancing in the costs. Thus, the cost of the electric equipment is pulled out from the values stated in the previous section, being included this time in the H_2 plant costs. The provided offshore platform cost includes hence the costs of the structure, facilities, installation and H_2 plant.

Pipelines costs from the Gulf of Mexico adjusted to 2020 inflation values were taken as reference due to its reliability, its cost within the range of other studied projects and a higher similarity to the intended study than the Nordstream project [67] [64]. Pipelines values are given by cm of diameter and km of length due to the influence of these factors in the cost of material and installation. Same values are used for O_2 pipelines as for H_2 ones. For the import terminal, only the costs of H_2 gas storage tanks are considered, following the assumptions of the IEA in its reports [40] [11]. Land costs are not included since it is expected that import terminals will be built in already existing terminals.

Both array cables and offshore platform decommissioning are the same as in the previous section. Pipelines decommissioning follow the same reasoning as the export cables in the previous section, where they are expected to be left in the seabed.

OPEX values follow the mentioned references in section 2.2.3.1.1.1. For the pipelines, the cost has been chosen in the lowest range for the pipelines, since it is assumed that with new materials, processes and no need of sub-sea compressor stations, the need of maintenance will be minimum compared to the projects mentioned in the cited sources.

Table 12 Economic values for Pathway 2

CAPEX		
Array cables [58]	160.000	€/MW
Offshore platform [58] [15]	1.127.661	€/MW
Pipelines [67]	28.170	€/cm/km
Compression of O_2 [119]	7.348	€/tO_2/day
Import terminal [86]	423.000	€/tH_2
Decommissioning		
Array cables [58]	86.580	€/MW
Offshore platform [58]	74.750	€/MW
Pipelines [70]	Not included	
OPEX		
Array cables [61]	0,50 %	Of CAPEX/year
Offshore platform [40]	1,50 %	Of CAPEX/year
Stack Replacement [120]	27,00 %	Of CAPEX
Pipelines [68]	0,00001 %	Of CAPEX/year
Compression of O_2	4,00 %	Of CAPEX/year
Import terminal [40]	4,00 %	Of CAPEX/year

Regarding the energy losses in the process, the same values regarding the intra-array cables are applied. The energy efficiency of the offshore H_2 plant already includes balancing of the electricity input, hence, losses included in the DC converter for the first case are considered to be already within the 36 % energy loss. Also, H_2 output pressure is assumed to be 70 bar, in the maximum range of PEM electrolyzers, this reduces the need of compression to 130 bar in order to raise the gas pressure to 200 bar for its transportation. Theoretical work for multi-stage compression processes is around 2,5 % of the HHV [72], which combined with assumed efficiency of H_2 liquid compressors of 90 % provides the stated values in Table 13.

Table 13 Energy expenditure for Pathway 2

Energy expenditure				
	Specific energy expenditure		Overall energy expenditure	
Array cables (33kV) [122]	1,10	MWh/MWh	0,0185	MWh/MWhH_2
Offshore platform [40]	13,34	MWh/tH_2	0,4029	MWh/MWhH_2
Pipelines (Compression to 200 bar) [106]	0,98	MWh/tH_2	0,0295	MWh/MWhH_2
Compressor of O_2 (116)	0,26	MWh/tO_2	0,0624	MWh/MWhH_2
Import terminal [40]	0,20	MWh/tH_2	0,0011	MWh/MWhH_2

3.3.3 Pathway 3 - Offshore H_2 production with vessel transportation of LH_2

In this configuration, there is H_2 production offshore, in a platform as the one presented previously. However, H_2 is not transported to shore via pipeline, but liquefied and loaded into a vessel that transports it to shore. This alternative is envisioned in order to facilitate the access to further locations and open the possibility to greater transportation distances from the production center to the demand point. In this case, in addition to the elements aforementioned, a storage tank has to be included in the platform, in order to be able to store the H_2 while the ship is not loading it, being assumed that the vessel loading frequency is once a day (see Table 14).

Also, the design of the tank size has to consider that in rough sea conditions, the boat operations may be interrupted. IDEALHY design already includes storage room for 7 days, therefore, storage costs are not added as an extra expense, but included in the liquefaction plant.

The values used for this configuration are similar to the previous one. Although the liquefaction plant is part of the offshore platform, it is shown separately in order to provide more clearance on what its impact on the total cost is. In this case, liquefaction costs from IDEALHY project have been considered [83]. This design includes the liquefaction equipment, but also storage for one week of LH_2 and the refueling station to offload the $LH_{2,}$

H_2 transportation is carried out by vessel in this case, being the values provided by the IEA the considered ones [40].

Regarding the decommissioning, liquefaction assets have been included within the offshore platform cost.

Table 14 Economic values for Pathway 3

CAPEX		
Array cables [58]	160.000	€/MW
Offshore platform [58]	1.124.234	€/MW
Compression of O_2 [119]	7.348	€/tO_2/day
Liquefaction [83]	2.000.000	€/tH_2/day
Vessel [40]	33.709	€/tH_2
Import terminal [40]	81.130	€/tH_2
Decommissioning		
Array cables [58]	86.580	€/MW
Offshore platform [58]	74.750	€/MW
Vessel	Not included	
Import terminal	Not included	
OPEX		
Array cables [61]	0,50 %	Of CAPEX/year
Offshore platform [40]	1,50 %	Of CAPEX/year
Stack Replacement [120]	27,00 %	Of CAPEX
Liquefaction [40]	4,00 %	Of CAPEX/year
Vessel [40]	4,00 %	Of CAPEX/year
Import terminal [40]	4,00 %	Of CAPEX/year

In this case, liquefaction adds an important energy expenditure compared to the previous pathways (as presented in Table 15). The considered efficiency is the one proposed by IDEALHY, consuming 6,4 kWh/kgH_2 [83]. Regarding the vessel energy loss, as mentioned in section 2.2.3.1.1.2 Suiso Frontier will operate without the need of cooling for 3 weeks, and therefore the energy consumption for propelling the boat has been considered the only energy expenditure here. Import terminal possible boil offs are assumed to be used for the system cooling or auxiliary needs.

Table 15 Energy expenditure for Pathway 3

Energy expenditure				
	Specific energy expenditure		**Overall energy expenditure**	
Array cables (33 kV) [122]	1,10	MWh/MWh	0,0185	MWh/MWhH_2
Offshore platform [40]	13,36	MWh/tH_2	0,3520	MWh/MWhH_2
Compressor of O_2 (116)	2,08	MWh/tH_2	0,0547	MWh/MWhH_2
Liquefaction [83]	6,40	MWh/tH_2	0,1683	MWh/MWhH_2
Vessel fuel consumption [40]	37,55	kWh/1000km/tH_2	0,0001	MWh/MWhH_2
Vessel boil-off [40]	0,2 %	per day	0,002	MWh/MWhH_2
Import terminal [40]	0,20	MWh/tH_2	0,0005	MWh/MWhH_2

3.3.4 Pathway 4 - Offshore NH_3 production

The possibility of NH_3 production explores a model similar to the offshore H_2 production, including in this configuration the necessary equipment to synthetize NH_3 in the offshore platform by a Haber Bosch reactor. NH_3 transportation is analyzed both by pipelines and vessel, always at liquid state.

In terms of costs, Haber Bosch synthesis reactor and the NH_3 cracker for the recovery of H_2 are the most significant additions in the system, as presented in Table 16. Also, the import terminal has different values than before, due to simpler tanks for NH_3 storage. With respect to the decommissioning of the assets, the same criteria aforementioned is followed, considering only the offshore equipment. As NH_3 plants cannot do stop and go operations, it is needed to have a H_2 storage buffer in order to smooth the H_2 input in the reactor and to avoid forced stops due to the lack of wind. The storage capacity of these tanks is expected to be enough for 12 hours feeding the reactor at full capacity.

Table 16 Economic values for Pathway 4a

Pipeline ammonia		
CAPEX		
Array cables [58]	160.000	€/MW
Offshore platform [58]	1.124.234	€/MW
CH_2 Storage Tank [86]	423.000	€/tH_2
Haber Bosch + ASU [86]	990.084	€/tH_2/day
Pipelines [67]	28.170	€/cm/km
Compression of O_2 [119]	7.348	€/tO_2/day
Import terminal [40]	7.990	€/tH_2
Reconversion [40]	845.209	€/tH_2/day
Decommissioning		
Array cables [58]	86.580	€/MW
Offshore platform [58]	74.750	€/MW
H_2 storage tank		
Haber Bosch + ASU		
Pipelines [70]	No decommissioning costs	
Import terminal	No decommissioning costs	
Reconversion	No decommissioning costs	
OPEX		
Array cables [61]	0,50 %	Of CAPEX/year
Offshore platform [40]	1,50 %	Of CAPEX/year
Stack Replacement [120]	27,00 %	Of CAPEX
CH_2 storage tank [86]	1,00 %	Of CAPEX/year
Haber Bosch + ASU [86]	2,00 %	Of CAPEX/year
Pipelines [68]	0,00 %	Of CAPEX/year
Compression of O_2	4,00 %	Of CAPEX/year
Import terminal [40]	2,00 %	Of CAPEX/year
Reconversion [40]	4,00 %	Of CAPEX/year

In terms of energy expenditure (Table 17), NH_3 synthesis and posterior cracking adds up two complex processes that occur under high temperatures, causing irreversible inefficiencies that are attached to those produced during the H_2 generation. Energy is used to compress the H_2 in order to store it in the CH_2 buffer tank, prior to the NH_3 synthesis, however, these losses are not considered since it is stored at an intermediate pressure between the electrolyzer output and the required pressure in the Haber Bosch process. Therefore, the energy used for the compression is already included in the Haber Bosch + ASU energy consumption. As NH_3 turns into liquid at 25 ºC and 7 bar, the energy losses in the pipelines are relatively small, since transporting liquids is more efficient than gases. No energy loss is considered in the pipeline for NH_3.

Table 17 Energy expenditure for Pathway 4a

Energy expenditure				
	Specific energy expenditure		**Overall energy expenditure**	
Array cables [122]	1,10	MWh/MWh	0,0185	MWh/MWhH_2
Offshore platform [40]	13,36	MWh/tH_2	0,4011	MWh/MWhH_2
CH_2 storage tank	Included in Haber Bosch + ASU value			
Haber Bosch reaction [86]	(-4,09)	MWh/tH_2	-	MWh/MWhH_2
Haber Bosch + ASU [86]	3,77	MWh/tH_2	0,0898	MWh/MWhH_2
Pipelines (15 bar)	No energy expenditure			
Compressor of O_2 (116)	2,08	MWh/tH_2	0,0684	MWh/MWhH_2
Import terminal [40]	0,02	MWh/tH_2	0,0006	MWh/MWhH_2
Reconversion (heat) [22]	6,30	MWh/tH_2	0,2072	MWh/MWhH_2
Reconversion (electricity) [40]	1,50	MWh/tH_2	0,0493	MWh/MWhH_2
PSA H_2 recovery rate [40]	90 %	Obtained H_2/Total H_2	0,1000	MWh/MWhH_2

Ammonia export by boat implies, as in the LH_2 case, the presence of an NH_3 storage tank in the platform, in order to store the H_2 carrier for periods where its offloading is not possible, such as rough sea conditions. The storage size required was estimated to be enough for 5 days. Moreover, the vessel is an added element regarding to the first configuration, substituting the pipelines. Costs of ammonia tankers are sensitively cheaper than those for hydrogen, due to easier handling of the gas and lower operating temperatures (see Table 18).

Table 18 Economic values for Pathway 4b

Vessel Ammonia		
CAPEX		
Array cables [58]	160.000	€/MW
Offshore platform [58]	1.124.234	€/MW
Compression of O_2 [119]	7.348	€/tO_2/day
CH_2 Storage Tank [86]	423.000	€/tH_2
Haber Bosch + ASU [86]	990.084	€/tH_2/day
NH_3 Storage tank [40]	7.990	€/tH_2
Vessel [40]	8.177	€/tH_2
Import terminal [40]	7.990	€/tH_2
Reconversion [40]	570.764	€/tH_2/day
Decommissioning		
Array cables [58]	86.580	€/MW
Offshore platform [58]	74.750	€/MW
H_2 Storage tank		
Haber Bosch Process		
NH_3 storage tank		
Vessel	No decommissioning costs	
Import terminal	No decommissioning costs	
Reconversion	No decommissioning costs	
OPEX		
Array cables [61]	0,50 %	Of CAPEX/year
Offshore platform [40]	1,50 %	Of CAPEX/year
Stack Replacement [120]	27,00 %	Of CAPEX
Compression of O_2	4,00 %	Of CAPEX/year
CH_2 Storage tank [86]	1,00 %	Of CAPEX/year
Haber Bosch + ASU [86]	2,00 %	Of CAPEX/year
NH_3 Storage tank [86]	1,00 %	Of CAPEX/year
Vessel [40]	4,00 %	Of CAPEX/year
Import terminal [40]	4,00 %	Of CAPEX/year
Reconversion [40]	4,00 %	Of CAPEX/year

Energy expenditures increase compared to pipelines transportation due to the vessel energy requirements, as can be observed in Table 19. NH_3 leaves the Haber Bosch process in liquid state, therefore, no losses are considered for the storage tank, since liquefaction or compression are not needed.

Table 19 Energy expenditure for Pathway 4b

Energy expenditure				
	Specific energy expenditure		Overall energy expenditure	
Array cables [122]	1,10	MWh/MWh	0,0185	MWh/MWhH_2
Offshore platform [40]	13,36	MWh/tH_2	0,4011	MWh/MWhH_2
Compressor of O_2 (116)	2,08	MWh/tH_2	0,0599	MWh/MWhH_2
CH_2 Storage tank	Included in Haber Bosch + ASU value			
Haber Bosch reaction [86]	(-4,09)	MWh/tH_2	-	MWh/MWhH_2
Haber Bosch + ASU [86]	3,62	MWh/tH_2	0,0898	MWh/MWhH_2
NH_3 Storage tank [40]	0,02	MWh/tH_2	0,0006	MWh/MWhH_2
Vessel [40]	74,24	kWh/1000km/t H_2	0,0002	MWh/MWhH_2
Import terminal [40]	0,02	MWh/tH_2	0,0006	MWh/MWhH_2
Reconversion (heat) [22]	6,3	MWh_{th}/tH_2	0,2072	MWh/MWhH_2
Reconversion (electricity) [40]	1,5	MWh/tH_2	0,0493	MWh/MWhH_2
PSA H_2 recovery rate [40]	90%	Obtained H_2/Total H_2	0,1000	MWh/MWhH_2

3.3.5 Pathway 5 - Offshore LOHC

Two scenarios are explored for the H_2 loading into LOHC pathway. These scenarios differ in the way in which the H_2 carriers are exported to land, pipeline and vessel transportation are the two considered possibilities.

In addition, LOHC present a peculiar characteristic in terms of logistic, since the carrier compound requires a round trip since it cannot be obtained at the H_2 production point. Therefore, in the pipelines transportation case, an extra pipeline needs to be installed to take back the toluene to the offshore platform, in order to load it with H_2, For the vessel transportation case, a similar situation occurs, where ships carry the toluene from land to the offshore platform and offload it into a tank situated in there, and take the loaded toluene (methylcyclohexane) to the demand points, running hence always at full load.

Costs for the first case include the H_2 generation assets and the array cables as the cases mentioned before (see Table 20). Additional economic values included in the assessment of LOHC H_2 offloading by pipelines are the cost of the organic carrier (toluene), the cost of pipelines, which is assumed to be the same kind of material as in the previous configurations, while being double the price due to the need of a return pipe. Lastly, costs for hydrogenation, dehydrogenation and import terminal are also new inclusions in the calculations.

For the decommissioning, the same assumptions as in the rest of the pathways have been followed, considering that only the offshore assets incur into removal costs.

Table 20 Economic values for Pathway 5a

Pipeline LOHC		
CAPEX		
Array cables [58]	160.000	€/MW
Offshore platform [58]	1.124.234	€/MW
Hydrogenation [40]	290.000	€/tH$_2$/day
Toluene [40]	300	€/t$_{toluene}$
Pipelines [67]	56.341	€/cm/km
Compression of O$_2$ [119]	7.348	€/tO$_2$/day
Import terminal [40]	8.230	€/tH$_2$
Reconversion [40]	845.000	€/tH$_2$/day
Decommissioning		
Array cables [58]	86.580	€/MW
Offshore platform [58]	74.750	€/MW
Hydrogenation		
Pipelines	No decommissioning costs	
Import terminal	No decommissioning costs	
Reconversion	No decommissioning costs	
OPEX		
Array cables [61]	0,50 %	Of CAPEX/year
Offshore platform [40]	1,50 %	Of CAPEX/year
Stack Replacement [120]	27,00 %	Of CAPEX
Hydrogenation [40]	4,00 %	Of CAPEX/year
Pipelines*2 [68]	0,000012 %	Of CAPEX/year
Compression of O$_2$	4,00 %	Of CAPEX/year
Import terminal [40]	4,00 %	Of CAPEX/year
Reconversion [40]	4,00 %	Of CAPEX/year

Hydrogenation releases heat, while dehydrogenation needs high quantities of it. This process adds important losses to the whole H_2 supply chain (see Table 21). Also, the need of purification of H_2 after being offloaded from the carrier means extra use of energy. Although the PSA unit is included in the costs of reconversion, here it is stated separately because of the different sort of energy needed for the process, in the dehydrogenation case, it is thermal energy that needs to be supplied, while for the plant power and PSA case, it is electricity. Dehydrogenation does not release all the H_2 contained in the liquid, efficiencies of 95 % in this process are considered. Afterwards, the H_2 purification in order to raise the gas standards has a H_2 recovery rate of 90 %. This is all included as one only process in the analysis.

Table 21 Energy expenditure for Pathway 5a

Energy expenditure				
	Specific energy expenditure		**Overall energy expenditure**	
Array cables [122]	1,10	MWh/MWh	0,0185	MWh/MWhH_2
Offshore platform [40]	13,36	MWh/tH_2	0,4011	MWh/MWhH_2
Hydrogenation [40]	(9,04)	MWh_{th}/tH_2	-	MWh/MWhH_2
Hydrogenation [40]	1,50	MWh/tH_2	0,0384	MWh/MWhH_2
Pipelines*2	Energy expenditure included in hydrogenation			
Compressor of O_2 (116)	2,08	MWh/tH_2	0,0533	MWh/MWhH_2
Import terminal [40]	0,01	MWh/tH_2	0,0003	MWh/MWhH_2
Dehydrogenation [40]	13,60	MWh_{th}/tH_2	0,4049	MWh/MWhH_2
Plant power + PSA [40]	1,50	MWh/tH_2	0,0447	MWh/MWhH_2
Dehydrogenation +PSA H_2 recovery [40]	86 %	Obtained H_2/Total H_2	0,1450	MWh/MWhH_2

Another alternative for the transportation of LOHC is the use of vessels. The similarity of the features of LOHC to oil, allows the use of oil tankers and tanks for its logistics. As in the LH_2 and NH_3 case, rough sea conditions need to be anticipated, and therefore storage for 5 days must be considered. Storage both for toluene and MCH is included. Therefore, two tanks are placed in the offshore platform.

Storage tanks and the vessel are new economic values included in the analysis, excluding the pipelines if compared to the first mentioned option for LOHC (see Table 22). The difference between tanks costs is due to the difference of densities between both liquids since tank price per kg is the same.

Table 22 Economic values for Pathway 5b

Vessel LOHC		
CAPEX		
Array cables [58]	160.000	€/MW
Offshore platform [58]	1.124.234	€/MW
Compression of O_2 [119]	7.348	€/tO_2/day
Hydrogenation [40]	290.000	€/tH_2
Toluene [40]	300	€/$t_{toluene}$
Toluene storage tank [40]	511	€/$t_{toluene}$
MCH storage tank [40]	8.230	€/tH_2
Vessel [40]	10.032	€/tH_2
Import terminal [40]	8.230	€/tH_2
Reconversion [40]	845.220	€/tH_2
Decommissioning		
Array cables [58]	86.580	€/MW
Offshore platform [58]	74.750	€/MW
Hydrogenation		
Toluene storage tank		
MCH storage tank		
Vessel	No decommissioning costs	
Import terminal	No decommissioning costs	
Reconversion	No decommissioning costs	
OPEX		
Array cables [61]	0,50 %	Of CAPEX/year
Offshore platform [40]	1,50 %	Of CAPEX/year
Stack Replacement [120]	27,00 %	Of CAPEX
Compression of O_2	4,00 %	Of CAPEX/year
Hydrogenation [40]	4,00 %	Of CAPEX/year
Toluene storage tank [40]	4,00 %	Of CAPEX/year
MCH storage tank [40]	4,00 %	Of CAPEX/year
Vessel [40]	4,00 %	Of CAPEX/year
Import terminal [40]	4,00 %	Of CAPEX/year
Reconversion [40]	4,00 %	Of CAPEX/year

Energy expenditure includes the energy required to power the ship, as presented in Table 23.

Table 23 Energy expenditure for Pathway 5b

Energy expenditure				
	Specific energy expenditure		Overall energy expenditure	
Array cables [122]	1,10	MWh/MWh	0,0185	$MWh/MWhH_2$
Offshore platform [40]	13,36	MWh/tH_2	0,4011	$MWh/MWhH_2$
Compressor of O_2 (116)	2,08	MWh/tH_2	0,0533	$MWh/MWhH_2$
Hydrogenation [40]	(9,04)	MW_{th}/tH_2	-	$MWh/MWhH_2$
Hydrogenation [40]	1,5	MWh/tH_2	0,0384	$MWh/MWhH_2$
Toluene storage tank [40]	0,01	MWh/tH_2	0,0003	$MWh/MWhH_2$
MCH storage tank [40]	0,01	MWh/tH_2	0,0003	$MWh/MWhH_2$
Vessel [40]	134,35	$kWh/1000km/tH_2$	0,0004	$MWh/MWhH_2$
Import terminal [40]	0,01	MWh/tH_2	0,0003	$MWh/MWhH_2$
Dehydrogenation [40]	13,60	MWh_{th}/tH_2	0,4049	$MWh/MWhH_2$
Plant power + PSA [40]	1,50	MWh/tH_2	0,0447	$MWh/MWhH_2$
PSA H_2 recovery rate [40]	86 %	Obtained H_2/Total H_2	0,1450	$MWh/MWhH_2$

3.4 Sensitivity analysis

The analyzed pathways are assessed for a specific offshore wind farm, being the physical and economic configuration explained in Section 3.2. However, this project does not aim to provide a best solution for any specific case, but to obtain a set of insights that help decision makers to choose the best H_2 offloading system in terms of the wind farm and the H_2 technologies characteristics.

Therefore, some of the variables that are observed to influence the final LCOH are analyzed more in deep by studying their influence carrying out a sensitivity analysis, in order to assess its weight in the final cost of H_2, These factors are:

- **Cost of electrolyzer systems**: As introduced in Section 2.2.1. Electrolyzer costs are in the range of 990-1.620 €/kW_e for the whole system. However, costs are foreseen to be as low as 200 €/kW_e in the long term (20 % of current cost) [14] [15]. This drop in the prices, mainly driven by a scale up of the H_2 supply chain [4] are included in the sensitivity analysis due to the big influence of electrolysis costs in the total cost of the system. Automated production of the electrolyzer cell components, cells and stacks will bring down the cost for the electrolyzer stacks and building GW scale electrolyzer plants will reduce the balance of plant costs per kW [14].
- **Electrolyzer efficiency**: Despite no big breakthroughs are announced in the field of PEM electrolyzers, new technological developments will gradually increase the performance of the electrolyzer systems, disregarding of the technology. Hence, a sensitivity analysis where the current efficiency of 60 % is gradually raised to 90 % (Maximum efficiency between SOEC, PEM and Alkaline Electrolysis) is performed.
- Electrolyzer plant costs are important, but the dominant factor in the H_2 production cost is the **Levelized Cost of Electricity**, determining 60-90 % of the H_2 cost [14]. Costs for offshore wind

have great variation. LCOE sensitivity analysis will study the cost variation from 20 to 70 €/MWh, according to the possible prices that offshore wind could reach in the upcoming years without accounting for the transmission assets [11].

- **Distance to shore of the wind farm**: Floating wind turbines will open the possibility of taking offshore wind farms further, thus, reaching better resources. Hence, similar LCOE from the wind farm can be obtained compared to closer to shore systems, however, transmission assets such as cables or pipelines can gain weight in the total costs of the project, making the respective configurations less attractive both from an economic a technical point of view. Distance to shore is assessed from 5 to 500 km, being 50 km the selected distance for the baseline case. 500 km from shore is a distance to shore that has not been announced yet for any project, but the irruption of floating wind farms could take wind farms that far. Therefore, it has been considered relevant for this study, in order to provide insights on how distance would affect the different pathways.

- **Capacity factor**: The aforementioned situation where floating wind turbines take the offshore wind farm to better resource locations, does not only opens the possibility of having more electricity at a competitive price, an increase in the capacity factor also increases the working hours of the H_2 production facilities, diluting their effects in the final costs. Capacity factors from 44-64 % are assessed, being this range common for offshore wind farms according to IEA [11].

- **Income tax rate**: When doing the LCOE calculations, income tax is not included in the analysis. Nevertheless, it has an influence in the economics of the project, affecting the net income and hence the NPV of the project. This factor can have great variance among different countries, affecting the economics of the project. The evaluated values are those for Europe, varying between 10-34 % [125]. Major markets in the world present the following income tax rates:

Table 24 Income tax for different countries in 2020 [126]

Country	Income tax
Brazil	34%
China	25%
Germany	30%
India	30%
Portugal	21%
Spain	25%
United States	27%

In summary, the different variables studied in the sensitivity analysis are stated in Table 25.

Table 25 Variables included in the sensitivity analysis

Tested variable	Minimum value	Maximum value	Units
Electrolyzer system costs	200	990	€/kW$_e$
Electrolyzer efficiency	60	90	%
LCOE	20	70	€/MWh
Distance to shore	5	500	km
Capacity factor	44	64	%
Income Tax Rate	10	34	%

3.5 Definition of scenarios

Two scenarios are proposed in order to foresee how the future of H_2 may look like. The first scenario follows the technology advancements forecasted from the different sources which have been consulted. This means that the development of the technology will follow the expected line.

The second scenario is based on the EU Hydrogen Strategy [6], which is part of the Energy System Integration Strategy [5], both published on 8th July 2020. Here, all the measures are put in place in order to be able to achieve a massive deployment of H_2, guaranteeing that by 2050 almost 15% of the total energy consumption in Europe comes from H_2. The means put in place to achieve this goal are distributed along the whole H_2 value chain. In the production, it is planned to reach at least 80 GW of electrolyzers installed between the UE and the neighboring countries (2x40 GW). Also, different innovation funds will foster the efficiency improvements, advancing not only on the costs due to economies of scale, but also in the performance of the systems. This strategy also mentions support on the development of infrastructure for transportation of H_2 in order to ease the access for consumers.

For both scenarios only three variables are modified, since they are the most significative, as seen in the previous section. These are the LCOE, the electrolyzer costs and the electrolyzer system efficiency.

3.5.1 Scenario 1

Scenario 1 is a technology driven case, in which both H_2 and offshore wind development follow the estimations of the already mentioned reports, without major breakthroughs but still offering learning curves over 10%. However, it is important to remark that the used values are forecasted to be achieved mainly by scaling up the adoption of H_2 and offshore wind in order to decarbonize the energy systems. This fact is supported by the recent support of institutions such as the EU, and the entry of big companies in the H_2 in the business.

For this scenario, three variables have been modified, in order to understand their combined effect in a future where the aim to reach net zero targets and the companies R&D driven by markets and current policies keep maintaining the expected learning curves. These new values are stated in Table 26.

Table 26 Selected values for Scenario 1

Scenario	Baseline case	Scenario 1
LCOE (€/MWh)	50	20
Electrolyzer cost (€/kW$_e$)	990	585
Electrolyzer efficiency (%)	60	68

These values are those of maximum relevance for the LCOH, and also those more prone to experience positive developments in the next years. Other components of the project, such as the offshore platforms, the vessels or the pipelines are already very mature technologies that are not expected to reduce their costs or improve their efficiencies significantly.

3.5.2 Scenario 2

The recently announced EU Hydrogen Strategy and EU Energy System Integration Strategy aim to establish H_2 as one of the main pillars of the future EU energy system, covering almost 15 % of the final energy demand [6]. The European Commission does not only want to encourage the presence of this energy vector in the energy mix, but also wants to support the H_2 technology manufacturing industry along all its value chain, and encourage the use of this technology in hard to abate sectors such as steel production, a key industry for Europe.

With this, the support from the EU to H_2 will not only help to its massive deployment, achieving 40 GW of electrolyzers in the continent, but also 40 GW more in the neighboring countries. Different funds will also support innovation along the whole value chain and the development of infrastructure to delivery H_2 to the consumers. All these actions will bring green H_2 to cost competitiveness with blue H_2 by 2030.

This scenario covers a future in which the technology does not only follow a market driven development but also acceleration in innovation and higher cost reductions due to a mass scale adoption. According to Hydrogen Europe, the 2x40 GW deployment would reduce the electrolyzer costs to less than 200 €/kW [14].

Scenario 2 is a case where the variables adopt values mentioned in the most optimistic cases of the abovementioned reports, hence the included values in the analysis are as shown in Table 27:

Table 27 Selected values for Scenario 2

Scenario	Baseline case	Scenario 2
LCOE (€/MWh)	50	20
Electrolyzer cost (€/kW$_e$)	990	200
Electrolyzer efficiency (%)	60	82

4. Results and Discussion

4.1 Evaluation of pathways

The results for the baseline scenario in the different considered pathways are shown below:

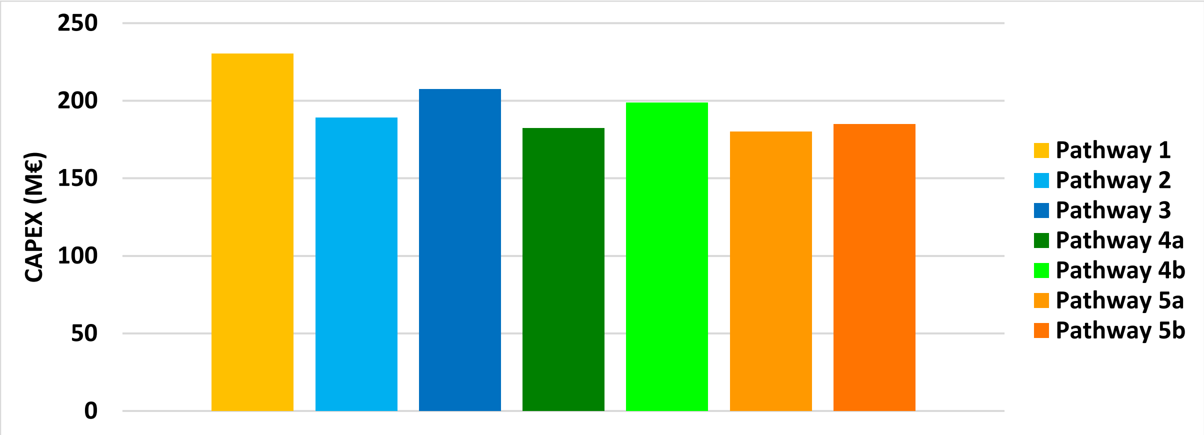

Figure 18 CAPEX (M€) for every pathway. (Pathway 1 - DC Electricity; Pathway 2 - H_2 Compression; Pathway 3 - H_2 Liquefaction; Pathway 4a - NH_3 Pipeline; Pathway 4b - NH_3 Vessel; Pathway 5a - LOHC Pipeline; Pathway 5b - LOHC Vessel)

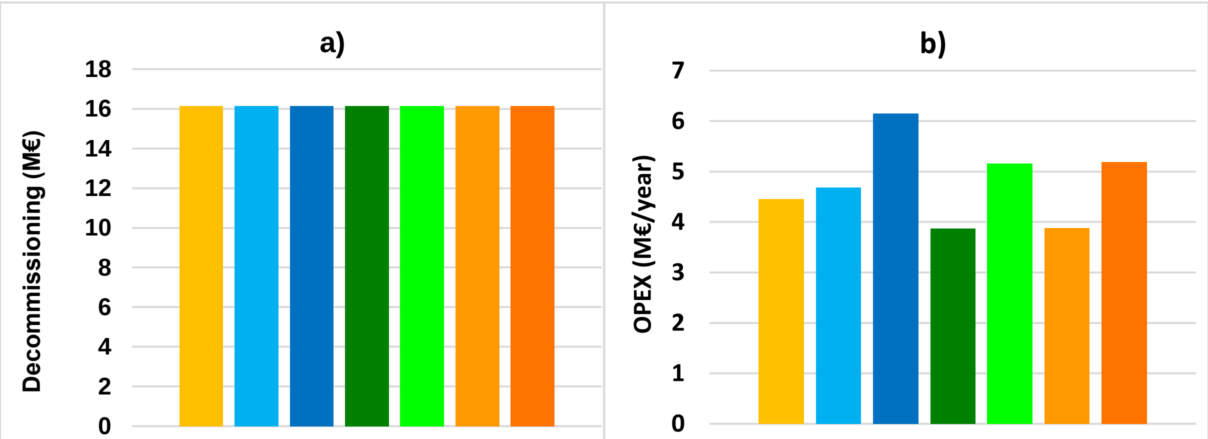

Figure 19 a) Decommissioning costs (M€) and b) OPEX (M€/year) for every pathway. (Pathway 1 - DC Electricity; Pathway 2 - H_2 Compression; Pathway 3 - H_2 Liquefaction; Pathway 4a - NH_3 Pipeline; Pathway 4b - NH_3 Vessel; Pathway 5a - LOHC Pipeline; Pathway 5b - LOHC Vessel)

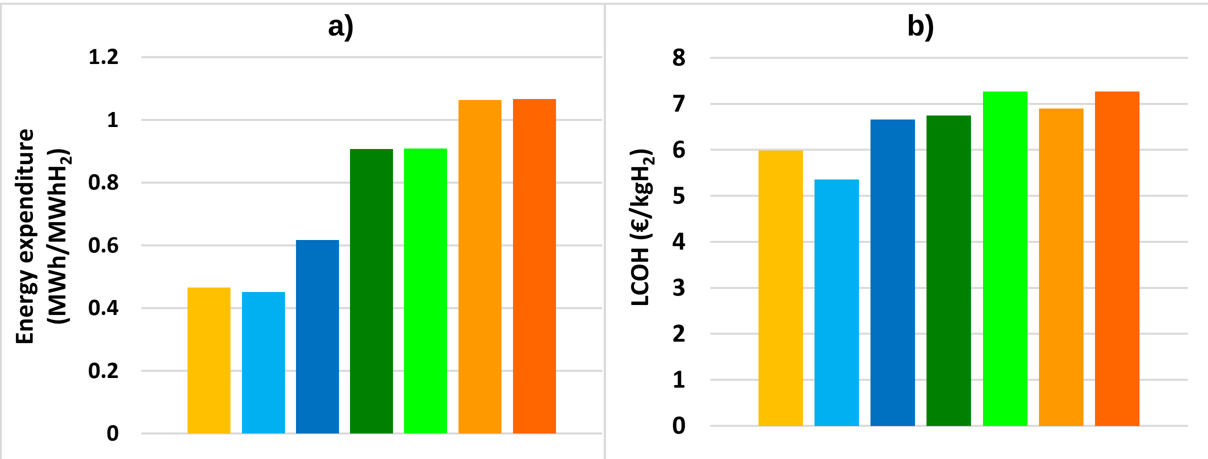

Figure 20 a) Energy expenditure (MWh/MWhH_2) along the process and b) LCOH (€/kgH_2) for every pathway. (Pathway 1 - DC Electricity; Pathway 2 - H_2 Compression; Pathway 3 - H_2 Liquefaction; Pathway 4a - NH_3 Pipeline; Pathway 4b - NH_3 Vessel; Pathway 5a - LOHC Pipeline; Pathway 5b - LOHC Vessel)

The first analysis of the baseline scenario shows similar values in terms of CAPEX for all the possible pathways, ranging these between 180 M€ for the LOHC pipelines exportation case (Pathway 5a) and 230 M€ for the inland H_2 production (Pathway 1), where the need of storage for 5 days adds up to 44,75 M€ for the baseline case, due to the high costs of storage for CH_2. The presence of a continuous demand of H_2 at the import terminal, such as the gas grid, would erase this cost for storage. Decommissioning costs are the same for all the scenarios, since only the removal of the platform and array cables is considered, as explained in previous sections.

In terms of OPEX, LH_2 case (Pathway 3) presents the highest OPEX, due to the high costs of the liquefaction facility and the vessel, since these compounds add up to 1,71 and 1,31 M€/year, respectively. This vessel influence can be observed both in Pathways 4b and 5b. Stack replacement, adds up around 30 M€ to the total cost, (1,15 M€/year in average). An average stack could run for approximately 20 years in the baseline scenario (87.600 hours). Therefore, the stack replacement would occur at the end of the project lifetime. Being possible that other solutions, such as more efficient PEM electrolyzers or improved alkaline electrolyzers or SOEC can be better alternatives. This is a decision that has to be assessed in the future, however, it is relevant to be aware this reality from an early stage of the project, in order to understand future costs. In this work, the stack replacement is input as an annual provision (1,15 M€/year in average)

The energy expenditure chart provides a good vision of how much energy is used in every pathway, it is easily appreciable that the energy carriers (Pathways 4a/b and 5a/b) represent higher energy losses, getting even to negative efficiencies (MWh/MWhH_2 higher than 1) for Pathways 5a/5b (LOHC cases). This fact is mainly due to the high energy requirements that the reconversion steps require. Representing between 20 % of the total energy contained in the final H_2 for the ammonia case and 40 % for the LOHC. This fact is reinforced by the loss of H_2 during the reconversion process, since only 90 % of H_2 is recovered in the purification unit for the case of NH_3 while this number goes down to 86 % in the LOHC case. These numbers compare against the energy expenditure of the state-of-the-art SMR plant, which requires around 1,2 MWh/MWhH_2 [127].

High energy inputs and final product losses in the reconversion units raise the LCOH for NH_3 and LOHC pathways. Since these reach costs of 7,27 €/kgH_2. Compared to 5,35 €/kgH_2 in Pathway 2 (CH_2 transportation). The possibility of using waste heat in these reconversion steps would bring the costs down 0,48 €/kgH_2 in the NH_3 cases, while in the LOHC cases this number is as high as 0,88 €/kgH_2.

LCOH can be broken down in order to understand the weight that every factor has on it, this is shown in Figure 21, and it is divided into the different steps of the supply chain showed in Figure 17.

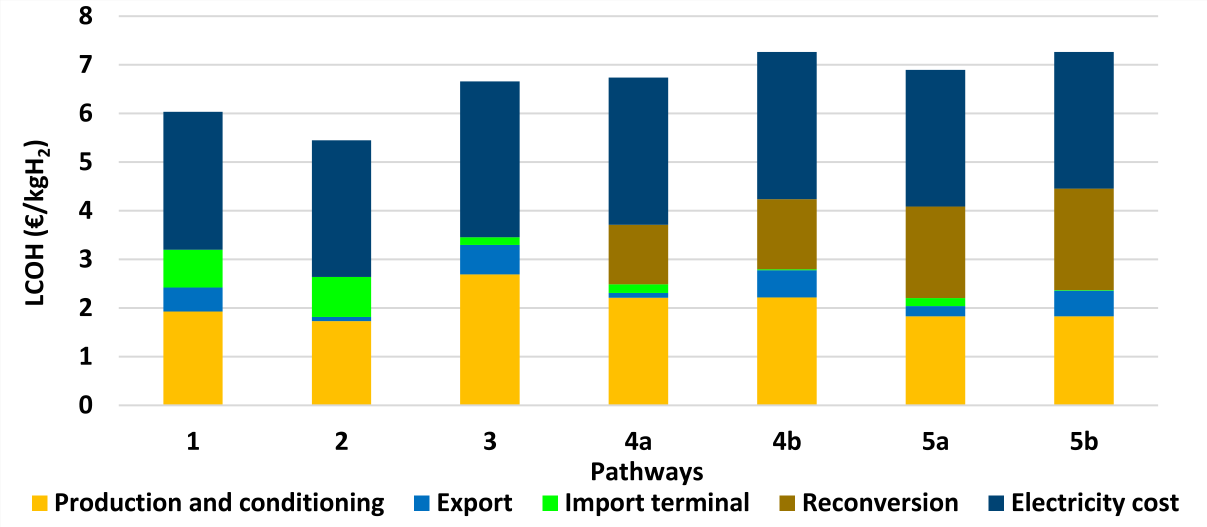

Figure 21 LCOH (€/kgH_2) cost breakdown for every pathway. (Pathway 1 - DC Electricity; Pathway 2 - H_2 Compression; Pathway 3 - H_2 Liquefaction; Pathway 4a - NH_3 Pipeline; Pathway 4b - NH_3 Vessel; Pathway 5a - LOHC Pipeline; Pathway 5b - LOHC Vessel)

It is visible that reconversion steps add up not only complexity but also increases in the H_2 price due to the required equipment costs and the high energy inputs that these require. These costs would be avoided if both NH_3 or LOHC were possible to be applied by the end-user without reconverting back to H_2. This is especially interesting for NH_3, which can be used for burning, as feedstock or even in a fuel cell. For the LOHC case, high costs of the compounds make them more valuable as carriers than as a fuels since they offer the molecule recovery possibility in order to be used again.

Calculations for the determination of LCOH are performed considering only the H_2 infrastructure. However, in order to improve the economics of the project O_2 sales are considered in the NPV calculation. These sales are shown in Table 28 for the baseline scenario, considering a case in which O_2 is sold at the lowest prince in the range provided beforehand (100 €/tO_2), and a second case more optimistic in which O_2 is sold at 280 €/tO_2.

Table 28 Yearly revenue from O_2 sales for every pathway. (Pathway 1 - DC Electricity; Pathway 2 - H_2 Compression; Pathway 3 - H_2 Liquefaction; Pathway 4a - NH_3 Pipeline; Pathway 4b - NH_3 Vessel; Pathway 5a - LOHC Pipeline; Pathway 5b - LOHC Vessel)

O_2 selling price	Pathway							
	1	2	3	4a	4b	5a	5b	
100 €/tO_2	6,18	6,23	5,47	6,83	6,00	5,33	5,33	M€/year
280 €/tO_2	17,30	17,45	15,31	19,13	16,79	14,92	14,92	M€/year

Sales of O_2 are a relevant factor to be included in the economics of the project, these vary between 10-34 % of total sales of H_2 and O_2.

NPV is calculated for the previously determined LCOH and compared against the NPV of a project in which O_2 is sold at two different prices (100-280 €/tO_2). Considering also the infrastructure needed for this purpose. Figure 22 shows the NPV for the three different cases.

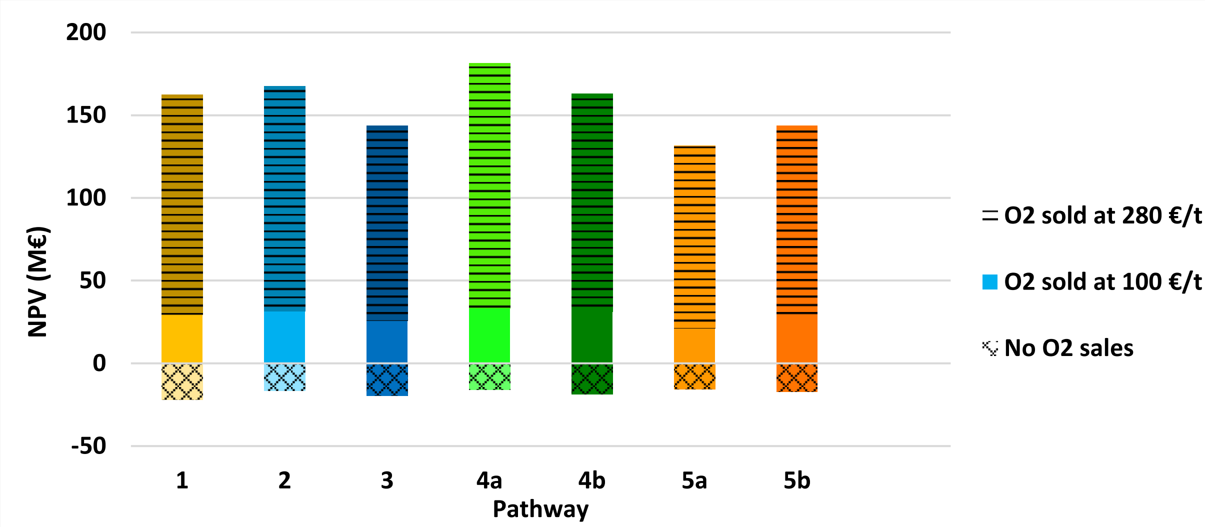

Figure 22 NPV (M€) in the baseline scenario for every pathway. (Pathway 1 - DC Electricity; Pathway 2 - H_2 Compression; Pathway 3 - H_2 Liquefaction; Pathway 4a - NH_3 Pipeline; Pathway 4b - NH_3 Vessel; Pathway 5a - LOHC Pipeline; Pathway 5b - LOHC Vessel)

It is observable how the NPV becomes positive thanks to the commercialization of this by-product. Even when O_2 is sold at the lowest price range, which is not a likely case due to the high purity of the obtained gas, the project becomes economically viable due to the inclusion of O_2 sales in the economic calculations.

As seen above, the sales of H_2 alone would incur in a negative NPV, due to the effects of income taxes, which are not considered in the LCOH calculations. Note that without income taxes NPV would equal 0. Sensitivity analysis on the income taxes is performed in section 4.2.2 in order to understand the effect it has on the NPV.

4.2 Sensitivity analysis

Both LCOH and NPV are considered as economic indicators in order to assess the performance of the project. Therefore, sensitivity analyses will be performed on the different variables that may affect the aforementioned indicators.

Thus, for the LCOH, the factors that may have higher or lower weight on the final cost of H_2 are electrolyzer cost, capacity factor, electrolyzer system efficiency, distance to shore of the plant and the LCOE of the energy used to produce the H_2.

However, the NPV is affected by variables such as the income tax and the final cost at which H_2 is sold.

4.2.1 Sensitivity analysis for LCOH

As explained in Section 3.2, sensitivity analysis has been performed in sensitive variables in order to evaluate the effect that these have on the LCOH. Maximum LCOH reduction or increase are compared against the baseline LCOH in the tables. The results for these simulations are presented next.

Electrolyzer cost is the first tested variable in the sensitivity analysis, as presented in Figure 23. The 80% cost reduction brings down the cost of the electrolyzer from 990 to 200 €/KW$_e$. This results in an average 17,7 % reduction over the LCOH for all the methods (see Table 29). This states the importance of electrolyzers as one of the main contributors to H_2 costs, however, it also evidences that electrolyzer cost reduction itself may not lead H_2 to a point where it is cost competitive with many applications.

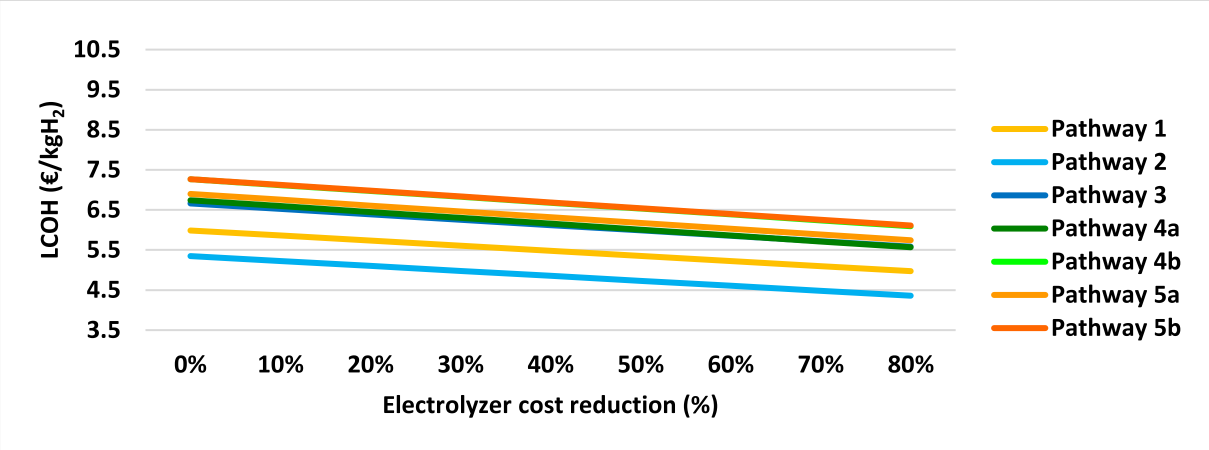

Figure 23 LCOH (€/kgH$_2$) sensitivity on electrolyzer cost reduction (%). (Pathway 1 - DC Electricity; Pathway 2 - H_2 Compression; Pathway 3 - H_2 Liquefaction; Pathway 4a - NH_3 Pipeline; Pathway 4b - NH_3 Vessel; Pathway 5a - LOHC Pipeline; Pathway 5b - LOHC Vessel)

The best case is still for CH_2, where LCOH falls down to 4,36 €/kgH$_2$. Some other pathways, such as LOHC case with pipeline transportation offer a slightly steeper decline in LCOH, due to the higher weight of the electrolyzer systems in the CAPEX of the whole system than for example the H_2 liquefaction case, where high costs of the vessel and the liquefaction system dilute the electrolyzer weight on the CAPEX.

Table 29 Maximum cost reduction in % due to electrolyzer costs compared to baseline case. (Pathway 1 - DC Electricity; Pathway 2 - H_2 Compression; Pathway 3 - H_2 Liquefaction; Pathway 4a - NH_3 Pipeline; Pathway 4b - NH_3 Vessel; Pathway 5a - LOHC Pipeline; Pathway 5b - LOHC Vessel)

Pathway	1	2	3	4a	4b	5a	5b
LCOH reduction	16,9%	18,5%	16,2%	17,4%	16,1%	16,8%	15,9%

The **capacity factor** of the windfarm is an enabler for the project to take place. Offering good resources (i.e. higher capacity factors), independently of the electricity price, enables a higher utilization of the equipment, raising its profitability, as presented in Figure 24.

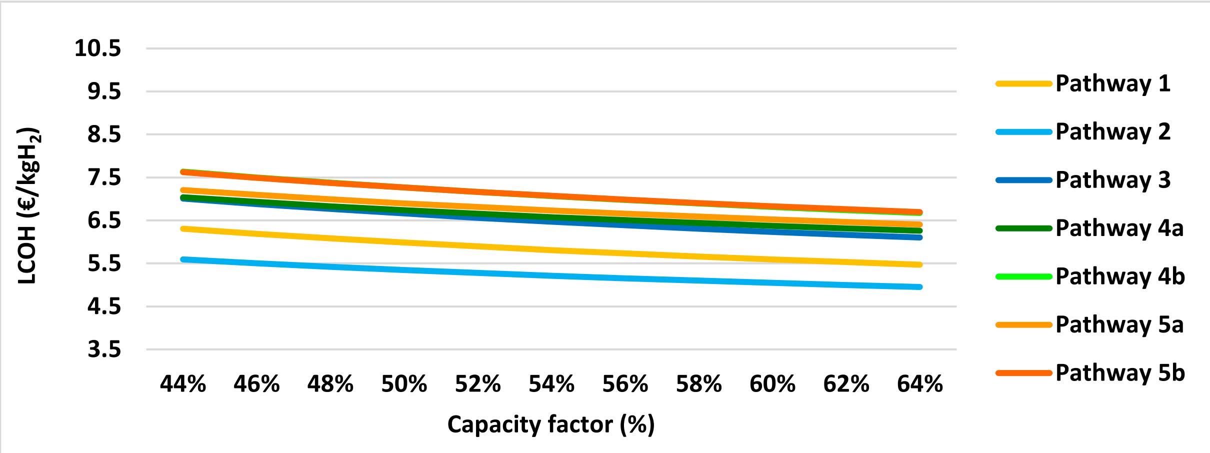

Figure 24 LCOH (€/kgH_2) sensitivity on capacity factor (%) for every pathway. (Pathway 1 - DC Electricity; Pathway 2 - H_2 Compression; Pathway 3 - H_2 Liquefaction; Pathway 4a - NH_3 Pipeline; Pathway 4b - NH_3 Vessel; Pathway 5a - LOHC Pipeline; Pathway 5b - LOHC Vessel)

A higher capacity factor should raise the profitability of the pathways with higher CAPEX due to a higher sensitivity of these to the utilization of the infrastructure, such as the inland production case or the LH_2 production (Pathways 1 and 3). However, an increase in the capacity factor also means higher expenditure in infrastructure such as storage tanks or size of pipelines or boats. These other elements partially offset the higher production of H_2. The problem of higher expenses due to higher tank volumes could be addressed by fixing a specific amount of final product in the import terminal, this could be done once the final consumer is known. In the modelling of this project, the import terminal storage is sized for 5 days of production and therefore higher production incurs into higher storage costs.

Import terminal costs could be kept under control even with an increase in the capacity factor, however, storage costs would increase anyways in the cases where vessels are used to transport the product towards land, since tanks are placed in the platforms to store the product (LH_2, LNH_3 or LOHC), and this storage, sized for 5 days, is established to avoid curtailments in case the sea conditions are rough and prevent the boat from offloading the product. In this case, costs surge is unavoidable.

Costs for the inland production case (Pathway 1) would be the most benefited by a capacity factor increase, due to a better utilization of the infrastructure that represents the higher CAPEX of all the possible paths. Proving that even if the costly storage tanks increase their cost, these don´t offset the higher utilization of the infrastructure, lowering the effect of CAPEX in the final LCOH. This one seems to be the factor with major weight in the cost reduction, since the major cuts in the LCOH are for those pathways with more CAPEX such as liquid H_2 transportation and NH_3 transportation by vessel (Pathways 3 and 4b), as presented in Table 30. Same explanation applies for the increase in LCOH due to a lower capacity factor.

Table 30 Maximum cost reduction/increase in % due to capacity factor compared to baseline case. (Pathway 1 - DC Electricity; Pathway 2 - H_2 Compression; Pathway 3 - H_2 Liquefaction; Pathway 4a - NH_3 Pipeline; Pathway 4b - NH_3 Vessel; Pathway 5a - LOHC Pipeline; Pathway 5b - LOHC Vessel)

Pathway	1	2	3	4a	4b	5a	5b
LCOH reduction	8,6%	7,4%	8,4%	7,1%	8,1%	7,2%	7,9%
LCOH increase	5,1%	4,4%	5,0%	4,2%	4,8%	4,3%	4,7%

LCOE is the largest contributor to LCOH, due to the high energy inputs required to produce H_2. Cases with lower CAPEX are more sensible to electricity prices. Cost reductions vary from 27,2-31,5 % in all the cases, reaching levels as low as 3,66 €/kgH_2 for the CH_2 transportation case (see Table 31). The same behaviour is shown in the prices increase, where costly pathways are sligthly less sensitive than those with lower CAPEX. However, LCOE is, in every pathway, the main cost driver. Variations between 20-70 €/MWh can represent costs rises of 80 % in the cases with higher weight of LCOE price.

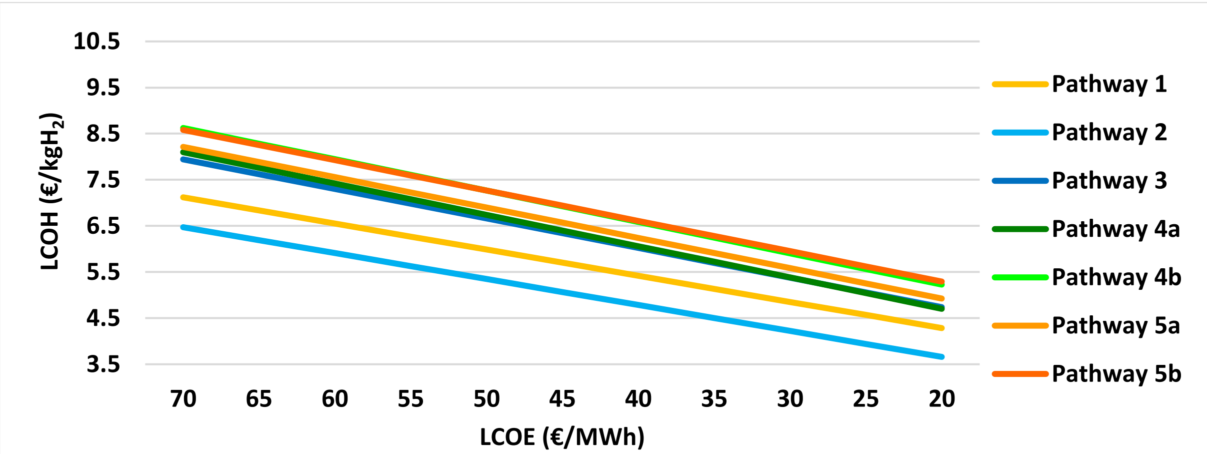

Figure 25 LCOH (€/kgH_2) sensitivity on LCOE (€/MWh). (Pathway 1 - DC Electricity; Pathway 2 - H_2 Compression; Pathway 3 - H_2 Liquefaction; Pathway 4a - NH_3 Pipeline; Pathway 4b - NH_3 Vessel; Pathway 5a - LOHC Pipeline; Pathway 5b - LOHC Vessel

This price sensitivity to the LCOE also highlights the importance of optimizing the use of electricity.

Table 31 Maximum cost reduction/increase in % due to LCOE compared to baseline case. (Pathway 1 - DC Electricity; Pathway 2 - H_2 Compression; Pathway 3 - H_2 Liquefaction; Pathway 4a - NH_3 Pipeline; Pathway 4b - NH_3 Vessel; Pathway 5a - LOHC Pipeline; Pathway 5b - LOHC Vessel

Pathway	1	2	3	4a	4b	5a	5b
LCOH reduction	28,4%	31,5%	28,9%	30,2%	28,0%	28,6%	27,2%
LCOH increase	19,0%	21,0%	19,2%	20,2%	18,7%	19,1%	18,1%

Distance to shore is a parameter that affects specially the cases than rely on pipelines or cables, since the material cost influences greatly the final investment. This is easily visible in the Figure 26 where the steeper lines correspond to the inland production method and the LOHC transportation by pipeline. This provides a key insight, which discards these methods when distances are above 100-150 km in comparison with the other alternatives. Also, higher distances represent more complexity in terms of installation. Specially interesting is the case of LOHC transportation by pipeline since, even offering smaller diameters for the same amount of transported hydrogen, it represents huge variations in the prices from 5-500 km. This is due to the already explained fact that this method needs a return pipe to transport the organic carrier back to the platform, doubling therefore the price. The O_2 transportation by pipelines also produces these methods to be less competitive in larger distances, due to more installation and material costs.

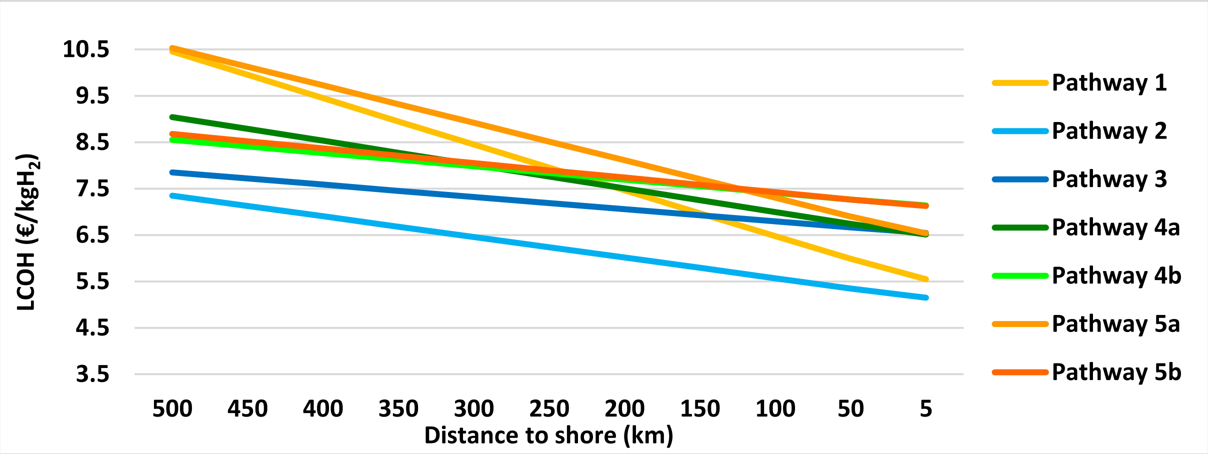

Figure 26 LCOH (€/kgH_2) sensitivity on distance to shore (km). (Pathway 1 - DC Electricity; Pathway 2 - H_2 Compression; Pathway 3 - H_2 Liquefaction; Pathway 4a - NH_3 Pipeline; Pathway 4b - NH_3 Vessel; Pathway 5a - LOHC Pipeline; Pathway 5b - LOHC Vessel)

Vessel transportation methods offer a more stable price line, however CH_2 never beaten in LCOH terms when distances are up to 500 km. In spite of this fact, other variables should be considered, since technical complexity of a 300-500 km pipeline could be a big drawback that needs to be assessed by the project developers and depends on many factors.

Costs for the inland production case rise from 5,99 to 10,43 €/kgH_2 in the range of 50-500 km, while LOHC transportation by pipeline (Pathway 5a) increases from 6,90 to 10,53 €/kgH_2 due to the presence of an extra pipeline for the toluene, turning these methods less competitive pathways for longer distances.

This analysis shows the potential of vessel use in these kinds of applications for long distance transportation of hydrogen, being not only cost-competitive but representing less technical complexity.

Table 32 Maximum cost increase in % due to distance to shore compared to baseline case. (Pathway 1 - DC Electricity; Pathway 2 - H_2 Compression; Pathway 3 - H_2 Liquefaction; Pathway 4a - NH_3 Pipeline; Pathway 4b - NH_3 Vessel; Pathway 5a - LOHC Pipeline; Pathway 5b - LOHC Vessel)

Pathway	1	2	3	4a	4b	5a	5b
LCOH increase	7,3%	3,7%	1,8%	3,4%	1,8%	5,3%	1,9%
LCOH reduction	74,6%	37,4%	17,8%	34,1%	17,7%	52,7%	19,4%

Electrolyzer efficiency improvement has an effect in many areas of the systems, mainly produced by a higher amount of H_2 produced, which incurs into higher sales, but also bigger size of the storage tanks, diameter of the pipelines, size of the boats, etc.

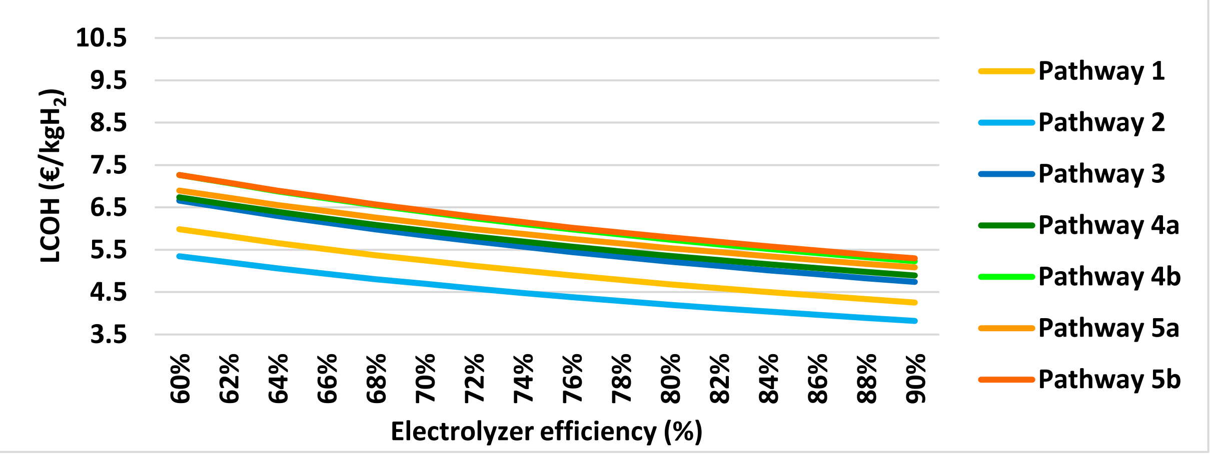

Figure 27 LCOH (€/kgH_2) sensitivity on electrolyzer efficiency (%). (Pathway 1 - DC Electricity; Pathway 2 - H_2 Compression; Pathway 3 - H_2 Liquefaction; Pathway 4a - NH_3 Pipeline; Pathway 4b - NH_3 Vessel; Pathway 5a - LOHC Pipeline; Pathway 5b - LOHC Vessel)

However, it is clearly visible that this variable is strongly beneficial for all the cases, achieving cost reductions between 26,3-28,9 % in all the cases (as presented in Table 33), being the lowest cost of 3,82 €/kgH_2 for the CH_2 transportation case (Pathway 2).

Table 33 Maximum cost reduction in % due to electrolyzer efficiency compared to baseline case. (Pathway 1 - DC Electricity; Pathway 2 - H_2 Compression; Pathway 3 - H_2 Liquefaction; Pathway 4a - NH_3 Pipeline; Pathway 4b - NH_3 Vessel; Pathway 5a - LOHC Pipeline; Pathway 5b - LOHC Vessel)

Pathway	1	2	3	4a	4b	5a	5b
LCOH reduction	28,9%	28,5%	28,8%	27,4%	28,0%	26,3%	27,1%

4.2.2 Sensitivity analysis for NPV

In the baseline scenario, it has been shown how NPV without O_2 sales would be negative because of the influence of **income taxes** on the economics of the project. Figure 28 shows the influence of this tax in the economic viability of the project when the selling cost of H_2 is equal to the LCOH and the O_2 is 100 €/tO_2.

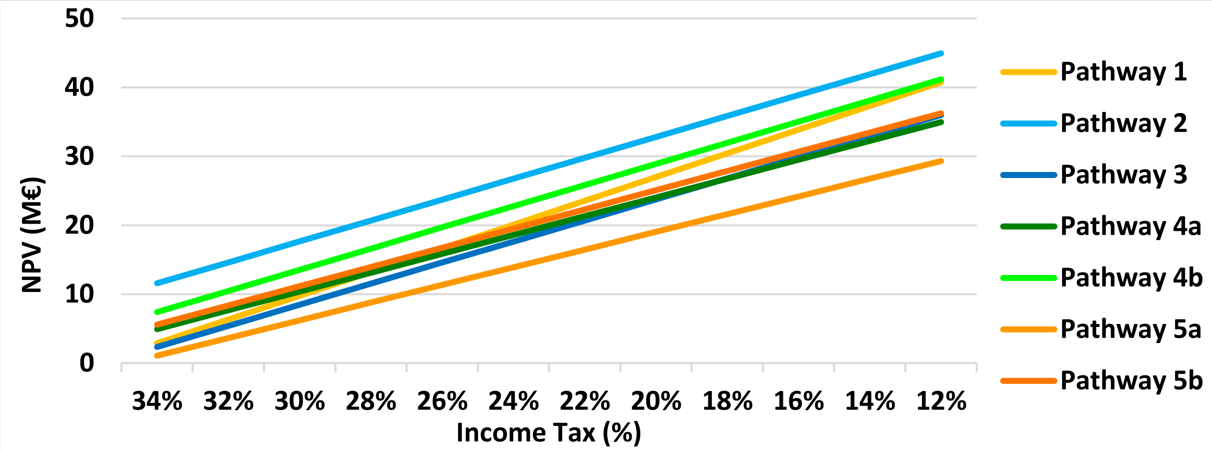

Figure 28 NPV (M€) sensitivity on Income Tax (%). (Pathway 1 - DC Electricity; Pathway 2 - H_2 Compression; Pathway 3 - H_2 Liquefaction; Pathway 4a - NH_3 Pipeline; Pathway 4b - NH_3 Vessel; Pathway 5a - LOHC Pipeline; Pathway 5b - LOHC Vessel)

A key insight from this analysis highlights how country-dependent the viability of such a project can be since higher income taxes will incur into higher costs of the H_2 sold or subsidies required.

Pathways 1,3 and 5a are those who show a higher sensitivity to the tax rates. These pathways are also those that represent higher initial investments, which is linked to the final NPV of the project. This higher influence of the tax rate in the final NPV is related to the dilution that CAPEX may have in the determination of the NPV. At lower rates, the discounted cash flows will represent a bigger share of the NPV, while at higher tax rates, these cash flows are shrunk, meaning higher influence of CAPEX in the final NPV.

The maximum NPV reduction/increase is shown for the tax rates of major markets in Table 34.

Table 34 Maximum cost reduction/increase in % due to income tax compared to baseline case. (Pathway 1 - DC Electricity; Pathway 2 - H_2 Compression; Pathway 3 - H_2 Liquefaction; Pathway 4a - NH_3 Pipeline; Pathway 4b - NH_3 Vessel; Pathway 5a - LOHC Pipeline; Pathway 5b - LOHC Vessel)

Pathway	1	2	3	4a	4b	5a	5b
NPV increase	51,0%	37,0%	51,5%	45,4%	42,5%	53,9%	44,4%
NPV reduction	89,3%	64,7%	90,1%	79,5%	74,4%	94,4%	77,7%

4.3 Assessment of scenarios

The results for the two scenarios are presented next.

4.3.1 Scenario 1

As explained in Section 3.5.1, this scenario explores a future where H_2 technology development is only driven by technology advances. Both H_2 and offshore wind development follow the projected estimations. For this scenario the three variables that have been modified, in order to understand their combined effect in a future where the aim to reach net zero targets boosts the innovation and the technological adoption. Improving not only the costs due to a scale up but also the performance because of technological developments. The selected values are stated in Table 35.

Table 35 Selected values for Scenario 1

Scenario	Baseline case	Scenario 1
LCOE (€/MWh)	50	20
Electrolyzer cost (€/kW)	990	585
Electrolyzer efficiency (%)	60	68

Being this said, the LCOH for Scenario 1 is shown below in Figure 29.

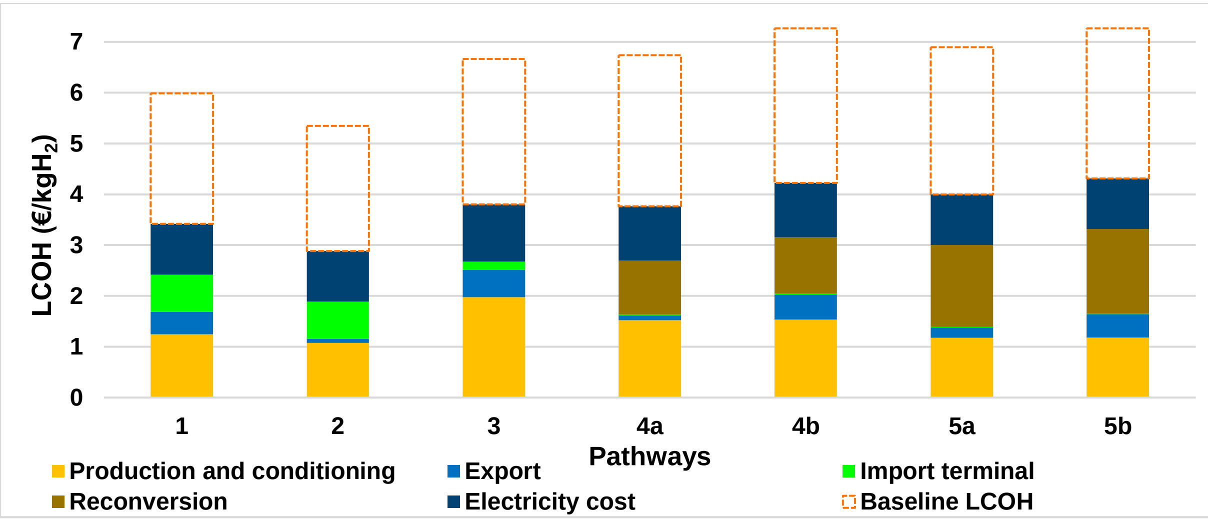

Figure 29 LCOH (€/kgH$_2$) breakdown for Scenario 1. (Pathway 1 - DC Electricity; Pathway 2 - H_2 Compression; Pathway 3 - H_2 Liquefaction; Pathway 4a - NH_3 Pipeline; Pathway 4b - NH_3 Vessel; Pathway 5a - LOHC Pipeline; Pathway 5b - LOHC Vessel)

These new LCOH are much lower than for the baseline case, opening possibilities for the introduction of H_2 in newer and bigger markets, as explained in Section 2.3. Table 36 shows the cost reduction compared to the baseline scenario for every pathway, being this between 40-46 %.

It can be observed that for pathways 1 and 2, the costs of storage at the import terminal add up a significant cost (Of 0,73 €/kgH$_2$). However, large scale storage of gaseous H_2 cost reduction is not expected to experience major advancements. Nevertheless, two situations could erase this problem. Firstly, the connection to the gas grid, with possibilities to inject all the produced H_2; secondly, the possibility of storing the H_2 in a nearby geological formation, where storage costs are much lower and capacities are vast.

An interesting fact of this case is that the production and conditioning of H_2 gains more weight compared to the LCOE than in the baseline case. This is because some of the costs included in the former are not reduced in this scenario, such as the array cables, the platforms or the conversion processes equipment (Liquefaction, NH_3 converter or LOHC hydrogenation units). The same fact applies to Pathways 4a/b 5a/b, where the reconversion step is the process that contributes with a higher share to the final LCOH.

Table 36 LCOH in Scenario 1 and cost reduction compared to baseline case. (Pathway 1 - DC Electricity; Pathway 2 - H_2 Compression; Pathway 3 - H_2 Liquefaction; Pathway 4a - NH_3 Pipeline; Pathway 4b - NH_3 Vessel; Pathway 5a - LOHC Pipeline; Pathway 5b - LOHC Vessel)

Pathway	1	2	3	4a	4b	5a	5b
Baseline LCOH (€/kgH$_2$)	5,99	5,35	6,66	6,74	7,27	6,90	7,27
Scenario 1 LCOH (€/kgH$_2$)	3,42	2,88	3,80	3,76	4,22	4,00	4,31
Cost reduction (%)	43%	46%	43%	44%	42%	42%	41%

The resulting prices are those for the pure H_2 after the import terminal. Any additional cost coming from the distribution or fueling station is not considered. While a general estimation for the fueling stations cost increase in the next years would be 1 €/kgH$_2$ [4], distribution depends more on the distance and the H_2 offloading method, since, for example, LOHC are much cheaper to transport than CH_2. At this point, it is already possible to assess where this green H_2 could be competitive in a net zero future.

Without consideration of additional costs due to distribution and fueling inland, Pathway 2 could address a demand of between 83-167 Mt of H_2 opening up a market of 449 billion € if H_2 were to be sold at 2,88 €/kgH$_2$ (See Table 9). In all the pathways, current demand of H_2 is overpassed creating market opportunities of between 229-449 billion €, for Pathway 1. The rest of the pathways are slightly behind these two mentioned options, rounding market opportunities of 299 billion € with costs between 3,76-4,31 €/kgH$_2$.

The complete reduction of the above-mentioned cost of 0,73 €/kgH$_2$ of gaseous H_2 storage could bring the prices down in Pathway 2 to 2,13 €/kg, reaching a market potential of around 749 billion €. Generating a market size of 333 Mt of H_2. Pathway 1 would drop to 2,69 €/kgH$_2$, a spot in which a market gap of 449 billion € is achievable.

As explained in Section 2.3, blue H_2 is currently produced at a cost of 2,3 €/kgH$_2$ in Europe or 1,5 €/kgH$_2$ in the US. Therefore, achieving costs below this number, can help to decarbonize H_2 at a higher pace than expected.

4.3.2 Scenario 2

This scenario follows the EU Hydrogen Strategy which aims to boost the innovation and the technological adoption of H_2 technologies. Improving not only the costs due to a scale up but also the performance because of technological developments. The abovementioned values are shown again for a better follow-up in Table 37.

Table 37 Selected values for Scenario 2. (Pathway 1 - DC Electricity; Pathway 2 - H_2 Compression; Pathway 3 - H_2 Liquefaction; Pathway 4a - NH_3 Pipeline; Pathway 4b - NH_3 Vessel; Pathway 5a - LOHC Pipeline; Pathway 5b - LOHC Vessel)

Scenario	Baseline case	Scenario 2
LCOE (€/MWh)	50	20
Electrolyzer cost (€/kW)	990	200
Electrolyzer efficiency (%)	60	82

For these values, the LCOH results as indicated in Figure 30:

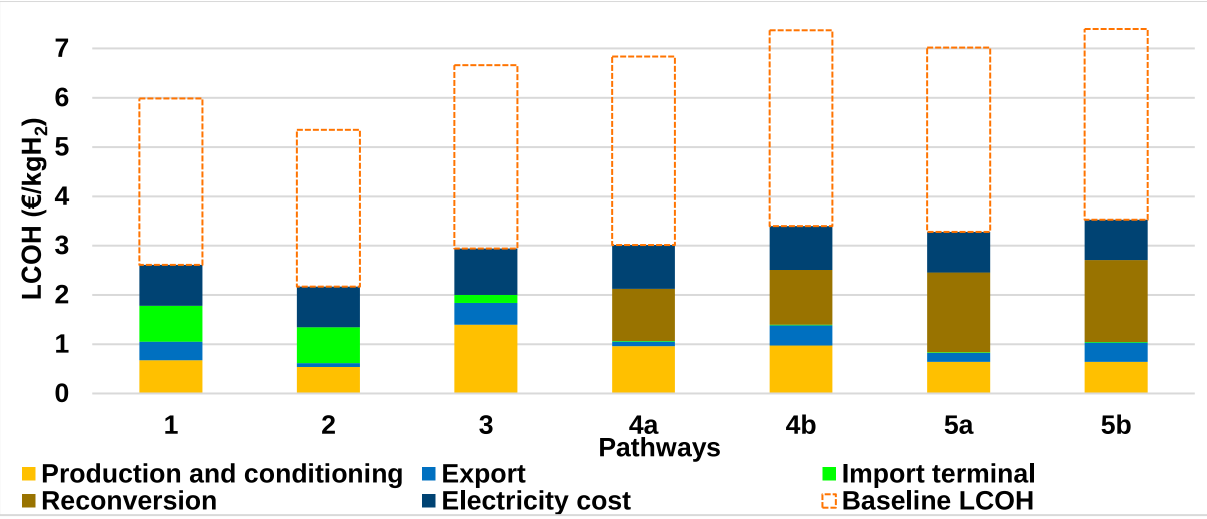

Figure 30 LCOH (€/kgH_2) breakdown for Scenario 2. (Pathway 1 - DC Electricity; Pathway 2 - H_2 Compression; Pathway 3 - H_2 Liquefaction; Pathway 4a - NH_3 Pipeline; Pathway 4b - NH_3 Vessel; Pathway 5a - LOHC Pipeline; Pathway 5b - LOHC Vessel)

These low costs for H_2 production allow to envision where this technology can be in the medium term, reaching target costs much sooner than expected, addressing thus more sectors than what previously though. Public support, providing market signals and security for the investments will drive H_2 to cost reductions of 53-59 % in all the studied pathways, achieving prices as low as 2,17 for Pathway 2, as seen in Table 38.

Table 38 LCOH in Scenario 2 and cost reduction compared to baseline case. (Pathway 1 - DC Electricity; Pathway 2 - H_2 Compression; Pathway 3 - H_2 Liquefaction; Pathway 4a - NH_3 Pipeline; Pathway 4b - NH_3 Vessel; Pathway 5a - LOHC Pipeline; Pathway 5b - LOHC Vessel)

Pathway	1	2	3	4a	4b	5a	5b
Baseline LCOH (€/kgH_2)	5,99	5,35	6,66	6,74	7,27	6,90	7,27
Scenario 2 LCOH (€/kgH_2)	2,61	2,17	2,94	2,92	3,29	3,16	3,40
Cost reduction (%)	56%	59%	56%	57%	55%	54%	53%

These costs round between 2,17 and 3,40 €/kgH_2 being able to address, in the best cases, more than 333 Mt of green H_2 demand, generating a market opportunity of 749 billion €. However, significant improvements can be achieved in Pathways 1 and 2. Here, if demand can be co-located nearby the import terminal, as suggested by the EU, the need for gaseous storage would be eliminated. Therefore, the aforementioned cost reductions of around 0,73 €/kgH_2 would happen. Lowering the costs to 1,88 1,44 €/kgH_2 respectively. The achievement of costs lower than 1,8 €/kgH_2 would open a market opportunity of 1.199 billion €, consuming at least 666 Mt of H_2 and becoming cheaper than blue H_2.

4.4 Assessment of pathways

In order to have a good understanding of the potential that every pathway offers, this section aims to combine the main economic indicators with the technical complexity offered by the different installations. Also, it includes the technology readiness level, which, even if was not analyzed before, will be analyzed in terms of the existing project, both in demonstration or commercial stages, according to bibliography. [128]. Table 39 summarizes these indicators:

Table 39 Economic and technical assessment of pathways. (Pathway 1 - DC Electricity; Pathway 2 - H_2 Compression; Pathway 3 - H_2 Liquefaction; Pathway 4a - NH_3 Pipeline; Pathway 4b - NH_3 Vessel; Pathway 5a - LOHC Pipeline; Pathway 5b - LOHC Vessel)

Pathway		1	2	3	4a	4b	5a	5b
LCOH (€/kgH_2)	Baseline	5,99	5,35	6,66	6,74	7,27	6,90	7,27
	Scenario 1	3,42	2,88	3,80	3,76	4,22	4,00	4,31
	Scenario 2	2,61	2,17	2,94	2,92	3,29	3,16	3,40
Complexity		Low	Low	Medium	High	High	High	High
TRL		9	6	6	5	5	5	5

The technology readiness level is considered to be limited by the weakest element in the chain. Hence, in Pathway 1, every single step has been demonstrated successfully at a real environment, from the offshore substation to the PEM H_2 production and storage. Pathways 2 and 3 steps are mainly at a TRL 9, since all of them are widely known processes that have been done for years. However, the offshore production of H_2 has not been successfully performed yet. The aforementioned PosHYdon project will be the first one trying to demonstrate the possibility of operating a PEM electrolyzer in an offshore platform. In Pathways 4a/b and 5a/b the main constraints are the reconversion processes, since their validation for large scale systems has not been proved yet. However, as mentioned above in this project, two projects which aim to export H_2 announced to be in operation after 2024 (Brunei and Saudi Arabia) will rely on LOHC and NH_3 respectively. Therefore, it seems that the challenges posed will not represent a major obstacle.

A common challenge of these pathways is the unfamiliarity with how these systems will behave in offshore platforms. Conversely, know-how from the petroleum industry can be imported since very similar installations have been done offshore for more than 40 years.

Complexity of the different pathways refer to the number of conversion steps and difficulties that these can attach. In Pathways 1 and 2 for example, the process is straightforward, incurring into few steps and therefore limiting the uncertainties and chances of errors. On the contrary, Pathways 4a/b and 5a/b include conversions and reconversions, adding more intermediate processes that can represent higher risks in the development of the project. Pathway 3 is considered to offer medium complexity, since the liquefaction of H_2 will increase the steps at the offshore platform, while keeping the rest of the supply chain simple.

4.5 Limitations of the study

The lack of large scale H_2 projects make that most of the values for new technologies stated in this work are theoretical and have not been demonstrated in systems as big as the one covered in this topic. Conversely, technical difficulties could arise when scaling up electrolyzer systems, or the combination of these with H_2 conversion methods into NH_3 or LOHC.

Further knowledge is required in order to see how systems that were never tested offshore will perform in such conditions. However, Oil&Gas activities are similar and have been taking place offshore for many years.

The area footprint of the process equipment for all the scenarios has been considered to be similar to that for the electric substation, not incurring into higher costs for the offshore platform that the one considered for an offshore substation structure. Even though PEM systems, Haber-Bosch reactors or LOHC hydrogenation units are not highly space demanding, the addition of storage or facilities for workers could have an effect on the final cost.

Remote control of the facilities is assumed for every pathway, following the working principles of offshore substations, however, it would be possible that for more complex processes, presence of workforce is needed, especially in the cases that include vessel transportation. O_2 storage at the offshore platforms could require large volumes which have not been considered to be an issue. In the case that O_2 had to be liquefied in order to increase its density, it would incur into additional costs.

Regarding the impacts of COVID-19, the slow down or acceleration on investments specific to H_2, such as the incentives to governments or posterior outbreaks that may occur are not considered in this report due to the short time frame since the outbreak happened. However, it is expected that governments will invest more in renewables and H_2 in order to promote a sustainable recovery from the crisis [129].

Reconversion processes are still not commercial and, therefore, its consideration as large-scale processes attach some risks both in TRL and cost projections, since the number of available sources is limited. However, recently announced projects that will enter into operation before 2025 will work with NH_3 and LOHCs at large scale as H_2 carriers [16] [130], therefore, these technologies are assumed to be feasible.

The way the study is considered, covering costs only up to the import terminal does not assess the whole H_2 supply chain. Therefore, the results must be carefully used since costs that can seem higher such as those for LOHC or NH_3 would result in bigger savings in distribution stages.

5. Conclusions and future work

The need of H_2 irruption in the global energy system is significant. H_2 is one of the most promising solutions for the decarbonization of many sectors, an enabler for the 100 % presence of renewables, storing large quantities of energy over seasonal periods and acting as a feedstock for applications that currently use grey H_2. Coupling offshore wind with H_2 production can bring several benefits to both technologies. H_2 can be directly coupled to an electricity source that offers good capacity factors without paying grid access feeds or taxes if the H_2 is dedicated. Moreover, offshore wind potential will be untapped when combined with H_2, reaching areas with vast energy resources that will help to decarbonize the economy. The introduction of novel concepts, taking the H_2 generation offshore offers great opportunities such as cost reductions or much more spots to exploit. However, challenges are big and H_2 handling difficulty poses several questions in terms of transportation and storage methods.

Despite the importance of improvements in the H_2 technologies cost, the main driver of cost reductions will be the LCOE, expected electricity prices of 20 €/MWh, without transmission assets, will enable the green H_2 deployment.

Among the studied pathways, the use of pipelines to transport H_2 seems to be the best solution, providing a LCOH of 5,35 €/kgH_2 for the baseline case, whereas it has the potential of being as low as 2,17 €/kgH_2 if the EU support is successful and achieves its targets, this pathway represents the lowest H_2 LCOH in all the cases. However, careful assessment of distance and sea depth needs to be considered along the development of the project since it has great impact on the cost but overall, in the technical complexity. The energy input in this pathway is 0,46 MWh/MWhH_2, being one of the less energy intensive methods, due to less conversion steps.

Inland production is a promising possibility only if the windfarm is relatively close to land, if not, prices increase rapidly due to the high costs of the wires, breaking even with the rest of the pathways, except from Pathway 2 (CH_2 case), when the distance from land exceeds 150-250 km. The LCOH offered by this pathway is one of the lowest, 5,99 €/kgH_2 at the baseline case, while it decreases up to 2,61 €/kgH_2 in the EU support case. This case has an energy input of 0,45 MWh/MWhH_2.

Inland production and CH_2 transportation would be of great interest if there was a large consumer close to the import terminal. This would reduce the need of gaseous H_2 storage, which is very expensive, adding around 0,73 €/kgH_2. The possibility of avoiding it by selling the H_2 directly would bring down costs to around 1,44 €/kgH_2 in the H_2 pipeline transportation case (Pathway 2). At this cost, and with a constant consumer such as a natural gas grid, there is an option to erase the intermediate storage and therefore achieving competitive prices. Moreover, the natural gas grid would benefit from the inclusion of a green molecule, reducing the CO_2 intensity. However, blending H_2 in the grid is more likely to be a bridge application, either towards a 100 % H_2 network or in order to ease the H_2 deployment. This is because blending H_2 diminishes the efficiency and the value of H_2.

Vessel transportation of H_2 or H_2 carriers does not outcompete the pipeline use unless distances are greater than 150-250 km. Therefore, this solution would be relegated to cases where the H_2 is to be transported long distances, or even between countries or continents. These methods are specially affected by the offshore storage required in case the boats cannot access to the platforms due to not suitable weather conditions. Therefore, solutions for this offshore storage would increase the competitiveness of these pathways.

Liquefaction of H_2 is an interesting option, it offers the lowest costs among all the vessel transportation studied pathways. However, its competitivity could be affected by cost reductions in the reconversion processes of the H_2 carrier pathways since these are more prone to suffer cost reductions and energy efficiency improvements due to their lesser maturity. NH_3 and LOHC for the transportation of H_2 are still under planning stages while liquefaction is a well-known process. Its LCOH in the baseline case is 6,66 €/kgH_2, while it would drop to 2,94 €/kgH_2 in the best case. However, both NH_3 and LOHC vessel transportation cases, (Pathways 4b and 5b) offer better behavior for longer transportation distances, and even if the costs are higher for all the assessed factors, these should be kept in mind due to the aforementioned possibility of cost reductions.

Baseline case costs for NH_3 and LOHC vessel transportation (Pathways 4b and 5b) are higher (7,27 €/kgH_2) while their cost reduction in the EU support scenario makes them more competitive, offering costs of 4,22 and 4,31 €/kgH_2 respectively. Moreover, larger molecules simplify the transportation, storage and distribution of H_2, offering benefits that are cannot be quantified in the scope of this project. Special consideration of the destination point is recommended for the selection of the offloading method, this is due to the possibility of cutting down the costs of reconversion by using waste heat (assumed as 0 €/MWh) compared against 50 €/MWh used for the costs of energy for the reconversion processes. This could reduce the LCOH in 0,49 €/kgH_2 and 0,88 €/kgH_2, achieving already better costs than LH_2 case (Pathway 3). Conversely, the energy requirements of the H_2 carriers pathways are higher, being of 0,91 MWh/MWhH_2 for the NH_3 cases (Pathways 4a/b) and 1,06 MWh/MWhH_2 for the LOCH (Pathways 5a/5b), where more energy is input than contained in the final product, being worth of noticing that the transportation method (pipeline or vessel) does not add up a significant energy expenditure compared to the rest of the process. In the H_2 liquefaction case (Pathway 3) the energy input is significantly smaller, being 0,62 MWh/MWhH_2.

Moreover, NH_3 and LOHC pathways could offer higher cost reductions and improved efficiencies due to their lesser maturity. They also represent less technological challenges due to higher knowledge of similar processes (LOHC are handled as oil) and more stable molecules. The choice of LOHC and NH_3 seems to be supported by the abovementioned projects that plan to export H_2 using these carriers [16] [130]. Eventually, NH_3 and LOHC transportation by pipelines (Pathways 4a and 5a) do not outcompete their homologue as pure H_2 and therefore they are not as appealing at first sight. Their costs in the baseline case are 6,74 and 6,90 €/kgH_2 or 2,92 and 3,16 €/kgH_2 in the best scenario, offering the same cost reductions as the vessel transportation case when reconversion is performed by using waste heat. As in the vessel transportation case, it is needed to bear in mind that larger molecules will simplify the distribution of H_2 for final consumers as well as the storage of H_2, requiring also less space. Conversely, the offshore platform would be more complex, posing a trade-off which will be project specific.

CH_2 transportation to land is the cheapest option in order to produce H_2 from offshore wind turbines. However, pure H_2 transportation represents additional challenges at a storage and distribution level. These need to be assessed in order to select this option as the offloading method. Industrial clusters near the ports, the ports themselves or natural gas pipelines where H_2 can be blended would be the enablers for this offloading method. When CH_2 is not a feasible option due to large distances from the offshore plant or large distribution costs inland, it seems that NH_3 will be likely the most recommendable offloading method. As seen above, it represents high cost reduction potential, while it guarantees a stable and well-known handling. Also, it can be directly consumed by the end-users, without the need of reconverting back to H2 for a wide range of applications. In addition, Haber-Bosch is a very bankable technology and can be scaled up easily, while for example LOHC methods still have their large-scale performance.

A key insight of this work is that what could seem a waste product such as O_2 can improve greatly the economics and viability of the project, increasing the NPV by more than 150 M€ without major complexities in the infrastructure. However, it is also important to keep in mind that most of the H_2 projects will be led by utilities or oil & gas companies as major stakeholders, therefore, the partnering with industrial gases providers will be key in order to get benefits from a market that is not within the scope of these businesses.

CO_2 prices are an important factor that determines the competitiveness of green or blue H_2. Prices above 45 €/tCO_2 are necessary to bring more opportunities to the market. Moreover, CCUS will likely be more cost efficient than green one in the next years. However, CCUS needs storage locations close and its sustainability in the long term is impossible.

Repurposing of oil & gas infrastructure is possible, in these cases, existing pipelines can be determinant in order to choose what offloading method will be used. As seen, if pipelines can resist H_2 diffusivity and embrittlement, CH_2 transportation is the most suitable option. In the case that these pipelines require less aggressive compounds, LOHC seem to be the most promising alternative both because of its lower cost than NH_3 (which is supported by higher cost reductions in the future) and by the suitability for inland H_2 distribution.

Dedicated offshore H_2 production is possible, providing H_2 at competitive prices. Moreover, it benefits from direct access to many of the biggest consumption areas for H_2 in the next years, such as ports and many industrial clusters. Besides this, around 40 % of the world population lives in coastal areas, therefore being easier to deliver this H_2 without major increases due to distribution costs.

Complementary work to this thesis in order to understand the full possibilities of coupling H_2 and offshore wind is recommended to be focused on the search of additional incomes such as the full market of O_2, the study of direct coupling of electrolyzers in the wind turbines platforms in order to reduce costs and complexity and the environmental effects of this concept, including an assessment on the CO_2 footprint of this green H_2 over its entire lifecycle. Also, determining where petroleum industry know-how can help to boost the implementation of the mentioned pathways by figuring out what processes are similar and which are the technical complexities of these and how to overcome them.

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